Note Title 12.01.2017

ME683 Field development and operations

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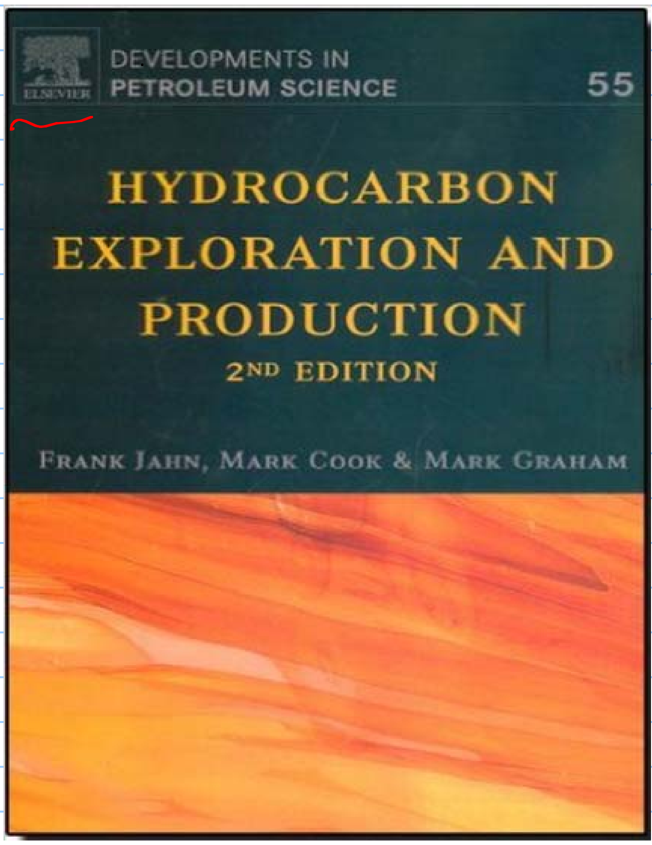
Reference material:

youtube channel https://www.youtube.com/playlist?list=PLXfmJjG2tXbrD3-g9DnROqGohUEcK6txe

TPG4230 Field development and operations



Elsevier.

Life cycle of a hydrocarbon field

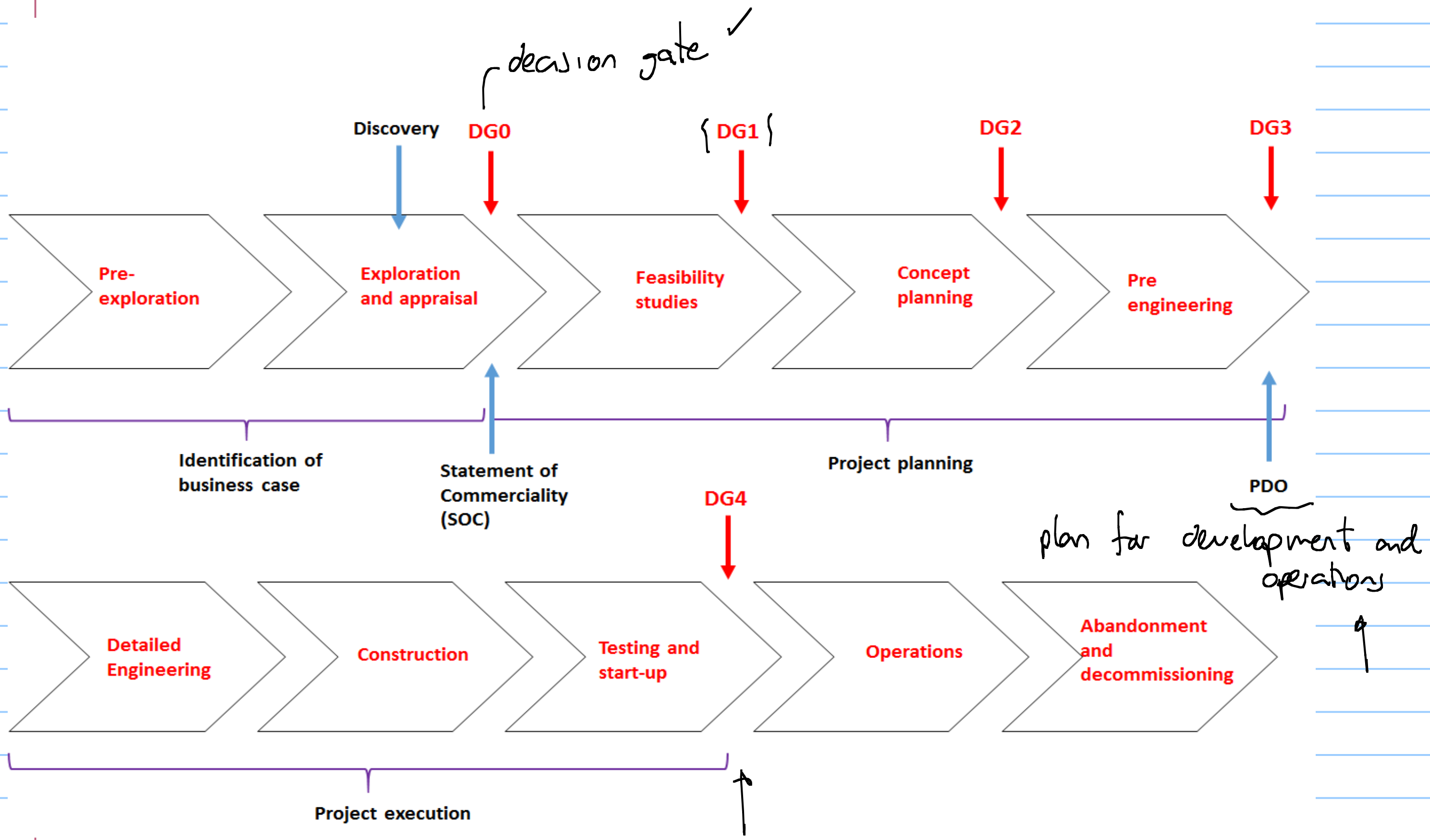
Pre-exploration → Exploration → (discovery) Appraisal → Field planning phase → project execution → (production start-up) operations (production)

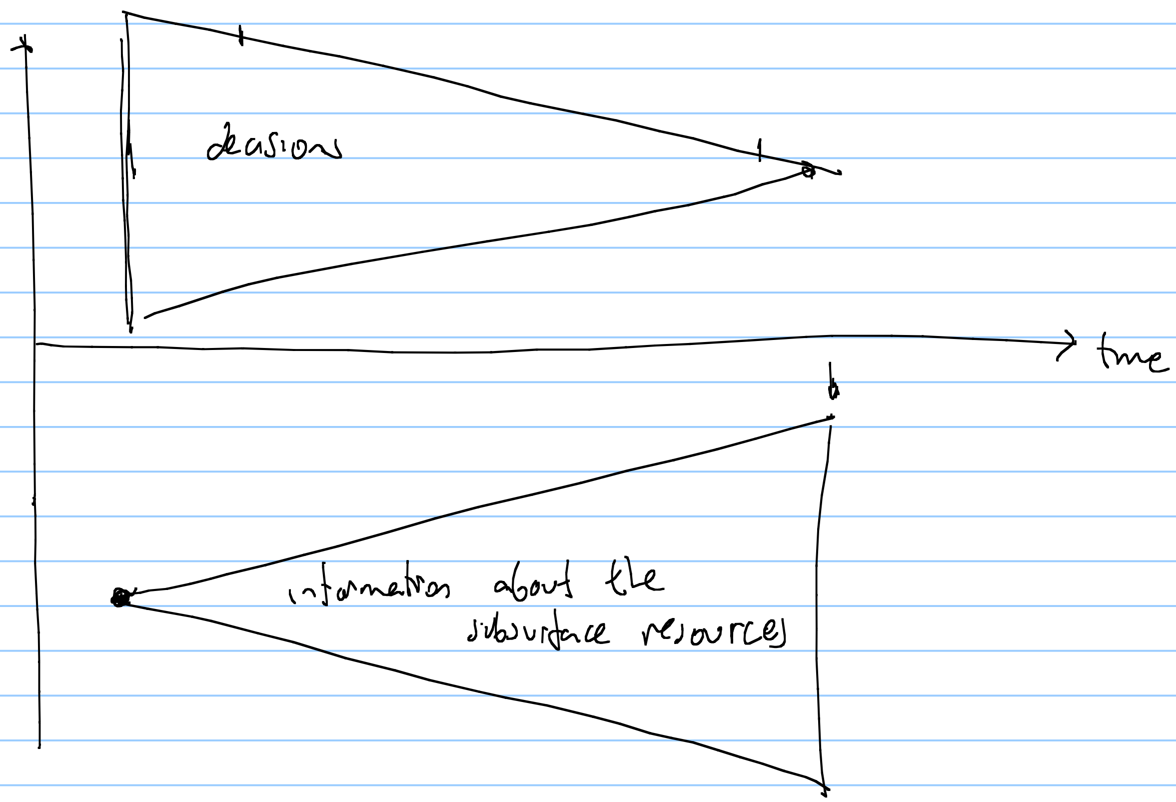
3-5 years

Business case identification

10-30 years

decommissions abandonment





things we are going to focus on this course: • estimation of TRR (TOTAL recoverable reserves)

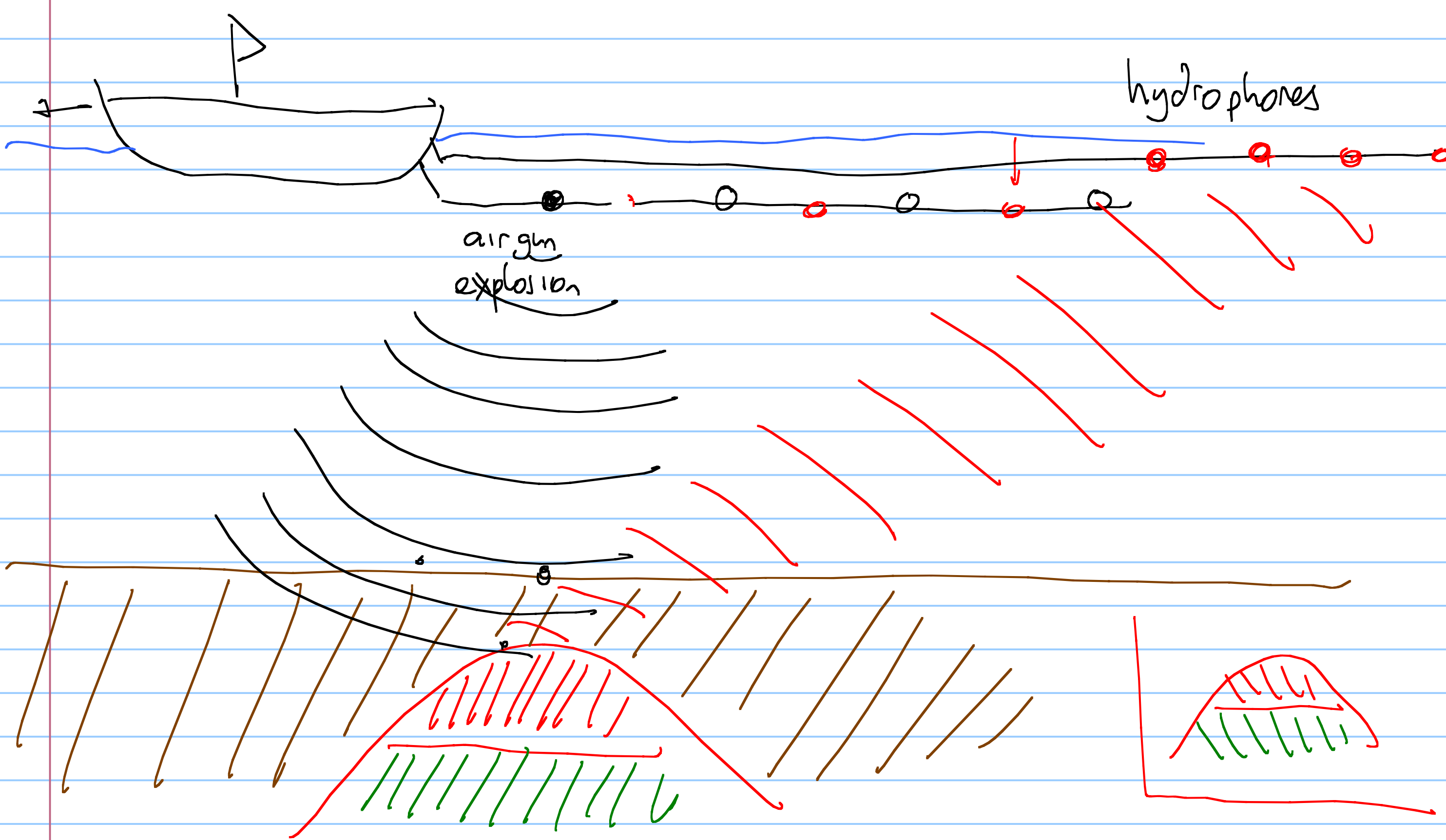
• NPV calculations ~ economic value of project

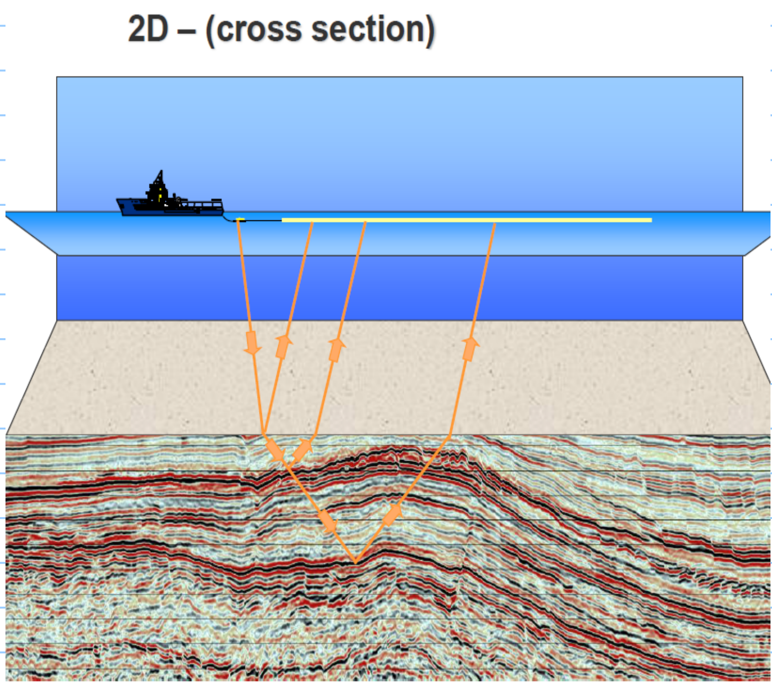
IMPORTANT source of revenue of field → { • Predicting production profiles

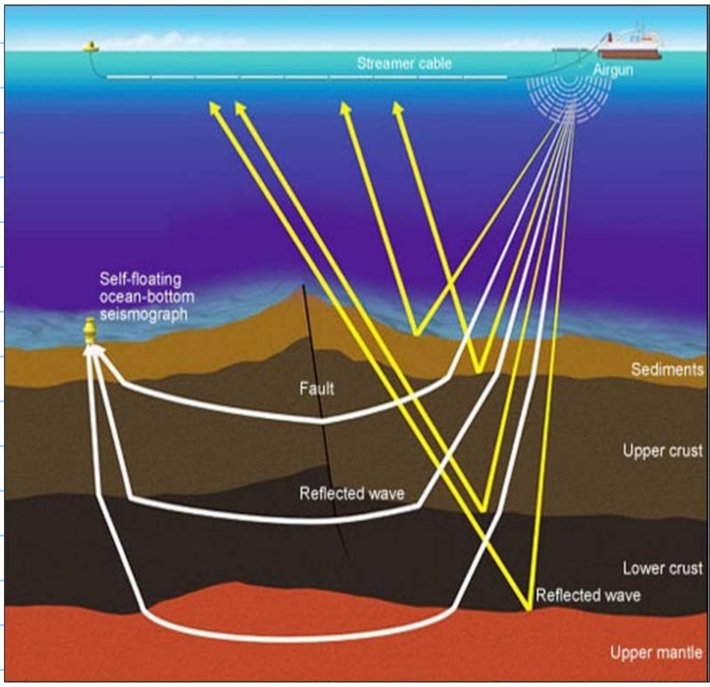
- pre-exploration: 1) scouting - gathering information about different areas of interests. Taking into account:
  - expectation to find hydrocarbons
  - geo-political
  - social
  - geographical
  - techical (logistics, access)
  - environmental
  - taxation regime
  - personnel security
  - experience in the region

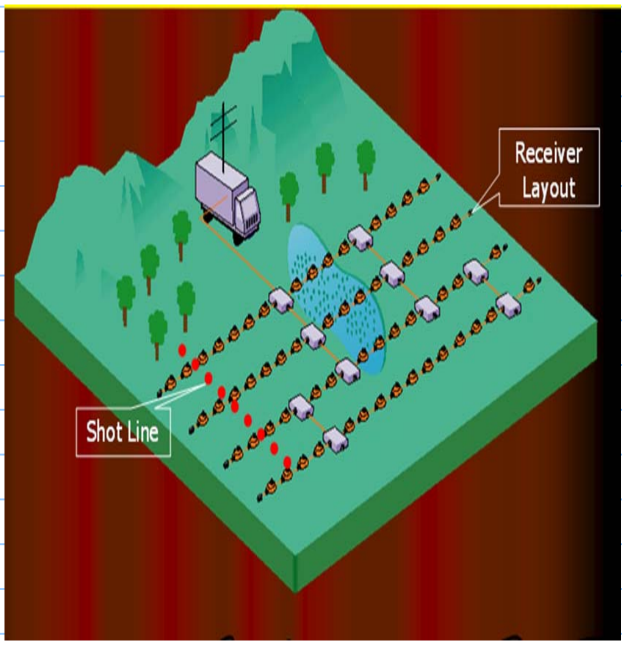
2) pre-exploration seismic to map the subsurface performed by a smaller company that applies for pre-exploration license.

offshore seismic




2D – (cross section)


Streamer cable
Airgun
Self-floating ocean-bottom seismograph
Fault
Sediments
Upper crust
Reflected wave
Lower crust
Reflected wave
Upper mantle


Receiver Layout
Shot Line

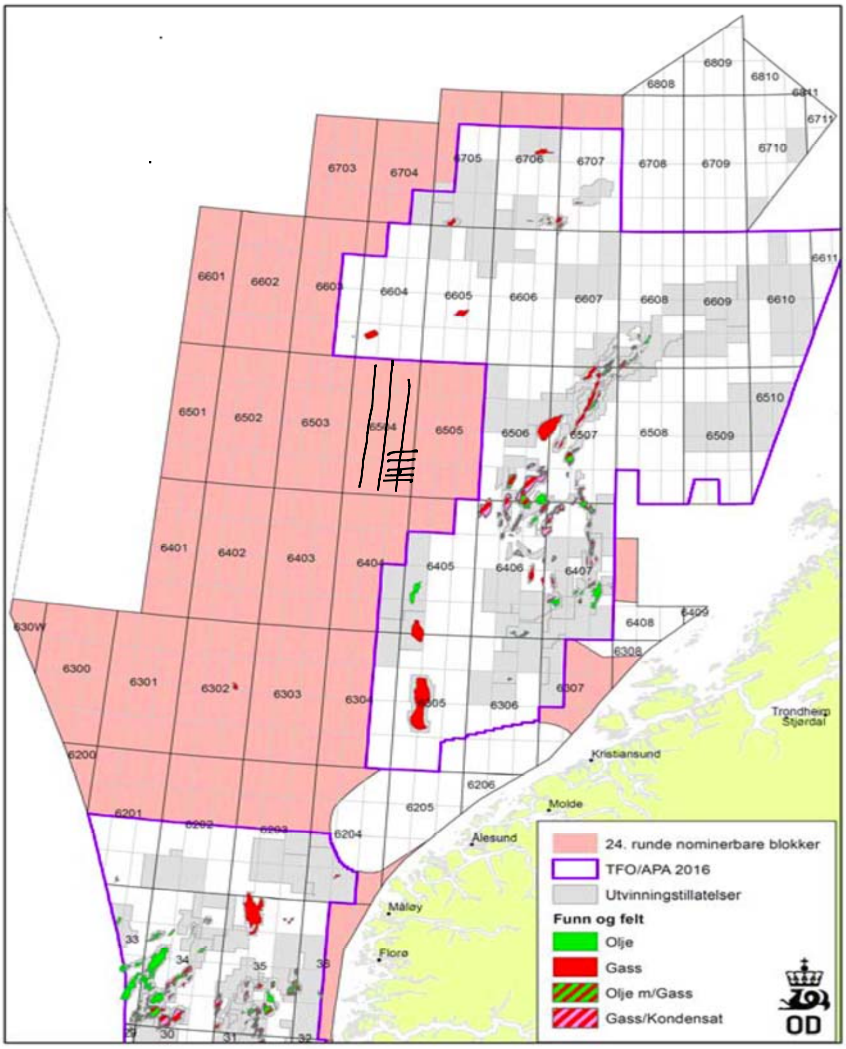
- apply for production . license with government

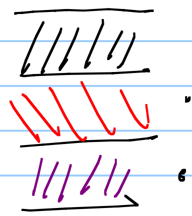
for Norway

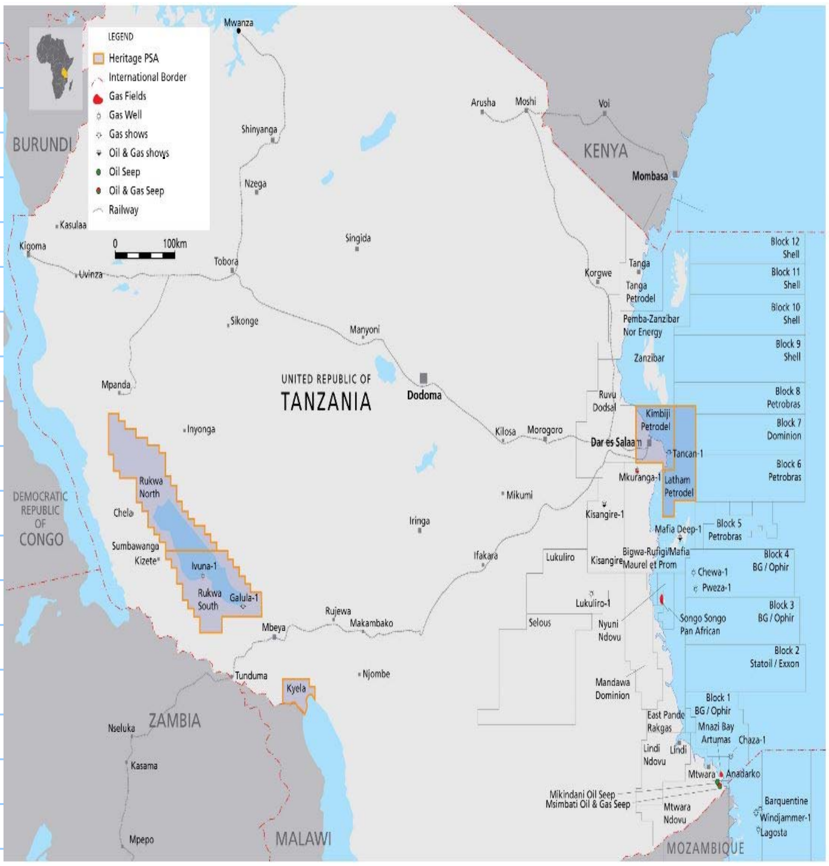
year 1 4000 USD/km^2

year 2 8000 USD/km^2

year 3 16000 USD/km^2



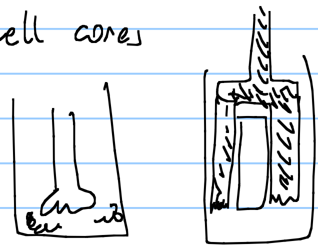




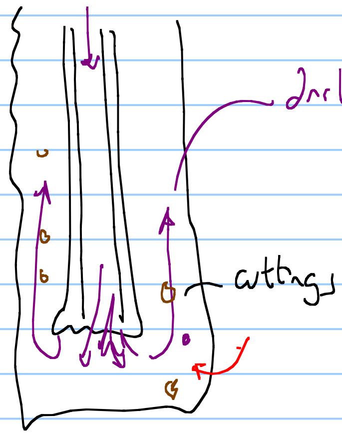
exploration :

- geological studies
- geophysical surveys (seismic)
- exploration drilling

well cores

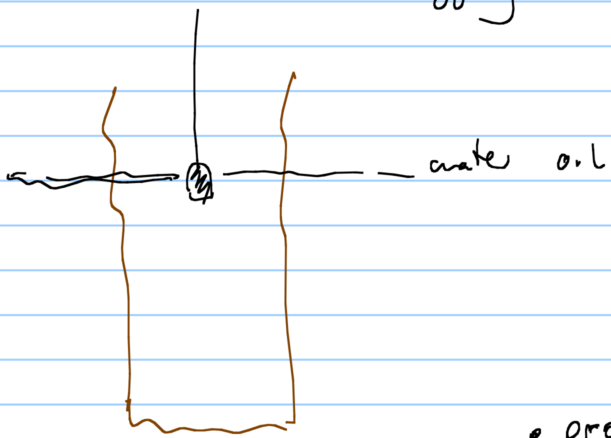


- cuttings analysis
- logging

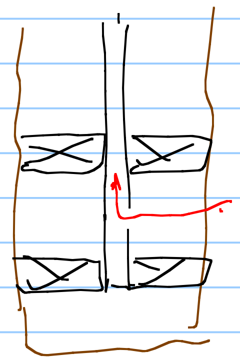


drilling mud
- avoiding kicks of formation fluid into the wellbore
- cooling the bit
- bring cuttings to surface

Logging

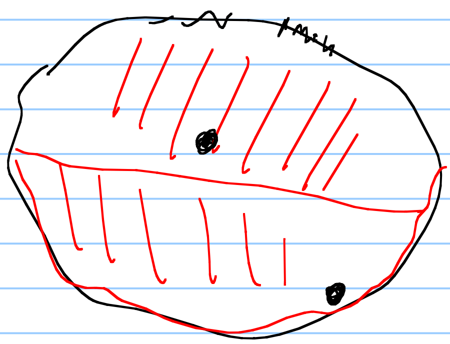


- productivity test (fluids, how productive the formation is, etc.)



OOIP (N) — original oil in place
OGIP (G) — original gas in place

Discovery !



- estimation of reserves — probabilistic estimation of reserves
- perform a simplified valuation of resources

Appraisal to reduce uncertainties
- more refined seismic
- drilling another well — appraisal wells

find reservoir extent. size !

DG0 — Statement of commerciality → it is commercial and we continue with field planning
- → more appraisal is required
- → relinquish to government
- → wait....
- → sell your discovery

field planning phase

1) Feasibility studies

- define an objective inline with corporate strategy.
- establish feasible field devopment scenarios
- establish a project timeline and a plan
- identify potential technology gaps.
- start creating the value chain model
- cost evaluation

DG1

2) Concept planning :

PEP ~> project execution plan

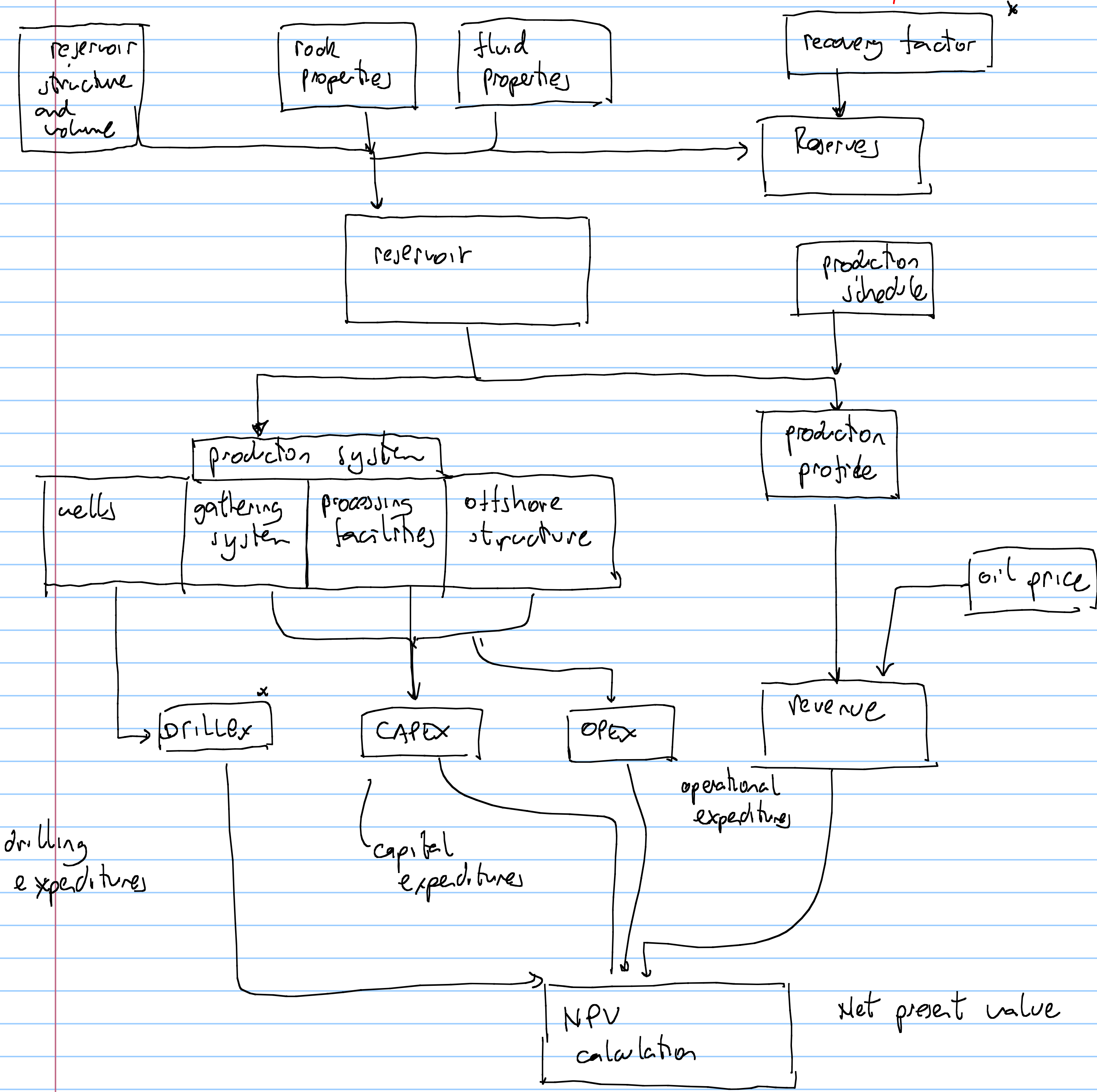
- evaluate and compare different development options and discard non viable options
- define commercial aspects : legislation, licensing, agreement, financing, taxes
- refine reservoir model ~> compute production profile

- refine cost figures
- detecting the best viable concept

062

gas: $\frac{G_p}{G}$ oil: $R_f = \frac{N_p}{N}$ $\begin{cases} \text{for oil} \sim 10\% - 50\% \\ \text{for gas} \sim 30\% - 70\% \end{cases}$

value chain model:



costs

oil/gas produced in year

end of year

time	CAPEX	DRILLEX	OPEX	q_o	ΔN_p	revenue	cashflow
1	□	□	0	0	0	0	revenue-cost
2	□	□	0	0	0	0	□
3	□	□	0	0	0	0	□
4	0	0	□	□	□	□	□
⋮	0	0	□	□	□	□	□
⋮	0	0	□	□	□	□	□
⋮	0	0	□	□	□	□	
⋮	0	0	□	□	□	□	

start of product →

discounted present value

calculated the present value of cash flow

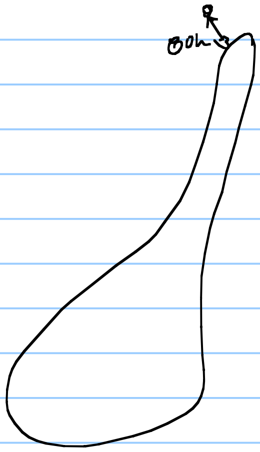
$$PV = \frac{\text{Cash flow}}{(1+i)^{\text{year}}}$$

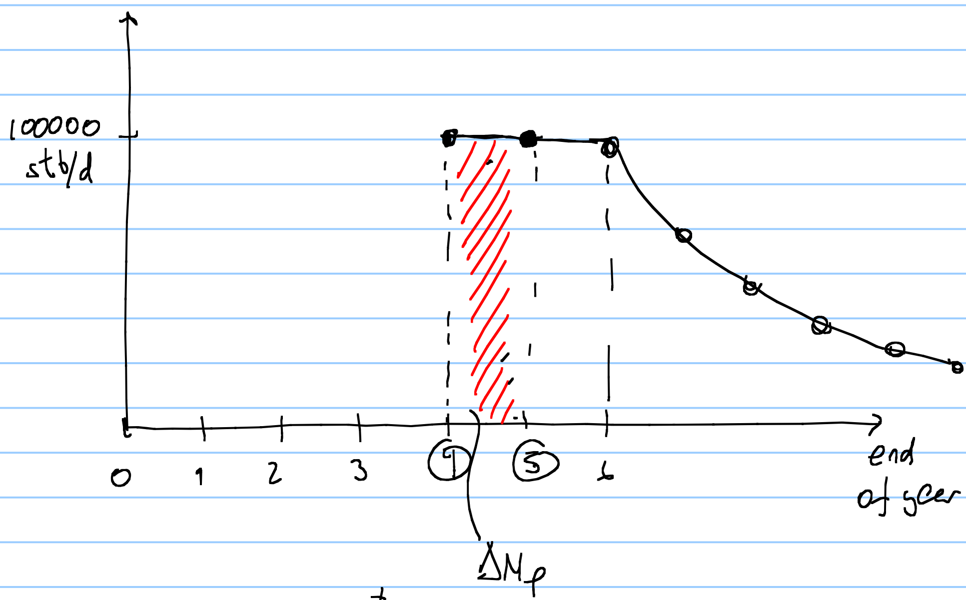
discounted cash flow
□
□
□
□
□
□

$$NPV = \sum (\quad)$$

(+)
(-)

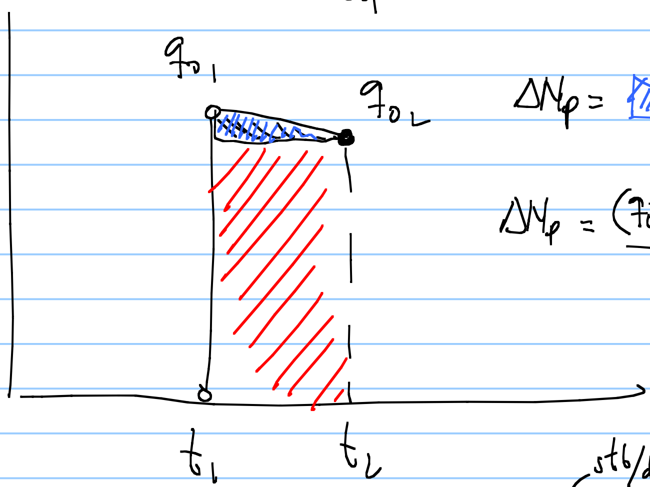
Clas exerase - Goliat field





$$\Delta N_p = \int_{t_4}^{t_5} q_{\bar{o}}\, dt = q_o (t_5 - t_1)$$

trapezoidal rule



$\Delta N_p = \triangle + \square$

$$\Delta N_p = \frac{(q_{\bar{o}1} + q_{\bar{o}2}) \cdot (t_2 - t_1)}{2}$$

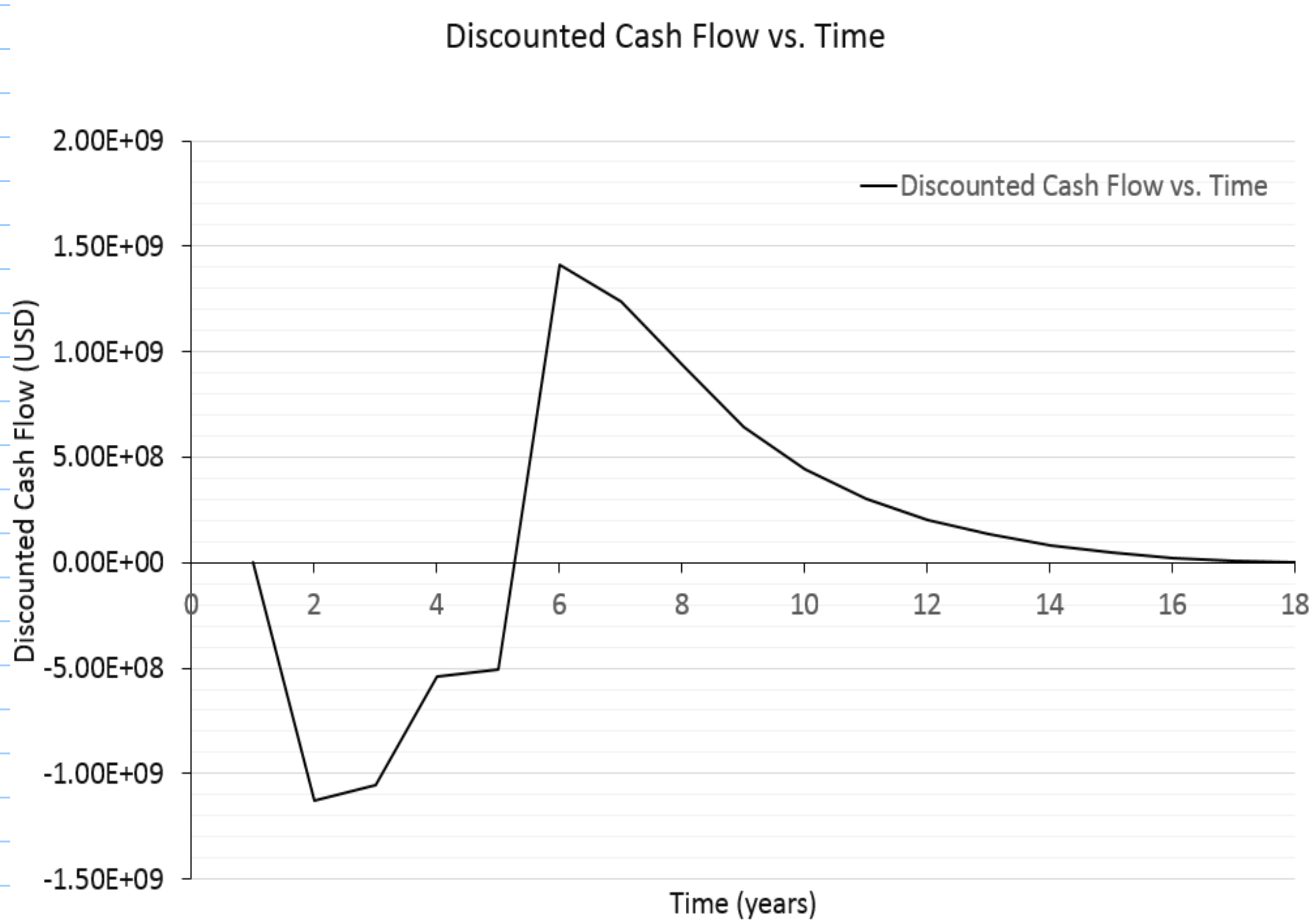
$$\Delta N_p = \frac{\overbrace{(q_{\bar{o}1} + q_{\bar{o}2})}^{stb/d} \cdot \overbrace{(t_2 - t_1)}^{years}}{2}$$

$$\Delta N_p = \left[\frac{stb}{d}\ years \cdot \frac{N_{days}}{year}\right]$$

$$uptime = \frac{N^r \text{ operational days in year}}{N_{days}\ year} \cdot 100$$

78 %

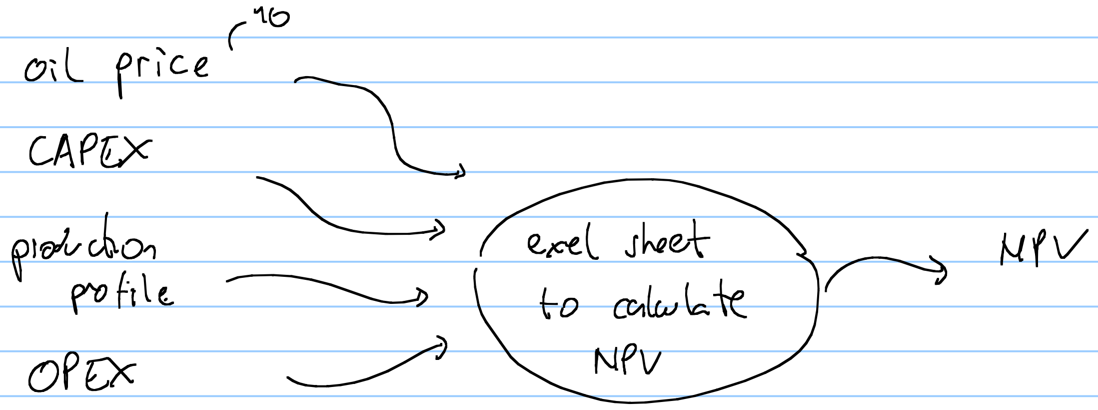
Oil Production	Oil production in year	Revenue	DRILLEX	CAPEX	OPEX	Total Cost	Cash Flow	Discounted Cash Flow: PV(i)
stb/d	[stb]	USD	USD	USD	USD	USD	USD	USD
0	0.00E+00	0.00E+00	6.60E+08	5.50E+08		1.21E+09	-1.21E+09	-1.13E+09
0	0.00E+00	0.00E+00	6.60E+08	5.50E+08		1.21E+09	-1.21E+09	-1.06E+09
0	0.00E+00	0.00E+00	6.60E+08			6.60E+08	-6.60E+08	-5.39E+08
100000.0	0.00E+00	0.00E+00	6.60E+08			6.60E+08	-6.60E+08	-5.04E+08
100000.0	3.47E+07	2.08E+09			1.00E+08	1.00E+08	1.98E+09	1.41E+09
88357.2	3.27E+07	1.96E+09			1.00E+08	1.00E+08	1.86E+09	1.24E+09
65601.4	2.67E+07	1.60E+09			1.00E+08	1.00E+08	1.50E+09	9.35E+08
50056.1	2.01E+07	1.20E+09			1.00E+08	1.00E+08	1.10E+09	6.42E+08
38174.4	1.53E+07	9.18E+08			1.00E+08	1.00E+08	8.18E+08	4.45E+08
28694.0	1.16E+07	6.96E+08			1.00E+08	1.00E+08	5.96E+08	3.03E+08
21618.0	8.72E+06	5.23E+08			1.00E+08	1.00E+08	4.23E+08	2.01E+08
16586.8	6.62E+06	3.97E+08			1.00E+08	1.00E+08	2.97E+08	1.32E+08
12329.0	5.01E+06	3.01E+08			1.00E+08	1.00E+08	2.01E+08	8.33E+07
9164.6	3.73E+06	2.24E+08			1.00E+08	1.00E+08	1.24E+08	4.79E+07
6765.7	2.76E+06	1.66E+08			1.00E+08	1.00E+08	6.57E+07	2.38E+07
5327.5	2.10E+06	1.26E+08			1.00E+08	1.00E+08	2.58E+07	8.74E+06
3845.9	1.59E+06	9.54E+07			1.00E+08	1.00E+08	-4.57E+06	-1.45E+06
2801.6	1.15E+06	6.92E+07			1.00E+08	1.00E+08	-3.08E+07	-9.13E+06
2102.5	8.50E+05	5.10E+07			1.00E+08	1.00E+08	-4.90E+07	-1.35E+07
							NPV [USD]	2.22E+09



perform sensitivity analysis on the results: there are some input parameters that are very uncertain

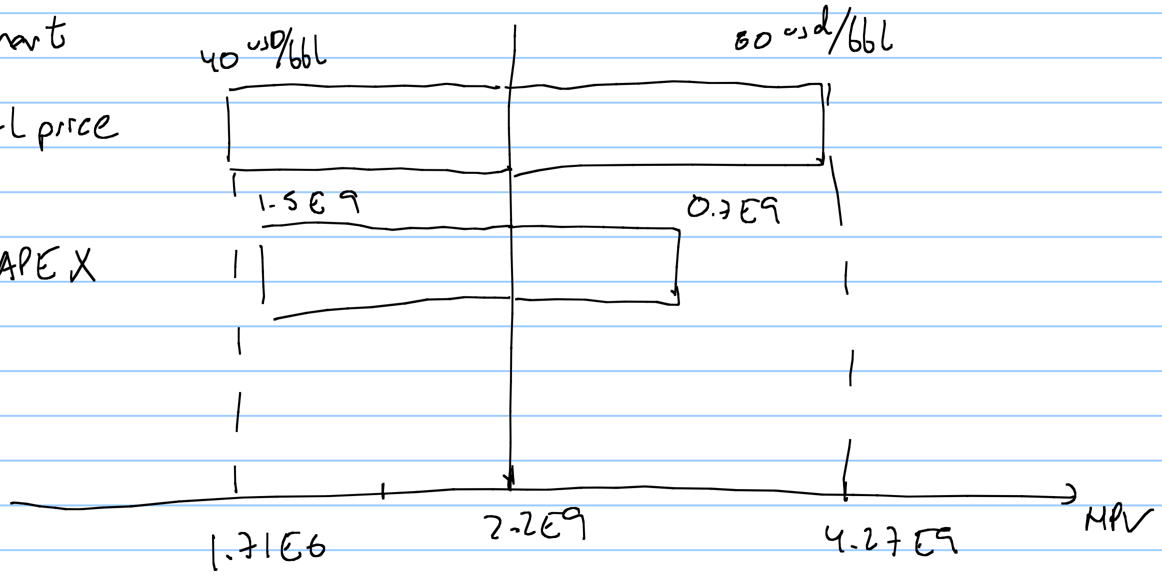
what happens if oil price = 40 usd/bbl ?

make sensitivity analysis by modifying the input

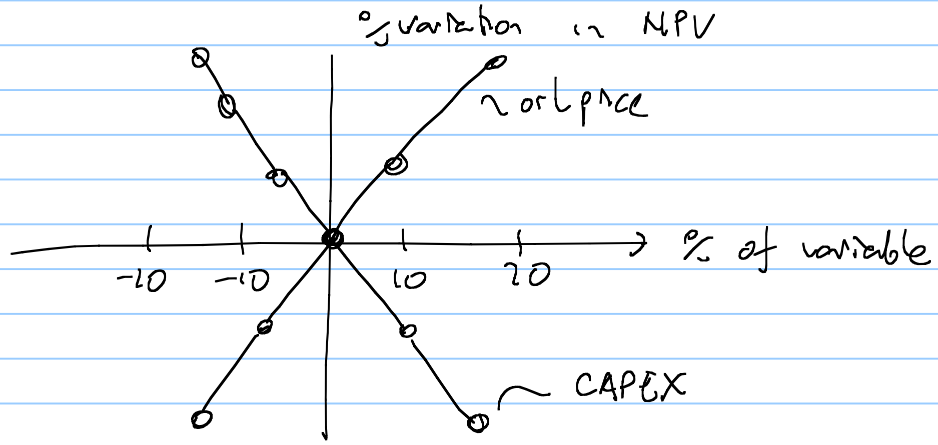


	NPV_{min}	NPV	NPV_{max}
oil price ± %	171 E6	2.2 E9	4.27 E9
CAPEX ±	1.86E9	2.2E9	2.58E9
OPEX			

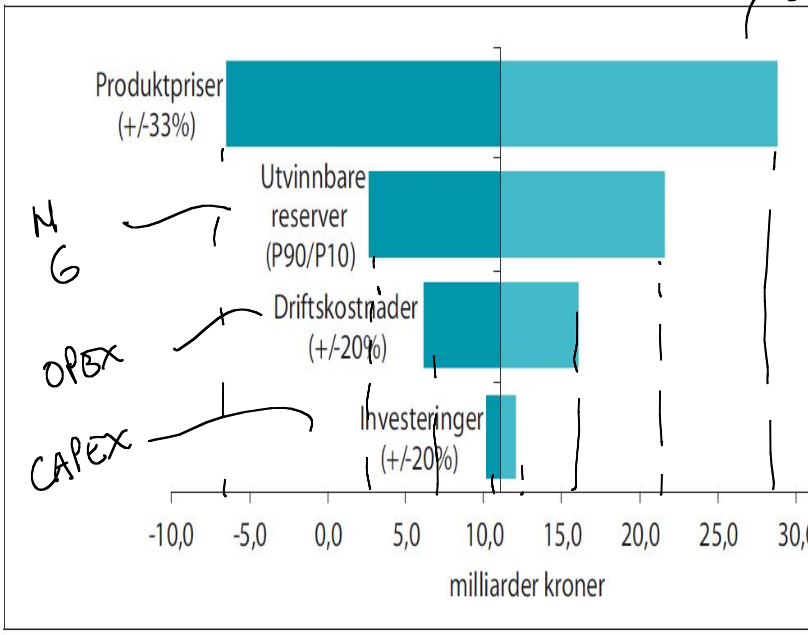
tornado chart



Spider plot



oil price



-6,6	28,8
2,6	21,5
6,1	16,0
10,1	12,0

Pre-engineering : • select the final solution

• FEED Front end engineering design. Define the requirements for all packages in the value chain model. Estimate the cost of each package.

• plan and prepare the execution phase

• prepare the submission of PDO plan for development and operations

• perform a socio-economical evaluation of project

• establish the base for awarding contracts

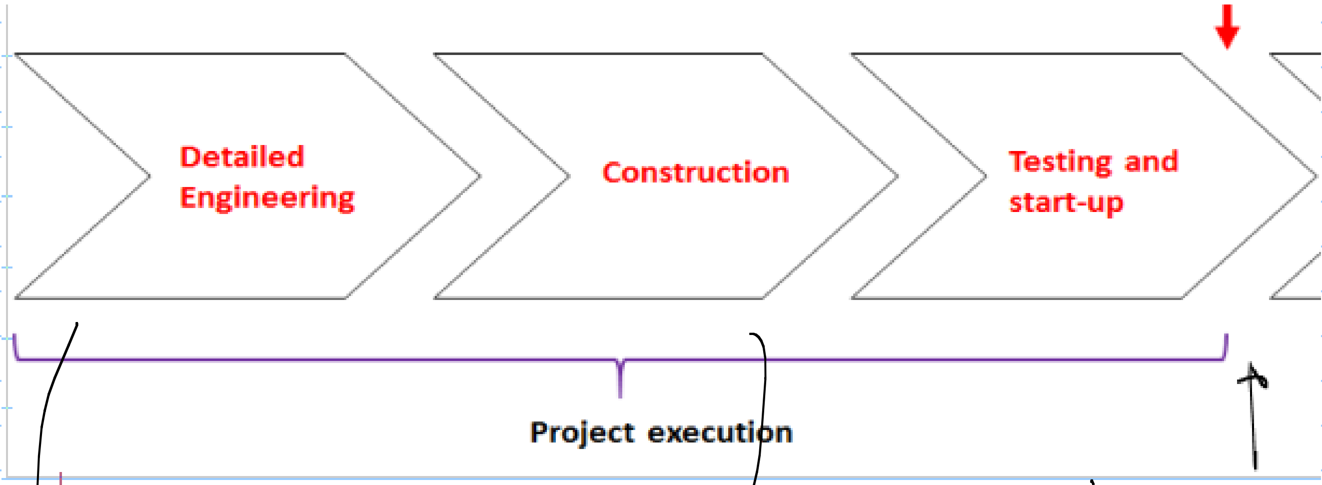
DG3 → issue the PDO

↓ if approved by authorities

NOT APPROVED → make modifications

↓ execution phase

D64

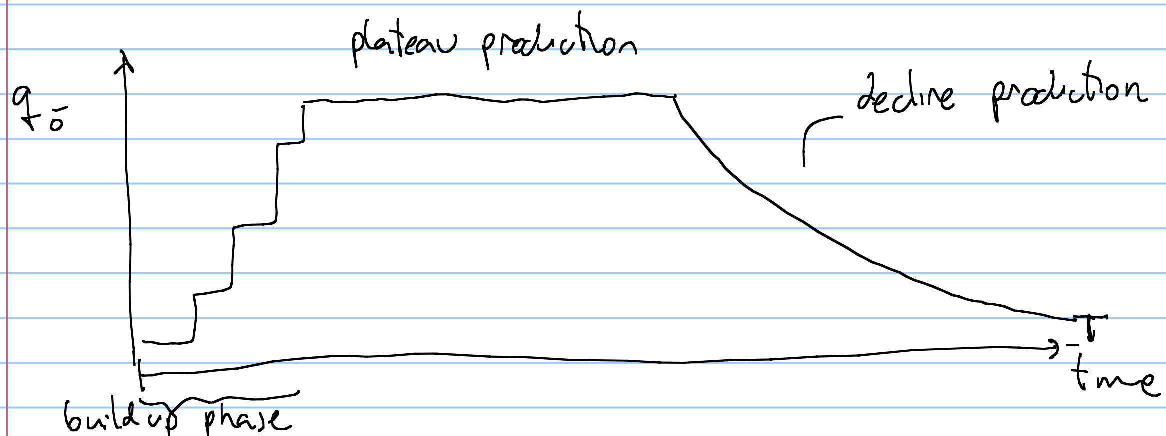


- detailed design of all components of the field.
  - individual contract for each package
  - EPCM
    - Engineering, procurement construction, management
    - single contract with vendor

- well are drilled
- processing facilities are build and assembled in place
- documentation

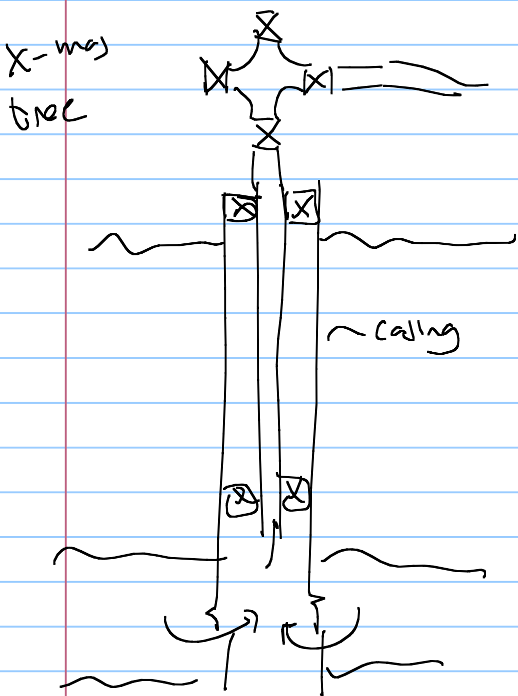
- testing and prepare to handover to operations

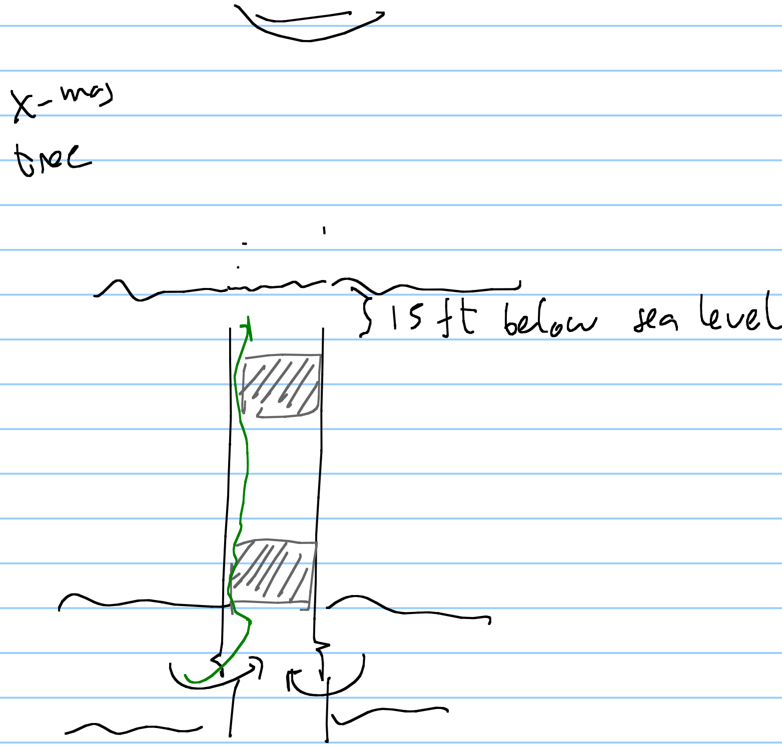
- operations:
  - producing the field
  - maintenance
  - optimize production (produce more and reduce cost)
  - IOR improved oil recovery
    - increase production
    - increase recovery factor
    - prolong the life of field
    - infill drillings
    - boosting
    - gas or water injection



abandonment and decommissioning:

- plan decommissioning with authorities following regulations
- cleaning and flushing production system, separator, pipes
- well plugging and abandonment





remove processing plant

removal of offshore structure

remove pipelines

monitor plugged wells

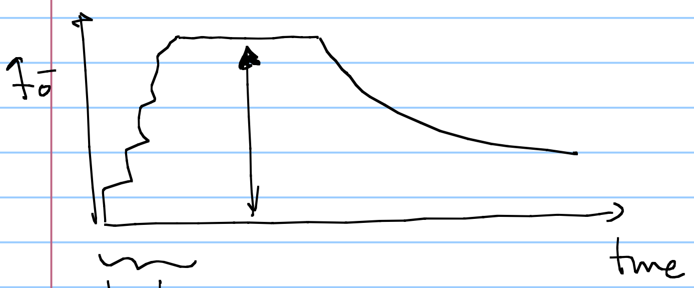
mark and register installations in maritime maps

- recovery of scrap material
- disposal of residues

ABEX

abandonment expenditures

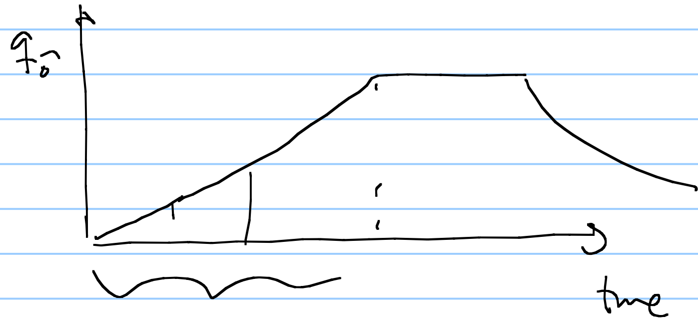
- Offshore



short build up phase

- start production as soon as possible
- the platform must be in place before starting production
- few wells decided beforehand

Onshore



Long build up phase

- perform appraisal while producing
- verify reservoir size, communication
- get revenue sooner.
- export neighborings field

