Note Title 02.12.2019

02.12.2019 ME683 Field development and operations

02.12 – 06.12 Prof Milan Stenko NTNU Norwegian University of science and Technology

09:00 – 14:00
3 breaks → 15 mins

Master program responsible: UDSM Joseph Kihedu
NTNU: Ole Jørgen Nydal

Evaluation:
10% homework (2019)
2x 15% Quizzes (2019, 2020)
60% Exam (2020)

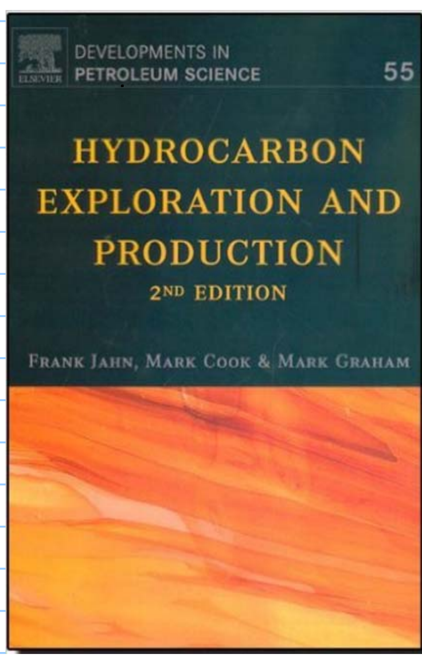
Supporting prof. @ UDSM: Liberato Haule
- Examination
- Exercises
- Quizzes

Students:
- Neema (petroleum)
- Wilfritus (chemical and process)
- Emmanuel (petroleum)
- Chrisostom (mechanical engineer)

course information: http://www.ipt.ntnu.no/~stanko/files/Courses/ME683/2019
/2018 previous course material

youtube channel: https://www.youtube.com/channel/UCWMfsCe1NQMgx4UZWrVvFgA
↳ playlist:
ME683 - Field development and operation (2018)

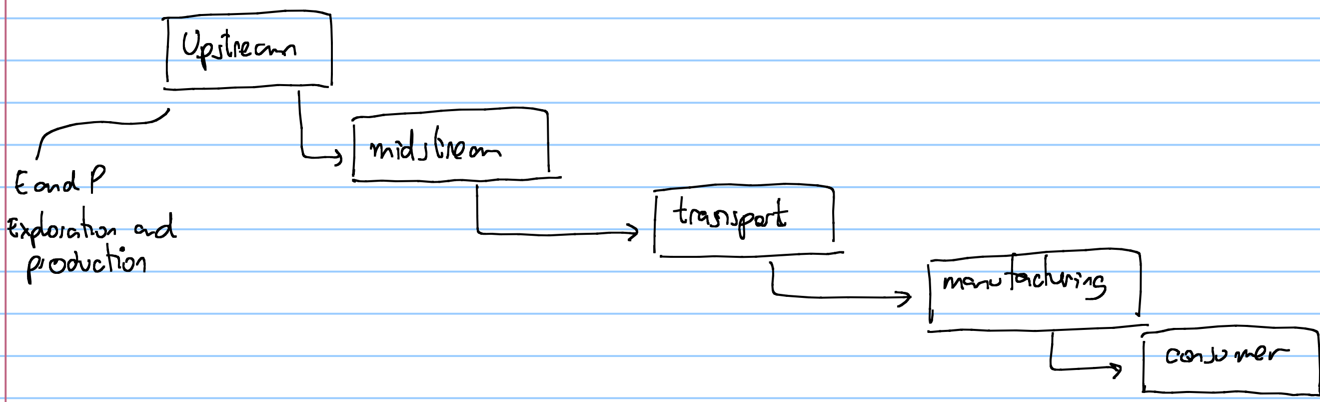
Book:



Authors: Frank Jahn, Mark Cook, Mark Graham

regular NTNU course: https://www.youtube.com/channel/UCWMfsCe1NQMgx4UZWrVvFgA
youtube channel: playlist: TPG4230 field development and operations (2019)

where are we?

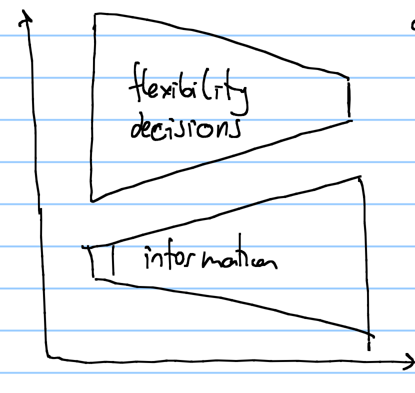


in E&P projects there are three distinct tasks:

field development and operations

- Understand the subsurface
- commercialize the discovery / reservoir
- optimize / effectivize the production
  - infill drilling
  - reduce maintenance and expenses
  - Enhanced oil recovery

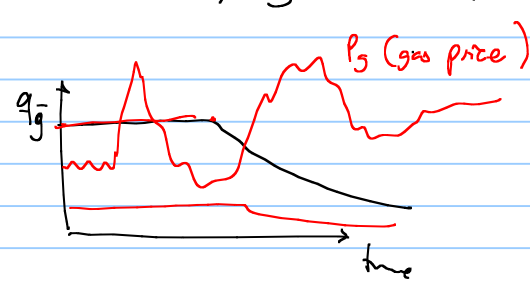
HSE compliant



any oil and gas project. Specially true for offshore

topics to cover in the course

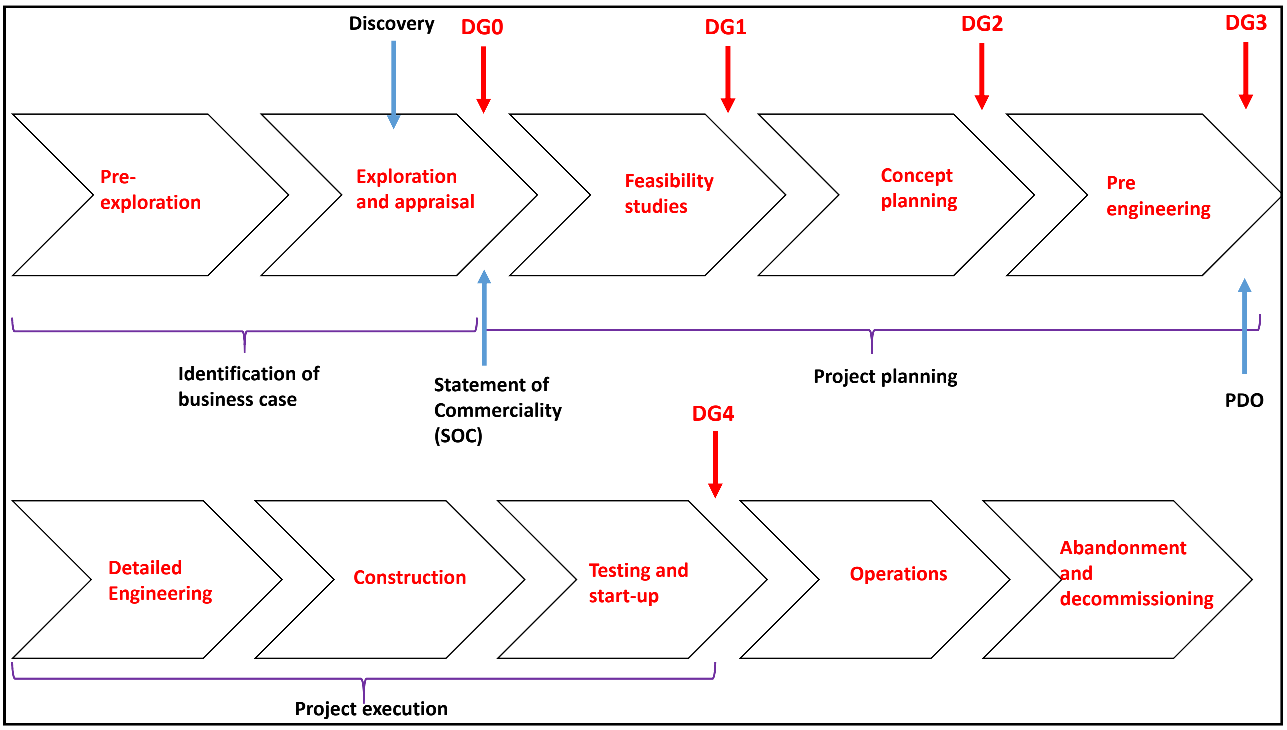
- Estimate and quantify reserve uncertainty
- Decision (probability) trees ⇝ appraisal
- flow assurance ⇝ hindrance to develop the field (multiphase transport Ole Jørgen Nydal) Corrosion, Roy Johnsen)
- offshore structure type and selection
- field production performance ~ q_{field} vs time, Price vs. time



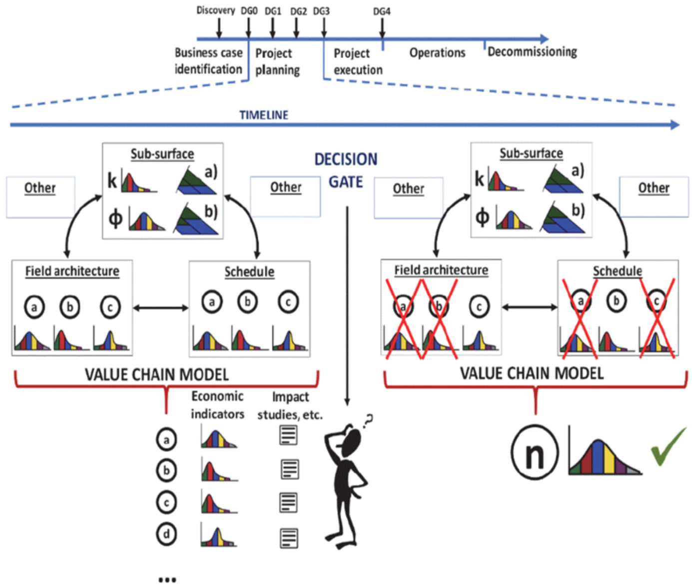
allows to compute: revenue, size of facilities → cost

THE FIELD DEVELOPMENT PROCESS

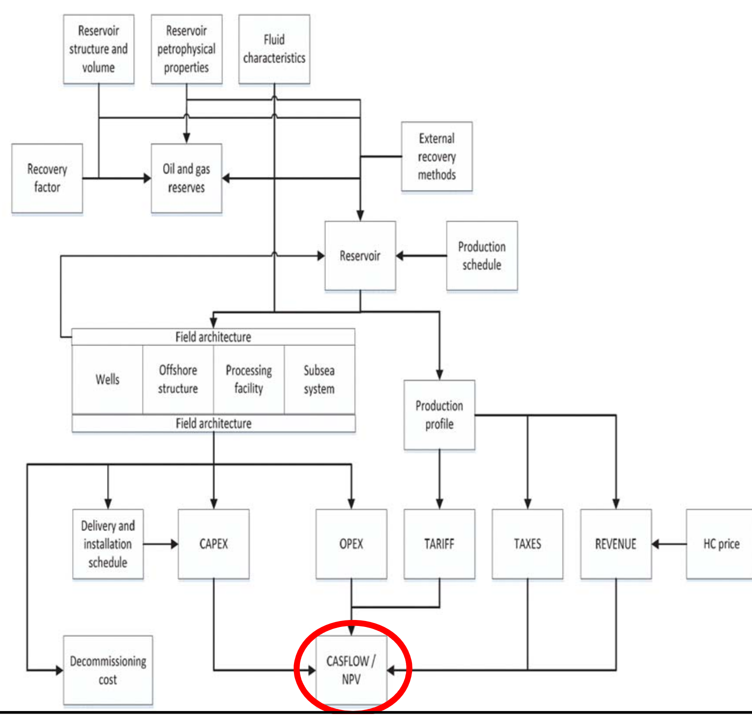
Prof. Milan Stanko (NTNU)

