NTNU | Norwegian University of Science and Technology

TPG4245 – Production wells

Autumn Semester 2022

Information

- Lecturer: Assoc. Prof. Milan Stanko (Production Tech) (milan.stanko@ntnu.no). Office 510.
- Teaching assistant: Ikhsan Aulia (auliain@stud.ntnu.no)
- Lecture schedule
  - Tuesdays, 10:15-12:00 (theory and exercises) – P12
  - Thursdays, 08:15-10:00 (theory and exercises) – P12
  - Thursdays*, 11:15-12:00 (TA/Exercises) – P10
- Course description

***EXCEPT First week**

Course scope

- Production performance of wells and gathering systems.
- Addresses the integrated production system, inflow, tubing and pipe flow, and technologies such as artificial lift
- Developing skills for planning, operating, monitoring, troubleshooting and controlling production of oil and gas production systems

Goals of the course

At the end of the course, the student should be able to:

- Perform common production engineering calculations
- Understand the fundamentals of petroleum production engineering
- Describe the main components of the production system, the most common well completions, artificial lift methods and configurations of production systems
- Describe, understand and explain the functionality of the main components of a production system
- Understand the factors and drivers involved in the planning and operation of oil and gas wells

Course content

- Introduction (well layout, production engineering domain)
- Flow equilibrium
- Inflow performance relationship
  - Undersaturated Oil
    - Radial and horizontal wells
    - Water coning
  - Dry Gas
    - High velocity flow
  - Saturated oil
- Choke performance
- Tubing performance
  - Dry Gas flow
  - Tubing size considerations
  - Multiphase flow of oil, gas and water
- Artificial lift
  - Gas lift
  - Electric submersible pump
- Temperature calculations in wellbore

Course scope

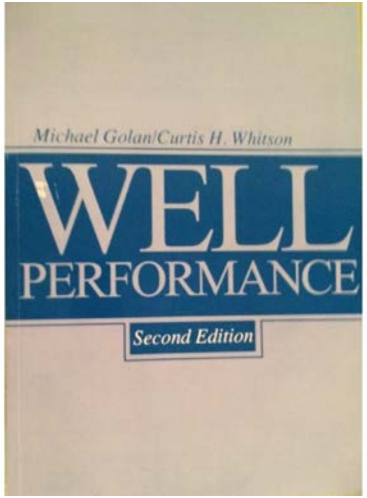
- Practical SI units only (bar, m3), not field units.
- Little on the structural and completion part, e.g. design, material selection
  - Completion tools, technology and procedures may vary between different vendors and companies
- Not all models and topics will be covered - Focus on the fundamentals

Information

- Lectures until 24 November
- Consultation time: preferably after class. Try to make an email appointment.
- Reference group – **any volunteers?**
  - Everyone can provide feedback using the anonymous comment box (in blackboard)
- **Use Blackboard to navigate the course**
  - Use the forum for Q&A
  - For group deliveries: Join a group before delivering the exercise (even if group consists of only one person!!)

Reference material

- Milan's Compendium
- Book: Well performance (Golan and Whitson)
- Other relevant material, e.g. articles, Excel files, notes, links, will be provided or mentioned in the videos



Other

- Production wells compendium (Asheim)
- Book Nodal analysis of Oil and Gas production Systems, (Jansen)

Evaluation

- 100% «written» school exam
  - Digital exam in Inspera, no written/handwritten material allowed (equations will be provided in the exam papers)
  - Previous years exams
  - Make it nice, easy to understand and follow. When provided, use the Excel template

Evaluation

- Mandatory assignments
  - All assignments must be **approved** to get access to the exam
  - All assignments must be delivered in Blackboard by the deadline
  - Some assignments will be discussed in class
  - Groups of up to 3 people may be allowed for some assignments
  - Video exercises are part of the assignments
  - Nr. of assignments is not yet known
  - **Let me know early if there is a deadline conflict with other courses**

Teaching

- Flipped classroom
  - Participants watch by themselves pre-recorded videos (ca 15-40 min) (on Youtube).
    - There are exercises in the videos
  - Live classes every week
    - Discussing theory, exercises, tutorials on software, Q&A, advanced topics

How to watch the pre-recorded videos

- Watch the entire video (can be watched at 1.5-2x speed)
- At certain time stamps (**or at the end of the video**), the videos might have embedded links to other relevant videos and material
- Pause when needed. Try to summarize what was presented with your own words. Take notes.
- DO THE EXERCISES BY YOURSELF
- Read the additional material provided, if any

Teaching - streaming

Fysisk tilstedeværelse for studenter ved Fakultet for ingeniørvitenskap fra høsten 2022

Etter en lang periode med koronatiltak er vi nå i en normalfase for undervisning og tilstedeværelse på campus. Fysisk oppmøte har en stor betydning for det psykososiale læringsmiljøet og trivsel blant studentene. Et godt psykososiale læringsmiljø og trivsel bidrar også til mindre frafall.

I løpet av vårsemesteret har vi opplevd manglende oppmøte i forelesninger som gjennomføres fysisk. Manglene oppmøte i undervisningen gjør det vanskeligere å følge opp det pedagogiske opplegget, og diskusjoner og samarbeid blir vanskelig å gjennomføre. I tillegg øker risikoen for faglige hull blant studentene noe som kan gi dårligere gjennomføringsevne.

Fra studiestart høsten 2022 blir forelesninger og undervisning primært gjennomført fysisk på campus for studenter ved Fakultet for ingeniørvitenskap. Studentene skal hovedsakelig være til stede i forelesningssalen eller i klasserom og verksted.

Hovedregelen er at vi ikke strømmer undervisningen.

Teaching – recording?

Course progress overview – Excel file

Tools

Primary:

- Excel (VBA)
- Pipesim (SLB) or Prosper (PETEX) – Computer lab P2

Secondary:

- Hysys (Aspentech) – farm.ntnu.no
- Python (Jupyter Notebook) – e.g. using Google Colaboratory

Questions?

COMPLETION BITE: WELLHEAD ARCHITECTURE

The wellhead has the following main functions:

- Provides structural support (suspension point) for all casings and tubing strings. It transfers all loads to the ground through the conductor.

- It seals off each annulus at the top (at the bottom such seal is achieved by cementing). This is to avoid leakages and to avoid that an outer casing, of a smaller pressure rating, will be exposed to full reservoir pressure and therefore fail.
- Provide a connection point (interface) with the BOP and the Christmas tree.
- Provide annulus access and monitoring.

The procedure to deploy a wellhead during onshore drilling operations is described next. The focus is primarily on the wellhead thus some details about the drilling process are omitted. The mechanical details of wellhead components are simplified for clarity.

1. Dig the cellar, drill the conductor hole (typically 36 in), run the conductor (typically 30 in and length 40 m-120 m) and cement it. Cut the conductor to the desired height (such that the production master valve will be easy to operate at ground level).

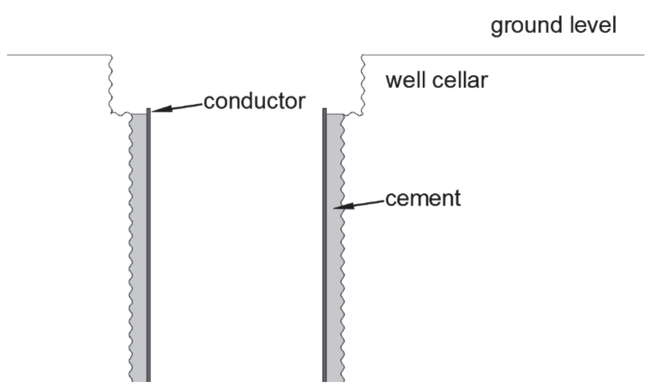


FIGURE 6-4. DEPLOYMENT OF THE CONDUCTOR

2. The BOP is placed, the surface casing hole is drilled (typically 24 in), the surface casing is run (typically 20 in) and cemented. The well is plugged and the BOP is removed. A baseplate is installed to transfer all loads to the conductor and the casing head. The casing head is attached to the surface casing by welding, threaded or with slips.

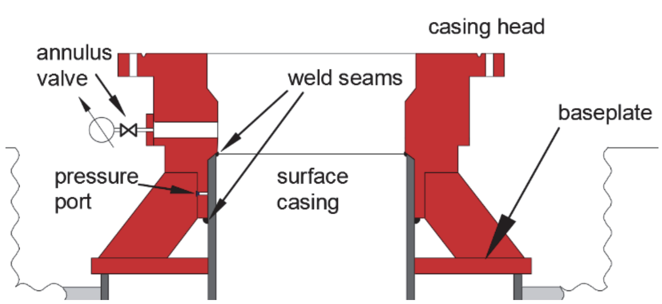


FIGURE 6-5. RUN OF THE SURFACE CASING AND CASING HEAD

The casing-casing head seal is positive-pressure tested from below with the pressure port.

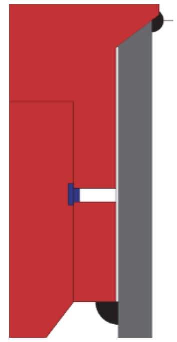


FIGURE 6-6. DETAILS OF THE PRESSURE PORT ON THE CASING HEAD TO MAKE THE PRESSURE TEST

3. The BOP is placed, the intermediate casing hole is drilled (typically 17 ½ in), the intermediate casing is run (typically 13 3/8 in) and cemented. The casing is hang on the casing head with the casing hanger (set of slips, wedge, elastomer and no-go shoulder).

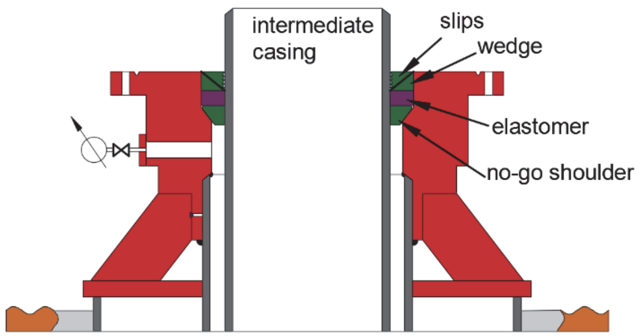


FIGURE 6-7. CASING HEAD WITH THE INTERMEDIATE CASING HANGED

The weight of the casing drives the slips down, presses the wedge that in turn squeezes the elastomer and activates the seal. Lockdown screws (that pass through the flange, not shown in the figure) are sometimes used to lock the upper part of the casing hanger and avoid unseating if the casing experiences thermal expansion.

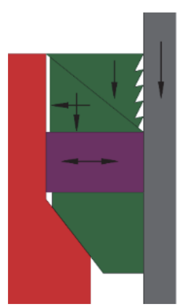


FIGURE 6-8. DETAILS OF THE CASING HANGER (SLIPS AND SEALS)

The casing hanger can also be screwed, instead of using slips (also known as mandrel-type hanger).

A negative pressure test is performed to ensure the casing hanger seal has been set properly.

4. The well is temporarily plugged, the BOP is removed and the casing spool for the intermediate casing is installed (flanged). The casing hanger seal and the gasket are positive-pressure tested from above using the pressure port.

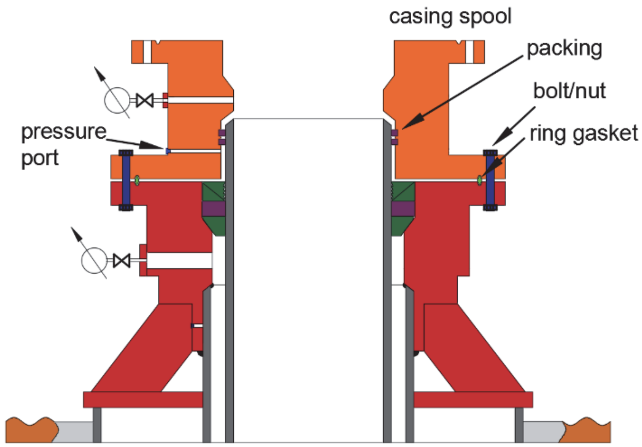


FIGURE 6-9. INSTALLATION OF THE CASING SPOOL TO THE CASING HEAD

Steps 3 and 4 are repeated as many times as number of intermediate casings are planned for the well.

5. After all casings are hanged on the wellhead, the tubing head is bolted to the last casing spool. The tubing is ran in hole and the tubing hanger is threaded to the last tubing joint. The tubing is then hanged on the tubing head. The seal of the tubing hanger is activated with the lockdown screws.

   Depending on the application, the tubing hanger may have a port for hydraulic lines (activation of SSSV, ICV), instrumentation line (pressure and temperature gauges), power lines (ESP), etc.

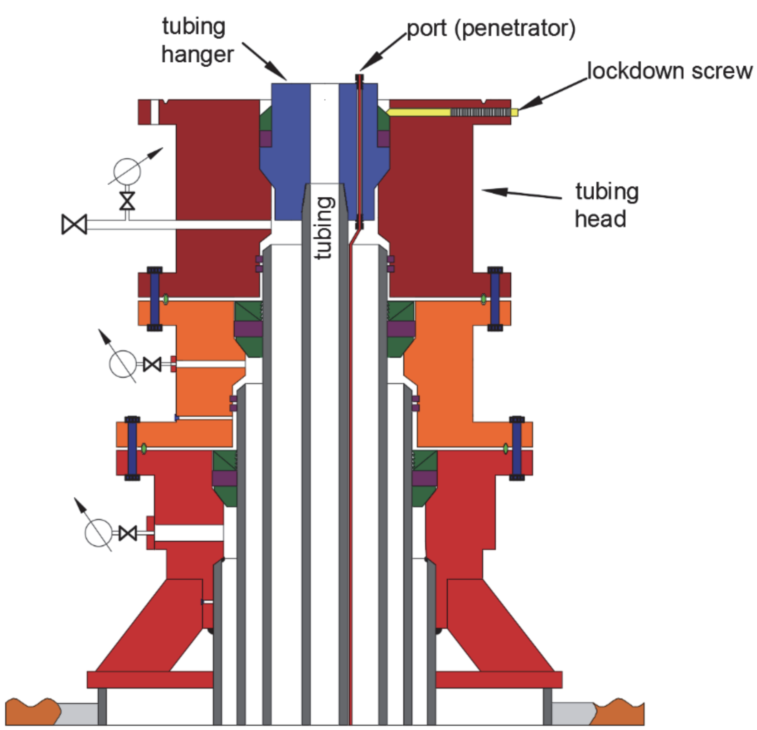
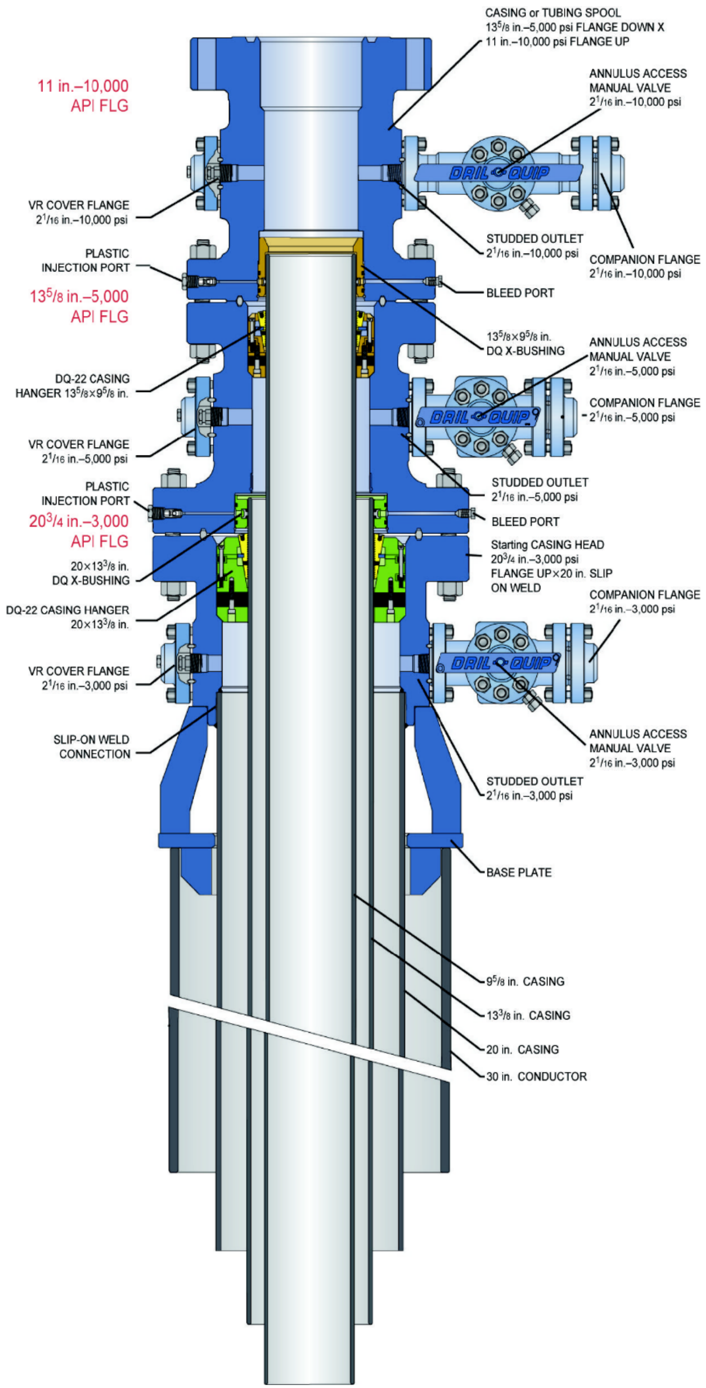


FIGURE 6-10. FINAL CONFIGURATION OF THE WELLHEAD

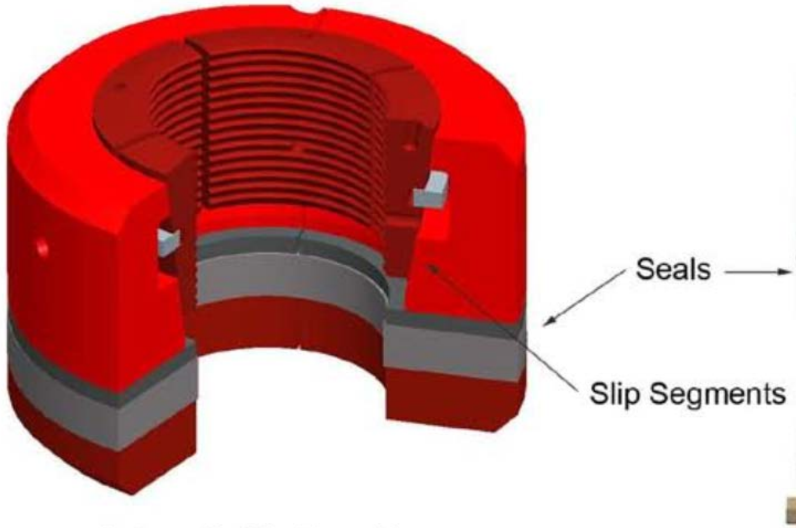
SAFETY STRATEGY FOR WELLS

- There must be two pressure barriers between the reservoir and the surface (in series)



11 in.–10,000 API FLG
VR COVER FLANGE $2^1/_{16}$ in.–10,000 psi
PLASTIC INJECTION PORT
$13^5/_8$ in.–5,000 API FLG
DQ-22 CASING HANGER $13^5/_8\times9^5/_8$ in.
VR COVER FLANGE $2^1/_{16}$ in.–5,000 psi
PLASTIC INJECTION PORT
$20^3/_4$ in.–3,000 API FLG
$20\times13^3/_8$ in. DQ X-BUSHING
DQ-22 CASING HANGER $20\times13^3/_8$ in.
VR COVER FLANGE $2^1/_{16}$ in.–3,000 psi
SLIP-ON WELD CONNECTION
CASING or TUBING SPOOL $13^5/_8$ in.–5,000 psi FLANGE DOWN X 11 in.–10,000 psi FLANGE UP
ANNULUS ACCESS MANUAL VALVE $2^1/_{16}$ in.–10,000 psi
STUDDED OUTLET $2^1/_{16}$ in.–10,000 psi
COMPANION FLANGE $2^1/_{16}$ in.–10,000 psi
BLEED PORT
$13^5/_8\times9^5/_8$ in. DQ X-BUSHING
ANNULUS ACCESS MANUAL VALVE $2^1/_{16}$ in.–5,000 psi
COMPANION FLANGE $2^1/_{16}$ in.–5,000 psi
STUDDED OUTLET $2^1/_{16}$ in.–5,000 psi
BLEED PORT
Starting CASING HEAD $20^3/_4$ in.–3,000 psi FLANGE UP×20 in. SLIP ON WELD
COMPANION FLANGE $2^1/_{16}$ in.–3,000 psi
ANNULUS ACCESS MANUAL VALVE $2^1/_{16}$ in.–3,000 psi
STUDDED OUTLET $2^1/_{16}$ in.–3,000 psi
BASE PLATE
$9^5/_8$ in. CASING
$13^3/_8$ in. CASING
20 in. CASING
30 in. CONDUCTOR
DRIL-QUIP
DRIL-QUIP
DRIL-QUIP

Mandrel-types



Automatic Slip Type Hanger

Class: 20220825

-First hour: we watched some videos about onshore and offshore (subsea) well construction, focusing on the wellhead.

- The well construction process: https://www.youtube.com/watch?v=z9eWHpEDRME
- A casing head https://youtu.be/mGqUvtbv9hs
- Installing BOP on a casing head https://youtu.be/HN4zmjBU4KY
- A X-mas tree https://youtu.be/kKzd47G1KVM
- Welding the casing head https://youtu.be/ja5mHG1vGiQ
- A casing hanger https://youtu.be/Phxlvd9z2RQ
- The drilling process in a subsea well (Dalia, Total) https://www.youtube.com/playlist?list=PL6FB4D0F75DF4FBED

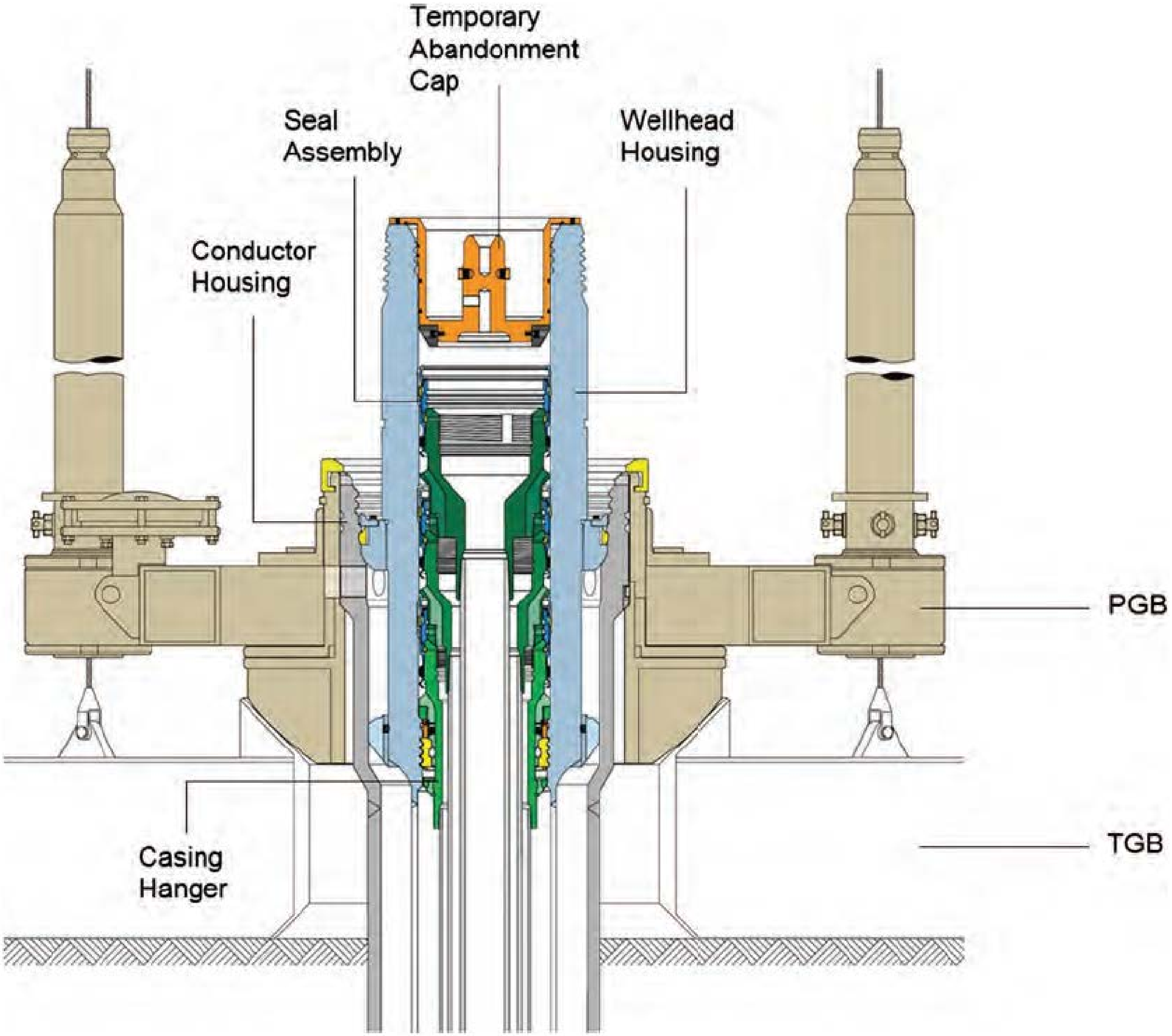


Figure 22-5 Typical $18^3/_4$-in.Subsea Wellhead System *(Courtesy of Dril-Quip)*

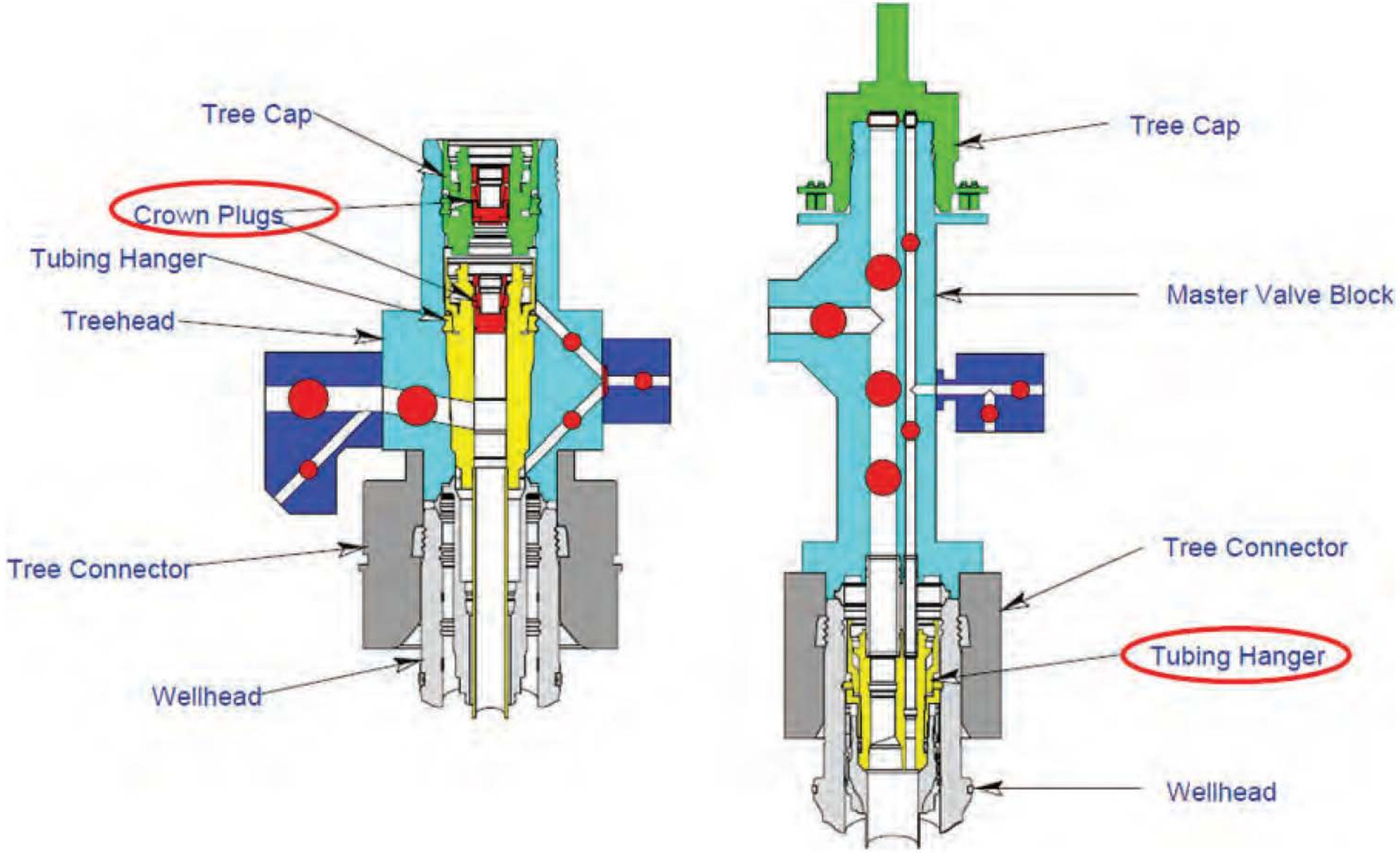


Figure 22-23 Differences between VXTs and HXTs *(Courtesy of Vetco Gray)*

-Second hour: Group activity as described in the pdf that follows.

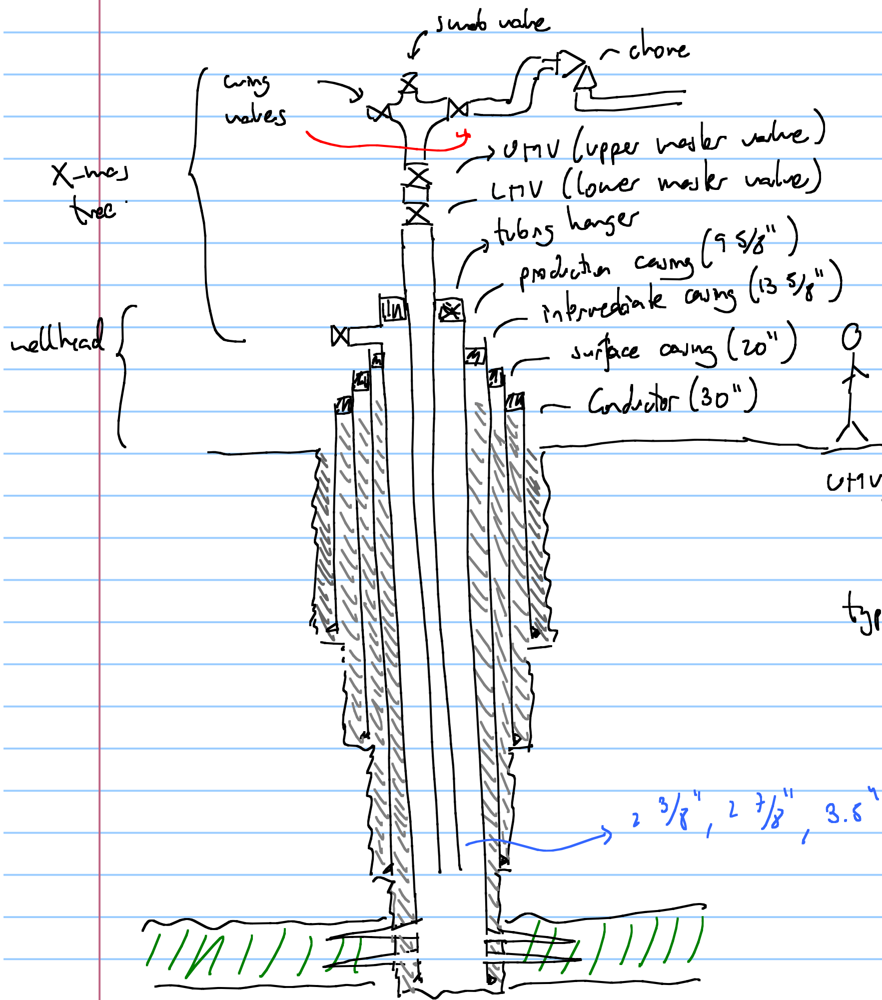
Class activity: Maximum allowable concentration of oil in water for discharge to sea

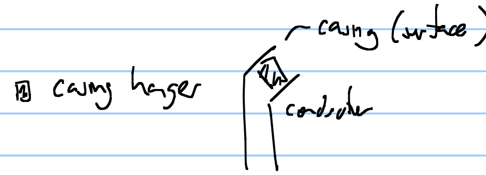
Offshore oil and gas facilities worldwide must keep the hydrocarbon content of discharges to sea below acceptable levels set by authorities. In the North Sea, for instance, the required average concentration of hydrocarbons discharged in effluents, such as produced water, must be below 30 mg/l (monthly average concentration).

Work in groups to conduct the following activities and answer the following questions

1. Read and understand the definition of ppm https://en.wikipedia.org/wiki/Parts-per_notation
2. Who is setting the limit of 30 mg/l in the Norwegian Continental shelf? (tip: do an internet search).
3. What is the average concentration of oil in produced water in the Norwegian Continental Shelf? (tip: do an internet search)
4. How is this requirement monitored and enforced? What are the reporting requirements the companies must comply with and to whom must they report? What happens if this is not achieved in a month? (tip: do an internet search)
5. Assume that an oil platform has been discharging produced water (around 500 000 stb/d) with an oil concentration of 10 ppm for 15 days in a month. If the water processing train suddenly has an emulsification problem, that causes the concentration of oil in produced water to increase to 60 ppm, for how many days will the platform be able to produce before shutting down to comply with the 30 ppm-in-a-month requirement?
6. As a follow-up to question 5, how many barrels of oil are released in a month by the oil platform discharging produced water (around 500 000 stb/d) with an oil concentration of 10 ppm.
7. Set a person in your group to be the controller. Ask this person to close their eyes or leave the room while preparations. Using the colorant and the syringe provided, and tap water, prepare two containers, one with a 30 ppm solution of colorant in water, and one with water only. Ask the controller to open their eyes. See if they can identify which one is the one with the colorant.
8. Find out what is the lethal concentration of oil in water for fish (tip: do an internet search)
9. Using the colorant and the syringe provided, and tap water, prepare a container, with the concentration found in task 8. Discuss the differences with the one prepared in 7.

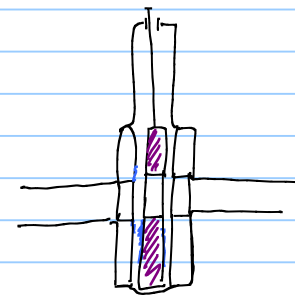
Video 01: Well layout and domain of production engineering



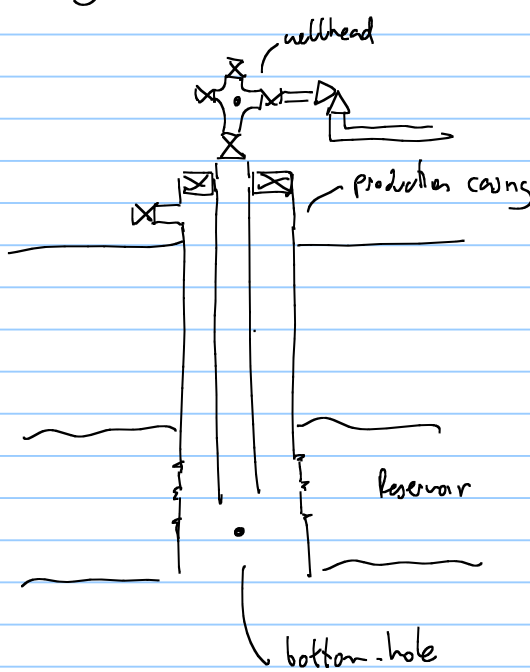


UMV, LMV, wing valves, swab valve on-off (fully open, fully closed)

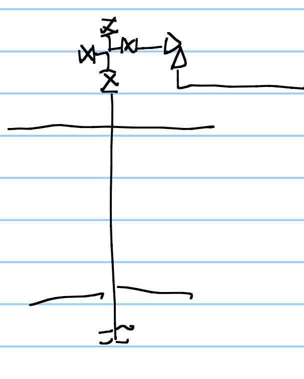
typically gate valves



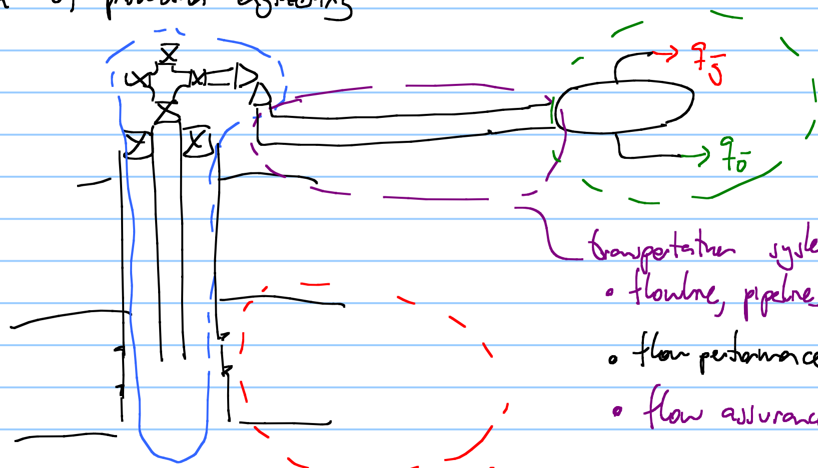
Drawing of a well



Line diagram



Domain of production engineering



processing facilities
- prepare reservoir streams to export (sales)

$\bar{o}$ standard conditions volumetric rate

stb/d

scf/d

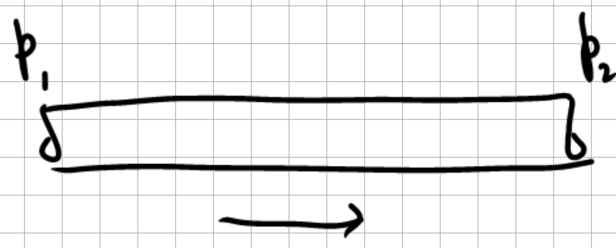
Sm^3/d

transportation system
- flowline, pipelines, network
- flow performance
- flow assurance

wellbore
- flow performance
  Δp, ΔT, v
- upper and lower completion
- structural performance
- Artificial lift

near well bore formation
- performance
- fluid distribution
- interface with wellbore
- damage
- stimulation

flow equilibrium

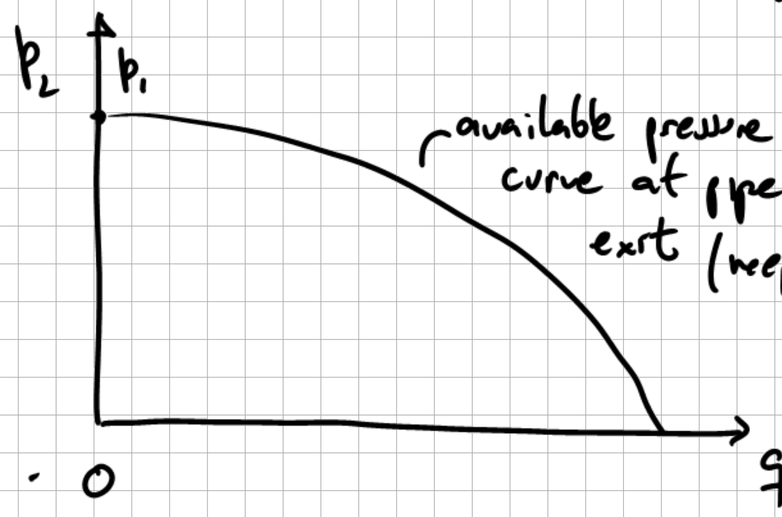


horizontal pipe

q volumetric rate circulating through pipe $[m^3/d]$

1) keep p_1 constant, vary q

$p_2 = p_1 - \Delta p_{pipe}(q)$



available pressure curve at pipe exit (keeping p_1 constant)

$q=0$

$\Delta p_{pipe}=0$

2) keep p_2 constant, vary q, compute p_1

$p_1 = p_2 + \Delta p_{pipe}$

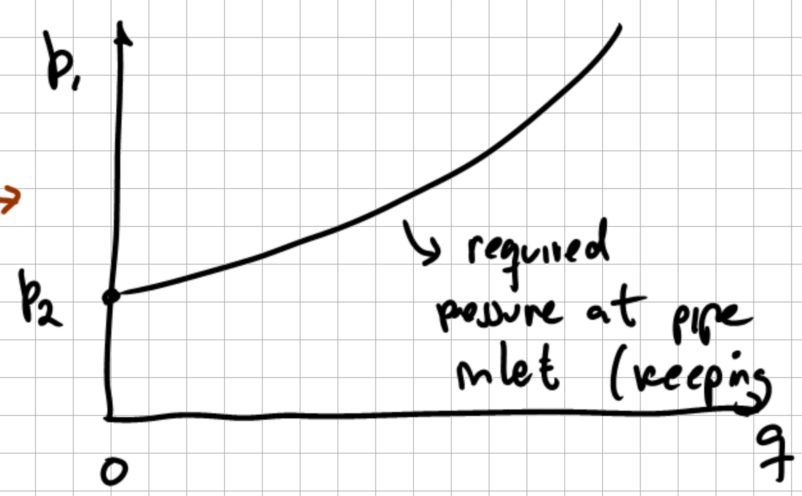
$q=0$

$\Delta p_{pipe}=0$

$q \neq 0$

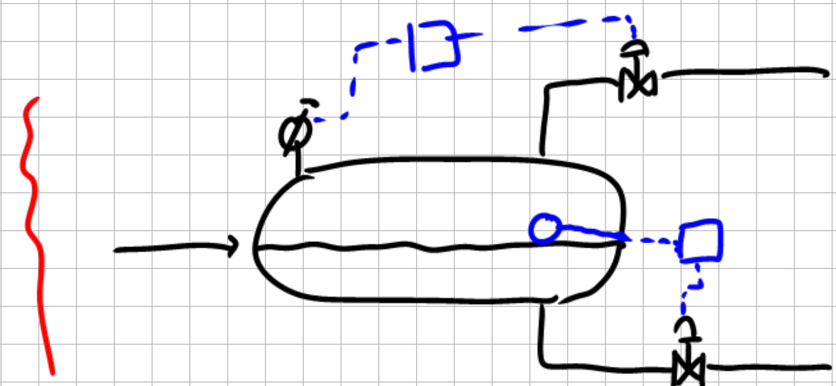
$\Delta p_{pipe} =$

$\uparrow q \quad \uparrow \Delta p_{pipe}$

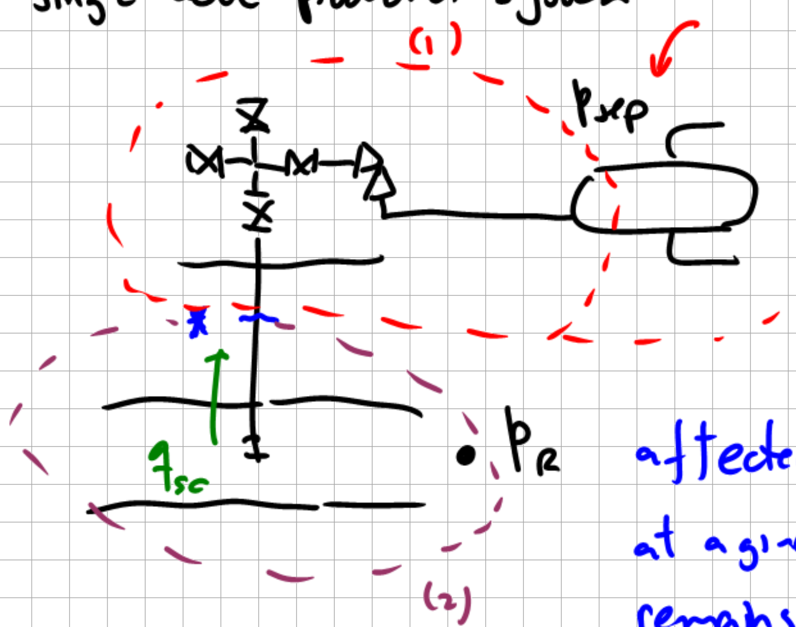


required pressure at pipe inlet (keeping p_2 constant)

3) provide $p_1, p_2 \rightarrow$ calculate q



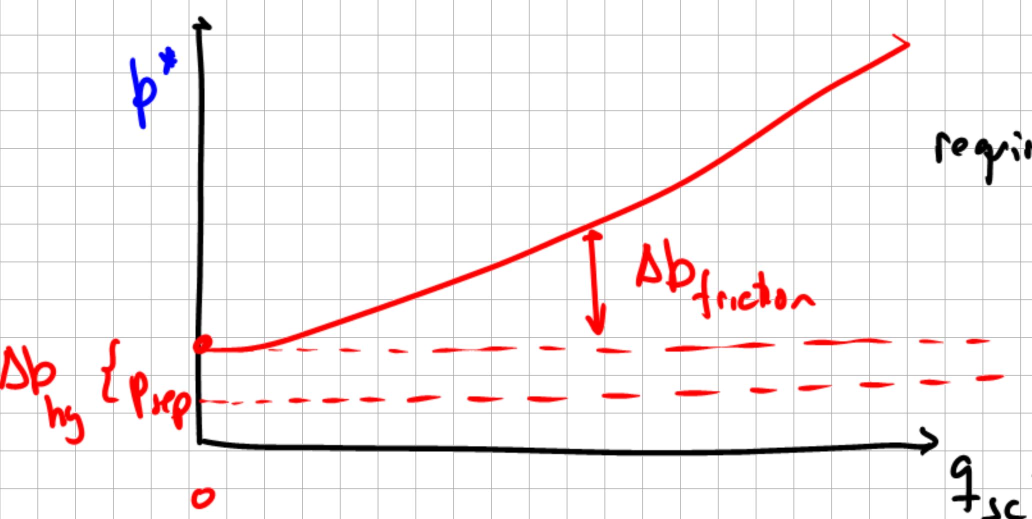
Single well production system



affected by depletion at a given time "t" remains fairly "constant"

system (1) resembles case 2

required pressure at p^* (seen from separator)

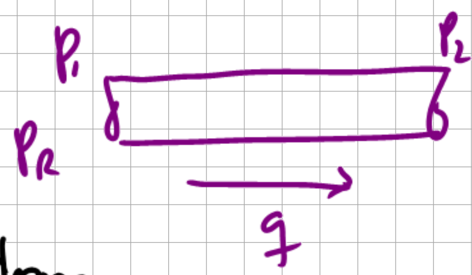


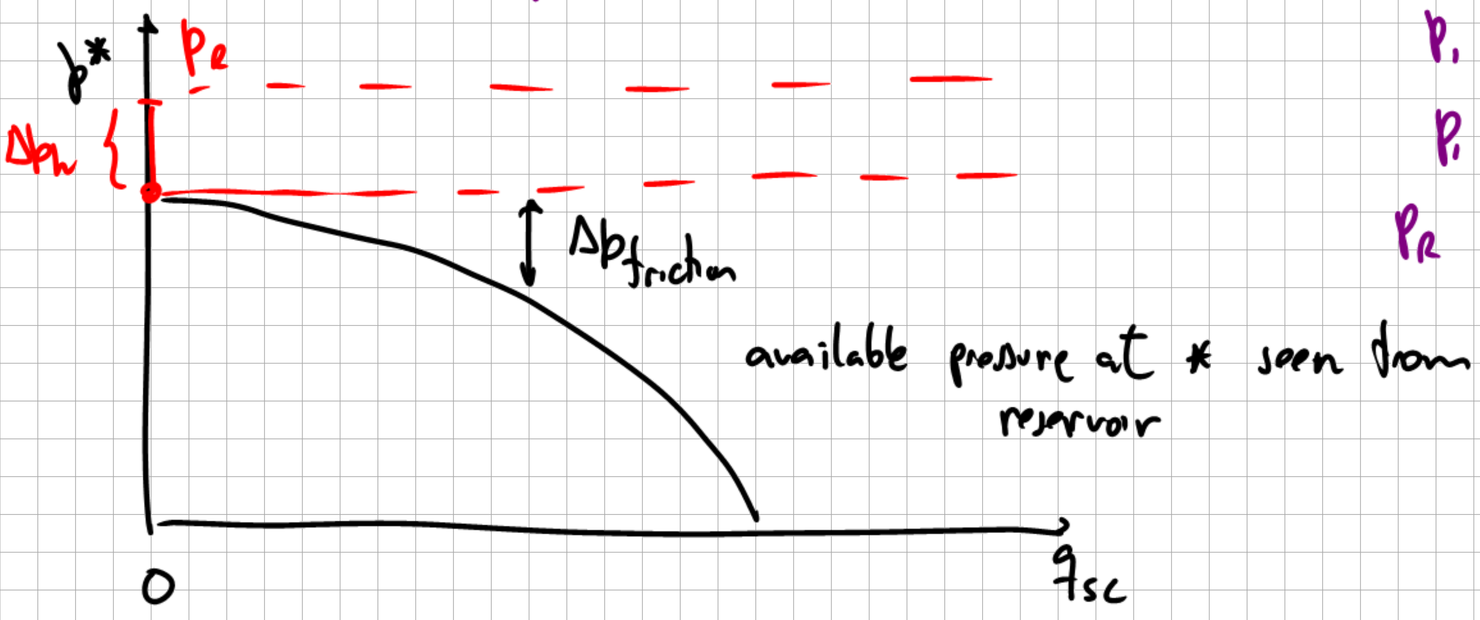
m^3/d affected by p, T $\quad T_{sc} = 15.56°C$

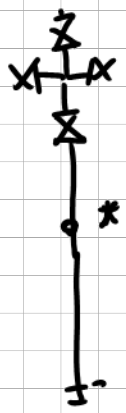
Sm^3/d unaffected by p, T, $p_{sc} = 1.01325$ bara

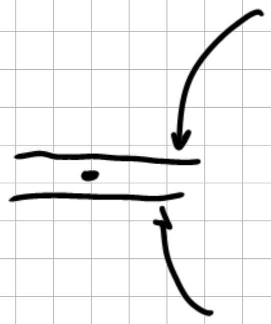
System (2) (formation and part of tubing) resembles case (1)

p_1 fixed, find p_2 by changing q



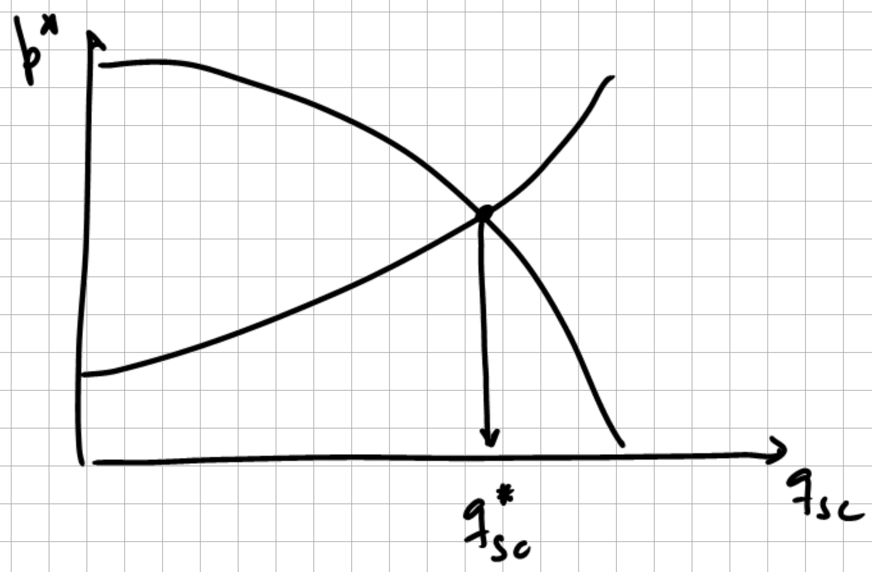




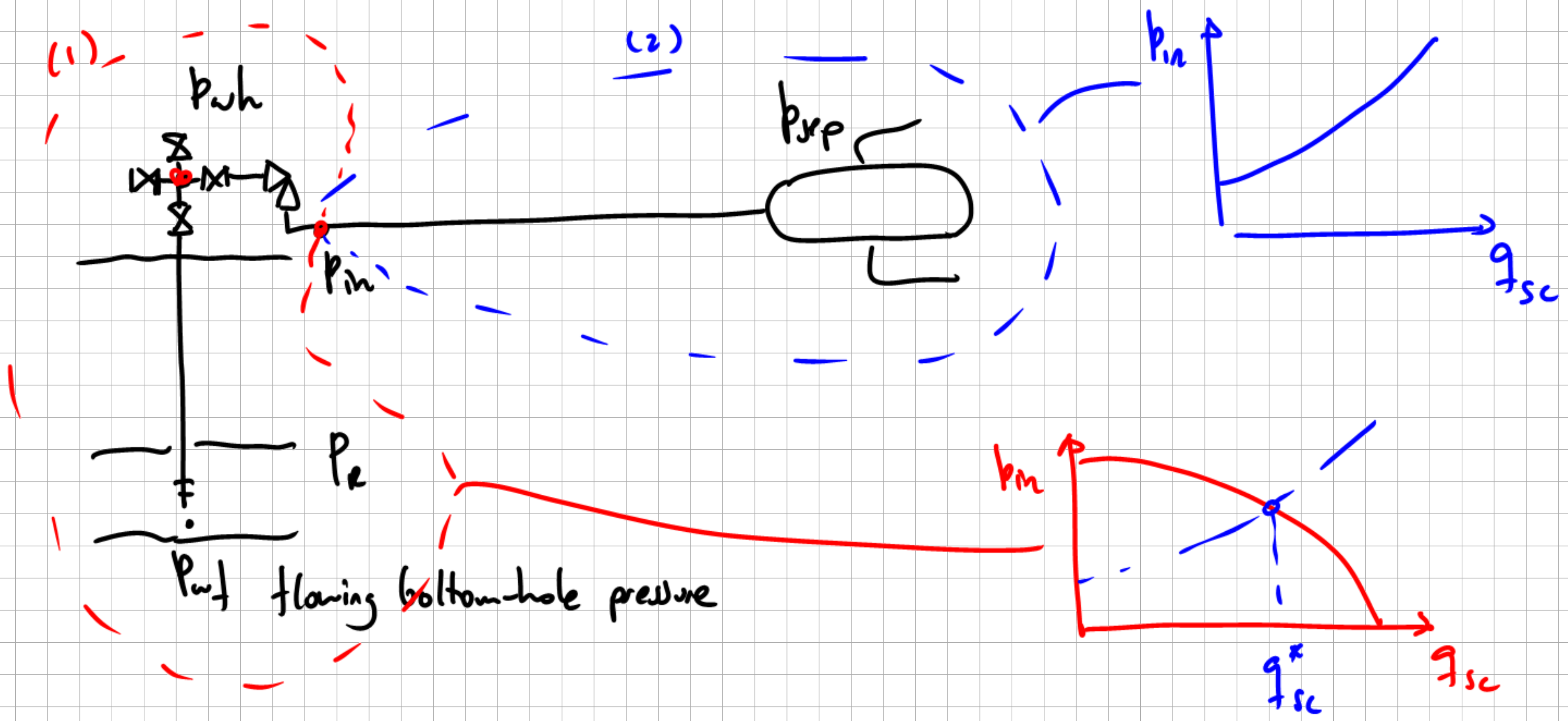


at p^* there should be only one pressure!

overimpose the two curves

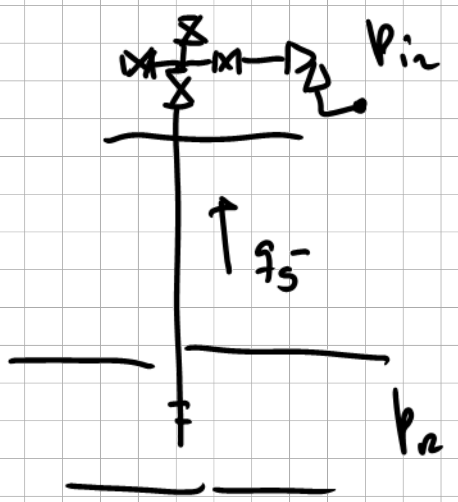


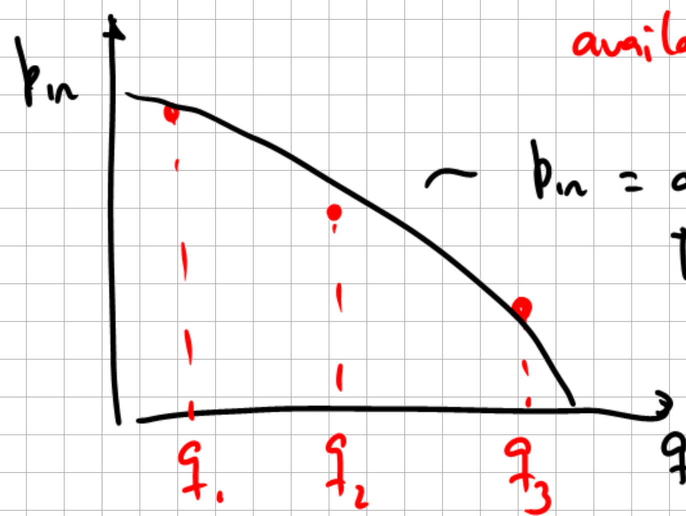
↳ equilibrium rate of the system when put together!



Example

Dry gas production system

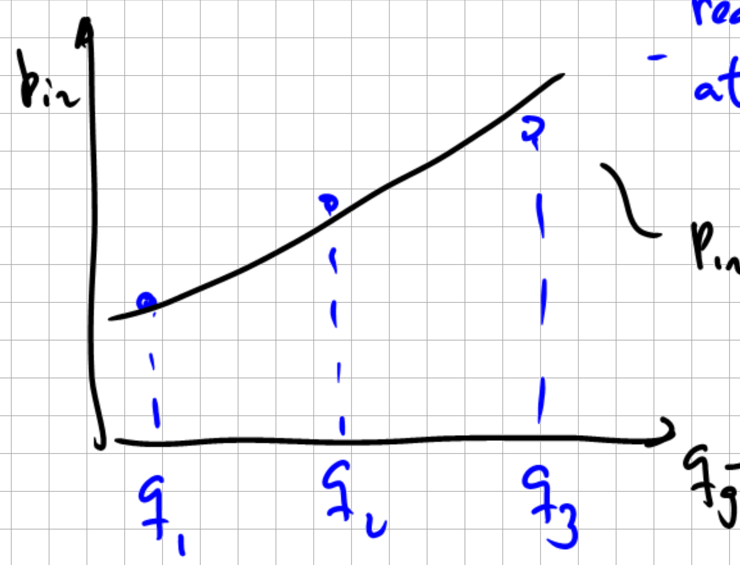




available pressure at choke discharge

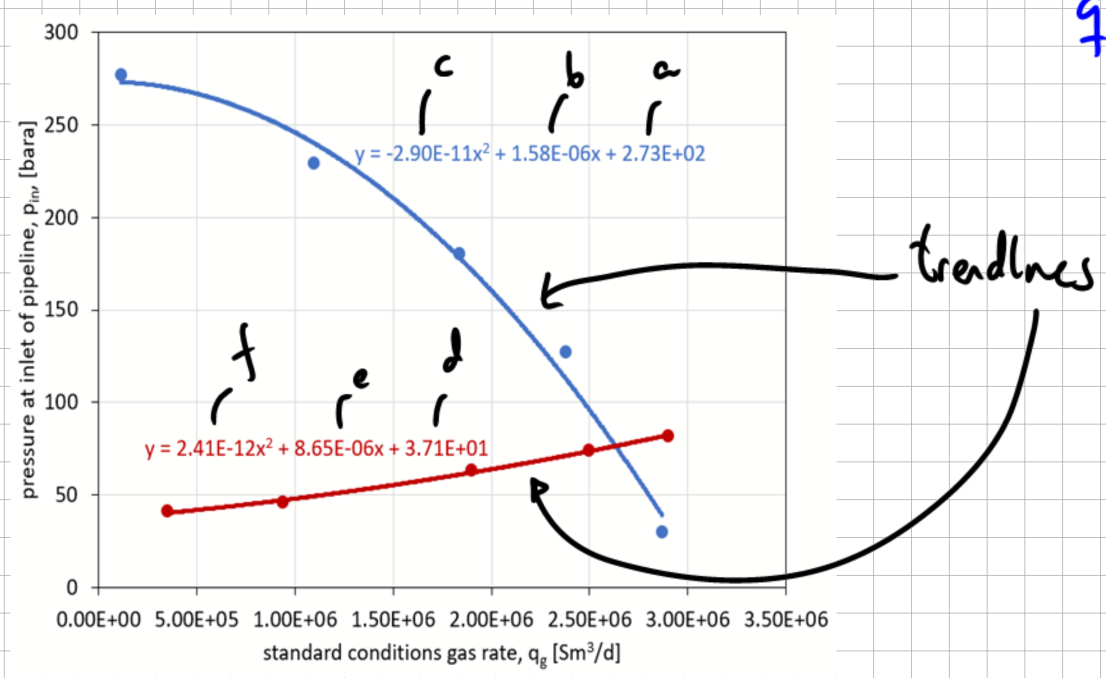
$\sim p_{in} = a + b\, q + c\, q^2$

q_g * at standard conditions



- required pressure at pipeline inlet

$p_{in} = d + e\, q + f \cdot q^2$



pin (available)							
c	[bara/(Sm3/d)^2]	-2.90E-11					
b	[bara/Sm3/d]	1.58E-06					
a	[bara]	2.73E+02		qg	pin (av)	pin(req)	error
				[Sm3/d]	[bara]	[bara]	[bara]
pin(required)				2.63E+06	76.5	76.5	0.0
f	[bara/(Sm3/d)^2]	2.41E-12					
e	[bara/Sm3/d]	8.65E-06					
d	[bara]	3.71E+01					

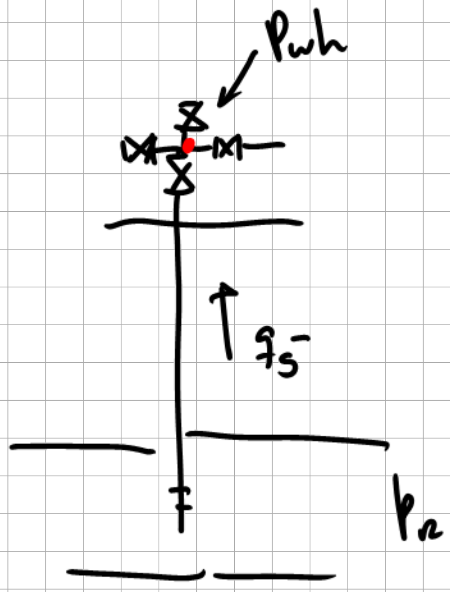
$p_{in} = 76.5$ bara

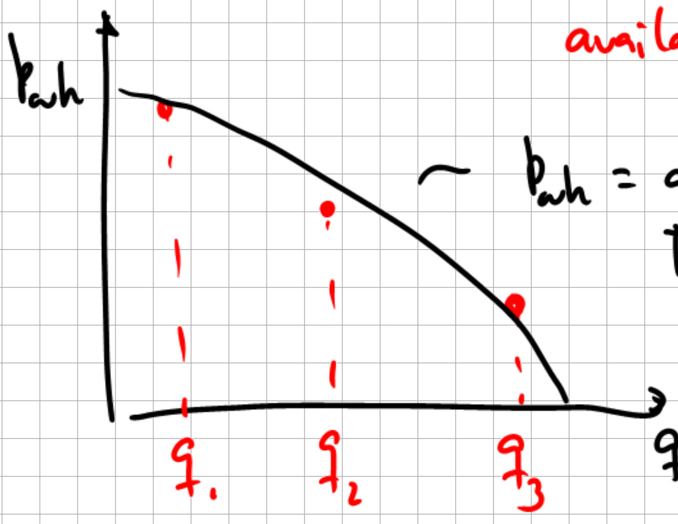
equilibrium gas rate

Video 04 - Exercise on flow equilibrium (part 2, choke, compressor)

Example

Dry gas production system

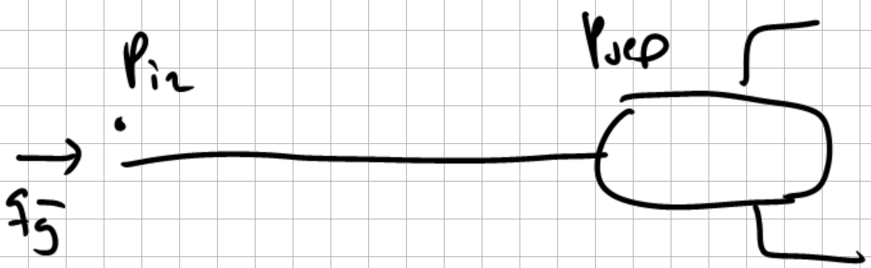


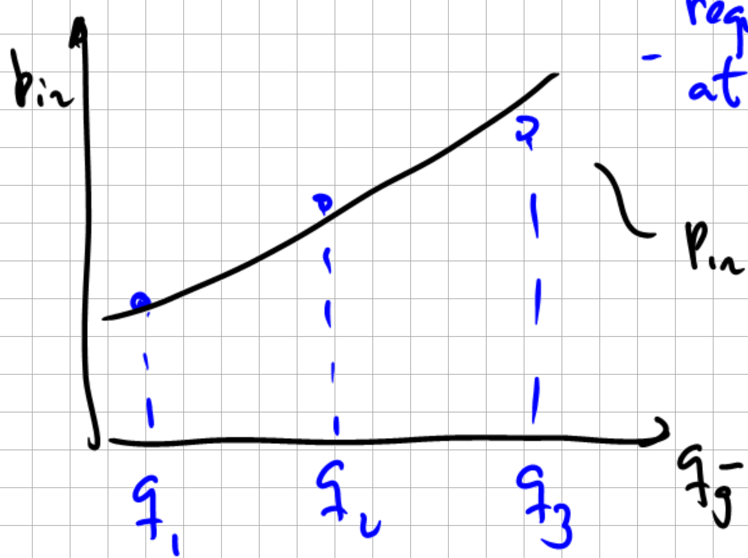


available pressure at wellhead

$$\sim p_{wh} = a + b\, q_g + c\, q_g^2$$

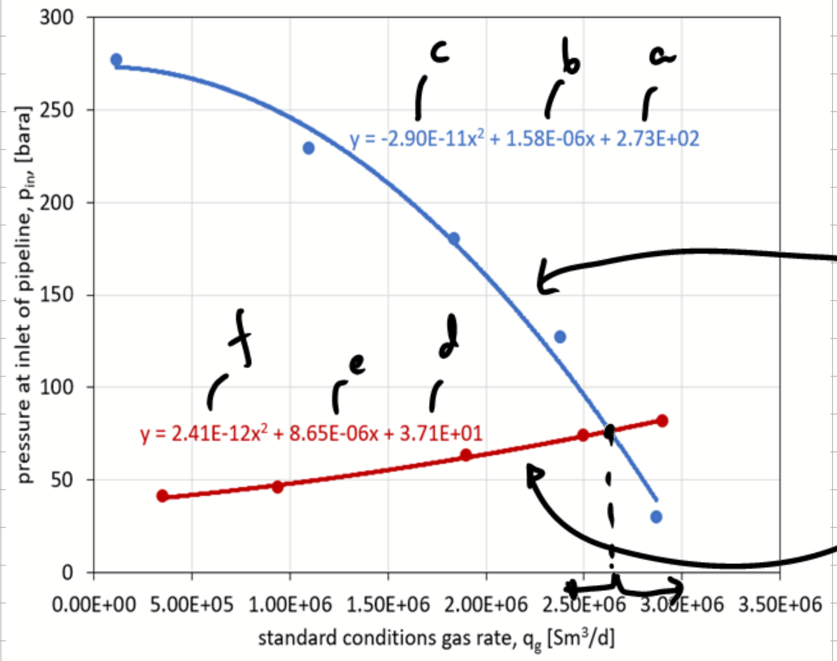
q_g → at standard conditions





required pressure at pipeline inlet

$$p_{in} = d + e\, q_g + f\, q_g^2$$

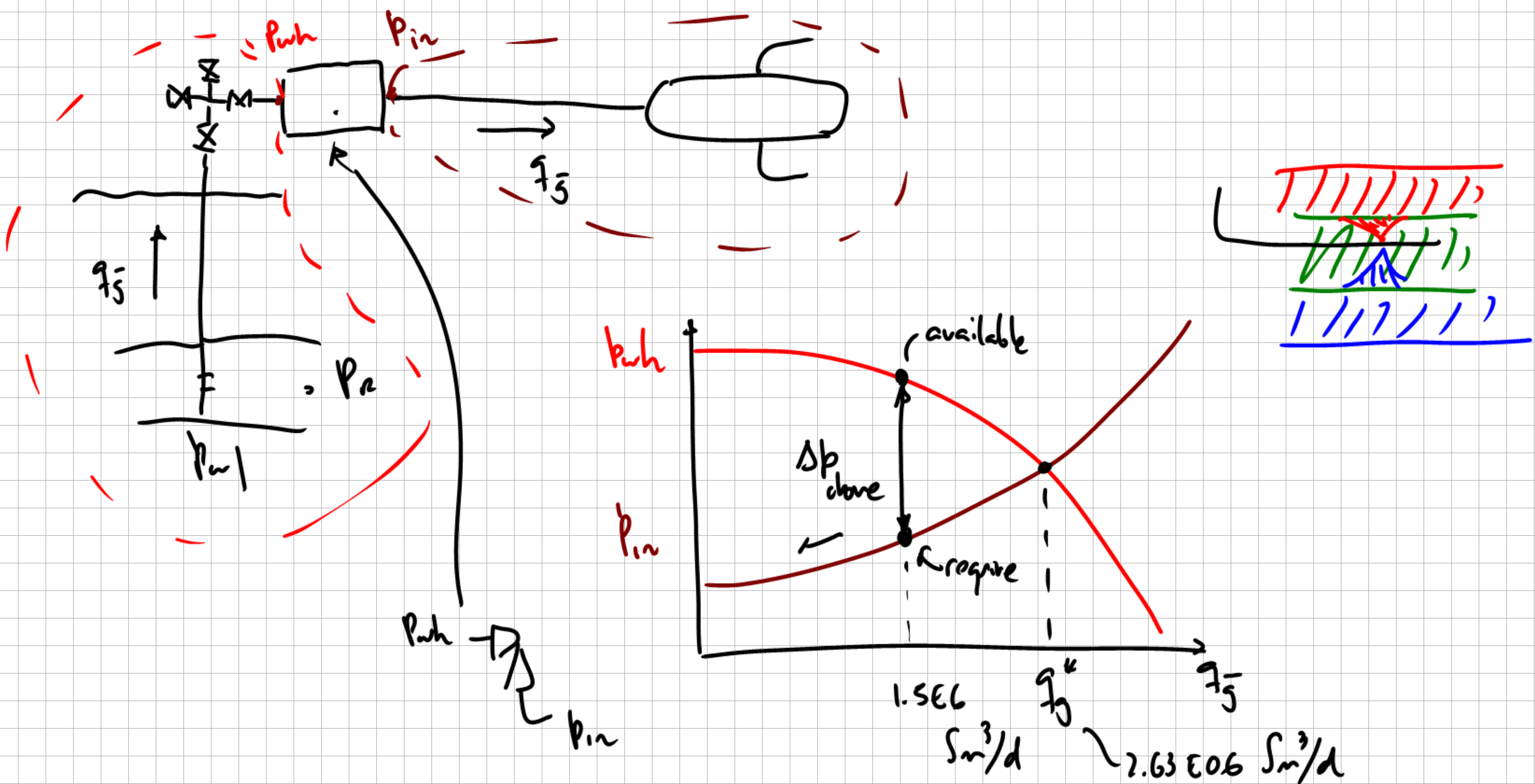


trendlines

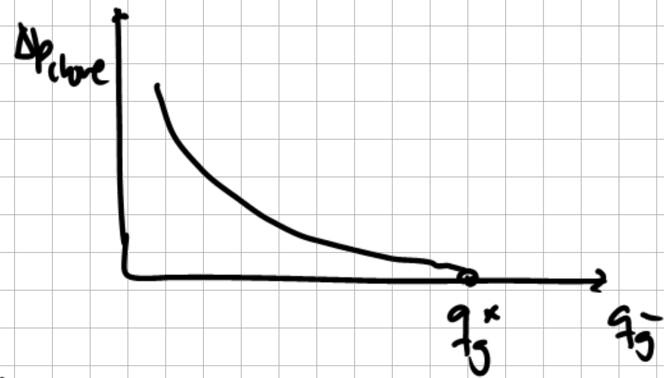
pin (available)						
c	[bara/(Sm3/d)²]	-2.90E-11				
b	[bara/Sm3/d]	1.58E-06				
a	[bara]	2.73E+02	qg	pin (av)	pin(req)	error
			[Sm3/d]	[bara]	[bara]	[bara]
pin(required)			2.63E+06	76.5	76.5	0.0
f	[bara/(Sm3/d)²]	2.41E-12				
e	[bara/Sm3/d]	8.65E-06				
d	[bara]	3.71E+01				

$p_{in} = 76.5$ bara

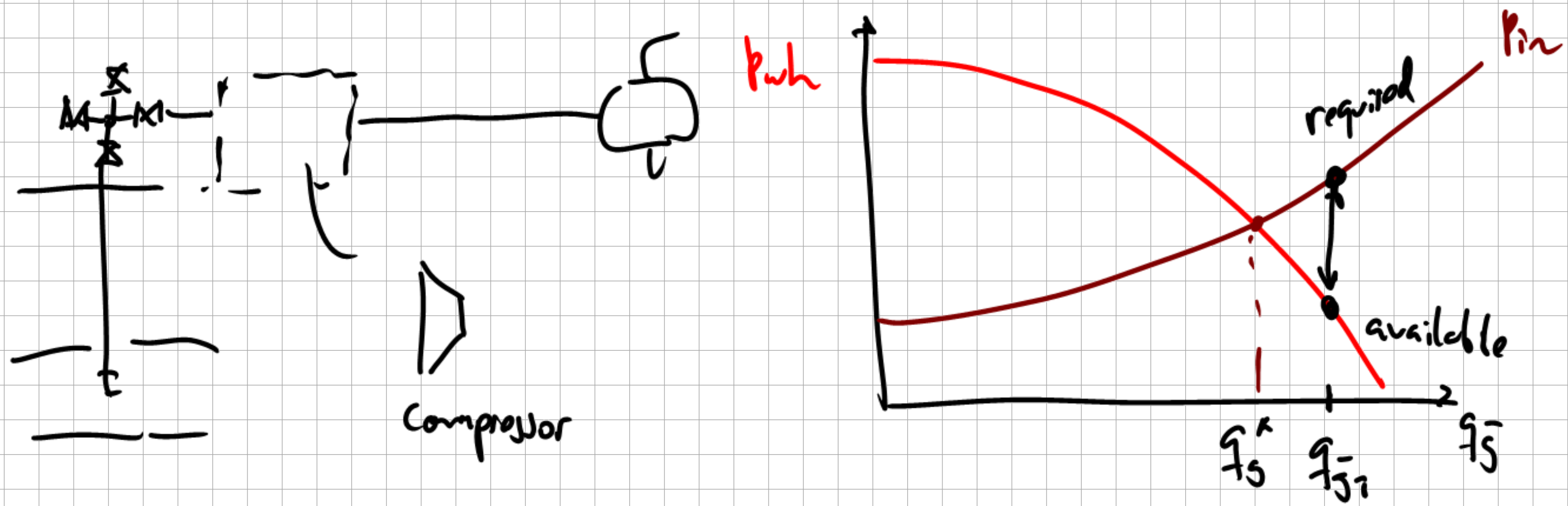
equilibrium gas rate



qg	p_{wh} (av)	p_{in} (req)	Deltap
[Sm3/d]	[bara]	[bara]	[bar]
1.50E+06	210.1	55.5	-154.6



what if i need a rate higher than equilibrium



required > avail
energy must be given to fluid

I desire to produce 2.8 E06 Sm3/d

qg	p_{wh} (av)	p_{in} (req)	Deltap
[Sm3/d]	[bara]	[bara]	[bar]
2.80E+06	50.1	80.2	30.2

deltap to be provided by wellhead compressor

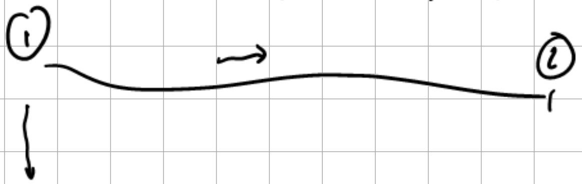
Class 20220830 :
-Re-cap of last week material
-LINEST Excel function: syntax:
LINEST(y's,x's^{1,2,...},TRUE, FALSE)

https://support.microsoft.com/en-us/office/linest-function-84d7d0d9-6e50-4101-977a-fa7abf772b6d

=LINEST(B6:B10;A6:A10^{1,2};TRUE;TRUE)

A	B	C	D	E
Exercise 1, Prof. Milan Stanko (NTNU)				
Formation+Tubing+choke (available)				Pipeline (re
q_g	p_{wh}			q_g
[Sm^3/d]	[bara]			[Sm^3/d]
1.15E+05	277			3.50E+05
1.10E+06	229			9.38E+05
1.84E+06	180			1.90E+06
2.38E+06	127			2.50E+06
2.87E+06	30			2.90E+06
-2.90E-11	2E-06	273.377		
8.2E-12	3E-05	16.2238		
0.98845	14.512	#N/A		
85.5883	2	#N/A		
36048	421.18	#N/A		

incompressible liquid, isothermal



$$z_1 + \frac{V_1^2}{2g} + \frac{P_1}{\rho g} = z_2 + \frac{V_2^2}{2g} + \frac{P_2}{\rho g} + \Delta h_L$$

[m] $[m^2/s^2 / (m/s^2)]$ $[m/s^2]$

$$\Delta h_L = \Delta h_f + \Delta h_{acc}$$

$$\Delta h_{acc} = \underbrace{K}_{\text{type of accessory}} \frac{V^2}{2g}$$

$$\Delta h_f = \underbrace{f}_{\text{moody friction factor}} \frac{L}{\underbrace{\phi}_{\text{diameter of pipe}}} \frac{V^2}{2g}$$

https://en.wikipedia.org/wiki/Darcy_friction_factor_formulae

$$P_1 = \rho g(\Delta z) + \cancel{\frac{(V_2^2 - V_1^2)}{2}}\rho + P_2 + f \cdot \frac{L}{\phi}\frac{V^2}{2}\rho$$

0

$\Delta z = z_2 - z_1$

incompressible
const diameter

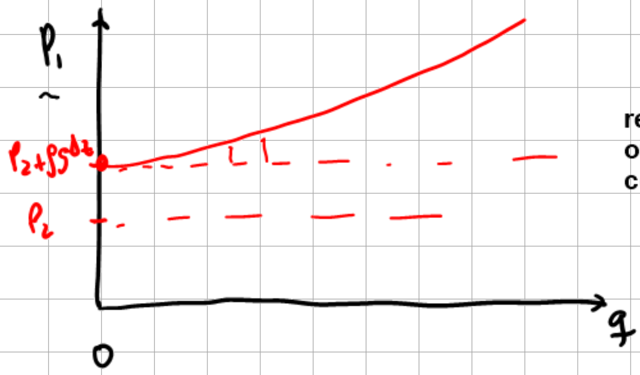
$$V_1 = V_2 = V = \frac{q}{A} \qquad A = \frac{\pi \phi^2}{4}$$

$$P_1 = \rho g \Delta z + P_2 + \rho f \frac{L}{\phi} \frac{q^2}{2 \frac{\pi^2 \phi^4}{16}} = \rho g \Delta z + P_2 + f \frac{L}{\phi^5} \frac{8 q^2}{\pi^2}\rho$$

$$V^2 = \left(\frac{q}{A}\right)^2$$

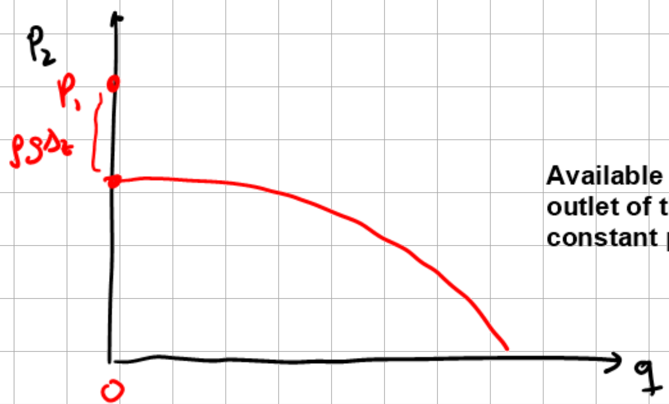
$$A^2 = \frac{\pi^2 \phi^4}{16}$$

Diameter is to the power of 5 has an important effect on friction presssure loss

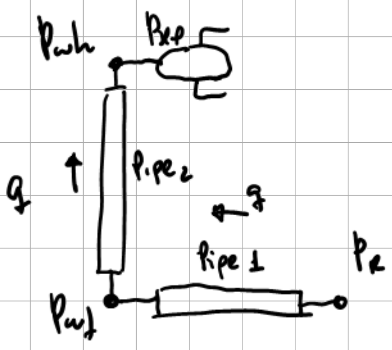


required pressure at the inlet of the pipe to flow against constant p2

$$P_2 = -\rho g \Delta z + P_1 - \rho f \frac{L}{\phi} \frac{q^2}{2 \frac{\pi^2 \phi^4}{16}}$$



Available pressure at the outlet of the pipe flowing from constant p1



IPR

$$p_{wf} = -\rho g \Delta z + P_R - \rho f_1 L_1 \frac{q^2 8}{\pi^2 \phi_1^5} \Rightarrow P_{wf} = \underset{\text{IPR}}{F_1}(\overset{\dot m}{q_{\bar{o}}}, P_R, T_R, \text{system parameters})$$

1 eq. 2 unknowns
q
Pwf

$\dot m = \text{constant} = \dot m_1 = \dot m_2$

$\dot m_1 = q_1 \cdot \cancel{\rho_1} = q_2 \cdot \cancel{\rho_2}$

$$P_{wh} = -\rho g \Delta z + P_{wf} - \rho f_2 L_2 \frac{q^2 8}{\pi^2 \phi_2^5}$$

1 eq - no new unknowns

(TPR)
Tubing Performance relationship

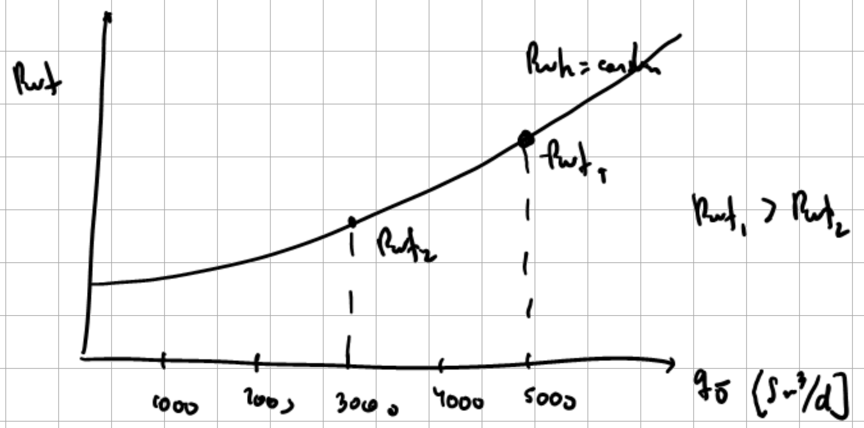
$$P_{wh} = F_2(P_{wf}, q_{\bar{o}}, \text{system parameters}, T_{wf})$$

find q, Pwf

Class activity, wellhead puzzle

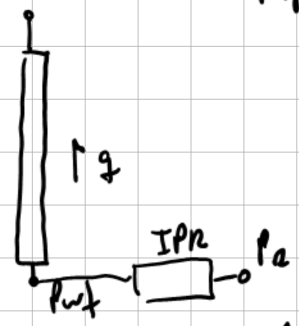
Class exercises

1. Consider a vertical tubing through which only undersaturated oil is flowing. Consider that wellhead pressure is kept constant and equal to separator pressure. Assume that at time t1, the rate is 5000 Sm3/d. At a later time t2, the rate is 3000 Sm3/d. What can you say about flowing bottomhole pressure in t2 and t1?
   a) pwf at t1 is greater than at t2
   b) pwf at t1 is smaller than at t2
   c) pwf at t1 and at t2 are equal



$P_{wf_1} > P_{wf_2}$

P_{wh} = constant = P_{sep}



$$q_o = J \cdot (P_R - P_{wf})$$

2. As a follow-up to question 1, assume that the IPR of the well can be modeled with the equation qo = J * (pR-pwf). What can you say about reservoir pressure in t1 and t2
   a) Reservoir pressure in t1 is greater than at t2 ←
   b) Reservoir pressure in t1 is smaller than at t2
   c) Reservoir pressure at t1 and at t2 are equal
   d) We need more information to determine the relationship between reservoir pressure in times t1 and t2

$t_1 \quad \overset{5000}{q_o} = J(P_R - \overset{P_{wf_1}}{P_{wf}})$

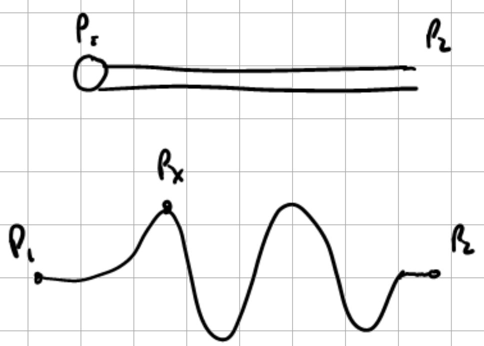
$t_2 \quad \overset{2000}{q_o} = J(P_R - P_{wf_2})$

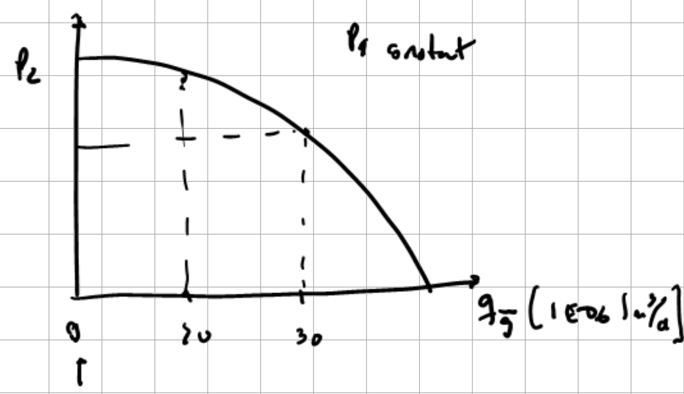
$P_{wf_1} > P_{wf_2}$

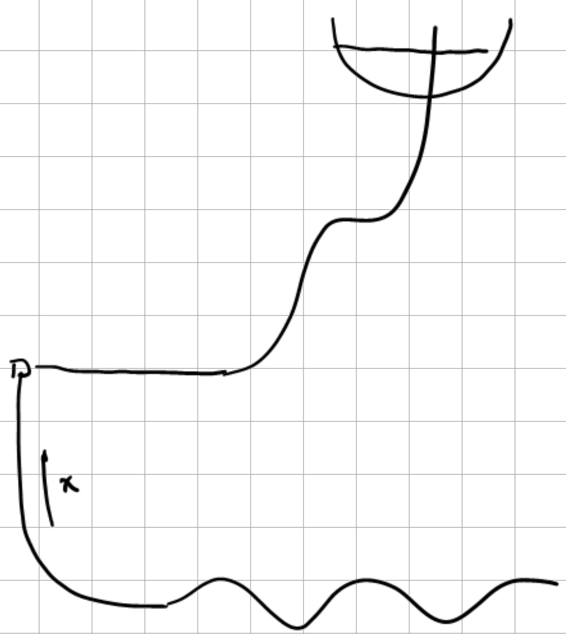
20220901

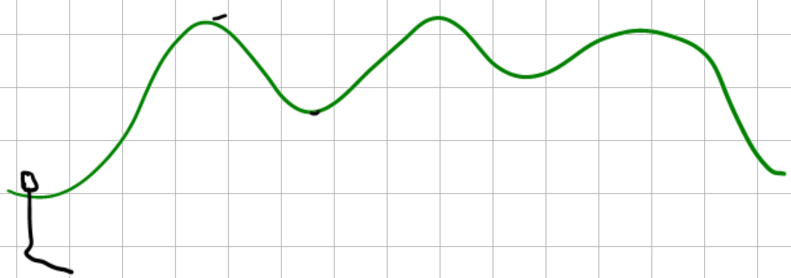
-Sign up for visit of Orkanger Spoolbase!
-Reference group members: Ali, Sean and Morten
-Information about mandatory exercises:
    -4 deliveries in BB (most likely individual)
    -What to deliver in each delivery is indicated in the work plan

3. Consider a horizontal flowline that transports gas from a compression station to a gas terminal located on the shore. The compressors ensure the pressure at the inlet to the pipeline is always constant. Select the alternatives that make sense:
   a) When the rate through the pipeline is 30 E06 Sm3/d, the pressure at the exit of the pipeline is higher than when the rate through the pipeline is 20 E06 Sm3/d
   b) When the rate through the pipeline is 30 E06 Sm3/d, the pressure at the exit of the pipeline is lower than when the rate through the pipeline is 20 E06 Sm3/d
   c) We need more information to determine the pressure at the exit of the pipeline when the flow is 30 E06 Sm3/d and 20 E06 Sm3
   d) When the valve is closed at the terminal, and there is no flow of gas, the pressure at the exit of the pipeline is equal to the pressure at the inlet of the pipeline



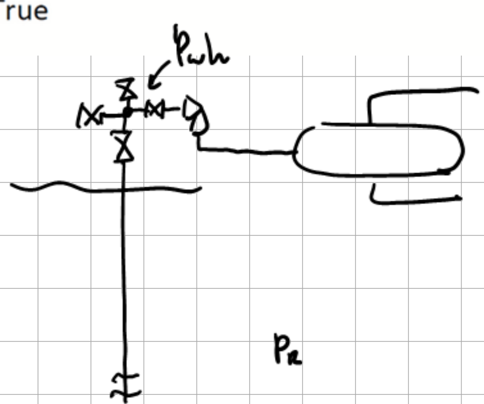


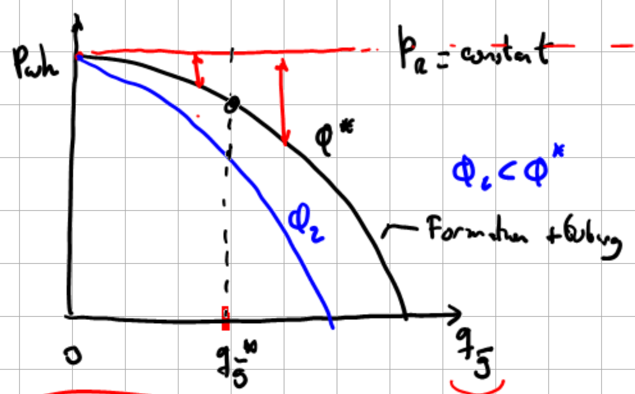


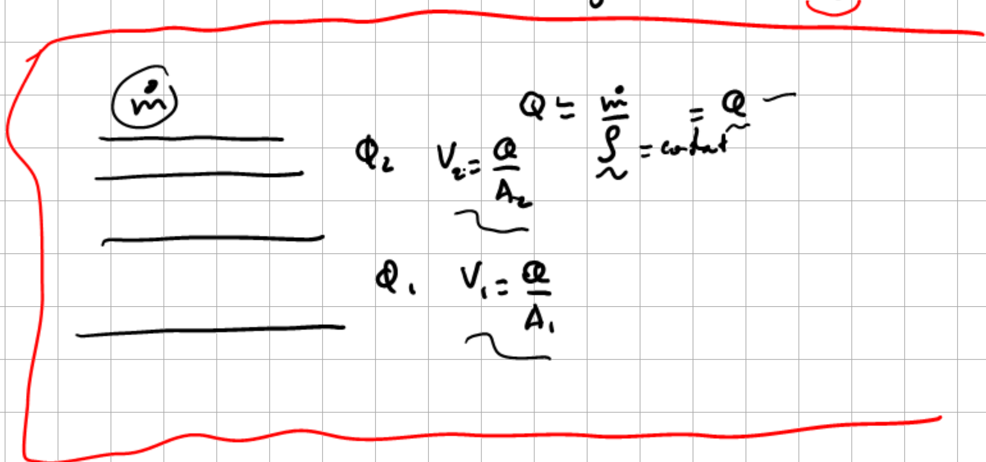


4. For a production system consisting of a single well producing to a separator through a flowline, the curve of available pressure at the wellhead consists of pressures calculated co-current from reservoir to wellhead considering pressure drop in the formation and in the tubing for several well rates.
   a) False
   b) True

5. As a follow-up to question 4, when comparing two curves of available pressure at the wellhead for the same dry gas well, but using two different tubing diameters, Phi1 > Phi2, for a given standard condition rate qg*, the corresponding available wellhead pressure pwh will be smaller for diameter 1 than for diameter 2.
   a) False
   b) True



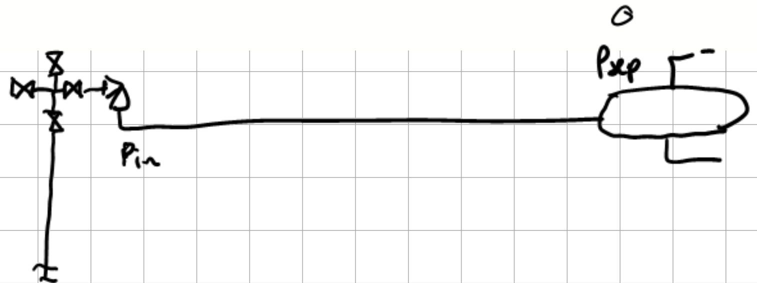


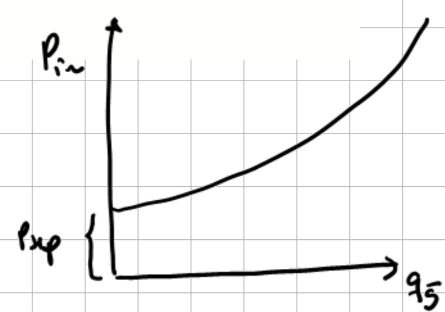


6. For a production system consisting of a single well producing to a separator through a flowline, the curve of required pressure at the inlet of the flowline consists of pressures calculated counter-current from separator to pipeline inlet considering pressure drop in the pipeline for several well rates.

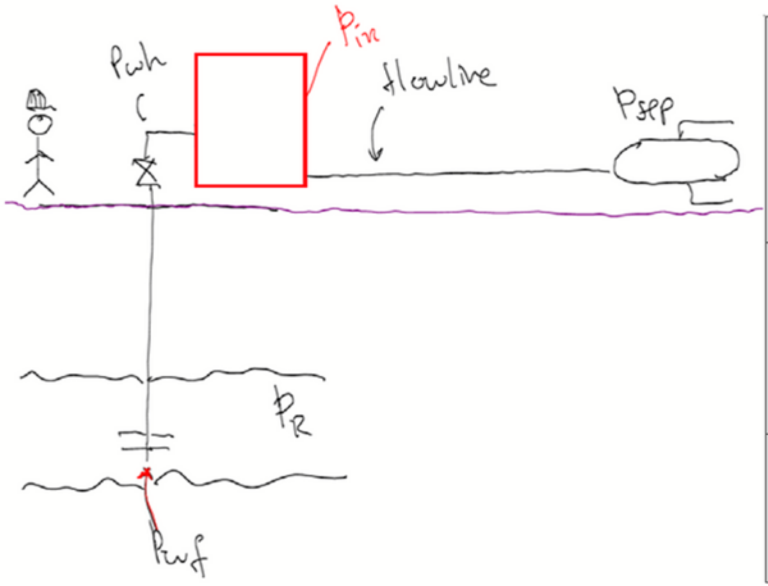
True

False





7. For the dry gas production system shown in the figure below, what is the choke pressure drop required (in bar) for the system to deliver a rate of 2.5 E6 Sm³/d.



Inflow equation:

$$q_g = C_R \cdot \left(p_R^2 - p_{wf}^2\right)^n$$

With

C_R = 104 Sm³/d/bar^2n

n= 0.9

p_R = 304 bara

Tubing equation:

$$q_g = C_T \cdot \left(\frac{p_{wf}^2}{e^S} - p_{wh}^2\right)^{0.5}$$

C_T = 4.41 E4 Sm³/d/bar

S = 0.31

Flowline wellhead-separator:

$$q_g = C_{FL} \cdot \left(p_{in}^2 - p_{sep}^2\right)^{0.5}$$

C_{FL} = 4E4 Sm³/d/bar

p_{sep} = 40 bara

$$C_R = \frac{q_g\,(Sm^3/d)}{\left(p_R^2 - p_{wf}^2\right)^n\,(bar^{2n})}$$

1: Define equilibrium point → removing choke

2: Calculate available pressure upstream the choke (pwh)

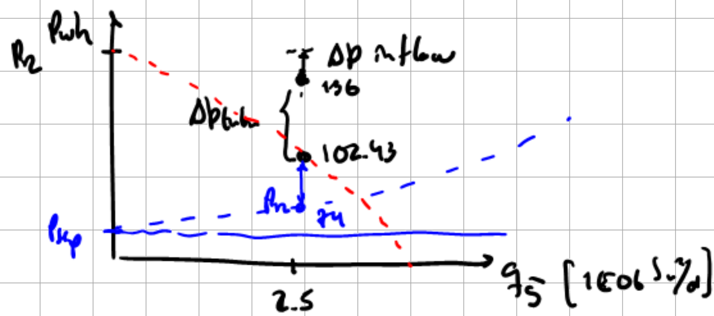
2.a. formation flow (IPR)

pwf=(pR^2-(qg/CR)^1/n)^0.5
pwf@qg=2.5e06 =136.7 bara

barg

2.b flow in tubing

qg = Ct*((pwf^2/e^s)-pwh^2)^0.5
pwh=((pwf^2/e^s)-(qg/Ct)^2)^0.5
pwh = 102.43 bara

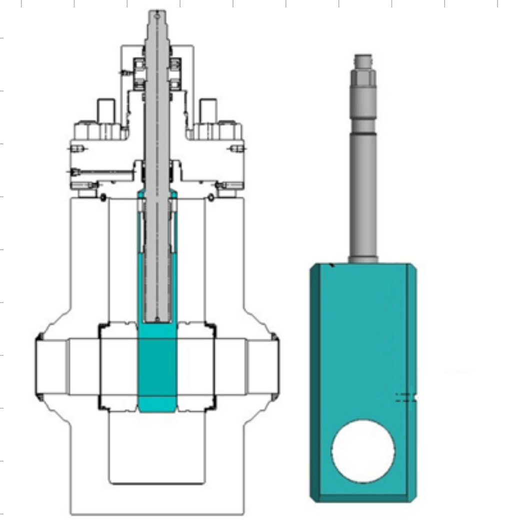


3. calculate pressure required at choke exit(discharge)

3.a. calculate counter-current pressure drop from separator to pin
qg=cflow*(pin^2-sep^2)^0.5
pin=(psep^2+(qg/cflow)^2)^0.5
pin=74.2 bara

4. calculate the choke deltap
chokedp=102.4-74.2=28.2 bar

Some gate valve images



Conventional gate valve

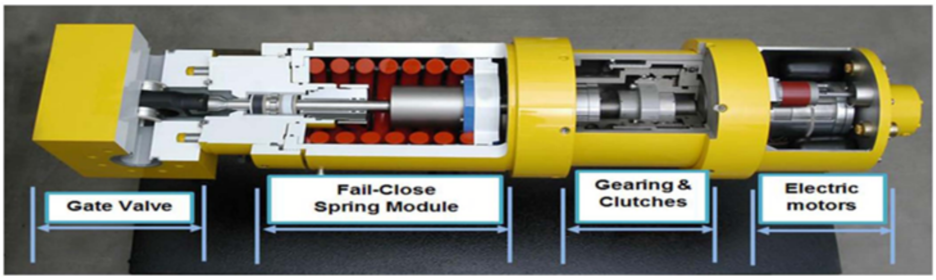


Figure 5—Cutout profile of the gate valve electric actuator.

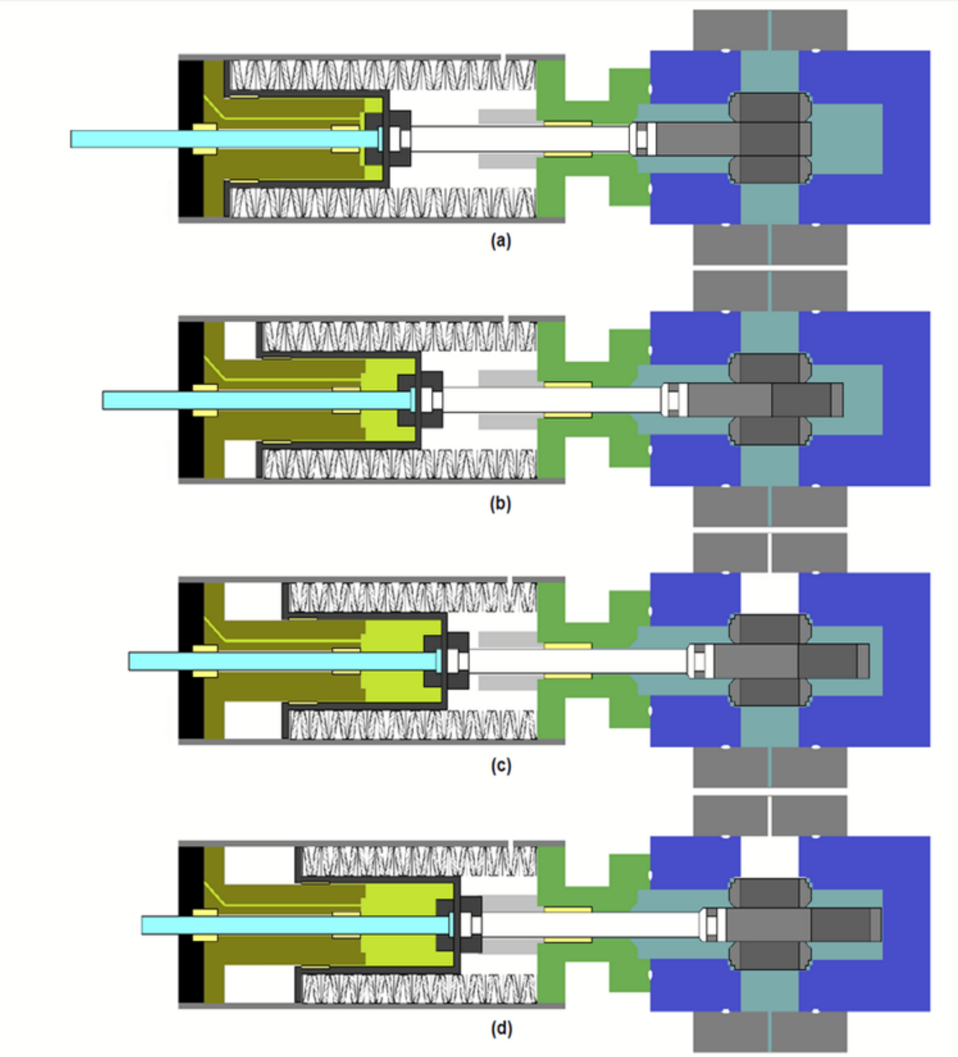
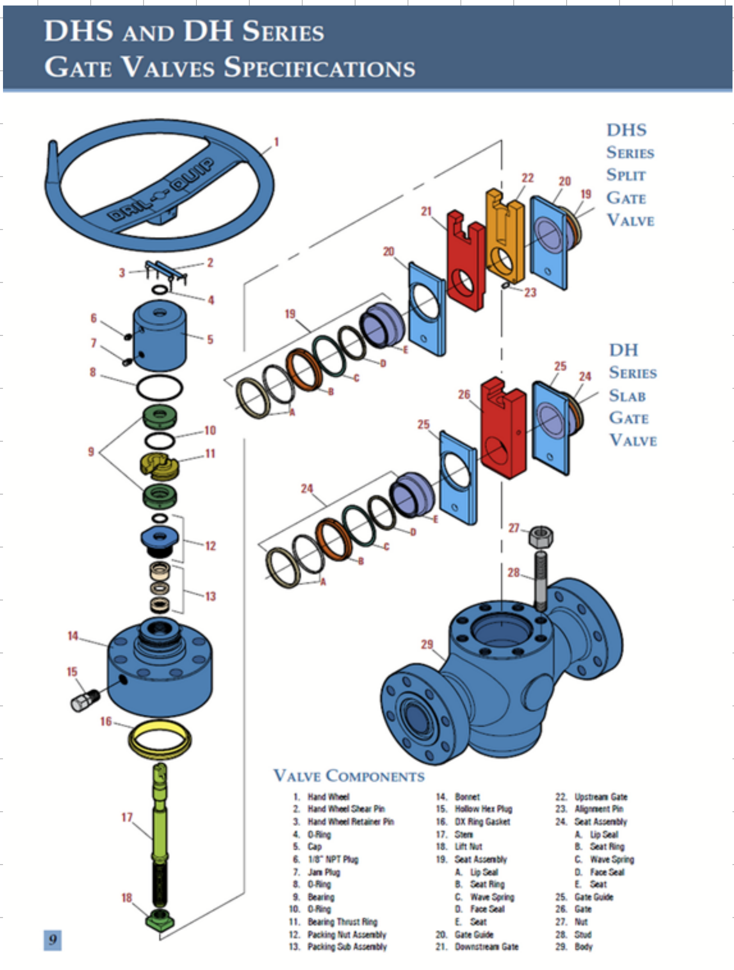
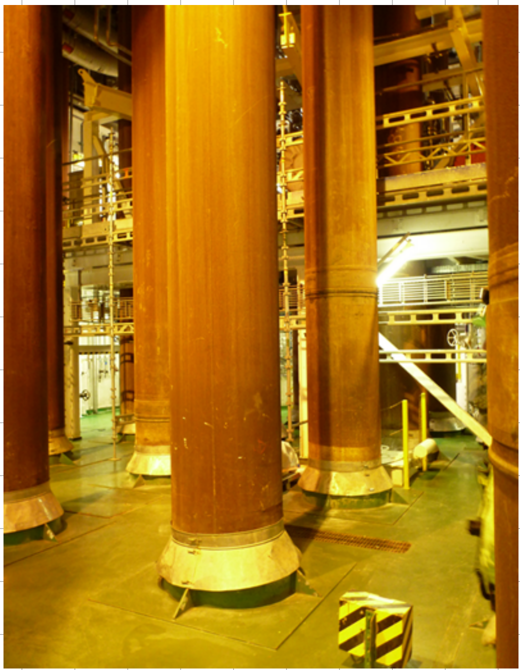
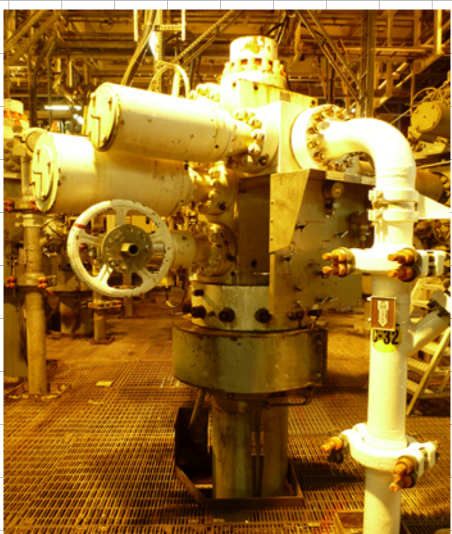


Figura 2-10. Trem de acionamento de uma válvula gaveta FSO nas posições: (a) aberta, (b) semi-fechada, (c) *pinch-off* e (d) completamente fechada.



Virtual tour of Gullfaks C Gravity-based platform





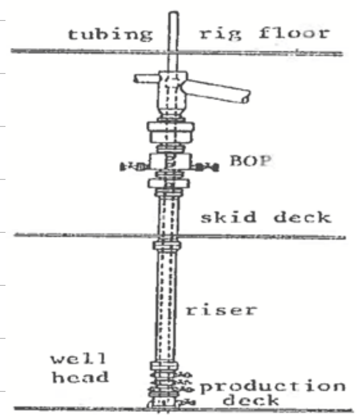


Fig. 2 Workover riser

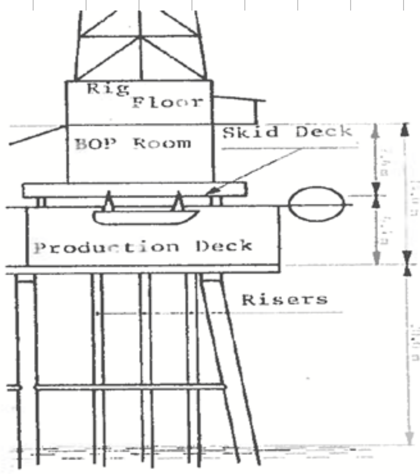
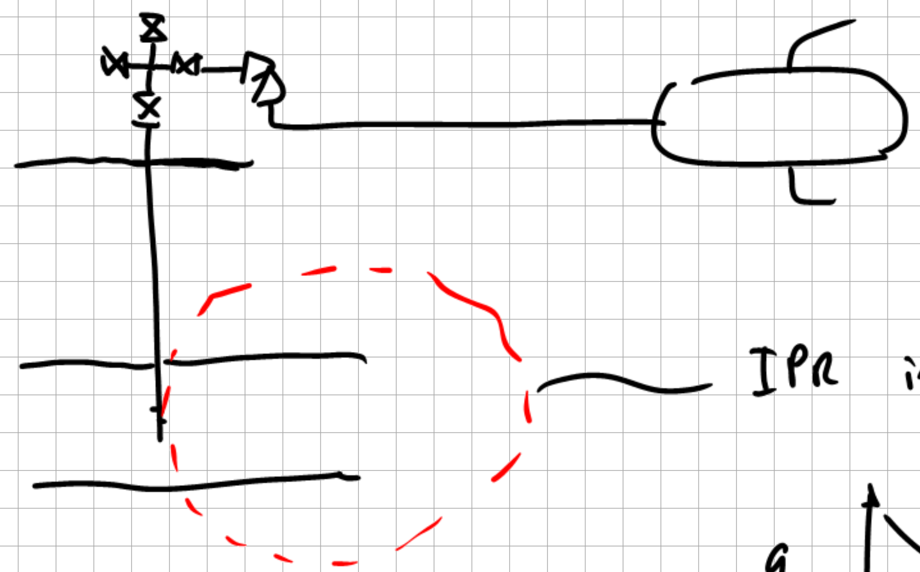
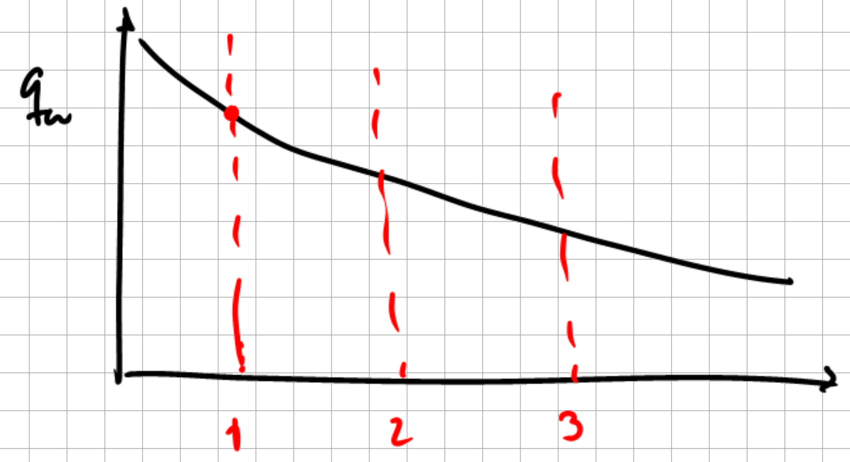


Fig. 3 Bravo platform – sideview

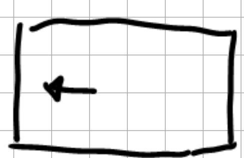


IPR inflow performance relationship



t (months, years)

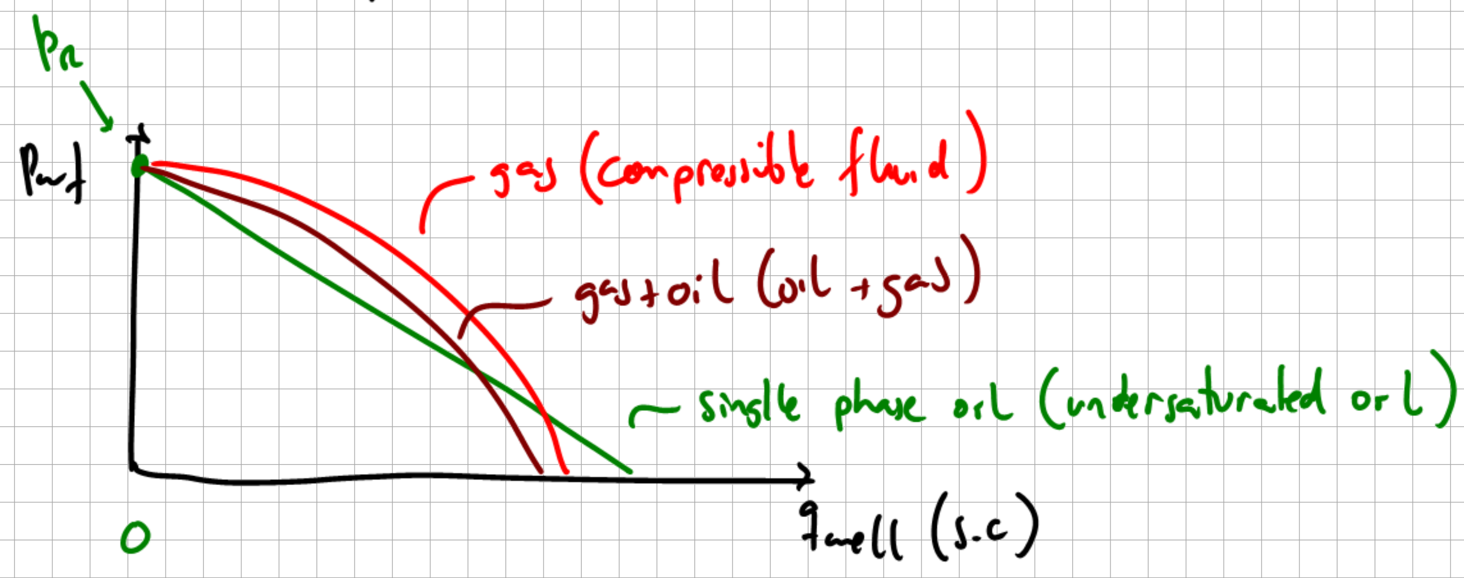
q, p_{wf}



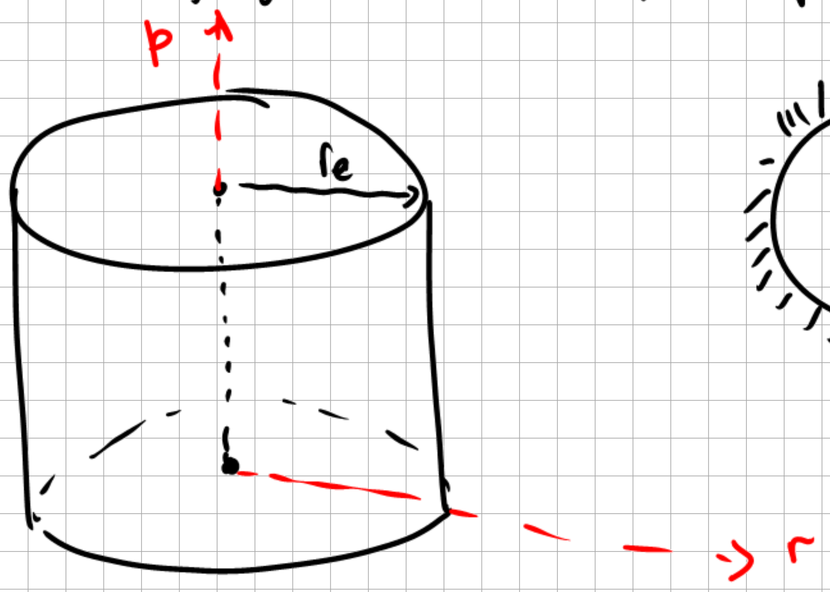
$q = f(p_{wf}, t)$

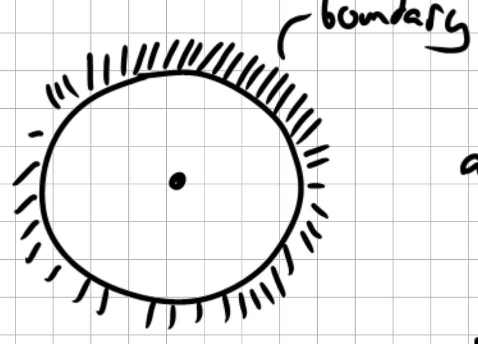
↳ instead of using t, i use p_R

at a given point in time:



vertical well, cylindrical reservoir, single phase fluid





at $t=0$

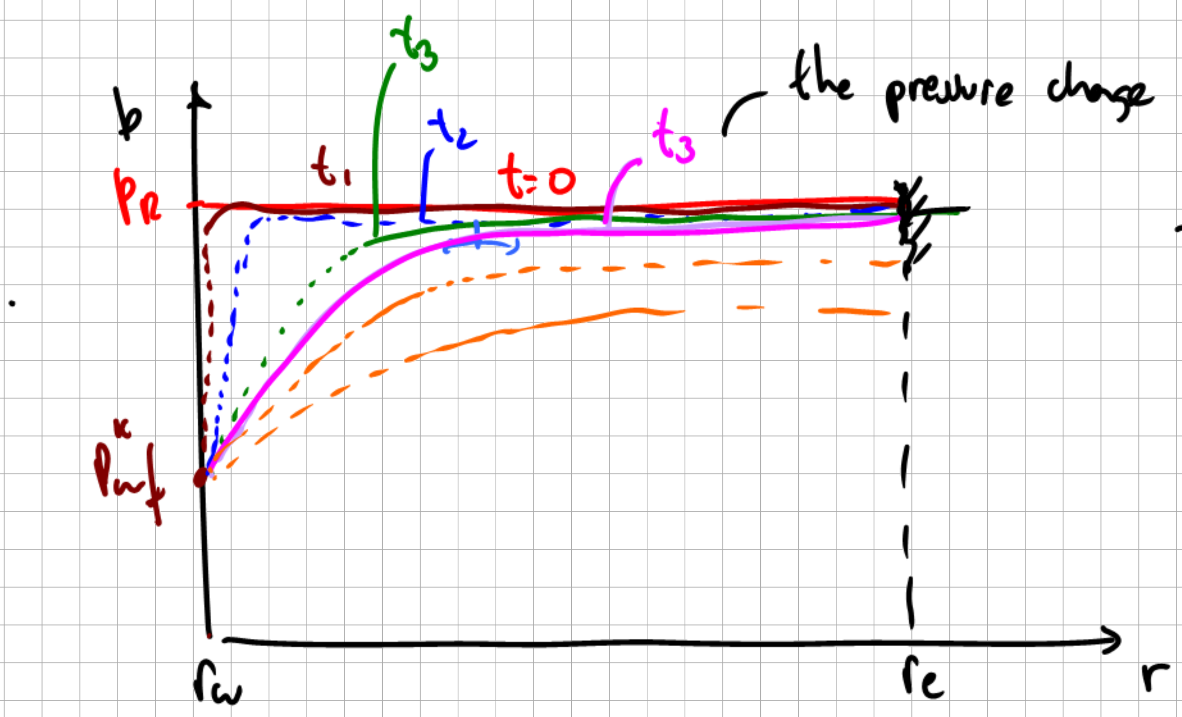
$q=0$

$p(r_w) = p_R$

at $t>0$

$q \neq 0$

$p(r_w) = p_{wf}^{*}$



the pressure change reaches the boundary

$t=0 \rightarrow t=t_3$ infinite acting

t is important for IPR

(no boundary effects)

$t_3 \rightarrow$ steady state $p(r_e) = const$

pseudo steady state $q(r_e)=0$

(pss)

$$t_{pss} = \frac{281.3\ \phi \cdot \mu \cdot C_t \cdot A}{k}$$

ϕ [-]

μ [cp] $1cp = 1E\text{-}3$ Pa s

C_t [1/bar] $C_t = C_f + C_{fluid}$ → gas / → 0.6 ; → $S_w C_w + S_o C_o + S_g C_g$

A [m^2]

k [md]

Formation compressibility, c_f	[1/bar]	4.35E-05		
Oil compressibility at res conditions, C_o	[1/bar]	2.18E-04		
Gas compressibility at res conditions, C_g	[1/bar]	7.25E-03		
Total compressibility, assuming oil-filled pore, C_t	[1/bar]	2.61E-04		
Total compressibility, assuming gas-filled pore, C_t	[1/bar]	7.30E-03		
Oil viscosity at res conditions, μ_o	[cp]	0.5		
Gas viscosity at res conditions, μ_g	[cp]	1.20E-02		
Porosity, ϕ	[-]	0.3		
Outer radius of reservoir, r_e	[m]	600		
Top area of reservoir, A	[m2]	1130973.4		
		FLUID:	Gas	Oil
		k	t_{pss}	t_{pss}
		[md]	[hr]	[hr]
		0.01	835552.28	1245853.30
		0.1	83555.23	124585.33
		1	8355.52	12458.53
		10	835.55	1245.85
		1000	8.36	12.46
		10000	0.84	1.25

- if t_{pss} is short most of the production will occur in pss (ss) therefore t is not necessary to compute IPR
- if t_{pss} is large, most of the production will occur in IA, therefore it is important to consider time in IPR

IPRs are obtained

- Empirical (field data) → "easier to use" → field data is needed
- Derived analytically (semi-analytically) from conservation equations.

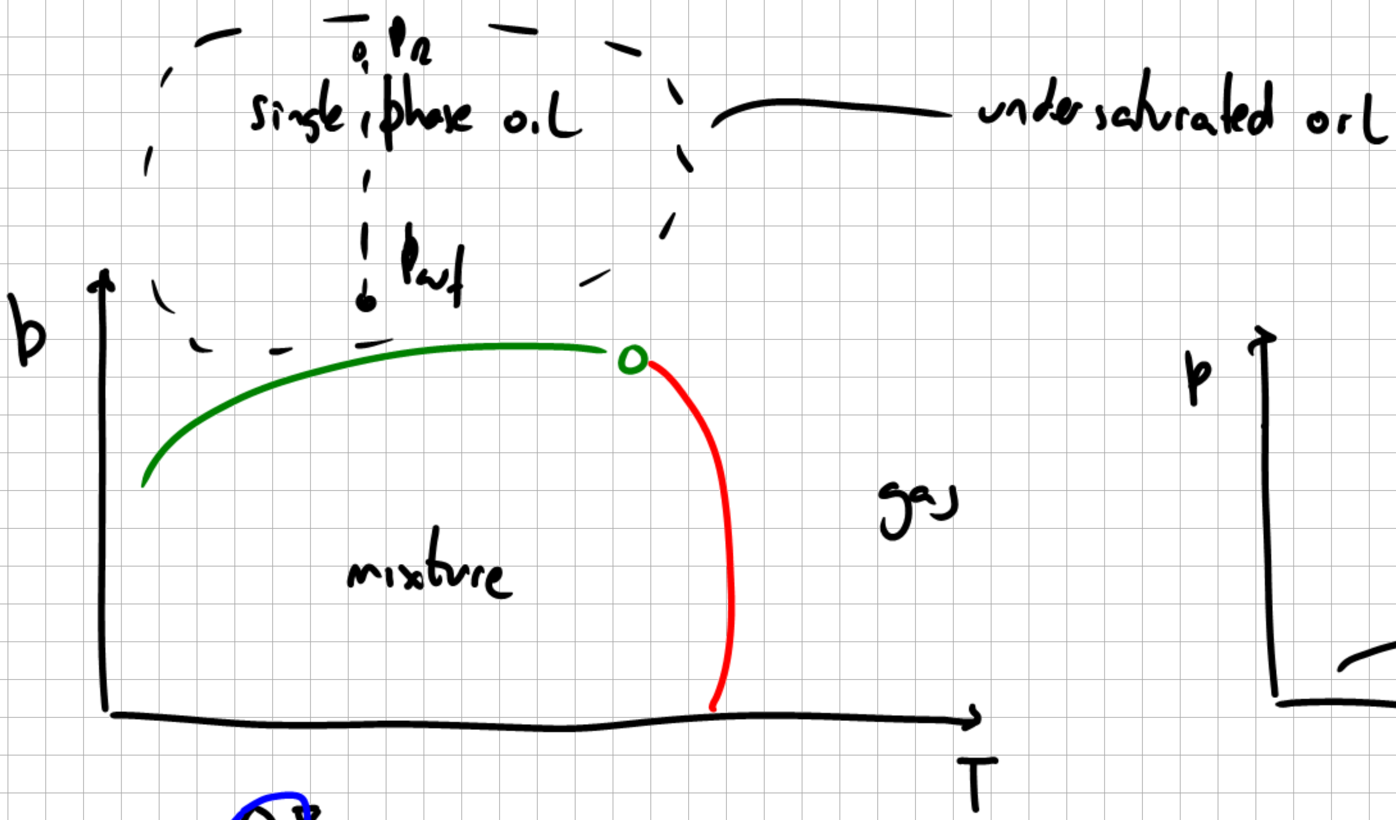
Conservation of mass + Darcy flow in a radial reservoir; single-phase fluid

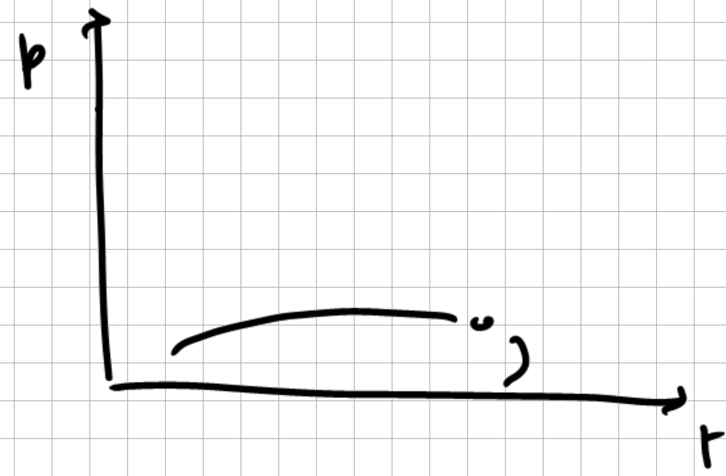
$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \alpha \frac{\partial p}{\partial t}$$

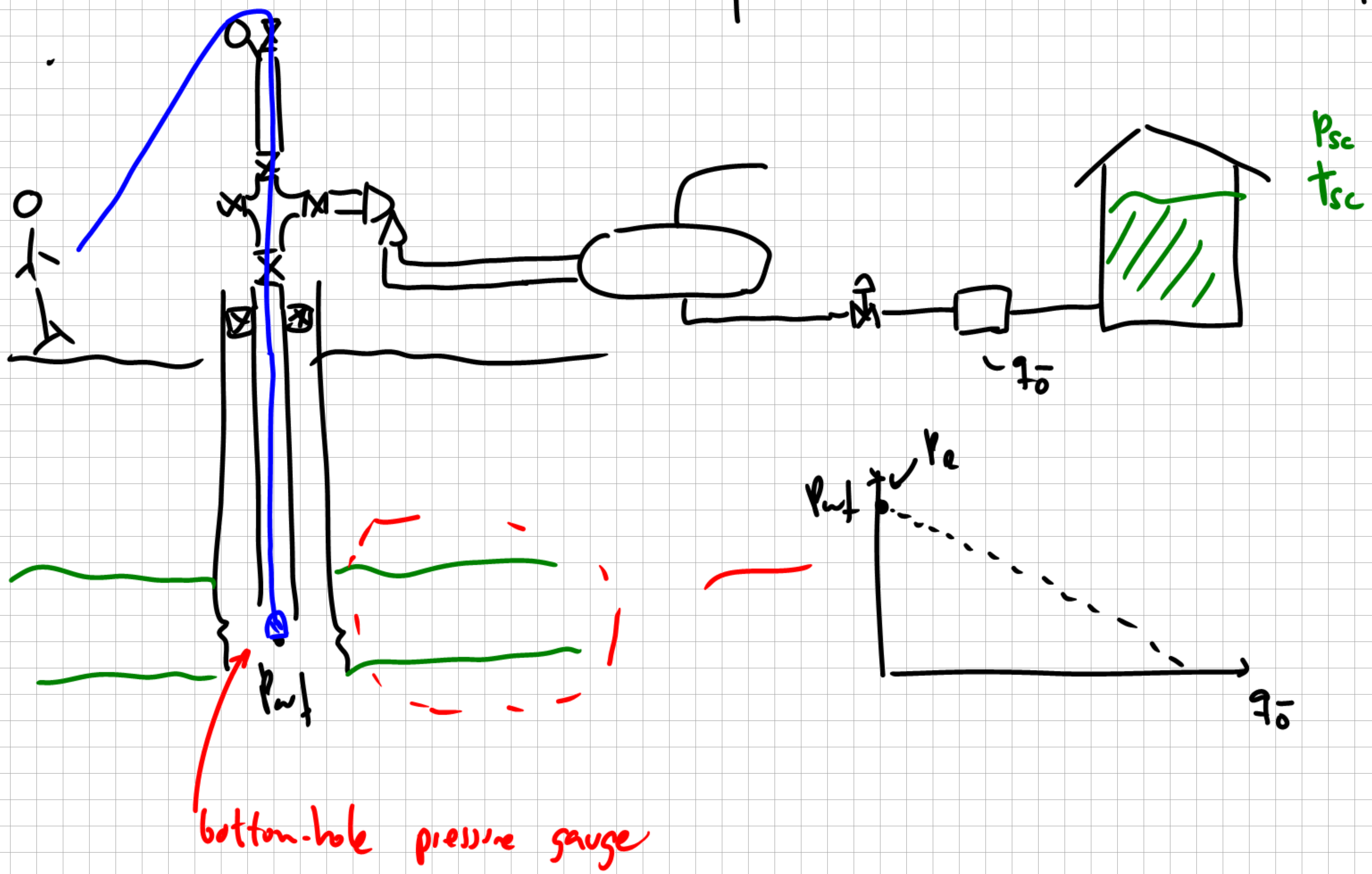
$$\alpha = \frac{\mu \phi C}{k}$$

- need a lot of parameters about the reservoir
- Allow for well design and to estimate future performance
- always need adjustment with field data

Video 06 - IPR for vertical undersaturated oil well (field test)







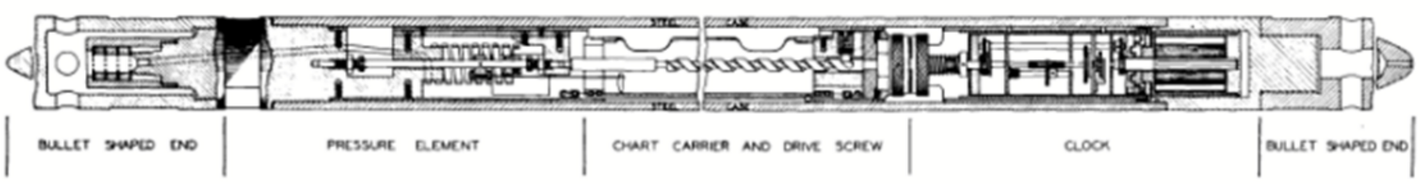


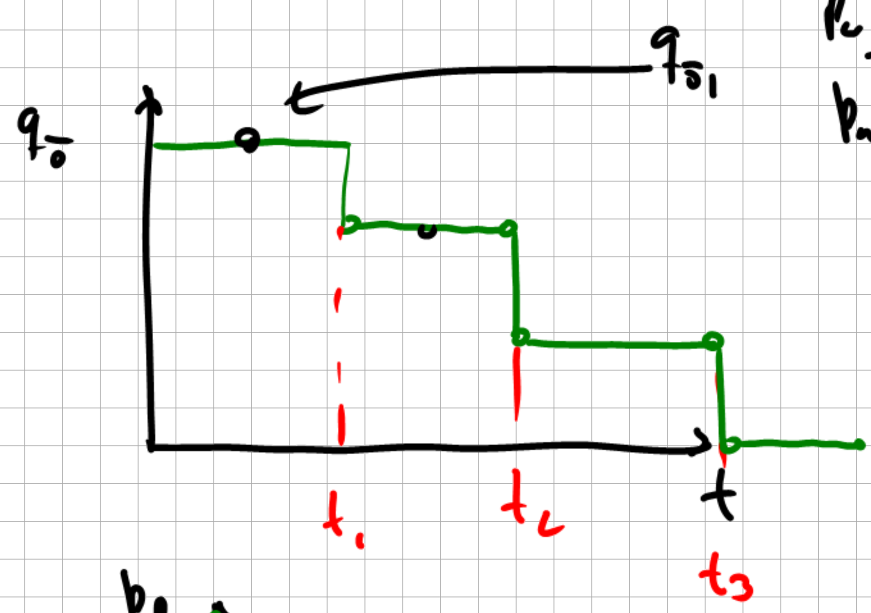
FIG. 1 CROSS-SECTION OF AMERADA PRESSURE GAGE.

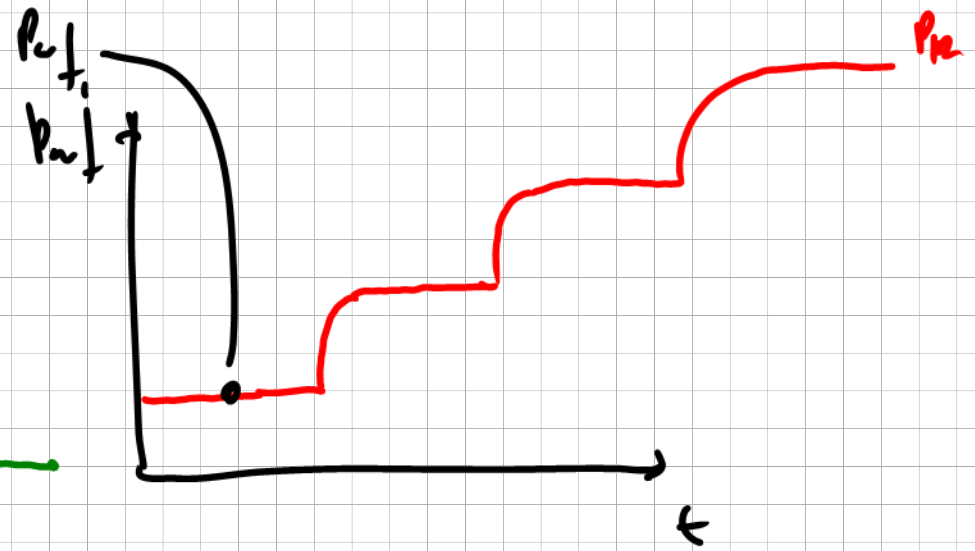
Bottom-hole Pressures in Oil Wells[1]

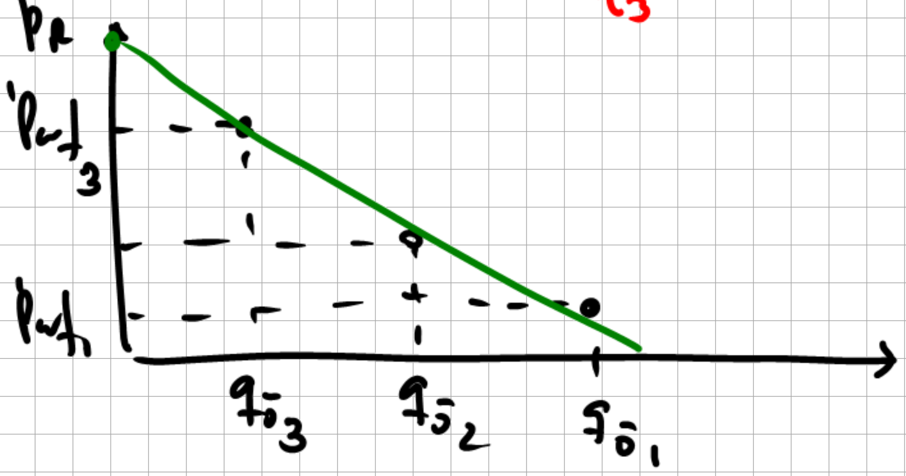
BY CHARLES V. MILLIKAN,[2] TULSA, OKLA. AND CARROLL V. SIDWELL,[3] SEMINOLE, OKLA.

(Tulsa Meeting, October, 1930)

THERE is nothing more important in petroleum engineering than a definite knowledge of the pressure at the bottom of an oil well at any existing operating condition, and the relation of this pressure to the pressure within the producing formation. A knowledge of bottom-hole pressures is fundamental in determining the most efficient methods of recovery and the most efficient lifting procedure, yet there is less information about these pressures than about any other part of the general problem of producing oil.



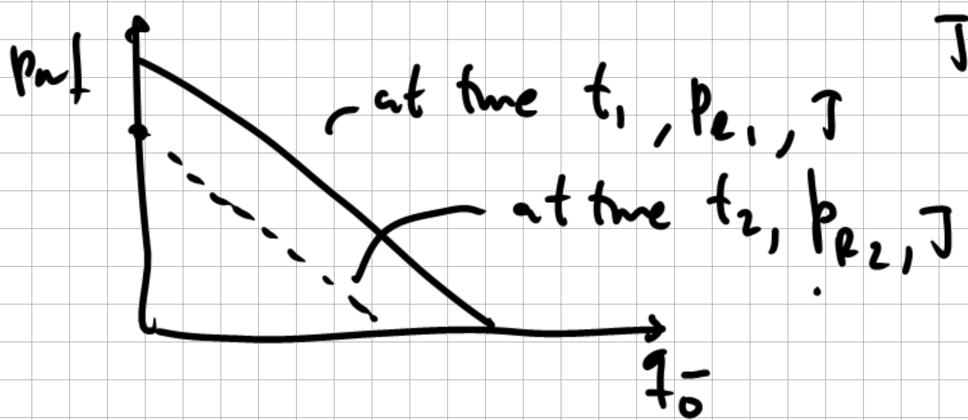




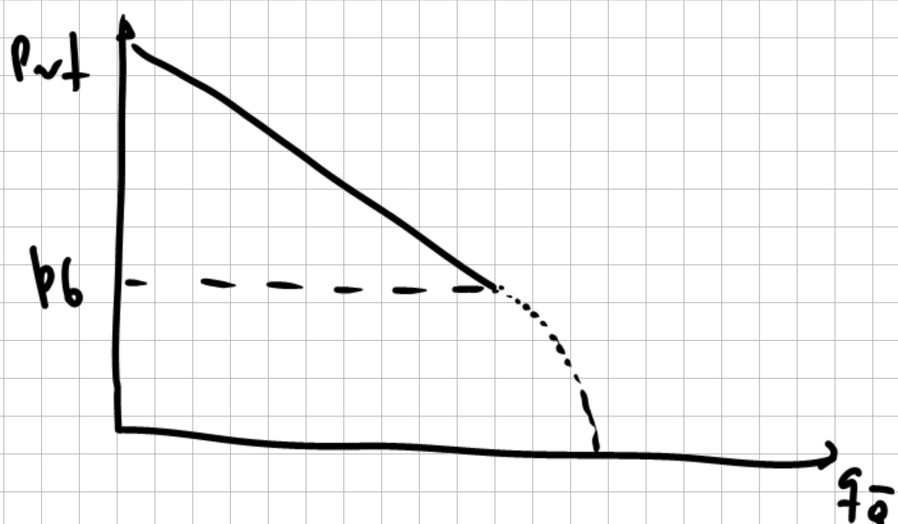
$$\underbrace{q_{\bar{o}}}_{Sm^3/d} = J\,(\overbrace{p_R - p_{wf}}^{bara})$$

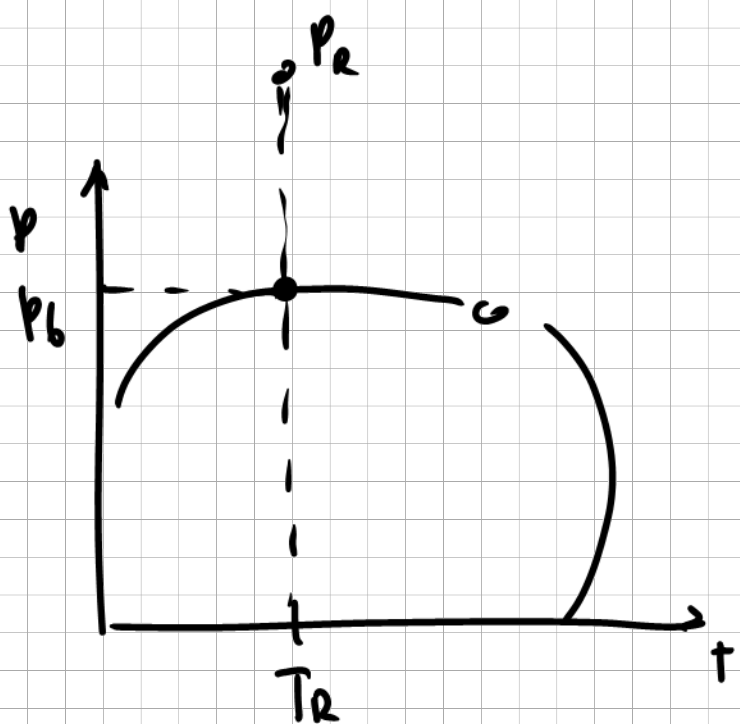
Productivity index

$$J = \left[\frac{Sm^3/d}{bara}\right]$$



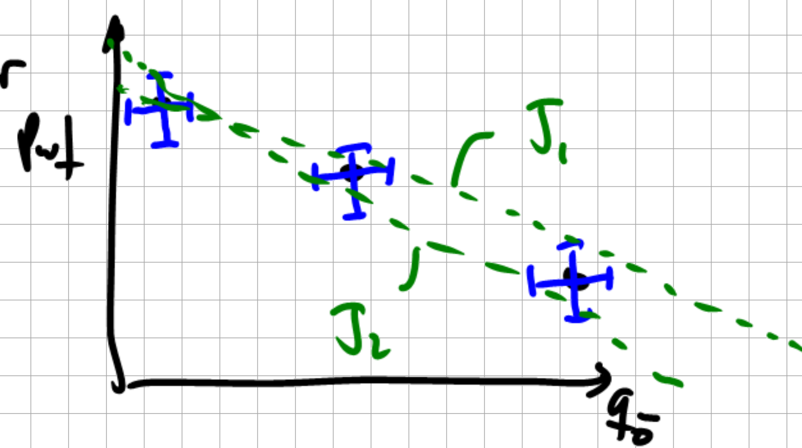
J usually doesn't change with depletion





- effect of measurement errors and variability

p = value + error



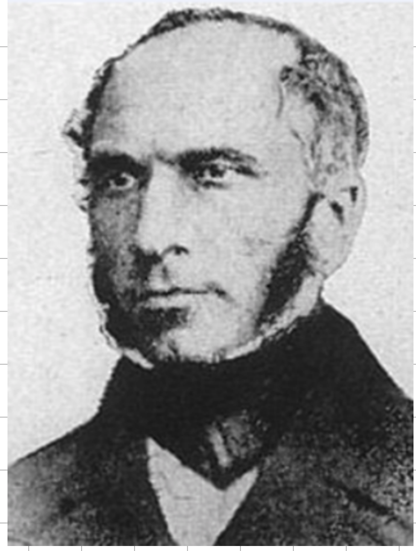
if one point is available, and reservoir pressure is known

P_{wf_1} , $q_{\bar{o}_1}$

$$q_{\bar{o}_1} = J\left(P_R - P_{wf_1}\right)$$

$$J = \frac{q_{\bar{o}_1}}{\left(P_R - P_{wf_1}\right)}$$

Darcy's law

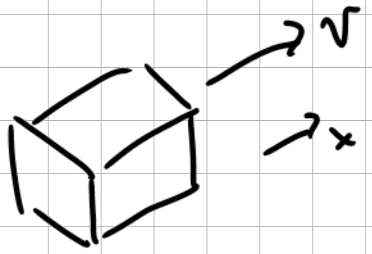


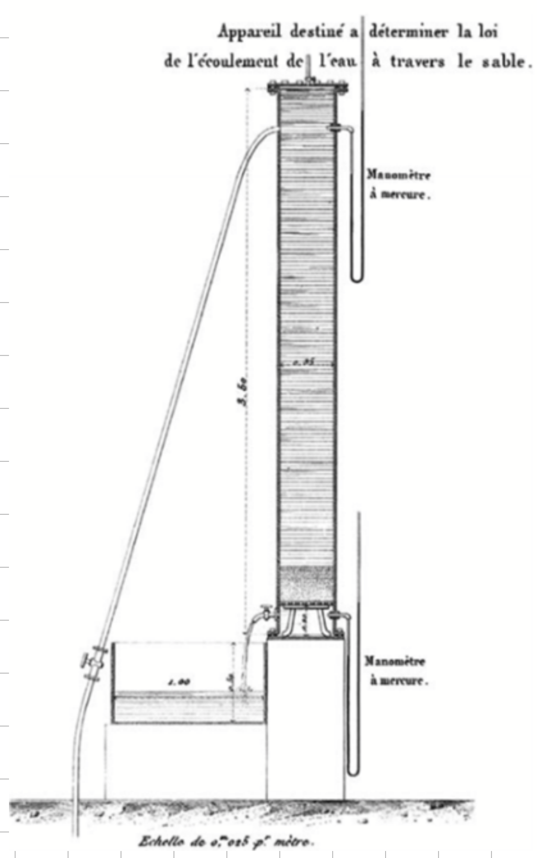
Dijon

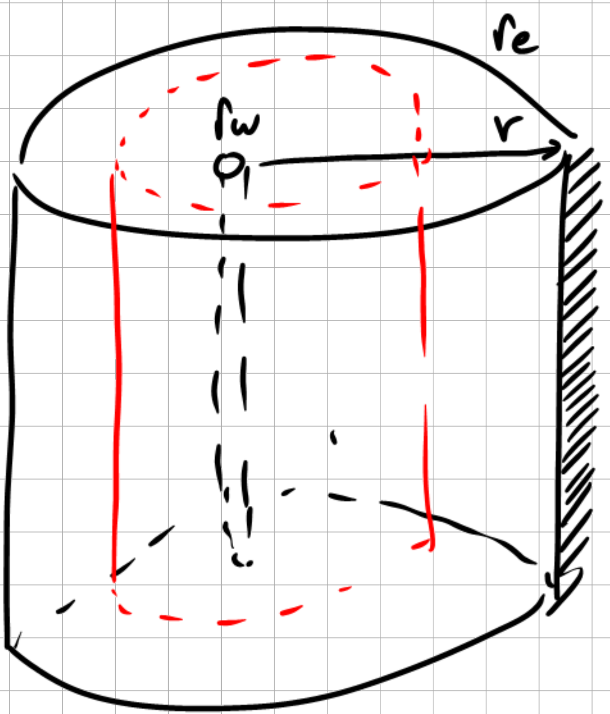
1856 → Retired to Dijon

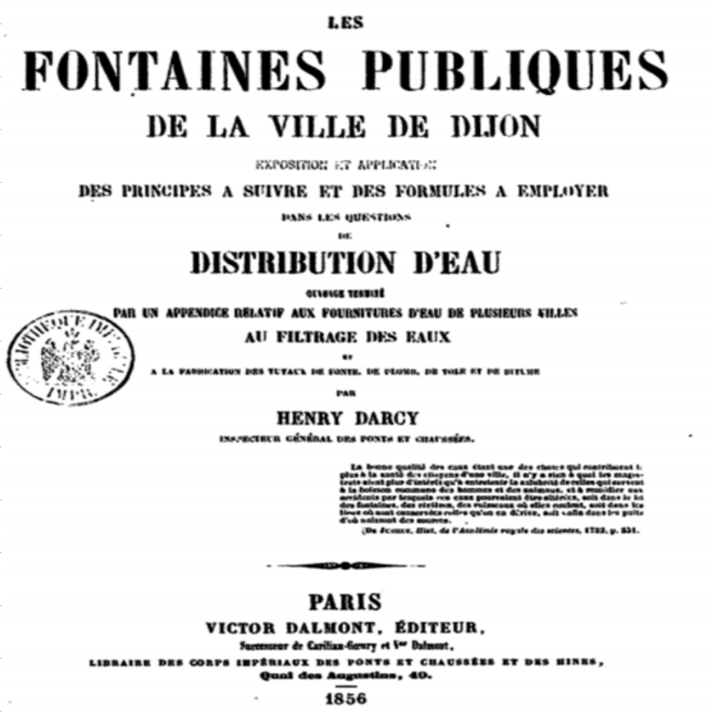
1858 → died

$$v = \frac{k}{\mu} \cdot \frac{dP}{dx}$$









LES
FONTAINES PUBLIQUES
DE LA VILLE DE DIJON
EXPOSITION ET APPLICATION
DES PRINCIPES A SUIVRE ET DES FORMULES A EMPLOYER
DANS LES QUESTIONS
DE
DISTRIBUTION D'EAU
OUVRAGE TERMINÉ
PAR UN APPENDICE RELATIF AUX FOURNITURES D'EAU DE PLUSIEURS VILLES
AU FILTRAGE DES EAUX
ET
A LA FABRICATION DES TUYAUX DE FONTE, DE PLOMB, DE TOLE ET DE BITUME
PAR
HENRY DARCY
INSPECTEUR GÉNÉRAL DES PONTS ET CHAUSSÉES.