Oil fields

- is easy to transport

→ 5 - 15 years

Gas fields

- pipeline . custumer/destination
- long term supply contracts

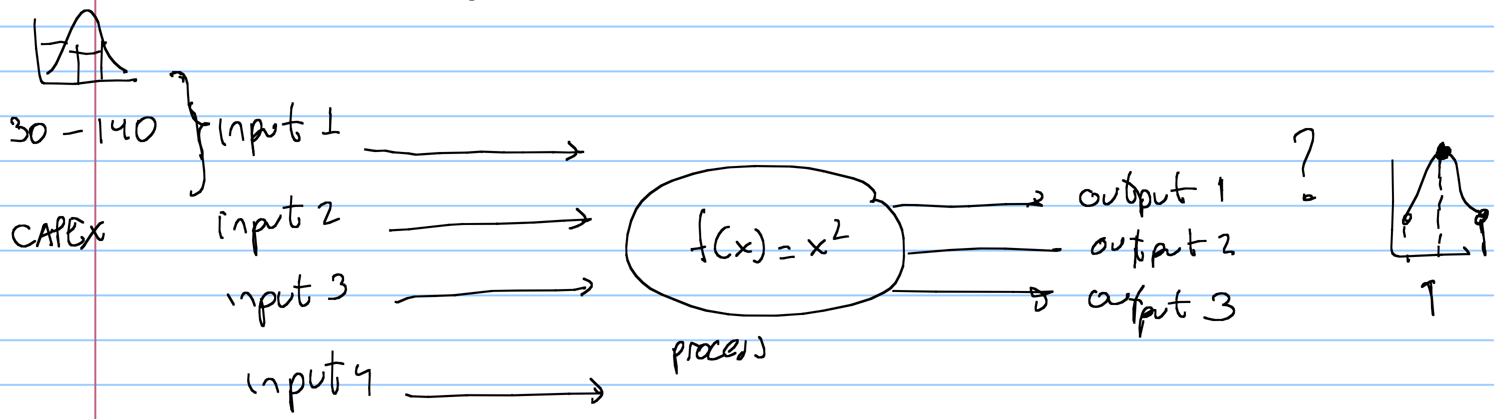
15 - 30 years

- LNG Liquified natural gas

LNG plant to cool and compress the gas → turns into liquid

receive it → LNG terminal

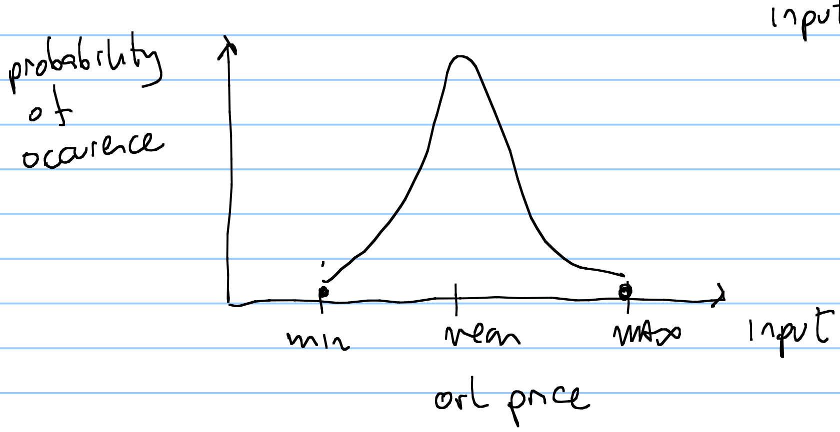
Uncertainty management in field development

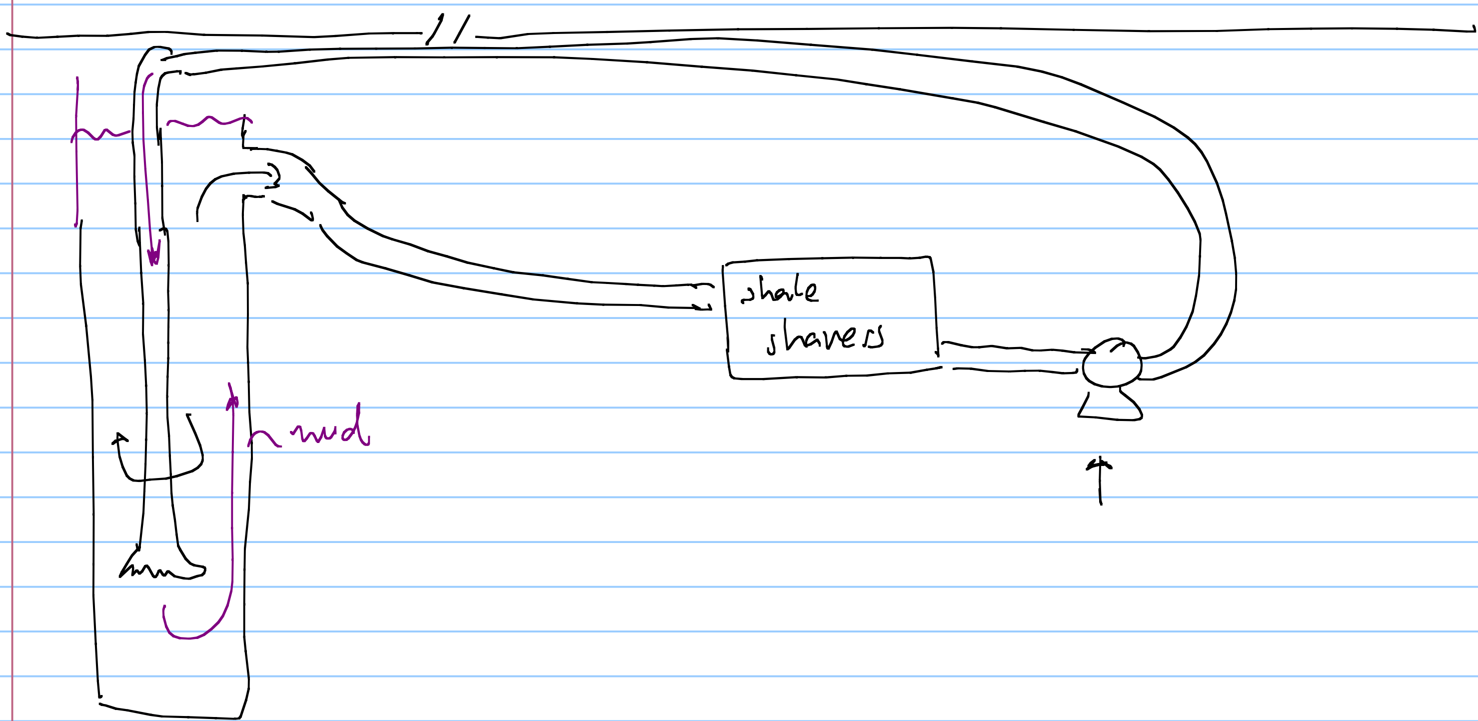


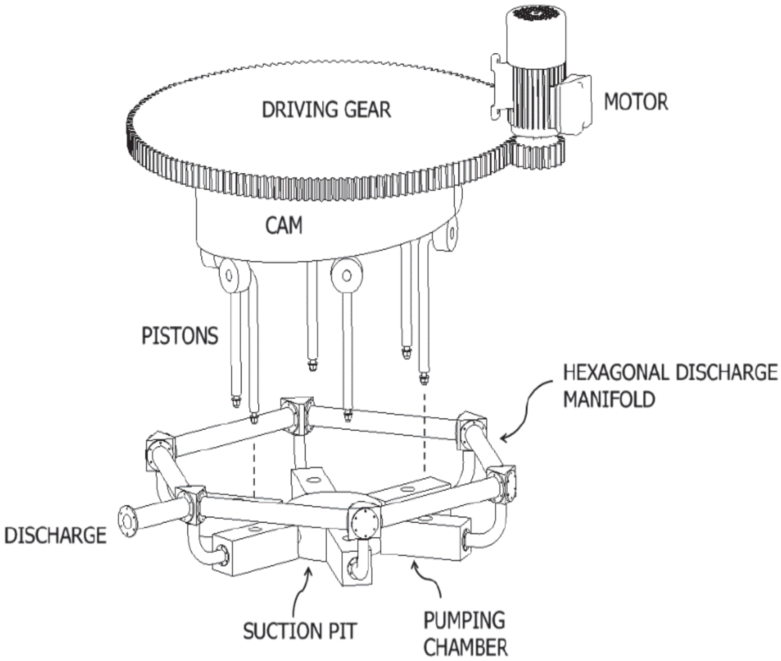
probabilistic distribution of input data

for every input

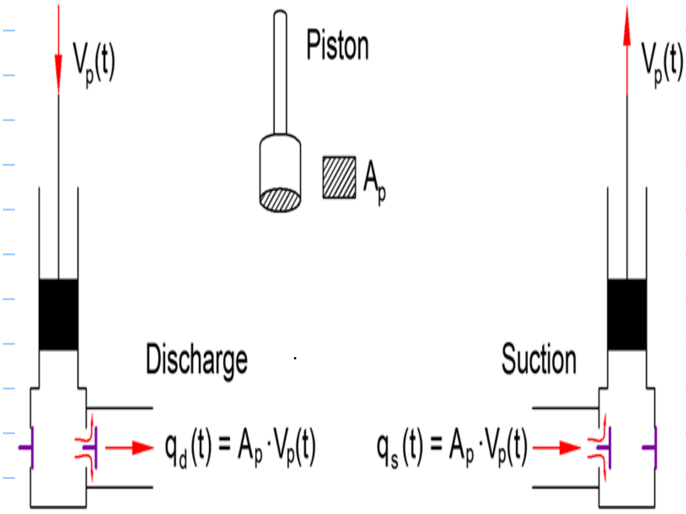
input 1 { min, mean, max }



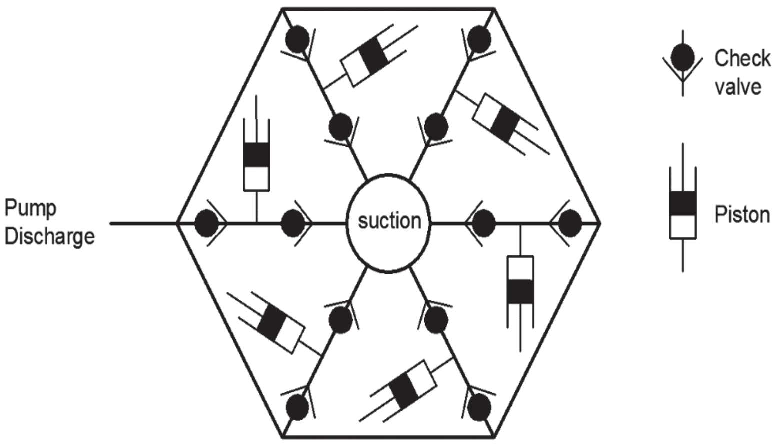




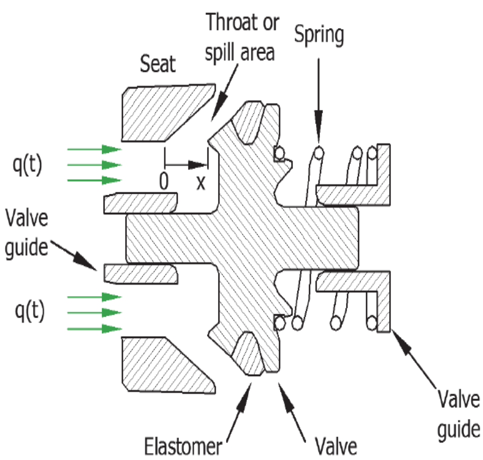
MOTOR
DRIVING GEAR
CAM
PISTONS
HEXAGONAL DISCHARGE MANIFOLD
DISCHARGE
SUCTION PIT
PUMPING CHAMBER



$V_p(t)$
Piston
A_p
$V_p(t)$
Discharge
Suction
$q_d(t) = A_p \cdot V_p(t)$
$q_s(t) = A_p \cdot V_p(t)$



Pump Discharge
suction
Check valve
Piston

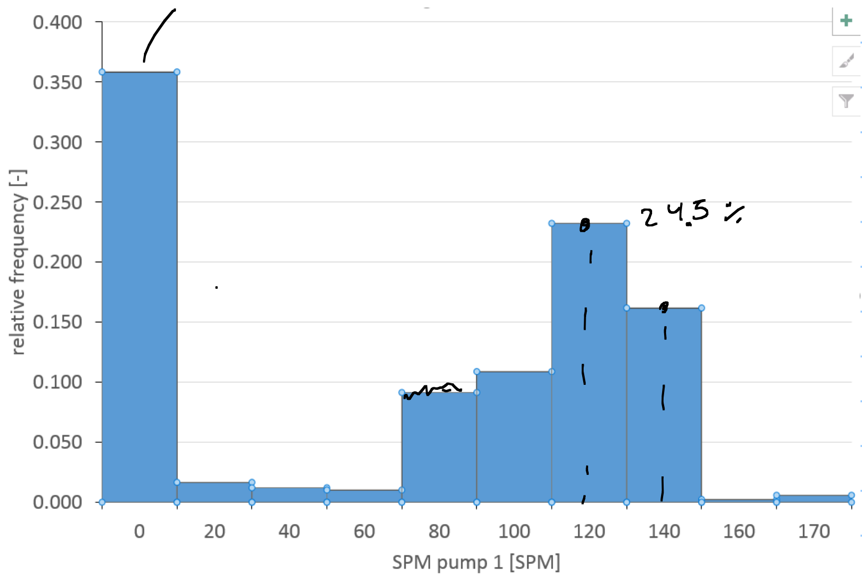


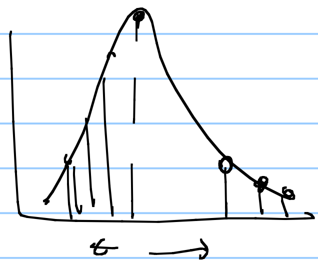
Seat
Throat or spill area
Spring
q(t)
0
x
Valve guide
q(t)
Elastomer
Valve
Valve guide

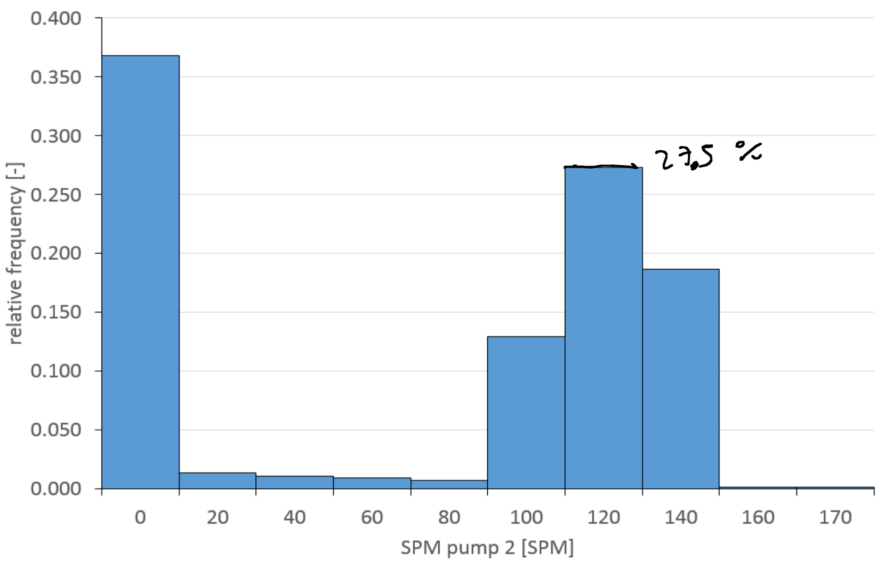
frequency analysis

time	SPM pump 1	SPM pump 2
	0	160
	20	155
	25	130
	30	90

SPM	pump 1
0	1
20	2
30 — 40	1
60	
80	
100	
120	
140	
160	
170	







Day 2

Evaluation:

10% delivery of class exercises. Deadline: 8.Dec.2017

2 x 15% Exam (15/12/2017) → January

60% final exam (end of semester → Feb – March).

uptime: 90% - 98%

365 days in year

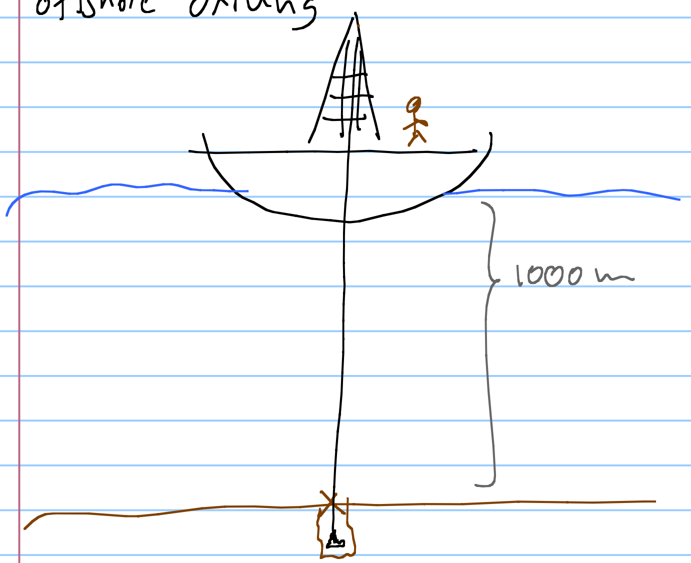
350 producing days in year

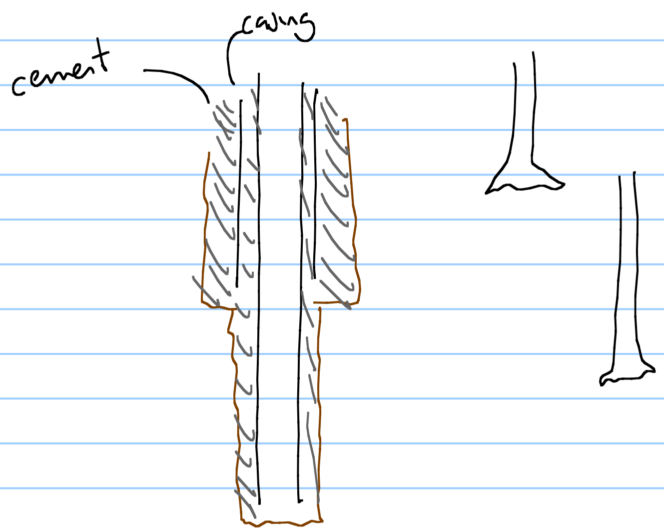
$$\text{uptime} = \frac{350}{365} = 0.9589 \quad \text{fraction}$$

$\times 100$

95.89 %

offshore drilling





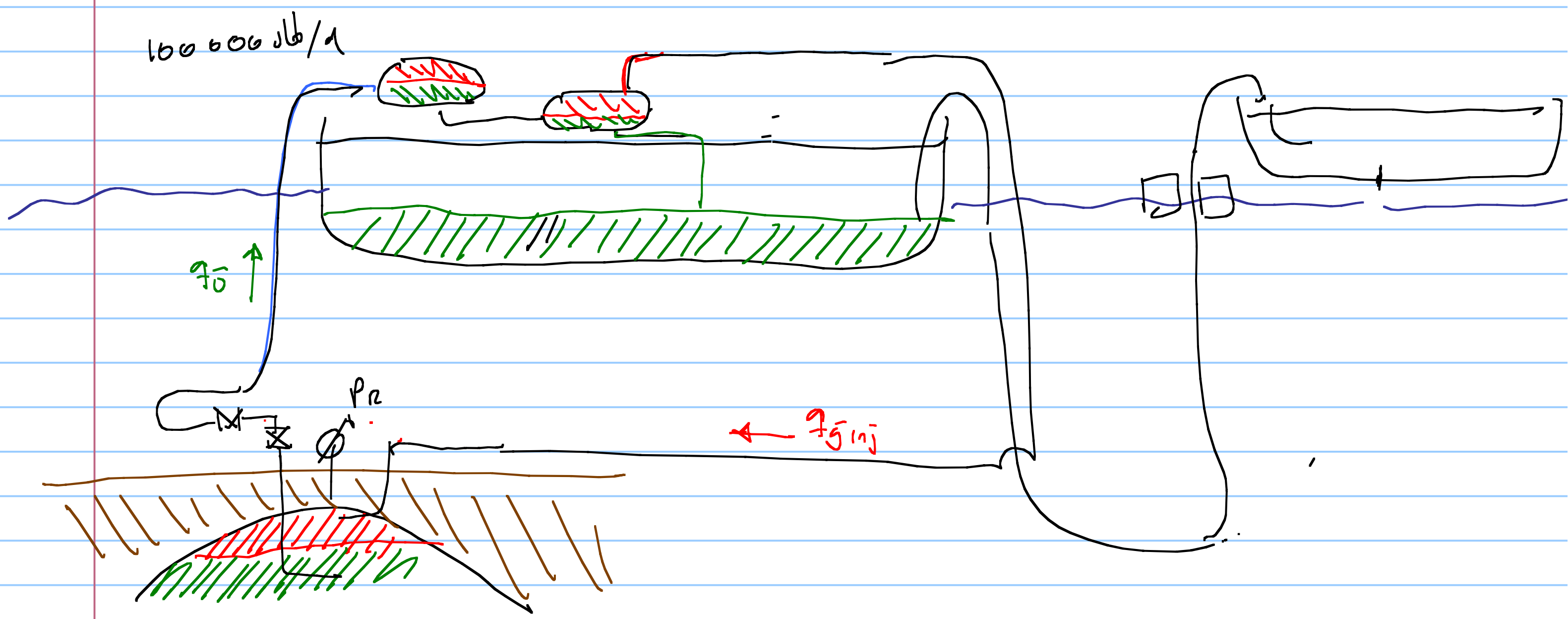
Drillex per well = 120 E6 USD ± 20% accurate

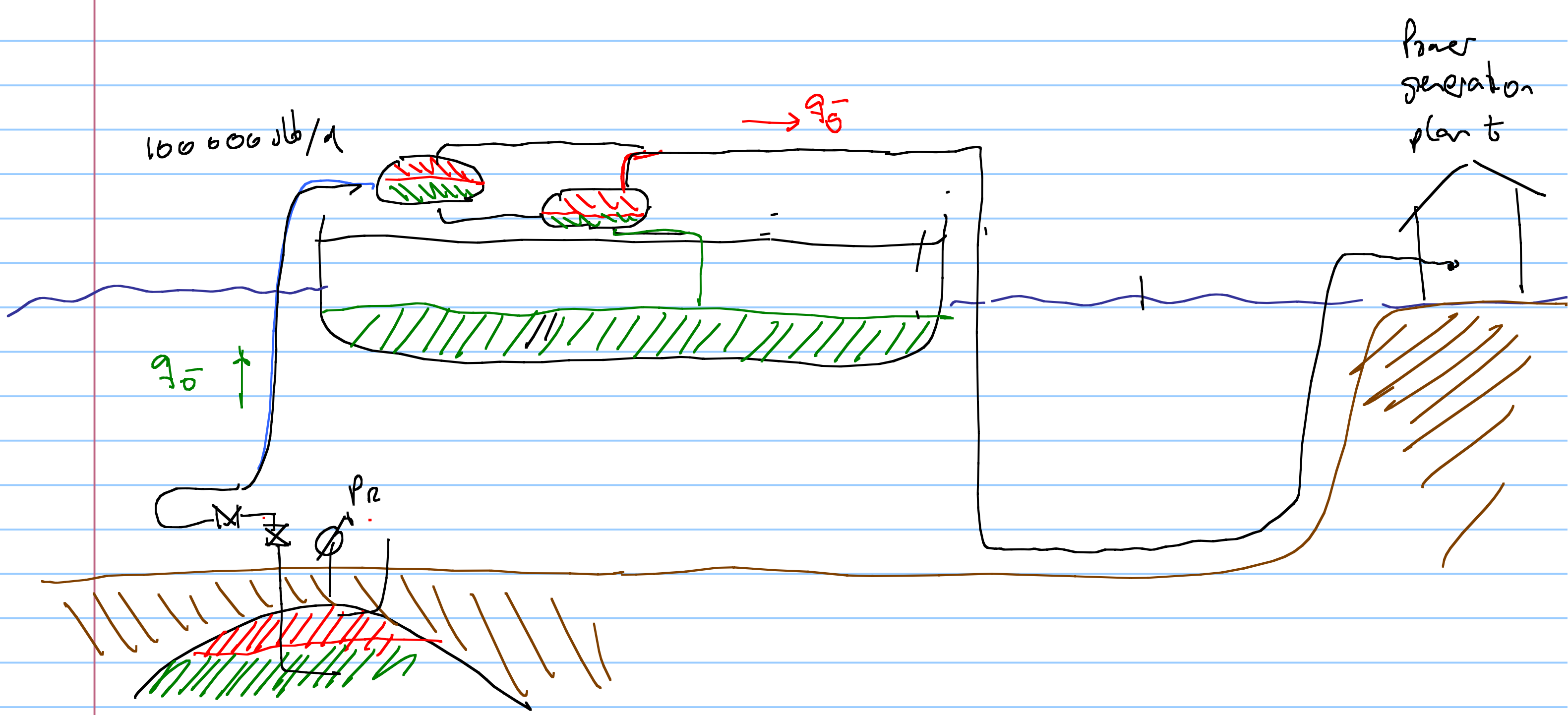
0.8 120E6 USD ≤ Drillex per well ≤ 1.2 . 120E6 USD

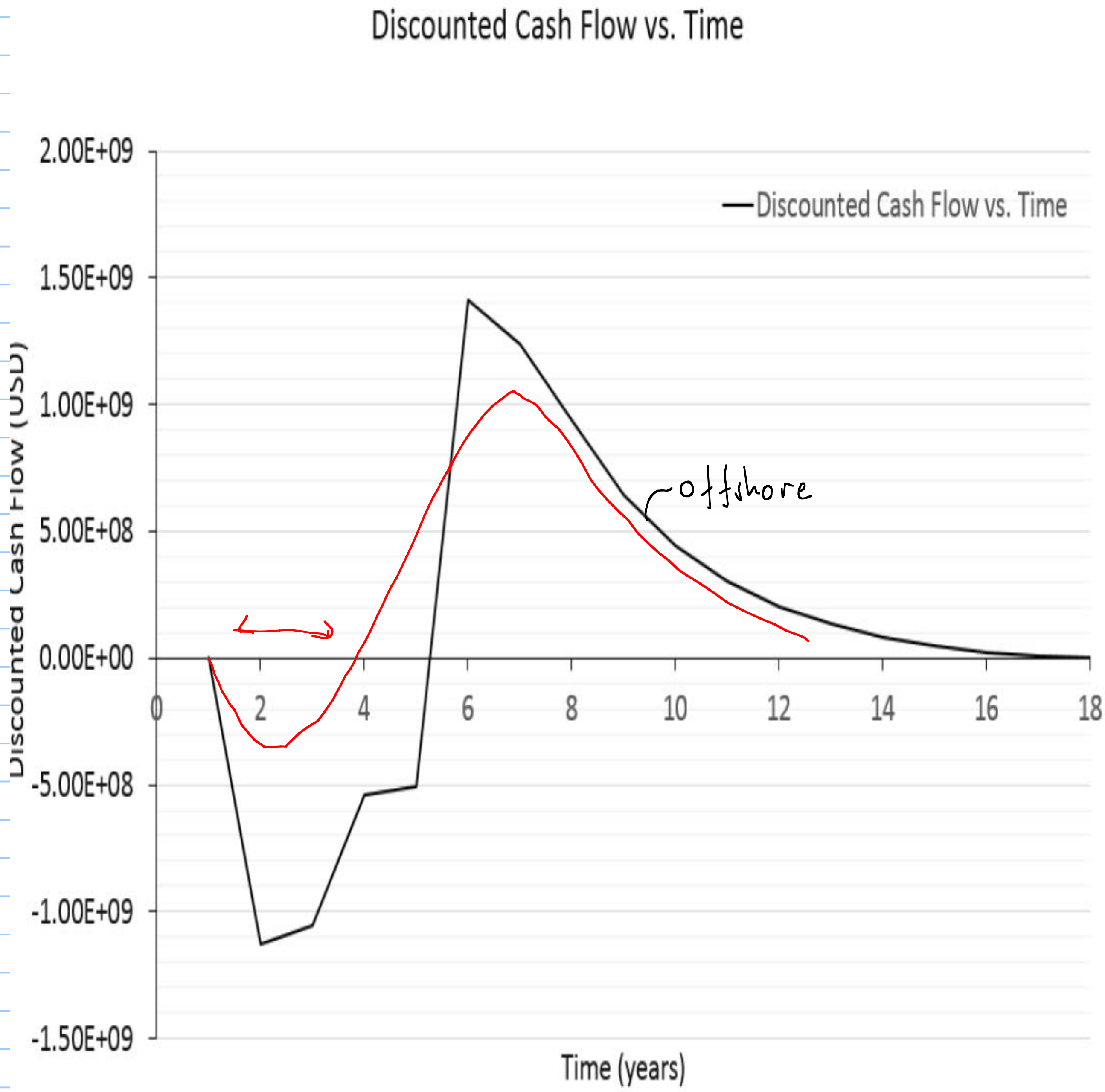
96 USD ≤ ≤ 144 E6 USD

CAPEX = 1.1E6 USD ± 20% accurate

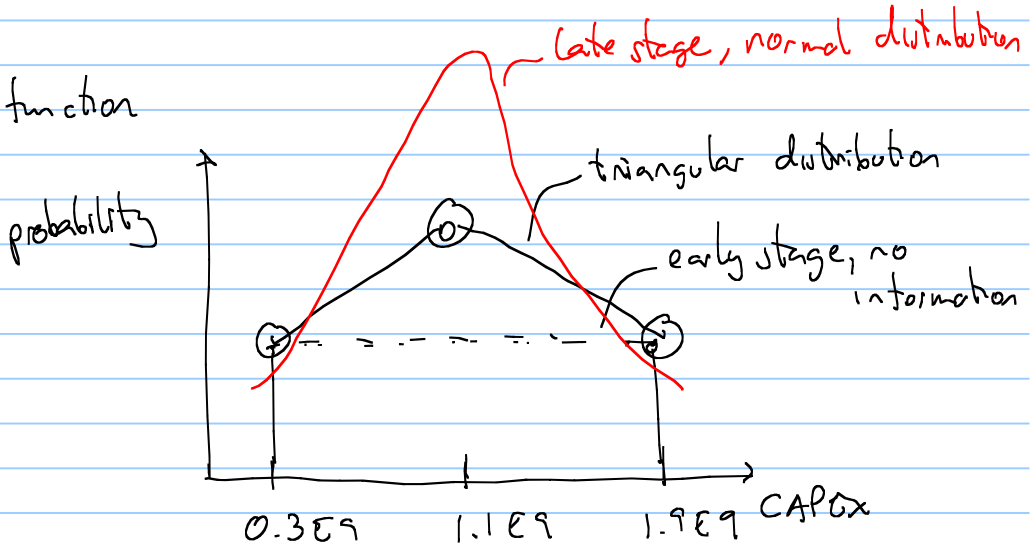
FPSO – floating - production storage offloading







probability distribution function
(pdf)



Class exercise TRR total recoverable reserves

SPE society of petroleum engineers

only one letter must be used for a variable

current time

$$N_p = \int_0^t q_o \, dt$$

when time is t_{final}

$$N_{pu} = \int_0^{t_{final}} q_o \, dt$$

ultimate

$TRR = N_{pu}$

recovery factor

$$RF = \frac{N_{pu}}{N}$$

is a very important number to know when developing a field

SPE nomenclature $F_{RU} = \frac{N_{pu}}{N}$

value of field $N_{pu} \cdot$ oil price

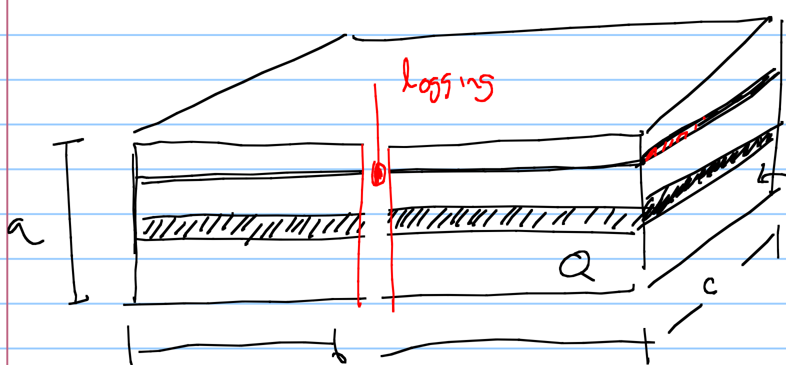
example $N_{pu} = 100$ E6 stb

Value of field $= 100$ E6 $\cdot$ 60 $\frac{USD}{bbl}$

$= 6$ E9 USD

We are in phase feasibility studies

we already have some information about the reservoir



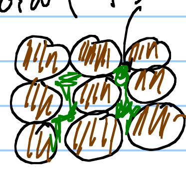
$$N_{pu} = F_{Ru} \cdot N$$

volume of oil

$$N = \underbrace{V_R \cdot \phi}_{\text{volume occupied by fluid } (V_f)} \cdot S_o \cdot (N/G) \ldots$$

if reservoir is rectangular then

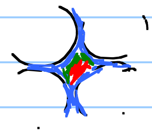
$V_R = a \cdot b \cdot c$



ϕ = porosity = $\dfrac{\text{Pore volume}}{\text{rock volume}}$

10% — 30%

water wet rock



saturation = $S = \dfrac{\text{volume occupied by phase}}{\text{fluid volume}}$ oil / gas / water

S_o only oil = 1 → 100%

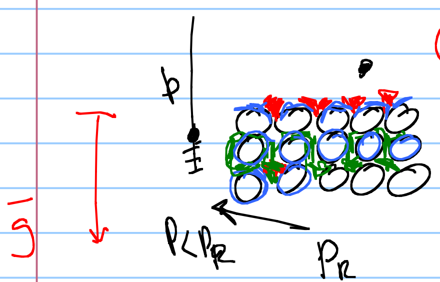
0 — 0%

if in the reservoir i have only oil and water

0.8 + 0.2

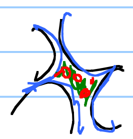
$$S_o + S_w = 1$$

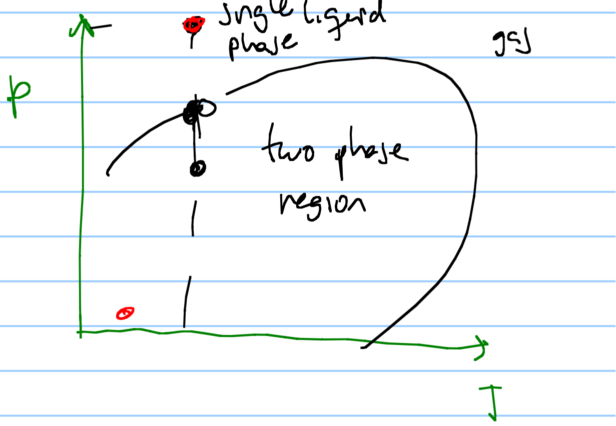
$$\frac{V_o + V_w}{V_f} = 1 \qquad \underbrace{\frac{V_o}{V_f}}_{S_o} + \underbrace{\frac{V_w}{V_f}}_{S_w} = 1$$



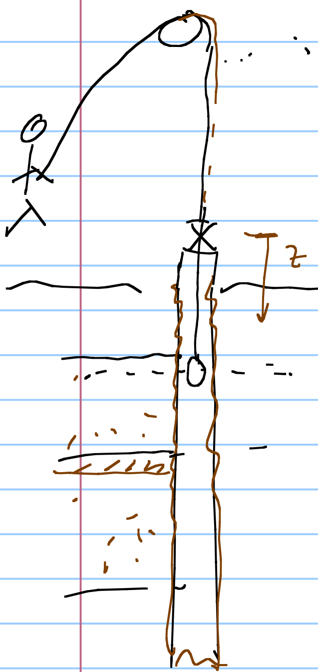
$S_o = 0$

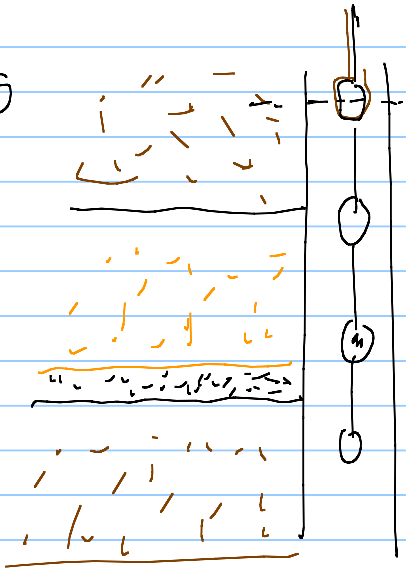
$S_g = 0$

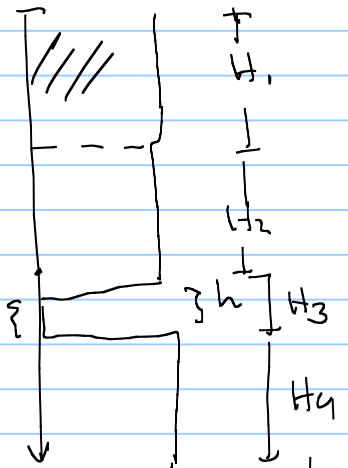




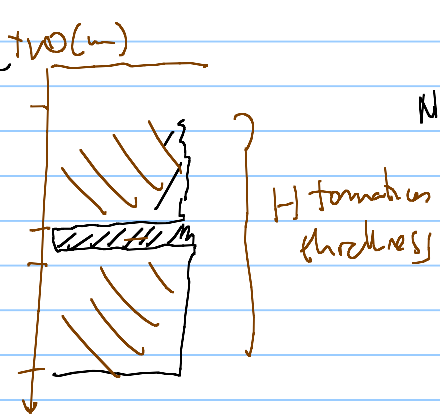
by well logging







TVD true vertical depth
(measured from surface



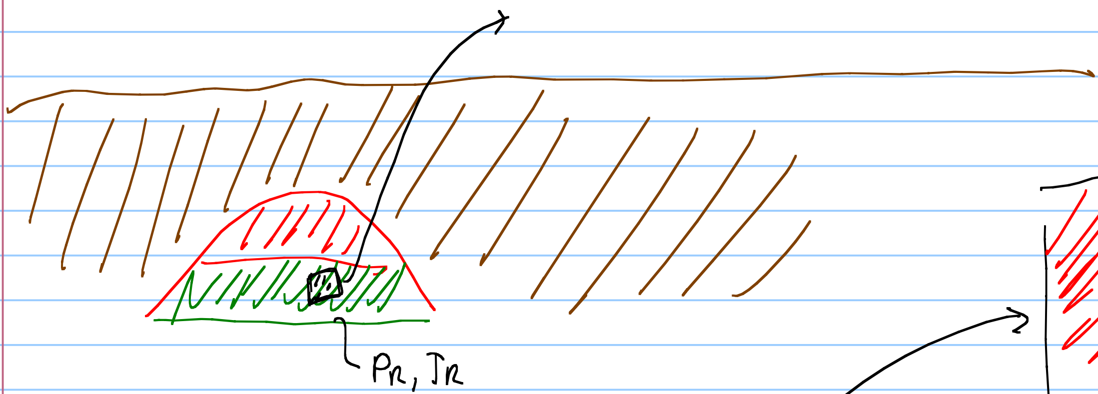
Net to gross = (N/G)

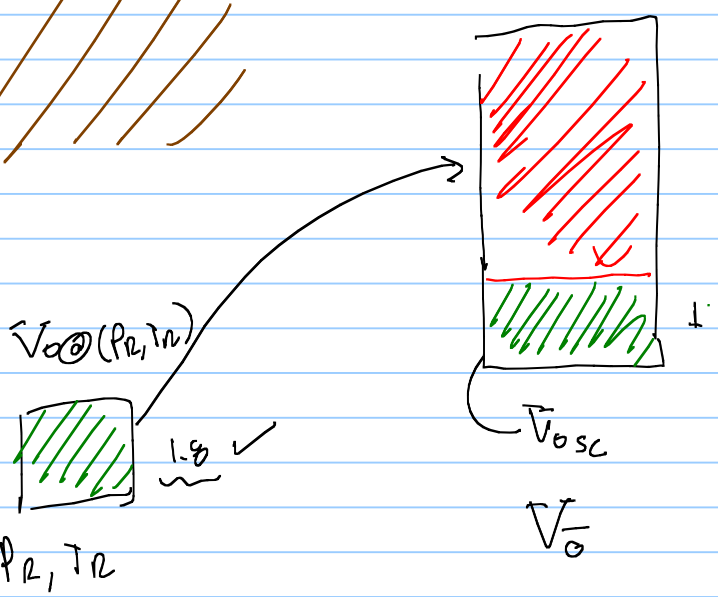
$$\left(\frac{N}{G}\right) = \frac{H_1 + H_2 + H_4}{H_1 + H_2 + H_3 + H_4}$$

$$N = \underbrace{V_R \cdot \phi \cdot S_o}_{\text{volume of oil}} \cdot (N/G) \ \infty \ \circ \ \circ$$

this oil volume is in the reservoir

surface conditions ~ 15.56 °C T_{sc}
1.01325 bara P_{sc}





API ≃ 8-10 API 40

oil formation volume factor $B_o = \frac{V_{o@(P_R,T_R)}}{\bar{V_o}} = 1.05 \rightarrow 1.8$

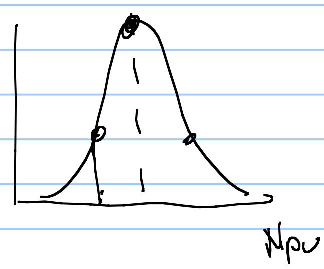
$V_{o@P_R,T_R} = \underbrace{V_R \cdot \phi \cdot S_o}_{\text{volume of oil}} \cdot (N/G)$

$\bar{V_o}$?

$\bar{V_o} = \frac{V_{o@P_R,T_R}}{B_o}$

$N = \frac{V_R \cdot \phi \cdot S_o \, (N/G)}{B_o}$

$TRR = N_{pu} = N \cdot F_{RU} = \frac{V_R \cdot \phi \cdot S_o \, (N/G)}{B_o} \cdot F_{RU}$

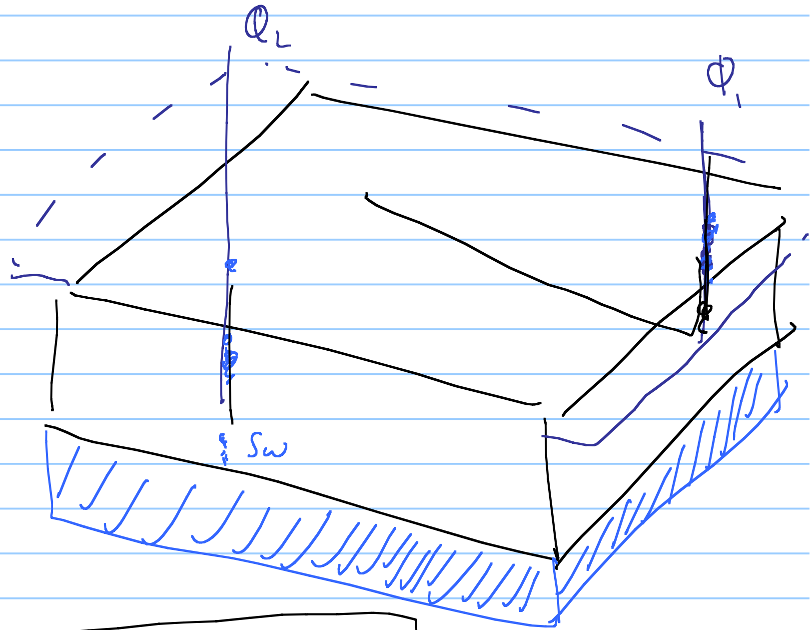


$N_{pu} \cdot$ Oil price

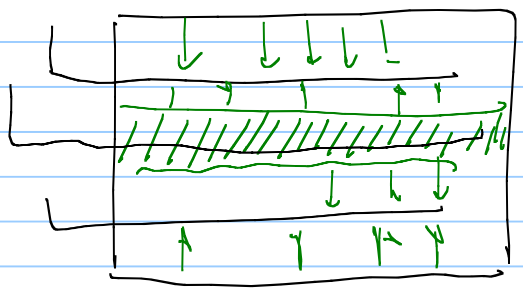
most uncertain

$\frac{V_R \quad \phi \quad S_o \quad (N/G) \quad F_{RU}}{B_o}$

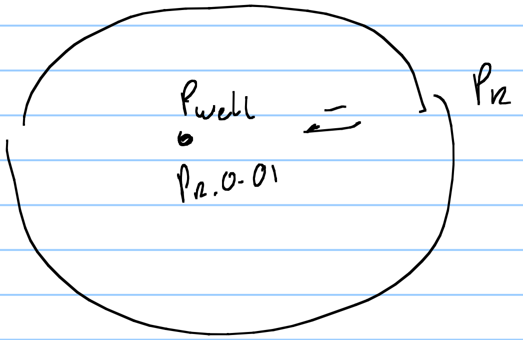
depends on many things
- well number
- well type



reservoir from top

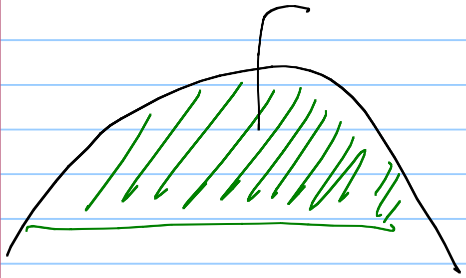


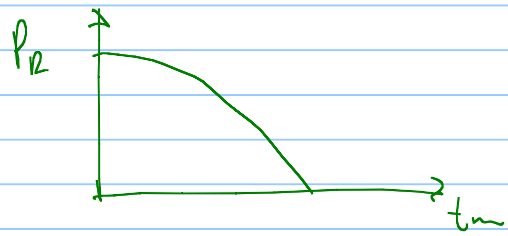
- formation properties   K permeability   K { 10 Darcy → … 1E-9 darcy ←



- fluid properties (oil viscosity)

- Pressure support of reservoir.

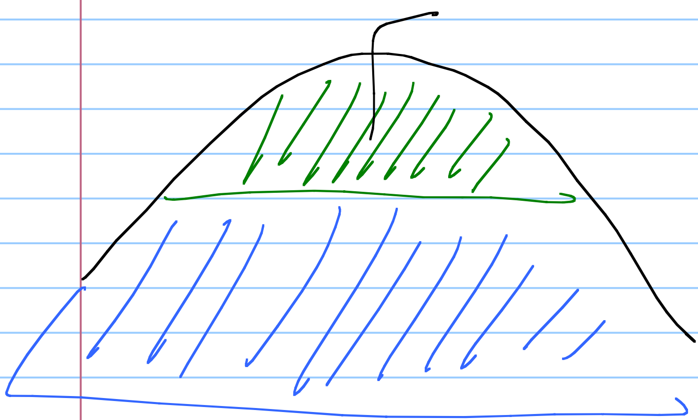


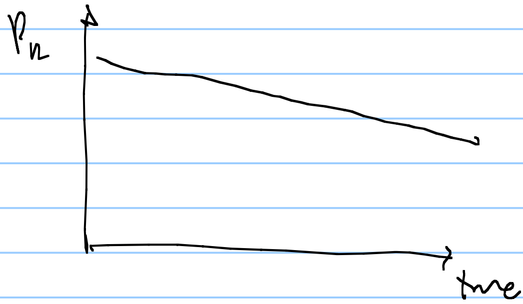


Natural pressure support { gas expansion / aquifer support

artificial EOR { water injection / gas injection

enhanced oil recovery



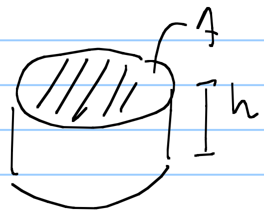


$$q_{well} \propto (P_R - P_{well})$$

Uncertainties in IOIP Estimation

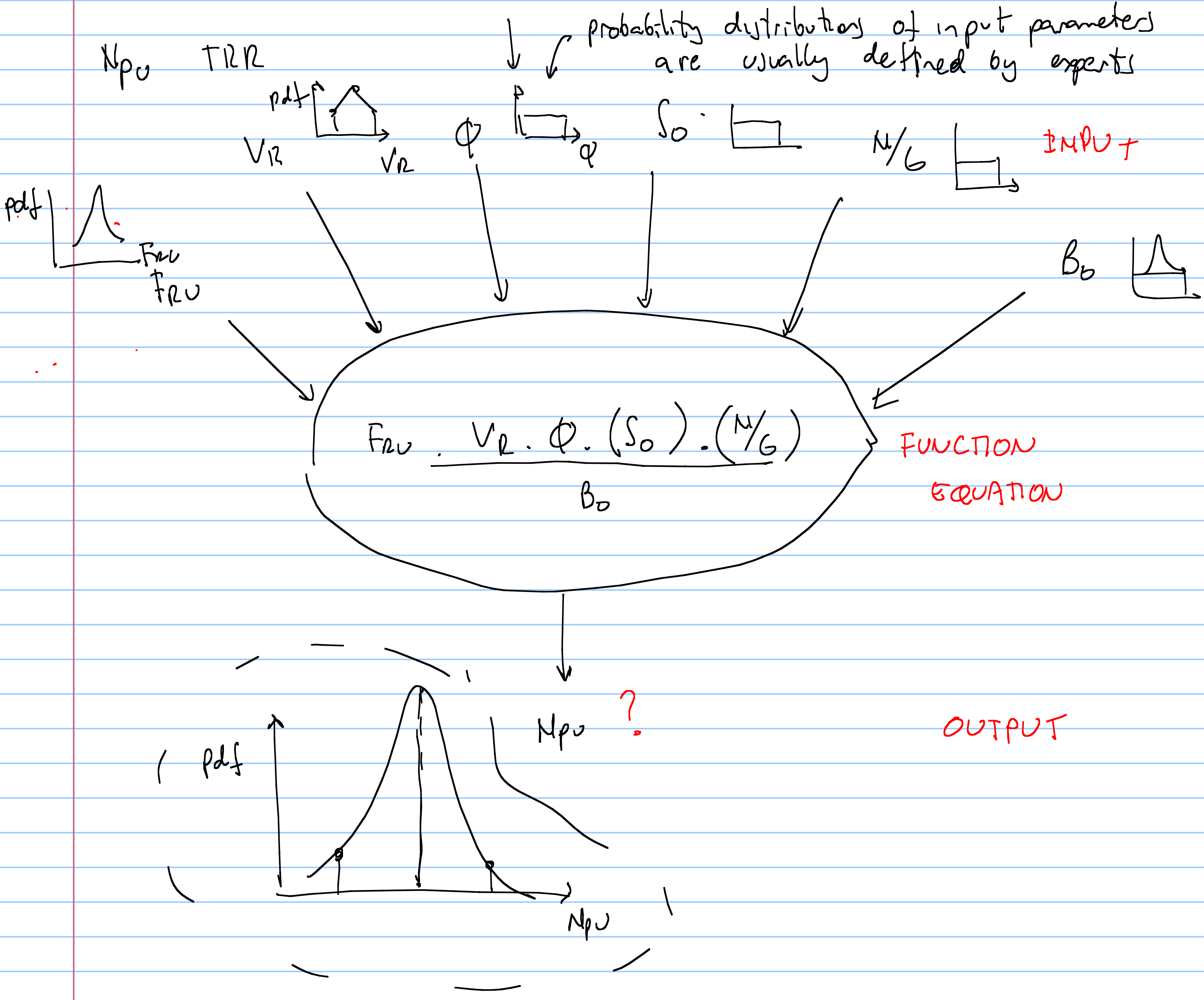
$V_R = a \cdot b \cdot c$

$V_R = A \cdot h$



Factor	Typical source of estimate	Approximate range of expected accuracy (%)
Area	drill holes	± 10–20
	geophysical data	± 10–20
	regional geology	± 50–80
	cores	± 5–10
Pay thickness	logs	± 10–20
	drilling time records and samples	± 20–40
	regional geology	± 40–60
Porosity	cores	± 5–10
	logs	± 10–20
	production data	± 10–20
	drill cuttings	± 20–40
	correlations	± 30–50
Interstitial water saturation	capillary pressure data	± 5–15
	oil base cores	± 5–15
	saturation logs	± 10–25
	routine cores with adjustments	± 25–50
	correlations	± 25–60
Formation volume factor	pressure volume temperature analysis of fluid samples	± 5–10
	correlation	± 10–30

- **Recovery factor, F_R depends on:**
  - Permeability and Permeability distribution
  - Relative permeability characteristics
  - Drive mechanism
  - Pressure support, displacement and sweep efficiency
  - Reservoir architecture-continuity, shape, layering, fault blocks
  - Reservoir anisotropy
  - Reservoir fluid properties
  - Well placement. Number of wells
  - Artificial lift
  - Minimum economical field rate



Monte Carlo → Los Álamos

Stanislaw Ulam

JOURNAL OF THE AMERICAN STATISTICAL ASSOCIATION

Number 247 SEPTEMBER 1949 *Volume 44*

THE MONTE CARLO METHOD

NICHOLAS METROPOLIS AND S. ULAM
Los Alamos Laboratory

steps

1) • take a random number for all inputs (has to be in the range)

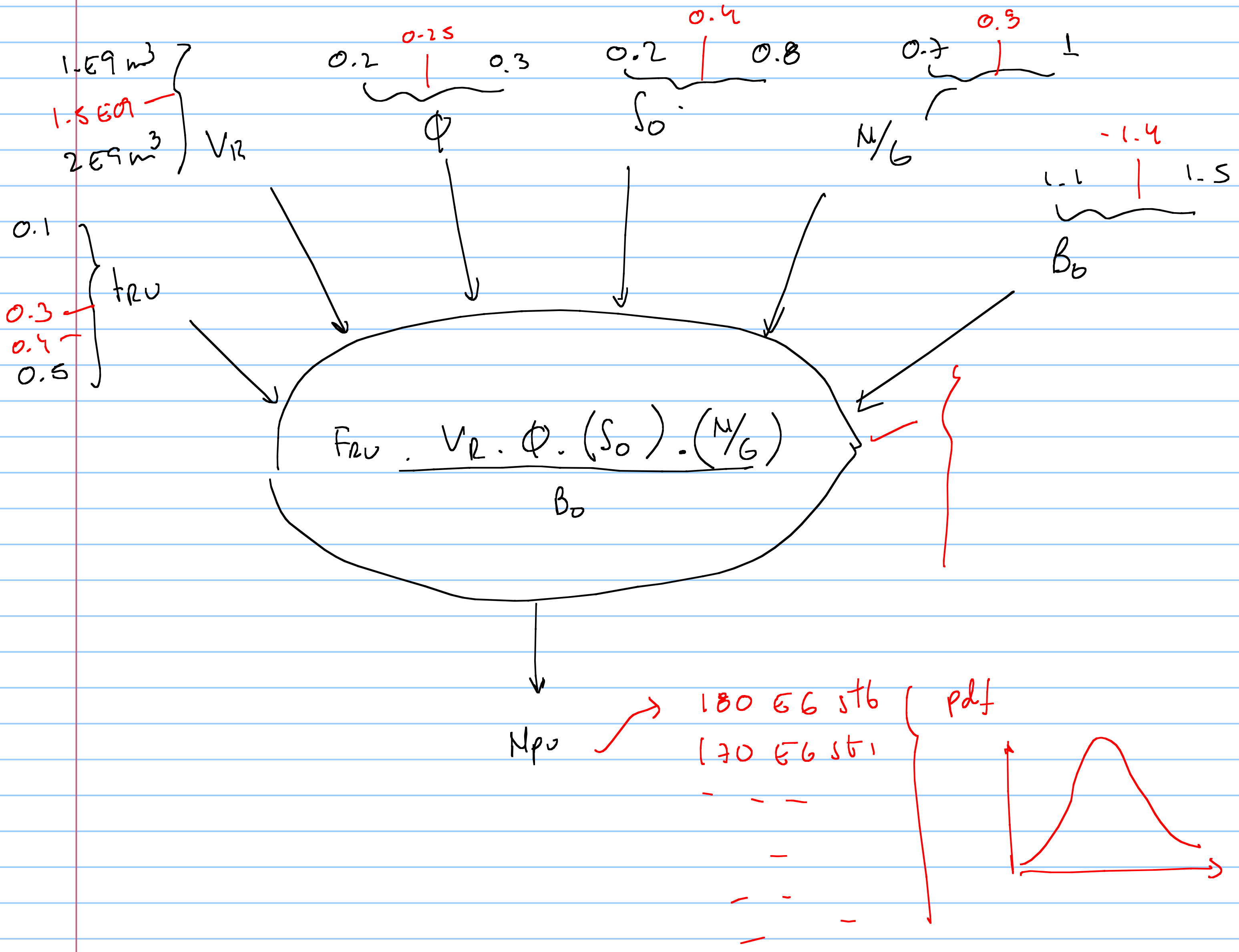
2) • perform the computation of the output variable

3) • save the result

4) • repeat from 1) — the number of iterations depends on the problem

↓ done with iterations

5) calculate the pdf (using frequency analysis) of the output variable



Class exercise : Probabilistic estimation of Total recoverable reserves

	Rock volume	Porosity	Net to Gros N/G	Oil Saturation So=(1-Sw)	Formation Volume Factor Bo	Ultimate Recovery Factor Fr
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction
Min	2000000000	0.18	0.3	0.8	1.35	0.42
Max	2500000000	0.3	0.5	0.9	1.6	0.65

MC iteration	Rock volume bbl	ϕ	N/G	S	Bo	Fr	Npu
1	$\boxed{\cdot}$	$\boxed{}$	$\boxed{}$				$V_R \cdot \phi \cdot N/G \cdot S_o \cdot F_R / B_o$
2							
3							
4							
5							

$= \min + \underbrace{\text{RAND}(\;)}_{\text{gives you a random number } 0-1} \cdot (\max - \min)$

Class example TPG4230, Michael Golan and Milan Stanko							
			Net to Gros	Oil Saturation	Formation Volume	Ultimate Recovery Factor	
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	
Min	2000000000	0.18	0.3	0.8	1.35	0.42	
Max	2500000000	0.3	0.5	0.9	1.6	0.65	
MC it	**Rock volume**	**Porosity**	**N/G**	**So=(1-Sw)**	**Bo**	**Fr**	**Npu**
[-]	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	[stb]
1	2020728372	0.18558	0.3782988	0.860746572	1.567215613	0.588794858	4.59E+07
2	2027103687	0.27871	0.4559073	0.859547478	1.572255682	0.57794969	8.14E+07
3	2244507704	0.22387	0.4309593	0.899014514	1.461948068	0.454182581	6.05E+07
4	2064960527	0.19461	0.3850365	0.846769099	1.458154221	0.421192174	3.78E+07
5	2409265466	0.23786	0.3522728	0.831730977	1.363105188	0.462438723	5.70E+07
6	2174336685	0.2807	0.3836723	0.823121152	1.527348792	0.540170926	6.82E+07
7	2468570171	0.23443	0.3400107	0.804494224	1.358463656	0.603918786	7.04E+07
8	2220185179	0.23463	0.4064523	0.837530278	1.414866359	0.636911743	7.98E+07
9	2329260119	0.21656	0.3356574	0.861782889	1.442495708	0.631760539	6.39E+07