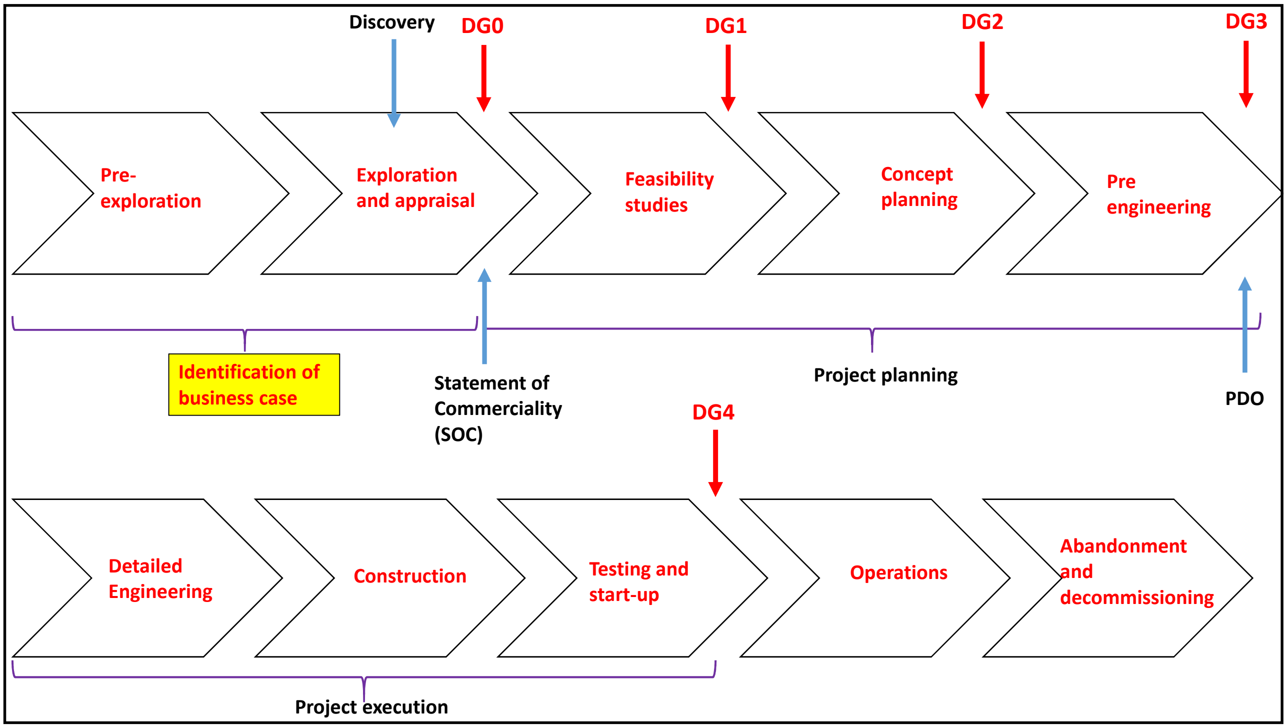


During the field development process a model of the value chain is made based on the disciplines involved and populated with information. Initially there are many alternatives and little information. As time progresses and decisions are taken, the model is expanded, there is more information but less flexibility.



Key performance indicators are computed with the value chain model and are used to take decisions in the decision gate process.





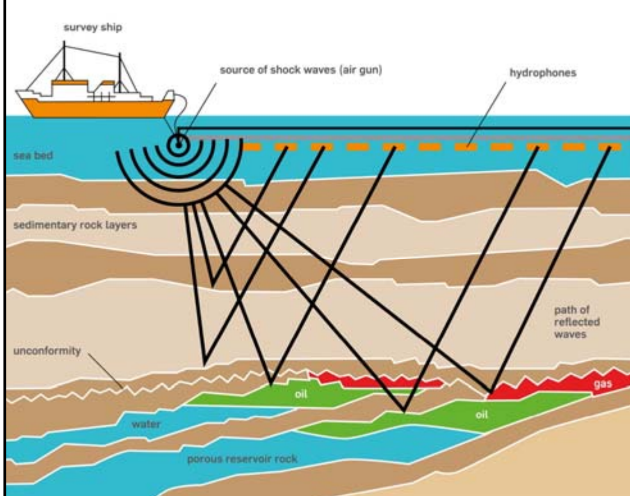
IDENTIFICATION OF BUSINESS CASE

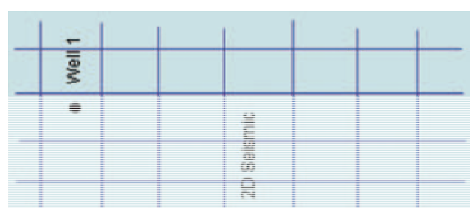
The main goal of this stage is to prove economic potential of the discovery and quantify and reduce the uncertainty in the estimation of reserves.

IDENTIFICATION OF BUSINESS CASE - TASKS

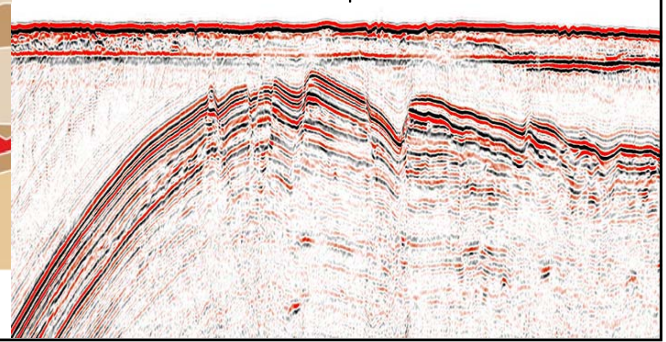
- Pre-exploration – scouting: collecting information on areas of interests. Technical, political, geological, geographical, social, environmental considerations are taken into account. E.g. expected size of reserves, political regime, government stability, technical challenges of the area, taxation regime, personnel security, environmental sensitivity, previous experience in the region, etc.
- Getting pre-exploration access – The exploration license (usually non-exclusive). In the NCS only seismic and shallow wells are allowed. This is usually done by specialized companies selling data to oil companies. Area: 500 Km^2
- Identify prospects.

IDENTIFICATION OF BUSINESS CASE - TASKS



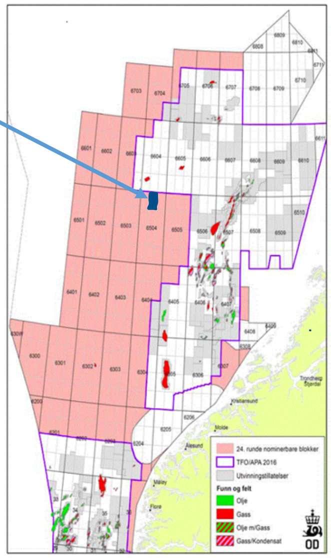


Seismic exploration



IDENTIFICATION OF BUSINESS CASE - TASKS

Ca 500 km^2

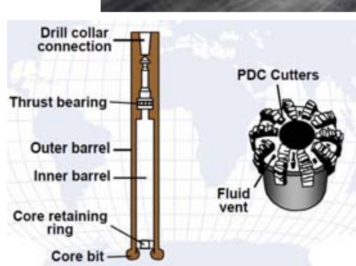


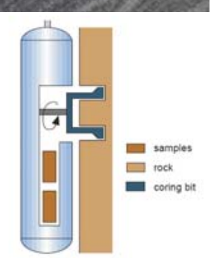
- Apply and obtain exclusive production license (6 years, possible to extend for 30 years). In the NCS: Licensing rounds (frontier areas) or Awards in predefined areas (APA). The current fees are 34 000 NOK/km^2 for the first year, 68 000 NOK/km^2 for the second year and 137 000 NOK/km^2 per year thereafter.

IDENTIFICATION OF BUSINESS CASE - TASKS

- Exploration. Perform geological studies, geophysical surveys, seismic, exploration drilling (Well cores, wall cores, cuttings samples, fluid samples, wireline logs, productivity test).

- Discovery!





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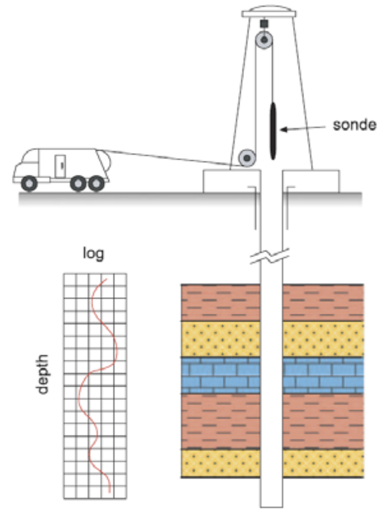

IDENTIFICATION OF BUSINESS CASE - TASKS

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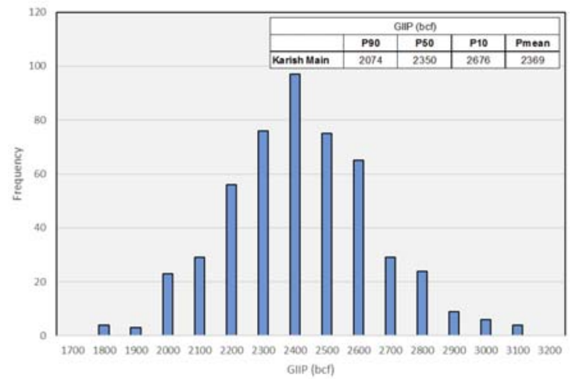
- Discovery!

IDENTIFICATION OF BUSINESS CASE - TASKS

- Assessment of the discovery and the associated uncertainty. Risk management:
  - o **Probabilistic reserve estimation.** Identify and assess additional segments.

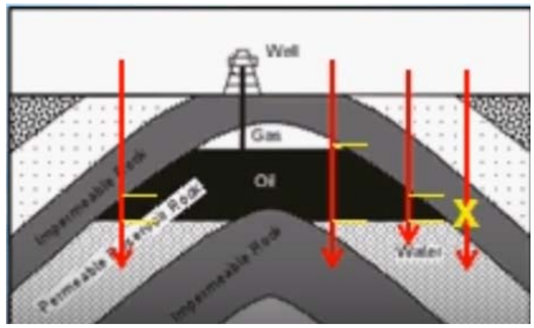


IDENTIFICATION OF BUSINESS CASE - TASKS

- Assessment of the discovery and the associated uncertainty. Risk management:
  - o **Probabilistic reserve estimation.** Identify and assess additional segments.
  - o Perform **simplified economic valuation** of the resources.
  - o Field **appraisal** to reduce uncertainty: more exploration wells and seismic to determine for example: fault communication, reservoir extent, aquifer behavior, location of water oil contact or gas oil contact.

IDENTIFICATION OF BUSINESS CASE - TASKS

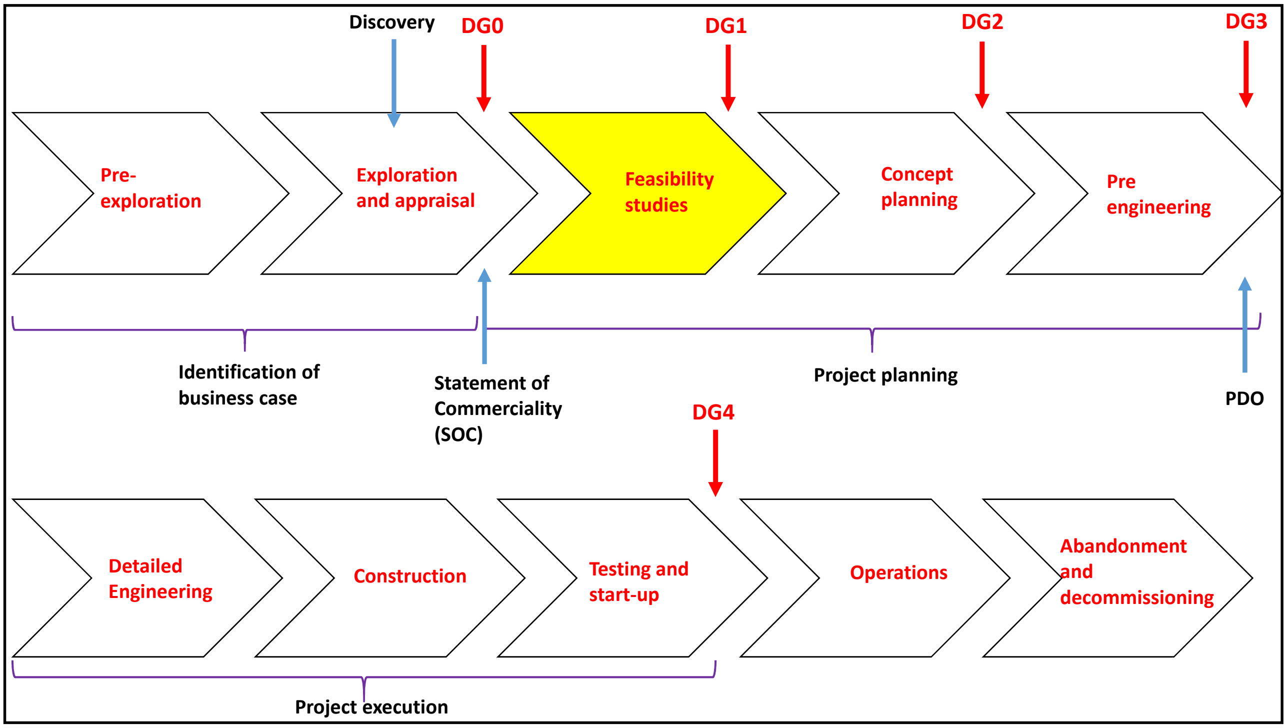
o Appraisal



IDENTIFICATION OF BUSINESS CASE - TASKS

DG0:

- Issue a SOC (Statement of Commerciality) and proceed with development.
- Continue with more appraisal
- Sell the discovery.
- Do nothing (wait)
- Relinquish to the government

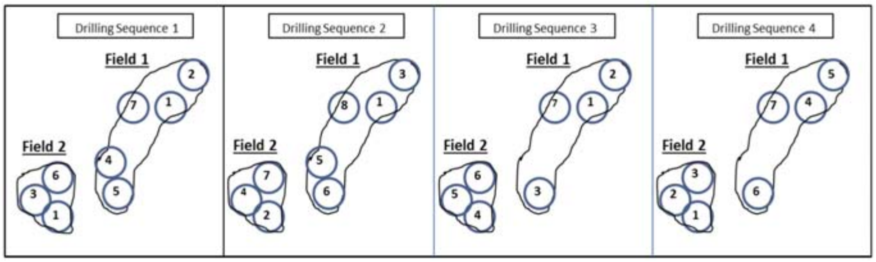


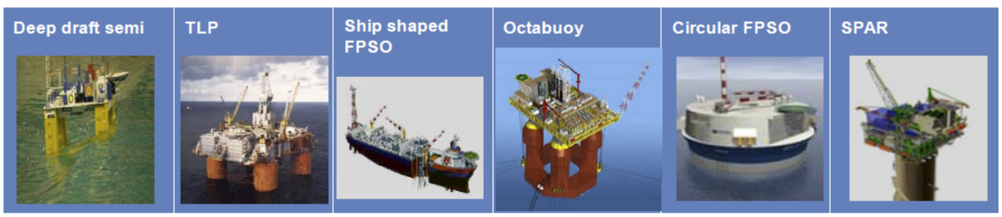
FEASIBILITY STUDIES - TASKS

OBJECTIVE: Justify further development of the project, finding one or more concepts that are technically, commercially and organizationally feasible

- Define objectives of the development in line with the corporate strategy.
- Establish feasible development scenarios.
- Create a project timeline and a workplan.