PARIS
VICTOR DALMONT, ÉDITEUR,
Successeur de Carilian-Gœury et V^{ve} Dalmont,
LIBRAIRE DES CORPS IMPÉRIAUX DES PONTS ET CHAUSSÉES ET DES MINES,
Quai des Augustins, 40.
1856

$$\left.\begin{matrix} SS \\ PSS \end{matrix}\right\} \frac{\partial}{\partial t} = 0$$

$$v = \frac{k}{\mu} \frac{dP}{dr}$$

$v \rightarrow q_{\bar{o}}$

$$v = \frac{q_o}{A} \rightarrow [m^3/d] \quad [m^3/s]$$

$A \rightarrow 2\pi r h$

$q_{\bar{o}}$?

$q_{\bar{o}} \overset{?}{\rightarrow} q_o$

Black oil properties

oil volume factor

$$B_o(P,T) = \frac{V_o(P,T)}{V_{\bar{o}}} > 1$$

$$q_o = B_o(P,T) \cdot q_{\bar{o}}$$

$$B_o = \left[m^3 / Sm^3 \right]$$

$$v = \frac{q_{\bar{o}} \cdot B_o}{2\pi r h} = \frac{k}{\mu_o} \frac{\partial P}{dr}$$

$f(P,T)$

$q_o \overset{?}{=} f(r)$

$q_o \neq f(r)$ } SS

$$\underbrace{\int_{r_w}^{r@p_R} \frac{dr}{r}}_{①} = \frac{2\pi k h}{q_o} \underbrace{\int_{p_{wf}}^{p_R} \frac{dp}{B_o \mu_o}}_{②}$$

for SS, $r@p_R = 0.61\, r_e$

$$p_R = \frac{\int_V p\, dV}{V}$$

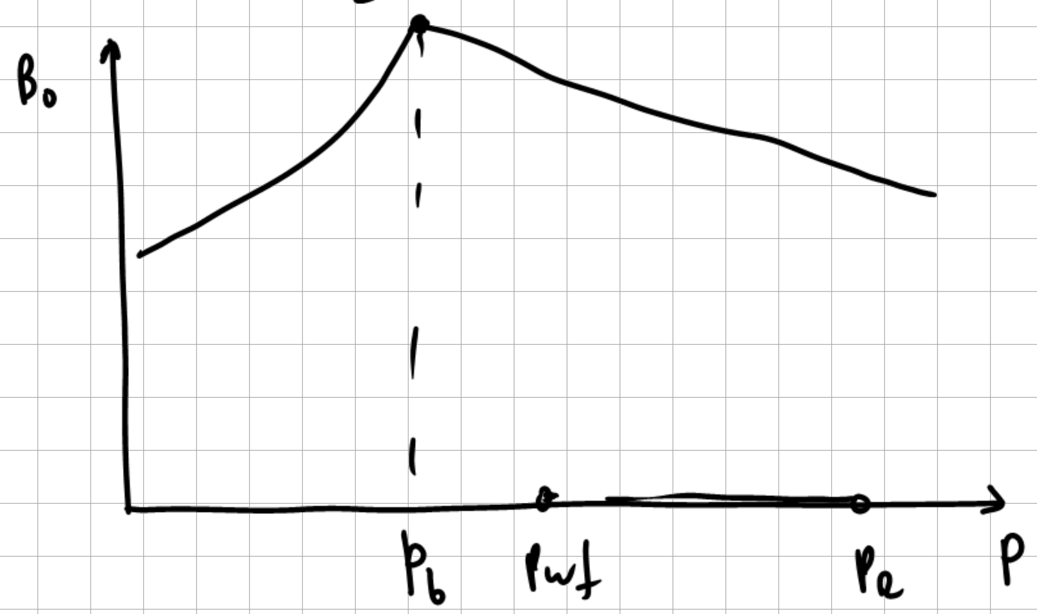
① $\ln\left(\frac{0.61\, r_e}{r_w}\right) = \ln(0.61) + \ln\left(\frac{r_e}{r_w}\right) = \ln\left(\frac{r_e}{r_w}\right) - 0.5$

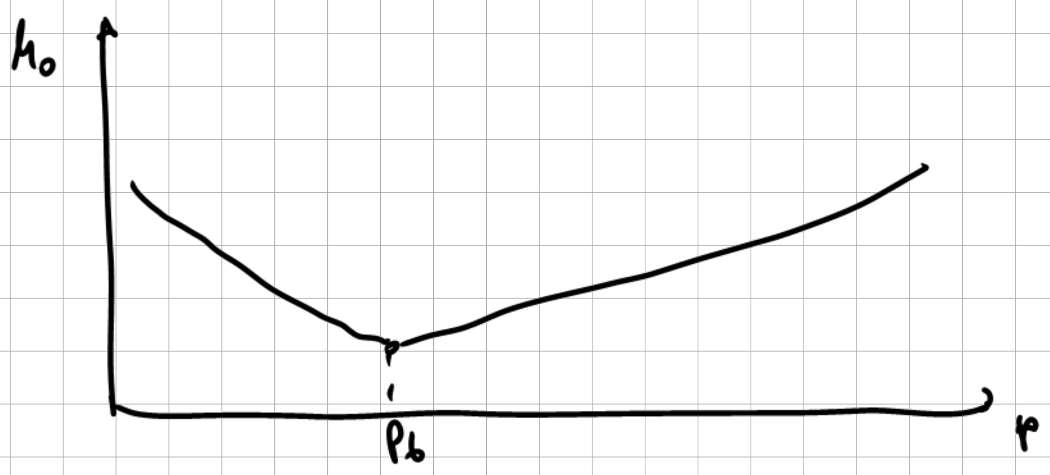
② $\int_{p_{wf}}^{p_R} \frac{1}{\mu_o B_o}\, dp$

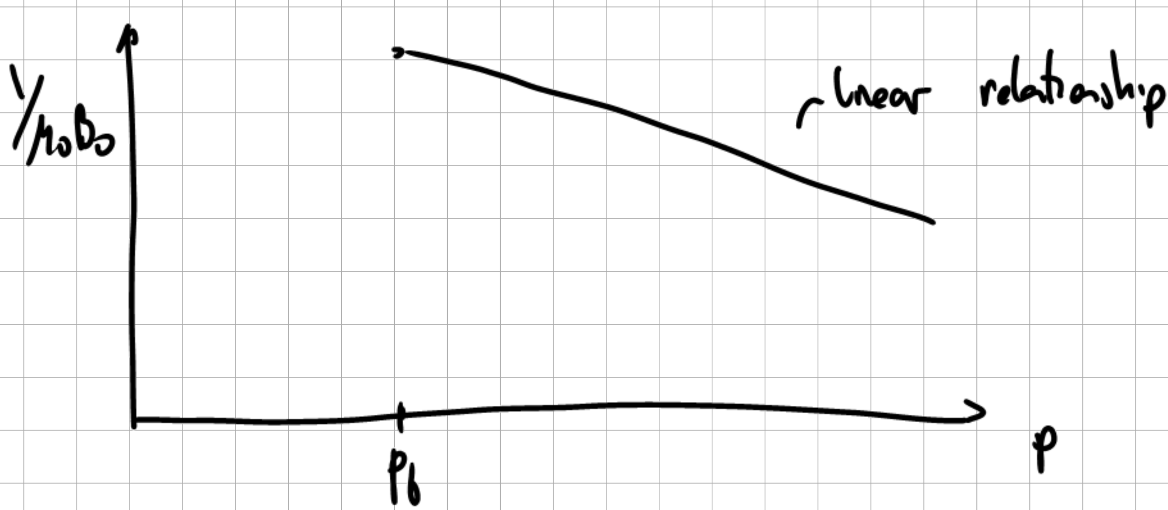
$\mu_o = f_1(p, T)$
$B_o = f_2(p, T)$

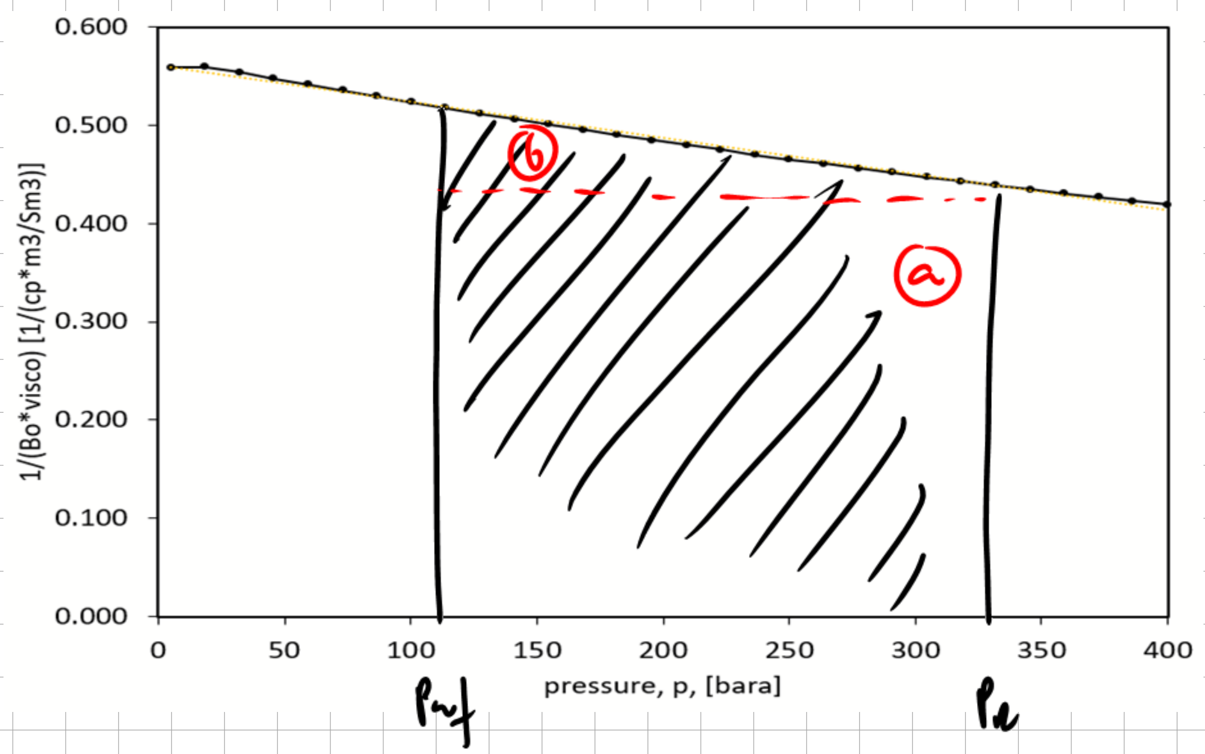
@ reservoir $T = \text{constant} = T_R$

sat ← | → undersaturated









$$② \quad \int_{p_{wf}}^{p_R} \frac{1}{\mu_o B_o} \cdot dp \simeq (p_R - p_{wf}) \cdot \underbrace{\left[\left.\frac{1}{\mu_o B_o}\right|_{p_{wf}} + \left.\frac{1}{\mu_o B_o}\right|_{@ p_R} \right] 0.5}_{\left.\frac{1}{\mu_o B_o}\right|_{@ p_{av} = \frac{(p_R + p_{wf})}{2}}}$$

$$② = \frac{(p_R - p_{wf})}{(\mu_o B_o)_{@ p_{av}}}$$

$$\ln\left(\frac{r_e}{r_w}\right) - 0.5 = \frac{2\pi k h}{q_o} \frac{(p_R - p_{wf})}{(\mu_o B_o)_{@ p_{av}}}$$

$$q_o = \frac{2\pi k h \quad (p_R - p_{wf})}{(\mu_o B_o)_{@ p_{av}} \left[\ln\left(\frac{r_e}{r_w}\right) - 0.5 \right]}$$

$J \simeq$ constant

$$q_o = \frac{2\pi k h \, (p_e - p_{wf})}{(\mu_o B_o)_{@p_{av}} \left[\ln\left(\frac{r_e}{r_w}\right) - 0.5\right]}$$

- steady-state
- vertical well, fully perforated
- undersaturated oil
- radial drainage volume
- homogeneous permeability

SI system

$$\left[Sm^3/s\right] = \frac{[m^2]\,[m]\,[Pa]}{[Pa\ s]\ [-]}$$

$$\left[Sm^3/d \ \frac{1\,d}{24\,h} \ \frac{1\,h}{3600\,s}\right] = \frac{\left[1\ md \ \frac{1\,d}{1000\,md} \ \frac{9.86E\text{-}13\ m^2}{1\,d}\right][m]\left[bara \ \frac{10^5\,Pa}{1\,bara}\right]}{\left[1\ cp \ \frac{10^{-3}\,Pa.s}{1\,cp}\right]} \ 2\pi$$

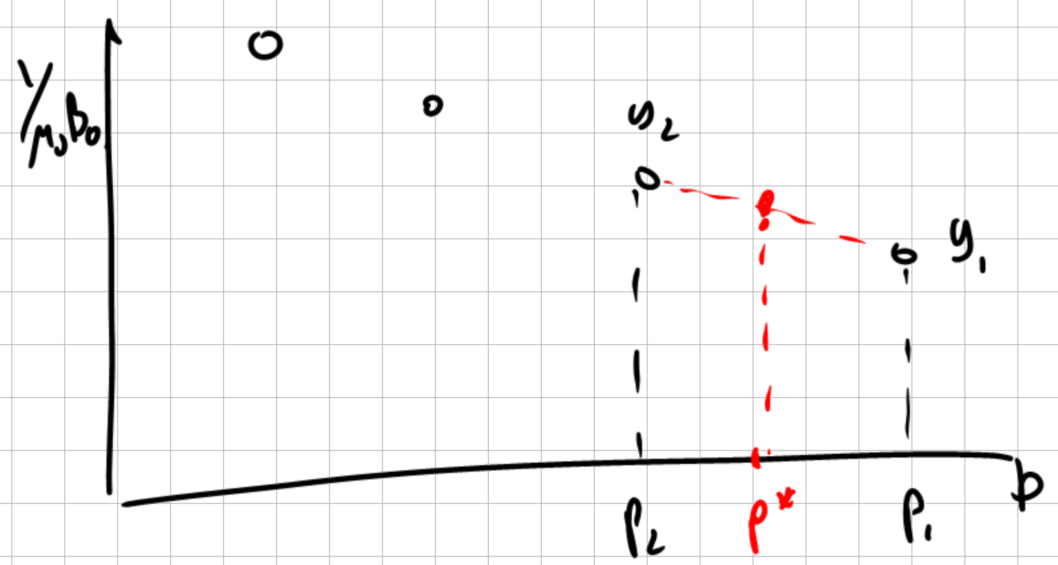
$$= \frac{1}{18.68}$$

$$q_o = \frac{k h \, (p_e - p_{wf})}{(\mu_o B_o)\big|_{@p_{av}} \left(\ln \frac{r_e}{r_w} - 0.5\right)} \ \frac{1}{18.68}$$

J

p in bara
k in md
μ_o in cp
$q_o = Sm^3/d$

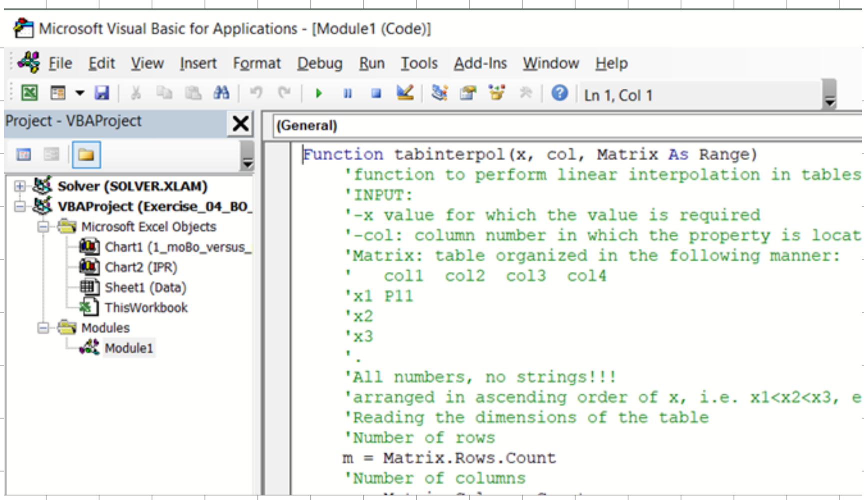
$$J = \frac{k h}{(\mu_o B_o)_{av} \left(\ln\left(\frac{r_e}{r_w}\right) - 0.5\right) \cdot 18.68}$$



$$\frac{y_2 - y_1}{p_2 - p_1} = \frac{y_2 - y^*}{p_2 - p^*} \qquad y = \frac{1}{\mu_o B_o}$$

VBA visual basic for application

while in excel press alt + F11


Microsoft Visual Basic for Applications - [Module1 (Code)]
File Edit View Insert Format Debug Run Tools Add-Ins Window Help
Ln 1, Col 1
Project - VBAProject
Solver (SOLVER.XLAM)
VBAProject (Exercise_04_BO_
Microsoft Excel Objects
Chart1 (1_moBo_versus_
Chart2 (IPR)
Sheet1 (Data)
ThisWorkbook
Modules
Module1
(General)

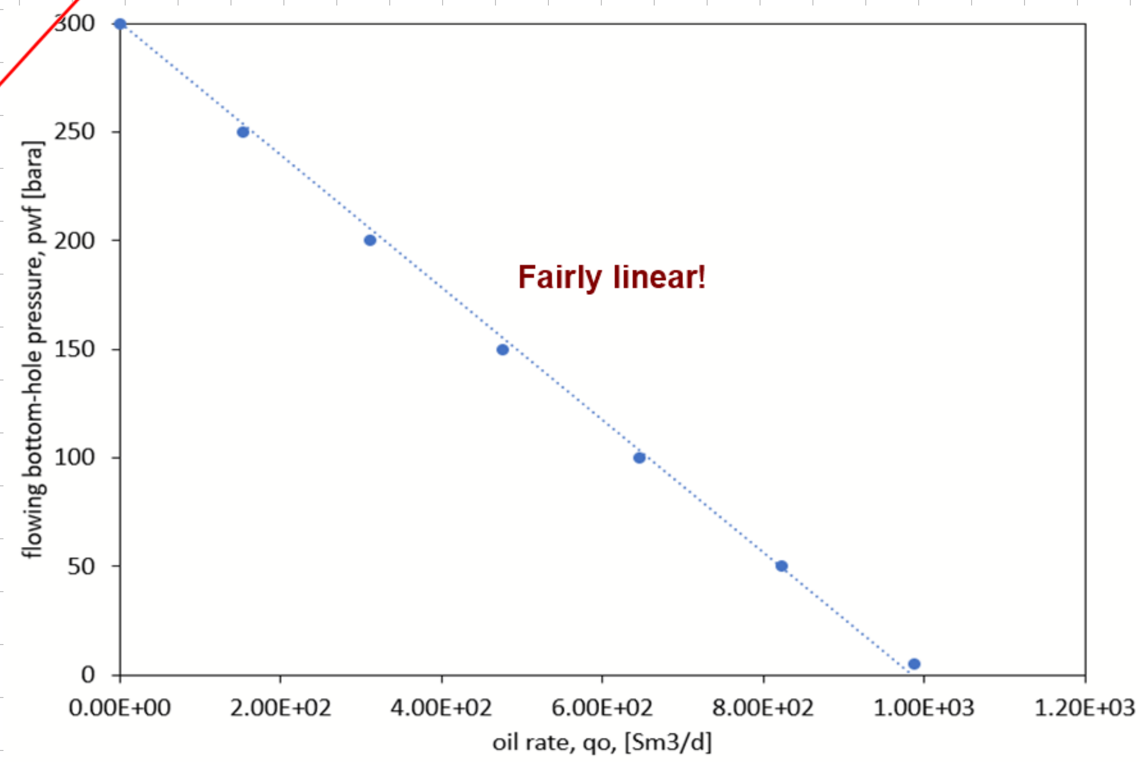
```
Function tabinterpol(x, col, Matrix As Range)
    'function to perform linear interpolation in tables
    'INPUT:
    '-x value for which the value is required
    '-col: column number in which the property is locat
    'Matrix: table organized in the following manner:
    '    col1  col2  col3  col4
    'x1 P11
    'x2
    'x3
    '.
    'All numbers, no strings!!!
    'arranged in ascending order of x, i.e. x1<x2<x3, e
    'Reading the dimensions of the table
    'Number of rows
    m = Matrix.Rows.Count
    'Number of columns
```

Use here the VBA function ProductivityIndex_J

use here the VBA function tabinterpol

r_e	[m]	500
r_w	[m]	0.1
k	[md]	10
h	[m]	100
p_R	[bara]	300

pwf [bara]	pav [bara]	1/(Bo visco) [1/(cp*m3/Sm3)]	J [Sm3/d/bar]	qo [Sm3/d]
300	300	0.449	3.0	0.00E+00
250	275	0.457	3.1	1.53E+02
200	250	0.465	3.1	3.11E+02
150	225	0.474	3.2	4.75E+02
100	200	0.483	3.2	6.46E+02
50	175	0.493	3.3	8.23E+02
5	153	0.502	3.3	9.88E+02

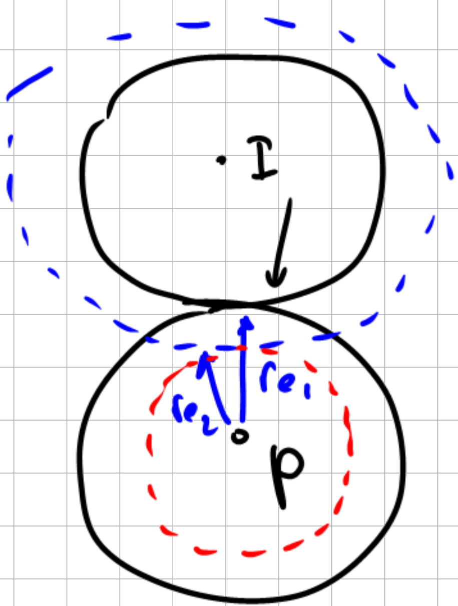


EFFECT OF THE BOUNDARY (re)

EFFECT OF THE REGIME (SS)

r_e	[m]	500
r_w	[m]	0.1
k	[md]	10
h	[m]	100
p_R	[bara]	300

$$\ln\left(\frac{r_e}{r_w}\right) = 8.52E+00$$



$$J = \frac{kh}{18.68\,(\mu_o B_o)_{av}\cdot\left(\underbrace{\ln\frac{r_e}{r_w}}_{8.5} - \underbrace{0.5}_{10\%}\right)}$$

SS, boundary effect

r_e	[m]	500
r_w	[m]	0.1
k	[md]	10
h	[m]	100
p_R	[bara]	300

pwf [bara]	pav [bara]	1/(Bo visco) [1/(cp*m3/Sm3)]	J [Sm3/d/bar]	qo [Sm3/d]
300	300	0.449	3.0	0.00E+00
250	275	0.457	3.1	1.53E+02
200	250	0.465	3.1	3.11E+02
150	225	0.474	3.2	4.75E+02
100	200	0.483	3.2	6.46E+02
50	175	0.493	3.3	8.23E+02
5	153	0.502	3.3	9.88E+02

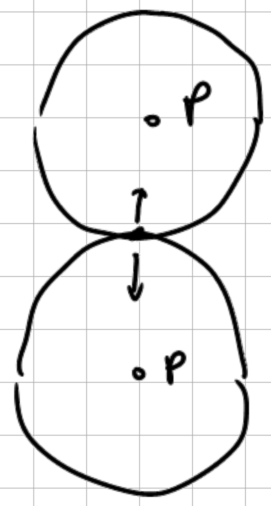
r_e	[m]	400
r_w	[m]	0.1
k	[md]	10
h	[m]	100
p_R	[bara]	300

pwf [bara]	pav [bara]	1/(Bo visco) [1/(cp*m3/Sm3)]	J [Sm3/d/bar]	qo [Sm3/d]
300	300	0.449	3.1	0.00E+00
250	275	0.457	3.1	1.57E+02
200	250	0.465	3.2	3.20E+02
150	225	0.474	3.3	4.89E+02
100	200	0.483	3.3	6.64E+02
50	175	0.493	3.4	8.46E+02
5	153	0.502	3.4	1.02E+03

Video 09 - Skin effect for IPR of vertical, undersaturated oil well

$$q_{\bar{o}} = \frac{kh}{(\mu_o B_o)_{av}\left(\underbrace{\ln\left(\frac{r_e}{r_w}\right)}_{8} - 0.5\right) \cdot 18.68}(p_R - p_{wf})$$

pseudo steady-state pss @ r_e → no-flow boundary



$$\int_{r_w}^{@p_R} \frac{dr}{r} = \frac{kh}{q_{\bar{o}} \cdot 18.68}\int_{p_{wf}}^{p_R} \frac{dp}{B_o \mu_o}$$

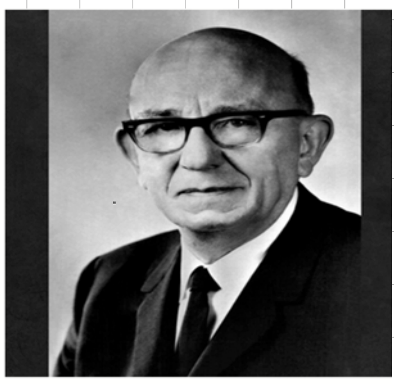
for pss r at which $p = p_R$ $r = 0.47\, r_e$

$$\ln\left(\frac{0.47\, r_e}{r_w}\right) = \ln\left(\frac{r_e}{r_w}\right) - 0.75$$

$$J = \frac{kh}{(\mu_o B_o)_{av}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75\right] 18.68}$$

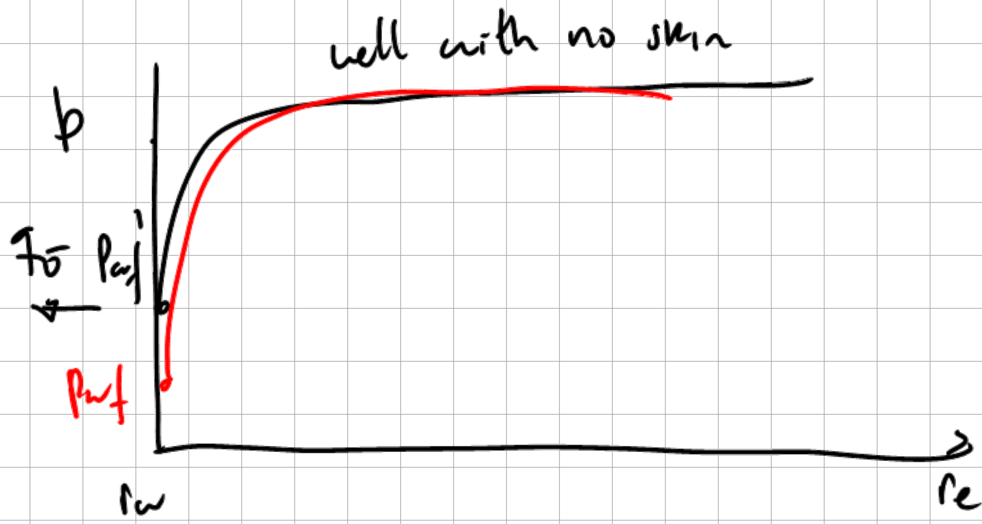
<u>Skin factor</u> 1953 → Hurst

↳ Antonius Van Everdingen (Dutch mining engineer) Shell



THE SKIN EFFECT AND ITS INFLUENCE ON THE PRODUCTIVE CAPACITY OF A WELL

A. F. VAN EVERDINGEN, SHELL OIL CO., HOUSTON, TEXAS, MEMBER AIME



$$(\underbrace{p_{wf}'}_{\substack{\text{ideal} \\ \downarrow \\ \text{no skin}}} - \underbrace{p_{wf}}_{\substack{\text{actual} \\ \text{with} \\ \text{skin}}}) = \Delta p_{skin} = S \underbrace{\left[\frac{18.68\,(\mu_o B_o)_{av} \cdot q_{\bar{o}}}{kh}\right]}_{\text{bar}}$$

$$P_R - \cancel{P_{wf}'} = \frac{q_o \, 18.68 \, (\mu_o B_o)_{av}}{k \cdot h} \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 \right]$$

$$\cancel{P_{wf}'} - P_{wf} = \frac{q_o \, 18.68 \, (\mu_o B_o)_{av}}{kh} S$$

$$P_R - P_{wf} = \frac{q_o \, 18.68 \, (\mu_o B_o)_{av}}{kh} \left[\ln \frac{r_e}{r_w} - 0.75 + S \right]$$

$$J = \frac{kh}{18.68 \, (\mu_o B_o)_{av} \left[\underbrace{\ln \frac{r_e}{r_w}}_{\text{convergence}} \underbrace{- 0.75}_{\text{boundary}} + \underbrace{S}_{\text{skin (near wellbore non-idealities)}} \right]}$$

8

other definitions "equivalent" to skin

- flow efficiency

$$E_F = \frac{P_R - P_{wf}'}{P_R - P_{wf}} = \frac{\frac{\cancel{q_o}}{J'}}{\frac{\cancel{q_o}}{J}} = \frac{\ln\left(\frac{r_e}{r_w}\right) - 0.75}{\ln\left(\frac{r_e}{r_{w}}\right) - 0.75 + S} \approx \frac{7}{7 + S}$$

- apparent wellbore radius

$$\ln\left(\frac{r_e}{r_w}\right) + S = \ln\left(\frac{r_e}{r_{wa}}\right) \qquad r_{wa} = r_w e^{-S}$$

if $S > 0$ ⤳ damage (less than ideal) $(P_{wf}' - P_{wf}) > 0$

if $S = 0$ ⤳ ideal

if $S < 0$ ⤳ "stimulation" → productivity more than ideal

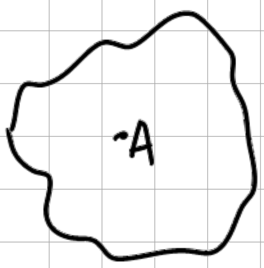
∘ Drainage area shape → 1965 Daniel Dietz

Determination of Average Reservoir Pressure From Build-Up Surveys

D. N. DIETZ
MEMBER AIME

KONINKLIJKE/SHELL LABORATORIUM
RIJSWIJK, THE NETHERLANDS

$$\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S + \underbrace{S_A}_{\text{shape-area skin}}$$



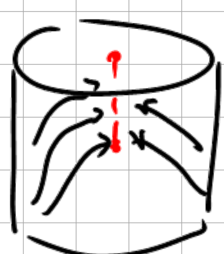
$$A = \pi \cdot r_e^2 \qquad r_e = \sqrt{\frac{A}{\pi}}$$

← well performance (2nd edition) Golan, Whitson

Table 2.4 Shape Factors for Nonradial Outer Boundary Geometries

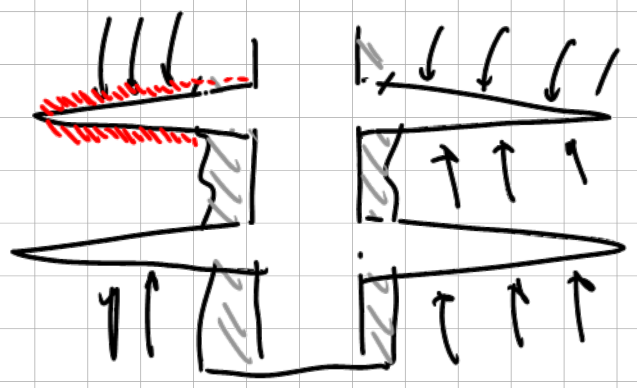
Geometry	C_A	s_A	t_{DAcia}[a]	t_{DApss}[b]
	31.62	0.000	0.1	0.1
	30.88	0.012	0.09	0.1
	31.60	0.000	0.1	0.1
	27.6	0.068	0.09	0.2
60°	27.1	0.077	0.09	0.2
1/3, 1	21.9	0.184	0.08	0.4
1, 2	21.84	0.185	0.025	0.3

- other cases than can be modeled (represented) with skin
- formation damage (due to drilling) $S > 0$
- partial penetration



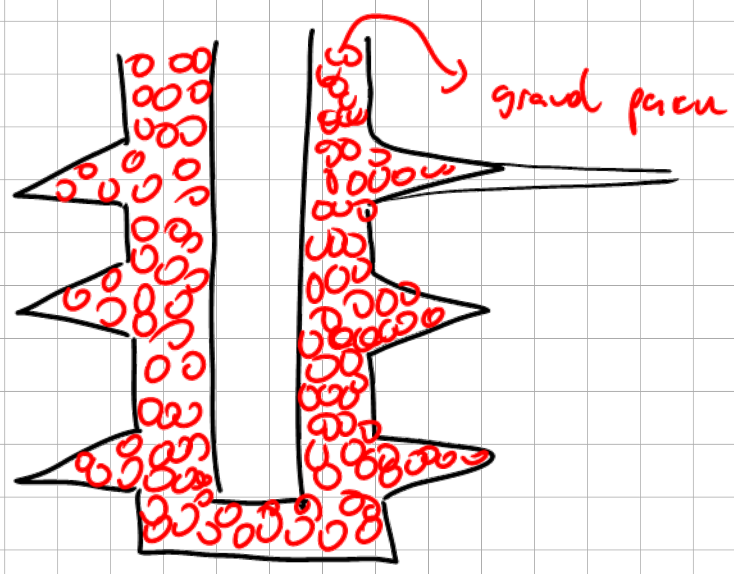
$k_v << k_H$ $S > 0$

- perforation



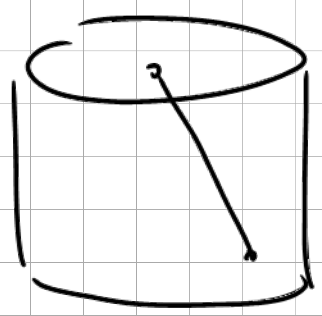
$S > 0$

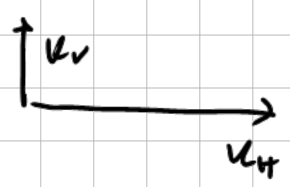
- Sand control (gravel pack)



$S > 0$

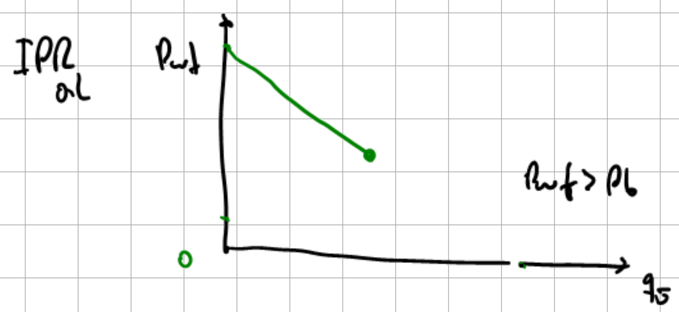
- wellbore inclination
  (permeability anisotropy)



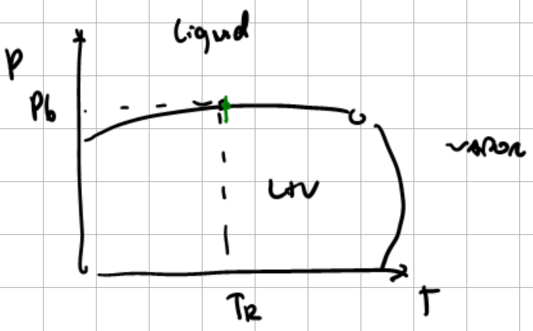


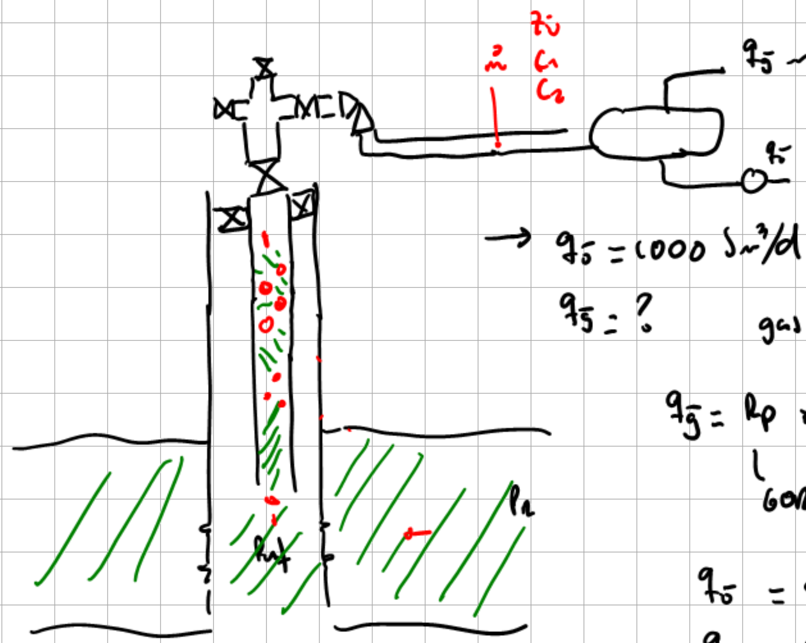
- acidizing (stimulation)
- fracking

$\left.\right\}$ $S < 0$



$P_{wf} > P_b$





→ $q_o = 1000\ Sm^3/d$

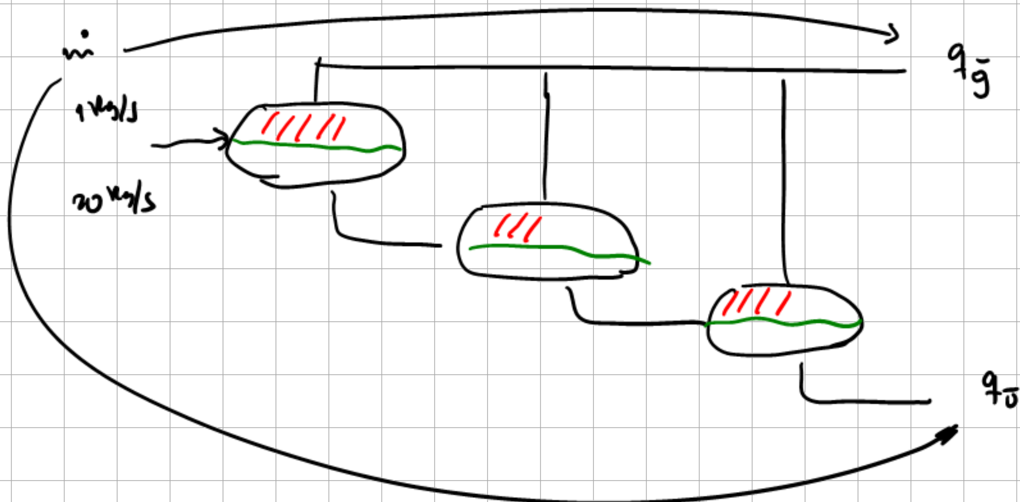
$q_g = ?$ gas in solution

$q_g = R_p \cdot q_o$

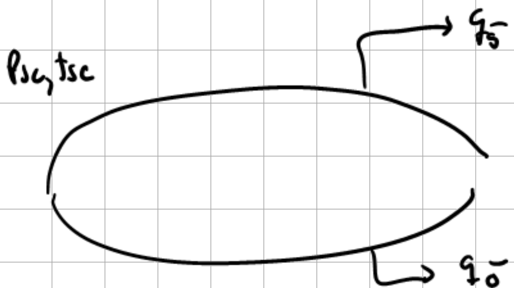
GOR producing gas-oil ratio

$q_o = 500\ Sm^3/d$

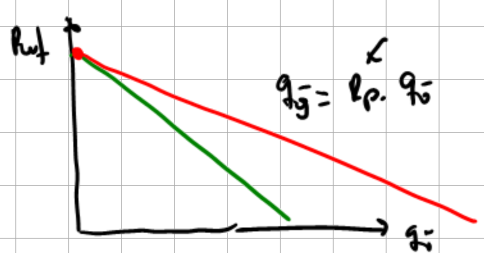
$q_g = q_o \cdot R_p$



$R_p = f(sep, q_o)$



$R_p \downarrow$



$q_g = R_p \cdot q_o$

$R_p = (700 - 3000)\ scf/stb$

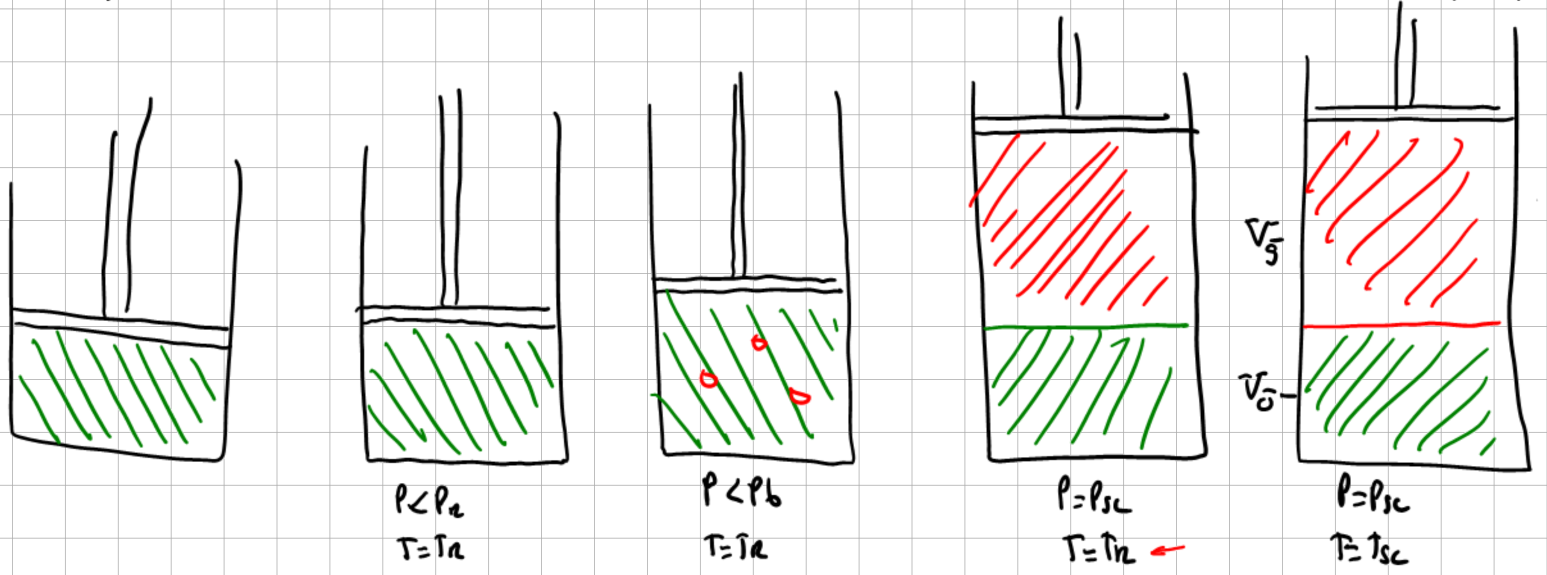
$50 - 300\ m^3/Sm^3$

For gas wells, we use

CGR condensate gas ratio

stb/1E06 scf

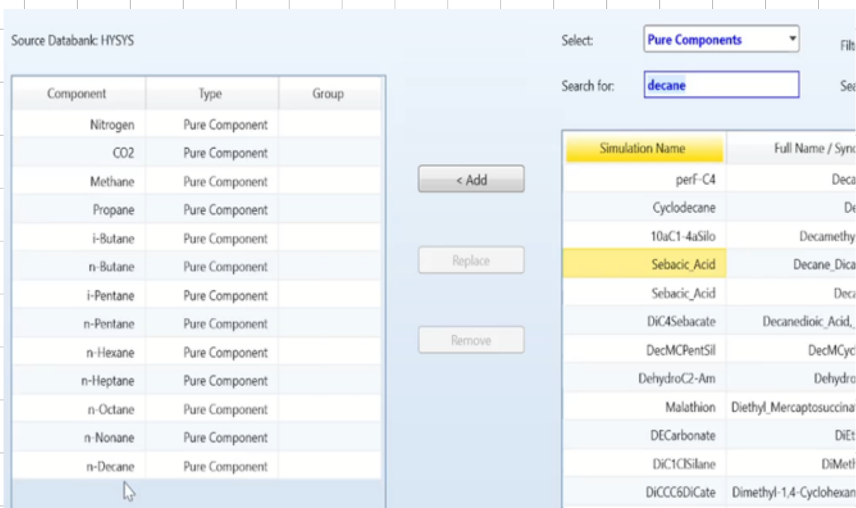
Sm^3/1E06 Sm^3

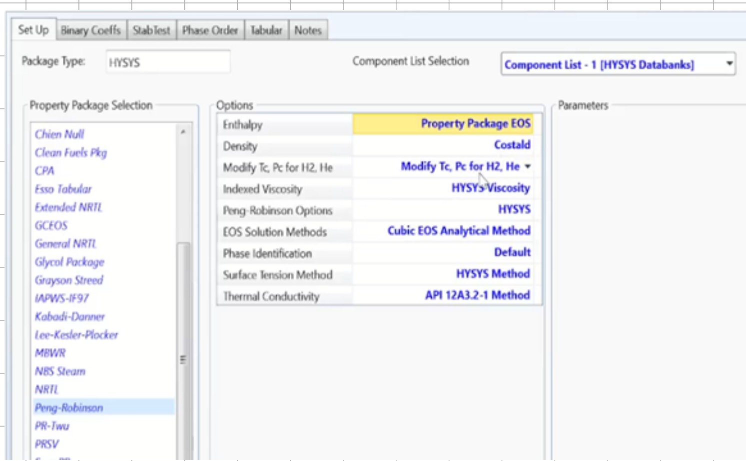


CCE constant composition expansion

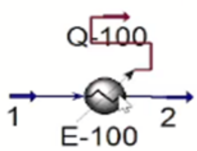
$$R_p = \frac{V_g}{V_o}$$

simulating a CCE in Hysys (using farm.ntnu.no), from reservoir conditions to surface conditions

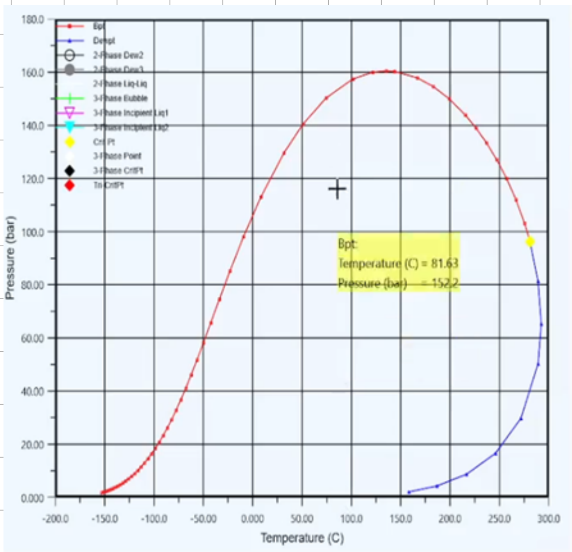




Stream Name	1
Vapour / Phase Fraction	<empty>
Temperature [C]	80,00
Pressure [bar]	300,0
Molar Flow [kgmole/h]	1,000
Mass Flow [kg/h]	<empty>
Std Ideal Liq Vol Flow [m3/h]	<empty>



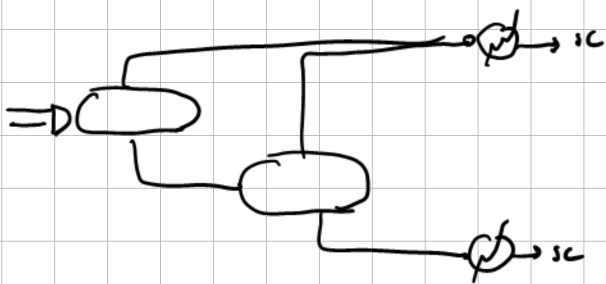
Stream Name	2
Vapour / Phase Fraction	<empty>
Temperature [C]	15,56
Pressure [bar]	1,013
Molar Flow [kgmole/h]	<empty>
Mass Flow [kg/h]	<empty>



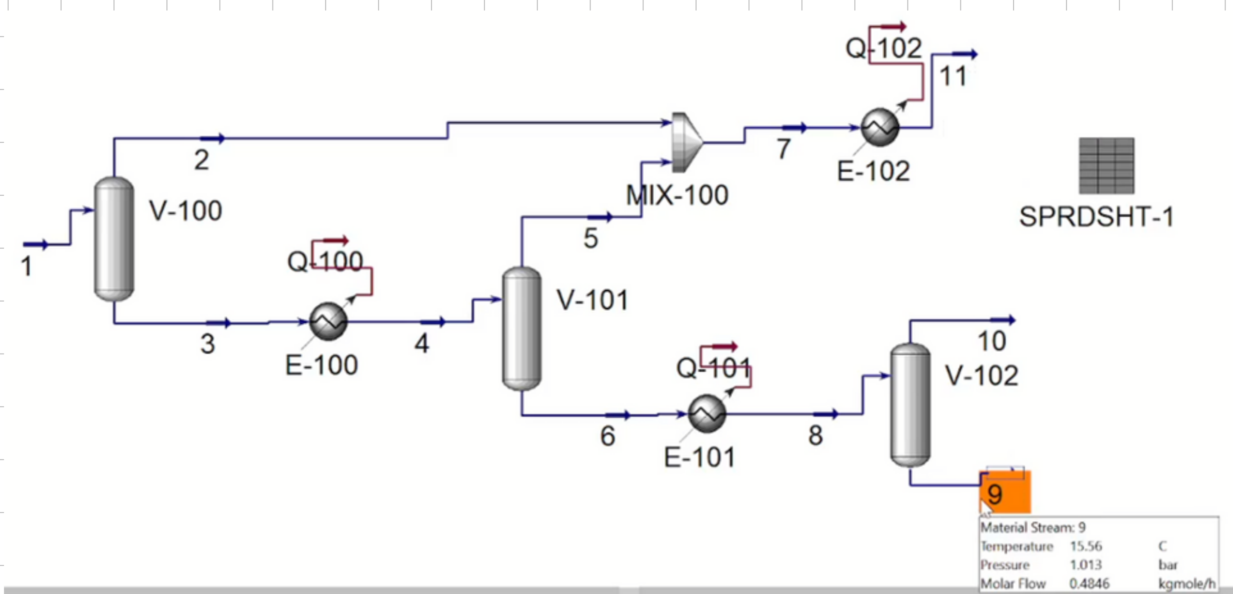
$$R_p = \frac{q_{g@sc}}{q_{o@sc}}$$

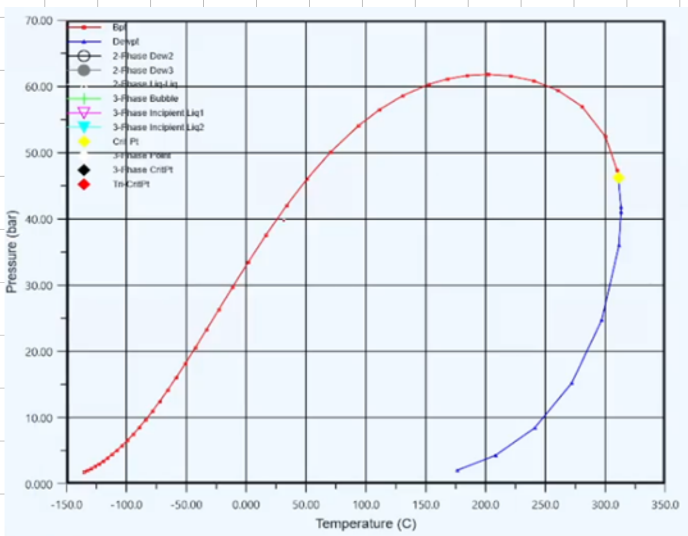
m [kg/h]	11.5952	59.7041
den [kg/m3]	0.91631	723.58
q [m3/h]	12.6542	0.08251
rp	153.362	

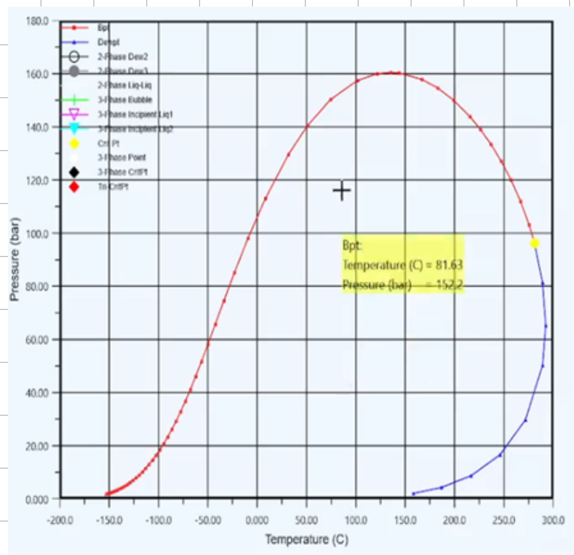
Let's now model the actual surface process (not CCE)



	HP p [bara]	HP T [C]	LP p [bara]	LP T [C]
SURFACE PROCESS 1	50	70	20	50





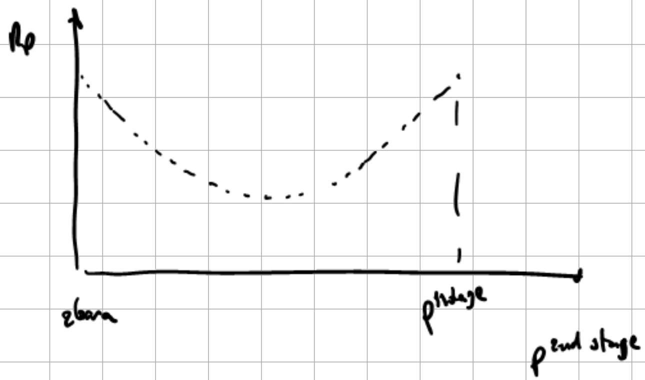


phase envelope of 3 (oil from first stage separator) **vs** **phase envelope of 1 (production fluid)**

When taking the oil and gas to standard conditions (using coolers E-101 and E-102), some oil will condense from the gas (Stream 11 has some oil, 1.7 E-04 kgmol/h), and some gas will vaporize from the oil (stream 10, gas has a rate of 0.07 kgmol/h). We should merge these gas with the sc gas (0.448 kgmol/h) and sc oil (0.48 kgmol/h). However they are very small, so will probably not affect much the results if we neglect them.

m [kg/h]	8.40241	60.9351
den [kg/m3]	0.80013	720.941
q [m3/h]	10.5013	0.08452
rp	124.244	

The pressure and temperature of the second stage is typically a design parameter people perform a sentitivty analysis on (using a process simulator) to determine values that minimize Rp



The pressure of the first stage is chosen such that rates are sufficiently high.

Class 20220908 -

Work in groups to conduct the following activities:

1. Get yourself familiar with the Hysys file created by Milan on the previous lecture. Examples:
   - Check the phase envelope of the reservoir stream and determine bubble pressure at 80 C
   - Determine density of standard conditions oil and convert to API. Does the value make sense? If not, what could be the reason?

Stream Name	Reservoir
Vapour / Phase Fraction	0.0000
Temperature [C]	80.00
Pressure [bar]	152.4
Molar Flow [kgmole/h]	1516
Mass Flow [kg/h]	1.080e+005

This happens because we are neglecting components heavier than decane C10. There are two options: including more components, or using pseudo components (e.g. C10+)

2. Assume that there is 30 kg/s of reservoir oil flowing to the processing facilities. If the price of oil is 80 usd/bbl, what is the difference in revenue (in USD/d) between using a CCE expansion to standard conditions or using the two-stage separation process provided in the Hysys file.

$$\dot{m} = q_{\bar{o}} \cdot \rho_{\bar{o}} + q_{\bar{g}} \cdot \rho_{\bar{g}} \qquad q_{\bar{g}} = q_{\bar{o}} \cdot R_p$$

$$\dot{m} = q_{\bar{o}} \left(\rho_{\bar{o}} + R_p \cdot \rho_{\bar{g}} \right)$$

$$q_{\bar{o}} = \frac{\dot{m}}{\left(\rho_{\bar{o}} + R_p \cdot \rho_{\bar{g}} \right)}$$

for CCE

$\rho_{\bar{o}} =$ Mass Density [kg/m3] 723.6

$\rho_{\bar{g}} =$ Mass Density [kg/m3] 0.9160

$R_p =$ **(17587.64/0.9160)/(90412.3/723.6) =153**

$$q_{\bar{o}} = 3000.87 \; Sm^3/d$$
$$= 18874 \; stb/d$$

for 2-stage sep

$\rho_{\bar{o}} =$ Mass Density [kg/m3] 720.9

$\rho_{\bar{g}} =$ Mass Density [kg/m3] 0.8501

$R_p =$ GOR 144.1

$$q_{\bar{o}} = 30/(720.9 + 144 \cdot 0.8501) = 0.0355 \; Sm^3/s$$
$$= 3073.59 \; Sm^3/d$$
$$= 19332.3 \; stb/d$$

Revenue $\quad q_{\bar{o}} \cdot P_o = 1.50$ USD/d $\quad$ CCE

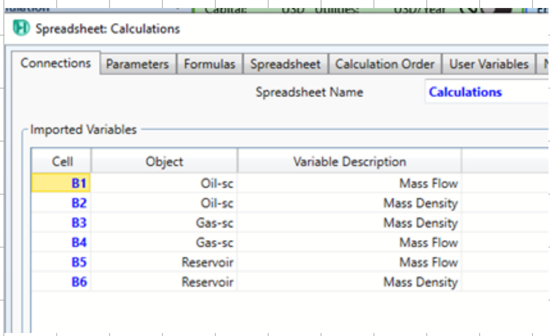
oil price

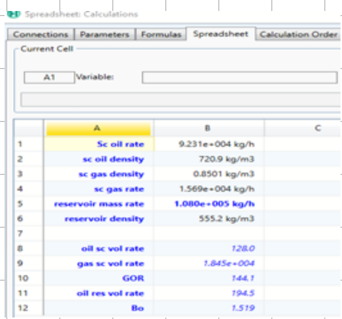
$= 19332.3 \cdot 80$ $\quad$ 2-stage sep

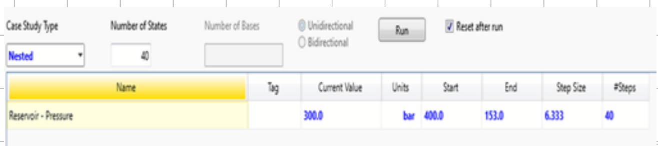
$= 1.54$ E06 USD/d

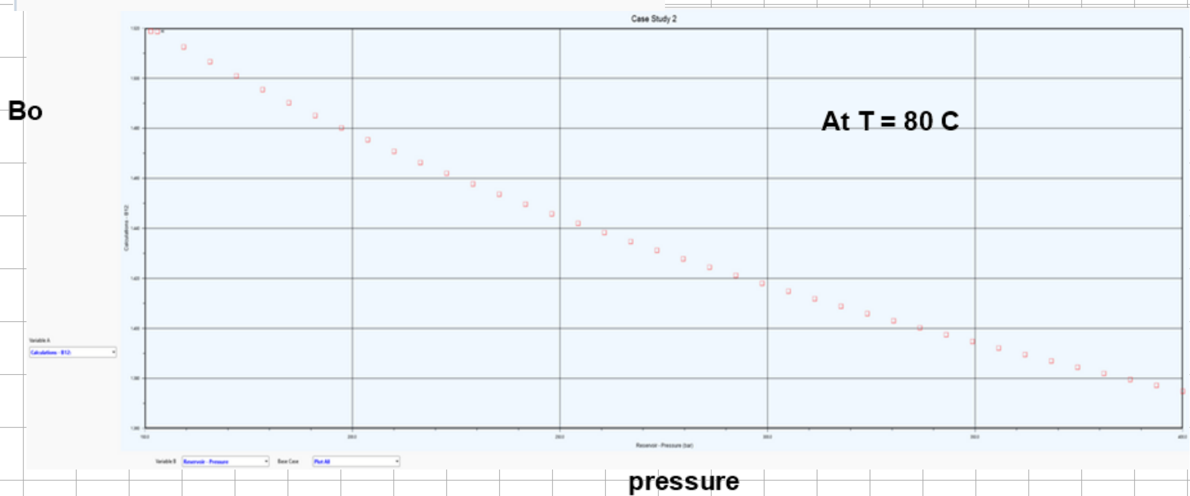
Difference: approx. 36.6 kUSD/d

3. Calculate Bo at reservoir pressure and temperature using the Hysys file and the spreadsheet. For that follow the steps:
    - In the spreadsheet, in the tab "connections", import mass flow and density of the reservoir stream. Compute volumetric rate at reservoir conditions in a cell on the spreadsheet
    - Use the volumetric rate at reservoir conditions and the oil rate at standard conditions to calculate Bo in the spreadsheet
4. Calculate Bo at several pressures from 400 bara to bubble point pressure at reservoir temperature. For this use the utility "Case Studies" (located in the tab "Home"). In case studies you must import pressure as an independent variable, and the cell where Bo is calculated in the spreadsheet as a "dependent variable"









5. Use a Bo correlation provided by Milan to calculate Bo. Compare the results obtained with the correlations with the ones estimated with Hysys. Is it possible to adjust the Bo correlation to match the results from Hysys?

Why does Bo behave like this with pressure?

Due to compressibility (single phase oil). The greater the pressure, the smaller the volume, the higher the density.

$$\beta = -\frac{1}{V}\frac{\partial V}{\partial p}$$

Volume of oil at the bubble point pressure (pb): Vob

Volume of oil at a pressure p: Vo@p

Integrating the equation above between these two volumes and assuming that compressibility is constant:

-beta*(p-pb) = ln(Vo@p/Vob)
Vo@p/Vob=exp(-beta*(p-pb)

Using the definitions
Bo = Vo@p/Vo_sc
and
Bob=Vob/Vo_sc

this gives (Vo_sc cancels out):
Bo=Bob*exp(-beta*(p-pb))

According to this equation, Bo is always smaller than Bob

If I want to estimate Bo using this equation, I need to input Bob, beta and pb.

If I don't want to use a compositional simulator --> Correlations for Black oil properties:

Several people have developed correlations for fields, fluids they have worked with/for which they have data.

From Harald's compendium, appendix:

Fluid properties

Harald Asheim
2006

A compressibility factor correlation has been developed by Vazquez and Beggs /1980/.

beta= $$c = 10^{-9}\,\frac{2.81\,R_t + 3.10\,T + 171/\gamma_o - 118\,\gamma_g - 1102}{p} \qquad (9)$$

The order of magnitude of this compressibility factor is typically: $c = \left[10^{-5} - 10^{-2}\right] bar^{-1}$

Standing's correlation, for input parameter as for Eq. (6) above.

Bob= $$B_o = c_B + 0.952 \cdot 10^{-3}\left(\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} R_s + 0.401\ T - 103\right)^{1.2}$$

Fluid properties.doc
18.08.2021
221/HA/alb

where:

c_B : calibration constant.
$c_B = 0.9759$ estimated by Standing for California crudes

TABLE A-1—BUBBLEPOINT PRESSURE CORRELATIONS

Author	Publication Date	Correlation	Origin
Standing[21,29]	1947	$p_b = 18.2\left[\left(\frac{R_s}{\gamma_g}\right)^{0.83} 10^{(0.00091\,T - 0.0125\,\gamma_{API})} - 1.4\right]$	California
Elam[30]	1957	$p_b = \frac{R_s^{0.702}}{\gamma_g^{0.514}} e^{(0.00348\,T - 0.0282\,\gamma_{API} + 3.58)}$	Texas
Lasater[1]	1958	$p_b = \frac{p_f (T + 459.67)}{\gamma_g}$ $x_g = \left[1 + \frac{\gamma_o}{7.521 \times 10^{-6} R_s M_o}\right]^{-1}$ $p_f = e^{\left(\frac{x_g - 0.15649}{0.33705}\right)} - 0.59162$	Midcontinent U.S.
Vazquez and Beggs[23,24]	1976	$p_b = \left[A\left(\frac{R_s}{\gamma_{gc}}\right) 10^{\left(\frac{B\,\gamma_{API}}{T + 459.67}\right)}\right]^{C}$ $\gamma_{gc} = \gamma_g\left[1 + \left(0.5912 \times 10^{-4}\right)\gamma_{API}\, T_{sp} \log\left(\frac{p_{sp}}{114.7}\right)\right]$	Worldwide

Coefficient	$\gamma_{API} \le 30$	$\gamma_{API} > 30$
A	27.64	56.06
B	−11.172	−10.393
C	0.9143	0.8425

Author	Publication Date	Correlation	Origin
Glasø[12]	1980	nonvolatile oils $X = \left(\frac{R_s}{\gamma_g}\right)^{0.816}\left(\frac{T^{0.172}}{\gamma_{API}^{0.989}}\right)$ volatile oils $X = \left(\frac{R_s}{\gamma_g}\right)^{0.816}\left(\frac{T^{0.130}}{\gamma_{API}^{0.989}}\right)$ $p_b = 1.7669 + 1.7447 \log X - 0.30218 (\log X)^2$	North Sea
Labedi[31,32]	1982	$p_b = \frac{6.0001}{\gamma_{g_{sp}}}\left[\frac{R_s^{0.6714}\left(T/\gamma_{API}\right)^{0.7097} T_{sp}^{0.08929}}{10^{(7.995 \times 10^{-5} R_s)}}\right]$	Libya, Nigeria, and Angola
Owolabi[33]	1984	$p_b = 55.0 + 0.8643\left[\left(\frac{R_s}{\gamma_g}\right)^{1.255} \frac{T^{0.172}}{\gamma_{API}^{0.178}}\right]$	Alaska Cook Inlet
Owolabi[33]	1984	$p_b = -987.56359 + 179.58816\left[\left(\frac{R_s}{\gamma_g}\right)^{0.48088266} \frac{T^{.093538150}}{\gamma_{API}^{0.16648326}}\right]$	Alaska North Slope
Al-Marhoun[34]	1985	$X = R_s^{0.722569} \frac{\gamma_o^{3.046590}}{\gamma_g^{1.879109}} (T + 459.67)^{1.302347}$ $p_b = -64.13891 + 7.02362 \times 10^{-3} X - 2.278475 \times 10^{-9} X^2$ where $11{,}309.1 < X < 1{,}541{,}298.4$	Saudi Arabia

https://petrowiki.spe.org/Oil_bubblepoint_pressure

5. Use a Bo correlation provided by Milan to calculate Bo. Compare the results obtained with the correlations with the ones estimated with Hysys. Is it possible to adjust the Bo correlation to match the results from Hysys?

```
Function pb_func(gamma_g, API, GOR_, T_):
    'end functions bubblepoint pressure according to the correlation by Standing, in bara
    'gamma_g, Gas specific gravity
    'API, API of the oil
    'GOR, Gas oil ratio in Sm3/Sm3
    'T, in C
    'F01, Tuning factor
    GOR = 5.61458 * GOR_ 'Converting to scf/stb
    T = T_ * 1.8 + 32 ' converting to F
    F01 = 1
    pb = 18 * F01 * ((GOR / gamma_g) ^ 0.83) * (10 ^ (0.00091 * T - 0.0125 * API))
    pb_func = 0.06894757 * pb 'converting from psia to bara
End Function
```

```
Function Co_func(gamma_g, gamma_o, GOR_, p_, T_):
    'The oil compressibility (Co 1/bar) is obtained from correlation of Vazquez and Beggs.
    'gamma_g, Gas specific gravity
    'gamma_o, oil specific gravity
    'GOR, Gas oil ratio in Sm3/Sm3
    'API, API of the oil
    'P, Pressure, bara
    'T, in C
    'F04, Tuning factor
    F04 = 1
    GOR = 5.61458 * GOR_ 'Converting to scf/stb
    T = T_ * 1.8 + 32 ' converting to F
    p = p_ / 0.06894757
    API = API_from_gamma_o(gamma_o)
    SGgS = gamma_g * (1 + 0.00005912 * gamma_o * 60 * Log(14.7 / 114.7) / Log(10))
    Co = F04 * (-1433 + 5 * GOR + 17.2 * T - (1180 * SGgS) + 12.61 * API) / (p * 100000)
    Co = Co / 0.06894757 'converting to 1/bar
    Co_func = Co
End Function
```

```
Function Bo_und_oil(Co, Bo1, p, p1):
    'Co oil compressibility (Co 1/bar)
    'gamma_g specific gravity of gas
    'p, pressure, bara
    'p1, reference pressure, bara
    'Bo1 reference oil volume factor at pressure 1
    Bo = Bo1 * Exp(Co * (p1 - p))
    Bo_und_oil = Bo
End Function
```

```
Function Bob_Standing(gamma_g, gamma_o, Rs, T_, pb):
    'saturation oil volume factor according to the correlation by Standing in m3/Sm3
    'T temperature in K
    'Rs solution gas oil ratio
    'gamma_o specific gravity of oil
    'gamma_g specific gravity of gas
    'p, pressure, bara
    'pb, bubble point pressure, bara
    T = T_ + 273.25 'converting to K
    A = ((gamma_g / gamma_o) ^ 0.5) * Rs + 0.401 * T - 103
    Bob_Standing = 0.97959 + 0.000952 * (A ^ 1.2)
End Function
```

```
Function gamma_o_from_API(API):
    'calculates specific gravity of oil given API gravity
    gamma_o_from_API = 141.5 / (API + 131.5)
End Function
```

```
Function API_from_gamma_o(gamma_o):
    'calculates  API gravity given specific gravity of oil
    API_from_gamma_o = (141.5 / gamma_o) - 131.5
End Function
```

Oil PVT calculator, Prof Milan Stanko (NTNU)

API	[-]	64.8
pb	[bara]	97.48
Bob	[m3/Sm3]	1.4642

p [bara]	Co [1/bar]	Bo [m3/Sm3]
97.48	5.78E-04	1.464
100	5.64E-04	1.462
120	4.70E-04	1.446
140	4.03E-04	1.432
160	3.52E-04	1.421
180	3.13E-04	1.411
200	2.82E-04	1.402
220	2.56E-04	1.394
240	2.35E-04	1.387
260	2.17E-04	1.380
280	2.01E-04	1.374
300	1.88E-04	1.369
320	1.76E-04	1.364
340	1.66E-04	1.359
360	1.57E-04	1.354
380	1.48E-04	1.350
400	1.41E-04	1.346

HYSYS DATA (2 stage)

GOR	[Sm3/Sm3]	144.1
deno_sc	[kg/m3]	720.9
deng_sc	[kg/m3]	0.8501
pb@80 C	[bara]	152.4
Bob@80C	[m3/Sm3]	1.519
gamma o	[-]	0.7209
gamma g	[-]	0.6951
T	[C]	80

p [bara]	Bo [m3/Sm3]
400.0	1.374906296
393.7	1.377243058
387.3	1.379620152
381.0	1.382038922
374.7	1.38450078
368.3	1.387007206
362.0	1.389559761
355.7	1.392160082
349.3	1.394809899
343.0	1.397511033
336.7	1.400265405
330.3	1.403075045

ERAGE | × ✓ fx | =pb_func(J13;C2;J7;J14)

	A	B	C	D	E	F	G	H	I	J
1	Oil PVT calculator, Prof Milan Stanko (NTNU)									
2	API	[-]	64.8							
3	pb	[bara]	=pb_func(J13;C2;J7;							
4	Bob	[m3/Sm3]	1.4642							
5								HYSYS DATA (2 stage)		
6		p	Co	Bo						
7		[bara]	[1/bar]	[m3/Sm3]				GOR	[Sm3/Sm3]	144.1
8		97.48	5.78E-04	1.464				deno_sc	[kg/m3]	720.9
9		100	5.64E-04	1.462				deng_sc	[kg/m3]	0.8501
10		120	4.70E-04	1.446				pb@80 C	[bara]	152.4
11		140	4.03E-04	1.432				Bob@80C	[m3/Sm3]	1.519
12		160	3.52E-04	1.421				gamma o	[-]	0.7209
13		180	3.13E-04	1.411				gamma g	[-]	0.6951
14		200	2.82E-04	1.402				T	[C]	80

ERAGE | × ✓ fx | =Bob_Standing(J13;J12;J7;J14;C3)

	A	B	C	D	E	F	G	H	I	J
1	Oil PVT calculator, Prof Milan Stanko (NTNU)									
2	API	[-]	64.8							
3	pb	[bara]	97.48							
4	Bob	[m3/Sm3]	=Bob_Standing(J13;							
5								HYSYS DATA (2 stage)		
6		p	Co	Bo						
7		[bara]	[1/bar]	[m3/Sm3]				GOR	[Sm3/Sm3]	144.1
8		97.48	5.78E-04	1.464				deno_sc	[kg/m3]	720.9
9		100	5.64E-04	1.462				deng_sc	[kg/m3]	0.8501
10		120	4.70E-04	1.446				pb@80 C	[bara]	152.4
11		140	4.03E-04	1.432				Bob@80C	[m3/Sm3]	1.519
12		160	3.52E-04	1.421				gamma o	[-]	0.7209
13		180	3.13E-04	1.411				gamma g	[-]	0.6951
14		200	2.82E-04	1.402				T	[C]	80
15		220	2.56E-04	1.394						
16		240	2.35E-04	1.387				p	Bo	

Because Co depends on pressure, it is better to apply the equation:
Bo=Bob*exp(-beta*(p-pb))
Between two points, 1 and 2

Bo2=Bo1*exp(-beta_1*(p2-p1))

Starting with the bubble point

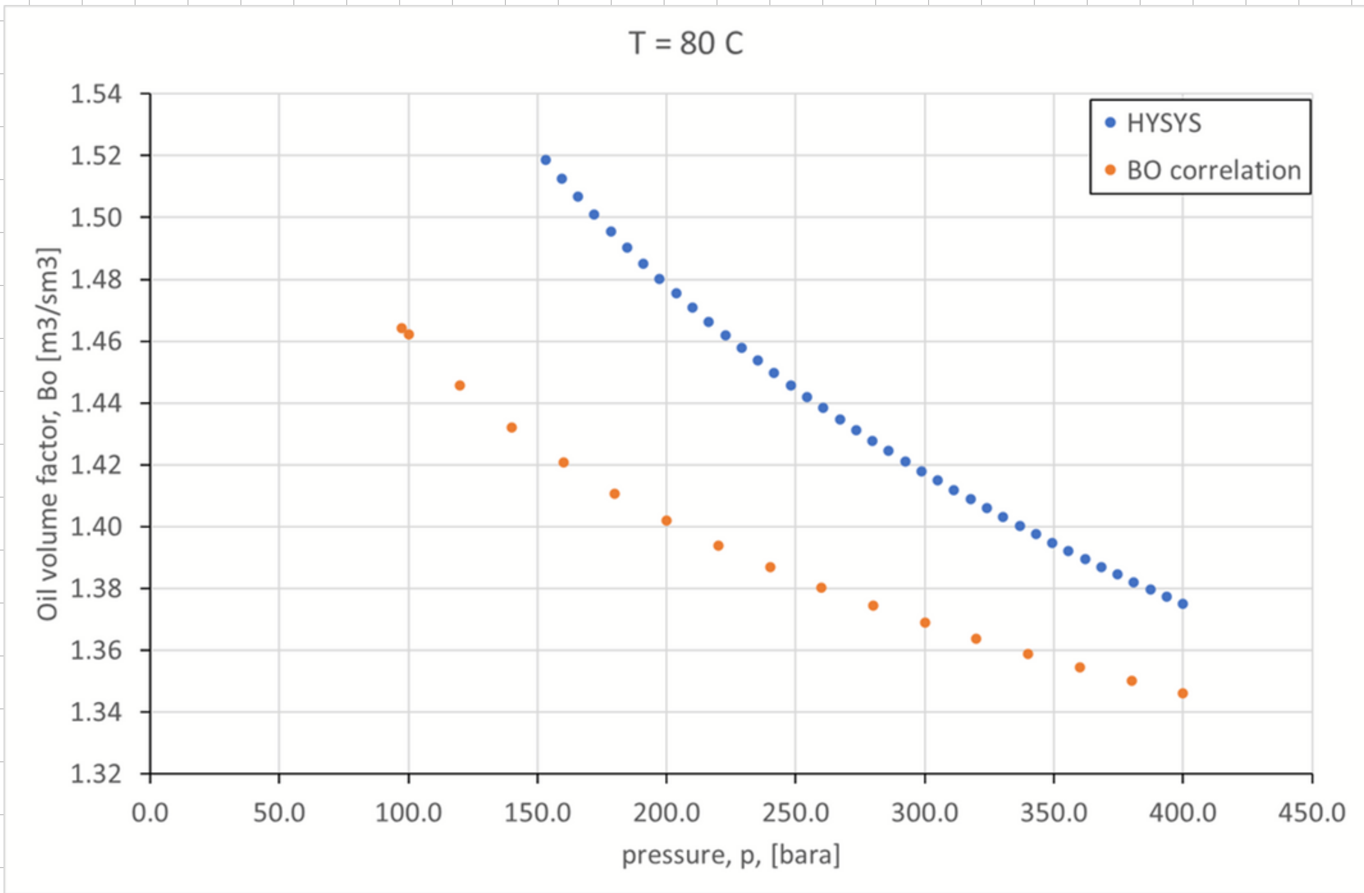
Copy (Ctrl+C)
Put a copy of the selection on the Clipboard so you can paste it somewhere else.

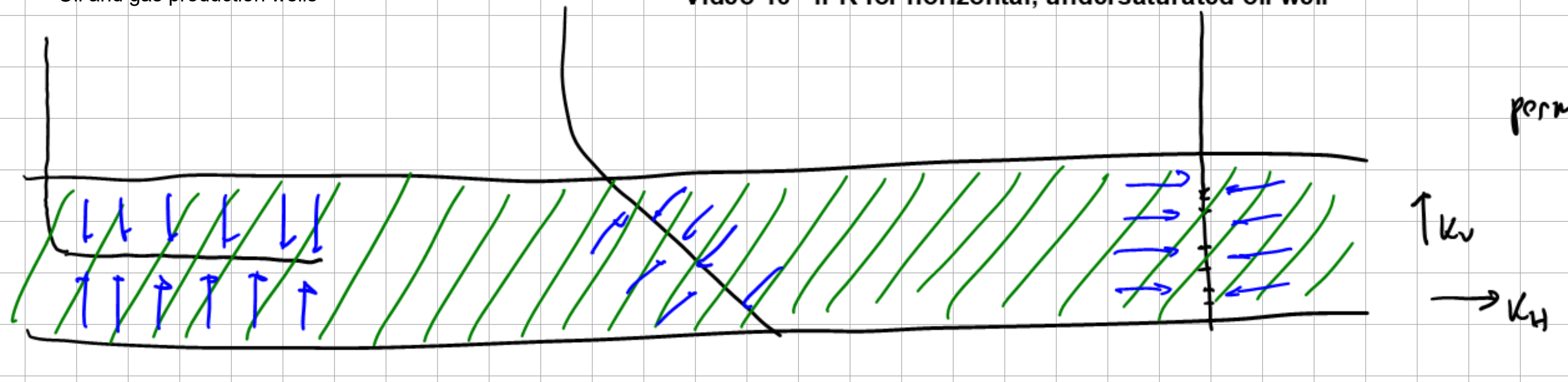
=Bo_und_oil(C8;D8;B9;B8)

A	B	C	D
Oil PVT calculator, Prof Milan Stanko (NTNU)			
API	[-]	64.8	
pb	[bara]	97.48	
Bob	[m3/Sm3]	1.4642	
	p	Co	Bo
	[bara]	[1/bar]	[m3/Sm3]
	97.48	5.78E-04	1.464
	100	5.64E-04	l(C8;D8;B9;
	120	4.70E-04	1.446
	140	4.03E-04	1.432

ERAGE | × ✓ fx | =Bo_und_oil(C9;D9;B10;B9)

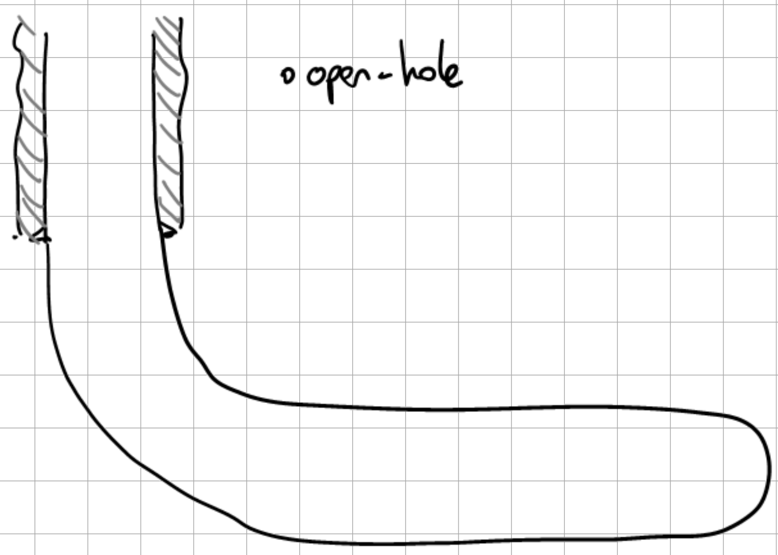
A	B	C	D
Oil PVT calculator, Prof Milan Stanko (NTNU)			
API	[-]	64.8	
pb	[bara]	97.48	
Bob	[m3/Sm3]	1.4642	
	p	Co	Bo
	[bara]	[1/bar]	[m3/Sm3]
	97.48	5.78E-04	1.464
	100	5.64E-04	1.462
	120	4.70E-04	B10;B9)
	140	4.03E-04	1.432


T = 80 C
HYSYS
BO correlation
Oil volume factor, Bo [m3/sm3]
pressure, p, [bara]
1.54
1.52
1.50
1.48
1.46
1.44
1.42
1.40
1.38
1.36
1.34
1.32
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
400.0
450.0

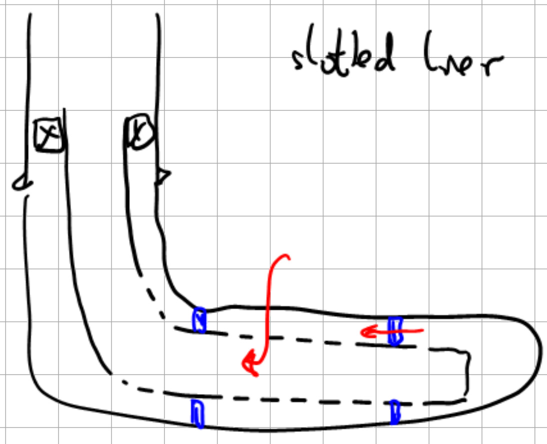


permeability anisotropy

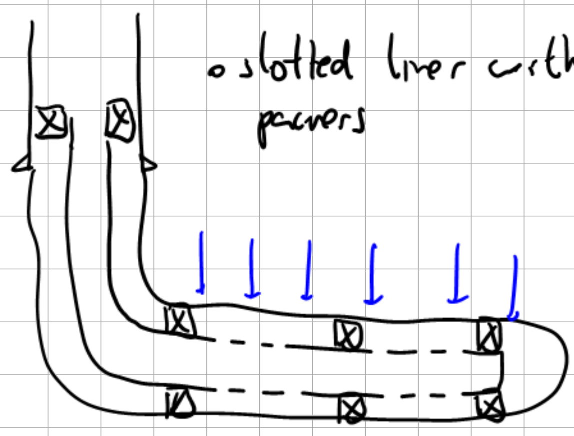
$\frac{k_H}{k_v} >> 1$ e.g. 10



o open-hole



slotted liner

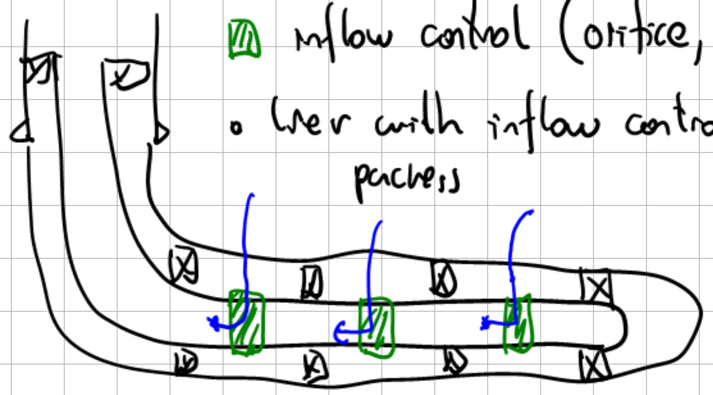


o slotted liner with packers

cemented and perforated liner

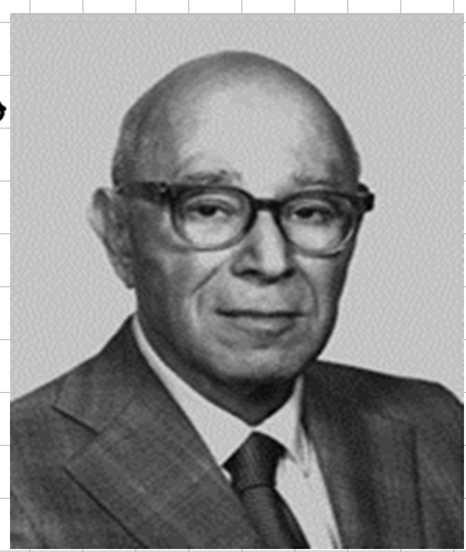
inflow control (orifice, control valve)

o liner with inflow control and packers

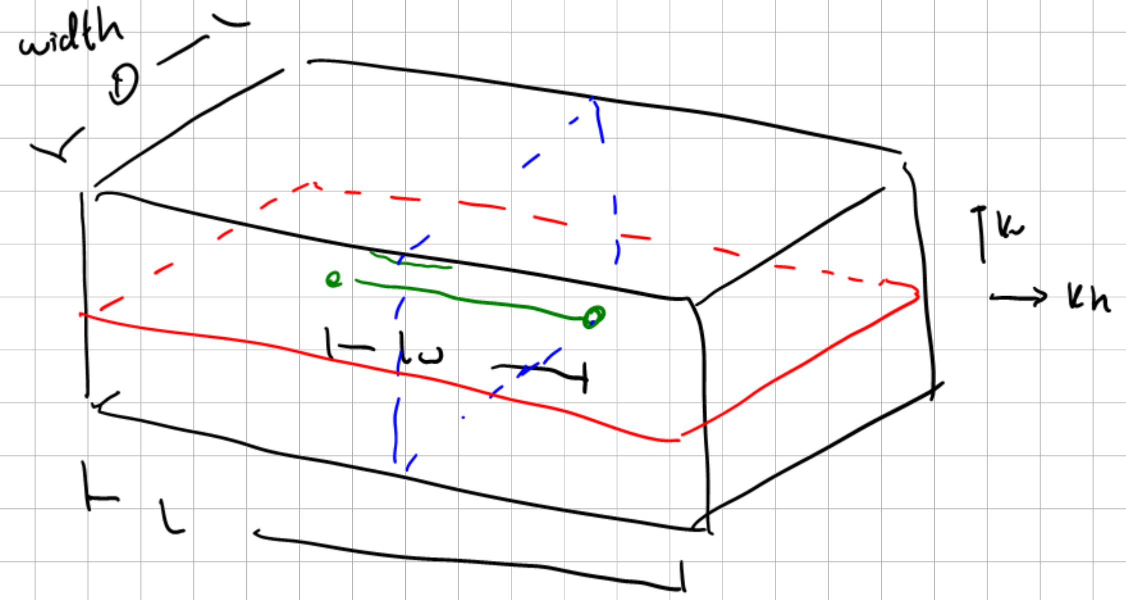


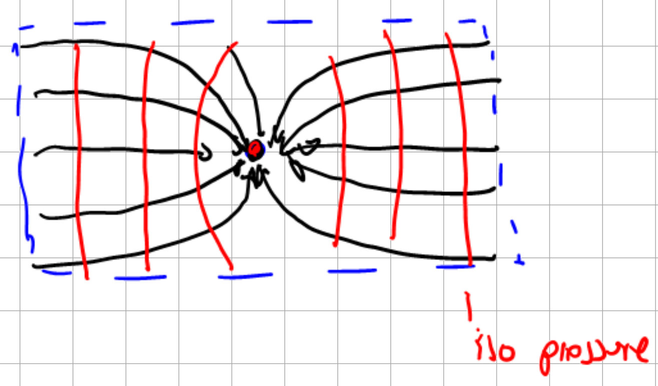
Morris

1937 - Muskat (1937) (Gulf oil)
1958 - Merkulov
1964 - Borisov
1974 - Gringarten (Imperial College), Ramey (Stanford)
1983 - Giger (IFP)
1988 - Joshi
1989 - Babuh, Odeh (Mobil)
1991 - Renard, Dupuy (IFP)
1994 - Buttler
Harald Asheim (NTNU)

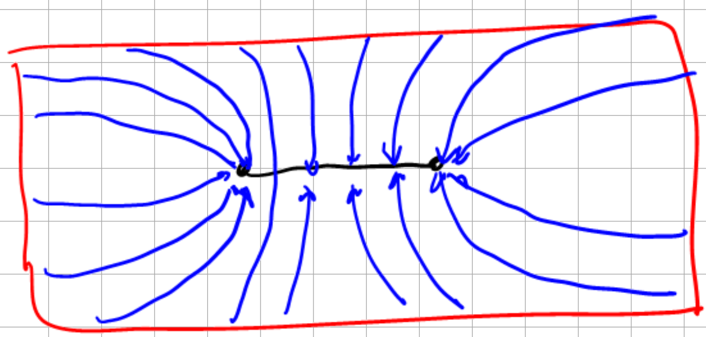


http://www.ipt.ntnu.no/~asheim/prodbr.html





$P = f(x)$

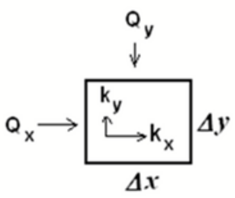


$\sim P = f(x)$

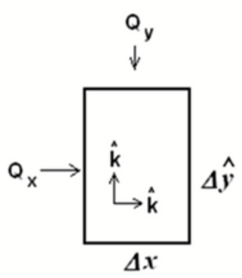
Superposition

Strategy to deal with permeability anisotropy

- Actual reservoir element



- Homogenous equivalent:



Permeability scaling: $\hat{k} = \sqrt{k_x k_y}$

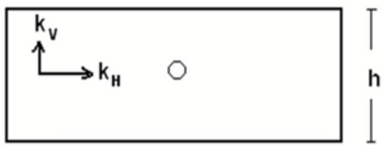
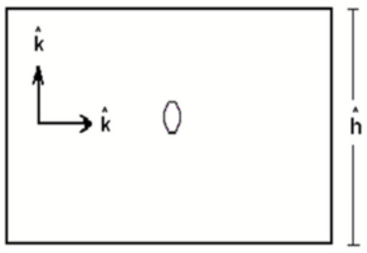


Figure 3.10 Anisotropic reservoir

$$k_H \frac{\partial^2 p}{\partial x^2} + k_V \frac{\partial^2 p}{\partial y^2} = \varphi \mu c \frac{\partial p}{\partial t}$$

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial \left(\sqrt{k_H / k_V}\, y\right)^2} = \frac{\varphi \mu c}{k_H} \frac{\partial p}{\partial t}$$



$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial \hat{y}^2} = 0$$

$$\hat{y} = (k_H / k_V)^{0.5}\, y$$

Height scaling: $\hat{h} = (k_H / k_V)^{0.5}\, h$

Harald Asheim's IPR equation

- undersaturated oil
- horizontal well
- pss
- scaling due to anisotropy

geometry related

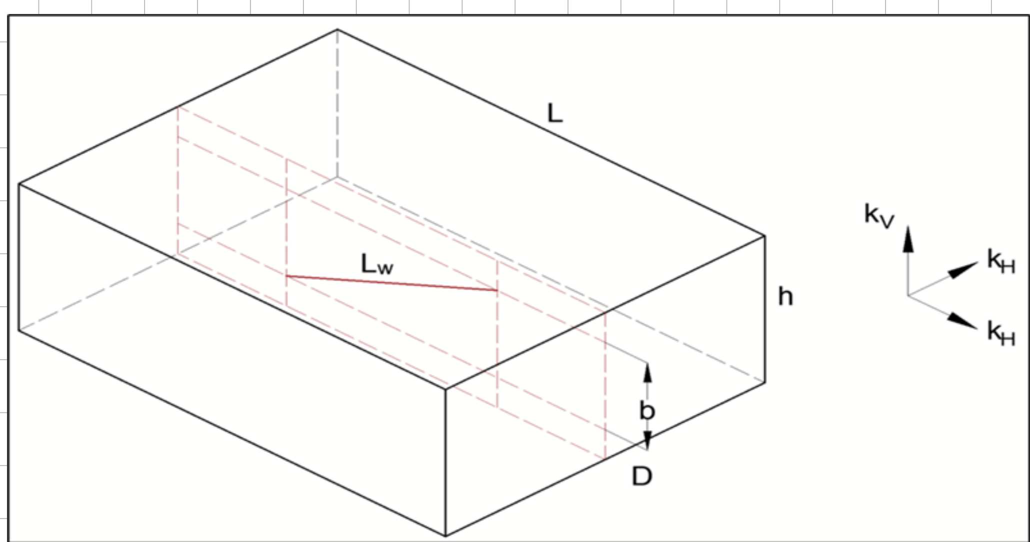
$$q_o = \frac{k_H \cdot h}{6.22 \cdot (\mu_o \cdot B_o)_{@p_{av}} \cdot \left[\frac{\pi \cdot D \cdot \hat{f}_a}{2 \cdot \bar{L}_w} + \frac{3 \cdot h \cdot \beta}{\hat{L}_w} \cdot \left(\ln\left(\frac{h \cdot \beta}{2 \cdot \pi \cdot \hat{r}_w}\right) + s_b\right)\right]} [p_R - p_{wf}]$$

function of PVT, fluid properties

$$\beta = \sqrt{\frac{k_H}{k_V}}$$

$$\hat{L}_w = L_w \cdot \sqrt{1 - \left(\frac{b}{L_w}\right)^2 \cdot (\beta^2 - 1)}$$

$$\bar{L}_w = L_w \cdot \sqrt{1 - \left(\frac{b}{L_w}\right)^2}$$



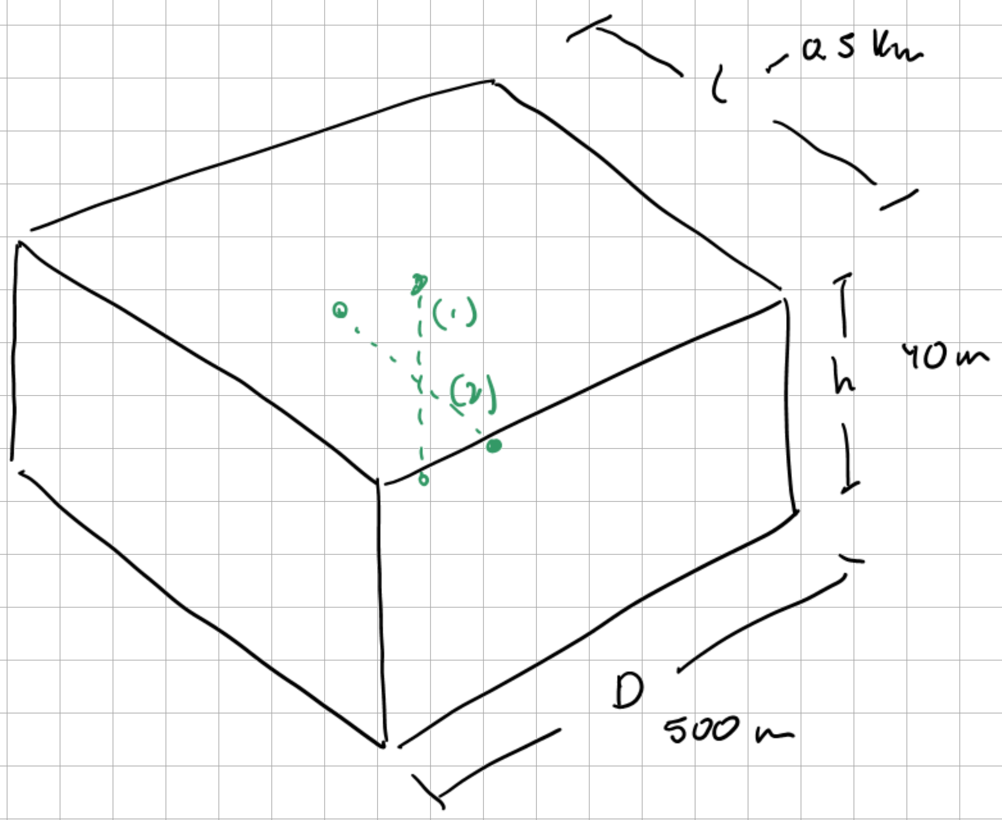
$$\boxed{\hat{r}_w = r_w \cdot \frac{1 + \sqrt{1 + (\beta^2 - 1) \cdot \left(\frac{\bar{L}_w}{L_w}\right)^2}}{2}}$$

well completed partially in the interval

$$\boxed{\hat{f}_a = \frac{\bar{L}_w}{L} \cdot \left[1 + \left(0.53 \cdot \left(\frac{L}{D}\right)^2 + 1.15 \cdot \left(\frac{L}{D}\right) + 0.164\right) \cdot \left(\frac{1 - \left(\frac{\bar{L}_w}{L}\right)}{0.45 + \left(\frac{\bar{L}_w}{L}\right)}\right)\right]}$$

$$\boxed{\acute{s}_b = \begin{cases} 0.69 \; if \; O(b) = O(h) \\ 0 \; if \; b = 0 \end{cases}}$$

~ skin factor, "shielding" effect from top and bottom walls



vertical well

$$\pi r_e^2 = A = 500 \cdot 500$$

$$r_e = \sqrt{\frac{500 \cdot 500}{\pi}}$$

Reservoir top area	[m2]	2.50E+05
Reservoir pressure, p_R	[bara]	300
Flowing bottom-hole pressure, p_{wf}	[bara]	200
p_{av}	[bara]	250
Oil viscosity, μ_o at average pressure	[cp]	1.877
Oil volume factor, B_o, at average pressure	[m3/Sm3]	1.144
Wellbore radius, r_w	[m]	0.15
Vertical well located in the center and perforated throughout		
External radius, r_e	[m]	282.1
Skin, s	[-]	0
Shape factor, s_A	[-]	0.012
Productivity Index, J	[Sm3/d/bar]	14.7
Horizontal well		
Wellbore length	[m]	500
Elevation difference between toe and heel, b (sign doesn't matter)	[m]	0
Productivity Index, J	[Sm3/d/bar]	63.2

```
Function J_vertical(k, h, Uo, Bo, re, rw, s, sa)
    'Productivity index for vertical well, undersaturated oil, pss, in Sm3/d/bar
    'k in md
    'h in m
    'Uo in cp
    'Bo in m^3/Sm^3
    'fa is shape factor
    J_vertical = (k * h) / (18.68 * Uo * Bo * (Log(re / rw) - 0.75 + s + sa))
    'Natural Log in Visual Basic is Log, not LN'
End Function

Function J_horizontal(L, D, h, b, Lw, kh, kv, Bo, viso, rw)
    'Productivity index for horizontal well, undersaturated oil, pss, in Sm3/d/bar
    'L Reservoir length along well direction [m]
    'D reservoir width [m]
    'h reservoir thickness [m]
    'Lw well length [m]
    'kh horizontal permeability [md]
    'kv vertical permeability [md]
    'Bo oil formation volume factor [m^3/Sm^3]
    'viso oil viscosity [cp]
    'rw well radius [m]
    'b, height difference betweeen heel and toe [m]
    Pi = Atn(1) * 4
    b = Abs(b)
    If b / h > 0.1 Then
        s_b = 0.69
    Else
        s_b = 0
    End If
    beta = (kh / kv) ^ 0.5
    Lw_hat = Lw * (1 + ((b / Lw) ^ 2) * (beta ^ 2 - 1)) ^ 0.5
    Lw_bar = Lw * (1 - (b / Lw) ^ 2) ^ 0.5
    rw_hat = 0.5 * rw * (1 + (1 + (beta ^ 2 - 1) * ((Lw_bar / Lw) ^ 2)) ^ 0.5)
    A1 = 0.53 * ((L / D) ^ 2) + 1.15 * (L / D) + 0.164
    A2 = (1 - (Lw_bar / L)) / (0.45 + (Lw_bar / L))
    fa = (Lw_bar / L) * (1 + A1 * A2)
    C1 = 3 * h * beta * (Log(beta * h / (2 * Pi * rw_hat)) + s_b) / Lw_hat
    C2 = (Pi * D * fa / (2 * Lw_bar))
    unit_conversion_constant = (9.869E-13 * 0.001) * 24 * 3600 * 100000 * 6 * Pi / (0.001)
    J_horizontal = unit_conversion_constant * kh * h / (viso * Bo * (C1 + C2))
End Function
```

Video 12 - Additional comments on linear IPR

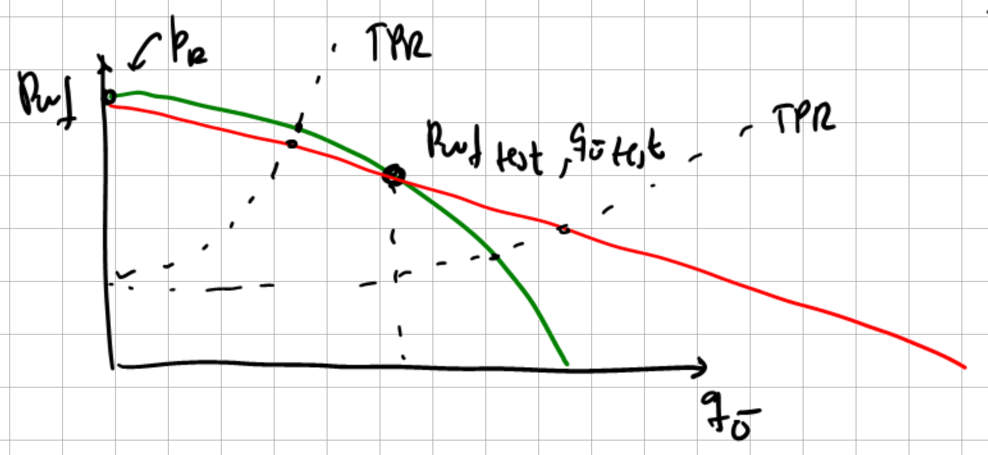
$q_o = J\,(p_R - p_{wf})$ ⟶ Undersaturated oil

J ~

geometry ~>

fluid-properties ⟶ $(\mu_o B_o)_{@\,p_{av}}$

for gas, saturated oil using a linear IPR is not adequate !

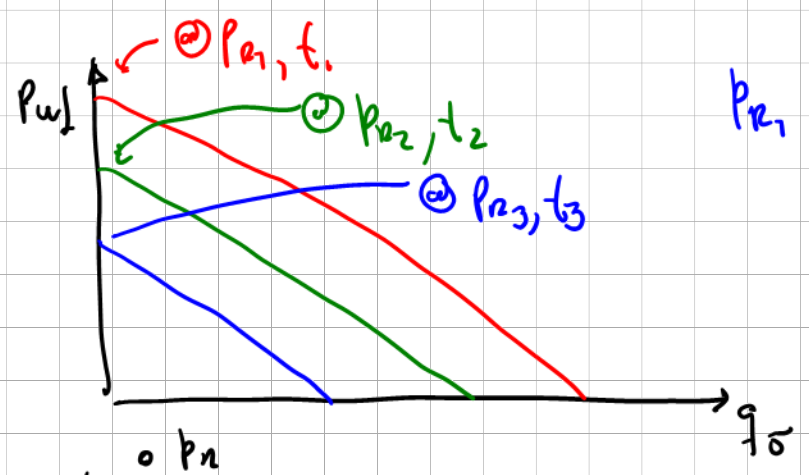


changes to IPR due to depletion

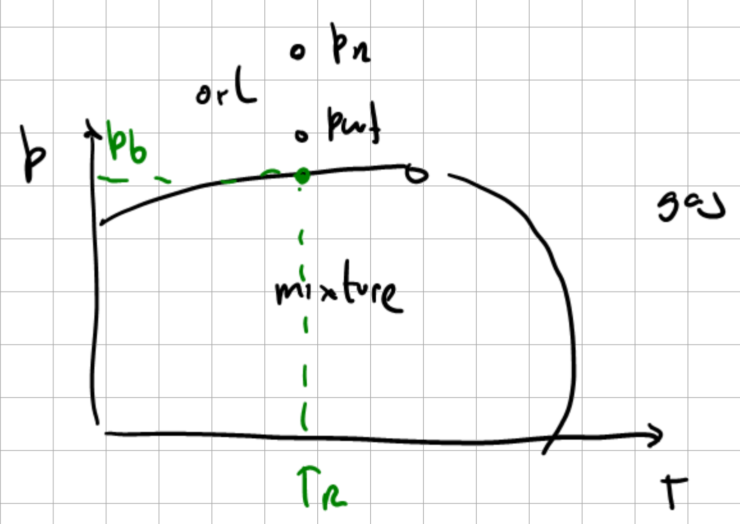
p_R → goes down

$J \sim (\mu_o B_o)_{@p_{av}}$, r_e, psd, ss, s, otherwise J remains fairly constant with time

$p_{av} = (p_R + p_{wf})\cdot 0.5$



$p_{R1} > p_{R2} > p_{R3}$

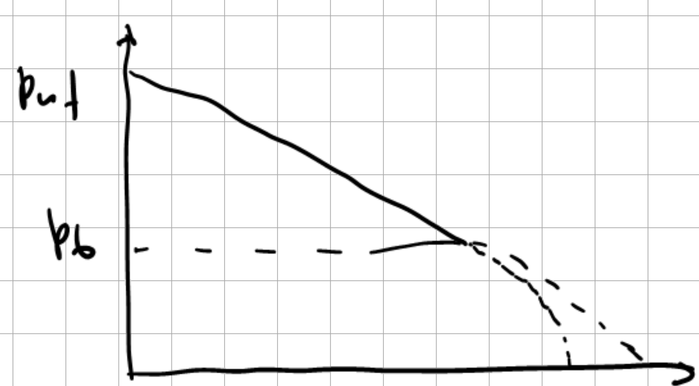


linear IPR valid if $p_{wf} > p_b$

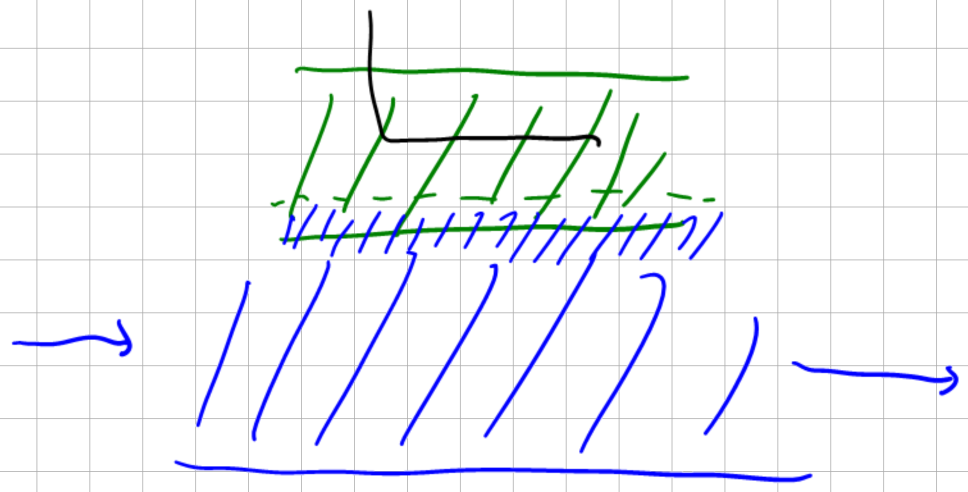
$p_e > p_b$

water injection

strong hydrodynamic aquifer



no aquifer, no injection, undersaturated oil reservoir



flow of water + oil (undersaturated) → Exhibits a linear IPR

liquid
incompressible

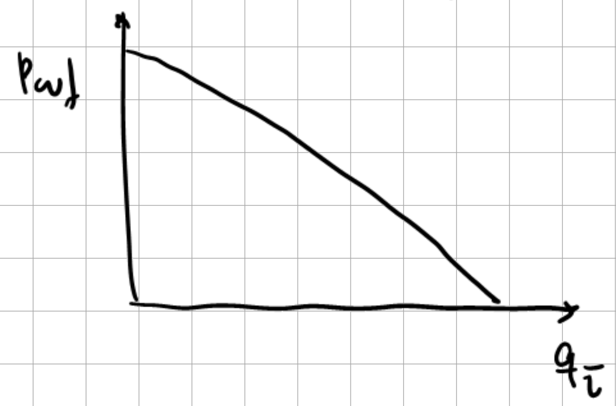
$$J_L = \frac{(q_o + q_w)}{(P_R - P_{wf})}$$

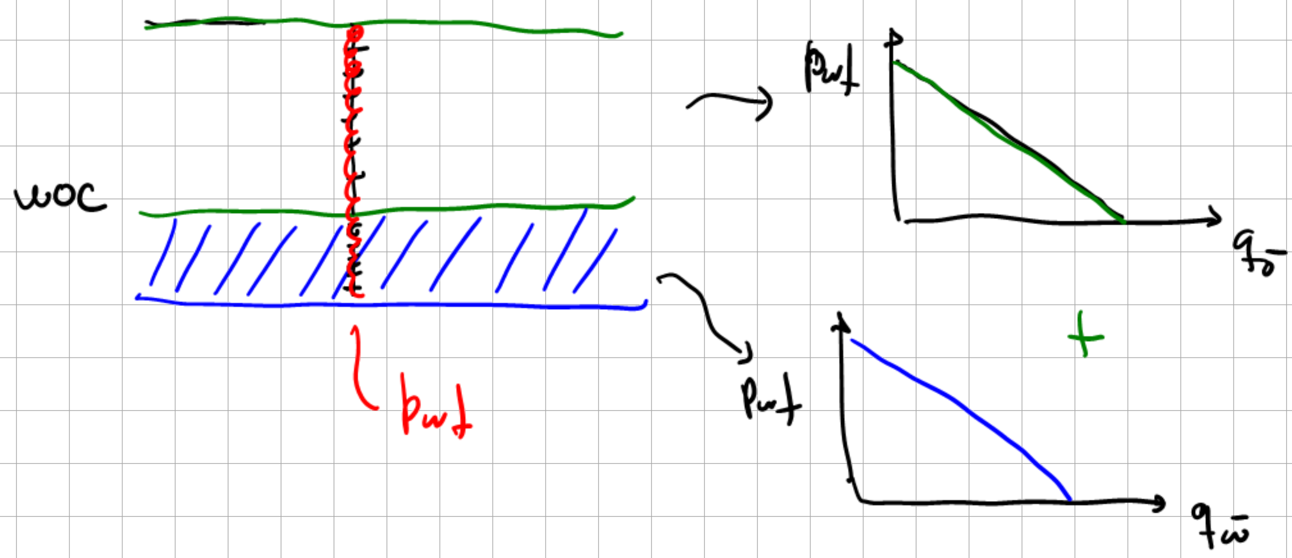
$$q_L = J_L \, (P_R - P_{wf})$$

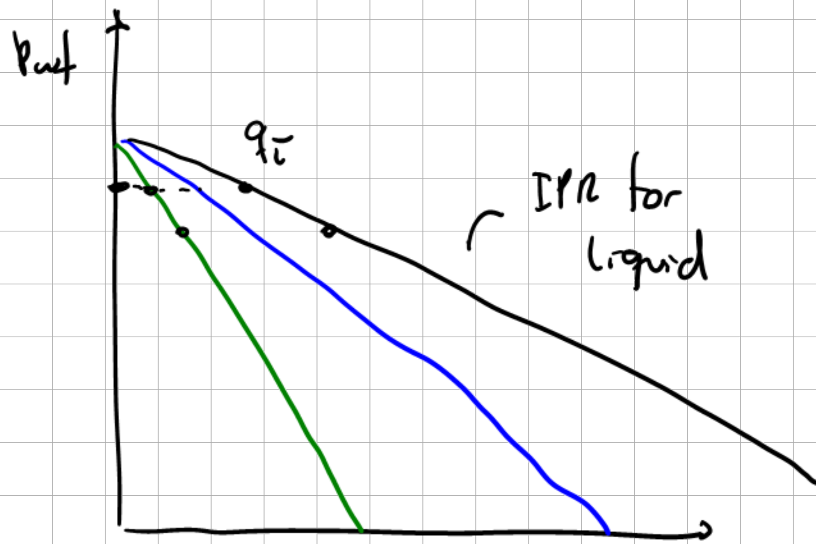
$$q_o = q_L (1 - w_c)$$

$$w_c = \frac{q_w}{q_o + q_w}$$

$$q_w = q_L (w_c)$$

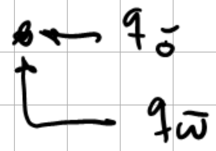


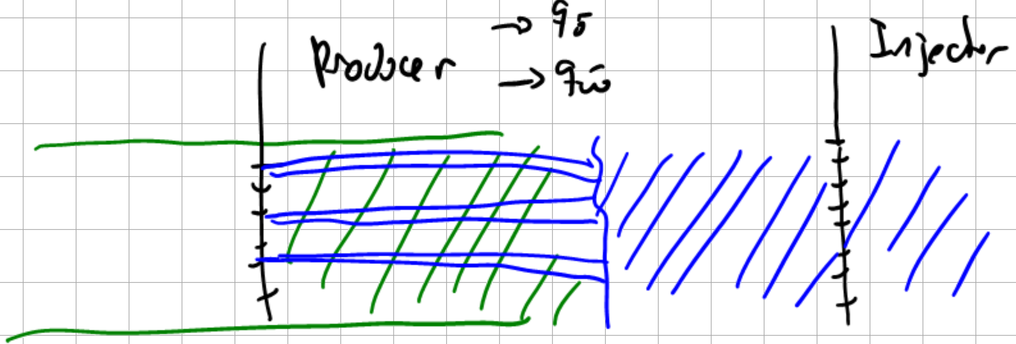


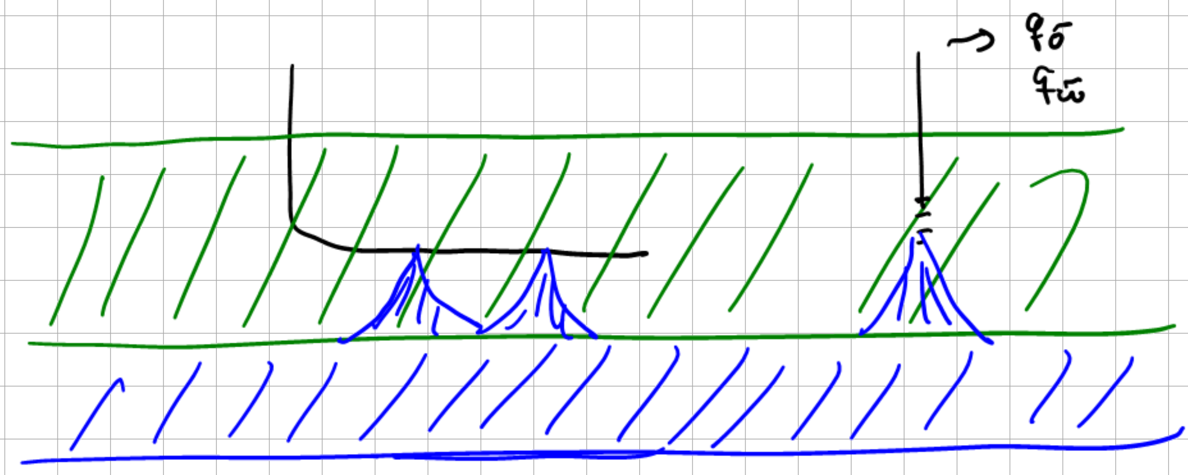


mobility $\quad \lambda_o = \frac{k_{ro}}{\mu_o} \quad \lambda_w = \frac{k_{rw}}{\mu_w}$

$\lambda_o < \lambda_w$





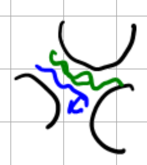


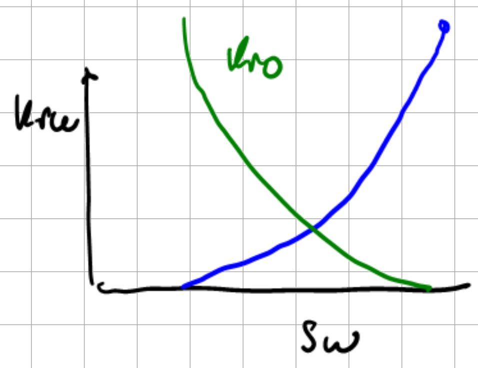
water coning - cusping

$J \; f(K)$ when two phases flowing

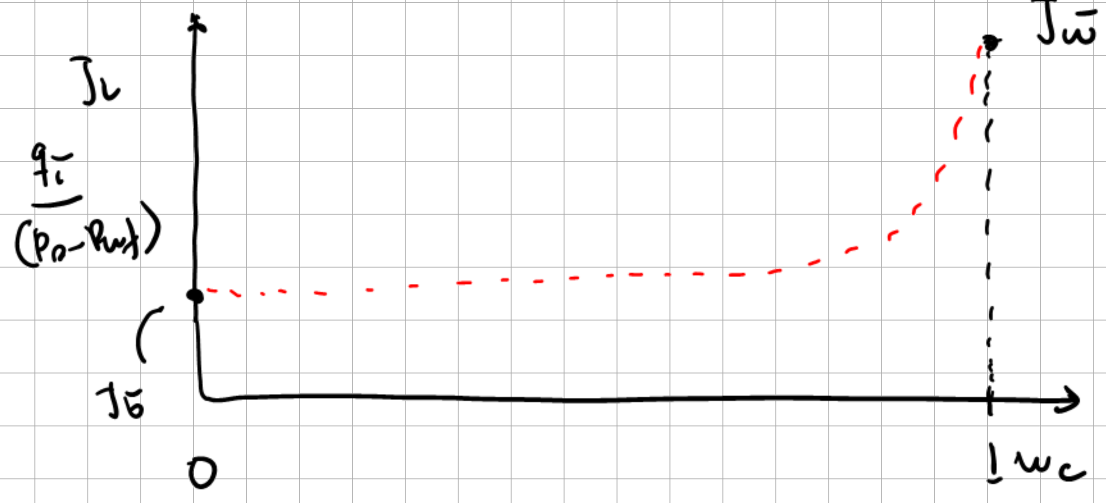
$K \; k_{ro}$

k_{rw}





$S_w = \dfrac{V_w}{V_T}$ in the pore

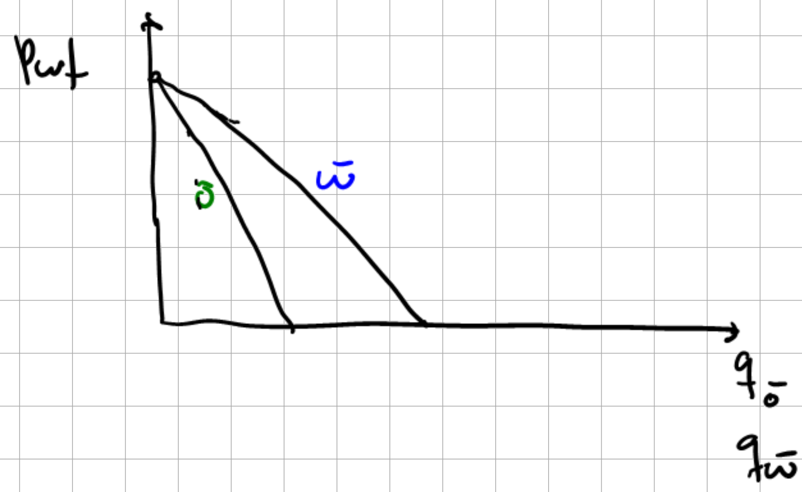


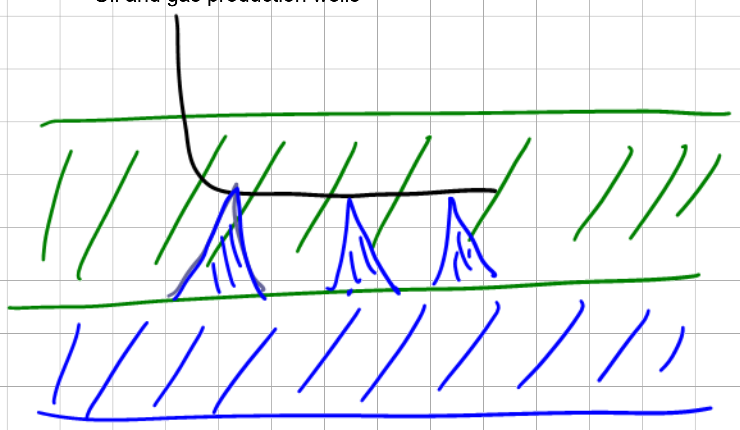
$wc = \dfrac{q_w}{q_o + q_w}$

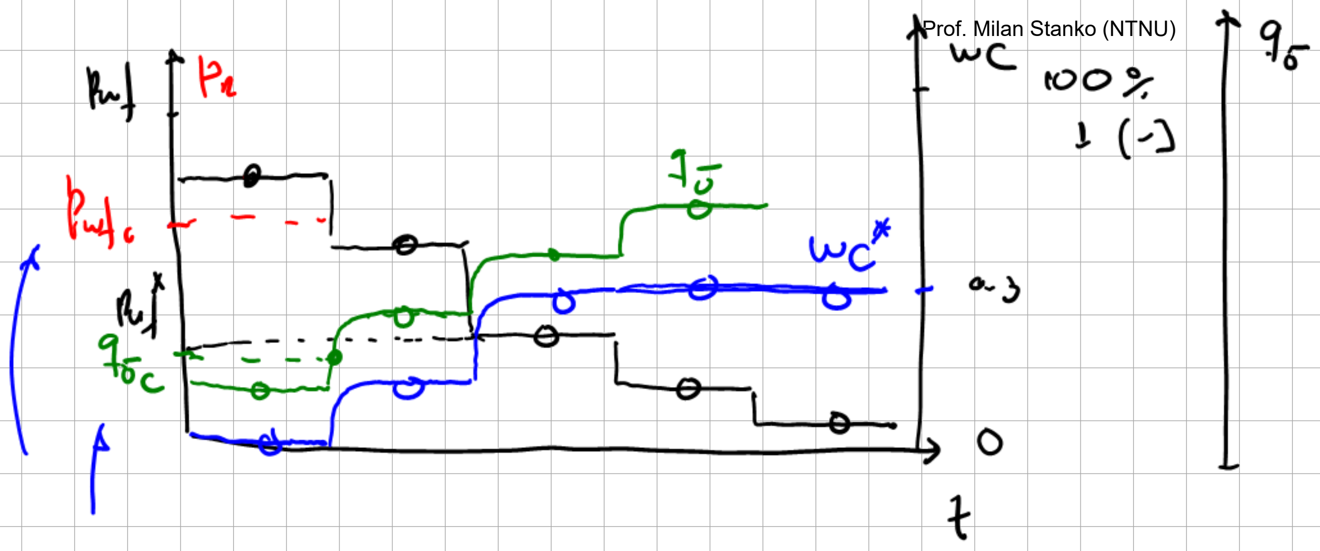
$$q_t = J_t \, (p_R - p_{wf})$$

$$q_o = q_t \cdot (1 - wc)$$

$$q_w = q_t \, (wc)$$

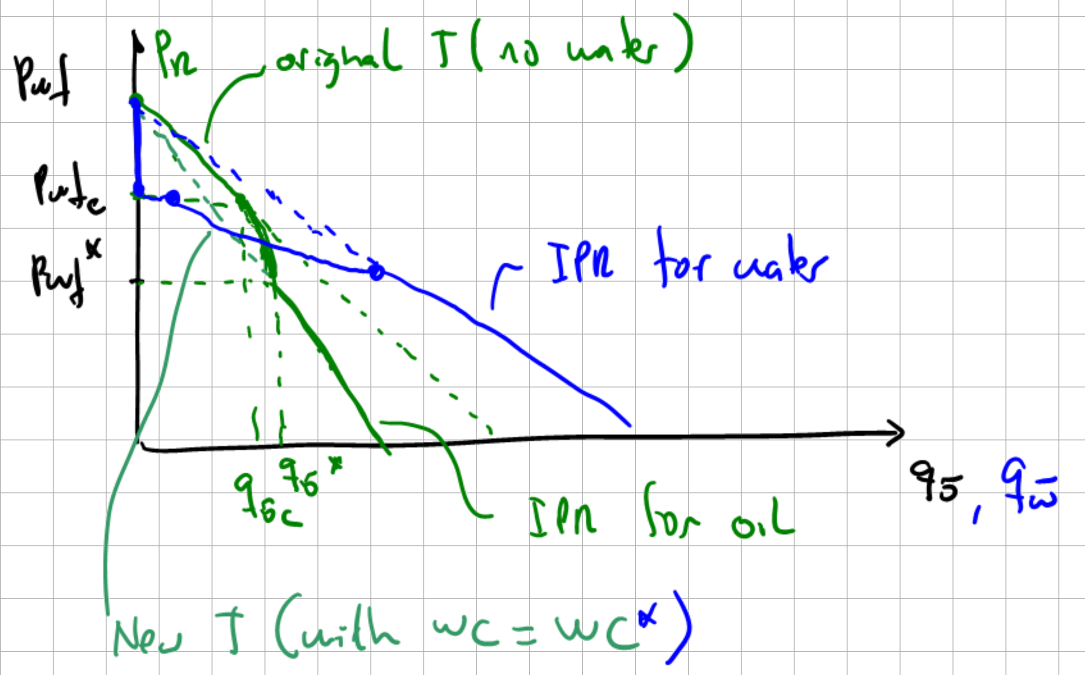






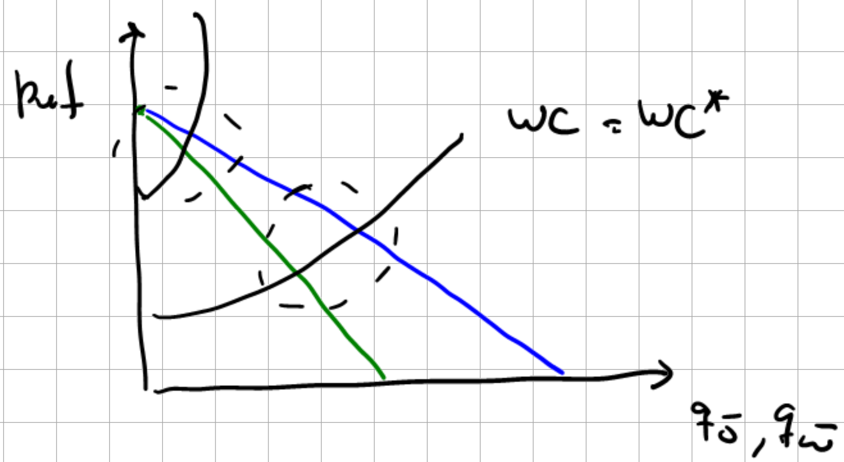
$q_{\bar{o}} < q_{\bar{o}c}$ $p_{wf_c} < p_{wf}$ ~> no coning

$q_{\bar{o}} \geq q_{\bar{o}c}$ $p_{wf_c} \geq p_{wf}$ ~> coning



in many cases $q_{\bar{o}c}$ is very small

$q_{\bar{o}}^*$ is very small



Example: one model for water coning from the literature:

Experimental Investigation of Cresting and Critical Flow Rate of Horizontal Wells

Tove Aulie, Evert Grødal, Harald Asheim, Norwegian Inst. of Technology, and Piet Oudeman, Koninklijke/Shell E&P Laboratorium

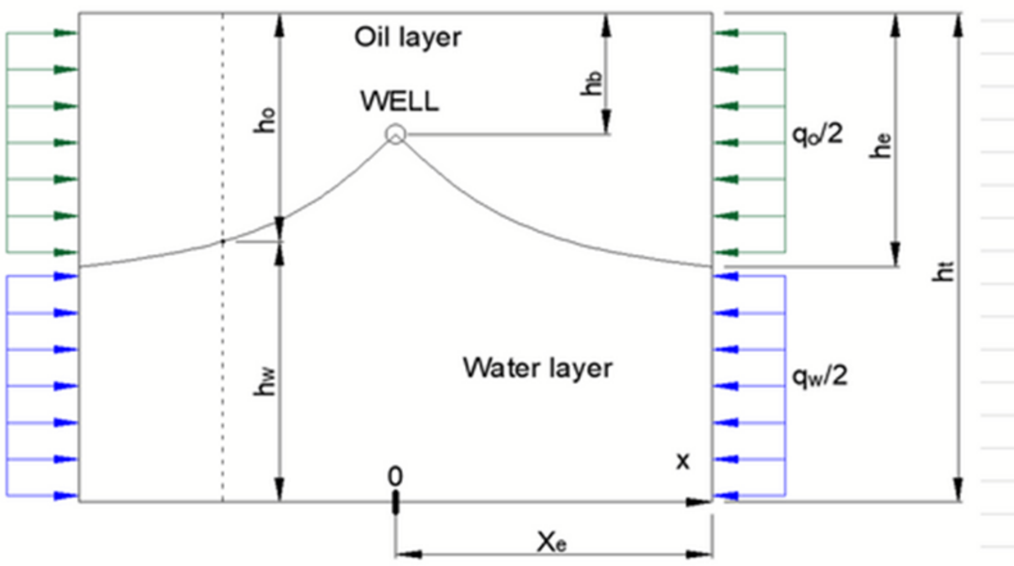
ABSTRACT

Cresting towards horizontal wells with bottom water drive and edge water drive has been experimentally investigated using a

$$h_o(x)^2 - h_e^2 + \frac{q_o}{\lambda_o \Delta\rho g D}\left(\frac{D}{2} - x\right)^2 = 0 \qquad (1)$$

Prof. Milan Stanko (NTNU)		
Total layer height, ht (oil plus water)	[m]	50
Initial water layer height, hw (ht-he)	[m]	10
Initial oil layer height, ho (he)	[m]	40
Horizontal distance from well to outer boundary, xe	[m]	300
Vertical distance between well and top of reservoir, hb	[m]	5
Horizontal permeability, k	[md]	100
Oil viscosity	[cp]	1.0
water viscosity	[cp]	0.6
Oil mobility	[md/cp]	100.0
water mobility	[md/cp]	166.7
Oil density	[kg/m^3]	800
Water density	[kg/m^3]	1024
Oil Bo	[m3/Sm3]	1.0
Water Bw	[m3/Sm3]	1.0
Well length, L, [m]	[m]	500
Critical oil flow to start producing water, qoc (ho=hb@x=0)	[Sm3/d]	49.19
Mobility ratio M (o/w)	[-]	0.6
upper limit of f (qw/qo)	[-]	0.42
upper limit for WC	[%]	29.4
deltaf (qw/qo) - for plotting	[-]	0.014

f (qw/qo)	WC	qo/qoc
[-]	[%]	[-]
0.00	0	1.0
0.01	1	1.0



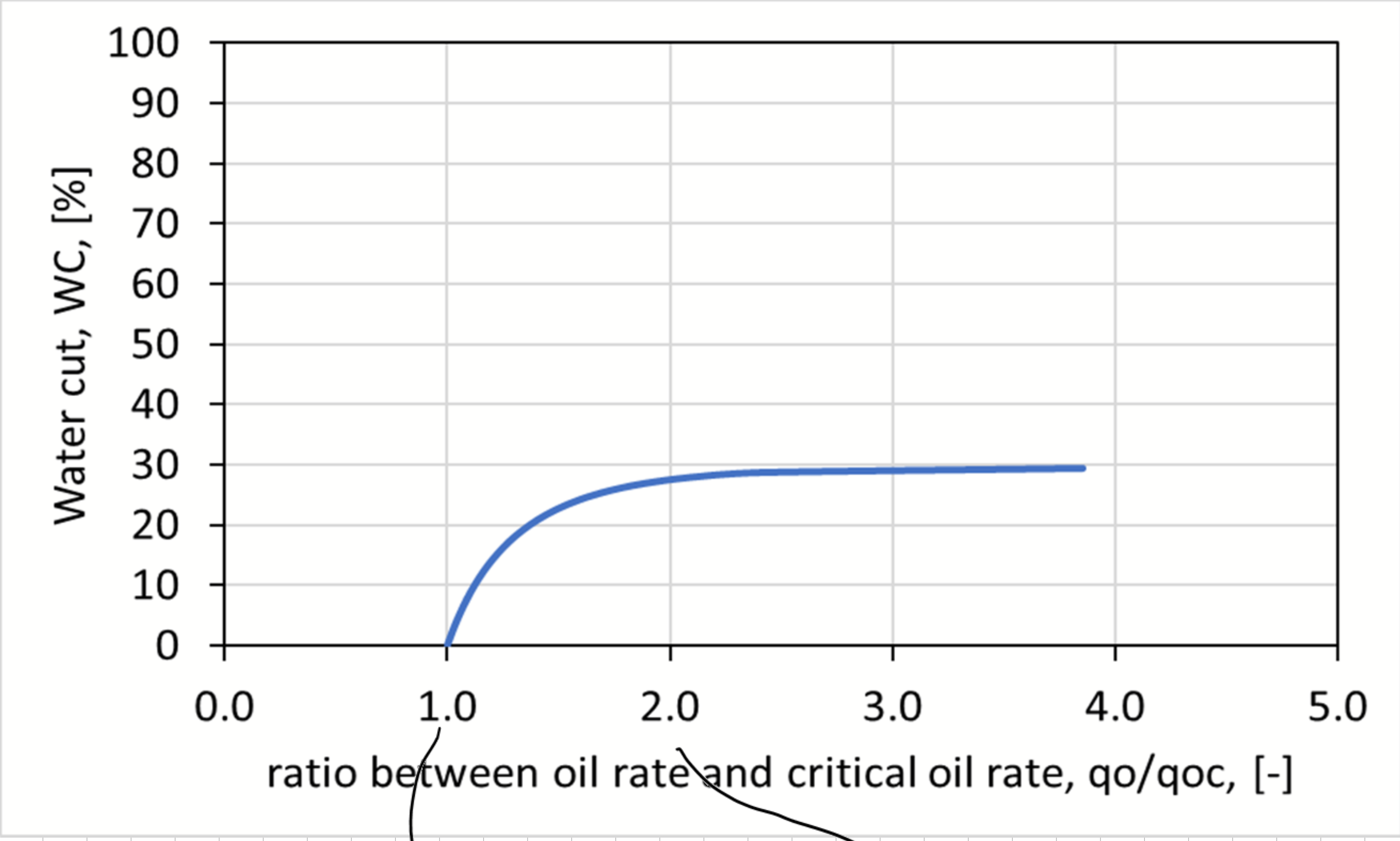
ASSUMPTIONS:

*Steady state flow, the oil and water volumetric flows in their layers

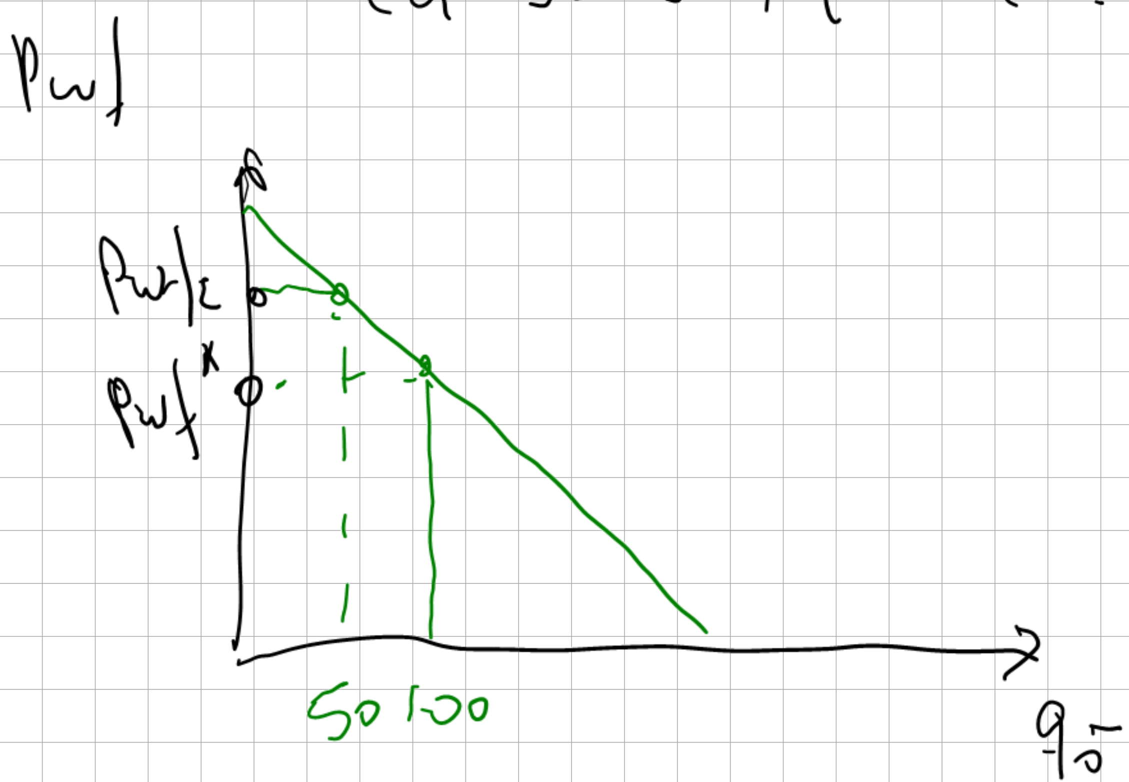
*Dupuis-Forchheim assumption: the flow towards the well is primari

*Capillary pressure is neglected

$$q_{\bar{o}c} = \frac{(\rho_w - \rho_o)\cdot g \cdot \lambda_o \cdot (h_e{}^2 - h_b{}^2)\cdot L}{x_e \cdot B_o}$$



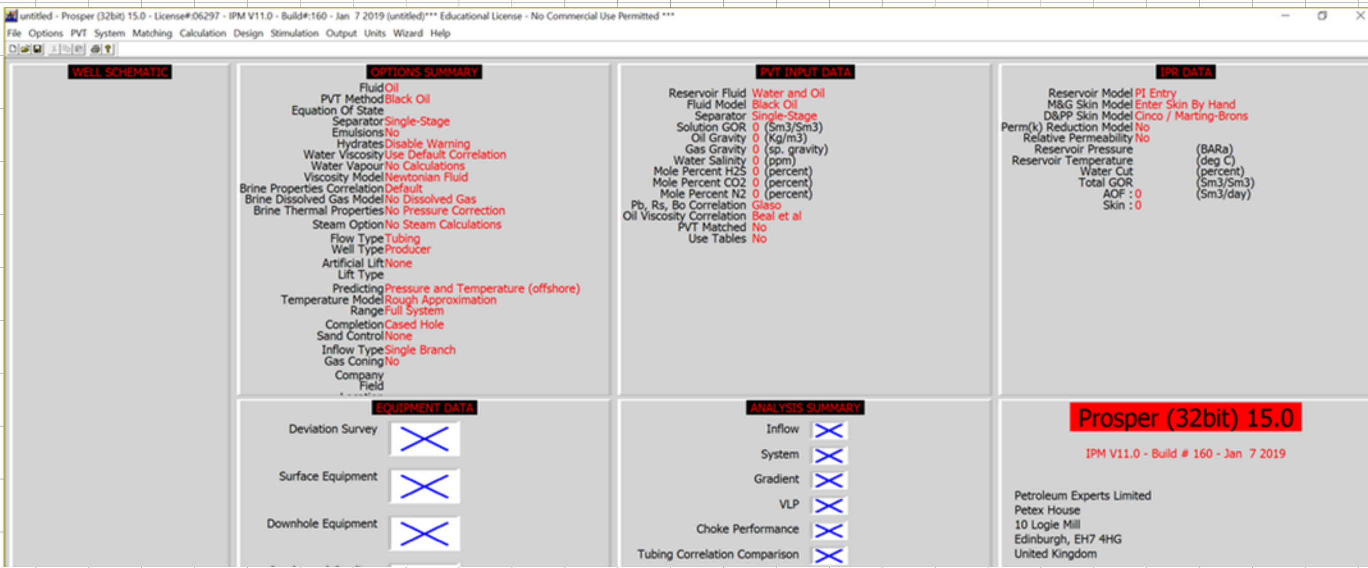
Ca 50 Sm^3/d Ca. 100 Sm^3/d

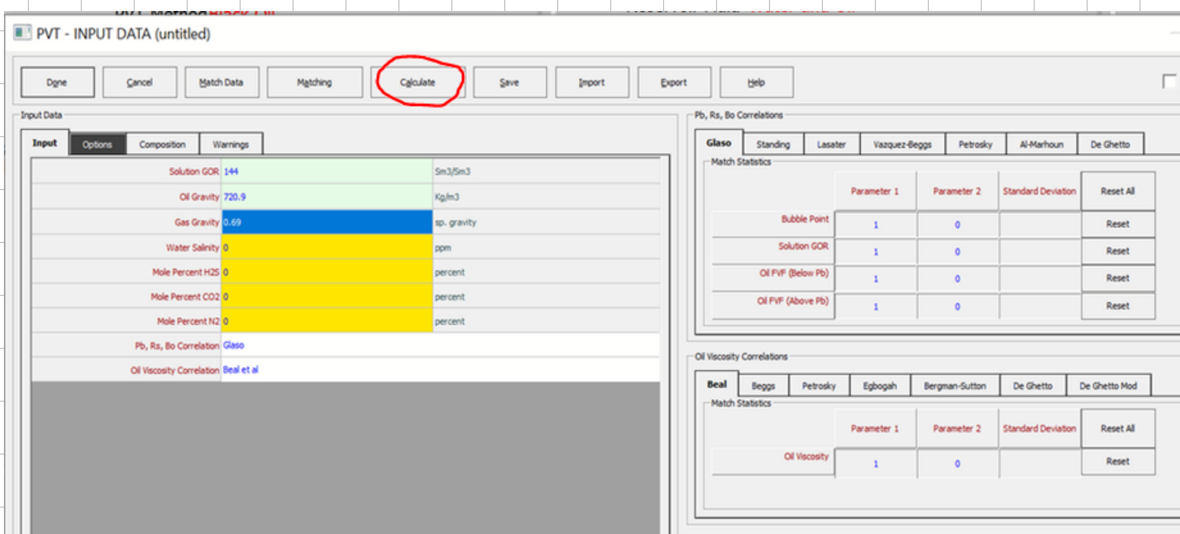


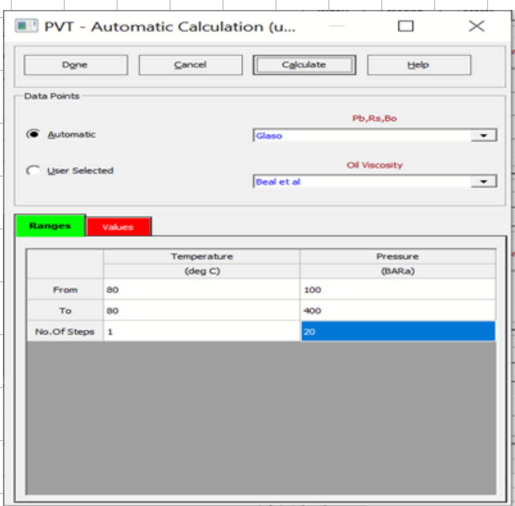
Class 20220913

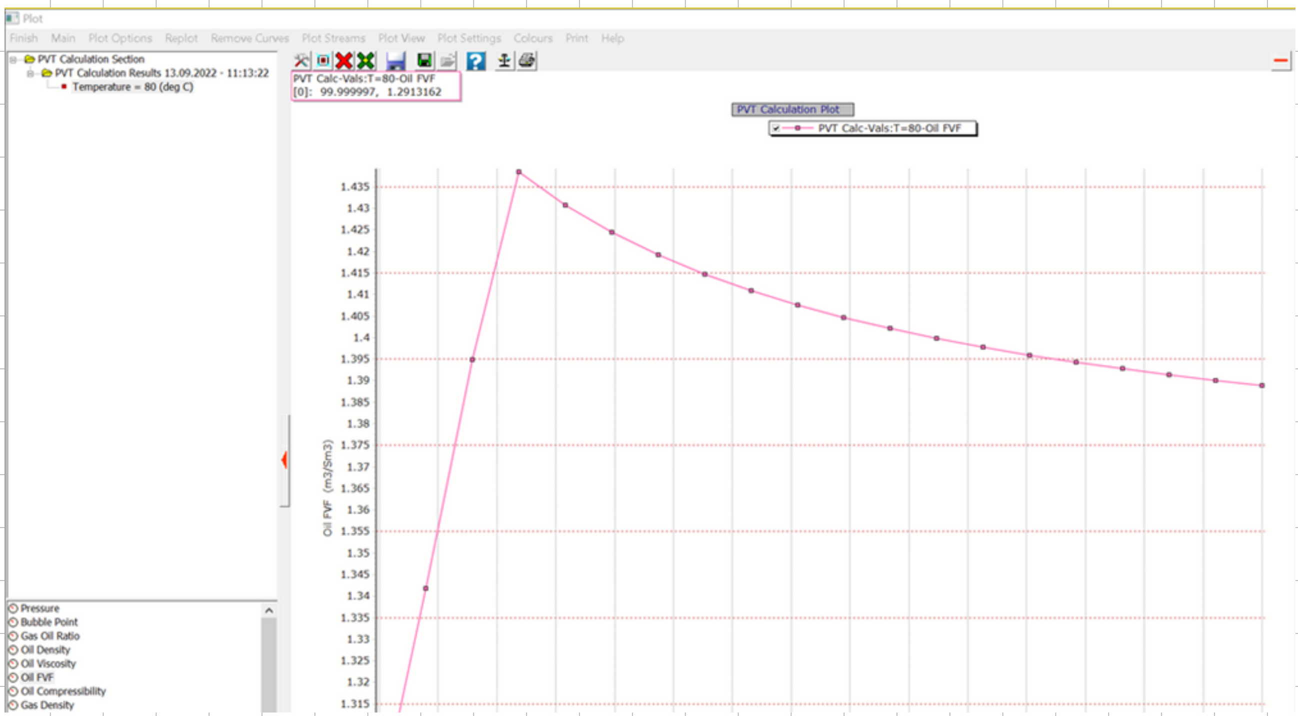
Options to get PVT properties for our production calculations
-Experiments and record results in tables: expensive, limited range, may not include the surface process
-EoS tuned with experiments: accurate, but computationally expensive. Must be regenerated when there are changes in composition (GOR) or surface process
-EoS and record results in tables: Accurate (use a proper number of points), good for computation. Must be regenerated when there are changes in composition (GOR)
-BO correlations: good for computation and for calculations with little data. Tuning is always required. Be careful with application range (p-T, gammao, gamma g) and max-min deviation and average error.