MC it	Npu						
[-]	[stb]		Min [stb]	3.21E+07			
1	5E+07		max [stb]	1.27E+08			
2	8.8E+07						
3	7.1E+07						Npu
4	4.2E+07						stb]
5	7.5E+07					1	3.21E+07
6	5.2E+07					2	
7	1E+08					3	
8	7.4E+07					4	
9	6.1E+07					5	
10	6E+07					6	
11	5.8E+07					7	
12	3.8E+07					8	
13	6.9E+07					9	
14	7E+07					10	
15	7E+07					11	
16	8.1E+07					12	

13

14

15 max

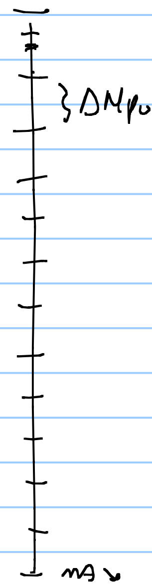
$$\Delta N_{pu} = \frac{max - min}{14} = \frac{\square - \square}{14}$$

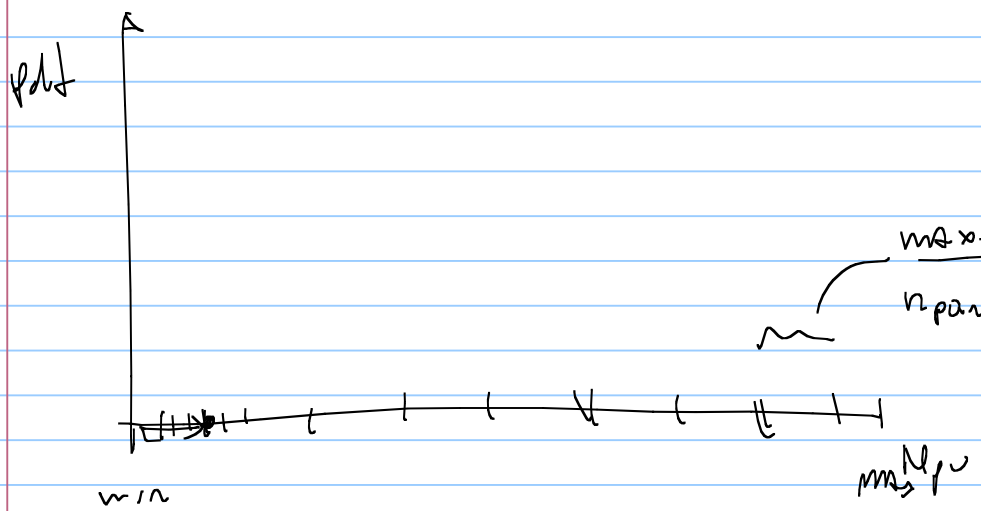
min

$+\Delta N_{pu}$

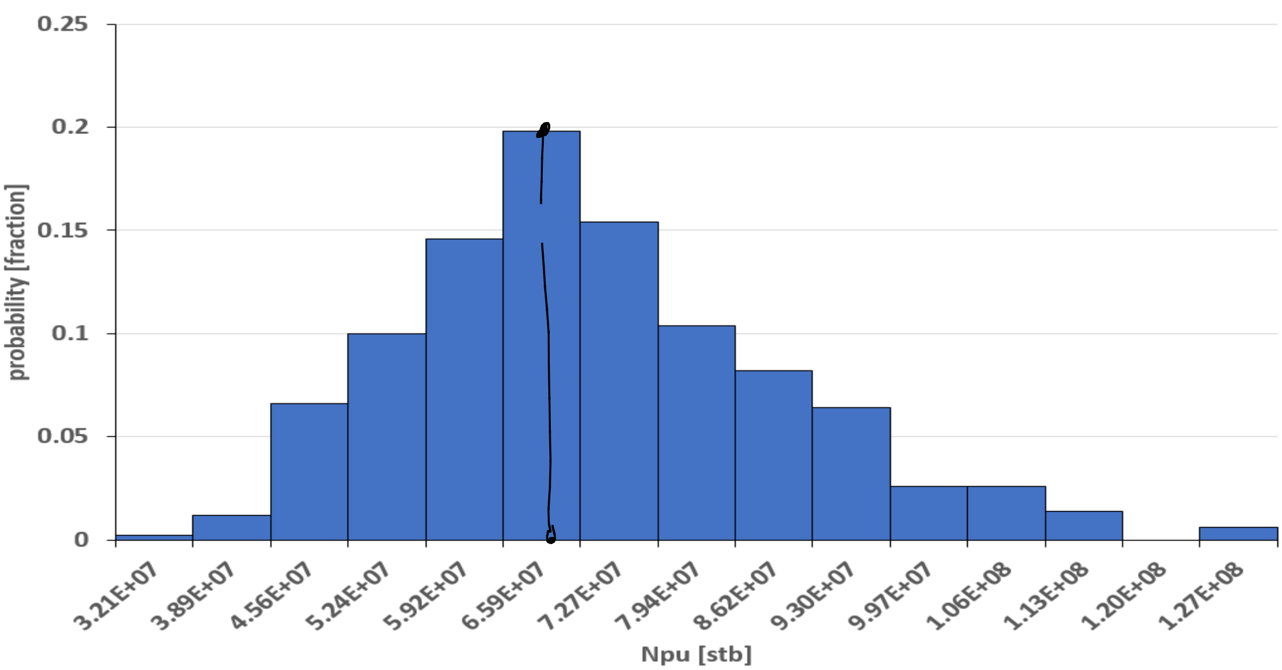
$+\Delta N_{pu}$

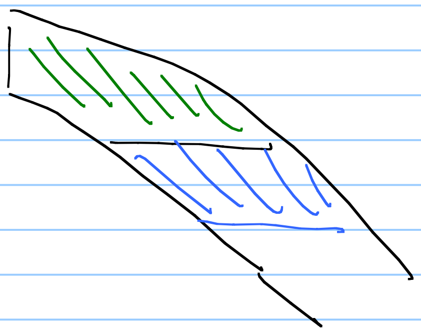
$+\Delta N_{pu}$





$$\frac{max - min}{n_{part} - 1} =$$



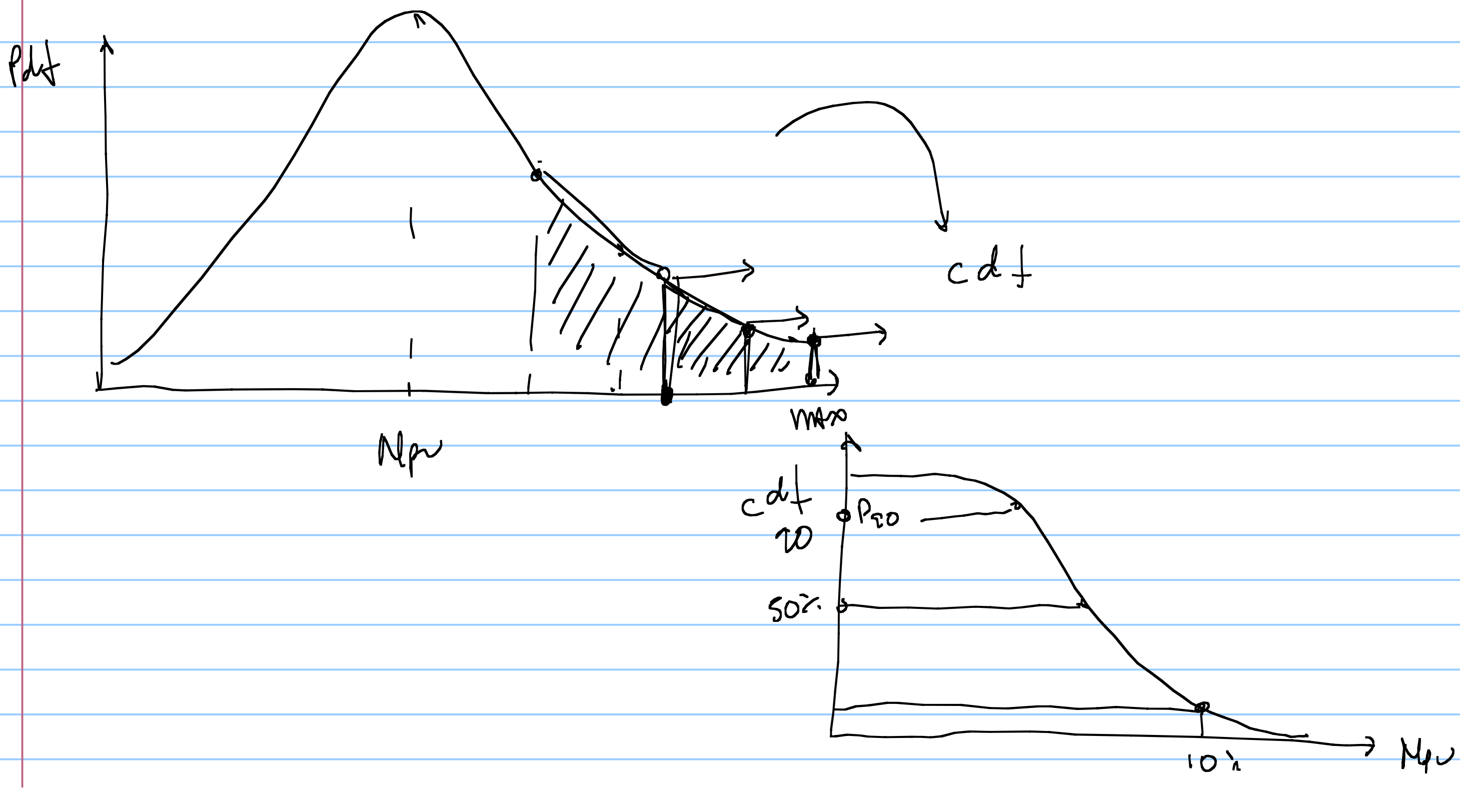


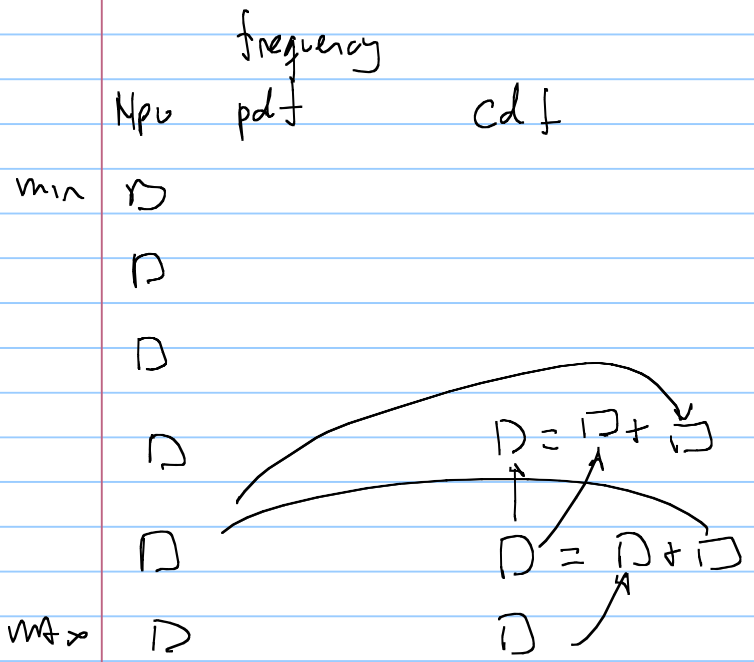
cumulative distribution function (cdf)

- Proven reserves $\underbrace{(100-66\%)}_{\text{depends on country}}$ → P_{90}, P_x — there is 90% probability that reserves are equal or higher than P90

- Proven + probable (60% - 33%) → P_{50} — there is a 50% probability that reserves are equal or higher than P50

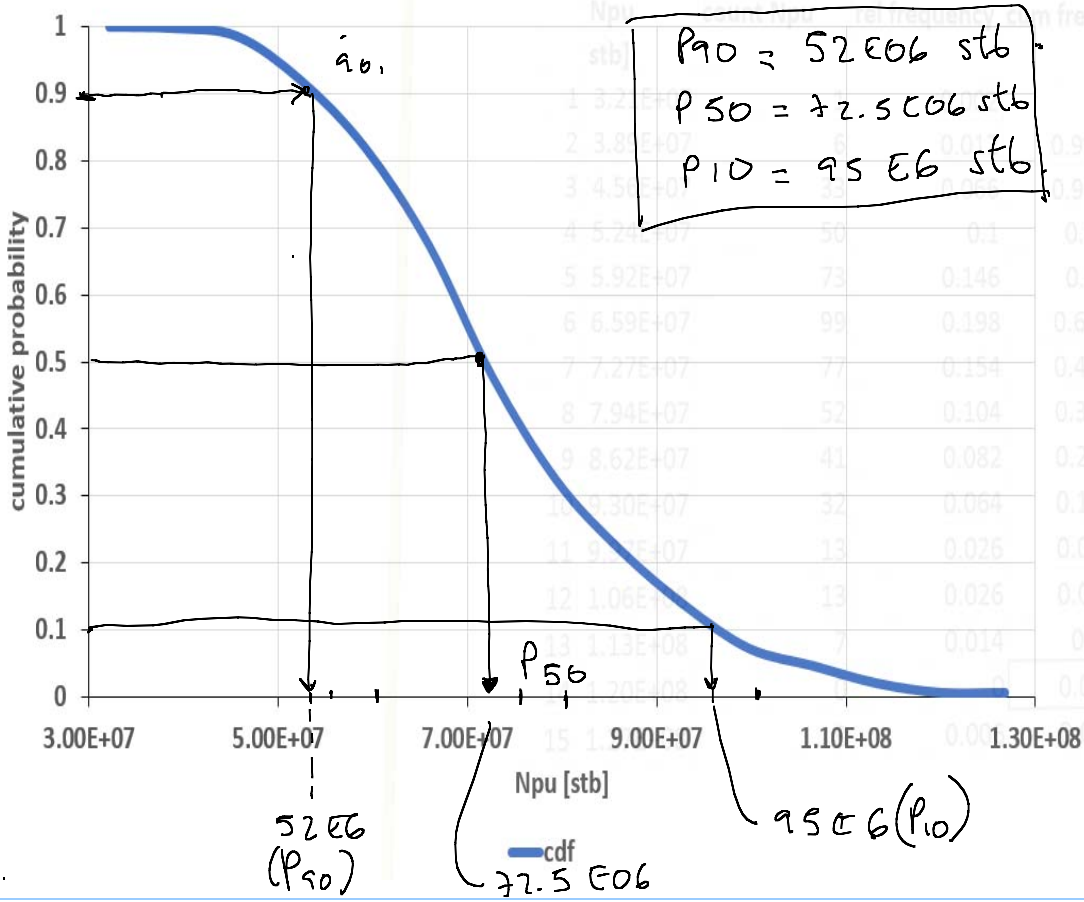
- Proven + Probable + possible (33% - 0%) P_{10} — there is a 10% probability that reserves are equal or higher than P_{10}





cumulative probability function (cpf)
distribution (cpd)

	Npu stb]	count Npu	rel frequency	cum freq
1	3.21E+07	1	0.002	1
2	3.89E+07	6	0.012	0.998
3	4.56E+07	33	0.066	0.986
4	5.24E+07	50	0.1	0.92
5	5.92E+07	73	0.146	0.82
6	6.59E+07	99	0.198	0.674
7	7.27E+07	77	0.154	0.476
8	7.94E+07	52	0.104	0.322
9	8.62E+07	41	0.082	0.218
10	9.30E+07	32	0.064	0.136
11	9.97E+07	13	0.026	0.072
12	1.06E+08	13	0.026	0.046
13	1.13E+08	7	0.014	0.02
14	1.20E+08	0	0	0.006
15	1.27E+08	3	0.006	0.006



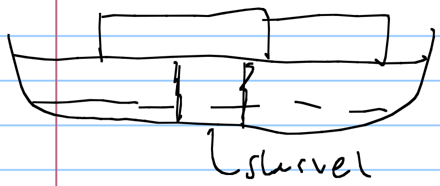
$$\boxed{\begin{array}{l} P90 = 52E06\ stb \\ P50 = 72.5E06\ stb \\ P10 = 95\ E6\ stb \end{array}}$$

Homework repeat calculations with 2000 iterations

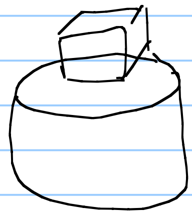
—— // ——

What happens when dealing with choices:
- which platform?
- well configuration on the seabed
- drill or not?

FPSO (regular)

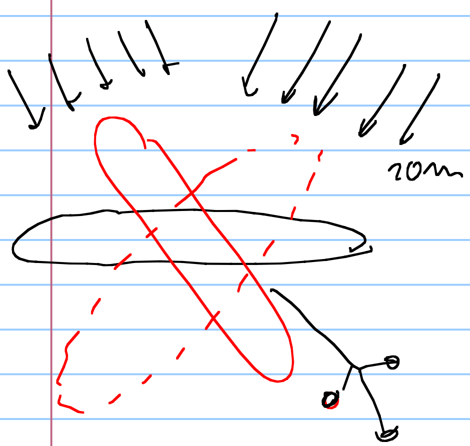


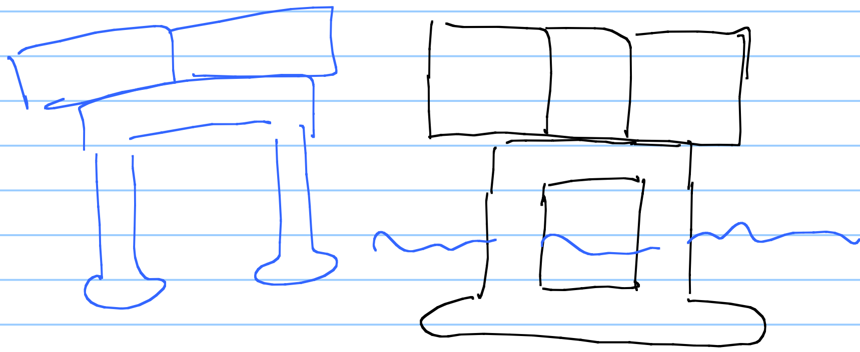
Sevan

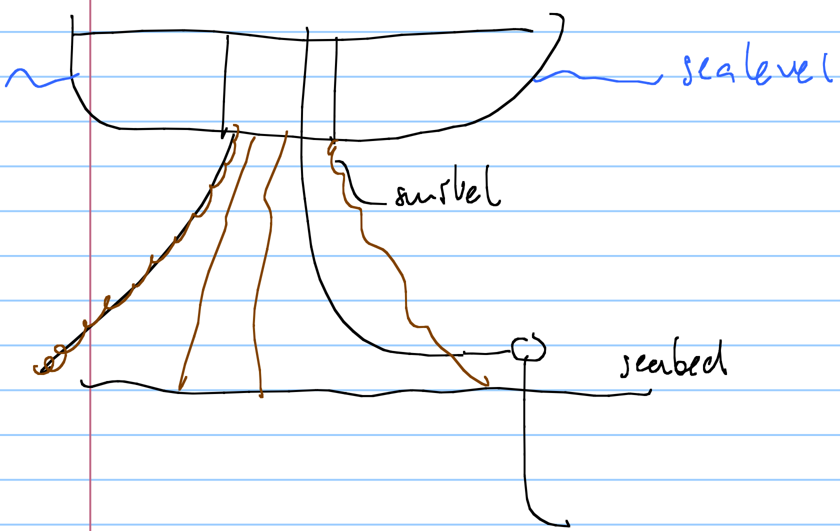


semi submersible

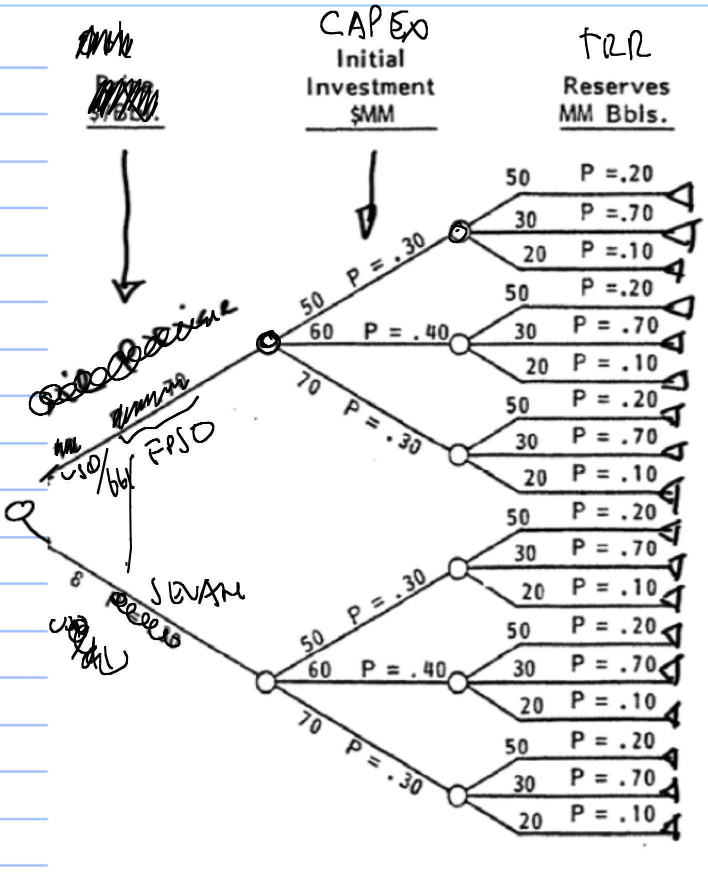
view from above







decision tree – probability tree



Case	Prob.	NPV	NPV x Prob.
1	.042	60	2.52
2	.147	15	2.21
3	.021	-10	-0.21
4	.056	53	2.97
5	.196	8	1.57
6	.028	-17	-0.48
7	.042	46	1.93
8	.147	1	0.15
9	.021	-24	-0.50
10	.018	35	0.63
11	.063	0	0.00
12	.009	-20	-0.18
13	.024	28	0.67
14	.084	-7	-0.59
15	.012	-27	-0.32
16	.018	21	-0.38
17	.063	-14	-0.88
18	.009	-35	-0.32
		Weighted Avg. NPV	9.55

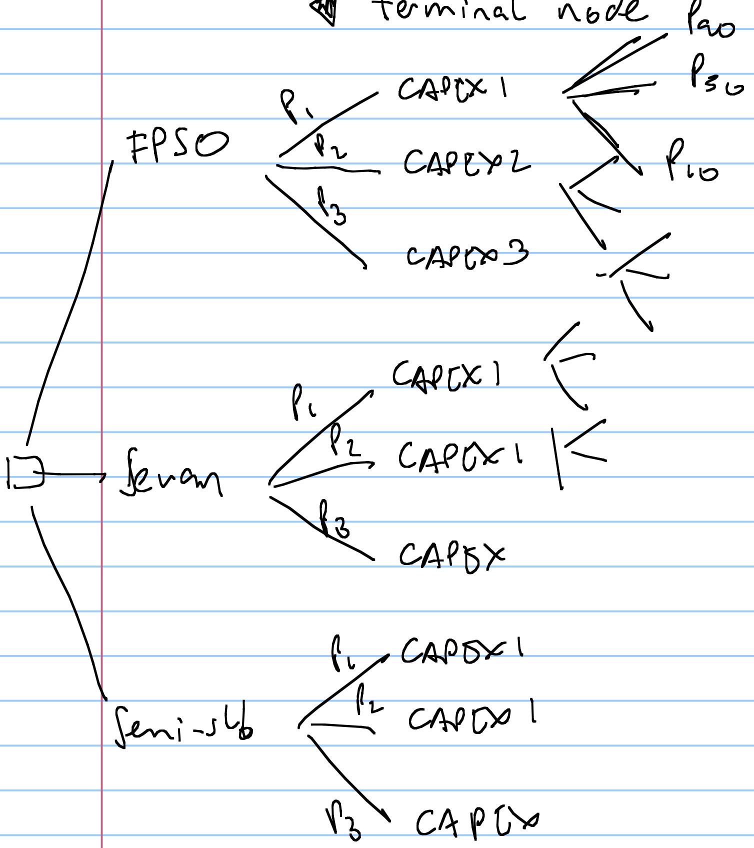
FPSO NPV (cases 1–9)

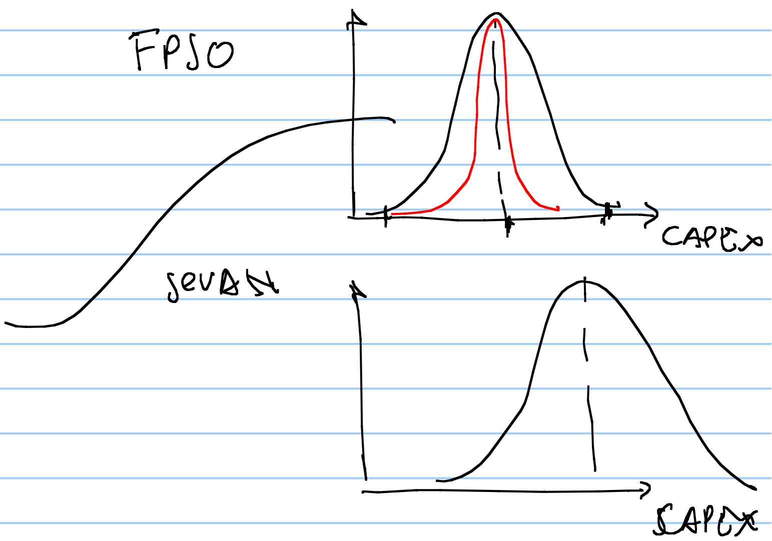
SEVAN NPV (cases 10–18)

decision

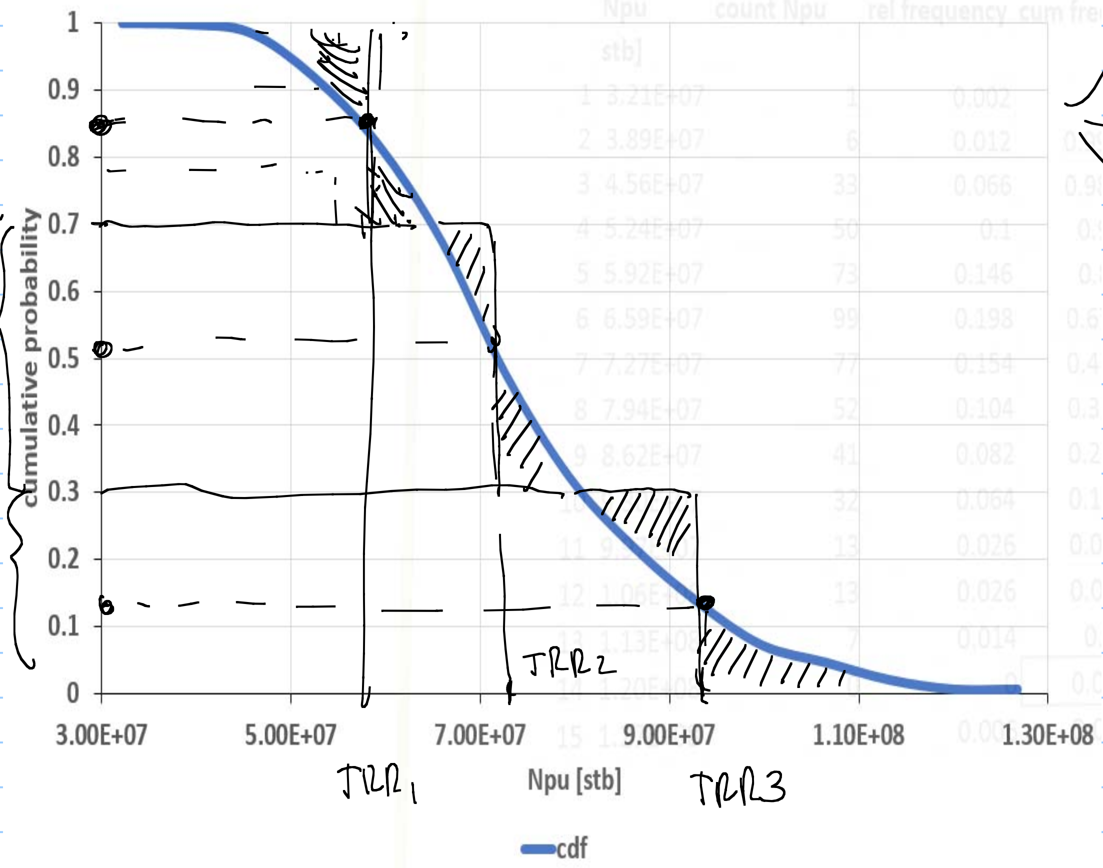
chance node

terminal node





Converting a continuous cdf to discrete



30
P_1 TRR1
P_2 40 TRR2
P_3 30 TRR3

	Probability CAPEX	CAPEX	Probability TRR	TRR	MV	Probability	MV*Prob	
	[-]	[USD]	[-]	[stb]	(USD)	Prob		
Sevan FPSO	0.3	700000000	0.25	1.3E+08	2.3E+09	0.075	1.73E+08	
			0.5	1.7E+08	3.5E+09	0.15	5.18E+08	
			0.25	2.4E+08	4.9E+09	0.075	3.71E+08	
	0.4	1100000000	0.25	1.3E+08	1.9E+09	0.1	1.90E+08	
			0.5	1.7E+08	3.1E+09	0.2	6.10E+08	
			0.25	2.4E+08	4.5E+09	0.1	4.54E+08	
	0.3	1500000000	0.25	1.3E+08	1.5E+09	0.075	1.13E+08	
			0.5	1.7E+08	2.7E+09	0.15	3.98E+08	
			0.25	2.4E+08	4.1E+09	0.075	3.11E+08	3.14E+09
FPSO	0.3	500000000	0.25	1.3E+08	2.5E+09	0.075	1.88E+08	
			0.5	1.7E+08	3.7E+09	0.15	5.48E+08	
			0.25	2.4E+08	5.1E+09	0.075	3.86E+08	
	0.4	800000000	0.25	1.3E+08	2.2E+09	0.1	2.20E+08	
			0.5	1.7E+08	3.4E+09	0.2	6.70E+08	
			0.25	2.4E+08	4.8E+09	0.1	4.84E+08	
	0.3	1300000000	0.25	1.3E+08	1.7E+09	0.075	1.28E+08	
			0.5	1.7E+08	2.9E+09	0.15	4.28E+08	
			0.25	2.4E+08	4.3E+09	0.075	3.26E+08	3.38E+09
Semi-sub	0.3	600000000	0.25	1.3E+08	2.4E+09	0.075	1.80E+08	
			0.5	1.7E+08	3.6E+09	0.15	5.33E+08	
			0.25	2.4E+08	5E+09	0.075	3.78E+08	
	0.4	900000000	0.25	1.3E+08	2.1E+09	0.1	2.10E+08	
			0.5	1.7E+08	3.3E+09	0.2	6.50E+08	
			0.25	2.4E+08	4.7E+09	0.1	4.74E+08	
	0.3	1400000000	0.25	1.3E+08	1.6E+09	0.075	1.20E+08	
			0.5	1.7E+08	2.8E+09	0.15	4.13E+08	
			0.25	2.4E+08	4.2E+09	0.075	3.18E+08	3.28E+09

27 cases

3.38 E9 USD

Day 3

- Brief: cash flow in field project
- Brief: petroleum fiscal systems
- Offshore structures for hydrocarbon production. Selecting criteria
- marine loads ~> wave statistics ~> marine environment
- Production scheduling
- Flow equilibrium

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Name	Last modified	Size	Description
Parent Directory		-	
Class_files/	2017-04-04 08:05	-	
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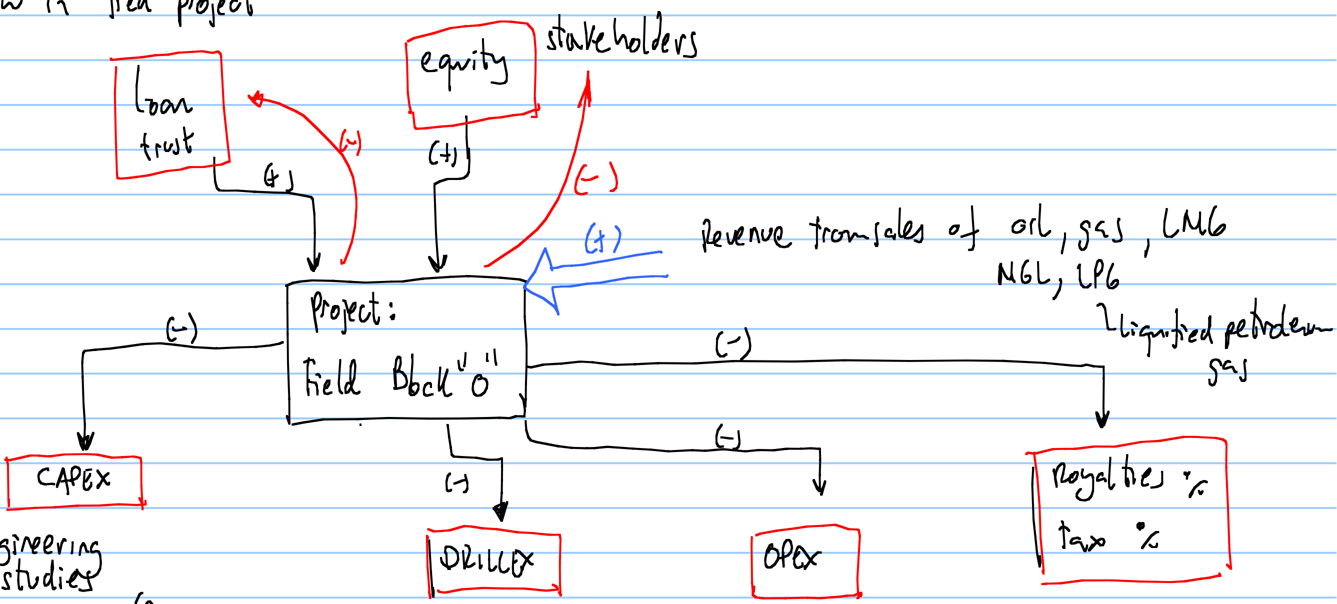
Exercises/	2017-04-07 11:14	-	
Notes/	2017-04-21 15:47	-	
Previous_years/	2017-03-22 13:49	-	
TPG4230_emnerapport.pdf	2017-06-01 09:20	1.4M	
Videos/	2017-04-07 11:16	-	

http://folk.ntnu.no/stanko/Courses/TPG4230

old exams

Cash flow in field project



CAPEX
- engineering studies
- facilities
  - Processing
  - Living quarters
  - auxiliary services
- offshore structure
- subsea system
- pipeline
- installation

DRILLEX
- Daily rig rate
- well completion
- well services
  - wireline
  - coiled-tubing

OPEX
- salary
- insurance
- energy consumption
- maintenance
- chemicals
  - corrosion
  - emulsion
  - scale
  - hydrate
- processing
- transport
- well intervention
- well stimulation

In almost every place the government is the owner of resources <u>EXCEPT</u> mainland US.

Petroleum fiscal systems / schemes

- **Concessionary system** royalty
  - based on production license Norway (30 years)
  - Pay a royalty based on gross sales and pay Tax
- **contractual system**
  - **service contract**: fee for producing the field
  - **PSC production sharing contract**: get a share of production. the government can manage the field

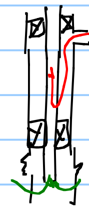
HC Sales
→ (−) royalty [%]
↓
NET REVENUE
→ (−) costs
→ OPEX
→ depreciation amortization
↓
TAXABLE INCOME
→ (−) TAX
↓
NET INCOME

HC production
→ (−) royalty
↓
NET PRODUCTION
→ (−) operating cost and obligations
↓
PROFIT PRODUCTION
→ % PARTNER 1 → (−) TAX → NET INCOME
→ % PARTNER 2
→ % government

Offshore structures for HC production

typically includes:

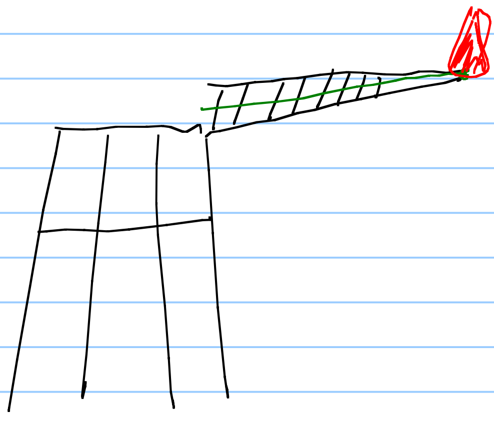
- manifolds to commingle production
- control valves
- processing facilities
  - separators
  - heat exchanger
  - scrubber (separators for high gas fraction)
  - pumps
  - compressor
  - coolers
  - skimmer
  - hydrocyclones
  - water separation system
- gas injection system
- water injection system
- Power generation (diesel engine, gas turbine)
- fire alarm system
- living quarters
- repair workshop
- control system
- gas-lift injection system



- well intervention system
  - light intervention
    - wireline
    - coil tubing
- drilling package
  - rig

USD ↑↑

- Helideck
- flare

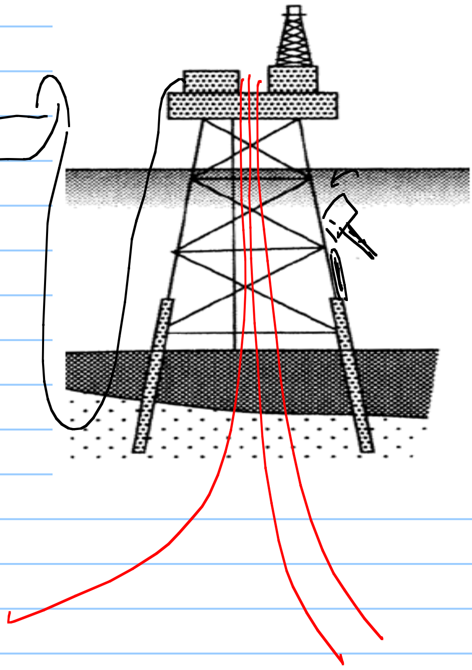


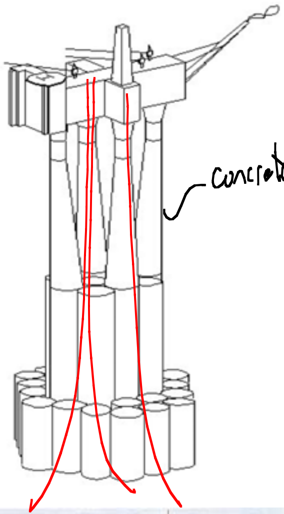
- oil storage
- utility system
  - water, air, ventilation
  - heating

platform

GBS
gravity based
structure

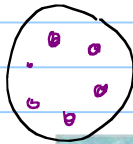
Bottom
supported
weight is laid
on seabed



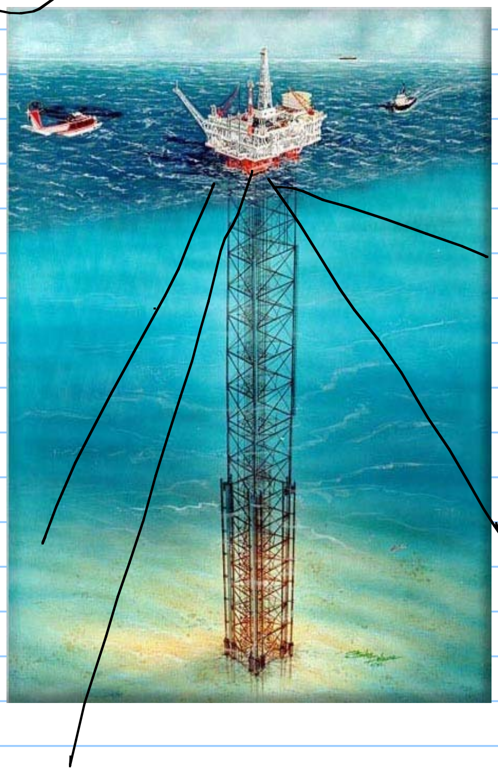


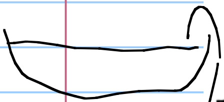
concrete

storage of
oil
water



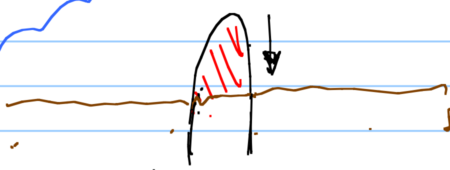
Compliant
tower





seabed

suction anchor



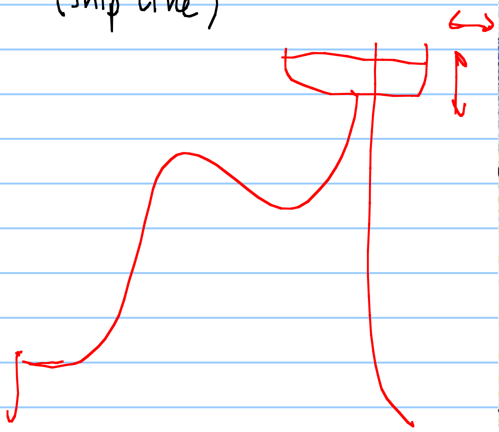
seabed

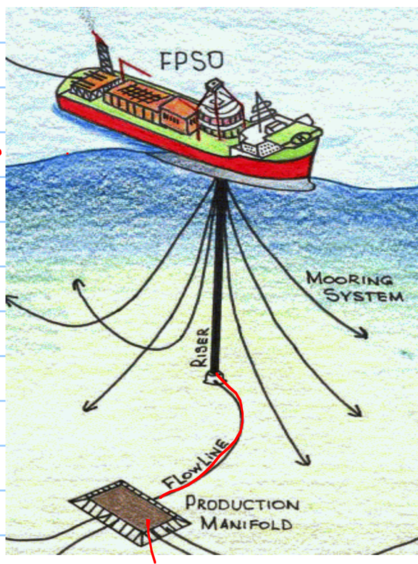
suction anchor

floating
structures

neutrally
naturally bouyant
(ship line)

FPSO





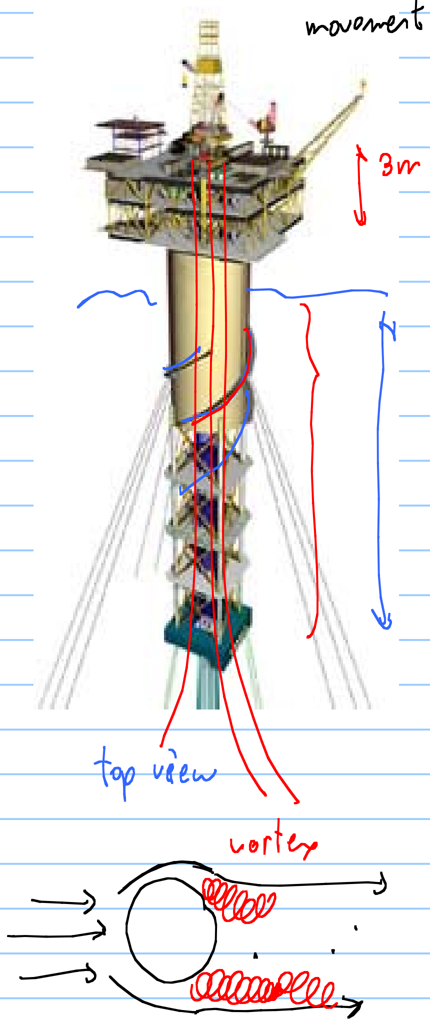
storage ~ 3000000 stb

Sevan FPSO

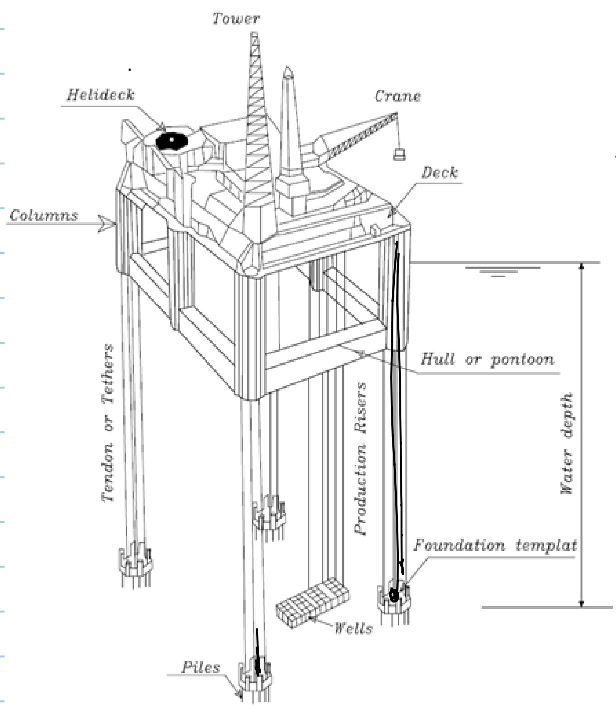
semi-submersible

SPAR

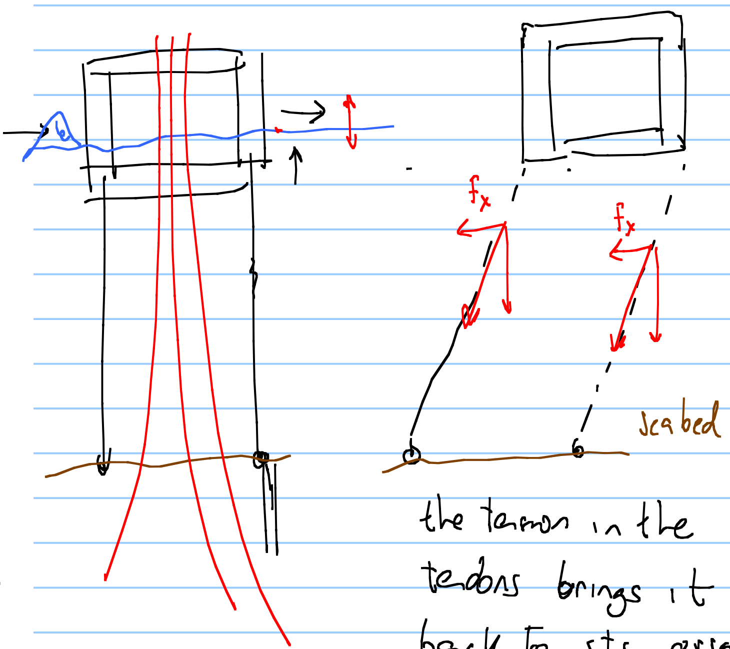
reduced vertical movement



positively bouyant Tension leg platform TLP



Limited vertical movement.

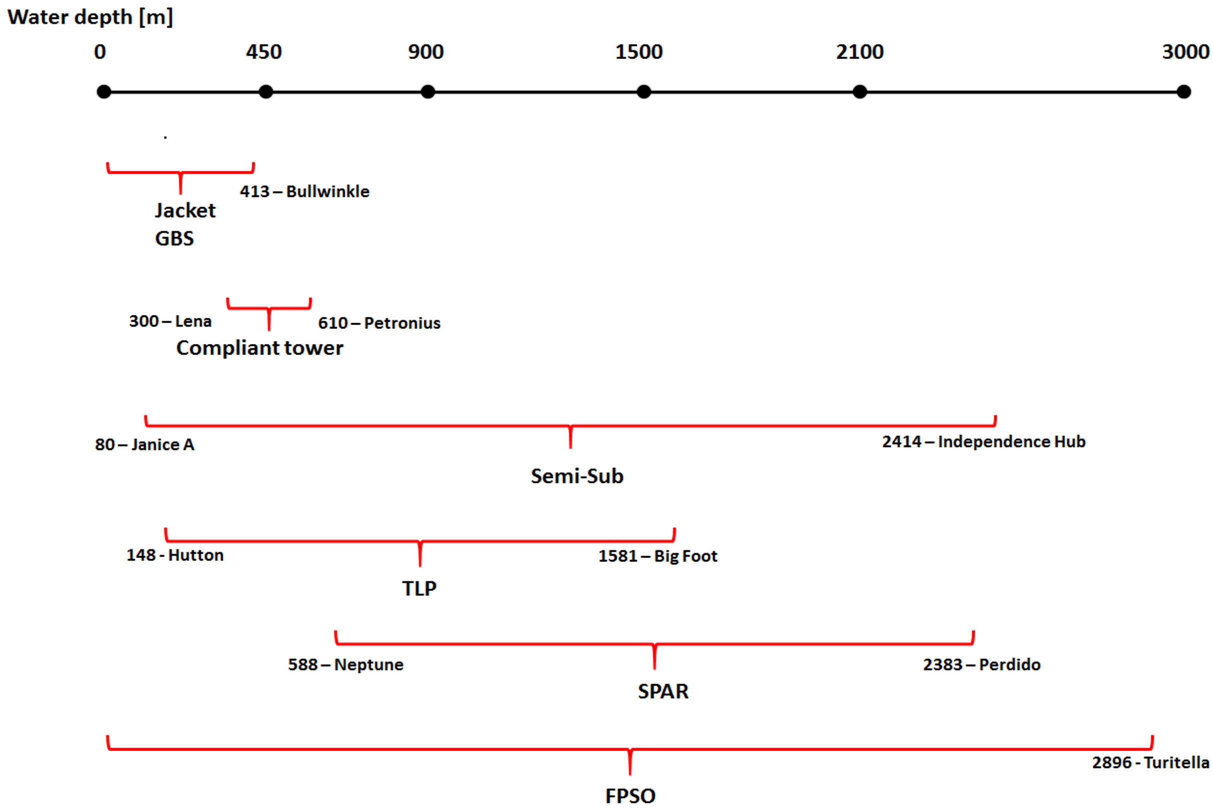


the tension in the tendons brings it back to its original place.

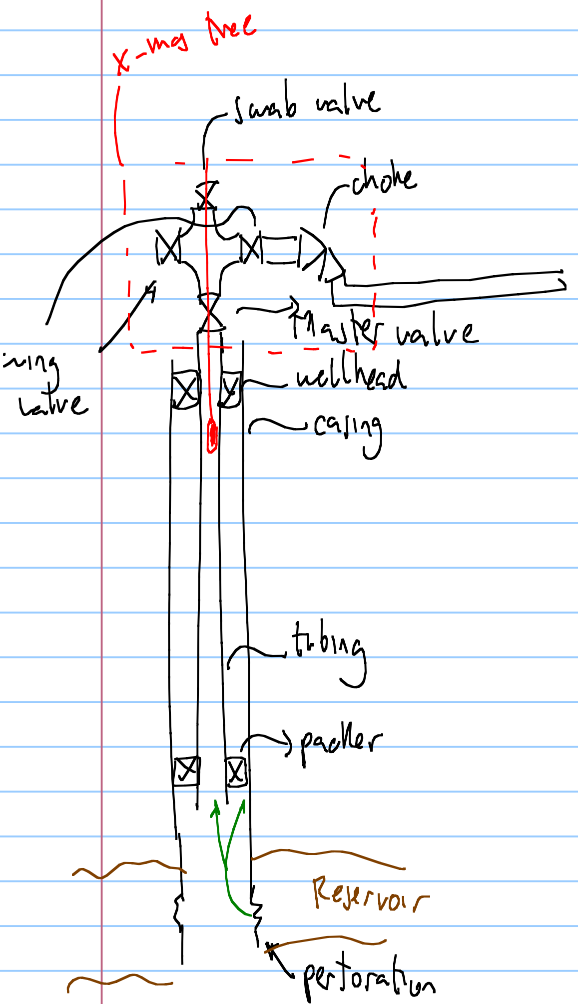
TLP

Selection criteria: shallow or not too deep 0 → 450m → bottom supported structures

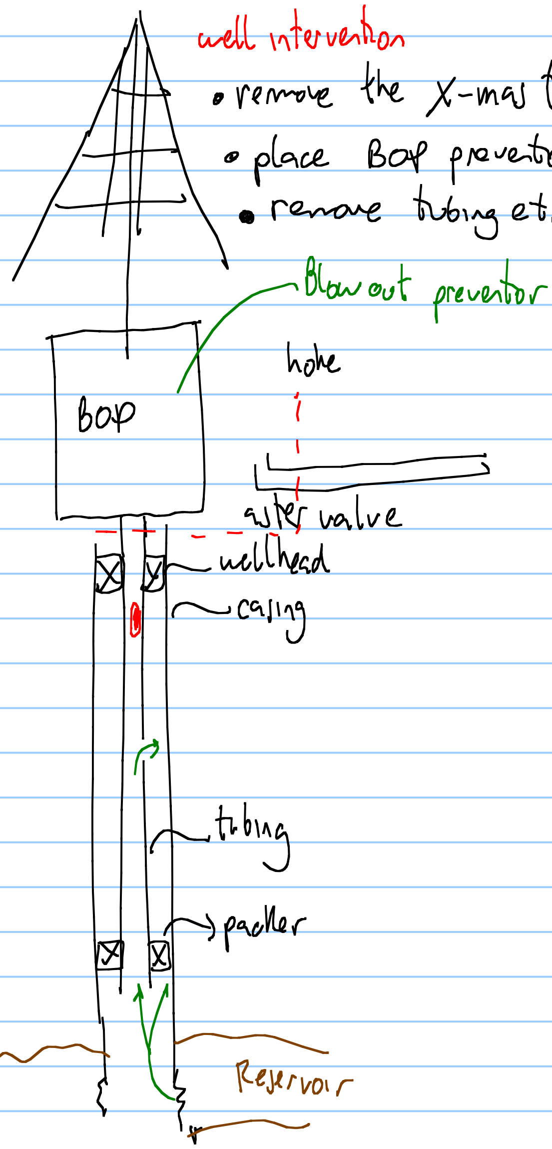
deep 500m → 2900m → floating

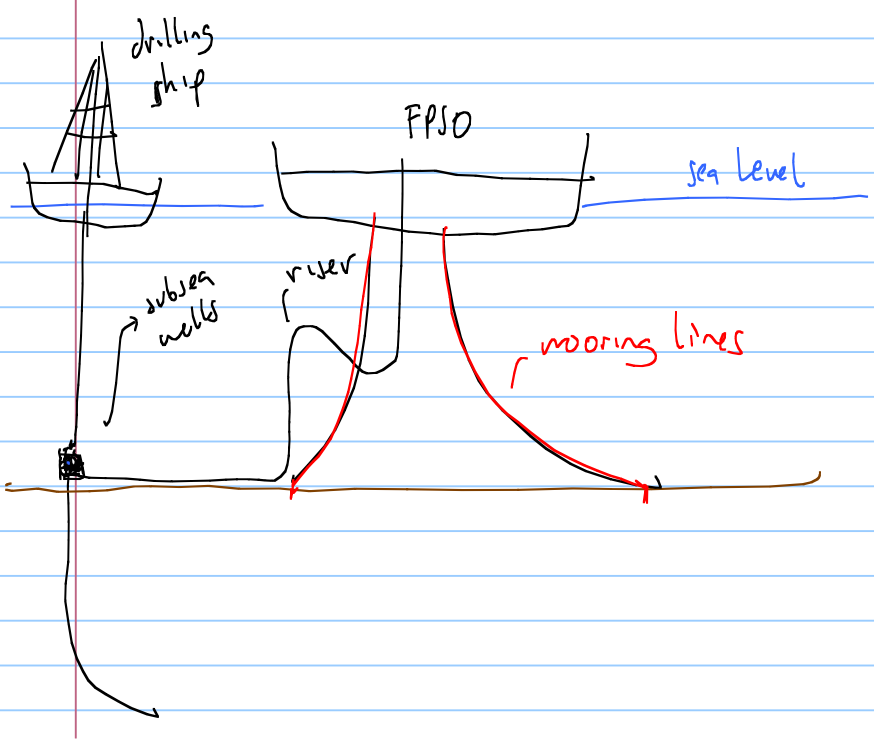


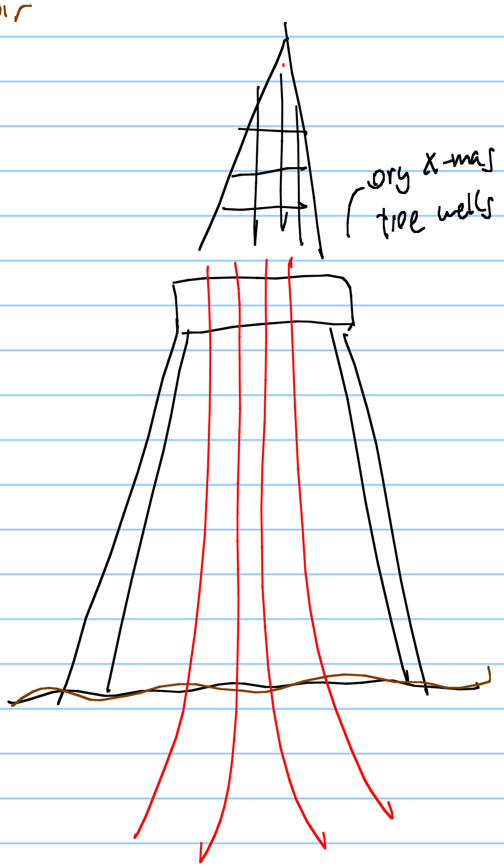
Type of well ⇝ Dry X-mas tree on the deck
wet X-mas tree (subsea)



well intervention
- remove the X-mas tree
- place BOP preventor
- remove tubing etc...