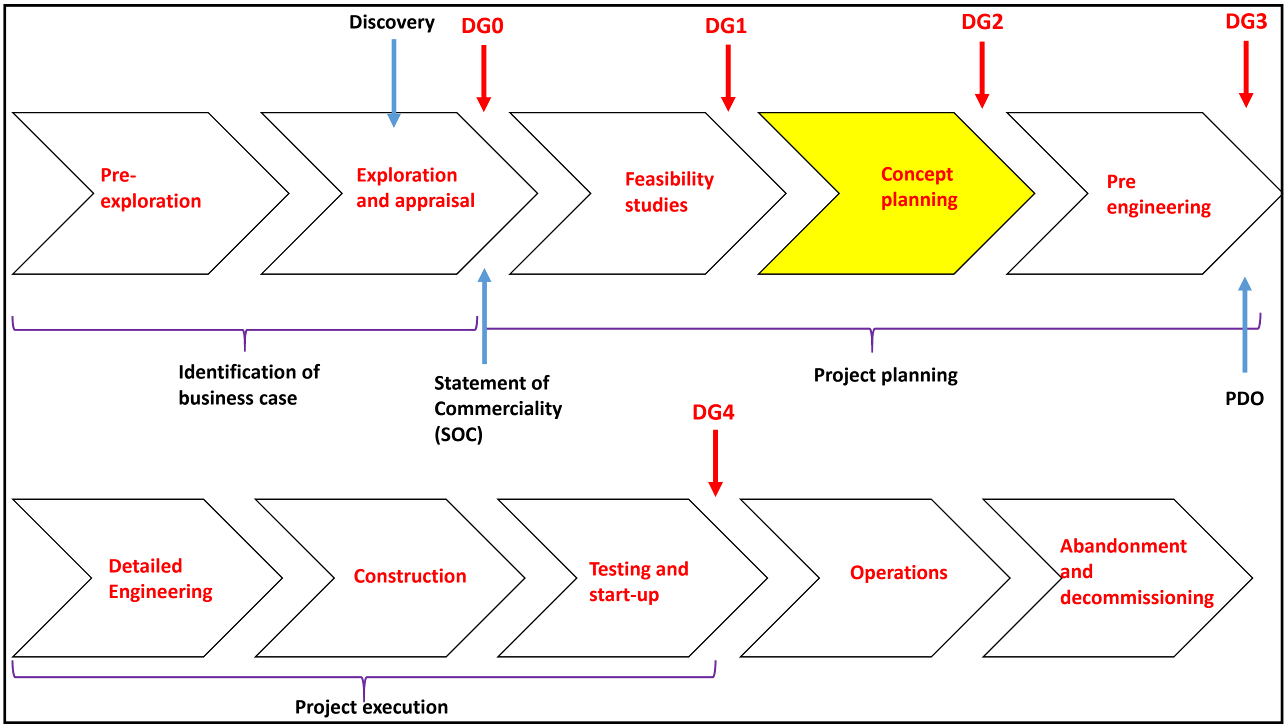
FEASIBILITY STUDIES - TASKS





FEASIBILITY STUDIES - TASKS

- Identify possible technology gaps and blockers.
- Identify the needs for new technology.
- Identify added value opportunities.
- Cost evaluation for all options (at this stage, cost figures are ±40% uncertain)



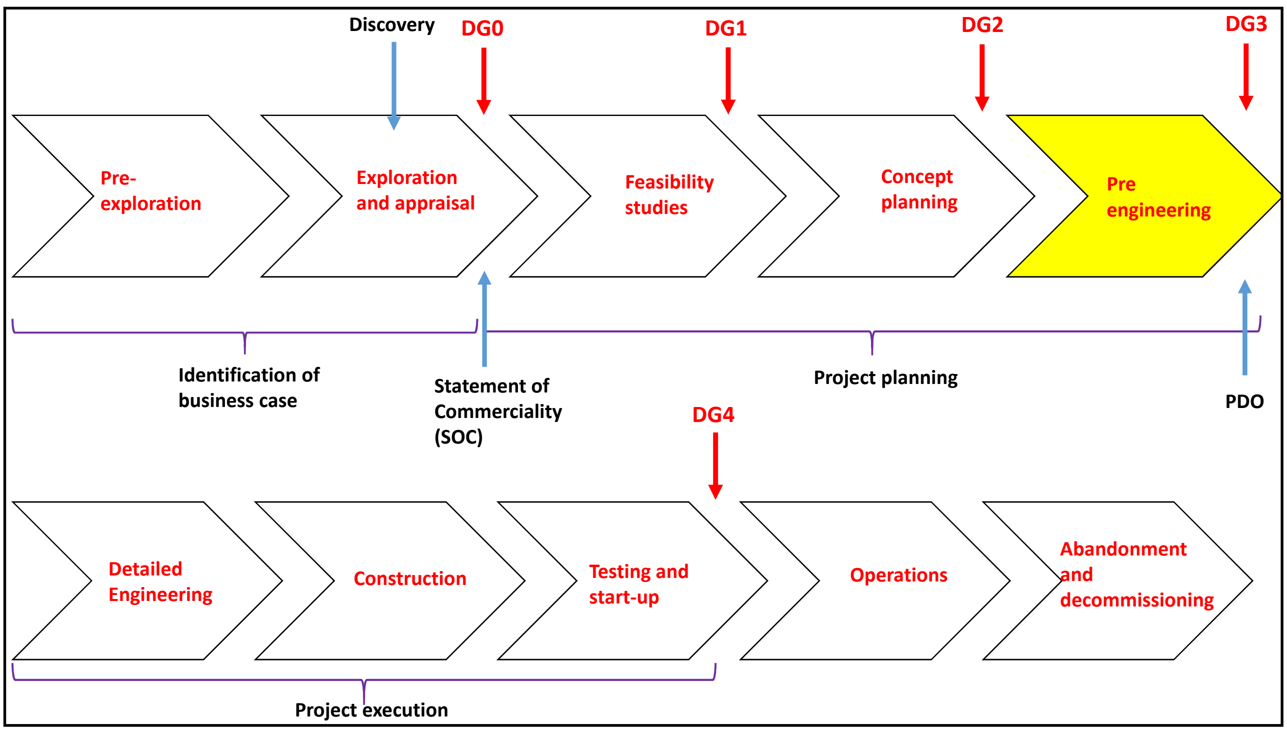
CONCEPT PLANNING - TASKS

OBJECTIVE: Identify development concepts, rank them and select and document a viable concept (Base Case Scenario).

- Evaluate and compare alternatives for development and screen out non-viable options.
- Elaborate a Project Execution Plan (PEP) which describes the project and management system.
- Define the commercial aspects, legislation, agreements, licensing, financing, marketing and supply, taxes.

CONCEPT PLANNING - TASKS

- Create and refine a static and a dynamic model of reservoir. **Define the depletion and production strategy.**
- Define an HSE program
- **Flow assurance evaluation.** Identification of challenges related with fluid properties, multiphase handling and driving pressure.
- Drilling and well planning
- Pre-design of facilities
- Planning of operations, start-up and maintenance
- Cost and manpower estimates of the best viable concept.



PRE-ENGINEERING - TASKS

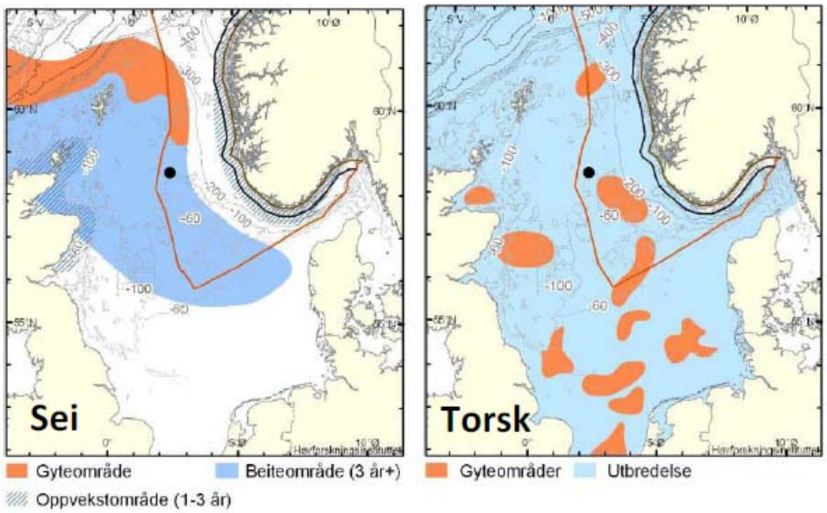
OBJECTIVE: Further mature, define and document the development solution based on the selected concept.

- Selection of the final technical solution. Decide and define all remaining critical technical alternatives.
- Execute Front End Engineering Design (FEED) Studies: determine technical requirements (arranged in packages) for the project based on the final solution chosen. Estimate cost of each package.
- Plan and prepare the execution phase.

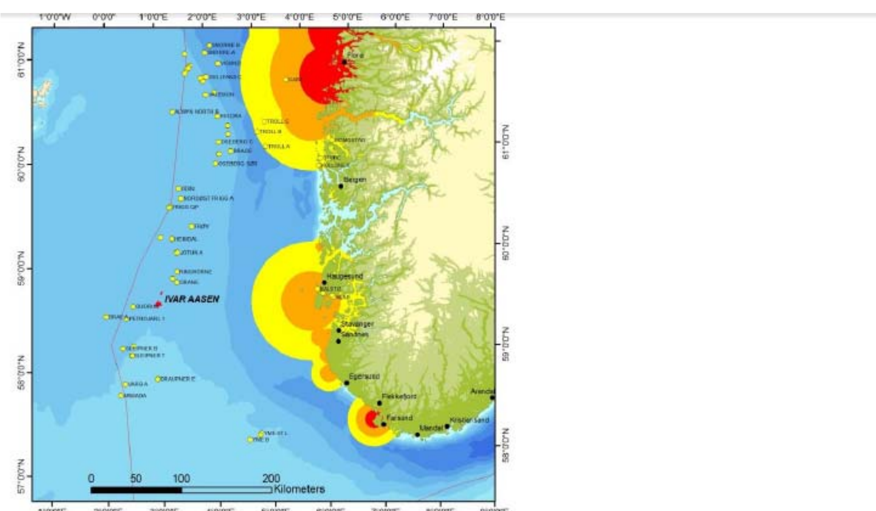
PRE-ENGINEERING - TASKS

- Prepare for submission of the application to the authorities.
- Perform the Environmental impact assessment.
- Establish the basis for awarding contracts.
- Issue:
  - Plan for development and operations
  - Plan for installation and operations of facilities for transport and utilization of petroleum (PIO)
  - Impact assessment report