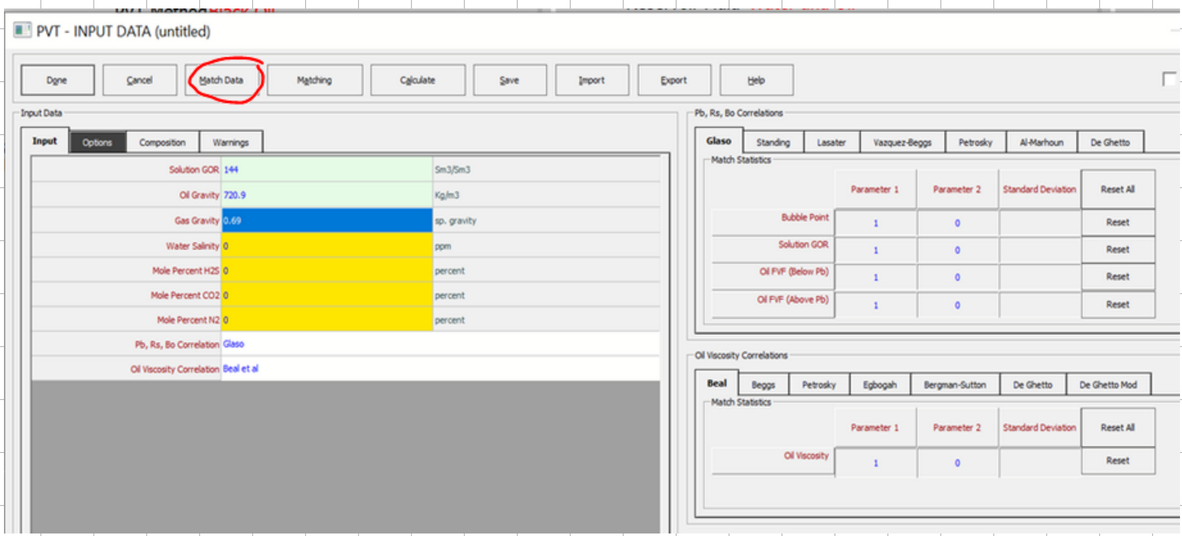
BO properties in Prosper

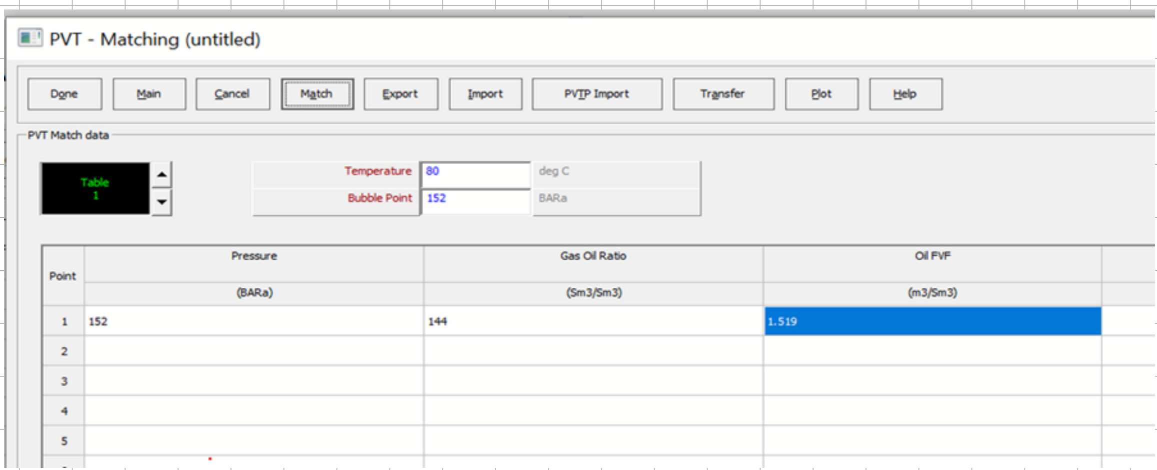


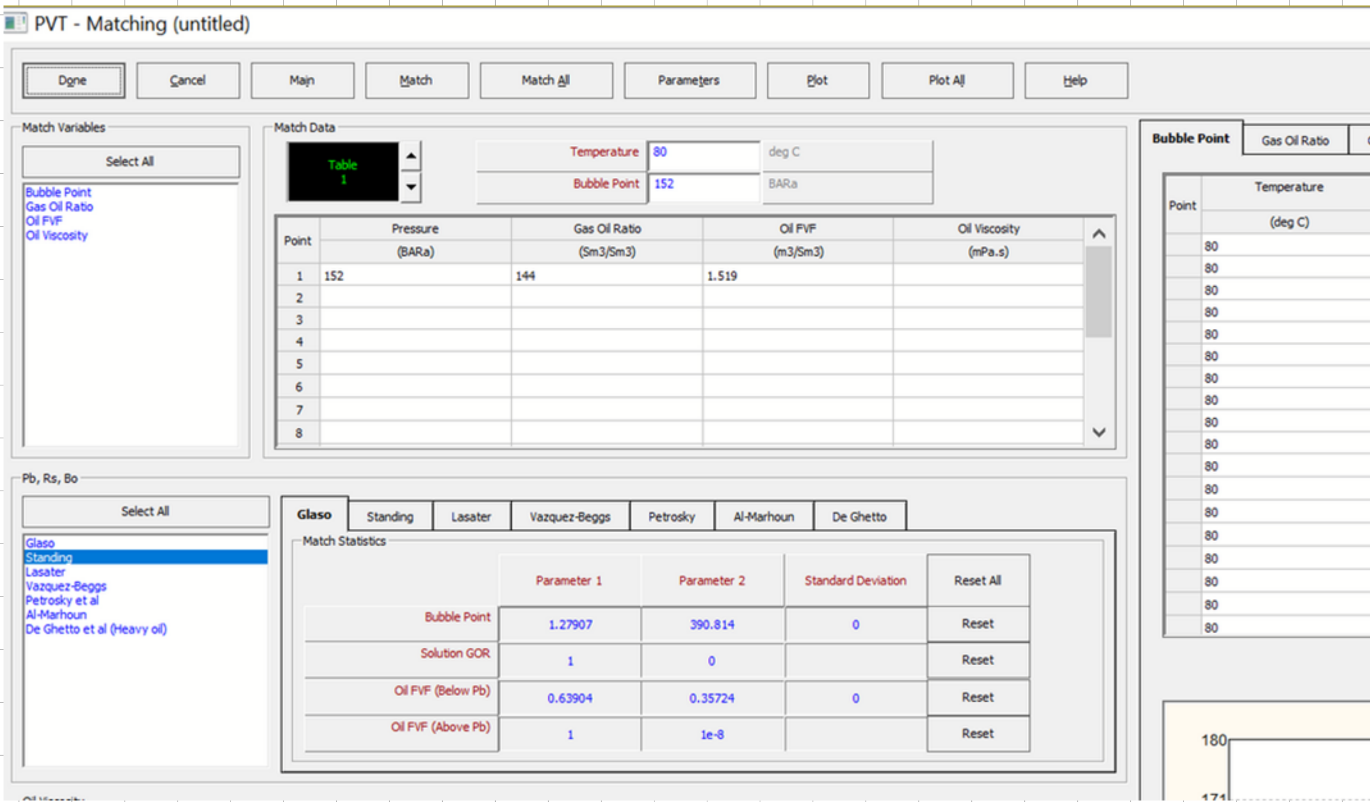




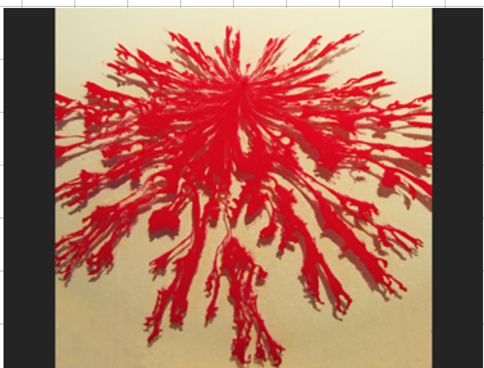

Plot
Finish Main Plot Options Replot Remove Curves Plot Streams Plot View Plot Settings Colours Print Help
PVT Calculation Section
PVT Calculation Results 13.09.2022 - 11:13:22
Temperature = 80 (deg C)
PVT Calc-Vals:T=80-Oil FVF
[0]: 99.999997, 1.2913162
PVT Calculation Plot
PVT Calc-Vals:T=80-Oil FVF
Oil FVF (m3/Sm3)
Pressure
Bubble Point
Gas Oil Ratio
Oil Density
Oil Viscosity
Oil FVF
Oil Compressibility
Gas Density


PVT - INPUT DATA (untitled)
Done Cancel Match Data Matching Calculate Save Import Export Help
Input Data
Input Options Composition Warnings
Solution GOR 144 Sm3/Sm3
Oil Gravity 720.9 Kg/m3
Gas Gravity 0.69 sp. gravity
Water Salinity 0 ppm
Mole Percent H2S 0 percent
Mole Percent CO2 0 percent
Mole Percent N2 0 percent
Pb, Rs, Bo Correlation Glaso
Oil Viscosity Correlation Beal et al
Pb, Rs, Bo Correlations
Glaso Standing Lasater Vazquez-Beggs Petrosky Al-Marhoun De Ghetto
Match Statistics
Parameter 1 Parameter 2 Standard Deviation Reset All
Bubble Point 1 0 Reset
Solution GOR 1 0 Reset
Oil FVF (Below Pb) 1 0 Reset
Oil FVF (Above Pb) 1 0 Reset
Oil Viscosity Correlations
Beal Beggs Petrosky Egbogah Bergman-Sutton De Ghetto De Ghetto Mod
Match Statistics
Parameter 1 Parameter 2 Standard Deviation Reset All
Oil Viscosity 1 0 Reset


PVT - Matching (untitled)
Done Main Cancel Match Export Import PVTP Import Transfer Plot Help
PVT Match data
Table 1
Temperature 80 deg C
Bubble Point 152 BARa
Point Pressure (BARa) Gas Oil Ratio (Sm3/Sm3) Oil FVF (m3/Sm3)
1 152 144 1.519
2
3
4
5

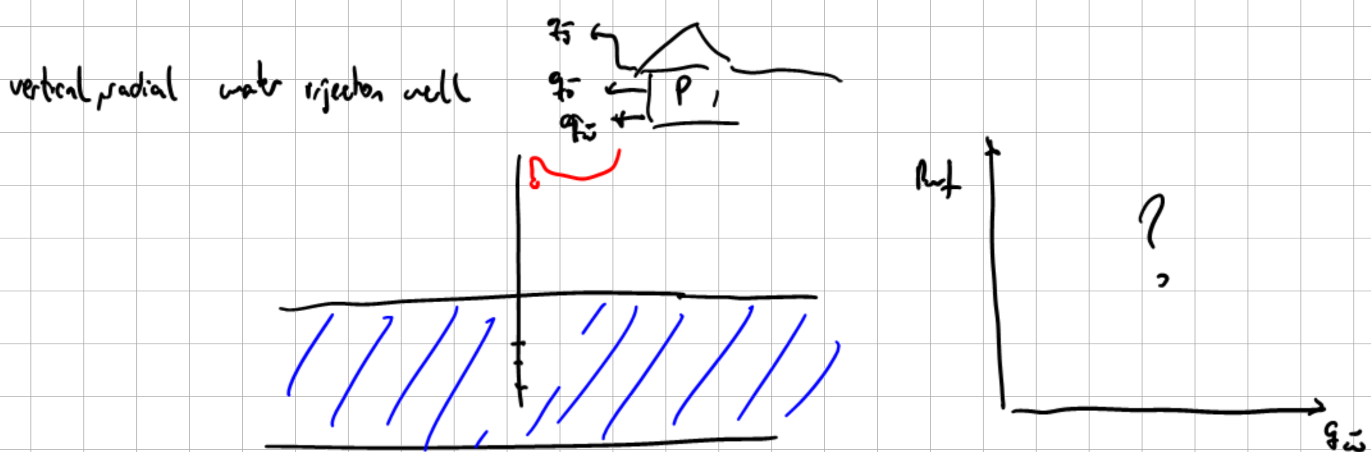


-Recap of the content of last week videos: horizontal well IPR equations, water+oil IPR, and coning
-Fingers are formed due to interface instabilities or due to heterogeneities (permeability variations along the wellbore). For oil-water is mainly due to the difference in viscosity



https://www.flowvis.org/2015/10/11/the-saffman-taylor-fingering-instability-was-formed-in-a-hele-shaw-cell-a-narrow-space-between-parallel-plates-as-red-india-ink-was-injected-into-the-more-viscous-tide-laundry-detergent/

another example: https://en.wikipedia.org/wiki/Rayleigh%E2%80%93Taylor_instability



Is it possible to use the undersaturated oil well IPR equation for this case? What changes must be made?

$$q_o = \frac{kh}{(\mu_o B_o)\big|_{@\bar{p}_{av}}} \frac{(p_R - p_{wf})}{\left(\ln\frac{r_e}{r_w} - 0.5\right)} \frac{1}{18.68}$$

Class 20220915

Announcements:

-Deadline for exercise set 1 this Sunday (18.09) . These deliveries are mandatory to take the exam
-Change of TA: Ikhsan resigns --> Amin Jelvani takes over from next week
-1rst Reference group meeting today, 15.09, 10:00.
-Guest presentation next week by company Inflow Control (20.09, 10:15) - Watch the video lectures 13.1 and 13.2 before the presentation

https://www.inflowcontrol.no/

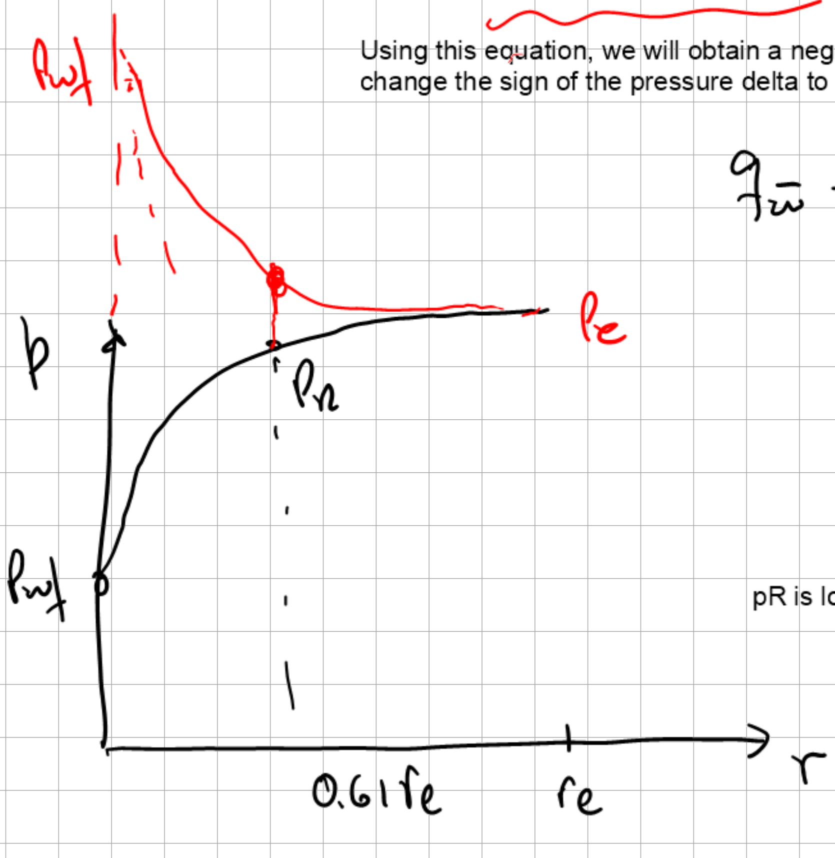
https://www.youtube.com/user/InflowControl/videos

cont. Discussion on IPR for vertical radial water injection wells

$$\int_{r_w}^{r@p_R} \frac{dr}{r} = \frac{2\pi k h}{q_{\bar{w}}} \int_{p_{wf}}^{p_R} \frac{dP}{B_o \mu_o}$$

$$\ln\left(\frac{0.61 r_e}{r_w}\right) = \frac{2\pi k h}{q_{\bar{w}}} \frac{(p_R - p_{wf})}{(\mu_w B_w)_{@p_{av}}}$$

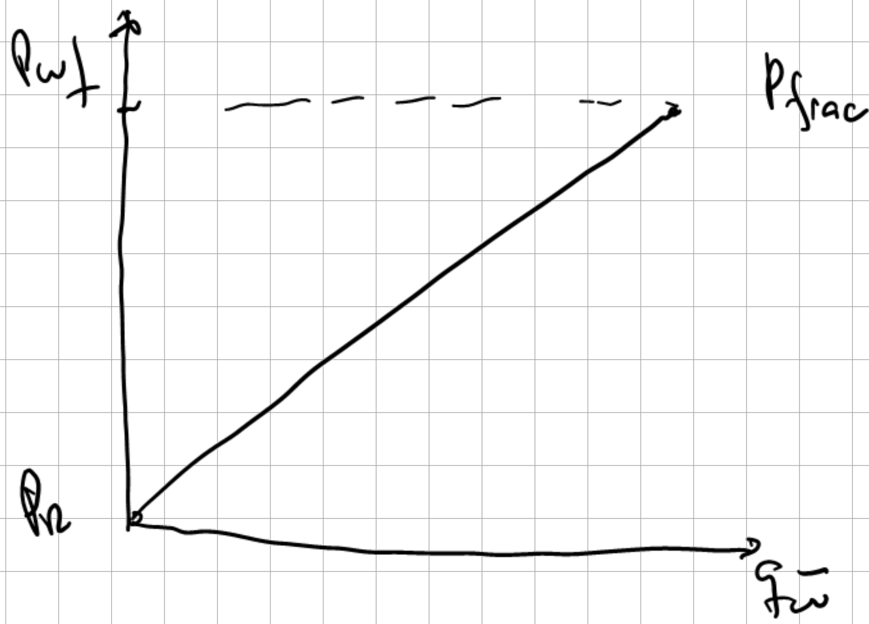
$$q_{\bar{w}} = \frac{2\pi k h \, (p_R - p_{wf})}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.5\right) \cdot (\mu_w B_w)_{@p_{av}}}$$



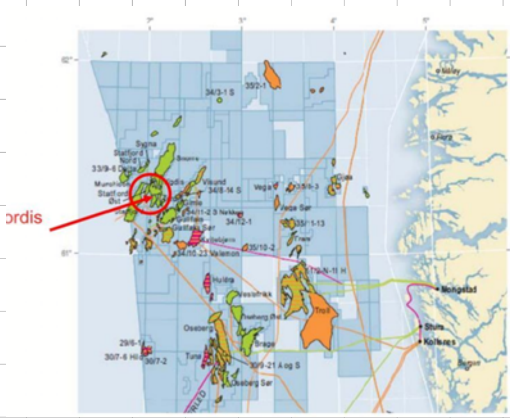
Using this equation, we will obtain a negative rate since pR<pwf, therefore, we change the sign of the pressure delta to obtain a positive value

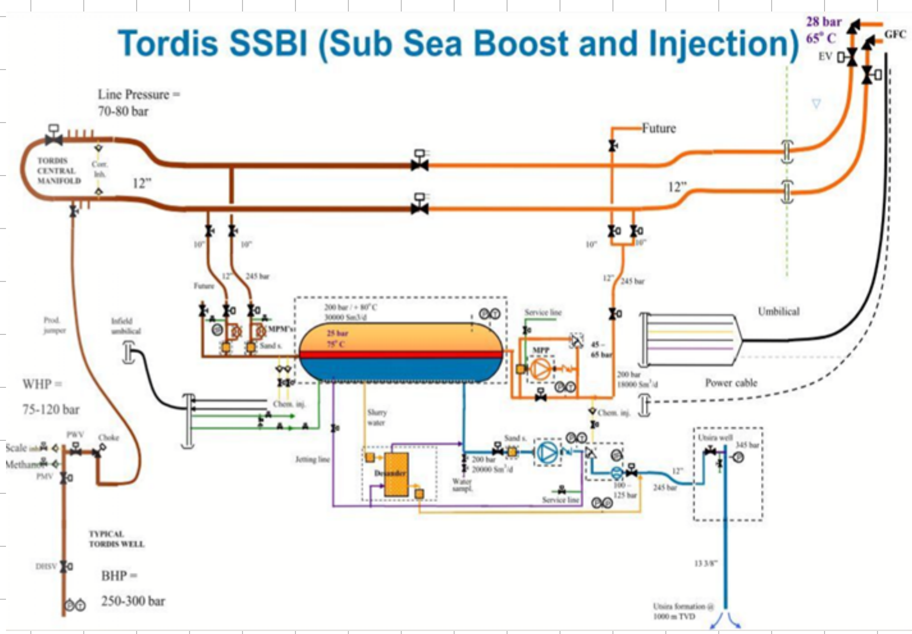
$$q_{\bar{w}} = \frac{2\pi k h \left(p_{wf} - p_R\right)}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.5\right) \left[B_w \mu_w\right]_{@p_{av}}}$$

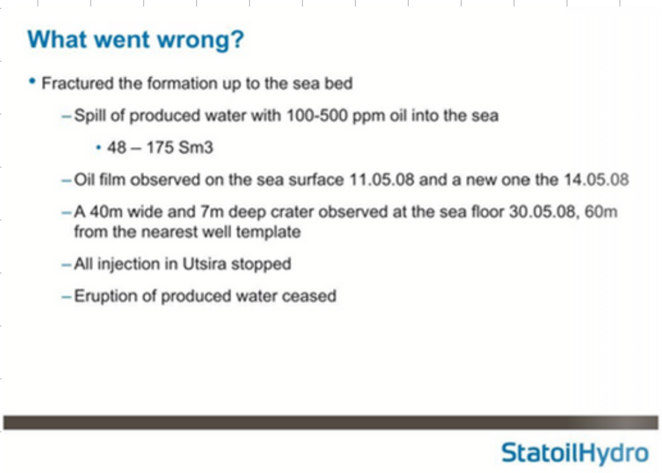
pR is located in the same place!

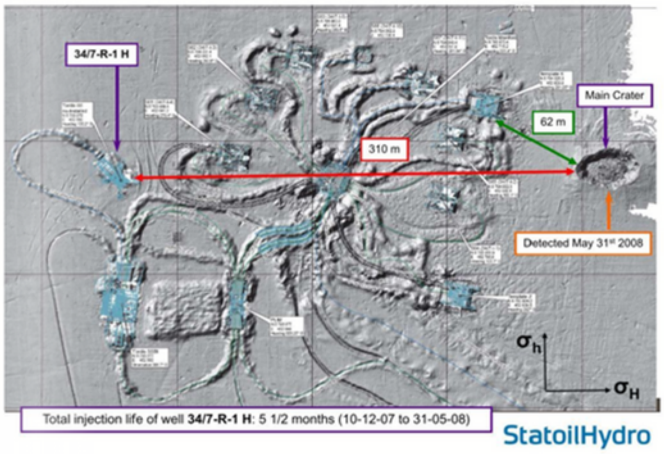


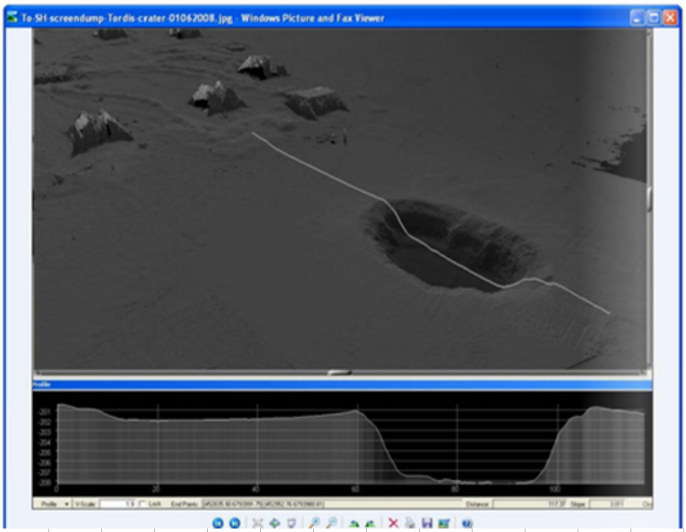
https://www.yumpu.com/en/document/read/4429451/tordis-incident-2008

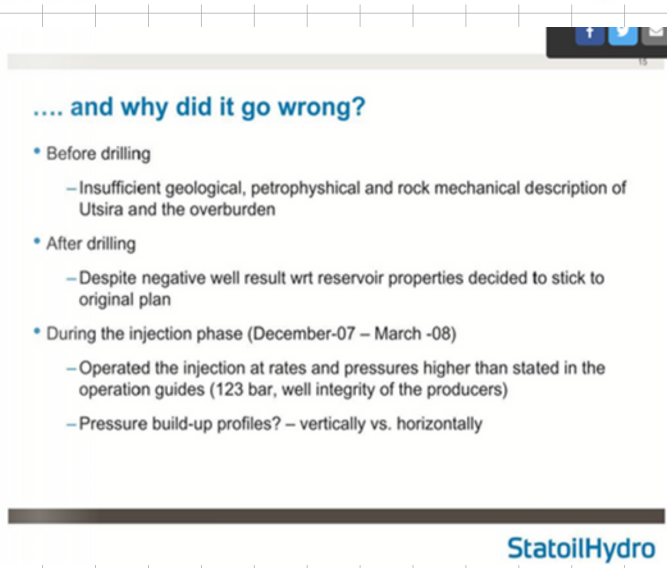






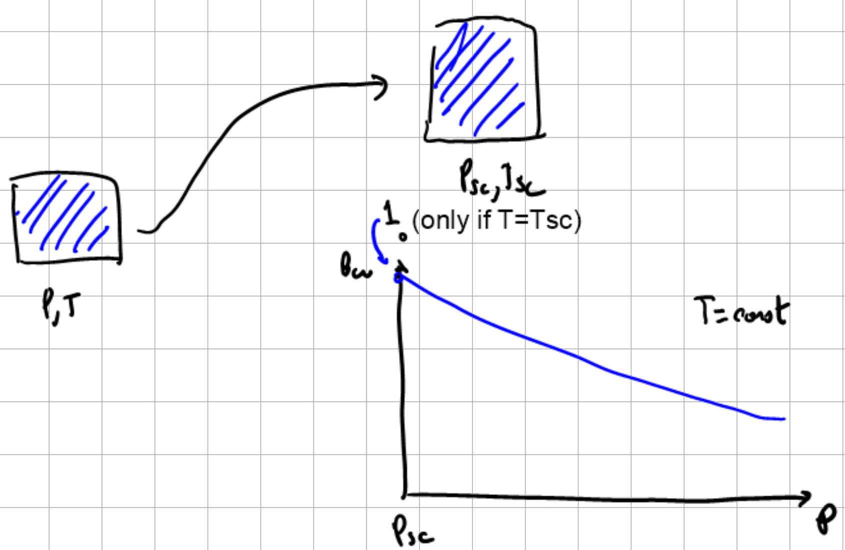


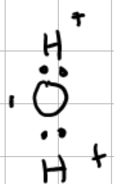




Water properties, Bw and viscw

$$B_w = \frac{V_w @ p,T}{V_{\bar{w}}}$$





- EOS PR, SRK not very suitable (H2O is a polar molecule)
- correlations

FVF vs VF

B_o

$B_w = \frac{V_w @ p, T}{V_w @ p_{sc}, T_{sc}}$

Chapter 9
Water/Hydrocarbon Systems

9.1 Introduction

9.2 Properties and Correlations

a negative sign is missing here

$$B_w^*(p,T) = B_w^o(p_{sc},T)\left(1 + \frac{A_1}{A_0}p\right)^{-(1/A_1)}, \qquad (9.18)$$

9.4.6 Water/Brine Viscosity. Fig. 9.9 presents the viscosities of pure water and NaCl brines as functions of temperature and salinity. The following equations (except for the pressure correction A_0) are presented by Kestin *et al.*,[29] who report an accuracy of $\pm0.5\%$ in the range $70 < T < 300°F$, $0 < p < 5{,}000$ psia, and $0 < C_{sw} < 300{,}000$ ppm ($0 < c_{sw} < 5$ M).

$$\mu_w = \left(1 + A_0 p\right)\mu_w^*,$$

$$\log\frac{\mu_w^*}{\mu_w^o} = A_1 + A_2 \log\frac{\mu_w^o}{\mu_{w20}^o},$$

$$A_0 = 10^{-3}[0.8 + 0.01(T - 90)\exp(-0.25c_{sw})],$$

$$A_1 = \sum_{i=1}^{3} a_{1i}c_{sw}^i,$$

$$A_2 = \sum_{i=1}^{3} a_{2i}c_{sw}^i,$$

$$\log\frac{\mu_w^o}{\mu_{w20}^o} = \sum_{i=1}^{4} a_{3i}\frac{(20-T)^i}{96+T},$$

$$\text{and } \mu_{w20}^o = 1.002 \text{ cp}, \qquad (9.22)$$

where $a_{11} = 3.324\times10^{-2}$, $a_{12} = 3.624\times10^{-3}$, $a_{13} = -1.879\times10^{-4}$, $a_{21} = -3.96\times10^{-2}$, $a_{22} = 1.02\times10^{-2}$, $a_{23} = -7.02\times10^{-4}$, $a_{31} = 1.2378$, $a_{32} = -1.303\times10^{-3}$, $a_{33} = 3.060\times10^{-6}$, $a_{34} = 2.550\times10^{-8}$, with μ in cp, T in °C, and p in MPa. Kestin *et al.*'s pressure correction A_0 contains 13 constants and does not extrapolate well at high temperatures. The pressure correction for A_0 in Eq. 9.22 is more well-behaved, with only small deviations from the original Kestin *et al.* correlation at low temperatures.

The effect of dissolved gas on water viscosity has not been reported. Intuitively, one might suspect that water viscosity decreases with increasing gas solubility, although Collins[30] suggests that dissolved gas may increase brine viscosity. As **Fig. 9.10** shows, systems saturated with CO_2 show an increase in viscosity with increasing gas solubility.

OPS. there was an error in the excel sheet

```
'   The water formation volume factor is calculated with the procedure
'   reported by Whitson, in his SPE monograph phase behavior (section 9.2.5).
'   The procedure uses the Rowe and Chou correlation, among others.
'   The procedure neglects gass dissolved in water

Function Bw(p, T, Csw, denw_sc)
    'p pressure in bara
    'T temperature in C
    'Csw water salinity in ppm_w
    'denw_sc water density at standard conditions kg/m3
    psc = 1.01325 'bara
    Tsc = 15.56 'C
    A0 = 5.91635 - 0.01035794 * (T + 273) + (0.000009270048) * (T + 273) ^ 2 - 1127.522 / (T + 273) + 100674.1 / (T + 273) ^ 2
    A1 = -2.5166 + 0.0111766 * (T + 273) - 0.0000170552 * (T + 273) ^ 2
    A2 = 2.84851 - 0.0154305 * (T + 273) + 0.0000223982 * (T + 273) ^ 2
    denw_o = 1 / (A0 + A1 * Csw / 10 ^ 6 + A2 * (Csw / 10 ^ 6) ^ 2) 'density of brine at zero pressure in g/cc
    denw_o = denw_o * 1000 'converting to kg/m3
    Bw_o = denw_sc / denw_o
    A0 = (10 ^ 6) * (0.314 + 0.58 * Csw / 10 ^ 6 + (1.9 * 10 ^ -4) * (T * 9 / 5 + 32) - (1.45 * 10 ^ -6) * (T * 9 / 5 + 32) ^ 2)
    A1 = 8 + 50 * Csw / 10 ^ 6 - 0.125 * (Csw / 10 ^ 6) * (T * 9 / 5 + 32)
    Bw_star = Bw_o * ((1 + (A1 / A0) * p * 14.7) ^ (-1 / A1))
    Bw = Bw_star
End Function
```

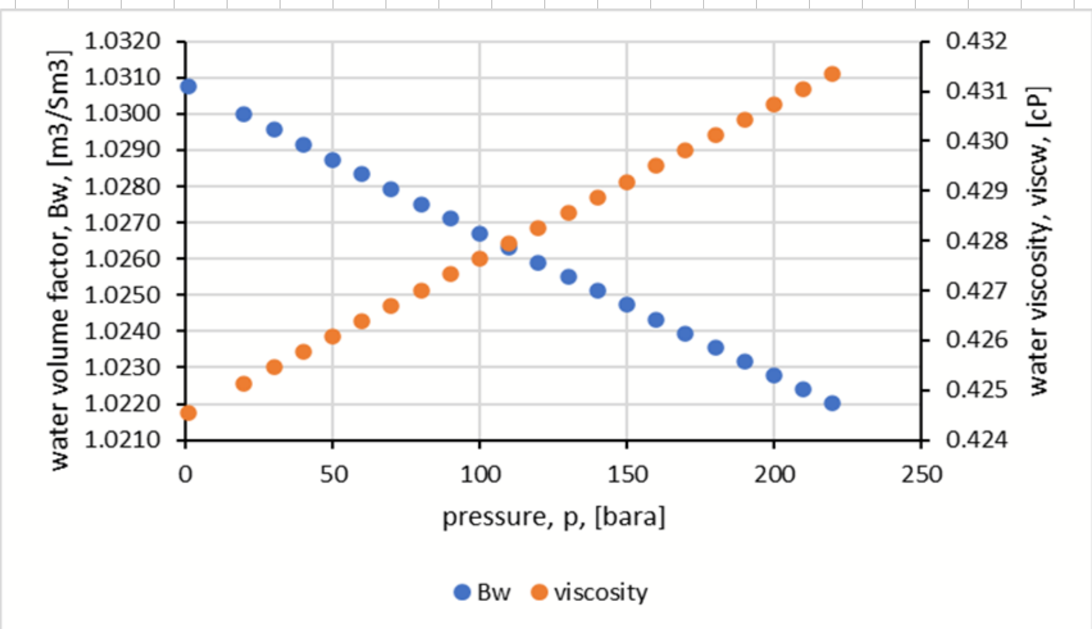
```
'   The water viscosity (Visw cp) is calculated from Kestin et al correlation
'   as reported by Whitson, in his SPE monograph phase behavior (section 9.4.6).

Function Visw(T, p, Csw)
'T, in °C
'p in bara
'Csw salinity in ppm
MW_H2O = 18
If Csw <> 0 Then
    Csw = 17.1 / ((1000000# / Csw) + 1) 'converting from ppm to molality
End If
    p = p / 10
    Ao = 0.001 * (0.8 + 0.01 * (T - 90) * Exp(-0.25 * Csw))
    visw0_20 = 1.002
    A1 = (0.03324 * Csw + 0.003624 * Csw ^ 2 - 0.0001879 * Csw ^ 3)
    A2 = (-0.0396 * Csw + 0.0102 * Csw ^ 2 - 0.000702 * Csw ^ 3)
    c1 = (20 - T)
    c2 = (20 - T) ^ 2
    c3 = (20 - T) ^ 3
    c4 = (20 - T) ^ 4
    log_ratio = ((1.2378 * c1 - 0.001303 * c2 + 0.00000306 * c3 + 0.0000000255 * c4) / (96 + T))
    visw0 = visw0_20 * (10 ^ log_ratio)
    visw_star = visw0 * (10 ^ (A1 + A2 * log_ratio))
    Visw = (1 + Ao * p) * visw_star
End Function
```

Prof. Milan Stanko (NTNU).

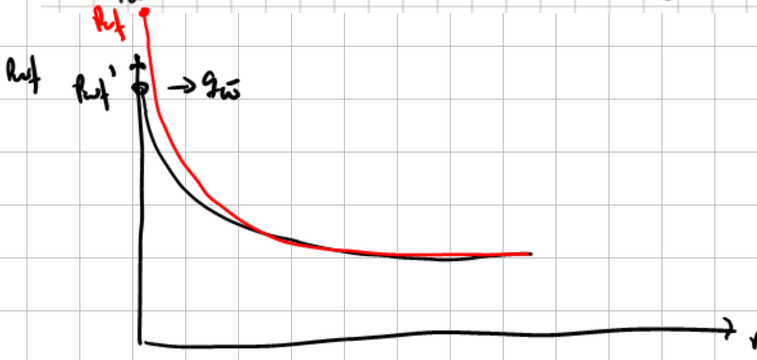
water Salinity	[ppm,w]	100000
Density of water at standard conditions	[kg/m3]	1072

p	T	Bw	viscw	denw
[bara]	[C]	[m3/Sm3]	[cp]	[kg/m3]
1	80	1.0308	0.425	1040.40
20	80	1.0300	0.425	1041.20
30	80	1.0296	0.425	1041.62
40	80	1.0291	0.426	1042.04
50	80	1.0287	0.426	1042.45



Skin factor for water injectors

$$\left(\underbrace{P_{wf}'}_{\substack{\text{ideal}\\ \downarrow \\ \text{no skin}}} - \underbrace{P_{wf}}_{\substack{\text{actual}\\ \text{with skin}}}\right) = \Delta p_{skin} = S\underbrace{\left[\frac{18.68\,(\mu_o B_o)_{av}\cdot q_{\bar o}}{kh}\right]}_{\text{bar}}$$



$$\left(\underset{\text{actual}}{P_{wf}} - \underset{\text{ideal}}{P_{wf}'}\right) = S\left[\frac{18.68\,(\mu_w B_w)_{@P_{av}}\cdot q_{\bar w}}{kh}\right]$$

$$P_R - P_{wf}' = \frac{q_{\bar o}\,18.68\,(\mu_o B_o)_{av}}{k.h}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75\right]$$

$$P_{wf}' - P_{wf} = \frac{q_{\bar o}\,18.68\,(\mu_o B_o)_{av}}{kh}\,S$$

$$P_R - P_{wf} = \frac{q_{\bar o}\,18.68\,(\mu_o B_o)_{av}}{kh}\left[\ln\frac{r_e}{r_w} - 0.75 + S\right]$$

$$J = \frac{kh}{18.68\,(\mu_o B_o)_{av}\left[\ln\frac{r_e}{r_w} - 0.75 + S\right]}$$

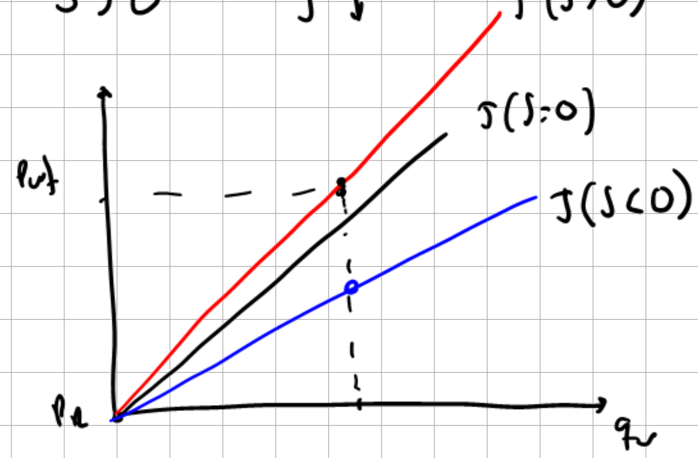
$$(P_{wf}' - P_R) = q_{\bar w}\,18.68\,(\mu_w B_w)_{av}\left(\ln\frac{r_e}{r_w} - 0.5\right.$$

$$(P_{wf} - P_{wf}') = \frac{S\,q_{\bar w}\,18.68\,(\mu_w B_w)_{@av}}{kh}$$

$$(P_{wf} - P_R) = \frac{q_{\bar w}\,18.68\,(B_w\mu_w)_{@av}}{kh}\left(\ln\frac{r_e}{r_w} - 0.5 + S\right]$$

$$J = \frac{kh}{18.68\,(B_w\mu_w)_{av}\left[\ln\frac{r_e}{r_w} - 0.5 + S\right]}$$

$S > 0$ $J \downarrow$



$$\overset{x}{q_{\bar w}} = J\,(\overset{y}{P_{wf} - P_R})$$

$$\overset{y}{P_{wf}} = \overset{b}{P_R} + \frac{\overset{x}{q_{\bar w}}}{J}$$

$$\frac{1}{J} \rightarrow \frac{1}{m}$$

$$y = b + mx$$

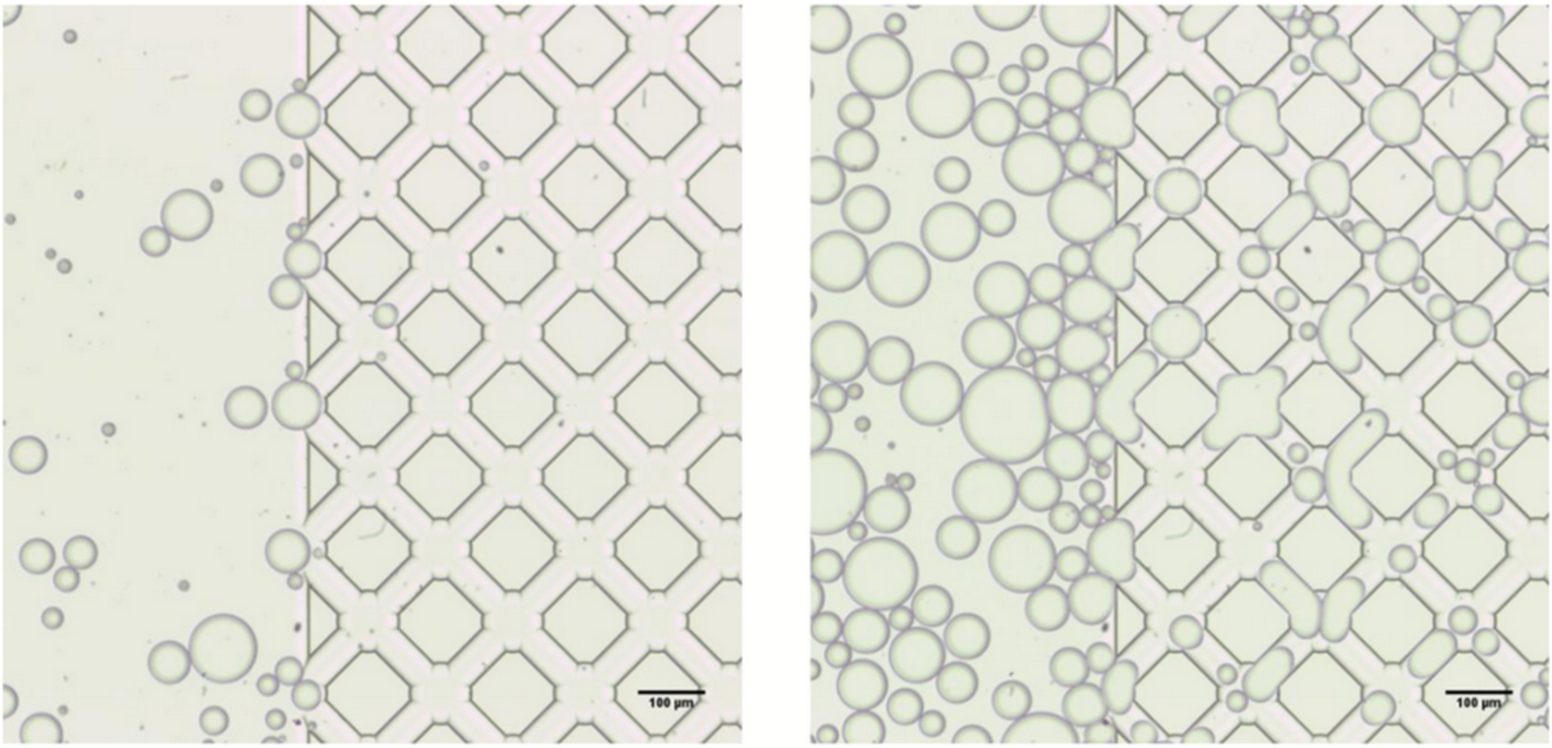
For an oil producer:

$$q_o = J \cdot (p_R - p_{wf})$$

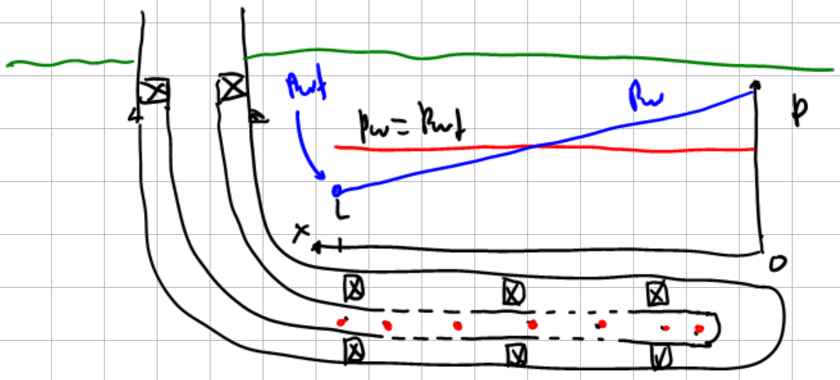
$$p_{wf} = p_R - \frac{q_o}{J}$$

$y \quad b \quad 1/m$

Injector plugging zoom-in due to oil particles in oil (Image from experiments by Ilgar Azizov, SUBPRO, NTNU)



Video 13.1 - Effect of wellbore pressure drop on horizontal undersaturated oil well IPR



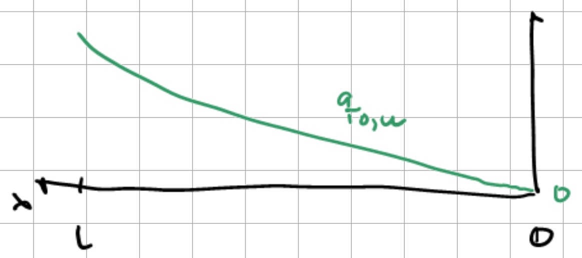
$$q_{\bar o} = J\,(p_R - p_{wf})$$

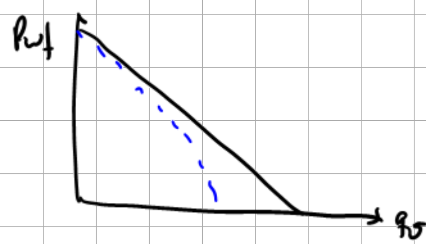
$$\frac{dp_w}{dx} = -\rho_o \frac{f}{D} \frac{v^2}{2}$$

$$v = \frac{q_{o,w}(x)}{A} \qquad q_{\bar o,w} \cdot B_{o,w} = q_{o,w}$$

$$A = \frac{\pi D^2}{4}$$

$$\frac{dp_w}{dx} = -\rho_o \frac{f}{D^5} \frac{8\, q_{\bar o,w}^2}{\pi^2} \cdot B_{o,w}^2$$





Pressure Drop in Horizontal Wells and Its Effect on Production Performance

Ben J. Dikken, SPE, Koninklijke/Shell E&P Laboratorium

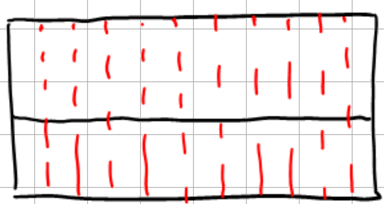
(1989)

Author

Ben J. Dikken is a reservoir engineer in the Technology Development Dept. of Shell Intl. Petroleum Mij. B.V. in The Hague, with interests in horizontal wells, propagating waterflood-induced fractures, and well testing. He previously worked at the Koninklijke/Shell E&P Laboratory in Rijswijk. He holds MS and PhD degrees in physics, both from the State U. of Utrecht, The Netherlands.

mass conservation in wellbore

$$\frac{d q_{\bar o,w}}{dx} = q_{\bar o,i}$$



$$q_{\bar o} = J\,(p_R - p_{wf})$$

$$q_{\bar o,i} = j\,(p_R - p_w)$$

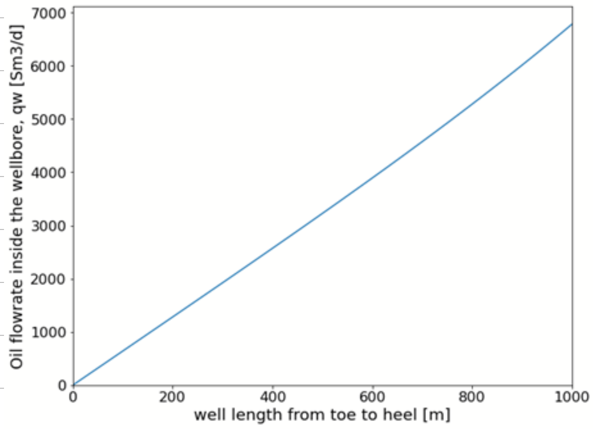
$$j = J/L = \left[\frac{Sm^3/d/bar}{m}\right]$$

$$\left.\begin{aligned} \frac{d q_{\bar o,w}}{dx} &= j\,(p_R - p_w) \\ \frac{dp_w}{dx} &= -\rho_o \frac{f}{D^5} \frac{8\, q_{\bar o,w}^2}{\pi^2} \cdot B_{o,w}^2 \end{aligned}\right\}$$

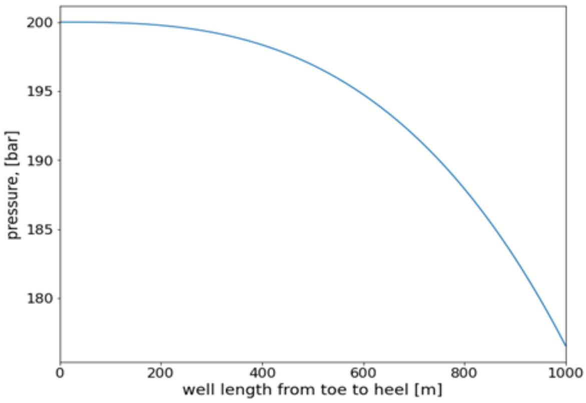
at $x^* = 0$ $\quad p_w$ = assumed value $< p_R$

$q_{\bar o,w} = 0$

Solution (using Python)



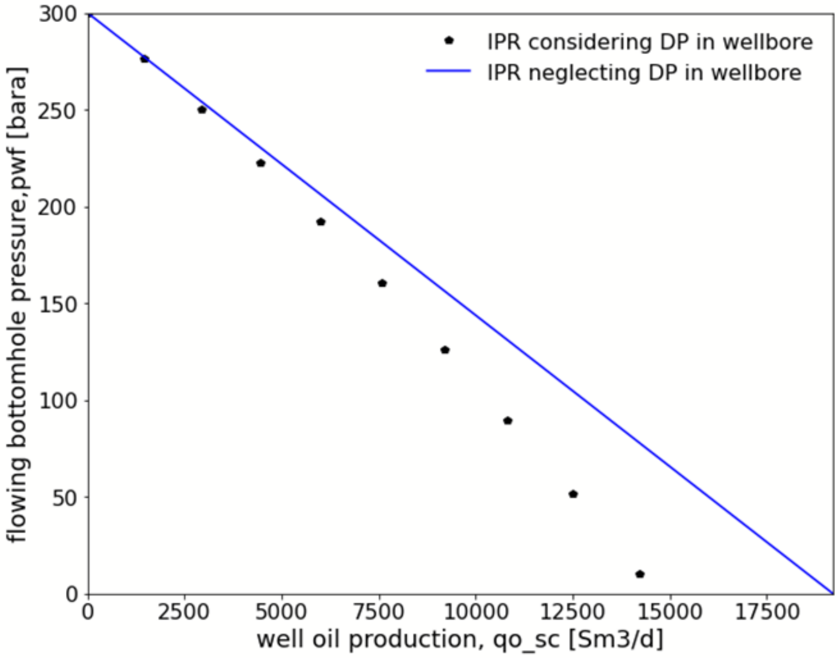
Uniform oil influx along the wellbore



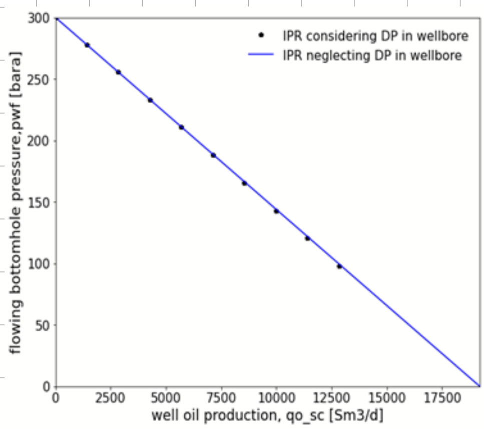
Non-linear distribution of wellbore pressure

How to obtain the IPR of the well?

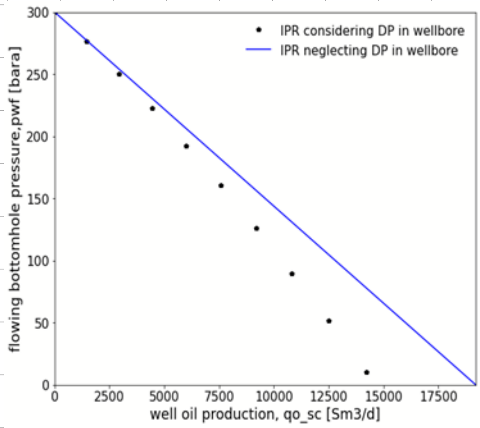
repeat using other values of pw@toe



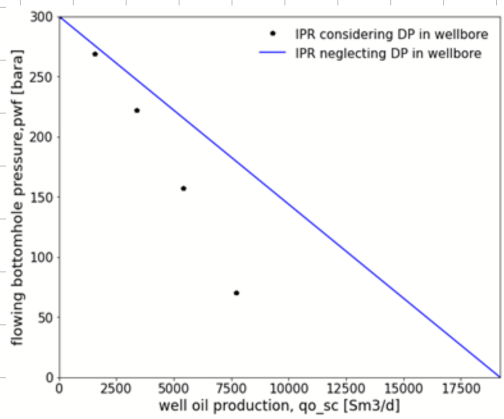
Effect of liner diameter



0.2 m



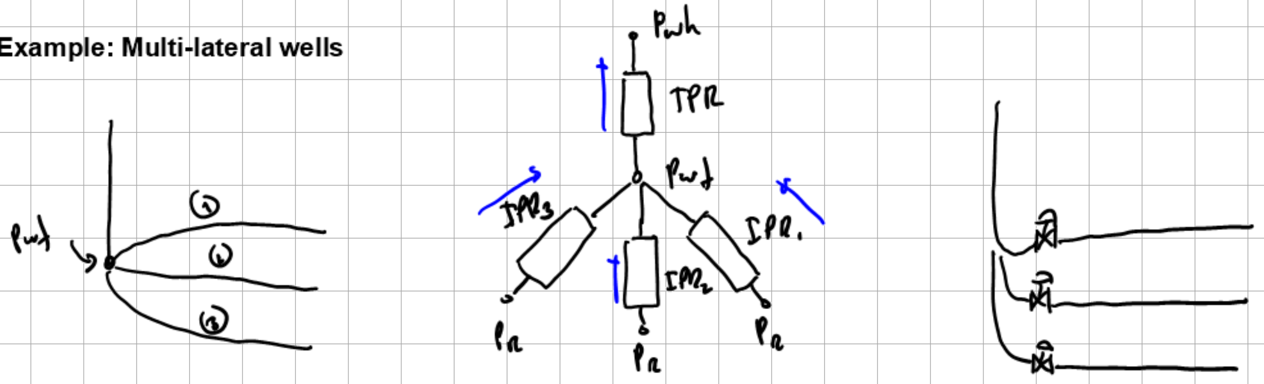
0.1 m



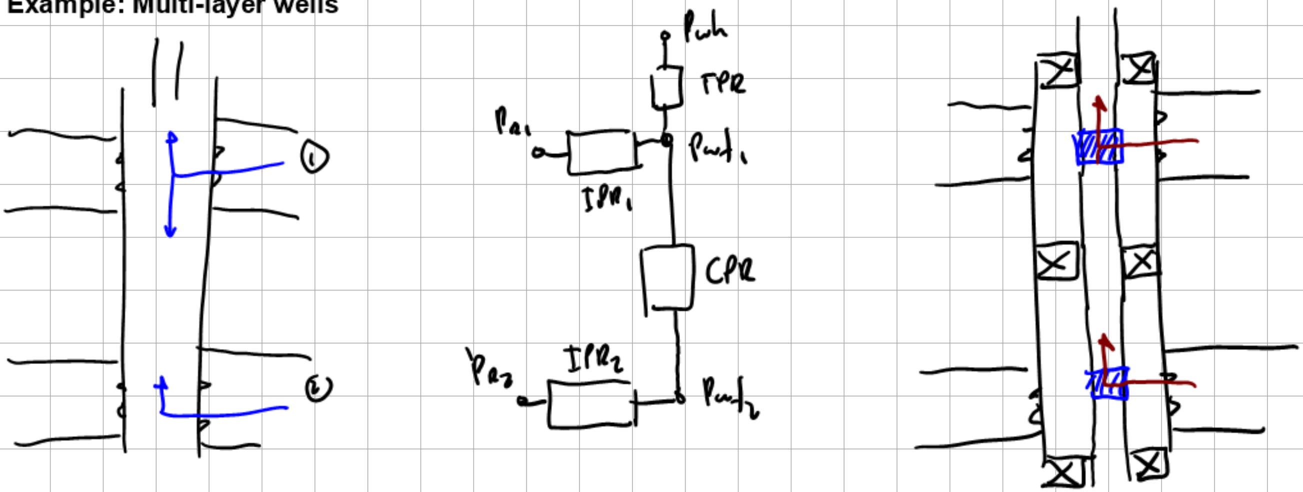
0.07 m

Video 13.2. - Downhole networks and inflow control

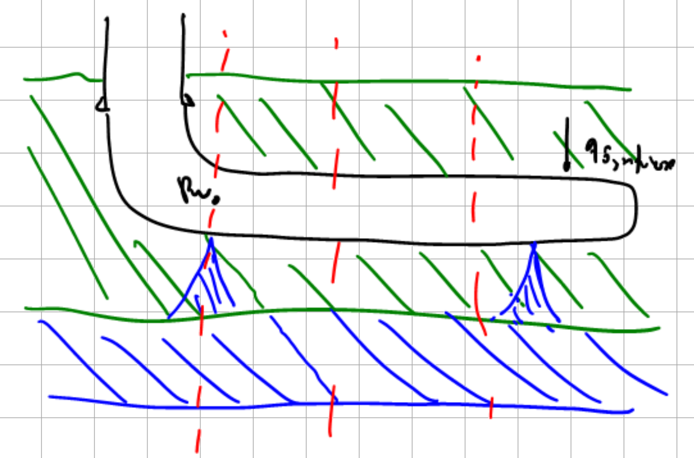
Example: Multi-lateral wells

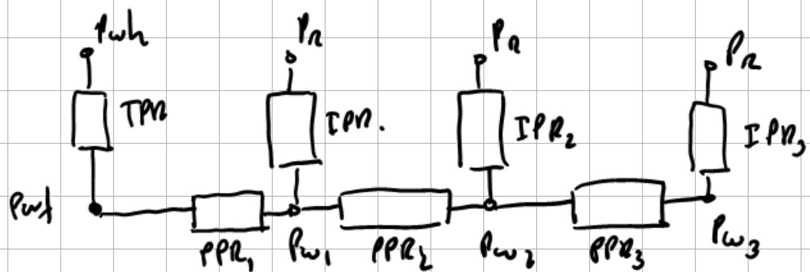


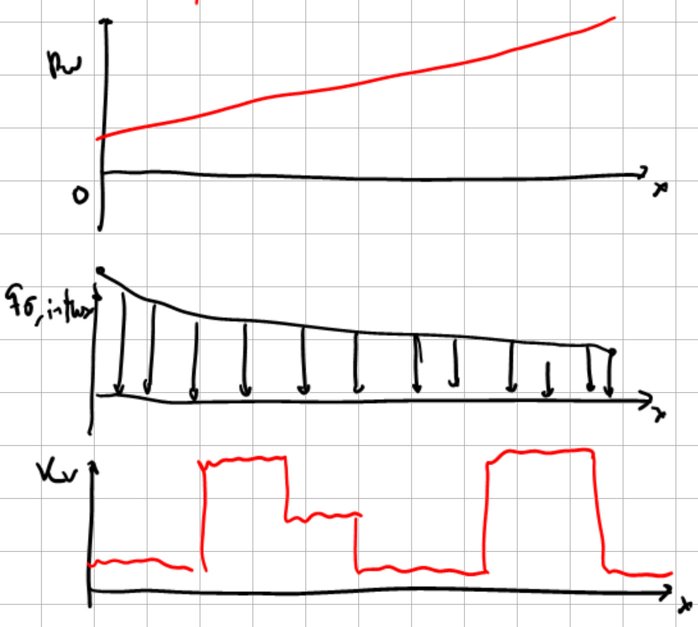
Example: Multi-layer wells

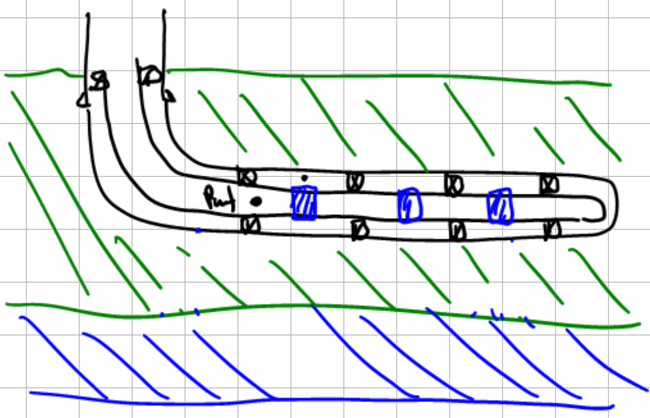


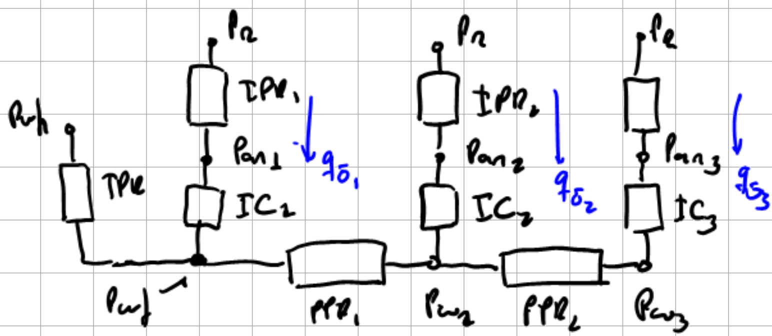
Example: horizontal oil well with an underlying aquifer

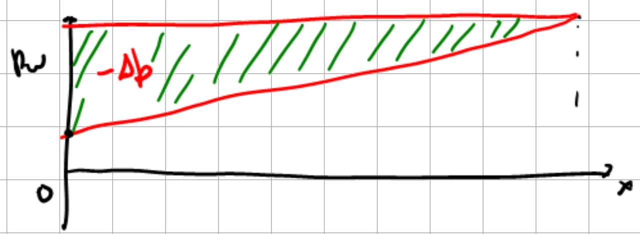


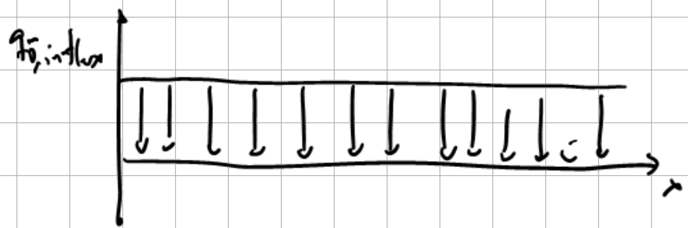






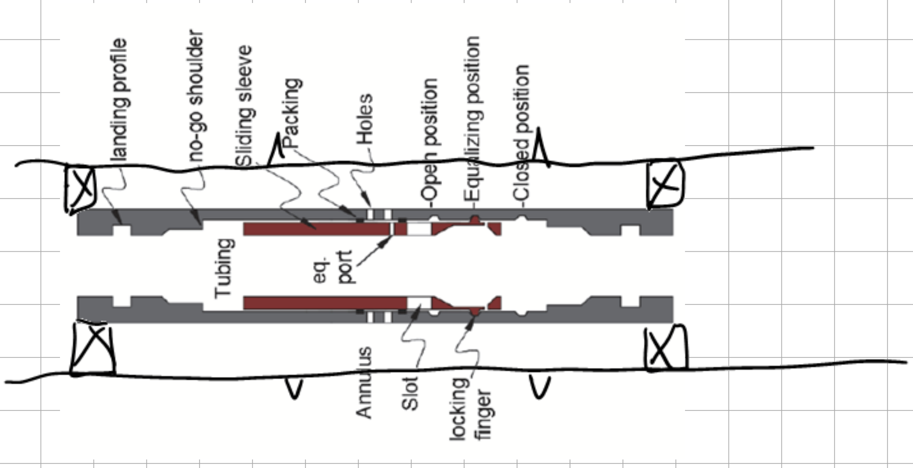

TPR
IPR1
IC1
IPR2
IC2
IC3
PPR1
PPR2


−Δp
0

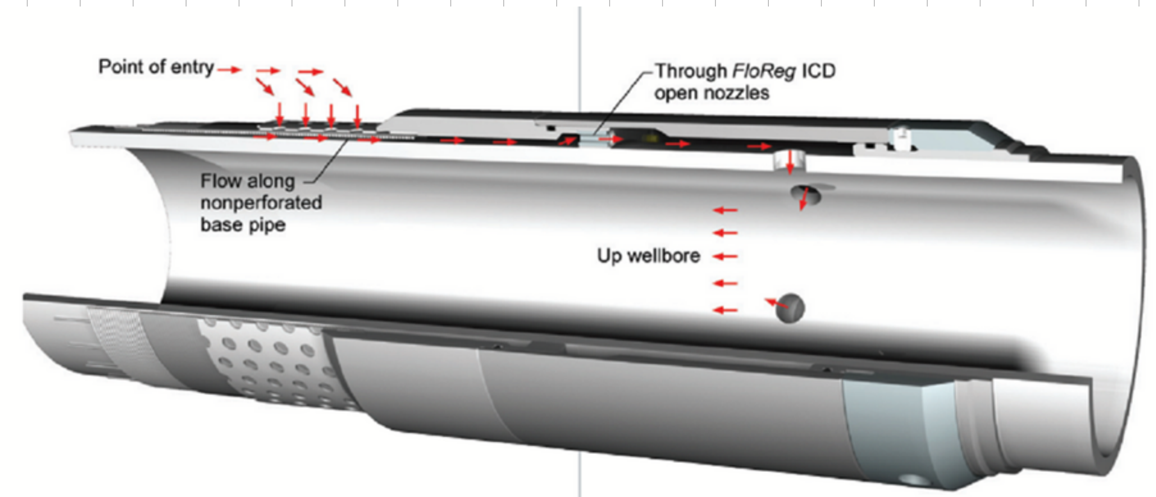


SOME FLOW CONTROL ELEMENTS

Sliding sleeve

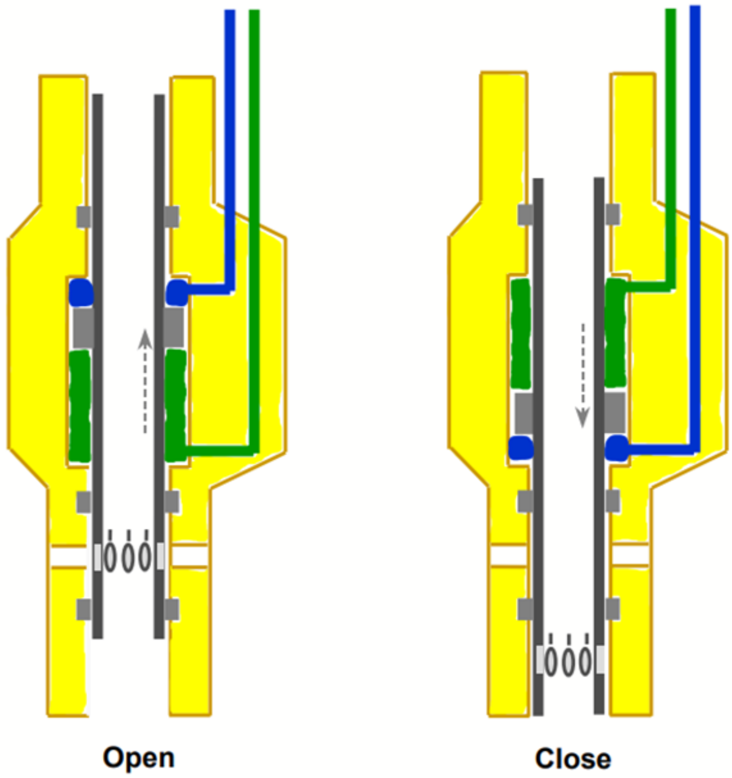


https://www.weatherford.com/documents/brochure/products-and-services/completions/floreg-inflow-control-device-(icd)/

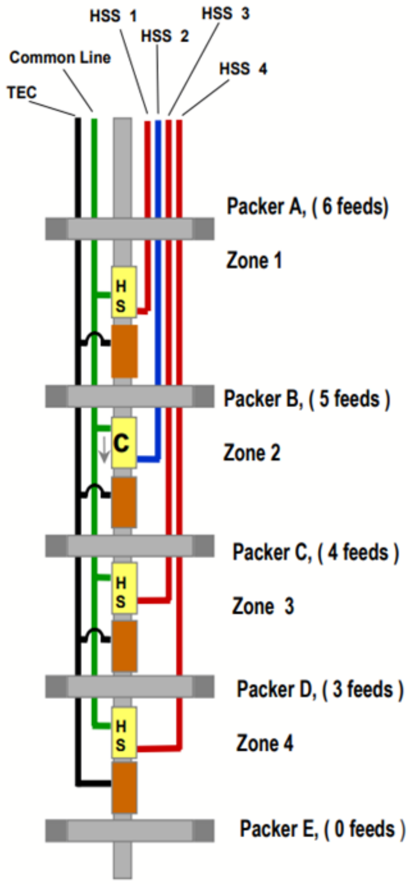


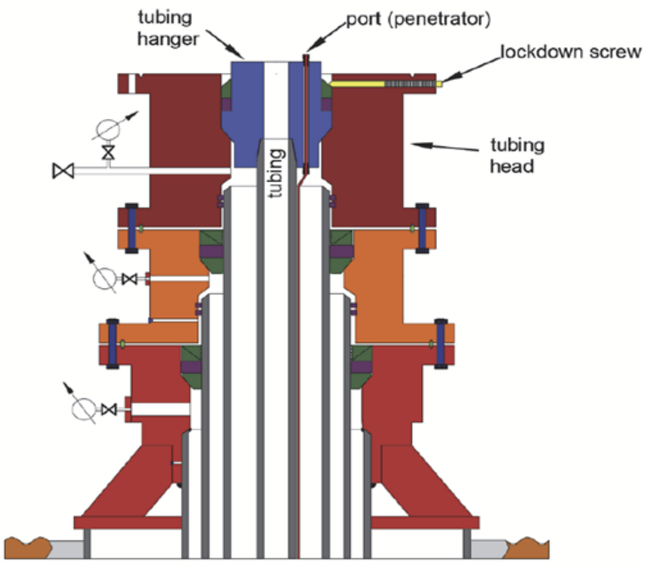
OTC 11933 HYDRAULICALLY ACTUATED INTELLIGENT COMPLETIONS: DEVELOPMENT AND APPLICATIONS 7

ICV inflow control valve

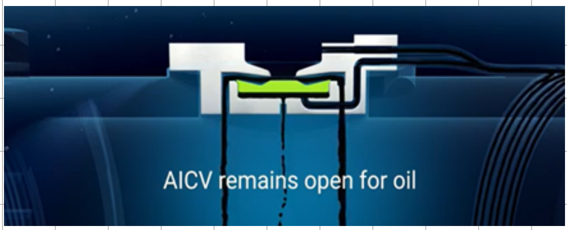


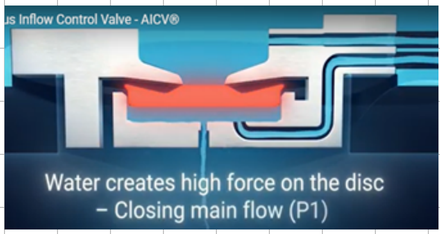
12 W. SIDES, S. HODGES, G. OLIN OTC 11933

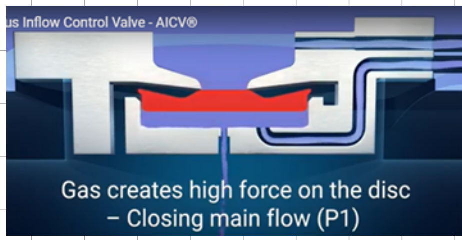




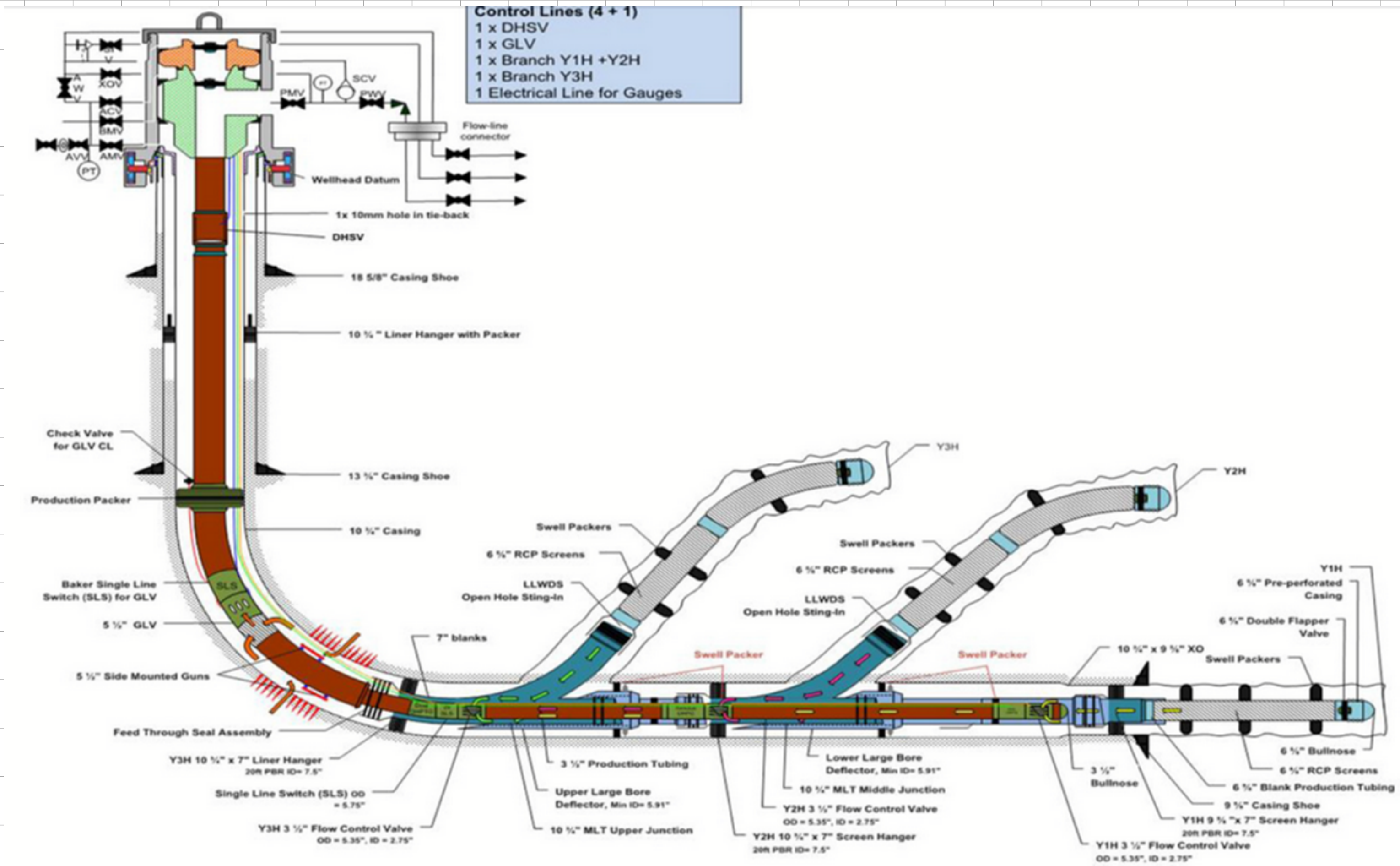
https://www.inflowcontrol.no/aicv-technology







Troll completion (Taken from SPE-180037-MS)

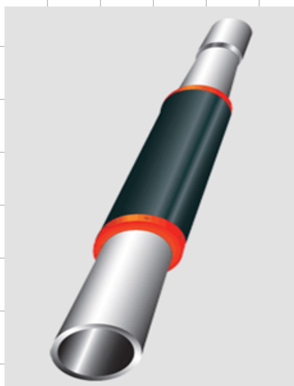


Short on packers:

Inflatable packers (open hole)

https://www.mgs.co.uk/product/borehole-packers/

Swellable packers (open hole)



http://poss.com.eg/index.php/portfolio-posts/freecap-i-swellable-packers/

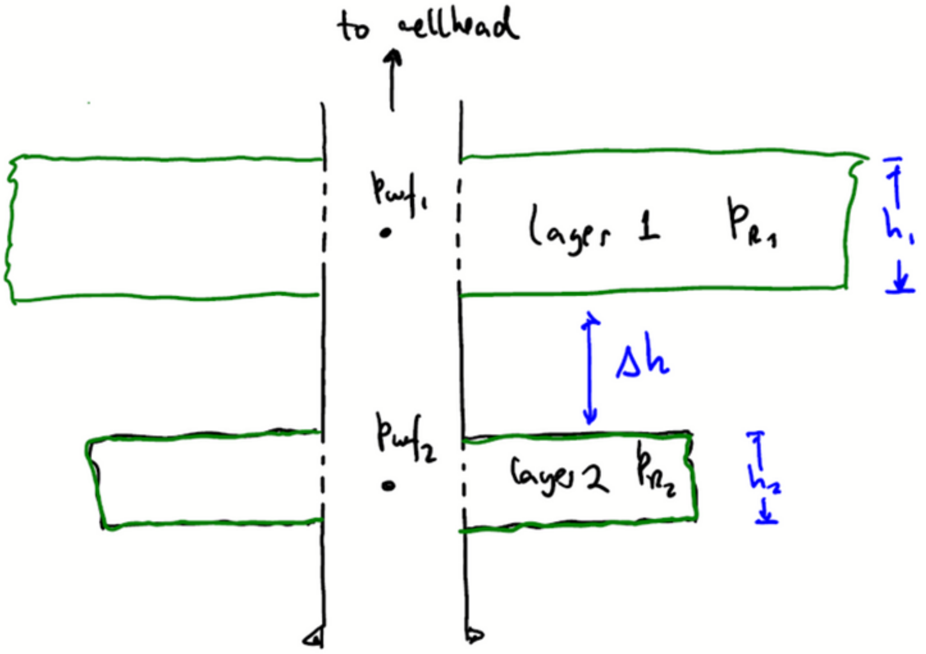
Mechanical/hydraulic packers (cased hole)

https://www.wellcareoiltools.com/packer-system/mechanical-packer/

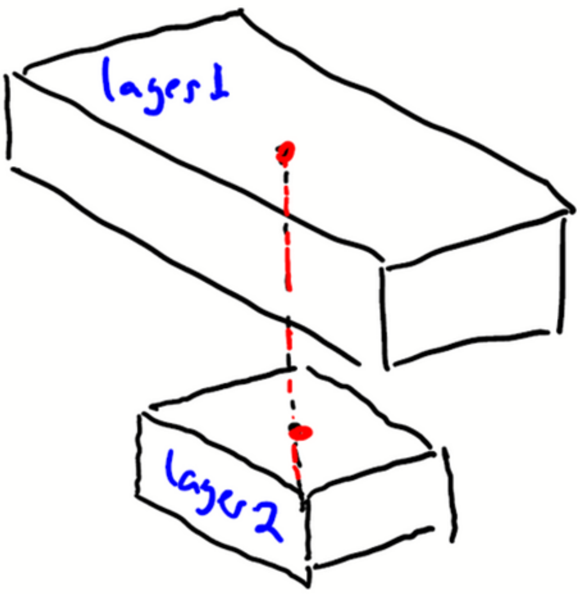
20220920

Problem 1: Planning a subsea well in the Alta-Gohta field

You are part of the well planning team in Lundin that is in charge to design a vertical production well for the Alta-Gohta field development. The plan is to produce two oil layers using the same well. The well will be fully perforated throughout each layer. The two layers contain undersaturated oil. Assume the wellbore diameter is 8-1/2".



A reservoir engineer has determined, considering neighboring wells, structural seals, etc. that the drainage volume of the well can be approximated by two rectangular boxes that are vertically stacked one above the other.



The layers have different lengths, widths, and thicknesses (as shown in Table 1). There is a 100 m thick shale layer in between the two oil bearing layers.

	Layer 1	**Layer 2**
Thickness [m]	20	25
Length [m]	1000	500
Width [m]	800	400
Horizontal permeability [md]	15	40
Permeability anisotropy	10	10
Reservoir pressure [bara]	400	500

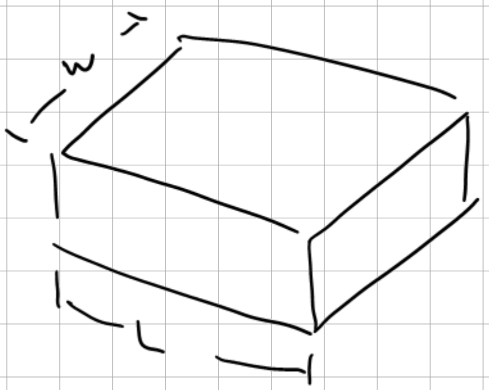
Samples were taken of each layer and the PVT expert has created tables of black oil properties Bo and oil viscosity for your use (available in the Excel file attached). Because the composition of each layer is slightly different, there is one BO table for each layer.

Due to the height difference between the layers, the flowing bottom-hole pressure of layer 1 is not the same as layer 2. The pressure difference between the bottom-hole pressures can be calculated using the hydrostatic oil column between 1 and 2. Assume that the bottom-hole location of each layer is located exactly in the middle of the layer.

Task 1.

Estimate the productivity index of each layer. To calculate the BO properties needed in the IPR equation, use the average between reservoir pressure and the bubble point pressure of the fluid (at reservoir temperature). Consider that the well is fully perforated throughout each layer.

```
Function J_vertical(k, h, Uo, Bo, re, rw, s, sa)
    'Productivity index for vertical well, undersaturated oil, pss, in Sm3/d/bar
    'k in md
    'h in m
    'Uo in cp
    'Bo in m^3/Sm^3
    'fa is shape factor
    J_vertical = (k * h) / (18.68 * Uo * Bo * (Log(re / rw) - 0.75 + s + sa))
    'Natural Log in Visual Basic is Log, not LN'
End Function
```

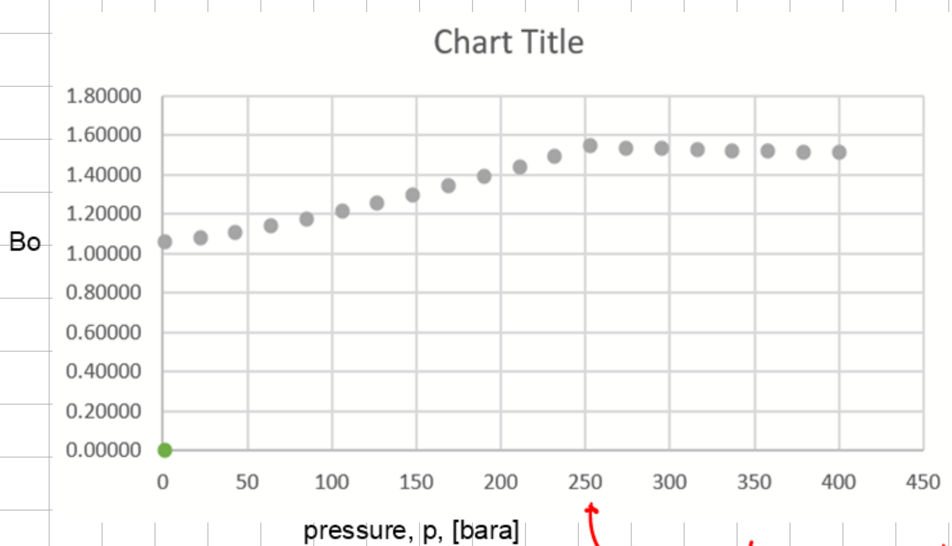


effective radius

$$A_D = W \cdot L = \pi r_e^2$$

$$r_e = \sqrt{\frac{W \cdot L}{\pi}}$$

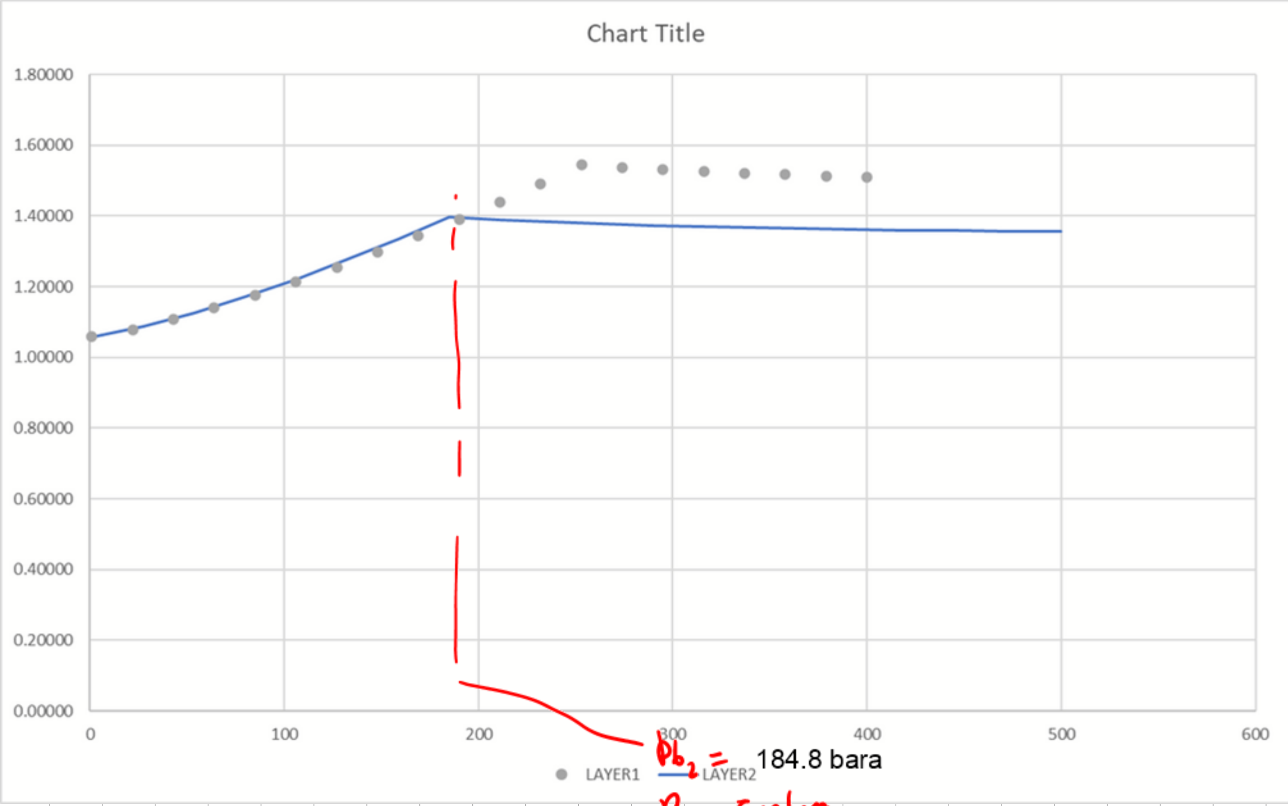
BO properties layer 1



$p_{b_2} = 253$ bara

$P_{b_1} = 400$ bara

$J_1 = 2.9$ $Sm^3/d/bar$ ← QC this number!!



P_{b_2} = 184.8 bara

$P_R = 500$ bara

$J_2 = 2.7$ Sm³/d/bar ← QC this number!!

Task 2.

What is the maximum oil rate that can be produced from the well and the well GOR (R_p) while ensuring the two following conditions:

- There is no gas is liberated in the reservoir
- There is no gas liberated in the wellbore section from layer 1 to layer 2

$P_{wf_2} \geq P_{b_2} \geq$ 184.8 bara (1)

$P_{wf_1} \geq P_{b_1} \geq$ 253 bara (2)

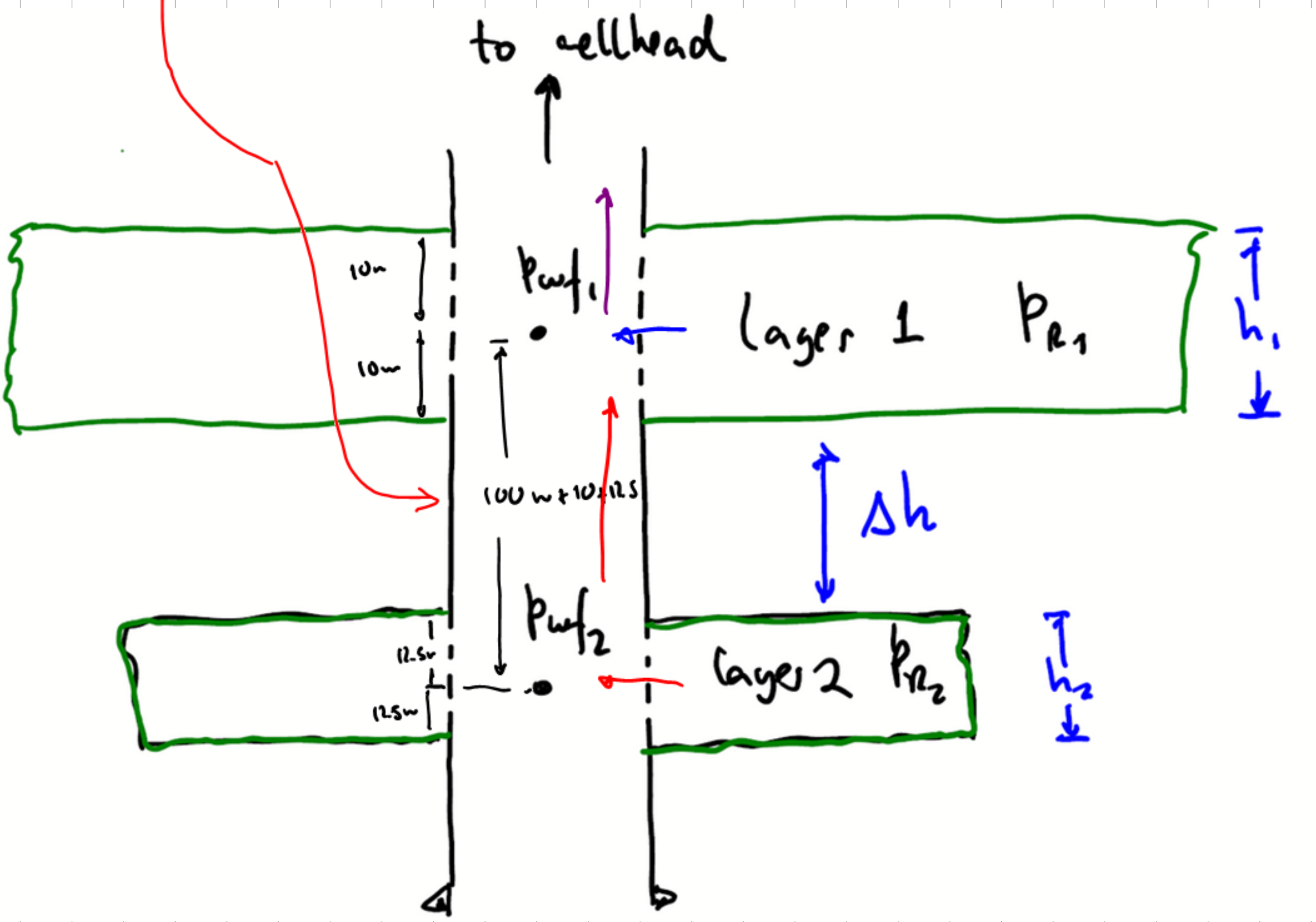
$P_{wf_2} = P_{wf_1} - \Delta z \cdot \rho \cdot g$

823.5 kg/m³ Average between pb2 and pR2

9.81 m/s²

$P_{wf_2} \geq$ pb2 >= 184.8 bara (3)

we set pwf1=253 bara, to honour equations 2 and 3



P_{wf_1} = 253 bara

$$P_{wf_2} = 253 + \frac{122.5 \cdot 723.5 \cdot 9.81}{1E5} = 261.7 \text{ bara}$$

$$q_o = q_{o_1} + q_{o_2}$$

$$q_{o_1} = \overset{\sim 2.9}{J_1}\left(\overset{400}{P_{R_1}} - \overset{253}{P_{wf_1}}\right) = 426.3 \ Sm^3/d$$

$$\rightarrow \ q_{o_2} = \underset{\sim 7.7}{J_2}\left(\overset{500}{P_{R_2}} - \overset{261.7}{P_{wf_2}}\right) = 1834.9 \ Sm^3/d$$

80% of production comes from layer 2!!

$\rightarrow GOR_1 = 173 \; Sm^3/Sm^3$ $\quad q_{\bar{o}} = 2261.2 \; Sm^3/d$

$\rightarrow GOR_2 = 126 \; Sm^3/Sm^3$

$$q_{\bar{g}} = \underbrace{q_{\bar{g}_1}} + \underbrace{q_{\bar{g}_2}}$$

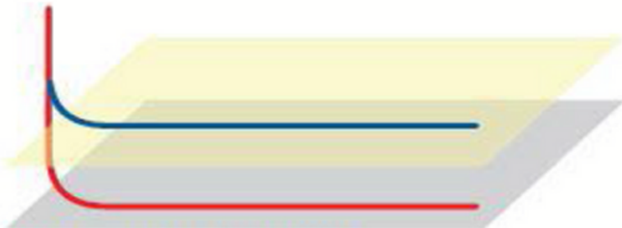
$$= q_{\bar{o}_1} \cdot GOR_1 + q_{\bar{o}_2} \cdot GOR_2$$

$$= 304948.6 \quad Sm^3/d$$

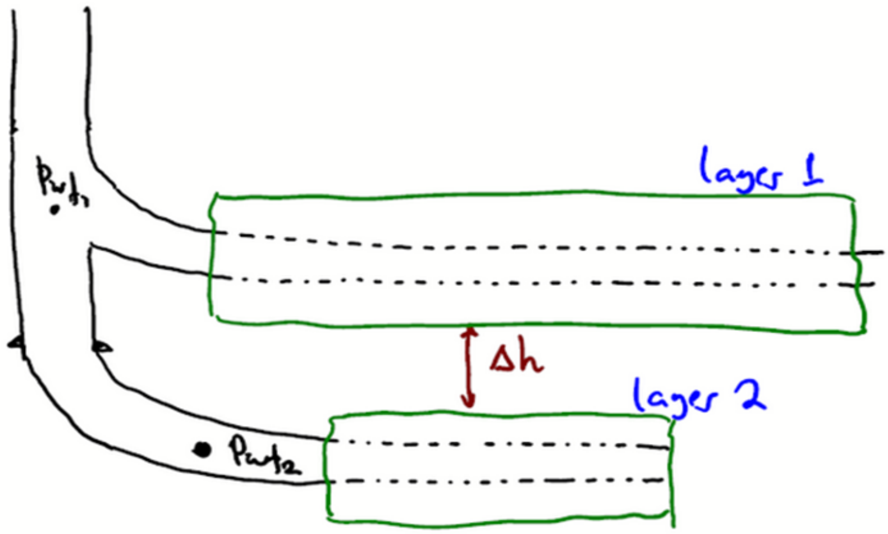
$$GOR = R_p = 304948.6/2261.2=134.9$$

Task 4.

One of your colleagues is suggesting drilling a multilateral well with two stacked horizontal laterals, to produce the two layers, instead of a single vertical well.



Stacked dual lateral



In this case, assume the flowing bottom-hole pressure of each layer is constant along the lateral.

A multilateral well is expensive, riskier and more complex to drill, compared to a vertical well. Additionally, in this case, the multilateral well must be drilled from another location on the sea floor which adds some extra costs in subsea equipment. Therefore, the cost department has determined that the cost of drilling such a well could be almost twice the cost of the vertical well.

However, if a multilateral well gives higher oil rates, the well revenue will also be higher, which would make it a better option. The reservoir group has indicated that an X increase in initial rate will give roughly the same increase in well revenue.

Assume that the lateral is located in the center of the layer, and it is completed all across with a slotted liner.

Use the equation by Harald for horizontal well IPR

According to Milan, it gives
J1= 34 Sm3/d/bar
J2= 51.6 Sm3/d/bar

Do QC!!!

It seems a horizontal well will give much more production than a vertical well. But it is necessary to do an economic analysis to consider the costs of drilling and completion, and the expenses due to intervention to make sure that horizontal wells is more profitable in the long term. There are more risks and complexities when drilling the horizontal well option.

Task 5. Effect of uncertainties

The value of horizontal permeability of each layer is highly uncertain. Formation tests have been performed on each layer using exploration wells, but the locations of the samples are far away the planned well location and the petrophysicist has indicated there is some permeability heterogeneity in the layers. He recommends using the following horizontal permeability range.

Horizontal permeability [md]	Min	Max
Layer 1	5	30
Layer 2	20	50

Additionally, due to formation damage (mud invasion) during the drilling process, one of your colleagues has mentioned that the skin of the vertical well could be of up to 5.

Does this change your conclusions regarding tasks 1-4 above?

We have to evaluate all combinations
-(poor perm layer 1, poor perm layer 2)
-(good perm layer 1, poor perm layer 2)
-(poor perm layer 1, good perm layer 2)
-(good perm layer 1, good perm layer 2)

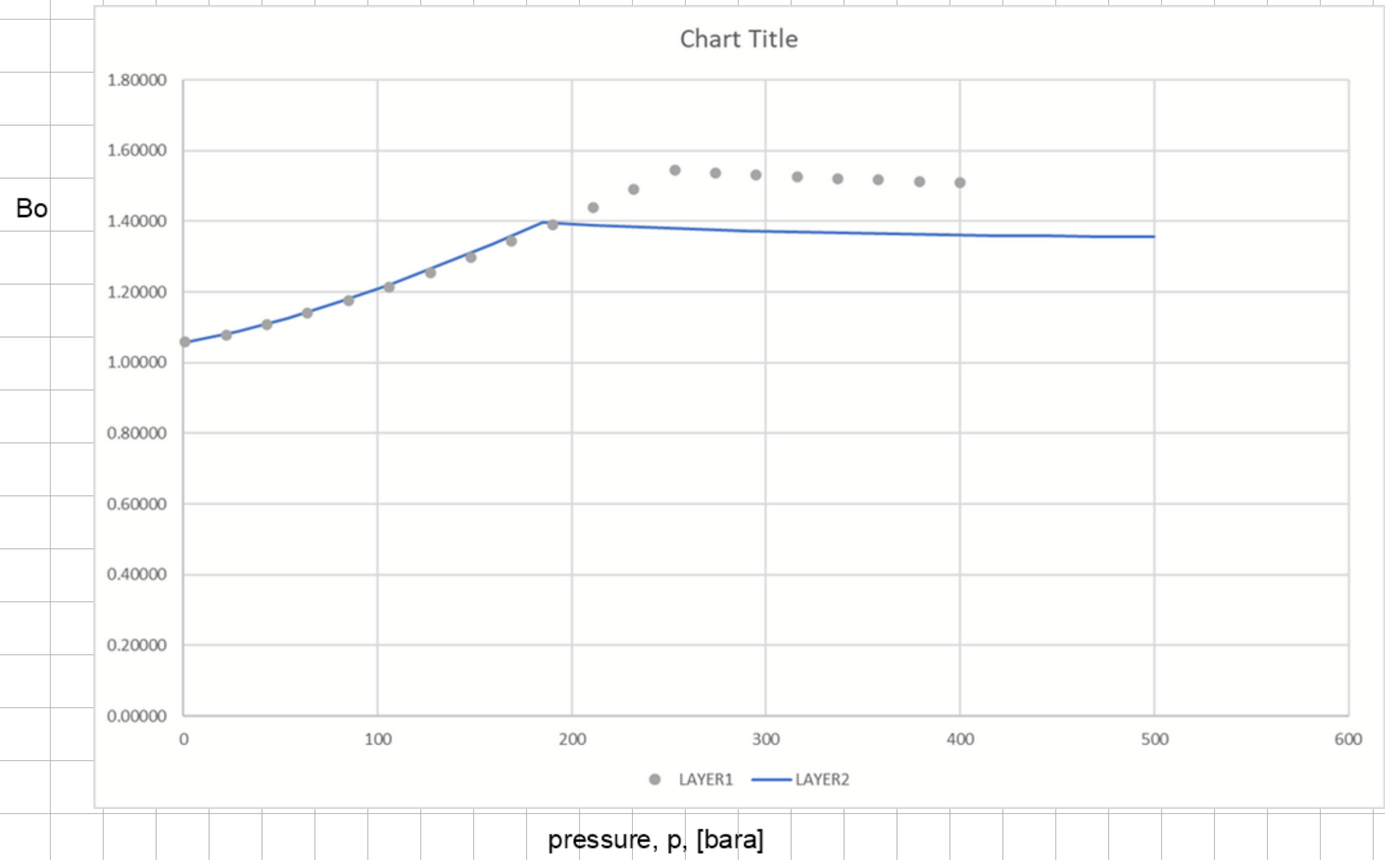
To determine which option (vertical or horizontal) is best. it might be that for some perm combinations, a vertical well is more attractive.

Task 6.

Each layer has slightly different oil composition. Because of these two BO tables have been provided for each layer. Provide some advice about what BO table should be used for the well flow downstream the bottom-hole location of layer 1?

-if using tables generated by compositional simulation:

1. it is possible to use the same table if the fluid properties are similar . For example, for the case below, if the pressure is below 184.8 bara it seems it is possible to use the same table. However, it is not possible to use the same table for pressures above 184.8.bara
2. If the fluid properties are not similar, it is necessary to generate a new BO table considering a new composition made out of fluid from layer 1 and 2. The amount of oil coming from each layer is required to estimate this composition, so it is an implicit process.



If using BO correlations,

-if the same correlations are employed for both layers and the standard gravity of oil and gas are similar between layers, then it is possible to estimate properties by changing the GOR.

20220922: live lecture

Some well hardware

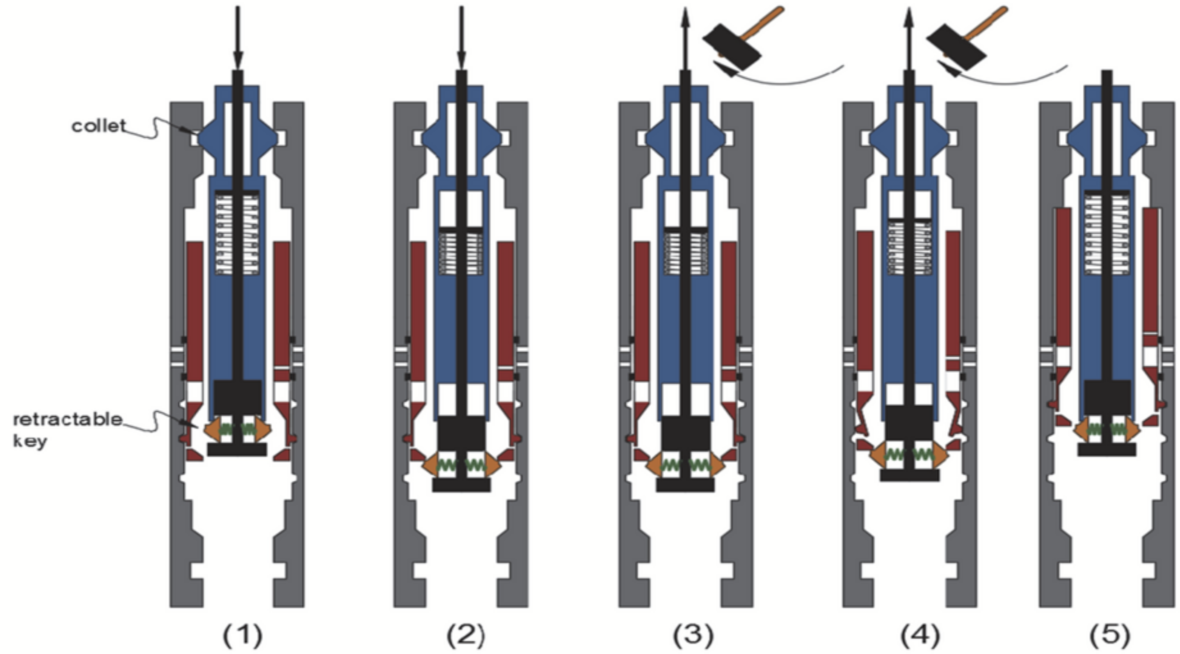
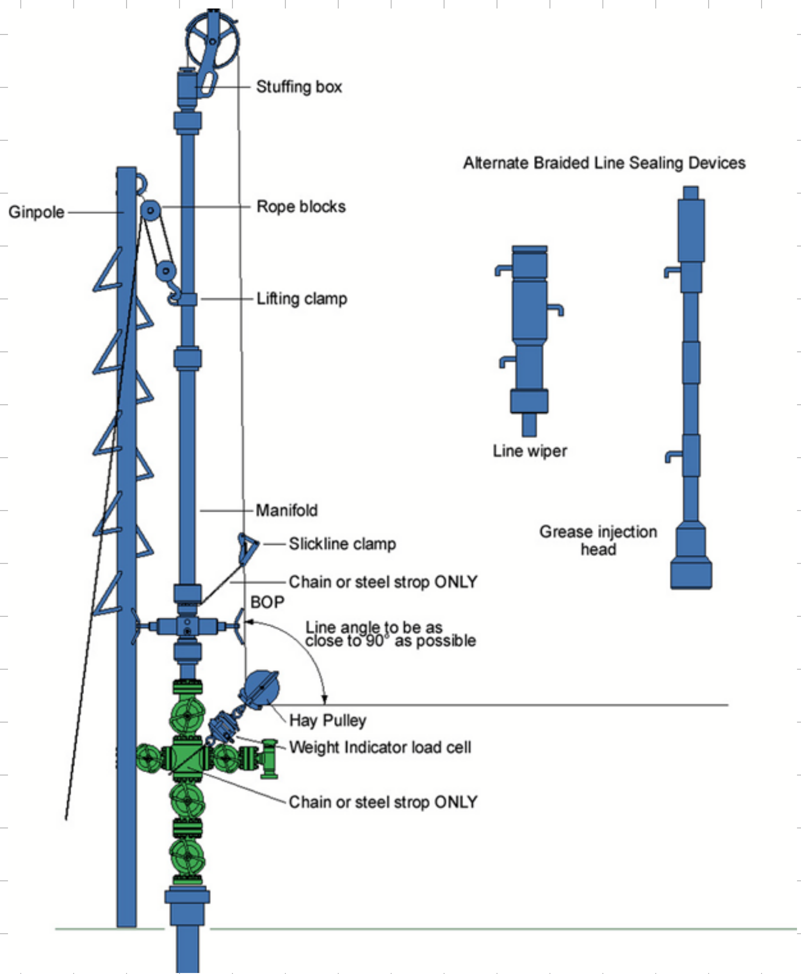


FIGURE 2-58. SHIFTING SEQUENCE OF A SLIDING SLEEVE USING SLICKLINE



Lubricator

2 Cable Tractor (Aker Solutions/2010 /)

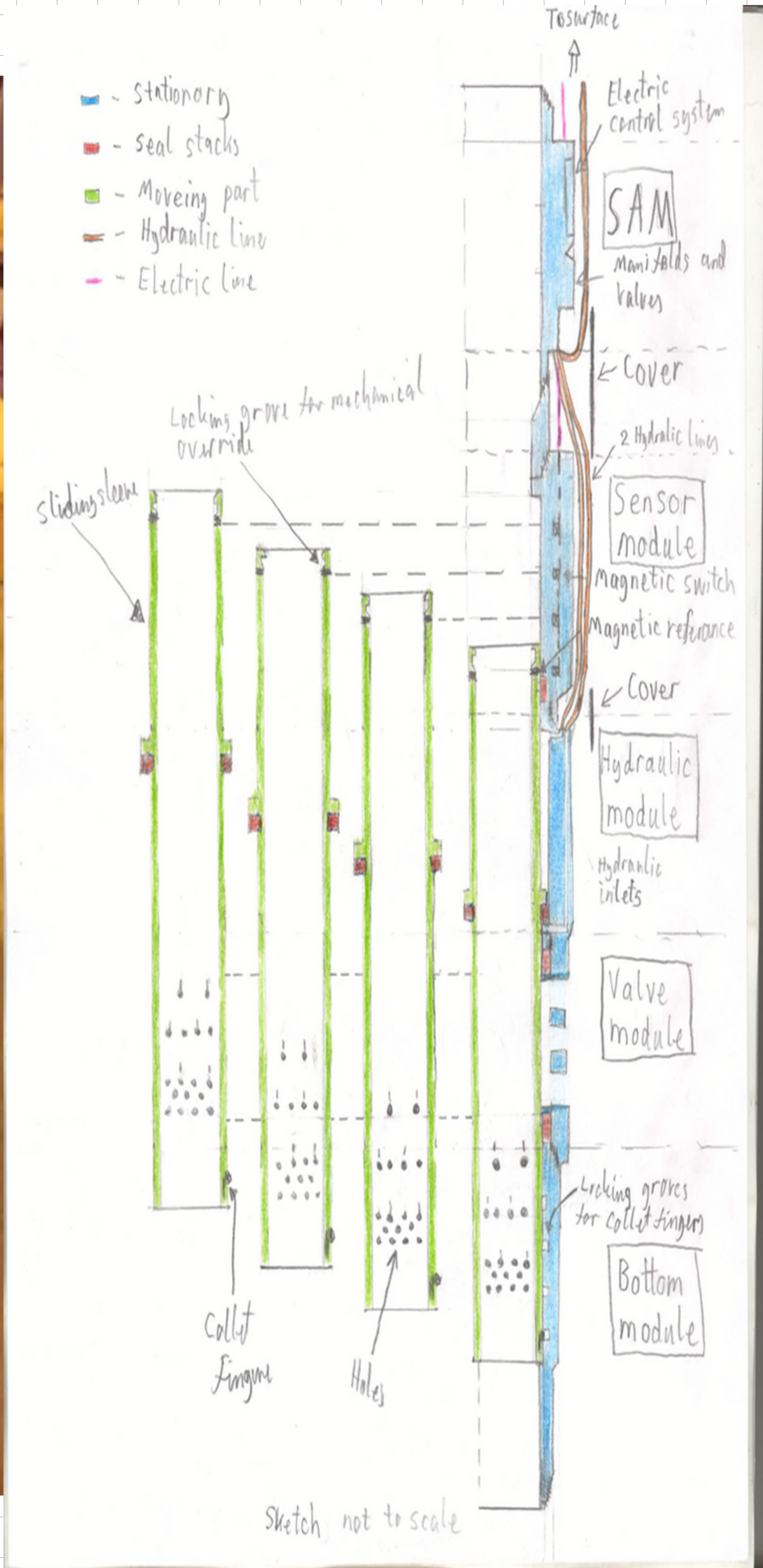
6.23 Cable tractor, equipped for milling (Aker solutions 2010)

Sub surface safety valve

Wellhead choke (disk type)

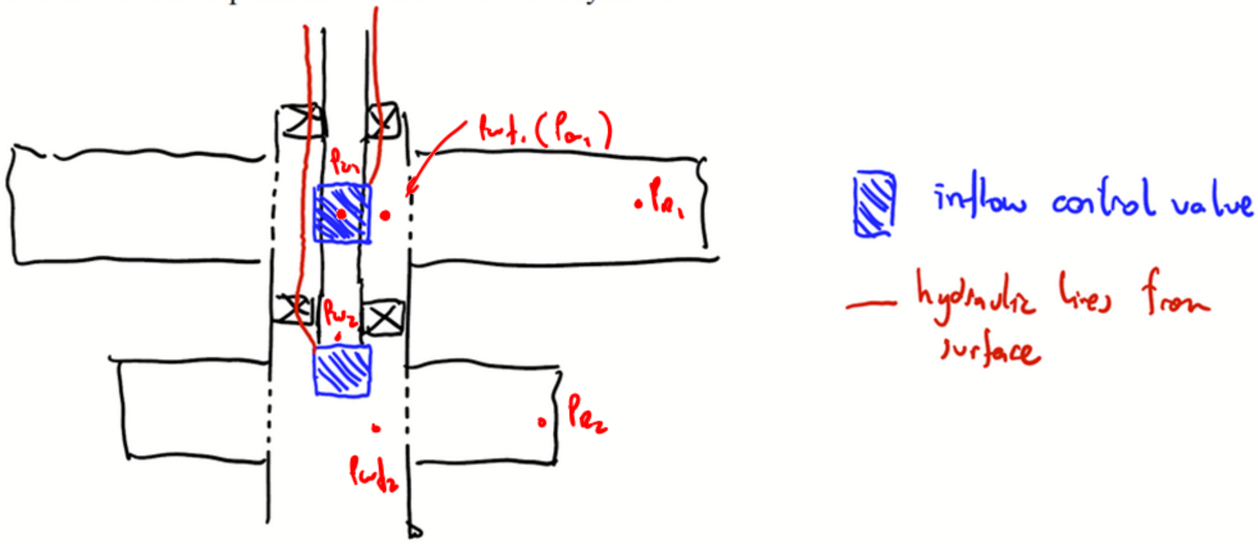
Hydraulic packer (Slip and packing element)

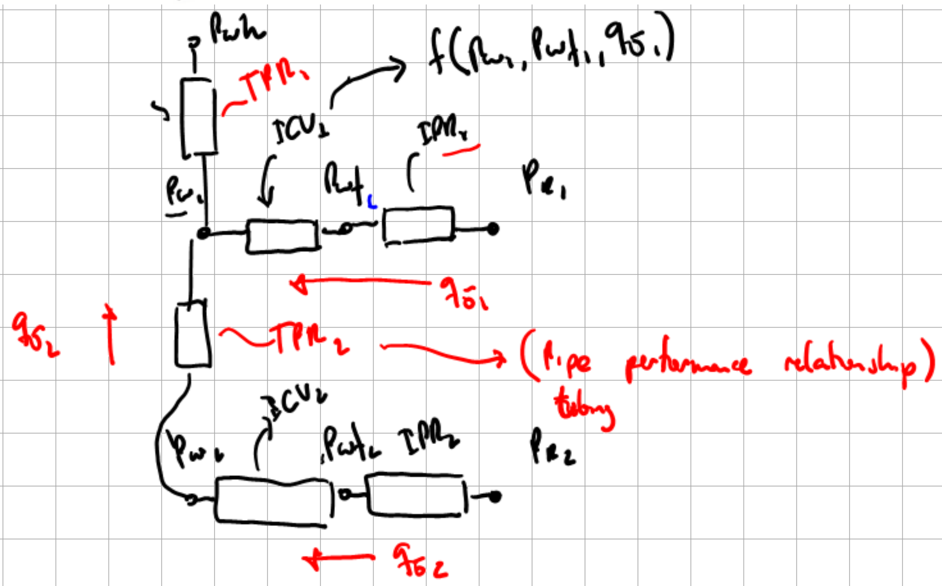
Inflow control valve (ICV)



Task 3.

Based on the results from task 2, one of your colleagues has suggested to use an inflow control valve to regulate the inflow of each layer, by creating a pressure drop. The colleague claims that this will allow to produce more oil from the system.





-To ensure production from layer 1 is maximum, pwf1=253 bara (pb1)
-To ensure production from layer 2 is maximum, pwf2=185 bara (pb2)

$$q_{o1} = \overset{2.9}{J_1}\,(\overset{400}{P_{R1}} - \overset{253}{P_{wf1}}) = 426.3 \text{ Sm}^3/d$$

$$q_{o2} = \overset{7.7}{J_2}\,(\overset{500}{P_{R2}} - \overset{185}{P_{wf2}}) = 2425 \text{ Sm}^3/d \quad \times$$

$P_{w1} = P_{b2} = 185$ bara

$$P_{w2} = 185 + \frac{122.5 \cdot 723.5 \cdot 9.81}{1E5} = 193.7 \text{ bara}$$

$\Delta p_{ICV2} = 0$ bar

$$q_{o2} = 7.7\,(500 - 193.7) = 2358.5 \text{ Sm}^3/d$$

Check, if pwf1>pw1 ---> production is possible.

$$q_{oT} = q_{o1} + q_{o2} = 426.3 + 2358.5 = 2785$$

$\Delta p_{ICV1} = 253 - 185 = 68$ bar $\quad q_{o1} = 426.3 \text{ Sm}^3/d$

U. S. DEPARTMENT OF THE INTERIOR
HAROLD L. ICKES, Secretary

BUREAU OF MINES
John W. Finch, Director

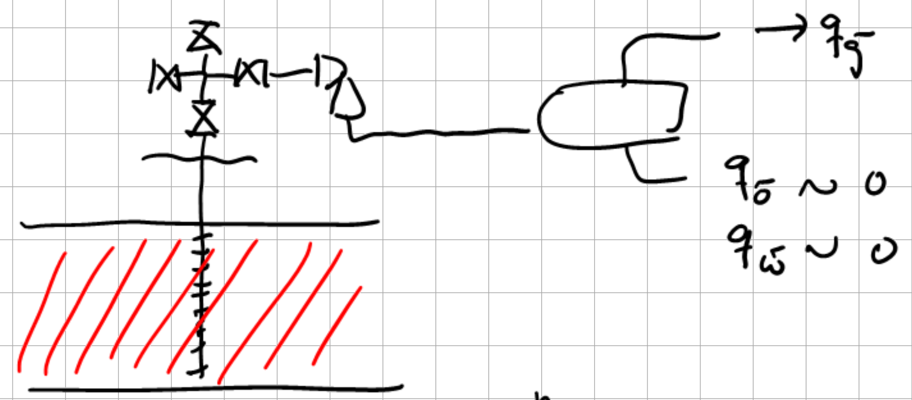
(1935)

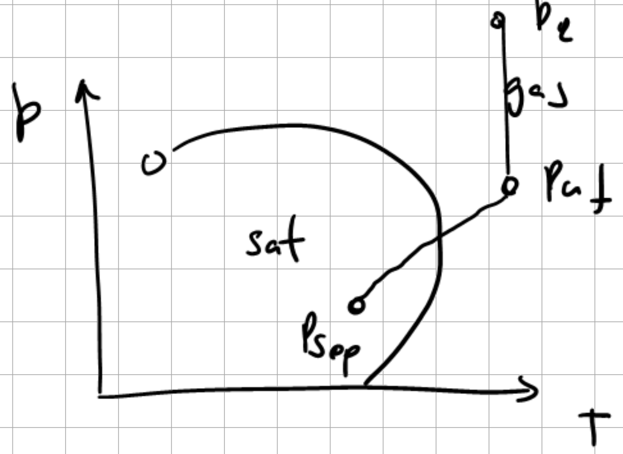
Monograph 7

Back-Pressure Data on Natural-Gas Wells and Their Application to Production Practices

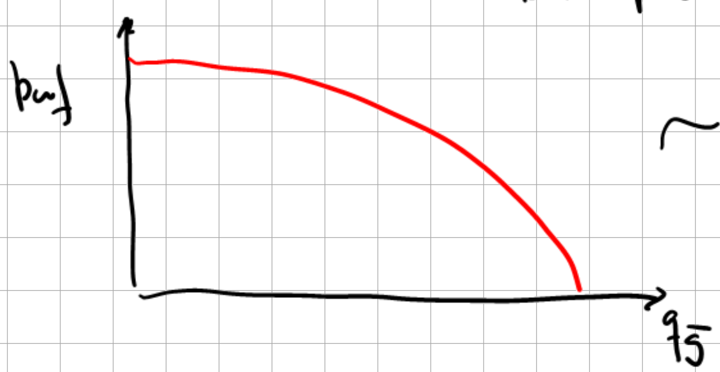
By

E. L. RAWLINS AND M. A. SCHELLHARDT





Back-pressure equation



empirically, measured in the field

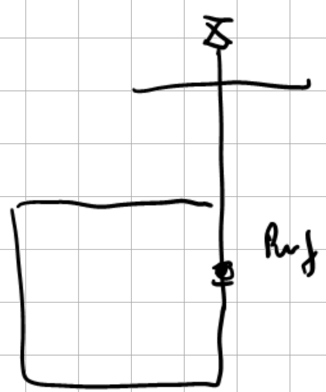
$$\sim q_g = C\left(p_R^2 - p_{wf}^2\right)^n \rightarrow 0 \le n \le 1$$

$$\frac{q_g}{C} = \left(p_R^2 - p_{wf}^2\right)^n \qquad \text{Log}$$

$$\log\left(\frac{q_g}{C}\right) = \log\left(\left(p_R^2 - p_{wf}^2\right)^n\right)$$

$$\log(q_g) - \log(C) = n \cdot \log\left(p_R^2 - p_{wf}^2\right)$$

$$\log(q_g) = \log(C) + n \log\left(p_R^2 - p_{wf}^2\right)$$



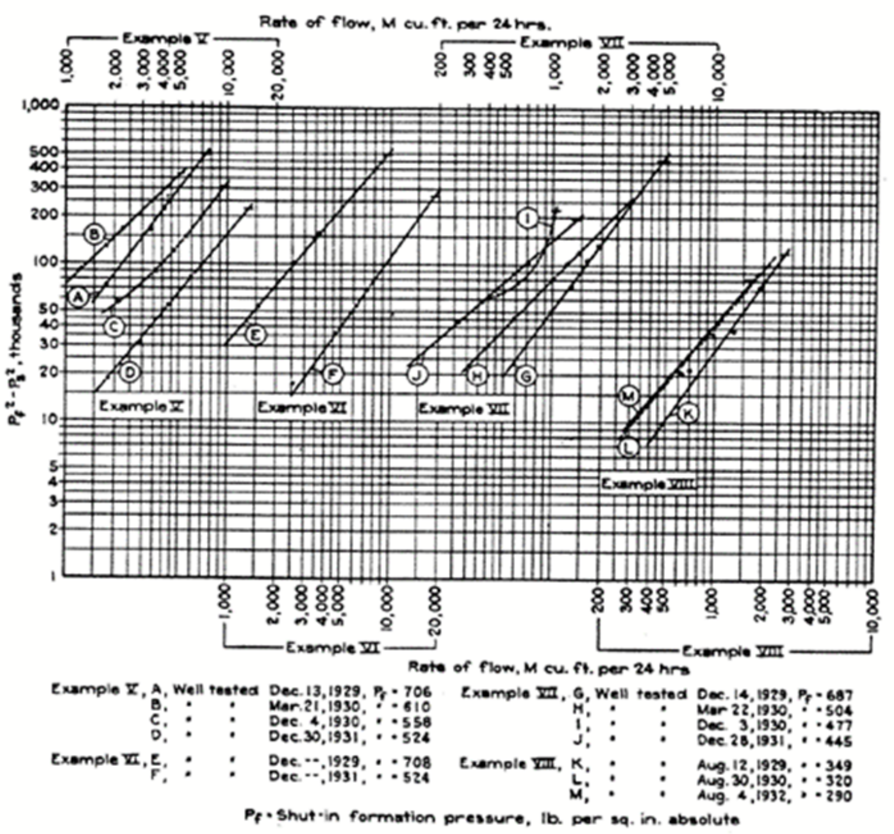
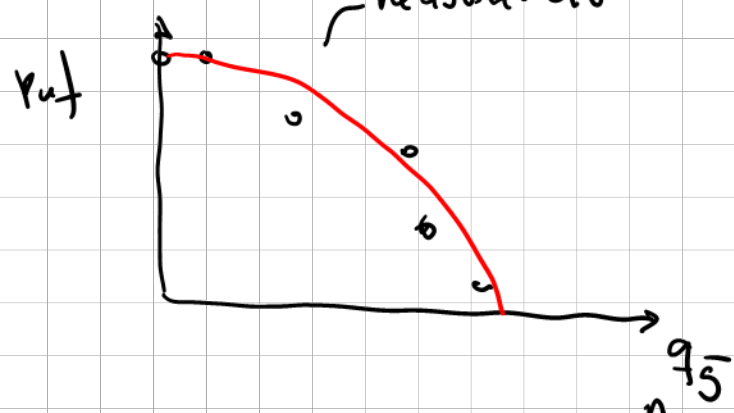


FIGURE 24.—Variation in delivery capacities of gas wells at different times in their productive lives, examples V, VI, VII, and VIII



$$q_g = C\left(p_R^2 - p_{wf}^2\right)^n$$

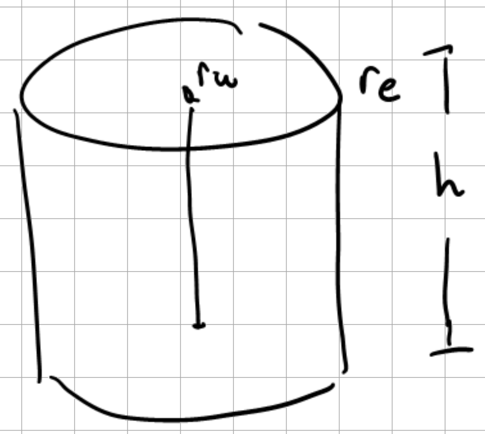
in Excel change C, n to match data

analytical derivation of Dry gas IPR

$q_{\bar{g}}$

$v = \frac{k}{\mu_g}\frac{dp}{dr}$

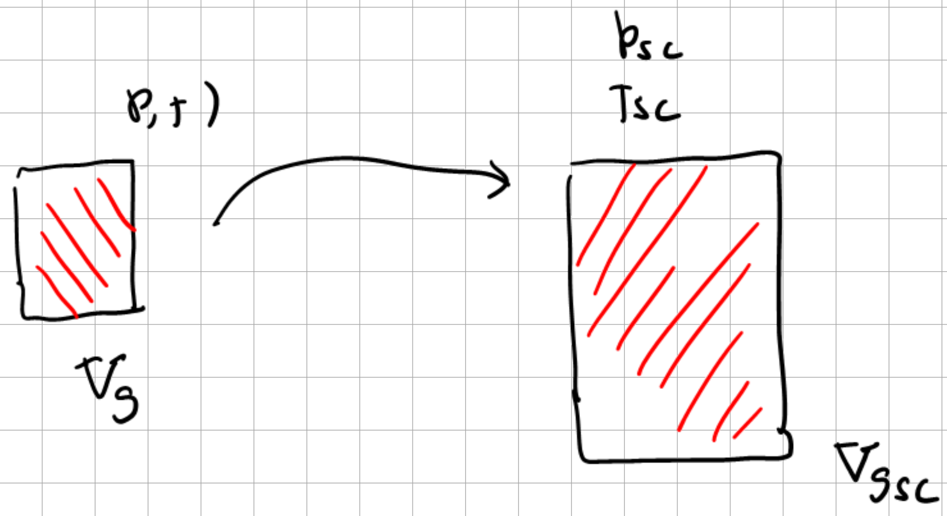
$\frac{q_g}{2\pi r h} = \frac{k}{\mu_g}\frac{dp}{dr}$



$q_g = f(q_{\bar{g}})$

$B_g = \frac{q_g}{q_{\bar{g}}}$

$q_g = q_{\bar{g}} \cdot B_g$



$B_g = \frac{V_g}{V_{\bar{g}}}$

gas volume factor

$B_g = f(p,T)$

$$\int_{r_w}^{r_{@pR}} \frac{q_{\bar{g}}}{r} = \int_{p_{wf}}^{p_R} \frac{2\pi k h}{B_g \mu_g}\frac{dp}{dr}$$

$B_g \sim 1E-2 \rightarrow 1E-3$

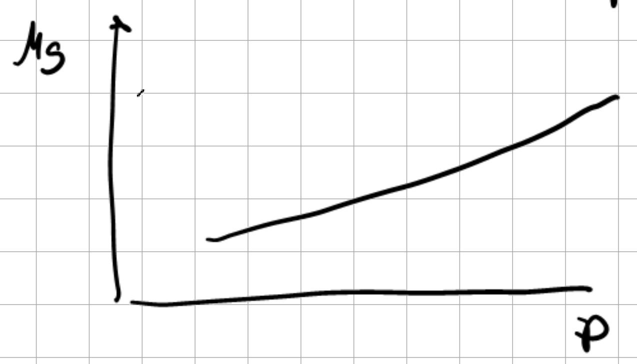
for PSS $q_{\bar{g}} = \frac{2\pi k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75\right)}$

$\int_{p_{wf}}^{p_R} \frac{1}{B_g \mu_g} dp \rightarrow ?$

mass conservation

$q_{\bar{g}} \cdot \rho_{\bar{g}} = q_g \rho_g$

$B_g = \frac{q_g}{q_{\bar{g}}} = \frac{\rho_{\bar{g}}}{\rho_g}$



Real gas equation $\frac{p}{\rho} = ZRT$ $R = \frac{R_u}{MW}$

gas deviation factor

deviation from ideal gas

$\rho = \frac{p}{ZRT}$

Boyle (English)

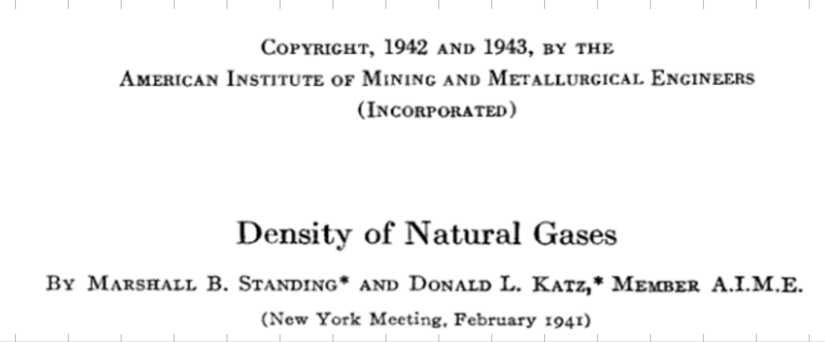
Hooke (English)

Charles (French)

Gay-Lussac (French)

Avogadro (Italian)

$z \sim$



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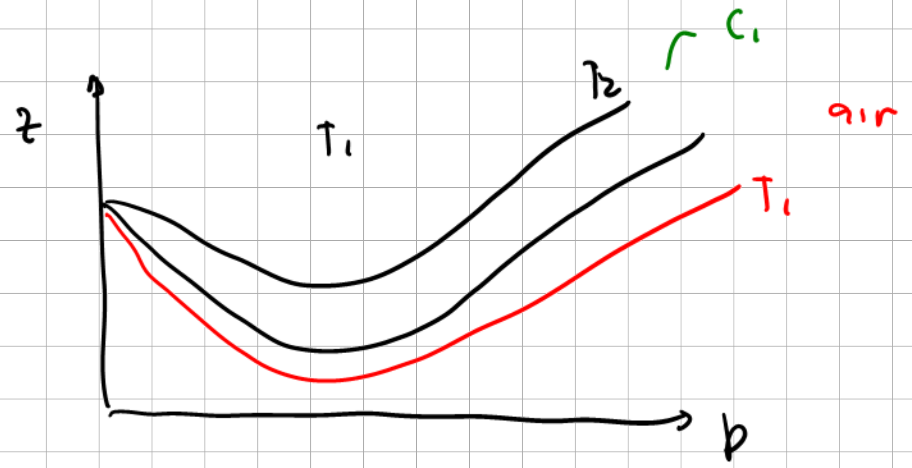
AMERICAN INSTITUTE OF MINING AND METALLURGICAL ENGINEERS
(INCORPORATED)

Density of Natural Gases

BY MARSHALL B. STANDING* AND DONALD L. KATZ,* MEMBER A.I.M.E.

(New York Meeting, February 1941)



$$T_r = \frac{T}{T_c} \qquad p_r = \frac{p}{p_c}$$

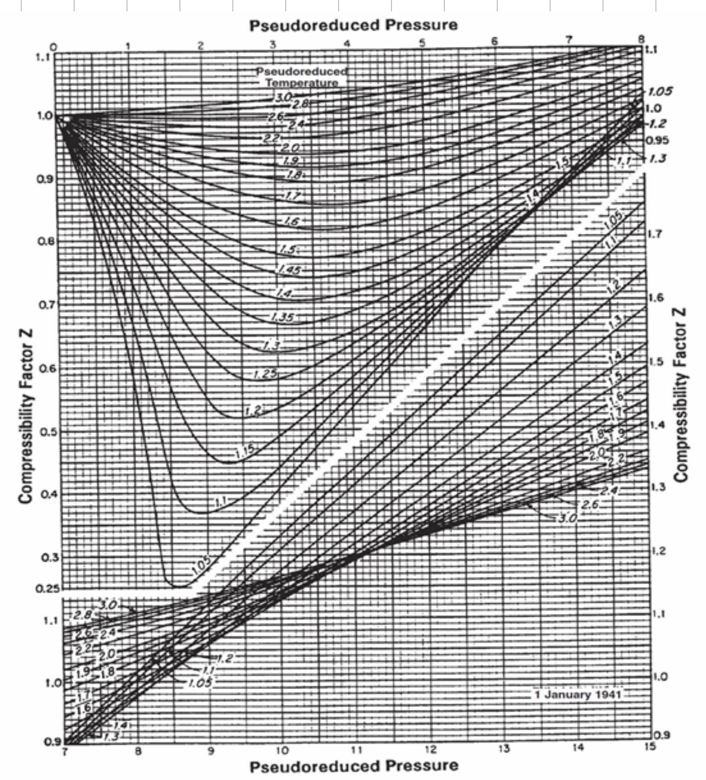
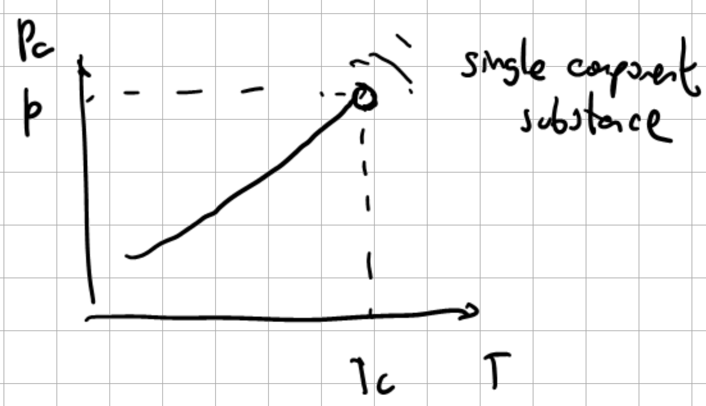


Fig. 3.6—Standing-Katz[4] Z-factor chart.