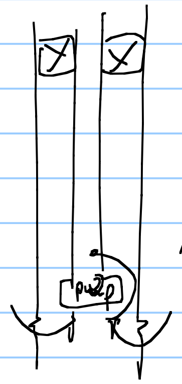


Dry X-mas trees ⤳ only on platform, GBS, compliant tower, SPAR, TLP

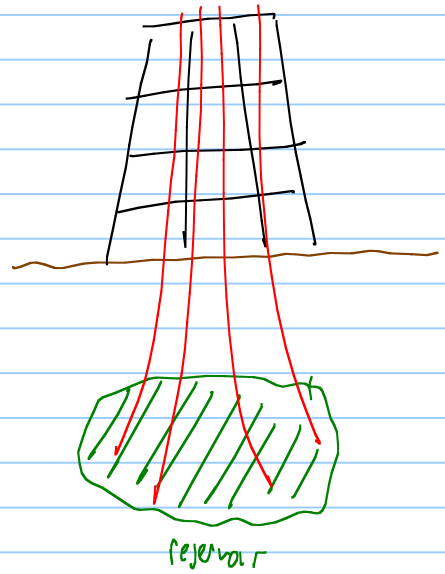
wet X-mas trees ⤳ FPSO, Sevan, Semi-sub

- Intervention frequency required by well   in subsea well ≈ 5 years

  wells with pump ⤳ Dry X-mas tree

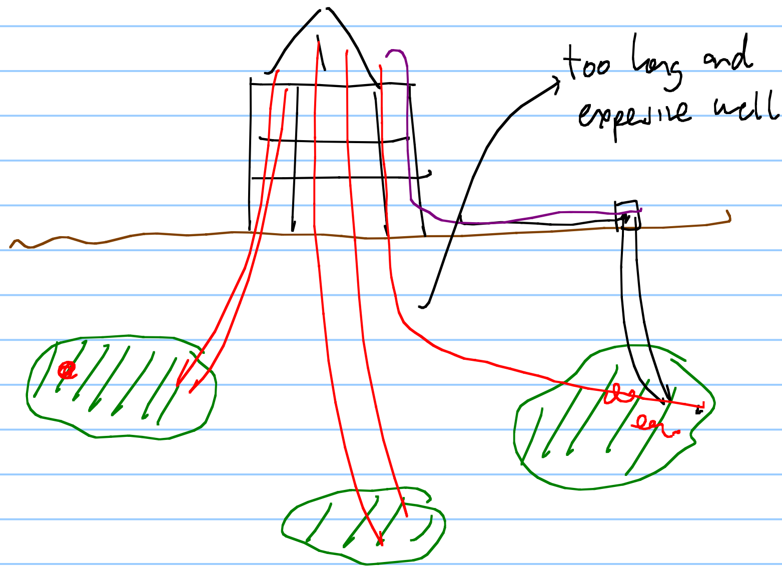


lifetime of pump 2 years

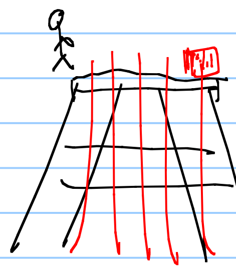


- Structure of reservoir → concentrated

→ spread



- Offshore structures for Dry X-mas trees have limited space on deck to perform infill drilling



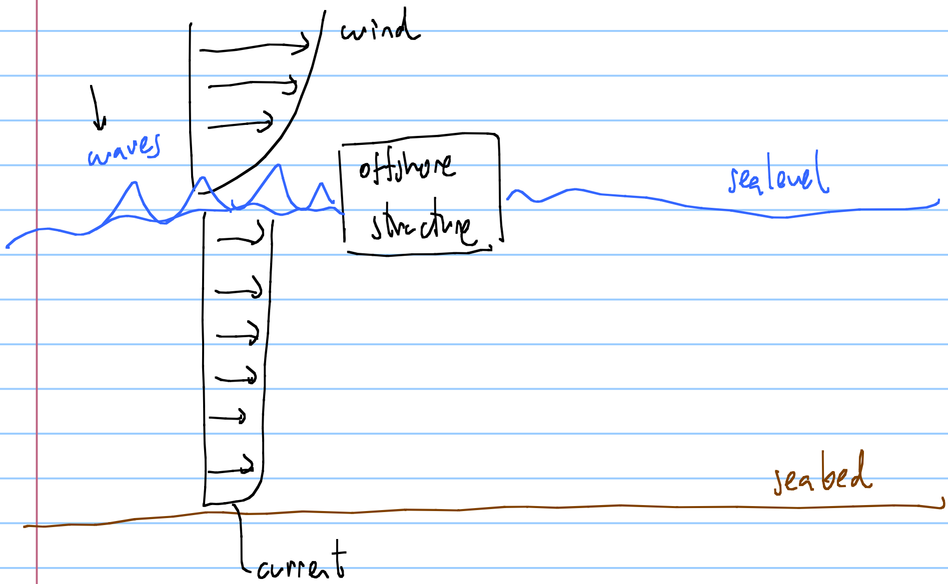
- Storage needs
  - rough weather
  - accessibility
  - tanker delays

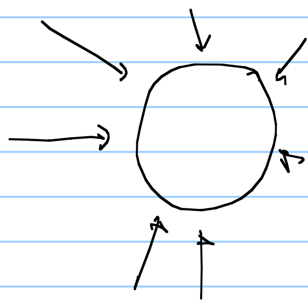
→ FPSO ~ max 3.E6 stb

→ GBS ~ 500.000 stb

→ SPAR ~ 150.000 stb

- Marine loads

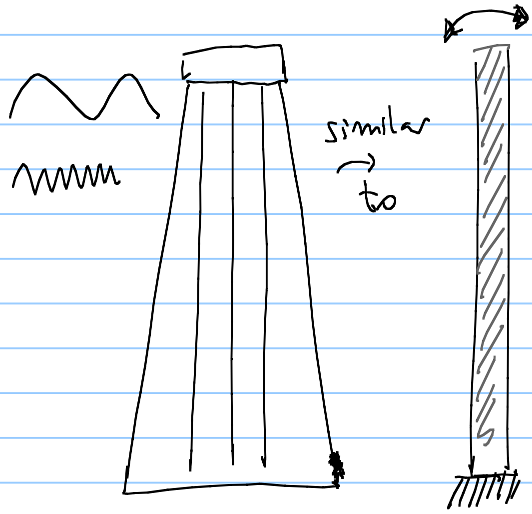




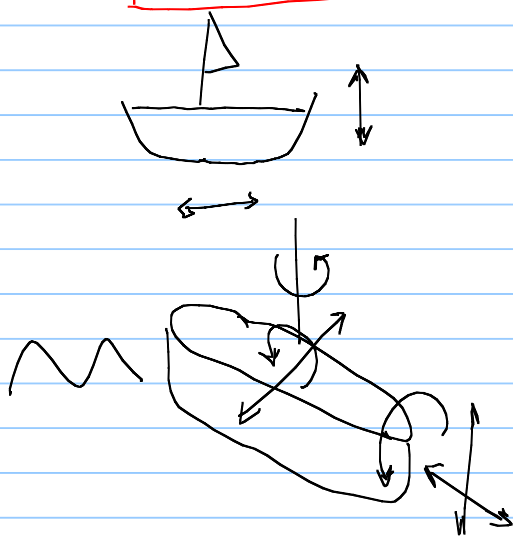
movement of offshore structures is affected by waves, wind and currents...

how do they move?

Bottom supported structure

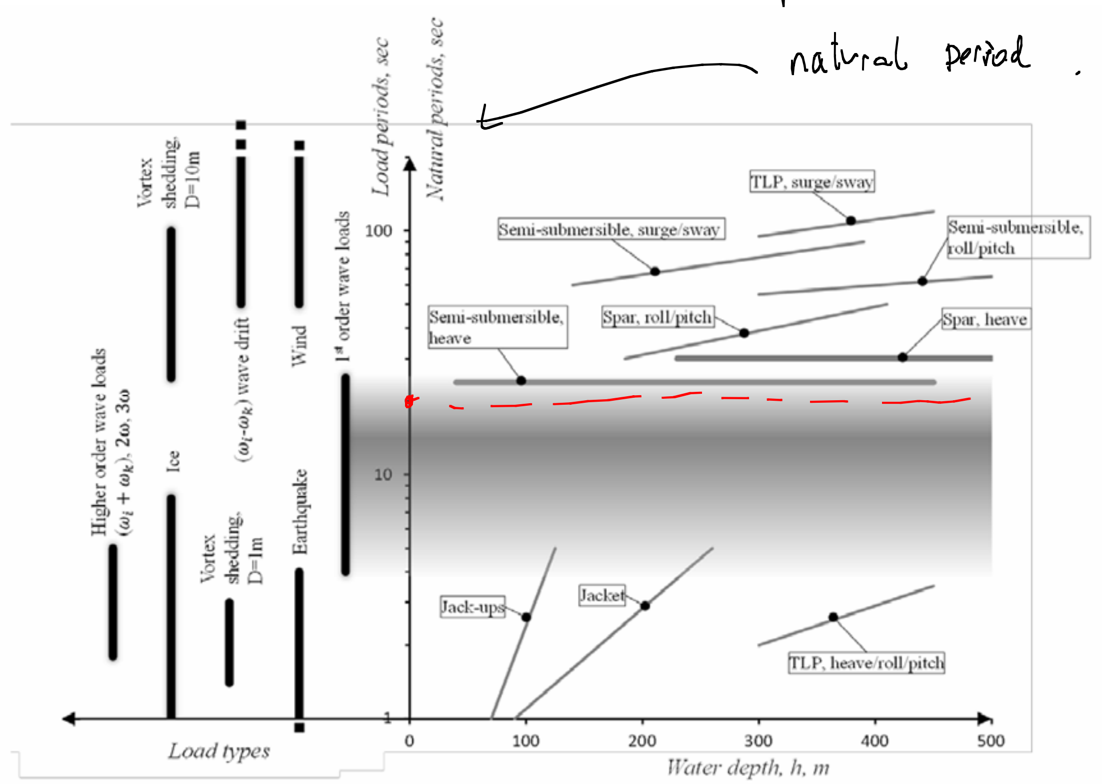


Floating structure

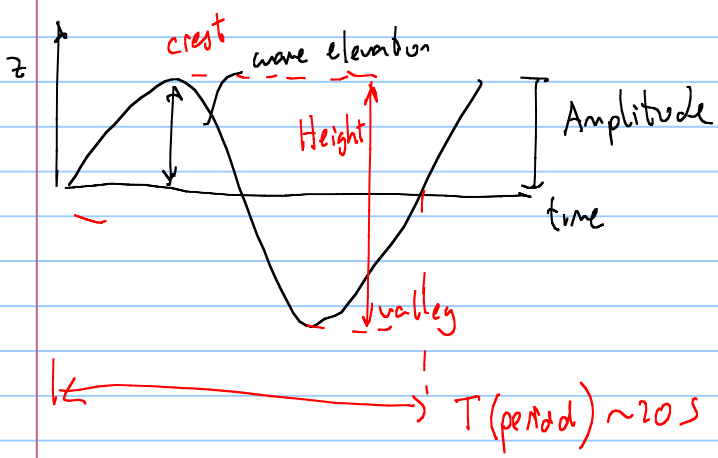


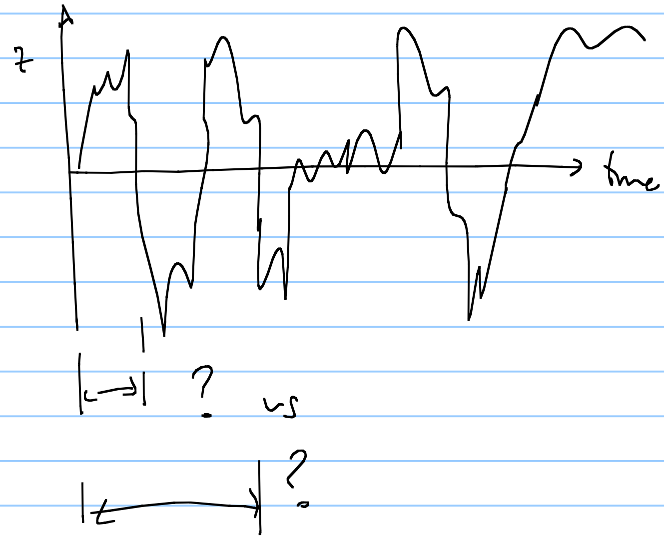
structures are susceptible to different load periods

natural period of structure



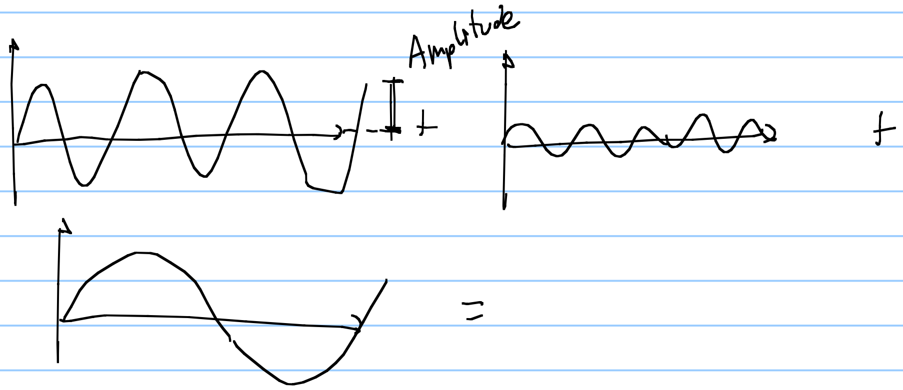
waves



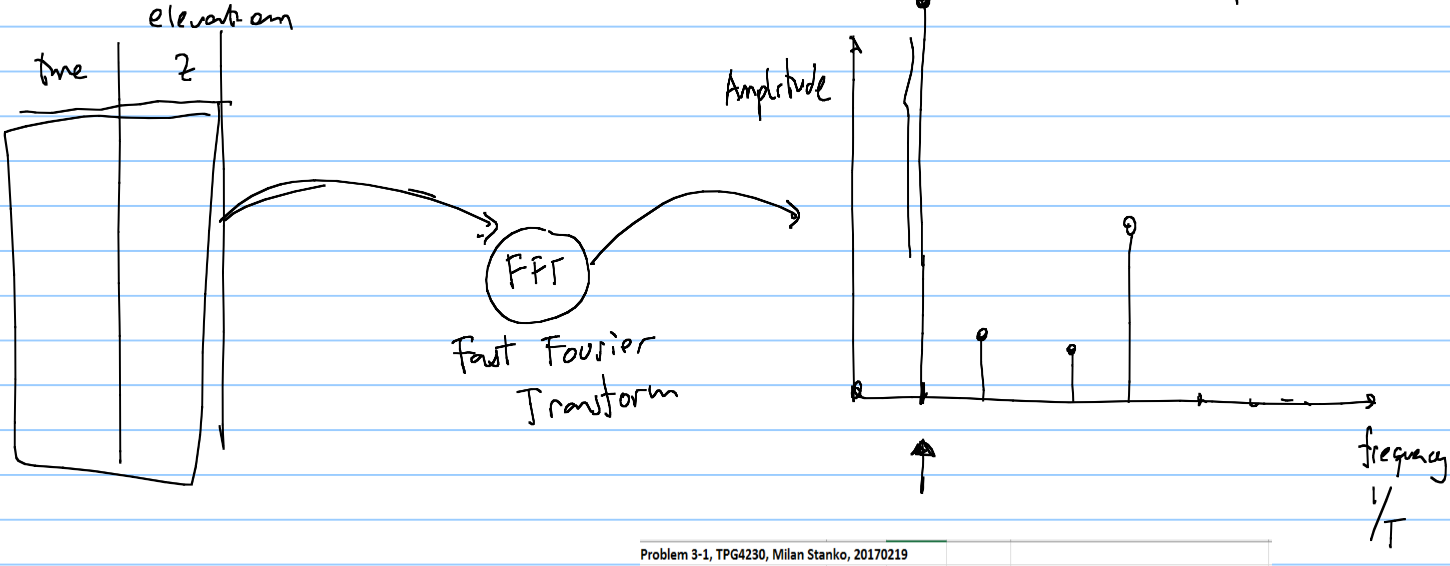


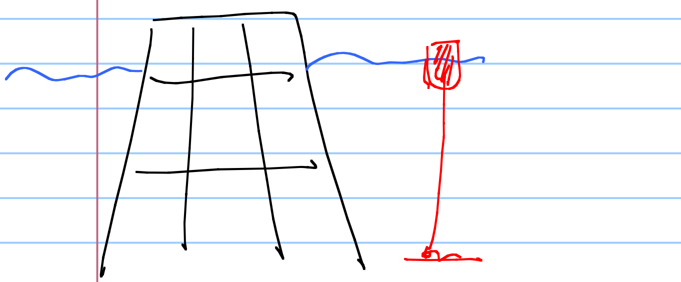
Fourier

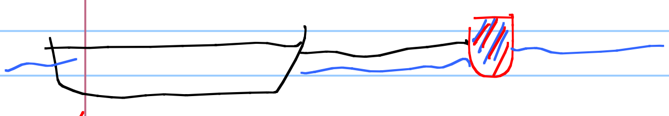
$$= \sum_{i=1}^{N} \zeta_i \sin(\omega_i t + \varepsilon_i) \qquad \frac{1}{T_i}$$



FFT fast Fourier Transform

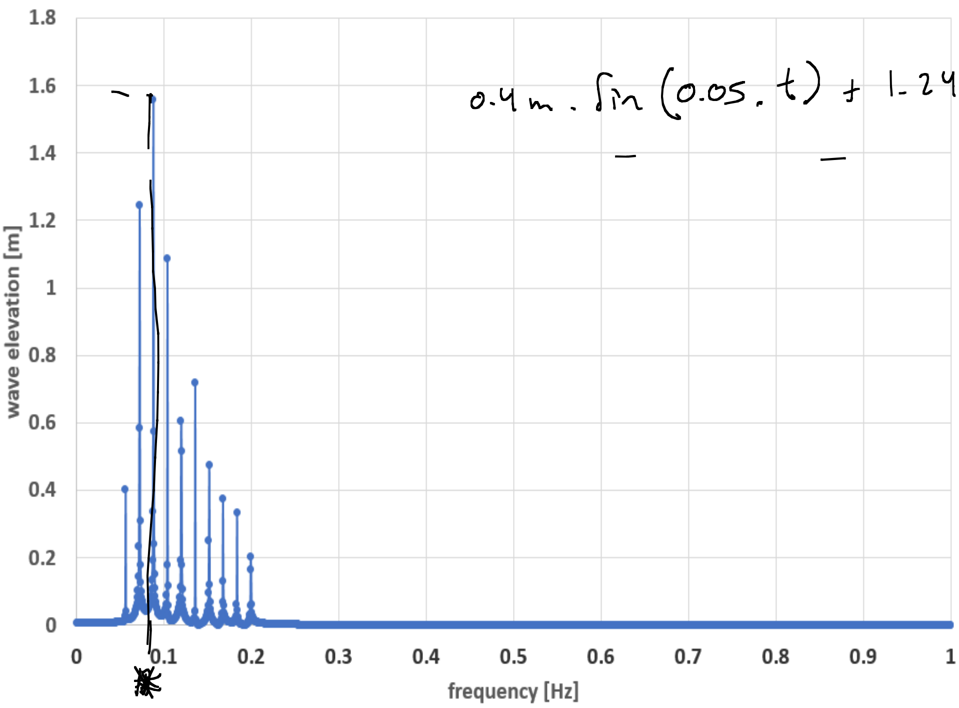






tanker
weather ship
survey ship

Problem 3-1, TPG4230, Milan Stanko, 20170219				
Time interval [s]	2047.5			
Number of points	4096			
sampling frequency [samples/s]	2.00			
Time	Elevation	FFT freq	FFT mag	FFT complex
[s]	[m]			
0.0	0.8	0	0.007144	-14.6310630637753
0.5	0.0	0.000	0.007144	-14.6314355376179-2.17584020171838E-02i
1.0	-0.5	0.001	0.007145	-14.6325531382138-4.35187835418294E-02i
1.5	-0.8	0.001	0.007146	-14.634416403011-6.52831256995594E-02i
2.0	-0.6	0.002	0.007147	-14.6370262285584-8.70534128729824E-02i
2.5	-0.1	0.002	0.007149	-14.6403838717195-0.108831634337723i
3.0	0.5	0.003	0.007151	-14.6444909513754-0.13061978594503i
3.5	1.1	0.003	0.007153	-14.6493494506153-0.152419871829957i
4.0	1.6	0.004	0.007156	-14.6549617194251-0.174233906173646i
4.5	1.7	0.004	0.007159	-14.6613304778867-0.196063915009091i
5.0	1.5	0.005	0.007163	-14.6684588198886-0.217911938100365i
5.5	0.9	0.005	0.007167	-14.6763502173536-0.239780030911572i
6.0	0.2	0.006	0.007172	-14.6850085250036-0.261670266637959i
6.5	-0.7	0.006	0.007176	-14.6944379856753-0.283584738366725i
7.0	-1.6	0.007	0.007182	-14.7046432361733-0.305525561331911i
7.5	-2.3	0.007	0.007187	-14.7156293137251-0.327494875310597i
8.0	-2.7	0.008	0.007193	-14.727401663005-0.349494847163372i
8.5	-2.8	0.008	0.0072	-14.7399661437619-0.371527673534929i
9.0	-2.6	0.009	0.007206	-14.7533290390982-0.393595583725473i
9.5	-2.1	0.009	0.007214	-14.7674970643682-0.415700842783696i
10.0	-1.5	0.010	0.007221	-14.7824773767678-0.43784575480329i
10.5	-0.7	0.010	0.007229	-14.7982775856108-0.460032666467342i
11.0	0.1	0.011	0.007238	-14.8149057633281-0.482263970877489i



$$0.4\,m \cdot \sin(0.05 \cdot t) + 1.24 \cdot \sin(0.07 \cdot t) + \ldots$$

gathering data is done by splitting

in periods of "sea states" ≈ 3hrs

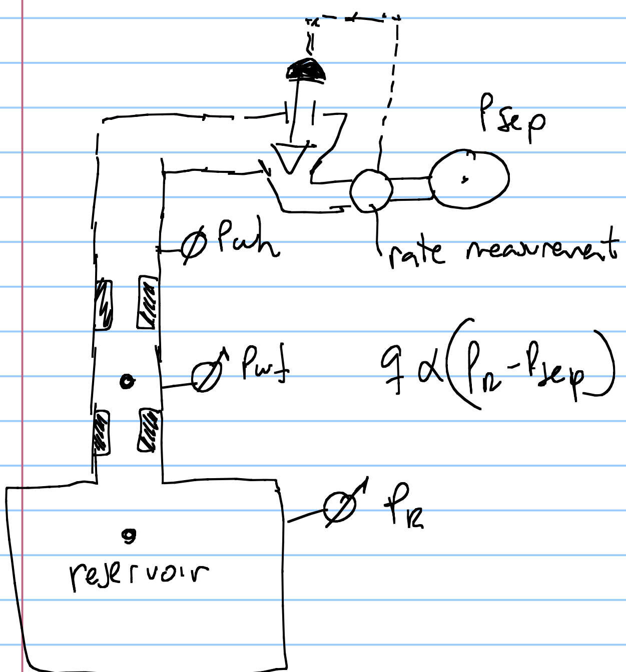
for each sea state { perform fft
↳ peak period *
↳ evelation

generate scatter diagram of wave statistics:

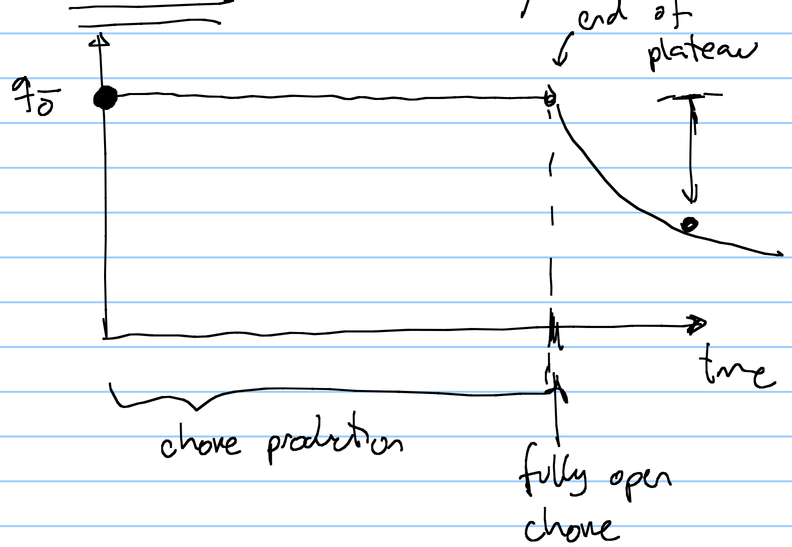
most frequent combination of period and wave height

	Spectral Peak period (T_p) [s]																					
Hs [m]	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1
2-3	0	2	94	1050	4532	10304	15020	15953	13457	9752	5991	3403	1795	894	426	197	88	39	17	7	3	1	1
3-4	0	0	2	72	686	2782	6171	8847	9189	7493	5082	2991	1577	762	345	148	61	24	9	4	1	0	0
4-5	0	0	0	2	51	433	1645	3495	4807	4750	3638	2286	1229	584	251	100	37	13	5	1	0	0	0
5-6	0	0	0	0	2	39	294	1037	2069	2664	2440	1709	968	463	193	72	25	8	2	1	0	0	0
6-7	0	0	0	0	0	2	32	215	692	1264	1485	1228	767	382	159	57	18	5	1	0	0	0	0
7-8	0	0	0	0	0	0	2	27	157	447	730	762	555	302	130	46	14	4	1	0	0	0	0
8-9	0	0	0	0	0	0	0	2	23	112	276	392	355	223	104	38	11	3	1	0	0	0	0
9-10	0	0	0	0	0	0	0	0	2	19	77	160	192	148	79	31	9	2	0	0	0	0	0
10-11	0	0	0	0	0	0	0	0	0	2	16	50	85	85	55	24	8	2	0	0	0	0	0
11-12	0	0	0	0	0	0	0	0	0	0	2	12	29	40	33	18	7	2	0	0	0	0	0
12-13	0	0	0	0	0	0	0	0	0	0	0	2	8	15	17	12	5	2	0	0	0	0	0
13-14	0	0	0	0	0	0	0	0	0	0	0	0	2	5	7	6	4	1	0	0	0	0	0
14-15	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0
15-16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0
16-17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17-18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	16	373	2616	9308	21070	34410	44041	46687	42514	34212	24268	15503	8892	4587	2143	921	372	146	55	22	8	6	2

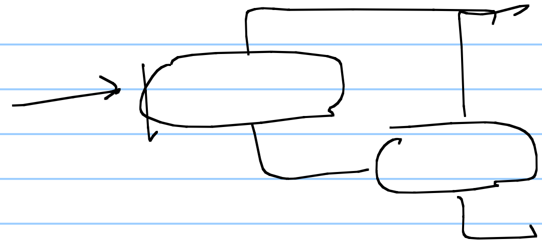
Production scheduling: define production profile



Mode A: constant rate, plateau mode

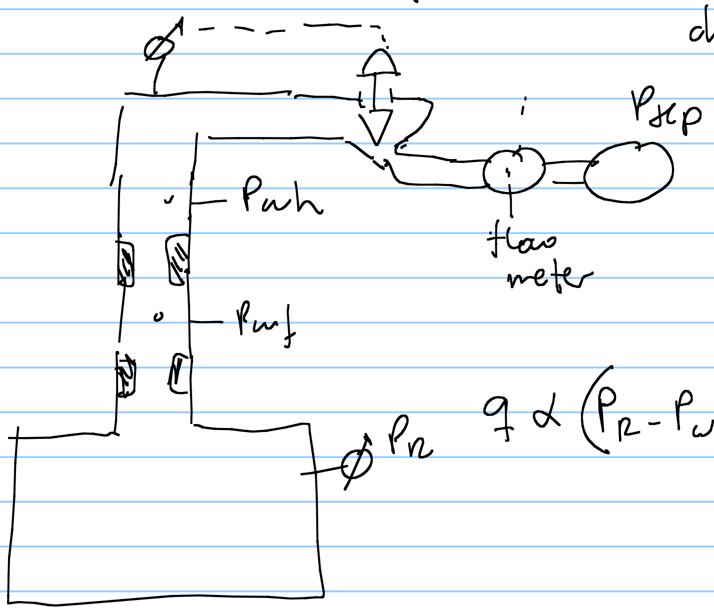


- Complete new development
- Its own facilities and platform
- Contract in place

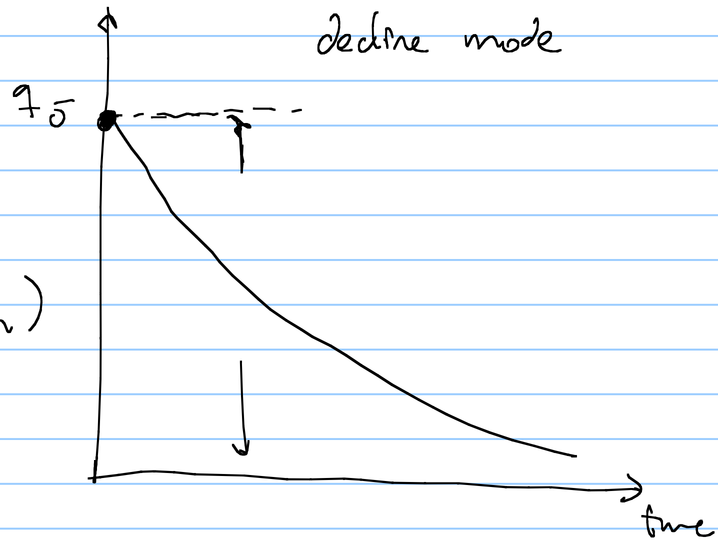


<u>Mode B</u> constant pressure

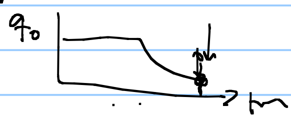
change choke such as $P_{wh} = \text{const}$

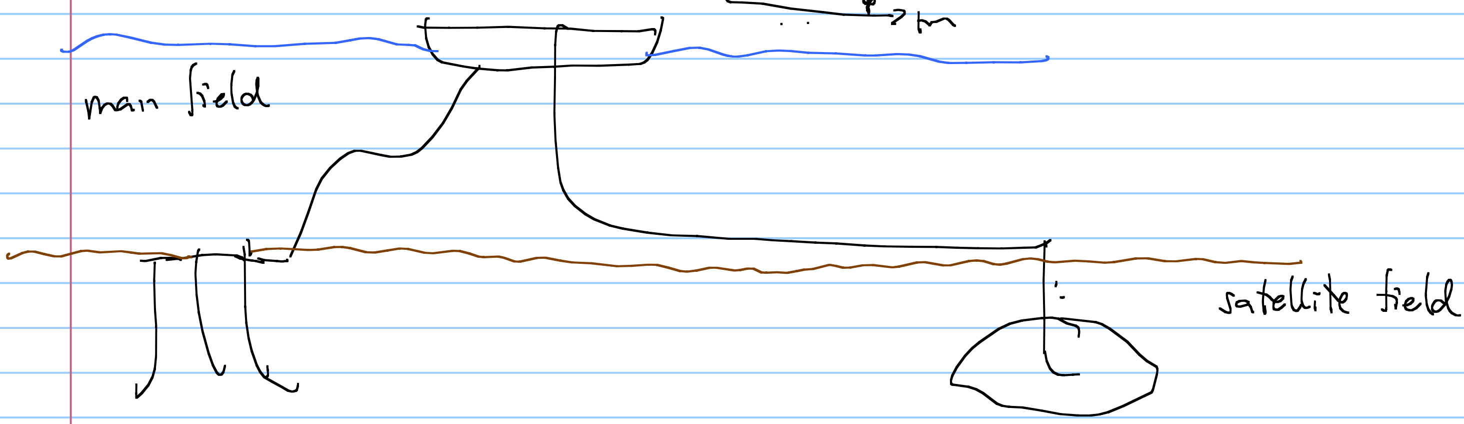


$q \propto (P_R - P_{wh})$

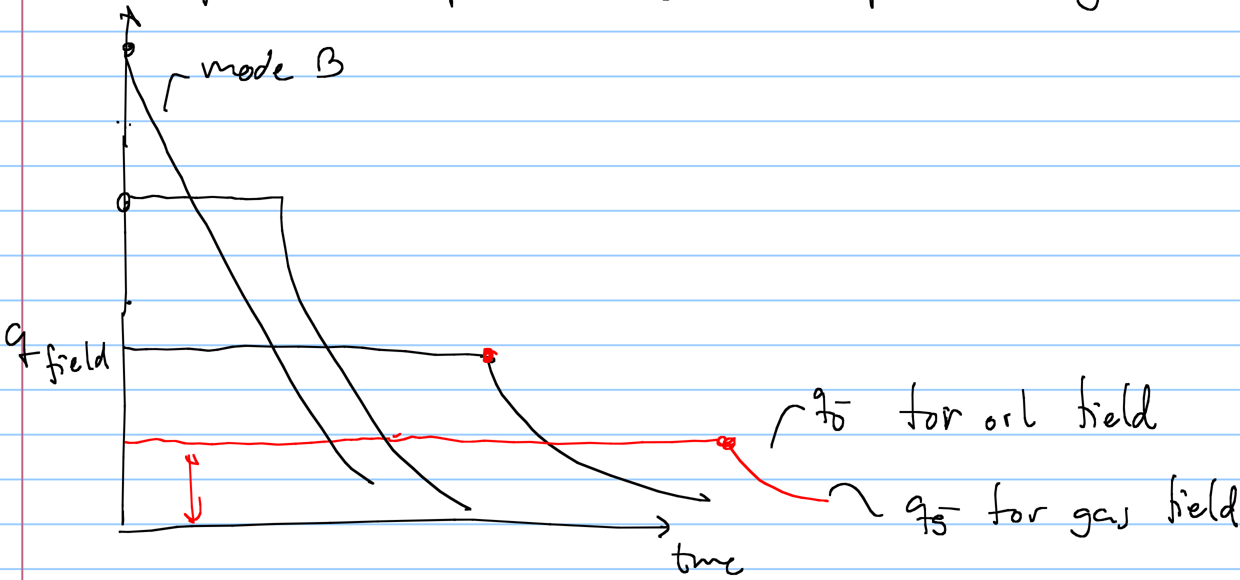


- for satellite fields producing to an existing field with spare capacity
- produce as much as possible, as fast as possible.



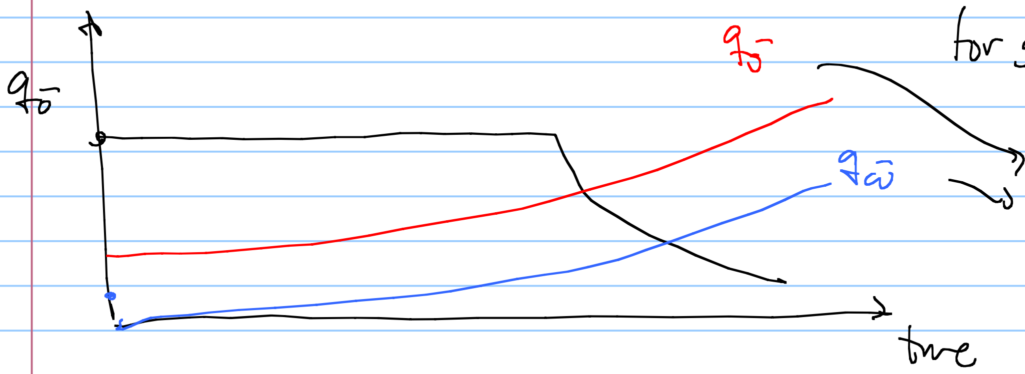


Relationship between plateau length and plateau height

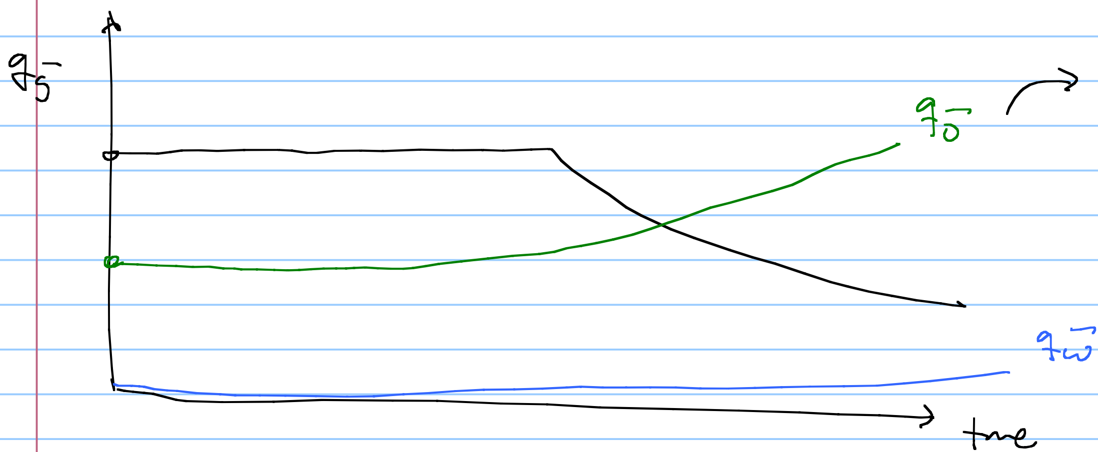


always consider the associated products → for oil ↗ gas ↘ water

for gas ↗ oil ↘ water

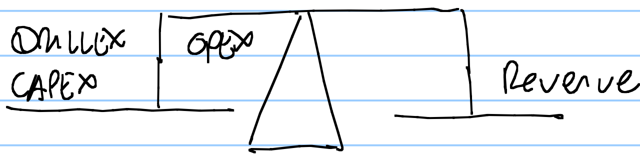


→ might bottleneck my processing facilities



→ is a very attractive source of additional revenue.

plateau rate must be defined by performing a sensitivity analysis to maximize NPV.



Rule of thumb to start making studies on plateau height

for oil field annual offtake of 10% . TRR

$$q_{\bar{o}\,plateau} = \frac{0.1 \cdot N_{pu}}{N^r \text{ operational days/year}}$$

ex. for our field yesterday $P_{90} \approx 50E6$ stb

assuming uptime 100%

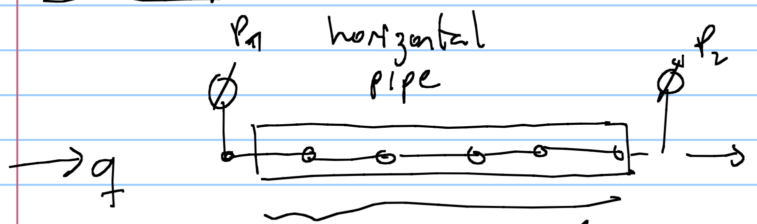
$$q_{\bar{o}\,plateau} = \frac{0.1 \cdot 50E6}{365} \approx 14000 \text{ stb/d}$$

for a gas field annual offtake 2% - 3% OR TRR (Gpu)

$$q_{\bar{g}} = \frac{0.02 \cdot G_{pu}}{N^r \text{ operational day in year}}$$

field and well flow performance

- Flow equilibrium:

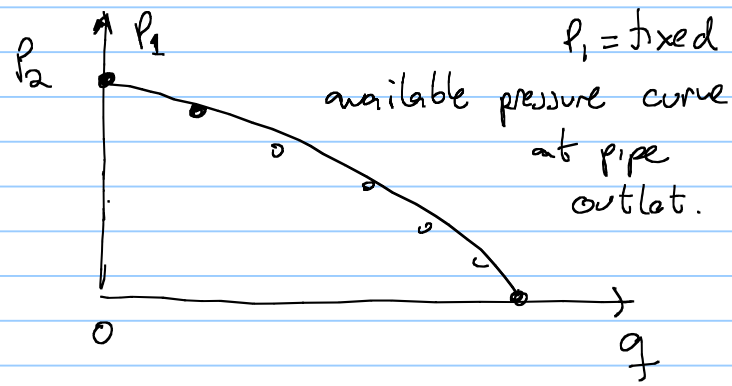


$$\Delta p_f = f \frac{L}{\phi} \frac{v^2}{2g}$$

3 ways to make calculations on this pipe

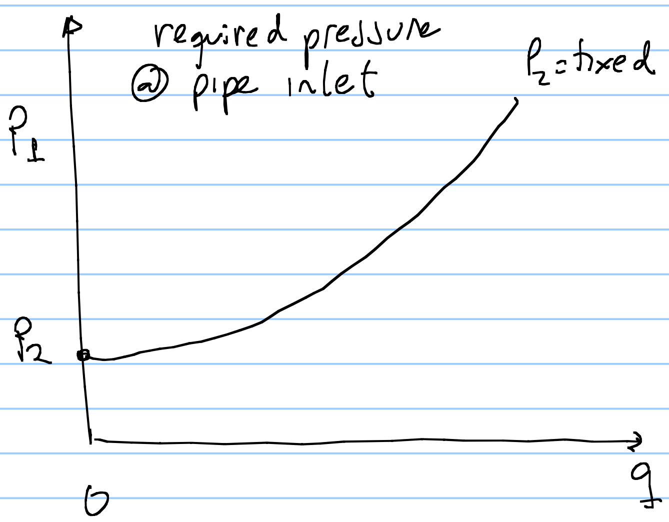
(1) fix q, fix P_1 calculate P_2

co-current pressure calculations



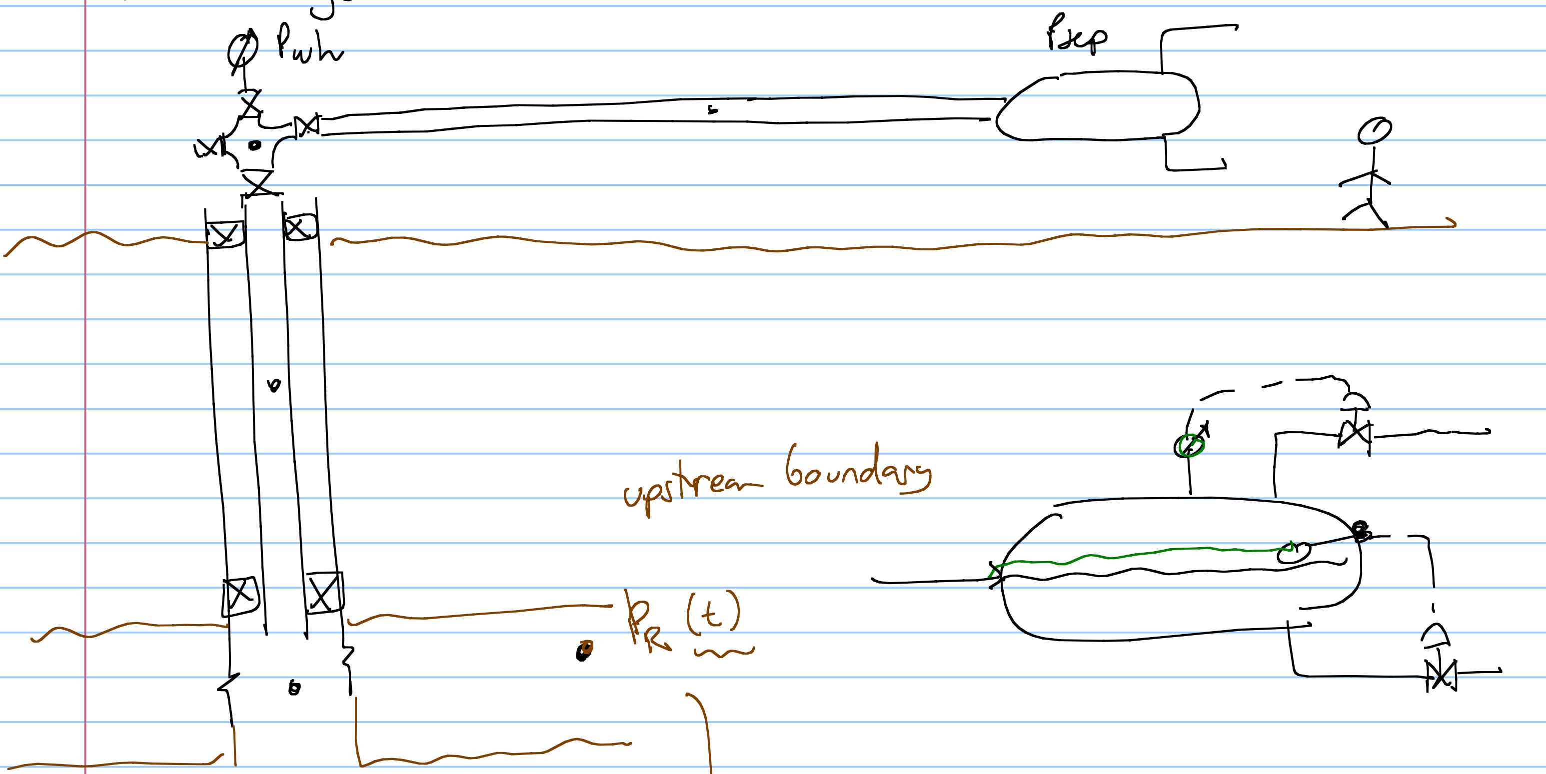
2) fix q, fix P_2, → calculate P_1

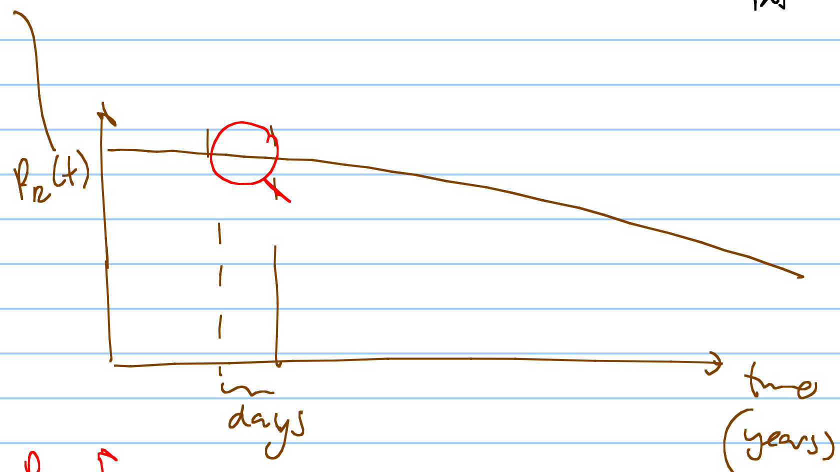
perform counter-current calculations P_1 until I reach P_1

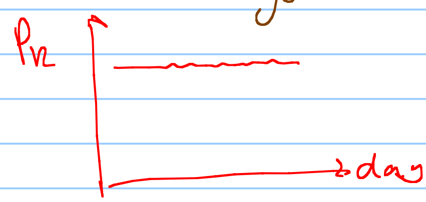


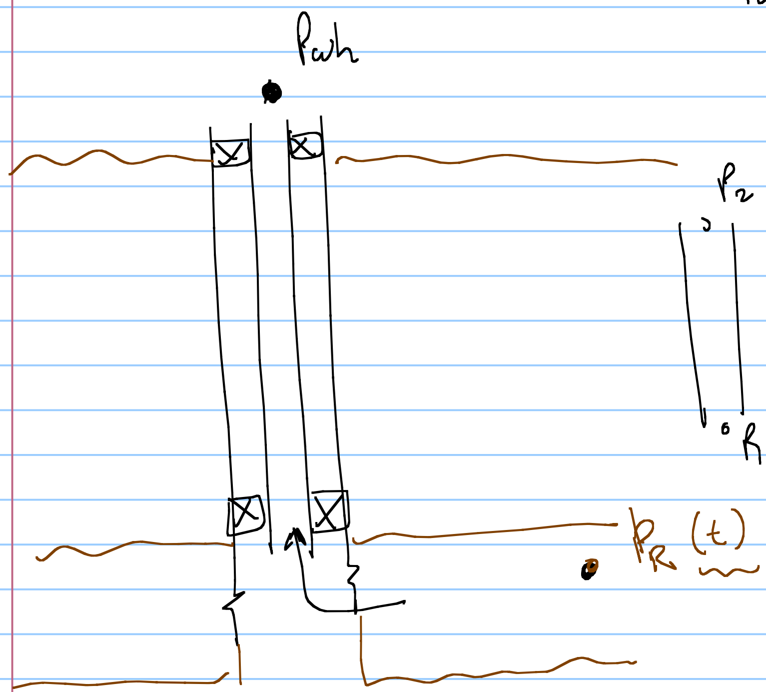
3) fix P_1, fix P_2 ⇒ find q

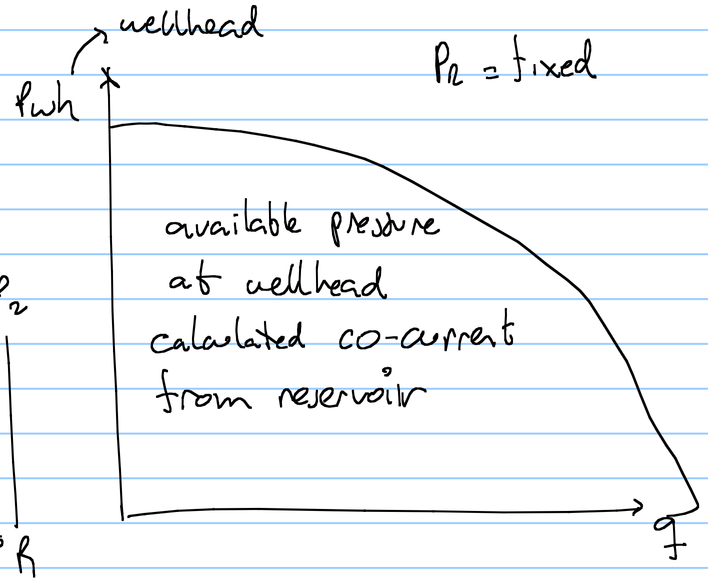
Production system

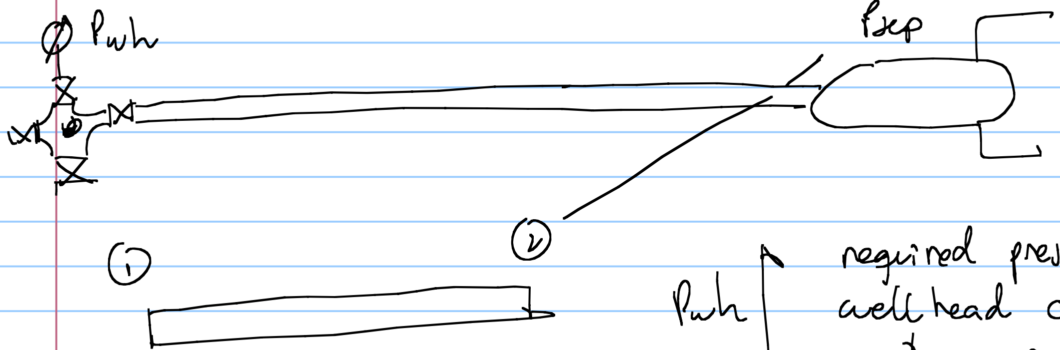


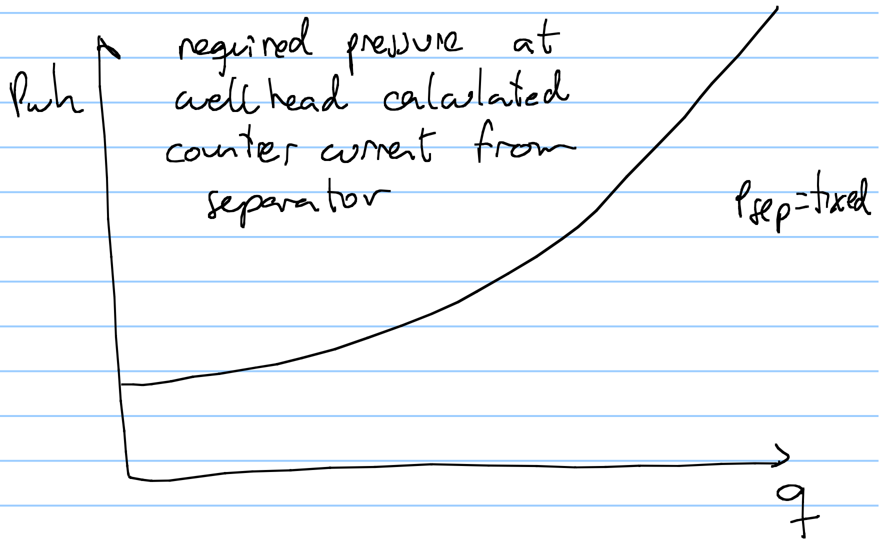


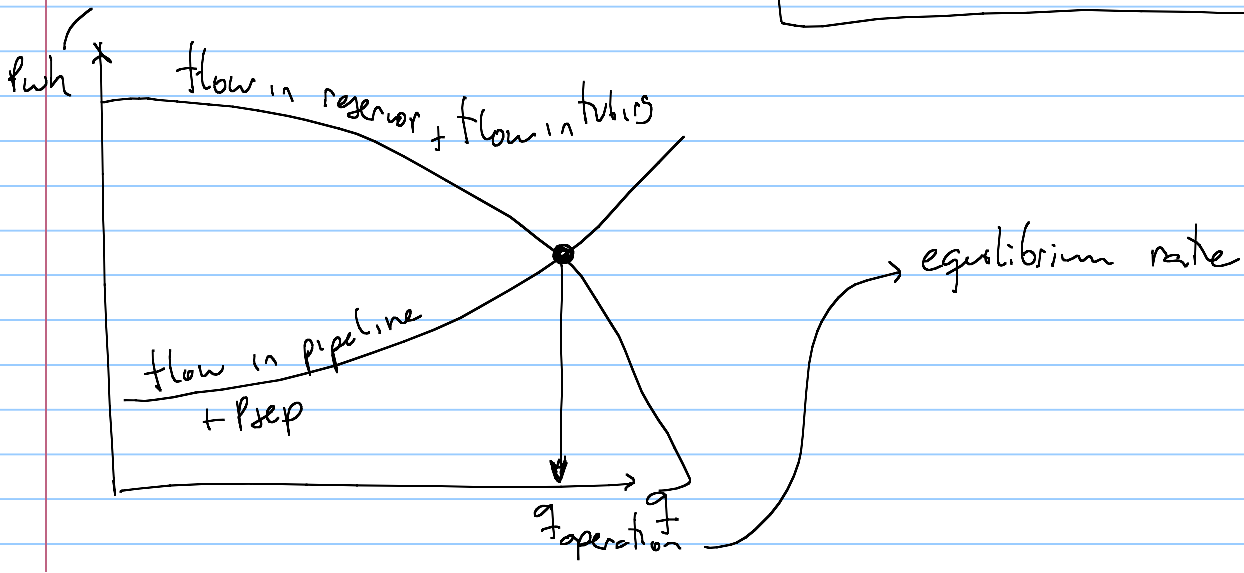


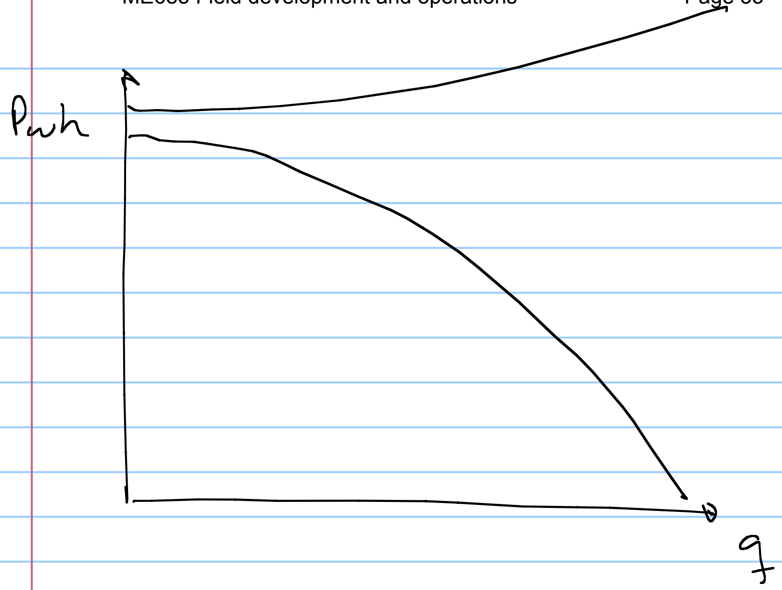

Pwh
P2
P1
PR (t)

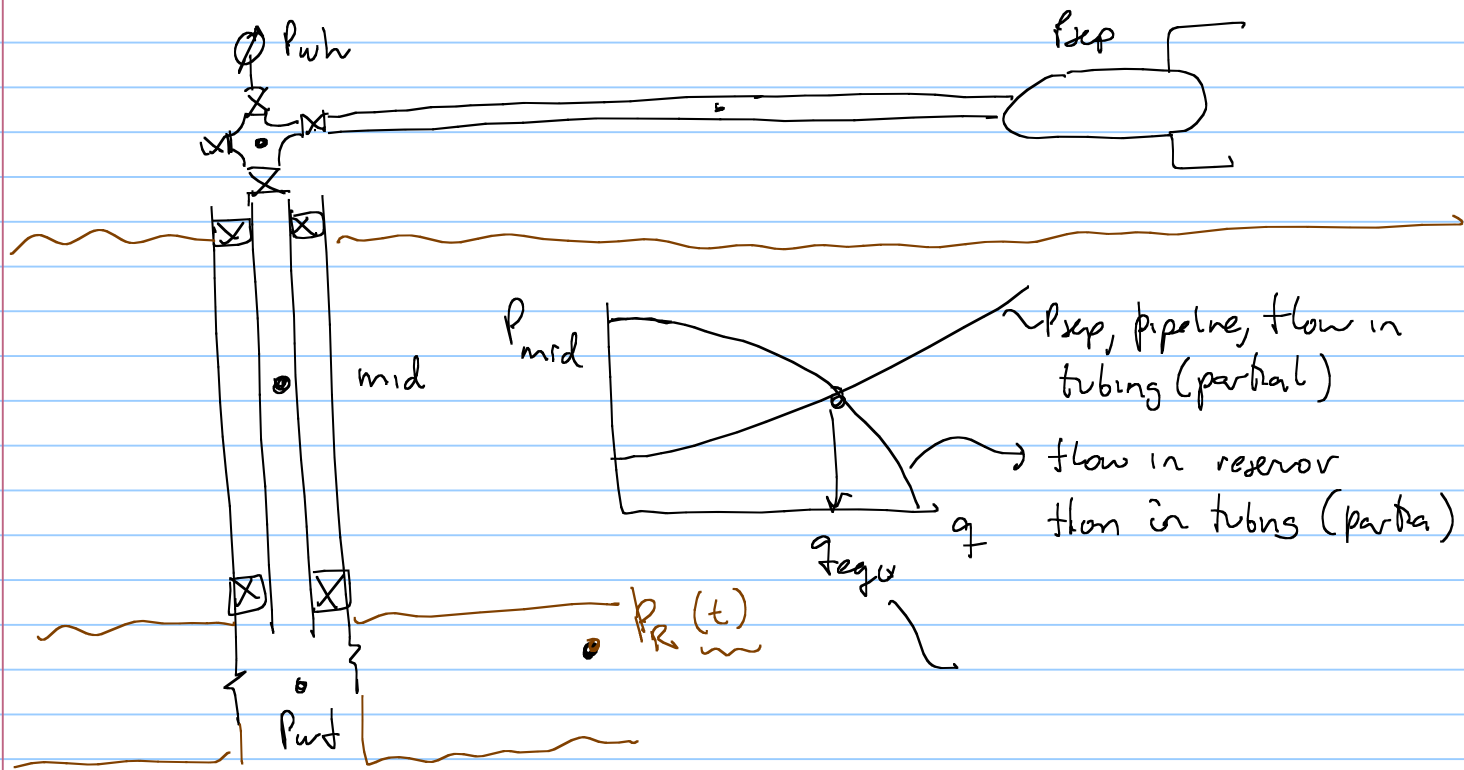

wellhead
Pwh
PR = fixed
available pressure
at wellhead
calculated co-current
from reservoir
q


Pwh
Psep
1
2


Pwh
required pressure at
wellhead calculated
counter current from
separator
Psep=fixed
q


Pwh
flow in reservoir + flow in tubing
flow in pipeline
+ Psep
equilibrium rate
q operation
q





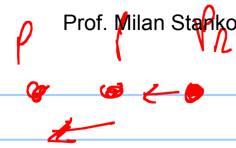
1) • flow in reservoir } gas

2) • flow in tubing } gas

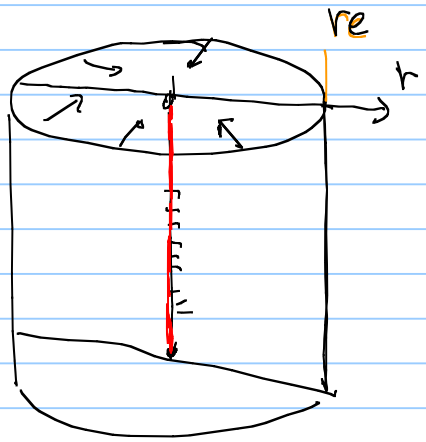
3) • flow in flowline / pipeline } gas

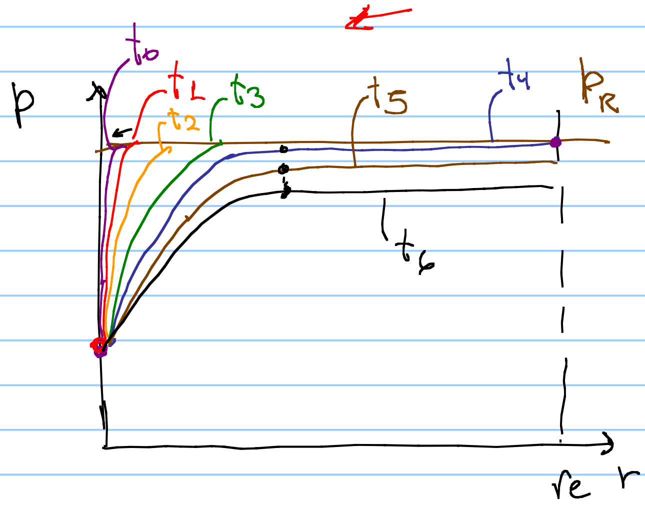
1) • flow in reservoir (IPR : inflow performance relationship)

equation that relates q_g, P_R, P_{wf}



focus on vertical well





$t_0 - t_4$ infinite acting transient

$t_4 \rightarrow$ boundary dominated period

(pseudo steady state (PSS))

- mass conservation
- momentum conservation $\sim\!\!\rightarrow$ $\dfrac{\partial p}{\partial r}\dfrac{K}{\mu} = V$
- Partial differential equation
- solve it for PSS

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

q_g: in S.C

C: Backpressure coefficient

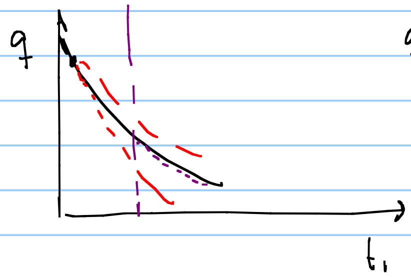
n: backpressure exponent

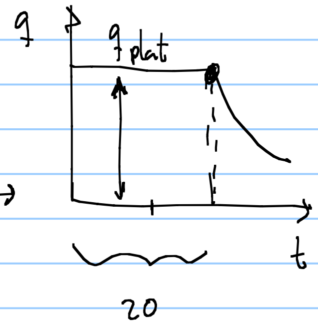
backpressure equation

- Tubing equation ..... tomorrow.