PRE-ENGINEERING - TASKS

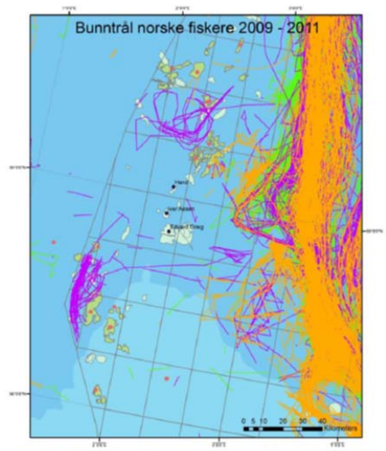


PRE-ENGINEERING - TASKS



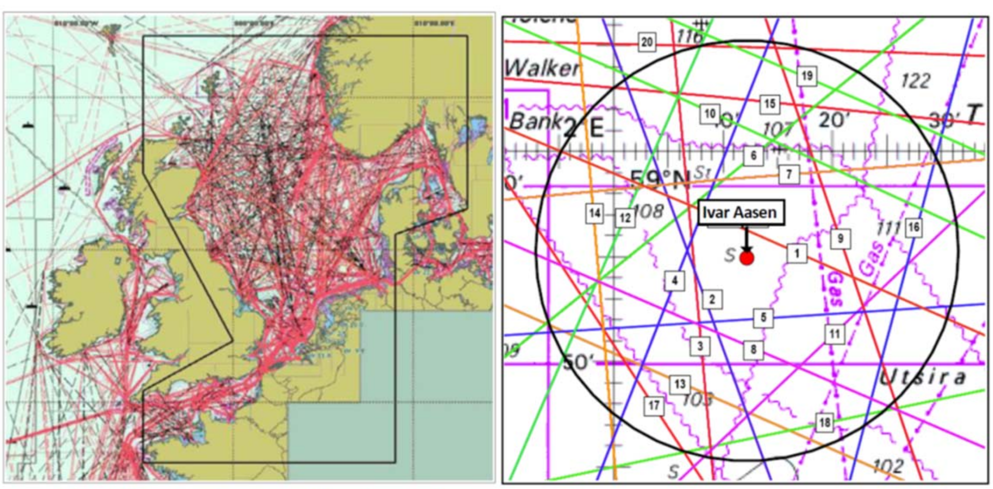
Figur 18. Svært viktige (rød), viktige (oransje) og nokså viktige (gule) leveområder for sjøfugl langs kysten av Nordsjøen i hekketiden. Kartet markerer buffersoner rundt de viktige hekkelokalitetene (NINA)

PRE-ENGINEERING - TASKS



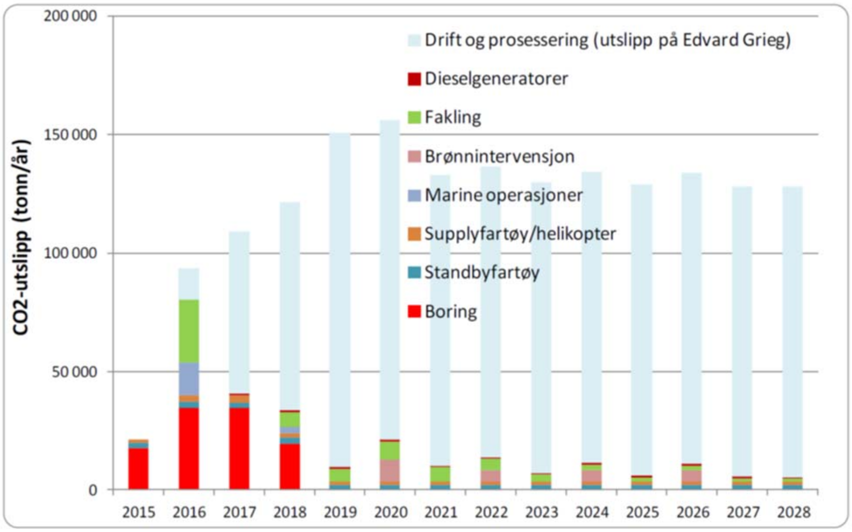
Figur 23. Registrert norsk fiskeriaktivitet med bunntrål i området omkring Aasen i 2009 (grønn), 2010 (fiolett) og 2011 (oransje). Figur utarbeidet på grunnlag av data fra Fiskeridirektoratets satellittsporing av større fiskefartøyer

PRE-ENGINEERING - TASKS



Figur 24. Trafikkompleksitet i Nordsjøen (venstre) og skipsleder for handels- og offshorefartøy innenfor en radius på 10 nautiske mil fra Aasen (høyre)

PRE-ENGINEERING - TASKS



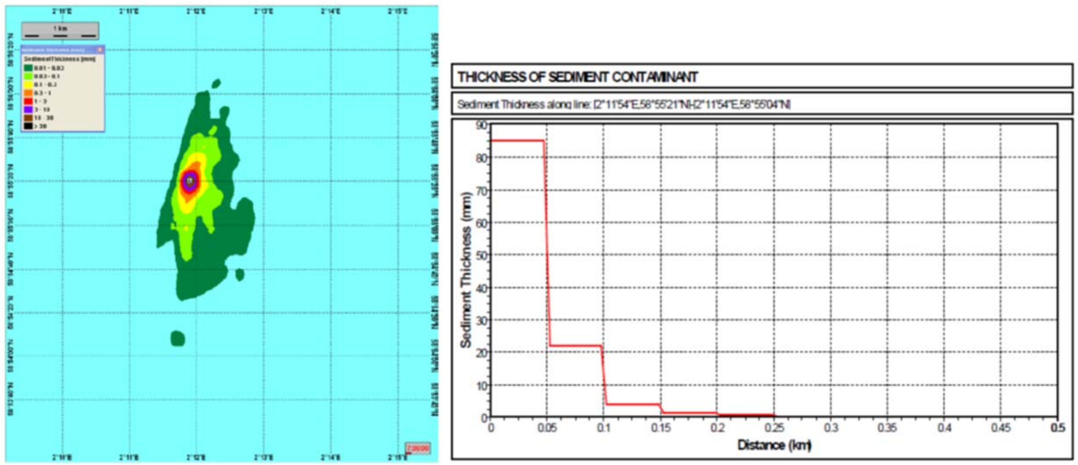
Figur 25. Samlede utslipp av CO_2 fra Aasenfeltet i perioden 2015 – 2028

PRE-ENGINEERING - TASKS

Tabell 5-1. Foreløpig oversikt over estimerte mengder kaks for typiske produksjonsbrønner på Aasen, West Cable og Hanz

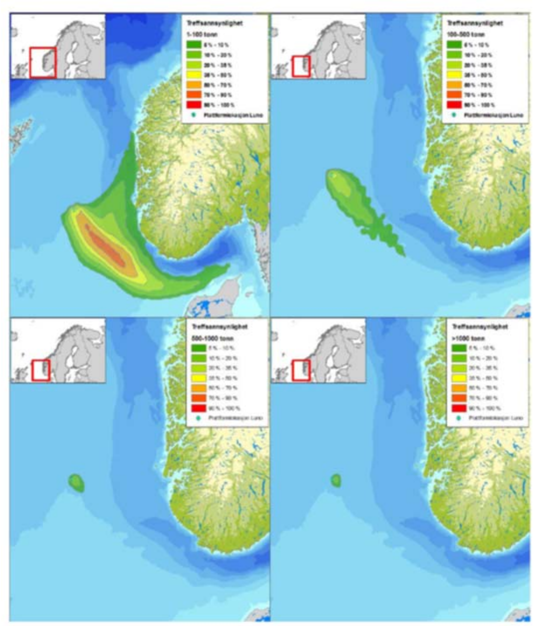
Seksjon	Borevæske	Boret lengde (m)			Mengde borekaks (tonn)		
		Aasen	West Cable	Hanz	Aasen	West Cable	Hanz
36"	WBM	88	88	86	70	70	70
26"	WBM	370	370	400	150	150	160
17 ½"	OBM	1 550	1 020	990	310	205	200
12 ¼"	OBM	860	3 890	1 700	90	390	170
8 ½"	OBM	1 390	1 530	90	70	80	5
SUM (avrundet)		**4 300**	**6 900**	**3 300**	**690**	**895**	**605**
SUM WBM kaks					**220**	**220**	**230**
SUM OBM kaks					**470**	**675**	**375**

PRE-ENGINEERING - TASKS



Figur 29. Sedimentering ved utslipp av vannbasert kaks ved havbunnen (sommersituasjon)

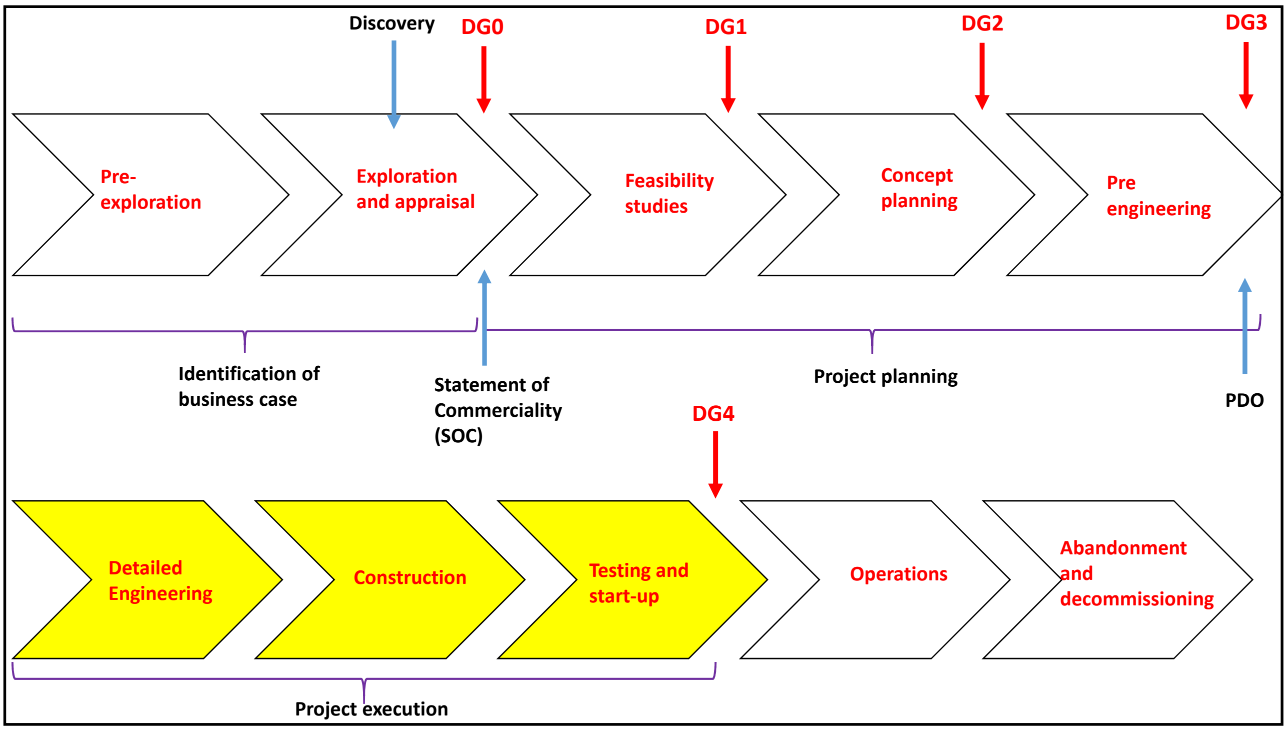
PRE-ENGINEERING - TASKS



Figur 37. Sannsynligheten for treff av ulike mengdekategorier av olje i 10 × 10 km ruter gitt en sjøbunnsutblåsning fra Aasen/Grieg (helårsstatistikk). Influensområdet er basert på alle utslippsrater og varigheter og deres individuelle sannsynligheter. Merk at det markerte området ikke viser omfanget av et enkelt oljeutslipp, men er det området som berøres i mer enn 5 % av enkeltsimuleringene av oljens drift og spredning (Lundin 2011).

PRE-ENGINEERING - TASKS

- Wait for the government to study the proposal



DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

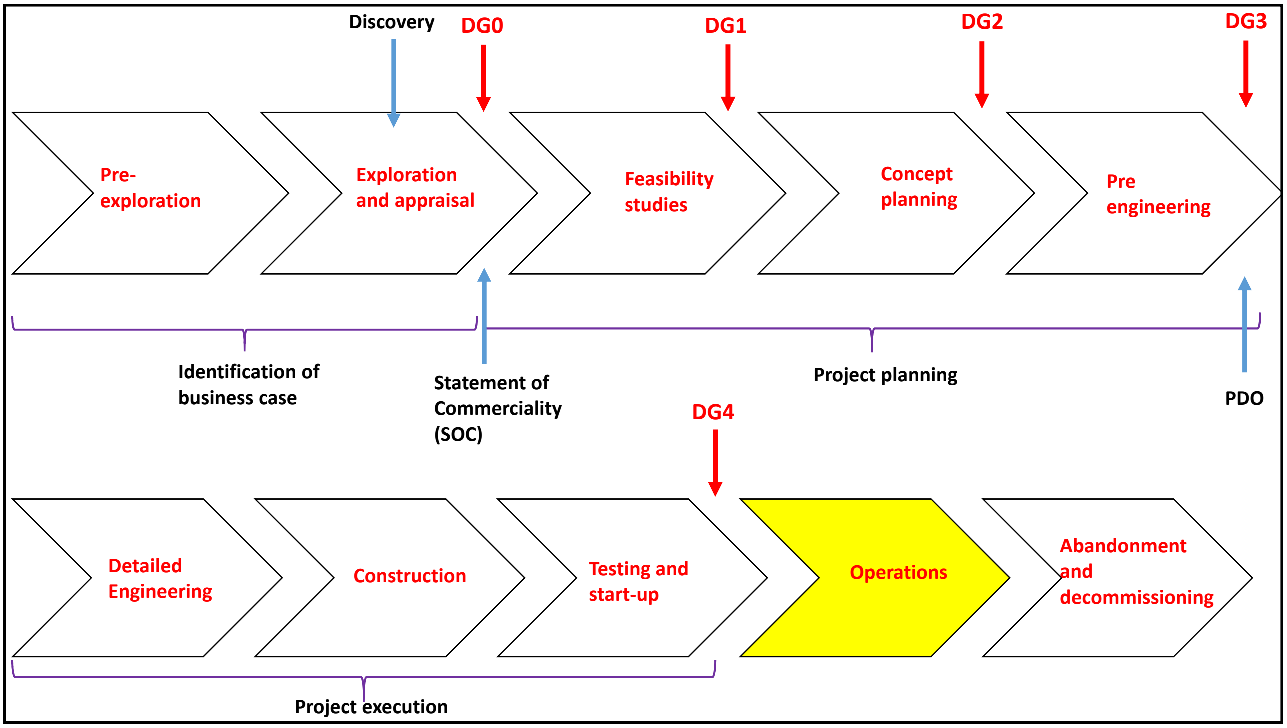
OBJECTIVE: Detailed design, procurement of the construction materials, construction, installation and commissioning of the agreed facilities.