T_c, p_c



$T_c, p_c = f(MW)$

Gas composition

Component	mole fraction
C_1	z_{C_1}
C_2	z_{C_2}
C_3	z_{C_3}
⋮	

$$\sum_{1}^{N} z_i = 1$$

$$MW_{mix} = \sum_{1}^{N} MW_i \, z_i \qquad T_c, p_c = f(MW_{mix}) \rightsquigarrow \text{Sutton}$$

$$B_g = \frac{\rho_{\bar{g}}}{\rho_g} \qquad \rho_{\bar{g}} = \frac{p_{sc}}{\underbrace{\cancel{z_{sc}}}_{1} R \, T_{sc}} \qquad \rho_g = \frac{p}{z \, R \, T}$$

$$B_g = \frac{p_{sc}}{T_{sc}} \cdot \frac{z \, T}{p}$$

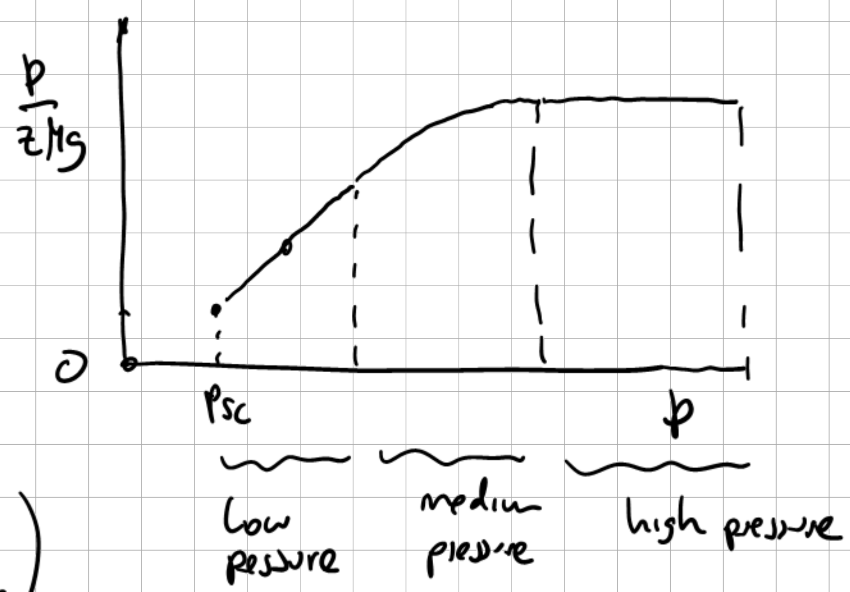
p_{sc} 1.01325 bara

T_{sc} 15.56 °C

$T = T_R$

$$q_{\bar{g}} = \frac{2\pi k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75\right)} \int_{p_{wf}}^{p_R} \frac{1}{\mu_g B_g} \, dp$$

$$q_{\bar{g}} = \frac{2\pi k h}{\ln\left(\frac{r_e}{r_w} - 0.75\right)} \frac{T_{sc}}{p_{sc} T_R} \int_{p_{wf}}^{p_R} \frac{p}{z \mu_g} \, dp$$



low pressure (p_{wf}, p_R)

$$q_g = \frac{2\pi k h}{\left(\ln\frac{r_e}{r_w} - 0.75\right)} \frac{T_{sc}}{p_{sc} T_R} \; 0.5 \left[p_R^2 - p_{wf}^2\right] \left(\frac{1}{z \mu_g}\right)_{@ p_R}$$

in the low pressure region $\left(\frac{1}{\mu_g z}\right) = \text{const}$

$q_{\bar{g}} = C \left(p_R^2 - p_{wf}^2\right)^n$ if $n = 1$ it's a match!

high pressure

$$q_{\bar{g}} = \frac{2\pi k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75\right)} \frac{T_{sc}}{p_{sc} T_R} \underbrace{\left(\frac{p}{\mu B_g}\right)_{@}}_{\text{avg pressure}} \int_{p_{wf}}^{p_R} dp = \underbrace{\frac{2\pi k h}{\left(\ln\frac{r_e}{r_w} - 0.75\right)} \frac{T_{sc}}{p_{sc} T_R} \left(\frac{p_R}{\mu_g z}\right)_{@ p_R}}_{\text{constant}} (p_R - p_{wf})$$

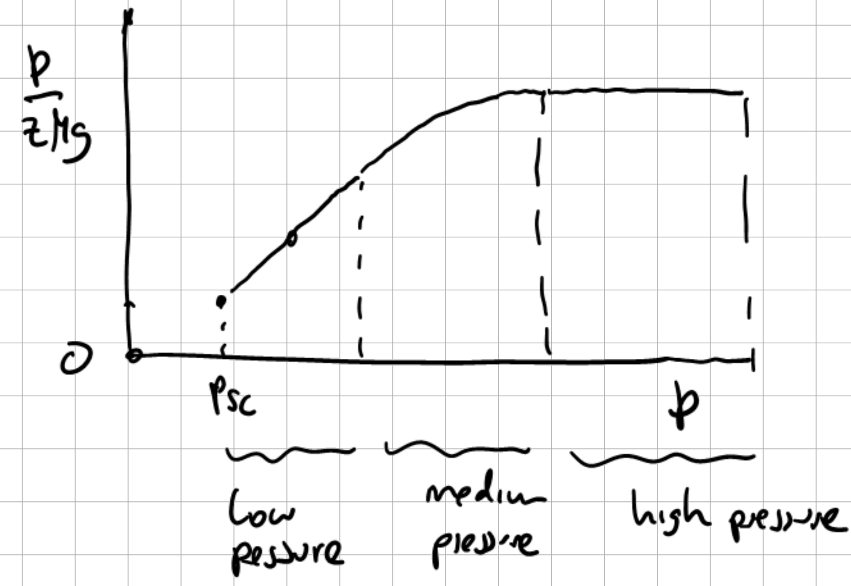
similar to undersaturated oil IPR

$q_{\bar{o}} = J \left(p_R - p_{wf}\right)$

doesn't resemble $q_{\bar{g}} = C \left(p_R^2 - p_{wf}^2\right)^n$

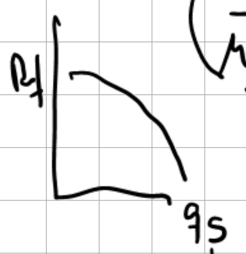
Video 15 - Dry gas IPR (Part 2)

$$q_g = \frac{2\pi k h}{\ln\left(\frac{r_e}{r_w} - 0.75\right)} \frac{T_{sc}}{p_{sc} T_R} \underbrace{\int_{p_{wf}}^{p_e} \frac{p}{z \mu_g}\, dp}$$



LP

$$\left(\frac{1}{\mu_g z}\right)_{@p_R} \frac{(p_R^2 - p_{wf}^2)}{2}$$



?

HP

$$\frac{p_R}{(\mu_g z)_{@p_R}} (p_R - p_{wf})$$

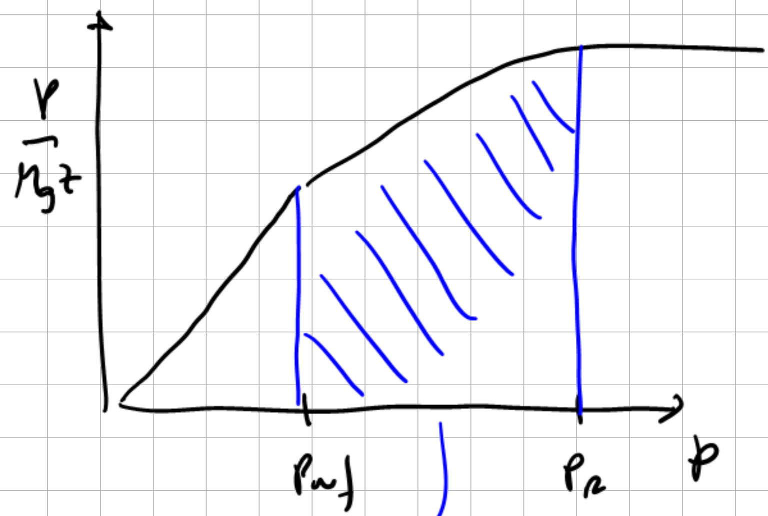
p [bara] $\quad q_g = [Sm^3/d] \quad p_{sc} = 1.01325$ bara

T [K] $\quad \mu_g = [cp] \quad T_{sc} = 15.56$ °C

k [md]

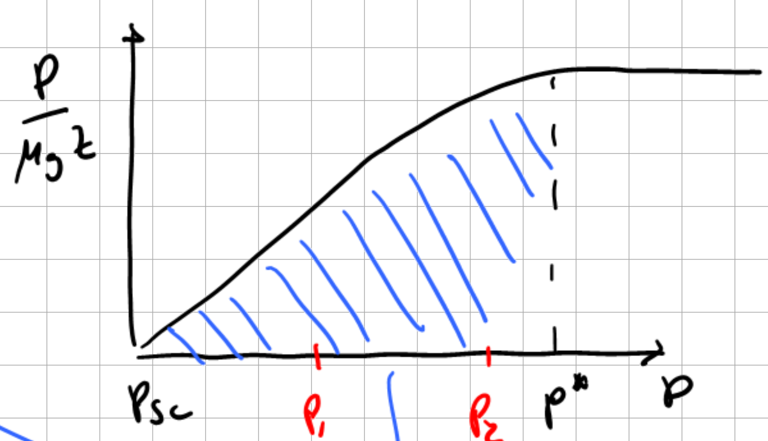
excluding the 2!

$$q_g = \frac{k h \, 7.63}{\left(\ln\frac{r_e}{r_w} - 0.75 + S\right) T_R} \, 2 \underbrace{\int_{p_{wf}}^{p_R} \frac{p}{\mu_g z}\, dp}$$



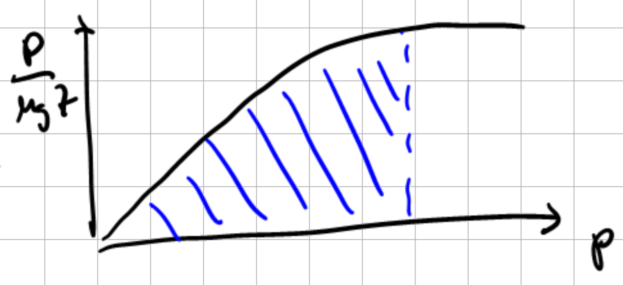
$$\Big(\underbrace{\bigcirc}_{p_R} - \underbrace{\bigcirc}_{p_{wf}}\Big)$$

$$m(p^*) = 2 \int_{0 \to p_{sc}}^{p^*} \frac{p}{\mu_g z}\, dp$$



$$2\int_{p_1}^{p_2} \frac{p}{\mu_g z}\, dp = 2\int_{p_{sc}}^{p_2} \frac{p}{\mu_g z}\, dp - 2\int_{p_{sc}}^{p_1} \frac{p}{\mu_g z}\, dp = m(p_2) - m(p_1)$$

=



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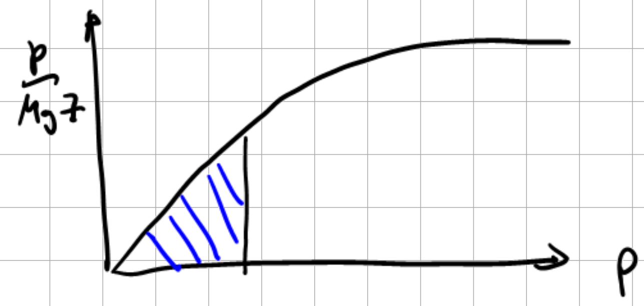
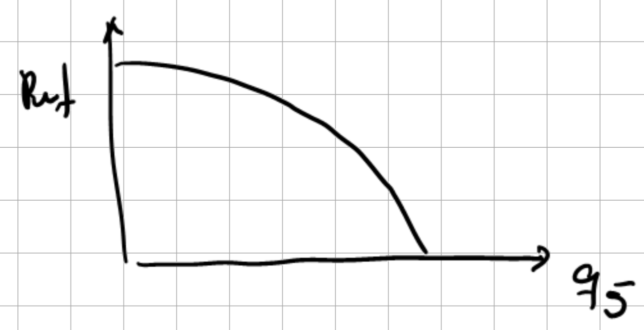


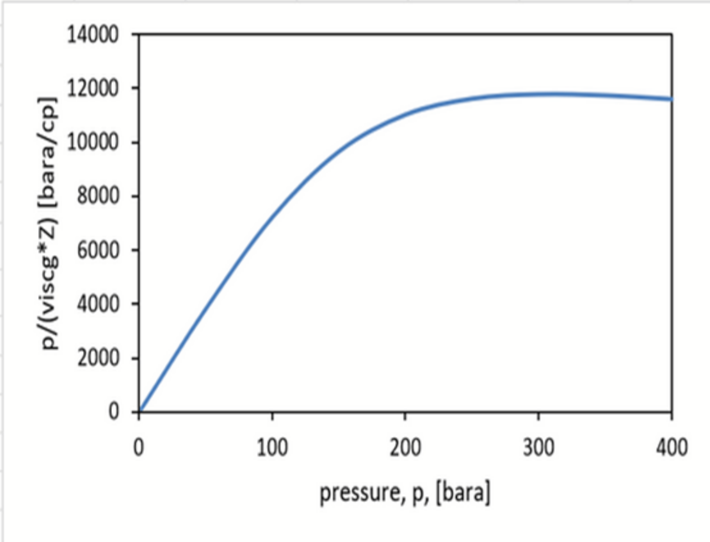
IPR og

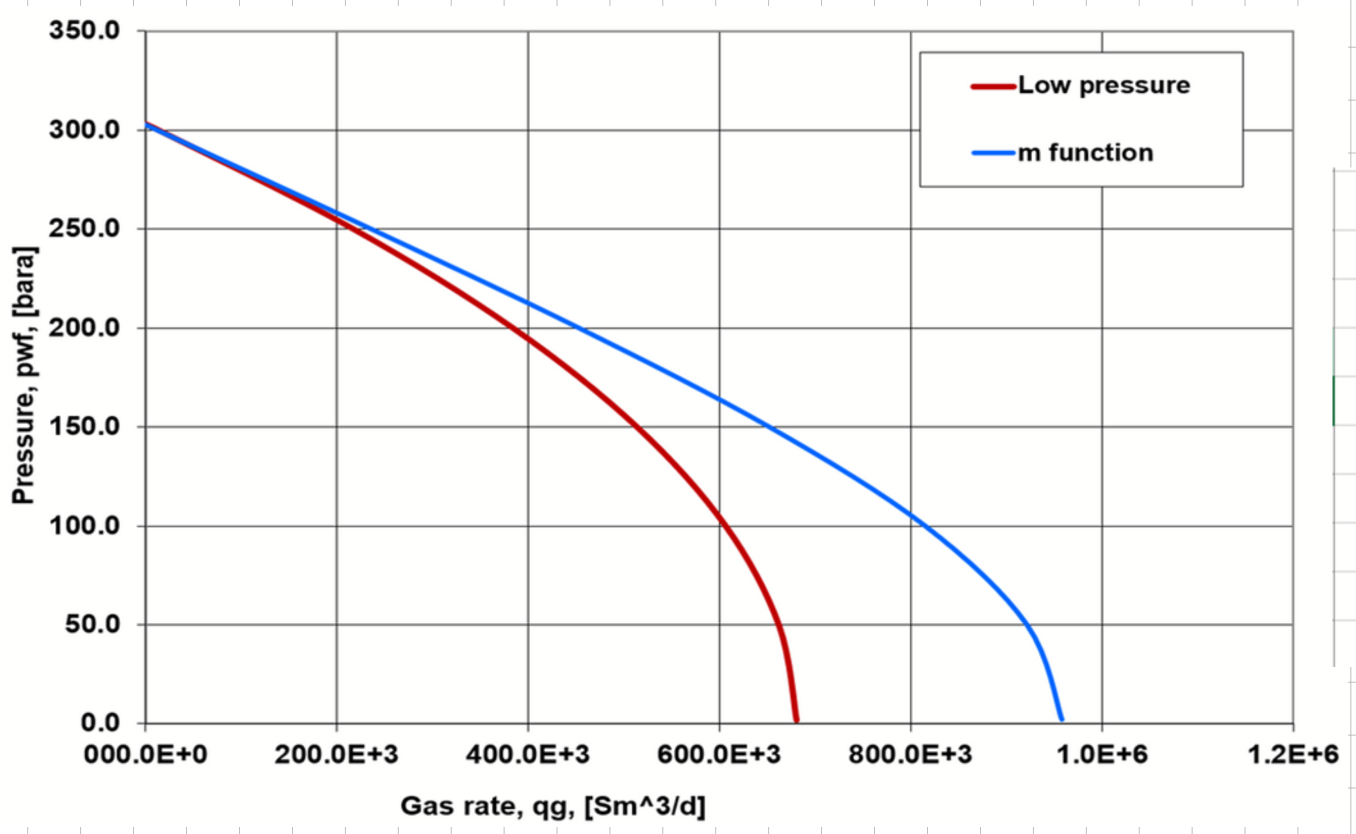
$$q_g = \frac{7.63\, k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right)} \frac{1}{T_R} \left[m(p_R) - m(p_{wf}) \right] \quad ?$$



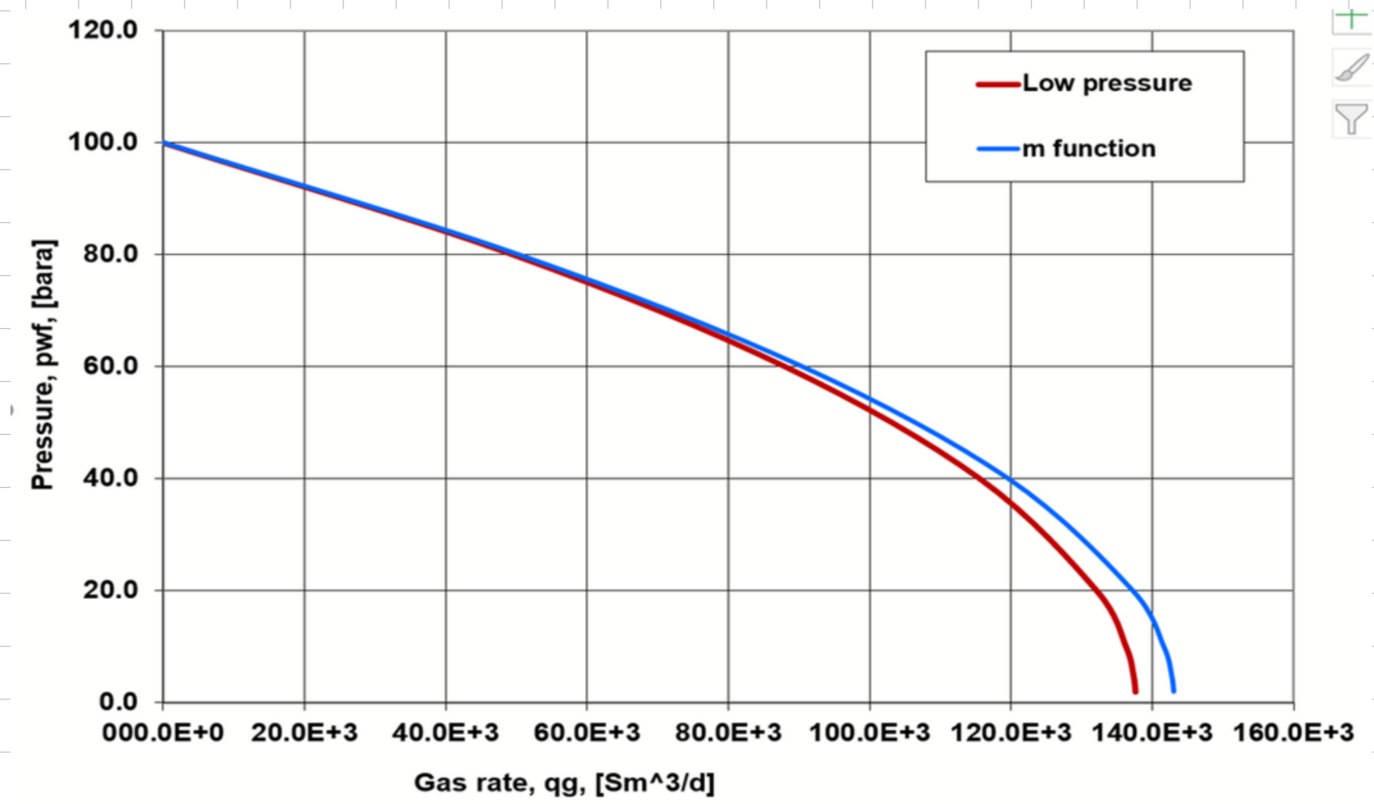
Well Data		
pR	[bara]	400
TR	[C]	105
TR	[K]	378
z_R	[-]	1.069
$deng_R$	[kg/m3]	276
$Viscosity_R$	[cp]	0.032

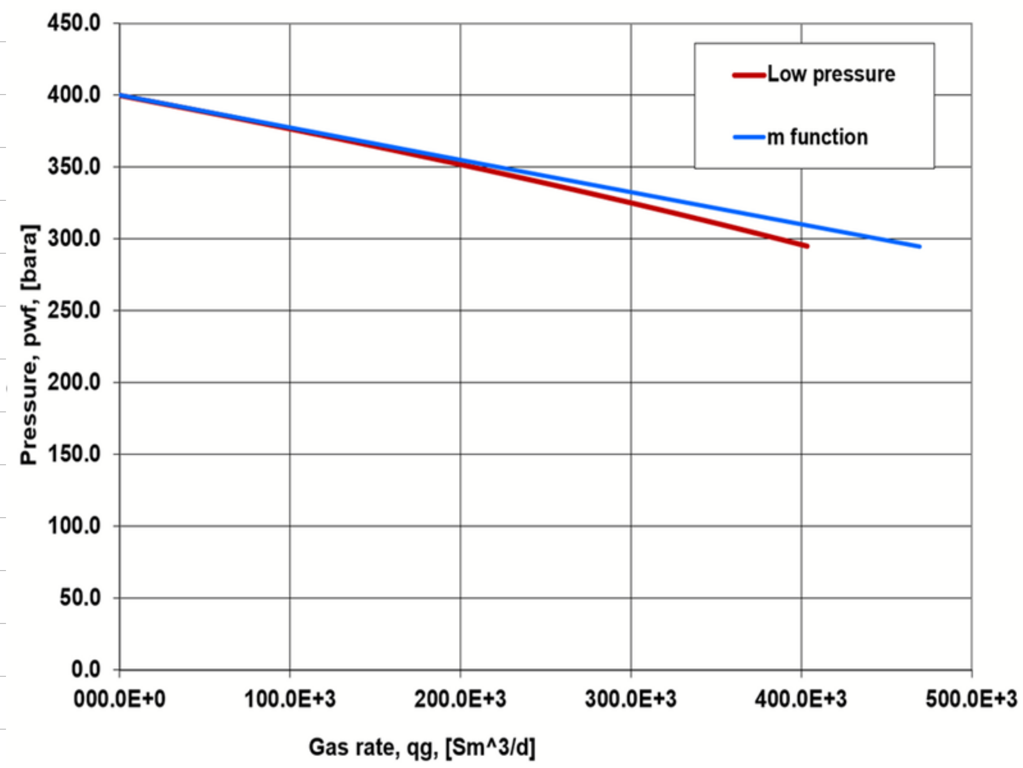
p [bara]	Z [-]	deng [kg/m3]	viscg [cp]	p/viscg*Z [bara/cp]
2	0.997	1.5	0.013	152
50	0.932	39.6	0.014	3825
100	0.882	83.6	0.016	7224
150	0.859	128.8	0.018	9662
200	0.867	170.2	0.021	11029
250	0.899	205.1	0.024	11622
300	0.948	233.6	0.027	11788
350	1.006	256.8	0.030	11745
400	1.069	276.1	0.032	11607



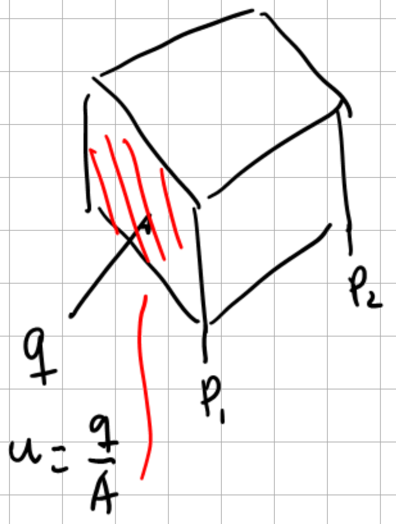


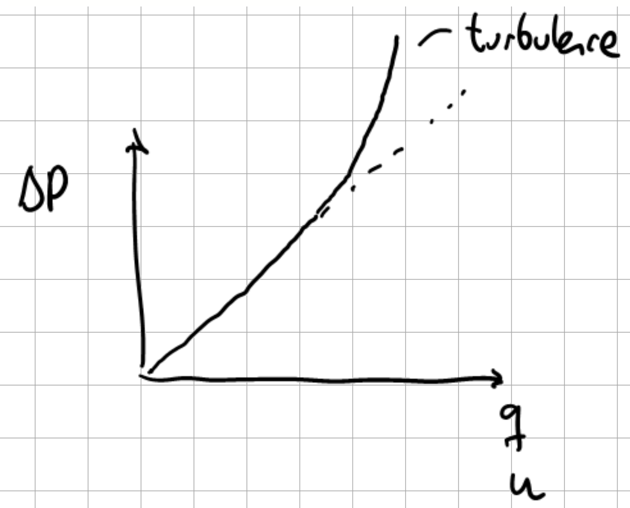
pwf bara	LP - qg [Sm3/d]	m(p) [bara2/cp]	qg [Sm3/d]
303.0	000.0E+0	5026555	000.0E+0
300.0	13.4E+3	4955852	13.5E+3
250.0	217.4E+3	3783006	237.1E+3
200.0	384.3E+3	2645766	453.9E+3
150.0	514.1E+3	1603483	652.6E+3
100.0	606.8E+3	750299.5	815.2E+3
50.0	662.5E+3	191885.9	921.7E+3
2.0	681.0E+3	226.2864	958.2E+3

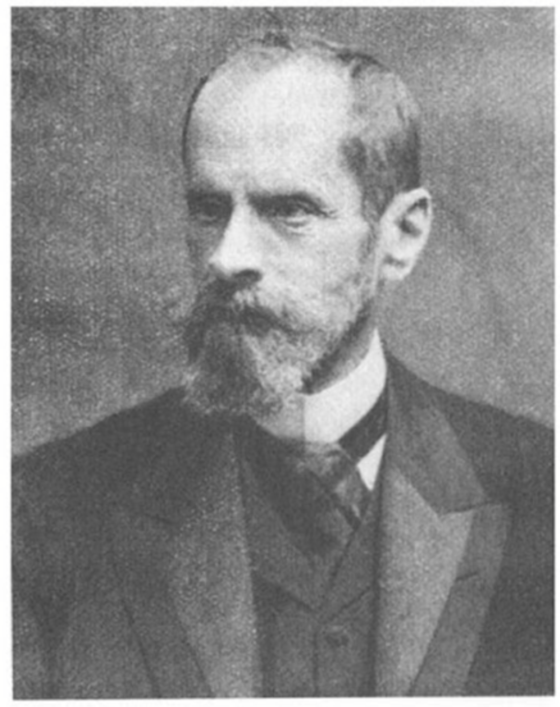



450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Pressure, pwf, [bara]
000.0E+0
100.0E+3
200.0E+3
300.0E+3
400.0E+3
500.0E+3
Gas rate, qg, [Sm^3/d]
Low pressure
m function

[19] P. Forchheimer. *Wasserbewegung durch Boden.* Zeitschrift des Vereines Deutscher Ingenieuer, 45 edition, 1901.

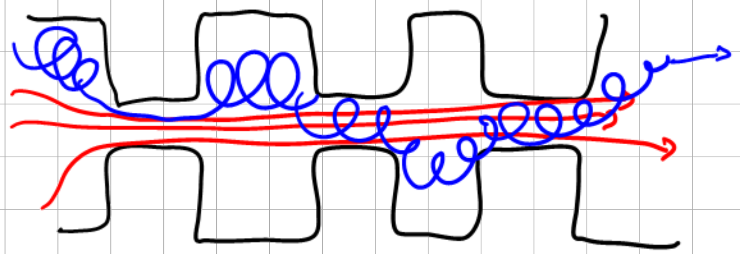






Professor Philipp Forchheimer.

not valid for medium-high rate gas wells
high rate sat oil



$$\Delta P = A \cdot u + B u^2$$

$$\Delta P = A u \left(1 + \frac{B}{A} u\right)$$

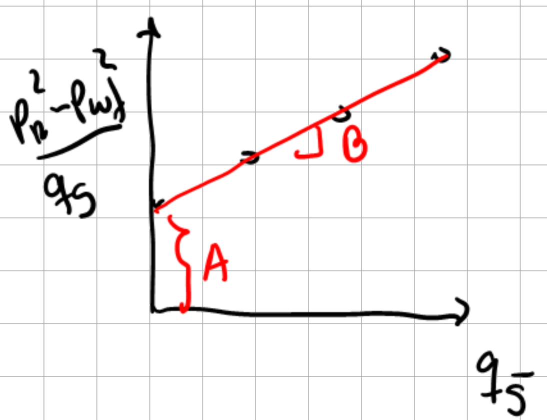
Use of Short Term Multiple Rate Flow Tests To Predict Performance of Wells Having Turbulence (1976)

Lloyd G. Jones and E. M. Blount, Mobil Research and Development Corp., and O. H. Glaze, Mobil Oil Corp., Members SPE-AIME

LP dry gas wells

$$(p_R^2 - p_{wf}^2) = A\, q_g + B\, q_g^2$$

$$\frac{(p_R^2 - p_{wf}^2)}{q_g} = A + B\, q_g$$



quadratic equation

$$a x^2 + b x + c = 0$$

$$q_g = \frac{7.63\, kh}{T_R\, \mu_g\, z} \frac{(p_R^2 - p_{wf}^2)}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right)}$$

$$(p_R^2 - p_{wf}^2) = \frac{T_R\, \mu_g\, z}{7.63\, kh}\left[\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right) q_g\right] + B\, q_g^2$$

rate dependent skin

$$B = D \frac{z\, \mu_g\, T_R}{7.63 \cdot kh}$$

$$(p_R^2 - p_{wf}^2)\frac{7.63\, kh}{T_R\, \mu_g\, z} = \left(\ln \frac{r_e}{r_w} - 0.75 + S\right) q_g + D\, q_g^2$$

$$\frac{(p_R^2 - p_{wf}^2)}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S + D\,q_{\bar{g}}\right)} \frac{7.63\ kh}{T_R\ \mu_g\ z} = q_{\bar{g}}$$

rate-dependent skin $D = \left[\frac{d}{Sm^3}\right]$

$\hookrightarrow D = f(?)$

alternative approach

USBM (1935) $q_{\bar{g}} = C\left(p_R^2 - p_{wf}^2\right)^n$ n ? $\nearrow$ 1 laminar (Darcy flow) $\searrow$ 0.5 turbulent (HVF)

$$q_{\bar{g}} = \underline{C\ \left(p_R^2 - p_{wf}^2\right)^{n}}$$ — accounts for turbulent flow

$$C = \frac{(7.63\ kh)^n}{(T\mu_g Z)^n D^{1-n}[\ln(r_e/r_w) - 0.75 + s]^{2n-1}}.$$

extends to other IPRs $q_{\bar{g}} = C\left[m(p_R) - m(p_{wf})\right]^n$

$$C = \frac{(7.63\ \ kh)^n}{T^n D^{1-n}[\ln(r_e/r_w) - 0.75 + s]^{2n-1}}.$$

$$q_{\bar{g}} = \frac{2\pi h}{\ln\left(\frac{r_e}{r_w} - 0.75\right)} \frac{7.63}{T_R} \underbrace{\int_{p_{wf}}^{p_e} \frac{p}{z\,\mu_g}\, dp}$$

LP:
$$\left(\frac{1}{\mu_g z}\right)_{@p_R} \frac{\left(p_R^2 - p_{wf}^2\right)}{2}$$

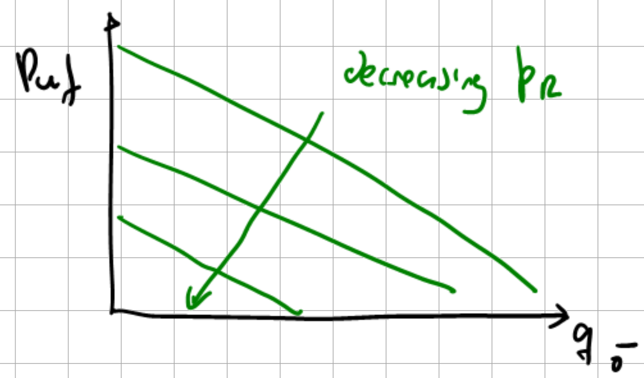
$$\frac{\left(m(p_e) - m(p_{wf})\right)}{2}$$

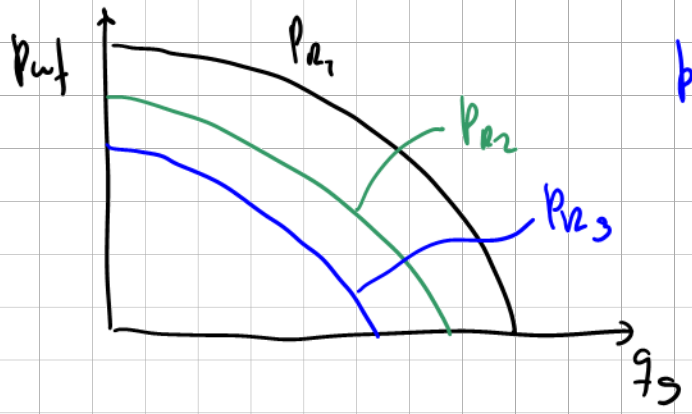
HP:
$$\frac{p_R}{(\mu_g z)_{@p_R}} \left(p_R - p_{wf}\right)$$

$$q_{\bar{o}} = \underset{\sim}{J}\left(p_R - p_{wf}\right)$$

geometry $\rightarrow$

fluid properties $\rightarrow$ $(\mu_o B_o)_{@p_{av}}$



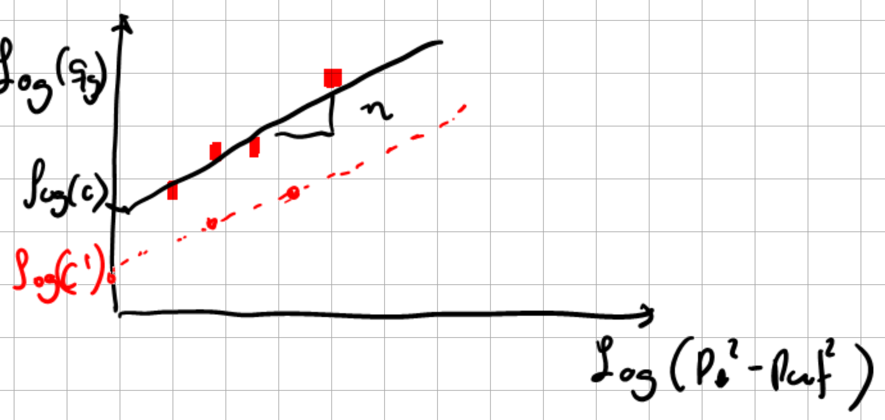


$p_{R_1} > p_{R_2} > p_{R_3}$

Diagnostic of well productivity issues

$$q_{\bar{g}} = C\left(p_R^2 - p_{wf}^2\right)^n$$

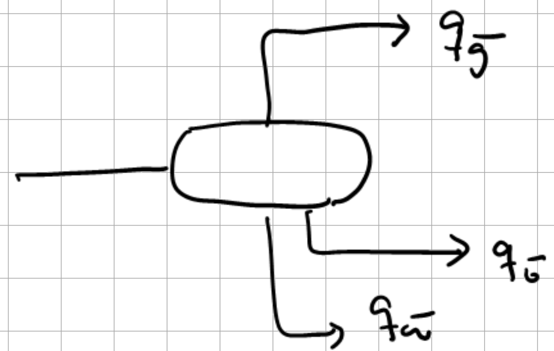
$$\log(q_{\bar{g}}) = \log(C) + n \log\left(p_R^2 - p_{wf}^2\right)$$



- Gas wells produce condensate $q_{\bar{o}}$, water $q_{\bar{w}}$

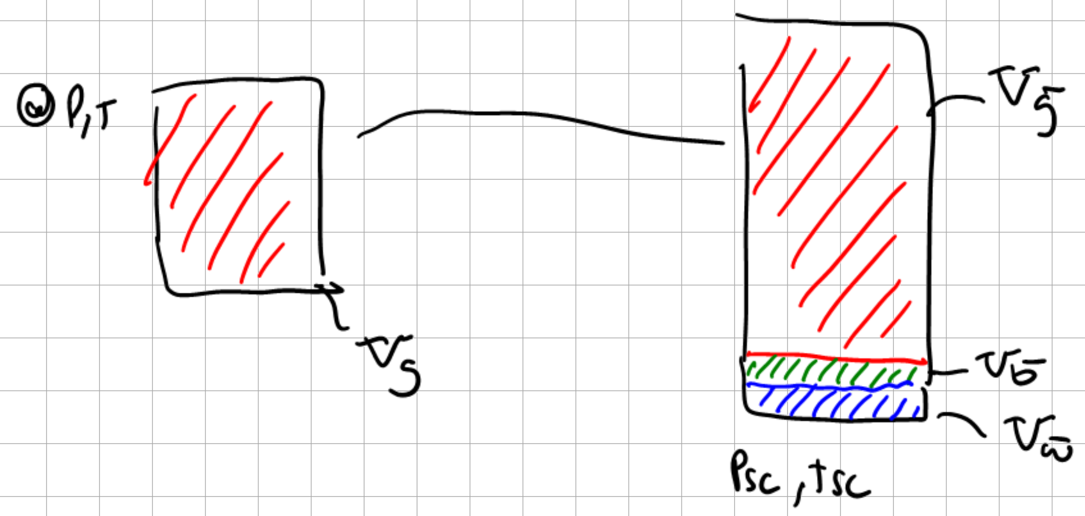
$$CGR = \frac{q_{\bar{o}}}{q_{\bar{g}}}$$

$$WGR = \frac{q_{\bar{w}}}{q_{\bar{g}}}$$



- the same IPR equations can be used as long as flow $p_R \rightarrow p_{wf}$ is single phase

B_g



$$B_{gd} = \frac{V_g}{V_{\bar g}}$$

$$B_{gw} = \frac{V_g}{V_{\bar g} + V_{\bar o} + V_{\bar w}}$$

$\frac{p}{\rho} = zRT$ → assumes single-phase gas

$$\int_{p_{wf}}^{p_R} \frac{p}{z\,\mu_g}\,dp$$ ~> neglects the dropout of condensate / water

If there is dropout of condensate and water ~> generate a table of B_{gd} $\left\{ \begin{array}{l} \text{e.g.} \\ \text{EOS} \end{array} \right\}$

$$\int_{p_{wf}}^{p_R} \frac{1}{\mu_g B_{gd}}\,dp$$ ← integrate B_{gd} directly

---

Expressions are available for horizontal wells:

SPE 99712

Generalized Horizontal Well Inflow Relationships for Liquid, Gas, or Two-Phase Flow

R. Kamkom and D. Zhu, Texas A&M U.

base pressure. The IPR equation for horizontal gas wells in term of the real gas pseudo-pressure is

$$q_g = \frac{kL\left(m(\bar{p}) - m(p_{wf})\right)}{1424T\left(\ln\left[\frac{hI_{ani}}{r_w(I_{ani}+1)}\right] + \frac{\pi y_b}{hI_{ani}} - 1.224 + s\right)} \quad (13)$$

$$I_{ani} = \sqrt{\frac{k_H}{k_V}}$$

IPR:

$$q_g = \underbrace{U}_{\text{geometry}} \int_{p_{wf}}^{p_e} \underbrace{F(p)\,dp}_{\text{function of fluid properties}}$$

20220927: Class

-Recap about dry gas IPR
-Class activity

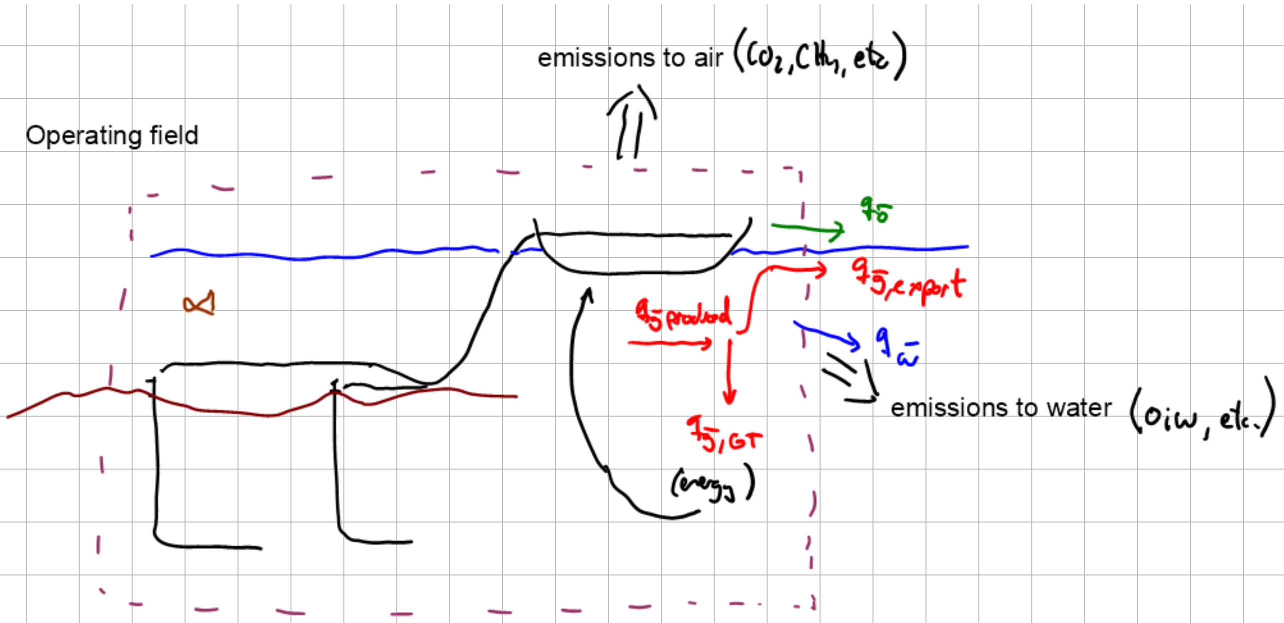
Problem 1: CO_2 emissions in an oil and gas field

Perform an internet search to answer the following questions:

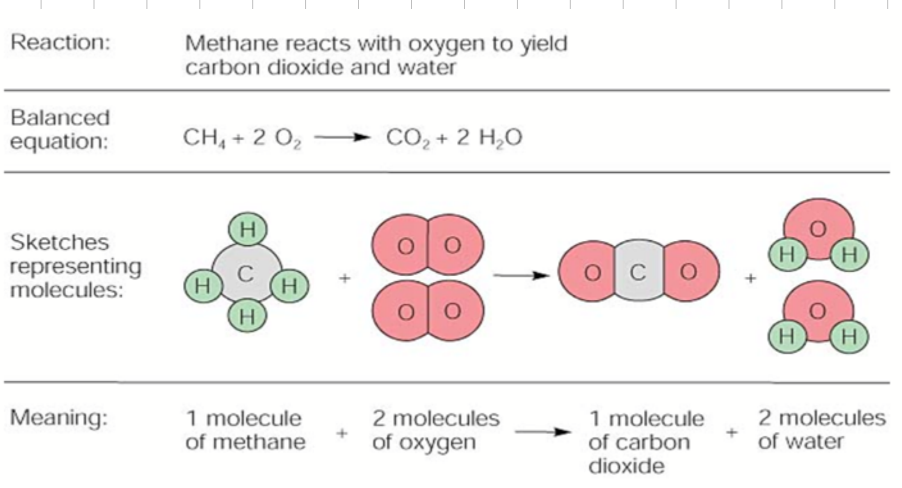
- What is the main source of CO2 emissions in an oil and gas field?
- What is the CO2 footprint (mass) per Sm3 of oil in the NCS? What does this number include?
- What is the CO2 emission (mass) per MWh produced by a gas turbine?
- What is the consumption of natural gas per MWh by a gas turbine?
- What is the average energy required to produce a barrel (or Sm3) of oil in the NCS?

Some useful links:

- https://www.api.org/~/media/files/ehs/climate-change/ghg_industry-guidelines-ipieca.pdf
- https://www.equinor.com/content/dam/statoil/documents/impact-assessment/wisting/equinor-wisting-forslag-til-ku-program-05-01-21.pdf



CO2 originates from combustion -> used for energy generation (electric power, shaft power, heat)



https://web.fscj.edu/Milczanowski/psc/lect/Ch11/slide3.htm

Not all the fuel that is burned is methane, so the reaction will look slightly different
--> natural gas has other heavier components
--> ships and helicopters burn liquid fuel
--> there are other components that might not react (inert) like N2 (but take some energy to heat up), or that generate compounds that are undesired.

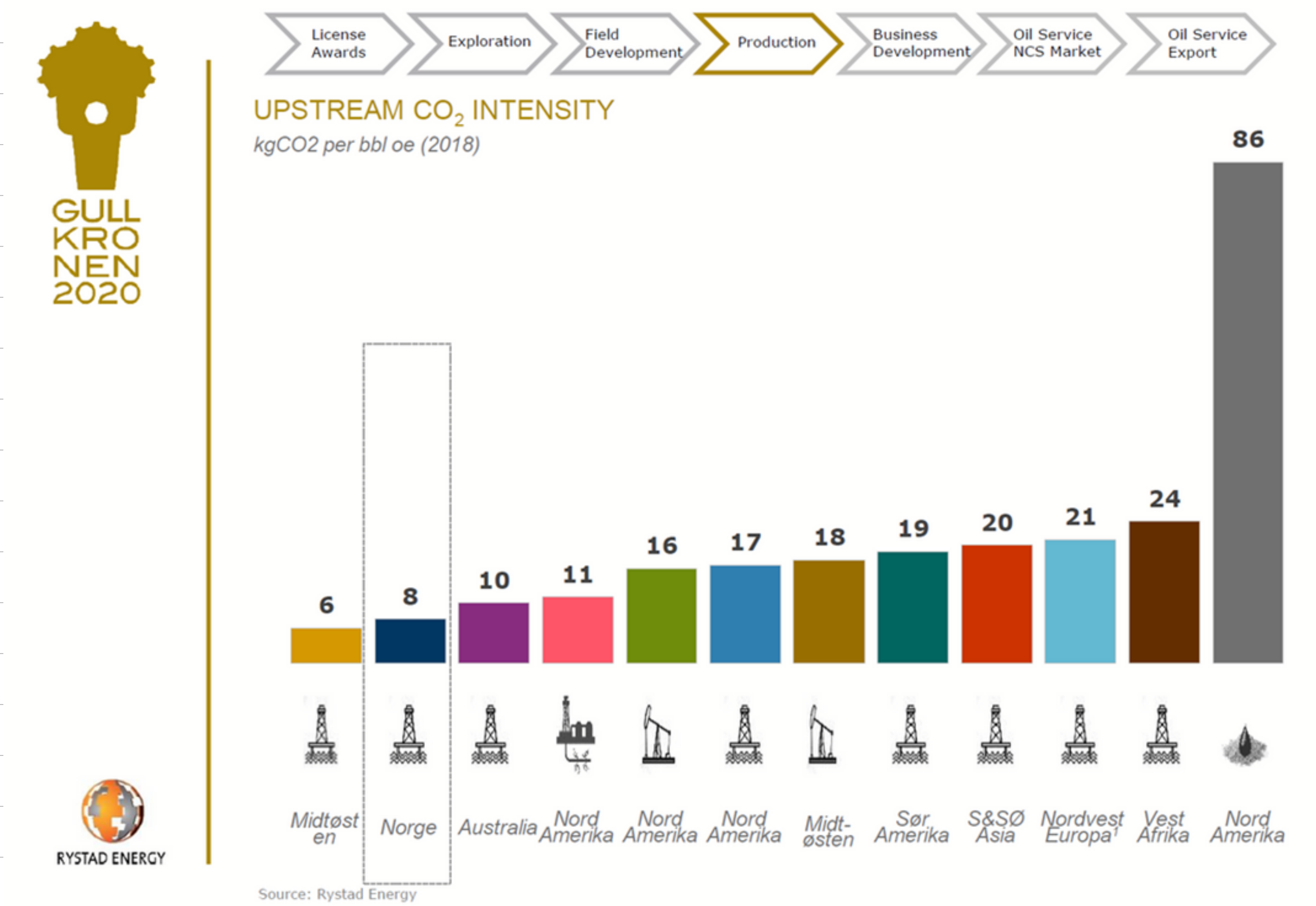
For an operating field, CO_2 emissions come mainly from Gas turbines used for electricity generation, shaft power, and from heaters.

Other sources of emissions (UPSTREAM):
-Transport of personnel and goods to and from the platform
-Drilling, completion and intervention
-Building facilities (steel production and manufacturing) --> part of life-cycle emissions, are not typically included.
-Tanker transport of oil to refineries
-Gas transport to customer (LNG or pipeline)

https://en.wikipedia.org/wiki/Gas_turbine

CO_2 emissions are typically estimated with equations based on fuel gas and liquid consumption and power generation numbers. Operators must report the numbers to the authorities, among other things to calculate carbon tax

- What is the CO_2 footprint (mass) per Sm3 of oil in the NCS? What does this number include?



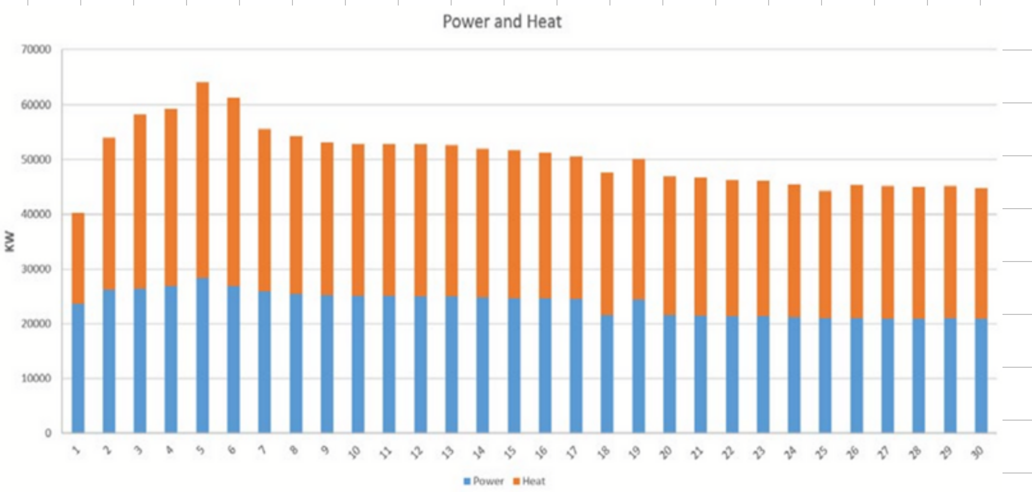
converting units:
8 kg CO_2/bbl * 6.29 bbl/Sm3 = 50.3 kg CO_2/Sm3

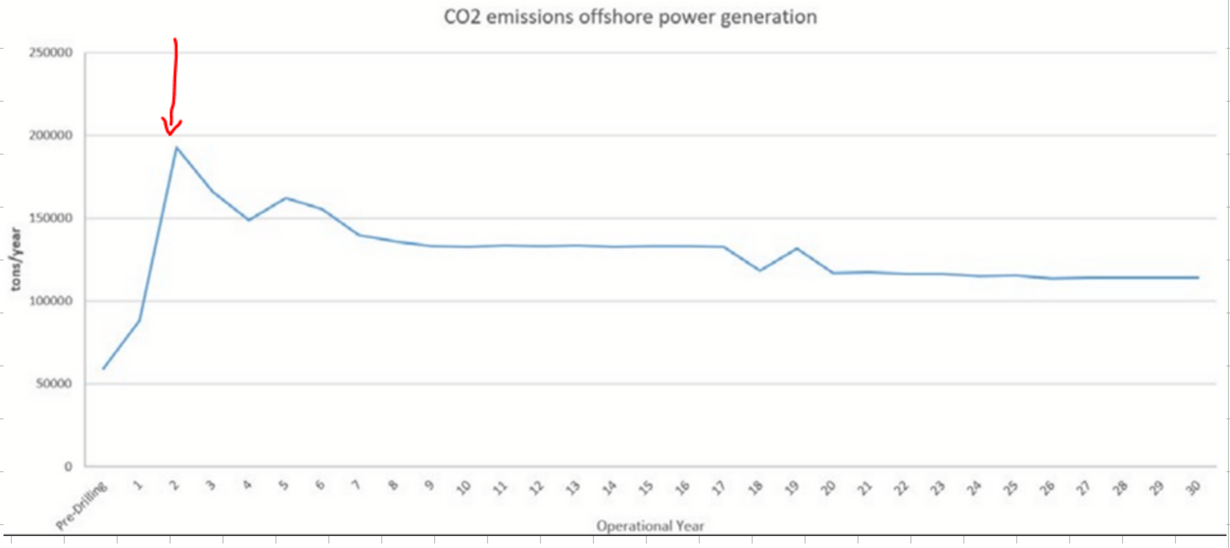
Let's use the case of Wisting to verify this number

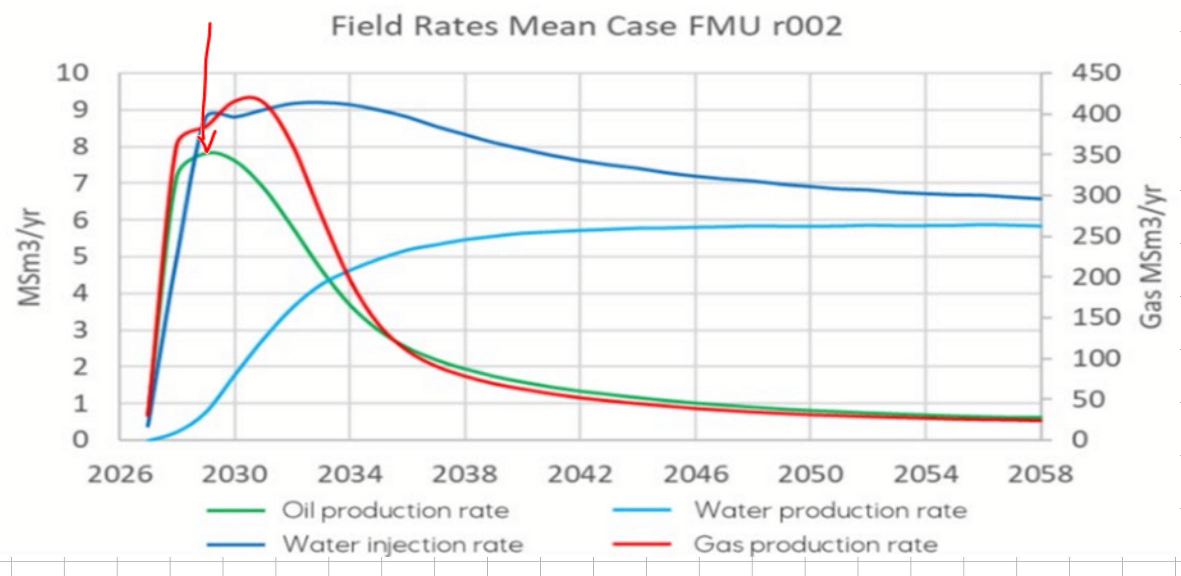
- https://www.equinor.com/content/dam/statoil/documents/impact-assessment/wisting/equinor-wisting-forslag-til-ku-program-05-01-21.pdf

Kilder til utslipp

Kilder til utslipp til luft i driftsfasen inkluderer normalt utslipp fra kraftgenerering på produksjonsenheten (turbiner), borerigg og fartøy (diesel), omlasting av råolje, lasteskip og helikopter. Ved import av kraft fra land vil det ikke være behov for gassturbiner på produksjonsinnretningen. Varmebehovet vil da dekkes gjennom elektriske kjeler.







Wisting ~ plateau oil volume ~7 E06 Sm^3/y → 19178 Sm^3/d

CO_2 emissions --> 190 000 tonnes/year

CO_2 per Sm3 oil --> 190 000 000 kg /7E06 Sm3 = 27.14 kg CO_2 per Sm3 oil

Considering oil+ gas
1000 Sm3 of gas = 1 Sm3 o.e.

during plateau --> oil+gas = 7e06 + 400 E06/1000 = 7.4E06 Sm3 o.e. per year

CO_2 per Sm3 oil equiv. --> 190 000 000 kg /7.4E06 Sm3 = 25.67 kg CO_2 per Sm3 oil equiv

It is somewhat similar to the number shown by Rystad.

The CO_2 intensity will increase with time because the CO_2 emissions are stable (power consumption is stable, is less affected by production rates) and oil and gas production is going down. For example, at end of field life

oil+gas production = 0.6e06 + 25 E06/1000 = 0.625 E06 Sm3 o.e.

CO_2 per Sm3 oil equiv. --> 115 000 000 kg /0.625 E06 Sm3 = 184 kg CO_2 per Sm3 oil equiv

- What is the average energy required to produce a barrel (or Sm3) of oil in the NCS?

No good references were found on the web for this question . Using the data of Wisting:

Wisting ~ plateau oil volume 7 E06 Sm^3/y → 19178 Sm^3/d

Power ~ plateau ~ 60 MW → Energy = $P \cdot n_{hrs/year}$ = 60 . 24 . 365 = 525600 MWh

$$\text{energy}/Sm^3\,\text{oil} = \frac{525600\ \text{MWh}}{7E06\ Sm^3} = 7.51\,E\text{-}2\ \frac{\text{MWh}}{Sm^3\,\text{oil}}$$

$75\ \frac{\text{kWh}}{Sm^3}$

https://en.wikipedia.org › wiki › Tesla_Model_S

Tesla Model S - Wikipedia

Battery — ... ions as charge carriers. The battery capacity within the Model S has changed numerous times since its debut, ranging **from 60–100 kWH**.

Considering oil+ gas
1000 Sm3 of gas = 1 Sm3 o3

during plateau --> oil+gas = 7e06 + 400 E06/1000 = 7.4E06 Sm3 o.e.

Energy/Sm3 oil = 71 kWh/Sm3 o.e.

How much energy is there in one(1) Sm3 of oil?

https://www.investopedia.com/terms/b/barrelofoilequivalent.asp

"There are 42 gallons (approximately 159 liters) in one barrel of oil. The energy contained in a barrel of oil is approximately 5.8 million British thermal units (MBtus) or 1,700 kilowatt-hours (kWh) of energy. "

Energy/Sm3 oil = (1700 kWh / 159 L) * 1000 L /Sm3 = 10 691 kWh/Sm3

A Sm3 of oil has 150 times (10691/71) more energy than what is required to extract it.

- What is the CO2 emission (mass) per MWh produced by a gas turbine?

"0.486 t CO2 eq /MWh for gas-turbine plants"

https://www.rte-france.com/en/eco2mix/co2-emissions

Verifying this number with the Wisting data

In plateau

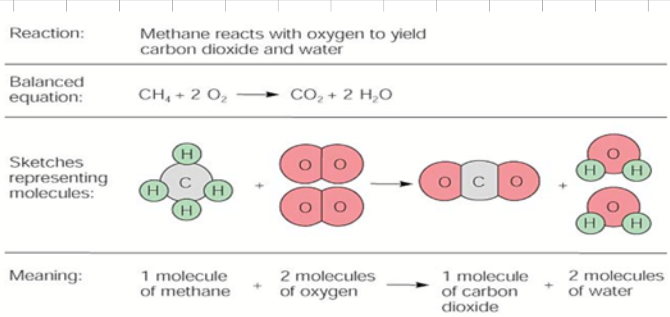
Power = ca .60 MW. In a year 60 * 24 * 365 = 525 600 MWh

Emissions = ca 190 000 tonnes

CO2 / MWh = 190 000 / 525 600 = 0.361 t CO2 / MWh --> similar number to the one provided above

- What is the consumption of natural gas per MWh by a gas turbine?

It comes from this reaction



https://web.fscj.edu/Milczanowski/psc/lect/Ch11 https://en.wikipedia.org/wiki/Gas_turbine

A Gas turbine has an efficiency of 40-50%,
The calorific value of natural gas is 40-55 MJ/kg

https://group.met.com/en/media/energy-insight/calorific-value-of-natural-g

standard conditions natural gas density around.
0.7 kg/m3

gas mass * calorific value * GT efficiency = 1 MWh = 3600 MJ

gass mass = 3600 / (50 * 0.4) = 180 kg

gass volume = 180 kg / 0.7 = 257 Sm3

Energy / Sm3 of gas = 1MWh / 257 Sm3 gas

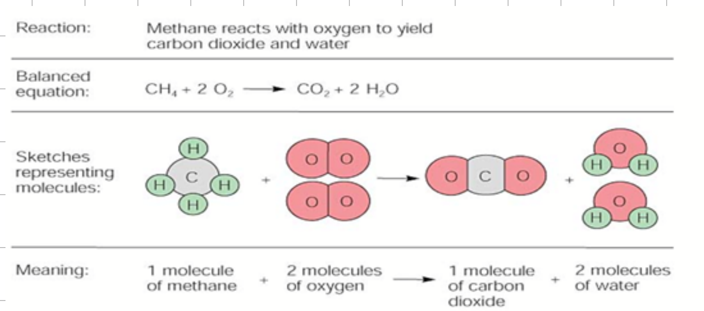
The actual number is highly dependent on the efficiency of the turbine, the type of gas and the type of combustion

How much gas do I need to burn to provide the energy requirements for Wisting?

Wisting requires in plateau year 525 600 MWh, this is 525 600 * 257 Sm3 of gas, i.e. 135 E06 Sm3 of gas, or 370 080 Sm3/d of gas.

It seems there is not enough gas in late life to feed the gas turbine?

Using the data from the previous question to verify



1 mol of methane (16 gr) gives 1 mol of CO2 (44 gr). There is a ratio of 16/44=0.36

if 1 MWh emits 361 kg of CO2, this means ca 129.9 kg of methane are combusted to generate 1 MWh

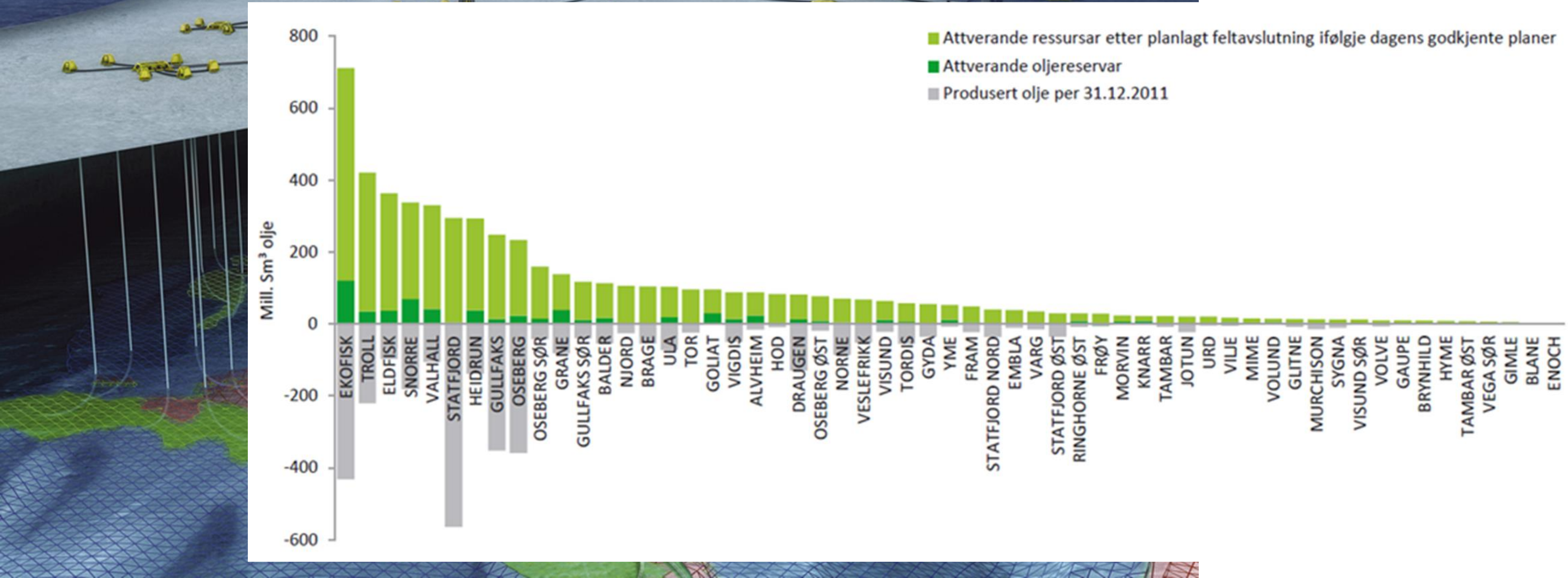
129.9 kg of methane are (den = 0.657 kg/m3) --> 197.7 Sm3 of methane

A number which is somewhat similar to the one above (257 Sm3 of natural gas)

20220929 – Presentation by Inflow Control – Haavard Aakre

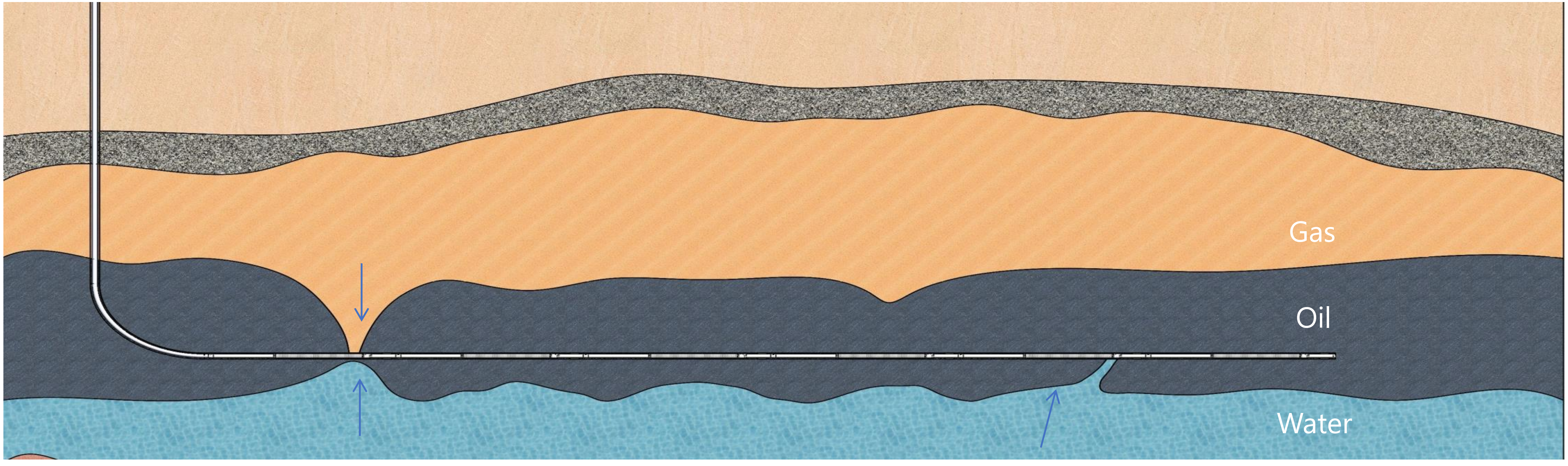
Background

- Significant amount of oil left in the reservoir
- More gas and water than oil are produced



Challenge

- Long horizontal wells to ensure maximum reservoir contact
  - Friction inside the well
  - Heterogeneous reservoirs (permeability and formation variations)
- Non-uniform well drainage creates gas/water breakthrough
  - Requires large gas/water handling systems
  - Gives reduced production
  - Gives reduced recovery
- Conventional ICD can delay the breakthrough problem, but:
  - The solution is to stop the gas/steam/water locally

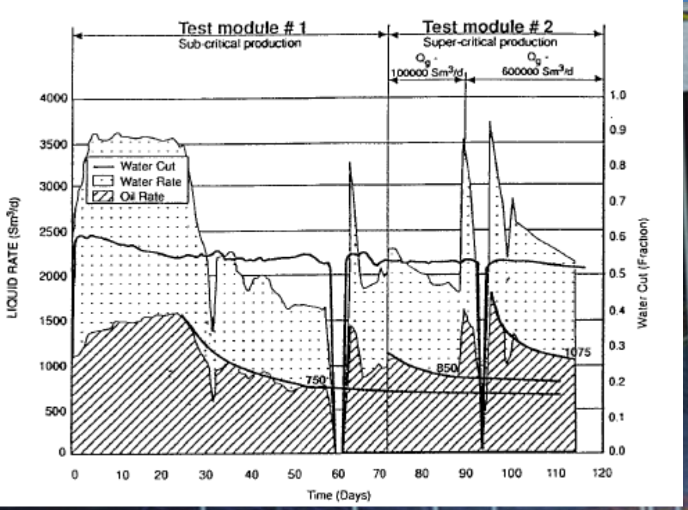


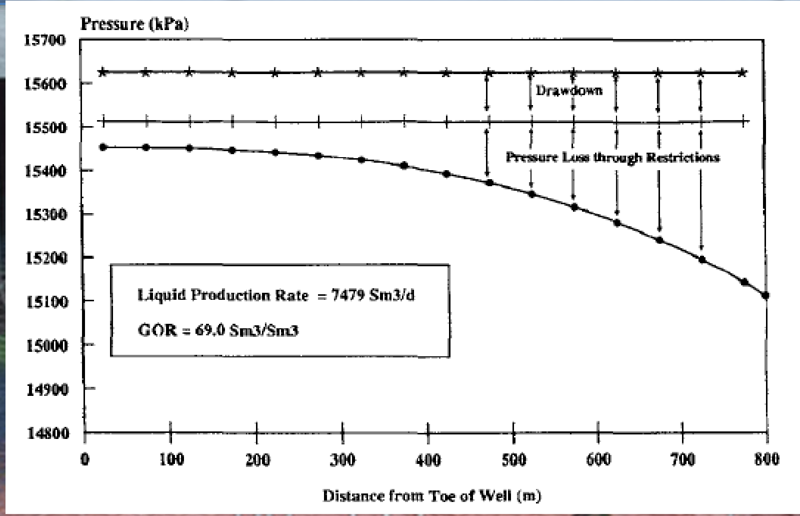
Historical

- 1988-90
- **Horizontal well**

- 1994
- **ICD**

- 2006
- **RCP**





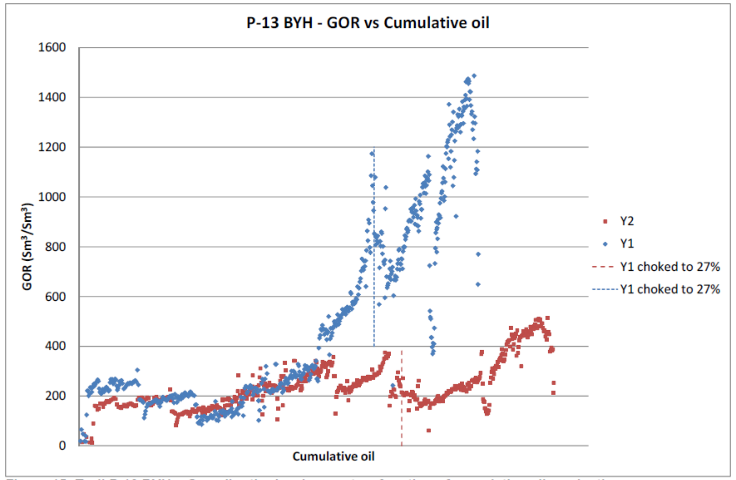
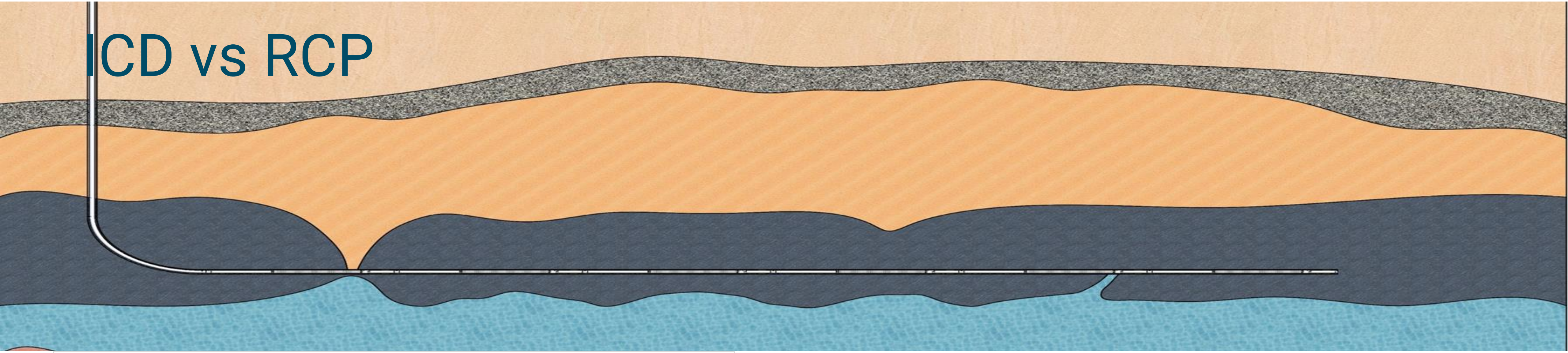
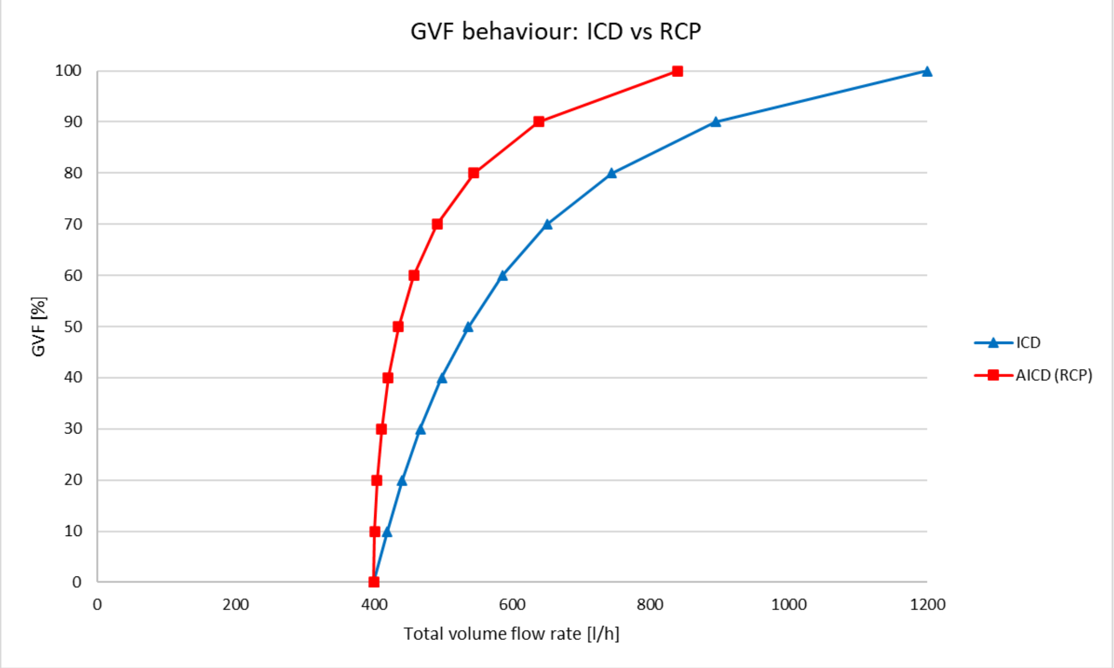


Figure 15: Troll P-13 BYH – Gas oil ratio development as function of cumulative oil production

ICD vs RCP





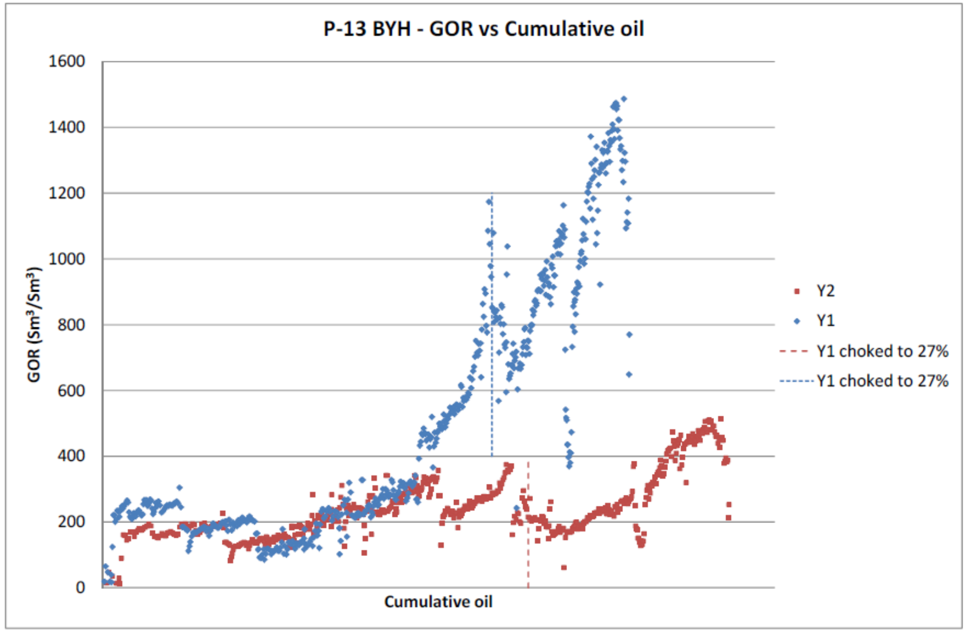
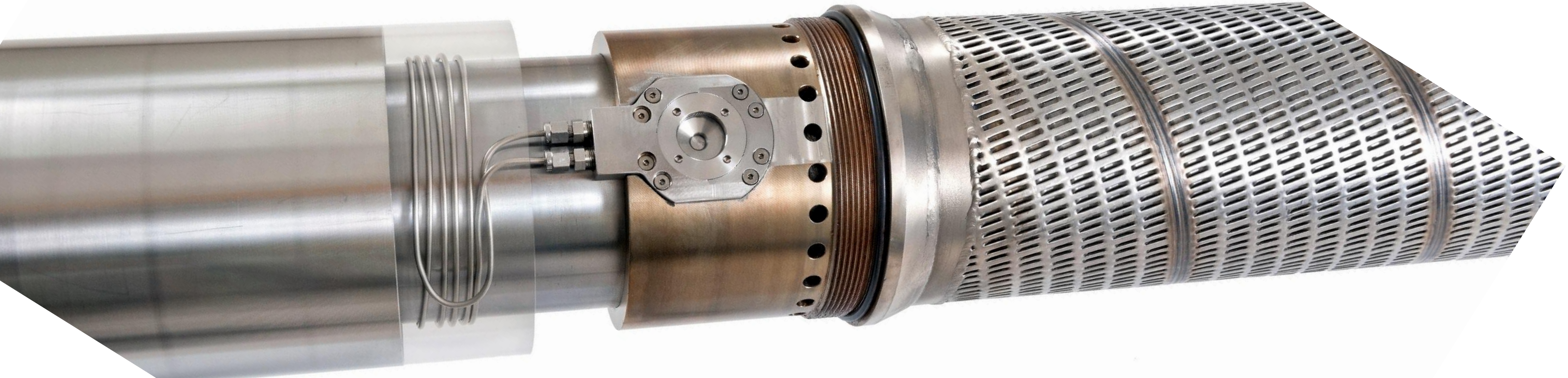


Figure 15: Troll P-13 BYH – Gas oil ratio development as function of cumulative oil production

AICV - Autonomous Inflow Control Valve

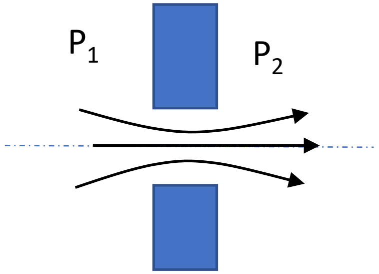
Characteristics:

- *Autonomous;* requires no external power or control
- *Effective*; can stop the gas/water completely
- *Reversible*; allow oil production after an earlier breakthrough
- *Distributed*; no limit in number of zones
- *Retrofitable*; can be installed in new and old wells
- *Compatible;* with standard completion



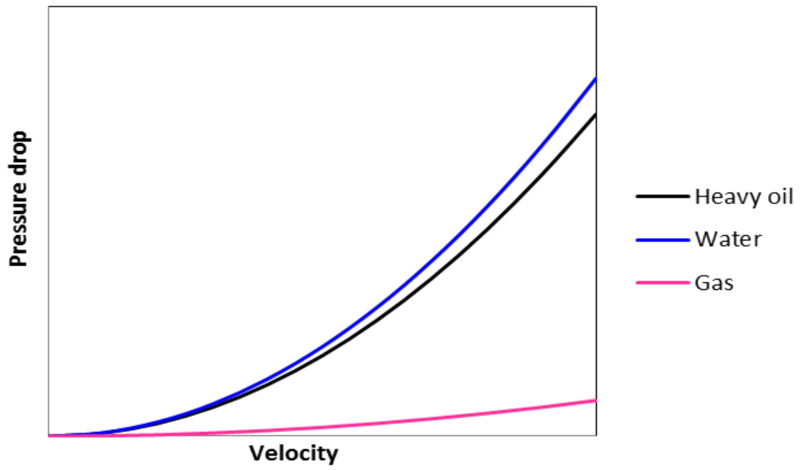
Fluid dynamic theory, I

Turbulent flow element:

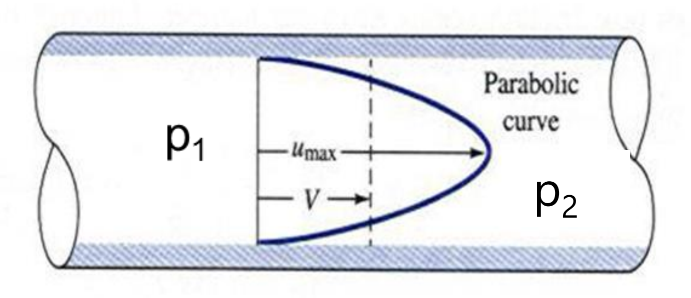


$$\Delta p = p_2 - p_1 = C \cdot \frac{1}{2}\rho v^2$$

$$\Delta p = f\left(\boldsymbol{\rho}, v^{\mathbf{2}}\right)$$

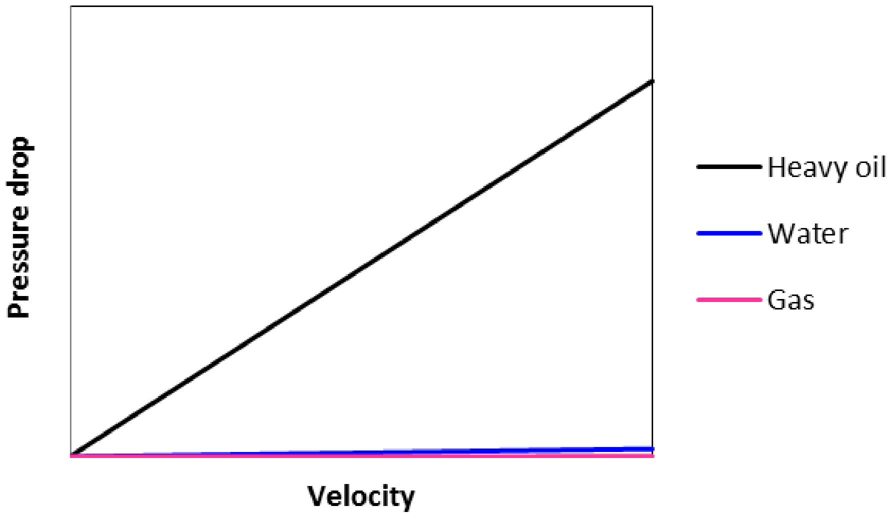


Laminar flow element:

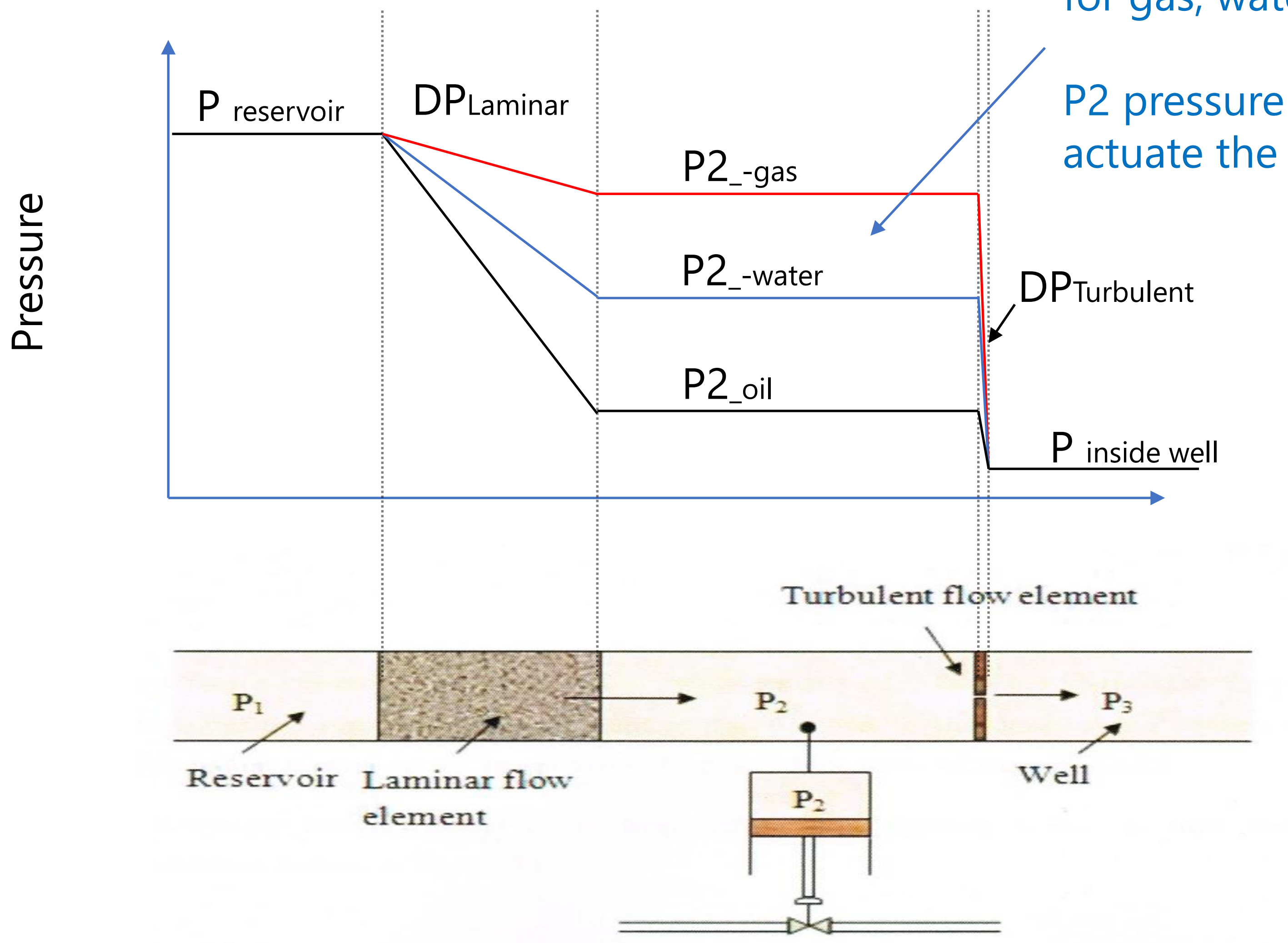


$$\Delta p = p_2 - p_1 = \frac{32\,\mu\,v\,L}{D^2}$$

$$\Delta p = f\,(\boldsymbol{\mu}, v)$$



Fluid dynamic theory, II

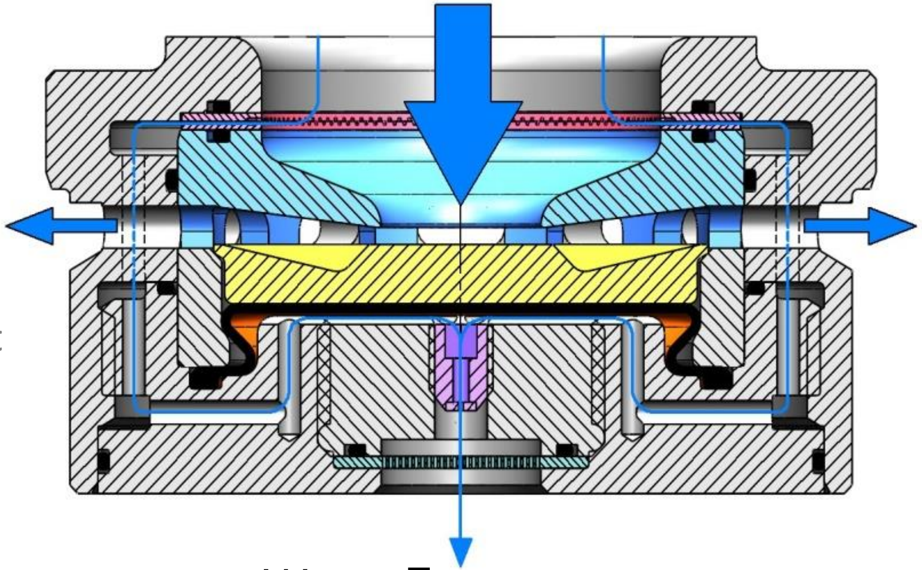


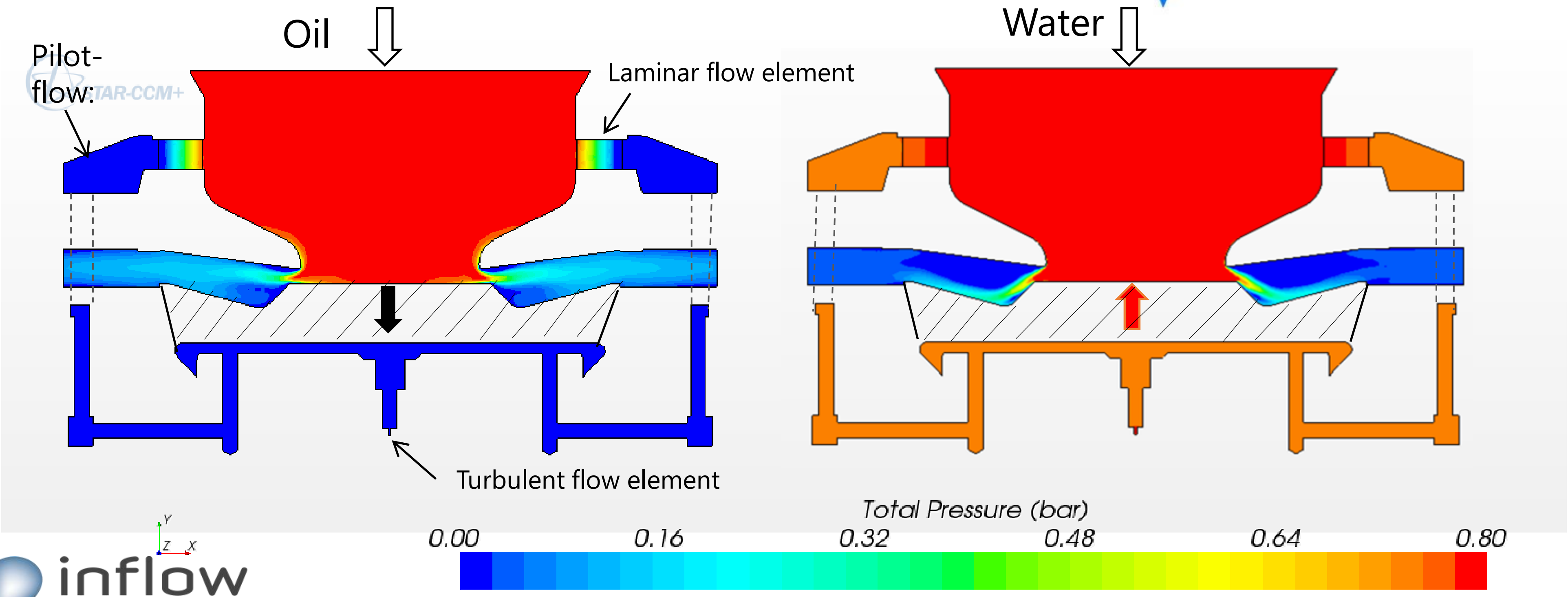
Different P2 pressure for gas, water, oil

P2 pressure used to actuate the main flow

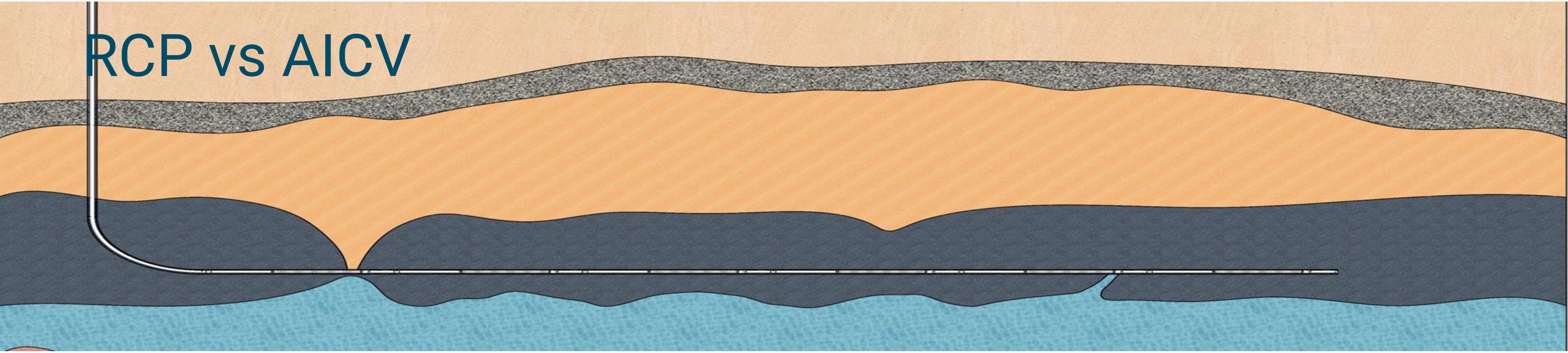
Design of the AICV

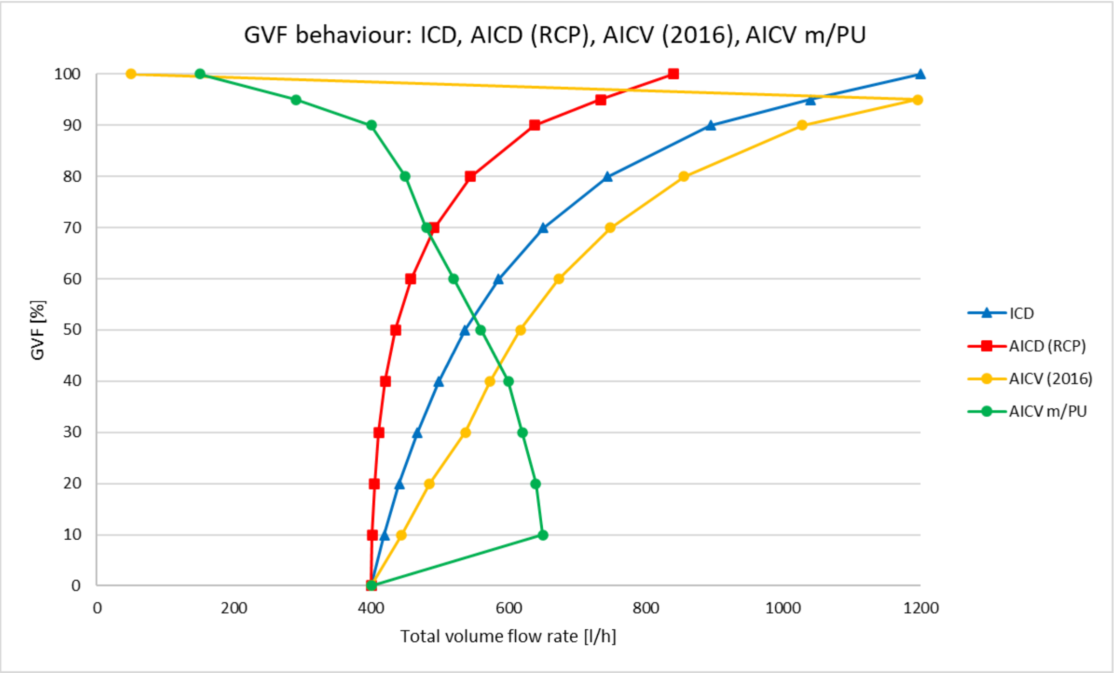
- Large flexibility of design/application;
  - ICD strength
  - Closed vs. open
  - Laminar flow and turbulent flow element
  - Area inlet and area pressure chamber

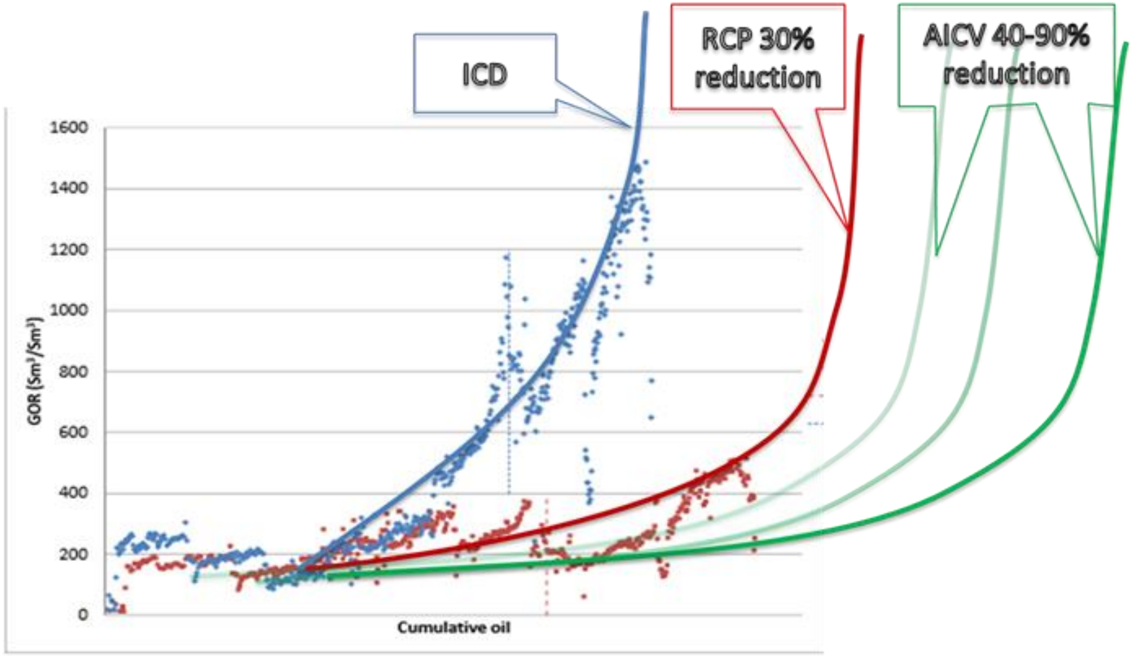




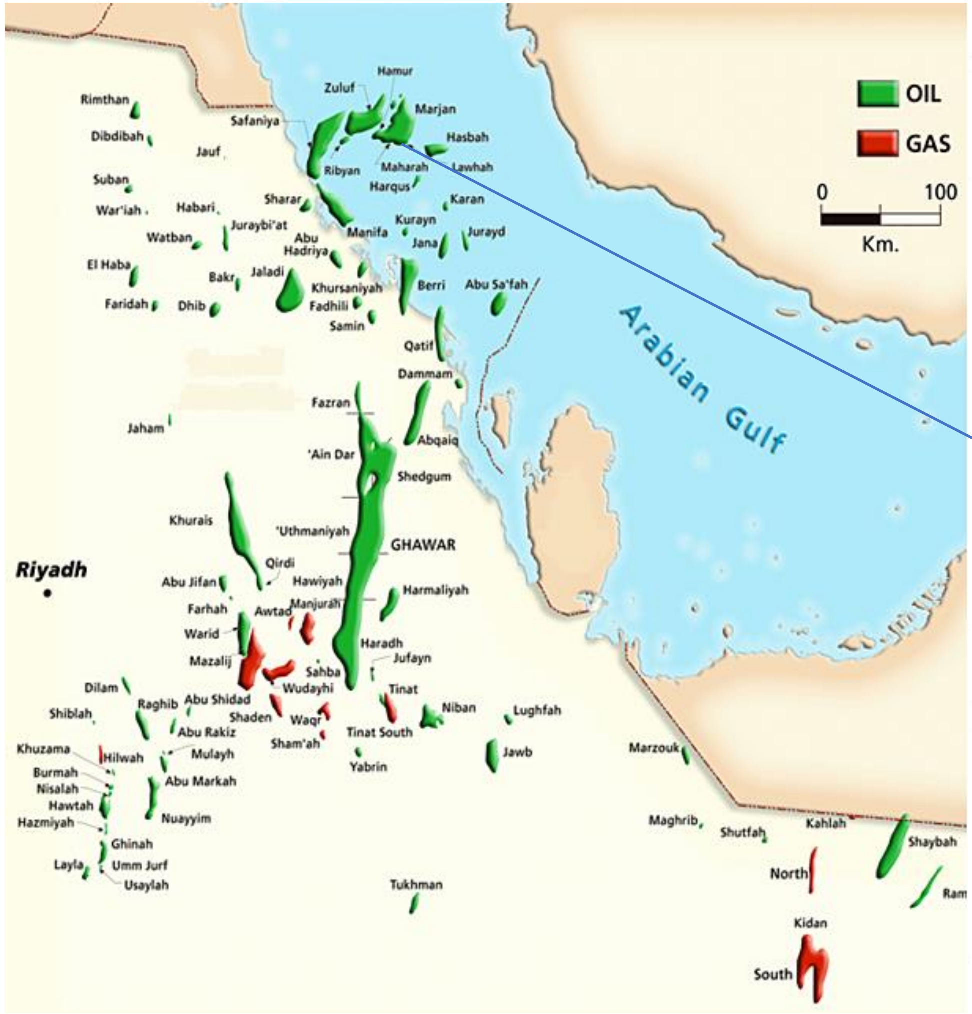
RCP vs AICV

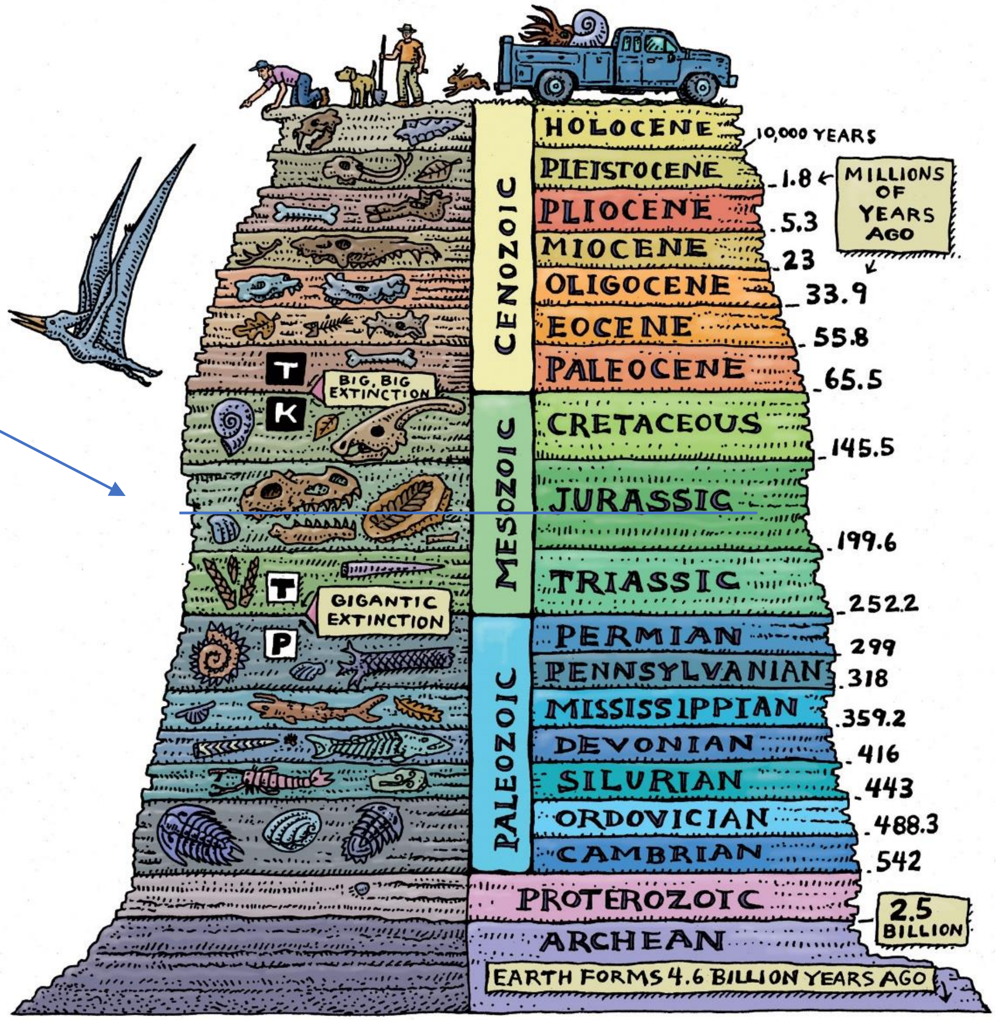



GVF behaviour: ICD, AICD (RCP), AICV (2016), AICV m/PU
GVF [%]
Total volume flow rate [l/h]
ICD
AICD (RCP)
AICV (2016)
AICV m/PU

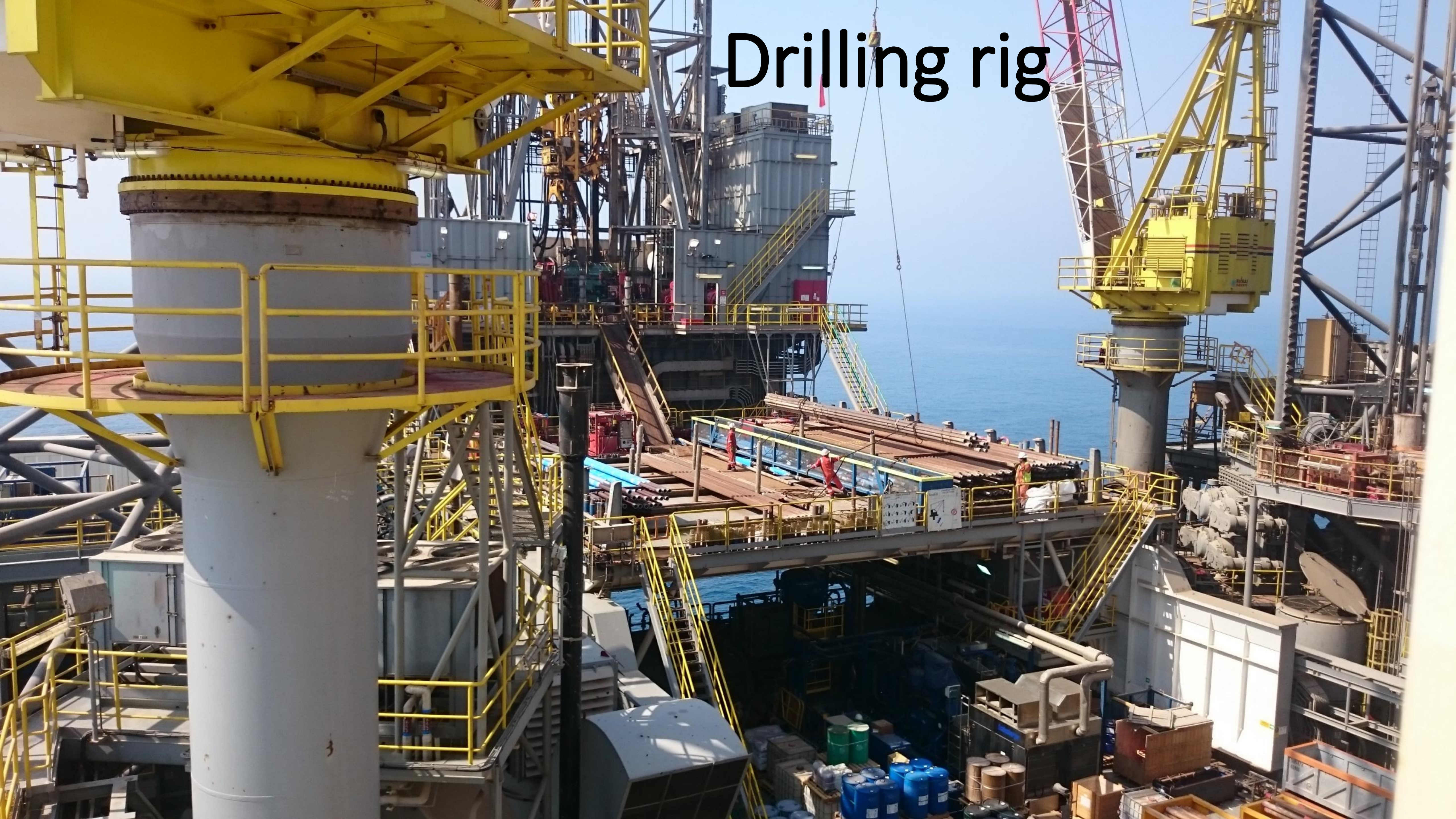

ICD
RCP 30% reduction
AICV 40-90% reduction
GOR [Sm³/Sm³]
Cumulative oil

Arabian Gulf.

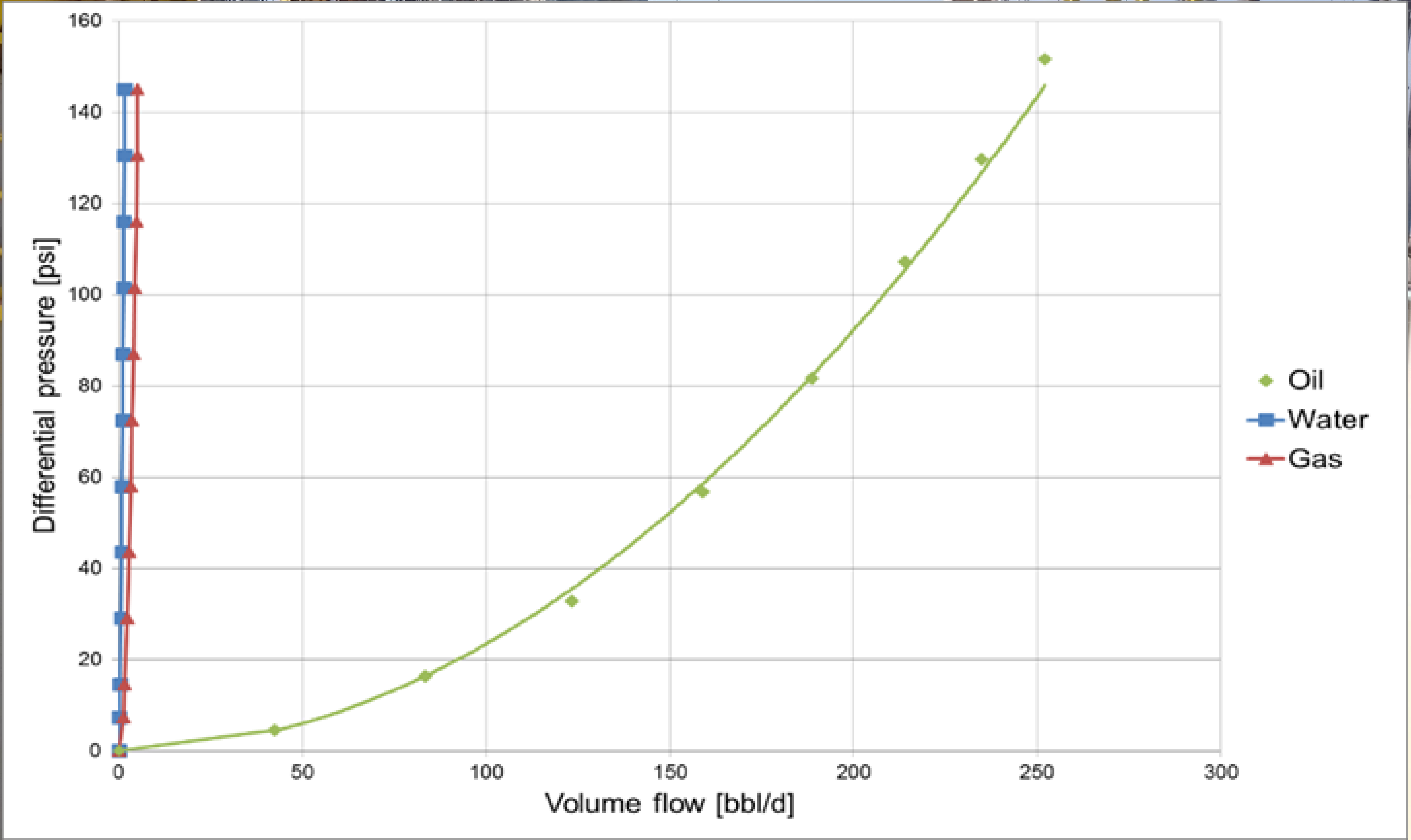




Drilling rig

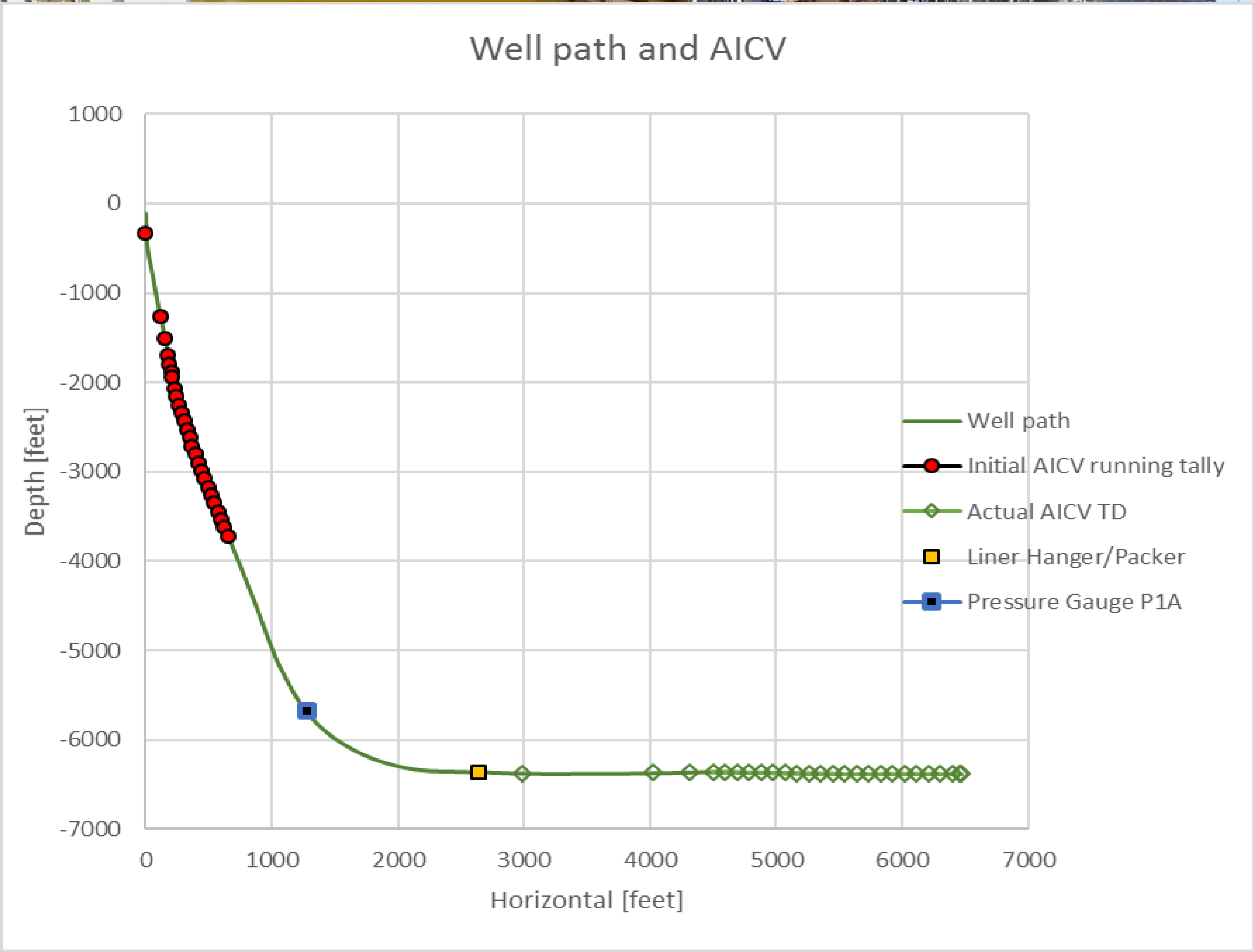


Flow rate

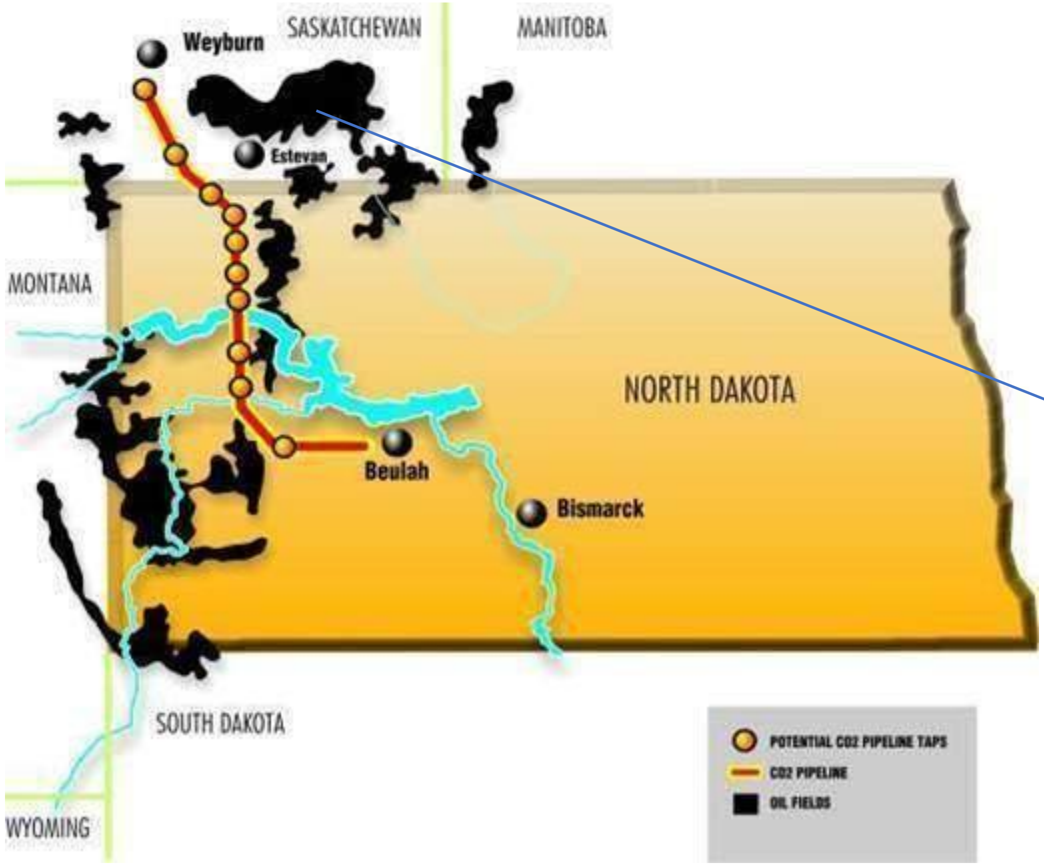


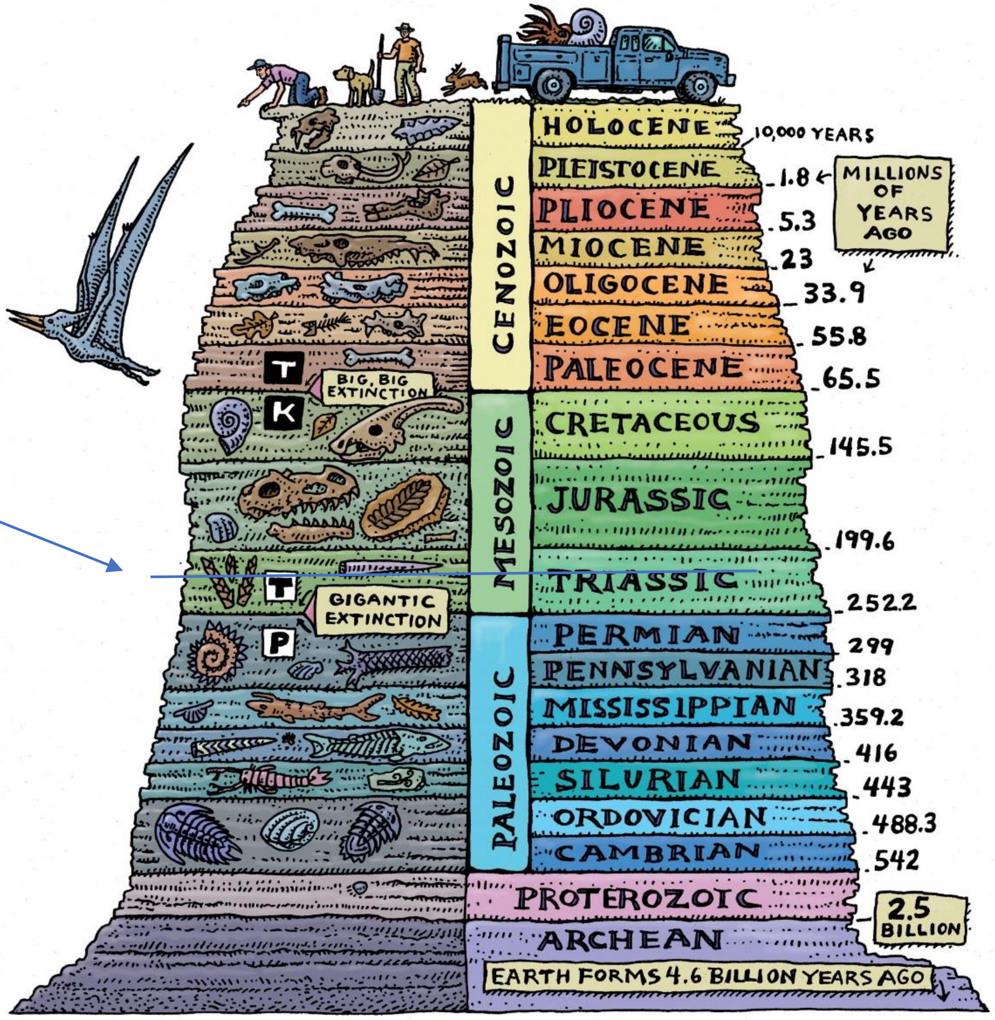
Differential pressure [psi]
0
20
40
60
80
100
120
140
160
Volume flow [bbl/d]
0
50
100
150
200
250
300
Oil
Water
Gas

Installation

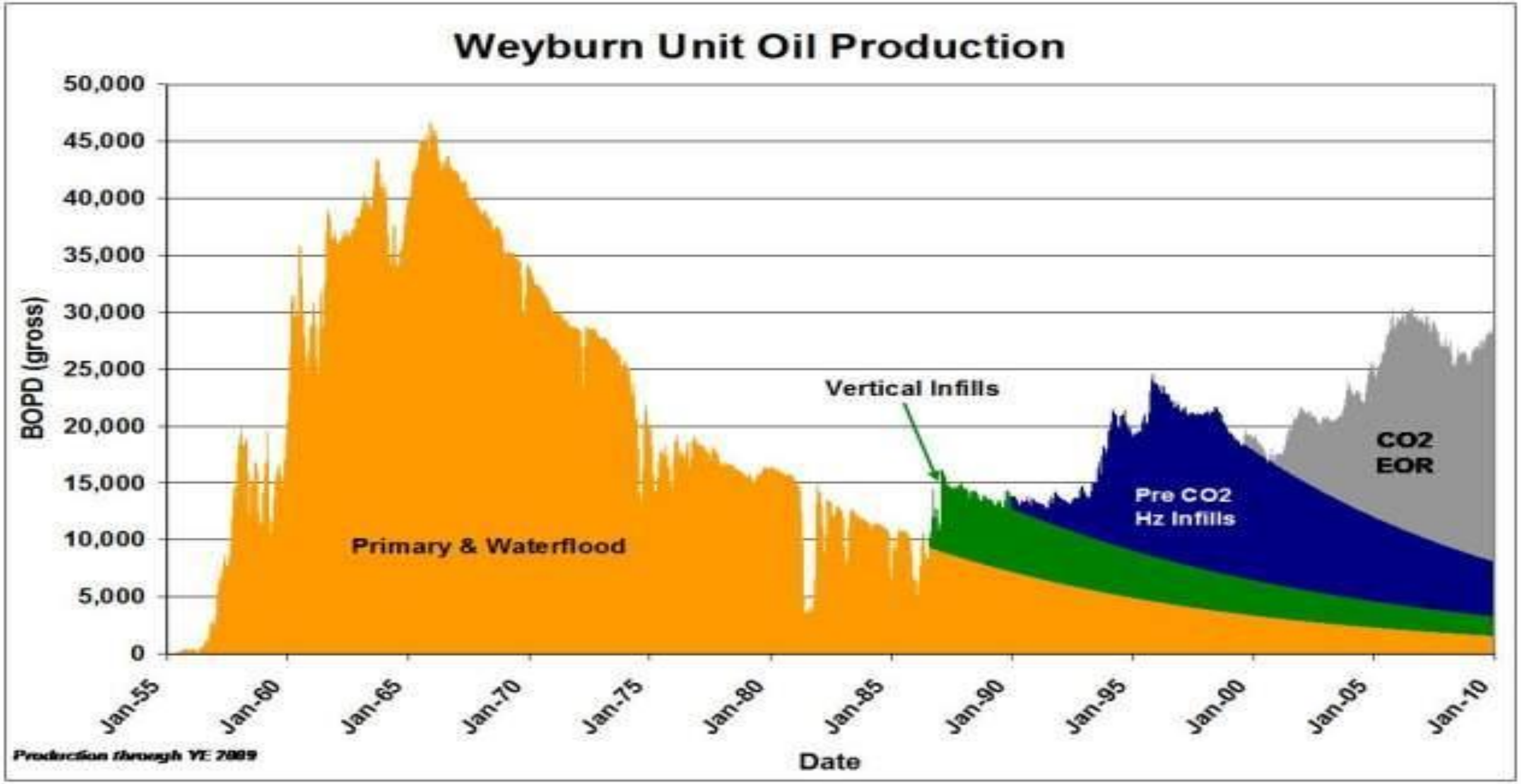


Canada, Saskatchewan (Weyburn-Midale)



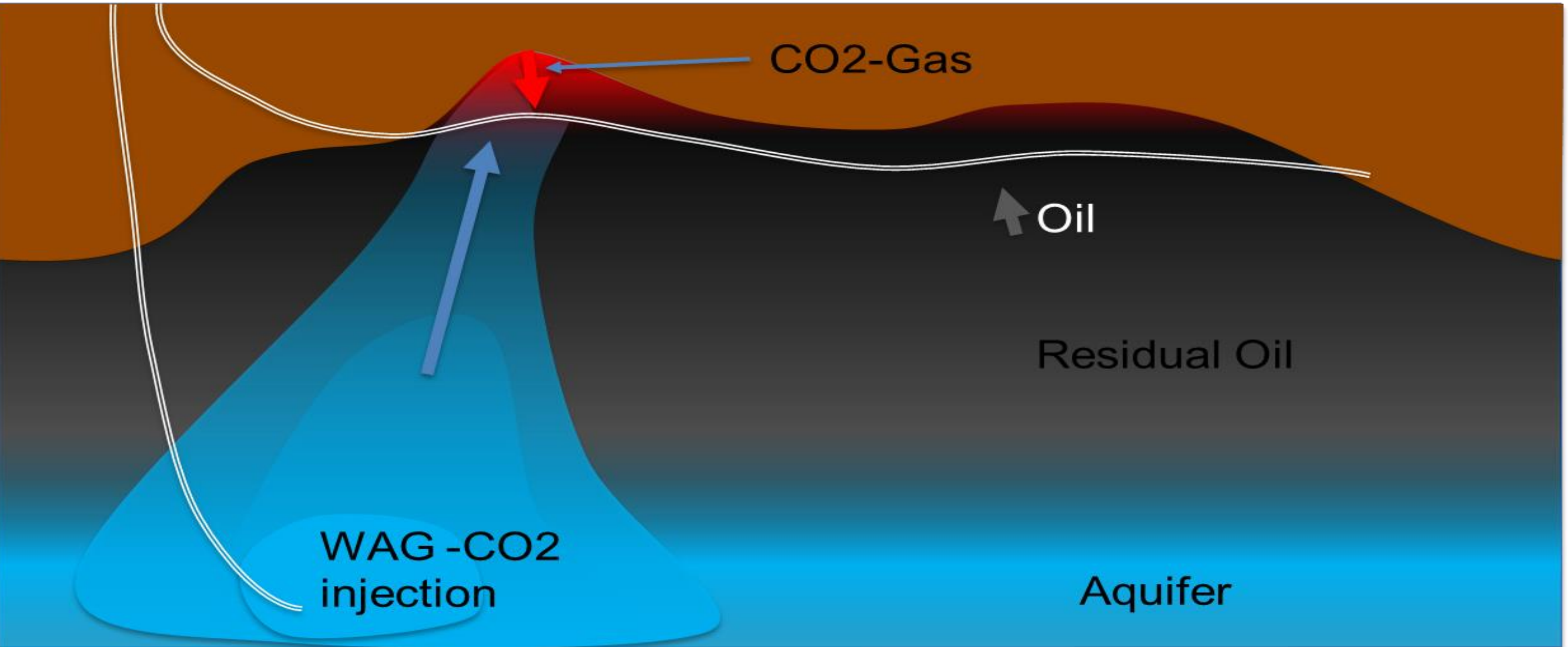


Weyburn-Midale CO2-EOR Project



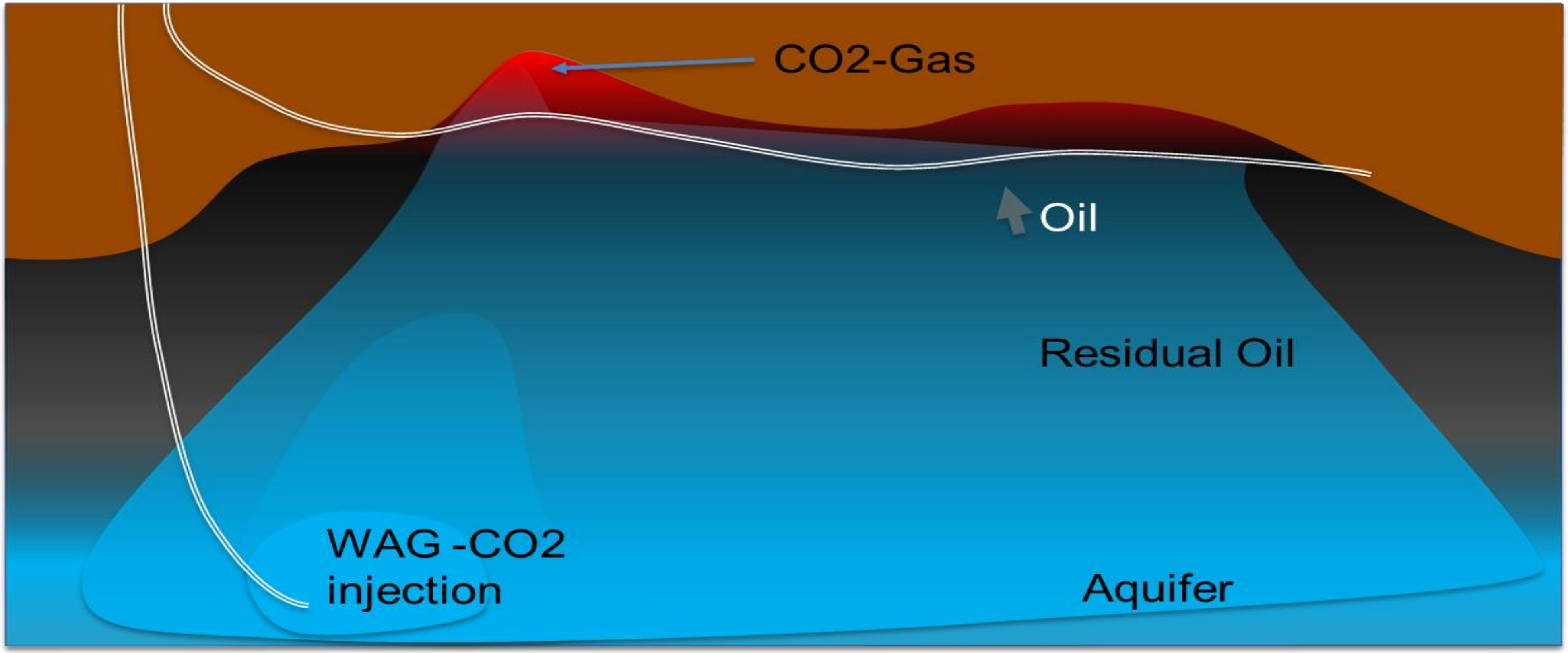
Conventional WAG EOR

- Non-uniform well drainage creates Gas/water (CO_2-) breakthrough
  - Poor sweep efficiency
  - Gives reduced production



AICV technology with WAG EOR

- AICV choke back the breakthrough zone
  - Gas/CO_2 stays in the reservoir
  - Oil production from the other zones along the well
- The WAG sweep increases to the whole well
  - Maximum WAG sweep are ensured
  - When residual oil releases and flows in to the well, the AICV will open again
  - Increased storage and contact of Gas/CO_2 with the residual oil

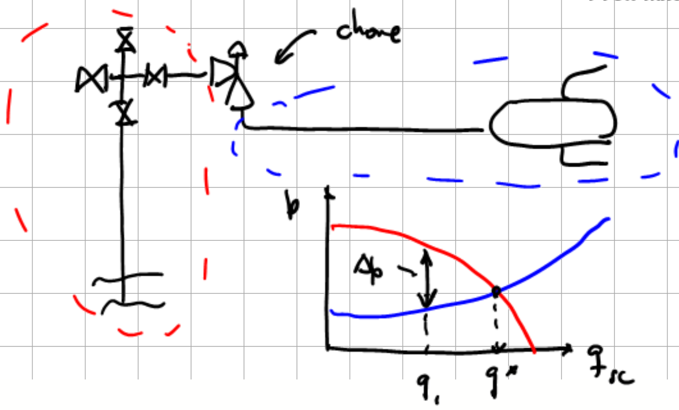


Summary

- At least 50% of the oil is left after shut down
  - Main reason: Breakthrough of gas and water
- New technology developed
  - Increases the oil recovery and production
  - Needs no power from surface, utilizing the fluid behaviour through the device
  - Choking or closing locally for unwanted fluids
  - Producing oil from zones with remaining oil
  - Water and gas remain in the reservoir and maintain the reservoir pressure
  - Can be utilized for CO_2 – EOR and storage

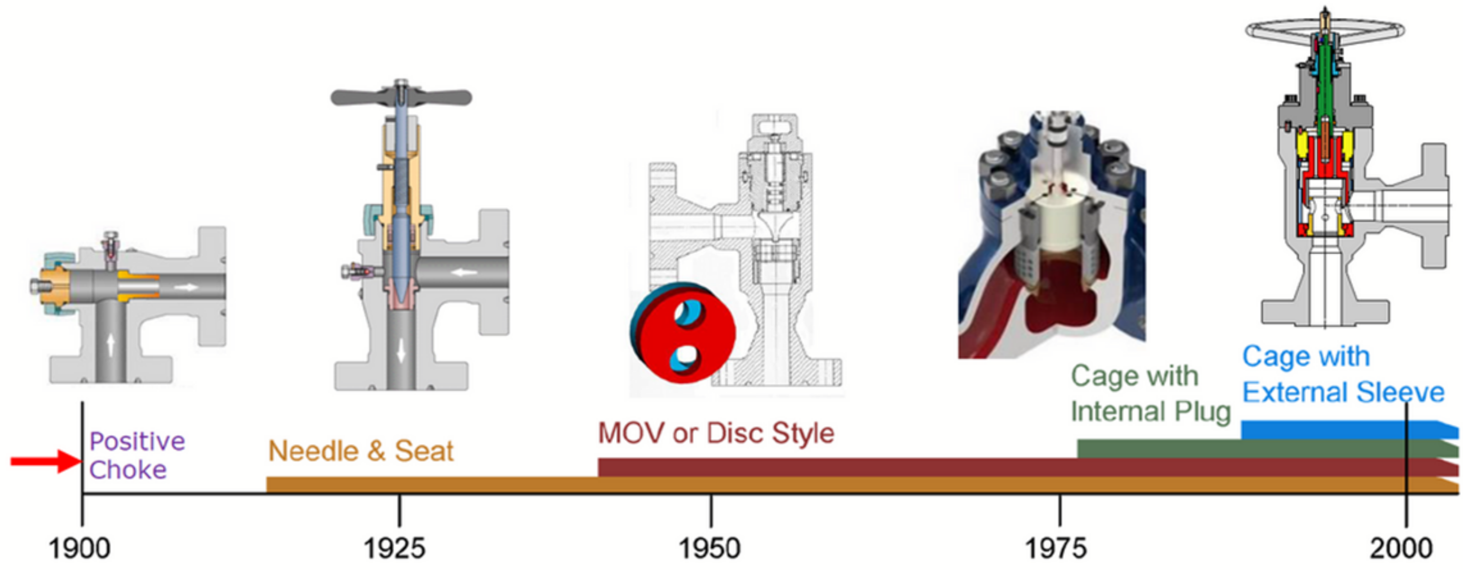
inflow control
Making Better Wells®

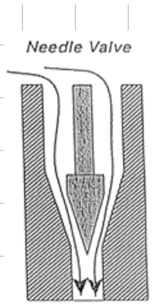
Video 17.1. - Production choke (Wellhead choke)

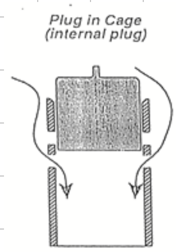


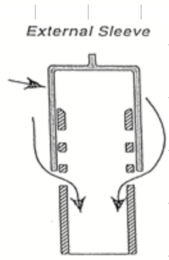
Taken from: https://www.spegcs.org/events/6333/

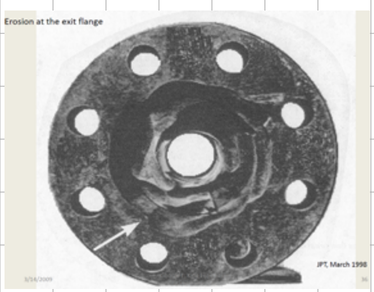
Choke Evolution





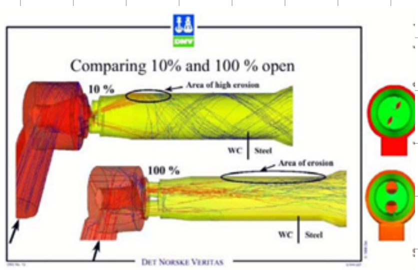


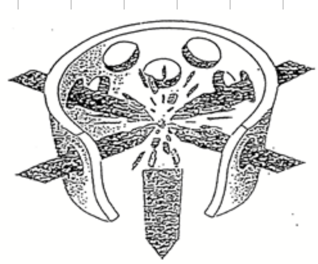




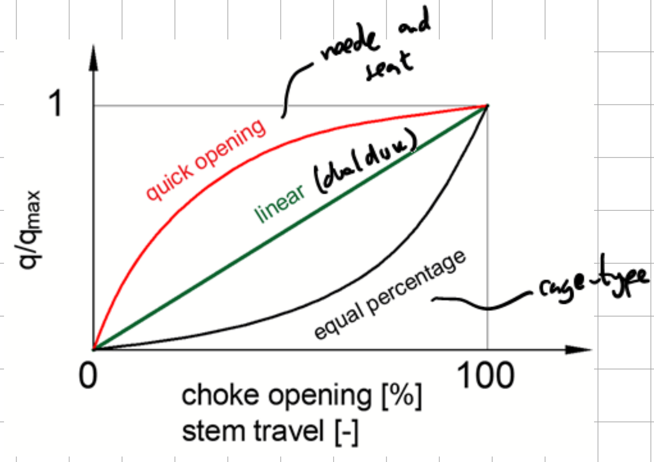
https://www.gekengineering.com/

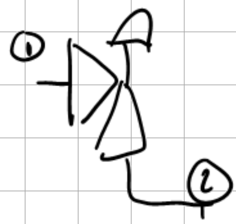
SPE94511





https://www.oedigital.com/news/447270-handling-sand

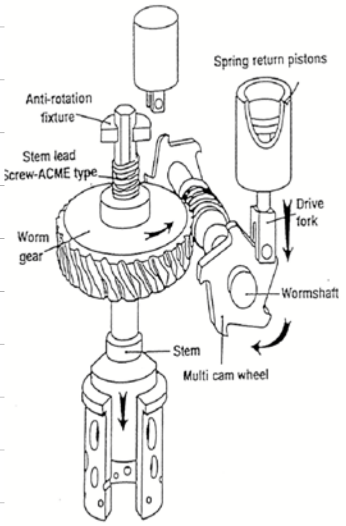




p_1 = constant

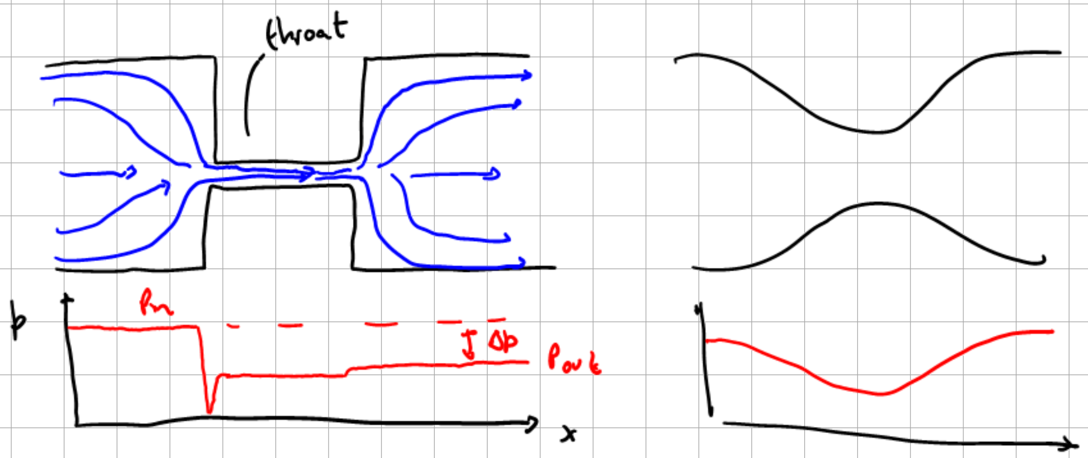
Δp = constant

Actuation



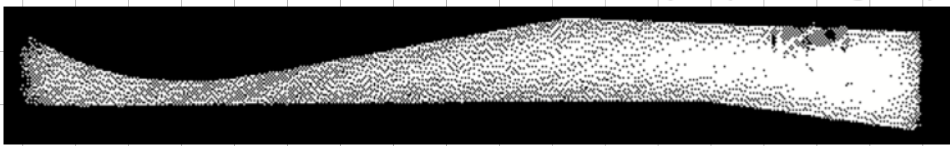
Prof. Milan Stanko (NTNU)

Flow inside a choke

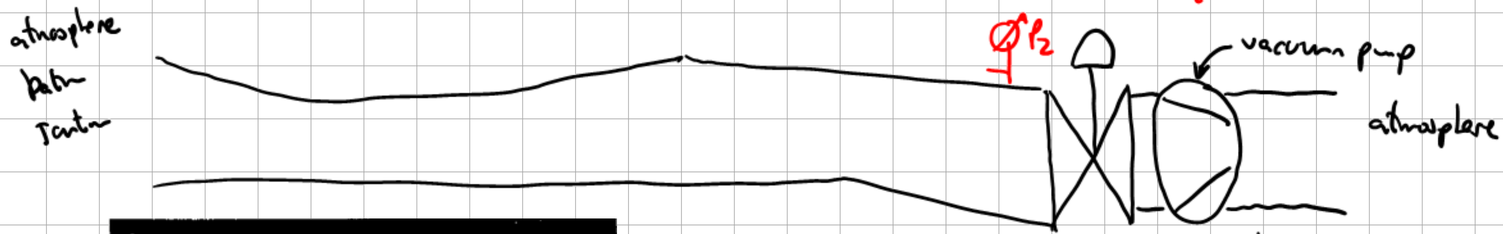


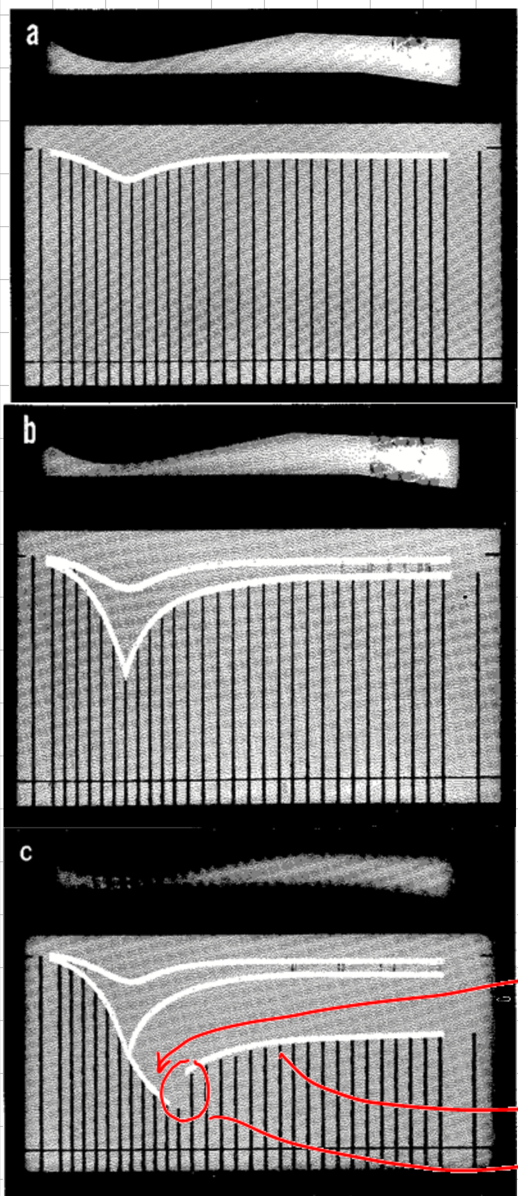
http://web.mit.edu/hml/ncfmf.html

Ascher Shapiro (Mech. Eng. MIT)



$P_2 \le P_{atm}$



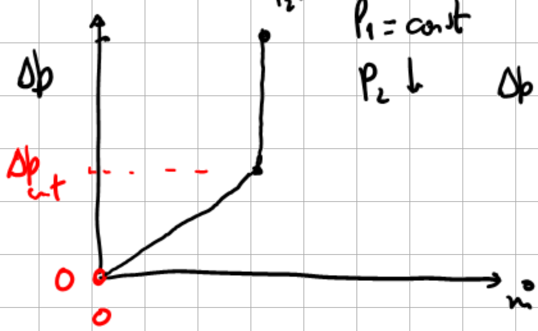


sub-critical

$P_2 = 0$ bara

$P_1 = \text{const}$

$P_2 \downarrow$ $\quad \Delta p = P_1 - P_2$



critical

a : velocity of sound in air ≈343 m/s

https://en.wikipedia.org/wiki/Speed_of_sound

c: velocity of sound in the fluid

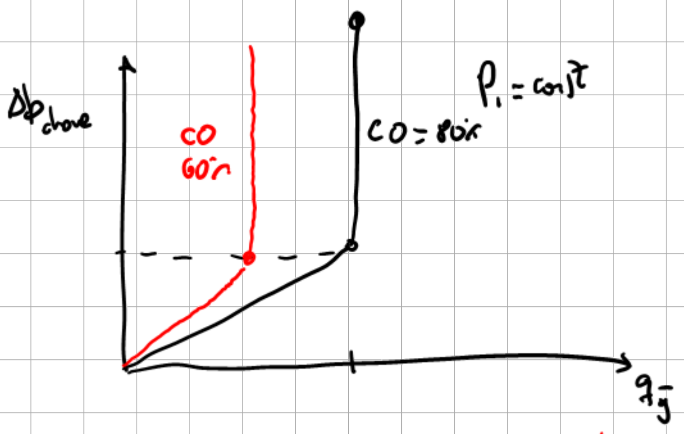
Mach number $\frac{V}{c} = M$

$V > c$, supercritical ($M > 1$)

super-critical

$V < c$, subcritical ($M < 1$)

"shockwave" (discontinuity)



$P_1 = \text{const}$

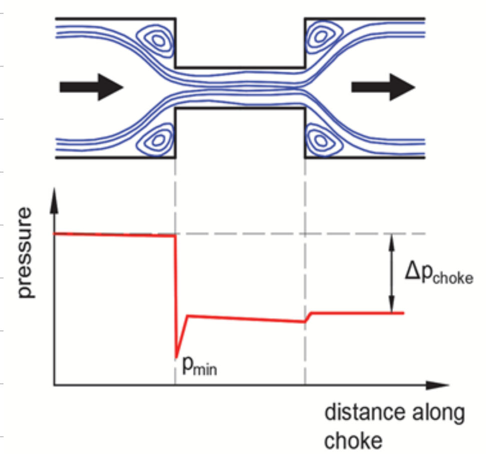
CO : choke opening

$$\frac{P_2}{P_1} \approx 0.5 \quad \text{gas}$$

$$\Delta p_{crit} = P_1 - P_2 = P_1 (1 - 0.5)$$

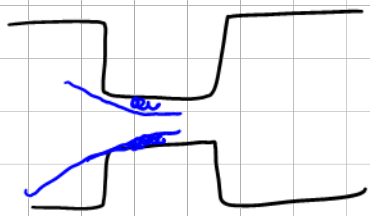
$$\Delta p_{crit} = P_1 (0.5)$$

Video 17.2. - Choke models



$f(q_{sc}, P_{in}, P_{out}, \emptyset)$

$\dot{m}$



UNDERSATURATED OIL FLOW

Based on a frictionless flow contraction from an upstream point 1 to a downstream point 2.