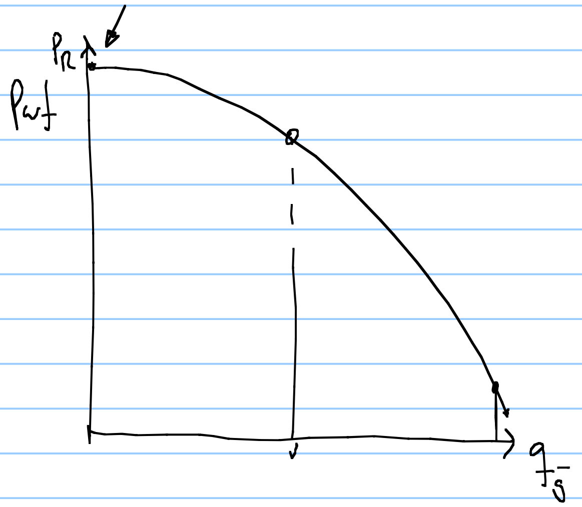
Day 4

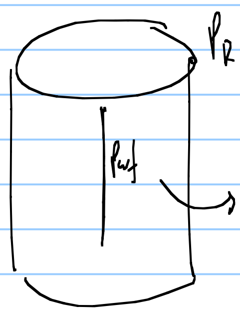
- production scheduling q vs time





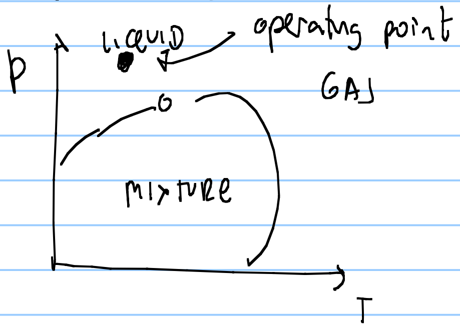
IPR gas $\quad q_g = C\left(p_R^2 - p_{wf}^2\right)^n$

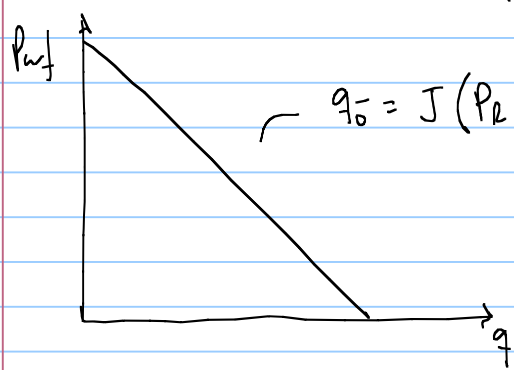




flowing bottom hole pressure

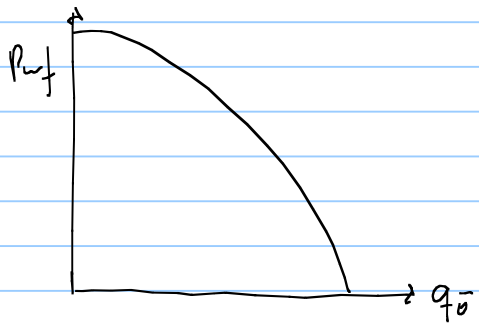
- for undersaturated oil $\quad p_{wf} > p_b$

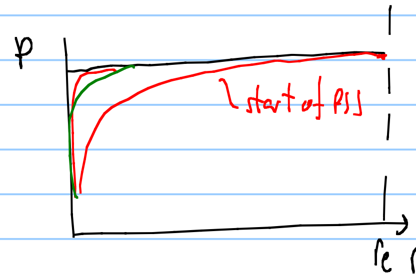




$q_o = J\left(p_R - p_{wf}\right)$

for O+G





$$\frac{dp}{dr}\frac{k}{\mu} = \underbrace{v}_{\propto q}$$

k: permeability (darcy)

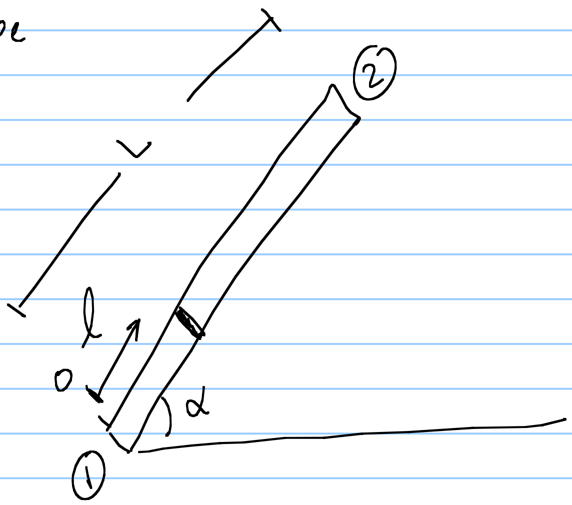
PSS IPR is usually a good approximation for field production over time

need to use a transient IPR

permeable sand	10 Darcy
	1 Darcy
	1E-3 Darcy
	1E-6 Darcy
tight formation	1E-9 Darcy

- flow in tubing is basically a pipe

$$\underbrace{\frac{dP}{dl}}_{\frac{P_1-P_2}{L_1-L_2}} = \underbrace{-\rho \cdot g \cdot \sin(\alpha)}_{\text{hydrostatic term}} - \underbrace{\frac{\rho f}{\Phi}\frac{V^2}{2}}_{\text{friction component}} \quad (a)$$



real gas equation $PV = ZRT$

$$P\frac{1}{\rho} = Z\frac{R}{M_w}T$$

$$\rho = \frac{P M_w}{Z R T}$$

to make the integration I assume average properties in tubing

$$T_{av} = \frac{T_1 + T_2}{2}$$

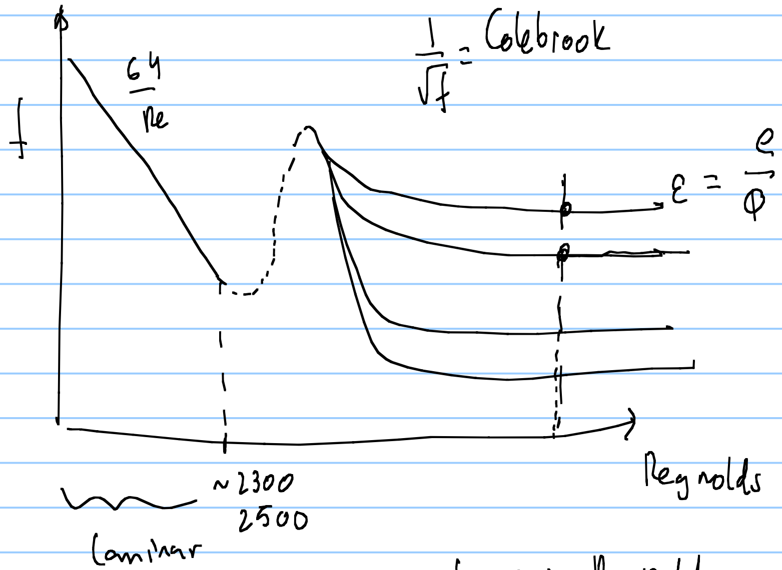
$$P_{av} = \frac{P_1 + P_2}{2}$$

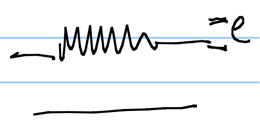
$$Z_{av} = \frac{Z_1 + Z_2}{2}$$

substitute in eq (a)

friction factor

$\frac{1}{\sqrt{f}}$ = Colebrook





Reynolds $\frac{\rho u \Phi}{\mu}$

for gas Reynold is very high

so friction factor $= F(\varepsilon)$

$$e = F(\Phi)$$

$$f = F(\Phi)$$

final equation

$$\left[\frac{p_1^2}{e^{s}} = p_2^2 + \frac{q_{\bar{g}}^2}{C_T^2}\right]$$

tubing coefficient

elevation coefficient

$q_{\bar{g}}$ is at s.c

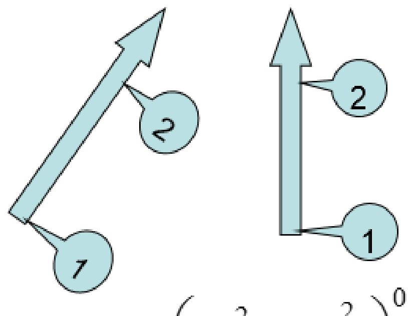
$\frac{dp}{dl} = V \cdot q_g$ at local conditions p, T

Tubing flow Equation-Dry gas

$$\boxed{q_{sc} = \underbrace{\left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g f_M Z_{av} T_{av}\, L}\right]^{0.5}\left(\frac{s e^S}{e^S - 1}\right)^{0.5}}_{C_T}\left(\frac{p_1^2}{e^S} - p_2^2\right)^{0.5}}$$

$$\boxed{\frac{s}{2} = \frac{M_g g}{Z_{av} R T_{av}} H = \frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H}$$

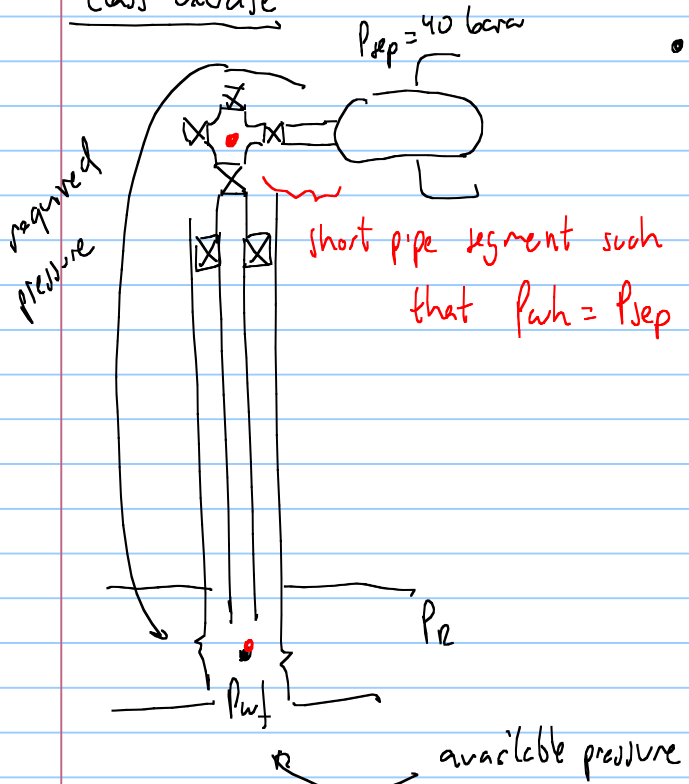
H is height difference



$$q_{gsc} = C_T\left(\frac{p_1^2}{e^s} - p_2^2\right)^{0.5}$$

$$p_{\text{inlet}} = p_1 = e^{s/2}\left(p_2^2 + \frac{q_g^2}{C_T^2}\right)^{0.5} \qquad p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

Class exercise



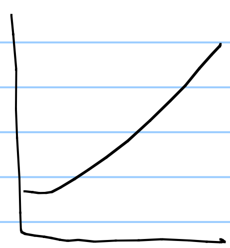
short pipe segment such that $P_{wh} = P_{sep}$

- from $P_R \rightarrow P_{wf}$ using IPR equation

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

from $P_{wh} \rightarrow P_{wf}$ use tubing equation

$$\frac{P_{wf}^2}{e^s} = P_{wh}^2 + \frac{q_{\bar{g}}^2}{C_T^2}$$



Christmas Tree Systems

Onshore tree | Offshore tree | Subsea tree

Eva No 3			
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	

Inflow performance relationship (IPR)

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

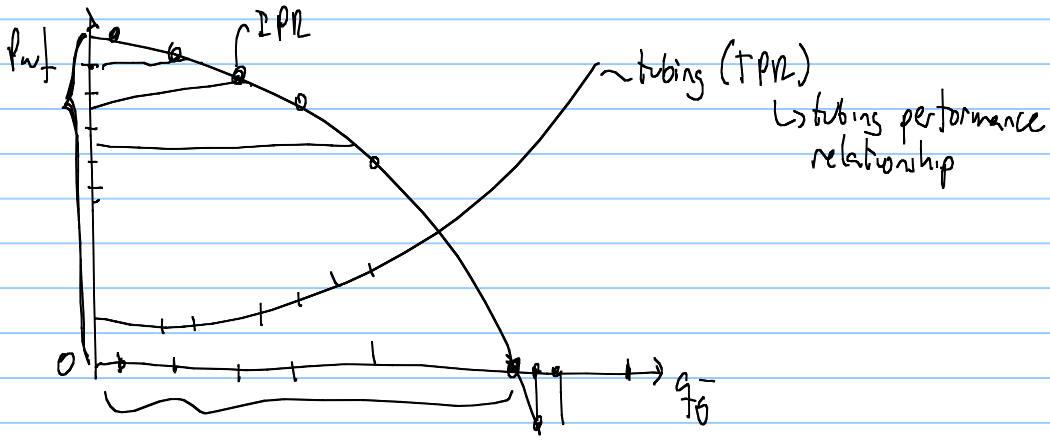
Tubing performance relationship (TPR)

$$p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

Flowline performance relationship (FPR)

$$\boxed{q_{\bar{g}} = C_{FL} \cdot \left(p_{in}^2 - p_{out}^2\right)}$$

	IPR	TPR		WPR
pwf_avail	qg	pwf_req	pwf_avail-pwf_req	pwh_avail
[bara]	[Sm^3/d]	[bara]	[bara]	[bara]

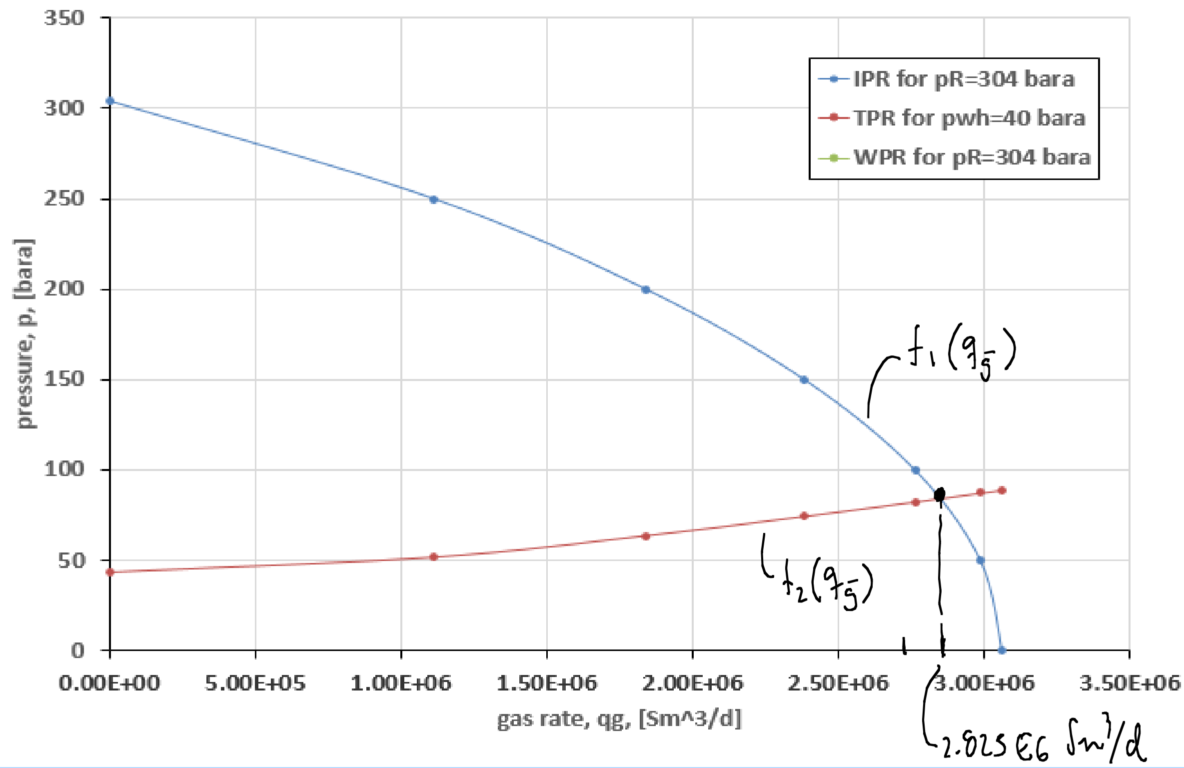


$q_g = C\left(P_R^2 - P_{wf}^2\right)^n$

IPR q_g

tubing P_1

	IPR	TPR
pwf_avail	qg	pwf_req
[bara]	[Sm^3/d]	[bara]
304	0.00E+00	43.2
250	1.11E+06	51.6
200	1.84E+06	63.7
150	2.38E+06	74.4
100	2.76E+06	82.5
50	2.99E+06	87.4
0	3.06E+06	89.1



find q_g^* such as $f_1(q_g^*) = f_2(q_g^*)$?

$q_g = C\left(P_R^2 - P_w^2\right)^n$

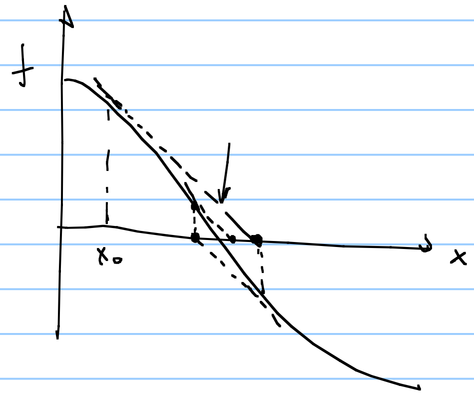
$\left(\left(\frac{q_g}{C}\right)^{1/n} - P_R^2\right)^{0.5} =$

find $f(x)$

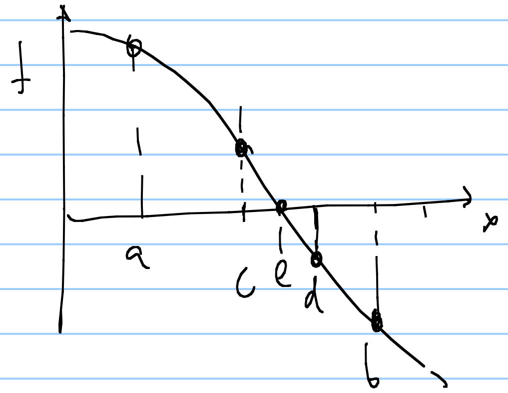
x^* such as $f(x^*) = 0$

root finding techniques

Newton raphson



Bisection



$c = \frac{a+b}{2}$

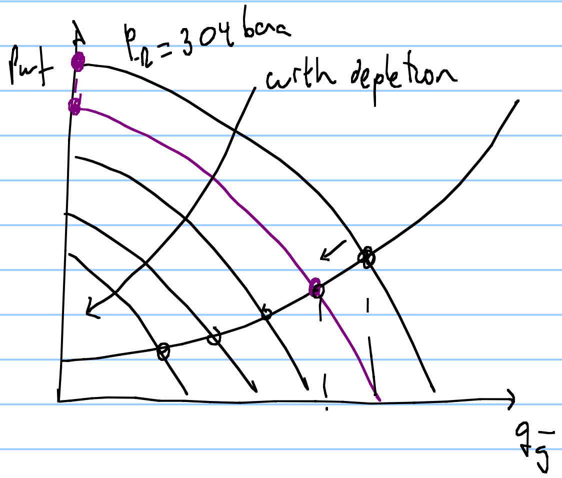
$d = \frac{c+b}{2}$

$e = \frac{c+d}{2}$

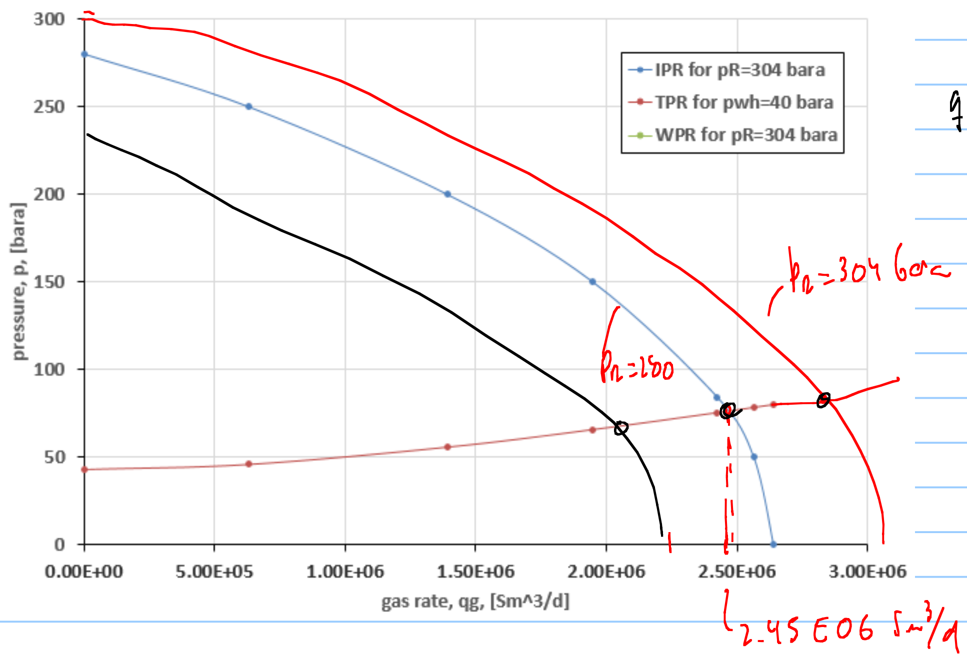
Create a third function $f_3(q_{\bar{g}}) = f_2(q_{\bar{g}}) - f_1(q_{\bar{g}})$

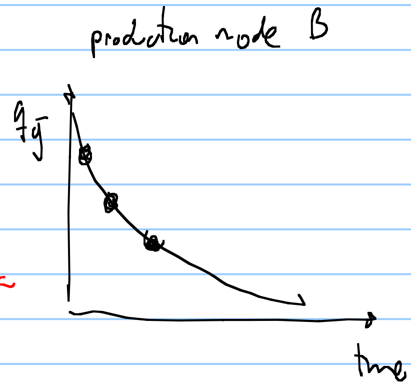
find $q_{\bar{g}}^*$ such as $f_3(q_{\bar{g}}^*) = 0$

what happens with the intersection with depletion $P_R \downarrow$

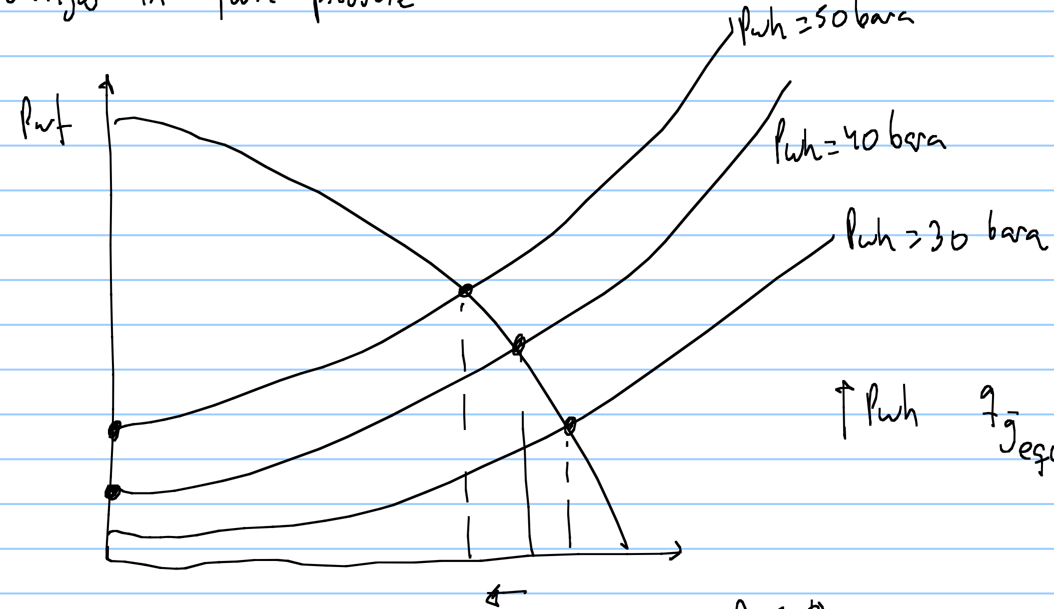


$P_R \downarrow$ equilibrium rate also goes down



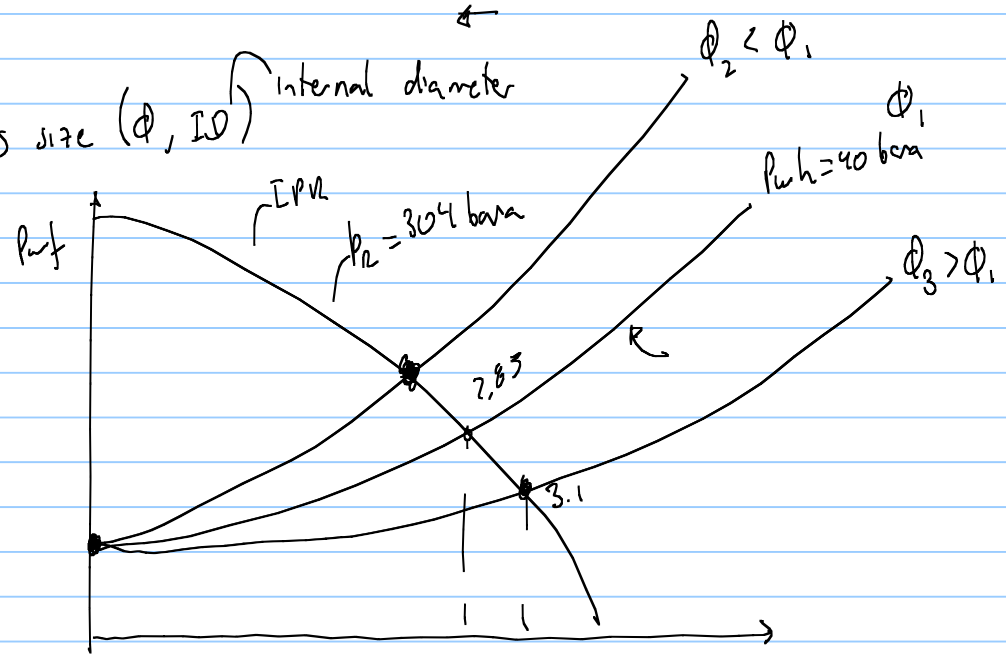


changes in Pwh pressure



↑ Pwh $q_{g_{esc}}$ ↓

effect of tubing size (Φ, ID) internal diameter

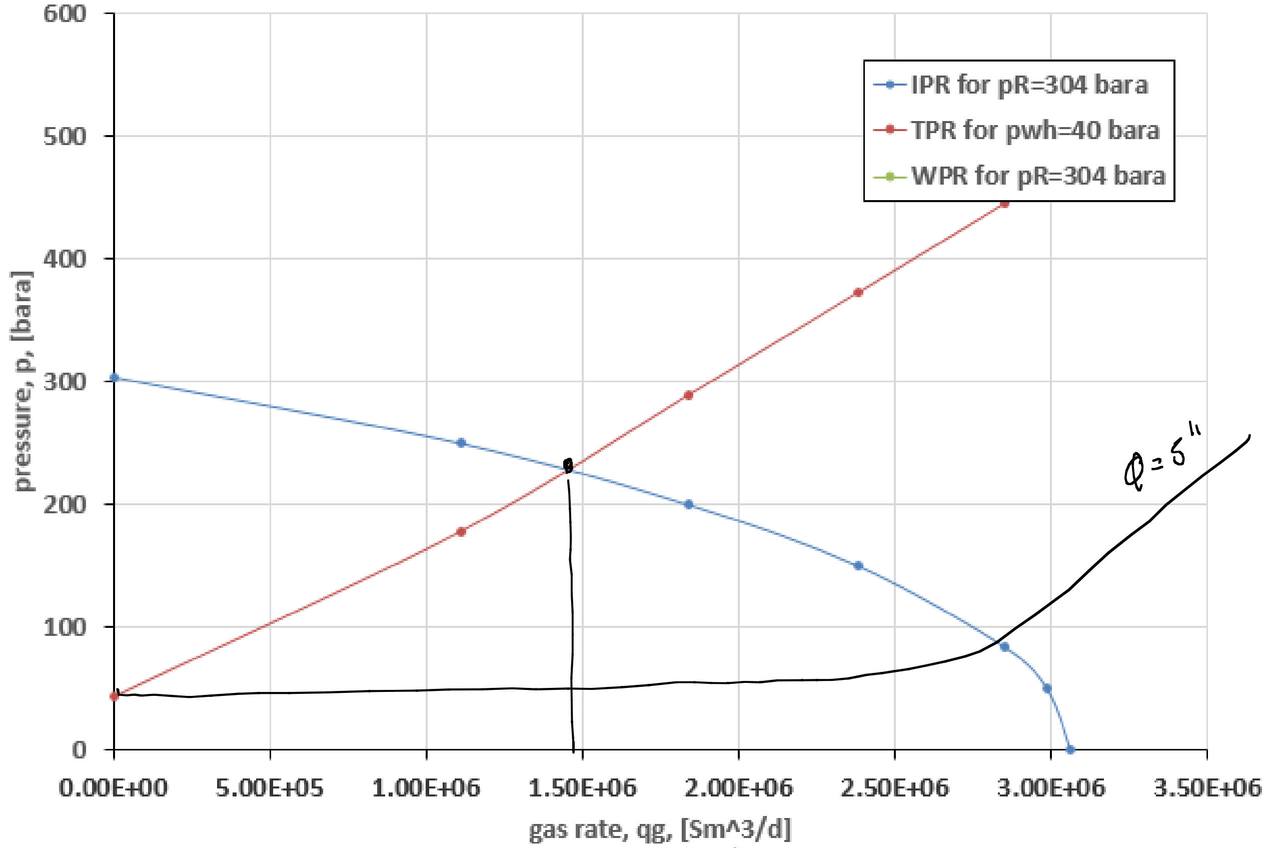


Φ affect C_T

↑ Φ ↑ C_T

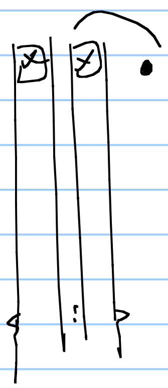
↓ Φ ↓ C_T

with 2.5'' ID, $C_T = 6.93E3$ $Sm^3/d\ bar^2$



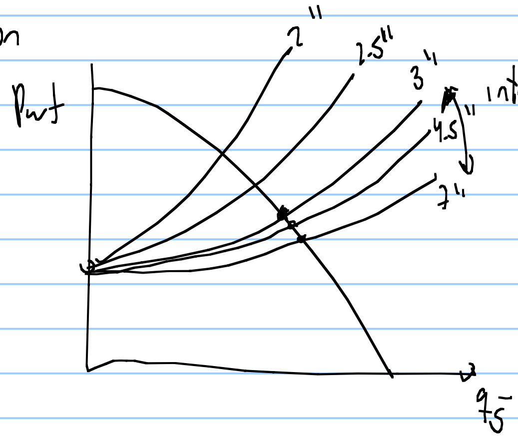
1.45 E06 Sm^3/d

how do we define tubing ID φ?

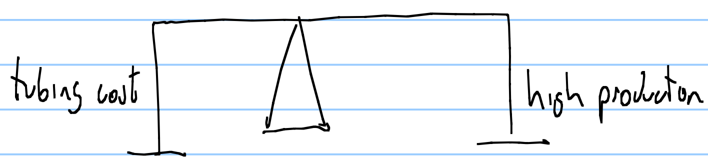


- ϕ_{tubing} < ID_{casing} 9 5/8''

- Reduce pressure drop in tubing to have high as possible production

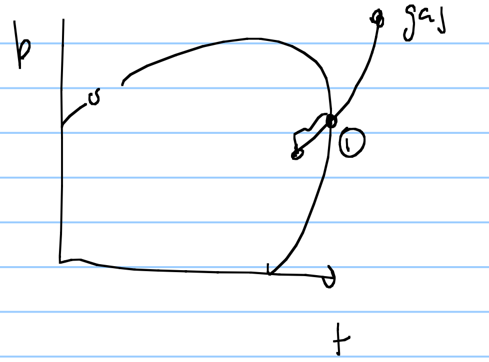


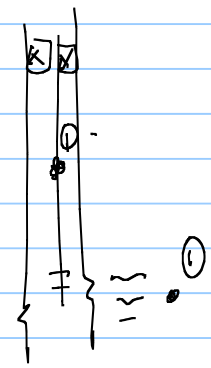
intersection doesn't change much with ID

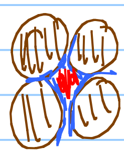


Liquid loading

liquid comes together with gas { condensation from gas / water dissolved in gas

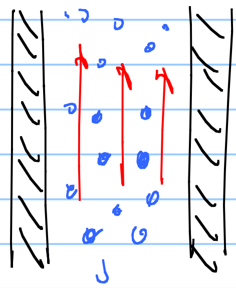


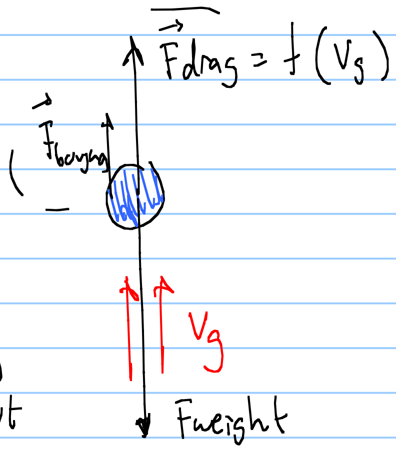


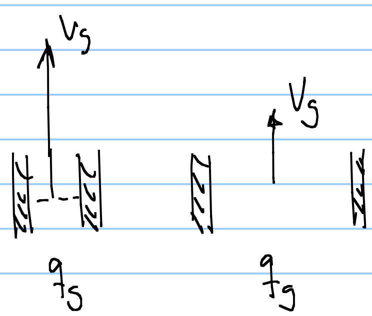


gas saturated with formation water

tubing

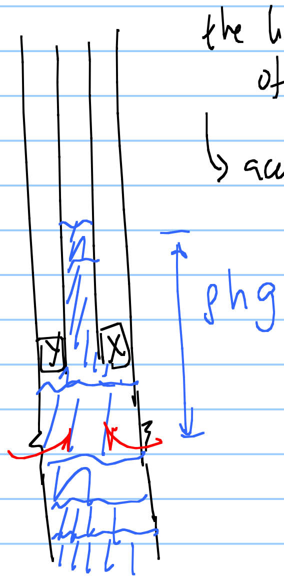




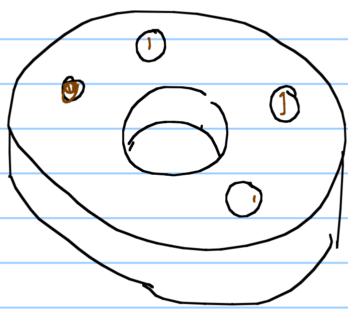


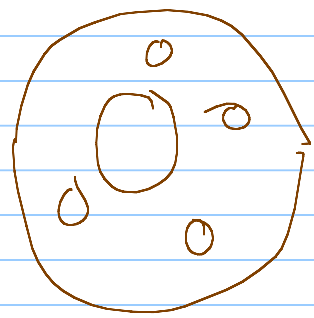
Liquid loading gas cannot carry the liquid out of well

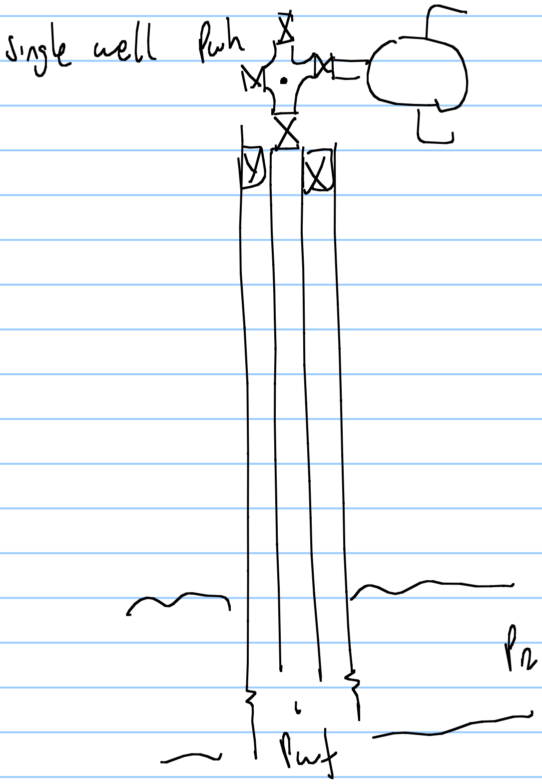
↳ accumulation



• tubing hanger





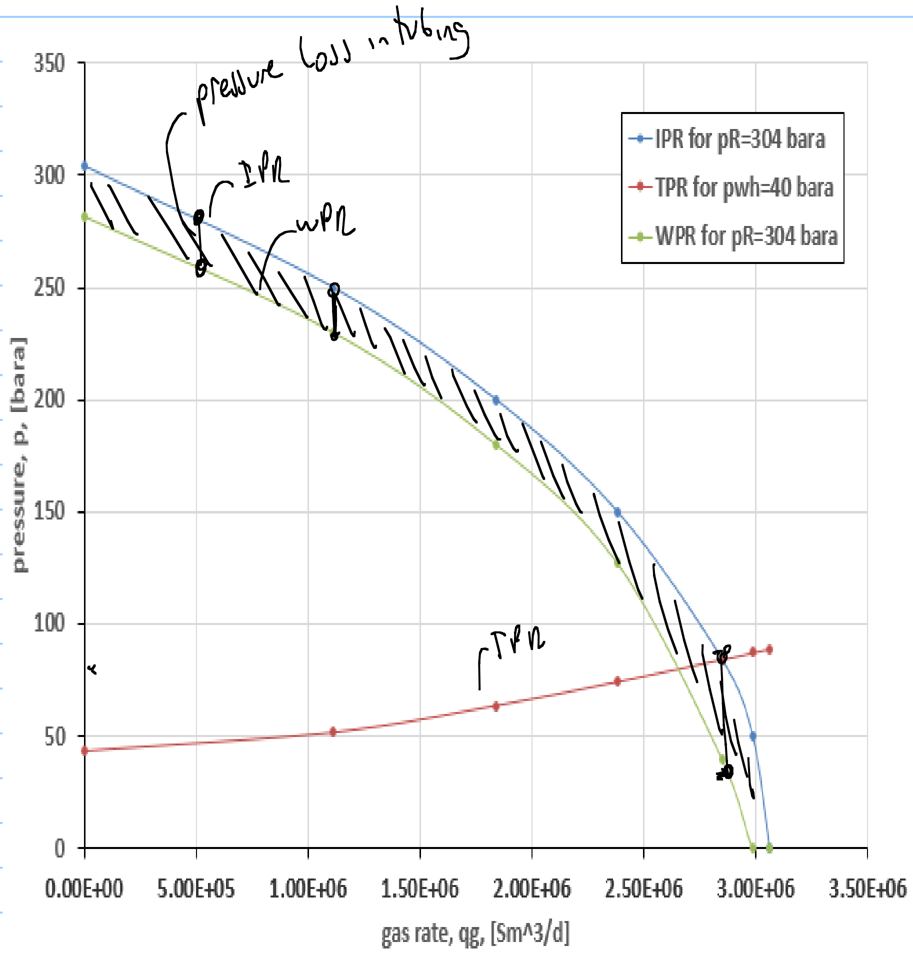


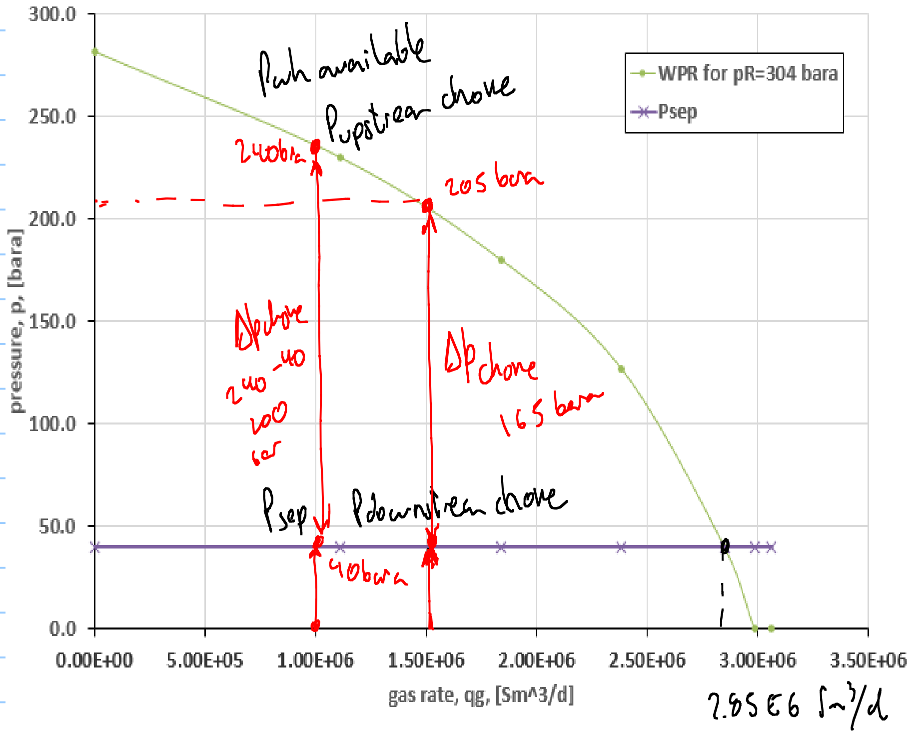
wellhead equilibrium

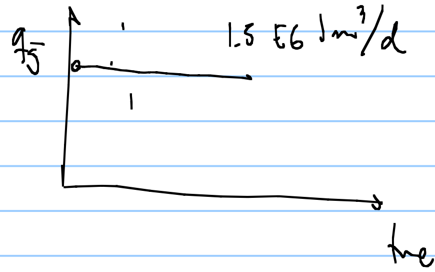
tubing p_1 (give p_2, q_g)

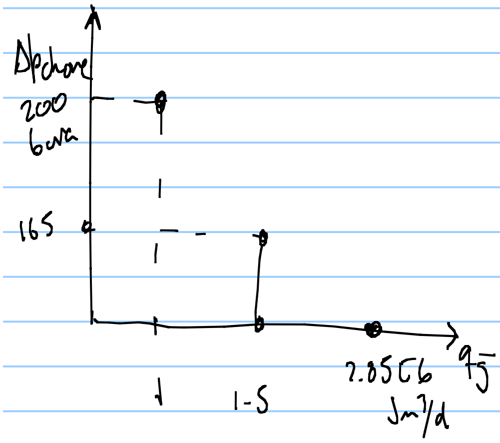
tubing q_g (p_2, p_1)

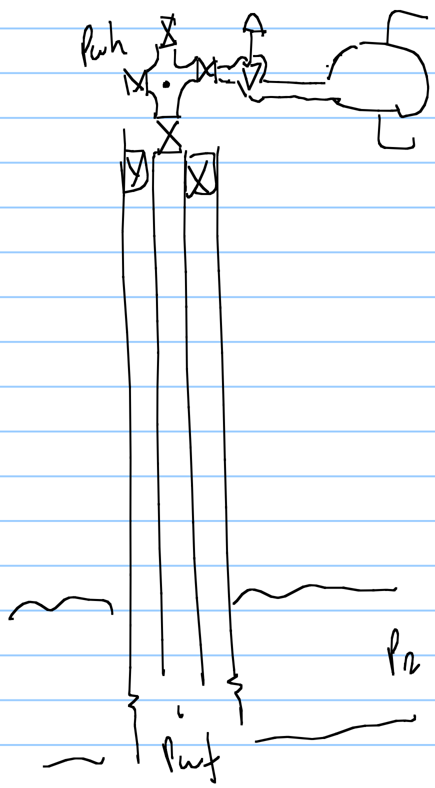
tubing p_2 (q_g, p_1)



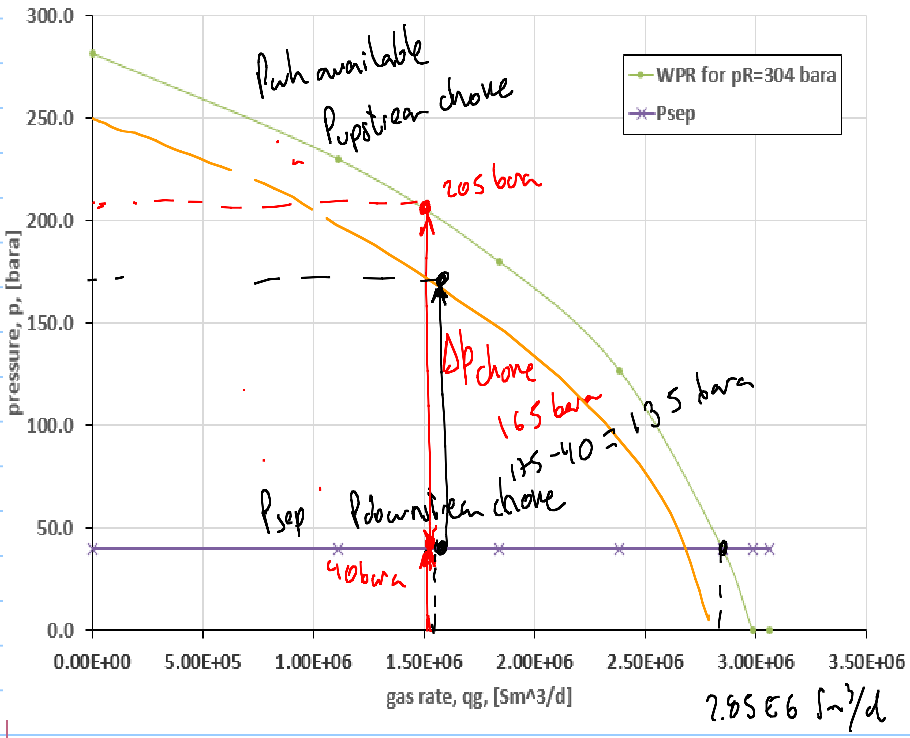

WPR for pR=304 bara
Psep
pressure, p, [bara]
gas rate, qg, [Sm^3/d]
Pwh available
Pupstream choke
240bar
205 bara
Δpchoke
240 -40
200 bar
Δpchoke
165 bara
Psep
Pdownstream choke
40bara
2.85 E6 Sm3/d


1.5 E6 Sm3/d

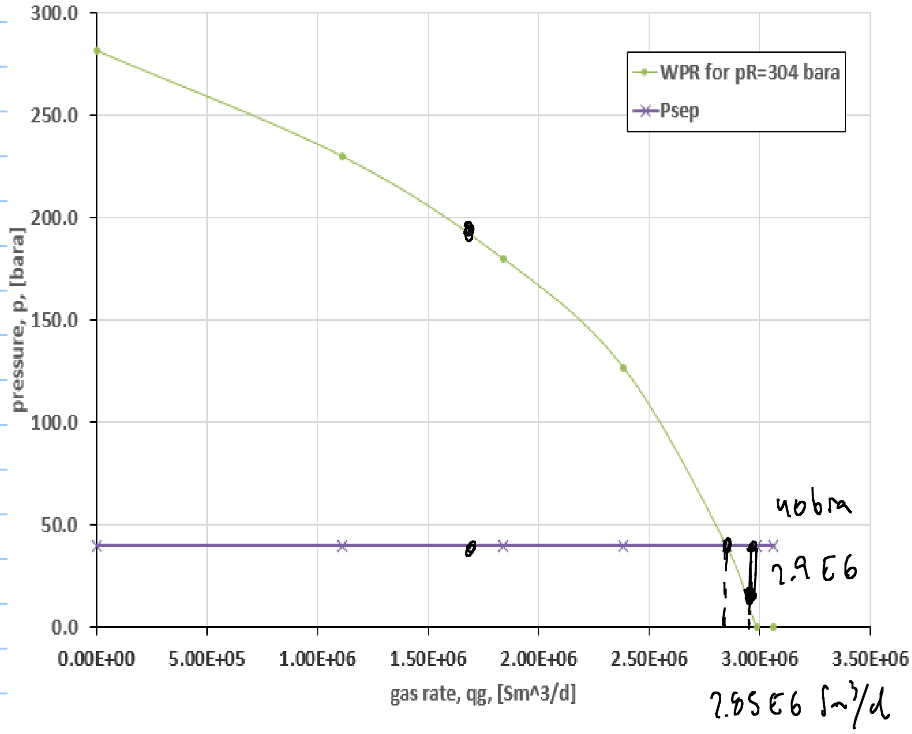

Δpchoke
200 bara
165
1.5
2.85E6 Sm3/d

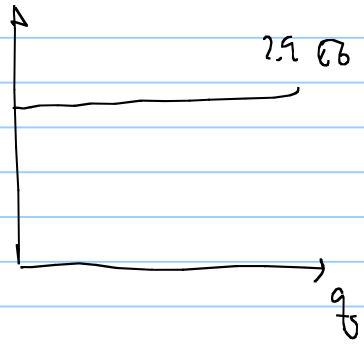

Pwh
PR
Pwf

with depletion



if I desire to produce $q_g > q_{g\,equi}$ → add energy → increase pressure compressor

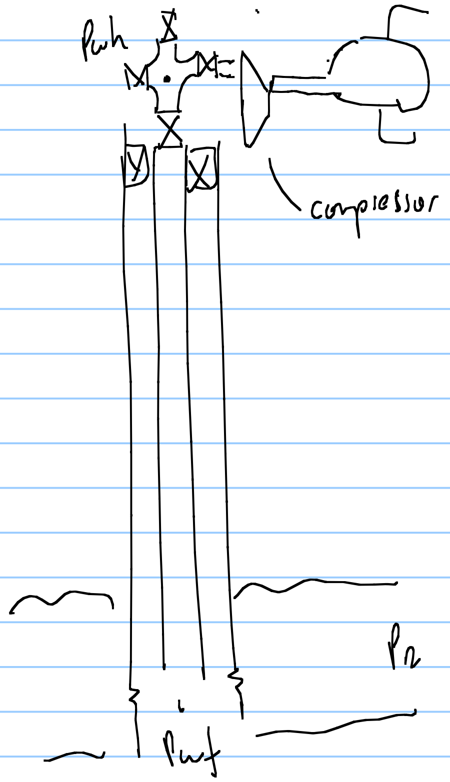




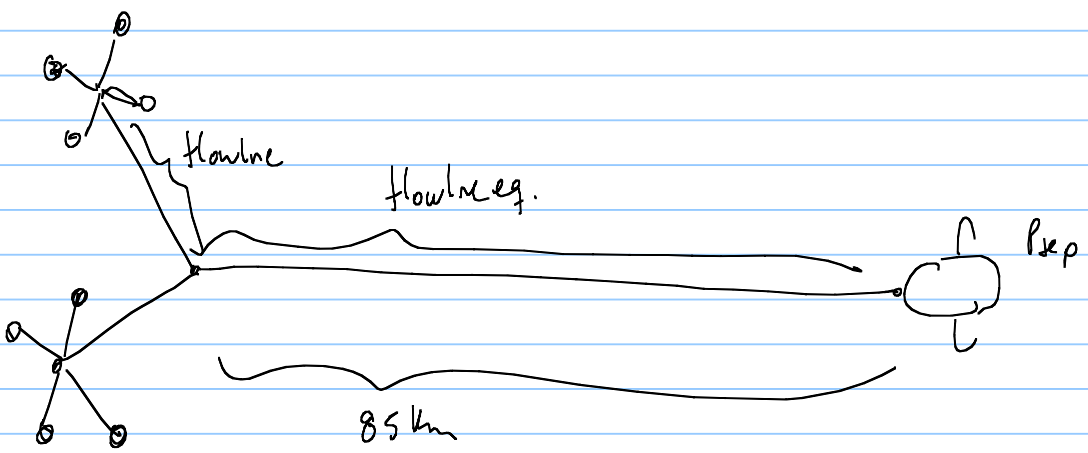
$P_{wh\,req}$ = 40 bara

$P_{wh\,avail}$ = 19 bara

$\Delta P_{compressor}$ = 40 - 19 = 21 bar



Block 2 offshore Tanzania



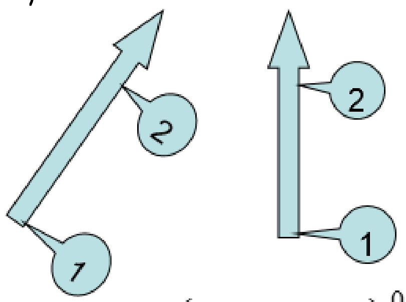
tubing equation $\frac{P_1^2}{e^S} = P_2^2 + \frac{q_g^2}{C_T^2}$ for horizontal pipe?