Individual contracts
- Detailed engineering
- Bids, contracts
- Construction, fabrication
- Installation
- Commissioning (Cold or Hot)

EPCM (Engineering, procurement, construction, and management contract) with one main contractor.

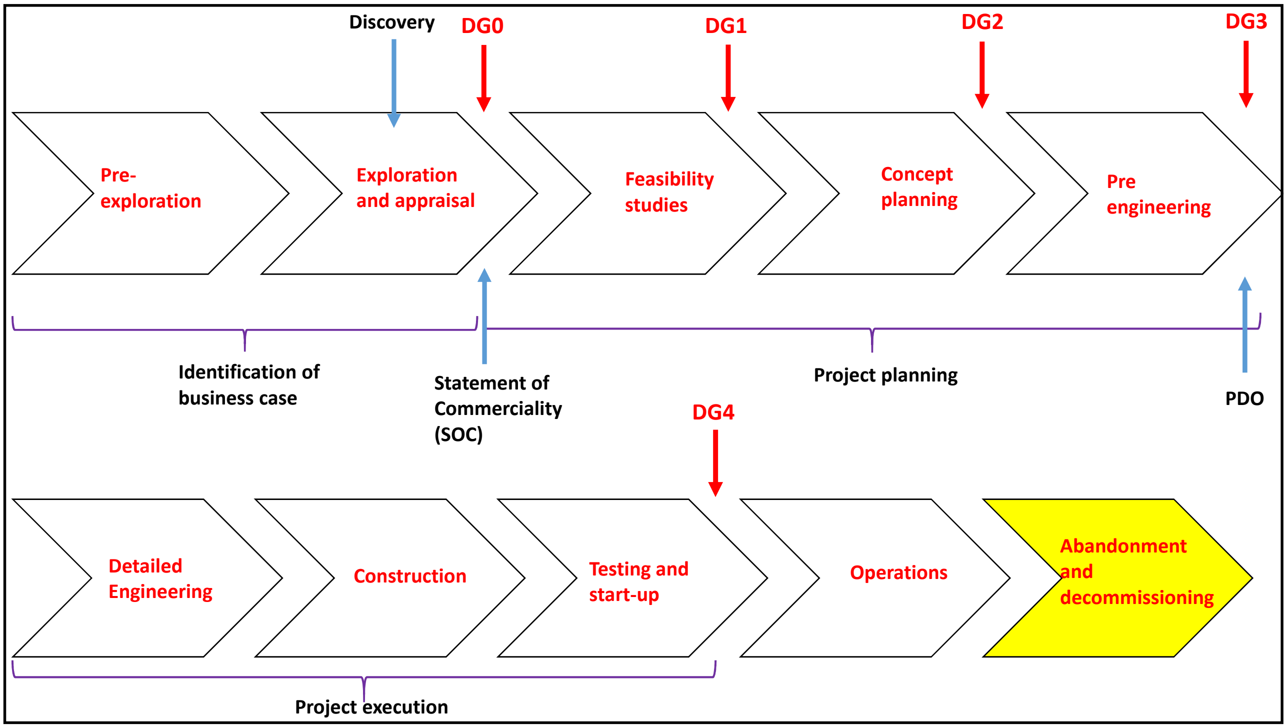
DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

- Constructing wells.
- Perform hand over to asset, operations
- Prepare for start-up, operation and maintenance



OPERATIONS

- Production startup, Build-up phase, Plateau phase, Decline phase, Tail production, Field shut-down.
- Maintenance.
- Planning Improved Oil recovery methods.
- Allocation and metering.
- De-bottlenecking.
- Troubleshooting.



DECOMISSIONING AND ABANDONMENT

- Engineering “down and clean”: flushing and cleaning tanks, processing equipment, piping.
- Coordinate with relevant environmental and governmental authorities.
- Well plugging and abandonment (P&A)
- Cut and remove well conductor and casing.
- Remove topside equipment.

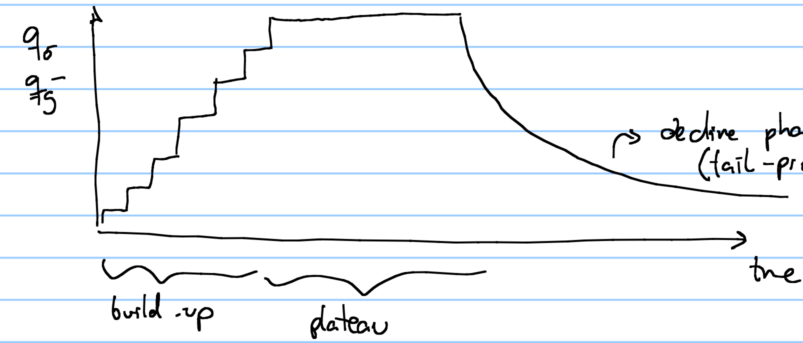
DECOMISSIONING AND ABANDONMENT

- Removal of the offshore structure: Lifting operations and transport
- Remove or bury subsea pipelines
- Mark and register leftover installations on marine maps
- Monitoring
- Recovery of material: Scrap (steel) and recycling equipment (Gas turbines, separators, heat exchangers, pumps, processing equipment)
- Disposal of residues

DECOMISSIONING AND ABANDONMENT

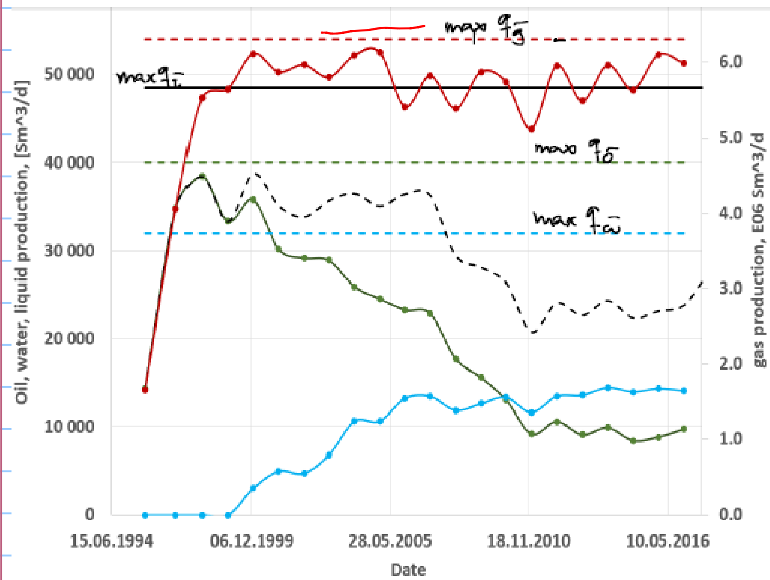
DECOMISSIONING AND ABANDONMENT

typical production profile (phases) of a field:



continue production as long as operating expenditures < revenue

↳ as short as possible (pre-drilled wells, platform wells versus subsea wells)



bottlenecked? (gas capacity)

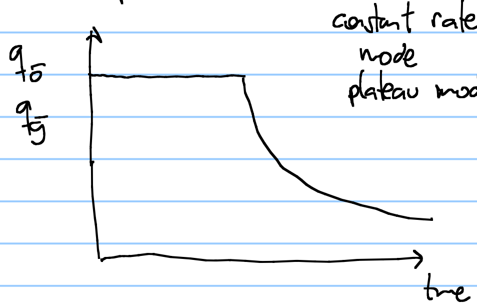
for oil field q_o

$q_g = \underline{GOR} \cdot \underline{q_o}$

GOR changes with time

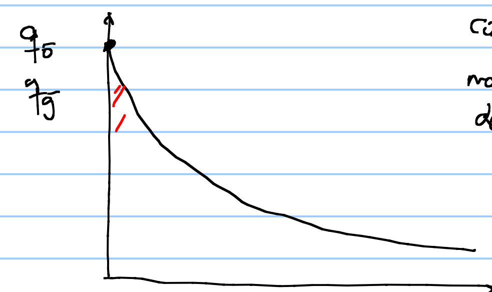
Predicting and quantifying field production performance

two production modes



constant rate mode
plateau mode

mode A



constant pressure mode
decline mode

mode B

$q_o \cdot P_o -$

NPV − CAPEX !

$$NPV = \frac{\text{cash flow}}{(1+i)^t}$$

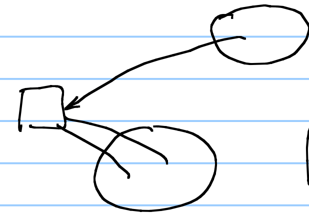
t years, i discount rate

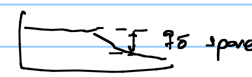
Used for:

- standalone fields that require new infrastructure to be built from scratch
- medium to large fields

Used for

- satellite fields that can be tied in to existing infrastructure (medium-small size)



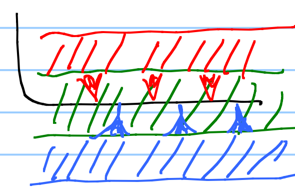


why not to produce as much as possible as early as possible?

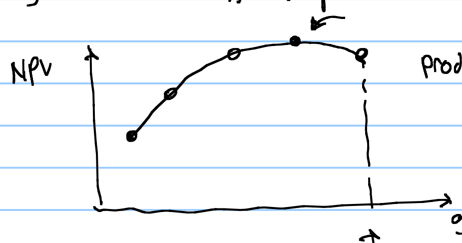
- trade off / balance between CAPEX and revenue.

higher plateau rate gives ↑ revenue

higher plateau rates give ↑ capital expenses → bigger processing facilities
↳ bigger offshore structure
↳ drill more wells (to avoid sand production, formation damage gas coning or water cusping)

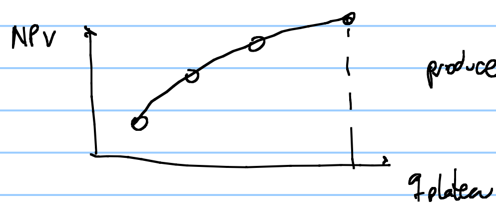


to study this dependency, we typically run analysis with different plateau rates



produce mode A

decline from beginning



produce in mode B

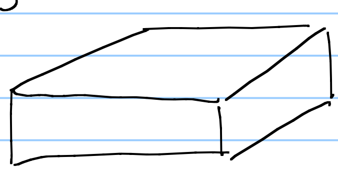
decline

rule of thumb to define plateau rates for standalone fields:

for oil 10% of TRR per year
↳ total recoverable reserves

N - OOIP original oil in place

only oil and water



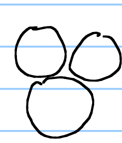
V_R

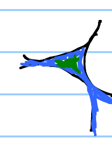
m³ - bbls

$$\underline{N} = \underbrace{V_R \cdot \phi}_{V_{Fluid}} \cdot \frac{S_{oi}}{B_o} = \frac{V_R \cdot \phi \cdot (1 - S_{wc})}{B_o @ P_R^i, T_R^i}$$

$$S_o = \frac{V_o}{V_{pore}}$$

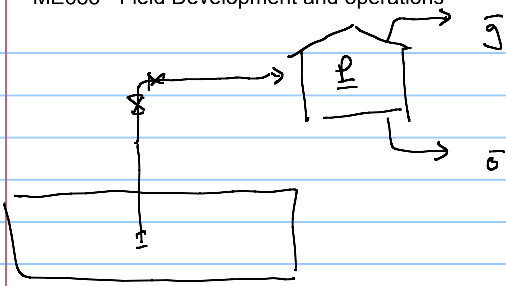
$$\phi = \frac{\text{pore volume}}{\text{rock volume}}$$





$$S_w = \frac{V_w}{V_{pore}}$$

connate water
S_{wc}



oil volume factor $B_o = \dfrac{V_o @ p, T \; [m^3]}{V_o @ p_{sc}, T_{sc} \; [Sm^3]}$ greater than 1