The single-phase Bernoulli equation for steady state frictionless flow along a streamline, neglecting elevation changes, is:

$$\frac{dp}{\rho} + V \cdot dV = 0 \qquad \text{Eq. B-1}$$

Where:

p	Pressure
ρ	Density
V	Velocity

Integrating Eq. B-1 from point 1 to 2:

$$\int_{p_1}^{p_2} \frac{dp}{\rho} + \int_{V_1}^{V_2} V \cdot dV = 0 \qquad \text{Eq. B-2}$$

Assuming incompressible flow:

$$\frac{p_2 - p_1}{\rho} + \frac{V_2^2 - V_1^2}{2} = 0 \qquad \text{Eq. B-3}$$

The mass is conserved in the choke, thus:

$$V_1 \cdot A_1 = V_2 \cdot A_2 \qquad \text{Eq. B-4}$$

The area upstream the choke can be expressed with the diameter of the pipe upstream the choke:

$$A_1 = \frac{\pi \cdot \emptyset_1^2}{4} \qquad \text{Eq. B-5}$$

In a similar way, the cross-section area of 2:

$$A_2 = \frac{\pi \cdot \emptyset_2^2}{4} \qquad \text{Eq. B-6}$$

Using Eq. B-4, Eq. B-5 and Eq. B-6, it is possible to express V_1 as a function of V_2:

$$V_1 = V_2 \cdot \frac{A_2}{A_1} \cdot \frac{\emptyset_2^2}{\emptyset_1^2} \qquad \text{Eq. B-7}$$

To simplify the nomenclature, the ratio between the diameters is named beta (which, in a contraction, is always less than 1):

$$\beta = \frac{\emptyset_2}{\emptyset_1} \qquad \text{Eq. B-8}$$

Substituting Eq. B-7 in Eq. B-3:

$$\frac{p_2 - p_1}{\rho} + \frac{V_2^2 - V_2^2 \cdot \beta^4}{2} \qquad \text{Eq. B-9}$$

Clearing V_2 in Eq. B-9:

$$V_2 = \sqrt{\frac{2 \cdot (p_2 - p_1)}{\rho \cdot (1 - \beta^4)}} \qquad \text{Eq. B-10}$$

$$V_2 = \frac{q_{o,2}}{A_2}$$

$$q_{o,2} = q_{\bar{o}} \cdot B_{o,2}$$

For petroleum production calculations, we often require the oil rate at standard conditions, not the velocity, thus, multiplying Eq. B-10 by A_2 and the oil volume factor $B_{o,@2}$:

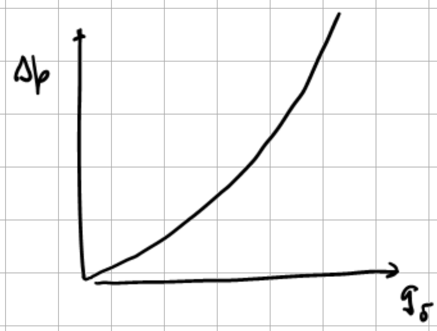
$$q_{\bar{o}} = \frac{A_2}{B_{o,@2}} \cdot \sqrt{\frac{2 \cdot (p_2 - p_1)}{\rho \cdot (1 - \beta^4)}} \qquad \text{Eq. B-11}$$

Where $B_{o,@2}$ and ρ are evaluated at p_2 and T_2.

As mentioned earlier, due to the "vena contracta" effect, the effective area at the throat is not exactly A_2, but slightly less. Thus, a correction factor called the flow coefficient is introduced in Eq. B-11:

$$q_{\bar{o}} = \frac{A_2 \cdot C_d}{B_{o,@2}} \cdot \sqrt{\frac{2 \cdot (p_2 - p_1)}{\rho \cdot (1 - \beta^4)}} \qquad \text{Eq. B-12}$$

$$\Delta p = C q_{\bar{o}}^2$$



Dry gas flow

(based on a frictionless flow contraction from an upstream point 1 to a downstream point 2)

Using Eq. B-2 as the starting point, the term related to pressure and density remains valid; however, in gas flow the velocity downstream is usually much higher than the velocity upstream, thus $V_2^2 >> V_1^2$:

$$\int_{p_1}^{p_2} \frac{dp}{\rho} + \frac{V_2^2}{2} = 0 \qquad \text{Eq. B-13}$$

The density will vary inside the choke. An assumption commonly used is that the contraction process is adiabatic (with an exponent k, the ratio between the specific heats of the gas):

$$p \cdot \rho^{-k} = C \qquad \text{Eq. B-14}$$

$$k = \frac{C_p}{C_v}$$

Where C is a constant. Substituting Eq. B-14 in Eq. B-13:

$$C^{\frac{1}{k}} \cdot \int_{p_1}^{p_2} \frac{dp}{p^{\frac{1}{k}}} + \frac{V_2^2}{2} = 0 \qquad \text{Eq. B-15}$$

Solving the integral:

$$C^{\frac{1}{k}} \cdot \frac{k}{k-1} \cdot \left(p_2^{\frac{k-1}{k}} - p_1^{\frac{k-1}{k}} \right) + \frac{V_2^2}{2} = 0 \qquad \text{Eq. B-16}$$

The constant C is expressed in terms of the inlet conditions:

$$C^{\frac{1}{k}} = \frac{p_1^{\frac{1}{k}}}{\rho_1} \qquad \text{Eq. B-17}$$

Substituting Eq. B-17 in Eq. B-16 and introducing the pressure ratio $y = p_2/p_1$:

$$\frac{p_1^{\frac{1}{k}}}{\rho_1} \cdot \frac{k}{k-1} \cdot p_1^{\frac{k-1}{k}} \cdot \left(y^{\frac{k-1}{k}} - 1\right) + \frac{V_2^2}{2} = 0 \qquad \text{Eq. B-18}$$

Clearing V_2 and simplifying p_1:

$$V_2 = \sqrt{2 \cdot \frac{p_1}{\rho_1} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-19}$$

Expressing ρ_1 with the real gas equation:

$$\rho_1 = \frac{p_1 \cdot M_w}{Z_1 \cdot R \cdot T_1} \qquad \text{Eq. B-20}$$

Where:

M_w	Molecular weight of the gas
R	Universal gas constant
Z	Generalized compressibility factor

Substituting Eq. B-20 in Eq. B-19:

$$V_2 = \sqrt{2 \cdot \frac{Z_1 \cdot R \cdot T_1}{M_w} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-21}$$

$V_2 = \frac{q_{g,2}}{A_2}$

For petroleum production calculations, we often require the gas rate at standard conditions, not the velocity, thus, multiplying Eq. B-21 by the "effective" cross-section area of 2 gives the local volume rate:

$$q_{g2} = A_2 \cdot C_d \cdot \sqrt{2 \cdot \frac{Z_1 \cdot R \cdot T_1}{M_w} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-22}$$

The local volumetric rate at point 2 is related to the rate at standard conditions by the following equation:

$$q_{g2} \cdot \rho_2 = q_{\bar{g}} \cdot \rho_{sc} \qquad \text{Eq. B-23}$$

Substituting Eq. B-23 in Eq. B-22 gives:

$$q_{\bar{g}} = \frac{\rho_2 \cdot A_2 \cdot C_d}{\rho_{sc}} \cdot \sqrt{2 \cdot \frac{Z_1 \cdot R \cdot T_1}{M_w} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-24}$$

ρ_2 is related with ρ_1 by Eq. B-17:

$$\frac{p_2^{\frac{1}{k}}}{\rho_2} = \frac{p_1^{\frac{1}{k}}}{\rho_1} \qquad \text{Eq. B-25}$$

Clearing ρ_2 from Eq. B-25 and substituting in Eq. B-24, and using the real gas equation to express the gas density at standard conditions:

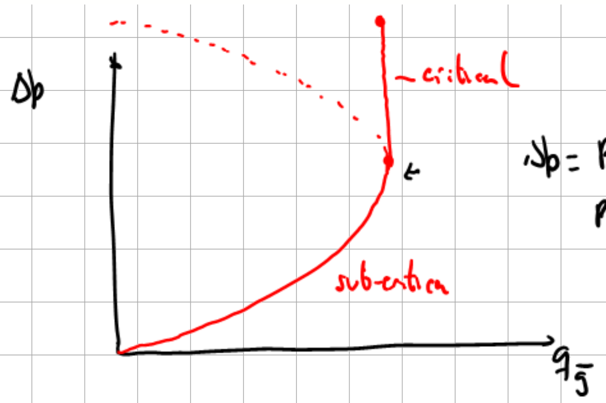
$$q_{\bar{g}} = \frac{\rho_1 \cdot p_2^{\frac{1}{k}} \cdot R \cdot T_{sc} \cdot A_2 \cdot C_d}{p_1^{\frac{1}{k}} \cdot p_{sc} \cdot M_w} \cdot \sqrt{2 \cdot \frac{Z_1 \cdot R \cdot T_1}{M_w} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-26}$$

Introducing Eq. B-20 for ρ_1:

$$q_{\bar{g}} = \frac{p_1 \cdot M_w \cdot p_2^{\frac{1}{k}} \cdot R \cdot T_{sc} \cdot A_2 \cdot C_d}{Z_1 \cdot R \cdot T_1 \cdot p_1^{\frac{1}{k}} \cdot p_{sc} \cdot M_w} \cdot \sqrt{2 \cdot \frac{Z_1 \cdot R \cdot T_1}{M_w} \cdot \frac{k}{k-1} \cdot \left(1 - y^{\frac{k-1}{k}}\right)} \qquad \text{Eq. B-27}$$

Simplifying and rearranging terms:

$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)} \qquad \text{Eq. B-28}$$



$\Delta p = P_1 - P_2$

$P_1 = \text{constant}$

$$\frac{d q_{\bar{g}}}{d P_2} = 0$$

$k = 1.3$

$$y_c = \left(\frac{2}{k+1}\right)^{\frac{k}{k-1}}$$

$y_c \simeq 0.5$

Choke model for multiphase flow

H_l

$H_g = \frac{\boxed{V_g}}{A_T}$

Momentum equation for gas-liquid flow:

$$-dp = H_l \cdot \rho_g \cdot V_g \cdot dV_g + H_g \cdot \rho_l \cdot V_l \cdot dV_l$$

mass fraction at inlet

$$p \cdot (v_g)^{\frac{x_o \cdot C_{v,o} + x_g \cdot C_{p,g} + x_w \cdot C_{v,w}}{x_o \cdot C_{v,o} + x_g \cdot C_{v,g} + x_w \cdot C_{v,w}}} = c$$

$$h_{mix} + x_g \cdot \frac{V_g^{\,2}}{2} + x_o \cdot \frac{V_o^{\,2}}{2} + x_w \cdot \frac{V_w^{\,2}}{2} = const$$

Exercise

$$y_c = \left(\frac{p_2}{p_1}\right)_c = \left(\frac{2}{k+1}\right)^{\frac{k}{k-1}} \quad k = \frac{c_p}{c_v} \quad k = 1.3 - 0.31 \cdot (\gamma_g - 0.55)$$

$$q_{SC} = \frac{C_n d_{ch}^2}{\sqrt{\gamma_g T_1 Z_1}} P_1 \sqrt{\left(\frac{k}{k-1}\right)\left[(y)^{\frac{2}{k}} - (y)^{\frac{k+1}{k}}\right]}$$

$$C_n = C_s C_d \left(\frac{T_{sc}}{p_{sc}}\right)$$

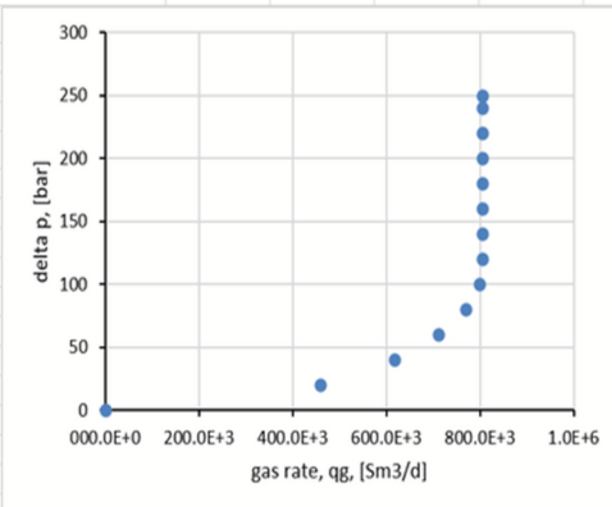
Symbol	Field Units	SI units
q_{sc}	Mscf/D	m^3/d
d_{ch}	in	mm
p	psia	kPa
T	R	K
Cs	27.611	1.6259
C_D	0.865	0.865
p_{sc}	14.696 psia	101.325 kPa
T_{sc}	519.68 R	288.72
c_n	844.57	4.0075

Taken from the book "Gas Production Operations" by Beggs

Prof. Milan Stanko (NTNU). Production wells. Choke Performance Equation for Dry Gas

C_D Discharge Coefficient [-]	0.865
Gas Gravity, [-]	0.55
k, Adiabatic Constant [-]	1.300
T1, choke inlet temperature [C]	70
y_c Critical Ratio [-]	0.546

p1 [bara]	p2 [bara]	d [mm]	y (p2/p1) [-]	qsc [Sm3/d]	dp [bar]
250.0	250.0	15	1.000	000.0E+0	0
250.0	230.0	15	0.920	459.6E+3	20
250.0	210.0	15	0.840	616.5E+3	40
250.0	190.0	15	0.760	712.0E+3	60
250.0	170.0	15	0.680	770.0E+3	80
250.0	150.0	15	0.600	799.1E+3	100
250.0	130.0	15	0.520	804.6E+3	120
250.0	110.0	15	0.440	804.6E+3	140
250.0	90.0	15	0.360	804.6E+3	160
250.0	70.0	15	0.280	804.6E+3	180
250.0	50.0	15	0.200	804.6E+3	200
250.0	30.0	15	0.120	804.6E+3	220
250.0	10.0	15	0.040	804.6E+3	240
250.0	0.0	15	0.000	804.6E+3	250

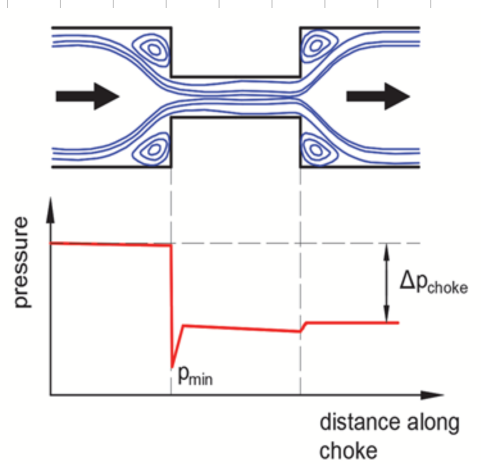


Using the choke model in "metering" mode: p1,p2 and diameter are given, calculate rate

Test yourself!, use the choke model for different purposes:

-Production performance mode: given a rate, p1 and diameter, find p2
-Production performance mode : given a rate, p2 and diameter, find p1
-Design mode: Given a rate, p1,p2, find diameter

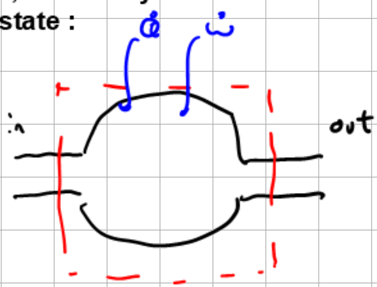
Video 17.3. - Change of temperature across choke



https://www.arab-oil-naturalgas.com/what-does-choke-valve-mean/?quad_cc

OTC26966

Energy conservation equation for open systems, stationary external boundary, steady-state :



shaft work = 0

flow work

pdv

$$\dot{E}_{in} - \dot{E}_{out} + \cancel{\dot{Q}}^{\,0} + \cancel{\dot{W}} = 0$$

variation → 0

internal energy, potential energy, kinetic energy

$$\dot{m}\left(u + \cancel{gz} + \frac{v^2}{2}\right)$$

enthalpy

$$h = u + p \cdot v$$

h is a thermodynamic property

$$u = f(p,T)$$

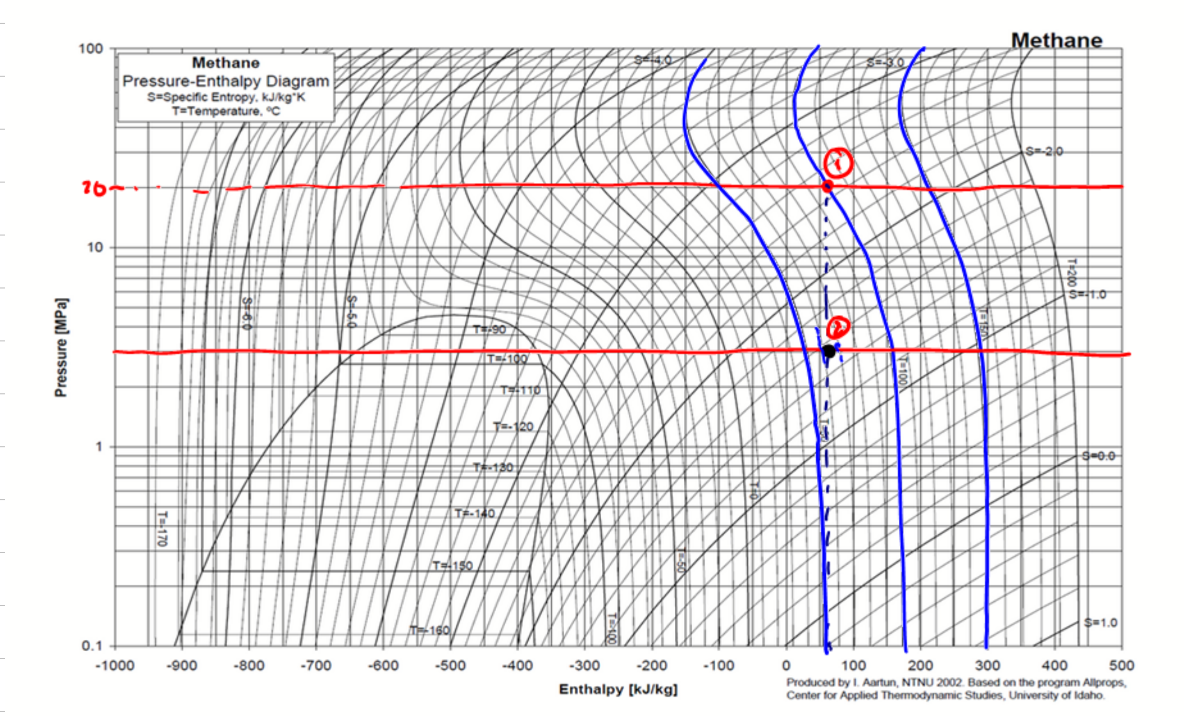
$$h = f(p,T)$$

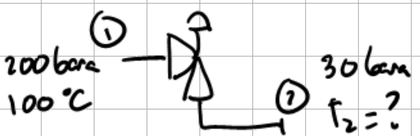
$$\dot{m}\left(h + \frac{v^2}{2}\right) = \text{constant}$$

$$h + \frac{v^2}{2} = \text{constant}$$

if $\Delta \frac{v^2}{2}$ is neglected (e.g. from in - out)

$$\boxed{h_{in} = h_{out}} \rightarrow \text{isenthalpic}$$





$h_1 = h_2$ CH_4

$h_1 = 50$ kJ/kg

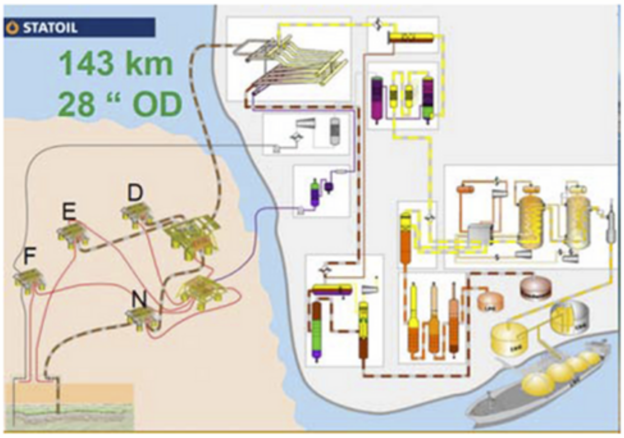
$h_2 = h_1 = 50$ kJ/kg

$T_2 \approx 63\ °C$

class 20221004

Problem 2: IPR for a vertical CO_2 injection well

The Snøhvit field is a subsea dry gas field, located in the Barents Sea. The field produces to a LNG facility on the island of Melkøya through a pipeline that is 140 km long. In the LNG plan, CO2 is captured, it is then pumped and transported for 140 km back to the field and injected in a deep formation (Tubåen). The CO2 is injected in an aquifer, but in this problem, we will assume that the layer has only CO2.



The discharge of the CO2 in Melkøya is usually at around 270 bara. During the transport in the CO2 pipeline, the temperature can be around 4 °C (seabed temperature) or less, due to cooling because of the Joule-Thompson effect. The maximum injection bottom-hole pressure is 390 bara. The initial temperature of the formation is 95 C.

Task 1. Consider the phase diagram of CO2 shown below. Discuss/speculate in what phase is the CO2 in when it reaches the injector well (wellhead and bottom hole).

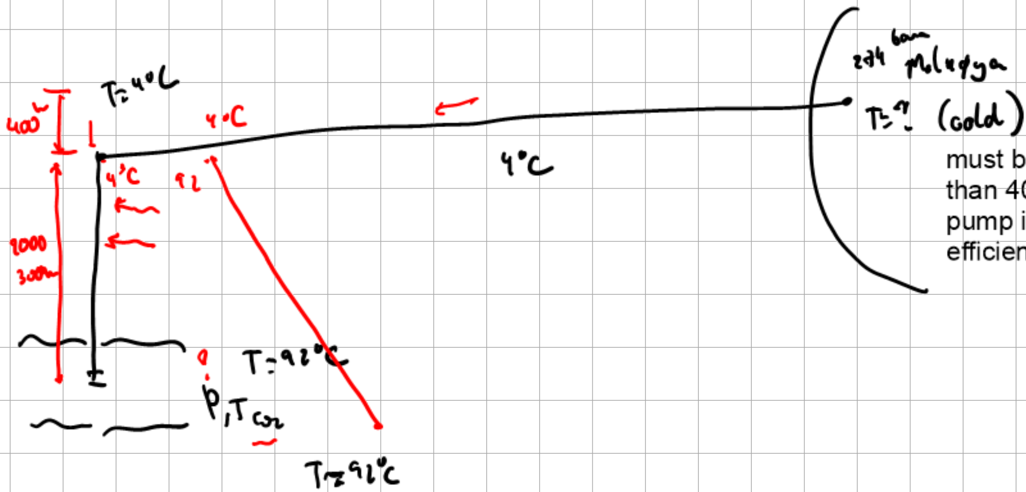
$P_{melkøya} = 274$ bara

$T_{seabed} = 4°C$

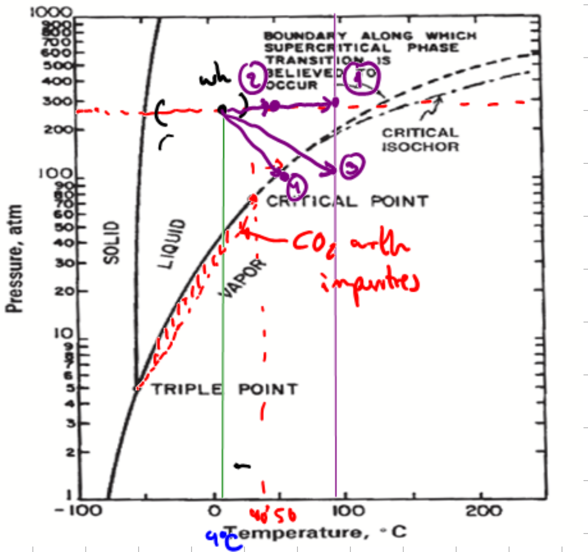
$T_{formation} = 92\ °C$

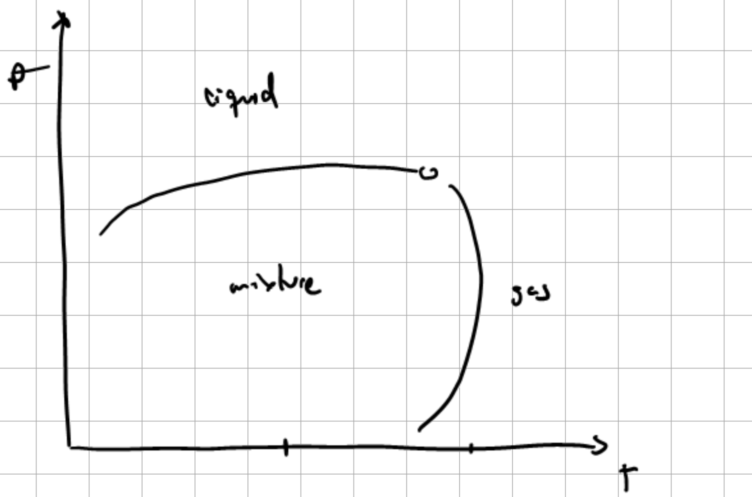
$P_{max} = 390$ bara

wellhead temperature depends on heat transfer along the pipeline. it should reach equilibrium with environment (Twh = 4 C), but sometimes can be colder due to Joule Tompson effect
Wellhead pressure: we assume there is little pressure drop and that frictional DP is equal to hydrostatic DP



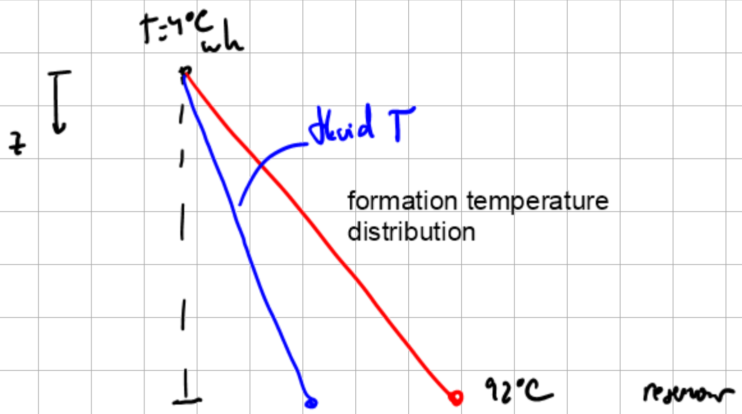
must be relatively cold (less than 40C) because we want to pump in liquid phase (more efficient)





be careful with the SCALE!!!! (left is log, right is linear)

Possibilities for flow in wellbore:
Point 1 - no pressure drop, good heat transfer
Point 2 - no pressure drop, poor heat transfer
Point 3 - pressure drop, good heat transfer
Point 4 - pressure drop, poor heat transfer



From this example, it seems CO2 at bottomhole is liquid or supercritical liquid-like fluid

Task 2. Compute the Injection Performance relationship of this well, using a reservoir pressure of 200 bara and up to a maximum pressure of 390 bara.

We are not sure if Zstanding can be use for pure CO2, so in this case we prefer to use tabulated data, from a source we trust

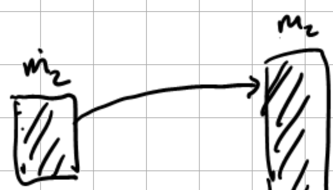
IPR can sometimes be expressed as a function of mass flow

$$q_g = q_{\bar{g}} \cdot B_g$$

calcd for CO_2 (compressible fluid)

$$@P,T \quad q_g = \frac{\dot{m}}{\rho_{g@P,T}}$$

$$\dot{m} = f(P_{wf}, P_R, --)$$



$$q_{\bar{g}} = \frac{2\pi k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75\right)} \int_{P_{wf}}^{P_R} \frac{1}{B_g \mu_g} dP$$

$$B_g = \frac{V_{g@P,T}}{V_{g@P_{sc},T_{sc}}}$$

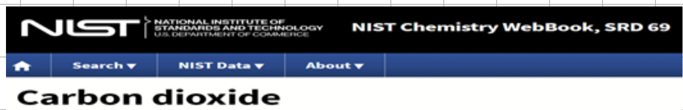
if no phase change
$m_1 = m_2$

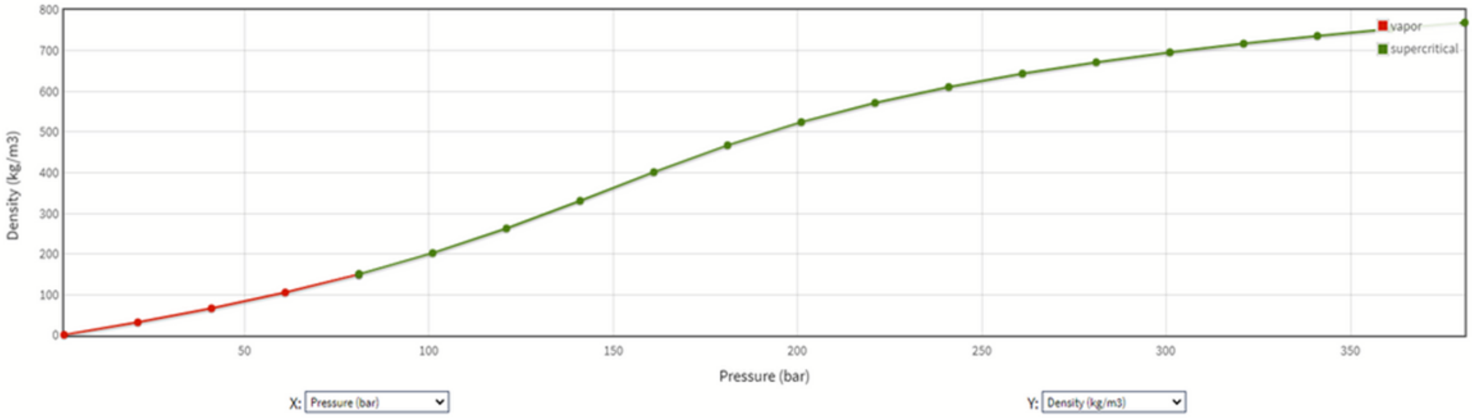
$$B_g = \frac{\dfrac{\cancel{m_1}}{\rho_{@p,T}}}{\dfrac{\cancel{m_2}}{\rho_{@p_{sc},T_{sc}}}} = \frac{\rho_{@p_{sc},T_{sc}}}{\rho_{@p,T}}$$

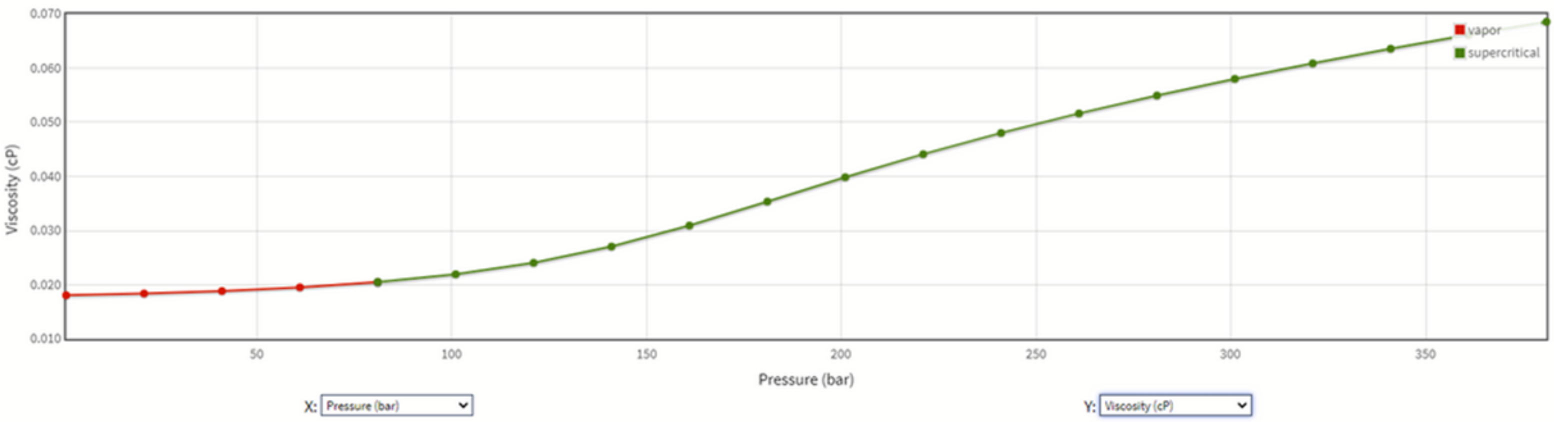
Visc and den of CO2 at T = 92 C
p (1.01325 to 390 bara)

https://automeris.io/WebPlotDigitizer/

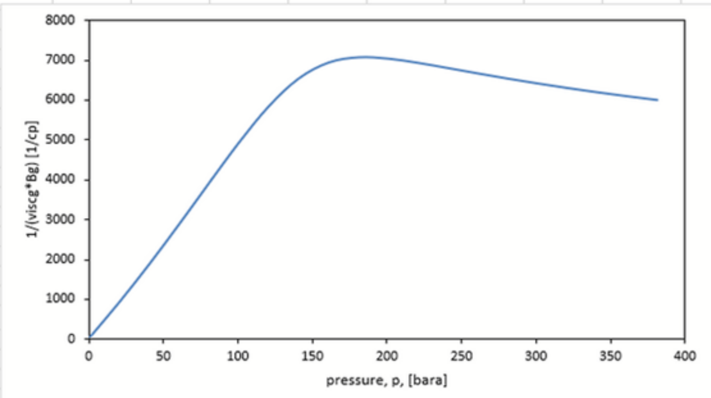
https://webbook.nist.gov/cgi/inchi/InChI=1S/CO2/c2-1-3

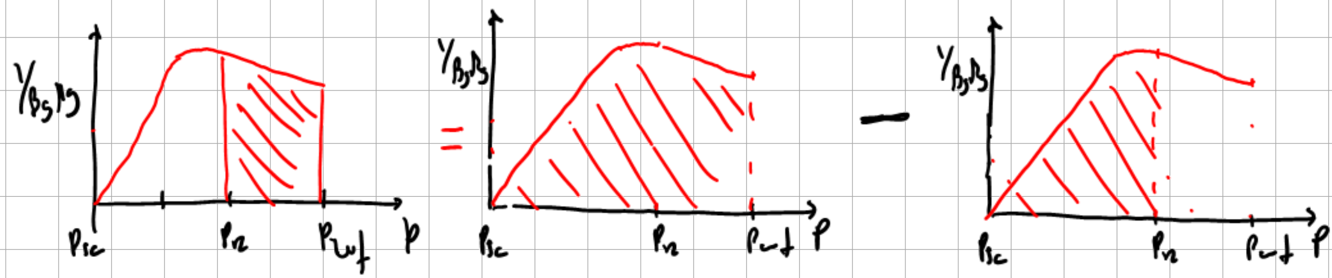






	deng_sc [kg/	1.8682		Data from NIST	
p [bara]	deng [kg/m3]	viscg [cp]	Bg [m3/Sm3]	1/viscg*Bg [1/cp]	m(p) [bar/cp]
1.0132	1.4725	0.018058	1.269	44	0.0
21.013	32.189	0.018381	0.058	937	9810.2
41.013	66.572	0.018847	0.028	1891	38091.1
61.013	105.58	0.01952	0.018	2895	85950.2
81.013	150.46	0.020502	0.012	3928	154184.9
81.013	150.46	0.020502	0.012	3928	154184.9
81.013	150.46	0.020502	0.012	3928	154184.9
101.01	202.62	0.021943	0.009	4943	242881.2
121.01	263.08	0.024057	0.007	5854	350844.0
141.01	330.97	0.027054	0.006	6548	474863.8
161.01	401.55	0.030941	0.005	6947	609815.1
181.01	467.65	0.03537	0.004	7077	750054.9
201.01	524.57	0.039864	0.004	7044	891263.8
221.01	571.81	0.04412	0.003	6937	1031073.9
241.01	610.91	0.048043	0.003	6806	1168512.2
261.01	643.72	0.051642	0.003	6672	1303299.5
281.01	671.73	0.054957	0.003	6543	1435447.4
301.01	696.04	0.058031	0.003	6420	1565075.4
321.01	717.45	0.060901	0.003	6306	1692336.3
341.01	736.55	0.0636	0.003	6199	1817384.8
361.01	753.76	0.066153	0.002	6099	1940365.1
381.01	769.42	0.068581	0.002	6005	2061408.5





$$m(p) = \int_{p_{sc}}^{p} \frac{1}{\mu_g B_g} dp$$

p	$1/\mu_g B_g$	$m(p)$
1.01	$\square$	0
10	$\square$	$\square + (\square - \square) \cdot 0.5 \cdot (\square + \square)$
20		
30		

https://en.wikipedia.org/wiki/Trapezoidal_rule

m(p) [bar/cp]
0.0
9810.2
38091.1
85950.2
154184.9
154184.9
154184.9
242881.2
350844.0
474863.8
609815.1
750054.9
891263.8
1031073.9
1168512.2
1303299.5
1435447.4
1565075.4
1692336.3
1817384.8
1940365.1
2061408.5

=2*PI()*(0.0000000000009869/1000)*(100000)*3600*24/(0.001)

D	E	F	G	H
IPR constant	5.3576E-02		deng_sc [kg/	1.8682

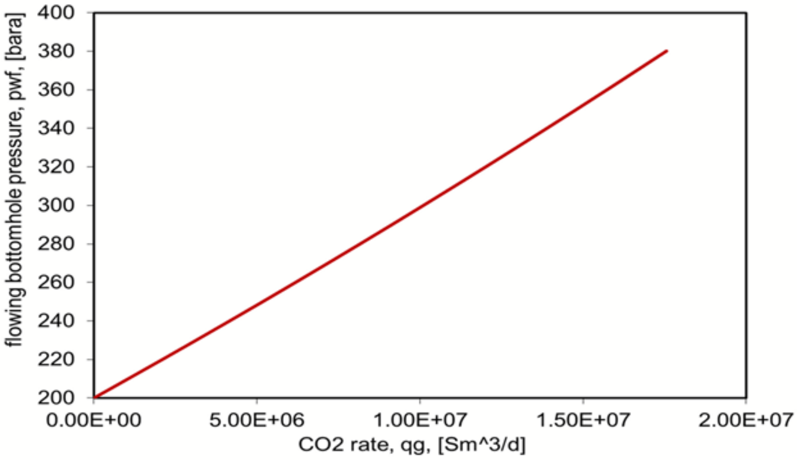
To input in md, m, bar,cP, and obtain Sm3/d

```
Function iprppgas_qg(k, h, re, rw, s, MpR, Mpwf)
    'iprlpgas_qg, gas rate in Sm3/d, calculated with the dry gas IPR with the m function
    'k, permeability, [md]
    'h, layer height, [m]
    're external radius of reservoir [m]
    'rw, wellbore radius [m]
    's, skin factor [-]
    'mpR, m function at reservoir pressure [bara^2/cp]
    'mpwf, flowing bottom-hole pressure [bara^2/cp]
    iprppgas_qg = 0.053576 * k * h * (Mpwf - MpR) / ((Log(re / rw) - 0.75 + s))
End Function
```

pwf bara	m(p) [bar/cp]	qg [Sm3/d]
200	884132.71	000.0E+0
220	1024013.5	2.1E+6
240	1161571.6	4.2E+6
260	1296492.7	6.2E+6
280	1428773.9	8.2E+6
300	1558529.2	10.1E+6
320	1685909.6	12.0E+6
340	1811069.9	13.9E+6
360	1934154.6	15.7E+6
380	2055295.8	17.6E+6

```
Function tabinterpol(x, col, Matrix As Range)
    'function to perform linear interpolation in tables
    'INPUT:
    '-x value for which the value is required
    '-col: column number in which the property is located
    'Matrix: table organized in the following manner:
    '   col1  col2  col3  col4
    'x1 P11
    'x2
    'x3
    '.
    'All numbers, no strings!!!
```

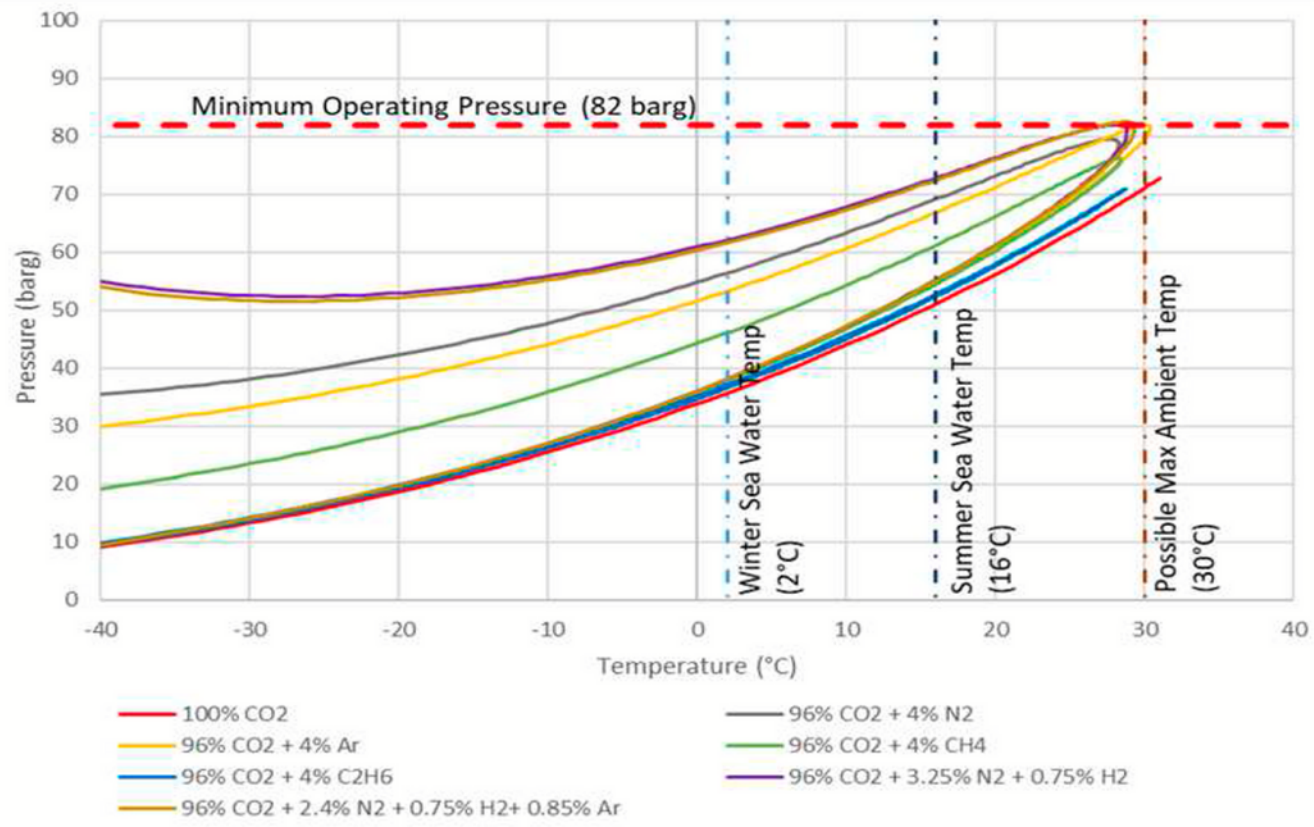
p [bara]	m(p) [bar/cp]
1.0132	0.0
21.013	9810.2
41.013	38091.1
61.013	85950.2
81.013	154184.9
81.013	154184.9
81.013	154184.9
101.01	242881.2
121.01	350844.0
141.01	474863.8
161.01	609815.1
181.01	750054.9
201.01	891263.8
221.01	1031073.9
241.01	1168512.2
261.01	1303299.5
281.01	1435447.4
301.01	1565075.4
321.01	1692336.3
341.01	1817384.8
361.01	1940365.1
381.01	2061408.5



IPR is fairly linear!
injection rate for pwf = 276 bara is 7.7 E06 Sm3/d. For comparison, a large offshore subsea gas well may have a production of 4 E06 Sm3/d

Lecture 20221006

Phase envelope for CO2 with impurities



https://webevents.spe.org/products/flow-assurance-for-ccs

class activities about choke performance:

Using the same excel sheet given in the video, try the following tasks:

Test yourself!, use the choke model for different purposes:

-Production performance mode: given a rate, p1 and diameter, find p2

e.g. p1 = 125 bara, d = 15 mm, qg = 500 E03 Sm3/d

-Production performance mode : given a rate, p2 and diameter, find p1

e.g. p2 = 50 bara, d = 15 mm, qg = 1 E06 Sm3/d

-Design mode: Given a rate, p1,p2, find diameter

e.g. p1 = 200 bara, P2 = 120 bara, qg = 1e06 Sm3/d

the choke model works with input p1,p2,d, and outputs qg. For all these cases we need to use a solver because the calculation is implicit

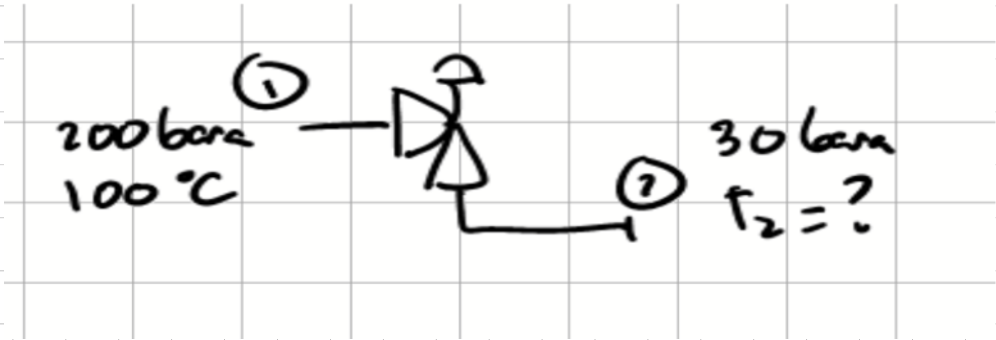
use goal seek to change the cells in violet to minimize the error

Gas Gravity, [-]	0.55							
k, Adiabatic Constant [-]	1.300							
T1, choke inlet temperature [C]	70							
y_c Critical Ratio [-]	0.546		Adjusted					
						Desired	Error	
	p1 [bara]	p2 [bara]	d [mm]	y (p2/p1) [-]	qsc [Sm3/d]	qsc [Sm3/d]		dp [bar]
Case 1	125.0	50.0	15.00	0.400	406.6E+3	500.0E+3	93.4E+3	75
Case 2	319.4	50.0	15.00	0.157	1.0E+6	1.0E+6	9.4E-6	269
Case 3	200.0	120.0	18.65	0.600	1.0E+6	1.0E+6	-407.0E-9	80

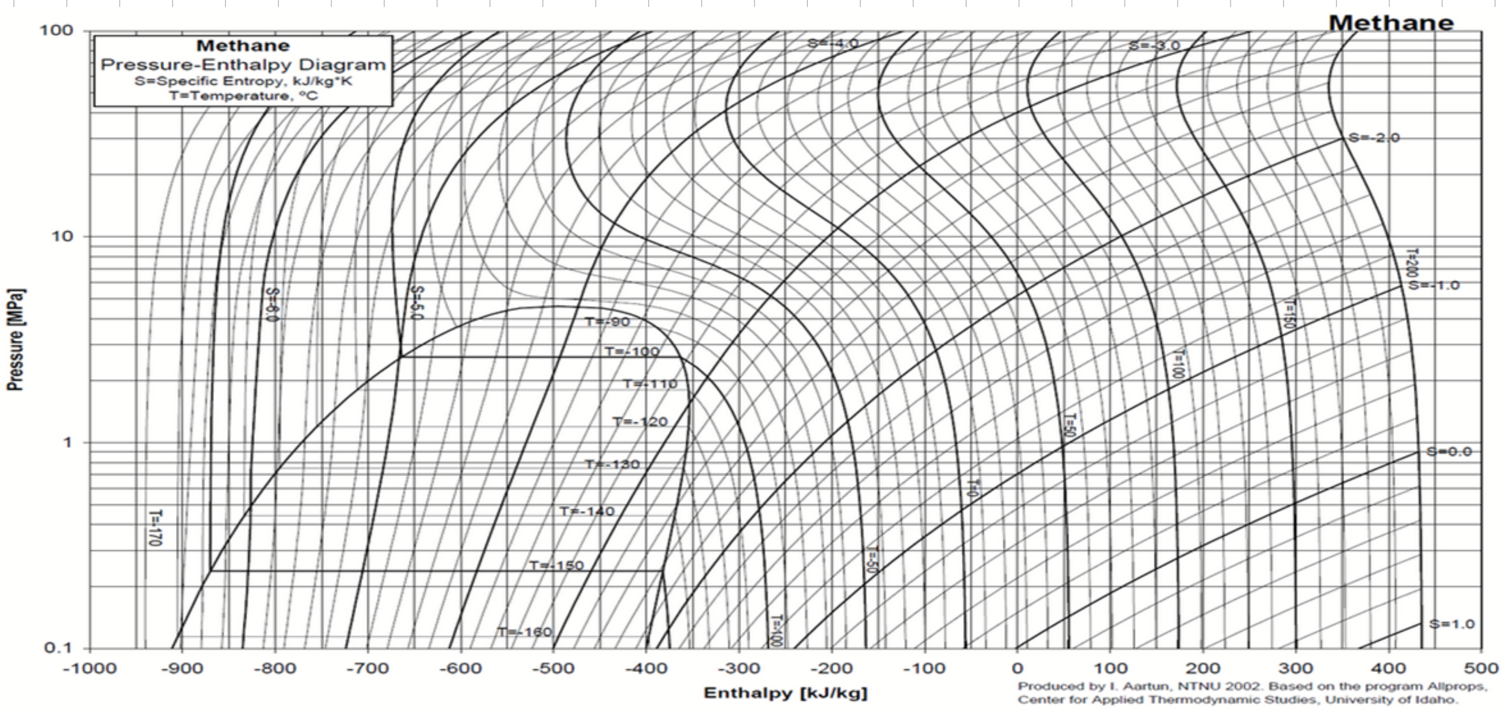
It is not possible to find a solution for 1, since it is in the critical regime and the rate comes determined by the inlet pressure (p2 does not affect the rate)

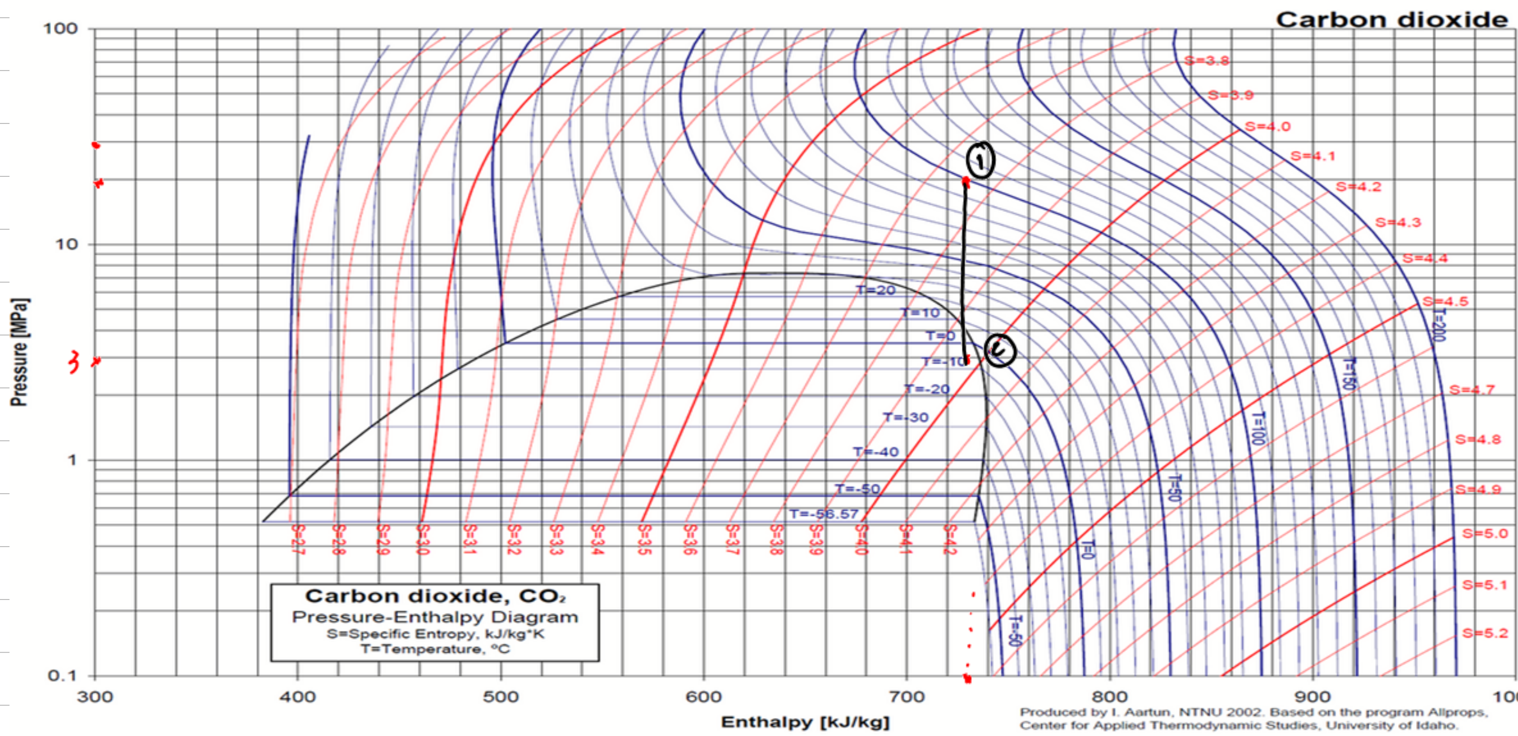
Activity 2:

repeat:



using CO_2





$h_1 = 730 \ \frac{kJ}{kg}$

$\frac{V_1^2}{2} = \frac{400}{2} = 200 \ m^2/s^2 = 0.2 \ kJ/kg$

$V = 20 \ m/s$

$\frac{J}{kg} = \frac{N \cdot m}{kg} = \frac{kg \ m/s^2 \cdot m}{kg} = \frac{m^2}{s^2}$

$h_1 + \frac{V_1^2}{2} = h_2 + \frac{V_2^2}{2}$

$730 \ kJ/kg + 0.2 = h_2 + 0.8$

$h_2 \approx 730$

$\frac{V_2^2}{2} = \frac{1600}{2} = 800 \ m^2/s = 0.8 \ kJ/kg$

$V_2 = 40 \ m/s$

$T_2 \approx 0 - (-10) \ °C$!

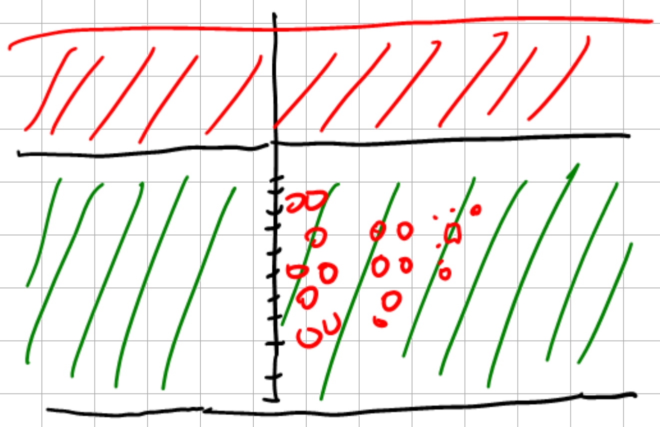
the iso-temperature curves for the CO_2 chart are more "deformed" for the T-p region of interest than in the CH_4 chart. This is because the saturation dome is more to the right. This causes big changes in temperature in isoenthalpic pressure expansion processes.

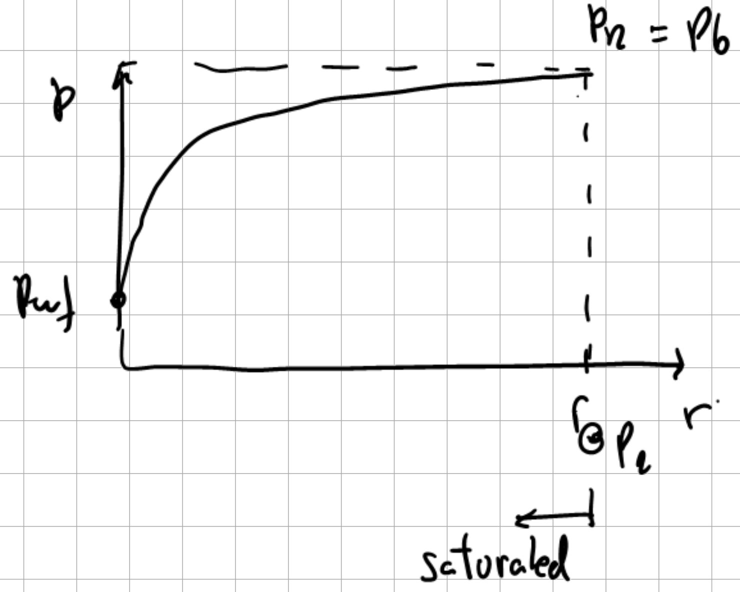
The kinetic energy term is very small!

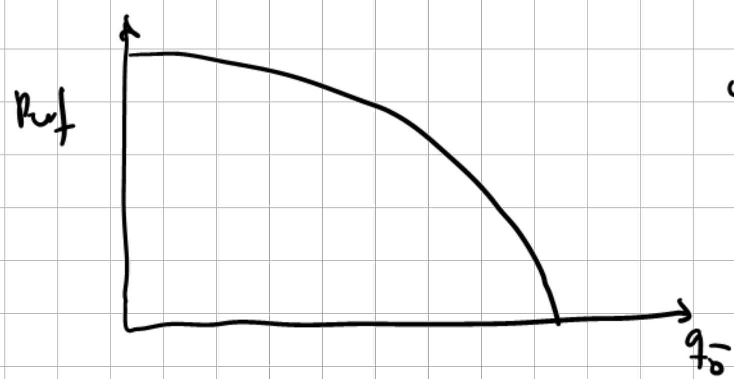
Saturated oil

$P_R = P_b$ @ T_R

solution-gas drive







what equation ?

$$\sim q_o = C\left(P_R^2 - P_{wf}^2\right)$$

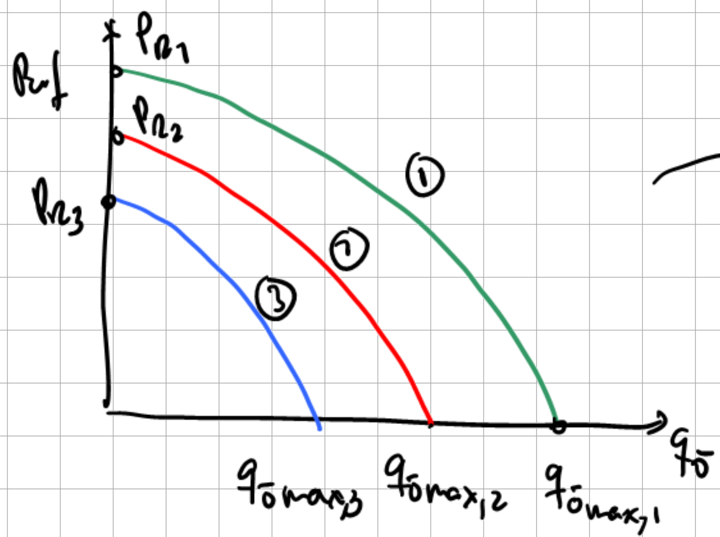
$$q_o = J\left(P_R - P_{wf}\right)$$

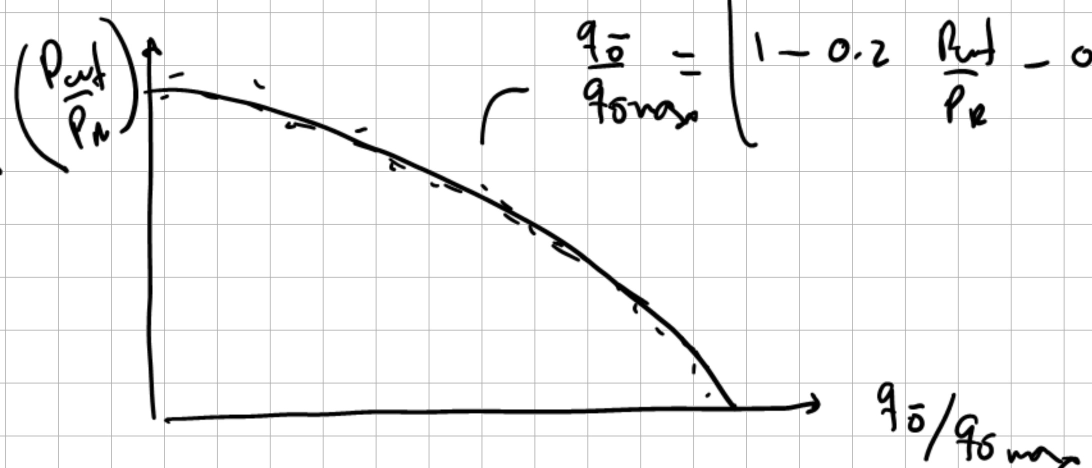
?

Reservoir simulation → 1968 Vogel

Inflow Performance Relationships for Solution-Gas Drive Wells

J. V. VOGEL
MEMBER AIME
SHELL OIL CO.
BAKERSFIELD, CALIF.





$$\frac{q_o}{q_{o max}} = \left[1 - 0.2\,\frac{P_{wf}}{P_R} - 0.8\left(\frac{P_{wf}}{P_R}\right)^2\right]$$

q_o	P_{wf}
□	□
□	□
□	□

→

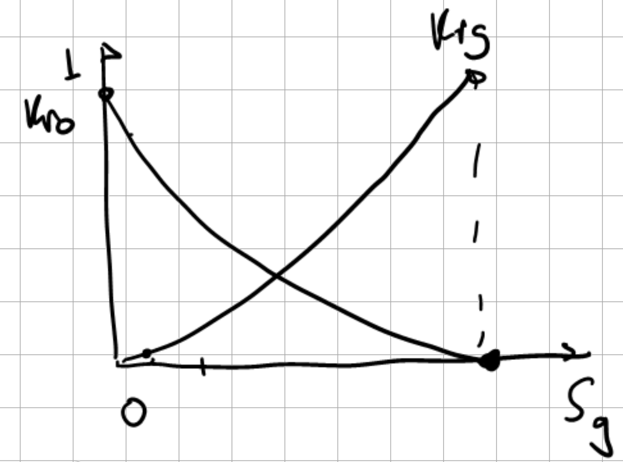
$\frac{q_o}{q_{o max}}$	$\frac{P_{wf}}{P_R}$

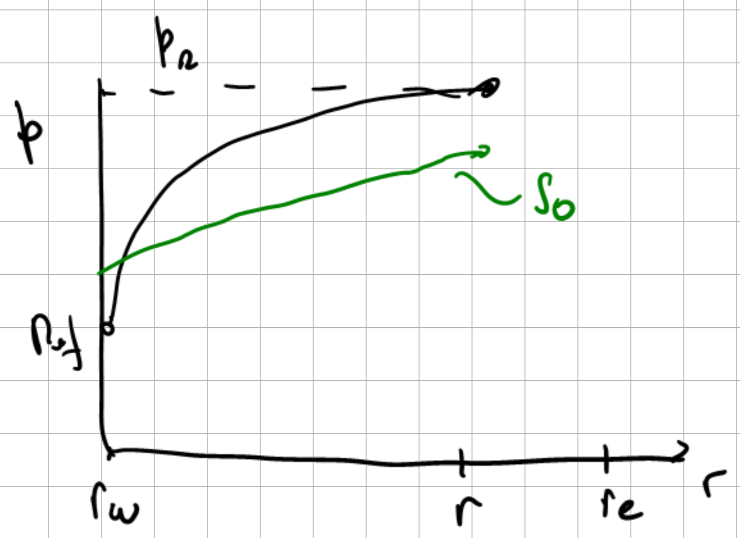
Analytical derivation

$$q_o = \frac{h \; k}{1868\left(\ln\frac{r_e}{r_w} - 0.75 + S\right)} \qquad \int_{P_{wf}}^{P_R} \frac{k_{ro}}{\mu_o B_o}\,dp$$

effective permeability $(k \cdot k_{ro})$

$k_{ro} = f(S_o)$

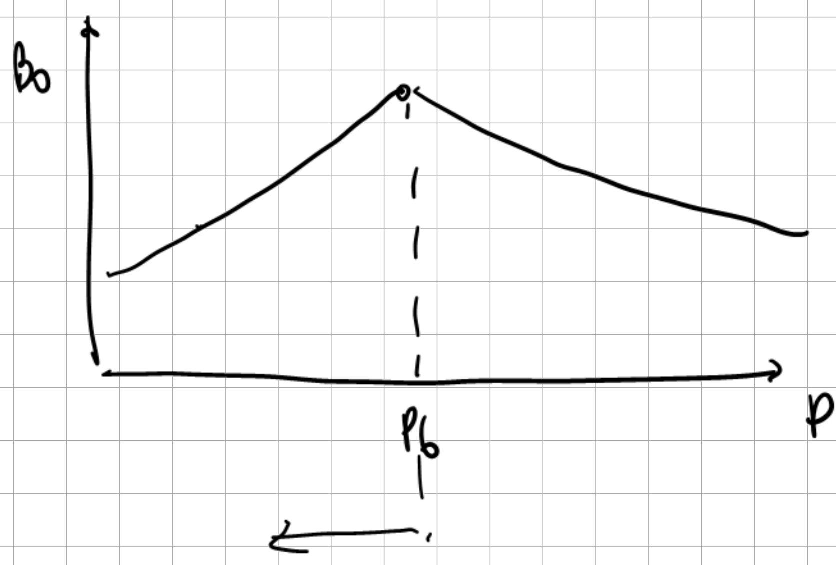


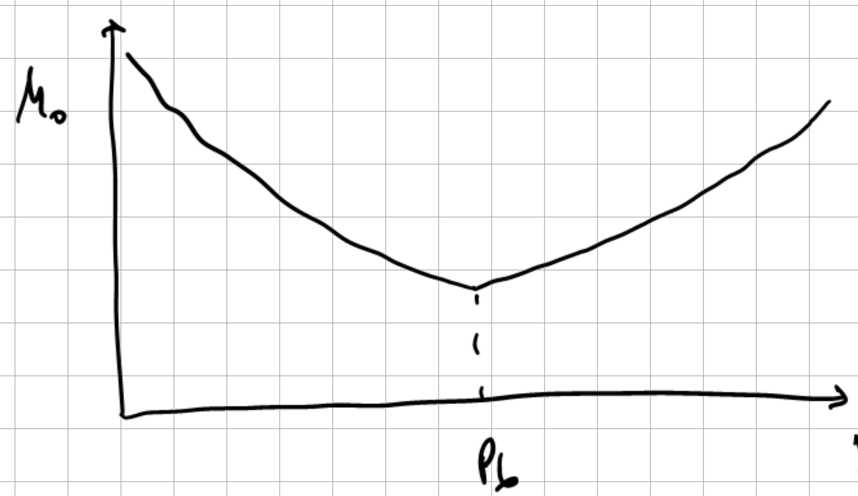


$S_o = f(p) \longrightarrow k_{ro} = f(p)$

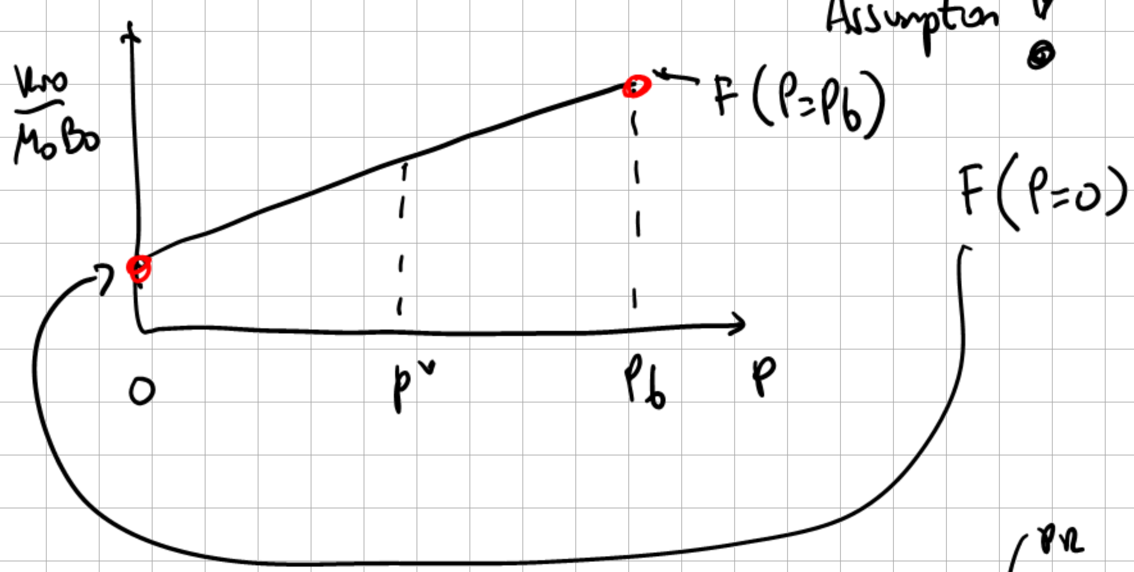
$$\int_{P_{wf}}^{P_R} \frac{k_{ro}}{\mu_o B_o}\,dp$$

$k_{ro} = f(S_o) = f(p)$





Assumption !



? $P = P_b$ single phase oil

$k_{ro} = 1$

$$\int_{P_{wf}}^{P_R} F(p)\,dp$$

$$F(P) = F(P=0) + \frac{F(P_b) - F(P=0)}{(P_b - 0)}\left(P^* - 0\right)$$

$$\int_{P_{wf}}^{P_R} (a + b\,x)\,dx$$

$$F(p) = F(p=0) + [F(p_R) - F(p=0)] \cdot \frac{p}{p_R} \quad \text{EQ. 2-16}$$

Therefore, the solution of the pressure function integral will have a linear term in addition to the quadratic term:

$$\int_{p_{wf}}^{p_R} F(p)dp = F(p=0) \cdot (p_R - p_{wf}) + [F(p_R) - F(p=0)] \cdot \frac{1}{p_R \cdot 2}(p_R{}^2 - p_{wf}{}^2) \quad \text{EQ. 2-17}$$

Expanding terms:

$$\int_{p_{wf}}^{p_R} F(p)dp = F(p=0) \cdot p_R - F(p=0) \cdot p_{wf} + [F(p_R) - F(p=0)] \cdot \frac{1}{p_R \cdot 2}(p_R{}^2 - p_{wf}{}^2) \quad \text{EQ. 2-18}$$

$$\int_{p_{wf}}^{p_R} F(p)dp = F(p=0) \cdot p_R - F(p=0) \cdot p_{wf} + F(p_R) \cdot \frac{p_R}{2} - F(p_R) \cdot \frac{p_{wf}{}^2}{p_R \cdot 2} - F(p=0) \cdot \frac{p_R}{2} + F(p=0) \cdot \frac{p_{wf}{}^2}{p_R \cdot 2} \quad \text{EQ. 2-19}$$

Grouping terms by pressure:

$$\int_{p_{wf}}^{p_R} F(p)dp = [F(p=0) + F(p_R)] \cdot \frac{p_R}{2} - F(p=0) \cdot p_{wf} - \frac{[F(p_R) - F(p=0)]}{2} \cdot \frac{p_{wf}{}^2}{p_R} \quad \text{EQ. 2-20}$$

Dividing by $[F(p=0) + F(p_R)] \cdot \frac{p_R}{2}$

$$\frac{2}{[F(p=0) + F(p_R)] \cdot p_R} \cdot \int_{p_{wf}}^{p_R} F(p)dp = 1 - \frac{F(p=0) \cdot 2}{[F(p=0) + F(p_R)]} \cdot \frac{p_{wf}}{p_R} - \frac{[F(p_R) - F(p=0)]}{[F(p=0) + F(p_R)]} \cdot \left(\frac{p_{wf}}{p_R}\right)^2 \quad \text{EQ. 2-21}$$

Defining a variable "V"

$$V = \frac{F(p=0) \cdot 2}{[F(p=0) + F(p_R)]} \quad \text{EQ. 2-22}$$

Therefore:

$$1 - V = \frac{F(p_R) - F(p=0)}{[F(p=0) + F(p_R)]} \quad \text{EQ. 2-23}$$

Substituting back in the integral of the pressure function:

$$\frac{2}{[F(p=0) + F(p_R)] \cdot p_R} \cdot \int_{p_{wf}}^{p_R} F(p)dp = 1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2 \quad \text{EQ. 2-24}$$

Substituting Eq. 2-24 back in the IPR equation:

$$q_{\breve{o}} = \frac{k \cdot h \cdot [F(p=0) + F(p_R)] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2}\left[1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2\right] \quad \text{EQ. 2-25}$$

Making $q_{\breve{o},max}$:

$$q_{\breve{o},max} = \frac{k \cdot h \cdot [F(p=0) + F(p_R)] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2} \quad \text{EQ. 2-26}$$

The following expression is obtained:

$$q_o = q_{o,max}\left[1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

Vogel says $V = 0.2$ →

Vogel found this same equation using data points generated with reservoir simulator, with V = 0.2.

Using Eq. 2-22, and assuming V = 0.2, $F(p=0)$ is then:

$$F(p=0) = \frac{F(p_R)}{9} \quad \text{EQ. 2-28}$$

Eq. 2-26 can then be further simplified:

$$q_{o,max} = \frac{k \cdot h \cdot \left[\frac{10}{9} \cdot F(p_R)\right] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2} = \frac{k \cdot h \cdot \left[\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{@p_R}\right] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 1.8} = \frac{J}{1.8} \cdot pR \quad \text{EQ. 2-29}$$

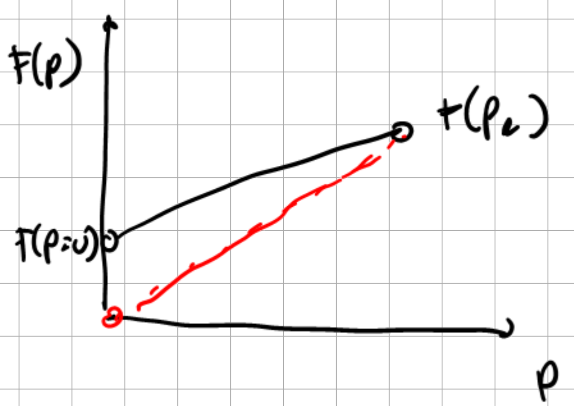
The Isochronal Testing of Oil Wells

By

M. J. Fetkovich, Member AIME, Phillips Petroleum Co.

1973

Fetkovich proposed



V = 0

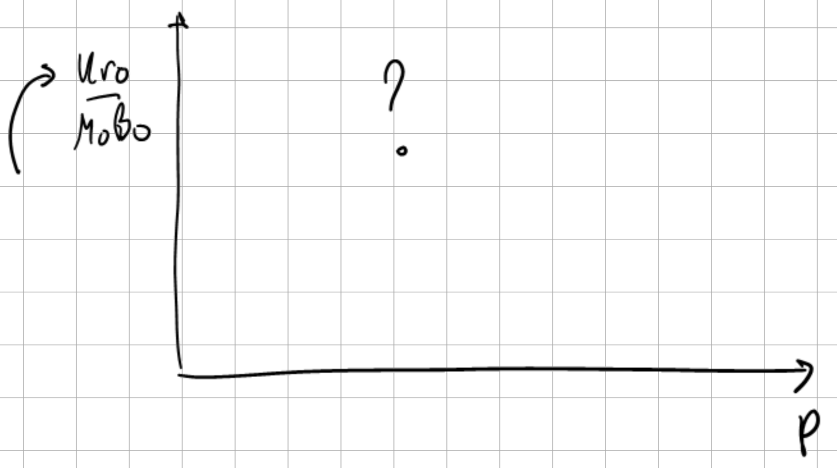
$$\frac{q_o}{q_{o,max}} = \left[1 - \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

$$q_{o,max} = \frac{k \cdot h \cdot [F(p_R)] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2} = \frac{k \cdot h \cdot \left[\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{@p_R}\right] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2} = \frac{J}{2} \cdot pR$$

$$q_o = \frac{J}{2} p_R \left(1 - \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

$$q_o = \frac{J}{2} \left[p_R - \frac{(p_{wf})^2}{p_R}\right]$$

$$q_o = \frac{J}{2 p_R} \left[p_R^2 - p_{wf}^2\right] \rightsquigarrow q_g = C\left(p_R^2 - p_{wf}^2\right)$$



(1941) Evinger and Muskat

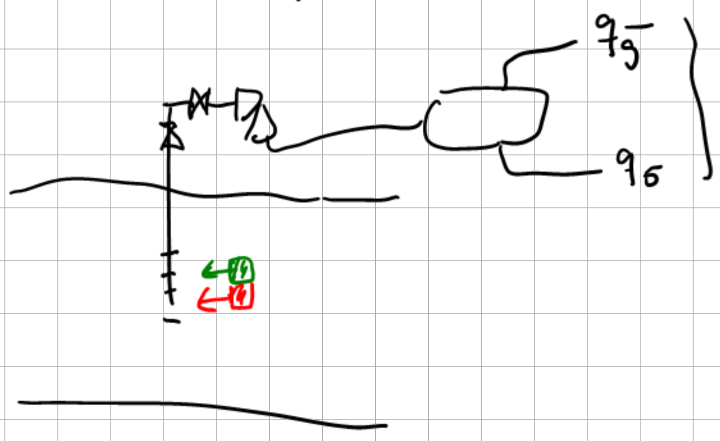
Calculation of Theoretical Productivity Factor

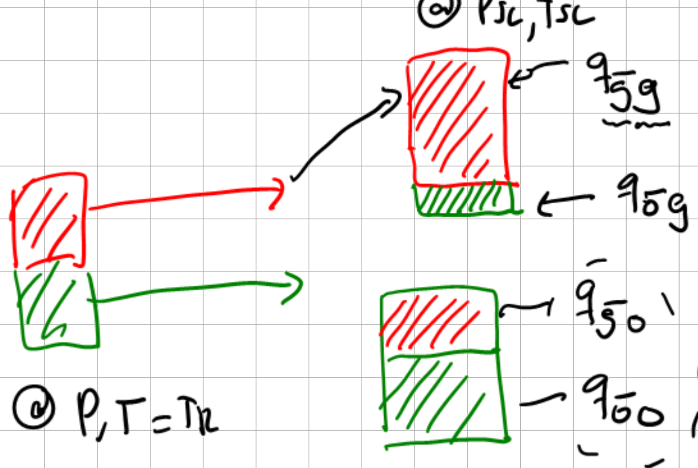
By H. H. Evinger* and M. Muskat*

(New York Meeting, February 1941)

$k_{ro} = f(p)$

$$\frac{q_{\bar g}}{q_{\bar o}} \qquad GOR = R_p = \frac{q_{\bar g}}{q_{\bar o}} = \frac{q_{\bar g g} + q_{\bar g o}}{q_{\bar o o}} = \frac{q_{\bar g g}}{q_{\bar o o}} + \frac{q_{\bar g o}}{q_{\bar o o}} = \frac{q_{\bar g g}}{q_{\bar o o}} + R_s(p)$$





$q_{\bar g} = q_{\bar g g} + q_{\bar g o}$

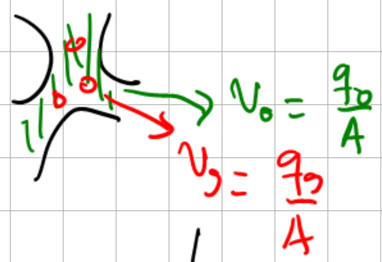
$q_{\bar o} = q_{\bar o g} + q_{\bar o o}$

very small

$q_{\bar o g} << q_{\bar o o}$

$q_{\bar o} = q_{\bar o o}$

$$\frac{q_{\bar g g}}{q_{\bar o o}} = \frac{q_g}{B_g}\frac{B_o}{q_o} = \frac{k_{rg}}{k_{ro}}\frac{\mu_o B_o}{\mu_g B_g}$$

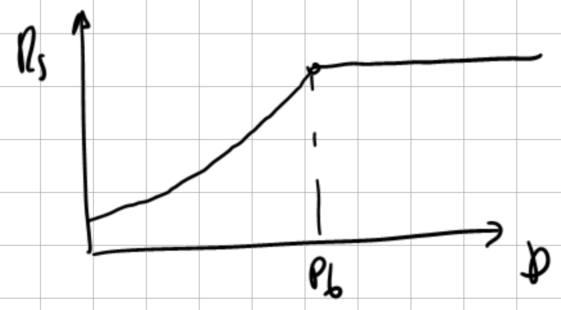


$$R_s = \frac{q_{\bar g o}}{q_{\bar o o}} \qquad R_s(p) \text{ solution gas oil ratio}$$

$$\frac{q_g}{q_o} = \frac{k_{rg}}{\mu_g}\frac{\mu_o}{k_{ro}}$$

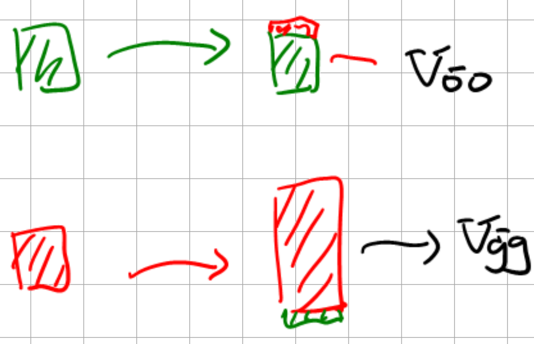
$$v_g = \frac{k_{rg} k}{\mu_g}\frac{dP}{dx}$$

$$v_o = \frac{k_{ro} k}{\mu_o}\frac{dP}{dx}$$



$$\frac{V_o}{V_{\bar o}} = B_o = \frac{q_o}{q_{\bar o o}}$$

$$\frac{V_g}{V_{\bar g}} = B_g = \frac{q_g}{q_{\bar g g}}$$



$$R_p = \frac{k_{rg}}{k_{ro}}\frac{\mu_o B_o}{\mu_g B_g} + R_s(p)$$

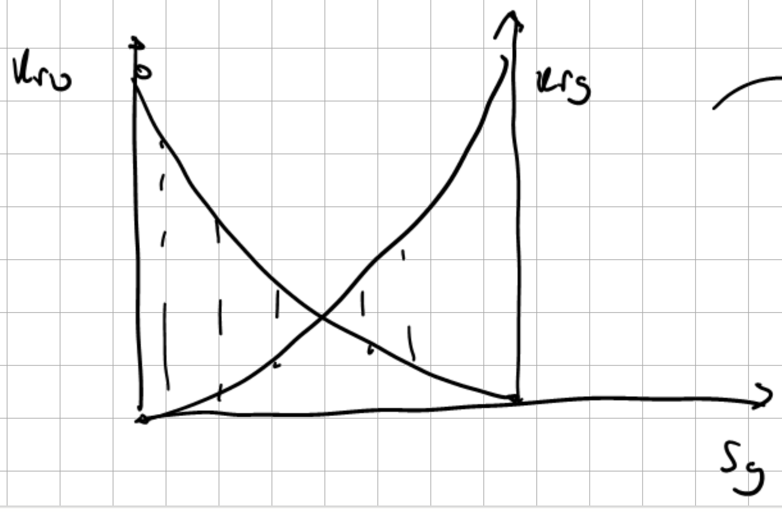
f(p)

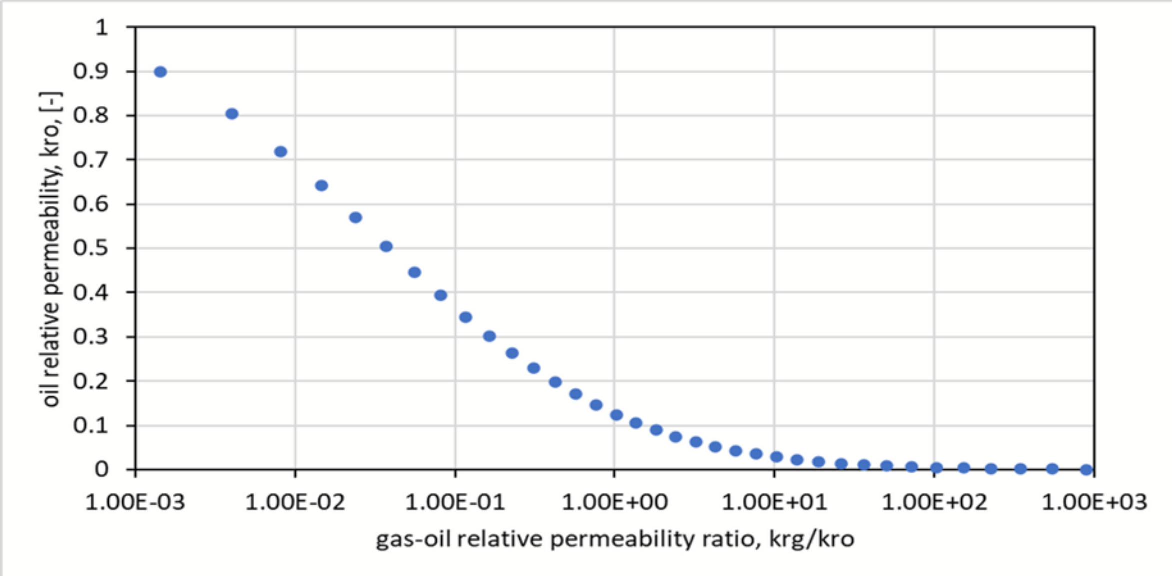
measured

$$\frac{k_{rg}}{k_{ro}} = \frac{\mu_g B_g}{\mu_o B_o}(R_p - R_s) \qquad (1)$$

f(p) !

But we need k_{ro}, NOT $\frac{k_{rg}}{k_{ro}}$!



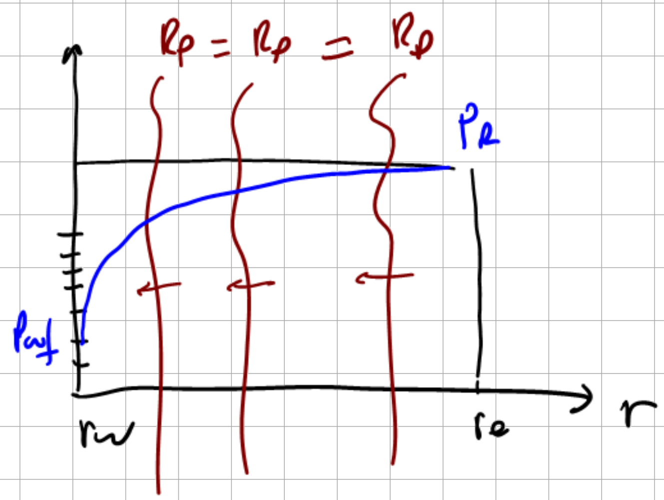


(2)

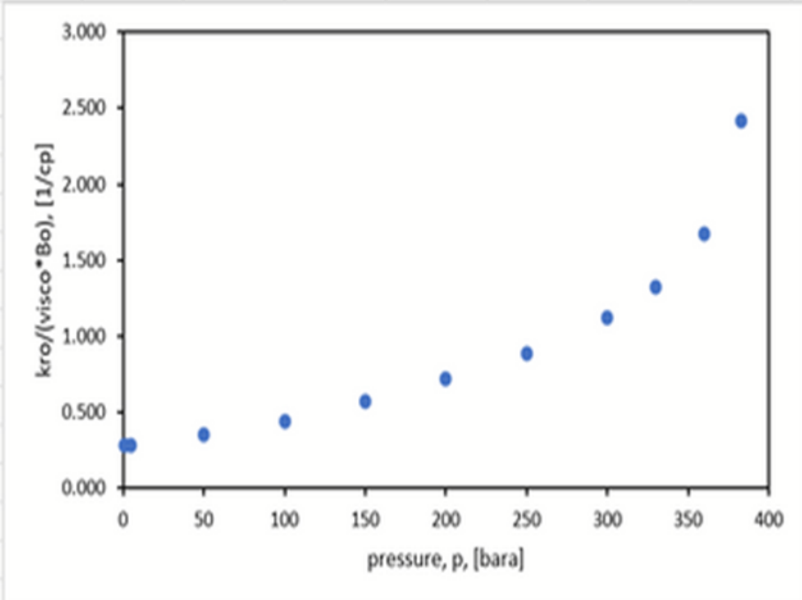
1) from (1) at p ⇝ $\frac{k_{rg}}{k_{ro}}$

2) from (2) with $\frac{k_{rg}}{k_{ro}}$ ⇝ k_{ro}

3) k_{ro} $f(p)$



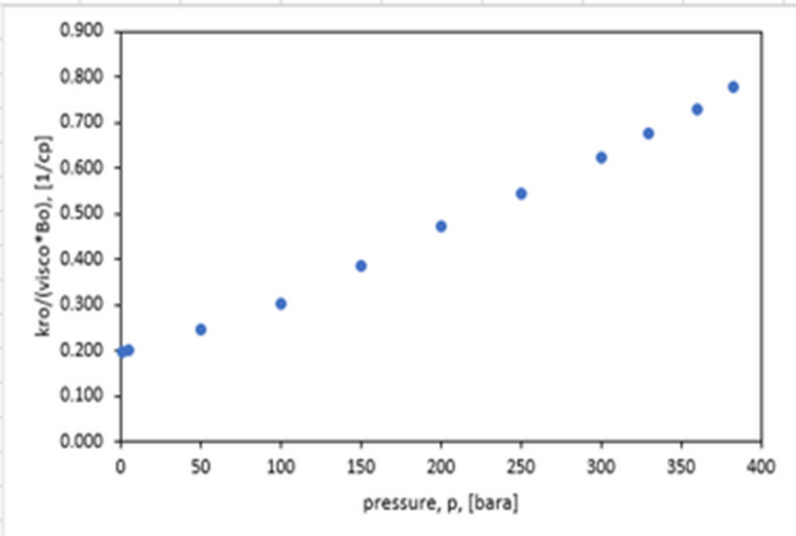
Rp	[Sm3/Sm3]	300							
COLUMN	4	6	3	5	2				
p	Rs	viscg	Bg	Visco	Bo	krg/kro	kro	kro/(visco*Bo)	So
[bara]	[Sm3/Sm3]	[cp]	[m3/Sm3]	[cp]	[m3/Sm3]	[-]	[-]	[1/cp]	[-]
1	0.5	1.12E-02	2.66E-02	1.4	1.2	5.54E-02	4.49E-01	0.277	0.60
5	2.6	1.14E-02	2.59E-02	1.4	1.2	5.50E-02	4.50E-01	0.282	0.60
50	25.5	1.32E-02	1.81E-02	1.1	1.2	4.96E-02	4.67E-01	0.352	0.60
100	48.8	1.58E-02	1.22E-02	0.9	1.2	4.46E-02	4.82E-01	0.443	0.60
150	76.4	1.82E-02	8.20E-03	0.7	1.3	3.81E-02	5.03E-01	0.573	0.61
200	107.2	2.14E-02	6.25E-03	0.5	1.4	3.65E-02	5.09E-01	0.722	0.61
250	143.9	2.51E-02	5.29E-03	0.4	1.5	3.59E-02	5.12E-01	0.888	0.61
300	187.9	2.90E-02	4.69E-03	0.3	1.6	3.23E-02	5.29E-01	1.121	0.62
330	220.4	3.15E-02	4.45E-03	0.3	1.7	2.65E-02	5.57E-01	1.322	0.62
360	258.3	3.41E-02	4.26E-03	0.2	1.8	1.61E-02	6.29E-01	1.672	0.64
383	292.6	3.60E-02	4.14E-03	0.2	1.9	3.19E-03	8.34E-01	2.414	0.67



NOT LINEAR!!!

For higher GOR

Rp	[Sm3/Sm3]	800							
COLUMN	4	6	3	5	2				
p	Rs	viscg	Bg	Visco	Bo	krg/kro	kro	kro/(visco*Bo)	So
[bara]	[Sm3/Sm3]	[cp]	[m3/Sm3]	[cp]	[m3/Sm3]	[-]	[-]	[1/cp]	[-]
1	0.5	1.12E-02	2.66E-02	1.4	1.2	1.48E-01	3.17E-01	0.196	0.56
5	2.6	1.14E-02	2.59E-02	1.4	1.2	1.47E-01	3.17E-01	0.199	0.56
50	25.5	1.32E-02	1.81E-02	1.1	1.2	1.40E-01	3.24E-01	0.244	0.56
100	48.8	1.58E-02	1.22E-02	0.9	1.2	1.33E-01	3.30E-01	0.304	0.56
150	76.4	1.82E-02	8.20E-03	0.7	1.3	1.23E-01	3.40E-01	0.387	0.56
200	107.2	2.14E-02	6.25E-03	0.5	1.4	1.31E-01	3.32E-01	0.471	0.56
250	143.9	2.51E-02	5.29E-03	0.4	1.5	1.51E-01	3.14E-01	0.545	0.56
300	187.9	2.90E-02	4.69E-03	0.3	1.6	1.77E-01	2.95E-01	0.624	0.55
330	220.4	3.15E-02	4.45E-03	0.3	1.7	1.93E-01	2.85E-01	0.675	0.54
360	258.3	3.41E-02	4.26E-03	0.2	1.8	2.09E-01	2.75E-01	0.730	0.54
383	292.6	3.60E-02	4.14E-03	0.2	1.9	2.19E-01	2.69E-01	0.778	0.54



LINEAR??

$$q_{\bar{o}} = \frac{k \cdot h}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right)} \underbrace{\int_{p_{wf}}^{p_R} \frac{k_{ro}}{\mu_o \cdot B_o} dp}_{\left[m(p_R) - m(p_{wf})\right]} =$$

$$\int_0^{p_{wf}} \frac{k_{ro}}{\mu_o B_o} dp = m(p_{wf})$$

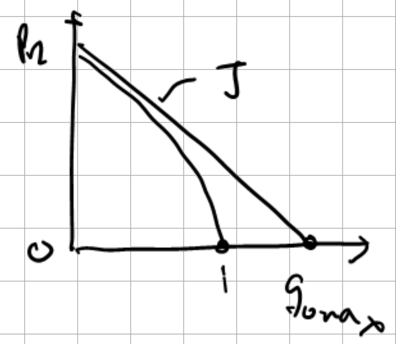
Not the same gas m function !

$$\int \frac{p}{z \mu_g} dp$$

Vogel ($V = 0.2$)

$$q_{\bar{o}} = q_{\bar{o},max} \left[1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

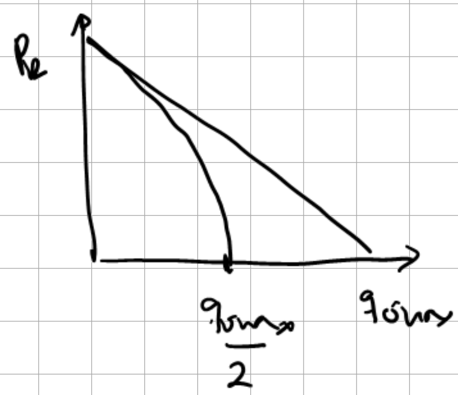
$$\underbrace{\frac{\overbrace{k \cdot h \cdot \left[\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{@pR}\right]}^{J} \cdot (p_R - 0)}{18.68 \cdot \left(ln\left(\frac{r_e}{r}\right) - 0.75 + s\right) \cdot 1.8}}_{q_{\bar{o}max}} = \frac{J}{1.8} \cdot pR$$



Fetkovich

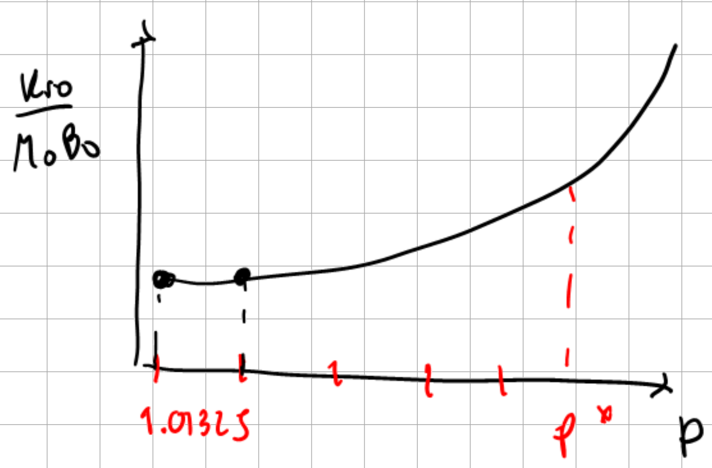
$$q_{\bar{o}} = q_{\bar{o},max} \left[1 - \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

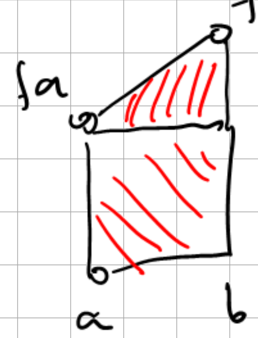
$$\frac{k \cdot h \cdot \left[\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{@pR}\right] \cdot p_R}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right) \cdot 2} = \frac{J}{2} \cdot pR$$



oil m function in VBA;

```
Function m_function_oil(p, col, Matrix As Range)
    'p in bara
    'n number of intervals to use in the integration
    p1 = 1.01325
    p2 = p
    If p2 - p1 > 40 Then
        n = Round((p2 - p1) / 10, 0)
    Else
        n = 10
    End If
    DP = (p2 - p1) / n
    pj = p1
    Sum = 0
    fa = tabinterpol(pj, col, Matrix)
    For J = 1 To n
        pj = pj + DP
        fb = tabinterpol(pj, col, Matrix)
        Sum = Sum + (DP * (fa + fb)) * 0.5
        fa = fb
    Next
    m_function_oil = Sum
End Function
```

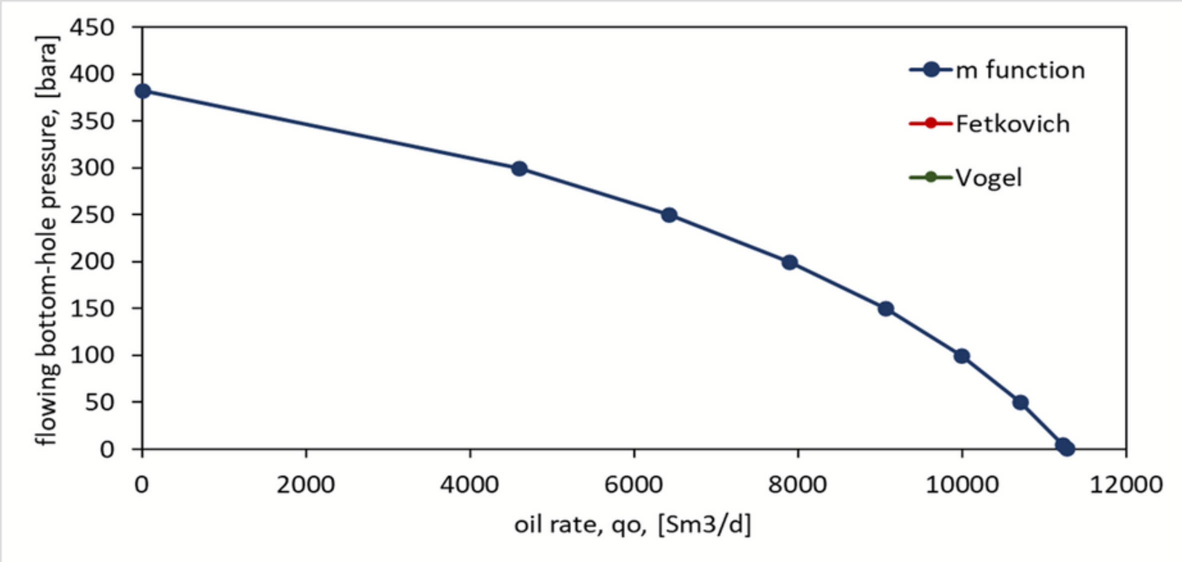




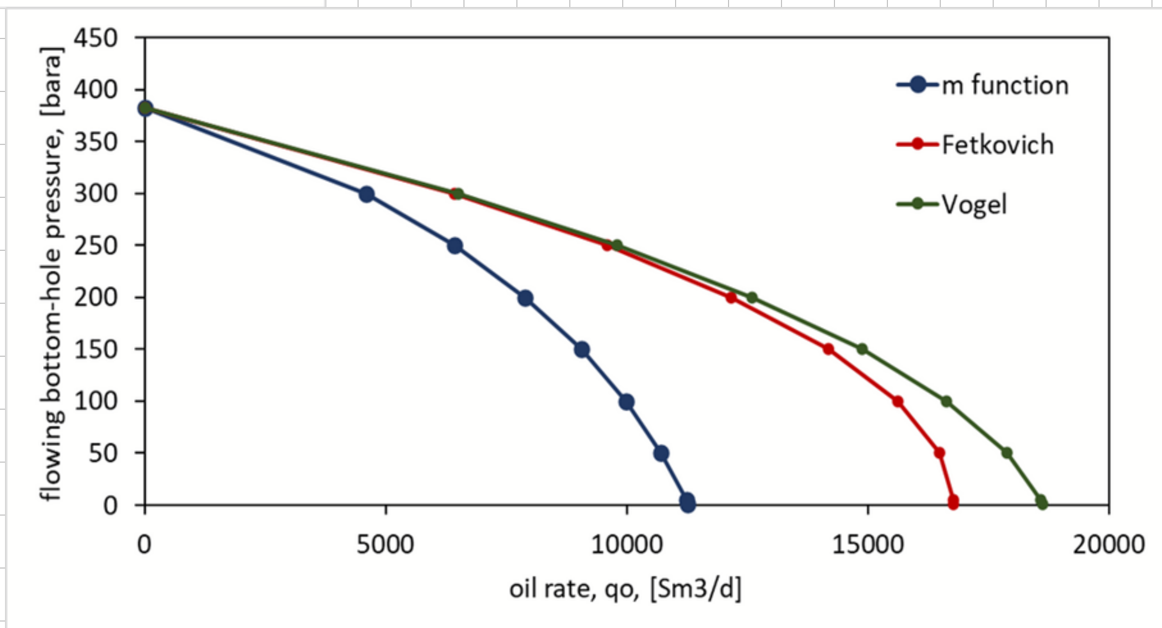
fb (from interpolation on table)

$$Area = (fa + fb) \cdot \frac{(b-a)}{2}$$

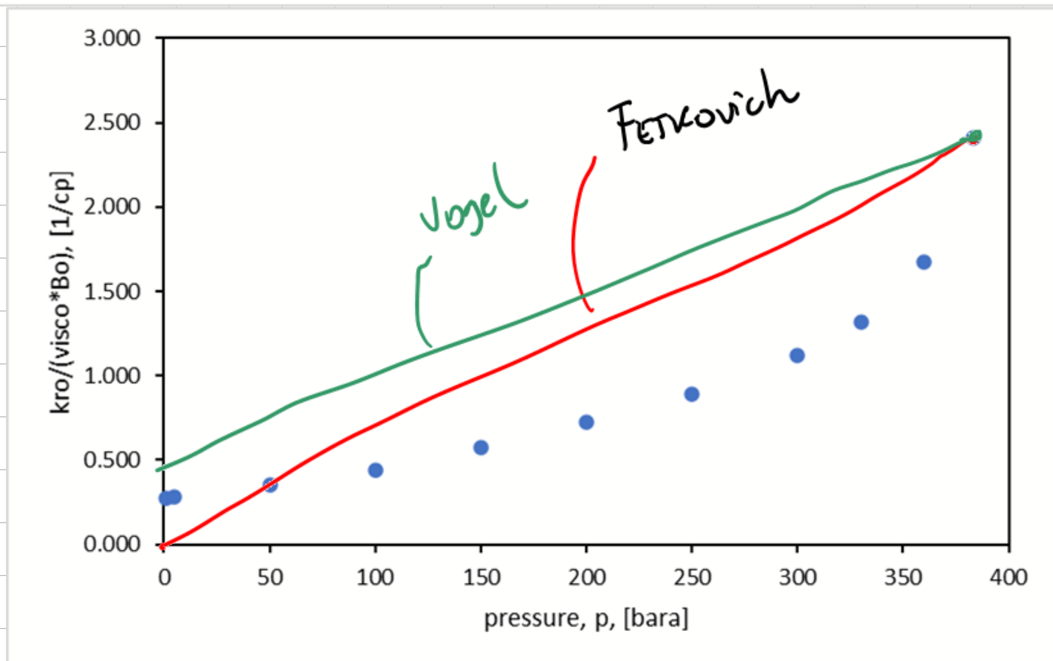
```
Function ipr_sat_oil_qo_m_function(k, h, re, rw, s, mpR, mPwf)
    'ipr_sat_oil, oil rate in Sm3/d, calculated with the m function
    'k, permeability, [md]
    'h, layer height, [m]
    're external radius of reservoir [m]
    'rw, wellbore radius [m]
    's, skin factor [-]
    'mpR, m function at reservoir pressure [bara/cp]
    'mpwf, m functino at flowing bottom-hole pressure [bara/cp]
    ipr_sat_oil_qo_m_function = k * h * (mpR - mPwf) / ((Log(re / rw) - 0.75 + s) * 18.68)
End Function
```



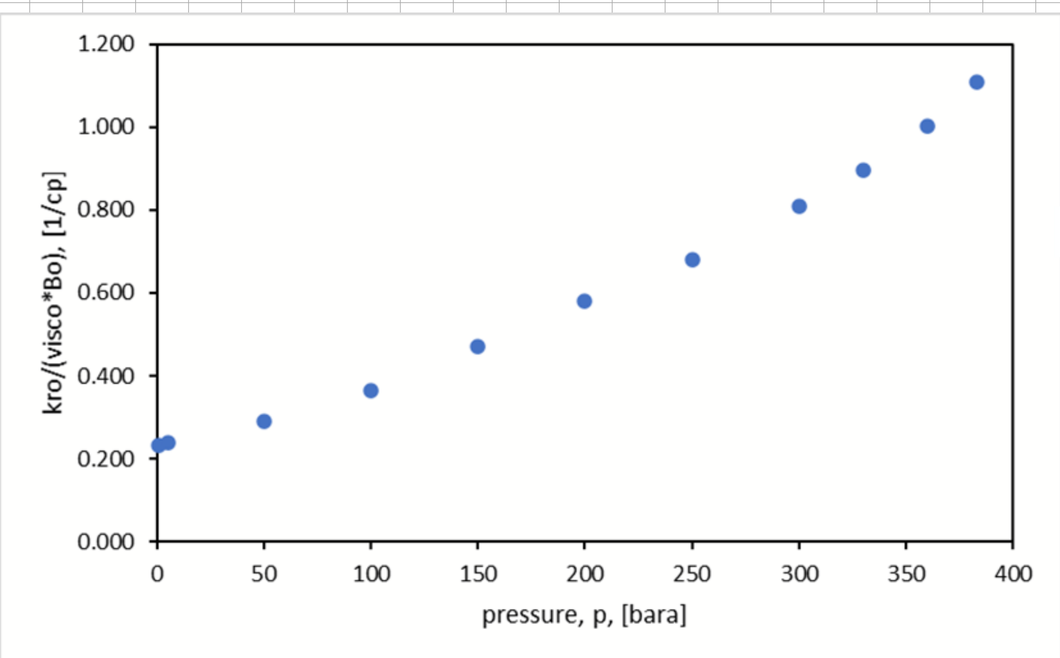

```
Function ipr_sat_oil_qo_Fetkovich(k, h, re, rw, s, pR, Pwf, Bo_pR, visco_pR, kro_pR)
    'ipr_sat_oil, oil rate in Sm3/d, calculated with the m function
    'k, permeability, [md]
    'h, layer height, [m]
    're external radius of reservoir [m]
    'rw, wellbore radius [m]
    's, skin factor [-]
    'pR, reservoir pressure [bara]
    'pwf, flowing bottom-hole pressure [bara]
    'kro_pR oil relative permeability at reservoir pressure, [-]
    'visco_pR oil viscosity at reservoir pressure [cp]
    'Bo_pR oil formation volume factor at reservoir pressure, [m3/Sm3]
    J = k * h * (kro_pR / (visco_pR * Bo_pR)) / ((Log(re / rw) - 0.75 + s) * 18.68)
    qomax = J * (pR - 0) / 2
    ipr_sat_oil_qo_Fetkovich = qomax * (1 - (Pwf / pR) ^ 2)
End Function
```




```
Function ipr_sat_oil_qo_Vogel(k, h, re, rw, s, pR, Pwf, Bo_pR, visco_pR, kro_pR)
    'ipr_sat_oil, oil rate in Sm3/d, calculated with the m function
    'k, permeability, [md]
    'h, layer height, [m]
    're external radius of reservoir [m]
    'rw, wellbore radius [m]
    's, skin factor [-]
    'pR, reservoir pressure [bara]
    'pwf, flowing bottom-hole pressure [bara]
    'kro_pR oil relative permeability at reservoir pressure, [-]
    'visco_pR oil viscosity at reservoir pressure [cp]
    'Bo_pR oil formation volume factor at reservoir pressure, [m3/Sm3]
    J = k * h * (kro_pR / (visco_pR * Bo_pR)) / ((Log(re / rw) - 0.75 + s) * 18.68)
    qomax = J * (pR - 0) / 1.8
    ipr_sat_oil_qo_Vogel = qomax * (1 - 0.2 * (Pwf / pR) - 0.8 * (Pwf / pR) ^ 2)
End Function
```



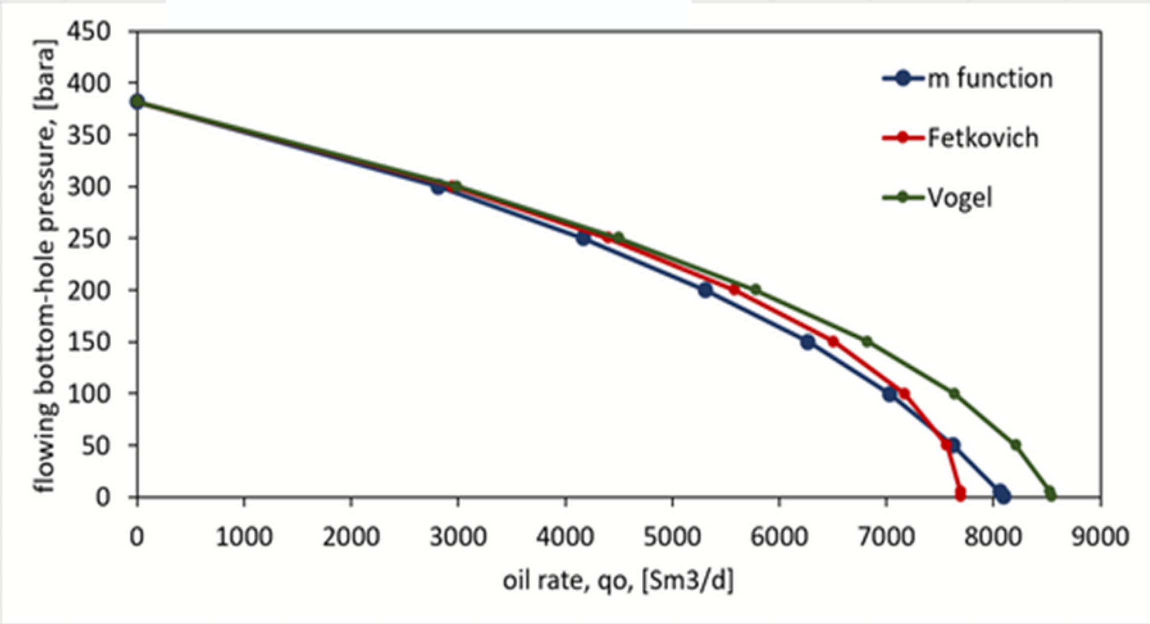
Changing the GOR (Rp) manually to 500 Sm3/Sm3

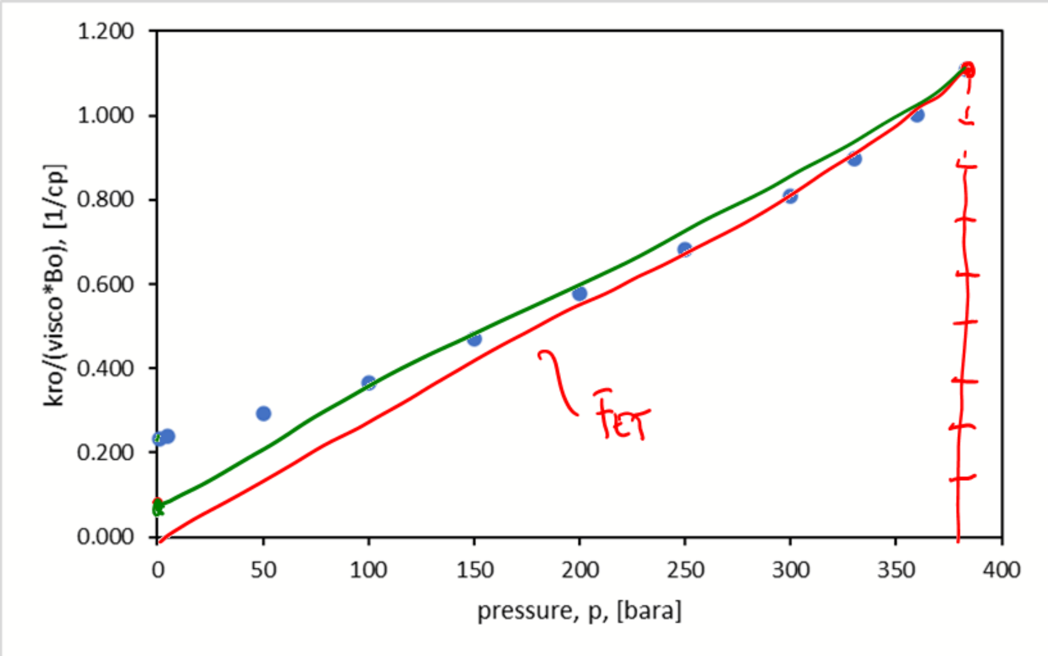


MORE LINEAR....

pwf [bara]	m(p) [bara/cp]	qo [Sm3/d]	qo - Fet [Sm3/d]	qo -Vogel [Sm3/d]	qo - Fet-v2 [Sm3/d]	qo -Vogel-v2 [Sm3/d]
382	222.6	0	0	0		
300	145.3	2810	2950	2990		
250	108.0	4166	4401	4503		
200	76.5	5312	5588	5782		
150	50.2	6268	6511	6826		
100	29.3	7028	7170	7637		
50	12.9	7625	7566	8212		
5	0.9	8059	7697	8530		
1	0.0	8094	7698	8549		

THE PREDICTION IS BETTER





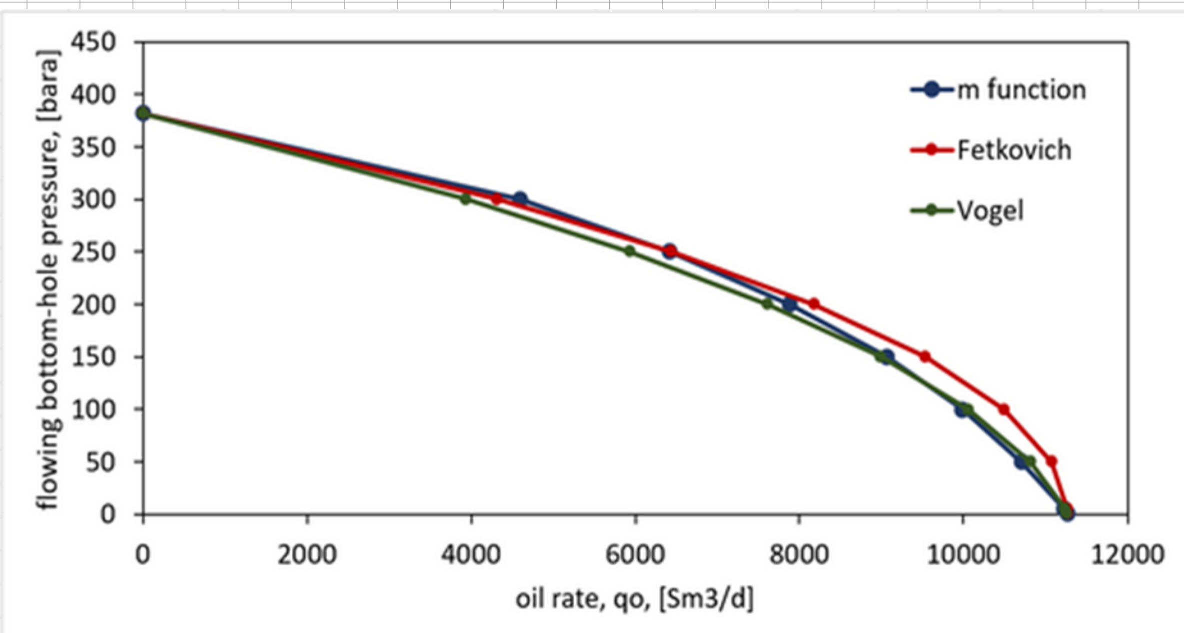
WE CHANGE THE RP BACK TO 300...

But, what if we use the q_{omax} from the m function equation? (11268 Sm³/d)

$$q_o = q_{omax}\left(1 - \left(\frac{P_{wf}}{P_R}\right)^2\right)$$

$$q_o = q_{omax}\left(1 - 0.2\left(\frac{P_{wf}}{P_R}\right) - 0.8\left(\frac{P_{wf}}{P_R}\right)^2\right)$$

pwf [bara]	m(p) [bara/cp]	qo [Sm3/d]	qo - Fet [Sm3/d]	qo -Vogel [Sm3/d]	qo - Fet-v2 [Sm3/d]	qo -Vogel-v2 [Sm3/d]
382	309.9	0	0	0	0	0
300	183.5	4596	6425	6511	4318	3938
250	133.3	6421	9584	9807	6442	5932
200	93.1	7884	12169	12592	8179	7617
150	60.7	9061	14180	14867	9530	8993
100	35.3	9985	15616	16631	10495	10060
50	15.4	10708	16477	17884	11075	10818
5	1.1	11227	16762	18576	11266	11236
1	0.0	11268	16765	18617	11267	11261



the prediction is improved considerably !

Lecture 20221011 - Class exercise

Problem 1: Selection of Inflow performance relationship equation for the "Borthne" saturated oil field

A small, saturated volatile oil reservoir will be produced using an unmanned platform with 4 well slots. The X-mas trees are on the platform. The platform has a separator with a constant pressure of 30 bar. Wells are equipped with wellhead chokes to regulate production. The separator is very close to the wellhead.

In this exercise, we will focus on well A01.

The reservoir engineering department has performed some preliminary studies and has provided well production profiles of oil, gas, reservoir pressure and flowing-bottomhole pressure (given in the Excel sheet attached). Unfortunately, after this, the reservoir engineer went on holidays (to the Bahamas) and is not available to help you.

Assume that all production comes from the oil layer (there is no coning from the gas cap)

Task 1:

For your production engineering calculations, you would like to find a suitable expression for IPR to represent the inflow. You are considering using an IPR of the form:

$$q_o = q_{\bar{o},max}\left[1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

From your lectures of TPG4245, you remember that V can usually be considered constant with depletion, but $q_{\bar{o},max}$ will vary.

Your main task is to find the behavior of $q_{\bar{o},max}$ versus reservoir pressure with the data provided by the reservoir engineering department. Consider several values of V, ranging from 0 (Fetkovich) to 1 (Linear PI).

Provide observations about your results.

In this exercise, instead of using reservoir, fluid and well properties and parameters to determine IPR, we will use production data "finding an IPR" means:

-Select a proper equation
-Find parameters in that equation for every time (typically pR, pwf and qo are input/calculated). In this case V and qomax are "equation parameters"

$$q_{\bar{o}} = q_{\bar{o},max}\left[1 - V\cdot\frac{p_{wf}}{p_R} - (1-V)\cdot\left(\frac{p_{wf}}{p_R}\right)^2\right]$$

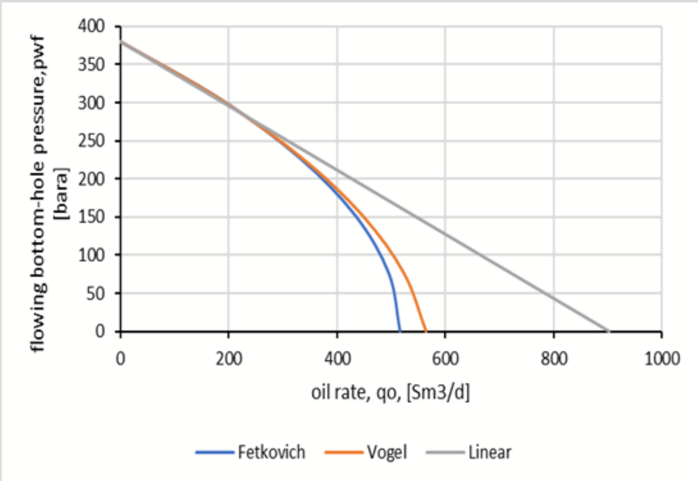
If we assume V and qomax change with depletion (varying with pR) then we have N equations, with N*2 unknowns (V and qomax for each time)

We cannot solve this!!

We assume V is known! we try with three values (0, 0.2 and 1)

Problem 1, Prof. Milan Stanko (NTNU)						Fet	Vogel	Linear
					V	0	0.2	1
time	pR	pwf	qg	qo	Rp	qomax		
[years]	[bara]	[bara]	[Sm3/d]	[Sm3/d]	[Sm3/Sm3]			
0.50	380.1	285.3	6.54E+04	225.0	290.4	515.4019	563.7462	902.2787
1.00	377.4	281.9	6.45E+04	225.0	286.7			

pR	[bara]	380.12		
qomax	[Sm3/d]	515.4	563.7	902.3
	V	0	0.2	1
pwf/pR	pwf	qo		
[-]	[bara]	[Sm3/d]		
1	380	0	0	0
0.8	304	186	185	180
0.6	228	330	334	361
0.4	152	433	446	541
0.2	76	495	523	722
0	0	515	564	902



The prediction of the three models is very similar for oil rates below 250 Sm3/d, but starts to deviate above it.

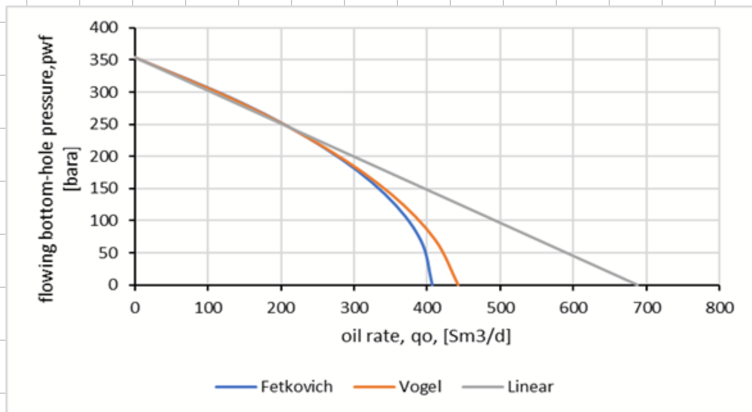
Task 2:

Well A01 will be produced in plateau mode, this means at a constant rate and then it eventually enters in decline. In the forecast calculated earlier by the reservoir engineering department, the plateau rate of the well is 225 Sm3/d. The plateau period ends between year 3 and year 3.5.

Your manager wishes to extend the plateau period by gas-lifting the well. Therefore, he would like you to conduct a study at year 3.5 to determine what flowing bottom-hole pressure value you need to maintain the rate of 225 Sm3/d. He will later use this information to determine if it is possible to achieve this pressure with gas-lift.
However, you are yet now sure about what IPR to use in this well. Using all possible IPRs calculated in task 1 for year 3.5, provide your manager a range of flowing bottom-hole pressures needed to provide the required rate.

Problem 1, Prof. Milan Stanko (NTNU)						Fet	Vogel	Linear
					V	0	0.2	1
time	pR	pwf	qg	qo	Rp	qomax		
[years]	[bara]	[bara]	[Sm3/d]	[Sm3/d]	[Sm3/Sm3]			
0.50	380.1	285.3	6.54E+04	225.0	290.4	515.4	563.7	902.3
1.00	377.4	281.9	6.45E+04	225.0	286.7	509.0	556.5	889.1
1.50	374.8	276.9	6.41E+04	225.0	285.0	495.4	541.4	861.4
2.00	369.7	271.6	6.40E+04	225.0	284.4	488.7	533.9	847.6
2.50	364.8	261.2	6.41E+04	225.0	284.8	461.8	503.8	792.4
3.00	359.6	249.0	6.50E+04	225.0	289.0	432.2	470.7	731.4
3.50	354.8	245.4	6.29E+04	211.9	296.7	406.4	442.6	687.5

pR	[bara]	354.79		
qomax	[Sm3/d]	406.4	442.6	687.5
	V	0	0.2	1
pwf/pR	pwf	qo		
[-]	[bara]	[Sm3/d]		
1	355	0	0	0
0.8	284	146	145	138
0.6	213	260	262	275
0.4	142	341	351	413
0.2	71	390	411	550
0	0	406	443	688



Using goalseek:

	pwf to produce 225 Sm3/d
Fet	237.033
Vogel	237.292
Linear	238.68

There is very little difference between the IPR models, therefore, it is not important to determine which one is the most adequate

However, if the rate would have been higher:

m3/d	pwf to produce 380 Sm3/d
Fet	90.4148
Vogel	111.27
Linear	158.693

Here determining the correct IPR model is very important. A design made based on Fetkovich is very conservative (it requires reducing the pwf a lot) while a design based on linear IPR is optimistic

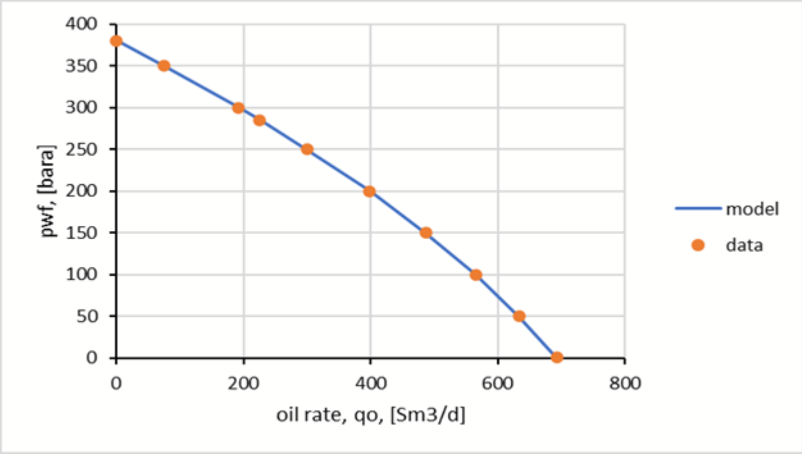
Task 3:

In task 1 you realized that you need more information to select a proper IPR model. Luckily, the reservoir engineer is back from his holidays and is in a good mood to help you. You asked him to perform a numerical multirate test at 0.5 years and at 10 years. The results are given in the excel sheet attached.
Use this information to decide which values of V and $q_{\bar{o},max}$ to use. Assume that V remains constant during depletion, but that $q_{\bar{o},max}$ changes.

TIP: use the excel solver to find values of V and $q_{\bar{o},max}$ that best fit the data provided.

With more test points at the same pR and time, it is possible to find the value of V and qomax (tune the values to obtain best fit)

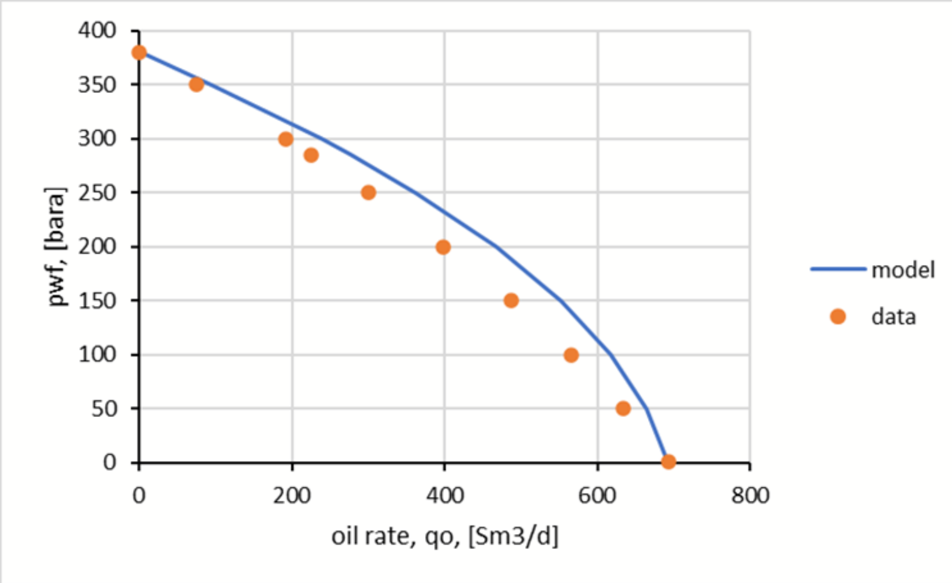
t	[years]	0.5	
pR	[bara]	380.1	
	V	0.5956	
	qomax	692.81	
pwf	qo	qocalc	error
[bara]	[Sm3/d]	[Sm3/d]	(Sm3/d)^2
380.1	0.0	0	0.0
350.0	75.2	75.3376	0.0
300.0	192.4	192.633	0.0
285.3	225.0	225.207	0.0
250.0	300.0	300.233	0.0
200.0	398.0	398.138	0.0
150.0	486.4	486.349	0.0
100.0	565.2	564.866	0.1
50.0	634.4	633.687	0.4
1.0	692.8	691.712	1.2
		error	1.9



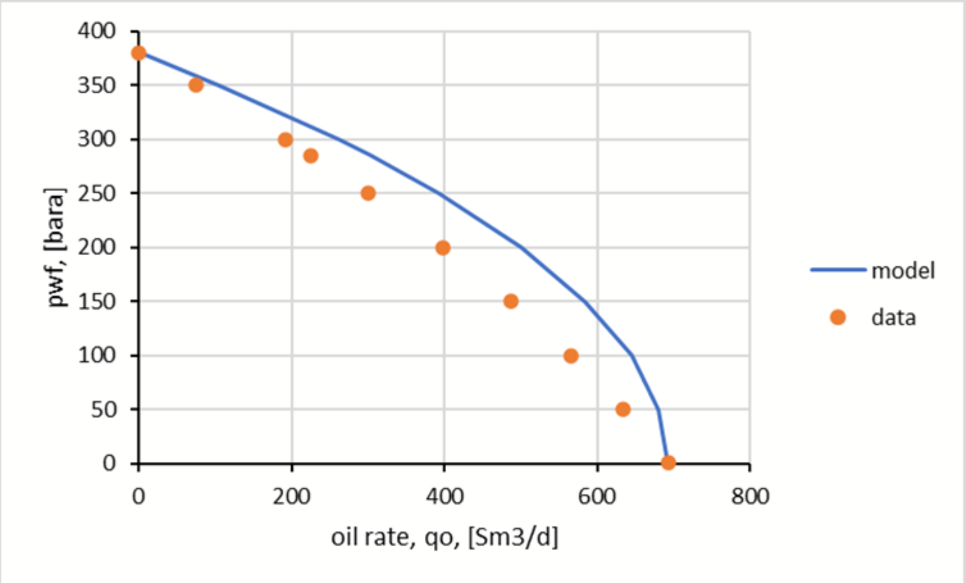
I use the solver to change V until error -->0
qomax is the last point on the table

Using Vogel

t	[years]	0.5	
pR	[bara]	380.1	
	V	0.2000	
	qomax	692.81	
pwf	qo	qocalc	error
[bara]	[Sm3/d]	[Sm3/d]	(Sm3/d)^2
380.1	0.0	0	0.0
350.0	75.2	95.3351	403.9
300.0	192.4	238.227	2096.8
285.3	225.0	276.513	2653.6
250.0	300.0	361.94	3832.8
200.0	398.0	466.474	4686.0
150.0	486.4	551.828	4280.3
100.0	565.2	618.003	2789.9
50.0	634.4	664.998	938.9
1.0	692.8	692.441	0.1
		error	21682.5

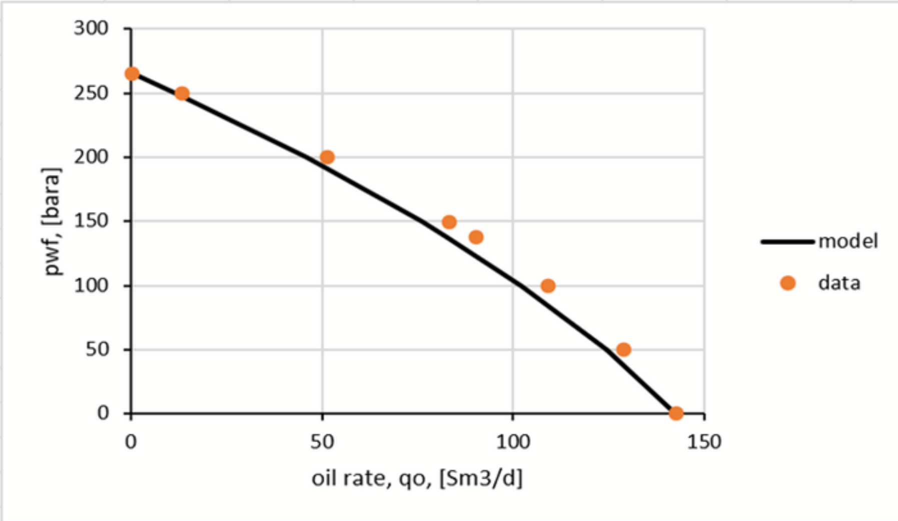


Using Fetkovich



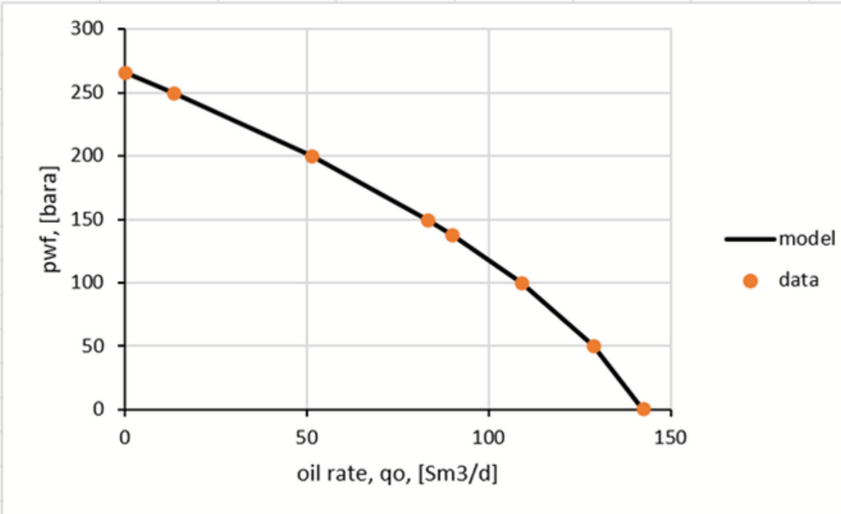
For the second time:

[years]	10	
[bara]	265.8	
V	0.6000	
qomax	142.37	
pwf	qo	qocalc
[bara]	[Sm3/d]	[Sm3/d]
265.8	0.0	0
250.0	13.2	11.6329
200.0	51.2	45.841
150.0	83.1	76.0183
137.8	90.0	82.7535
100.0	109.0	102.165
50.0	128.8	124.281
1.0	142.4	142.039



Best fit

t	[years]	10	
pR	[bara]	265.8	
	V	0.4000	
	qomax	142.37	
	pwf	qo	qocalc
	[bara]	[Sm3/d]	[Sm3/d]
	265.8	0.0	0
	250.0	13.2	13.223
	200.0	51.2	51.1439
	150.0	83.1	83.0186
	137.8	90.0	89.862
	100.0	109.0	108.847
	50.0	128.8	128.629
	1.0	142.4	142.147



When having the value of qomax from the multi-rate test, the prediction of the IPR model improved significantly! The effect of V is modest.

It seems that V is changing with time

Task 4:

In case the well exhibits high velocity flow, how could this affect your results? Discuss.

Drawing an analog to the dry gas case, the IPR of saturated oil with High velocity flow might look like this

$$q_o^2 \cdot \overset{?}{D} + q_o = \overset{?}{q_{omax}}\left(1 - \overset{?}{V}\left(\frac{p_{wf}}{p_R}\right) - (1-V)\left(\frac{p_{wf}}{p_R}\right)^2\right)$$

Now there are three parameters to determine from the data, V, qomax and the high velocity coefficient D Therefore, it is impossible to determine them with only one test point. One should have a multi-rate test or use an analytical expression based on reservoir and PVT properties to estimate D. For our case we have a good prediction without including D.

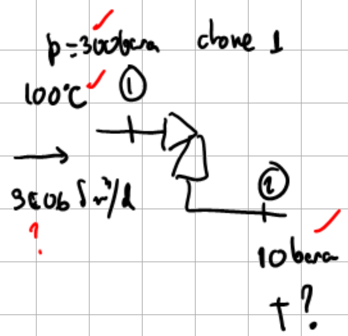
Lecture 20221013

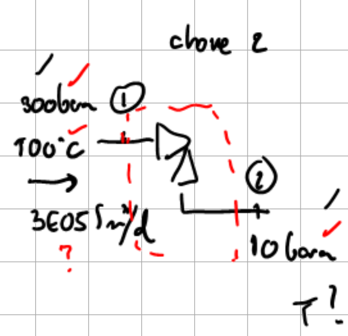
Review of some exam questions:

PROBLEM 1 (7 POINTS)

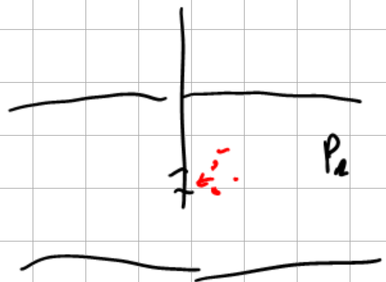
Task 1.1 (4 points). Consider a dry gas well that is choked. The pressure upstream the choke is 300 bara and the pressure downstream the choke is 10 bara. The temperature upstream the choke is 100 C. Consider the gas consists mainly of methane. Estimate the outlet temperature. The pressure enthalpy diagram of Methane is provided next.

Task 1.2 (3 points). Consider two choke models operating with the same conditions indicated in Task 1. However, the two chokes are of slightly different size, and one has a flow of 3E06 Sm3/d, and the other of 3E05 Sm3/d. Indicate how will this affect the outlet temperature.