Tubing flow Equation-Dry gas

$$\boxed{q_{sc} = \underbrace{\left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g f_M Z_{av} T_{av}\, L}\right]^{0.5}\left(\frac{s e^S}{e^S - 1}\right)^{0.5}}_{C_T}\left(\frac{p_1^2}{e^S} - p_2^2\right)^{0.5}}$$

$$\boxed{\frac{s}{2} = \frac{M_g g}{Z_{av} R T_{av}} H = \frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H}$$

$H = 0$ $\qquad$ $S = 0$



$$q_{gsc} = C_T\left(\frac{p_1^2}{e^s} - p_2^2\right)^{0.5}$$

$$p_{\text{inlet}} = p_1 = e^{s/2}\left(p_2^2 + \frac{q_g^2}{C_T^2}\right)^{0.5} \qquad p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

when $s=0$ $\quad \left(\frac{s \cdot e^s}{e^s - 1}\right) \qquad \frac{0 \cdot e^0}{e^0 - 1} = \frac{0}{0}$

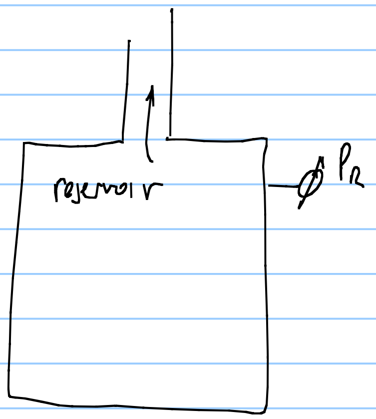
L'Hopital

$$\lim_{s \to 0}\left(\frac{s \cdot e^s}{e^s - 1}\right) = \lim_{s \to 0} \frac{\frac{d}{ds}\left(s \cdot e^s\right)}{\frac{d}{ds}\left(e^s - 1\right)} = \frac{e^s + s\, e^s}{e^s} \overset{s=0}{=} \frac{1 + 0}{1} = 1$$

$$\frac{p_1^2}{\cancel{e^s}_{1}} = p_2^2 + \frac{q_g^2}{C_T^2} \qquad \boxed{\left(p_1^2 - p_2^2\right)^{0.5} C_T = q_g}$$

horizontal pipeline

field performance



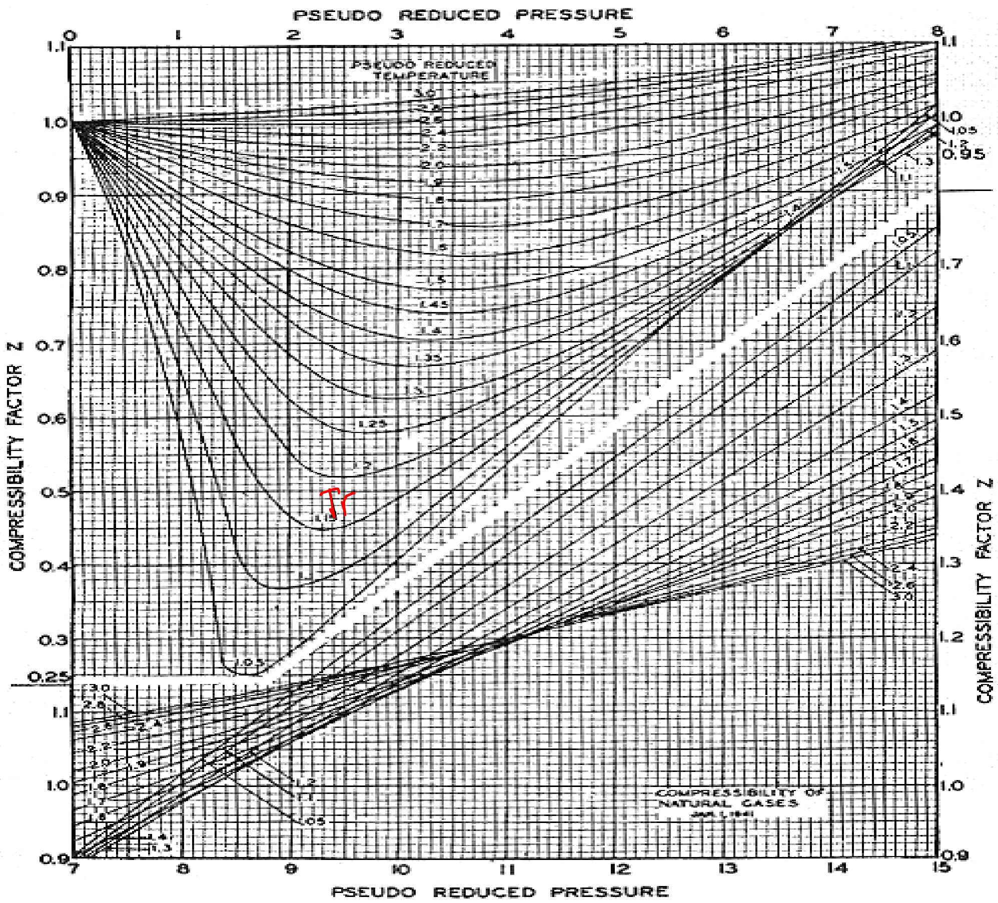
P_R vs G_p

dry gas material balance

$$p_R = p_i \frac{z_R}{z_i}\left(1 - \frac{G_p}{G}\right)$$

$$\frac{G_p}{G} = RF = F_{Ru}$$

deviation factor z



$z_R = f(p_R, T_R)$

$T_r = \frac{T}{T_c}$

$p_r = \frac{p}{p_c}$

assume $P_{R_{assumed}}$ → Calculate z_R

estimate $P_{R_{calc}} = P_i \dfrac{z_R}{z_i}\left(1-\dfrac{G_p}{G}\right) =$

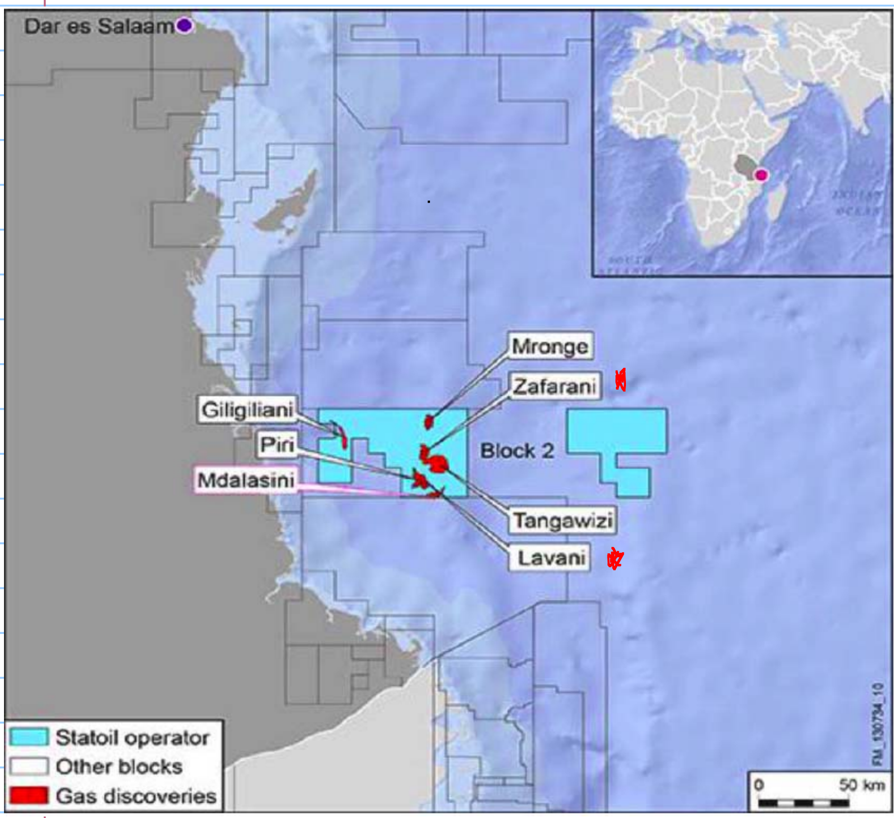
compare is $P_{Rcalc} = P_{Rassume}$

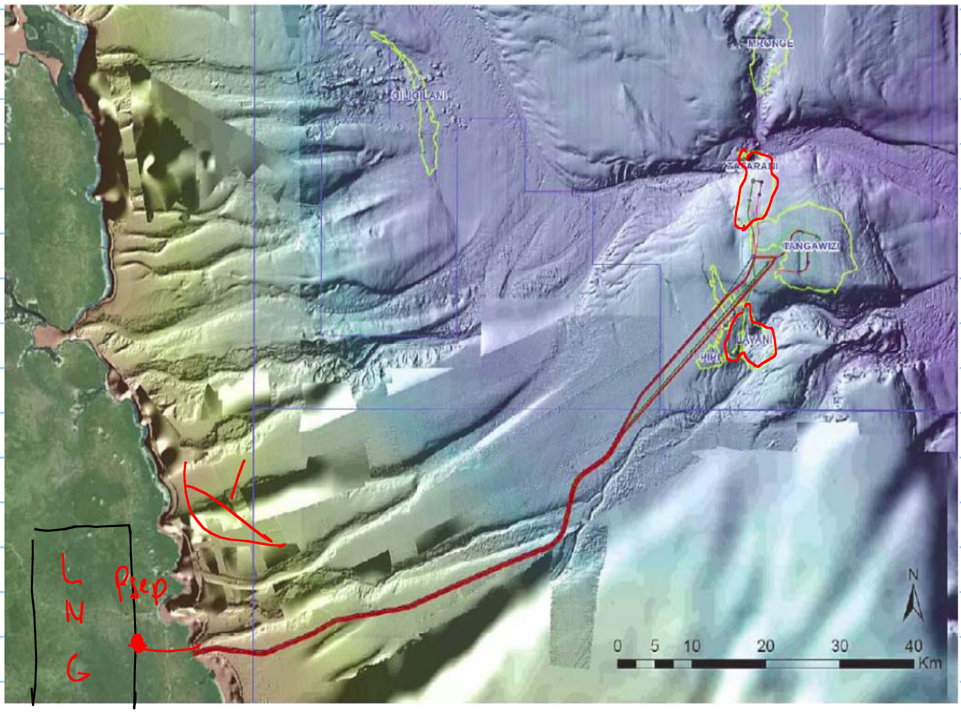
NO → P_{Rcalc} → assume $P_{R_{assumed}}$

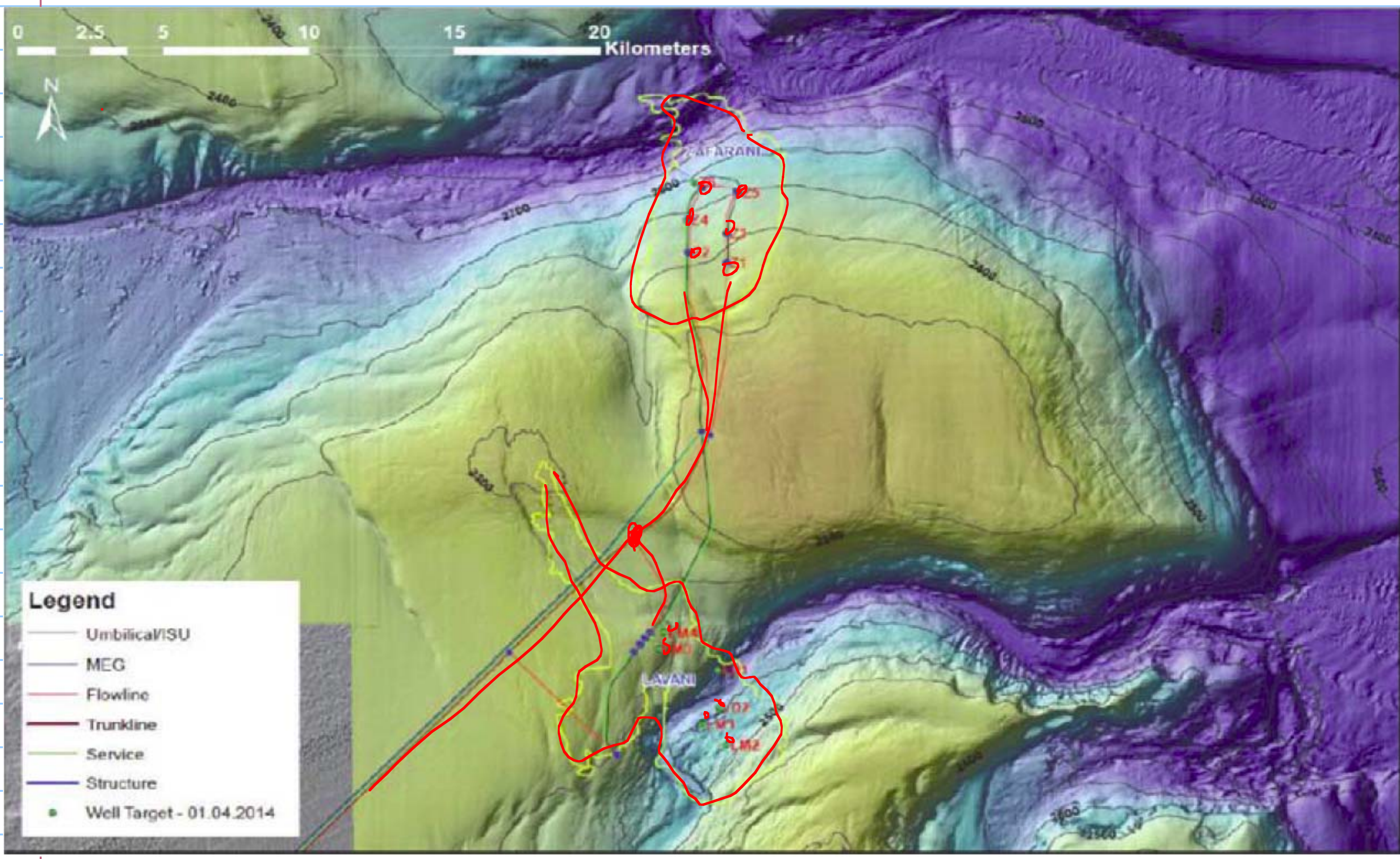
yes

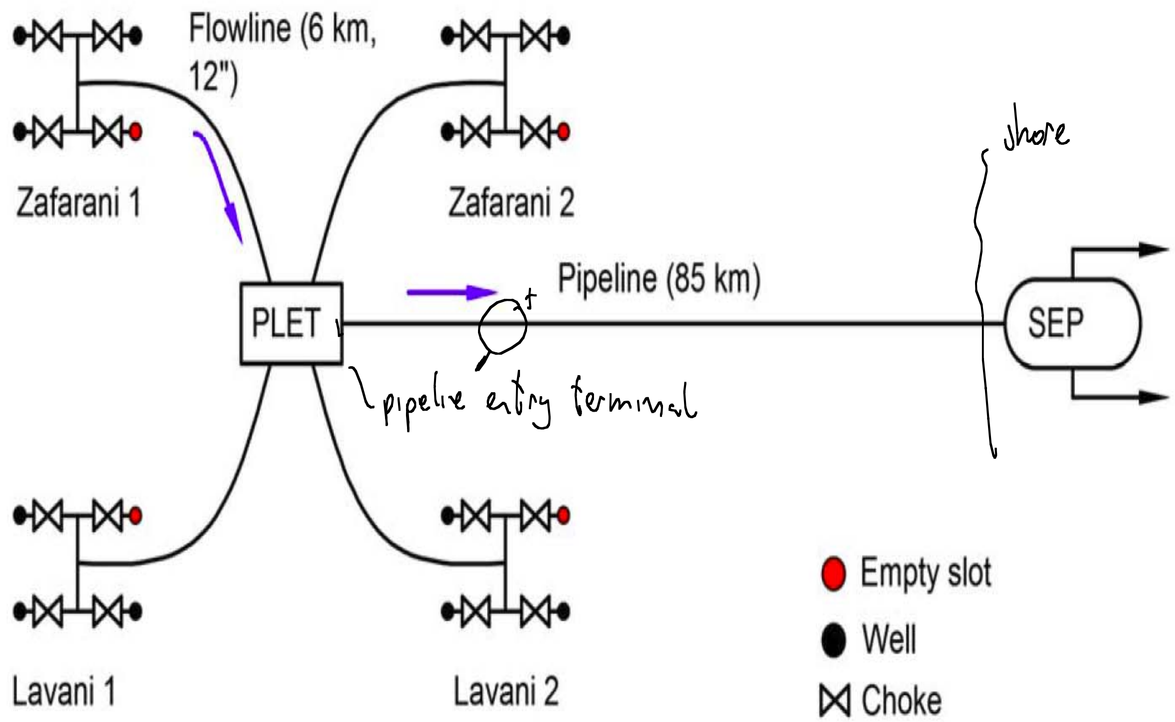
$P_R = P_{Rcalcul}$

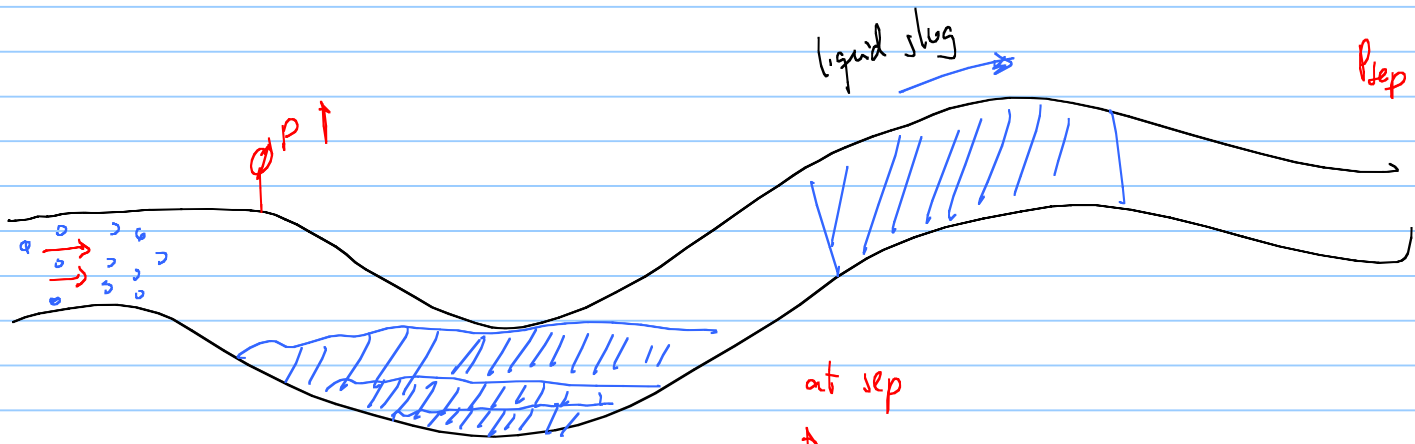
Block 2 offshore Tanzania

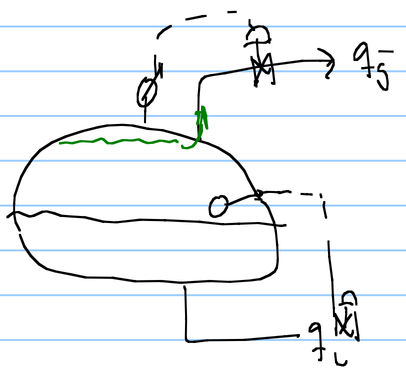


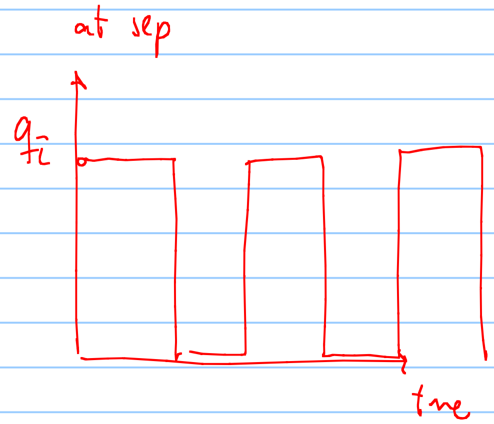

ZAFARANI
TANGAWIZI
LAVANI
N
0 5 10 20 30 40
Km
L
N
G

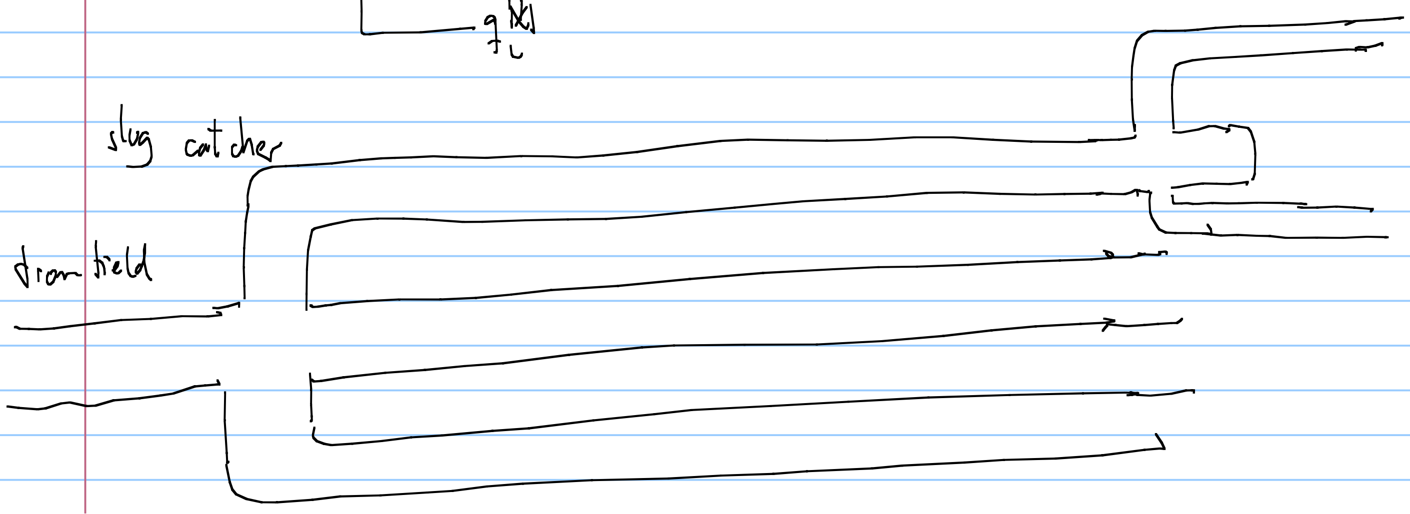

0 2.5 5 10 15 20
Kilometers
N
ZAFARANI
LAVANI
Legend
Umbilical/ISU
MEG
Flowline
Trunkline
Service
Structure
Well Target - 01.04.2014


Flowline (6 km, 12")
Zafarani 1
Zafarani 2
PLET
Pipeline (85 km)
SEP
shore
pipeline entry terminal
Lavani 1
Lavani 2
Empty slot
Well
Choke

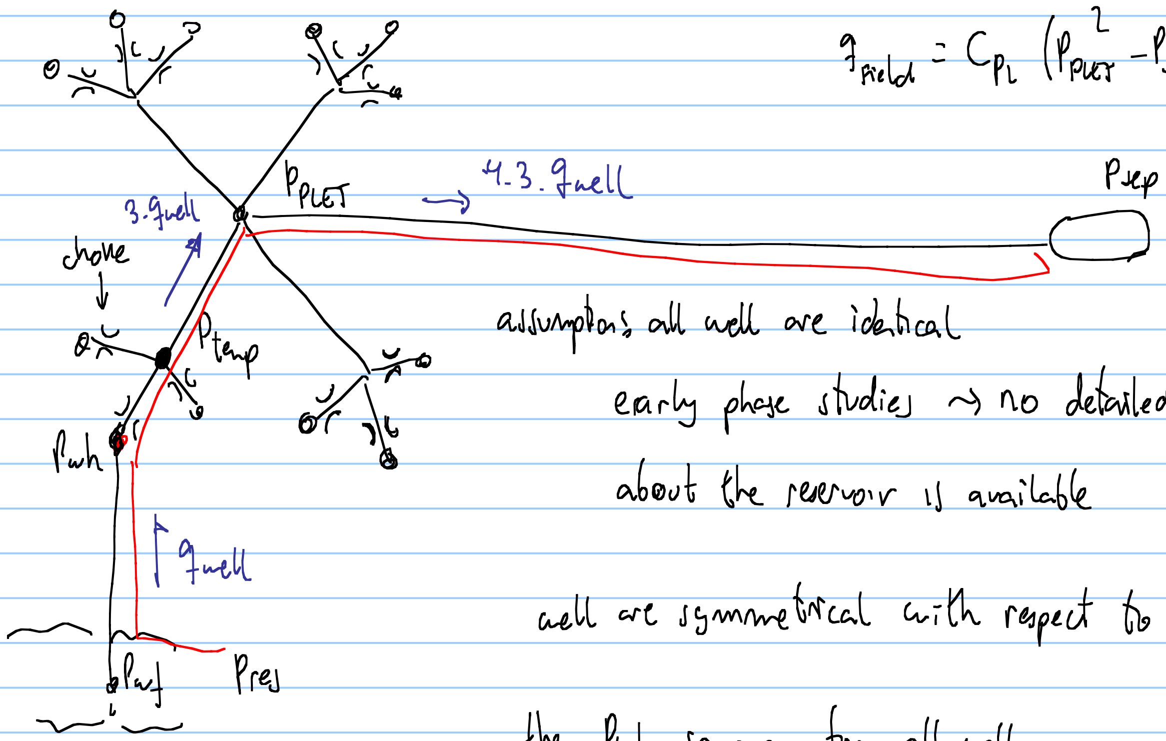

P ↑
liquid slug
P_sep


q_g
q_L


at sep
q_L
time


slug catcher
from field

$$q_{field} = C_{PL}\left(P_{PLET}^2 - P_{sep}^2\right)^{0.5}$$



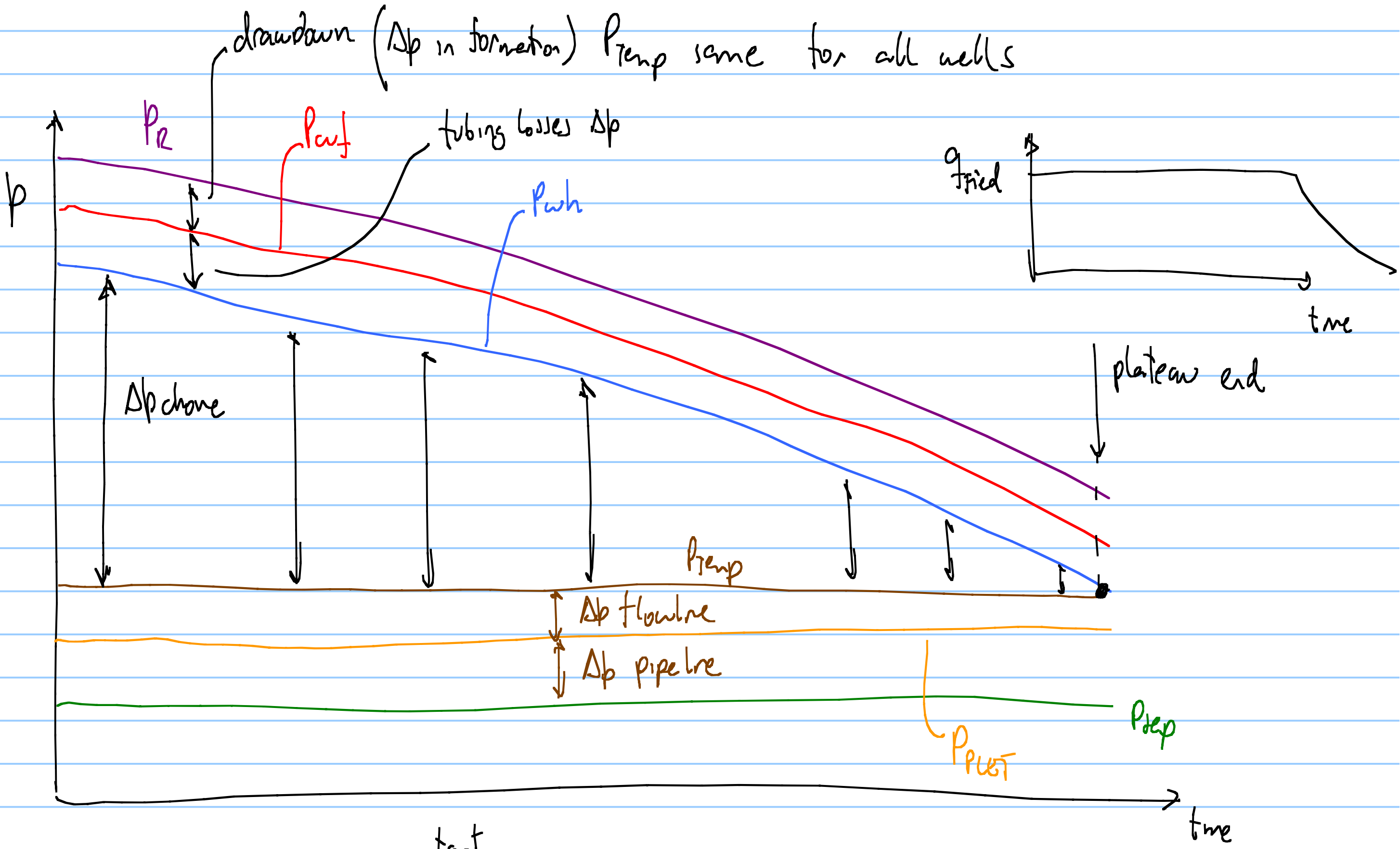
assumptions all well are identical

early phase studies → no detailed information about the reservoir is available

well are symmetrical with respect to PLET

the P_{wh} same for all wells

P_{temp} same for all wells



what happens with P_{wf} with time?

$$\underbrace{q_{well}}_{\text{constant}} = C\left(P_R^2 - \underbrace{P_{wf}^2}_{\text{going down}}\right)^n$$

what happens with P_{wh} with time?

$$\frac{P_{wf}^2}{e^s} = P_{wh}^2 + \frac{q_{well}^2}{C_T^2}$$

how P_{PLET} changes with time?

$$q_{Field} = C_{PL} \cdot \left(P_{PLET}^2 - P_{sep}^2\right)^{0.5}$$

how P_{Temp} changes with time?

$$q_{Temp} = C_{FL} \left(P_{Temp}^2 - P_{PLET}^2\right)^{0.5}$$

Class exercise

G=IGIP	311E+09	Sm3
Production days per year	360	day
T_R	70	°C
Pi, initial Res pressure	390	bara
C, inflow Back pressure coefficient	123	Sm3/bar^2n
n, backpressure, exponent	1	
Ct, Tubing coefficient	3.56E+04	Sm3/bar
Tubing elevation coeff, S	0.155	
$C_{FL\ Flowline}$ Template-PLET	2.83E+05	Sm3/bar
$C_{PL\ Pipeline}$ PLET-Shore	3.46E+05	Sm3/bar
~~Pipeline elevation coeff, S~~		
Separator (slug catcher) pressure	35	bara
Gas molecular weight (Methane)	16.5	kg/kmole
Gas specific gravity	0.57	Gas specific gravity
Number of templates	4	
Number of wells per template	3	
qfield	18.0E+6	[Sm^3/d]

? MB

$$p_R = \frac{z_R}{z_i} p_i \left(1 - \frac{G_p}{G}\right)$$

$$G_p = \int_0^t q_{field}\, dt$$

? z_R

MB gas

IPR

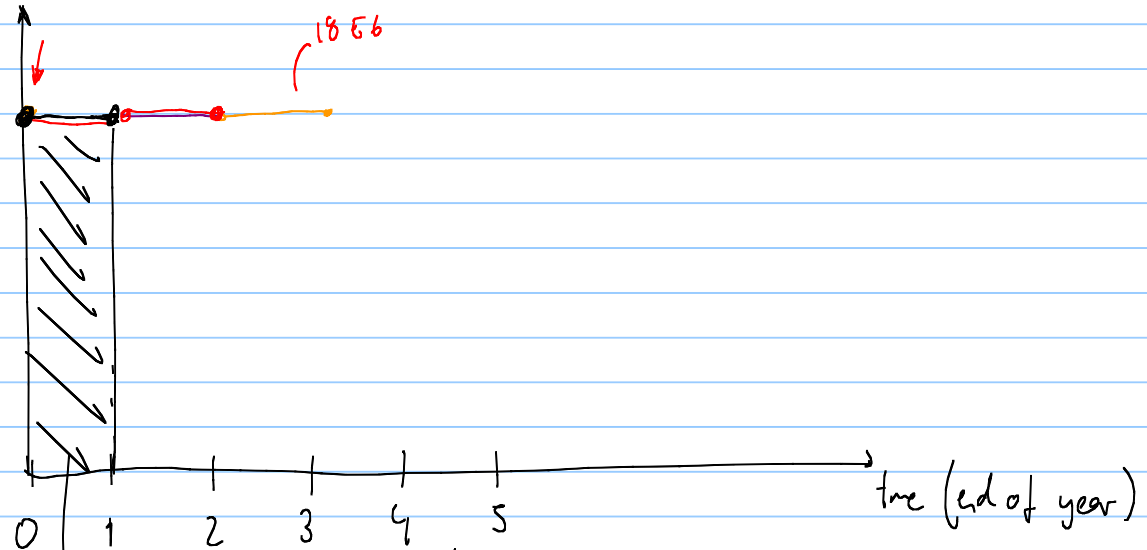
TPR

flowline

pipeline

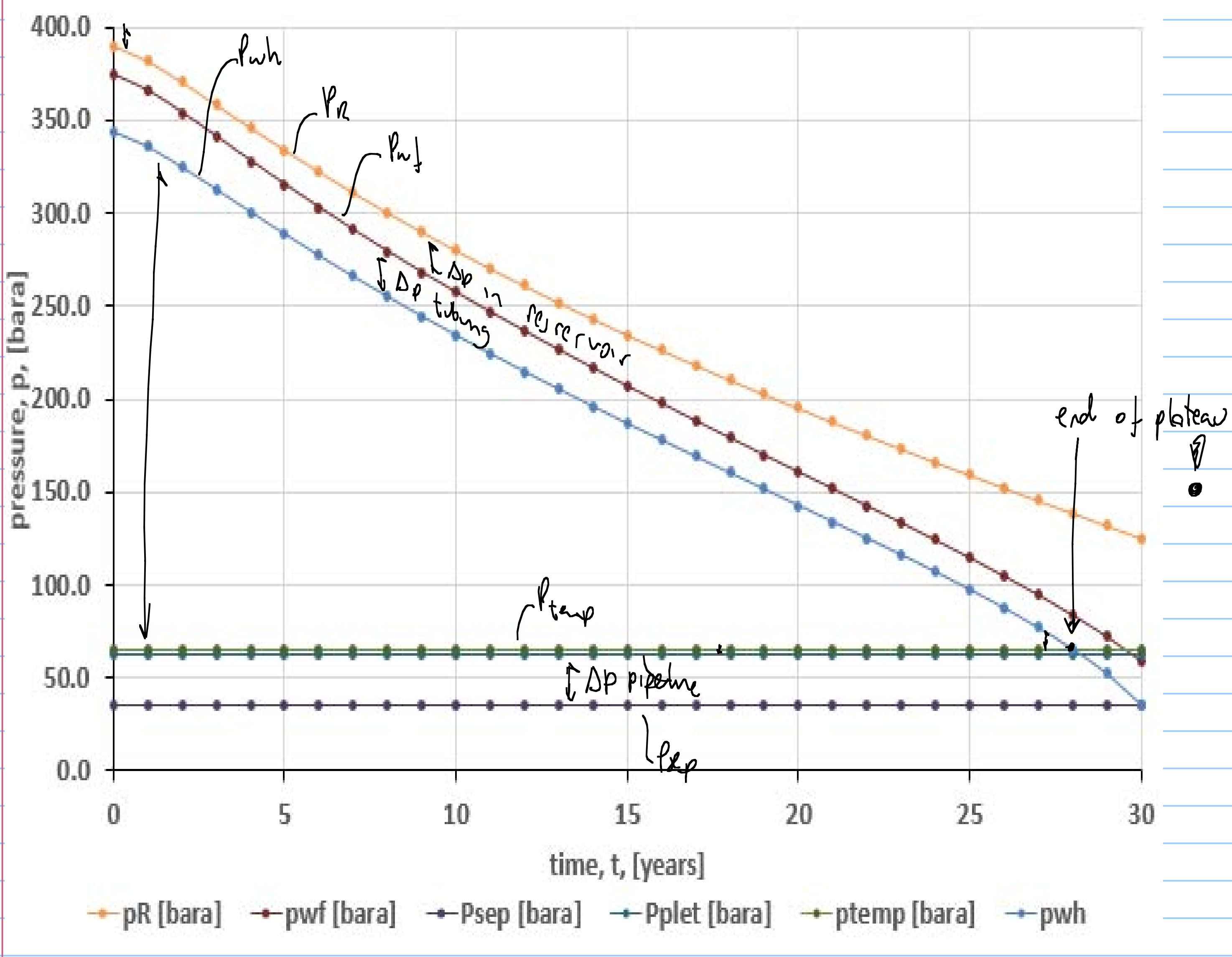
P_{sep}

P_c, T_c



$$\Delta G_p = q_{field}^{0} \cdot (\overbrace{t_1 - t_0}^{years}) \cdot N\,days/year$$

time	qwell	qfield	ΔGp	Gp	RF	pR	Z	pwf	pwh	Psep	Pplet	qtemp	ptemp	Deltpchoke
[years]	[Sm^3/d]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[bara]	[-]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bara]	[bara]
0	1.50E+06	18.0E+6	000.0E+0	000.0E+0	0.00	390.0	1.045	374.0	343.6	35.0	62.7	4.50E+06	64.7	279
1	1.50E+06	18.0E+6	6.5E+9	6.5E+9	0.02	381.9	1.036	365.6	335.7	35.0	62.7	4.50E+06	64.7	271
2	1.50E+06	18.0E+6	6.5E+9	13.0E+9	0.04	370.6	1.024	353.8	324.7	35.0	62.7	4.50E+06	64.7	260
3	1.50E+06	18.0E+6	6.5E+9	19.4E+9	0.06	358.4	1.012	340.9	312.7	35.0	62.7	4.50E+06	64.7	248
4	1.50E+06	18.0E+6	6.5E+9	25.9E+9	0.08	346.1	0.999	328.0	300.6	35.0	62.7	4.50E+06	64.7	236
5	1.50E+06	18.0E+6	6.5E+9	32.4E+9	0.10	334.0	0.987	315.3	288.7	35.0	62.7	4.50E+06	64.7	224
6	1.50E+06	18.0E+6	6.5E+9	38.9E+9	0.13	322.4	0.976	302.9	277.1	35.0	62.7	4.50E+06	64.7	212
7	1.50E+06	18.0E+6	6.5E+9	45.4E+9	0.15	311.2	0.966	291.0	265.9	35.0	62.7	4.50E+06	64.7	201
8	1.50E+06	18.0E+6	6.5E+9	51.8E+9	0.17	300.4	0.957	279.4	255.1	35.0	62.7	4.50E+06	64.7	190
9	1.50E+06	18.0E+6	6.5E+9	58.3E+9	0.19	290.0	0.948	268.2	244.6	35.0	62.7	4.50E+06	64.7	180
10	1.50E+06	18.0E+6	6.5E+9	64.8E+9	0.21	280.0	0.940	257.3	234.4	35.0	62.7	4.50E+06	64.7	170
11	1.50E+06	18.0E+6	6.5E+9	71.3E+9	0.23	270.4	0.933	246.8	224.5	35.0	62.7	4.50E+06	64.7	160
12	1.50E+06	18.0E+6	6.5E+9	77.8E+9	0.25	261.0	0.926	236.5	214.8	35.0	62.7	4.50E+06	64.7	150
13	1.50E+06	18.0E+6	6.5E+9	84.2E+9	0.27	252.0	0.920	226.5	205.3	35.0	62.7	4.50E+06	64.7	141
14	1.50E+06	18.0E+6	6.5E+9	90.7E+9	0.29	243.2	0.915	216.7	196.0	35.0	62.7	4.50E+06	64.7	131
15	1.50E+06	18.0E+6	6.5E+9	97.2E+9	0.31	234.7	0.910	207.1	186.9	35.0	62.7	4.50E+06	64.7	122
16	1.50E+06	18.0E+6	6.5E+9	103.7E+9	0.33	226.4	0.906	197.6	178.0	35.0	62.7	4.50E+06	64.7	113
17	1.50E+06	18.0E+6	6.5E+9	110.2E+9	0.35	218.3	0.902	188.3	169.1	35.0	62.7	4.50E+06	64.7	104



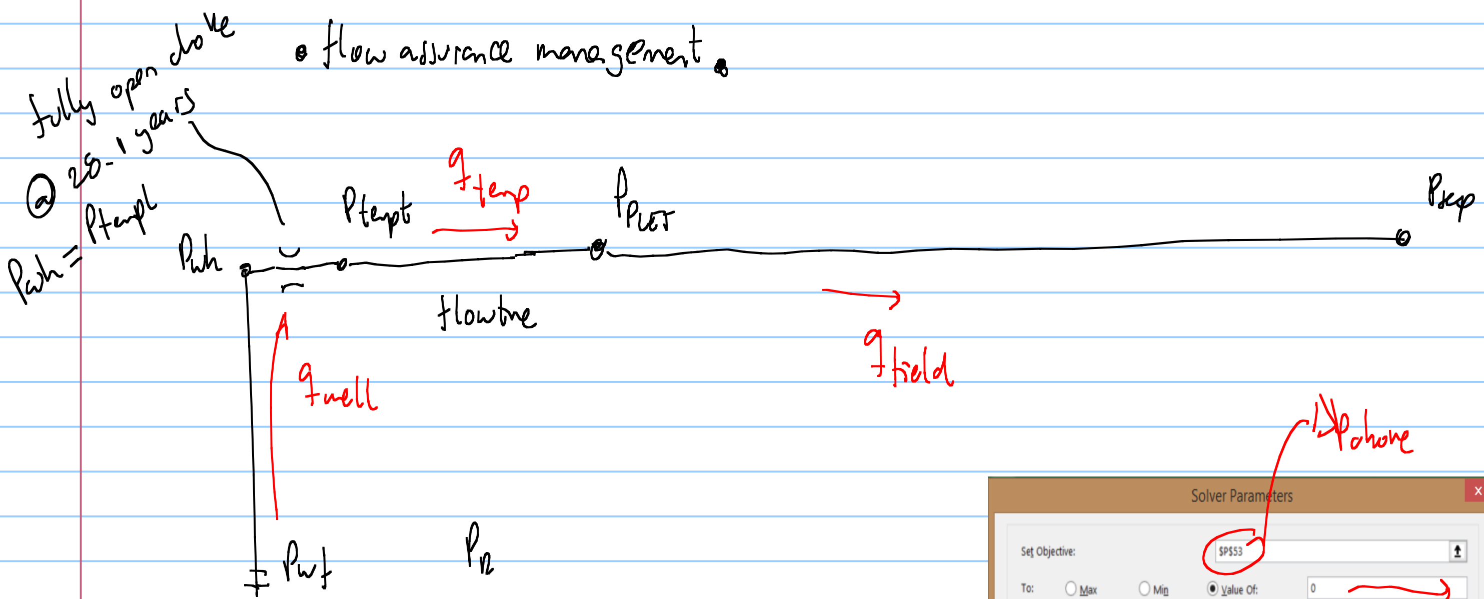
end of plateau using goal seek:

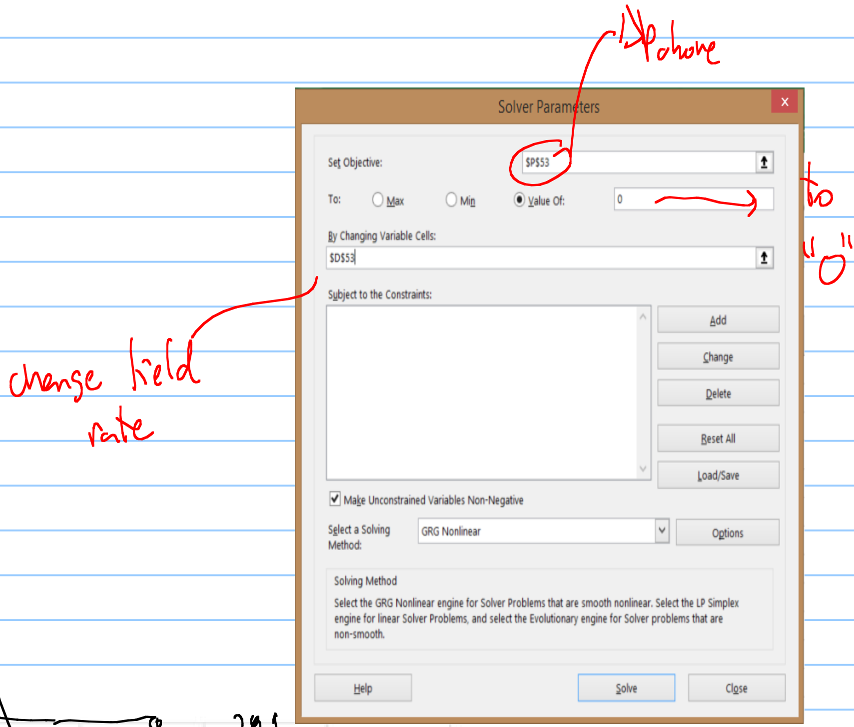
28	1.50E+06	18.0E+6	6.5E+9	181.4E+9	0.58	138.9	0.895	84.2	65.5	35.0	62.7	4.50E+06	64.7	1
28.09879707	1.50E+06	18.0E+6	640.2E+6	182.1E+9	0.59	138.4	0.895	83.4	64.7	35.0	62.7	4.50E+06	64.7	0

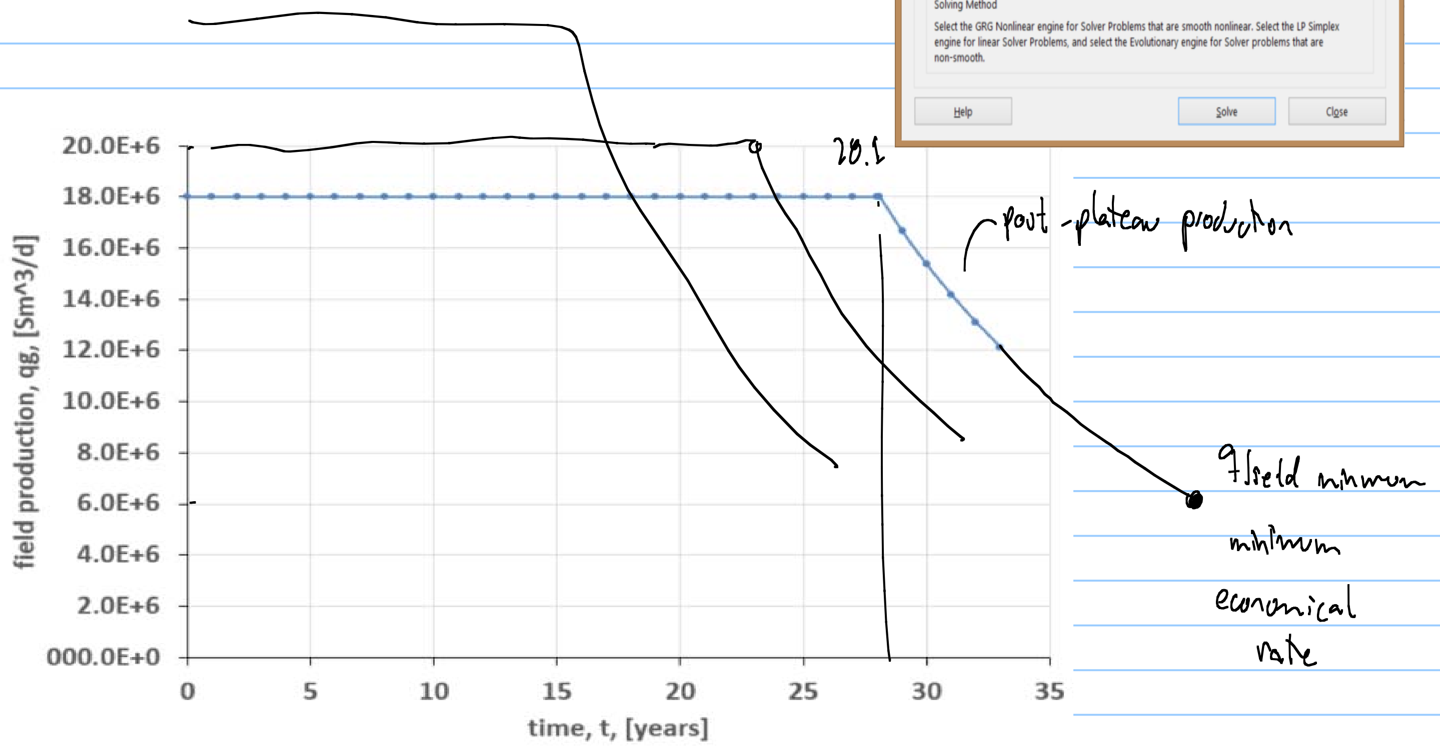
@ 28.0987 years ≈ 28 years + 1.2 months

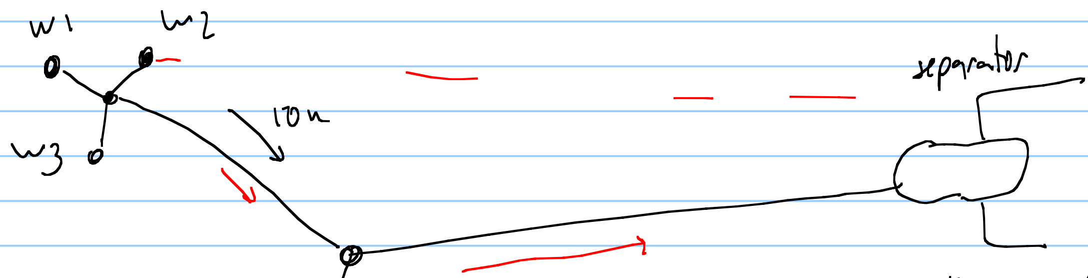
Day 5

- Computing field production post-plateau → solver ◦ goal seek not suitable
- Networks { surface / downhole
- TPR - multiphase.
- flow assurance management.

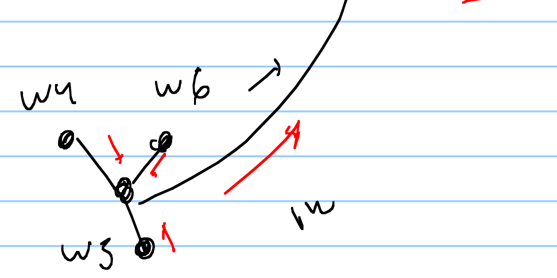








gathering network



Surface network: gather the production of individual wells and take it to the processing facilities

well have different productivity

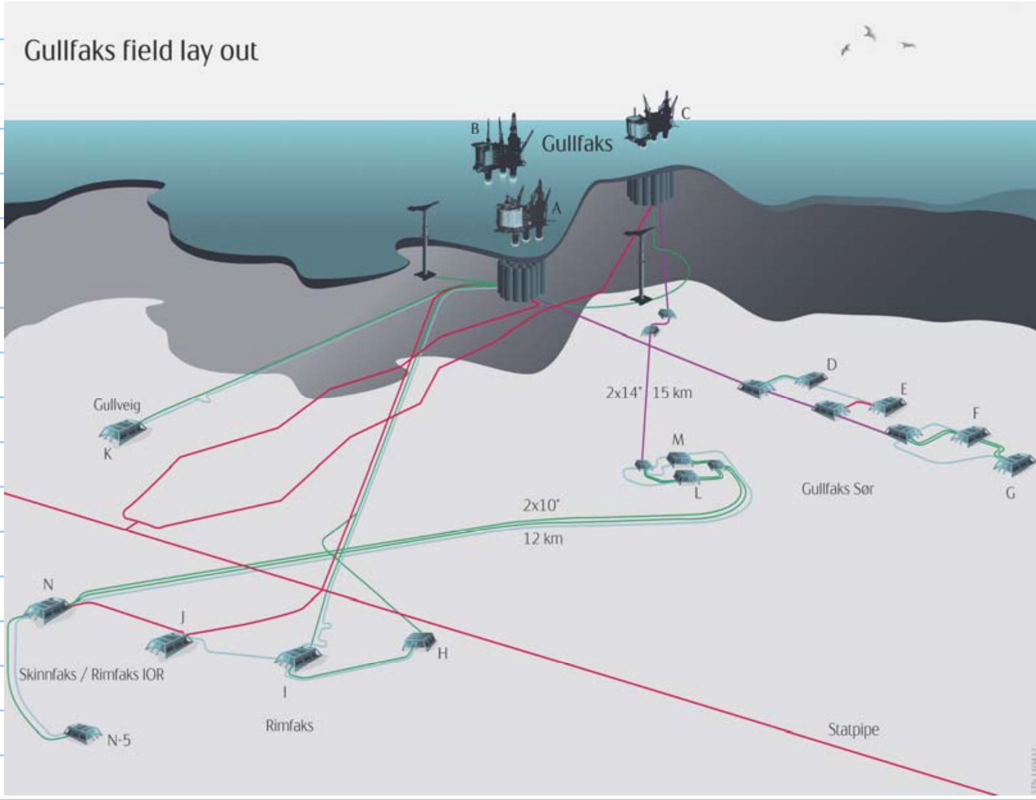
IPR

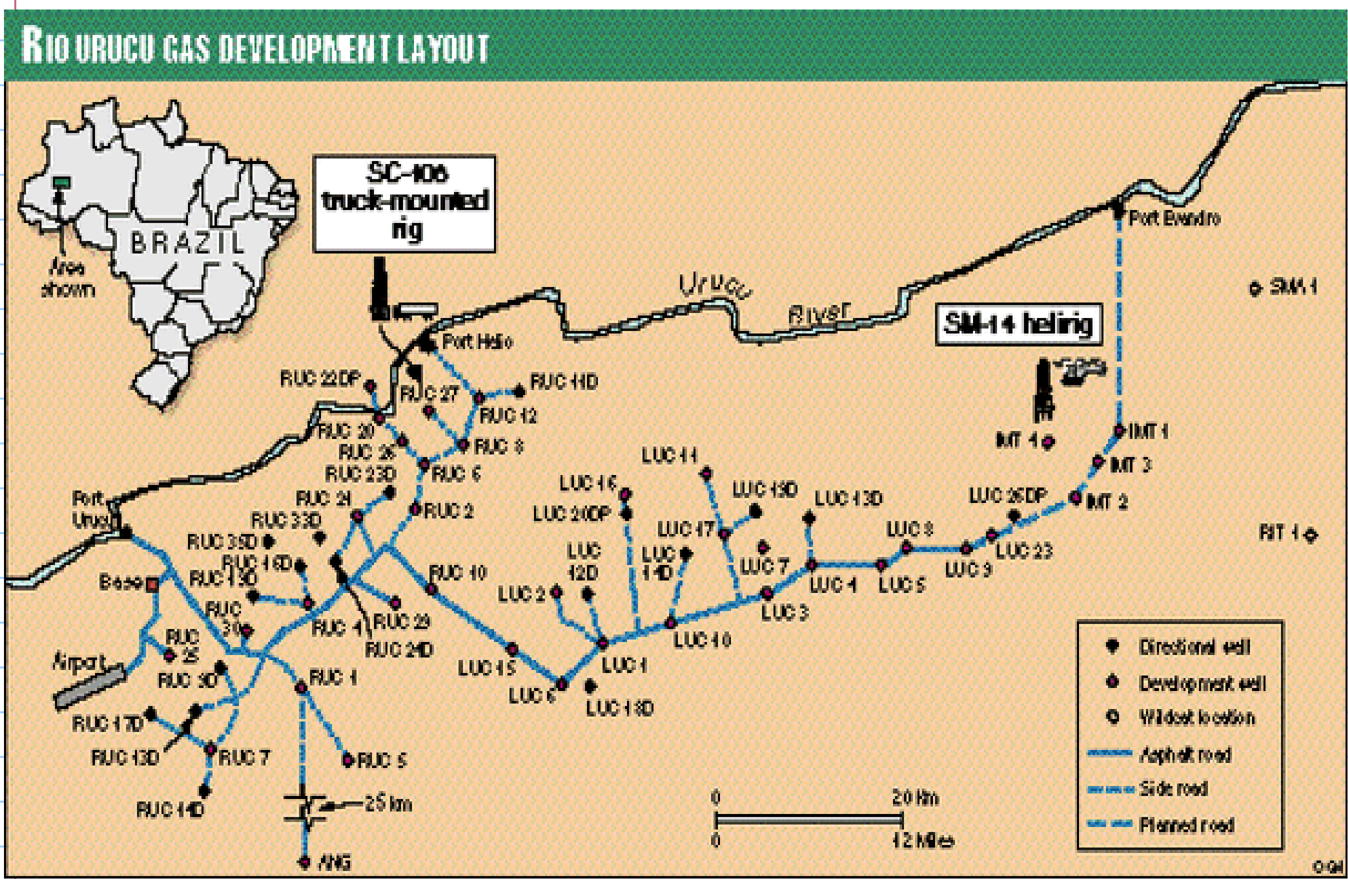
well depth

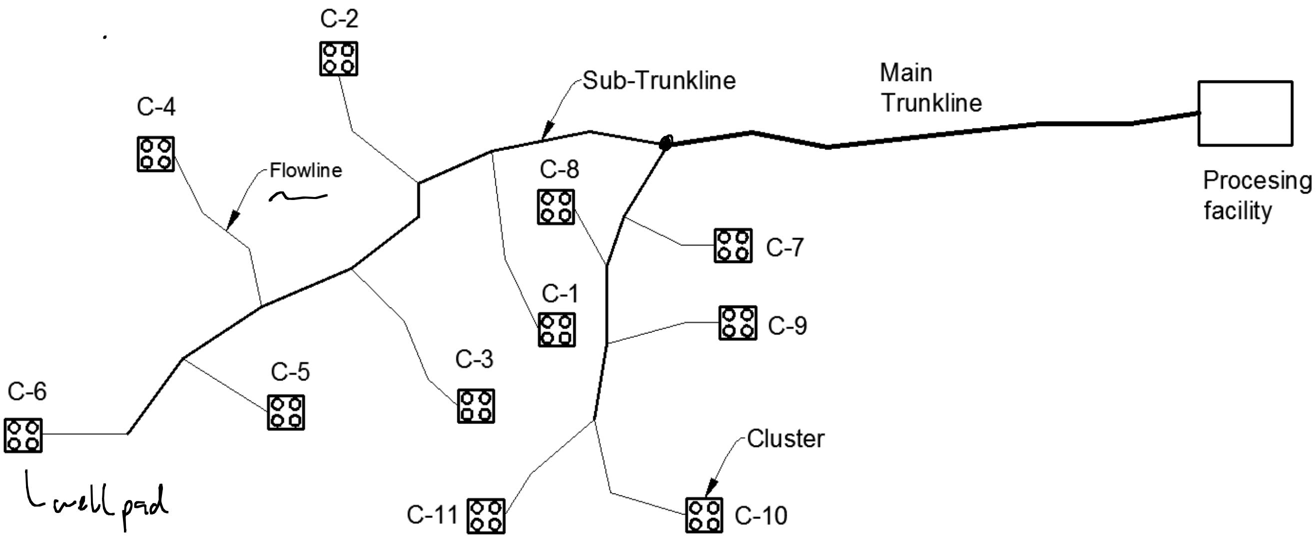
tubing size

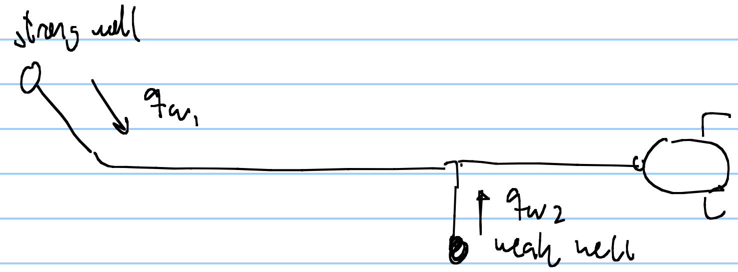
pipeline size length

Some examples

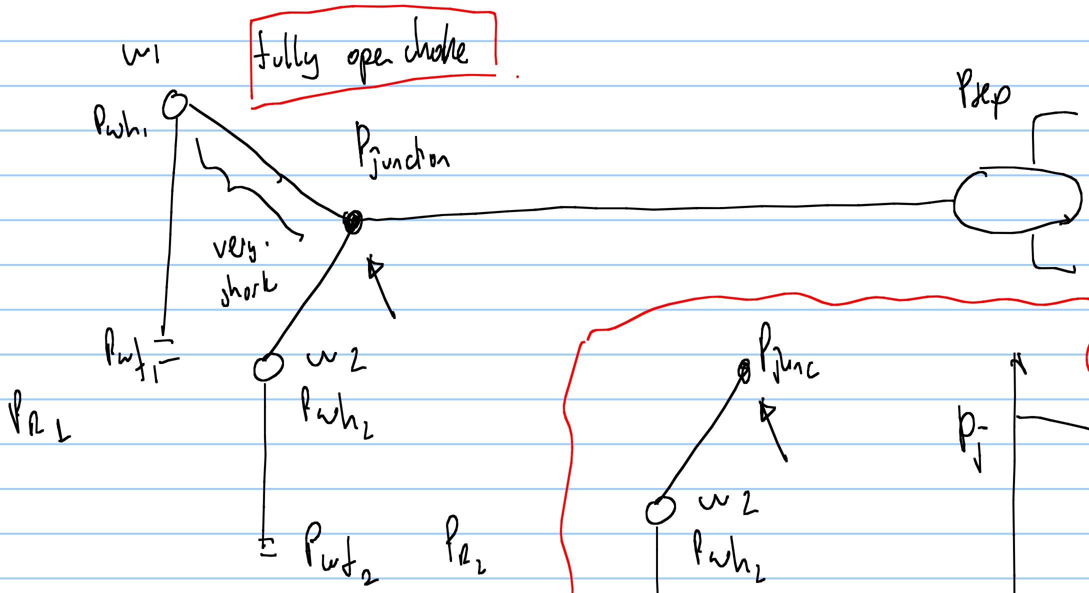

Gullfaks field lay out
Gullfaks
B
C
A
D
E
F
G
Gullveig
K
2x14" 15 km
M
L
Gullfaks Sør
2x10"
12 km
N
J
H
Skinnfaks / Rimfaks IOR
I
Rimfaks
N-5
Statpipe