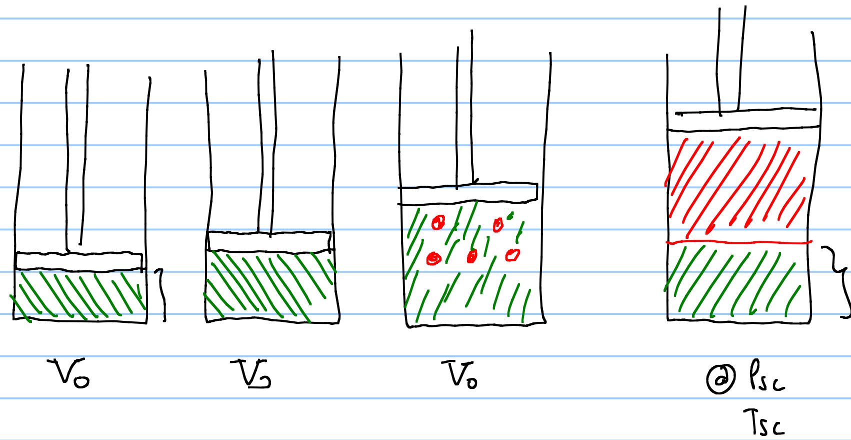
1 – 1.7

heavy oil low GOR — light oil high GOR

standard conditions depend

$p_{sc} = 1.01325$ bara

$T_{sc} = 15.56$ °C



$$TRR = N_{pu} = RF_u \cdot N = V_R \frac{\Phi(1-S_{wc})}{B_o} \cdot RF_u$$

for gas (0.5 – 0.8)
for oil (0.2 – 0.6)

N_{pu}: ultimate cumulative production

RF_u: ultimate recovery factor

an example. a field with

$N = 100\,000\,000$ stb   10% of TRR in every year

assume $RF_u = 0.4$

$TRR = N_{pu} = 40E06$ stb $q_{plateau} = \dfrac{0.1\, N_{pu}}{365} = \dfrac{0.1 \cdot 40E06 \text{ stb}}{365 \text{ days}}$

$q_{plateau} = \underline{10958 \text{ stb/day}}$

for gas   IGIP, G   2% – 5% of TRR (G_{pu}) per year

differences between oil and gas production:

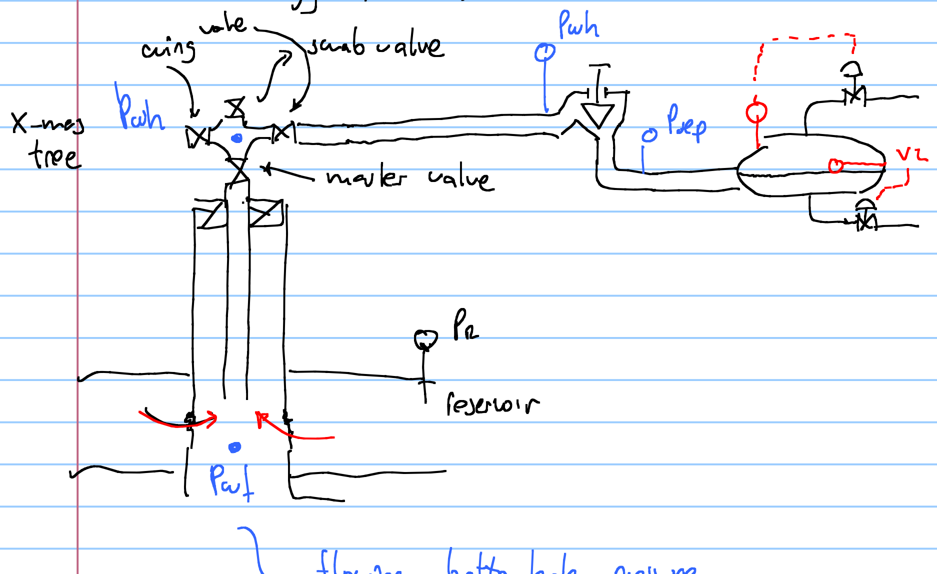
- oil can be sold in the spot market, with tanker. gas must be sold to a customer with a pre-existing contract, infrastructure
- Gas contracts are typically long term, they specify a plateau rate, swing factor

because of this, plateau duration of gas fields is much longer than oil fields (1-5 years)
↳ (5-30 years)

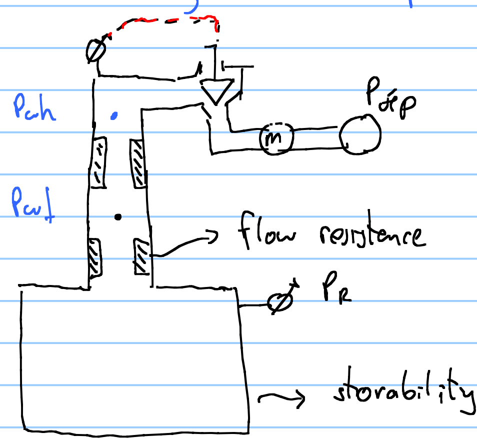
LNG Liquified natural gas CH_4 methane C_2H_6 ethane → liquid $-160°C$

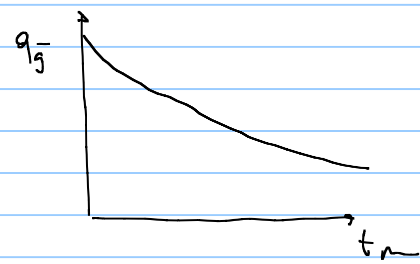
Mechanical analogy of a field

always P_{sep} is constant no matter the rate q_o, q_g, q_w

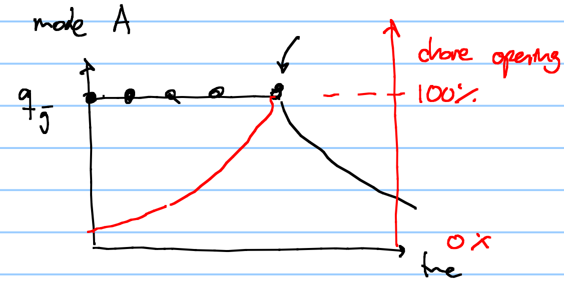


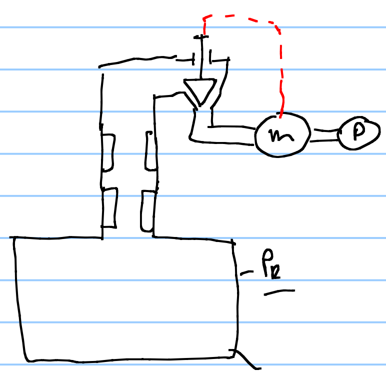
mode B (decline mode)
keep the choke opening fixed





mode A

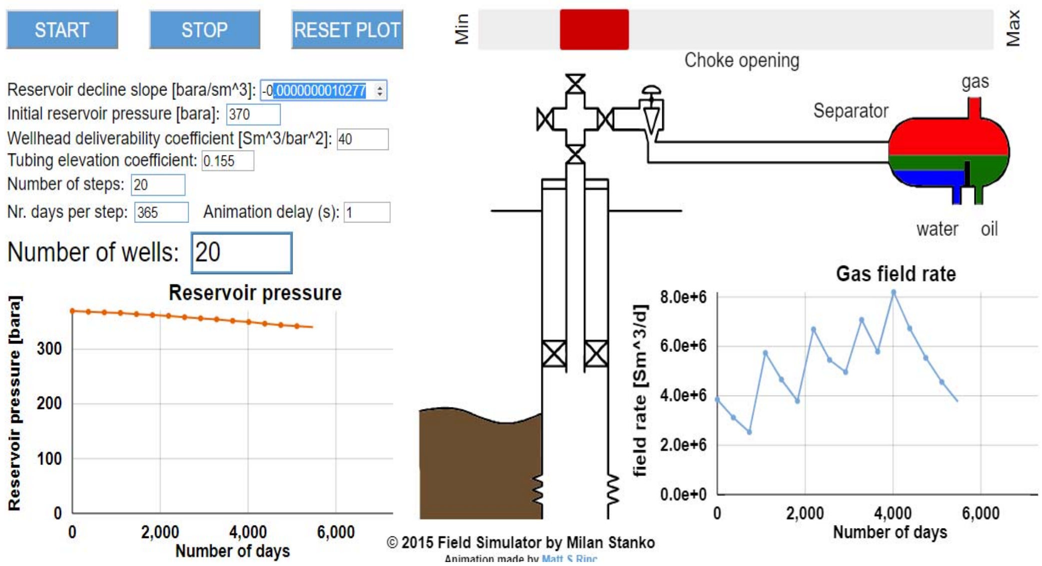




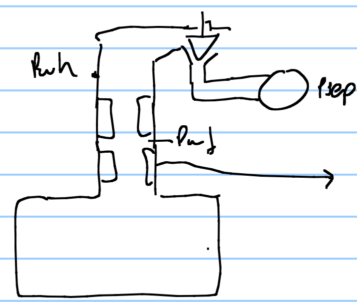
$q \propto (P_R - P_{sep})$

P_R vs G_p

http://www.ipt.ntnu.no/~stanko/Field_Simulator.html



Dry gas →



material balance

$P_R = f(G_p)$

cumulative production

$$G_p = \int_0^t q_g \, dt$$

$P_{wf} = f(P_R, q_g)$

Inflow performance relationship (IPR)

$P_{wh} = f(P_{wf}, q_g)$

tubing performance relationship (TPR)

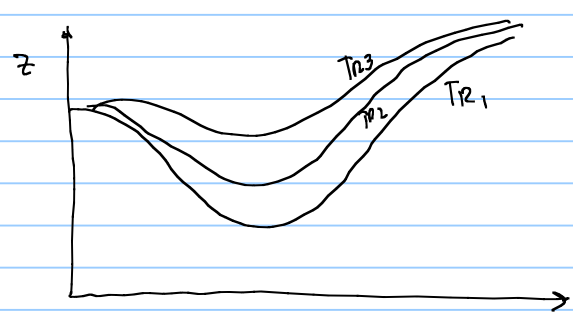
initial pressure

$$P_R = \frac{P_i \, z_R}{z_i}\left(1 - \frac{G_p}{G}\right)$$

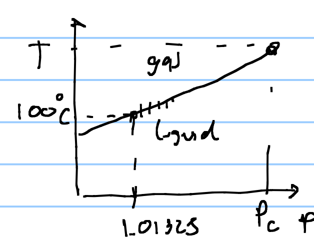
initial gas in place

gas deviation factor $PV = zRT$

$$RF = \frac{G_p}{G} \quad (0 \rightarrow RF_u)$$



$P_c, T_c = f(\gamma_g)$



reduced pressure $\frac{p}{p_c}$ critical pressure gas

$$\overset{?}{P_R} = P_i \frac{\overset{?}{Z_R}}{Z_i} \left(1 - \frac{G_p}{G}\right)$$

$$Z_R = f\left(\frac{P_R}{P_c}, \frac{T_R}{T_c}\right)$$

1: Assume P_R

2: from chart, read Z_R with P_r, T_r

$$\frac{P_R}{P_c}, \frac{T_R}{T_c}$$

3: verify

$$\overset{\text{assumed}}{P_R} - P_i \frac{\overset{\text{assumed}}{Z_R}}{Z_i} \left(1 - \frac{G_p}{G}\right) = 0 \quad ?$$

if not → back to 1

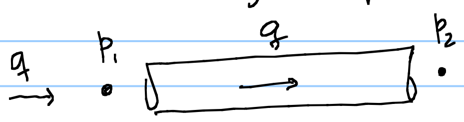
if yes

P_R is the solution!