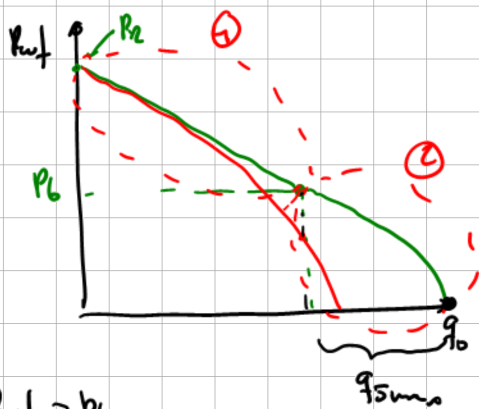


Composite IPR



$P_R > P_b$

$P_{wf} < P_b$



1 if $P_R \geq P_{wf} \geq P_b$

$q_o = J\cdot(P_R - P_{wf})$

2 if $P_{wf} < P_b$?

fetkovich $q_o = q_{omax}\left(1-\left(\frac{P_{wf}}{P_R}\right)^2\right)$

$q_o = q_{omax}\left(1-\left(\frac{P_{wf}}{P_b}\right)^2\right)$

when $P_{wf} = P_b$ $q_{ob} = J\left(P_R - P_b\right)$

$q_o = q_{omax}\left(1-\left(\frac{P_{wf}}{P_b}\right)^2\right) + q_{ob}$

- tubing : mechanical aspects

https://production-technology.org/tubing-specifications/

OILProduction.net

API Tubing Table

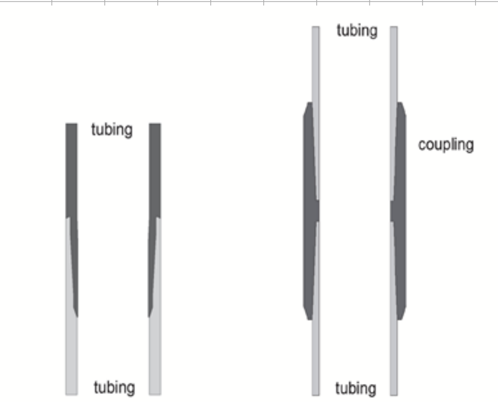
Tubing Size		Nominal Weight						Threaded Coupling					Joint Yield Strength		Capacity Table	
								Coupling Outside Dia.								
Nom. in.	OD in.	T & C Non-Upset lb/ft	T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Drift Dia. in.	Non-Upset in.	Upset Reg. in.	Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	T & C Non-Upset lb	T & C Upset lb	Barrels per Linear ft	Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40	0.113	0.824	0.730	1.313	1.660		7,200	7,530	6,360	13,300	0.0007	1516.13
				J-55							9,370	10,360	8,740	18,290		
				C-75							12,250	14,120	11,920	24,940		
				N-80							12,710	15,070	12,710	26,610		
1	1.315	1.700	1.800	H-40	0.113	1.049	0.955	1.660	1.900		6,820	7,080	10,960	19,760	0.0011	935.49
				J-55							8,860	9,730	15,060	27,160		
				C-75							11,590	13,270	20,540	37,040		
				N-80							12,270	14,160	21,910	39,510		
1 1/4	1.660	2.300	2.400	H-40	0.125	1.410	1.286	2.054	2.200		5,220	5,270			0.0019	517.79
				H-40	0.140	1.380					5,790	5,900	15,530	26,740	0.0018	540.55
				J-55	0.125	1.410					6,790	7,250			0.0019	517.79
				J-55	0.140	1.380					7,530	8,120	21,360	36,770	0.0018	540.55
				C-75	0.140	1.380					9,840	11,070	29,120	50,140	0.0018	540.55
				N-80	0.140	1.380					10,420	11,810	31,060	53,480	0.0018	540.55
1 1/2	1.900	2.750	2.900	H-40	0.125	1.650	1.516	2.200	2.500		4,450				0.0026	378.11
				H-40	0.145	1.610					5,290		19,090	31,980	0.0025	397.14
				J-55	0.125	1.650					5,790				0.0026	378.11
				J-55	0.145	1.610					6,870		26,250	43,970	0.0025	397.14
				C-75	0.145	1.610					8,990	10,020	35,800	59,960	0.0025	397.14
				N-80	0.145	1.610					9,520	10,680	38,180	63,960	0.0025	397.14

An example, total weight of tubing string

4.5" tubing, 2500m, weight 12.75 lb/ft

$$8202 \times 12.75 = 104575 \text{ lb}$$

$$= 47.4 \text{ t}$$



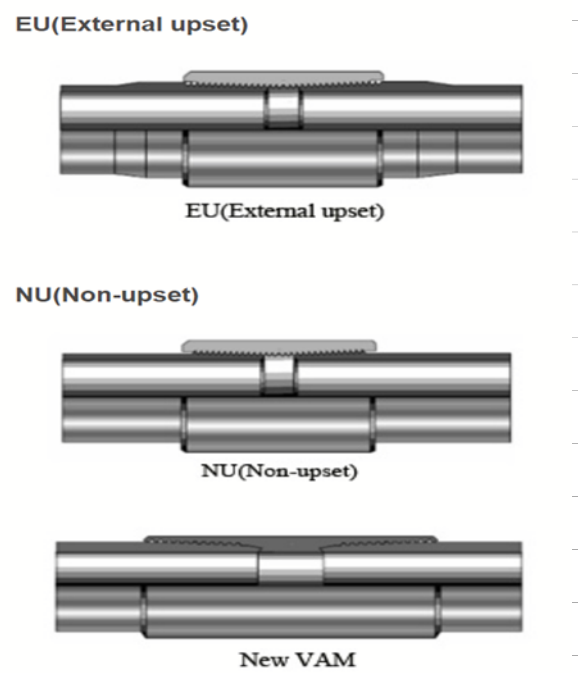
Coupling make up https://www.youtube.com/watch?v=PWt9k7mYBoI

Joint make-up on rig floor
https://www.youtube.com/watch?v=3fdbX7rpxao

type of tubing end/connections

https://www.lksteelpipe.com/news/how-to-distinguish-the-thread-of-oil-pipeline-12768040.html

https://www.worldironsteel.com/news/what-s-the-difference-between-upset-tubing-and-13703095.html



What's The Difference Between Upset Tubing And Non-Upset Tubing?

World Iron & Steel Co.,Ltd | Apr 18, 2018

What's The Difference Between Upset Tubing And Non-Upset Tubing?

APT 5CT specified the requirements of Casing and tubing for the purpose of oil or gas production, must be cased with material with sufficient strength and functionality.

Oil tubing are the main parts of the well drilled construction. They are selected for the specific conditions anticipated in a given well. The anticipated production flow rates and economics of the well determine tubing size, which then determines the necessary size of each previous hole and tubular. Once the tubular size and setting depths are determined, the wall thickness and grade of material are then chosen by the well designer to ensure the strength is adequate for the expected loads. API 5CT developed specifications for three different connectors for use as casing tubing joints: External-upset tubing and coupling (Upset tubing),Non-upset tubing and couplings,Integral-joint tubing.

Upsetting is a forging process that makes for a thicker wall on the tube ends. **Upset Tubing** (EUE) is a long tubing with joint installed in a wellbore to facilitate the extraction of oil and gas. The tubing joints are designed to suit a certain well type, based on the underground conditions and fluids.It acts as a conduit, through which the produced fluids or gas get transmitted from the bottom to the surface. Tubing joint is relatively a single length pipe that can vary in length anywhere from 25 to 30 ft. This ideal length allows easy production as the tubing joint is fitted with threads on both sides and can run down through a well of any depth.

important for hoisting capacity

more material, more weight

important for running in hole tolerances

OILProduction.net **API Tubing Table**

Tubing Size		Nominal Weight						Threaded Coupling					Joint Yield Strength		Capacity Table	
								Coupling Outside Dia.								
Nom. in.	OD in.	T & C Non-Upset lb/ft	T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Drift Dia. in.	Non-Upset in.	Upset Reg. in.	Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	T & C Non-Upset lb	T & C Upset lb	Barrels per Linear ft	Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40 J-55 C-75 N-80	0.113	0.824	0.730	1.313	1.660		7,200 9,370 12,250 12,710	7,530 10,360 14,120 15,070	6,360 8,740 11,920 12,710	13,300 18,290 24,940 26,610	0.0007	1516.13
1	1.315	1.700	1.800	H-40 J-55 C-75 N-80	0.113	1.049	0.955	1.660	1.900		6,820 8,860 11,590 12,270	7,080 9,730 13,270 14,160	10,960 15,060 20,540 21,910	19,760 27,160 37,040 39,510	0.0011	935.49
1 1/4	1.660	2.300	2.400	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.140 0.125 0.140 0.140 0.140	1.410 1.380 1.410 1.380 1.380 1.380	1.286	2.054	2.200		5,220 5,790 6,790 7,530 9,840 10,420	5,270 5,900 7,250 8,120 11,070 11,810	 15,530 21,360 29,120 31,060	 26,740 36,770 50,140 53,480	0.0019 0.0018 0.0019 0.0018 0.0018 0.0018	517.79 540.55 517.79 540.55 540.55 540.55
1 1/2	1.900	2.750	2.900	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.145 0.125 0.145 0.145 0.145	1.650 1.610 1.650 1.610 1.610 1.610	1.516	2.200	2.500		4,450 5,290 5,790 6,870 8,990 9,520	 10,020 10,680	 19,090 26,250 35,800 38,180	 31,980 43,970 59,960 63,960	0.0026 0.0025 0.0026 0.0025 0.0025 0.0025	378.11 397.14 378.11 397.14 397.14 397.14

Important when doing wireline/tractor operations in the tubing, to avoid getting stuck
https://www.youtube.com/watch?v=i77v2snWZ1c

Mechanical resistance, composition (carbon, iron and other elements) and heat treatment

OILProduction.net **API Tubing Table**

Tubing Size		Nominal Weight					Threaded Coupling						Joint Yield Strength		Capacity Table	
Nom. in.	OD in.	T & C Non-Upset lb/ft	T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Drift Dia. in.	Coupling Outside Dia. Non-Upset in.	Coupling Outside Dia. Upset Reg. in.	Coupling Outside Dia. Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	T & C Non-Upset lb	T & C Upset lb	Barrels per Linear ft	Linear ft per Barrel
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				N-80	0.140	1.380					10,420	11,810	31,060	53,480	0.0018	540.55
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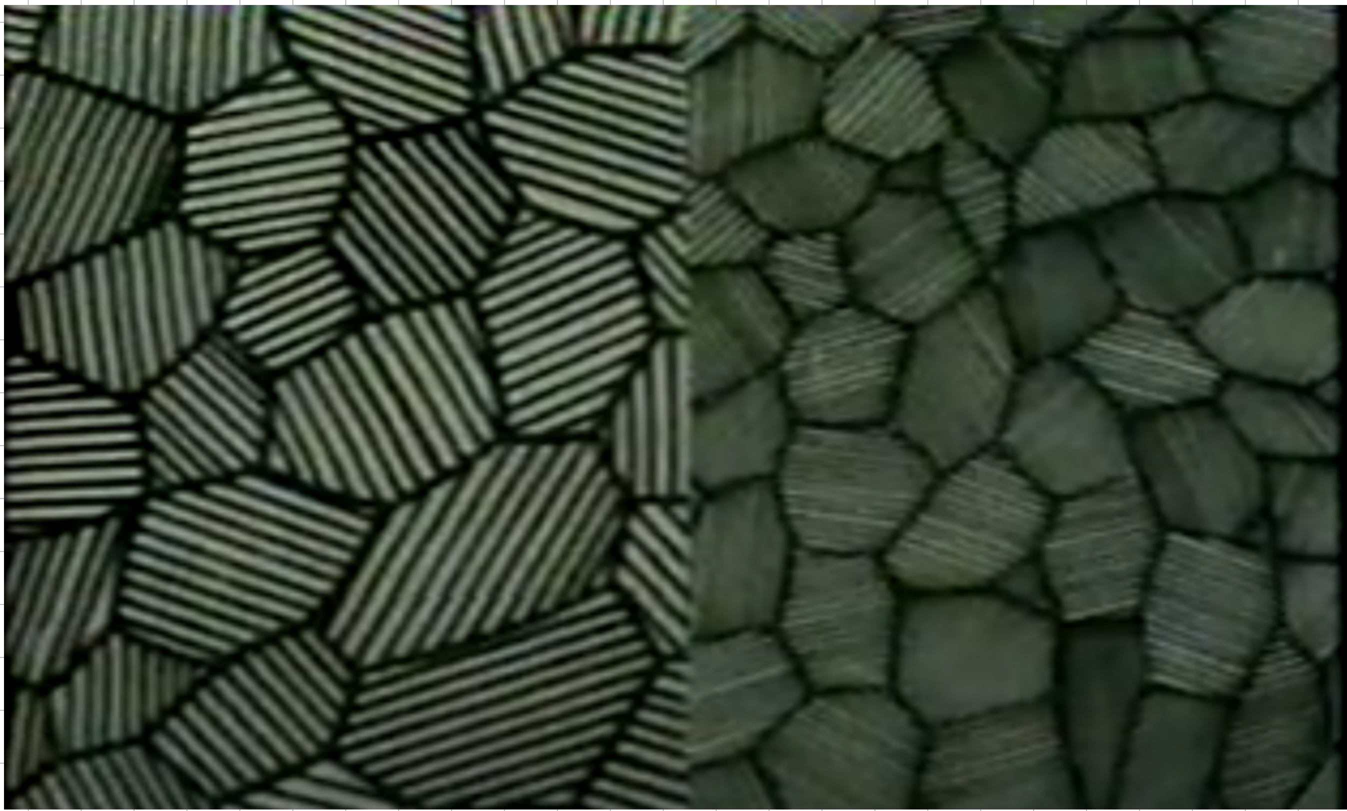
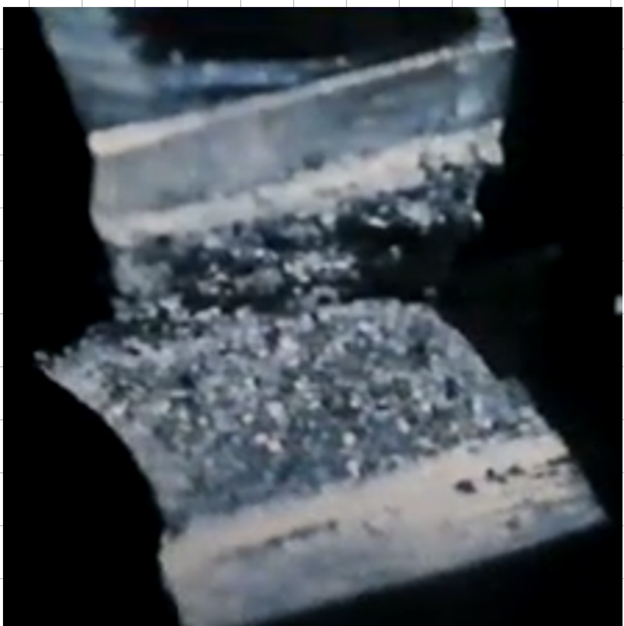
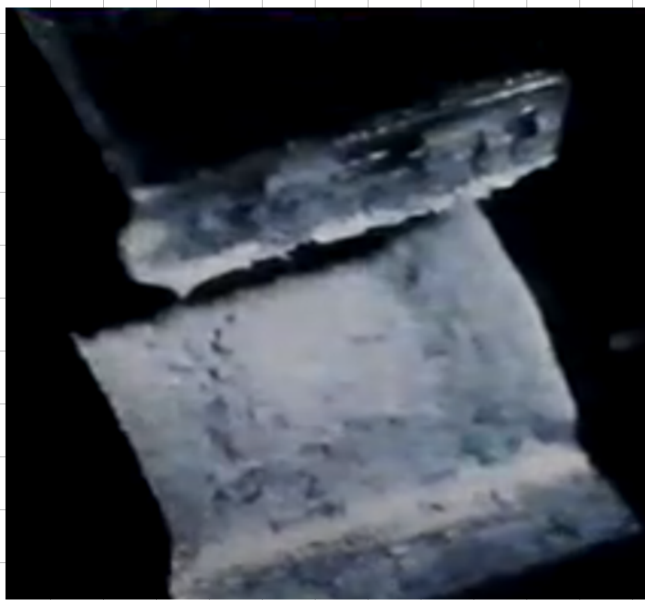
				N-80	0.145	1.610					9,520	10,680	38,180	63,960	0.0025	397.14

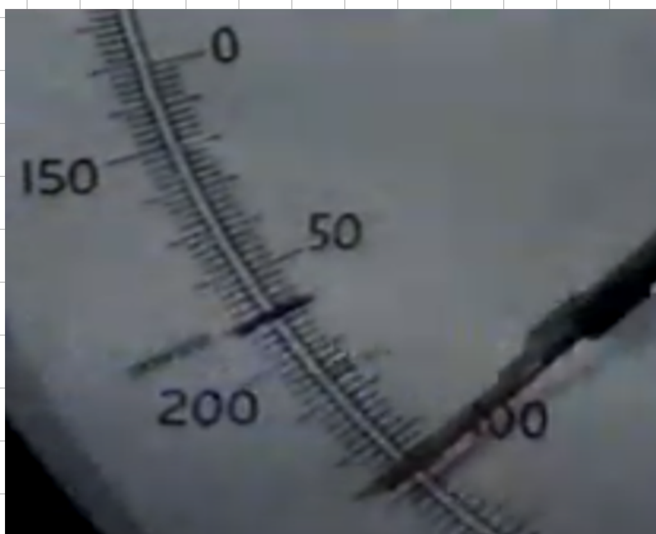
Effect of heat treatment on material: https://www.youtube.com/watch?v=0SIr2sBHxA4



Normalization



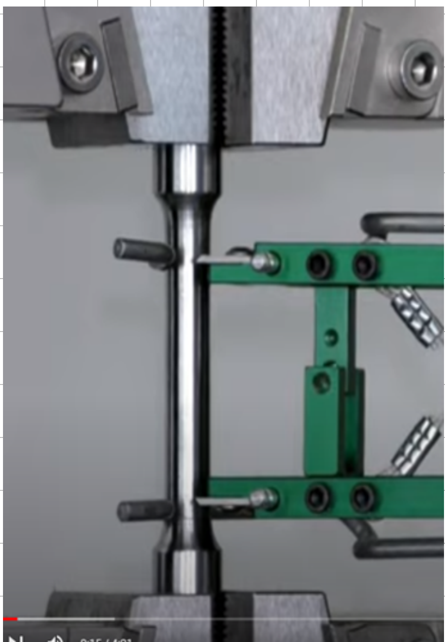


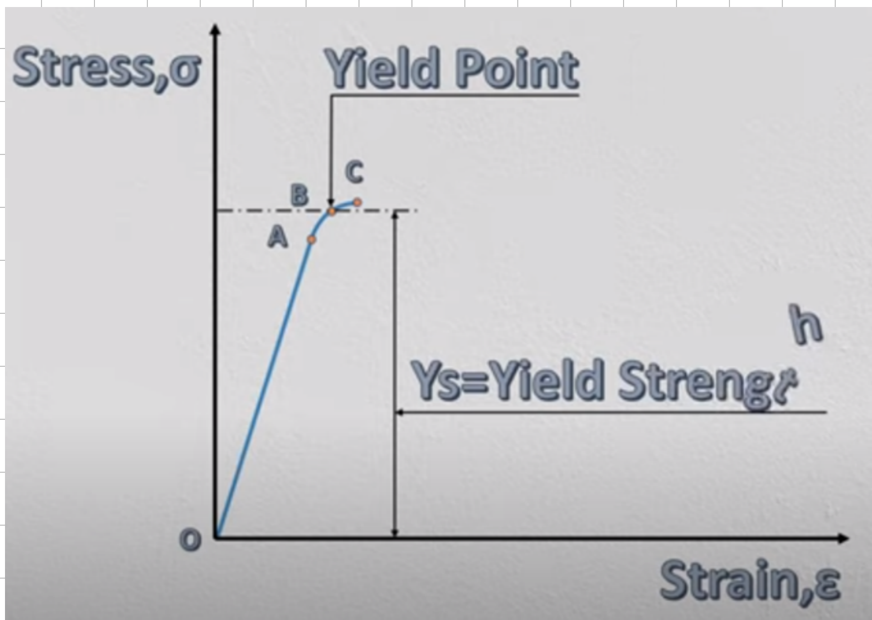


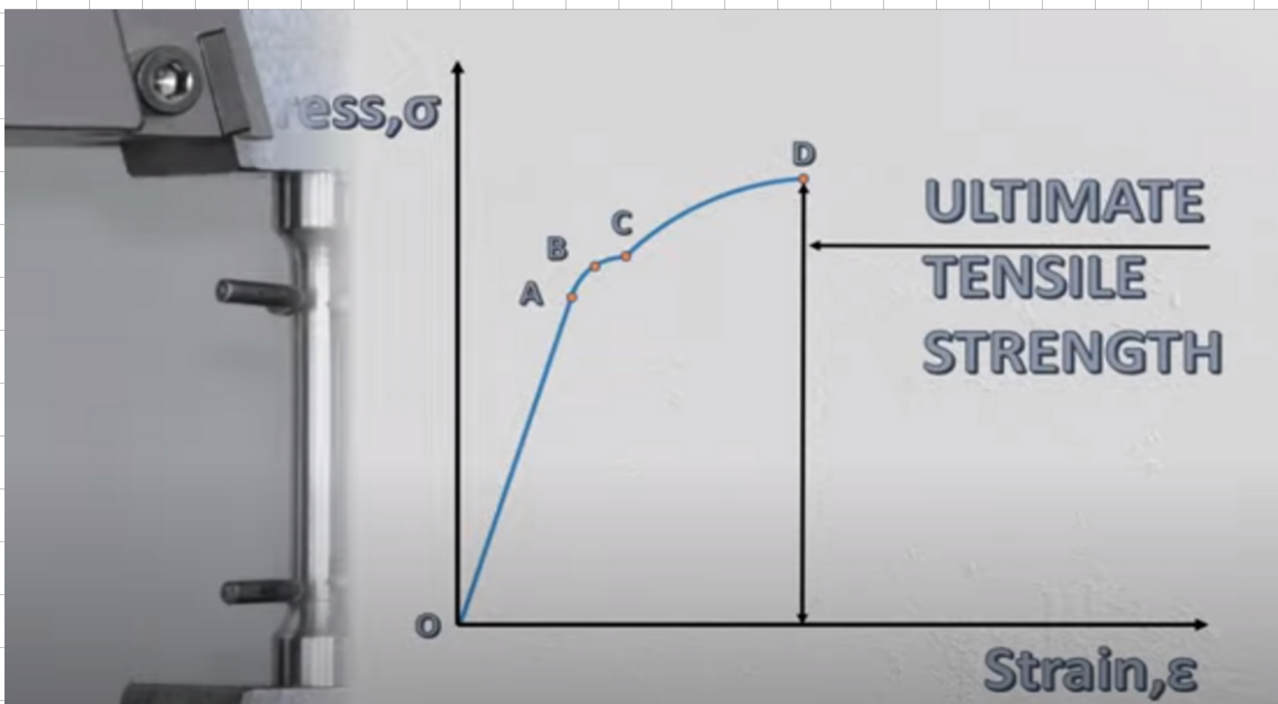
What is yield stress: https://www.youtube.com/watch?v=RY9X_O8is-k

$$\text{Stress}, \sigma = \frac{\text{LOAD ‘P’}}{\text{AREA ‘A’}} \qquad \text{Strain}, \varepsilon = \frac{\text{change in length ‘}\Delta L\text{’}}{\text{Initial length ‘L’}}$$

$$E = \frac{\text{Stress}}{\text{Strain}}$$



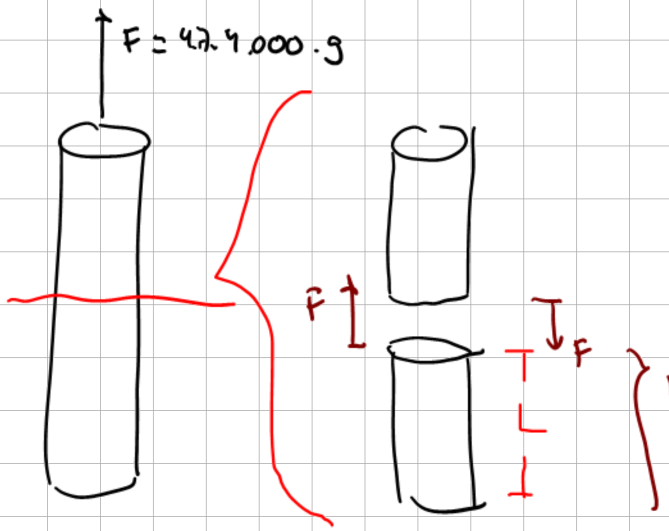




Axial loads in tubing:

-weight

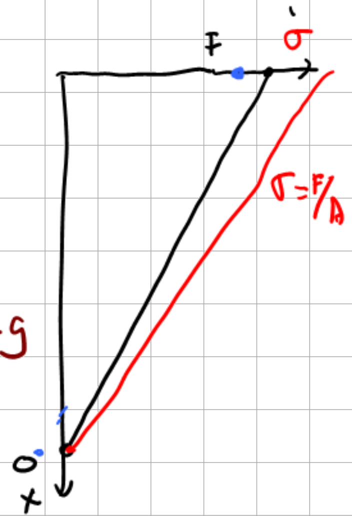
$F = 47.4000 \cdot g$



$w \cdot g = L \cdot ppf \cdot g$

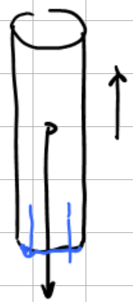
pounds per foot

axial distribution of force and stress due to weight



$\sigma = F/A$

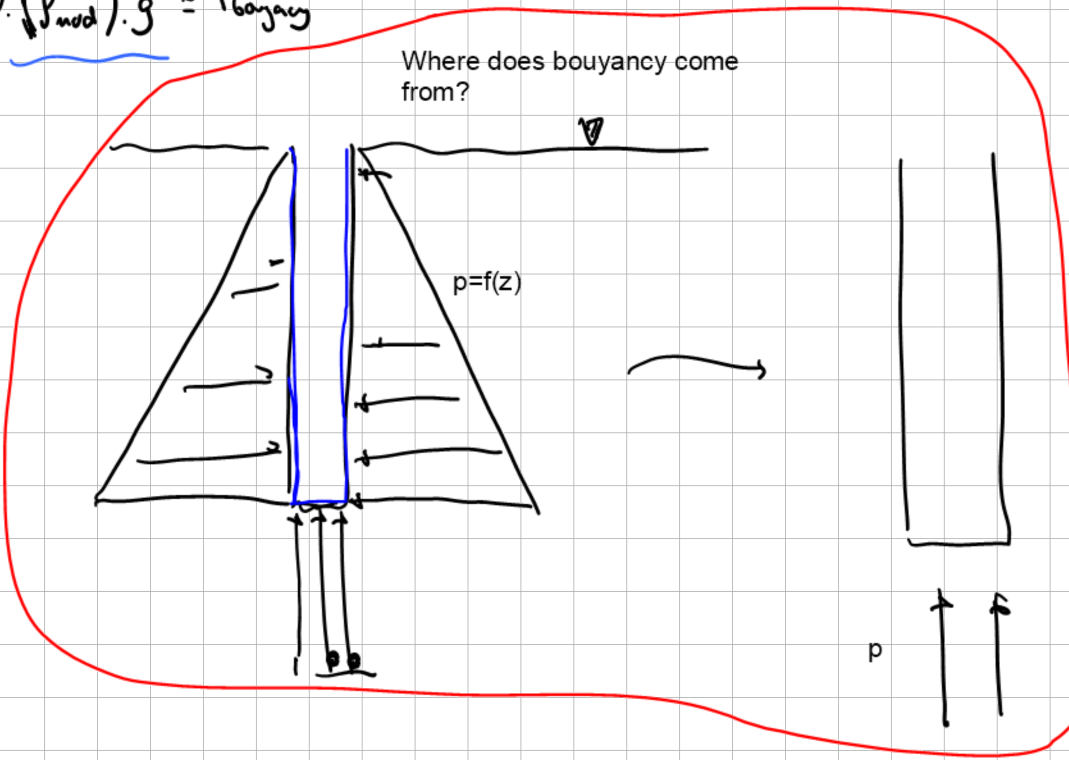
-Bouyancy



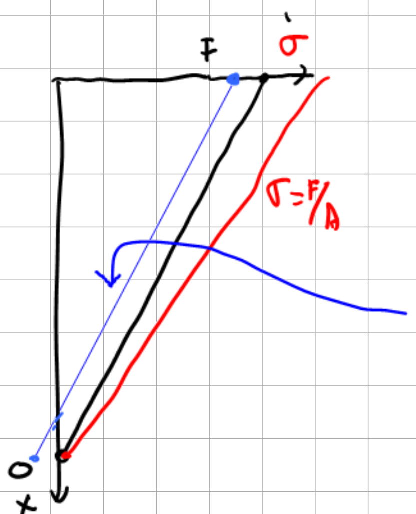
displaced volume (be careful if open end pipe or closed end pipe!)

$V \cdot (\rho_{mud}) \cdot g = F_{bouyancy}$

Where does bouyancy come from?



axial distribution of force and stress due to weight and bouyancy

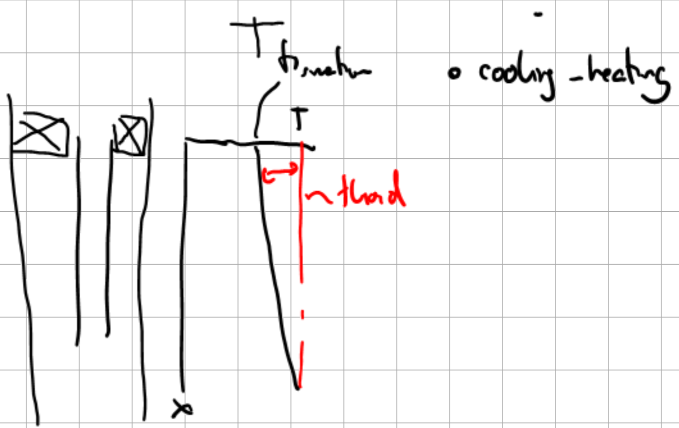


$\sigma = F/A$

the black curve is shifted because the bouyancy creates a constant compressive force that counteracts the tensioning force due to weight

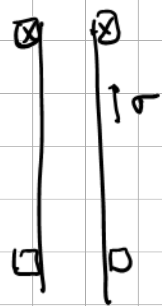
-Pre-tensioning (e.g. due to packer setting) - The tubing is "pulled up" with the hoisting mechanism. This also shifts the black curve to the right (tensioning) or left (compressing), as the force is applied uniformly to all the string

-Axial stress due to thermal expansion-contraction



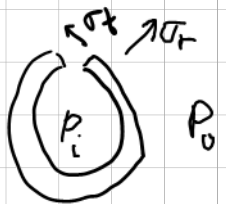
Black line is formation temperature distribution (just after the well is completed, no flow)
The red line is the temperature distribution when the well is put to production (the fluid flow warms up the tubing). This temperature difference causes tubing expansion

Tubing is typically fixed at both ends (wellhead above and packer below) so the thermal expansion creates an axial compressive stress. This shifts the black curve to the left.

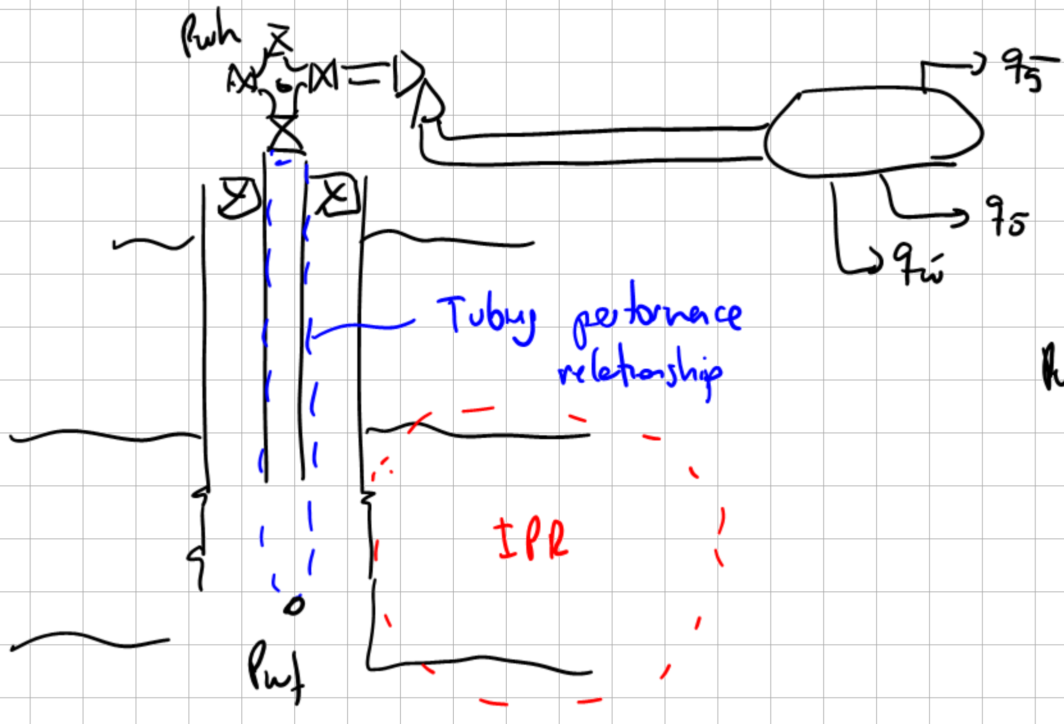


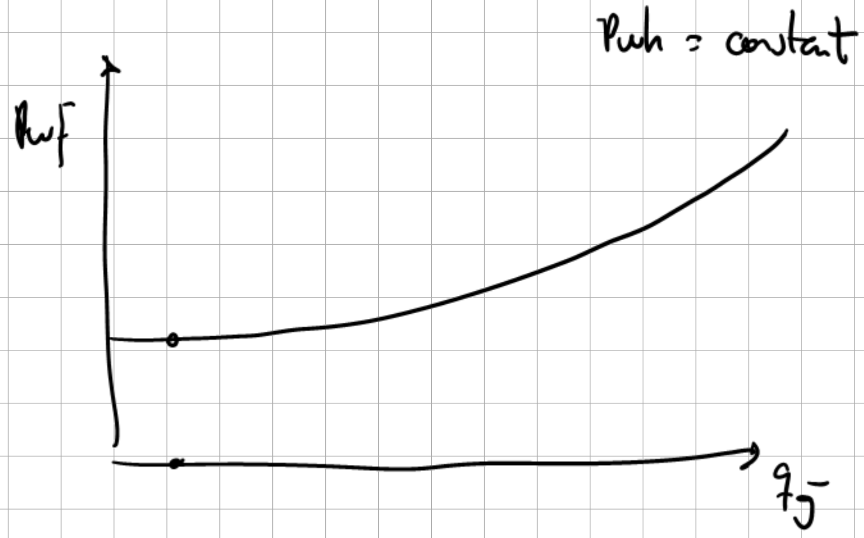
Other loads that must be considered:

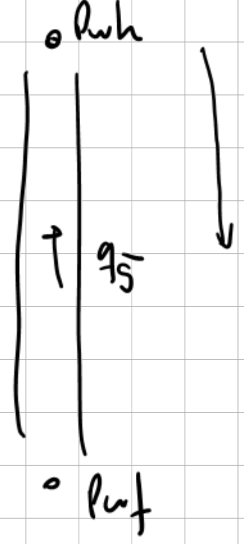
-Inner-outer pressure: cause an axial and radial stress
-Etc (to be discussed later)



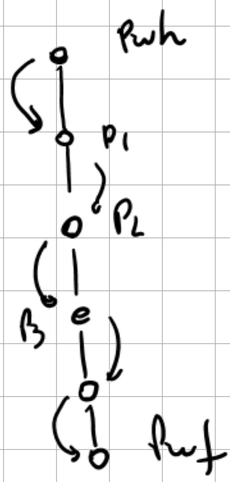
The "combination" of all these stresses must be taken into account and compared against the yield stress, to make sure the tubing will withstand the loads.







Counter current to calculate Pwf (pressure integration)



Head → $h_1 = h_2$ (no energy losses) $h = z + \frac{p}{\rho g} + \frac{v^2}{2g}$ incompressible

$h_1 = h_2 + \Delta h_{losses}$ $\Delta h_{losses} = \underbrace{\cancel{\Delta h_{accessories}}}_{\text{valves restrictions}}{}^{0} + \Delta h_{friction}$ $\Delta h_{friction} = f \frac{L}{D} \frac{v^2}{2g}$

Moody friction factor

$$h_1 = z_1 + \frac{p_1}{\rho g} + \cancel{\frac{v_1^2}{2g}} = z_2 + \frac{p_2}{\rho g} + \cancel{\frac{v_2^2}{2g}} + f \frac{L}{D} \frac{v^2}{2g}$$

its incompressible, so $v_1 = v_2 = v$, D = constant

$$\Delta p = (p_1 - p_2) = \rho g \cdot \left((z_2 - z_1) + f \frac{L}{D} \frac{\rho g}{2g} v^2\right)$$

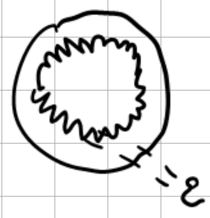
$$(p_1 - p_2) = \underbrace{\Delta z \cdot \rho g}_{\text{hydrostatic}} + \underbrace{f \frac{L}{D} \rho \frac{v^2}{2}}_{\text{friction}}$$

for gas $\rho = f(p, T)$

laminar region

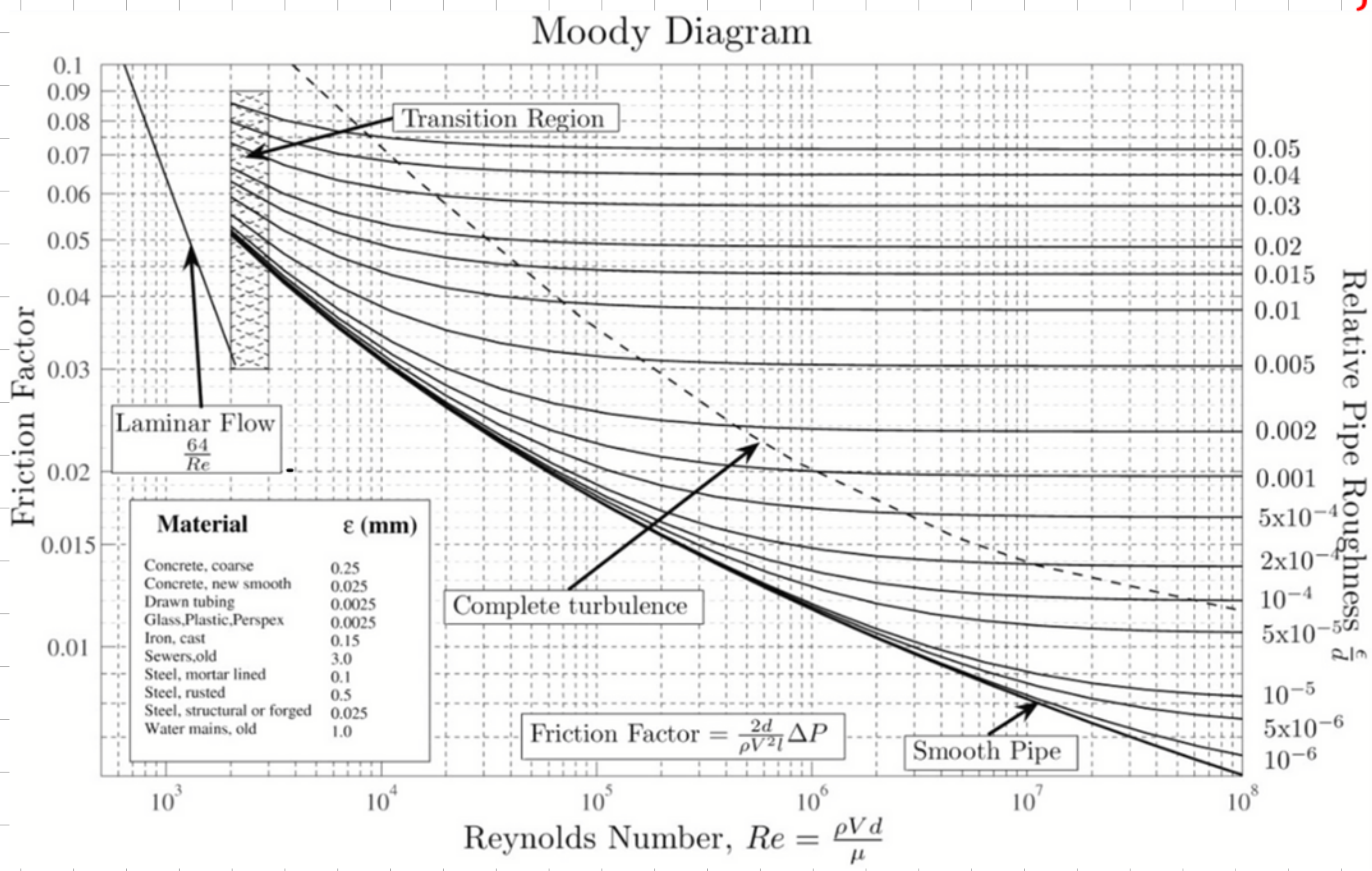
$Re < 2500$

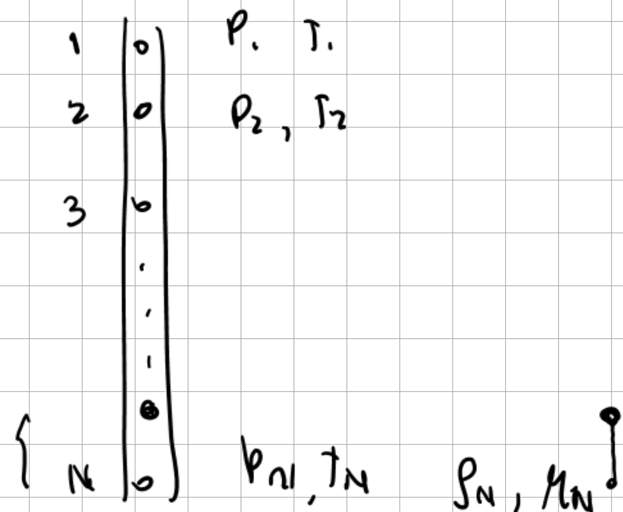
ε / D dimensionless roughness



$$Re = \frac{\rho D v}{\mu} = \frac{\text{inertial forces}}{\text{viscous forces}}$$

$f(p, T)$





$N \to N-1$, gas properties don't change much

valid if ΔL is small

ΔT, Δp is small

$$v_g = \frac{q_g}{A} = \frac{q_{\bar{s}} B_g(p,T)}{A}$$

$$B_g = \frac{q_g}{q_{\bar{s}}}$$

$$q_{\bar{s}} \cdot \rho_{\bar{s}} = q_s \cdot \rho_s$$

$$B_g = \frac{q_g}{q_{\bar{s}}} = \frac{\rho_{\bar{s}}}{\rho_g} = \frac{z T}{p} \left(\frac{p_{sc}}{T_{sc}} \right)$$

$$\rho_{\bar{s}} = \frac{p_{sc}}{R z_{sc} T_{sc}}$$

$$\rho_s = \frac{p}{z R T}$$

m^3/d $\quad \frac{1\,d}{24\,h}$ $\quad \frac{1\,h}{3600\,s}$

qg [Sm3/d]	2.85E+06
Gas gravity	0.7
Tubing ID [m]	0.157
Tubing cross section area [m2]	0.019
Tubing roughness [m]	1.50E-06

TVD	p	T	Z	deng	Bg	viscg	qg	vg	p-calc
[m]	[bara]	[C]	[-]	[kg/m3]	[m3/Sm3]	[cp]	[m3/d]	[m/s]	[bara]
0	40	87	0.948	28.6	3.00E-02	1.36E-02	8.54E+04	51.03	
284	46	89	0.942	32.9	2.60E-02	1.38E-02	7.41E+04	44.28	
567	51	90	0.938	36.8	2.32E-02	1.39E-02	6.63E+04	39.61	
851	56	92	0.934	40.4	2.12E-02	1.41E-02	6.04E+04	36.14	
1135	61	94	0.930	43.6	1.96E-02	1.43E-02	5.59E+04	33.43	
1418	66	96	0.928	46.7	1.83E-02	1.45E-02	5.23E+04	31.25	
1702	70	98	0.926	49.5	1.73E-02	1.46E-02	4.92E+04	29.44	
1986	74	99	0.924	52.2	1.64E-02	1.48E-02	4.67E+04	27.92	
2269	78	101	0.922	54.8	1.56E-02	1.49E-02	4.45E+04	26.61	
2553	81	103	0.921	57.3	1.49E-02	1.51E-02	4.26E+04	25.47	
2837	85	105	0.920	59.6	1.44E-02	1.52E-02	4.09E+04	24.46	

$\circ\ p_{N-1}$

$\circ\ p_{wf}$

2837 - 2553

$$p_{N-1} = p_{wf} - \rho g \Delta z - f \frac{L}{D} \rho \frac{v^2}{2}$$

using conditions at p_{wf} !

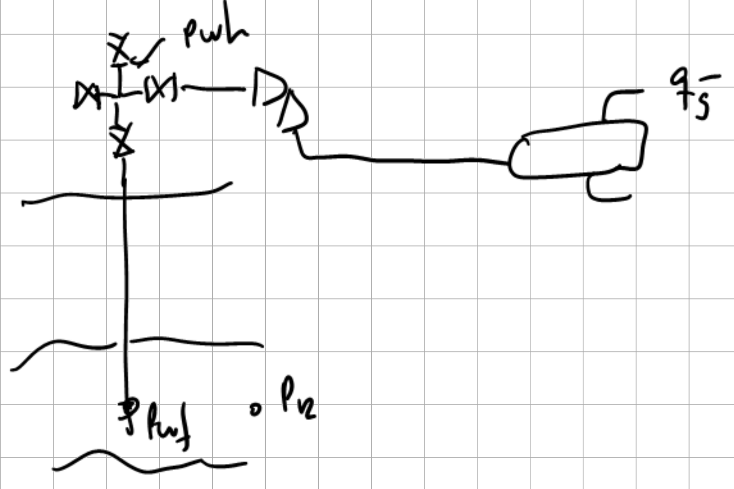
```
Function Pout(qt1, ID, den, visc, Length, teta, pin, roughness)
    'Function that give pressure available at the oulet of a pipe with a flow qt and inlet pressure pressure pin
    'Calculation made for liquid single phase flow
    'Takes in data in SI
    'qt flow [m^3/d]
    'ID inner diameter of pipe [m]
    'den density of fluid, [kg/m^3]
    'visc viscosity of fluid, [Pa s]
    'Length, pipe length, [m]
    'teta inclination angle of pipe with respect to horizontal [°]
    'pin, discharge pressure required, [bara]
    'roughness of pipe [m]

    'Gravitational acceleration g, [m/s(2]
    g = 9.81
    'Pi number
    Pi = 4 * Atn(1)
    qt = qt1 / (3600# * 24#)  '[m^3/s]

    'Calculating area and velocity
    Area = Pi * (ID ^ 2) / 4
    v = qt / Area

    Presscalcl = pin - (Length * Sin(teta * Pi / 180) * den * g / 100000#) - (ffactor(den, visc, ID, roughness, v) * Length * (v ^ 2) * den / (ID * 200000#))
    Pout = Presscalcl

End Function
```

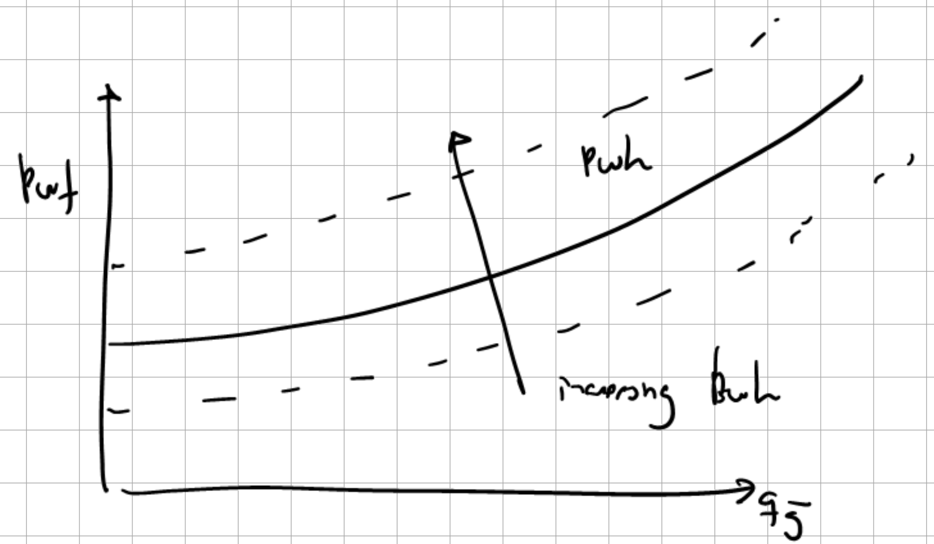
change for m3/d to m3/s

dividing by 1E5 to take from Pa to bara

TVD	p	T	Z	deng	Bg	viscg	qg	vg	p-calc
[m]	[bara]	[C]	[-]	[kg/m3]	[m3/Sm3]	[cp]	[m3/d]	[m/s]	[bara]
0	40	87	0.948	28.6	3.00E-02	1.36E-02	8.54E+04	51.03	35.55
284	46	89	0.942	32.9	2.60E-02	1.38E-02	7.41E+04	44.28	41.50
567	51	90	0.938	36.8	2.32E-02	1.39E-02	6.63E+04	39.61	47.03
851	56	92	0.934	40.4	2.12E-02	1.41E-02	6.04E+04	36.14	52.27
1135	61	94	0.930	43.6	1.96E-02	1.43E-02	5.59E+04	33.43	57.29
1418	66	96	0.928	46.7	1.83E-02	1.45E-02	5.23E+04	31.25	62.15
1702	70	98	0.926	49.5	1.73E-02	1.46E-02	4.92E+04	29.44	66.88
1986	74	99	0.924	52.2	1.64E-02	1.48E-02	4.67E+04	27.92	71.52
2269	78	101	0.922	54.8	1.56E-02	1.49E-02	4.45E+04	26.61	76.08
2553	81	103	0.921	57.3	1.49E-02	1.51E-02	4.26E+04	25.47	80.59
2837	85	105	0.920	59.6	1.44E-02	1.52E-02	4.09E+04	24.46	85.04

surprisingly close !





for same p_{wf}, p_{wh}:

- C_T ↑ q_s ↑
- S ↑ q_s ↓

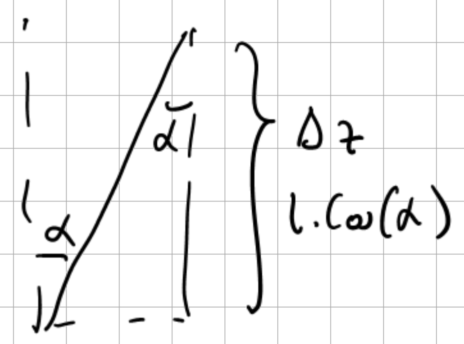
$$q_{\bar{s}} = C_T \cdot \left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$$

tubing coefficient, tubing elevation coefficient

$$u_g = \frac{q_g}{A} = \frac{\dot{m}_g}{\rho_g \cdot A} \qquad \rho_g = \frac{p}{z R T} \rightarrow \frac{R_0}{MW}$$

$$u_g^2 = \left(\frac{\dot{m}_s}{\rho_g A}\right)^2$$

$$-\frac{dp}{dl} = \frac{p \cdot M_g}{\underbrace{Z}_{f(p)} \cdot \underbrace{R}_{\text{“}R_u\text{”}} \cdot T} \cdot g \cdot \cos(\alpha) + \frac{8 \cdot \overbrace{f_M}^{f(v,\rho,\mu)} \cdot \dot{m}^2}{\pi^2 \cdot D^5} \cdot \frac{\overbrace{Z}^{} \cdot R \cdot T}{p \cdot M_g}$$



$$S = 2 \cdot L \cdot C_a = 2 \cdot \frac{M_g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot g \cdot \cos(\alpha)$$

$$q_{sc} = \left(\frac{\pi}{4}\right) \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \cdot \left(\frac{T_{sc}}{p_{sc}}\right) \cdot \left(\frac{D^5}{f_M \cdot L \cdot \gamma_g \cdot Z_{av} \cdot T_{av}}\right)^{0.5} \cdot \left[\left(p_{wf}^2 - p_t^2 \cdot e^S\right) \cdot \left(\frac{S}{e^S - 1}\right)\right]^{0.5}$$

By defining the tubing constant C_T:

$$C_T = \left(\frac{\pi}{4}\right) \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \cdot \left(\frac{T_{sc}}{p_{sc}}\right) \cdot \left(\frac{D^5}{f_M \cdot L \cdot \gamma_g \cdot Z_{av} \cdot T_{av}}\right)^{0.5} \cdot \left(\frac{S \cdot e^S}{e^S - 1}\right)^{0.5} \qquad \text{EQ. A-24}$$

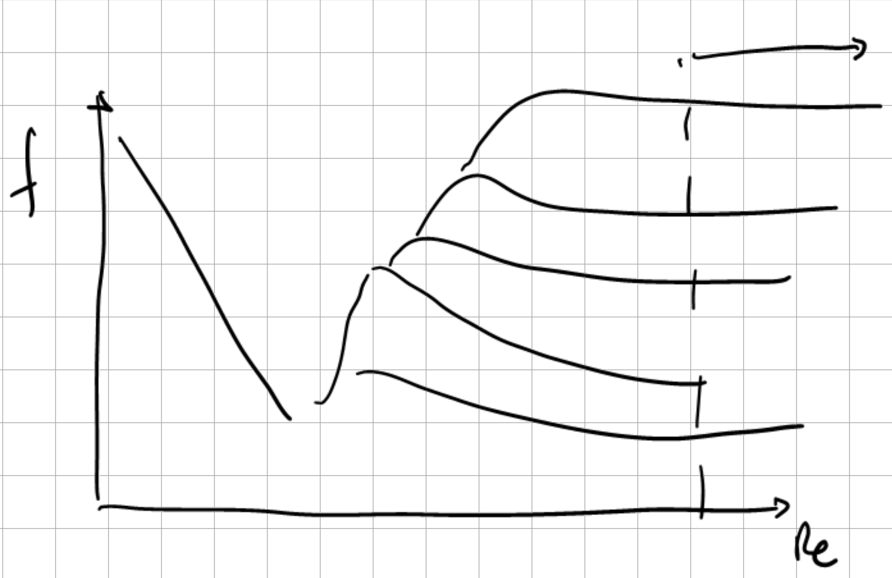
This yields:

$$q_{sc} = C_T \cdot \left[\left(\frac{p_{wf}^2}{e^S} - p_t^2 \cdot\right)\right]^{0.5} \qquad \text{EQ. A-25}$$

→ to calculate C_T, S, a seed p_{wf}, p_{wh}, T_{wf}, T_{wh} are required!

Z_{av}, T_{av}

Usually the effect of seed is modest



fully turbulent regime → $f = f(e/D)$

$$Re = \frac{v D \rho}{\mu}$$

ρ is low

v is high

μ is high

Re is very high

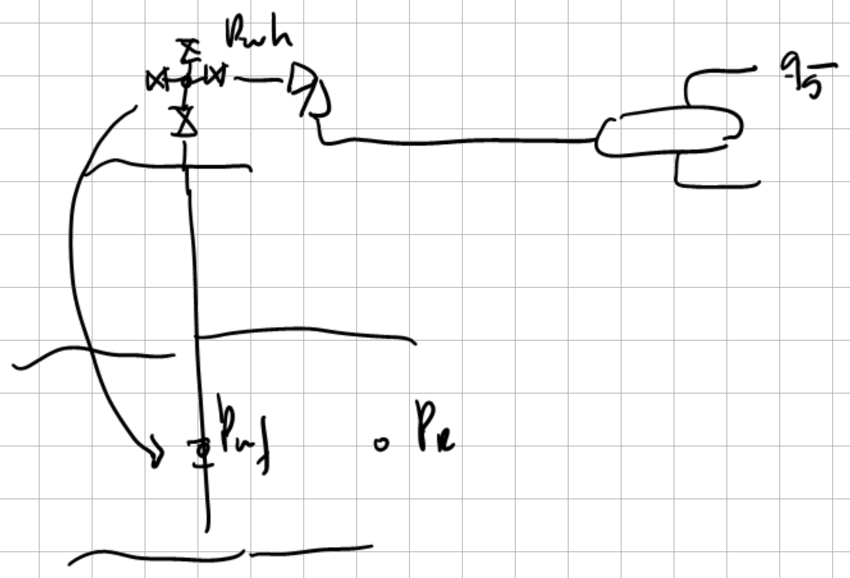
$e = f(D)$ Smith (1950)

↳ $f = f(D)$

DETERMINING FRICTION FACTORS FOR MEASURING PRODUCTIVITY OF GAS WELLS

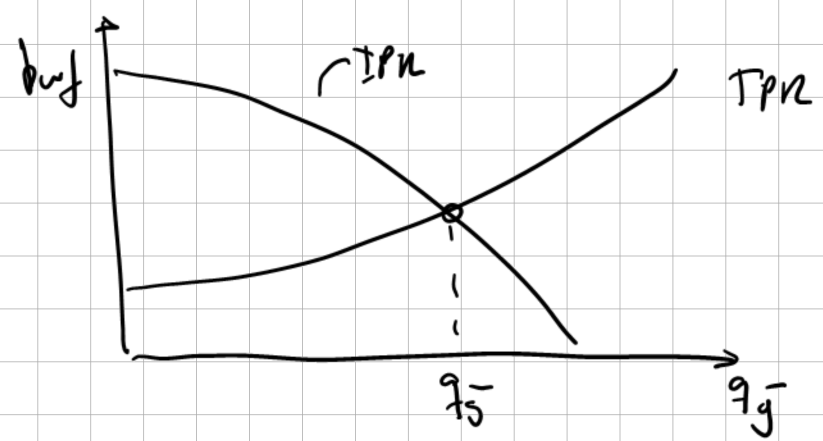
R. V. SMITH, U. S. BUREAU OF MINES, BARTLESVILLE, OKLAHOMA

$$f_M = \frac{0.01748}{D^{0.224} \cdot \left(|1\,m| \cdot \left|\frac{39.37\,in}{1\,m}\right|\right)^{0.224}} = \frac{0.0077}{D^{0.224}}$$



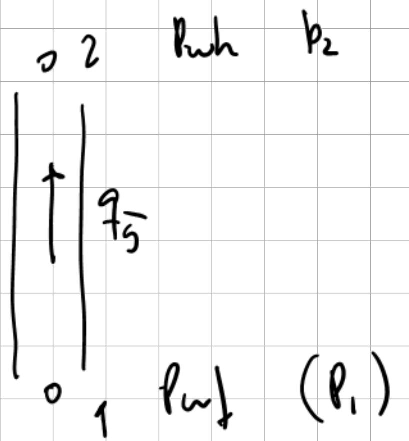
1) neglecting flowline → $p_{wh} = p_{sep}$
fully open choke

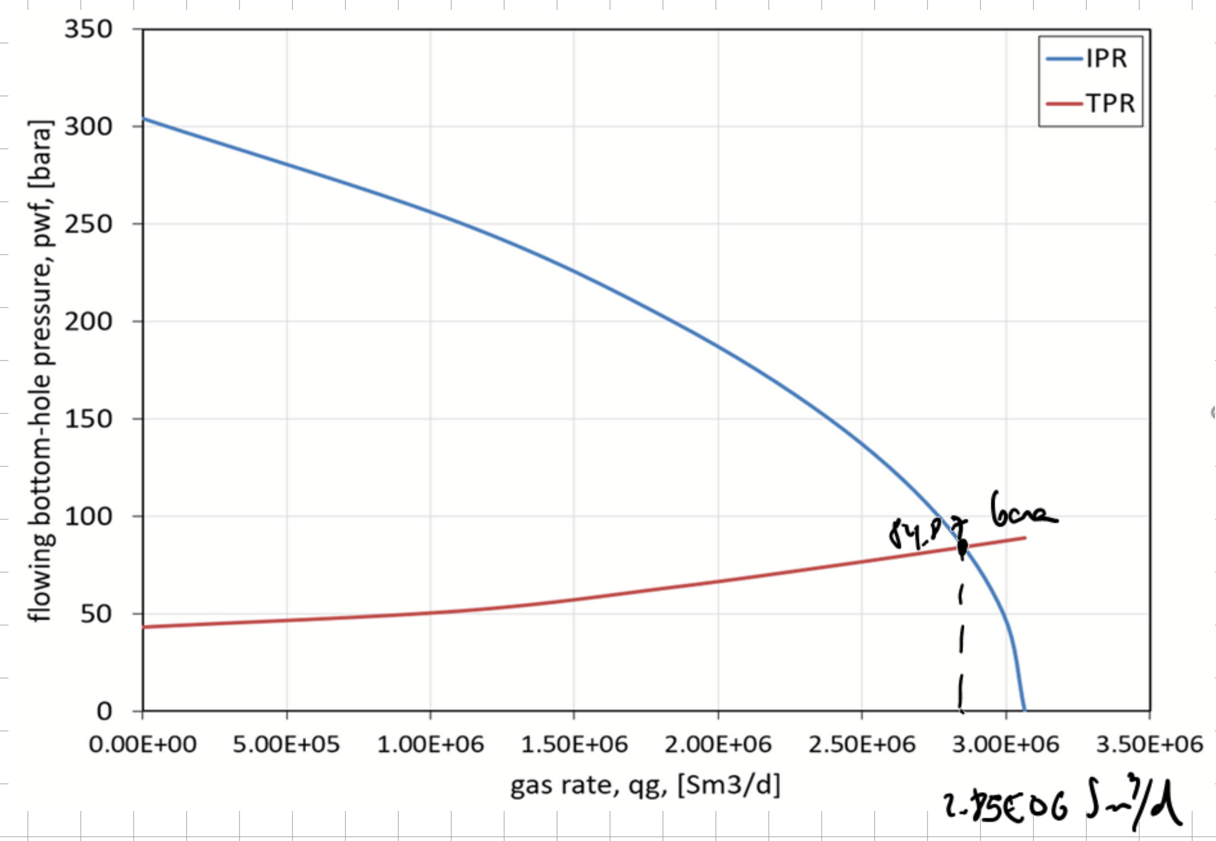
• select an equilibrium point → bottom-hole

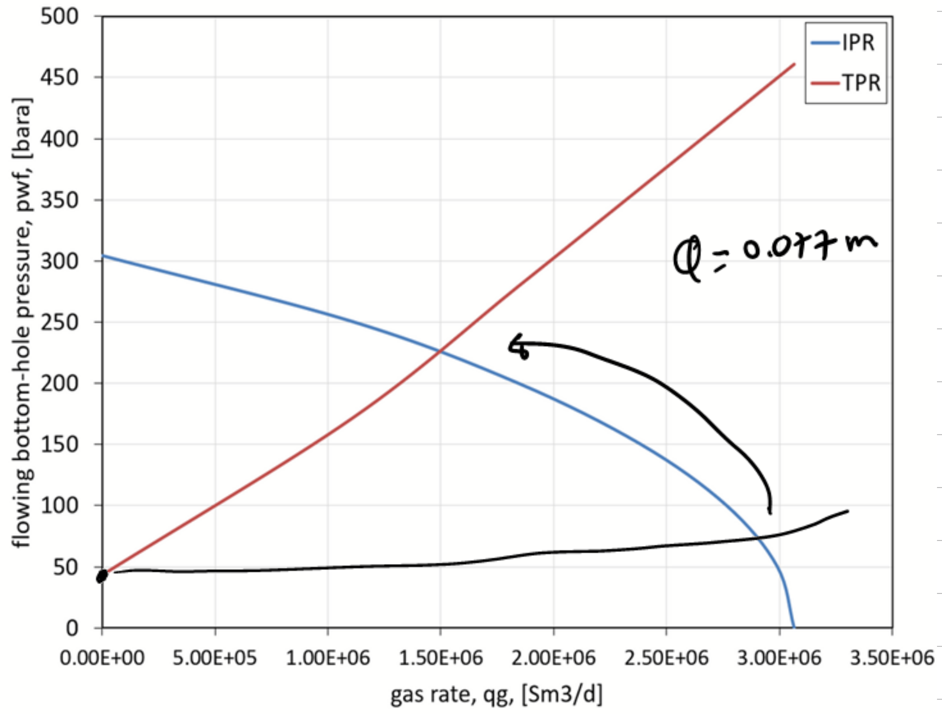


$$q_g = C_R \left(p_R^2 - p_{wf}^2\right)^{n}$$

$$q_g = C_T \left(\frac{p_{wf}^2}{e^S} - p_{wh}^2\right)^{0.5} \rightarrow p_{wf} = \sqrt{\left(p_{wh}^2 + \left(\frac{q_g}{C_T}\right)^2\right) e^S}$$







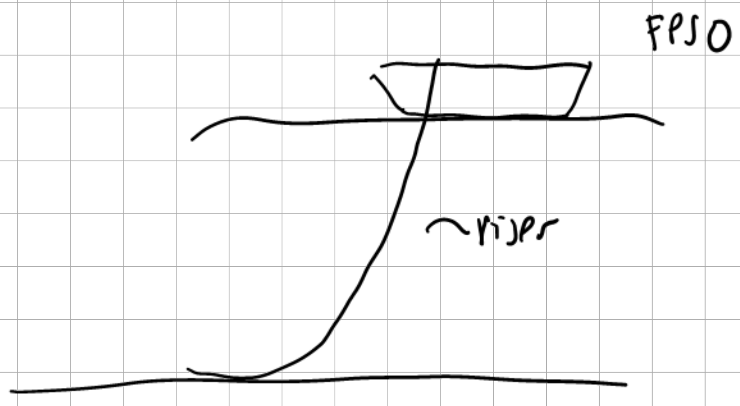
effect of tubing size

$D \downarrow \rightarrow G \downarrow \rightarrow q_g^* \downarrow$

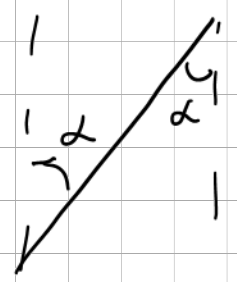
$C_{PL}, C_{FL}, C_{riser}$

$p_1 \rightarrow p_2$

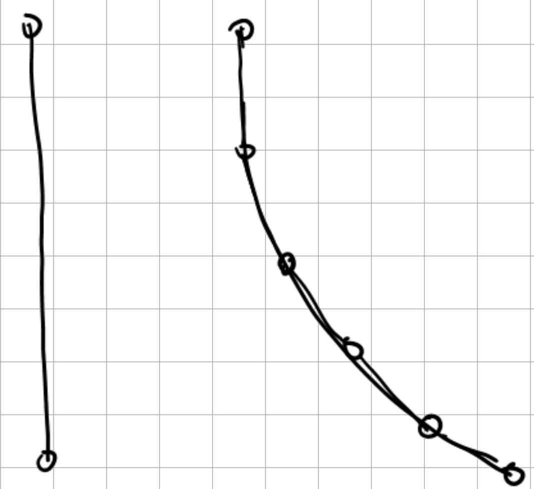
$$q_{sc} = C_T \cdot \left[\left(\frac{p_{wf}^2}{e^S} - p_t^2 \cdot\right)\right]^{0.5}$$

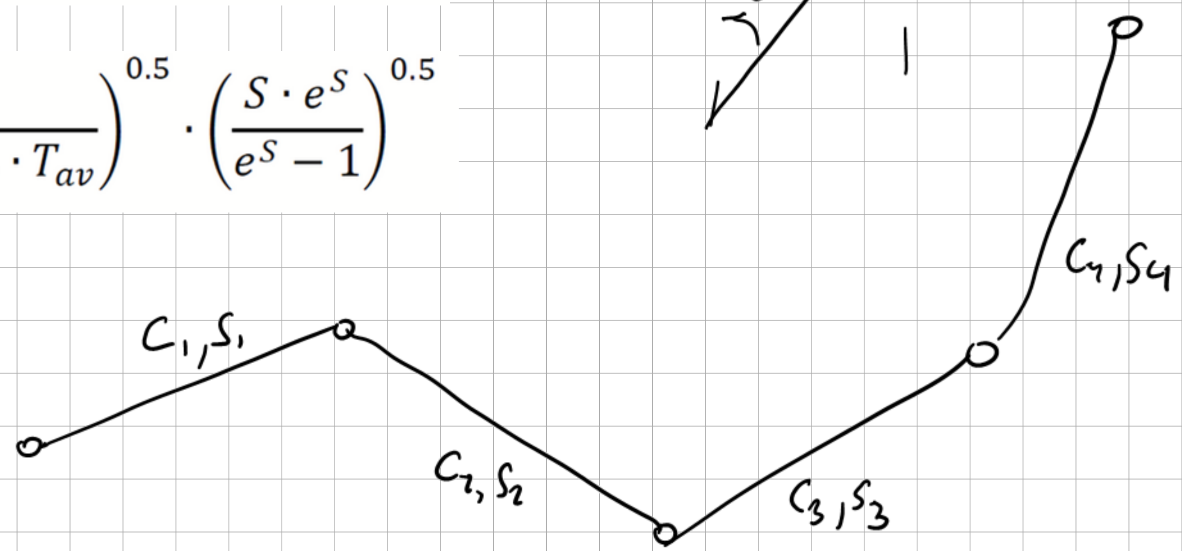


$$S = 2 \cdot L \cdot C_a = 2 \cdot \frac{M_g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot g \cdot \cos(\alpha)$$



$$C_T = \left(\frac{\pi}{4}\right) \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \cdot \left(\frac{T_{sc}}{p_{sc}}\right) \cdot \left(\frac{D^5}{f_M \cdot L \cdot \gamma_g \cdot Z_{av} \cdot T_{av}}\right)^{0.5} \cdot \left(\frac{S \cdot e^S}{e^S - 1}\right)^{0.5}$$





Special case of horizontal pipe $S=0$

however when calculating $C \longrightarrow \frac{S \cdot e^S}{(e^S - 1)}$

$S=0$

$\frac{0 \cdot 1}{(1-1)^{-0}} = \frac{0}{0}$

use L'Hopital rule

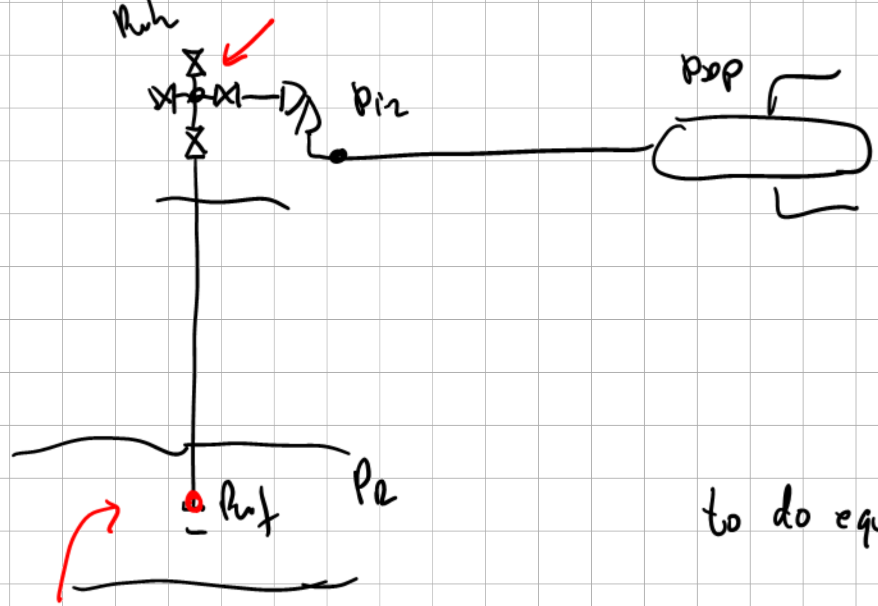
$\lim_{x \to 0} \frac{f(x)}{g(x)} \rightarrow$ undefined

$\lim_{x \to 0} \frac{f'(x)}{g'(x)} \quad \frac{(e^S + Se^S)}{(e^S)} \overset{S \to 0}{=} \frac{1 + 0}{1} = 1$

in horizontal pipe $\frac{Se^S}{(e^S - 1)} = 1$

if $D \uparrow \rightarrow C_{FL} \uparrow \rightarrow$ lower Δp (or larger rate)

if $L \uparrow \rightarrow C_{FL} \downarrow \rightarrow$ higher Δp (or lower rate)



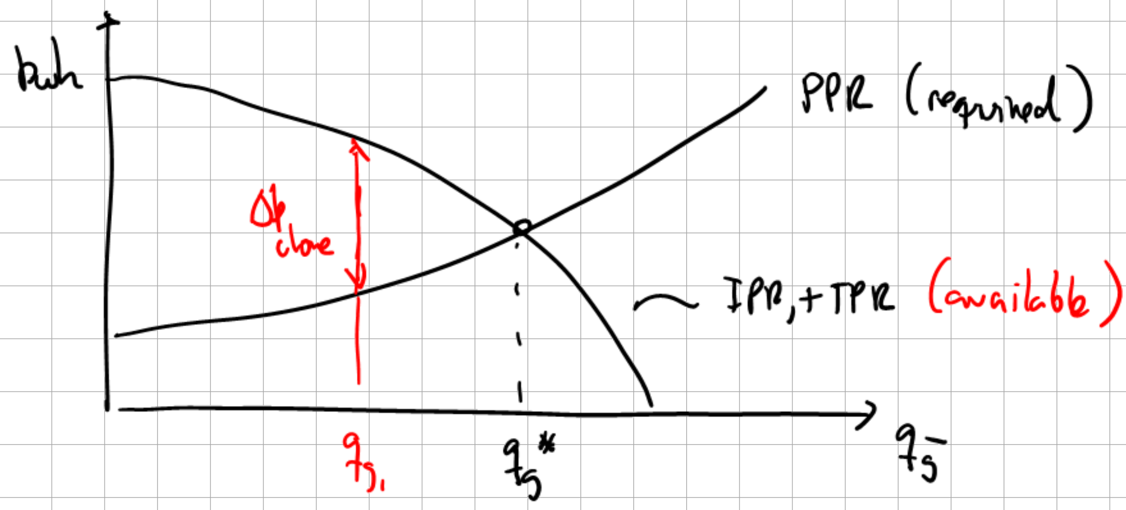
bottom-hole equilibrium

$\Delta p_{choke} = (p_{wh} - p_{in})$

when $\Delta p_{choke} = 0$

$p_{wh} = p_{in}$

to do equilibrium with flowline



p_R, Res pressure	304	bara	
C_R	104	Sm3/d/bar^2n	
n, exponent	0.9		
C_t, tubing	4.25E+04	$Sm^3/d/bar$	
s, elevation	0.155		
C_{fl}, flowline	1.25E+05	4.00E+04	$Sm^3/d/bar$
p_{sep}	40	bara	

$$q_g = c(p_R^2 - p_{wf}^2)^n$$

Tubing performance relationship (TPR)

$$p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

Flowline performance relationship (FPR)

$$\boxed{q_{\bar{g}} = C_{FL} \cdot \left(p_{in}^{\ 2} - p_{out}^{\ 2}\right)}$$

assumed

IPR-q_g

pwf [bara]	qg-IPR [Sm3/d]	pwf-TPR [Sm3/d]	WPR [Sm3/d]	PPR - 1 [bara]	PPR - 2 [bara]
304	0.00E+00	43			
250	1.11E+06	52			
200	1.84E+06	64			
150	2.38E+06	74			
100	2.76E+06	82			
50	2.99E+06	87			
0	3.06E+06	89			
84.378937	2.85E+06	84			

wellhead performance relationship

$p_{wf} \xrightarrow{} p_{wh}$

TPR

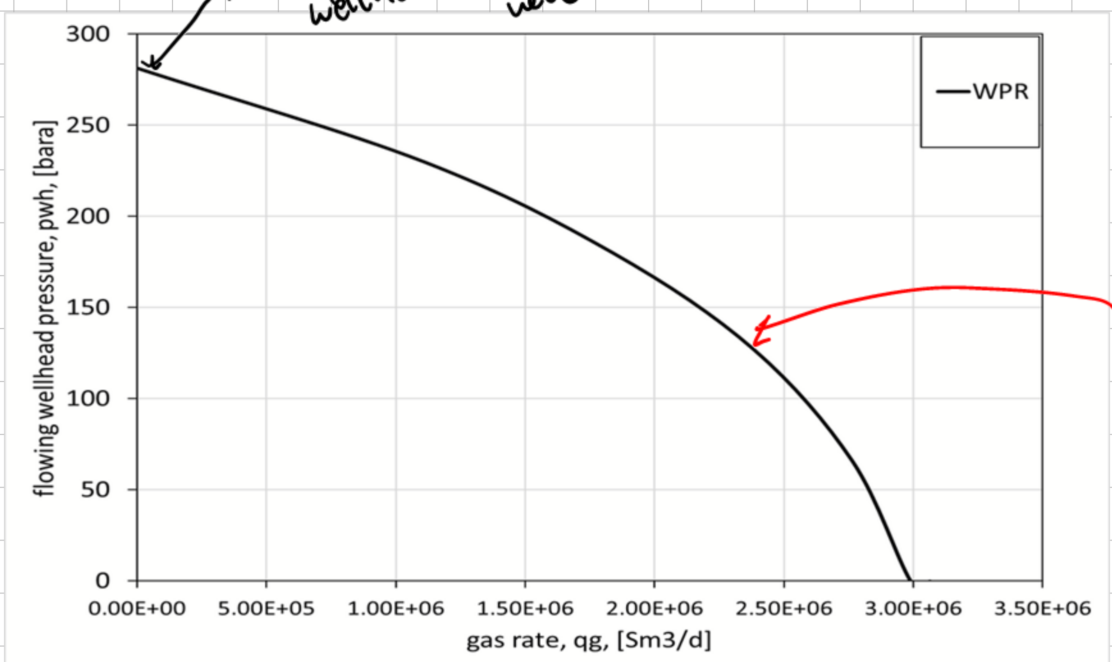
required, with TPR, assuming p_{wh} = 40 bar

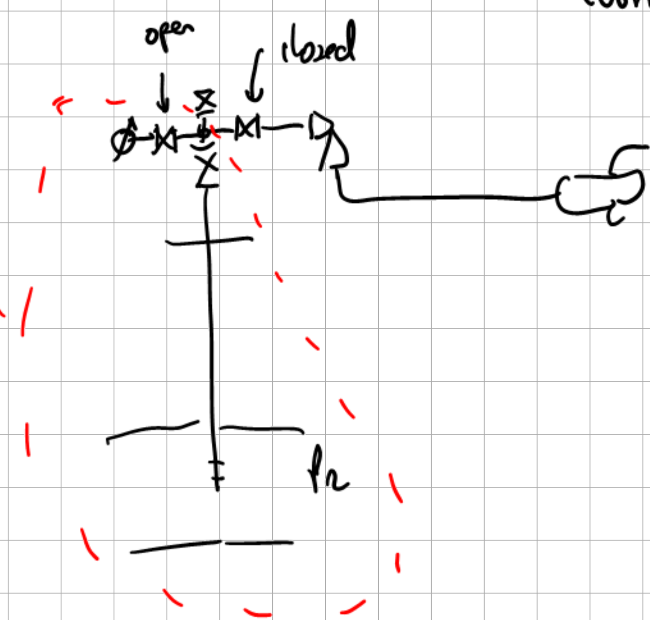
tubing_qg (P_1, P_2)

can be computed → tubing_P_1 (P_2, q_g)

tubing_P_2 (P_1, q_g)

pressure required at wellhead with closed well

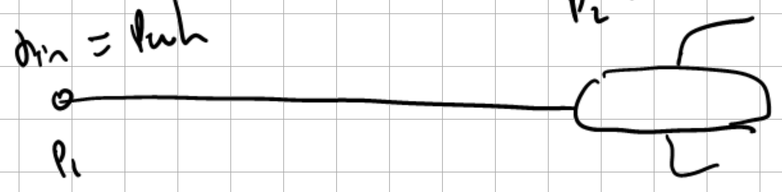


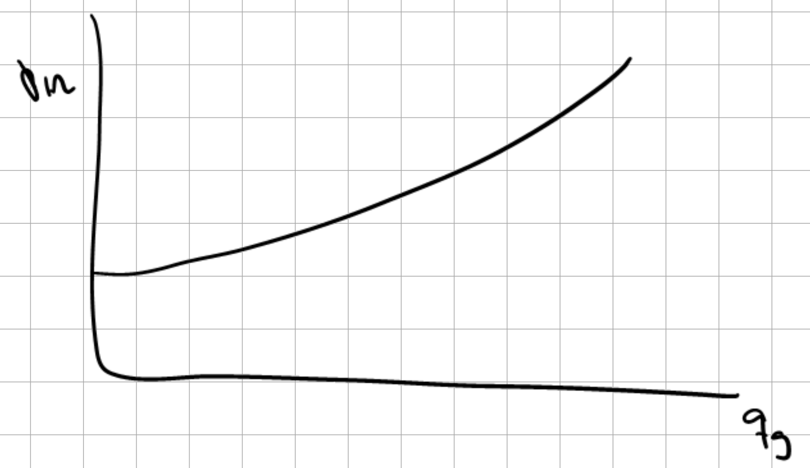


$q_{in} = p_{wh}$

$p_2 = 40$ bara

p_1





$$q_g = C_{FL} \cdot \left(\frac{p_1^2}{e^s} - p_2^2 \right)^{0.5}$$

horizontal $\quad s \to 0$

$$q_g = C_{FL} \left(p_1^2 - p_2^2 \right)^{0.5}$$

required pressure

$$p_1 = \sqrt{p_2^2 + \left(\frac{q_g}{C_{FL}} \right)^2}$$

```
Function Linep1(Cfl, p2, qg)
Linep1 = (p2 ^ 2 + (qg / Cfl) ^ 2) ^ 0.5
End Function
```

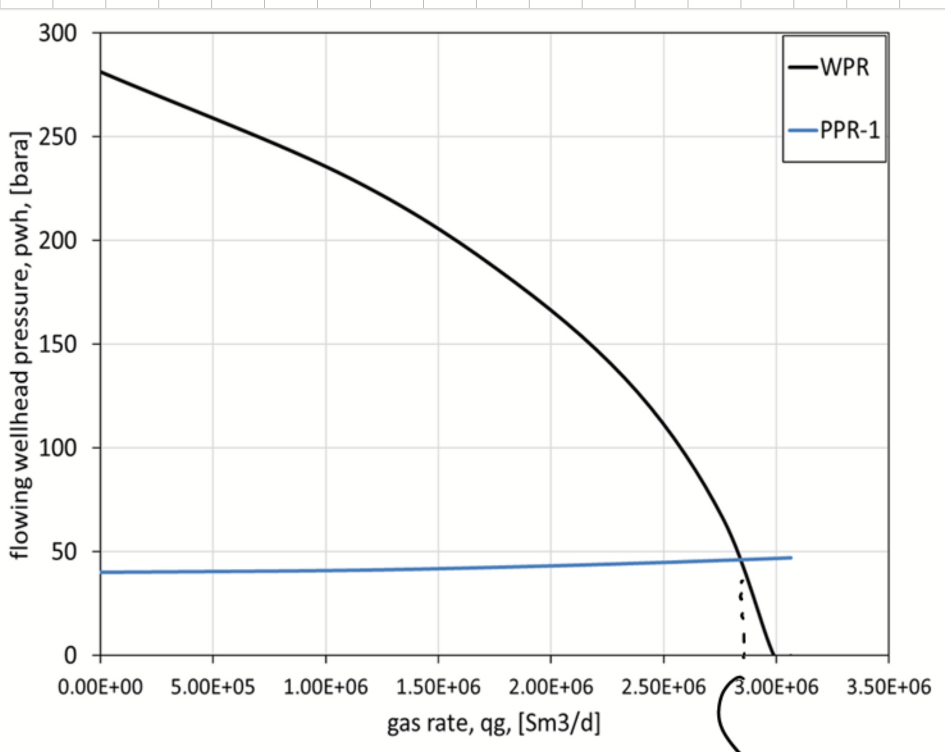
pwf [bara]	qg-IPR [Sm3/d]	pwf-TPR [Sm3/d]	WPR [Sm3/d]
304	0.00E+00	43	281
250	1.11E+06	52	230
200	1.84E+06	64	180
150	2.38E+06	74	127
100	2.76E+06	82	66
50	2.99E+06	87	#VALUE!
0	3.06E+06	89	#VALUE!

$$q_g = C_T \left(\frac{p_{wf}^2}{e^s} - p_{wh}^2 \right)^{0.5}$$

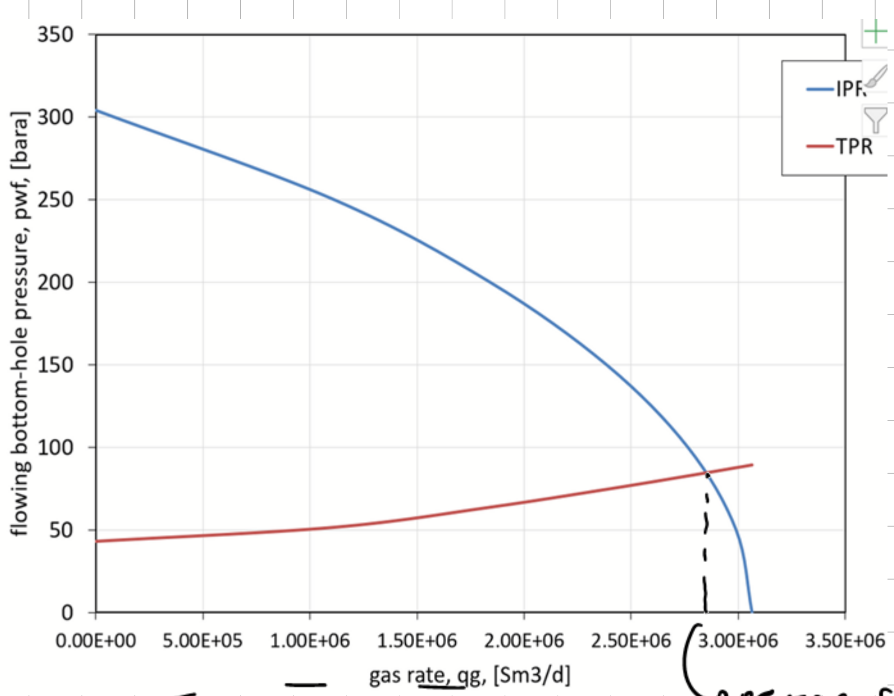
$$p_{wh} = \sqrt{\underbrace{\frac{(p_{wf})^2}{e^s} - \left(\frac{q_g}{C_T} \right)^2}}$$

(+)

(−)



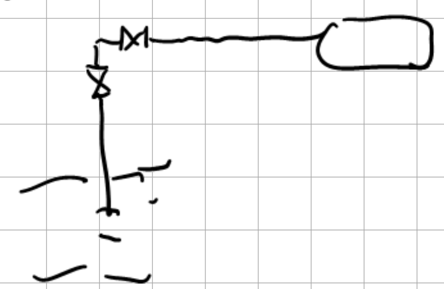
a bit lower



→ 2.85E06 Sm^3/d

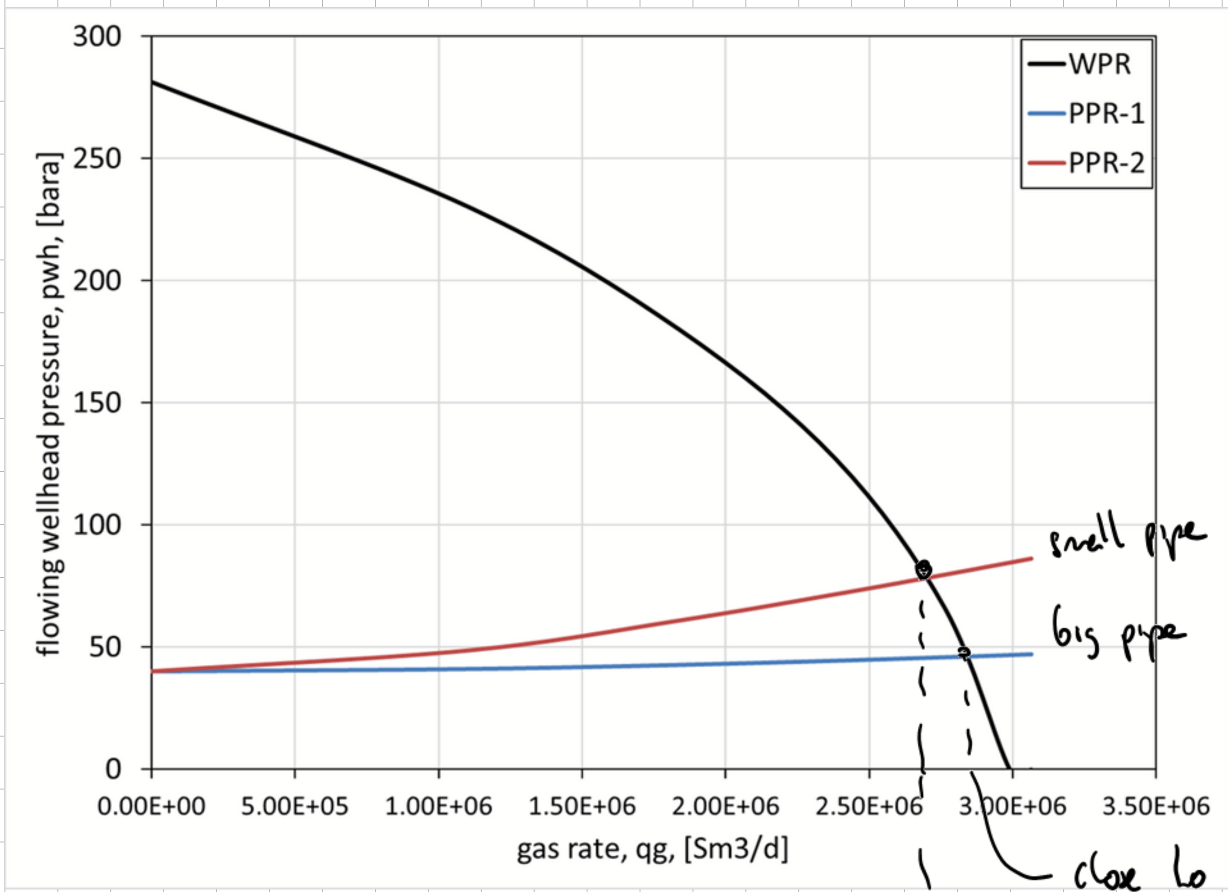
$p_{sep} = 40$ bara

wellhead eq



bottom-hole eq

$p_{wh} = 40$ bara

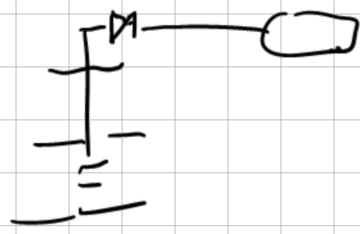


close to 2.85 E06 Sm^3/d

much lower than 2.85 E06 Sm^3/d

wellhead eq.

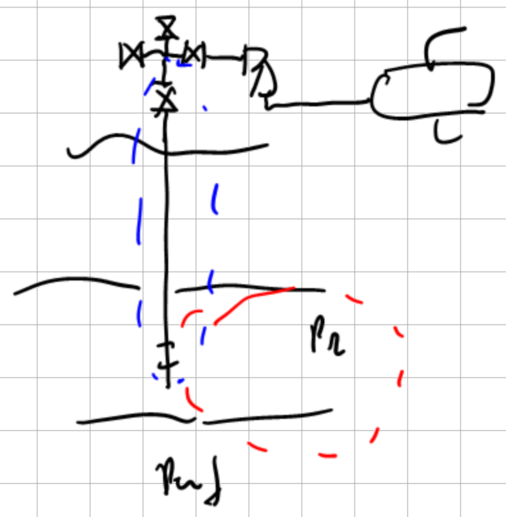
pipeline included



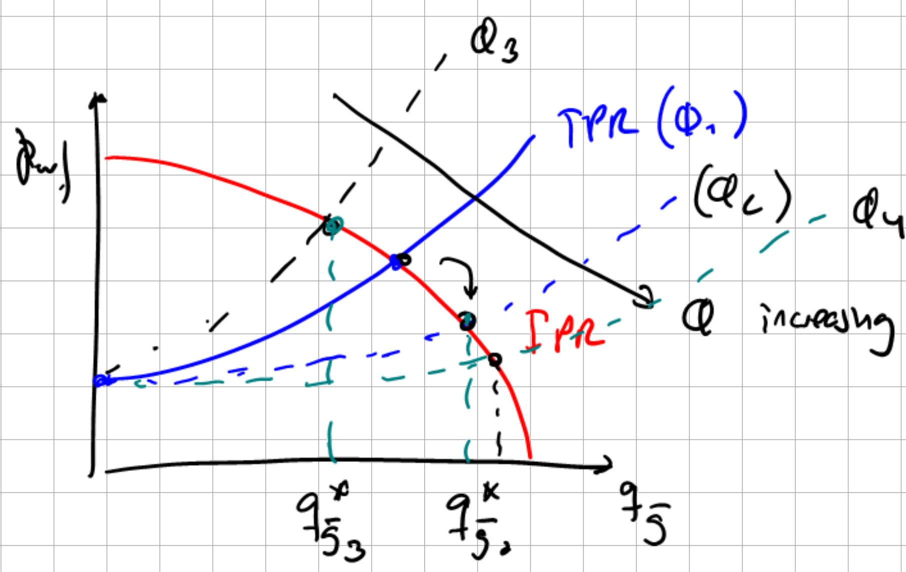
{ Small pipeline
long pipeline

Tubing size considerations: (ϕ)

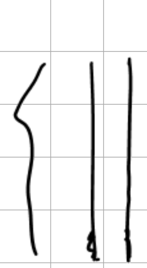
- Maximize $q_{\bar{o}}$, $q_{\bar{g}}$ → increase equilibrium rate
  ↳ revenue



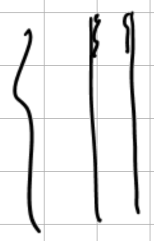
$P_{wh} = P_{sep}$



- minimize cost ↓ϕ, ↓ cost



tubing comes in discrete sizes $\phi \rightarrow \begin{cases} \phi_1 \\ \phi_2 \\ \phi_3 \end{cases}$



tubing according to API specs

used in pipe flow calculations

Tubing Size		Nominal Weight					Threaded Coupling						Joint Yield Strength		Capacity Table	
								Coupling Outside Dia.								
Nom. in.	OD in.	T & C Non-Upset lb/ft	T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Drift Dia. in.	Non-Upset in.	Upset Reg. in.	Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	T & C Non-Upset lb	T & C Upset lb	Barrels per Linear ft	Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40 J-55 C-75 N-80	0.113	0.824	0.730	1.313	1.660		7,200 9,370 12,250 12,710	7,530 10,360 14,120 15,070	6,360 8,740 11,920 12,710	13,300 18,290 24,940 26,610	0.0007	1516.13
1	1.315	1.700	1.800	H-40 J-55 C-75 N-80	0.113	1.049	0.955	1.660	1.900		6,820 8,860 11,590 12,270	7,080 9,730 13,270 14,160	10,960 15,060 20,540 21,910	19,760 27,160 37,040 39,510	0.0011	935.49
1 1/4	1.660	2.300	2.400	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.140 0.125 0.140 0.140 0.140	1.410 1.380 1.410 1.380 1.380 1.380	1.286	2.054	2.200		5,220 5,790 6,790 7,530 9,840 10,420	5,270 5,900 7,250 8,120 11,070 11,810	15,530 21,360 29,120 31,060	26,740 36,770 50,140 53,480	0.0019 0.0018 0.0019 0.0018 0.0018 0.0018	517.79 540.55 517.79 540.55 540.55 540.55

Non-API tubing (tubulars)

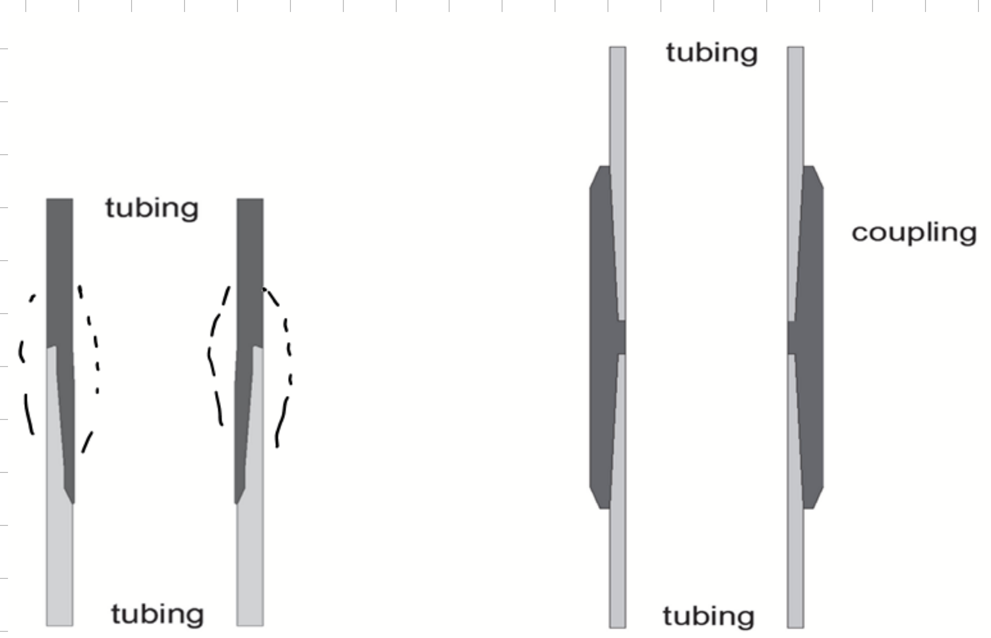
VAM – Vallourec (French)

		VAM® 21	VAM® 21 HT	VAM TOP ®	VAM TOP ® HT	VAM TOP ® HC	VAM® HTTC	VAM® HP	VAM® HW ST	VAM® LOX	VAM® BOLT-II	VAM® HTF-NR	VAM® FJL	VAM® MUST	VAM® SG	VAM® EDGE SF	VAM® SLIJ-II	VAM® LIFT	DINO VAM®	BIG OMEGA ®	VAM TOP ® FE	VAM® TTR
tub	2 3/8			✓									✓									
	2 7/8			✓									✓									
	3 1/2	✓		✓			✓						✓									
	4			✓									✓									
	4 1/2	✓	✓	✓	✓	✓	✓					✓	✓		✓		✓					
	5	✓	✓	✓	✓	✓	✓		✓			✓	✓		✓	✓	✓					
	5 1/2	✓	✓	✓	✓	✓	✓		✓			✓	✓	✓	✓	✓	✓					
	5 3/4			✓																		
	6	✓	✓	✓	✓	✓																
	6 5/8	✓	✓	✓	✓	✓	✓		✓			✓	✓				✓				✓	
	6 7/8																✓					
	7	✓	✓	✓	✓	✓	✓	✓	✓			✓	✓				✓		✓		✓	
	7 5/8	✓	✓	✓	✓	✓		✓	✓			✓	✓	✓			✓				✓	
	7 3/4	✓		✓		✓						✓					✓				✓	
	8																				✓	
	8 1/8												✓									
	8 5/8	✓		✓				✓					✓				✓				✓	✓
	8 3/4	✓																				
casing	9							✓														
	9 3/8											✓	✓									
	9 5/8	✓	✓	✓			✓		✓			✓	✓				✓		✓		✓	✓
	9 3/4																✓		✓			
	9 7/8	✓		✓								✓	✓				✓		✓		✓	
	10	✓		✓													✓					
	10 1/8	✓		✓				✓			✓						✓					
	10 1/2							✓														
	10 3/4	✓		✓				✓	✓				✓	✓			✓		✓		✓	✓

riser flowline :
26

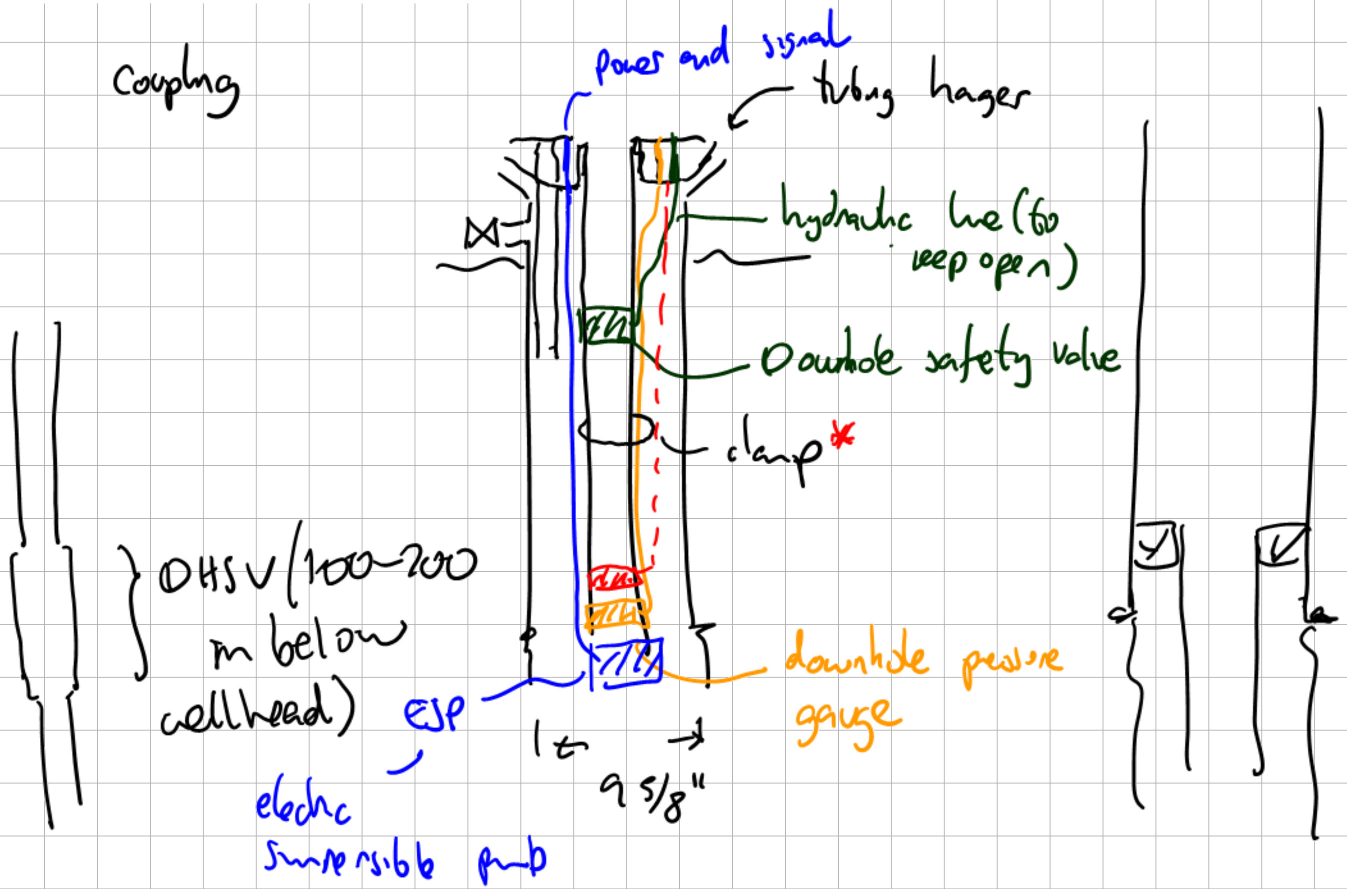
7'' - 32# - P-110 - BTC/LTC

- 7'': nominal size
- 32#: weight per length, pound per foot, ppf
- P-110: steel "type", grade, resistance
- BTC/LTC: type of thread

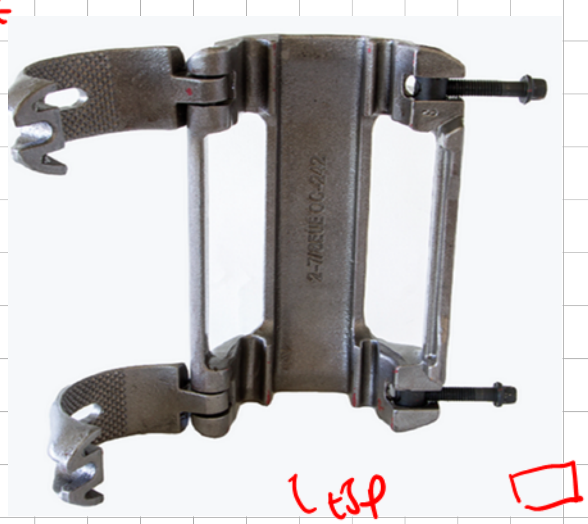


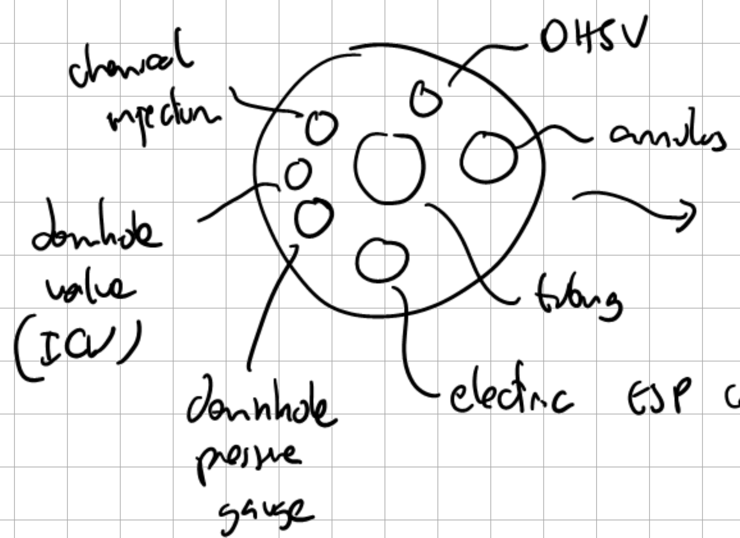
integrated joint Coupling

- tubing hanger considerations

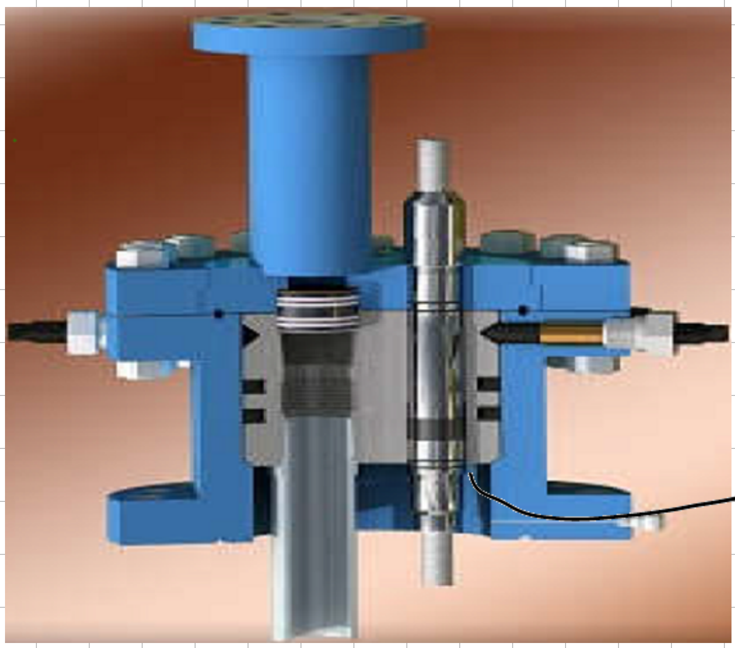


*





→ structurally "solid"



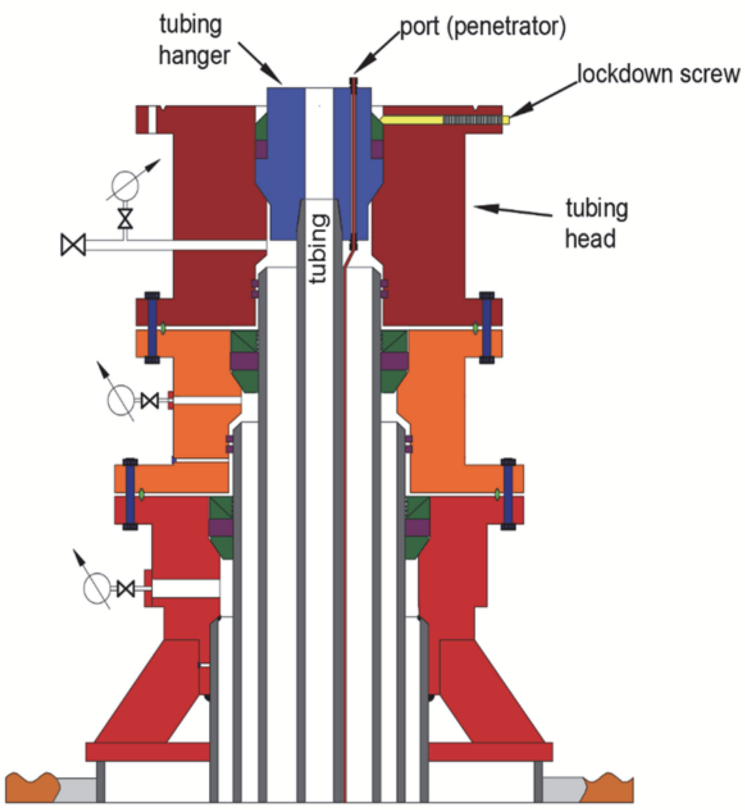
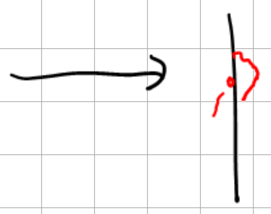


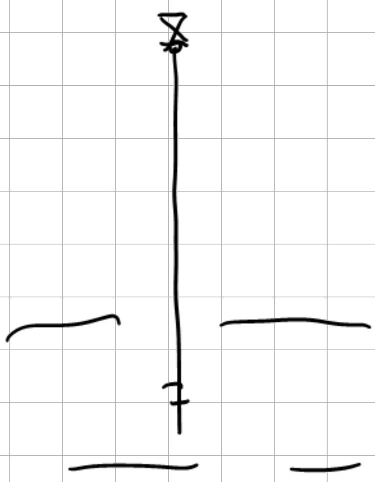
FIGURE 6-10. FINAL CONFIGURATION OF THE WELLHEAD

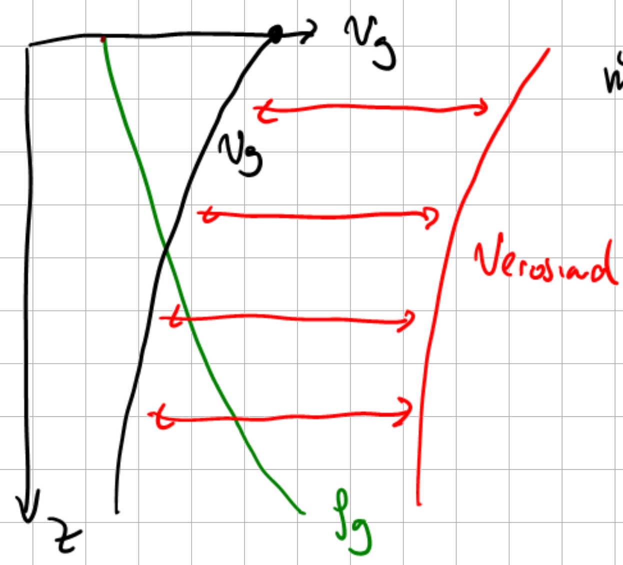
- erosional velocity



$$v_f < V_{erosional\ velocity}$$

gas well $\quad v_f = v_g = \frac{q_g}{A}$





$$\dot{m}_g = \bar{\rho}_g \bar{q}_g = q_g \cdot \rho_g = v_g \cdot A \cdot \rho_g$$

$$v_g = \frac{\bar{\rho}_g \bar{q}_g}{A \rho_g}$$ constant with depth

API 14E $\sim$ $V_{erosional} = \frac{C}{\sqrt{\rho_m}} \rightarrow (100 - 125)$ "severe" $\left[ft/s \right]$

conservative

$\rho_m \sim \left[lb/ft^3 \right]$

$$\rho_m = f(\rho_L, \rho_g)$$

e.g. $$\rho_m = \frac{q_o \rho_o + q_g \rho_g + q_w \rho_w}{q_o + q_g + q_w}$$

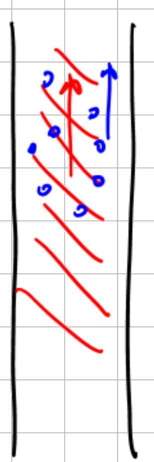
what happens if there is more than 1 fluid in the tubing?

$$o + g + w$$

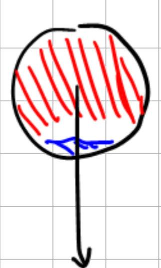
$$v_m = \frac{(q_o + q_g + q_w)}{A} = \underbrace{\frac{q_o}{A}}_{u_{so}} + \underbrace{\frac{q_g}{A}}_{u_{sg}} + \underbrace{\frac{q_w}{A}}_{u_{sw}}$$

↳ superficial velocity

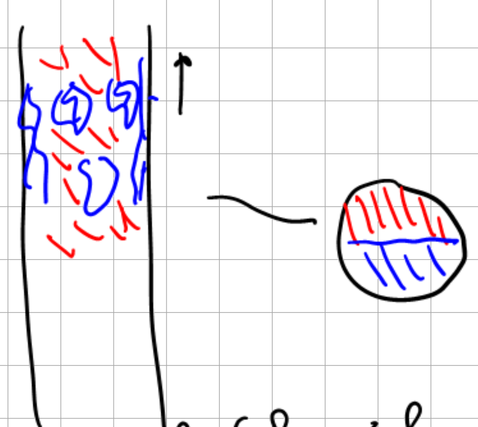
- only in gas wells → avoid liquid loading



if $v_g \downarrow$



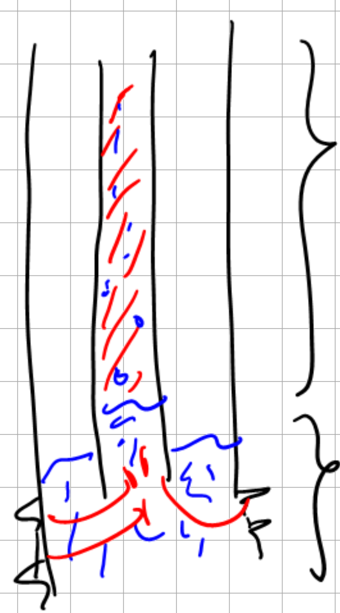
$\rho_m \rightarrow \rho_g$



$\rightarrow \uparrow \Delta p$

$\rho_g < \rho_m < \rho_L$

$H_L = \frac{A_L}{A} \qquad \rho_m = (H_L)\rho_L + (1 - H_L)\rho_g$

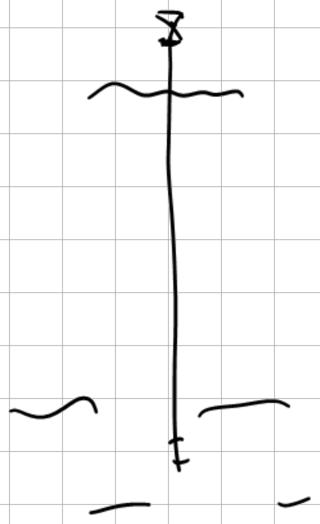


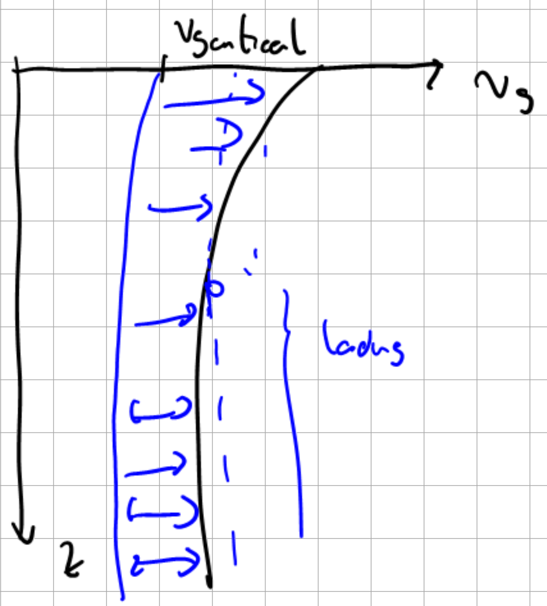
un-loaded

loaded "liquid loading"

in general $H_L \neq \frac{q_L}{q_L + q_g}$

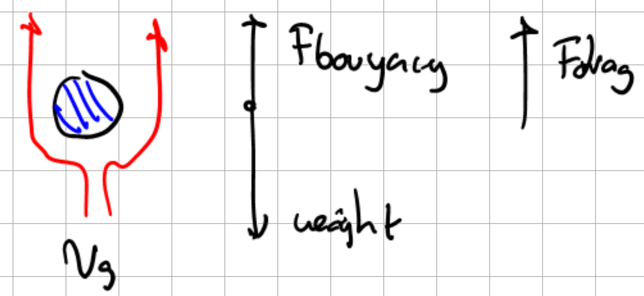
$v_g > v_{critical}$ for all tubing depths





How to calculate $v_{critical}$?

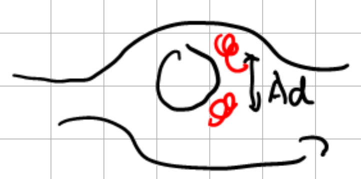
Turner criteria



$F_{drag} + F_{bouyancy} = F_{weight}$

$\frac{1}{2}\rho_g C_D v_g^2 A_d + V_d \rho_g g = V_d \cdot \rho_L \cdot g$

$C_D \rightarrow 0.44$



$V_d = \frac{\pi \phi^3}{6}$ $A_d = \frac{\pi \phi^2}{4}$

$\frac{1}{2}\rho_g\, 0.44\, v_g^2 \frac{\pi \phi^2}{4} = (\rho_L - \rho_g) g \frac{\pi \phi^3}{6}$

Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells

R. G. Turner, SPE-AIME, Baker Oil Tools, Inc.
M. G. Hubbard, SPE-AIME, U. of Houston
A. E. Dukler, U. of Houston

1969

$v_{crit} = \sqrt{\frac{4}{3}\frac{(\rho_L - \rho_g)}{\rho_g}\frac{\phi\, g}{0.44}}$

$N_{We} = \frac{\rho_g u_g^2 d}{\sigma_{gL}}$ — Drag

σ_{gL} — interfacial tension

weber

Fundamentals of the Hydrodynamic Mechanism of Splitting in Dispersion Processes

J. O. Hinze, Royal Dutch Shell-Laboratory, Delft, Holland

1955

$N_{We} = 30 \rightarrow \phi_{max}$

$30 = \frac{\rho_g u_g^2 \phi}{\sigma_{Lg}}$

$\phi = \frac{\sigma_{Lg}\, 30}{\rho_g u_g^2}$

for every depth in tubing

$v_g \geq v_{crit}$

$v_{crit} = 5.46 \left[\frac{\sigma_{Lg}^{0.25}(\rho_L - \rho_g)^{0.25}}{\rho_g^{0.5}}\right]$ [m/s]

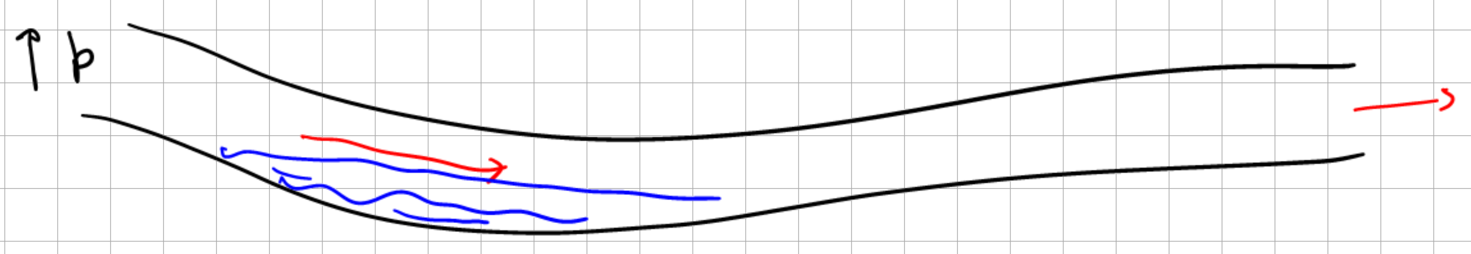
σ in $\left(\frac{N}{m}\right)$

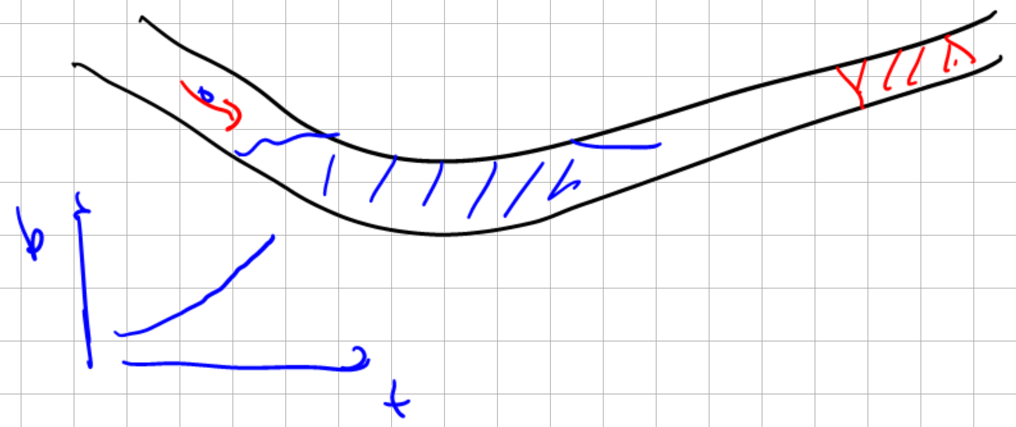
ρ in $\left(\text{kg}/\text{m}^3\right)$

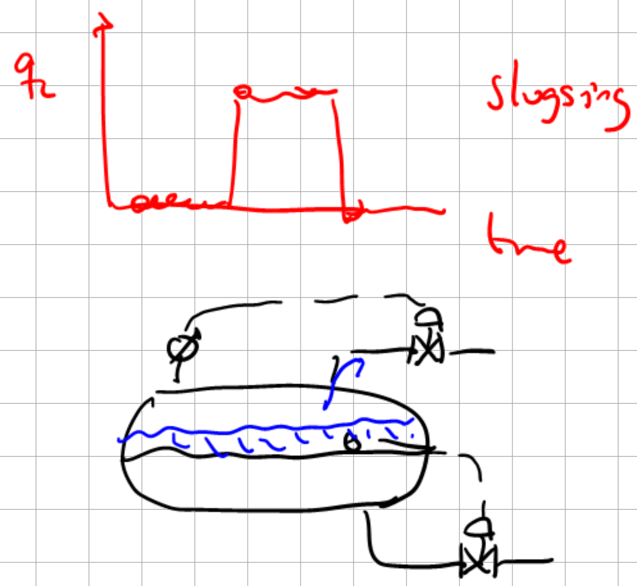
- pipeline sizing considerations

$\uparrow q_{fs}, \uparrow q_{fo} \quad \downarrow \text{cost}$

- v_g high enough to avoid accumulation of liquid (gas condensate pipeline)



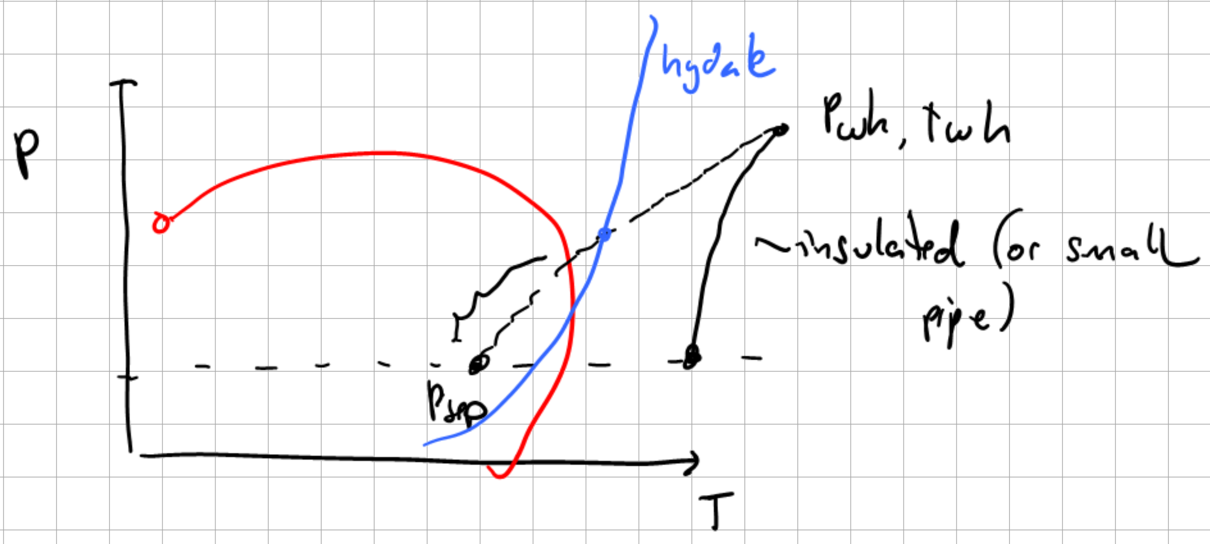




- heat transfer

$$\mathring{q} = A \cdot U (T_f - T_{amb})$$
$$= \pi D \cdot L\, U (T_f - T_{amb})$$

$$D \uparrow \quad \mathring{q} \uparrow \quad T_f \rightarrow \downarrow$$



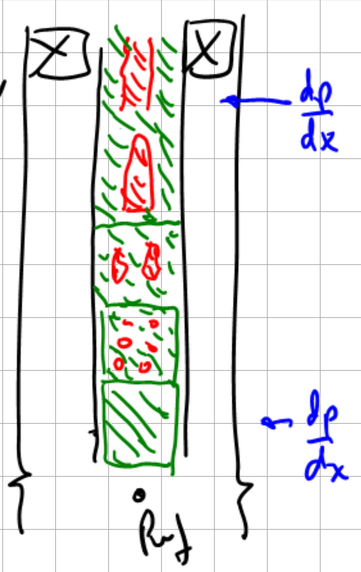
can also cause hydrate formation

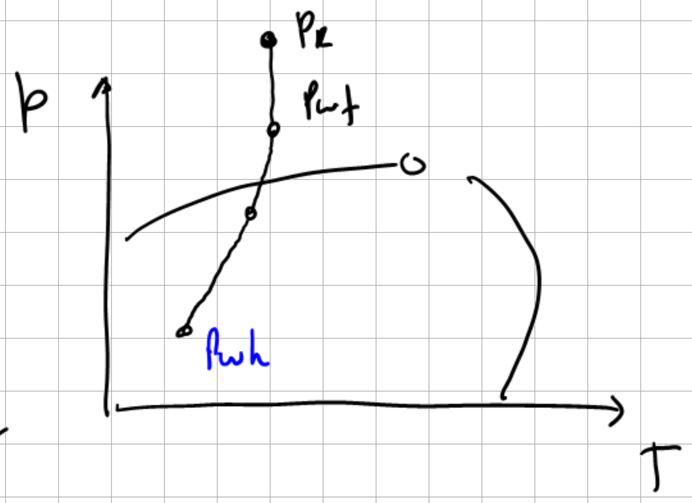
amular flow

slug flow

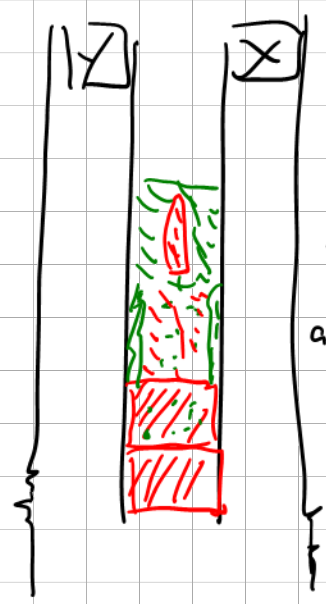
churn flow

buble flow





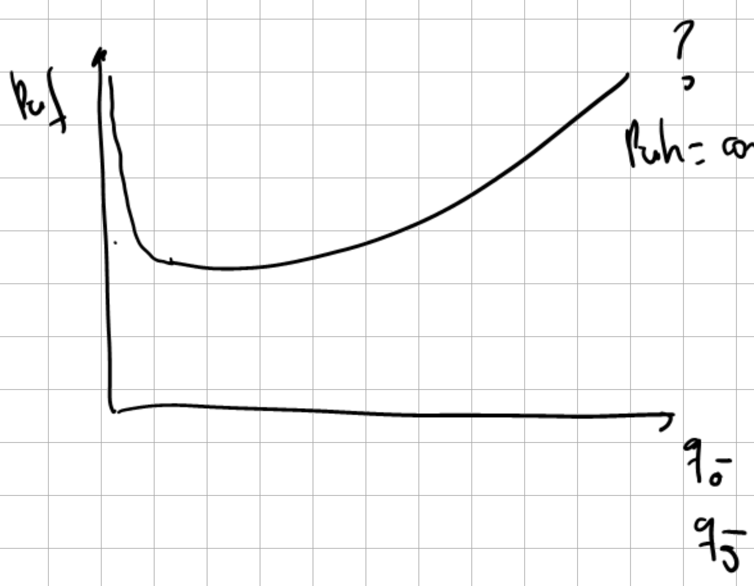
flow patterns

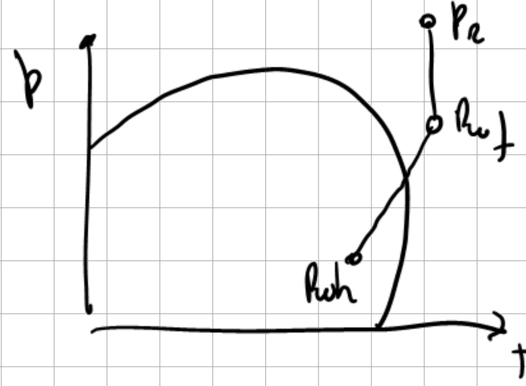


slug flow

amular flow

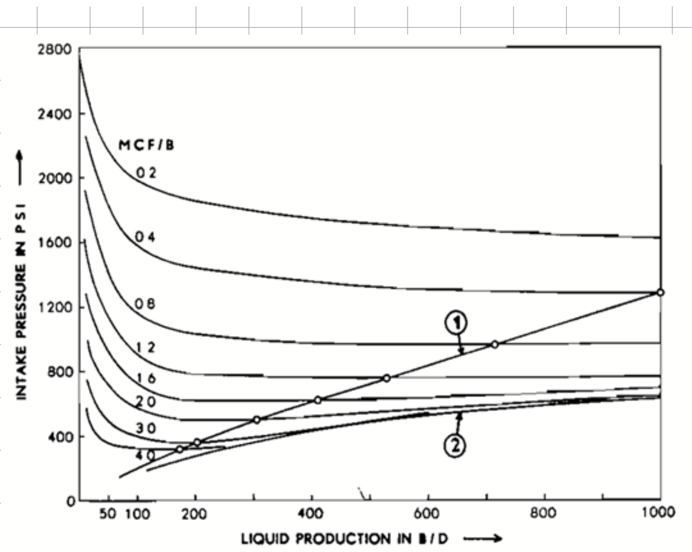
mist flow





Flowing and Gas-lift Well Performance†

W. E. GILBERT*



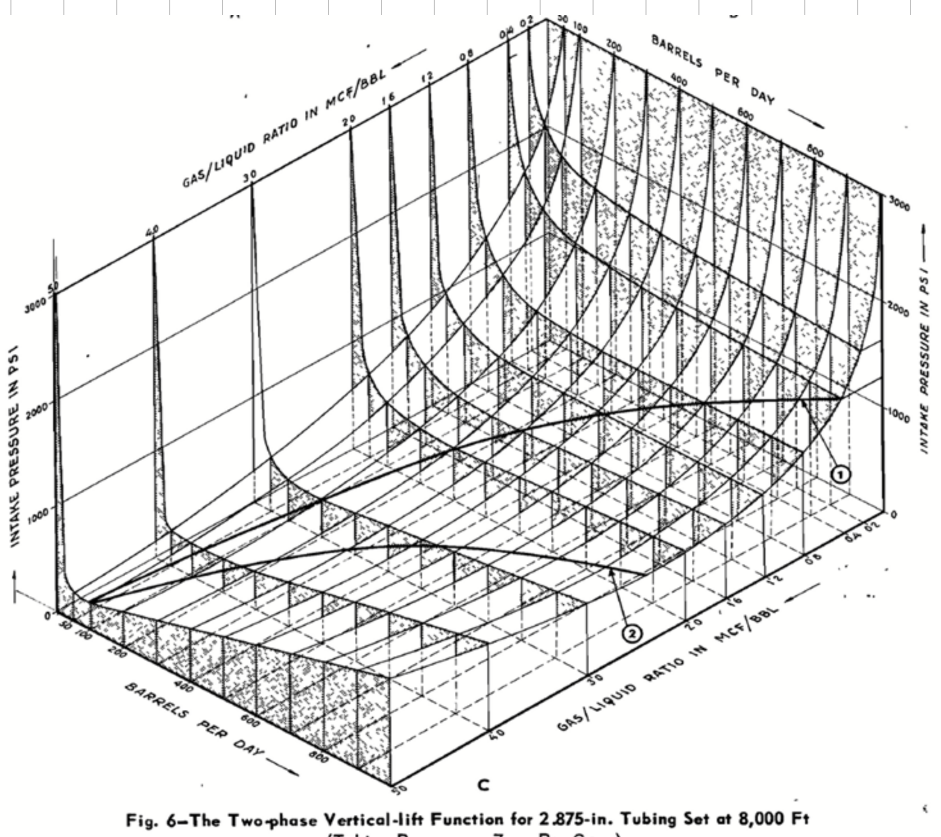
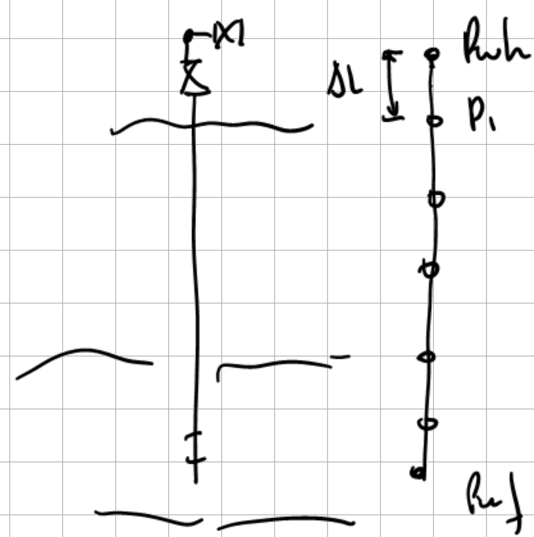


Fig. 6–The Two-phase Vertical-lift Function for 2.875-in. Tubing Set at 8,000 Ft
(Tubing Pressure = Zero Psi Gage)

$$\Delta p_{tubing} = \Delta p_{hydrostatic} + \Delta p_{friction}$$



$$\frac{dp}{dx}\Big|_{P_{wh}} \rightarrow P_1$$

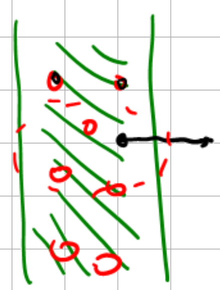
$$P_1 = P_{wh} + \frac{dp}{dx}\Big|_{P_{wh}} \cdot \Delta L$$

?

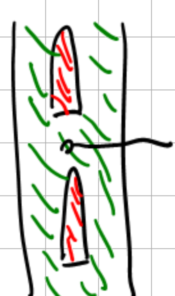
$$P_2 = P_1 + \frac{dp}{dx}\Big|_{P_1} \cdot \Delta L$$

integration

marching algorithm



$$\frac{d}{dt} \neq 0$$



$x \qquad \bar{x} = \int_t x \, dt \qquad \bar{x} = \int_A x \, dA$

$\frac{dp}{dx}$ ~> PVT properties $(\rho_L, \rho_g, \mu_L, \mu_g, \sigma_{Lg}, x_g)$ mass fraction

~> velocity (q_g, q_L)

~> A, Φ, θ, e roughness

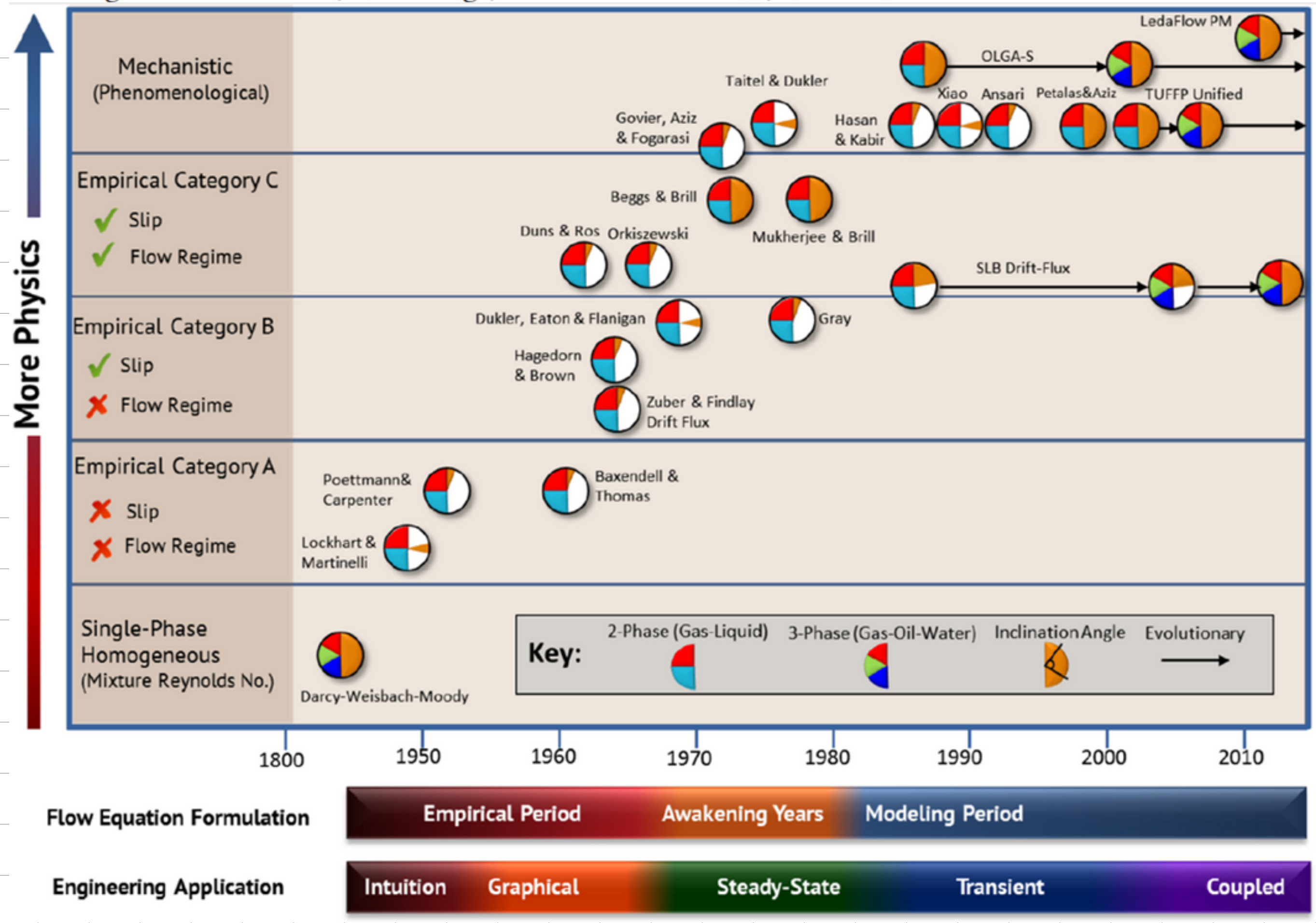
Steady-State Multiphase Flow—Past, Present, and Future, with a Perspective on Flow Assurance

Mack Shippen*

Schlumberger SIS, Houston, Texas 77056, United States

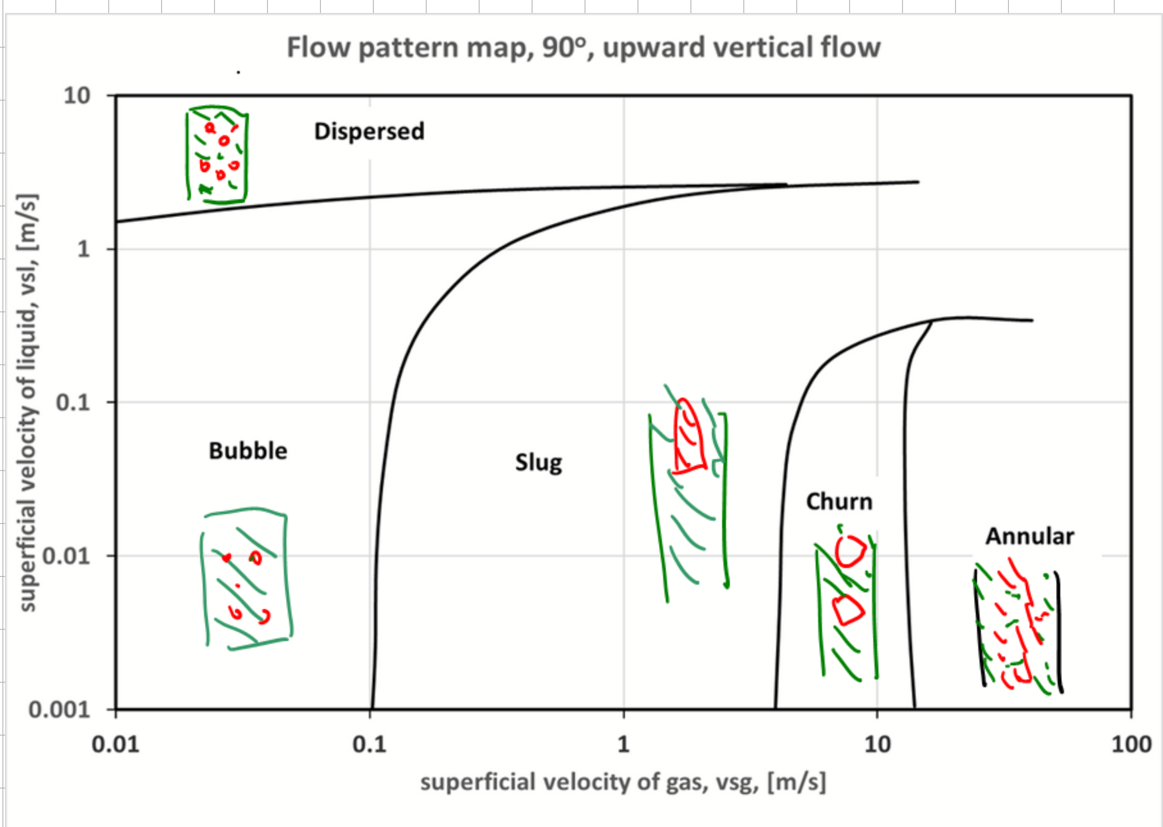
William J. Bailey

Schlumberger—Doll Research, Cambridge, Massachusetts 02139, United States



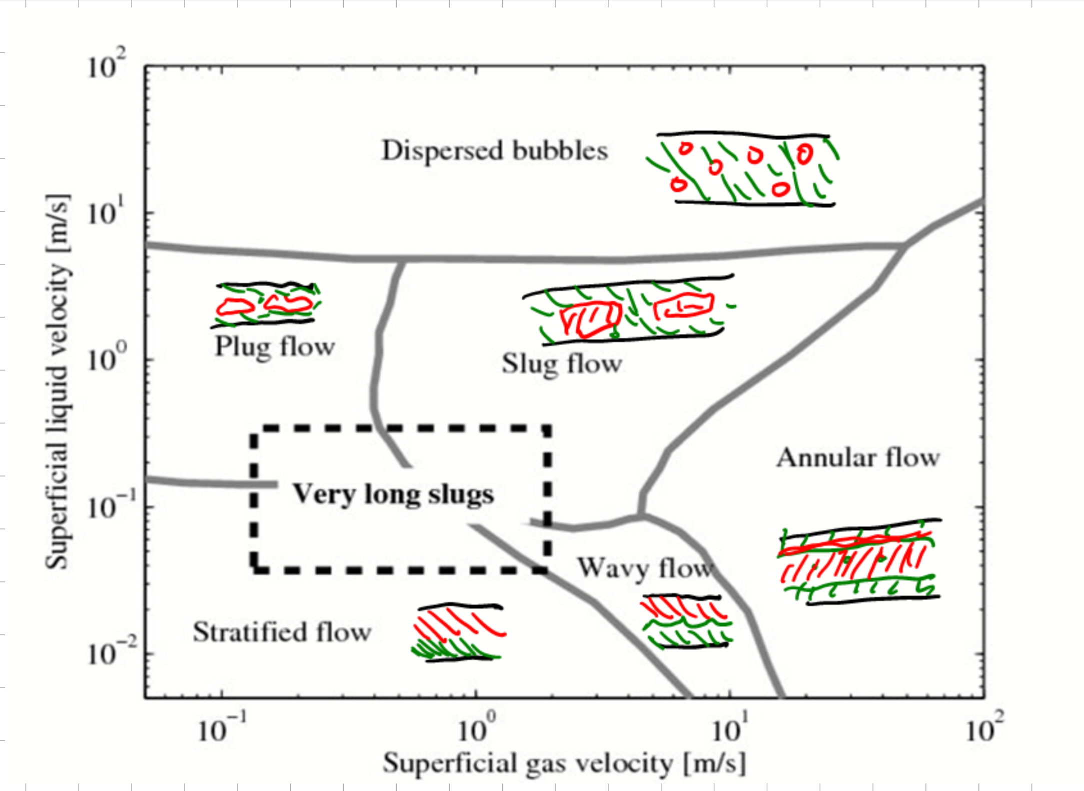
flow pattern map

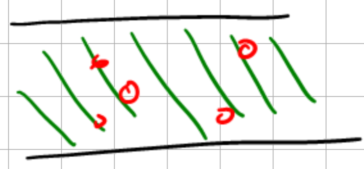
for a given fluid, pipe, inclination, etc



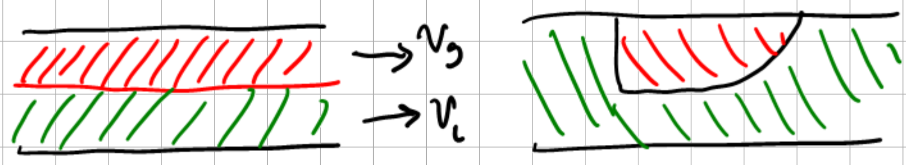
$u_{sL} = \frac{q_L}{A}$

$u_{sg} = \frac{q_g}{A}$


Dispersed bubbles
Plug flow
Slug flow
Very long slugs
Annular flow
Wavy flow
Stratified flow
Superficial liquid velocity [m/s]
Superficial gas velocity [m/s]
10^{-2}
10^{-1}
10^{0}
10^{1}
10^{2}

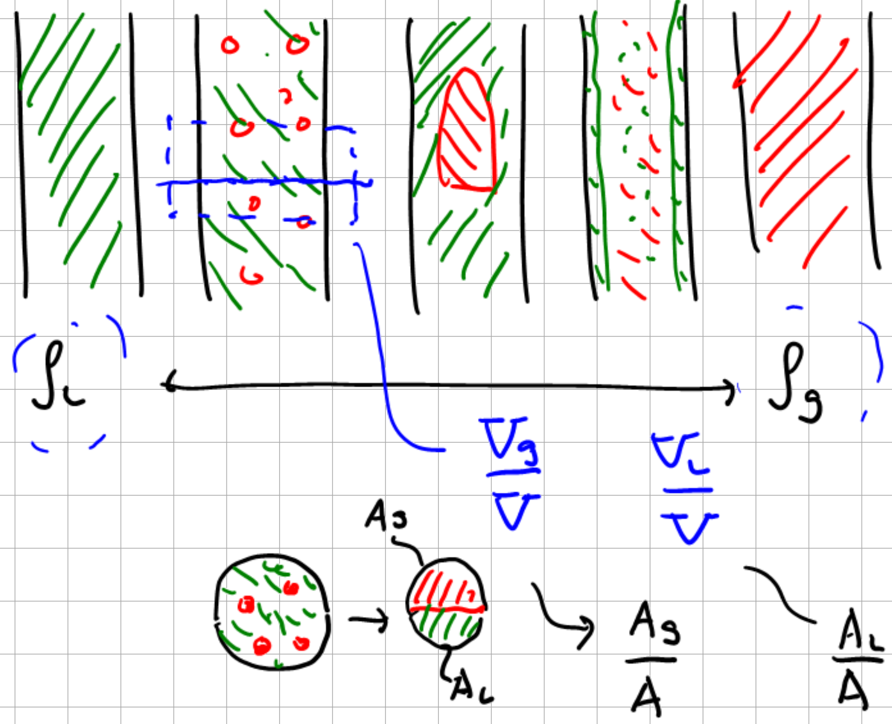


- flow patterns

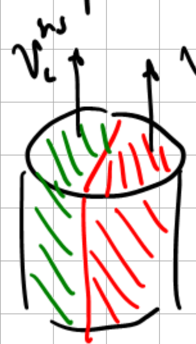


- phase velocity $\rightsquigarrow$ friction Δp

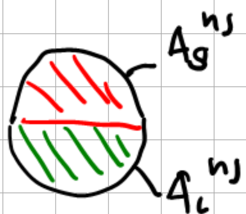
- phase spatial distribution $\rightsquigarrow$ hydrostatic Δp



Liquid and gas travel at the same velocity (no-slip)



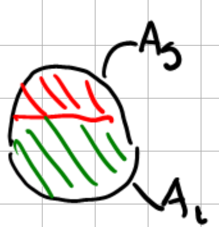
$$V_L^{ns} = V_g^{ns} = V_m = \frac{q_g + q_L}{A} = \frac{q_g}{A} + \frac{q_L}{A} = u_{sg} + u_{sL}$$



$$\lambda_g = \frac{A_g^{ns}}{A} = 1 - \lambda_L = \frac{q_g}{q_g + q_L} \qquad q_g \uparrow\uparrow >> q_L \longrightarrow \lambda_g \to 1$$

$$\lambda_L = \frac{A_L^{ns}}{A} = 1 - \lambda_g = \frac{q_L}{q_g + q_L} \qquad q_L >> q_g \longrightarrow \lambda_L \to 1$$

gas and liquid move at different velocities $V_g \neq V_L$ (slip condition)



void fraction

$$\varepsilon = \underbrace{H_g}_{\text{gas holdup}} = \frac{A_g}{A} = 1 - H_L$$

$$\underbrace{H_L}_{\text{liquid holdup}} = \frac{A_L}{A} = 1 - H_g$$

V_g ?