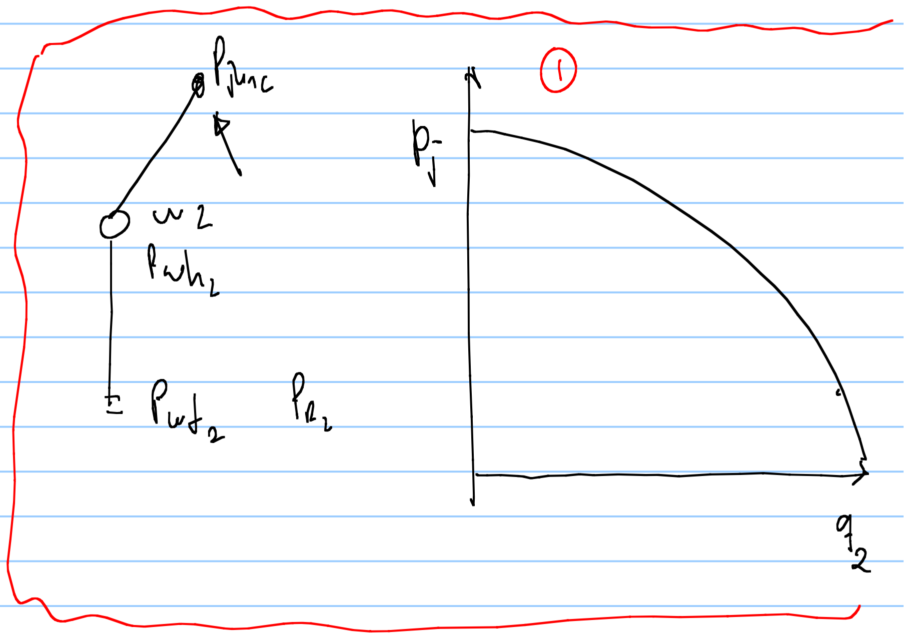

RIO URUCU GAS DEVELOPMENT LAYOUT
BRAZIL
Area shown
SC-106 truck-mounted rig
Urucu River
SM-14 helirig
Port Evandro
Port Urucu
Base
Airport
Directional well
Development well
Wildcat location
Asphalt road
Side road
Planned road
20 km
12 Miles
ANG

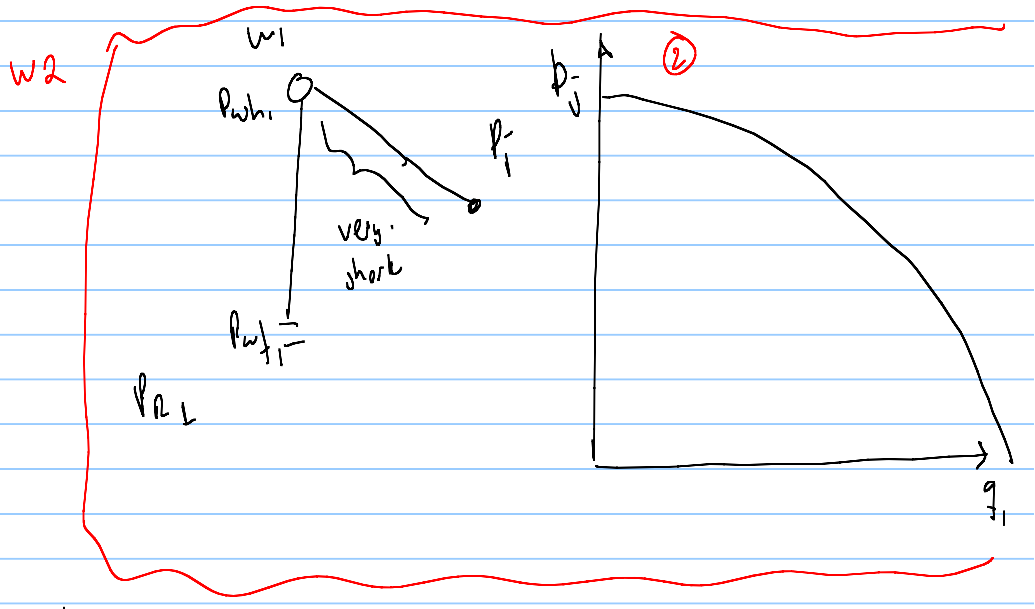




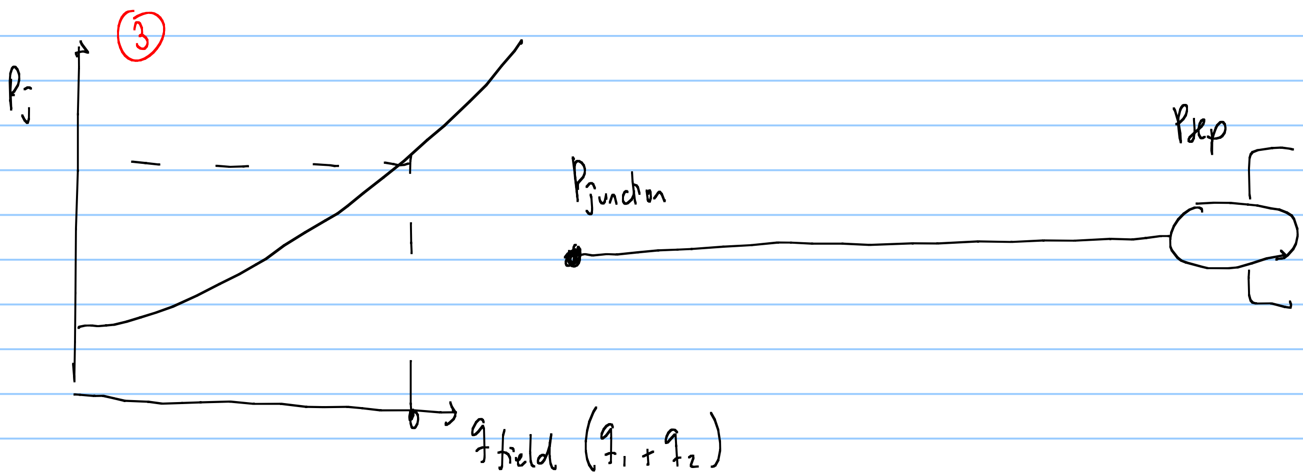
Simple 2-well system







required pressure at junction

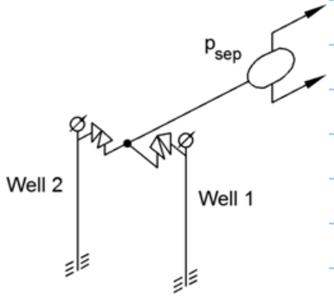


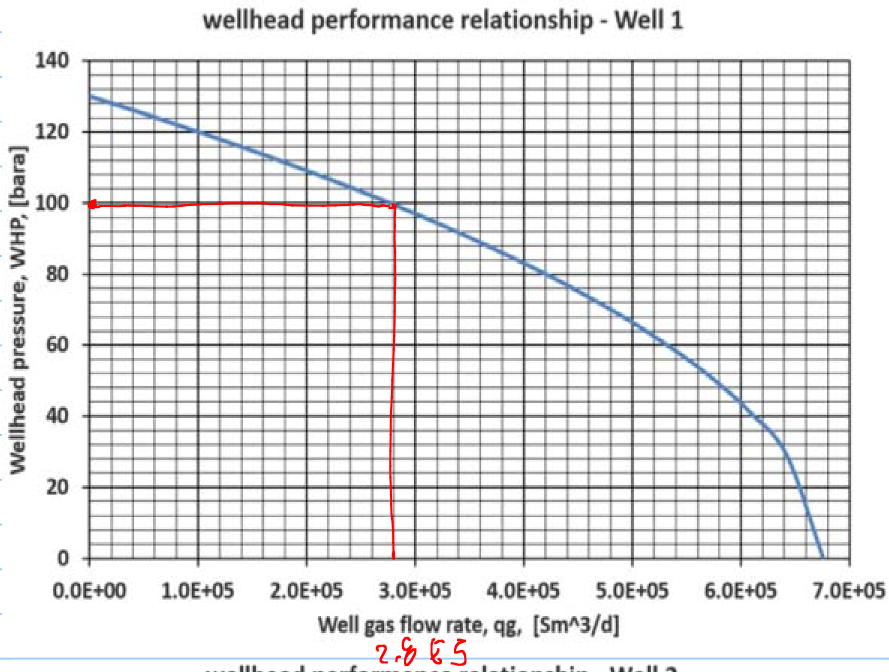
P_j should be the same for curve 1, 2, 3 also $q_{field} = q_1 + q_2$

- assume P_j^*
- go to curve ① and read q_2 with P_j^*
- go to curve ② and read q_1 with P_j^*
- go to curve ③ and read q_{field} with P_j^*
- verify $q_{field} = q_1 + q_2$? if yes → P_j is equilibrium pressure

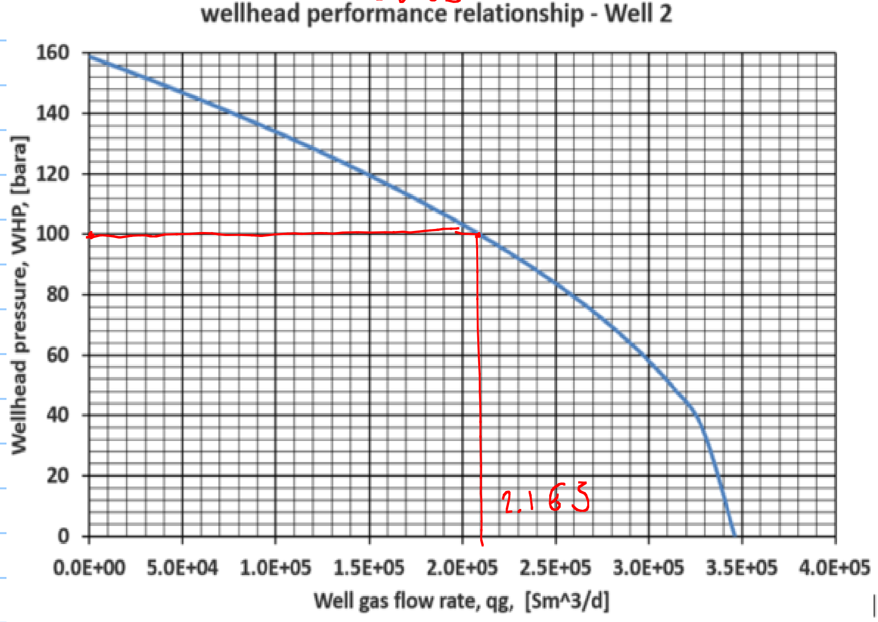
NOT ↓ try another P_j

class exercise





iteration ① assume $p_j = 100$ bara



$q_1 + q_2 = 2.8$ E5 +

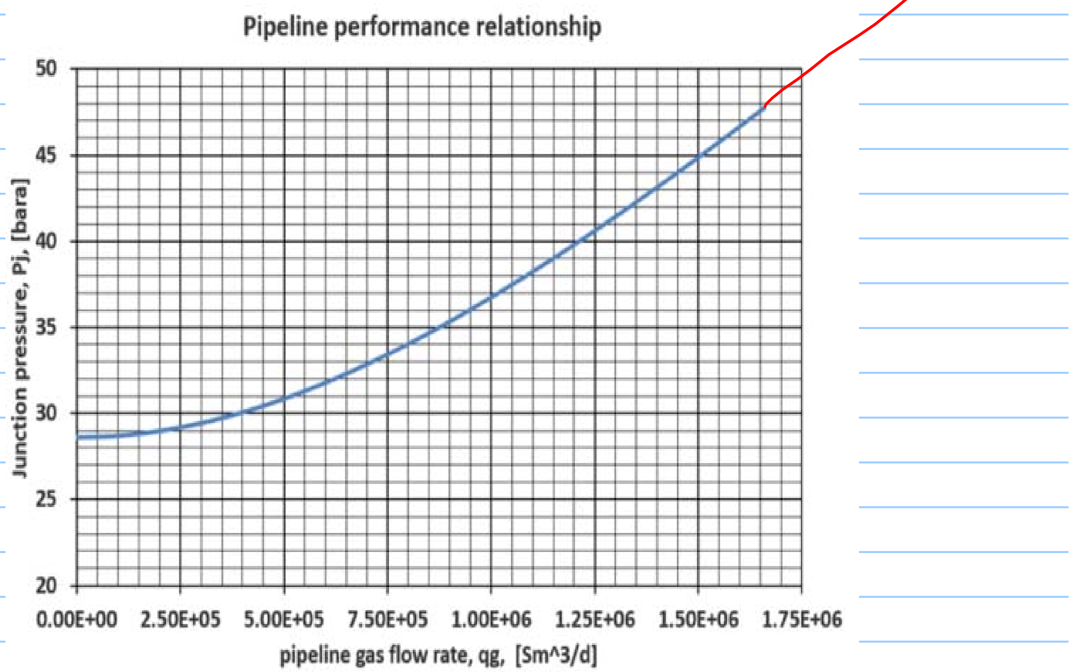
2.1 E5

4.9 E5

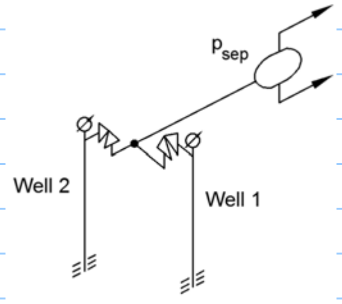
for 100 bar

q is very high

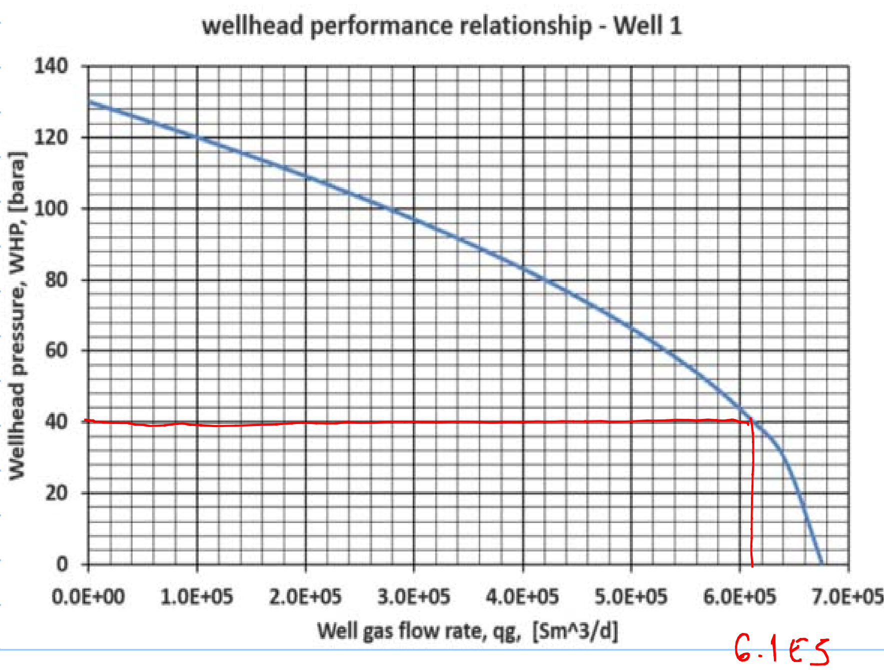
not possible



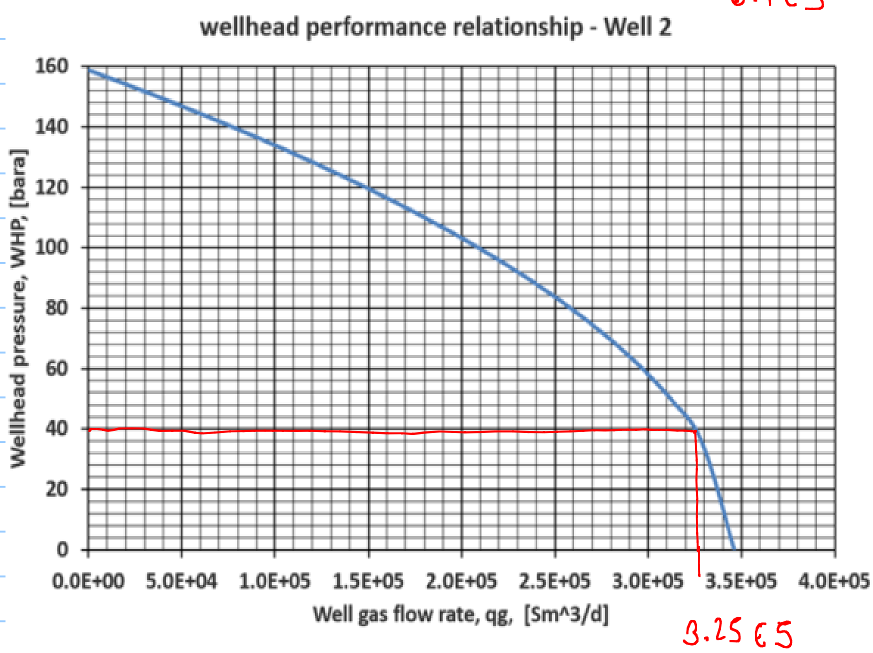
class exercise



Iteration ② assume $p_j = 40$ bara



6.1 E5



3.25 E5

$q_1 + q_2 =$

6.1 E5 + 3.25 E5

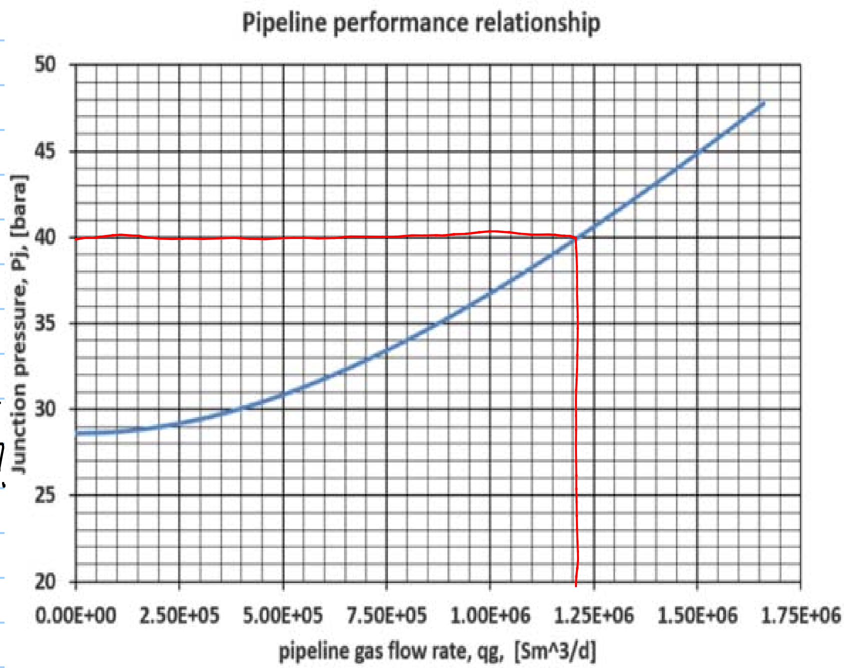
9.35 E5

$\neq$

1.2 E6

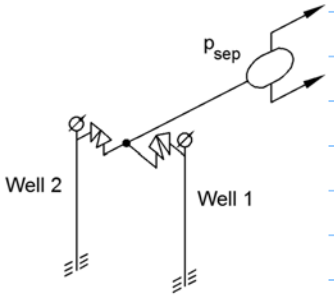
try a lower $p_j \approx 38$ bar

39 bar?

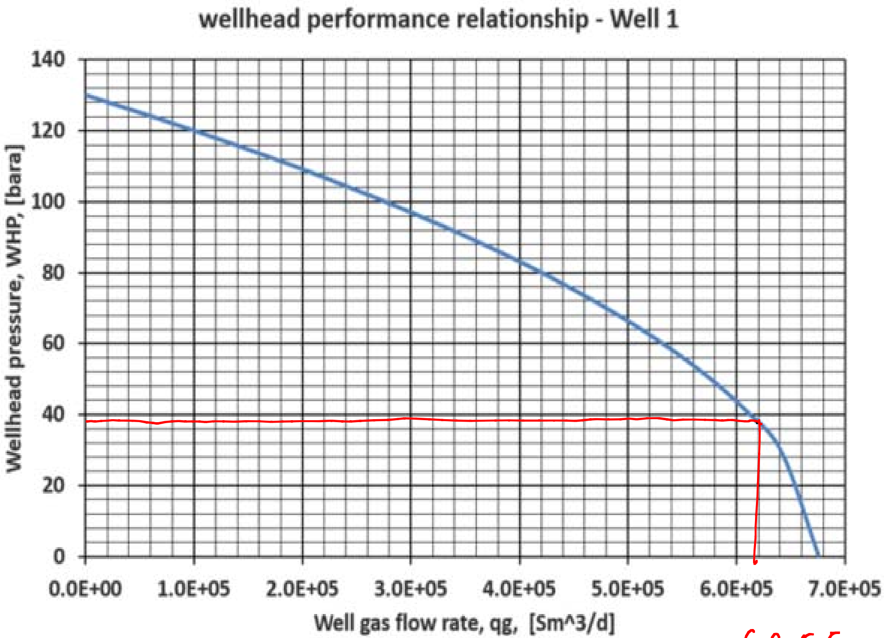


1.20 E6

class exercise

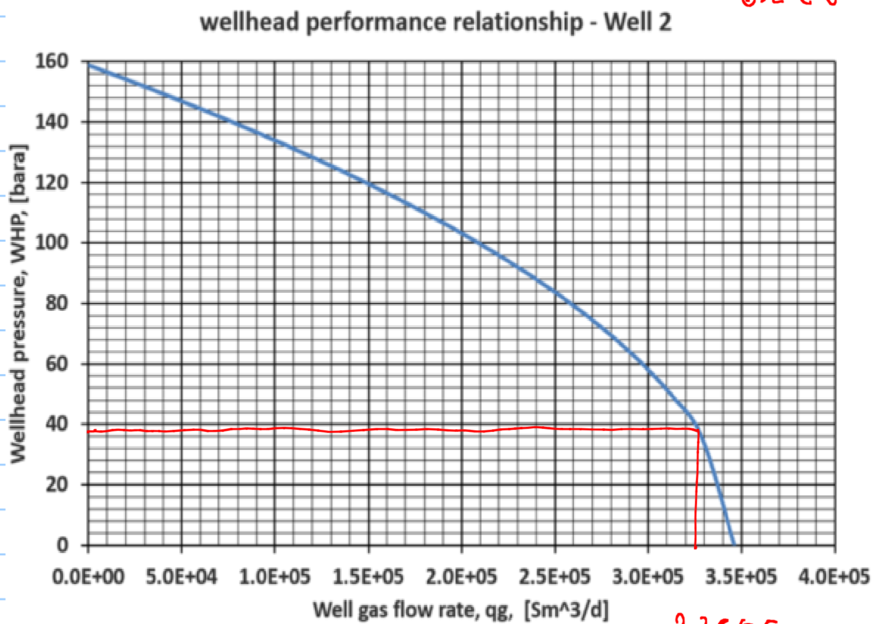


Iteration ③ assume $p_j = 38$ bara

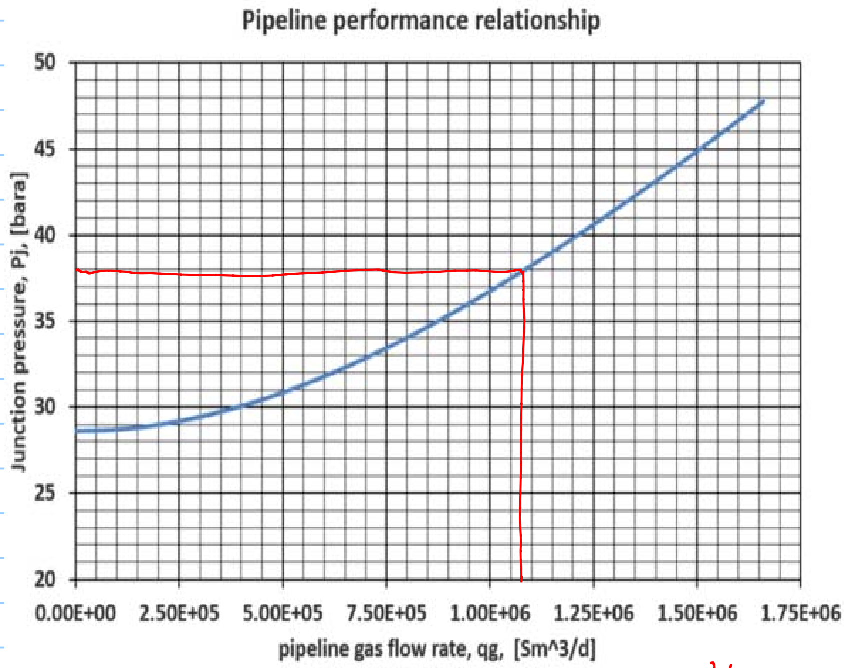


6.2 E 5

$q_1 + q_2 = 9.45\text{E}5 \ Sm^3/d$

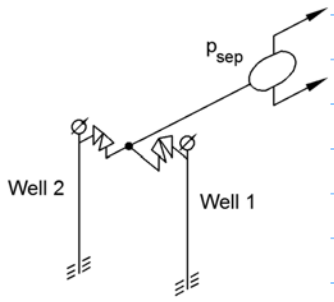


3.25 E 5

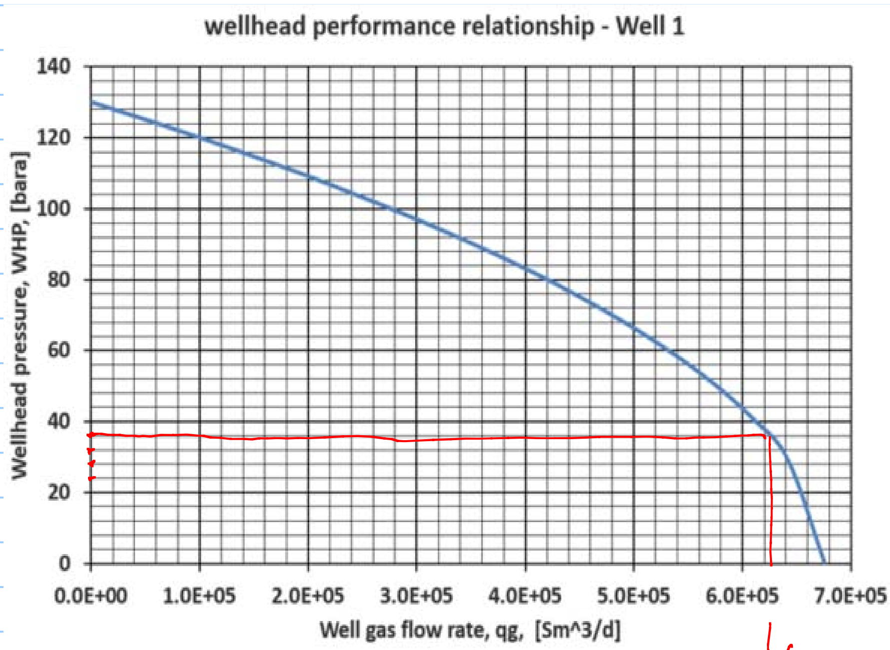


1.075 E6 Sm^3/d

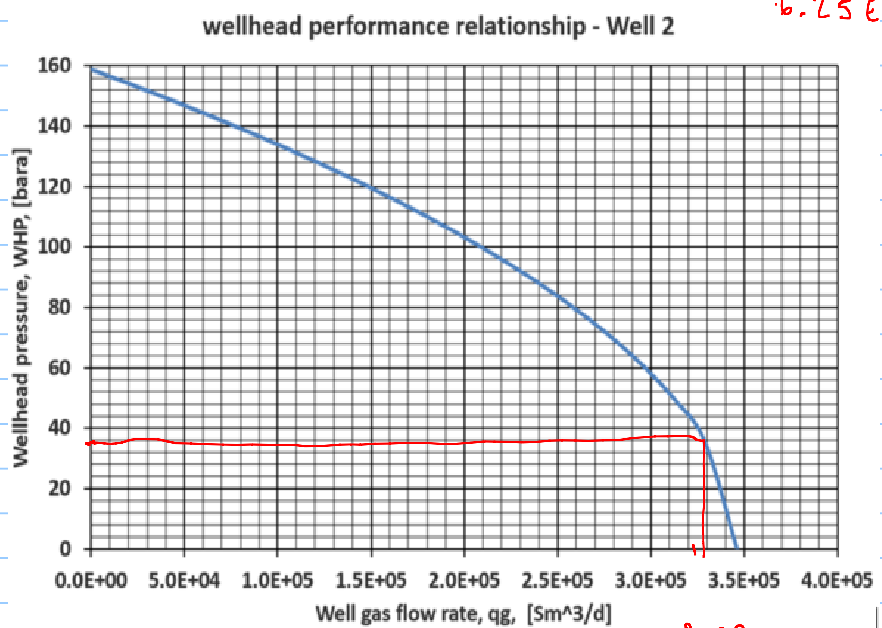
class exercise



Iteration (iv) assume p_j = 36 bara



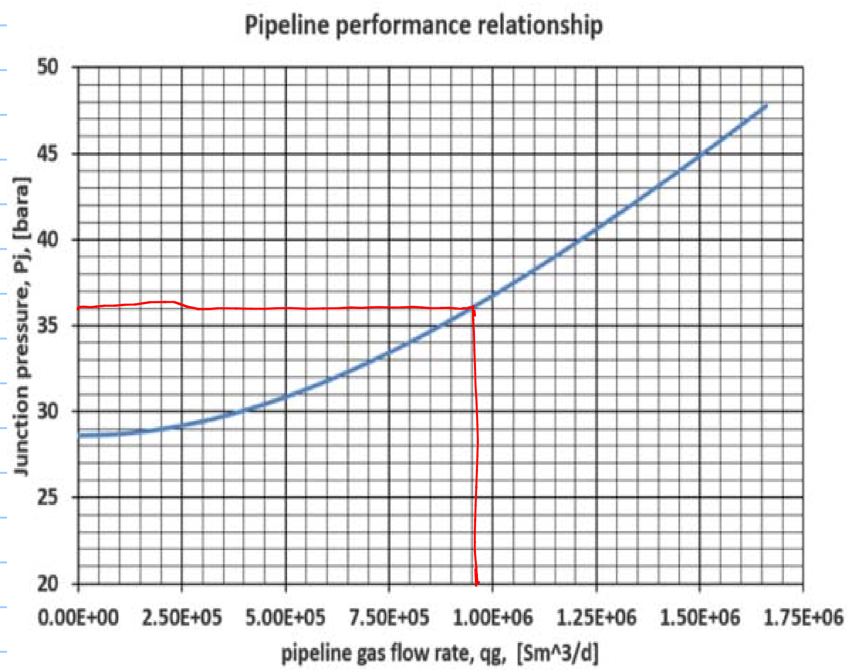
6.25 E5



3.28 E5

$q_1 + q_2$ = 9.5 E5

q_1



q_{field} = 9.5 E5

this is the equilibrium point

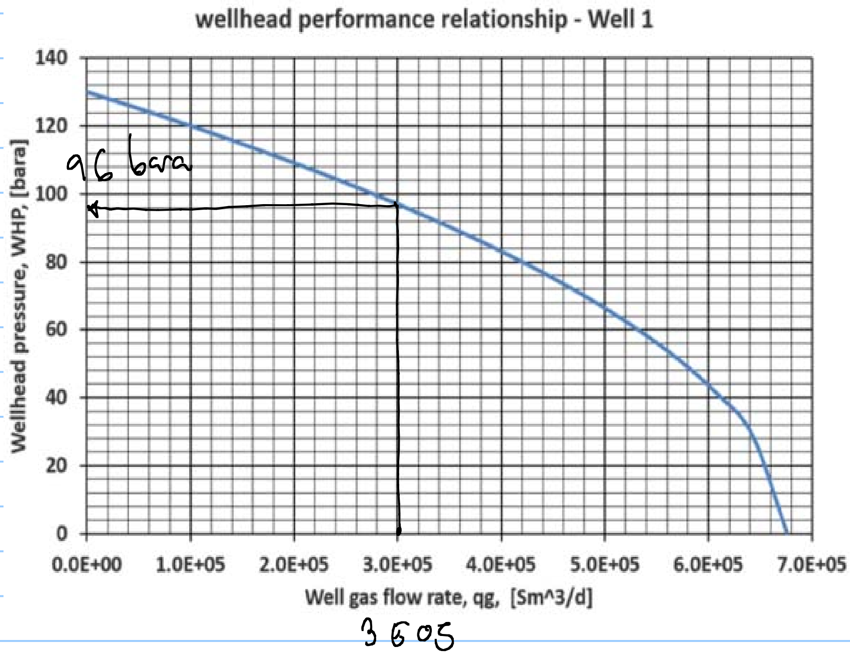
9.5 E5

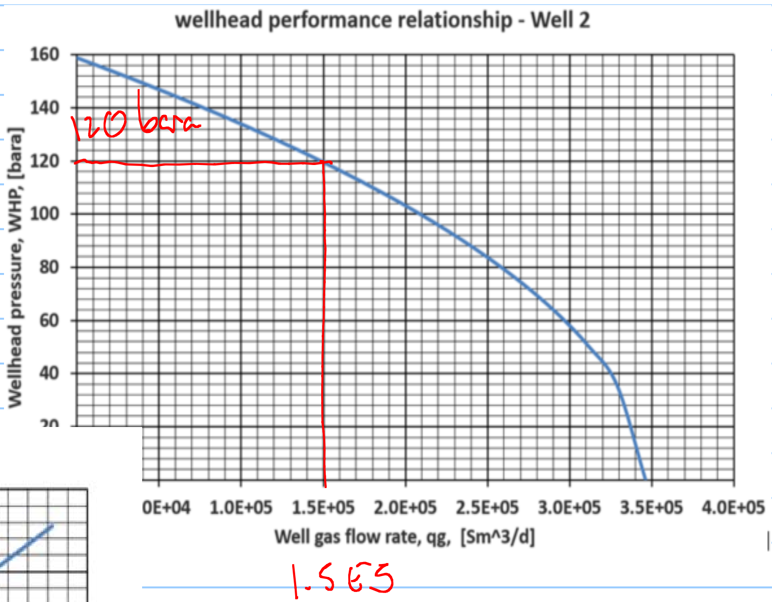
Reservoir engineer asked to produce at eq=

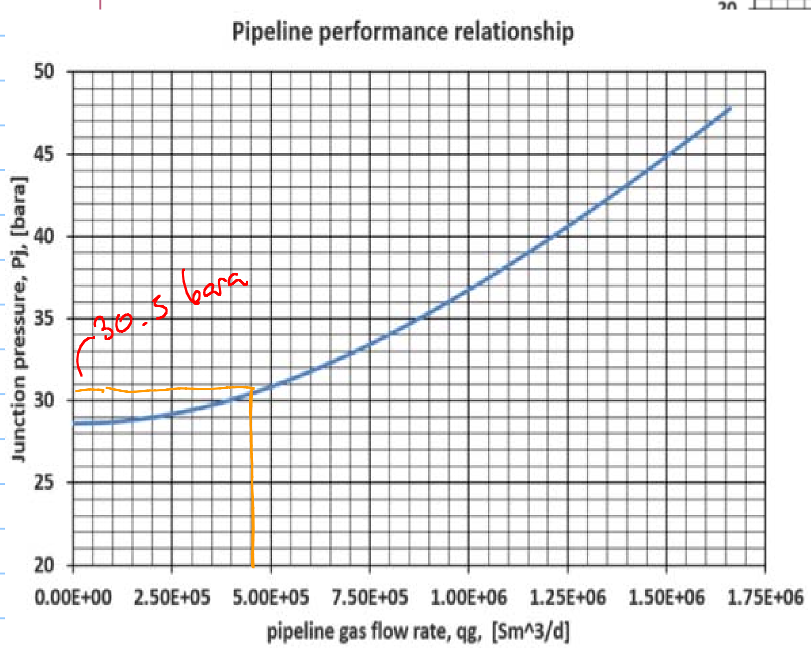
$q_1 = 3.E5\ Sm^3/d \quad < \quad q_1 = 6.25\ E5\ Sm^3/d$

$q_2 = 1.5\ E5\ Sm^3/d \quad < \quad q_2 = 3.28\ E5\ Sm^3/d$

I have to choke wells

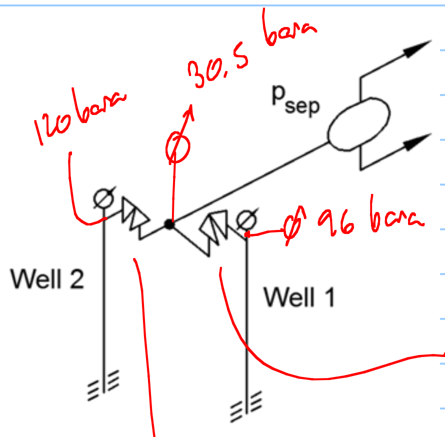






$q_{flowline} = 1.5\ E5 + 3\ E5$

$4.5\ E5\ Sm^3/d$

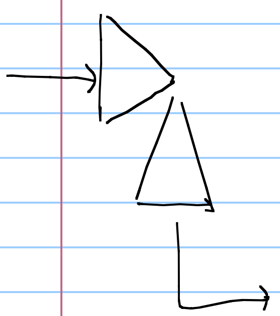


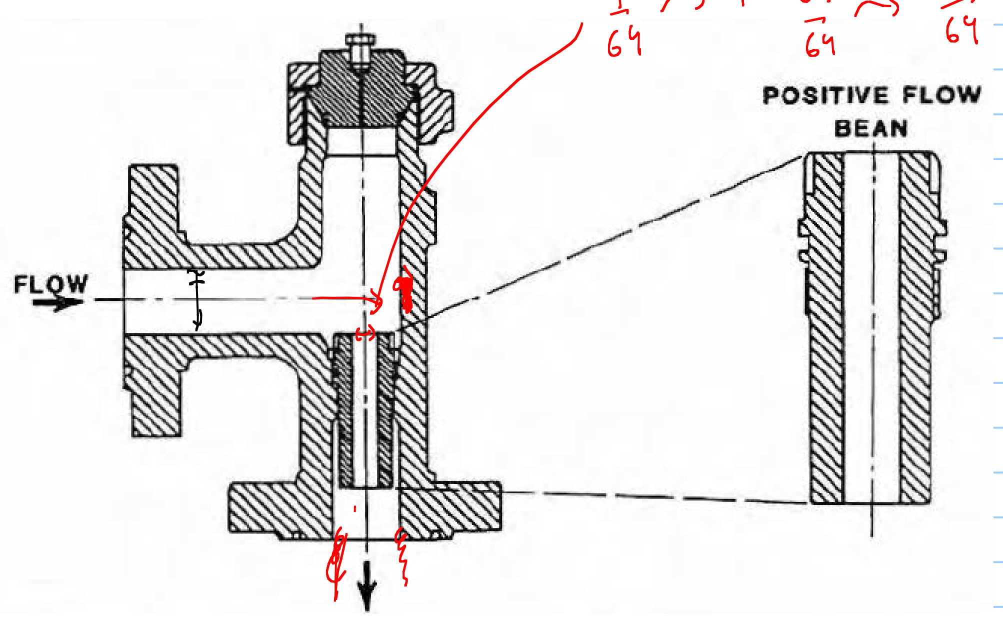
choke well 1 $\Delta p = 96 - 30.5$ bara $= 59.5$ bar

choke well 2 $\Delta p = 120 - 30.5$ bar $= 89.5$ bar

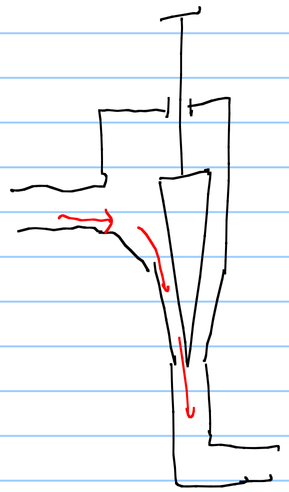
Choke → types
- Fixed opening
  bean choke

$\frac{1}{64}$" → 1" $\frac{64}{64}$" → $\frac{128}{64}$"

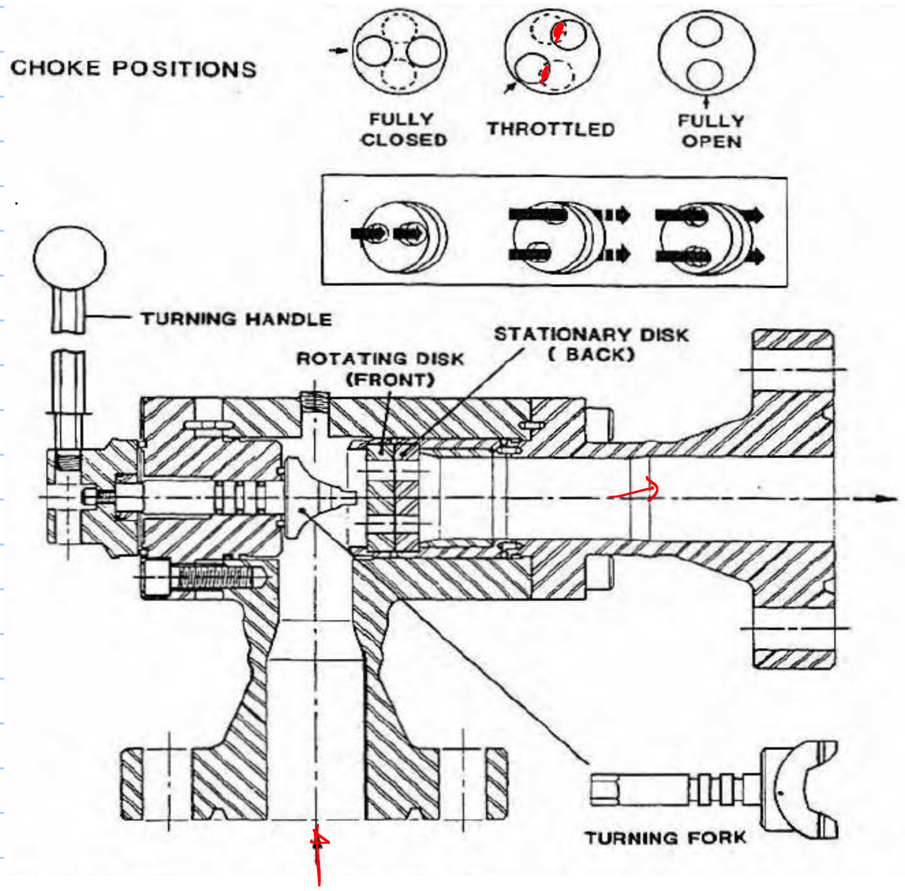




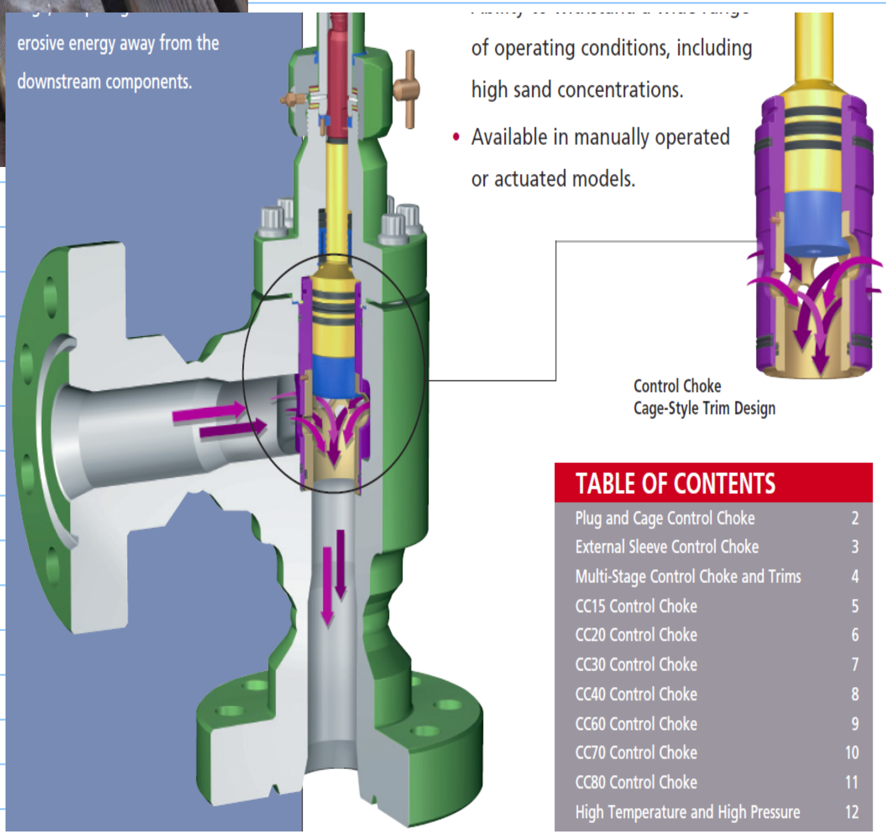
→ adjustable choke — Needle choke

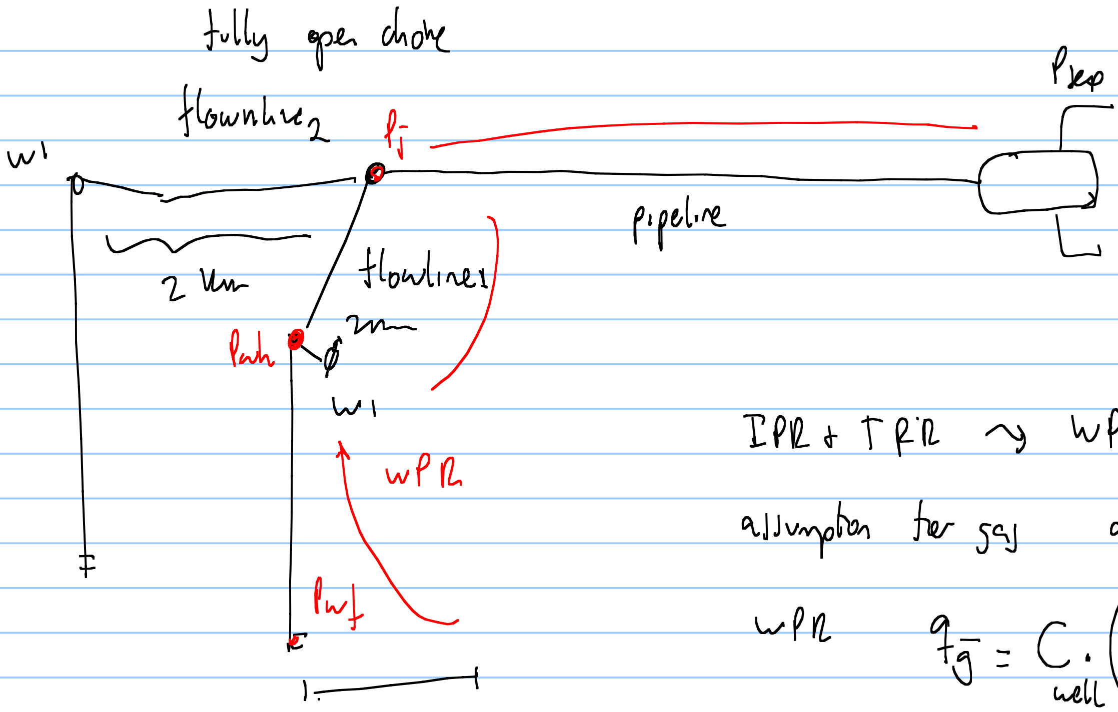


willis choke



Cage choke





IPR + TPR ⇝ WPR

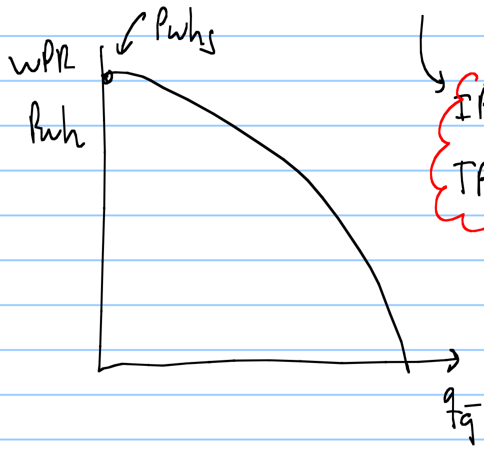
assumption for gas approximation

WPR $\quad q_{\bar{g}} = C_{well} \cdot \left(P_{wh_s}^2 - P_{wh_f}^2\right)$

static

IPR, C, n

TPR, S, C_T



Number of equations $\quad$ WPR$_1$, WPR$_2$

	eq	new unknow	6 equations
$q_{\bar{g}_1} = C_{w_1}\left(P_{wh_{s1}}^2 - P_{wh_{f1}}^2\right)$	1	2	$q_{\bar{g}_1}$, $P_{wh_{f1}}$
$q_{\bar{g}_2} = C_{w_2}\left(P_{wh_{s2}}^2 - P_{wf_2}^2\right)$	2	2	$q_{\bar{g}_2}$, $P_{wh_{f2}}$
$q_{\bar{g}_1} = C_{FL_1}\left(P_{wf_1}^2 - P_j^2\right)^{0.5}$	3	1	P_j
$q_{\bar{g}_2} = C_{FL2}\left(P_{wf_2}^2 - P_j^2\right)^{0.5}$	4	0	
$q_{field} = C_{PL}\left(P_j^2 - P_{sep}^2\right)^{0.5}$	5	1	q_{field}
$q_{field} = q_1 + q_2$	1	6	unknown

gas network m.xls

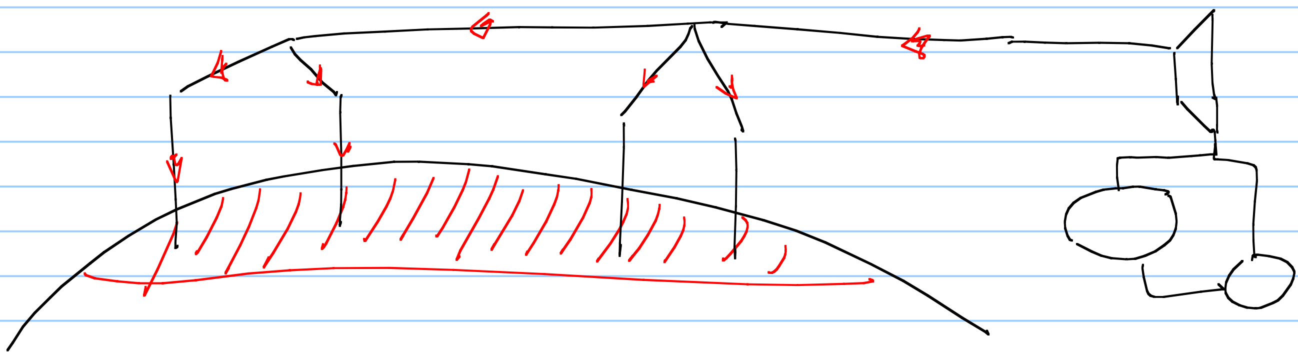
Surface Gas Network	p_{whs}, Shutin Wellhead Pressure	C_{wh}, Wellhead deliverability coefficient	C_{fl} coefficient , flowlines	Pwhf	qg	Pjn	Error^2
	bara	Sm^3/D/bar^2	Sm^3/D/bar	bara	Sm^3/D	bara	
Well 1	130	40	8.67E+03				
Well 2	159	13.7	9.50E+03				
Psp, Separator	28.60		4.34E+04				
					Average=		

$P_{sep} \leq P_{whf} \leq P_{whs}$

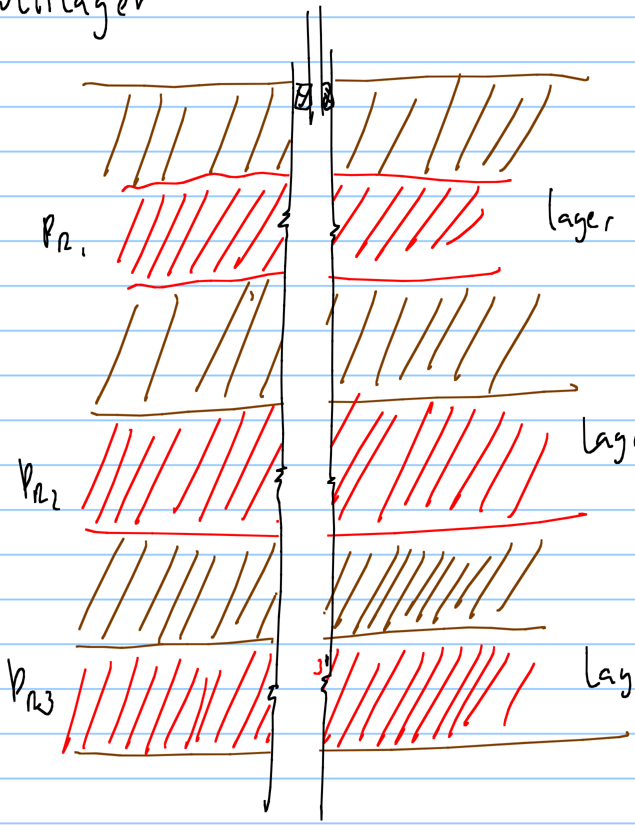
Surface Gas Network	p_{whs}, Shutin Wellhead Pressure	C_{wh}, Wellhead deliverability coefficient	C_{fl} coefficient , flowlines	Pwhf	qg	Pjn	Error^2
	bara	Sm^3/D/bar^2	Sm^3/D/bar	bara	Sm^3/D	bara	
Well 1	130	40	8.67E+03	66.789	497.6E+3	34	1.9E-06
Well 2	159	13.7	9.50E+03	47.653	315.2E+3	34	8.7E-07
Psp, Separator	28.60		4.34E+04		812.8E+3	34	5.4E-06
					Average=	34	8.2E-06

other types of network gas injection distribution network !