Day 2 03.12.2019

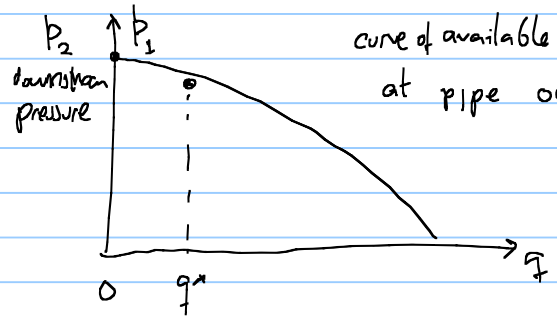
flow equilibrium

horizontal pipe

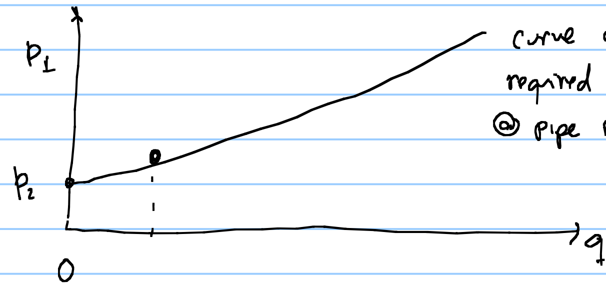


$$\Delta p_f = f \frac{L}{\phi} \frac{v^2}{2g}$$

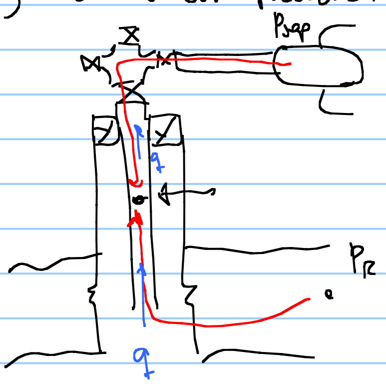
1) Fixed upstream pressure, P_1, change q

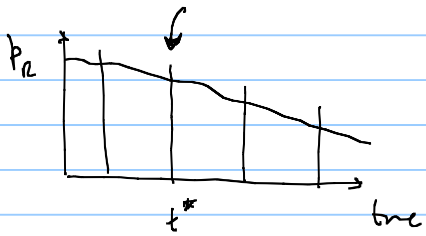


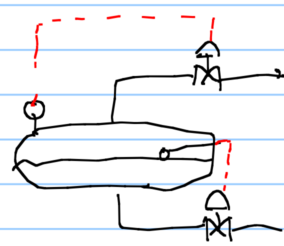
2) fixed downstream pressure p_2, vary the rate



looking back at our production system

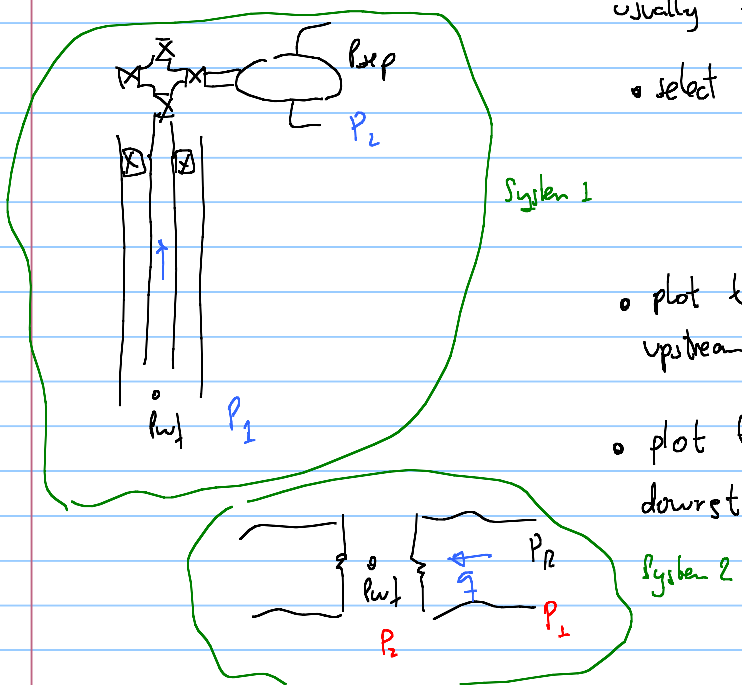






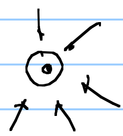
to determine flow rate of petroleum systems we usually use equilibrium analysis

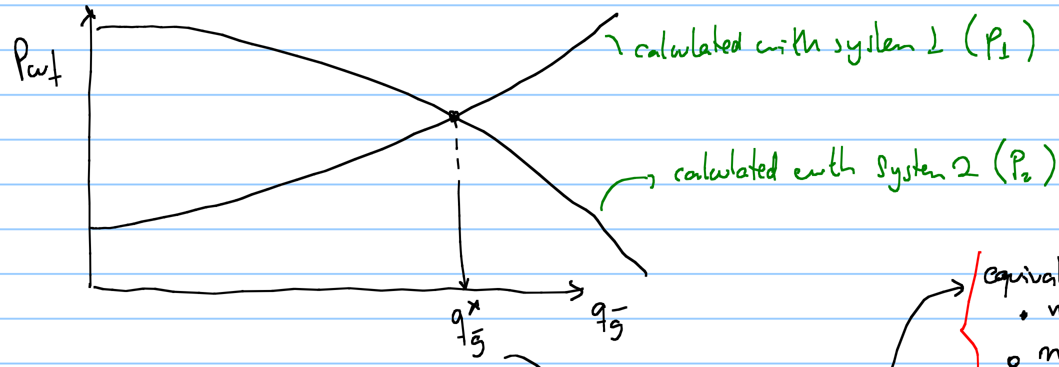
- select an equilibrium point (wellhead P_{wh}, bottom-hole P_{wf}) chokes, pumps



- plot the available pressure curve calculated from the upstream boundary with constant pressure

- plot the curve of required pressure from the downstream boundary with constant pressure

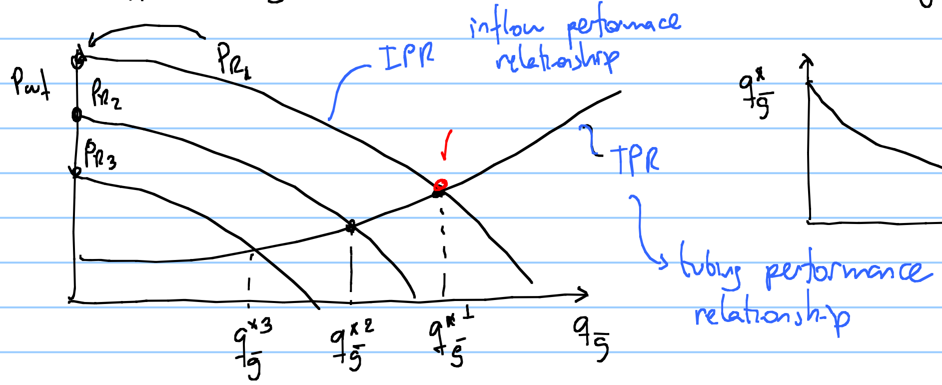


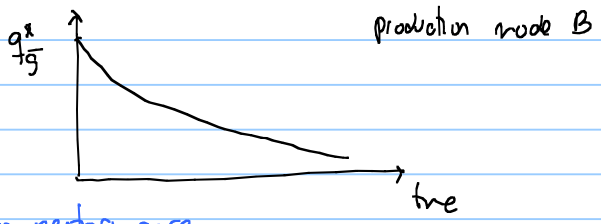


q_g^* → equilibrium rate → equivalent to solve:

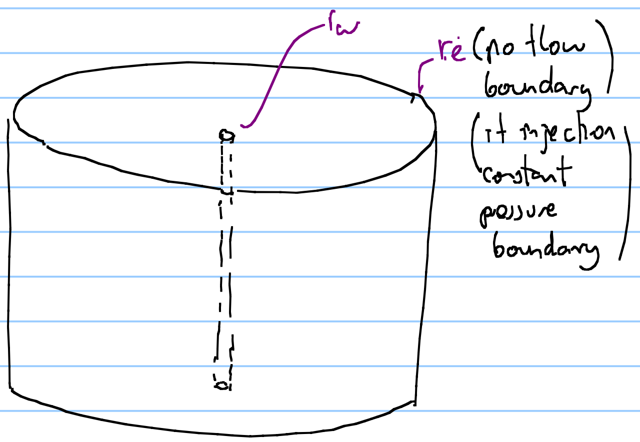
- mass conservation eq
- momentum conservation eq
- energy conservation eq

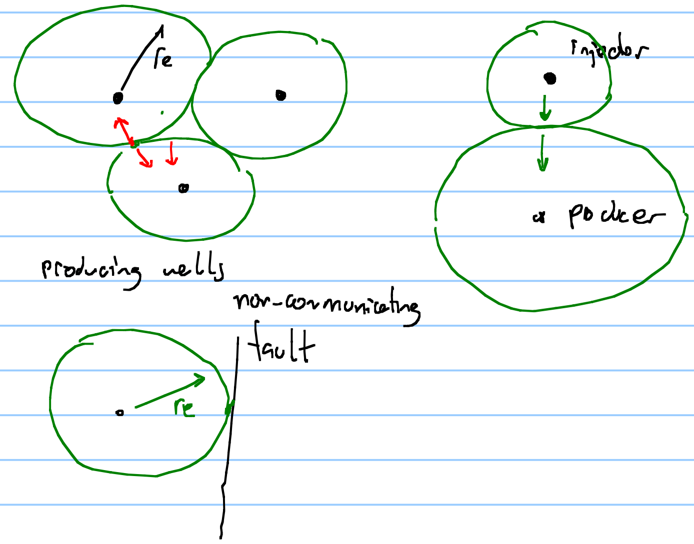
in time P_R usually declines. how does the intersection change? q_g^*



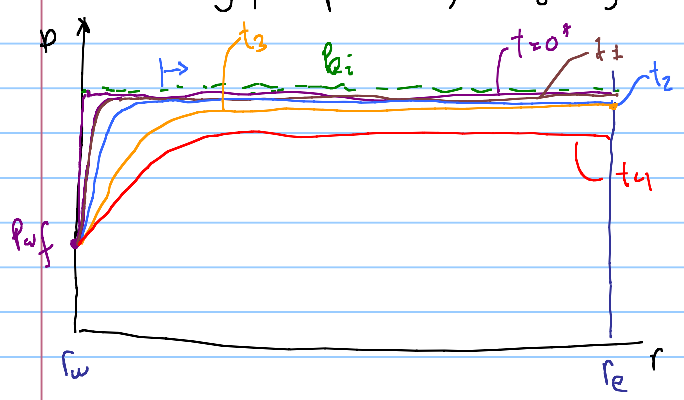


IPR:





initially, no production, everything @ P_{Ri}



so at time $t=0$ $\quad P_{(r=r_w)} = P_{wf}$ const

@ t_3 the pressure change reaches the boundary

two distinct regimes

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

$t_3 \rightarrow$ forward PSS

pseudo steady state

for PSS, IPR equations can be written as a function of q_g, P_R, P_{wf} only

for IT, IPR equations must be a function of time, q_g, P_{Ri}, P_{wf}

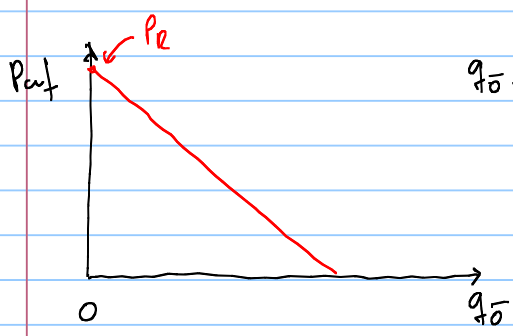
(1) for conventional reservoirs where K (permeability) is medium-high, the infinite acting $t=0 \rightarrow t_3$ is very short (hours → days). therefore, most of the production occurs in PSS

→ we will work with PSS equations in class

(2) However for unconventional reservoirs tight reservoir, shale reservoir, K low to super low, the infinite acting period $t=0 \rightarrow t_3$ might take months → years. therefore most of the production occurs in II

↳ IPR must consider time

PSS IPRs for oil (undersaturated), Gas, oil+gas



$$q_{\bar{o}} = J\,(P_R - P_{wf})$$

↑ productivity index

$$J = \frac{2\pi \cdot k \cdot h}{\mu_o \cdot B_o \cdot \left[ln\left(\frac{r_e}{r_w}\right) - 0.75\right]}$$

h: height of reservoir layer

$q_{\bar{o}}$ ↑ @ sc

undersaturated oil

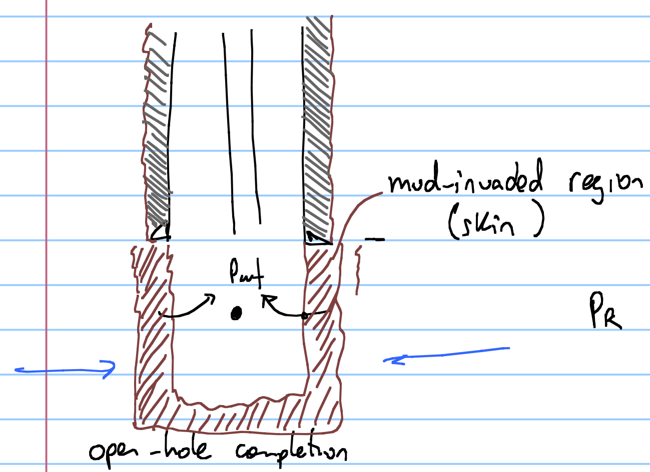
for dry gas

$$q_{\bar{g}} = C\,(P_e^2 - P_{wf}^2)^n$$

n → back pressure exponent (0.5 - 1) — turbulence of flow

dry gas backpressure equation for medium-low pressure

C ↳ backpressure coefficient

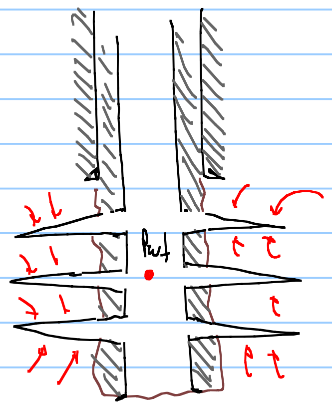


to capture the effect of skin, a factor S is included in the IPR. for example, for liquid

$$J = \frac{2\pi\, k\, h}{B_o\, \mu_o \left(ln\, \frac{r_e}{r_w} - 0.75 + S\right)}$$