V_L ?

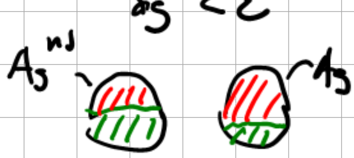
mass conservation between non-slip condition and slip condition

$$q_g = V_g^{ns} \cdot A_g^{ns} = V_g \cdot A_g \qquad \text{divide by } A$$

$$V_g^{ns} \lambda_g = V_g \cdot \varepsilon$$

$$\lambda_g < \varepsilon \longleftarrow \boxed{V_g = V_m \frac{\lambda_g}{\varepsilon}} \longrightarrow \lambda_g = \varepsilon$$

$$V_g = V_m$$



$V_g < V_m$

$\downarrow$

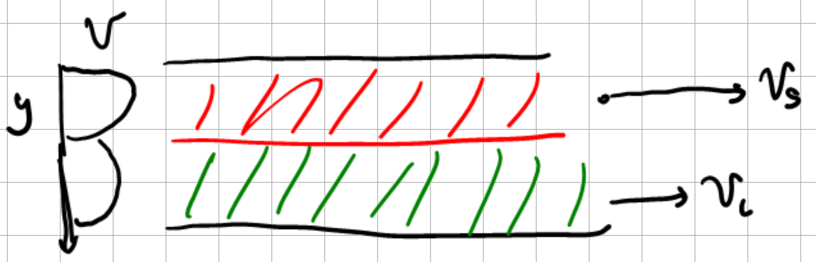
$\lambda_g > \varepsilon$

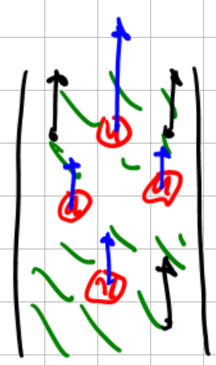
$V_g > V_m$

$$\boxed{v_L = v_m \frac{\lambda_L}{H_L}}$$

$$v_g = \frac{v_m \lambda_g}{\varepsilon} = \frac{\cancel{q_g + q_L}}{A} \cdot \frac{q_g}{\cancel{q_g + q_L}} \cdot \frac{1}{\varepsilon} = \frac{u_{sg}}{\varepsilon}$$

$$\boxed{v_g = \frac{u_{sg}}{\varepsilon} \qquad v_L = \frac{u_{sL}}{H_L}}$$





ε, H_L, v_L, v_g is a result of solving our {mass conservation, momentum conservation}

one example

$$v_g = C_0 v_m + \underbrace{u_0}_{\text{velocity of a bubble in stagnant liquid}}$$

TWO-PHASE FLOW IN VERTICAL TUBES

By D. J. NICKLIN, B.Sc. App.,* J. O. WILKES, M.A.*† and J. F. DAVIDSON, M.A., Ph.D., A.M.I.Mech.E.,*

* University of Cambridge, Department of Chemical Engineering, Pembroke Street, Cambridge.
† *Present address:* University of Michigan, Department of Chemical and Metallurgical Engineering, Ann Arbor, Michigan, U.S.A.

TRANS. INSTN CHEM. ENGRS, Vol. 40, 1962

SUMMARY

A study has been made of the properties of long bubbles in vertical tubes. It has been shown that these bubbles rise relative to the liquid ahead of them at a velocity exactly equal to the rising velocity of wakeless bubbles of the type studied by Dumitrescu and by Davies and Taylor. For 1 in. tubes, this velocity is closely predicted by Dumitrescu's theory and equals 0·35 $(gD)^{\frac{1}{2}}$ where g is the acceleration of gravity and D the tube diameter. The motion of the bubbles in moving liquid streams has been studied, and the results applied to the problem of two-phase slug flow. An expression for the voidage in steady two-phase slug flow has been derived, and this predicted voidage agrees well with results reported here and elsewhere.

$$u_s = 1{\cdot}2\, \bar{u}_L + 0{\cdot}35\, (gD)^{\frac{1}{2}}$$

N. ZUBER
Advanced Technology Laboratories. Mem. ASME

J. A. FINDLAY
Knolls Atomic Power Laboratory. Mem. ASME

General Electric Co., Schenectady, N. Y.

Average Volumetric Concentration in Two-Phase Flow Systems

A general expression which can be used either for predicting the average volumetric concentration or for analyzing and interpreting experimental data is derived. The analysis takes into account both the effect of nonuniform flow and concentration profiles as well as the effect of the local relative velocity between the phases. The first effect is taken into account by a distribution parameter, whereas the latter is accounted for by the weighted average drift velocity. Both effects are analyzed and evaluated. The results predicted by the analysis are compared with experimental data obtained for various two-phase flow regimes, with various liquid-gas mixtures in adiabatic, vertical flow over a wide pressure range. Good agreement with experimental data is shown.

[2] Numbers in brackets designate References at end of paper.
Contributed by the Heat Transfer Division and presented at the Winter Annual Meeting, New York, N. Y., November 29–December 3, 1964, of THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS. Manuscript received at ASME Headquarters, September 15, 1964.

"v_0"

THE FLOW OF LIQUID-GAS MIXTURES IN VERTICAL TUBES.

By

Hans Behringer

ZEITSCHRIFT FUR DIE GESAMTE KALTE-INDUSTRIE, 43, 55-58, 1936.

Z. angew. Math. Mech. Bd. 23 Nr. 3 Juni 1943 Dumitrescu, Strömung an einer Luftblase im senkrechten Rohr 139

Strömung an einer Luftblase im senkrechten Rohr.

Von *D. T. Dumitrescu* in Bukarest.

The mechanics of large bubbles rising through extended liquids and through liquids in tubes

By R. M. DAVIES AND SIR GEOFFREY TAYLOR, F.R.S.

(*Received* 13 *September* 1949)

$$\varepsilon = \frac{U_{SG}}{U_{SG}\left(1+\left(\frac{U_{SL}}{U_{SG}}\right)^{\left(\frac{\rho_G}{\rho_L}\right)^{0.1}}\right) + 2.9\left[\frac{gD\sigma(1+\cos\theta)(\rho_L-\rho_G)}{\rho_L^2}\right]^{0.25}(1.22+1.22\sin\theta)^{\frac{P_{atm}}{P_{system}}}}$$

Comparison of void fraction correlations for different flow patterns in horizontal and upward inclined pipes

Melkamu A. Woldesemayat, Afshin J. Ghajar *

School of Mechanical and Aerospace Engineering, Oklahoma State University, Stillwater, OK 74078, USA

Received 1 June 2006; received in revised form 13 September 2006

$$H_g = \frac{\lambda_g + 1 - \left[(\lambda_g+1)^2 - 4\cdot\lambda_g^{\,2}\right]^{0.5}}{2\cdot\lambda_g}$$

Pipe Fractional Flow Theory: Principles and Applications

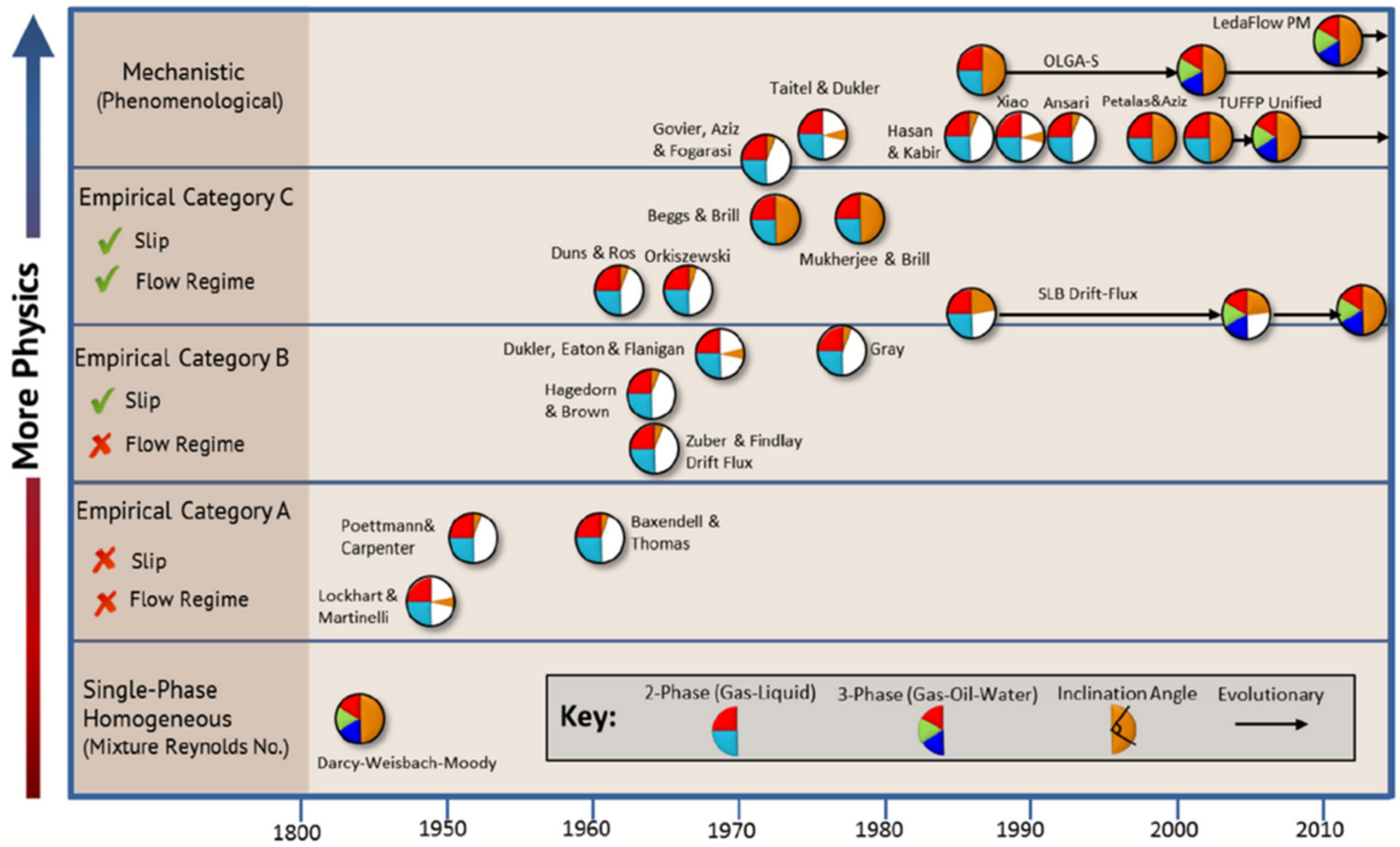
by

Anand Subhash Nagoo, B.Sc., M.S., M.S.

2013

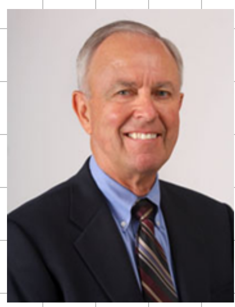
- $U_s = v_g - v_L$ slip velocity
- $S = \frac{v_g}{v_L}$ slip ratio

Video 29 - Some examples of pressure drop models for multiphase flow



A Study of Two-Phase Flow in Inclined Pipes

H. Dale Beggs,* SPE-AIME, U. of Tulsa
James P. Brill, SPE-AIME, U. of Tulsa

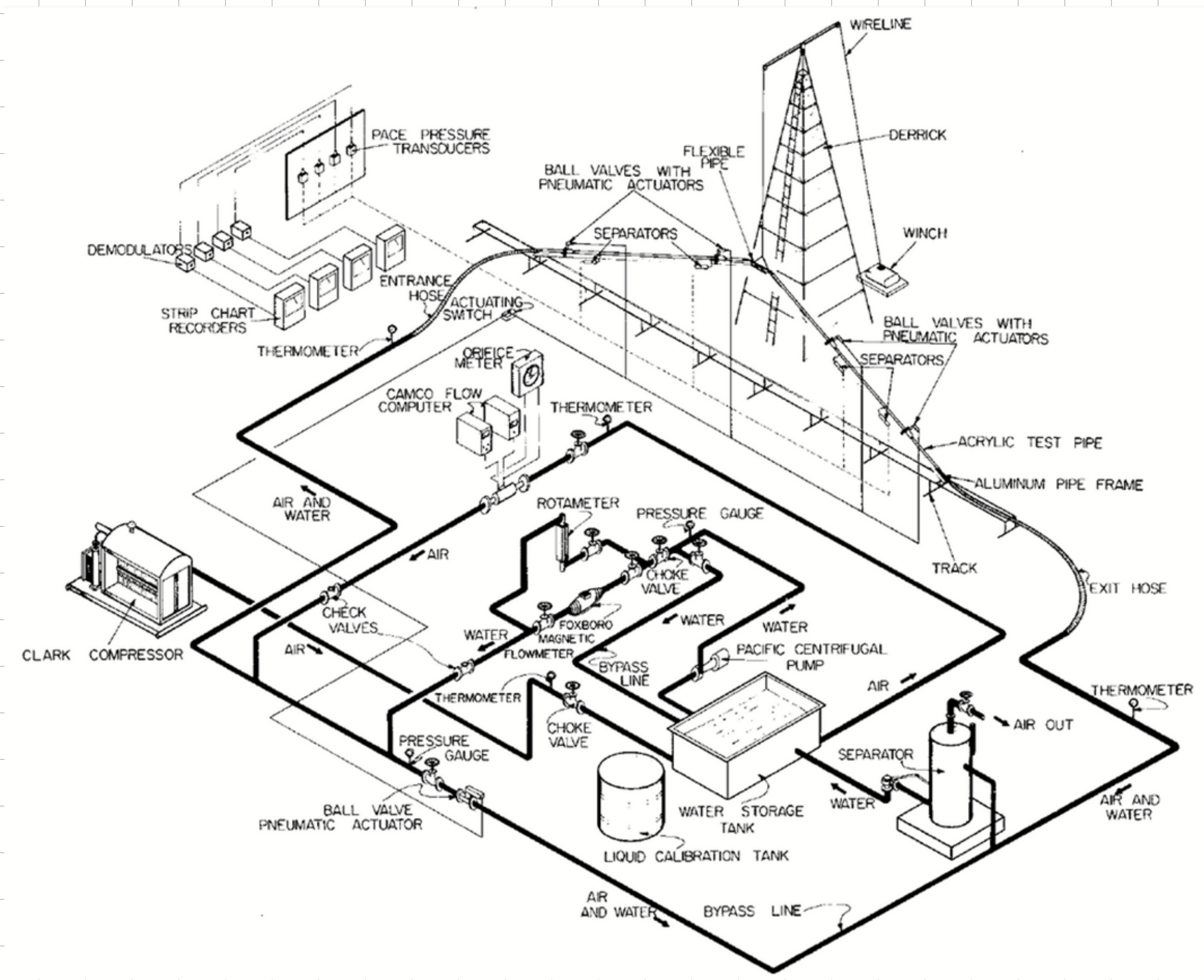


1973

$$-\frac{dp}{ds} = \left.\frac{dp}{ds}\right|_{grav.} + \left.\frac{dp}{ds}\right|_{fric.} + \left.\frac{dp}{ds}\right|_{accel.}$$

$$-\frac{dp}{dZ} = \frac{\frac{g}{g_c}\sin\theta\,[\rho_L H_L + \rho_g(1-H_L)] + \frac{f_{tp} G_m v_m}{2 g_c d}}{1-\{[\rho_L H_L + \rho_g(1-H_L)]\, v_m v_{sg}\}/g_c p}$$

https://wiki.whitson.com/pipeflow/correlations/beggs_brill/



A UNIFIED MODEL FOR PREDICTING FLOW-PATTERN TRANSITIONS FOR THE WHOLE RANGE OF PIPE INCLINATIONS

D. BARNEA
Faculty of Engineering, Department of Fluid Mechanics and Heat Transfer, Tel-Aviv University, Ramat-Aviv 69978, Israel

(*Received* 2 *February* 1986; *in revised form* 9 *June* 1986)

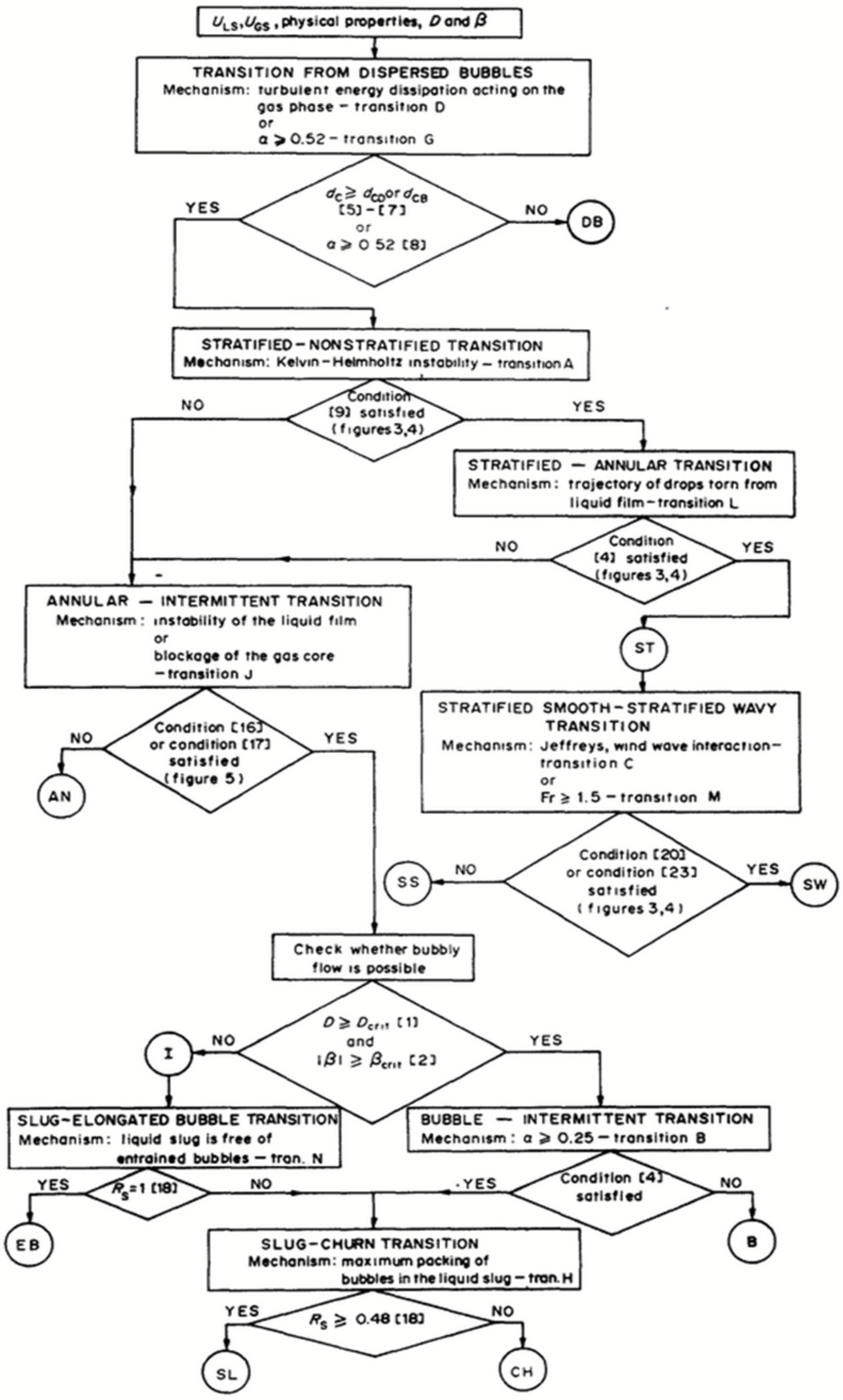
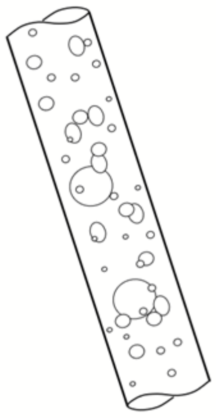


Figure 6. Logical pass for flow-pattern determination.

Bubble Flow-Pattern

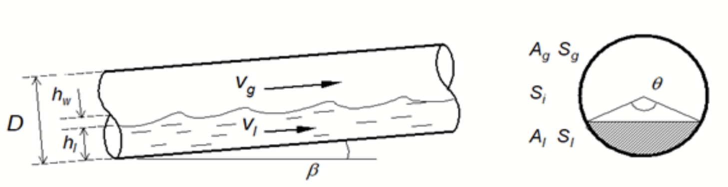
- Turbulent forces prevent bubble agglomeration and slip effect.
- Transition from bubble flow is given in the work of Barnea et al. (1987).
- The bubble flow-pattern is modeled as homogenous single fluid flow with averaged properties of liquid and gas.



Pressure gradient equation:

$$-\left(\frac{dP}{dx}\right) = f_m \frac{2\rho_m v_m^2}{D} + \rho_m g \sin\beta$$

Stratified Flow-Pattern Model



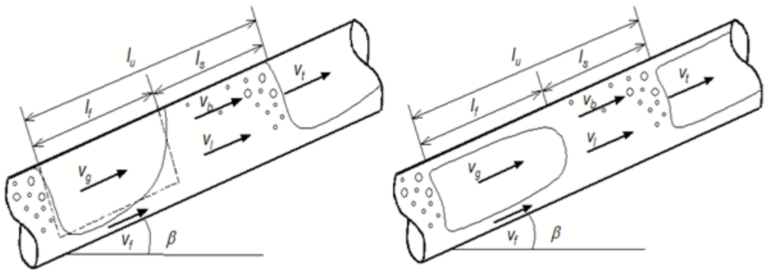
Combined momentum equation:

$$\frac{\tau_g S_g}{A_g} - \frac{\tau_i S_i}{A_l} + \tau_i S_i\left(\frac{1}{A_l}+\frac{1}{A_g}\right) - (\rho_l-\rho_g)\, g \sin\beta = 0$$

Pressure gradient equation:

$$-\left(\frac{dP}{dx}\right) = \frac{\tau_l S_l + \tau_g S_g}{A} + \left(\frac{A_l}{A}\rho_l + \frac{A_g}{A}\rho_g\right) g \sin\beta$$

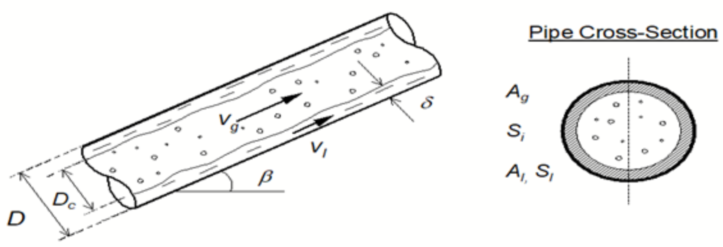
Intermittent Flow-Pattern Models



Pressure gradient equation:

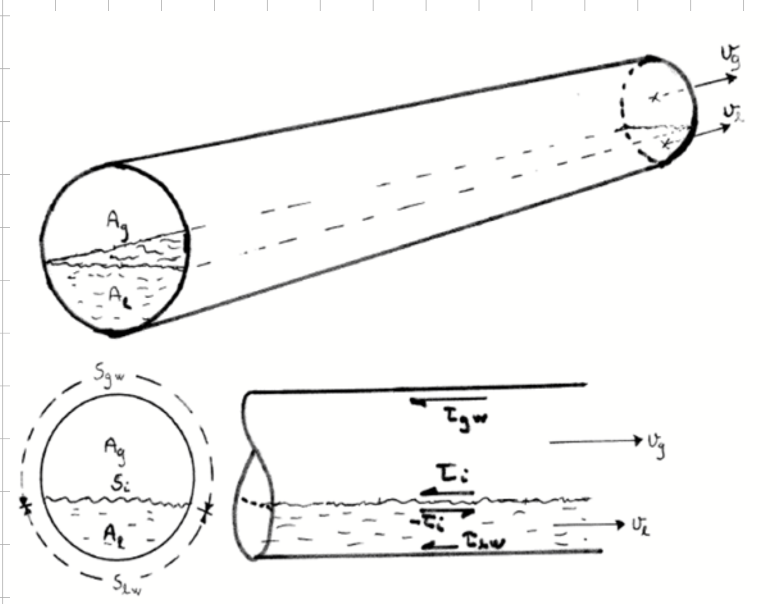
$$-\left(\frac{dP}{dx}\right) = \rho_u g \sin\beta + \frac{1}{l_u}\left[\left(\frac{\tau_s \pi D}{A} l_s\right) + \left(\frac{\tau_f S_f + \tau_g S_g}{A} l_f\right)\right]$$

Annular Flow-Pattern Model



Pressure gradient equation:

$$-\left(\frac{dP}{dx}\right) = \frac{\tau_l S_l}{A} + \left(\frac{A_l}{A}\rho_l + \frac{A_g}{A}\rho_{gc}\right) g \sin\beta$$



Harald Asheim's drift flux model

$$A_g\,dp + A_g\,\rho_g\,g_x\,dx + A_g\,\rho_g\,v_g\,dv_g + \tau_{gw}\,S_{gw}\,dx + \tau_i\,S_i dx = 0$$

+

$$A_l\,dp + A_l\,\rho_l\,g_x\,dx + A_l\,\rho_l\,v_l\,dv_l + \tau_{lw}\,S_{lw}\,dx - \tau_i\,S_i dx = 0$$

$$dp + \left(\rho_g y_g + \rho_l y_l\right) g_x dx + \rho_g v_g y_g dv_g + \rho_l v_l y_l dv_l + \frac{\tau_g S_{gw} + \tau_{lw} S_{lw}}{A} dx = 0$$

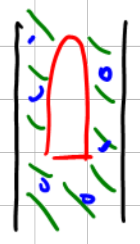
$$\tau_g = \frac{1}{8} f_g \rho_g v_g |v_g|$$

$$\tau_l = \frac{1}{8} f_l \rho_l v_l |v_l|$$

$$S_{gw} = \pi d y_g$$

$$S_{gw} = \pi d y_l$$

$$\frac{dp}{dx} + \rho_{TP} g_x + \rho_g v_{sg} \frac{dv_g}{dx} + \rho_l v_{sl} \frac{dv_l}{dx} + \frac{1}{2 \cdot d}\left(f_g \rho_g v_g |v_g| y_g + f_l \rho_l v_l |v_l| y_l\right) = 0$$



$p^*, T^* \rightarrow$

o	g	w

ρ

M

σ_{og} σ_{wg} σ_{ow}

h

$\dot{m}_o$ $\dot{m}_g$ $\dot{m}_w$ $\rightarrow q_o$ q_g q_w $\rightarrow u_{so}$ u_{sg} u_{sw} $\rightarrow \frac{dp}{dx}, \frac{dT}{dx}$

2 approaches:

- Compositional z_i — C_1, C_2, C_3, ..., i, pseudo components (mole frac) + EOS (Peng Robinson) + EOS parameters
  - mixing rules
  - Binary interaction parameters

→ mass fraction o, g, w

$$x_o = \frac{\dot{m}_o}{\dot{m}_o + \dot{m}_g} \qquad x_g = (1 - x_o)$$

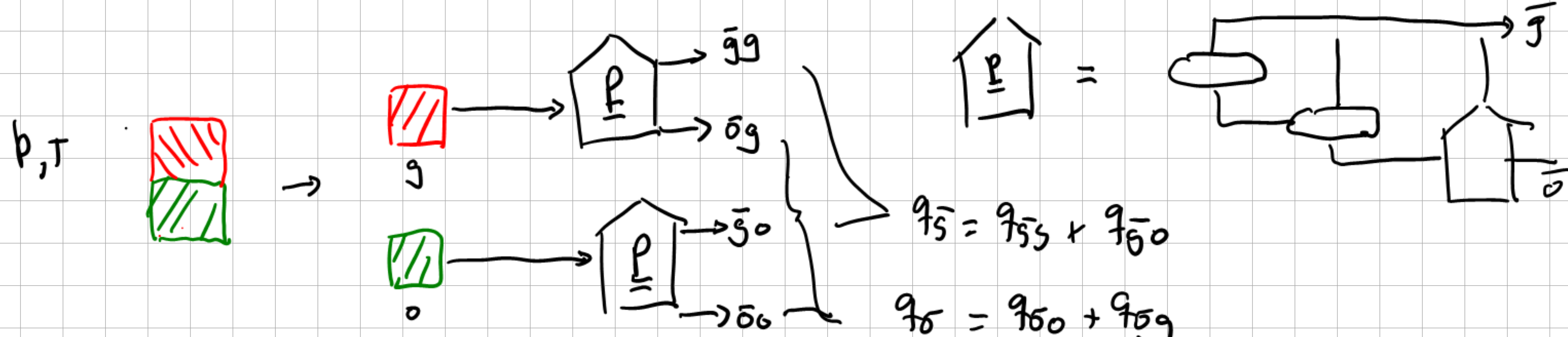
$$\dot{m}_o = \dot{m}\, x_o$$

$$\dot{m}_g = \dot{m}\, x_g$$

run in two ways

- live: flash calculation (equilibrium calculation) → property estimation
- precompute tables and interpolate on table

- Black oil tables generated by:
  - EOS
  - correlations
  - lab experiments



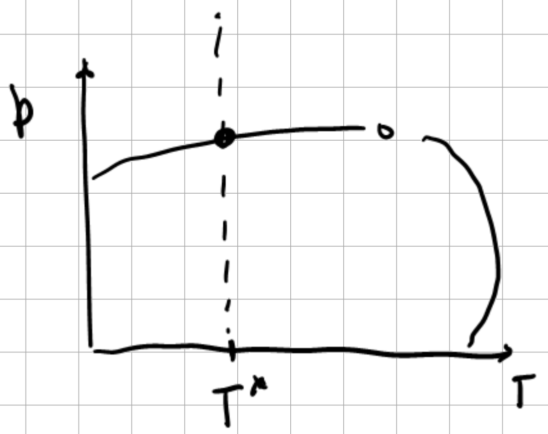
$$q_{\bar{g}} = q_{\bar{g}g} + q_{\bar{g}o}$$

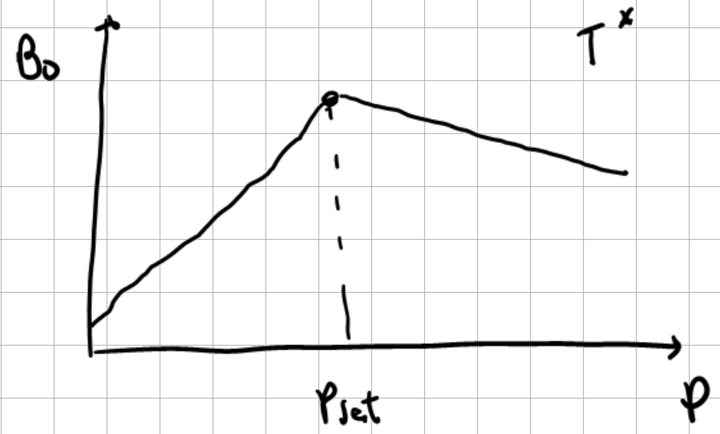
$$q_{\bar{o}} = q_{\bar{o}o} + q_{\bar{o}g}$$

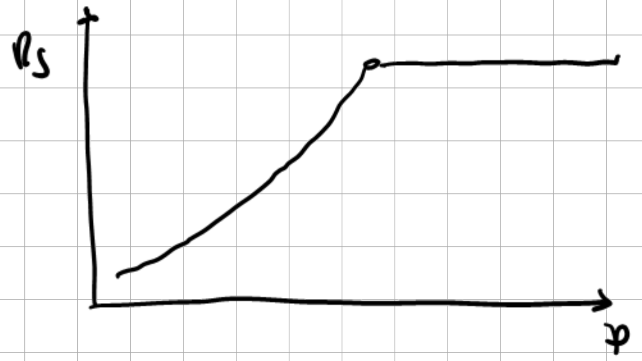
$$B_o = \frac{V_o}{V_{\bar{o}o}} \qquad B_g = \frac{V_g}{V_{\bar{g}g}} \qquad R_s = \frac{V_{\bar{g}o}}{V_{\bar{o}o}} \qquad r_s\,(r_v) = \frac{V_{\bar{o}g}}{V_{\bar{g}g}}$$

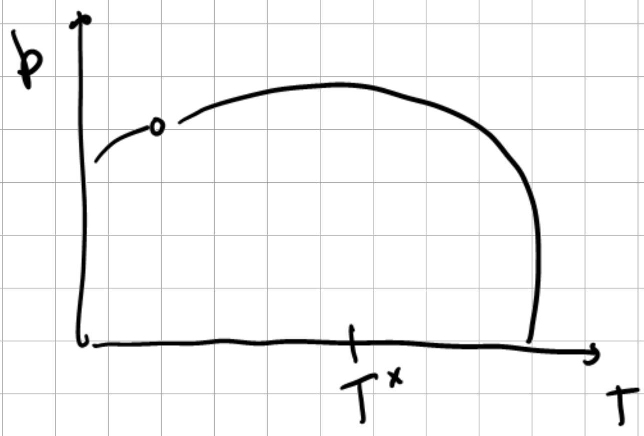
solution gas-oil ratio

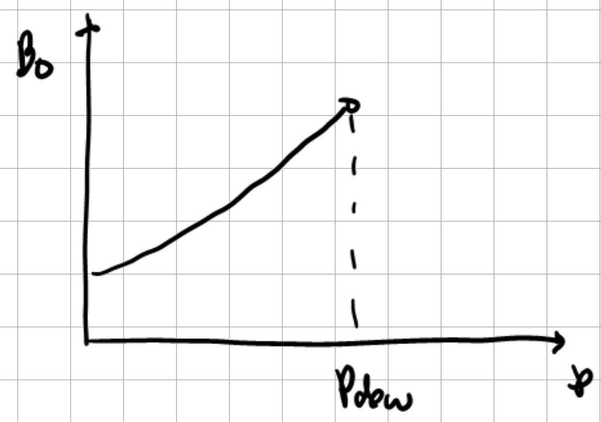
solution oil-gas ratio

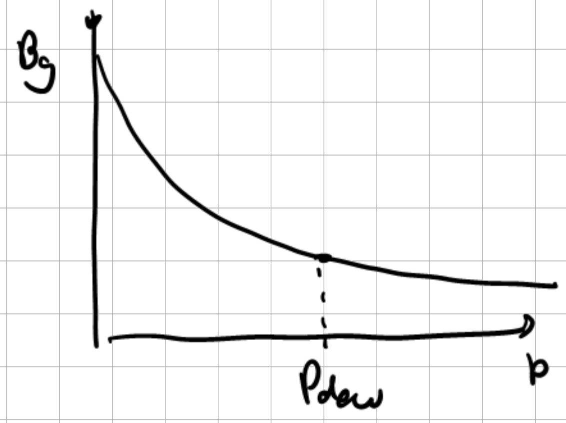


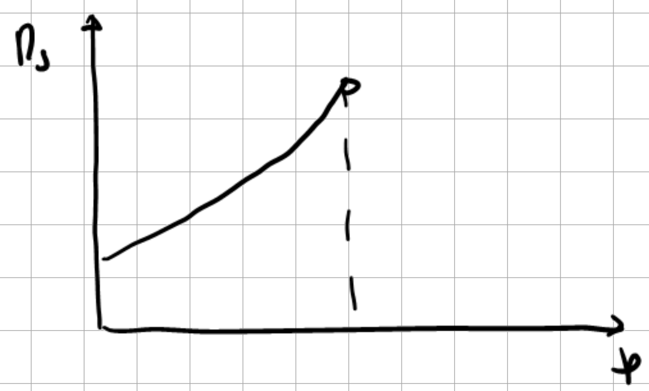












$\begin{bmatrix} q_{\bar g} \\ q_{\bar o} \\ q_{\bar w} \end{bmatrix} = \begin{bmatrix} \frac{1}{B_g} & \frac{R_s}{B_o} & 0 \\ \frac{r_s}{B_g} & \frac{1}{B_o} & 0 \\ 0 & 0 & \frac{1}{B_w} \end{bmatrix}_{(p,T)} \cdot \begin{bmatrix} q_g \\ q_o \\ q_w \end{bmatrix}$	$\begin{bmatrix} q_g \\ q_o \\ q_w \end{bmatrix} = \begin{bmatrix} \frac{B_g}{1-\cancel{R_s \cdot r_s}\,0} & \frac{-R_s \cdot B_g}{1-R_s \cdot r_s} & 0 \\ \frac{-B_o \cdot r_s}{1-R_s \cdot r_s} & \frac{B_o}{1-R_s \cdot r_s} & 0 \\ 0 & 0 & B_w \end{bmatrix}_{(p,T)} \cdot \begin{bmatrix} q_{\bar g} \\ q_{\bar o} \\ q_{\bar w} \end{bmatrix}$
Standard conditions calculated from local conditions	Local conditions calculated from standard conditions

$q_{\bar g} = q_{\bar g g} + q_{\bar g o}$

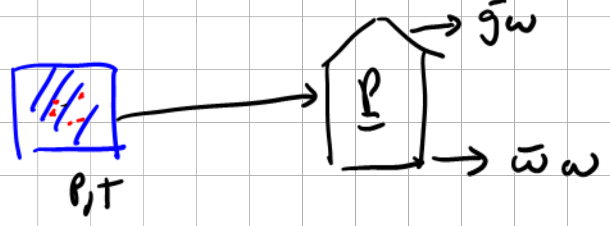
$q_{\bar o} = q_{\bar o o} + q_{\bar o g}$

for conventional / heavy oil $r_s = 0$

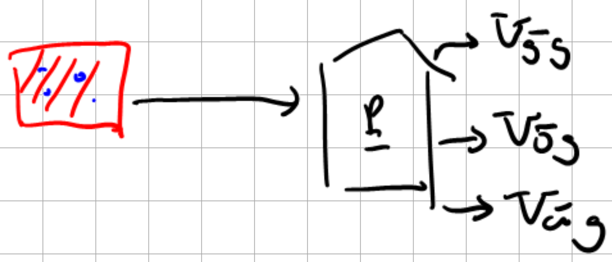
not adequate for volatile oils

gas condensate

Water BO properties



$$B_w = \frac{V_w}{V_{\bar{w}w}}$$

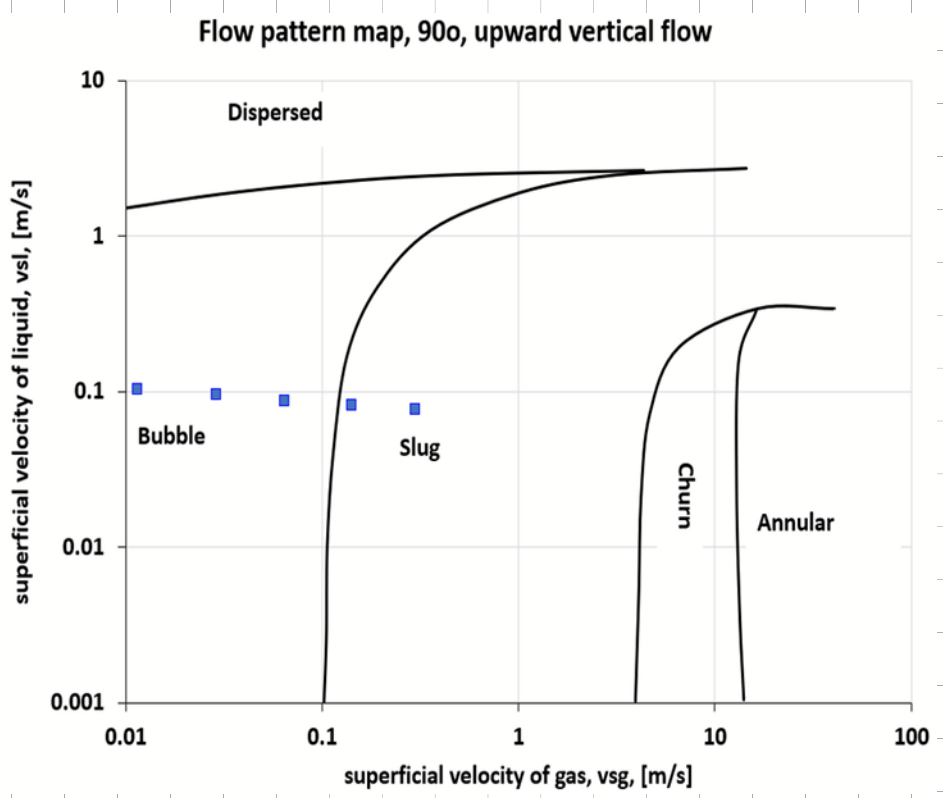


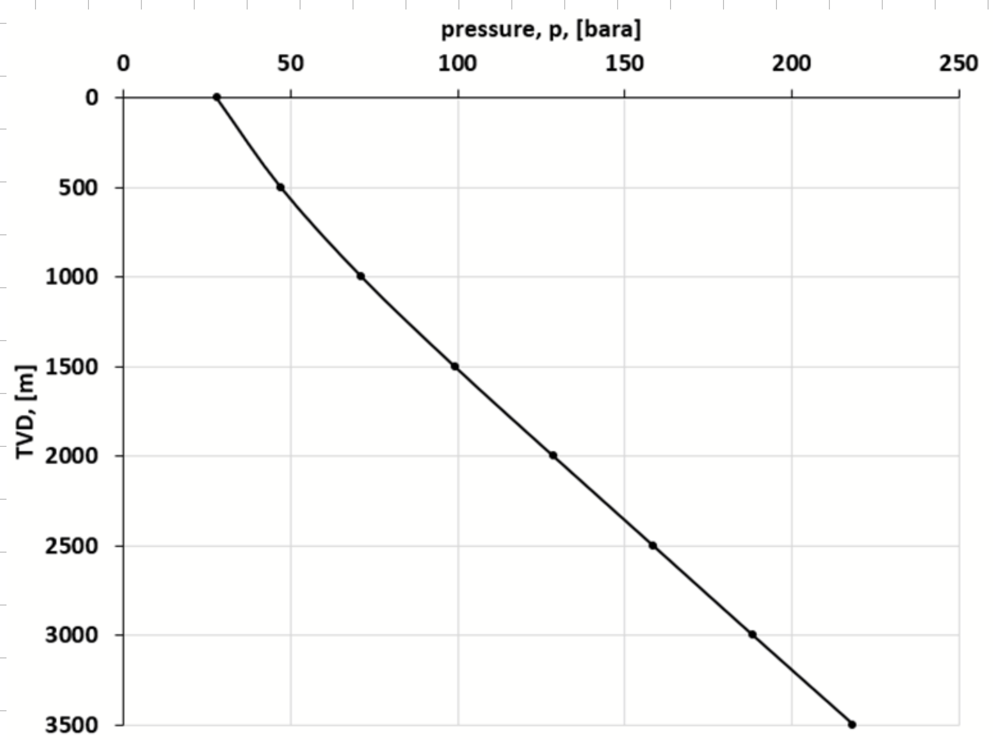
Some cases it could be important to include surface gas from local water and surface water from local gas.

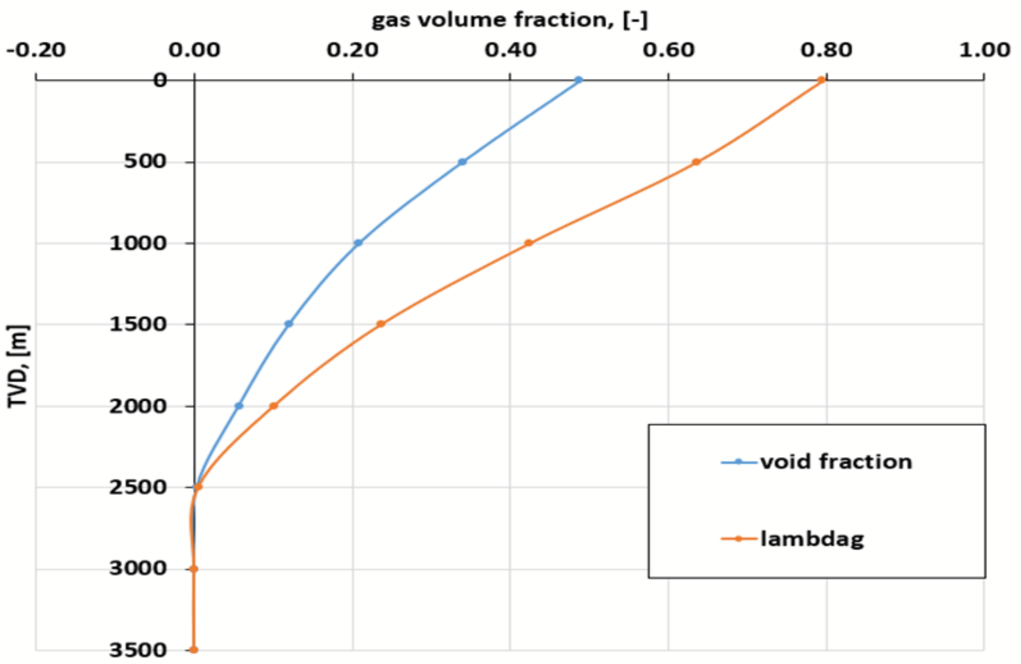
Exercise: Pressure drop calculation in saturated oil well, Prof. Milan Stanko (NTNU)

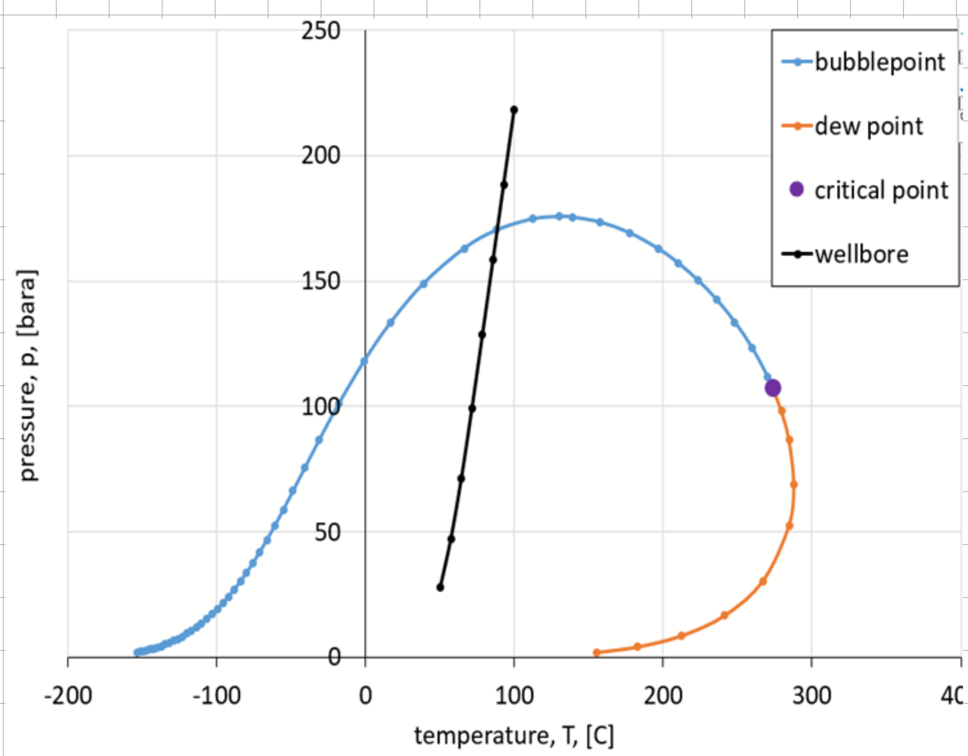
GOR	[Sm3/Sm3]	155.1
Pipe ID	[m]	0.15
Pipe cross section area	[m2]	0.0177
Pipe roughness	[m]	1.50E-05
Pipe inclination from hor	[deg]	90
qo	[Sm3/d]	100
qg	[Sm3/d]	1.55E+04

		BO table column	3	4	5	6	8	10	7	9	11						Woldesemayat and Ghajar	
TVD [m]	T [C]	p[bara]	Rs [Sm3/Sm3]	rs [Sm3/Sm3]	Bo [m3/Sm3]	Bg [m3/Sm3]	deng [kg/m3]	viscg [cp]	deno [kg/m3]	viso [cp]	sigma_o_g [N/m]	qo [m3/d]	qg[m3/d]	uso [m/s]	usg [m/s]	lambdag[-]	e[-]	dp/dx [bara/m]
0	50.0	28	22.6	1.28E-05	1.2	3.44E-02	37.8	1.10E-02	728.8	1.8	1.15E-02	117.4	4.566E+02	0.077	0.299	0.80	0.49	0.0384
500	57.1	47.2	41.1	1.31E-05	1.2	1.90E-02	70.8	1.25E-02	708.8	1.2	8.37E-03	124.2	2.173E+02	0.081	0.142	0.64	0.34	0.0483
1000	64.3	71.4	65.3	1.43E-05	1.3	1.09E-02	119.4	1.49E-02	684.3	0.8	5.12E-03	133.2	9.832E+01	0.087	0.064	0.42	0.21	0.0556
1500	71.4	99.2	93.9	1.69E-05	1.4	7.29E-03	178.7	1.91E-02	657.3	0.6	2.64E-03	144.4	4.468E+01	0.095	0.029	0.24	0.12	0.0589
2000	78.6	128.6	124.4	2.13E-05	1.6	5.71E-03	228.2	2.38E-02	630.8	0.5	1.33E-03	156.8	1.761E+01	0.103	0.012	0.10	0.06	0.0597
2500	85.7	158.4	153.2	2.41E-05	1.7	4.49E-03	229.5	2.44E-02	607.9	0.4	6.71E-04	169.0	8.799E-01	0.111	0.001	0.01	0.00	0.0595
3000	92.9	188.2	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	607.3	0.4	0.00E+00	169.5	0.000E+00	0.111	0.000	0.00	0.00	0.0602
3500	100.0	218.3	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	607.4	0.4	0.00E+00	169.5	0.000E+00	0.111	0.000	0.00	0.00	0.0602



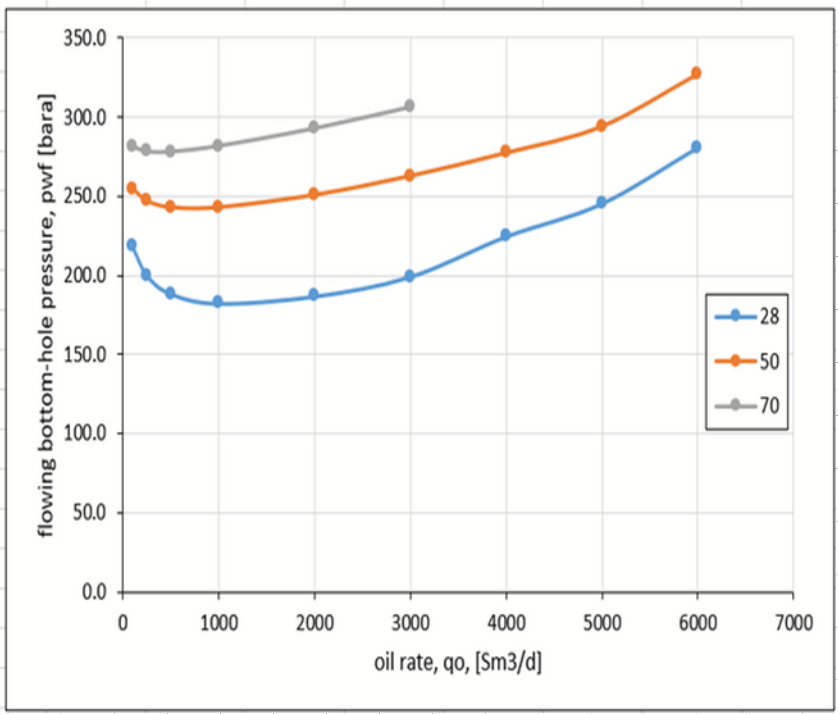






With Wolgha model

pwh[bara]	28	50	70
qo	pwf	pwf	pwf
[Sm3/d]	[bara]	[bara]	[bara]
100	218.3	254.9	281.4
250	200.0	247.1	278.3
500	188.5	243.0	278.2
1000	182.4	243.0	281.8
2000	186.9	250.8	292.9
3000	199.2	262.8	306.3
4000	224.5	277.3	
5000	245.2	294.0	
6000	280.5	327.0	



lculation in saturated oil well, Prof. Milan Stanko (NTNU)

[Sm3/Sm3]	155.1
[m]	0.15
[m2]	0.0177
[m]	1.50E-05
[deg]	90
[Sm3/d]	100
[Sm3/d]	1.55E+04

		BO table column	3	4	5	6	8	10	7	9	11						Woldesemayat and Ghajar	
TVD [m]	T [C]	p[bara]	Rs [Sm3/Sm3]	rs [Sm3/Sm3]	Bo [m3/Sm3]	Bg [m3/Sm3]	deng [kg/m3]	viscg [cp]	deno [kg/m3]	viso [cp]	sigma_o_g [N/m]	qo [m3/d]	qg[m3/d]	uso [m/s]	usg [m/s]	lambdag[-]	e[-]	dp/dx [bara/m]
0	50.0	28	22.6	1.28E-05	1.2	3.44E-02	37.8	1.10E-02	728.8	1.8	1.15E-02	117.4	4.566E+02	0.077	0.299	0.80	0.49	0.0384
500	57.1	47.2	41.1	1.31E-05	1.2	1.90E-02	70.8	1.25E-02	708.8	1.2	8.37E-03	124.2	2.173E+02	0.081	0.142	0.64	0.34	0.0483
1000	64.3	71.4	65.3	1.43E-05	1.3	1.09E-02	119.4	1.49E-02	684.3	0.8	5.12E-03	133.2	9.832E+01	0.087	0.064	0.42	0.21	0.0556
1500	71.4	99.2	93.9	1.69E-05	1.4	7.29E-03	178.7	1.91E-02	657.3	0.6	2.64E-03	144.4	4.468E+01	0.095	0.029	0.24	0.12	0.0589
2000	78.6	128.6	124.4	2.13E-05	1.6	5.71E-03	228.2	2.38E-02	630.8	0.5	1.33E-03	156.8	1.761E+01	0.103	0.012	0.10	0.06	0.0597
2500	85.7	158.4	153.2	2.41E-05	1.7	4.49E-03	229.5	2.44E-02	607.9	0.4	6.71E-04	169.0	8.799E-01	0.111	0.001	0.01	0.00	0.0595
3000	92.9	188.2	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	607.3	0.4	0.00E+00	169.5	0.000E+00	0.111	0.000	0.00	0.00	0.0602
3500	100.0	218.3	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	607.4	0.4	0.00E+00	169.5	0.000E+00	0.111	0.000	0.00	0.00	0.0602

```
Function e_wolgha(usl, usg, denl, deng, sigma_lg, teta_deg, p, D)
    'p in bar
    'D in m
    'usl in m/s
    'usg in m/s
    'denl kg/m^3
    'deng kg/m^3
    'teta deg in deg
    'sigma_lg in N/m
    If usg = 0 Then
        e_wolgha = 0
    Else
        Pi = Atn(1) * 4
        teta = teta_deg * Pi / 180
        'void fraction correlation by Woldesemayat and Ghajar (2006)
        a = usg * (1 + ((usl / usg) ^ ((deng / denl) ^ 0.1)))
        B = 2.9 * ((9.81 * sigma_lg * D * (1 + Cos(teta)) * (denl - deng) / (denl ^ 2)) ^ 0.25)
        C = (1.22 + 1.22 * Sin(teta)) ^ (1.01325 / p)
        e_wolgha = usg / (a + (B * C))
    End If
End Function
```

```
Function dpdx_mpf(roughness, viscl, viscg, denl, deng, usl, usg, D, angle, voidfraction)
    'dpdx_mpf pressure gradient, in bar/m, for multiphase flow
    'denl, liquid density, [kg/m3]
    'deng, gas density, [kg/m3]
    'usl superficial liquid velocity, [m/s]
    'usg superficial gas velocity, [m/s]
    'angle, inclination angle of pipe with respect to horizontal [deg]
    'D hydraulic diameter of pipe [m]
    'roughness pipe roughness, [m]
    'viscl, liquid viscosity [cP]
    'viscg, gas viscosity, [cP]
    'voidfraction [-]
    Pi = Atn(1) * 4
    denm = voidfraction * deng + (1 - voidfraction) * denl
    If voidfraction = 0 Or usg = 0 Then
        ug = 0
        ul = usl
        fg = 0
        fl = ffactor(denl, viscl, D, roughness, ul)
    ElseIf voidfraction = 1 Or usl = 0 Then
        ug = usg
        ul = 0
        fl = 0
        fg = ffactor(deng, viscg, D, roughness, ug)
    Else
        ug = usg / voidfraction
        ul = usl / (1 - voidfraction)
        fg = ffactor(deng, viscg / 1000#, D, roughness, ug)
        fl = ffactor(denl, viscl / 1000, D, roughness, ul)
    End If
    dpdx_f = (fg * deng * (ug * Abs(usg)) * 0.5 / D) + (fl * denl * (ul * Abs(usl)) * 0.5 / D)
    dpdx_h = denm * 9.81 * Sin(angle * Pi / 180)
    dpdx_mpf = dpdx_f + dpdx_h
    dpdx_mpf = dpdx_mpf / 100000#
End Function
```

lculation in saturated oil well, Prof. Milan Stanko (NTNU)

[Sm3/Sm3]	155.1
[m]	0.15
[m2]	0.0177
[m]	1.50E-05
[deg]	90
[Sm3/d]	1000
[Sm3/d]	1.55E+05

		BO table column	3	4	5	6	8	10	7	9	11							Nagoo
TVD [m]	T [C]	p[bara]	Rs [Sm3/Sm3]	rs [Sm3/Sm3]	Bo [m3/Sm3]	Bg [m3/Sm3]	deng [kg/m3]	viscg [cp]	deno [kg/m3]	viso [cp]	sigma_o_g [N/m]	qo [m3/d]	qg[m3/d]	uso [m/s]	usg [m/s]	lambdag[-]	e[-]	dp/dx [bara/m]
0	50.0	28	22.6	1.28E-05	1.2	3.44E-02	37.8	1.10E-02	728.8	1.8	1.15E-02	1174.3	4.566E+03	0.769	2.991	0.80	0.61	0.0313
500	57.1	43.7	37.3	1.29E-05	1.2	2.08E-02	63.4	1.22E-02	711.9	1.2	8.90E-03	1229.4	2.451E+03	0.805	1.605	0.67	0.50	0.0387
1000	64.3	63.0	56.3	1.36E-05	1.3	1.34E-02	100.1	1.40E-02	691.6	0.9	6.20E-03	1301.4	1.320E+03	0.852	0.865	0.50	0.38	0.0461
1500	71.4	86.1	79.2	1.53E-05	1.4	8.91E-03	146.3	1.68E-02	668.7	0.6	3.75E-03	1390.6	6.776E+02	0.911	0.444	0.33	0.26	0.0525
2000	78.6	112.3	105.7	1.84E-05	1.5	6.67E-03	195.8	2.08E-02	644.3	0.5	2.05E-03	1497.1	3.306E+02	0.981	0.217	0.18	0.16	0.0567
2500	85.7	140.7	134.2	2.32E-05	1.6	5.56E-03	234.6	2.48E-02	620.2	0.4	1.12E-03	1615.5	1.167E+02	1.058	0.076	0.07	0.06	0.0588
3000	92.9	170.1	154.6	1.91E-06	1.7	3.87E-04	17.9	1.91E-03	604.6	0.4	6.30E-05	1701.8	2.006E-01	1.115	0.000	0.00	0.00	0.0597
3500	100.0	200.0	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	605.0	0.4	0.00E+00	1702.0	0.000E+00	1.115	0.000	0.00	0.00	0.0649

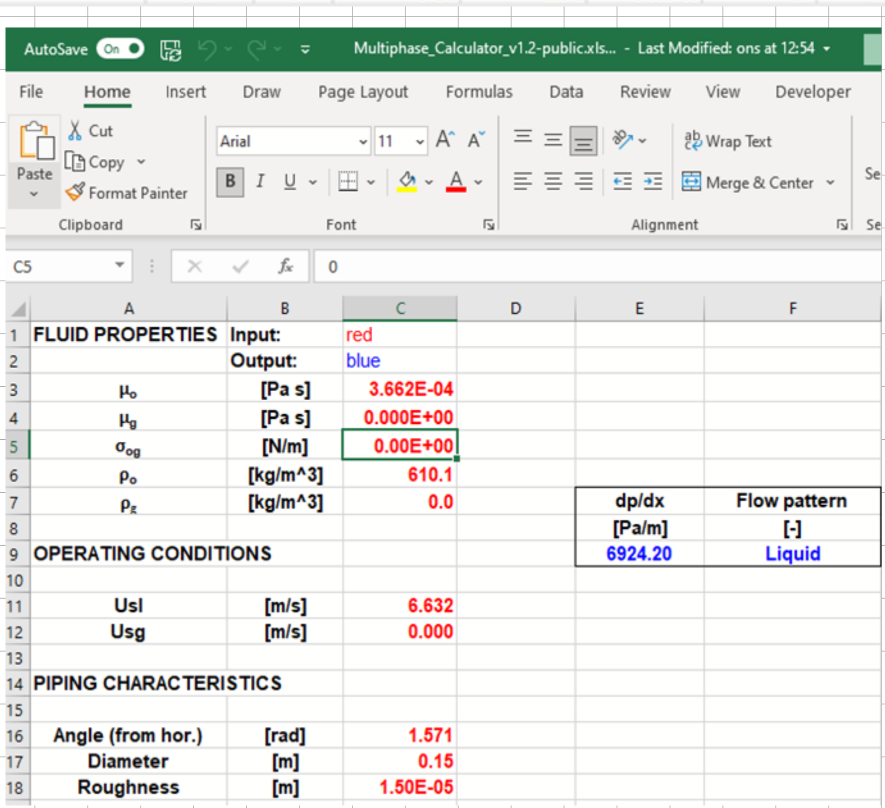
```
Function e_Nagoo(lambdag)
    ' e_Nagoo, the void fraction of gas, in fraction, using the ANSLIP equation by Nagoo, 2013
    'lambdag is non slip volume fraction of gas, in fraction
    If lambdag = 0 Then
        e_Nagoo = 0
    Else
        e_Nagoo = (lambdag + 1 - ((lambdag + 1) ^ 2 - 4 * (lambdag ^ 2)) ^ 0.5) / (2 * lambdag)
    End If
End Function
```


```
Function dpdx_mpf(roughness, viscl, viscg, denl, deng, usl, usg, D, angle, voidfraction)
    'dpdx_mpf pressure gradient, in bar/m, for multiphase flow
    'denl, liquid density, [kg/m3]
    'deng, gas density, [kg/m3]
    'usl superficial liquid velocity, [m/s]
    'usg superficial gas velocity, [m/s]
    'angle, inclination angle of pipe with respect to horizontal [deg]
    'D hydraulic diameter of pipe [m]
    'roughness pipe roughness, [m]
    'viscl, liquid viscosity [cP]
    'viscg, gas viscosity, [cP]
    'voidfraction [-]
    Pi = Atn(1) * 4
    denm = voidfraction * deng + (1 - voidfraction) * denl
    If voidfraction = 0 Or usg = 0 Then
        ug = 0
        ul = usl
        fg = 0
        fl = ffactor(denl, viscl, D, roughness, ul)
    ElseIf voidfraction = 1 Or usl = 0 Then
        ug = usg
        ul = 0
        fl = 0
        fg = ffactor(deng, viscg, D, roughness, ug)
    Else
        ug = usg / voidfraction
        ul = usl / (1 - voidfraction)
        fg = ffactor(deng, viscg / 1000#, D, roughness, ug)
        fl = ffactor(denl, viscl / 1000, D, roughness, ul)
    End If
    dpdx_f = (fg * deng * (ug * Abs(usg)) * 0.5 / D) + (fl * denl * (ul * Abs(usl)) * 0.5 / D)
    dpdx_h = denm * 9.81 * Sin(angle * Pi / 180)
    dpdx_mpf = dpdx_f + dpdx_h
    dpdx_mpf = dpdx_mpf / 100000#
End Function
```

Exercise: Pressure drop calculation in saturated oil well, Prof. Milan Stanko (NTNU)

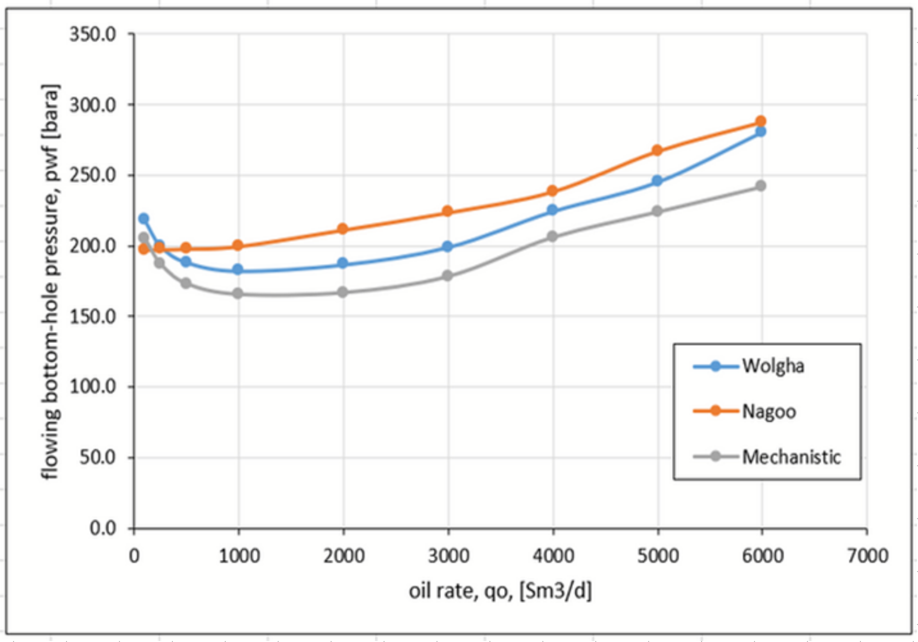
GOR	[Sm3/Sm3]	155.1
Pipe ID	[m]	0.15
Pipe cross section area	[m2]	0.0177
Pipe roughness	[m]	1.50E-05
Pipe inclination from hor	[deg]	90
qo	[Sm3/d]	6000
qg	[Sm3/d]	9.31E+05

			BO table column	3	4	5	6	8	10	7	9	11						Mechanistic model	
	TVD [m]	T [C]	p[bara]	Rs [Sm3/Sm3]	rs [Sm3/Sm3]	Bo [m3/Sm3]	Bg [m3/Sm3]	deng [kg/m3]	viscg [cp]	deno [kg/m3]	viso [cp]	sigma_o_g [N/m]	qo [m3/d]	qg[m3/d]	uso [m/s]	usg [m/s]	lambdag[-]	flowpattern	dp/dx [bara/m]
	0	50.0	28	22.6	1.28E-05	1.2	3.44E-02	37.8	1.10E-02	728.8	1.8	1.15E-02	7046.0	2.740E+04	4.615	17.944	0.80	Slug	0.0492
	500	57.1	52.6	46.8	1.34E-05	1.3	1.64E-02	82.1	1.29E-02	704.1	1.1	7.56E-03	7564.5	1.065E+04	4.954	6.976	0.58	Slug	0.0417
	1000	64.3	73.5	67.6	1.45E-05	1.3	1.05E-02	125.0	1.53E-02	682.4	0.8	4.88E-03	8044.2	5.540E+03	5.269	3.628	0.41	Bubble	0.0605
	1500	71.4	103.7	99.2	1.76E-05	1.5	6.90E-03	189.5	2.00E-02	653.3	0.6	2.35E-03	8781.2	2.322E+03	5.751	1.521	0.21	Bubble	0.0675
	2000	78.6	137.5	134.8	2.33E-05	1.6	5.37E-03	243.1	2.55E-02	623.6	0.4	1.07E-03	9650.4	6.558E+02	6.321	0.430	0.06	Bubble	0.0708
	2500	85.7	172.9	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	609.0	0.4	0.00E+00	10144.6	0.000E+00	6.644	0.000	0.00	Liquid	0.0693
	3000	92.9	207.5	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	610.1	0.4	0.00E+00	10127.0	0.000E+00	6.633	0.000	0.00	Liquid	0.0693
	3500	100.0	242.1	155.1	0.00E+00	1.7	0.00E+00	0.0	0.00E+00	610.1	0.4	0.00E+00	10125.7	0.000E+00	6.632	0.000	0.00	Liquid	0.0692



pwh=28 bara

Models	Wolgha	Nagoo	Mechanistic
qo	pwf	pwf	pwf
[Sm3/d]	[bara]	[bara]	[bara]
100	218.3	197.5	205.5
250	200.0	197.6	187.5
500	188.5	198.2	173.2
1000	182.4	200.0	165.6
2000	186.9	211.5	166.8
3000	199.2	223.7	178.4
4000	224.5	238.5	206.2
5000	245.2	266.9	224.2
6000	280.5	287.5	242.1



• g

l { oil, water } →

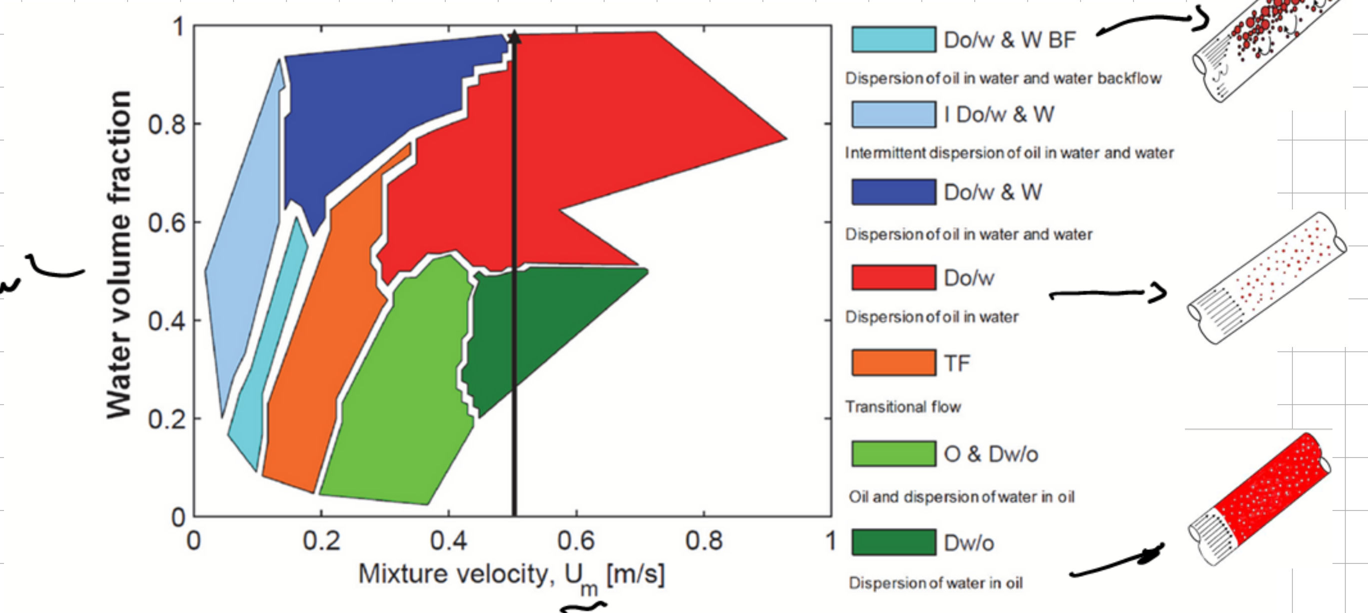


FIGURE 7-24. OIL-WATER FLOW PATTERN MAP OF WATER VOLUME FRACTION VERSUS MIXTURE VELOCITY FOR AN UPWARD PIPE INCLINATION OF 45°. FIGURE ADAPTED FROM RIVERA[7-5] [7-1] .

g	u_{sg}	λ_g	H_g	V_g
o	u_{so}	λ_o	H_o	V_o
w	u_{sw}	λ_w	H_w	V_w

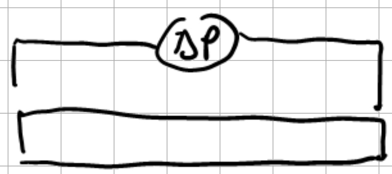
$V_o \approx V_w$

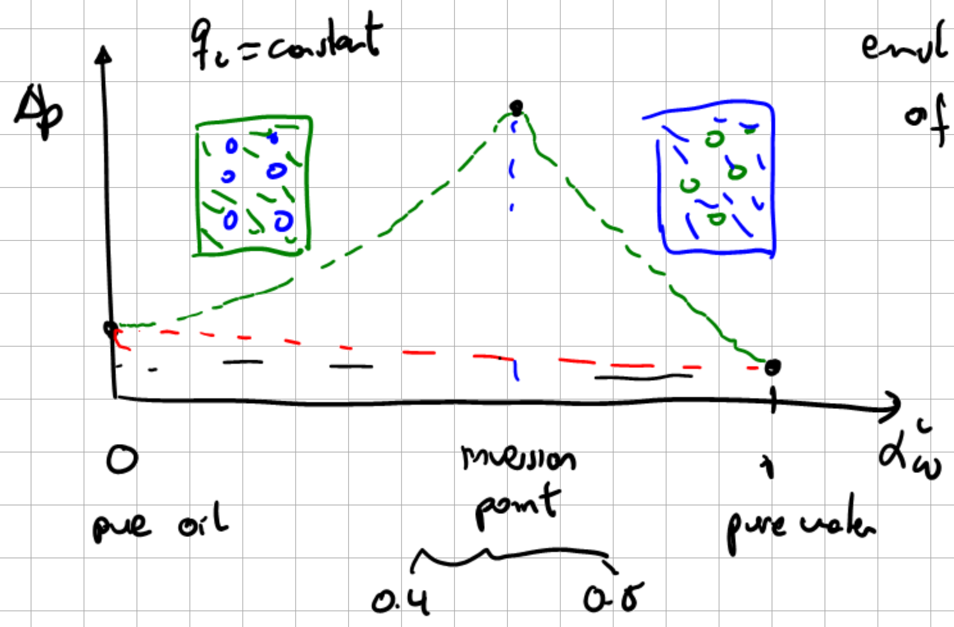
little slip

assume both travel at the same speed V_L

$$\rho_L = \rho_o \alpha_o^L + \rho_w \alpha_w^L \qquad \mu_L = \mu_o \alpha_o^L + \mu_w \cdot \alpha_w^L$$

$$\alpha_o^L = \frac{q_o}{q_o+q_w} \qquad \alpha_w^L = \frac{q_w}{q_o+q_w} = 1-\alpha_o^L$$





emulsion behavior of oil + water mixture

$$\mu_L = \mu_o \cdot e^{c_1(\alpha_w^L)} \qquad \mu_L = \mu_w \cdot e^{c_2(1-\alpha_w^L)}$$

$$wc = \frac{q_{\bar{w}}}{q_{\bar{o}}+q_{\bar{w}}} \qquad \alpha_w^L = \frac{q_w}{q_o+q_w}$$

sometimes in the literature, if $q_{\bar{o}} = q_o$

$wc = \alpha_w^L$

Pressure integration method

p_3

p_2

p_1

ΔL

$$p_2 = p_1 + \left.\frac{dp}{dx}\right|_{@p_1} \cdot \Delta L$$

} not so accurate for large ΔL

$$p_2 = p_1 + \left.\frac{dp}{dx}\right|_{@p_{av}} \Delta L$$

$$p_{av} = \frac{p_1 + p_2}{2}$$

implicit calculation

- assume a value of p_2^*
- compute $\left.\frac{dp}{dx}\right|_{p_{av}}$
- compute $p_2^{calc} = p_1 + \left.\frac{dp}{dx}\right|_{@p_{av}} \Delta L$
- check $p_2^{calc} = p_2^*$

not → (back to assume)

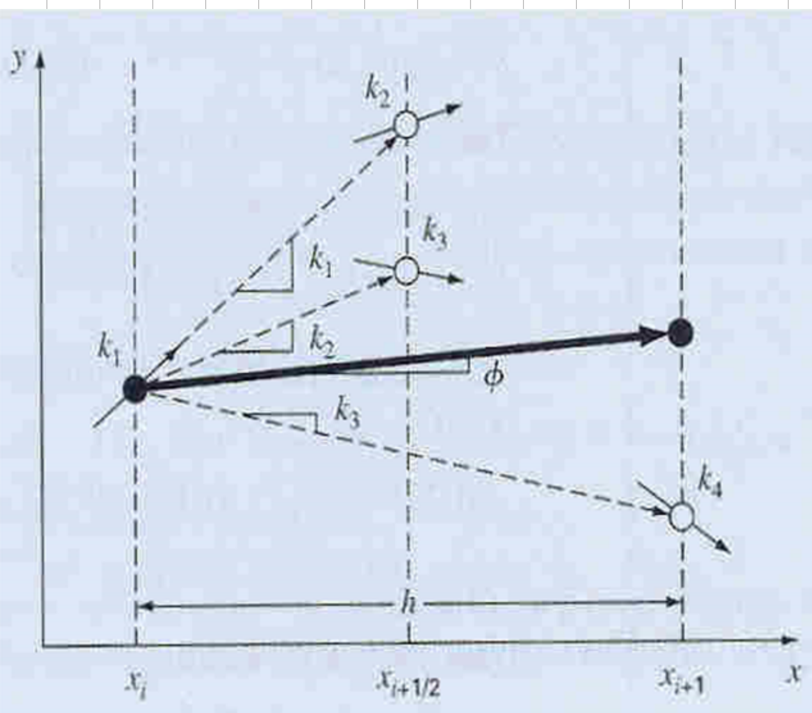
yes ↓

proceed to next step

explicit approach (higher order)

Runge-Kutta 4th

$$y_{n+1} = y_n + \frac{1}{6} \cdot h \cdot (k_1 + 2 \cdot k_2 + 2 \cdot k_3 + k_4)$$



p_1 p^* p_2

$$p_2 = p_1 + \frac{1}{6} \Delta L (k_1 + 2k_2 + 2k_3 + k_4)$$

$$k_1 = \left.\frac{dp}{dx}\right|_{@p_1}$$

$$p^* = p_1 + \left.\frac{dp}{dx}\right|_{@p_1} \cdot \frac{\Delta L}{2}$$

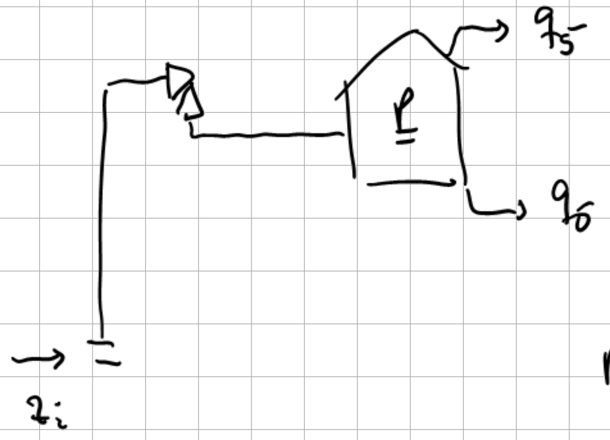
$$k_2 = \left.\frac{dp}{dx}\right|_{@p^*}$$

$$p^{**} = p_1 + k_2 \frac{\Delta L}{2}$$

$$k_3 = \left.\frac{dp}{dx}\right|_{@p^{**}}$$

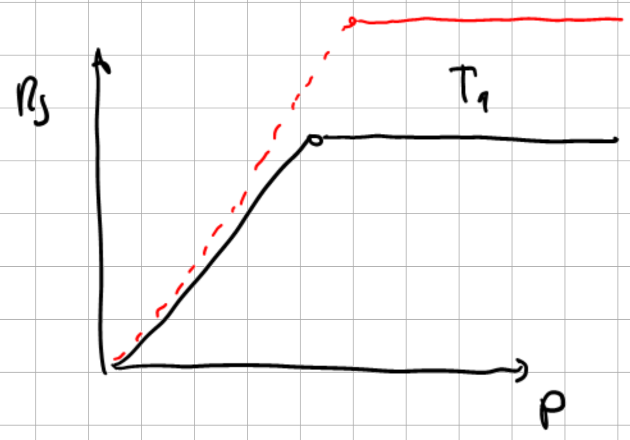
$$p^{***} = p_1 + k_3 \Delta L$$

$$k_4 = \left.\frac{dp}{dx}\right|_{@p^{***}}$$



$$R_p = \frac{q_g}{q_o}$$

If z_i changes then R_p should also change

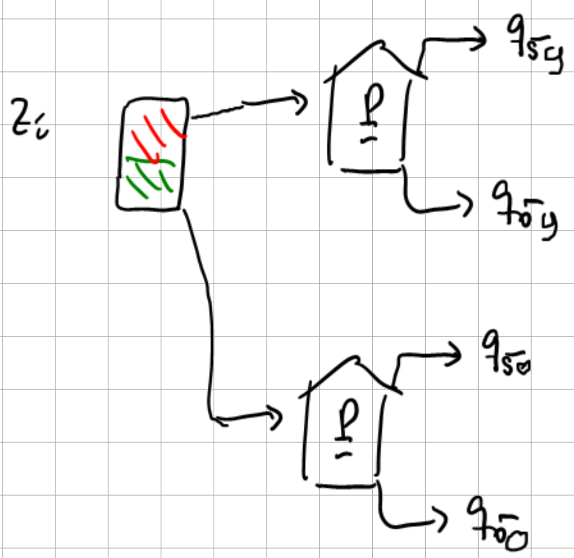


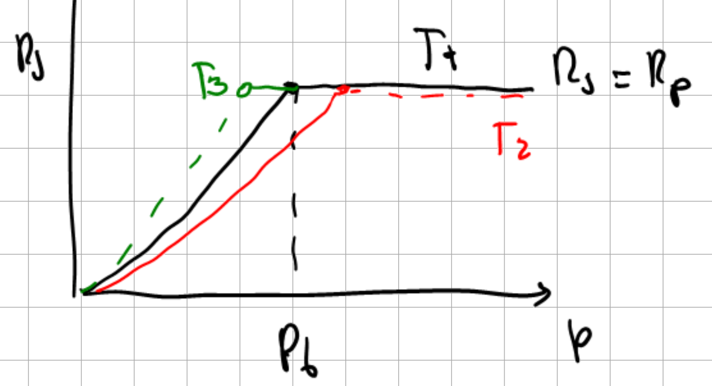
If z_i changes

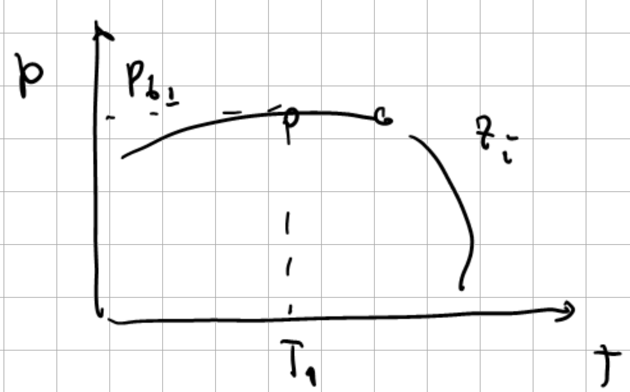
z_i^*

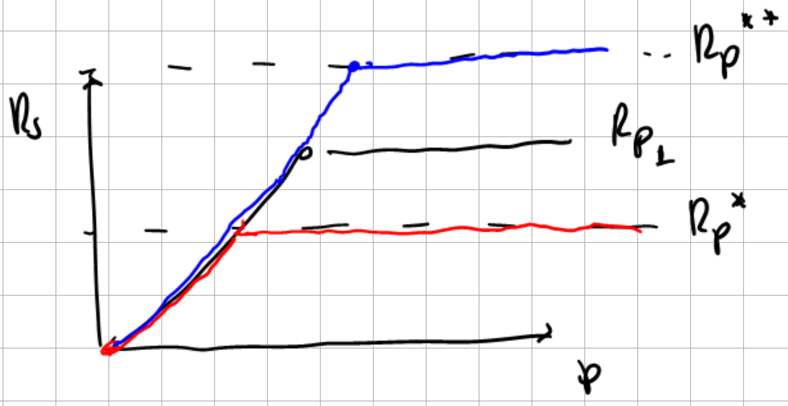
If z_i changes (or R_p)

it is usually necessary to generate a new black oil table









1. Subsea oil well modeling

Goal: set up a computational model of the well and perform some production engineering analysis.

Fluid information:

Use a black oil correlation of Glasø (p_b, R_s, B_o) and Beal (viscosity) to characterize your PVT behavior.

Solution GOR = 142 Sm^3/Sm3 Producing GOR = 142 Sm^3/Sm^3 Oil gravity = 37 API (840 Kg/m^3) Gas gravity = 0.76 At initial conditions no water.	Formation Water salinity = 23000 ppm No H2S, CO2, N2. Heat capacity of oil = 2.219 KJ/Kg/K Heat capacity of gas = 2.1353 KJ/Kg/K Heat capacity of water = 4.1868 KJ/Kg/K

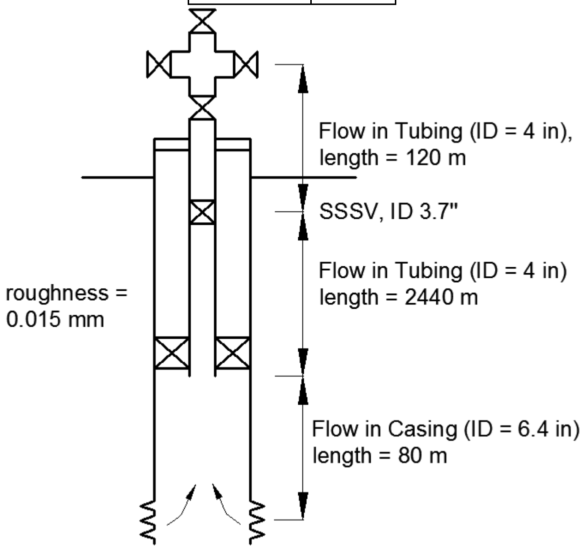
Well layout:

Deviation survey

MD [m]	TVD [m]
0	0
123	122
1059	1036
2164	2103
2640	2560

Geothermal gradient

MD [m]	T [C]
0	4
2640	100



Overall heat transfer coefficient = 45 W/m^2 K

Reservoir info:

Producing from a single layer
Reservoir pressure = 360 bara
Reservoir temperature = 100 C
Water cut = 0%
Productivity index = 12 Sm^3/d/bara

Tasks

PVT

- Determine the bubble point pressure of the oil and gas mixture at reservoir temperature
- Plot Bo, Rs and visco versus pressure at reservoir temperature. Export the curves to Excel.
- Perform a calibration of the BO correlations. Assume that the viscosity of the oil at reservoir pressure and temperature is known and equal to 1.3 cP.

Pressure transverse calculations

- Perform a calculation assuming wellhead pressure is 35 bara and oil rate is 1000 Sm3/d. examine the results and plot versus measured depth the following variables:
    - Total pressure gradient, hydrostatic, frictional and acceleration pressure gradient components
    - Liquid holdup and non-slip volume fraction. Compute slip between liquid and gas.
    - Gas and liquid velocities
    - Temperature
- Repeat the calculations above for a wellhead pressure of 70 bara and oil rate of 1000 Sm3/d. How does this change affect your results?
- Change the overall heat transfer coefficient to 10 W/m2 K and repeat your calculations. How does this change affect your results?
- Assume the well is producing with a water cut of 20%. How does this affect your results?

TPR

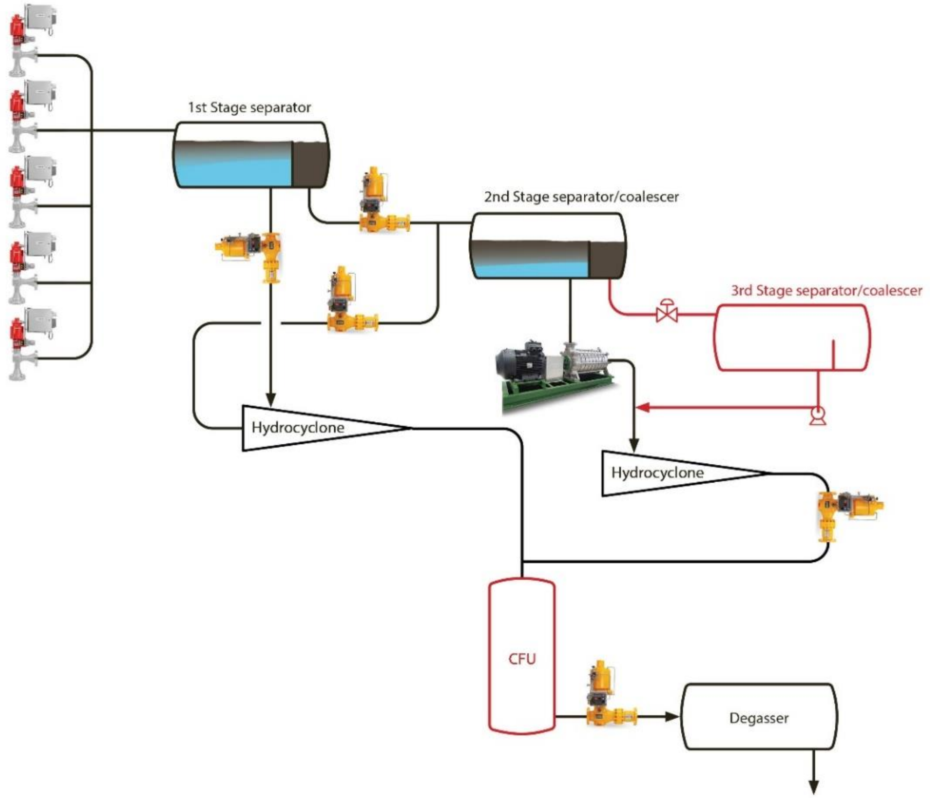
- Calculate TPR curves for wellhead pressures equal to 35 bara, 70 bara, and 100 bara.
- Calculate TPR curves for GOR equal to 200, 300 and 600 Sm3/Sm3.

Flow equilibrium

- Estimate the producing rate using flow equilibrium and wellhead pressure is 35 bara.
- The team is considering using a bigger tubing. Evaluate the effect this could have in the equilibrium rate.
- Assume the well is producing with a water cut of 20%. How does this affect your results?

Low Shear

- What?
  - Why?
    - Where?
      - How?
        - What's next?



November 1, 2022

Rune Husveg, PhD
R&D Manager

Produced water definition, origin, and characteristics

- Produced water definition
  - …water which is produced in oil and/or gas production operations and includes formation water, condensation water and re-produced injection water; it also includes water used for desalting oil.

- Origin/Characteristics

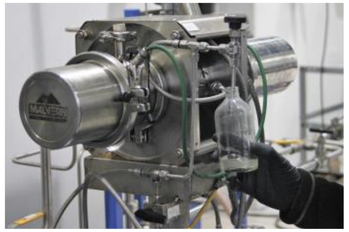
- Water to oil ratio

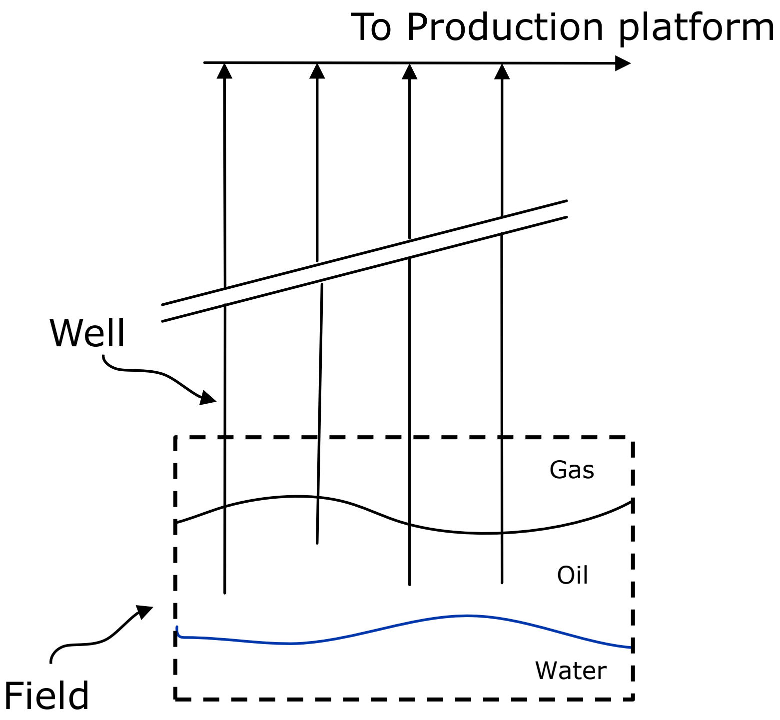
  3:1 –> 4:1

  90% NCS

- 40% discharged globally
- Discharge limit

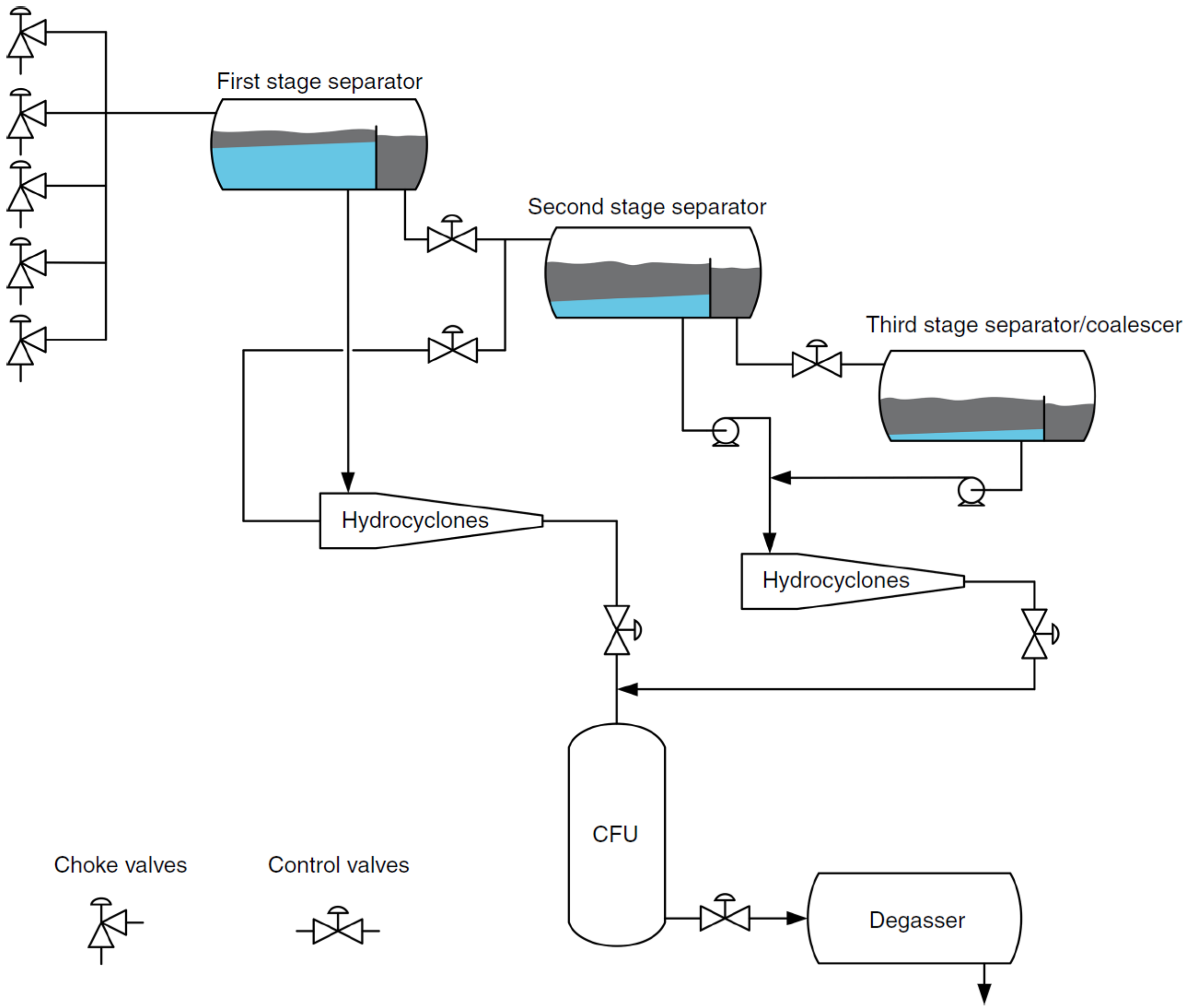
  30 mg/l





OSPAR
PSA

Produced water management



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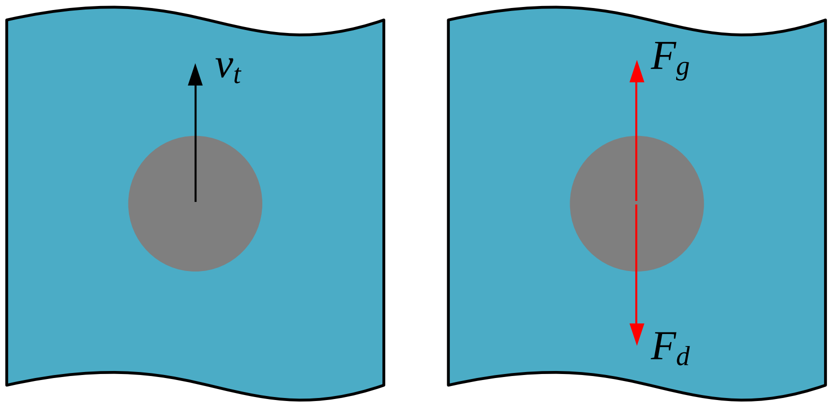
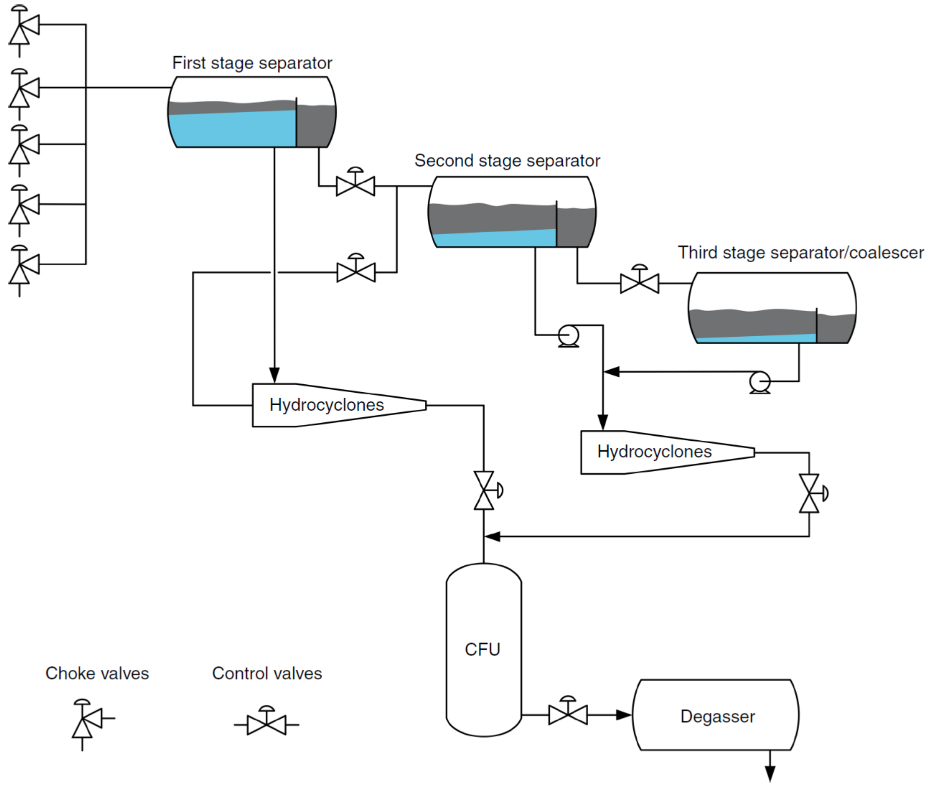
SPE-159713-PA

Gravity separation





Stokes' law:

$$v_t = \frac{(\rho_w - \rho_o) \cdot g \cdot d^2}{18 \cdot \mu_w}$$

d	droplet diameter
F_d	drag force
F_g	settling force
g	gravitational acceleration
v_t	terminal velocity
μ_w	water dynamic viscosity
ρ_o	oil density
ρ_w	water density

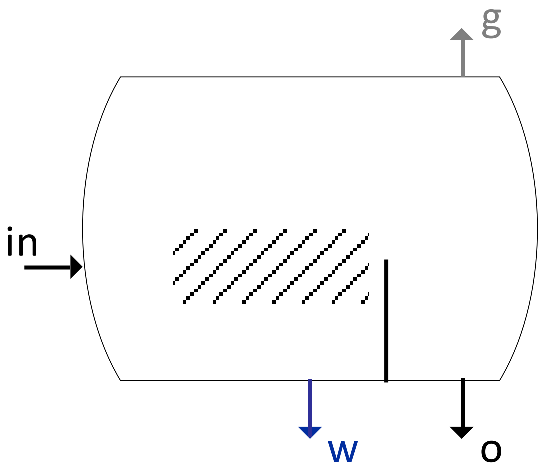
$$F_d = F_g$$

$$F_g = \frac{\pi \cdot (\rho_w - \rho_o) \cdot g \cdot d^3}{6}$$

$$F_d = 3 \cdot \pi \cdot \mu_w \cdot v_t \cdot d$$

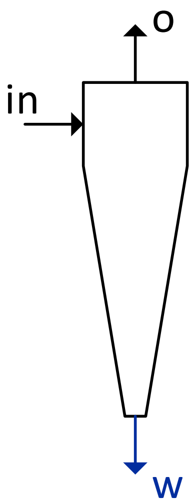
Enhanced separation

Gravity separation
Corrugated plate interceptor (CPI)



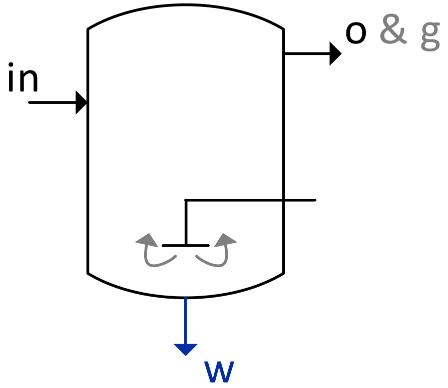
$$v_t = \frac{(\rho_w - \rho_o) \cdot g \cdot d^2}{18 \cdot \mu_w}$$

Enhanced gravity separation
Hydrocyclone



$$v_t = \frac{(\rho_w - \rho_o) \cdot g \cdot d^2}{18 \cdot \mu_w}$$

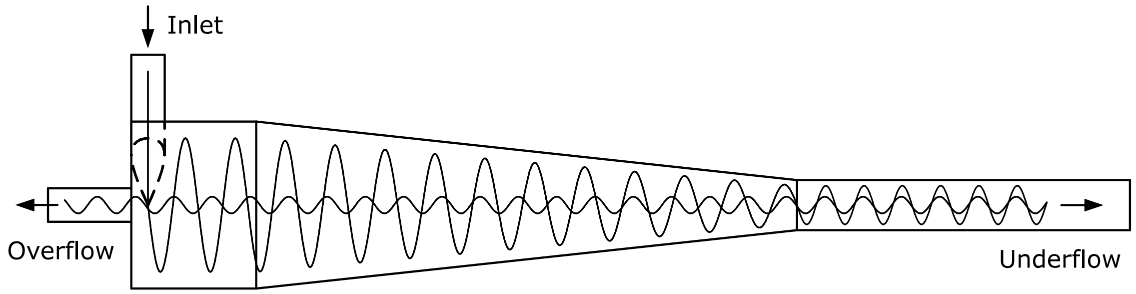
Flotation
Compact Flotation Unit (CFU)



$$v_t = \frac{(\rho_w - \rho_o) \cdot g \cdot d^2}{18 \cdot \mu_w}$$

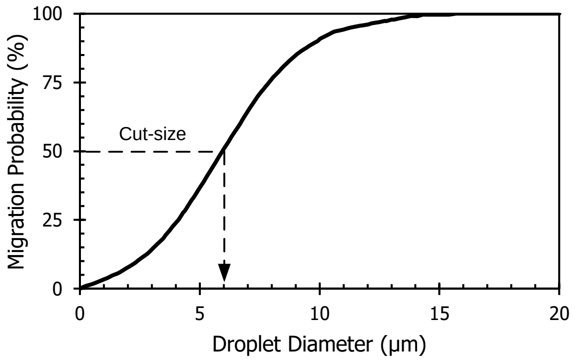
Enhanced gravity separation - Hydrocyclone

$$v_t = \frac{(\rho_w - \rho_o) \cdot g \cdot d^2}{18 \cdot \mu}$$



$$g = a_r = \frac{{v_T}^2}{r}$$

$$v_t = \frac{(\rho_w - \rho_o) \cdot {v_T}^2 \cdot d^2}{18 \cdot \mu_w \cdot r}$$



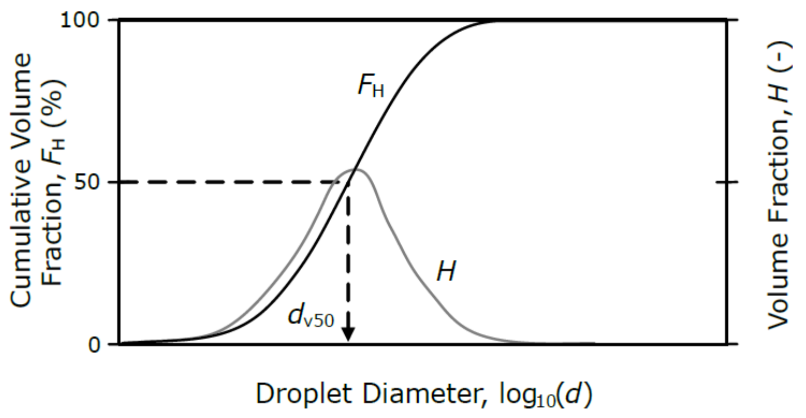
Source: Schlumberger

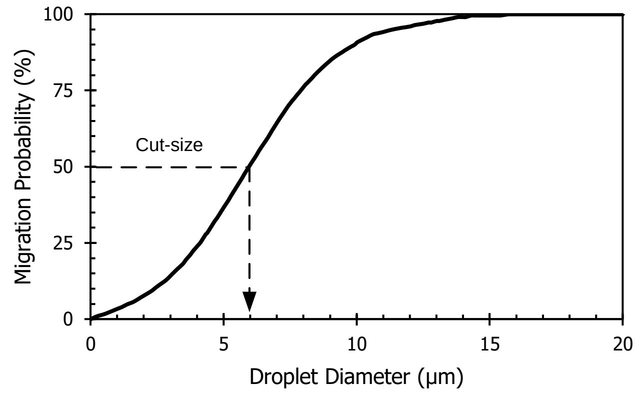
a_r radial acceleration

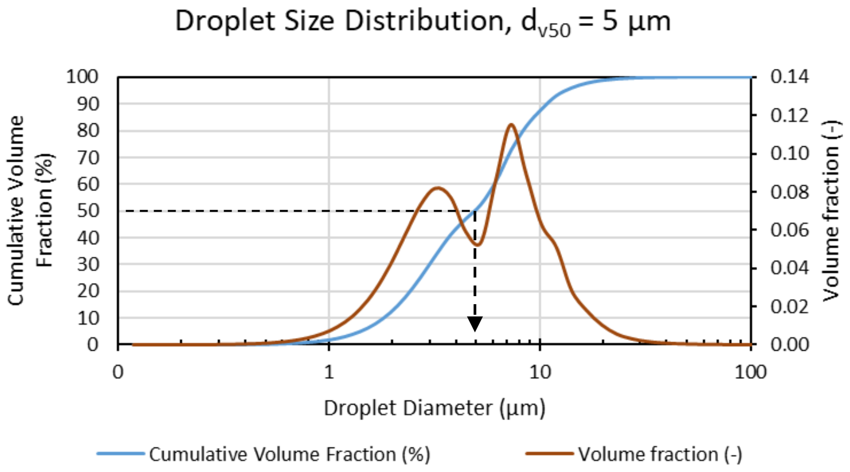
r distance from cyclone center

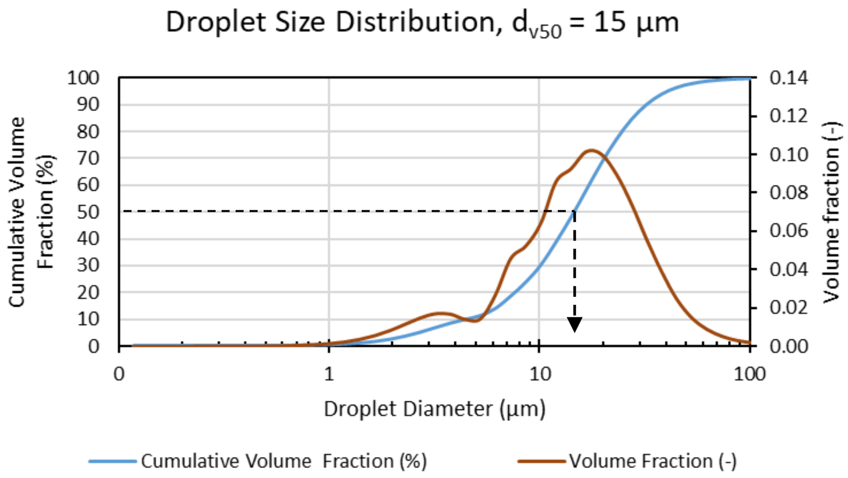
v_T tangential velocity

Droplet size distribution – d_{v50}

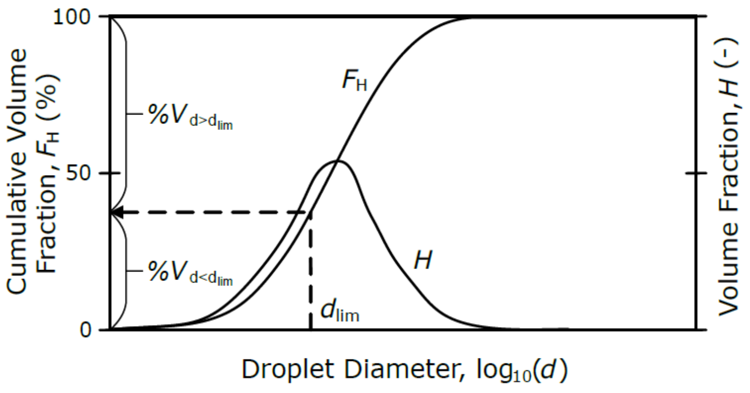


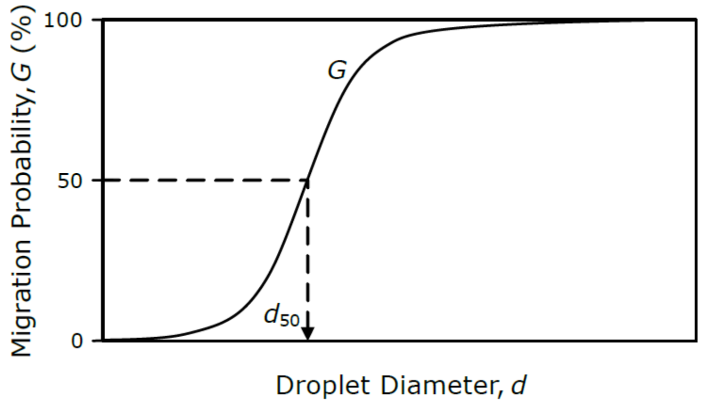


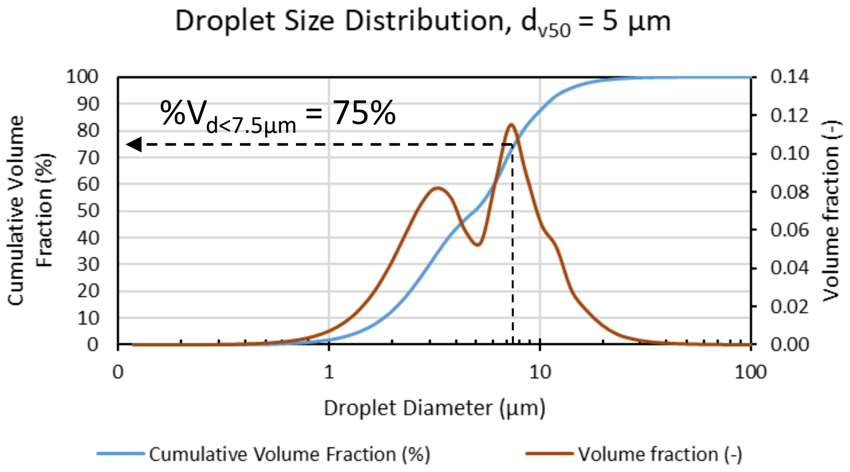


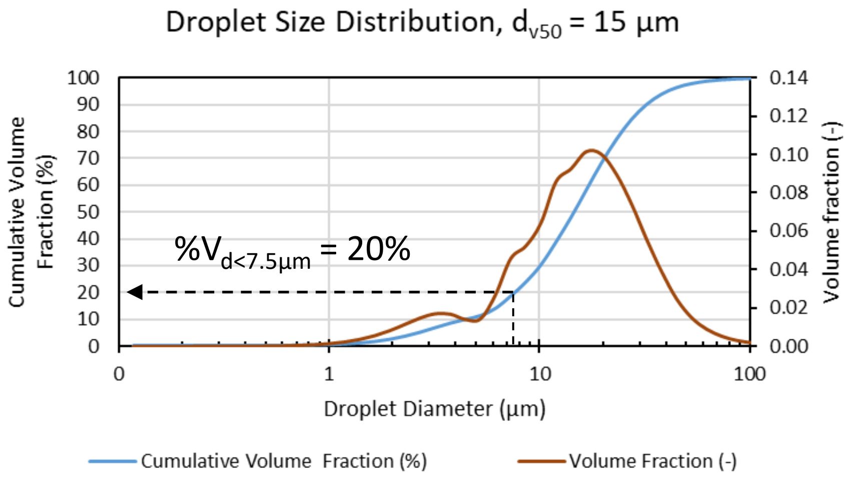


Droplet size distribution – $\%V_{d<dlim}$





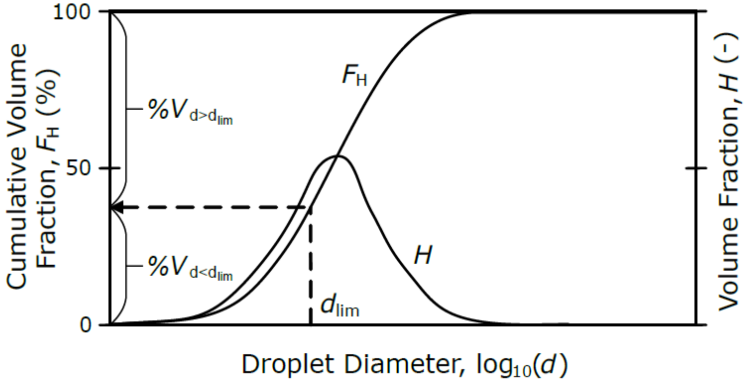


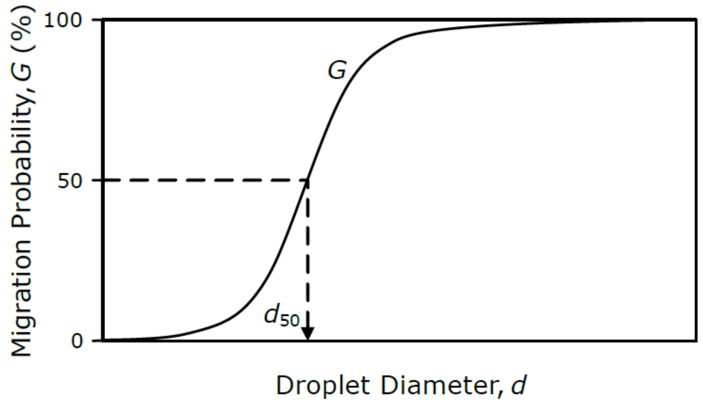


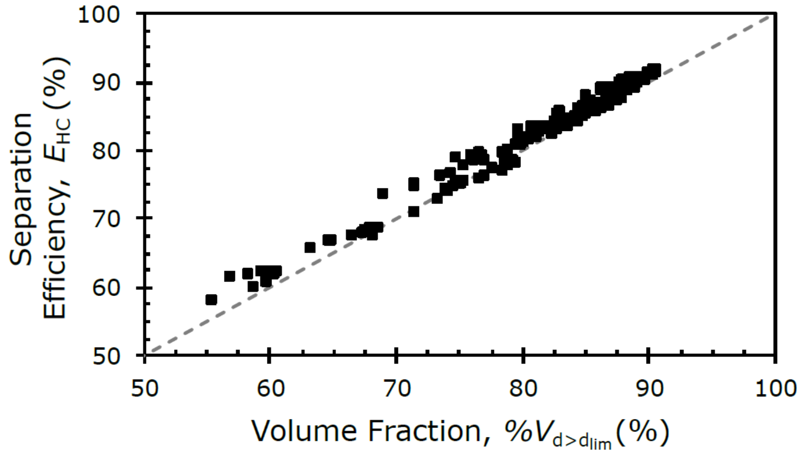
d_{lim} = 7.5 µm

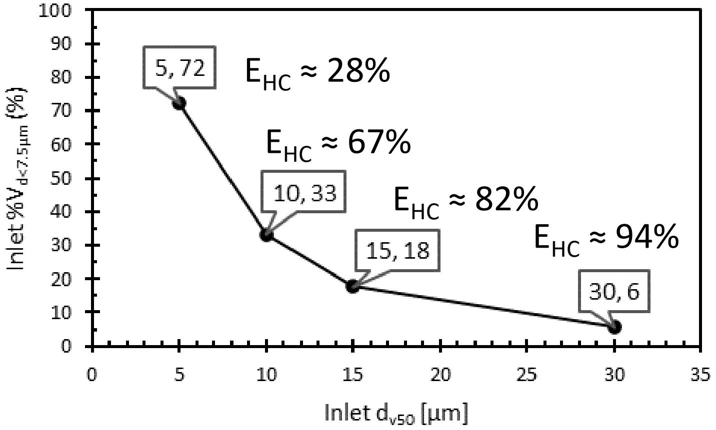
SPE-195591-PA

Droplet size distribution – $\%V_{d<dlim}$ -> E_{HC}









$d_{lim} = 7.5\ \mu m$

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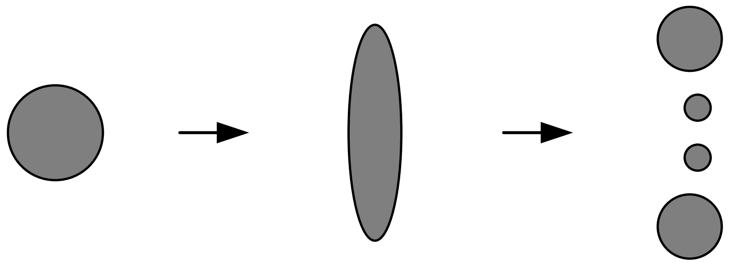
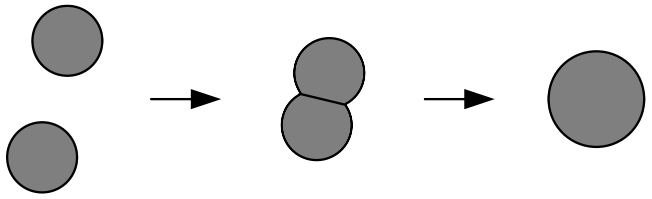
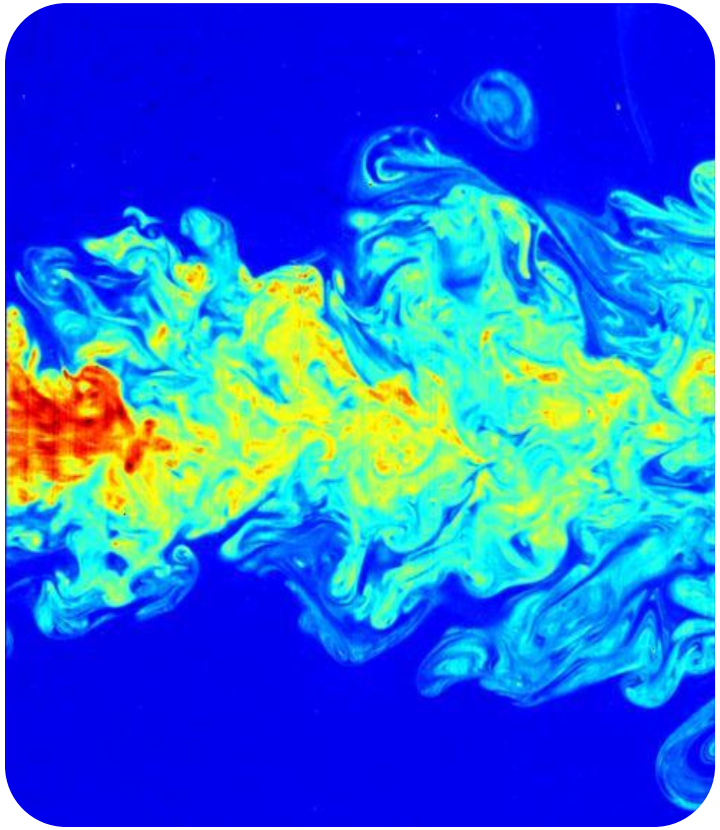
Droplet size development

- High intensity turbulence → droplet break-up and emulsions



- Low intensity turbulence can cause droplet coalescence





Source: Wikipedia

LOW SHEAR SHORTS

DEMONSTRATING SHEAR

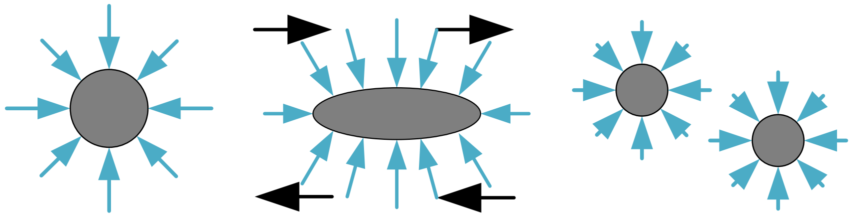
IN 30 SEC

typhonix
cleaner production

https://youtu.be/xZ8LWVUDuoQ

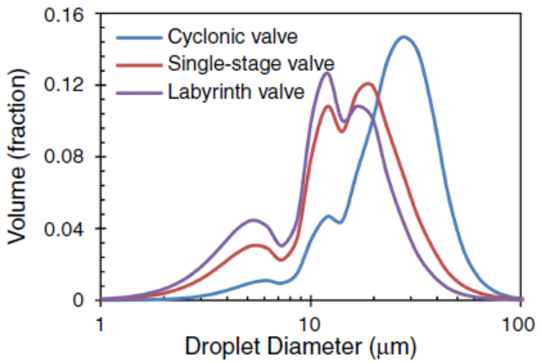
Droplet breakup

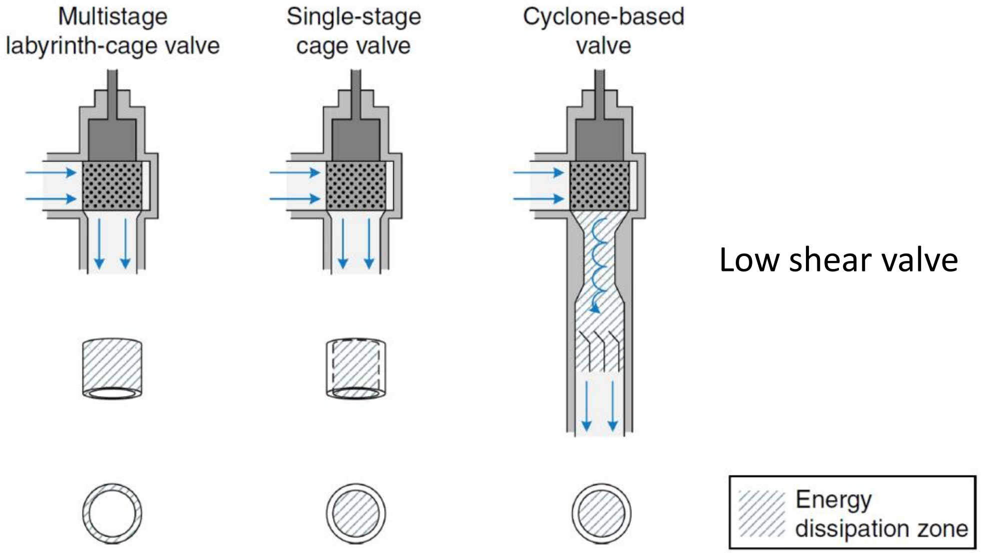
1. Dispersed droplets formed by the surrounding water
2. Shear stress due to turbulence elongates and increases surface area
3. Droplet breaks into smaller droplets reduce the surface area



$$d_{max} \propto \left(\frac{\sigma}{\rho_c}\right)^{3/5} \cdot \varepsilon^{-2/5} \qquad \varepsilon = \frac{\Delta p \cdot Q}{\rho_c \cdot V_{dis}}$$

d	droplet diameter
ε	energy dissipation per unit mass
Δp	pressure drop
Q	flow rate
V_{dis}	dissipation volume
σ	interfacial tension
ρ_c	continuous phase density





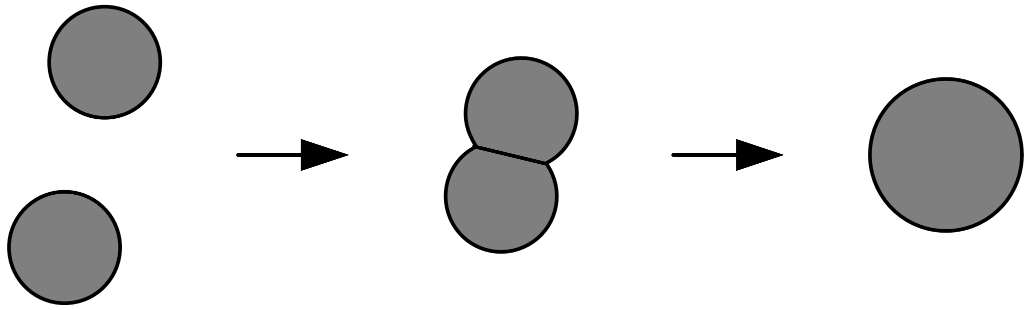
Low shear valve

Hinze 1955
SPE-205016-PA

Droplet-droplet coalescence

Film drainage model

1. Collision of droplets
2. Drainage of fluid film



Coalescence rate governed by

- Turbulence intensity
- Number and size of droplets
- Fluid properties (e.g., viscosity, density and interfacial tension)

Collision frequency

Coalescence probability

Total time

LOW SHEAR SHORTS

"LOW SHEAR"

IN 30 SEC

typhonix
cleaner production

https://youtu.be/pQAGm0q-yp4

Benefits of low shear oil production

- Increase production
- Longer production
- Cleaner production
- More compact separation systems
- Cost-efficient debottlenecking

Challenges with shear in oil production

Pictures: www.norskpetroleum.no

Brownfield challenges

- Limited capacity to increase production or tie-back new satellites to current facilities
- Expensive solutions to debottleneck processing capacity on mature fields

Low shear benefits

- Higher production rates
  - Faster separation through lower retention times
- Longer profitable production
  - Extended life of existing equipment/fields
  - Better opportunities for tie-backs

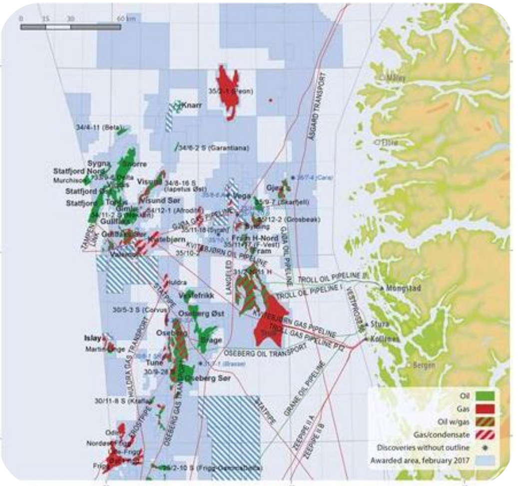
Challenges with shear in oil production

Greenfield challenges

- Costly to develop marginal fields
- Process plants with big footprint

Low shear benefits

- More compact separation systems
  - Smaller separators
  - Fewer separation- and PW handling stages
- Cleaner production
  - Less use of chemicals and heating
  - Less emissions to the sea



Pictures: www.norskpetroleum.no

Typhonix AS

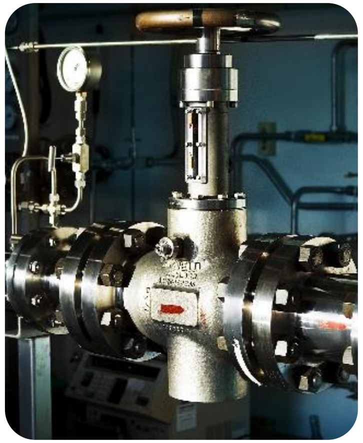
Typhonix develops **LOW SHEAR** process equipment for cost efficient oil production

- Established in 2006
- Office and test facilities near Stavanger, Norway
- Core competence in combined fields of petroleum flow control and oil/water separation
- Technology development together with leading oil companies

ConocoPhillips eni vår energi equinor TotalEnergies NEPTUNE ENERGY PETROBRAS OMV wintershall dea Lundin

Typhonix low shear technologies for oil and gas production

Typhoon® valve system



PROTOTYPE

TEST EQUINOR

50-90% reduction of oil in the produced water

PILOT TEST

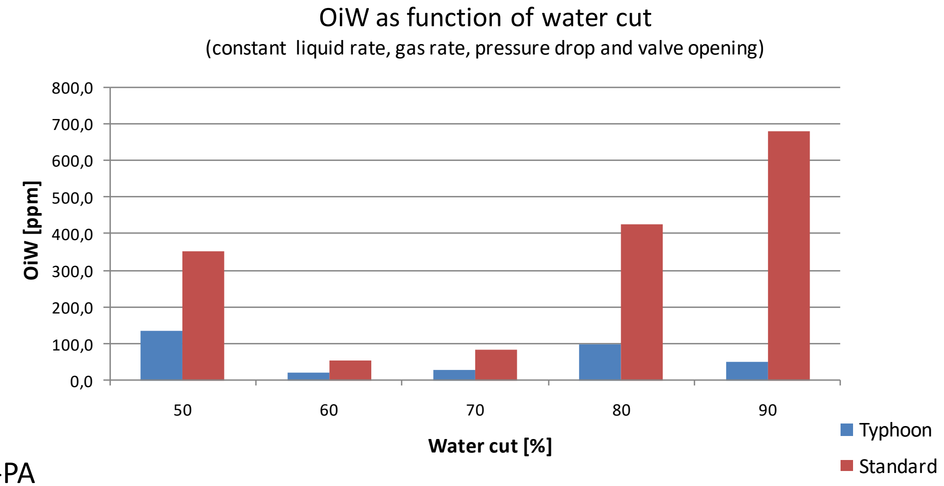
OSEBERG C

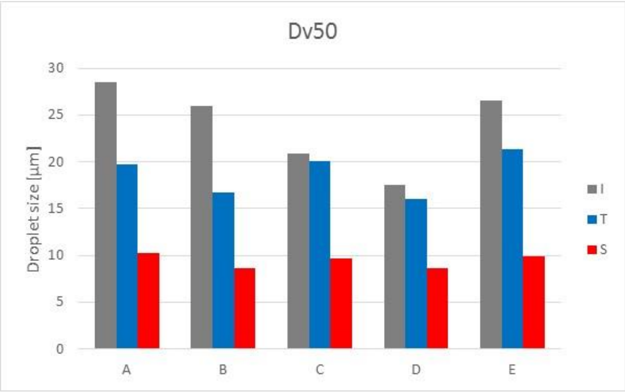
45% reduction of oil in the produced water

INSTALLATION

TROLL C

60% reduction of oil in the produced water





PRODUCED

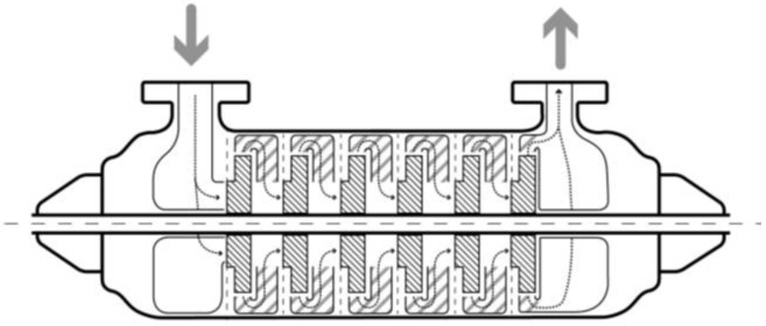
WATER TESTING

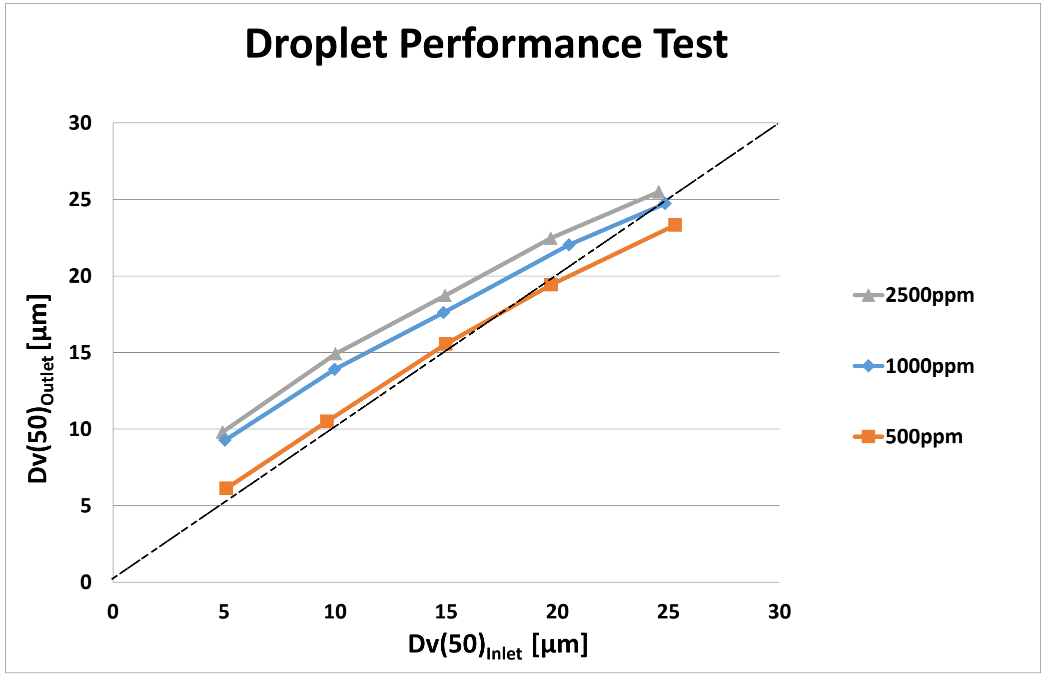
Typically double Dv50 compared to conventional valves

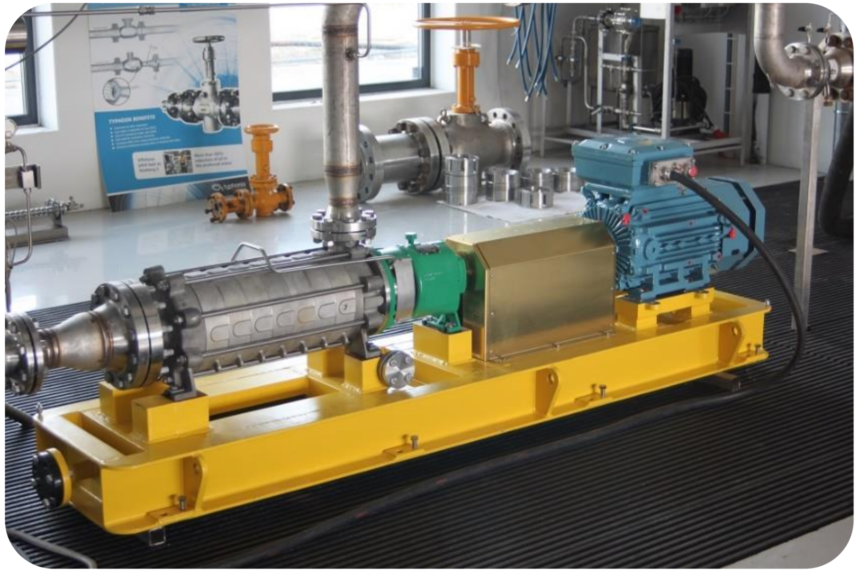
SPE-205016-PA

Typhonix low shear pumps

- Installed offshore Malaysia as feed pumps (2 x 100%) to a filter system
- Design chosen for high reliability and low shear performance
- In continuous operation since August 2017







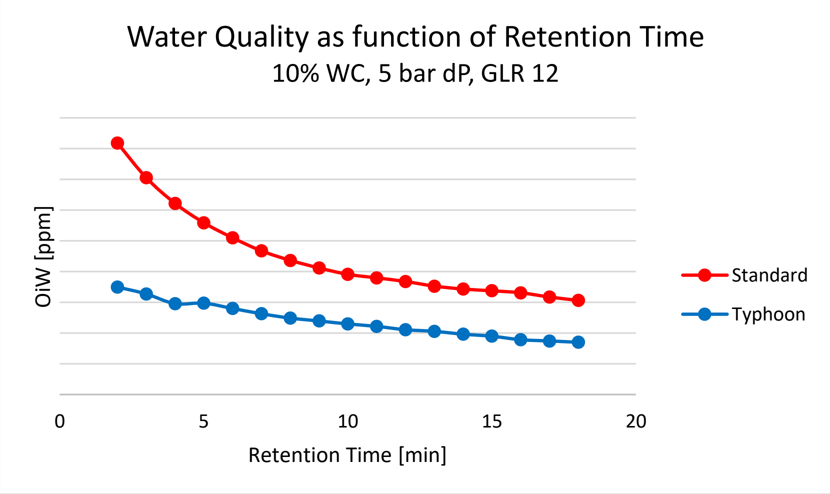
Case studies and field results

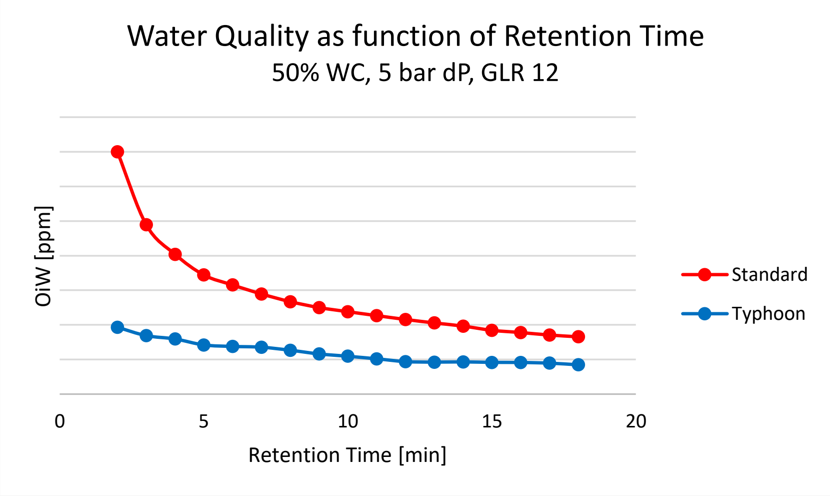
Example 1:

Increasing separator capacities and
enabling higher well production rates

Separator debottlenecking

- Conventional approach:
  - Modification of separator internals
  - Use of compact inline separation equipment
- Low shear approach:
  - Install low shear choke/LCV
- Brownfield case study:
  - Maintain constant OiW and WiO d/s separator
  - Expect 10 to 15% increase in droplet size (conservative)
  - **Result: 20 to 30% increase in liquid flow rate**
- Greenfield case study:
  - **15 to 20% reduction in liquid separation volume**





Offshore Magazine 2018

Example 2:

Extending the profitable period of

late-life field production

Low shear water LCV installed in Australia

Challenge:

- Upgrading of production capacity and extending the operational lifetime of FPSO
- Limits on oil content in the overboard discharge (less than 30 ppm)

Solution:

- Low shear valve installed between hydrocyclone and compact flotation unit

Result:

- **23%** improvement of CFU efficiency

INSTALLATION

FAR EAST

23% improvement of CFU efficiency

Operation conditions:

- Inlet pressure: 4.5 – 5 barg
- Outlet pressure 2.3 barg

SPE-205016-PA

Example 3:

Designing greenfield process plants

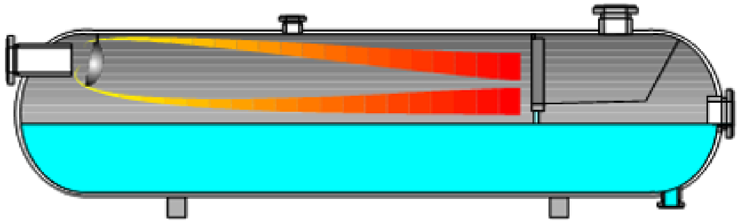
with a smaller footprint

Separator optimization with focus on footprint

Conventional Separator:

110 ton

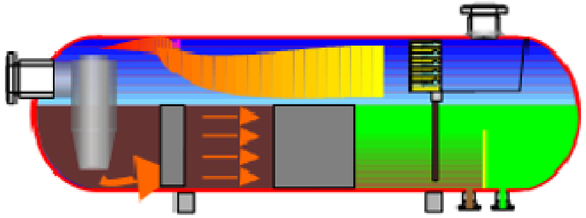
H T/T 16m



Internal Optimisation:

67 ton

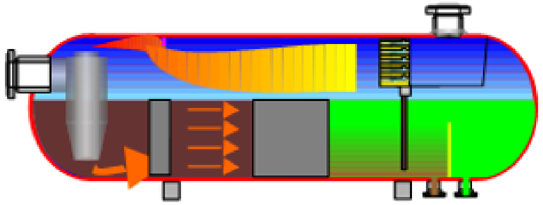
T/T 12m



Low Shear & Internal Optimisation:

52 ton

T/T 10m



Example 4:

Reduced chemical consumption

Effects on chemical consumption

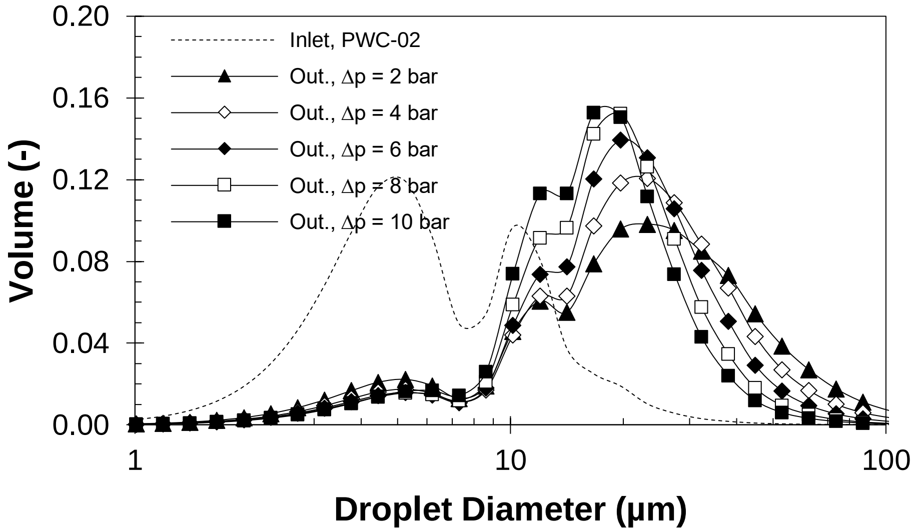
Flocculant

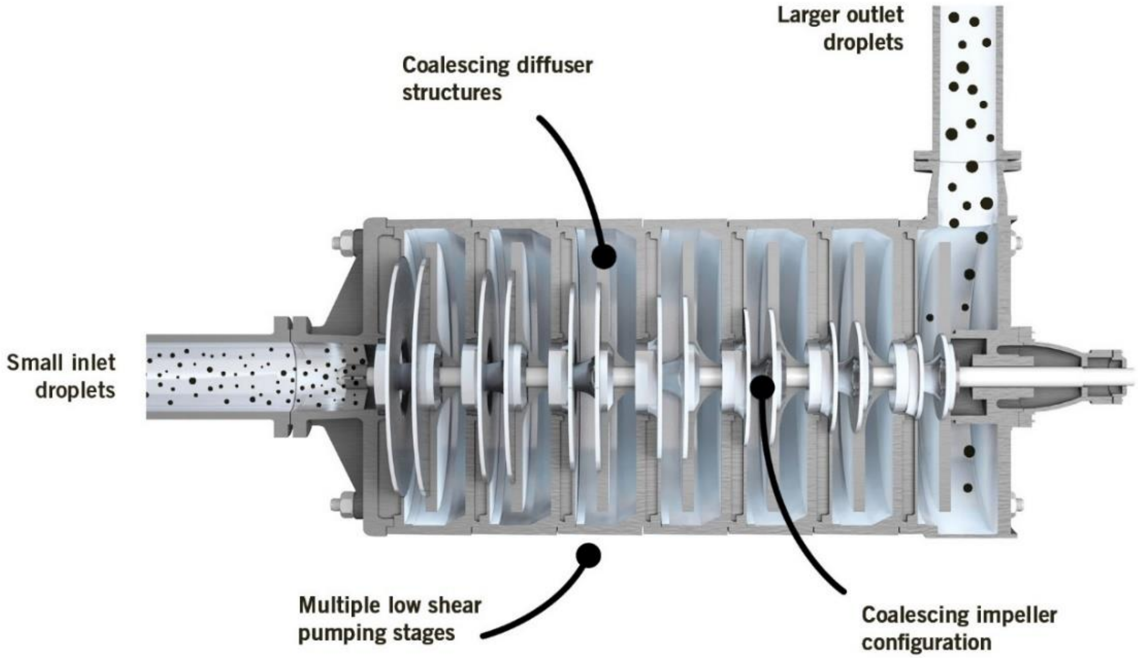
- Flocculant dosing is dependent on OiW concentration
- Case study for Oseberg C
  - 45% reduction in OiW with Low shear valves
  - 37 to 110 ton reduction in flocculant injection per year
  - € 30.000 to 100.000 potential annual savings in flocculant

- Additional potential to reduce demulsifier injection

Typhonix coalescing technologies

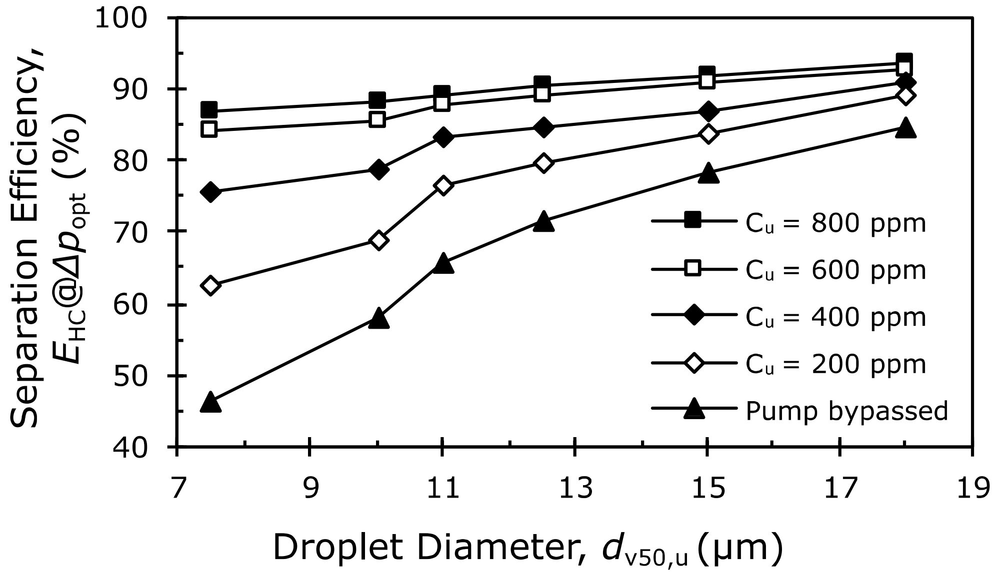
Typhonix coalescing pumps

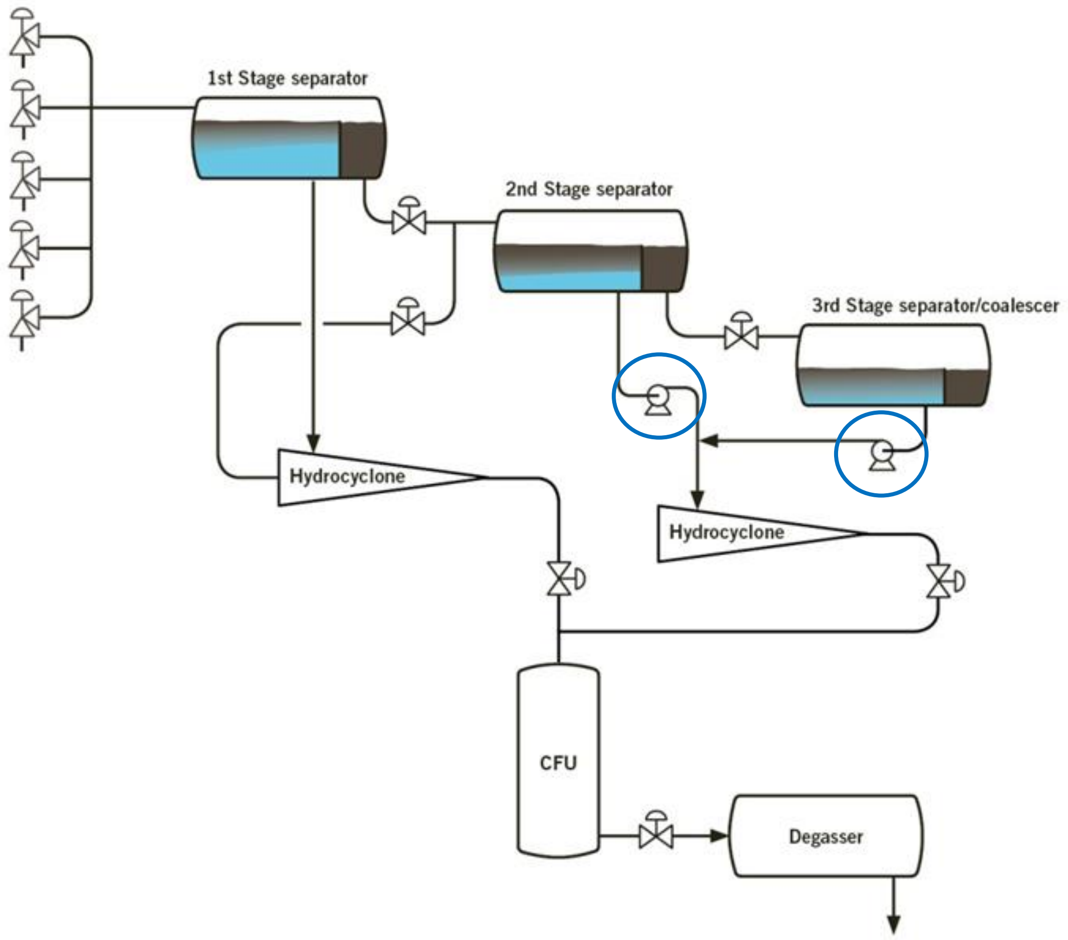




SPE 188772

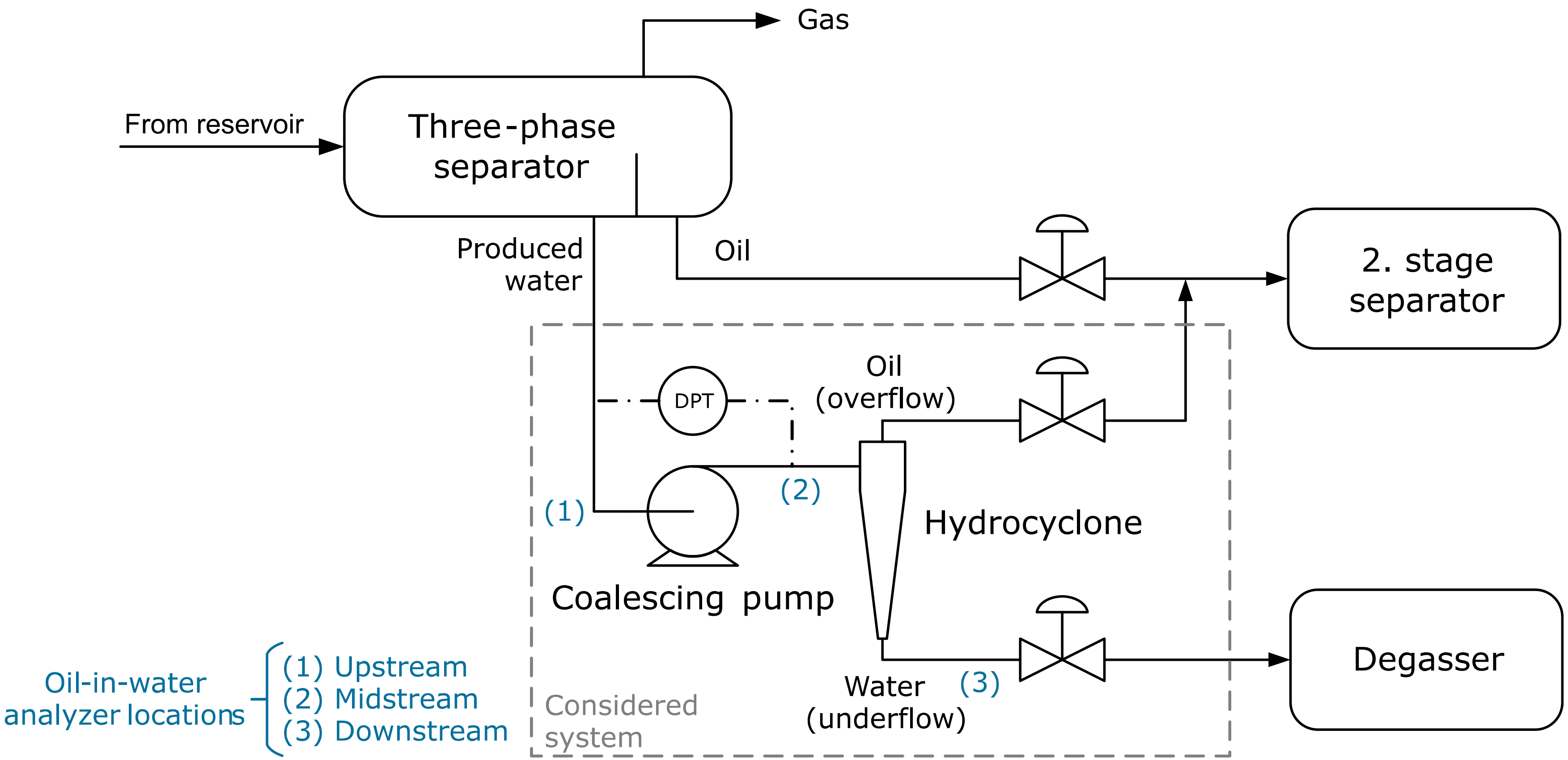
Typhonix coalescing pumps





SPE 195591

Typhonix coalescing pumps – optimizing algorithm



Typhonix coalescing valve

Energy dissipation used for droplet growth rather than droplet breakup

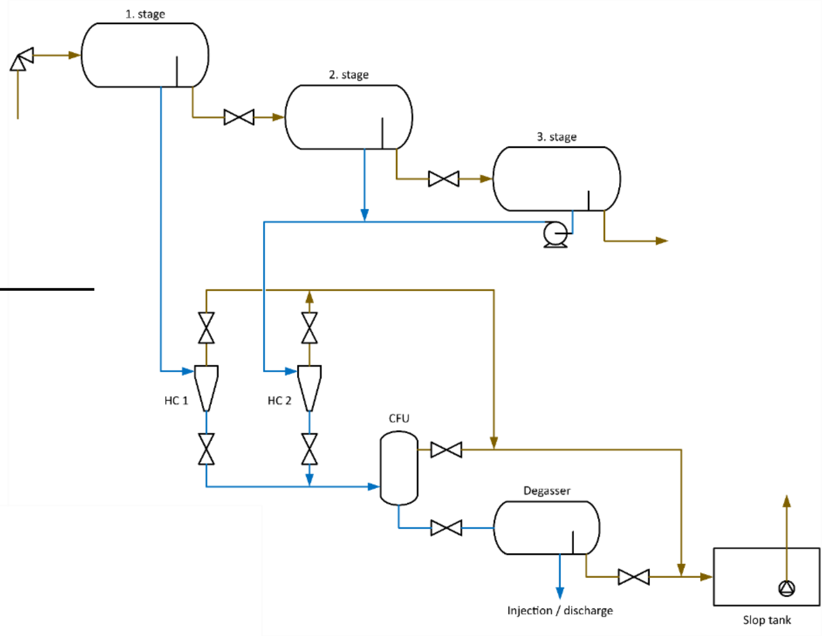
Level of turbulence independent of capacity

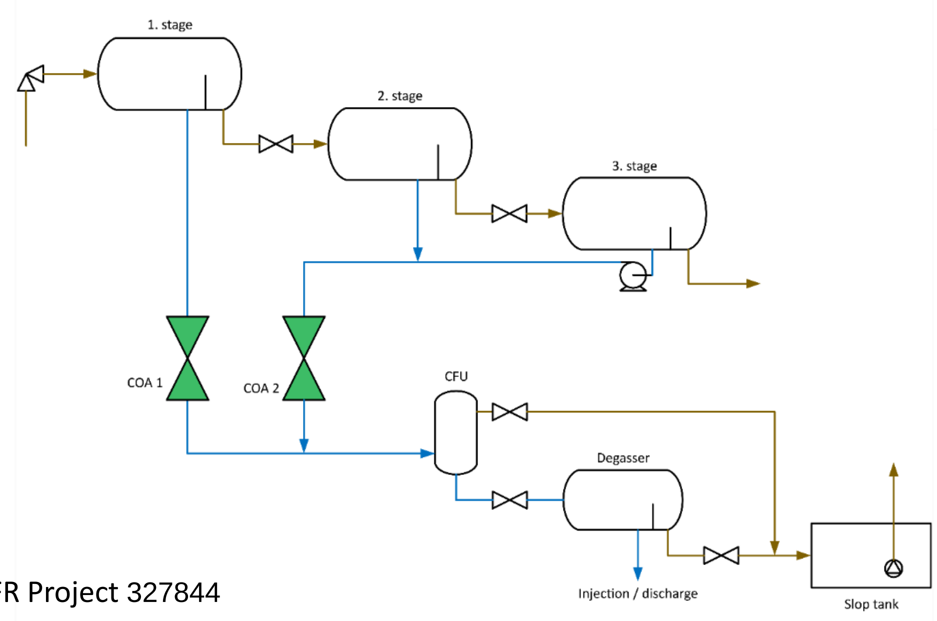
Two design criteria:

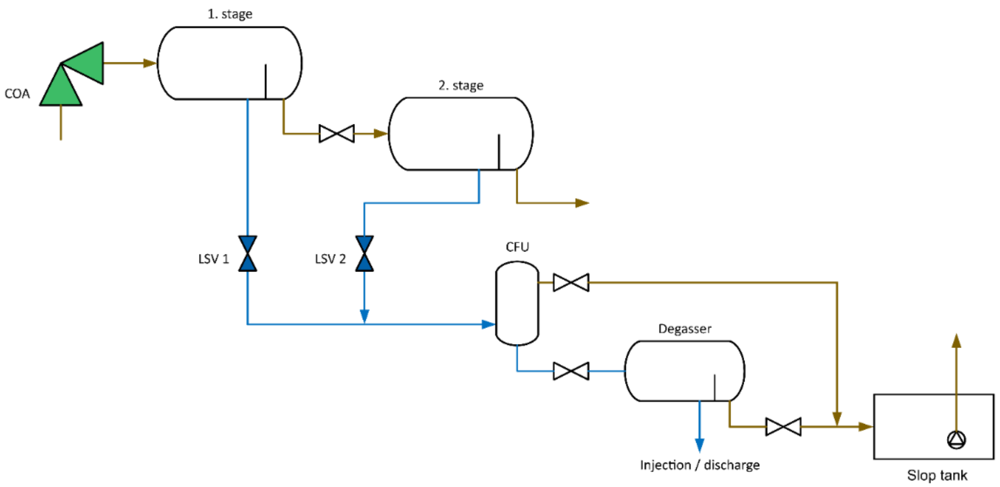
- Capacity
- Turbulence intensity

NFR Project 327844

Typhonix coalescing valve – potential applications



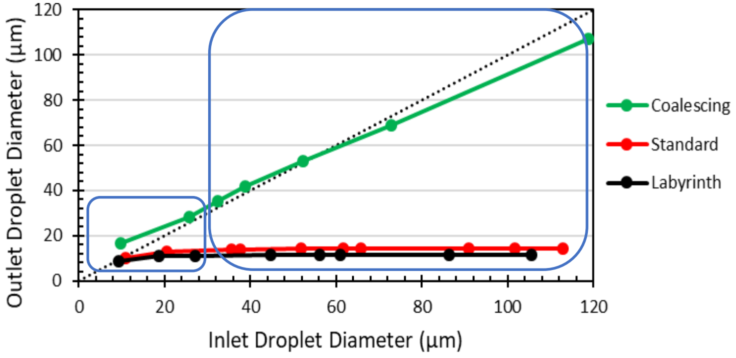


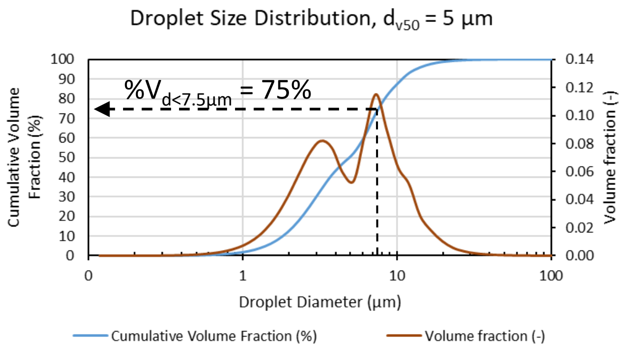


NFR Project 327844

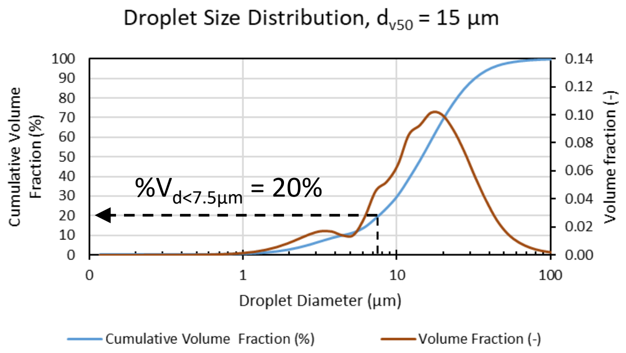
typhonix
cleaner production

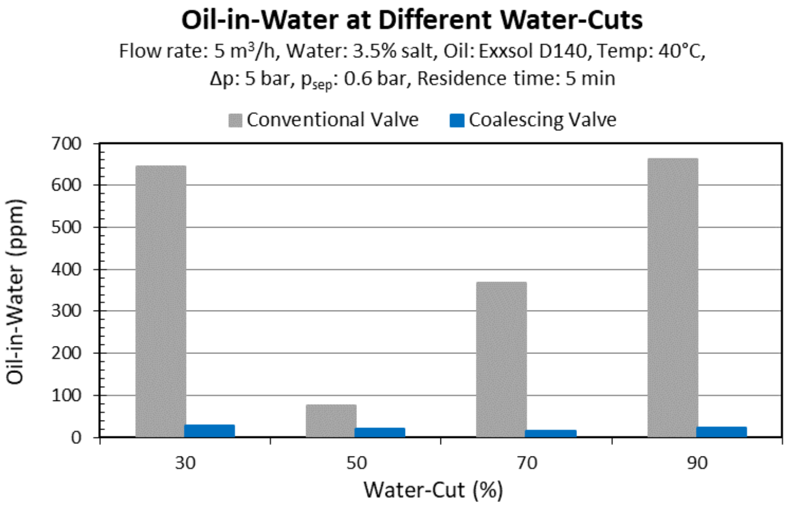
Typhonix coalescing valve – potential applications





75% reduction





NFR Project 327844

typhonix cleaner production

Summary

- Low Shear

- What? – Increased treatment efficiency through reduced droplet breakup
  - Why? – Increased production rates, extended profitable production, reduced plant size, reduced chemical consumption and reduced environmental emissions.
    - Where? – Throughout the whole process plant, but the earlier the better (low shear choke > low shear control valve >> standard valves)
      - How? – Replace standard equipment with low shear alternatives, where reduced turbulence intensity reduces shear forces and droplet breakup
        - What's next? – Coalescing technologies, online monitoring and intelligent control

Some sources and further reading

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- youtube.com/TyphoonMPS
- linkedin.com/company/typhonix-as
- typhonix.com/learn-more-about-low-shear

For more information contact:

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General information about the delivery:

- You can use Prosper or Pipesim to make your calculations. It is recommended you use a different software for each problem such that you can practice both.
- The computer laboratory P2 will be available for you to work on the exercise in the following time-slots:
  - 8.11, 10:15-12:00
  - 10.11, 08:15-11:00
  - 15.11, 10:15-12:00
  - 17.11, 08:15-12:00

The student assistant will be in the room during the sessions.

- Make your own plots in Excel using the data from the software. Do not present charts taken directly from the software.
- Make a document (short report) with the answer to the questions. Add some discussion and analysis to the plots.

1. **<u>Subsea oil well modeling</u>**

Goal: set up a computational model of the well and perform some production engineering analysis.

<u>Fluid information:</u>

Use a black oil correlation of Glasø (p_b, R_s, B_o) and Beal (viscosity) to characterize your PVT behavior.

Solution GOR = 142 Sm3/Sm3 Producing GOR = 142 Sm3/Sm3 Oil gravity = 37 API (840 Kg/m3) Gas gravity = 0.76 At initial conditions no water.	Formation Water salinity = 23000 ppm No H2S, CO2, N2. Heat capacity of oil = 2.219 KJ/Kg/K Heat capacity of gas = 2.1353 KJ/Kg/K Heat capacity of water = 4.1868 KJ/Kg/K

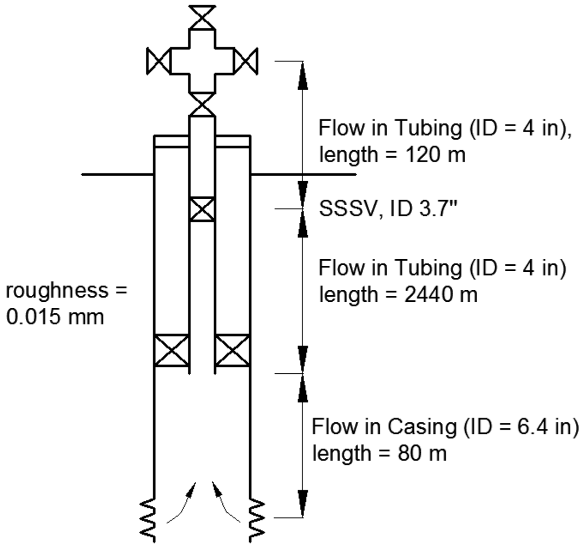
<u>Well layout:</u>

Deviation survey

MD [m]	TVD [m]
0	0
123	122
1059	1036
2164	2103
2640	2560

Geothermal gradient

MD [m]	T [C]
0	4
2640	100



Packer depth (MD): 2500 m

Overall heat transfer coefficient = 45 W/m^2 K

Reservoir info:
Producing from a single layer
Reservoir pressure = 360 bara
Reservoir temperature = 100 C
Water cut = 0%
Productivity index = 12 Sm3/d/bara

Tasks

PVT
• Determine the bubble point pressure of the oil and gas mixture at reservoir temperature
Flow equilibrium
• Estimate the producing rate using flow equilibrium and wellhead pressure is 35 bara. Plot versus measured depth the following variables: o Total pressure gradient, hydrostatic, frictional and acceleration pressure gradient components o Liquid holdup and non-slip volume fraction. o Compute slip between liquid and gas velocities (Vg/Vl). o Gas and liquid velocities. o Temperature. • The team is considering using a bigger tubing. Evaluate the effect this could have in the equilibrium rate (consider tubing sizes of 2,3,4,5,6”). • Calculate equilibrium rates for water cuts of 0, 20, 50 and 90% • Calculate equilibrium rates for reservoir pressures equal to 360, 300, 250 and 200 bara. • Evaluate the effect of at least two pressure drop correlations on the equilibrium point. • Consider gas lift. Add a gas-lift injection valve at a depth of 2450 m. Consider wellhead pressure of 35 bara. Make a plot of oil production versus gas injection rate. Report the GLR (gas liquid ratio) for all the points. Determine the optimal gas lift injection rate that gives highest reservoir oil production.

2. Snøhvit subsea gas well modeling

Fluid information:

Use the compositional PVT model for your PVT behavior.

Component	Moles
Water	0
Methane	78
Ethane	8
Propane	3.5
Isobutane	1.5
Butane	1.2
Isopentane	0.8
Pentane	0.5
Hexane	0.5
C7+	6

Properties for pseudo component C7+: Molecular weight: 115, specific gravity: 0.683

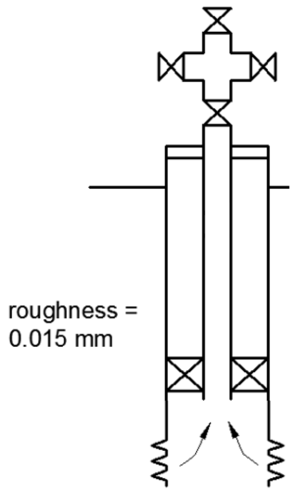
Well layout:

Deviation survey

MD [m]	TVD [m]
0	0
2100	2100

Geothermal gradient

MD [m]	T [C]
0	4
2100	92



Flow in tubing only, tubing diameter 0.15 m

Overall wellbore heat transfer coefficient = 30 W/m^2 K

Reservoir info:

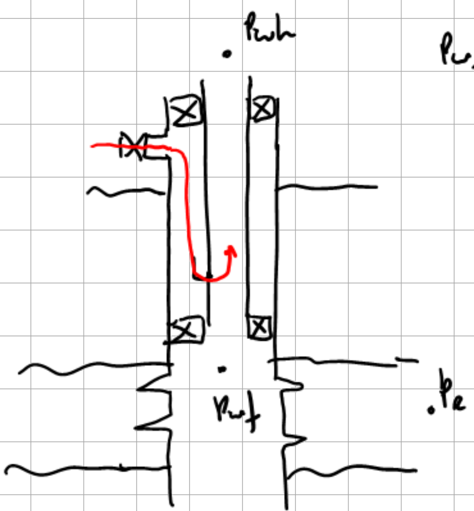
Producing from a single layer
Reservoir pressure = 276 bara
Reservoir temperature = 92 C
Backpressure coefficient = 1000 Sm^3/d/bara
Backpressure exponent = 1

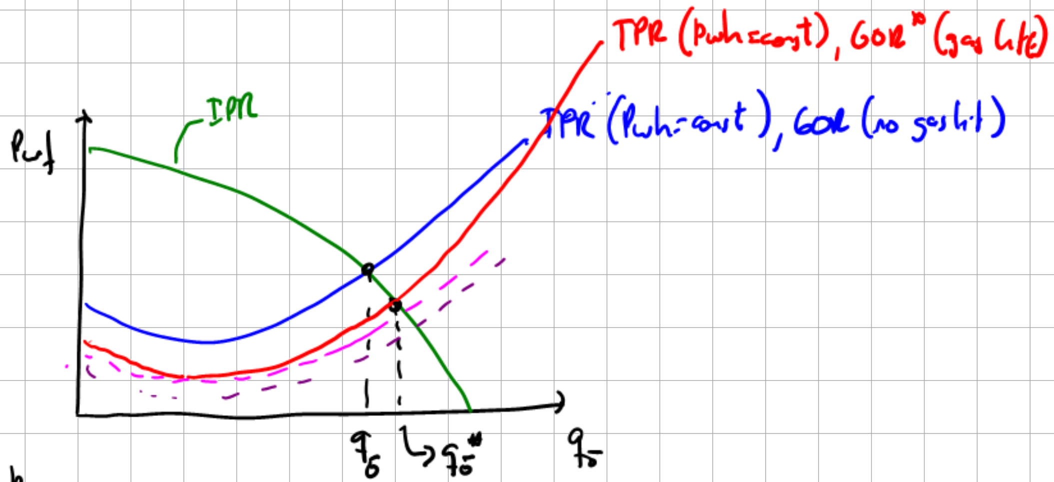
Tasks:

- Determine the saturation pressure of the fluid at reservoir temperature.
- Plot the phase envelope of reservoir fluids.
- What is the condensate gas ratio, and the water gas ratio of the well?
- Estimate the producing rate using flow equilibrium assuming that the well is producing against a constant wellhead pressure of 100 bara.
- Calculate equilibrium rates for wellhead pressures equal to 100 bara, 120 bara, and 150 bara.
- Add a wellhead choke with size 16/64". Report the new equilibrium rate and temperature downstream the choke.
- **Pressure gradient calculations:** Perform a calculation assuming wellhead pressure is 100 bara and gas rate is 3 E06 Sm3/d. Examine the results and plot versus measured depth the following variables:
    - Total pressure gradient, hydrostatic, frictional and acceleration pressure gradient components
    - Liquid holdup and non-slip volume fraction. Compute slip between liquid and gas.
    - Gas and liquid velocities
    - Temperature

Lecture 34, Gas lift intro

Artificial lift technique to:
-Increase production rate from natural flow
-enable production (natural flow is zero)
-Improve well flow (e.g. avoid instabilities)





$$\Delta p = p_{wf} - p_{wh} = \underbrace{\Delta p_{Hydrostatic}}_{\rho_m \cdot g \cdot \Delta h} + \underbrace{\Delta p_{friction}}_{\rho_m \cdot f \frac{L}{D} \frac{v^2}{2}} + \Delta p_{acceleration}$$

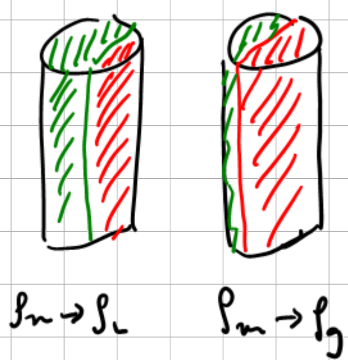
① ②

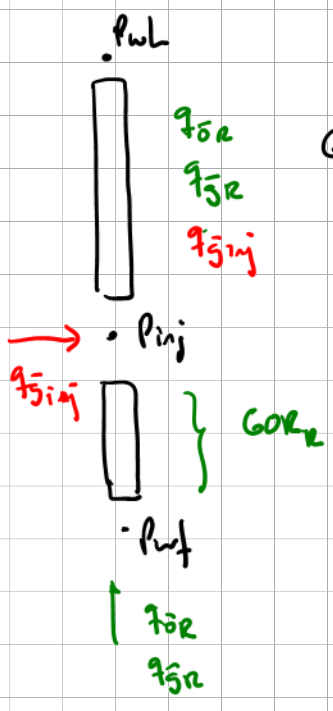
$$\rho_g \leq \rho_m \leq \rho_L$$

$$\rho_m \rightarrow \rho_g$$

the goal of gas lift : reduce ① increasing ②

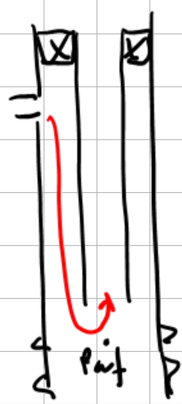
$$\rho_m = H_g \cdot \rho_g + H_L \cdot \rho_L \qquad H_g = \frac{A_g}{A}$$





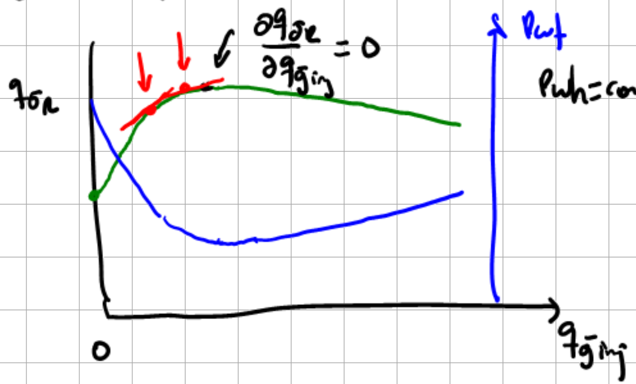
$$GOR^* = \frac{q_{g_{inj}} + q_{g_R}}{q_{o_R}}$$

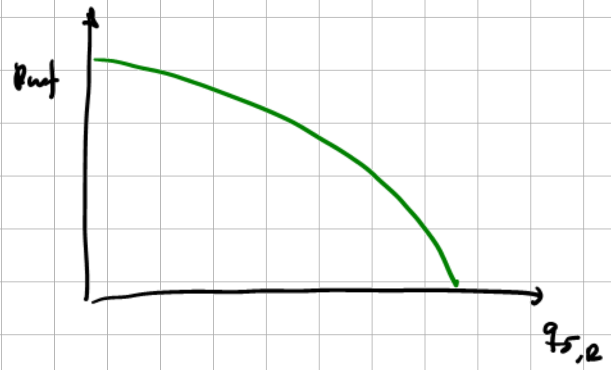
$$GOR^* > GOR_R$$



all tubing has GOR^*

gas lift performance curve





$$\text{Profit} = \text{revenue} - \text{cost}$$

$$= q_{o,R} \cdot P_o - \text{cost}(q_{g,inj})$$

$$= q_{o,R} \cdot P_o - P_g \cdot q_{g,inj}$$

max Profit

$$\frac{\partial \text{Profit}}{\partial q_{g,inj}} = \frac{\partial q_{o,R}}{\partial q_{g,inj}} \cdot P_o - P_g = 0 \quad \Rightarrow \quad \frac{\partial q_{o,R}}{\partial q_{g,inj}} = \frac{P_g}{P_o} > 0 \quad \text{close to zero}$$

Lecture 35: Gas lift exercise

Exercise goals:

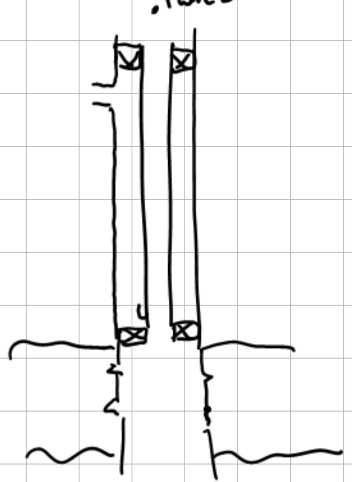
1 -Learn how to use a VBA function to estimate flowing bottom-hole pressure by performing tubing pressure drop calculations from wellhead

2 -Calculate IPR and TPR and visualize results. Calculate TPR for several Rp and see the effect on the intersection and estimate how much gas lift gas is needed

3 -Calculate the gas lift performance curve of the well

Well details

$P_{wh} = 30$ bara



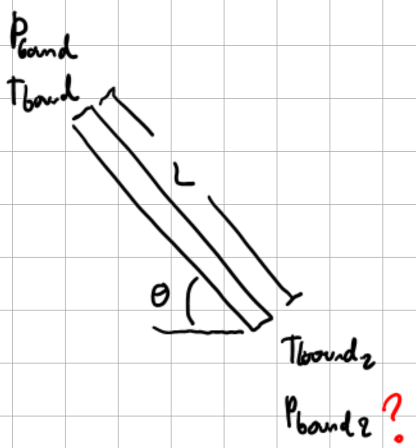
GOR = 53.7 Sm^3/Sm^3

Tubing diameter, D	[m]	0.1
Tubing angle from hor, angle	[deg]	90
Tubing length, L	[m]	2500
Tubing roughness	[m]	2.00E-05
wellhead pressure, pwh	[bara]	30
Wellhead temperature, Twh	[C]	70
Flowing bottom-hole temperature, Twf	[C]	100

$P_R = 200$ bara

use Fetkovich equation for IPR ($q_{o\,max} = 3000$ Sm^3/d)

Part 1. For estimation of flowing bottom-hole pressure, we will use a VBA function




```
Function mpf_p(pBound, BoundType, qo_sc, qg_sc, qw_sc, L, angle, roughness, D, TBound, TBound2, PVTMatrix, Profile)
    'mpf_p, function that calculates pressure at inlet or outlet of pipe, in bara, depending on the input
    'pBound, pressure at the boundary, [bara]
    'BoundType, type of boundary, -1 for inlet, 1 for outlet
    'qo_sc, oil rate at standard conditions, [Sm3/d]
    'qg_sc, gas rate at standard conditions, [Sm3/d]
    'qw_sc, water rate at standard conditions, [Sm3/d]
    'L, pipe length, [m]
    'angle, pipe inclination angle, in deg, measured from the horizontal
    'roughness, pipe roughness, in [m],
    'D, pipe hydraulic radius, [m]
    'TBound, fluid temperature at the boundary, [C]
    'TBound2, fluid temperature at the other boundary, [C]
    'PVTMatrix, matrix with BO properties for the flowing composition, arranged in the following manner
    ''GOR(1)    p(2)      T(3)      PROP1   PROP2   PROP3   PROP4
    ' value   value   value   value   value   value
    ' value   value   value   value   value   value
    ' value   value   value   value   value   value
    ' value   value   value   value   value   value
    'profile, provides the profile along the conduit, 1 yes, 0, no
    'Preparing to perform interpolation in the property table
    ColRs = 4
    ColRv = 5
    ColBo = 6
    ColBg = 7
    ColViscg = 8
    ColDeng = 9
    ColVisco = 10
    ColDeno = 11
```

This function does the following:

-Estimation of PVT properties by interpolating on a BO table.

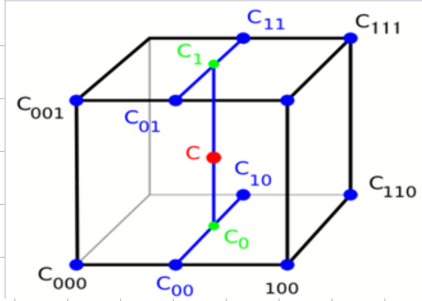
As Gas lift increases the GOR, then properties for several GORs, pressures and temperatures must be provided

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
GOR [Sm3/Sm3]	Pressure [bara]	Temperature [C]	Rs [Sm3/Sm3]	rs [Sm3/Sm3]	Bo [m3/Sm3]	Bg [m3/Sm3]	viscg [cp]	deng [kg/m3]	visco [cp]	deno [kg/m3]	IFTog [N/m]	rsw [Sm3/Sm3]	Bw [m3/Sm3]	viscw [cp]	denw [kg/m3]
54	10	20	10.4	0.00E+00	1.030	1.00E-01	1.12E-02	7.8	0.65	711.8	2.04E-02	0.00E+00	1.000	1.0	997.0
54	10	60	7.1	2.63E-05	1.072	1.15E-01	1.25E-02	7.6	0.43	680.6	1.74E-02	0.00E+00	1.000	1.0	997.0
54	10	100	5.2	2.45E-04	1.123	1.33E-01	1.39E-02	8.1	0.30	647.8	1.44E-02	0.00E+00	1.000	1.0	997.0
54	20	20	21.0	0.00E+00	1.054	4.88E-02	1.15E-02	15.4	0.60	706.1	1.92E-02	0.00E+00	1.000	1.0	997.0
54	20	60	16.0	8.90E-06	1.096	5.63E-02	1.28E-02	14.4	0.40	674.5	1.64E-02	0.00E+00	1.000	1.0	997.0
54	20	100	12.8	1.18E-04	1.148	6.45E-02	1.41E-02	14.6	0.28	640.8	1.36E-02	0.00E+00	1.000	1.0	997.0
54	30	20	30.1	0.00E+00	1.073	3.18E-02	1.17E-02	23.2	0.56	700.3	1.81E-02	0.00E+00	1.000	1.0	997.0
54	30	60	24.0	5.53E-06	1.116	3.69E-02	1.30E-02	21.3	0.38	668.8	1.56E-02	0.00E+00	1.000	1.0	997.0
54	30	100	20.3	8.28E-05	1.171	4.23E-02	1.44E-02	21.0	0.27	634.4	1.29E-02	0.00E+00	1.000	1.0	997.0
54	40	20	39.2	0.00E+00	1.092	2.33E-02	1.20E-02	31.4	0.53	694.2	1.72E-02	0.00E+00	1.000	1.0	997.0
54	40	60	31.6	4.79E-06	1.134	2.73E-02	1.33E-02	28.4	0.36	663.0	1.49E-02	0.00E+00	1.000	1.0	997.0
54	40	100	27.2	6.89E-05	1.191	3.13E-02	1.46E-02	27.5	0.26	628.1	1.24E-02	0.00E+00	1.000	1.0	997.0
54	50	20	48.5	0.00E+00	1.112	1.82E-02	1.24E-02	40.0	0.50	687.9	1.64E-02	0.00E+00	1.000	1.0	997.0
54	50	60	39.4	5.08E-06	1.154	2.15E-02	1.35E-02	35.6	0.35	657.1	1.43E-02	0.00E+00	1.000	1.0	997.0
54	50	100	34.3	6.32E-05	1.213	2.48E-02	1.48E-02	34.1	0.25	621.7	1.18E-02	0.00E+00	1.000	1.0	997.0
54	60	20	53.7	0.00E+00	1.123	0.00E+00	0.00E+00	0.0	0.49	684.8	0.00E+00	0.00E+00	1.000	1.0	997.0
54	60	60	47.3	5.99E-06	1.174	1.77E-02	1.38E-02	43.1	0.34	651.0	1.36E-02	0.00E+00	1.000	1.0	997.0
54	60	100	41.5	6.15E-05	1.235	2.05E-02	1.51E-02	40.8	0.24	615.1	1.13E-02	0.00E+00	1.000	1.0	997.0
54	70	20	53.7	0.00E+00	1.121	0.00E+00	0.00E+00	0.0	0.50	686.0	0.00E+00	0.00E+00	1.000	1.0	997.0
54	70	60	53.7	0.00E+00	1.190	0.00E+00	0.00E+00	0.0	0.33	646.4	0.00E+00	0.00E+00	1.000	1.0	997.0
54	70	100	49.0	6.22E-05	1.258	1.74E-02	1.54E-02	47.7	0.23	608.3	1.09E-02	0.00E+00	1.000	1.0	997.0
54	80	20	53.7	0.00E+00	1.119	0.00E+00	0.00E+00	0.0	0.50	687.2	0.00E+00	0.00E+00	1.000	1.0	997.0
54	80	60	53.7	0.00E+00	1.187	0.00E+00	0.00E+00	0.0	0.33	648.1	0.00E+00	0.00E+00	1.000	1.0	997.0

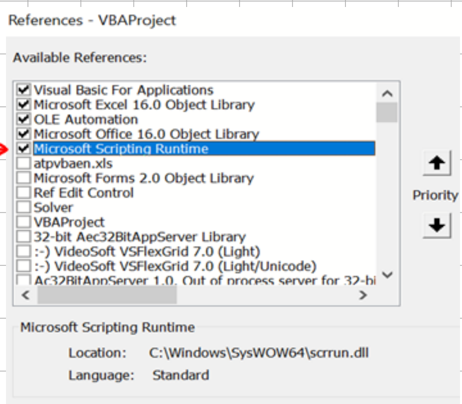
Interpolation is performed using a tri-linear interpolation (GOR, p and T must be provided)

https://en.wikipedia.org/wiki/Trilinear_interpolation

```
Rs = TrilinearInterpol(GOR, p, T, GOR_bounds(0), GC
Rv = TrilinearInterpol(GOR, p, T, GOR_bounds(0), GC
Bo = TrilinearInterpol(GOR, p, T, GOR_bounds(0), GC
Bg = TrilinearInterpol(GOR, p, T, GOR_bounds(0), GC
viscg = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
deng = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
visco = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
deno = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
IFTog = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
'rsw = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
Bw = TrilinearInterpol(GOR, p, T, GOR_bounds(0), GC
denw = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
Viscw = TrilinearInterpol(GOR, p, T, GOR_bounds(0),
```



To make the interpolation efficient, a "dictionary" is used in the VBA code. Therefore, you must have this library active (inside the VBA menu Tools--> references)




```
Set dictx = CreateObject("Scripting.Dictionary")
Set dictx1 = CreateObject("Scripting.Dictionary")
Set dictx2 = CreateObject("Scripting.Dictionary")
Set dictx3 = CreateObject("Scripting.Dictionary")
```

-pressure gradients (dp/dx) are calculated using the drift flux model (neglecting the acceleration term)

$$\frac{dp}{dx} + \rho_{TP} g_x + \rho_g v_{sg} \frac{dv_g}{dx} + \rho_l v_{sl} \frac{dv_l}{dx} = 0$$

-The gas holdup (void fraction) was calculated using the correlation by Woldesemayat and Ghajar

$$\varepsilon = \frac{U_{SG}}{U_{SG}\left(1 + \left(\frac{U_{SL}}{U_{SG}}\right)^{\left(\frac{\rho_G}{\rho_L}\right)^{0.1}}\right) + 2.9\left[\frac{gD\sigma(1+\cos\theta)(\rho_L - \rho_G)}{\rho_L^2}\right]^{0.25}(1.22 + 1.22\sin\theta)^{\frac{P_{atm}}{P_{system}}}}$$

Comparison of void fraction correlations for different flow patterns in horizontal and upward inclined pipes

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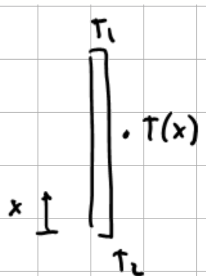
Received 1 June 2006; received in revised form 13 September 2006

-Temperature of an intermediate point was calculated by doing a linear interpolation between inlet and outlet and using the position of the point



The pressure integration was performed using Euler's method. 10 intervals were used

```
Nsec = 10
deltaL = L / Nsec
```

Pressure integration method

p_3

p_2

$\Big\} \Delta L$

p_1

$$p_2 = p_1 + \left.\frac{dp}{dx}\right|_{@p_1} \cdot \Delta L$$

PART 1: Learning how to use the VBA tubing function to calculate pwf			
qo [Sm3/d]	qw [Sm3/d]	qg [Sm3/d]	pwf [bara]
500	500	50000	271

-Calculate IPR and TPR and visualize results. Calculate TPR for several Rp and see the effect on the intersection and estimate how much gas lift gas is needed

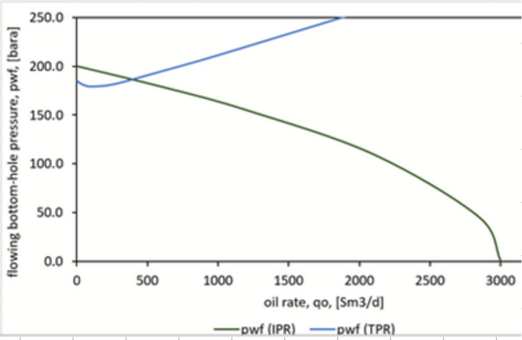
Natural flow

PART 2: IPR vs TPR

WC= 0 Rp_R= 54 Rp^*= 54

qo [Sm3/d]	WC [-]	qw [Sm3/d]	Rp_R [Sm3/Sm3]	qg_R [Sm3/d]	Rp^* [Sm3/Sm3]	qg_{total} [Sm3/d]	qg_{inj} [Sm3/d]	pwf (TPR) [bara]
0.1	0	0	54	5.37E+00	54	5.37E+00	0.00E+00	185
1	0	0	54	5.37E+01	54	5.37E+01	0.00E+00	185
10	0	0	54	5.37E+02	54	5.37E+02	0.00E+00	184
50	0	0	54	2.69E+03	54	2.69E+03	0.00E+00	181
100	0	0	54	5.37E+03	54	5.37E+03	0.00E+00	179
250	0	0	54	1.34E+04	54	1.34E+04	0.00E+00	181
500	0	0	54	2.69E+04	54	2.69E+04	0.00E+00	191
750	0	0	54	4.03E+04	54	4.03E+04	0.00E+00	201
1000	0	0	54	5.37E+04	54	5.37E+04	0.00E+00	211
2000	0	0	54	1.07E+05	54	1.07E+05	0.00E+00	256

PART 3: gas lift performance curve



Natural flow approx. 400 Sm3/d oil

Gas lift, GOR in tubing = 100

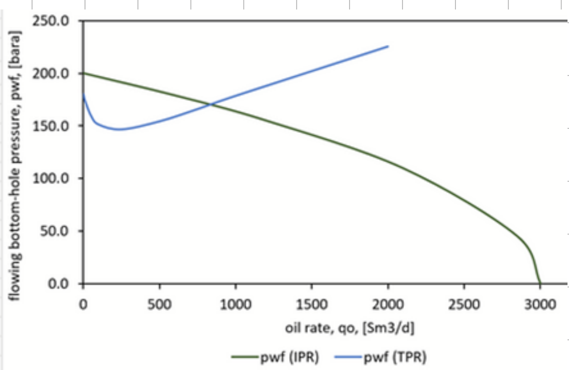
PART 2: IPR vs TPR

WC= 0 Rp_R= 54 Rp^*= 100

qo [Sm3/d]	WC [-]	qw [Sm3/d]	Rp_R [Sm3/Sm3]	qg_R [Sm3/d]	Rp^* [Sm3/Sm3]	qg_{total} [Sm3/d]	qg_{inj} [Sm3/d]	pwf (TPR) [bara]
0.1	0	0	54	5.37E+00	100	1.00E+01	4.63E+00	180
1	0	0	54	5.37E+01	100	1.00E+02	4.63E+01	180
10	0	0	54	5.37E+02	100	1.00E+03	4.63E+02	174
50	0	0	54	2.69E+03	100	5.00E+03	2.31E+03	160
100	0	0	54	5.37E+03	100	1.00E+04	4.63E+03	151
250	0	0	54	1.34E+04	100	2.50E+04	1.16E+04	147
500	0	0	54	2.69E+04	100	5.00E+04	2.31E+04	154
750	0	0	54	4.03E+04	100	7.50E+04	3.47E+04	166
1000	0	0	54	5.37E+04	100	1.00E+05	4.63E+04	179
2000	0	0	54	1.07E+05	100	2.00E+05	9.25E+04	226

PART 3: gas lift performance curve

SOLVER



Intersection approx. 800 Sm3/d oil
qginj between 34 700-46 300 Sm3/d gas

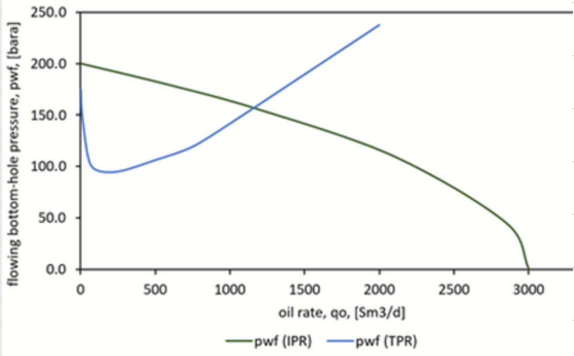
gas lift, GOR in tubing =300

PART 2: IPR vs TPR

WC=	0	Rp_R=	54	Rp^*=	300			
qo	WC	qw	Rp_R	qg_R	Rp^*	qg_{total}	qg_{inj}	pwf (TPR)
[Sm3/d]	[-]	[Sm3/d]	[Sm3/Sm3]	[Sm3/d]	[Sm3/Sm3]	[Sm3/d]	[Sm3/d]	[bara]
0.1	0	0	54	5.37E+00	300	3.00E+01	2.46E+01	175
1	0	0	54	5.37E+01	300	3.00E+02	2.46E+02	172
10	0	0	54	5.37E+02	300	3.00E+03	2.46E+03	149
50	0	0	54	2.69E+03	300	1.50E+04	1.23E+04	109
100	0	0	54	5.37E+03	300	3.00E+04	2.46E+04	97
250	0	0	54	1.34E+04	300	7.50E+04	6.16E+04	95
500	0	0	54	2.69E+04	300	1.50E+05	1.23E+05	106
750	0	0	54	4.03E+04	300	2.25E+05	1.85E+05	119
1000	0	0	54	5.37E+04	300	3.00E+05	2.46E+05	141
2000	0	0	54	1.07E+05	300	6.00E+05	4.93E+05	237

PART 3: gas lift performance curve

SOLVER



Intersection approx. 1200 Sm3/d oil
qinj betweeen 246 000-493 000 Sm3/d gas

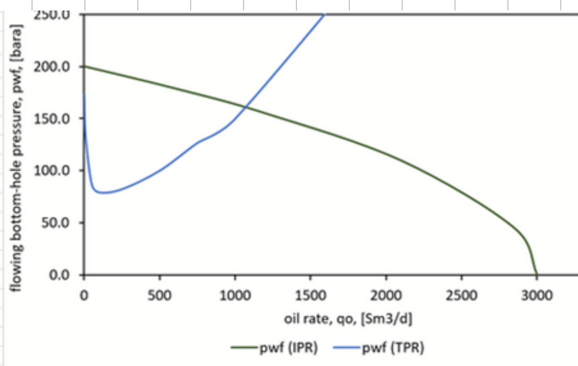
GOR = 500 (gas lift)

PART 2: IPR vs TPR

WC=	0	Rp_R=	54	Rp^*=	500			
qo	WC	qw	Rp_R	qg_R	Rp^*	qg_{total}	qg_{inj}	pwf (TPR)
[Sm3/d]	[-]	[Sm3/d]	[Sm3/Sm3]	[Sm3/d]	[Sm3/Sm3]	[Sm3/d]	[Sm3/d]	[bara]
0.1	0	0	54	5.37E+00	500	5.00E+01	4.46E+01	173
1	0	0	54	5.37E+01	500	5.00E+02	4.46E+02	168
10	0	0	54	5.37E+02	500	5.00E+03	4.46E+03	132
50	0	0	54	2.69E+03	500	2.50E+04	2.23E+04	87
100	0	0	54	5.37E+03	500	5.00E+04	4.46E+04	79
250	0	0	54	1.34E+04	500	1.25E+05	1.12E+05	82
500	0	0	54	2.69E+04	500	2.50E+05	2.23E+05	100
750	0	0	54	4.03E+04	500	3.75E+05	3.35E+05	127
1000	0	0	54	5.37E+04	500	5.00E+05	4.46E+05	150
2000	0	0	54	1.07E+05	500	1.00E+06	8.93E+05	320

PART 3: gas lift performance curve

SOLVER



Intersection approx. 1100 Sm3/d of oil

-Calculate the gas lift performance curve of the well

Flow equlibrium-> pwf calculated from TPR should be equal to pwf calculated from IPR by adjusting the rate

PART 3: gas lift performance curve

SOLVER

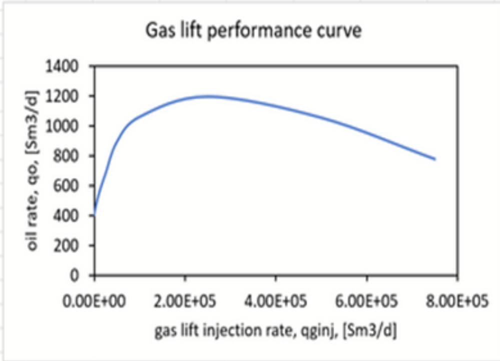
oil rate, qo, [Sm3/d]

pwf (IPR) pwf (TPR)

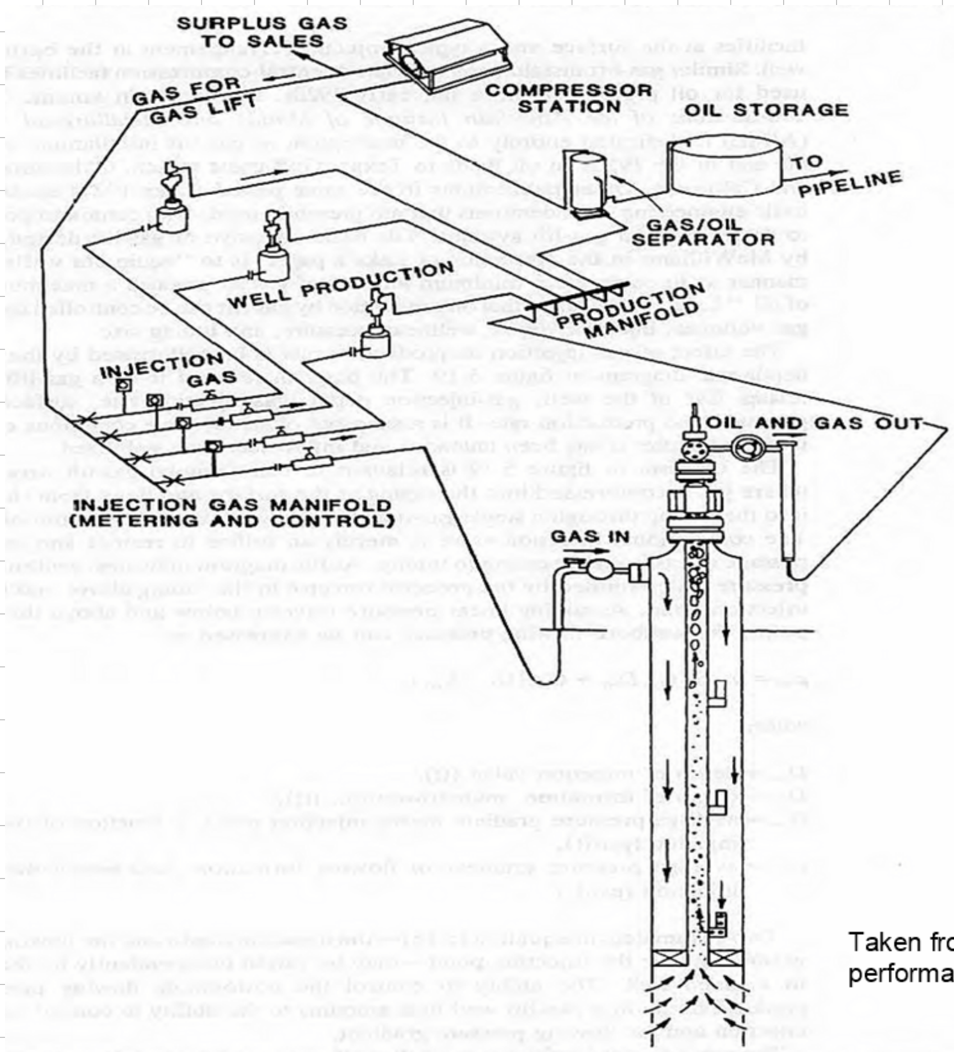
qo	WC	qw	Rp_R	qg_R	qg_{inj}	qg_{total}	Rp^*	pwf (TPR)	pwf (IPR)	error
[Sm3/d]	[-]	[Sm3/d]	[Sm3/Sm3]	[Sm3/d]	[Sm3/d]	[Sm3/d]	[Sm3/Sm3]	[bara]	[bara]	[bara]
777.0667545	0	0	54	4.18E+04	7.50E+05	7.92E+05	1019	172	172	1

POINTS

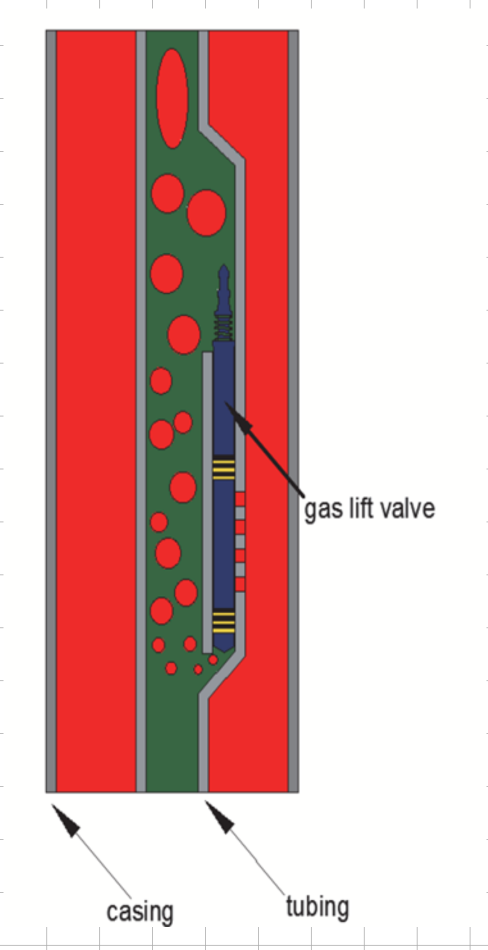
qg_{inj}	qo_R	Rp^*
[Sm3/d]	[Sm3/d]	[Sm3/Sm3]
0.00E+00	400	54
1.00E+03	423	56
1.00E+04	539	72
2.50E+04	679	91
5.00E+04	893	110
1.00E+05	1061	148
2.50E+05	1197	263
5.00E+05	1055	528
7.50E+05	777	1019

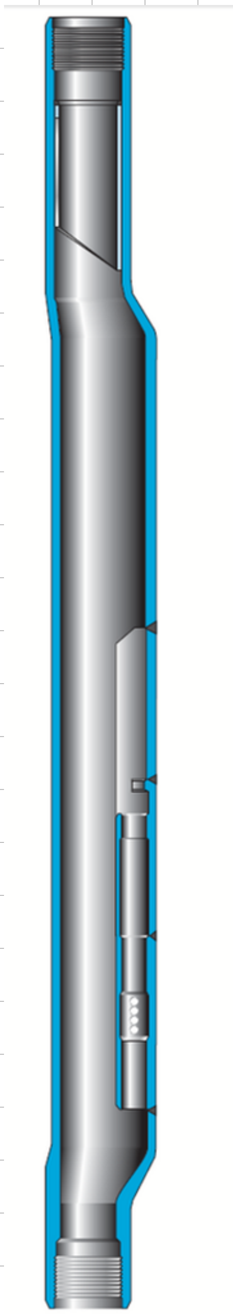


Lecture 36: Hardware for gas lift well



Taken from Book Well performance (Golan& Whitson)

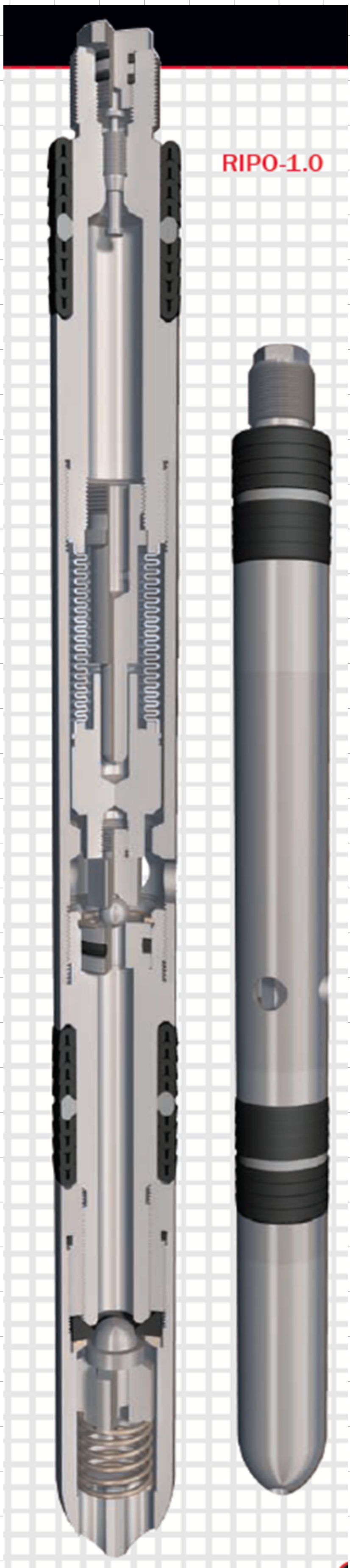




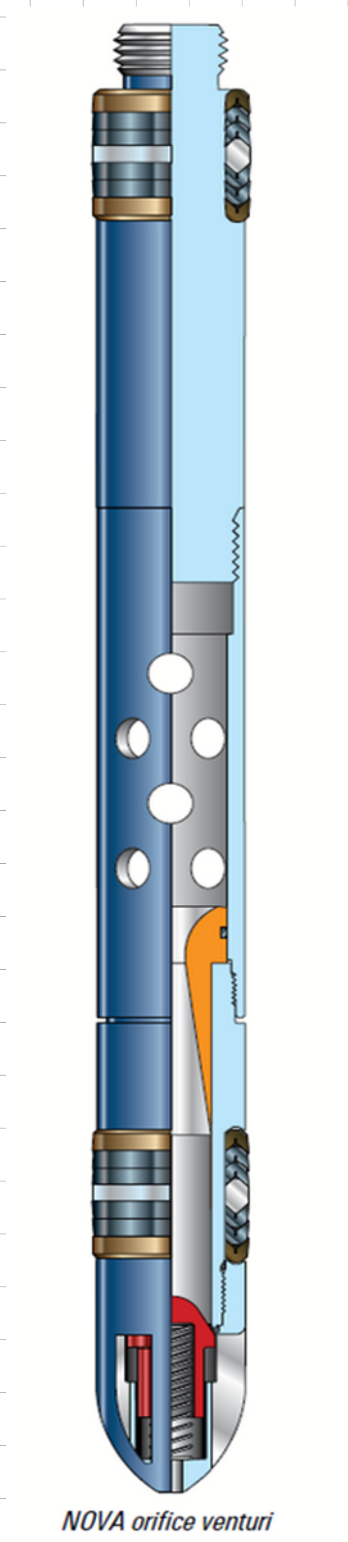
MMM Series
side pocket mandrel.

From Schlumberger catalog

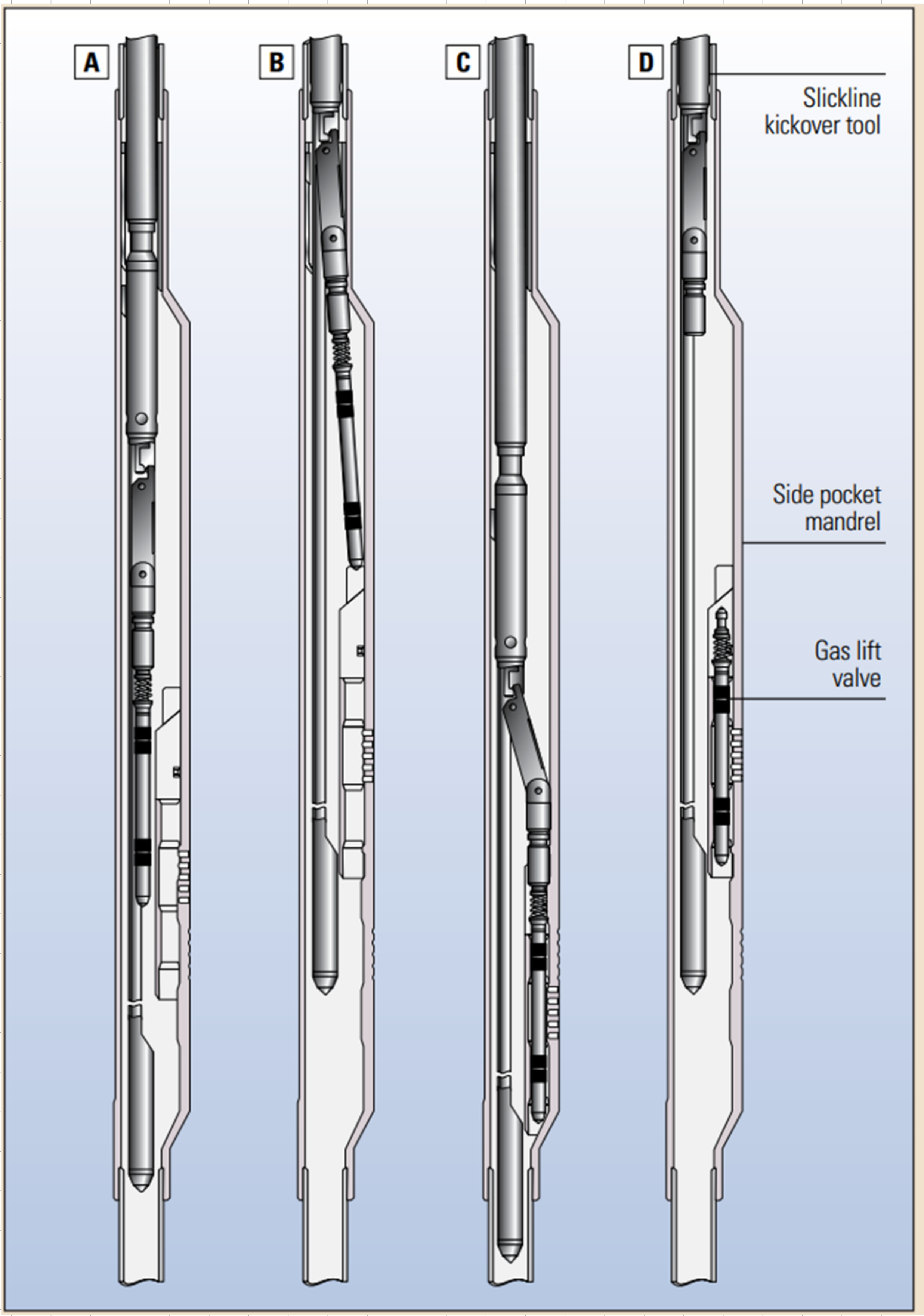
From Lufkin catalog



From Lufkin catalog

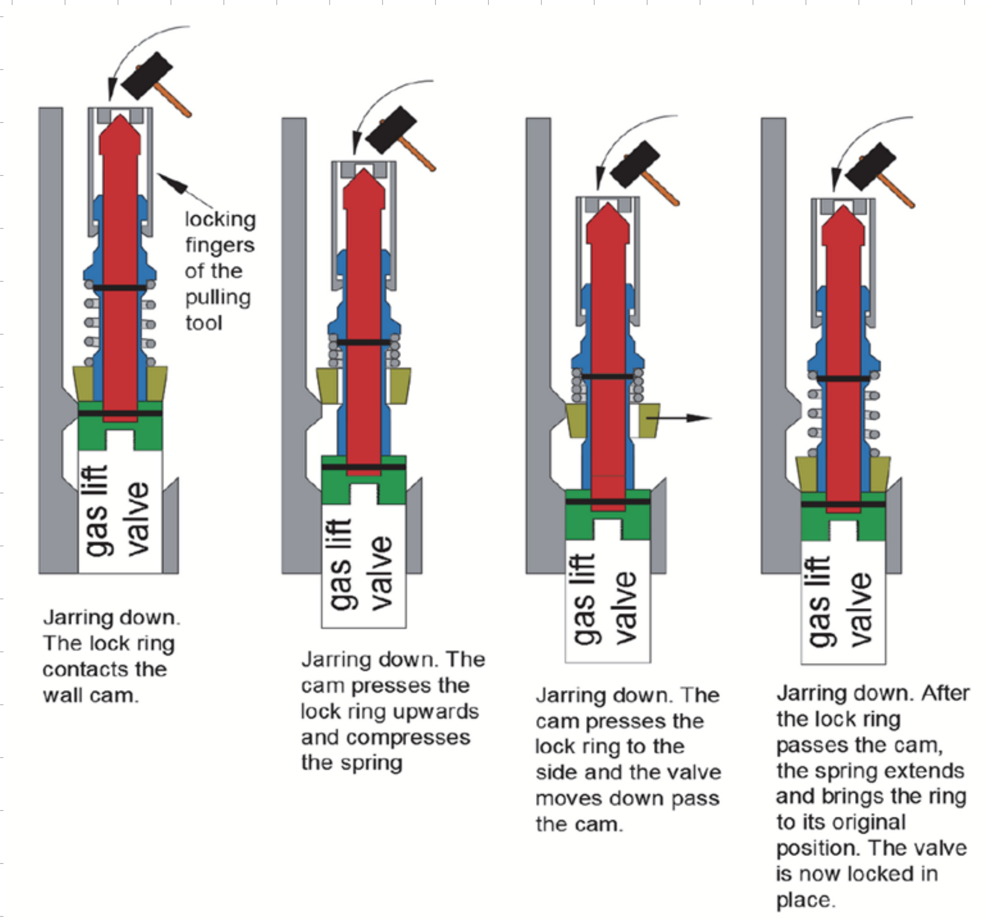


From Schlumberger catalog



https://www.slb.com/-/media/files/oilfield-review/defining-gas-lift.ashx

For an animation check: https://www.youtube.com/watch?v=RA3V42bdrDk at 01:00



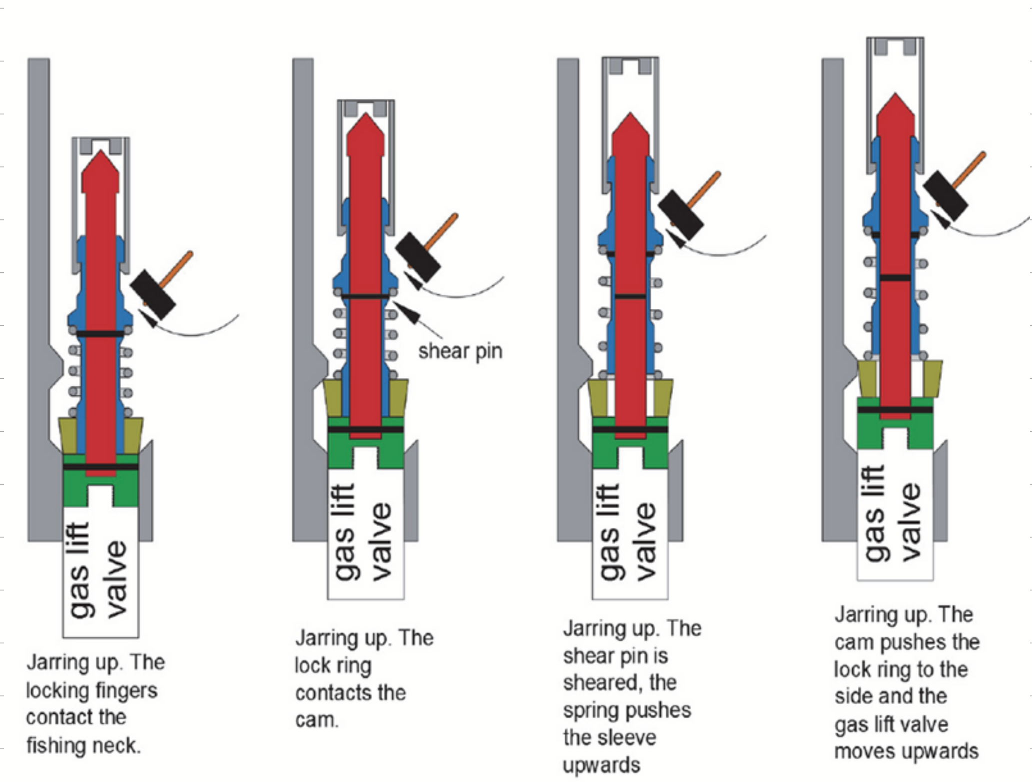
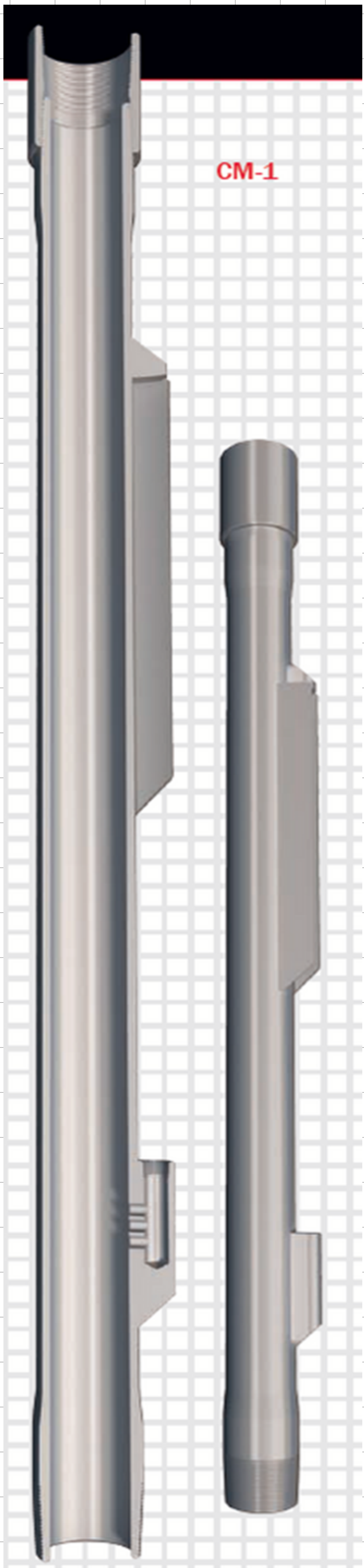
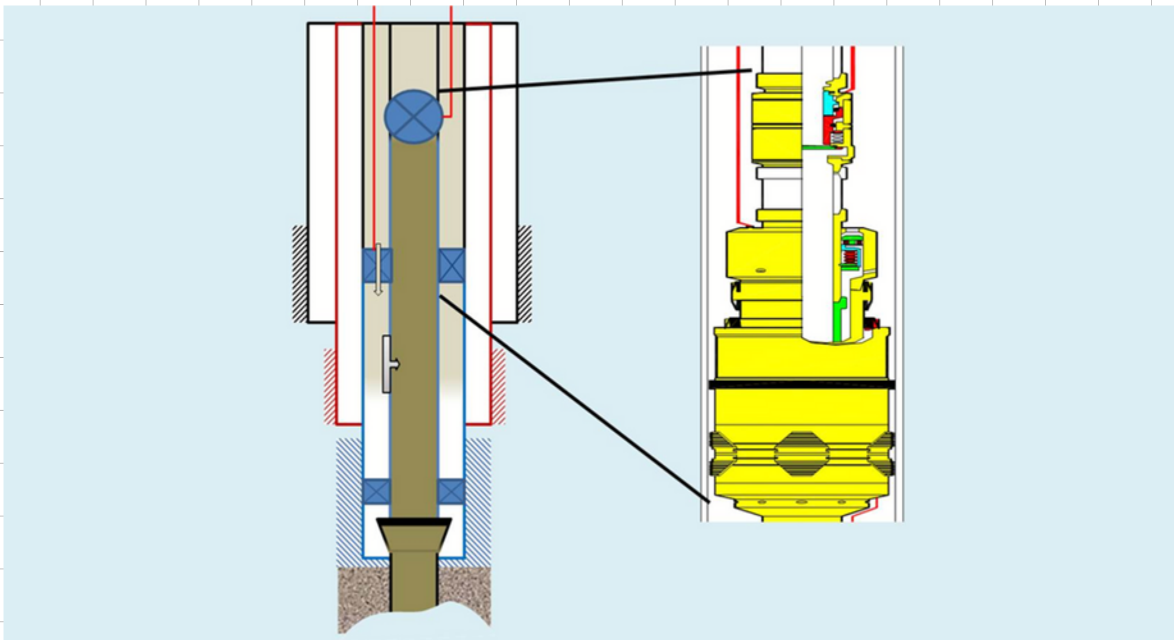


FIGURE 3-8. SEQUENCE TO RETRIEVE A GAS-LIFT VALVE FROM THE MANDREL POCKET



Tubing-retrievable gas lift mandrels (From Lufkin catalogue)

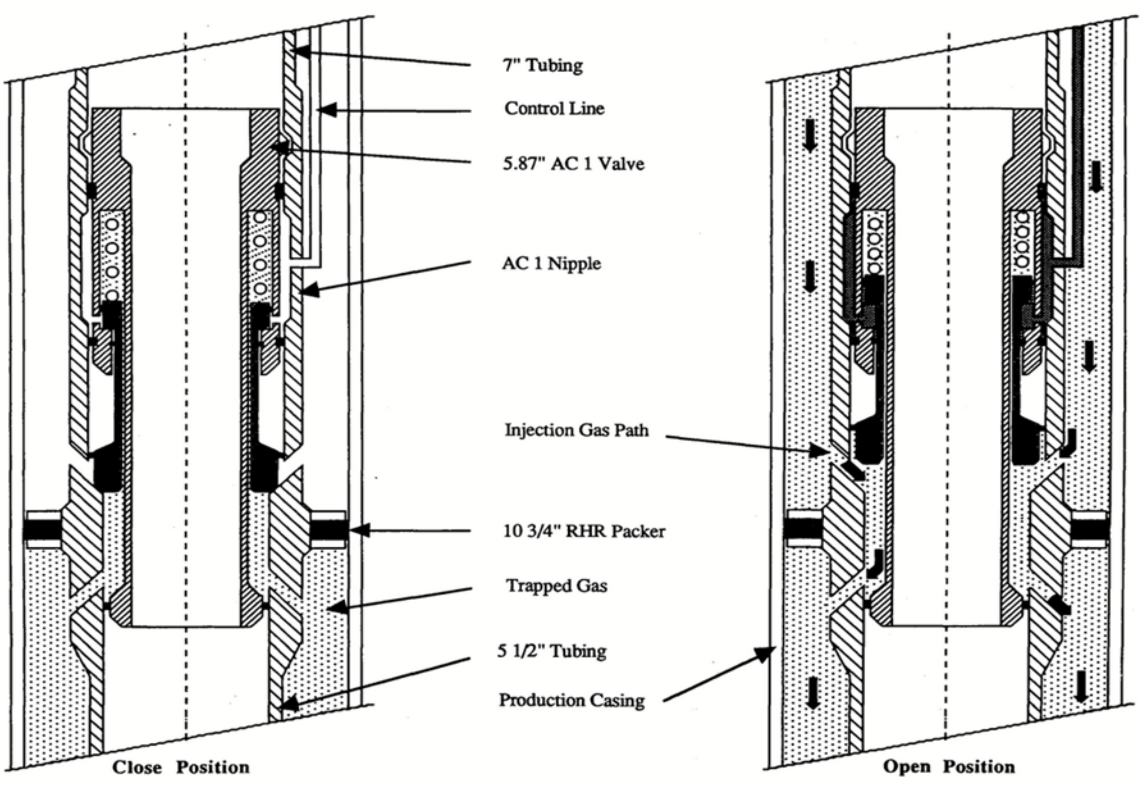
Annular safety valve



https://ndla.no/subject:1:01c27030-e8f8-4a7c-a5b3-489fdb8fea30/topic:2:182061/topic:2:151959/resource:1:182399/332

ASV skal alltid plasseres under DHSV i kompletteringen. Det er fordi kontrollinjen til DHSV ikke skal føres gjennom ASV.

Fig 1 - PRINCIPLE OF AC 1 ANNULUS VALVE



SPE number/page 19278/1

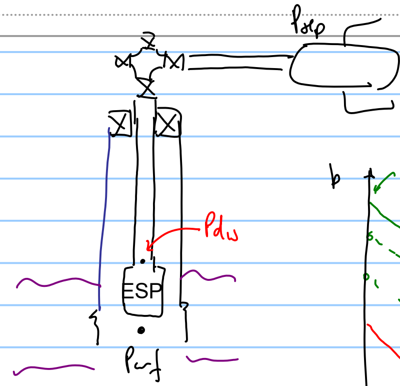
Title FIELD EXPERIENCE IN DOWN HOLE ANNULUS SAFETY VALVE

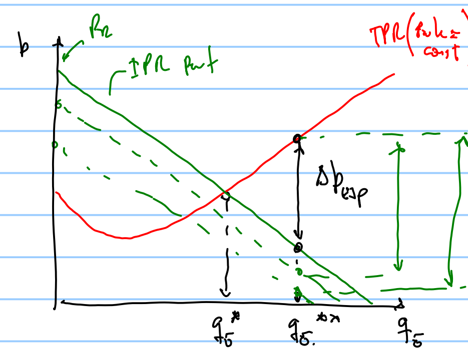
Authors J L GEYELIN

TOTAL-CFP

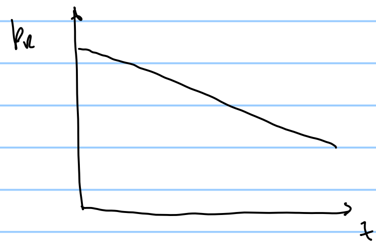
Note Title

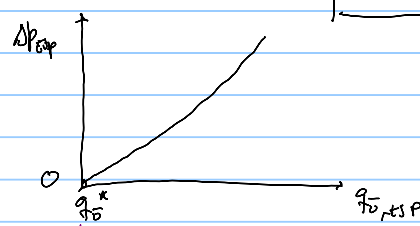
ESP electric submersible pump

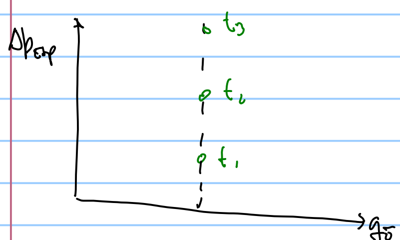




Depletion



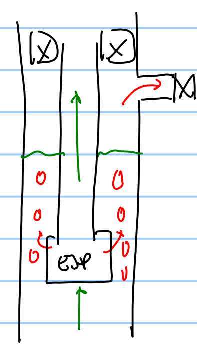




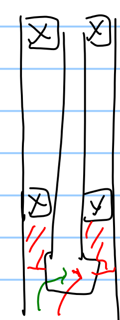
the pump has operational constraints

- limited available motor capacity (maximum power)
- operational map (envelope)
- $P_{suc} \geq P_b(T_R)$
  - ↳ buble point pressure (no gas is allowed in the pump)

onshore



offshore



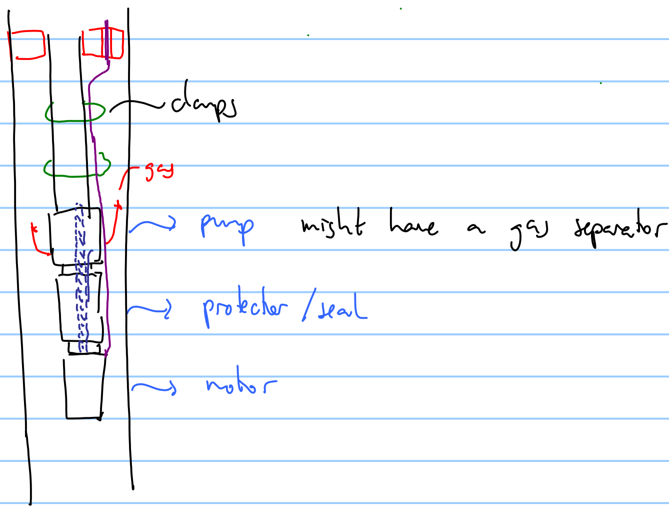
typical gas tolerance in esp is GVF = 10%

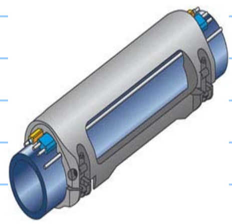
gas volume fraction

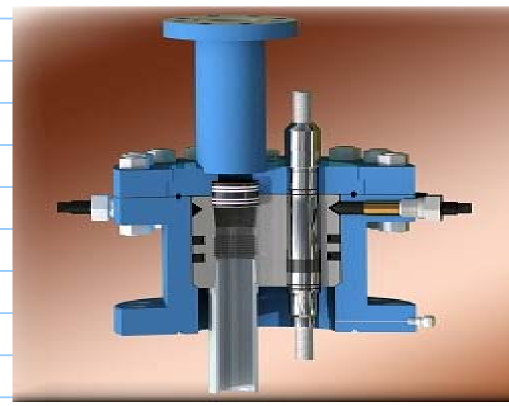
$$GVF = \frac{q_g}{\underbrace{q_L}_{q_o + q_w} + q_g} \times 100\%$$

Armais Arutunoff

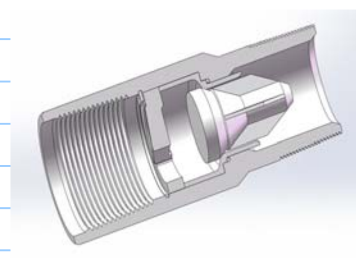
https://jpt.spe.org/legends-artificial-lift-part-3-history



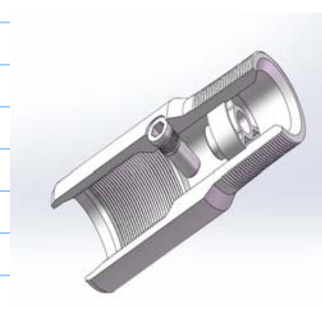




Other important components:
-other gas-handling equipment (after the gas separator)
-Check valve (above the pump)
-Bleeder valve (above the check valve)



http://www.orisun.asia/Products.asp?dl=111&xl=165

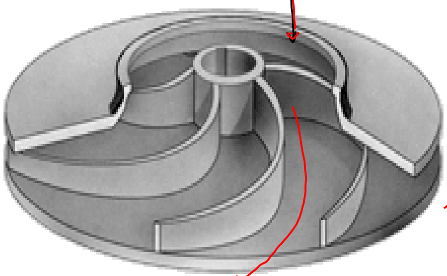


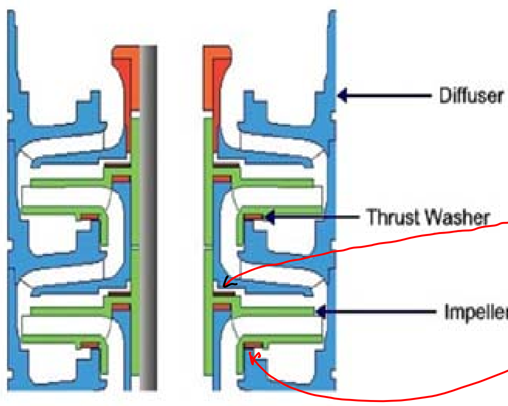
http://www.orisun.asia/Products.asp?dl=111&xl=164

Stage: impeller+diffuser

p_1 p_2

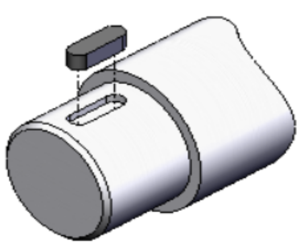
50 - 100 "stages"

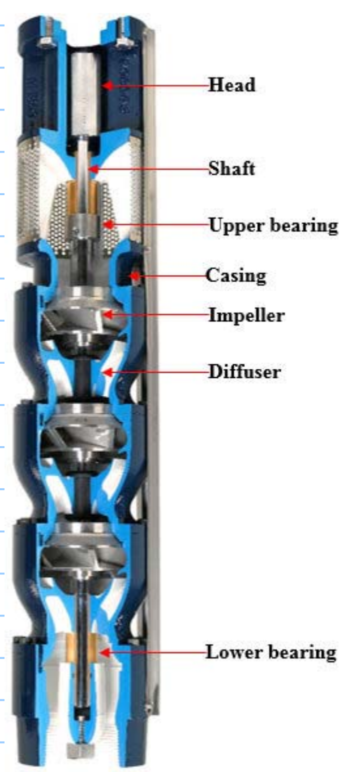


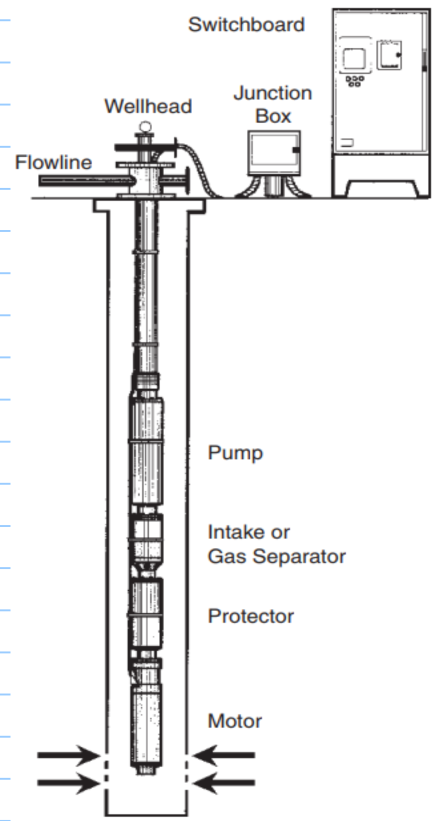


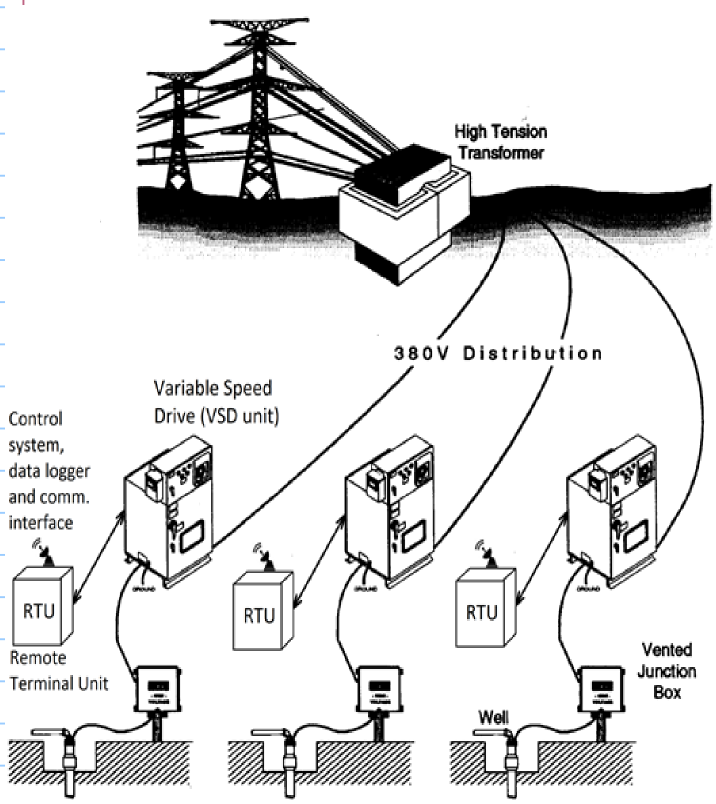
-Upthrust q is high

-Downthrust q is low





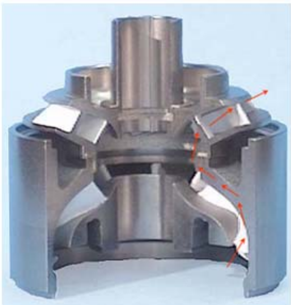




pump frequency

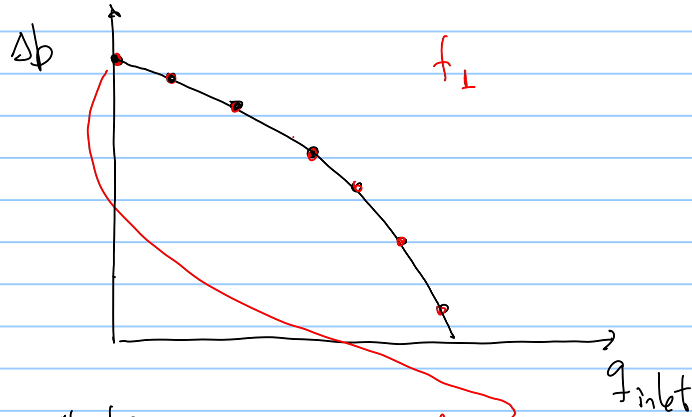
$f = 30 - 70\ Hz$

gas impeller and diffuser more
(tolerant to gas



Note Title

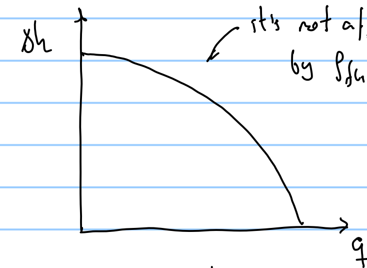
operational map of ESP



-Bench test → 1 stage, f_{ref} {50 Hz, 60 Hz}, water
-Definition of head

head

$$\delta h = h = \frac{\Delta p}{\rho_{fluid} \cdot g}$$



Δp	q
Δp_1	q_1
Δp_2	q_2
Δp_3	q_3
⋮	⋮

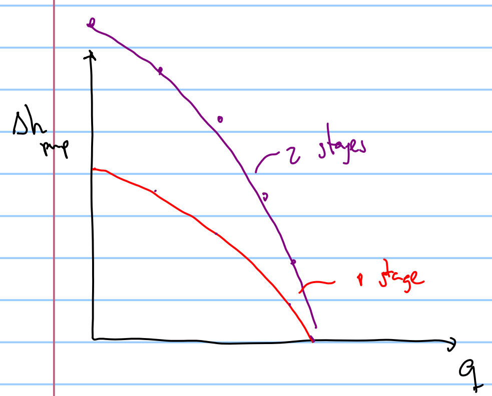
$$\delta h = a \cdot q^2 + b\, q + c$$

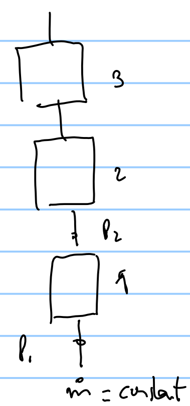
$$\Delta p = \delta h \cdot \rho_{fluid} \cdot g$$

affected by viscosity

$\mu \approx \mu_w = 1\,cP$

Single stage vs multi-stage (50 - 100)





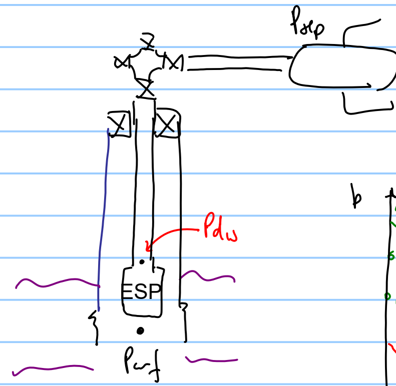
$$\Delta p_{esp} = \sum_{i=1}^{N_{stage}} \Delta p_i = N_{stages} \cdot \Delta p_{stage} \cdot F_{pancake}$$

$F_{pancake} < 1$

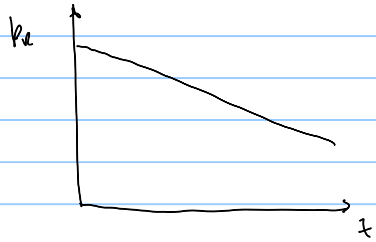
$q_{\bar{o}}$

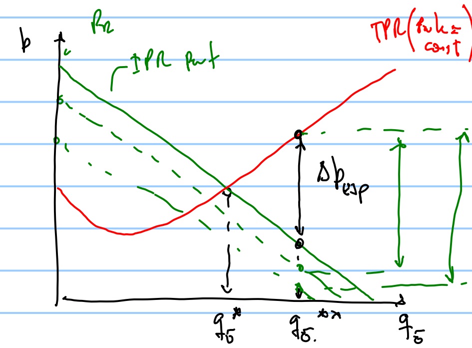
$$q_{o_i} = q_{\bar{o}} \cdot B_{o_i}(P_i, T_r)$$

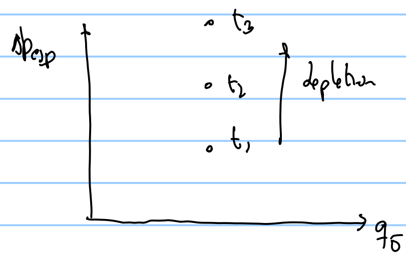
Variation of frequency - why?

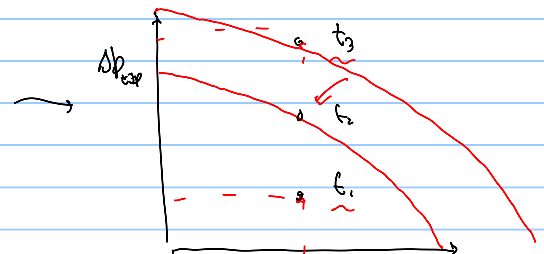


Depletion

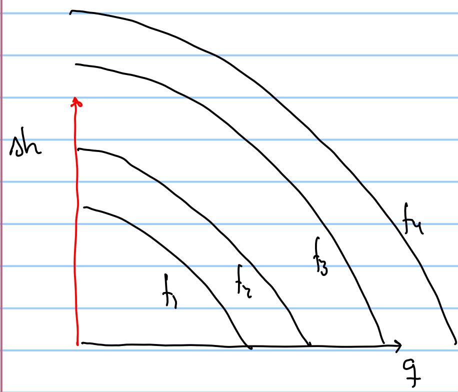








$q_o = q_{sc} \cdot B_o(p_{wo}, t_{wo})$



$f_4 > f_3 > f_2 > f_1$

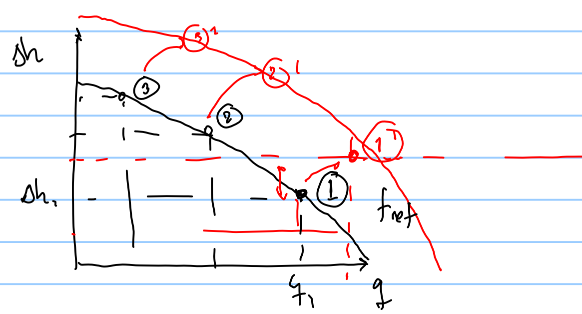
Analytical estimation:

Affinity laws
Similarity laws

$$Q_B = Q_A \cdot \frac{n_B}{n_A}$$

$$H_B = H_A \cdot \left(\frac{n_B}{n_A}\right)^2$$

$$P_B = P_A \cdot \left(\frac{n_B}{n_A}\right)^3$$



$$\frac{\Delta h_1}{\Delta h_{1*}} = \left(\frac{f_{ref}}{f}\right)^2 \Rightarrow \Delta h_{1*} = \Delta h_1 \cdot \left(\frac{f}{f_{ref}}\right)^2$$

$$\frac{q_1}{q_{1*}} = \left(\frac{f_{ref}}{f}\right) \Rightarrow q_1^* = q_1 \left(\frac{f}{f_{ref}}\right)$$

f_{ref}

Δh	q
D	D
D	D
D	D

f

Δh	q
D	D
D	D
D	D

$a q^2 + b q + c$

$$\frac{q_{ref}}{q} = \frac{f_{ref}}{f}$$

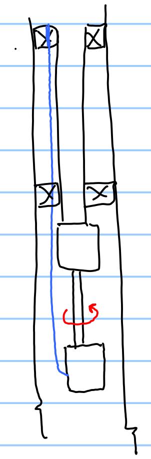
$$\Delta h_{ref} = a\, q_{ref}^2 + b\, q_{ref} + c$$

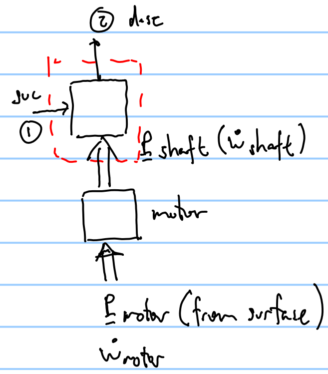
$$\Delta h_{ref} = a \cdot \left(\frac{f_{ref}}{f}\right)^2 q^2 + b \cdot \frac{f_{ref}}{f} q + c$$

$$\Delta h = \Delta h_{ref} \cdot \left(\frac{f}{f_{ref}}\right)^2 = a q^2 + b \left(\frac{f}{f_{ref}}\right) q + \left(\frac{f}{f_{ref}}\right)^2 C$$

Lecture 39 - Flow performance of ESP - part 2

Hydraulic efficiency





$$\eta_H = \frac{P_{pump}}{P_{shaft}}$$

$$\eta_m = \frac{P_{shaft}}{P_{motor}} \approx 0.95 - 0.98$$

$$\cancel{\dot{Q}}^{\,0} + \dot{W} + \dot{E}_1 - \dot{E}_2 = 0$$

$$\dot{W}_{shaft} = \dot{E}_2 - \dot{E}_1 = \dot{m}\,(e_2 - e_1)$$

$$e = (\underbrace{\cancel{g \cdot z}}_{0} + \underbrace{\cancel{\frac{v^2}{2}}}_{0} + \underbrace{h}_{u + pv})$$

ideal pumping process $\Delta s = 0$ isentropic

$\Delta u = 0 \quad u = f(T)$

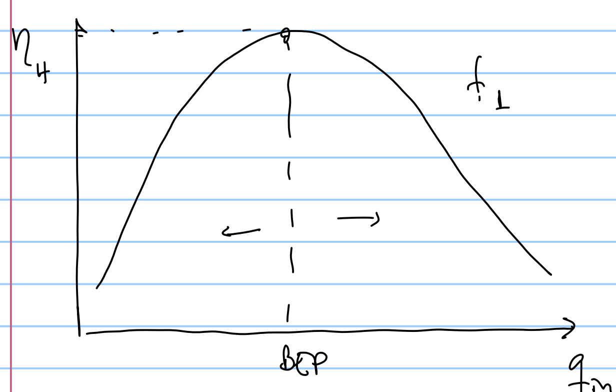
$$\dot{W}_{ideal} = \dot{m}\,(p_2 v_2 - p_1 v_1)$$

v = constant $= \frac{1}{\rho}$

$$\dot{W}_{ideal} = q\,(p_2 - p_1)$$

$$\eta_H = \frac{q\,(p_2 - p_1)}{P_{shaft}} = 0.4 - 0.8$$

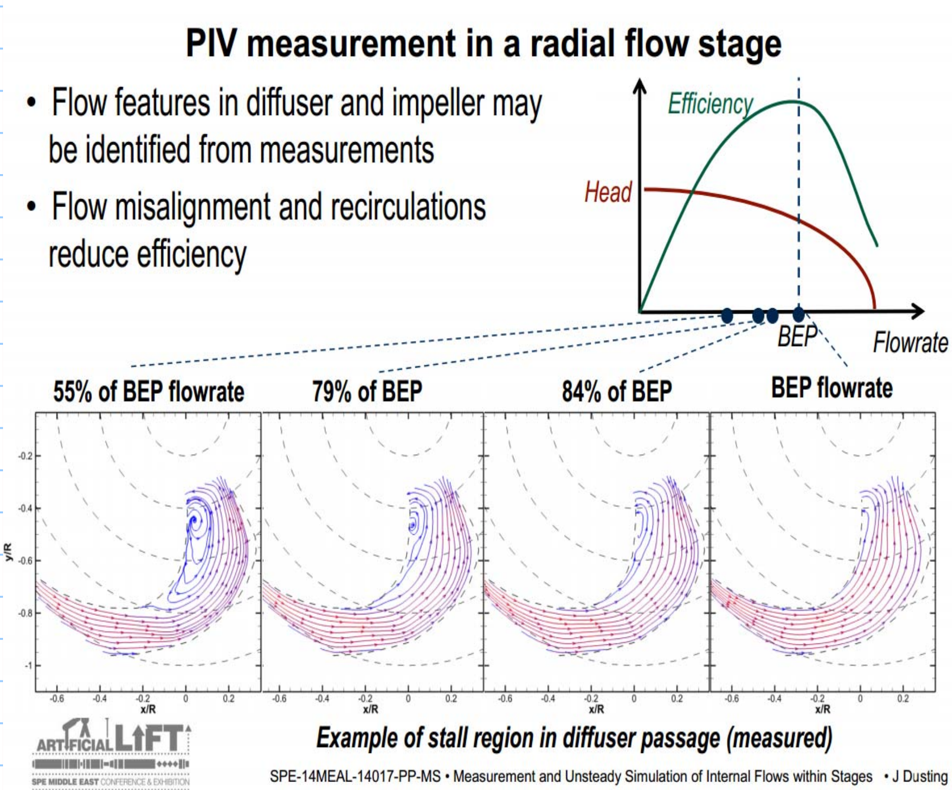
- friction: vanes, bearing impeller
- volumetric: backflow in pump
- turbulence, eddies



$$\eta_H = b_1 q^2 + b_2 q + b_3$$

$$\dot{W}_{shaft} = \frac{\Delta p \cdot q}{\eta_H}$$

$$\dot{W}_{motor} = \frac{\dot{W}_{shaft}}{\eta_m}$$


PIV measurement in a radial flow stage
• Flow features in diffuser and impeller may be identified from measurements
• Flow misalignment and recirculations reduce efficiency
Efficiency
Head
BEP
Flowrate
55% of BEP flowrate
79% of BEP
84% of BEP
BEP flowrate
y/R
x/R
Example of stall region in diffuser passage (measured)
ARTIFICIAL LIFT
SPE MIDDLE EAST CONFERENCE & EXHIBITION
SPE-14MEAL-14017-PP-MS • Measurement and Unsteady Simulation of Internal Flows within Stages • J Dusting

analytical

$$Q_B = Q_A \cdot \frac{n_B}{n_A}$$

$$H_B = H_A \cdot \left(\frac{n_B}{n_A}\right)^2$$

$$P_B = P_A \cdot \left(\frac{n_B}{n_A}\right)^3$$

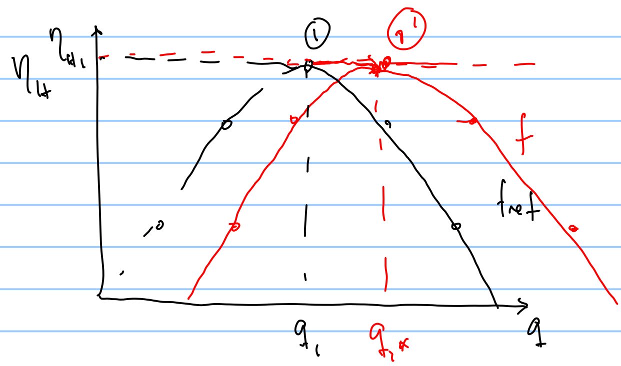
Similarity law

$$\eta_{H\,ref} = \frac{q_{ref}\,\Delta h_{ref}}{P_{shaft\,ref}} \longrightarrow \eta_{H@f} = \frac{q\,\Delta h}{P_{shaft}}$$

$$\eta_{H@f} = \frac{q_{ref}\cancel{\frac{f}{f_{ref}}}\,\Delta h_{ref}\cancel{\left(\frac{f}{f_{ref}}\right)^2}}{P_{shaft\,ref}\cancel{\left(\frac{f}{f_{ref}}\right)^3}}$$

ω_{shaft}

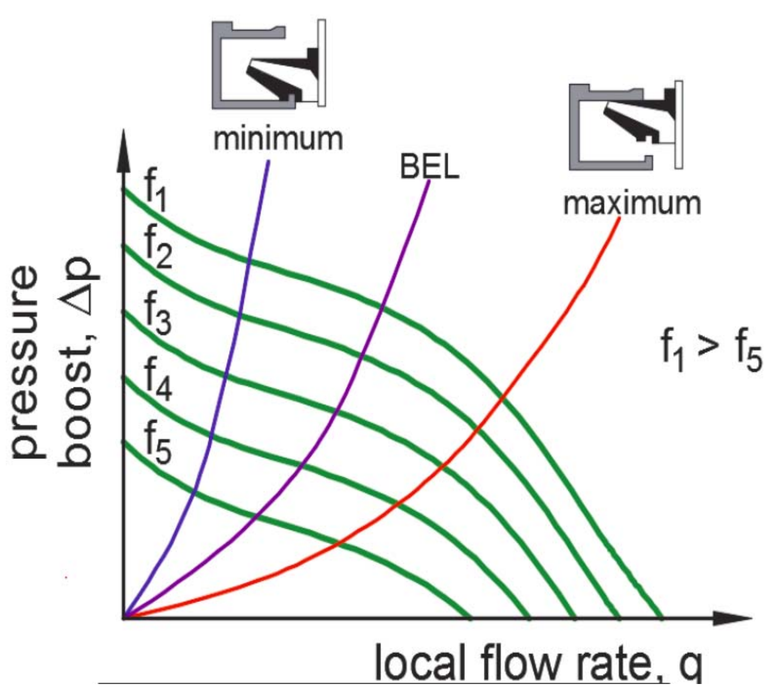
$$\eta_{H@f} = \eta_{H@f_{ref}}$$

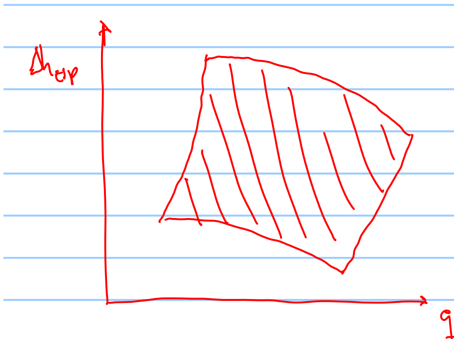


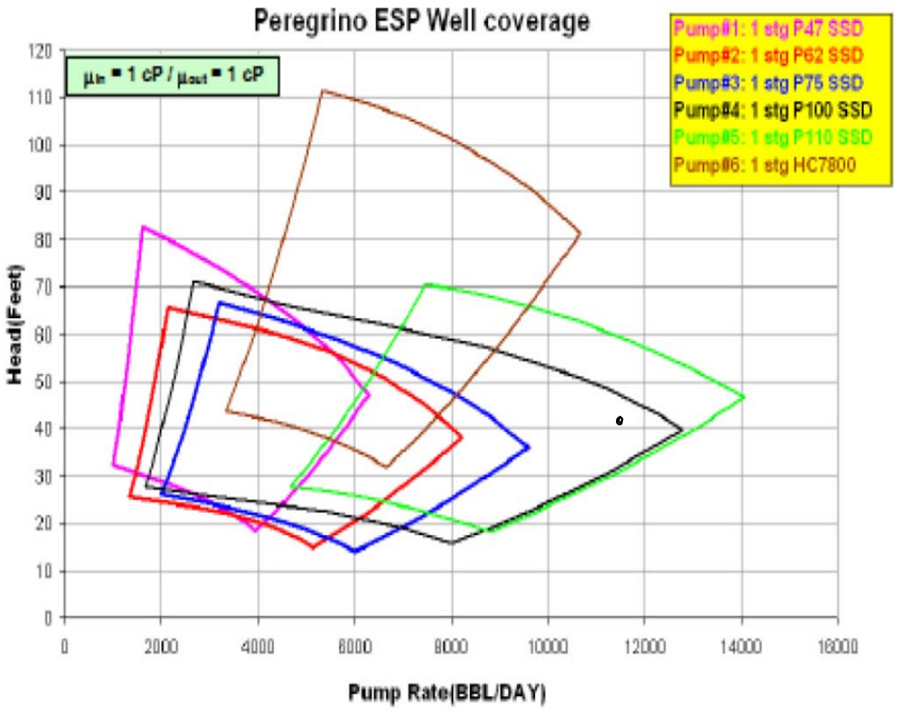
$$\eta_{H,q^*@f} = \eta_{H,1@f_{ref}}$$

$q_{1@f_{ref}}$

$$q_{2^*@f} = q_{1@f_{ref}} \cdot \frac{f}{f_{ref}}$$





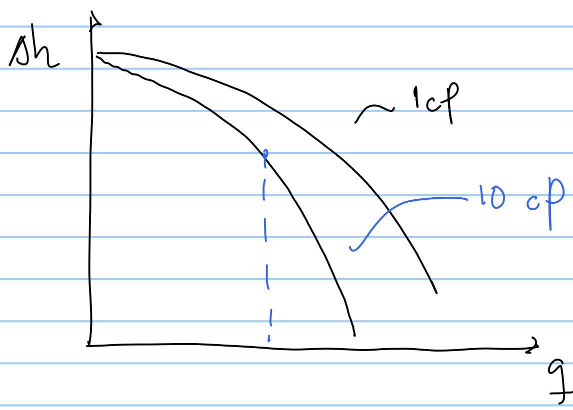


SPE-173948-MS

ESP Application on Heavy Oil in Peregrino Field

Vinicius Castro, and Daniela Leite, Statoil; Daniel Lemos, Jean Marins, Rui Pessoa, and João Magalhães, Baker Hughes

the viscosity of fluid also affects the performance of pump



 ANSI/HI 9.6.7-2010

American National Standard (Guideline) for

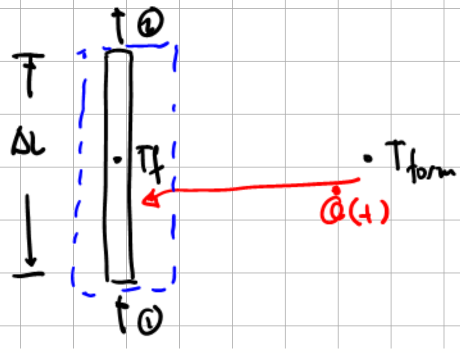
Effects of Liquid Viscosity on Rotodynamic (Centrifugal and Vertical) Pump Performance

Lecture 40: ESP exercise

Goal of the exercise: verify that the ESP model selected for the application will work properly for 5 times of production profile
-Verify that the points of dh vs q fall inside the operational envelope of the pump
-Estimate ESP frequency and hydraulic efficiency for all years
-Compute required pumping power

Study case: Peregrino field, offshore Brazil

Lecture 41: Temperature calculations in wellbore



8. HEAT TRANSFER FOR FLOW IN CONDUITS

The equation for conservation of energy for a section of a conduit is

$$\dot{Q} + \dot{W} = \dot{m} \cdot (e_{out} - e_{in}) \quad \text{EQ. 8-1}$$

The specific energy that the stream has is usually split in internal energy (u), potential energy (z·g) and kinetic energy ($V^2/2$).

A conduit doesn't exchange work with the surroundings, but the fluid must perform work to enter and leave the system. This specific work is: $(p_{in} \cdot v_{in} - p_{out} \cdot v_{out})$ (Here v is specific volume).

By combining the inlet and outlet specific internal energy "u" with the specific work to enter and leave the system to obtain specific enthalpy, the energy conservation equation is written as:

$$\dot{Q} = \dot{m} \cdot \left(h_{out} + z_{out} \cdot g + \frac{(V_{out})^2}{2} - h_{in} - z_{in} \cdot g - \frac{(V_{in})^2}{2} \right) \quad \text{EQ. 8-2}$$

Or, alternatively

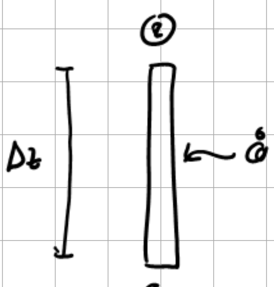
$$\dot{Q} = \dot{m} \cdot \left(\Delta h + \Delta z \cdot g + \frac{(V_{out})^2}{2} - \frac{(V_{in})^2}{2} \right) \quad \text{EQ. 8-3}$$

Here Δ represents outlet minus inlet.

In differential form (for an infinitesimally small length of pipe) the equation can be expressed as follows:

$$\frac{d\dot{Q}}{dL} = \dot{m} \cdot \left(\frac{dh}{dL} + g \cdot \frac{dz}{dL} + \cancel{v \cdot \frac{dv}{dL}}^{\approx 0} \right) \quad \text{EQ. 8-4}$$

Heat leaving the system is negative (the temperature of the outlet fluid is lower than the temperature at the inlet and the term Δh is usually negative). Heat entering the system is positive.



$\dot{Q} = \dot{m}(h_2 - h_1 + \Delta z \cdot g)$

p distribution in unknown $p(z)$

① $P_{wf}, T_{wf} (T_R), h_1 \{x_{g1}, x_{o1}, x_{w1}, h_{g1}, h_{o1}, h_{w1})$

$\dot{Q} = f(T_f, T_{form})$

↳ T_2

$h_2 = \frac{\dot{Q}}{\dot{m}} + h_1 - \Delta z \cdot g$

with P_2, assume $T_2 \rightarrow h_2^{calc}$

specific enthalpy (h):

-Another BO property, just like viscosity, density, etc
-calculated at p-T with e.g. EOS

Mixture specific enthalpy:

$$h_{mix} = x_g \cdot h_g + x_o h_o + x_w h_w$$

$$x_g = \frac{\dot{m}_g}{\dot{m}_T}$$ mass fraction

p [bara]	T [C]	ho [kJ/kg]	hg [kJ/kg]
300.0	148.0	-2108.26	-3529.99
300.0	137.1	-2136.36	-3602.31
300.0	126.2	-2164.67	-3672.1
300.0	115.3	-2193.21	-3739.34
300.0	104.4	-2221.97	-3803.95
300.0	93.6	-2250.97	-3865.83
300.0	82.7	-2280.24	-3924.82
300.0	71.8	-2305.53	0
300.0	60.9	-2329	0
300.0	50.0	-2351.97	0
285.7	148.0	-2094.13	-3547.64
285.7	137.1	-2122.44	-3619.91
285.7	126.2	-2150.93	-3689.79
285.7	115.3	-2179.62	-3757.24

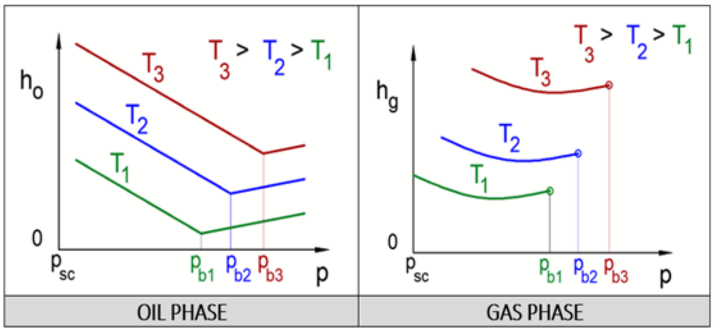


FIGURE 8-6. BEHAVIOR OF SPECIFIC ENTHALPY OF GAS AND OIL VS. PRESSURE FOR THREE TEMPERATURES

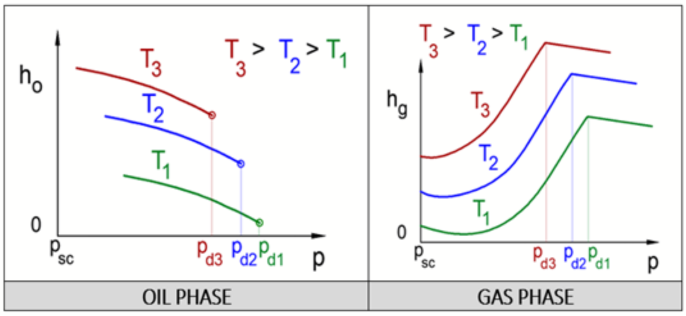
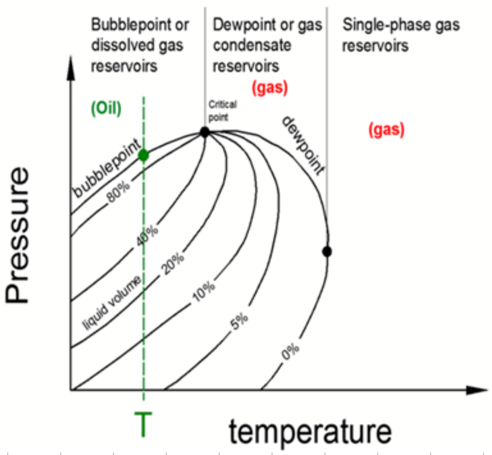
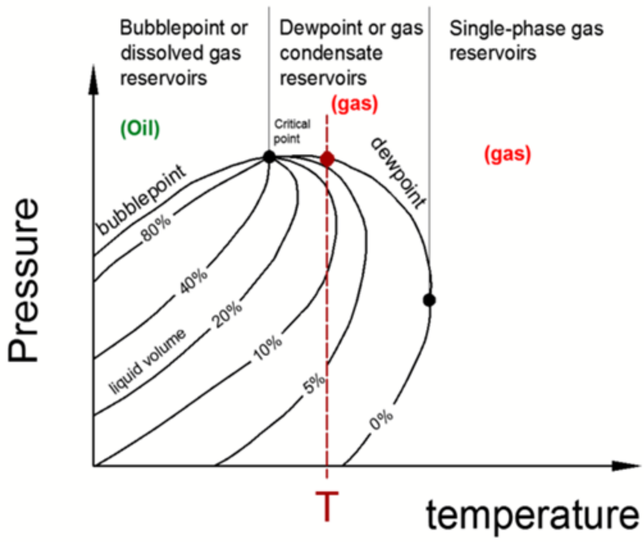


FIGURE 8-8. BEHAVIOR OF SPECIFIC ENTHALPY OF GAS AND OIL VS. PRESSURE FOR THREE TEMPERATURES





$\Delta h = C_p \cdot \Delta T$ for liquids

for gases $C_p = f(p,T)$ and requires frequent update

$\boxed{\text{Heat term } (\dot{Q})}$

sign

$$\dot{Q} = -2 \cdot \pi \cdot L \cdot r \cdot U \cdot (T_f - T_\infty) \qquad \text{Eq. 8-20}$$

Where:

r	reference radius [m]
U	Overall heat transfer coefficient, expressed in terms of the reference radius r [W/m^2.K]
T_∞	Mean ambient temperature [K or °C]
T_f	Mean fluid temperature in the section [K or °C]

In this section we will work with the heat by unit of conduit length $\frac{\dot{Q}}{L} = \frac{d\dot{Q}}{dL}$.

Heat transfer mechanisms:

-Forced convection
-Free convection
-Conduction

In pipes:

$$\mathrm{Nu}_L = \frac{\text{Convective heat transfer}}{\text{Conductive heat transfer}} = \frac{h}{k/L} = \frac{hL}{k}$$

$$\frac{d\dot{Q}}{dL} = -2 \cdot \pi \cdot r_i \cdot h_i \cdot (T_f - T_i)$$

forced: $\mathrm{Nu} = f(\mathrm{Re}, \mathrm{Pr})$

free: Nu= f(Gr,Pr)

IMPLICIT! T is required to find h!!

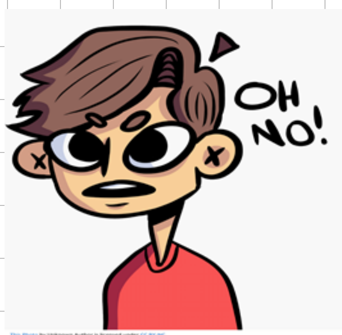
steady state $$\frac{d\dot{Q}}{dL} = -2 \cdot \pi \cdot k_p \cdot \frac{(T_i - T_o)}{\ln\left(\frac{r_o}{r_i}\right)}$$

Transient?

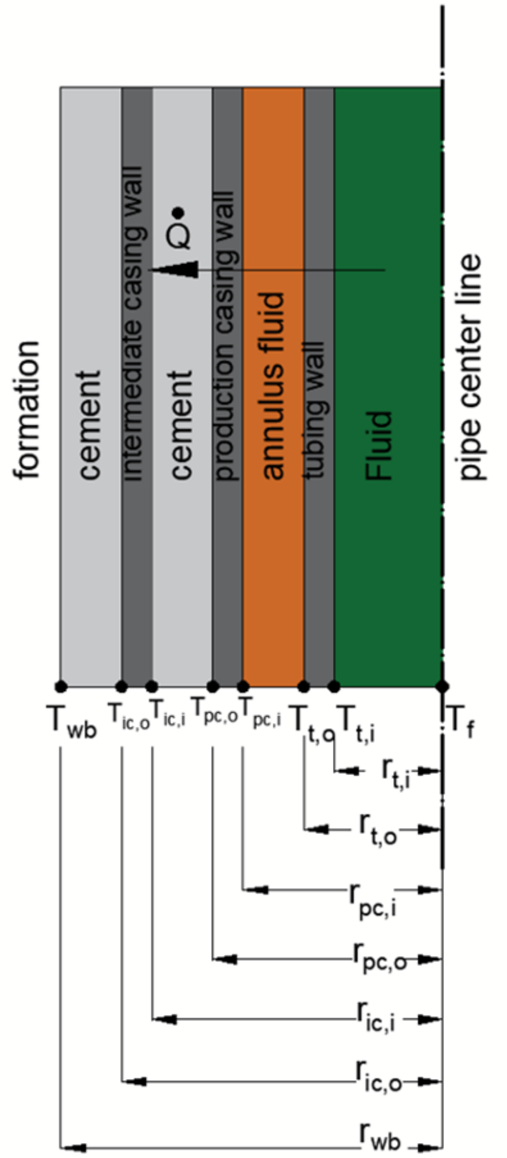
ATTENTION!!!

-h can be pump head (deltap/(den*g))
-h can be specific enthalpy (u+p*v)
-h can be forced/free convection coefficient

BE CAREFUL!!!



Example:



Overall heat transfer coefficient:

$$(T_f - T_{t,i}) + (T_{t,i} - T_{t,o}) + (T_{t,o} - T_{pc,i}) + (T_{pc,i} - T_{pc,o}) + (T_{pc,o} - T_{ic,i}) + (T_{ic,i} - T_{ic,o}) + (T_{ic,o} - T_{wb}) = \frac{-\frac{d\dot{Q}}{dL}}{2\cdot\pi\cdot r_{t,i}\cdot h_i} + \frac{-\frac{d\dot{Q}}{dL}}{\frac{2\cdot\pi\cdot k_t}{\ln\left(\frac{r_{t,o}}{r_{t,i}}\right)}} + \frac{-\frac{d\dot{Q}}{dL}}{2\cdot\pi\cdot r_{t,o}\cdot h_{ann}} + \frac{-\frac{d\dot{Q}}{dL}}{\frac{2\cdot\pi\cdot k_{pc}}{\ln\left(\frac{r_{pc,o}}{r_{pc,i}}\right)}} + \frac{-\frac{d\dot{Q}}{dL}}{\frac{2\cdot\pi\cdot k_c}{\ln\left(\frac{r_{ic,i}}{r_{pc,o}}\right)}} + \frac{-\frac{d\dot{Q}}{dL}}{\frac{2\cdot\pi\cdot k_{ic}}{\ln\left(\frac{r_{ic,o}}{r_{ic,i}}\right)}} + \frac{-\frac{d\dot{Q}}{dL}}{\frac{2\cdot\pi\cdot k_c}{\ln\left(\frac{r_{wb}}{r_{ic,o}}\right)}}$$

Clearing the temperature difference between fluid and wellbore wall:

$$(T_f - T_{wb}) = -\frac{d\dot{Q}}{dL} \cdot \left[\frac{1}{2\cdot\pi\cdot r_{t,i}\cdot h_i} + \frac{1}{\frac{2\cdot\pi\cdot k_t}{\ln\left(\frac{r_{t,o}}{r_{t,i}}\right)}} + \frac{1}{2\cdot\pi\cdot r_{t,o}\cdot h_{ann}} + \frac{1}{\frac{2\cdot\pi\cdot k_{pc}}{\ln\left(\frac{r_{pc,o}}{r_{pc,i}}\right)}} + \frac{1}{\frac{2\cdot\pi\cdot k_c}{\ln\left(\frac{r_{ic,i}}{r_{pc,o}}\right)}} + \frac{1}{\frac{2\cdot\pi\cdot k_{ic}}{\ln\left(\frac{r_{ic,o}}{r_{ic,i}}\right)}} + \frac{1}{\frac{2\cdot\pi\cdot k_c}{\ln\left(\frac{r_{wb}}{r_{ic,o}}\right)}} \right]$$

If the inner tubing radius will be used as reference radius, we then we divide by the inner perimeter of the inner tubing:

$$(T_f - T_{wb}) = -\frac{d\dot{Q}}{dL} \cdot \frac{1}{2\cdot\pi\cdot r_{t,i}} \cdot \left[\frac{1}{h_i} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{t,o}}{r_{t,i}}\right)}{k_t} + \frac{r_{t,i}}{r_{t,o}\cdot h_{ann}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{pc,o}}{r_{pc,i}}\right)}{k_{pc}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{ic,i}}{r_{pc,o}}\right)}{k_c} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{ic,o}}{r_{ic,i}}\right)}{k_{ic}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{wb}}{r_{ic,o}}\right)}{k_c} \right]$$

Then:

$$U = \left(\frac{1}{h_i} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{t,o}}{r_{t,i}}\right)}{k_t} + \frac{r_{t,i}}{r_{t,o}\cdot h_{ann}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{pc,o}}{r_{pc,i}}\right)}{k_{pc}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{ic,i}}{r_{pc,o}}\right)}{k_c} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{ic,o}}{r_{ic,i}}\right)}{k_{ic}} + \frac{r_{t,i}\cdot\ln\left(\frac{r_{wb}}{r_{ic,o}}\right)}{k_c} \right)^{-1}$$

- Inner forced convection: The inner forced-convection coefficient (h_i) is usually in the range 100-50 000 W/m^2 K.[23] It is lower for low velocities and for gas flow. This gives a term in the range O(1E-5) to O(1E-2).
- Conduction in metal: Inner radii of well tubulars and pipelines are usually in the range 0.01-0.25 m. The ratio between inner and outer radius is usually between 1.05-1.3 (thickest pipe walls are usually for the small pipe diameters), thus the natural log of it is between 0.04-0.24. Lastly, the conductivity of the steel is around 45 W/m^2 K. This gives a term O(1E-4).

Free convection in the annulus (Term 3): The free convection coefficient in the annulus usually has values around 100 W/m^2 K. The ratio between outer and inner tubing diameter can range from 1.05 to 1.3. Therefore, this term is usually O(1E-2).

Conduction in cement (terms 5 and 7): The thermal conductivity of cement (k_c) is usually in the range between 0.3 to 2 W/m K. The ratio between the outer and inner diameter of the annular space is usually around 1.2. The inner tubing diameter is usually 0.02-0.2. Therefore, this term is usually O(1E-2).

Heat transfer in formation or soil

$$\frac{\partial^2 T_e}{\partial r^2} + \frac{1}{r} \cdot \frac{\partial T_e}{\partial r} = \frac{c_e \cdot \rho_e}{k_e} \cdot \frac{\partial T_e}{\partial t}$$

$$T_e(r, t=0) = T_{ei}$$

$$\frac{\partial T_e}{\partial r}(r \to \infty, t) = 0$$

$$\frac{d\dot{Q}}{dz} = -2 \cdot \pi \cdot k_e \cdot r_{wb} \cdot \left. \frac{\partial T_e}{\partial r} \right|_{r=r_{wb}}$$

input

Transient!!!!

k_e	Thermal conductivity, soil [W/m.K]
C_e	Specific heat capacity, soil [J/K.kg]
t	Time [s]

An approximate, analytical solution:

Wellbore Heat Transmission

H. J. RAMEY, JR.
MEMBER AIME

MOBIL OIL CO.
SANTA FE SPRINGS, CALIF.

SPE 22866

Heat Transfer During Two-Phase Flow in Wellbores: Part I—Formation Temperature

A.R. Hasan, U. of North Dakota, and C.S. Kabir, Chevron Oil Field Research Co.
SPE Members

Using that solution, and doing some math:

$$U_{eff}(t) = \left(\frac{U \cdot k_e}{k_e + T_D \cdot r_{t,i} \cdot U} \right)$$

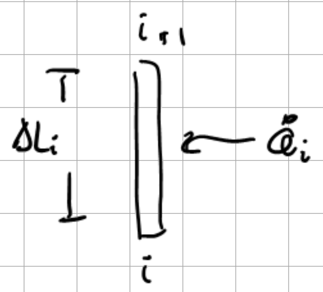
$$\begin{cases} T_D = 1.1281 \cdot \sqrt{t_D} \cdot (1 - 0.3 \cdot \sqrt{t_D}), & for \quad t_D \leq 1.5 \\ T_D = (0.4063 + 0.5 \cdot \ ln(t_D)) \left(1 + \frac{0.6}{t_D}\right) & for \quad t_D > 1.5 \end{cases}$$

Dimensionless time, $t_D = \frac{\alpha_e \cdot t}{{r_{wb}}^2}$

And α_e is the thermal diffusivity of the soil, [m2/s], equal to $\frac{k_e}{\rho_e \cdot C_e}$

Lecture 42 : Temperature calculations in wellbore - exercise

		BO table column
TVD [m]	T [C]	p[bara]
0	50.0	28
500	57.1	39.2
1000	64.3	58.6
1500	71.4	82.5
2000	78.6	109.4
2500	85.7	138.4
3000	92.9	168.9
3500	100.0	200.2



$$h_{i+1} = \frac{\dot{Q}_i}{\dot{m}} + h_i - \Delta z \cdot g$$

$$\left.\frac{d\dot{Q}}{dL}\right|_i = -2\pi r \cdot U_i \left(T_{f_i} - T_{form,i}\right)$$

$$\dot{Q}_i = \underbrace{\left(\left.\frac{d\dot{Q}}{dL}\right|_i + \left.\frac{d\dot{Q}}{dL}\right|_{i+1}\right)\frac{1}{2} \cdot \Delta L_i}_{\text{trapezoidal rule!}}$$

residual $\varepsilon_i = 0 = \frac{\dot{Q}_i}{\dot{m}} + h_i - h_{i+1} - \Delta z g$

		BO table column
TVD [m]	T [C]	p[bara]
0	50.0	28
500	57.1	39.2
1000	64.3	58.6
1500	71.4	82.5
2000	78.6	109.4
2500	85.7	138.4
3000	92.9	168.9
3500	100.0	200.2

TVD [m]	T [C]	p[bara]
0	65.6	28
500	74.5	44.8
1000	81.2	65.3
1500	86.3	89.1
2000	90.9	115.8
2500	94.9	144.5
3000	97.9	174.7
3500	100.0	205.9

TPG4245. Summary of content covered – Autumn 2022 Assoc. Prof. Milan Stanko (NTNU)

LEGEND

Not included in Exam

Less relevant for exam

Course content (covered in Youtube video lectures)

- Introduction (well layout, production engineering domain)
- Flow equilibrium
- Inflow performance relationship
  - Undersaturated Oil
    - Radial and horizontal wells
    - Water coning
  - Dry Gas
    - High velocity flow
  - Saturated oil
- Choke performance
- Tubing performance
  - Dry Gas flow
  - Tubing size considerations
  - Multiphase flow of oil, gas and water
- Artificial lift
  - Gas lift
  - Electric submersible pump
- Temperature calculations in wellbore

Class activities

-Theory: Wellhead architecture, well construction and wellhead onshore versus subsea
-Group work: Content of oil in produced water discharged to sea

-LINEST Excel function
-Flow equilibrium example with incompressible liquid and the Bernoulli equation
-Group activity: casing hanger puzzle

-Class exercises about Flow Equilibrium
-Discussion on Rp (GOR) and class exercise with Hysys
-Class activity with Hysys - Bo calculation

TPG4245. Summary of content covered – Autumn 2022 Assoc. Prof. Milan Stanko (NTNU)

-Bo calculation with BO correlations and Prosper
-IPR for water injection, Skin factor
-Water properties (Bw, viscw)

-Class Exercises on undersaturated oil IPR and downhole networks
-Hardware showcase (ICV, Packer, SSSV, choke)

-CO2 emissions and energy accountancy

-IPR for CO2 injection well
-Choke class exercises
-Expansion in choke of CO2

-Exercise on saturated oil IPR (Borthne field)
-Composite IPR for undersaturated-saturated oil wells
-Mechanical properties of tubing

-Learn Prosper and Pipesim

-Gas condensate IPR

Company presentations

- Inflow control (autonomous ICV)
- Typhonix (low shear/coalescing pump and choke)

Industry visits

- Shawcor AS (spoolbase)

Mandatory Exercises

- Flow equilibrium (natural flow, wellhead compressor and choke)
- Time to steady state in formation
- BO properties and IPR for undersaturated oil vertical well
- Estimation of productivity index J for vertical and horizontal undersaturated oil well
- Water coning
- OiW content
- Flow equilibrium questions and dry gas natural flow equilibrium
- Vertical Dry gas well IPR
- Vertical Saturated oil well IPR (Evinger & Muskat, Fetkovich, Vogel)
- Choke flow performance
- Temperature change in choke
- Estimation of IPR and production of well with 2-layers undersaturated oil reservoirs with and without ICV, horizontal or vertical
- Pressure drop in tubing for dry gas
- Flow equilibrium at bottom-hole and wellhead for dry gas with the tubing equation

- Pressure drop, TPR calc in tubing for multi-phase flow (drift flux and mechanistic)
- IPR for CO_2 injector
- Choke flow performance – Using the model to predict rate, outlet pressure or inlet pressure.
- Gas lift
- ESP
- Temperature calculations
- Exercise with Prosper or Pipesim