water injection network

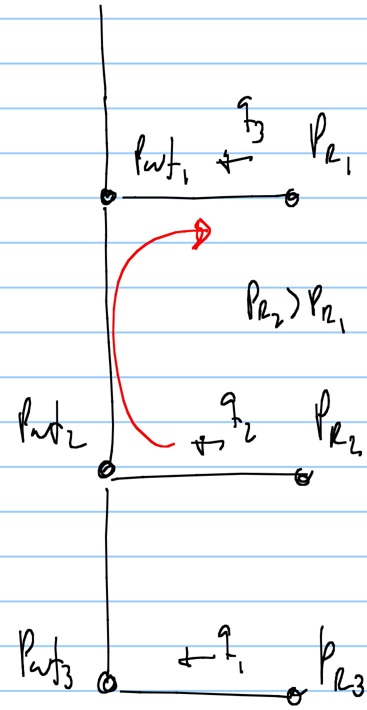


well multilayer

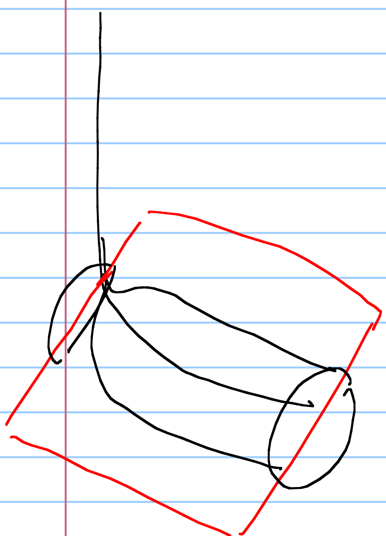


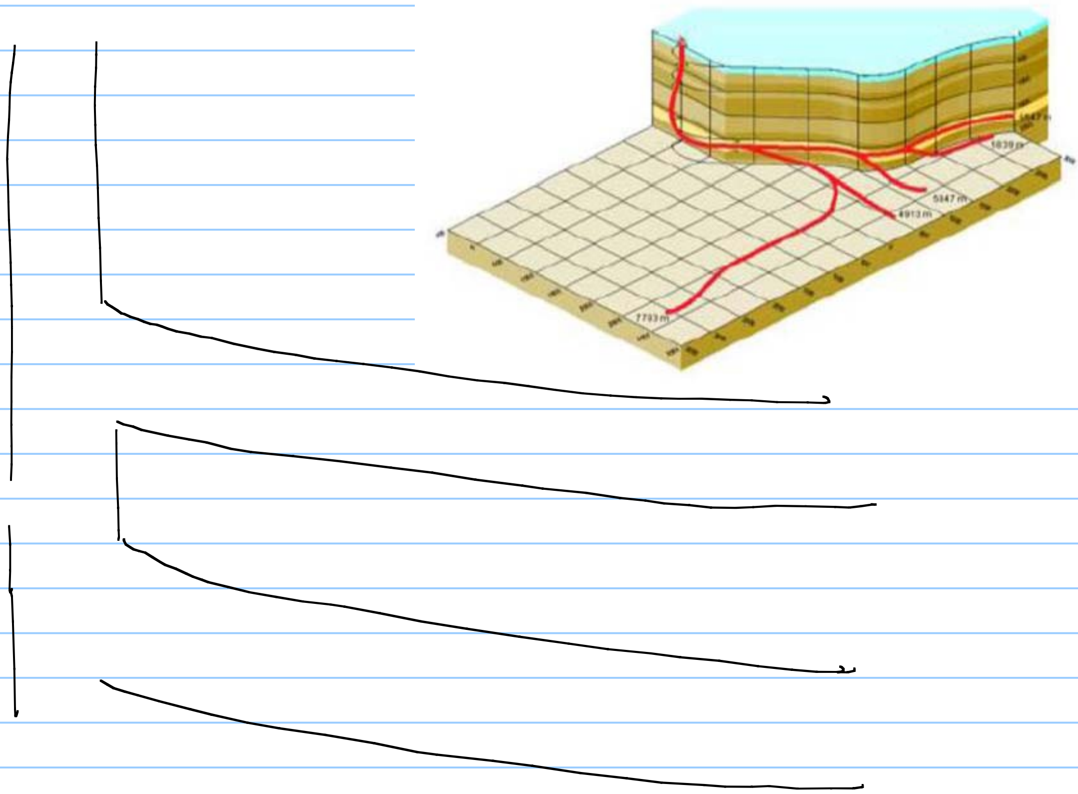
line analog

with closed well

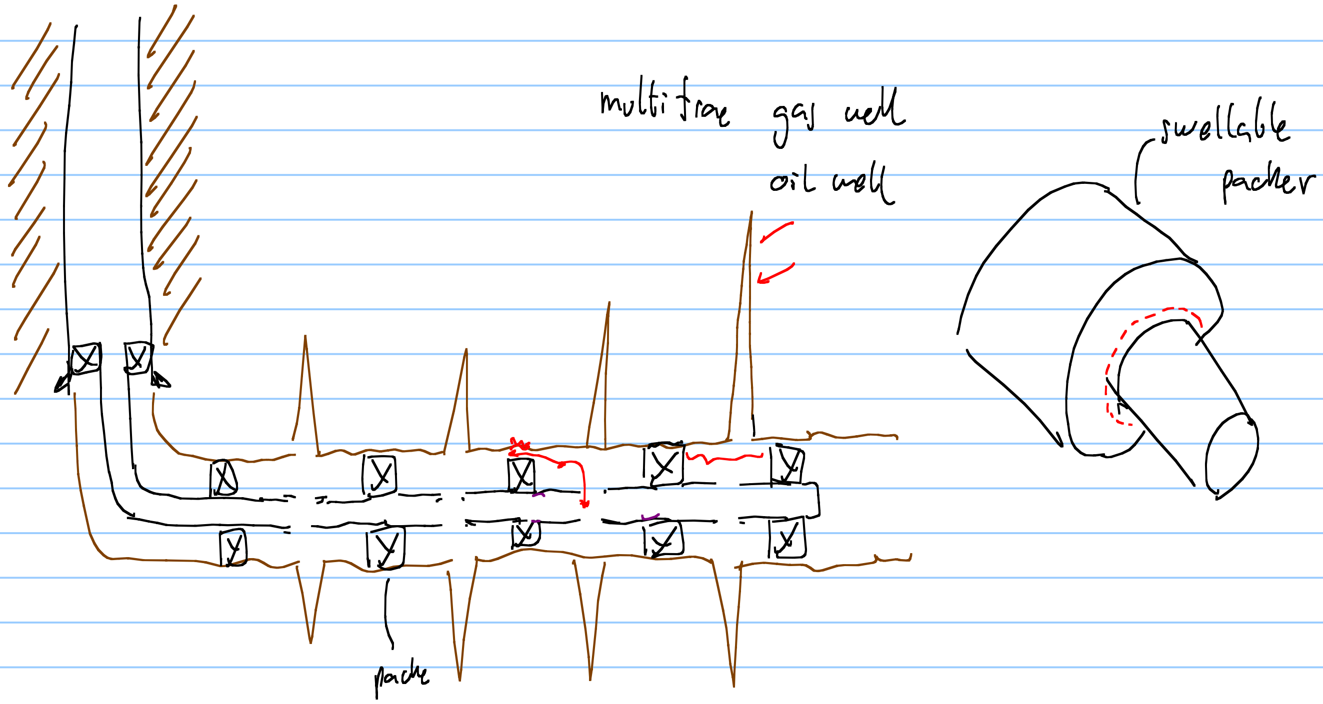


multi lateral

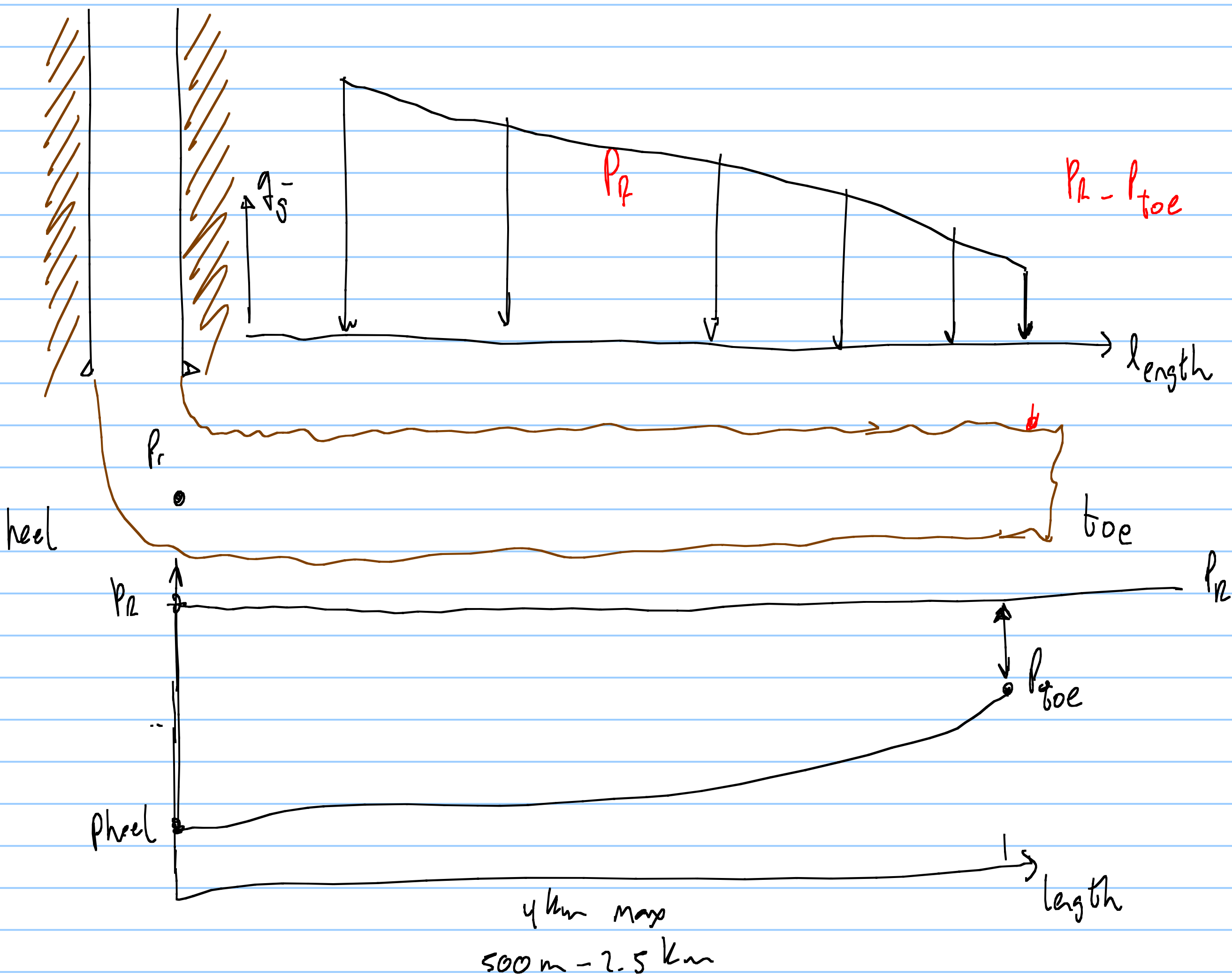


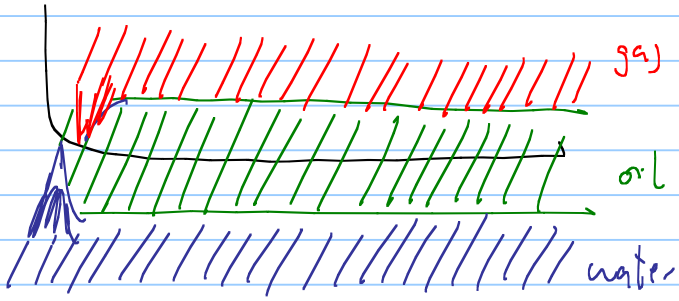


multisection horizontal well (shale gas) tight formations

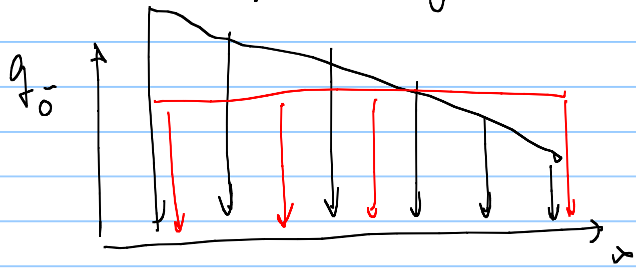


horizontal well with gas/water coning

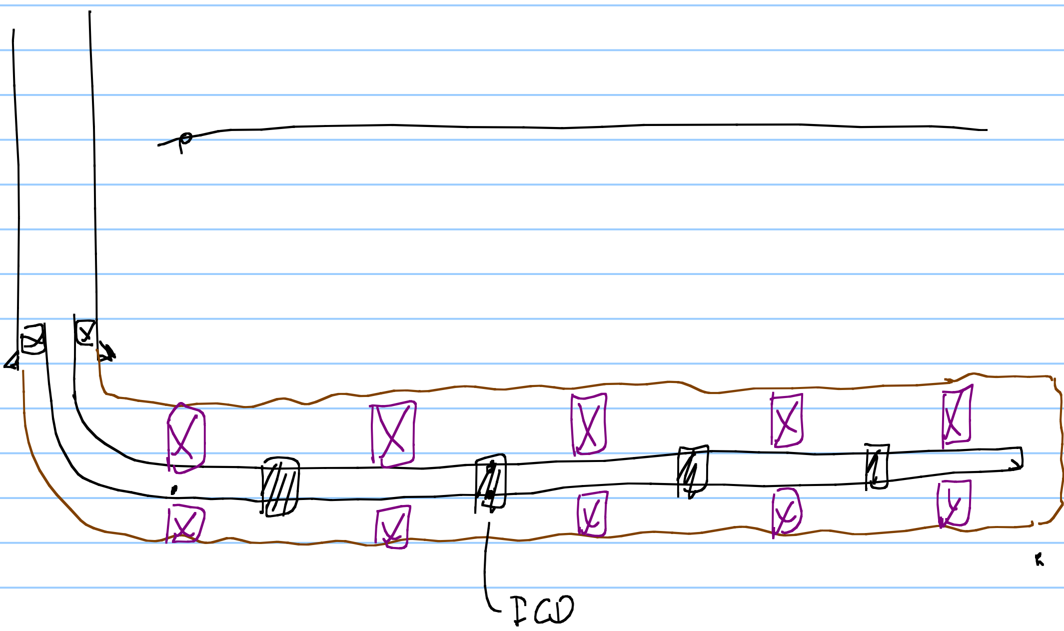


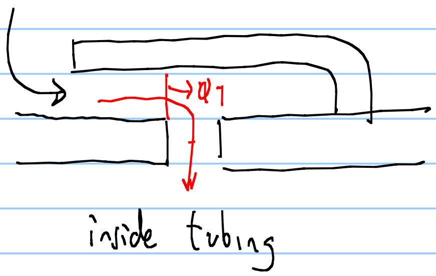


a measure to make more uniform along the well bore



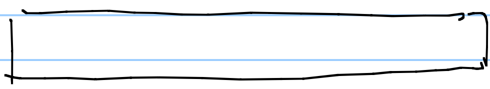
ICD inflow control device





for sections close heel Q is small

for section close to toe Q is big



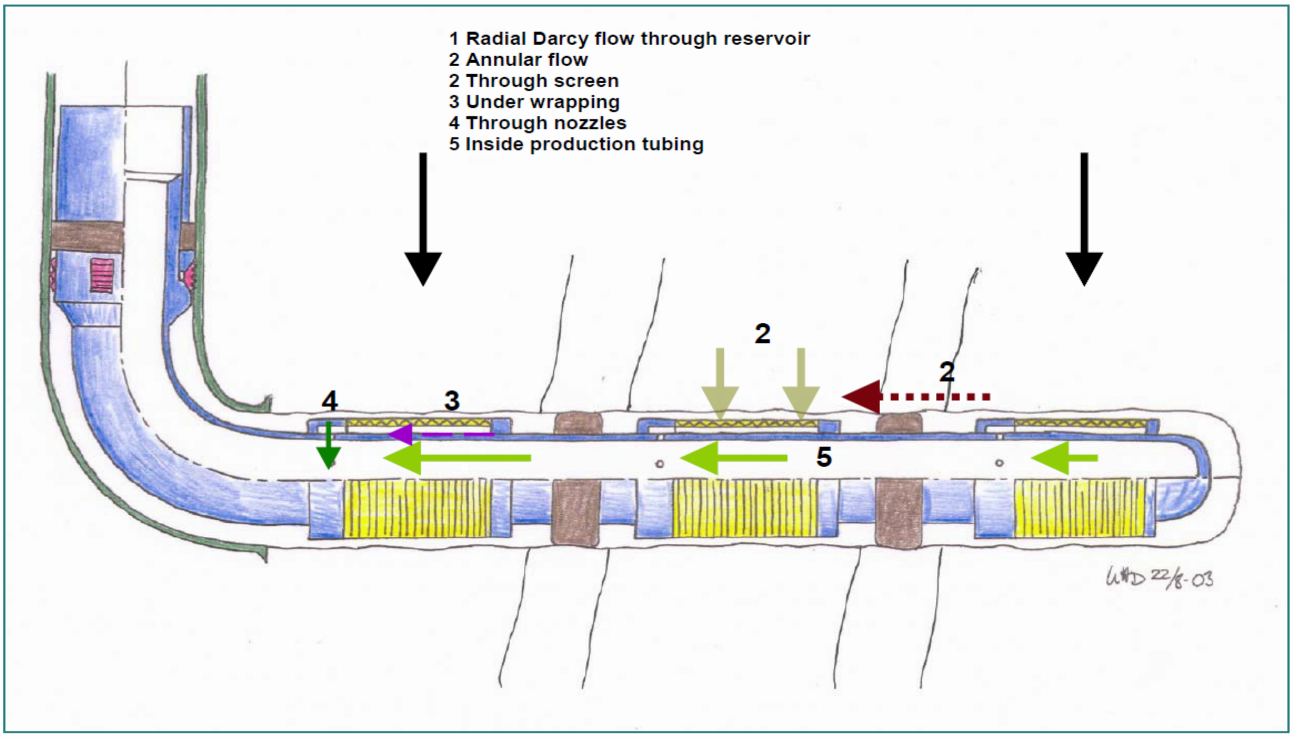
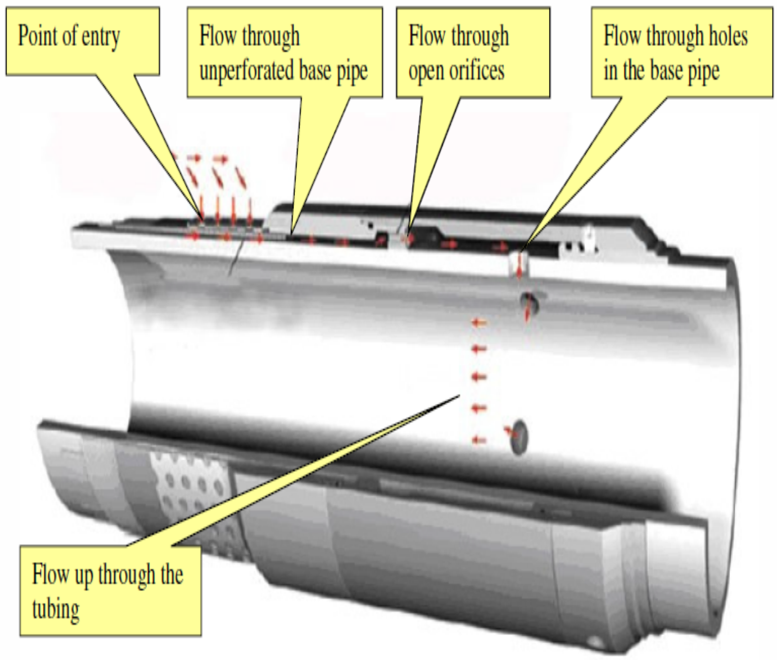
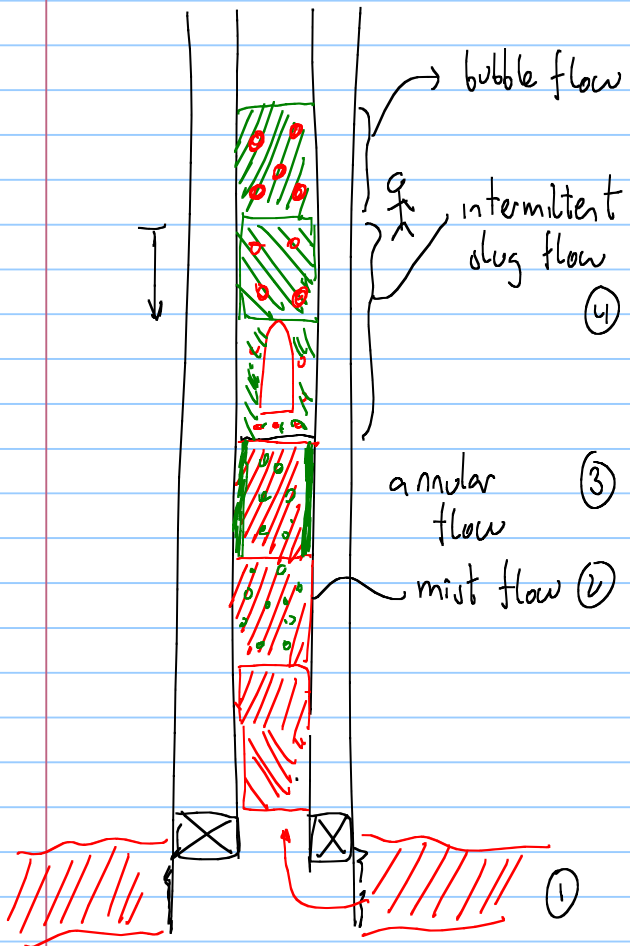
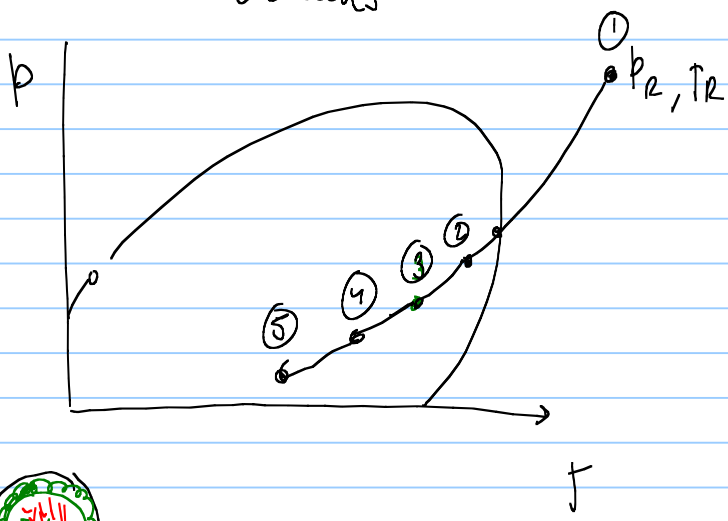


Figure-8 Functioning and interplay of an ICD completion architecture. Fluids enter the screen and flow between the axial wires and the un-perforated base pipe into the ICD housing, before passing through the nozzles and entering into the base pipe. All these flow issues are properly analyzed and put in the right perspective to achieve an optimal well completion design and solution.

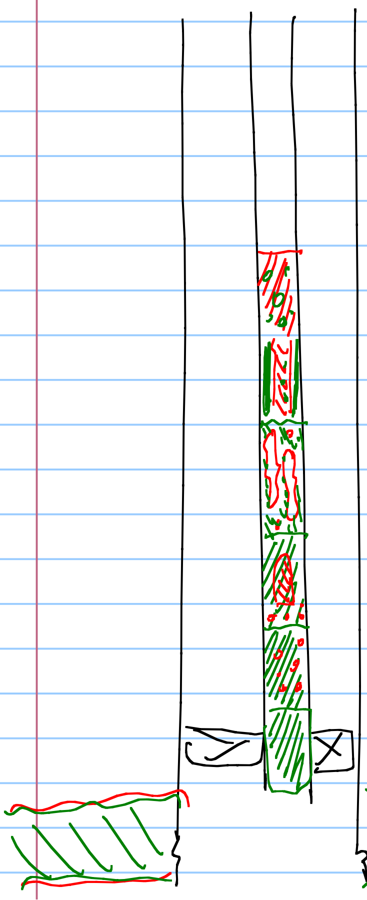


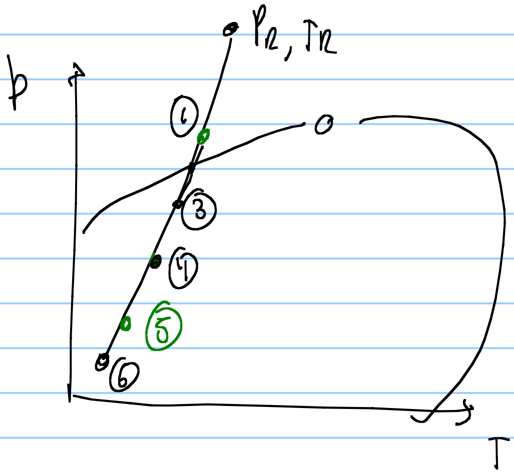
- TPR tubing performance relationship for saturated gas wells
  oil wells





an oil well





<u>flow patterns in well.</u>

mist flow

annular flow

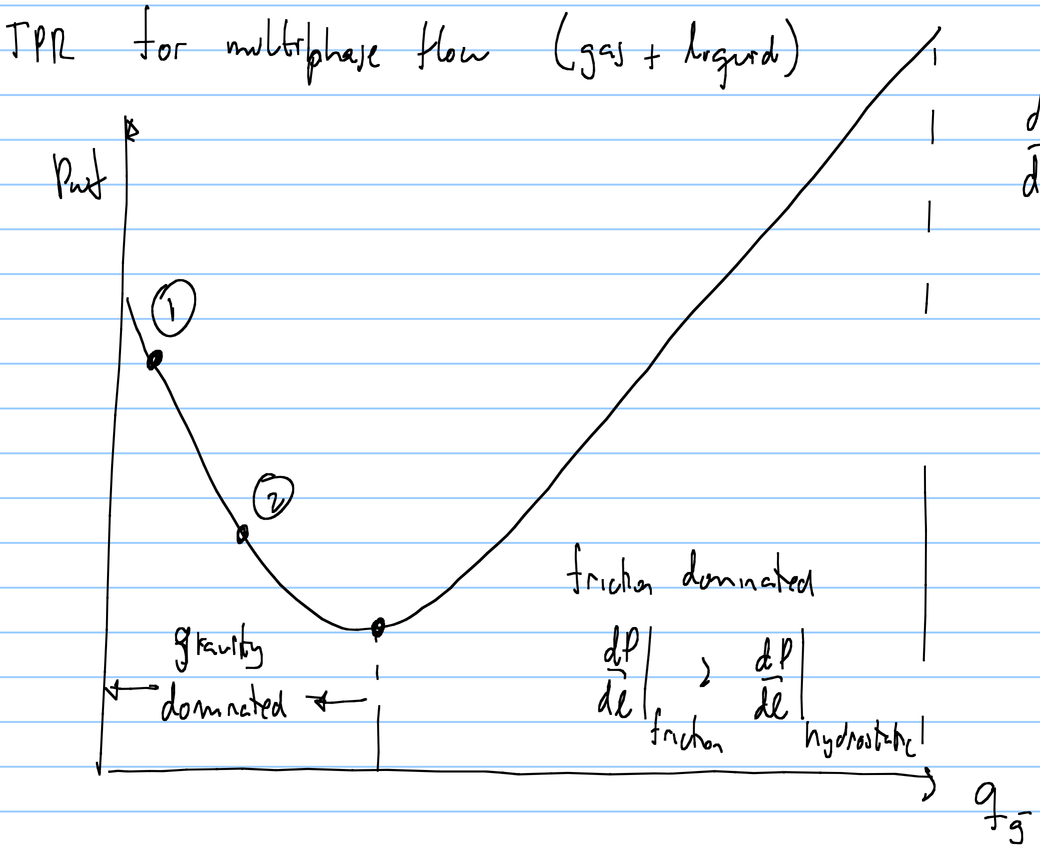
churn flow ④

intermittent/slug flow ③

bubble flow ②

single phase ①

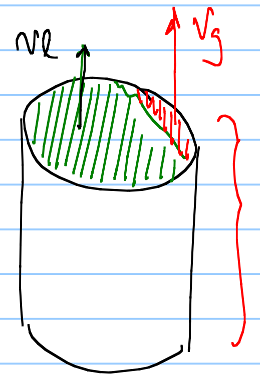
TPR for multiphase flow (gas + liquid)



$$\frac{dp}{dl} = \left.\frac{dp}{dl}\right|_{hydrostatic} + \left.\frac{dp}{dl}\right|_{friction}$$

ρ_{mix}

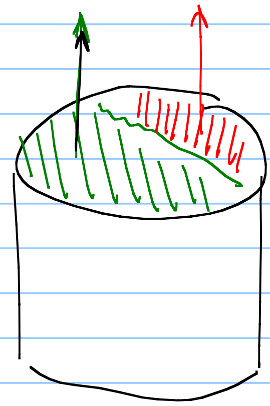
in 1



$\rho_m \approx \rho_l$

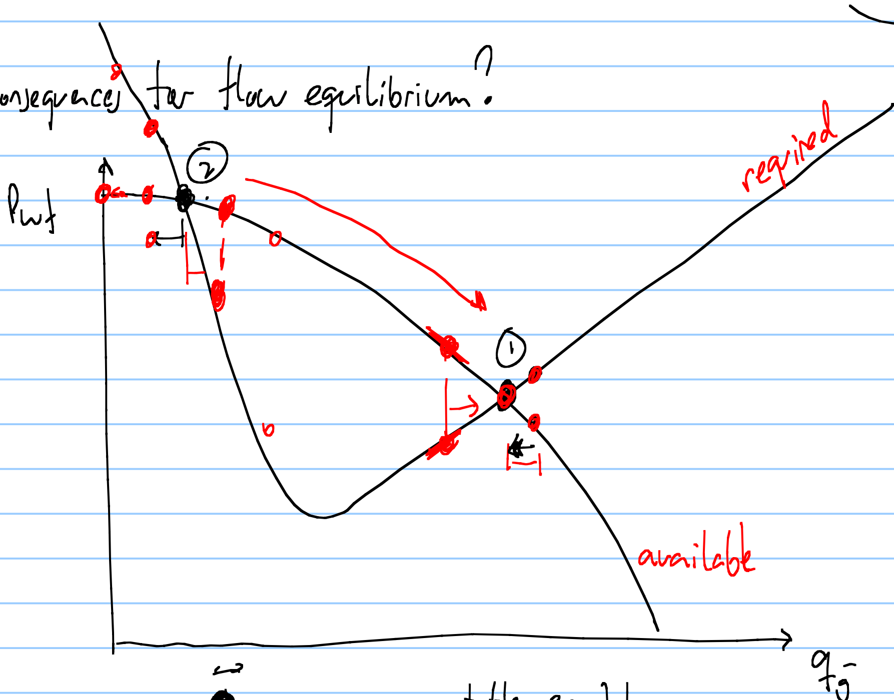
is const: $q_l = A_L \cdot v_L$

in 2

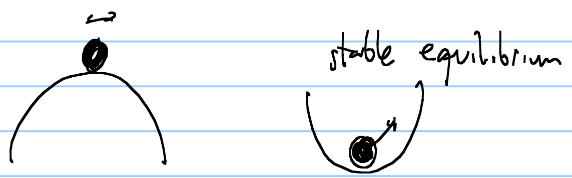


$\rho_g \leq \rho_m \leq \rho_L$

consequences for flow equilibrium?

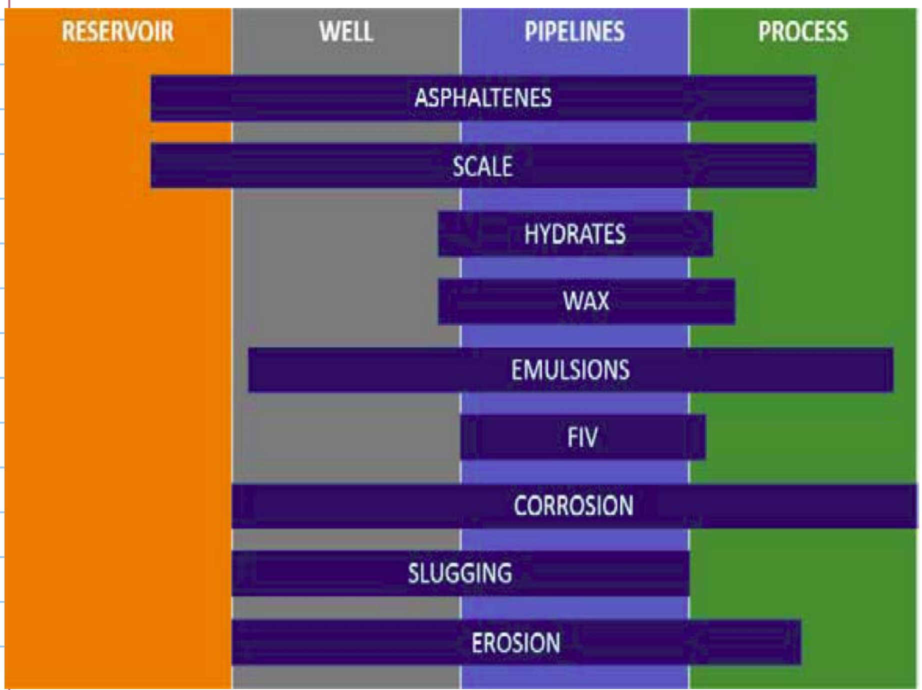


1 ? or 2 ?

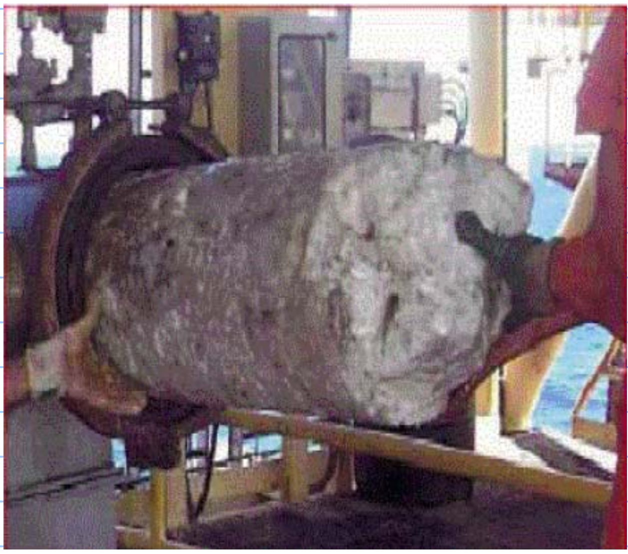


q_o
q_g vs time → (NPV)

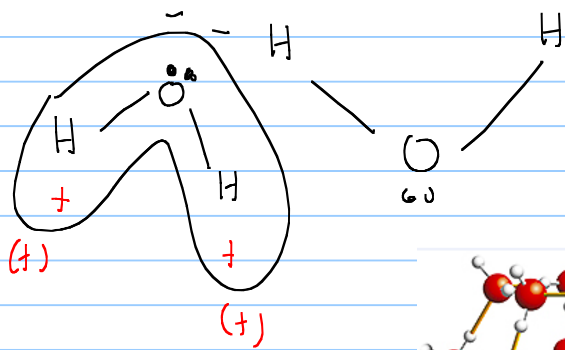
- flow assurance — measures that must be executed to ensure uninterrupted flow of hydrocarbon from reservoir to processing facities



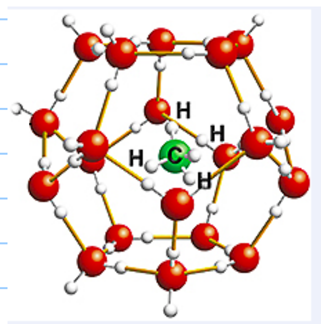
- $\boxed{\text{Hydrates}}$ when $T\downarrow$ or $T\downarrow$ $p\uparrow$

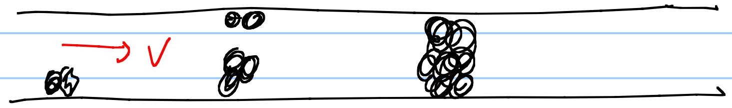


Solid substance Ice-like



$9\,\mathring{A}$ $\begin{cases} CH_4 \\ C_2H_3 \\ C_3H_8 \end{cases}$ CO_2

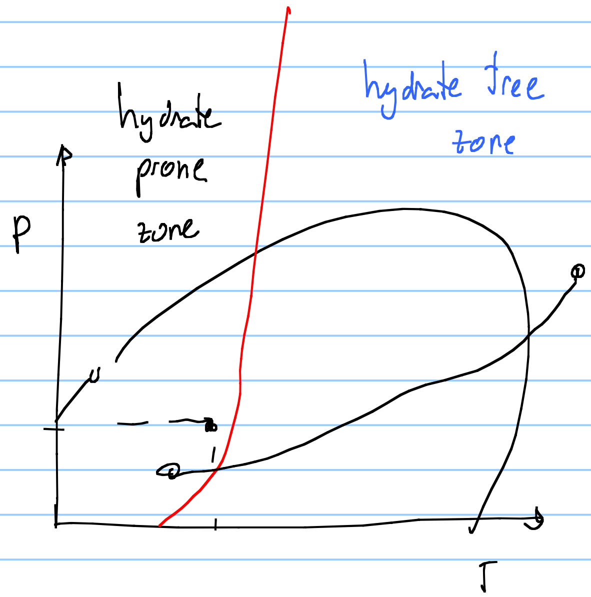


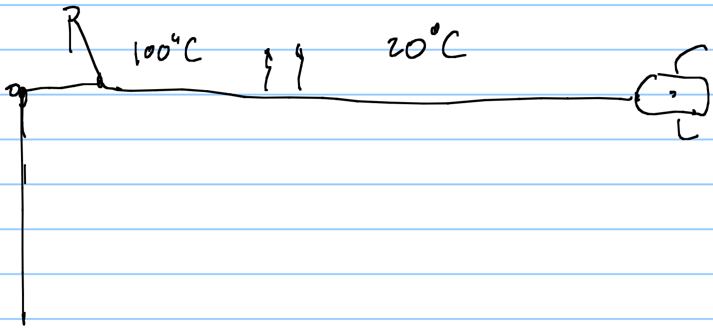


3 conditions: • free water (liquid)

• small hydrocarbon molecules

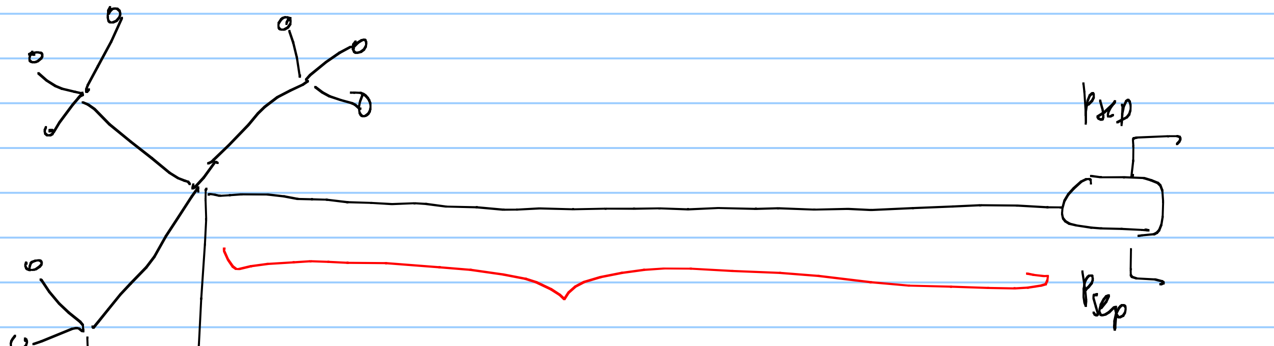
• combination of p, T →

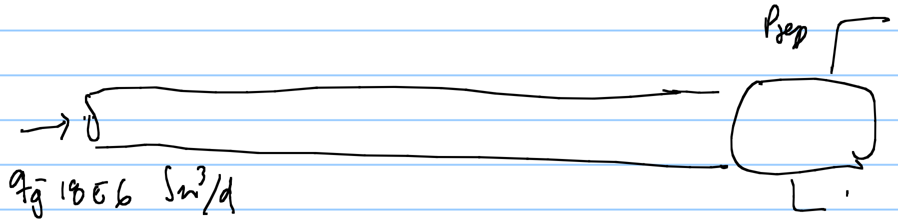




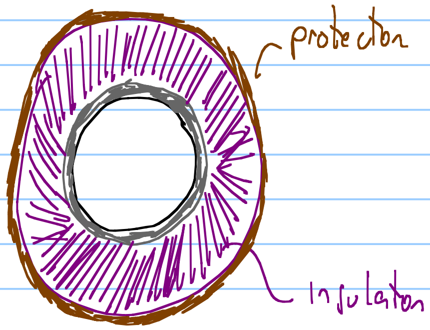
• During early studies: compute p, T along the main flowline and pipelines of the system and verify if p, T fall inside the hydrate region

Class exercise Block 2 P_T along pipeline block 2.xls

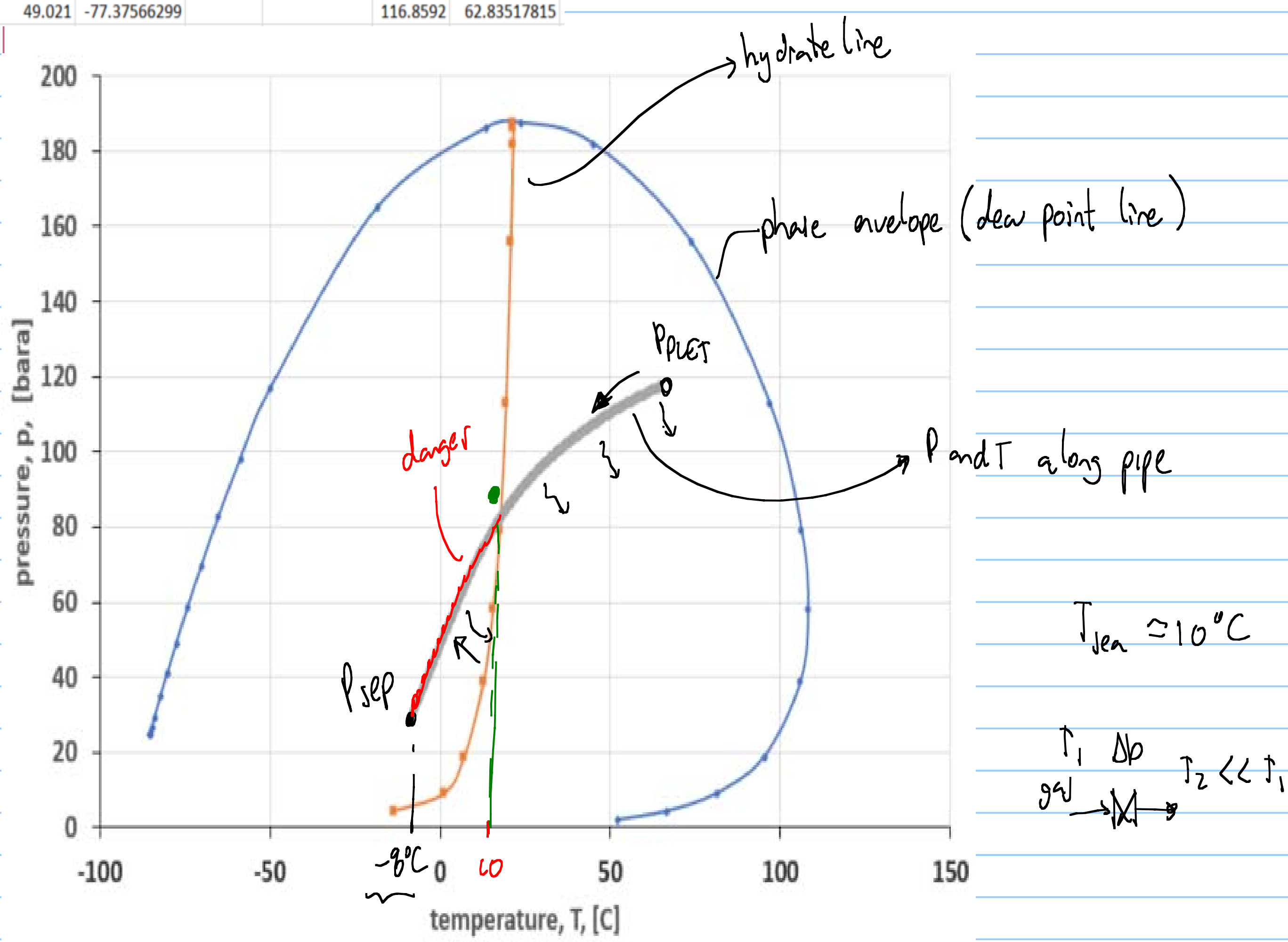




Cross section of pipeline



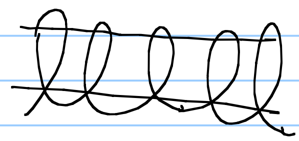
Dewpoint		Hydrate line		Along pipeline	
Pressure [bar]	Temperature [C]	Pressure [bar]	Temperature [C]	Pressure [bar]	Temperature [C]
2.0265	52.22035802	4.290101	-13.54876609	117.7714	64.93461369
4.290101	66.44222041	9.00647	1.159792331	117.7207	64.81627631
9.00647	81.11490252	18.74151	7.084058334	117.67	64.69813059
18.74151	95.12805581	38.69453	12.72666664	117.6193	64.58018781
38.69453	105.7858643	57.98941	15.55421038	117.5687	64.46244765
57.98941	108.1106953	79.35551	17.48070774	117.518	64.34490977
79.35551	106.0997213	112.7726	19.3044054	117.4673	64.22757387
112.7726	96.8255477	155.7708	20.71587828	117.4166	64.11043961
155.7708	73.75418309	181.98	21.35377989	117.366	63.99350666
181.98	44.95253713	187.4592	21.47522294	117.3153	63.87677471
187.4592	23.9420427	186.1369	21.44591881	117.2646	63.76024342
186.1369	13.57588933			117.2139	63.64391247
164.9891	-18.39447037			117.1633	63.52778154
116.6442	-49.93281956			117.1126	63.4118503
98.07692	-58.58544804			117.0619	63.29611845
82.46519	-65.09938144			117.0112	63.18058563
69.33851	-70.15679231			116.9606	63.06525152
58.30131	-74.16140884			116.9099	62.9501158
49.021	-77.37566299			116.8592	62.83517815

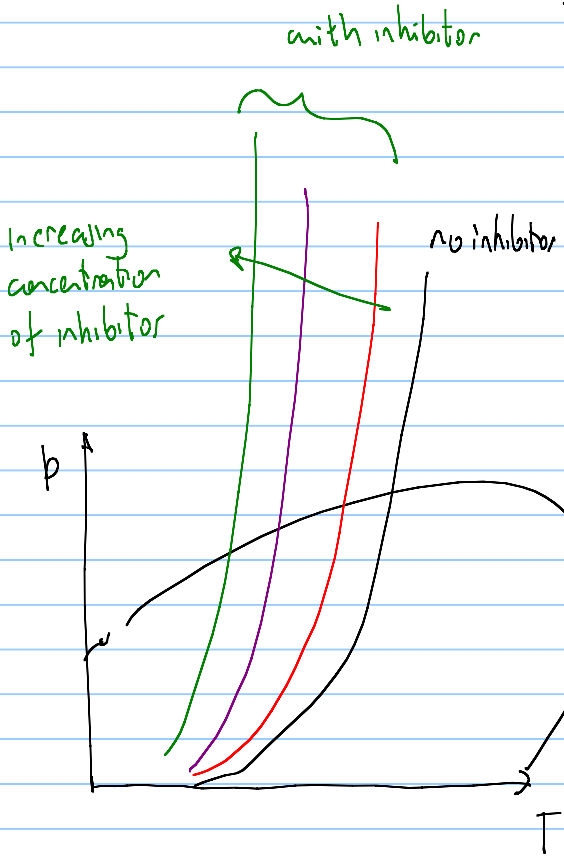


measures to avoid hydrates

- improve insulation USD ↑↑
- electrical heating (heat tracing)

not very economical for long pipes





- inject hydrate inhibitor MeOH methanol
  - MEG mono-ethylene glycol
  - TEG tri ethylene glycol

typical concentration of inhibitor

40% → 60% weight

$q_g = 18E6\ Sm^3/d$

$WGR = 6E{-}6\ Sm^3/d$

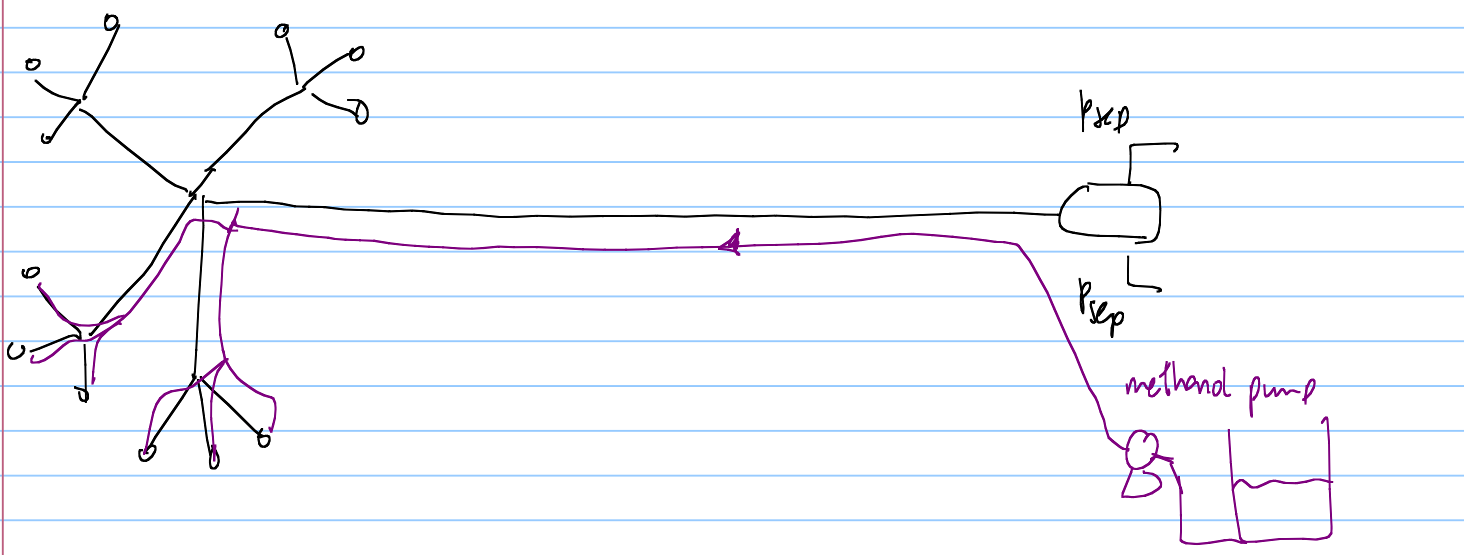
water gas ratio $\frac{q_w}{q_g}$

$q_w = 108\ Sm^3/d$

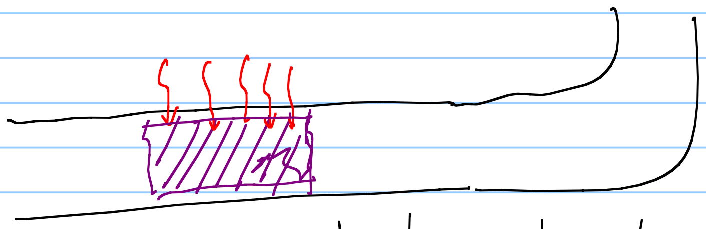
50%w MeOH 180 Sm^3/d of methanol ≈ 180000 l/d

0.5 USD/l

≈ 90000 USD/d

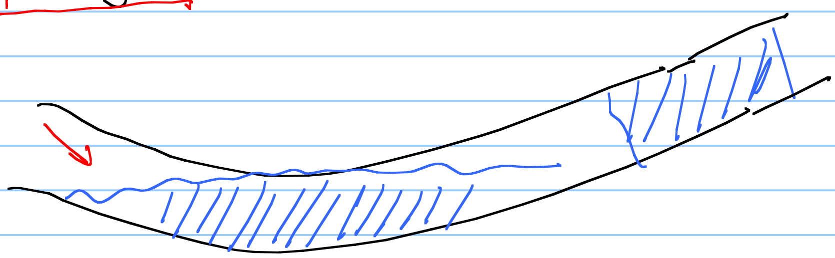


Increase Δp in pipe, cause blockage

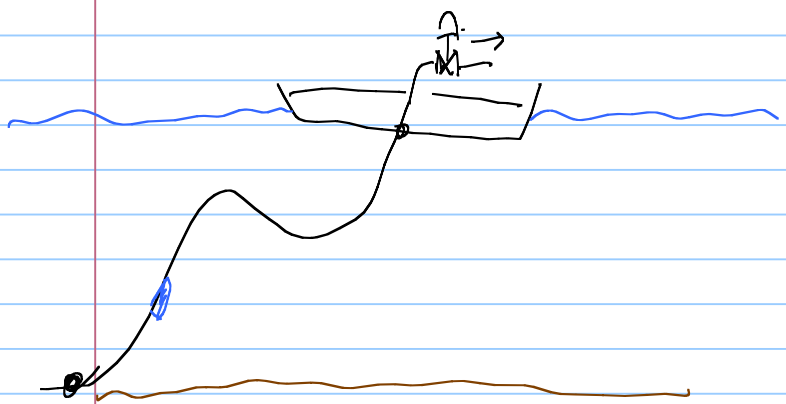


heating a hydrate plug

- Slugging



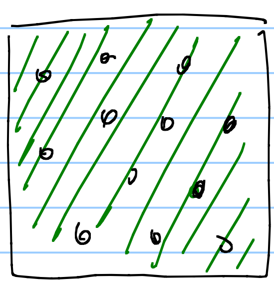
- Increase Δp reduction in production
- collapse and bottleneck separators
- structural fatigue and damage in flowlines and risers



- Solutions: decrease ϕ pipe ($\uparrow \Delta p$)
- change pipeline trajectory (avoid trenches and lower points)
- dynamic control (topside choking)

For field development flowlines and pipelines are simulated (using OLGA, flow manager, LEDAFLOW) during the life of field to flag or detect problems with slugging!

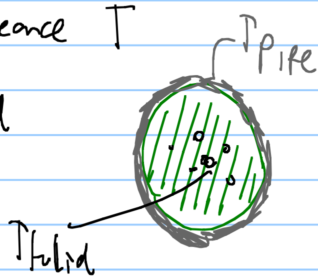
WAX at low T (20 °C) heavy alkane chains precipitate out of oil C_{18}^{+}

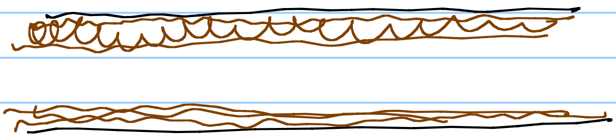


$T_{cloud\ point}$ (WAT) wax appereance T

pipe wall is colder than fluid

$T_{fluid} > T_{pipe}$

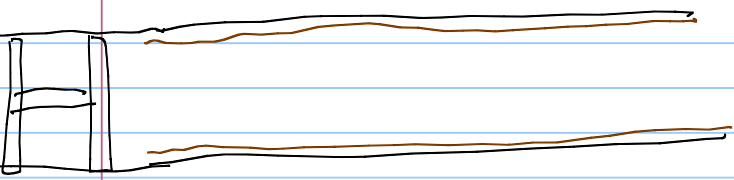




Reduce the cross section

Increase the Δp

eventually cause pipe blockage



pigging

If wax deposition is expected then pigging facilities must be included and regular piggings must be performed

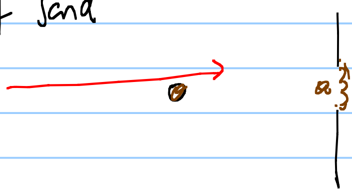
Prevention:

- pig the pipe (lose production)
- insulation
- heat tracing
- wax inhibitors

traditional methods

EROSION

- high fluid velocities
- presence of sand



main solution: • reduce rate (lose production)

• increase ϕ (increase cost)

• for some components change dimensions

$\boxed{\text{Scale}}$ → with water production

Minerals dissolved in water come out of solution and precipitate on pipe wall, choke, valve

K, Na, Mg, Ca, Ba, Fe

• Changes of P, T — T is increased; P is reduced $\sim (CO_3^{=}) \sim$ can be dissolved with chemicals

• mix water from different sources — salt water + production water

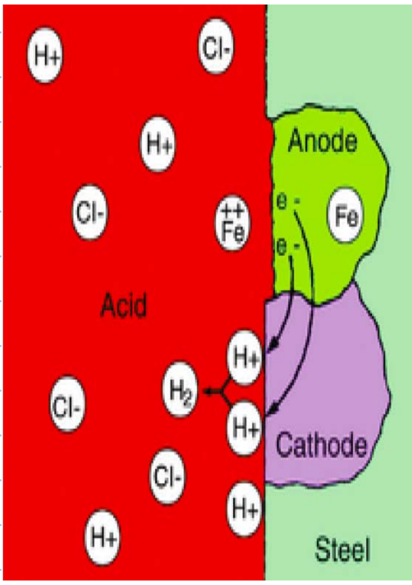
$(SO_4^{=}) \sim$ mechanically removed

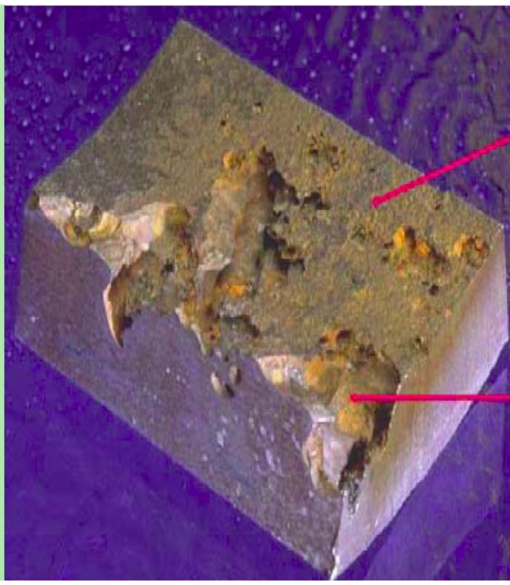
◦ creates blockage

◦ creates high Δp

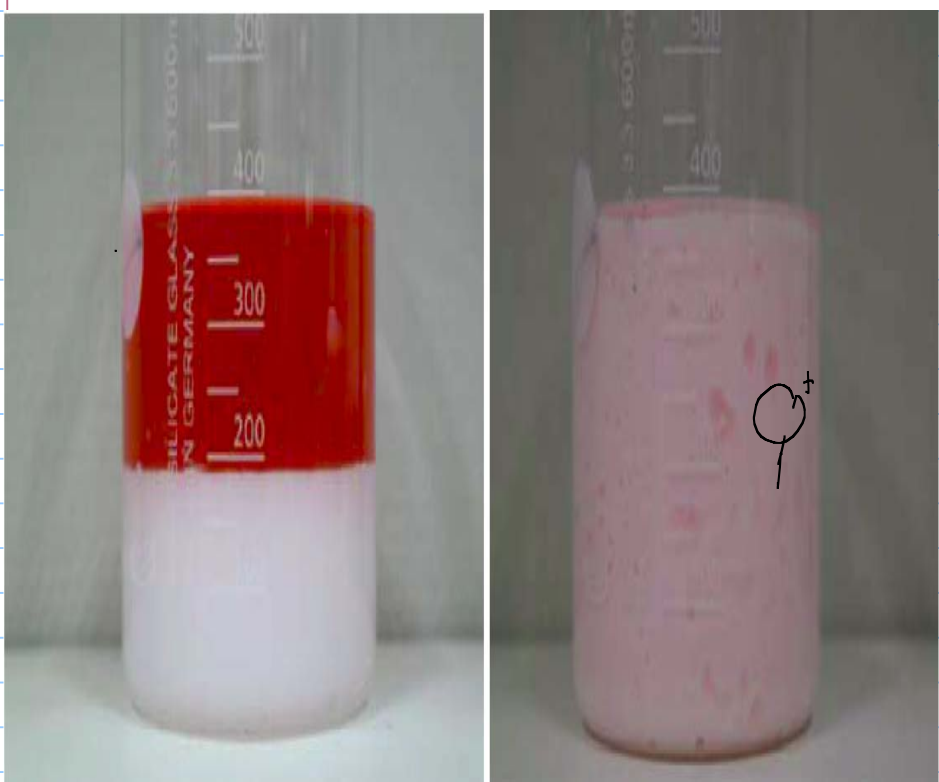
◦ affects equipment functionality (valves, Downhole safety valve) prevention: scale inhibitor.

• Corrosion   water + metal

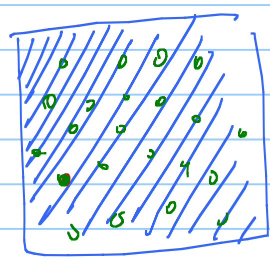




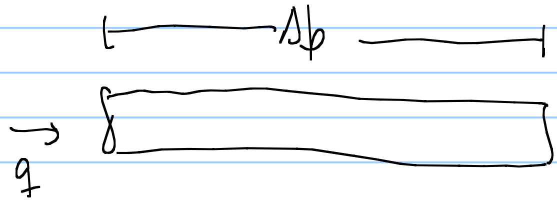
• Oil + water emulsion



stable dispersion



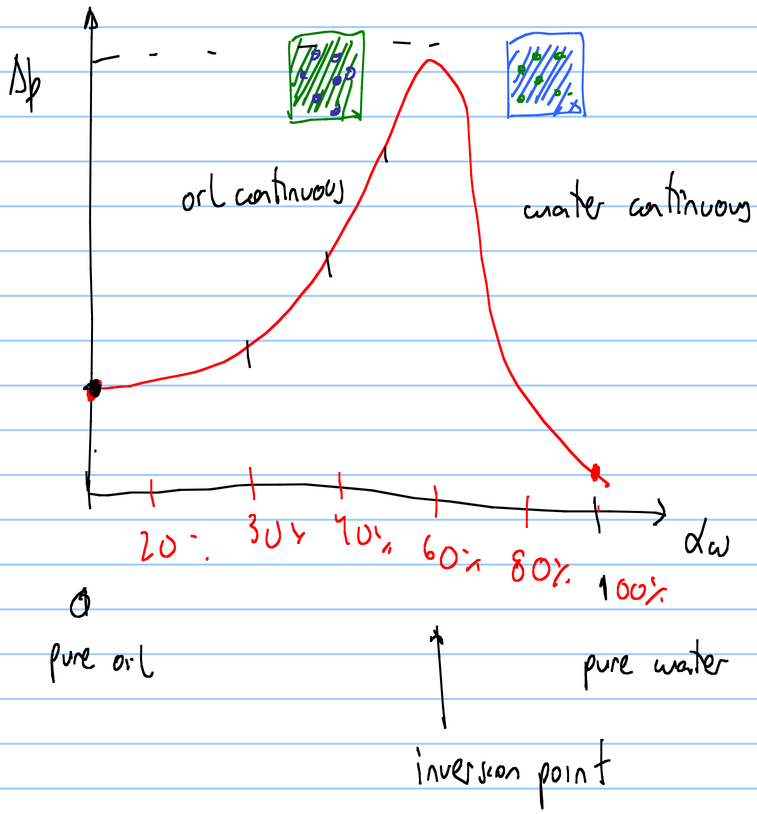
after vigorous stirring



$\alpha_w = \frac{V_w}{V_T}$ 1 pure water

0 pure oil

emulsion also affect separation time in processing facilities!



Course end!

5 days, 25 hrs of class

thanks for your active participation.

10 exercises