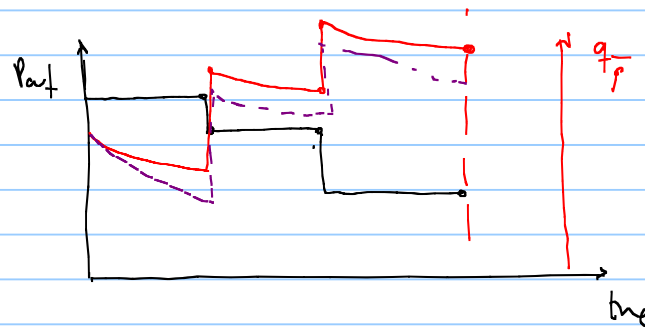
S: usually consider near well flow impairment "restrictions".

$$q = J\,(P_R - P_{wf})$$



cased and perforated completion

well testing



in programs $q_g = f(t, P_{Ri}, k, \phi, \mu_o, P_{wf}, h, r_e)$

$q_{g\,measured} \neq q_{g\,simulated}$

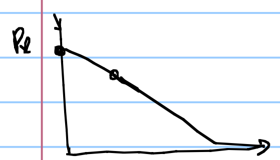
find reservoir properties (h, k, ϕ) such that

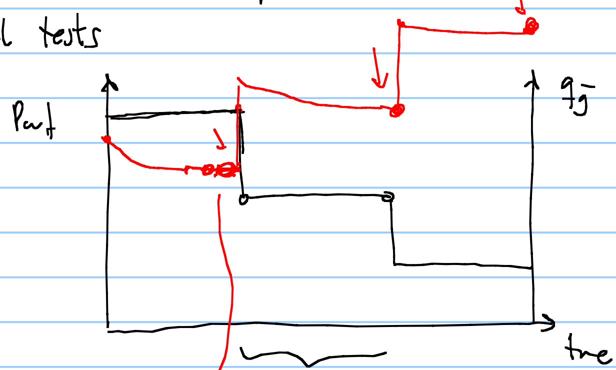
$q_{g\,measured} = q_{g\,simulated}$

$$q_g = \underbrace{\frac{\cancel{2}\pi k h}{\left[\ln\frac{r_e}{r_w} - 0.75 + S\right]} \frac{T_{sc}}{T_R P_{sc}} \left(\frac{1}{\mu z}\right) \frac{1}{\cancel{z}}}_{C,\ \text{backpressure coefficient}} \left(P_R^2 - P_{wf}^2\right)$$

IPR's can be estimated from analytical equations derived for simple cases or can be derived from stabilized well tests

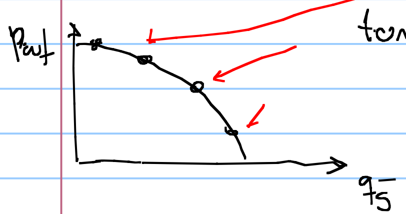
$q = J(P_R - P_{wf})$





depending on reservoir mins → hrs → days

$q = C(P_R^2 - P_{wf}^2)^n$?



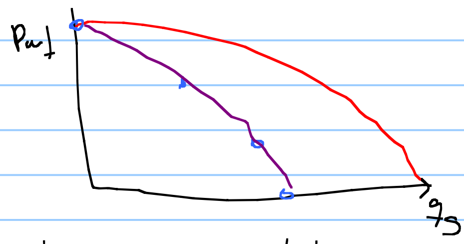
tune C and n to reproduce test results

C □

n □

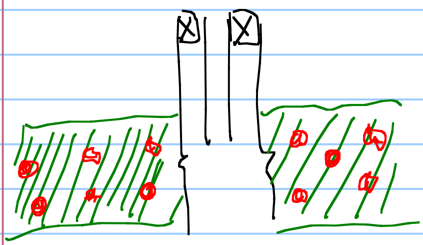
P_{wf}	q_g
□	□
□	□
□	□

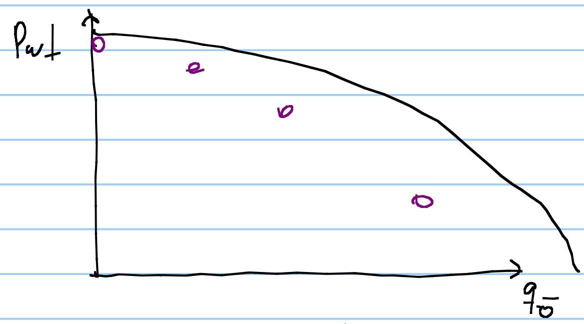
○ measured



change C, n until ——— passes through ○

Saturated oil (simultaneous flow of oil and gas near wellbore)

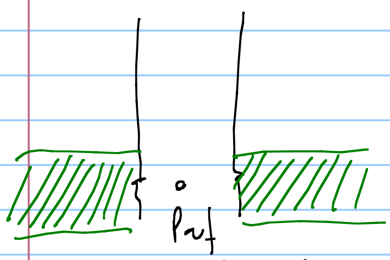




analytical expressions are more complex, but people typically use Vogel

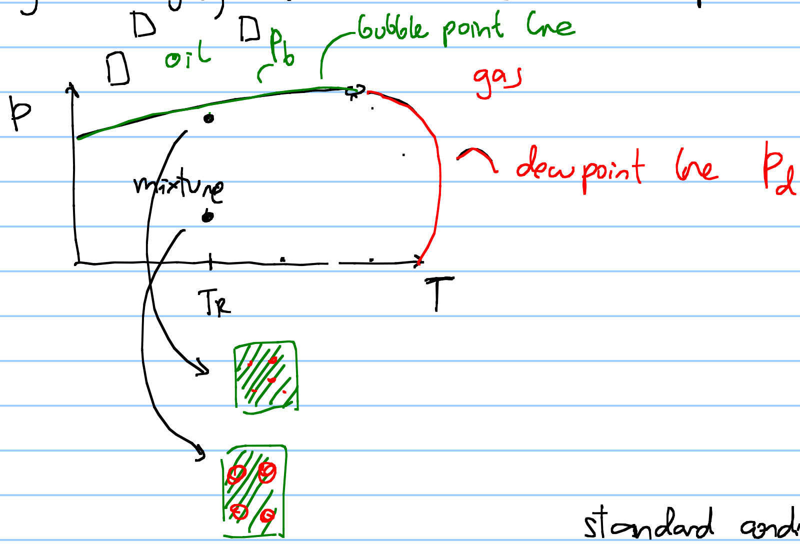
$$\frac{q_{\bar{o}}}{q_{\bar{o}max}} = 1 - 0.2\frac{P_{wf}}{P_R} - \frac{P_{wf}^2}{P_R^2}$$ tune $q_{\bar{o}max}$ to measurements

How to compute other phases? e.g gas, water when well is oil producer?

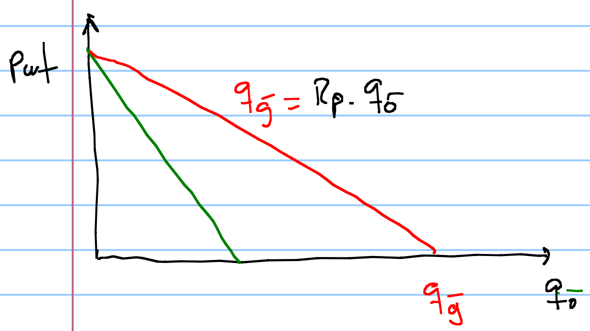


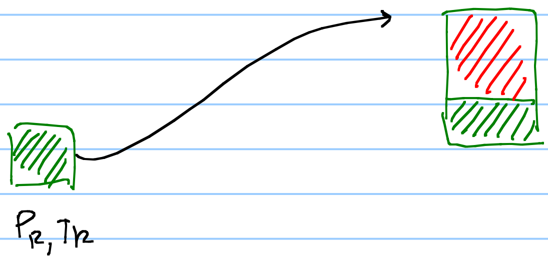
undersaturated oil

$P_{wf} > P_b @ T_R$



standard conditions P_{sc}, t_{sc}



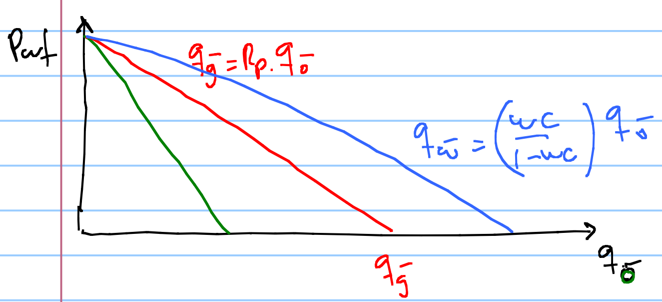


GOR,

$$R_p = \frac{V_{\bar{g}}}{V_{\bar{o}}}$$

$$WC = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}} \Rightarrow q_{\bar{w}}(1 - WC) = q_{\bar{o}}\, WC$$

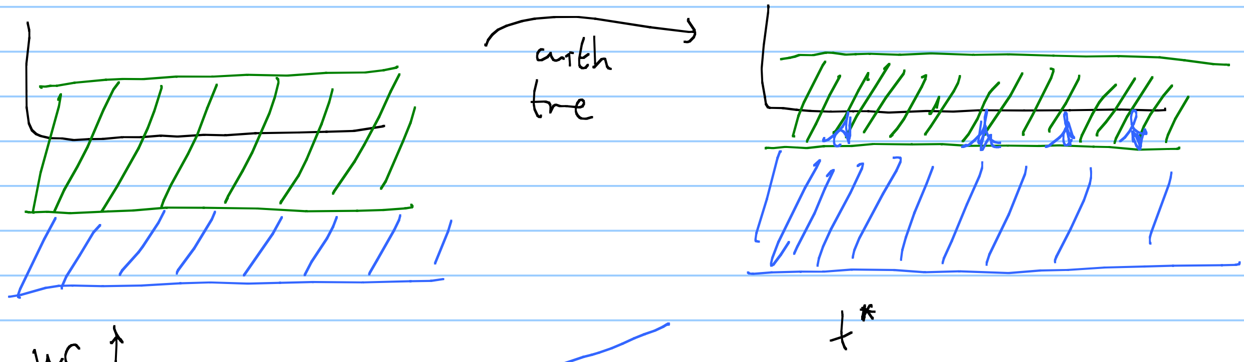
$$q_{\bar{w}} = q_{o}\left(\frac{WC}{1-WC}\right)$$

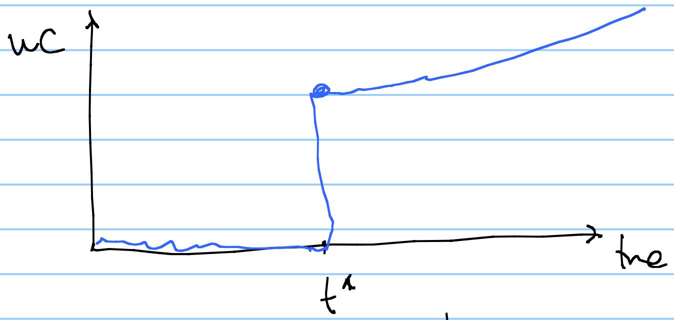


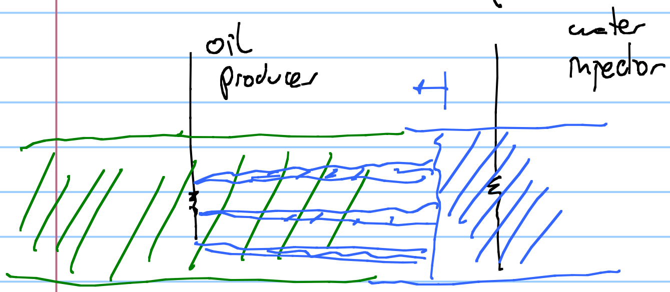
R_p and WC might change with time!

for example

for example WC migh change with water coning







"Available" curve (IPR)

required curve (TPR) tubing performance relationship

$$q_g = C_T \left(\frac{P_1^2}{e^s} - P_2^2 \right)^{0.5}$$

tubing coefficient

elevation coefficient (NOT Skin)

$$P_1 = \left[\left(\left(\frac{q_g}{C_T} \right)^2 + P_2^2 \right) e^s \right]^{0.5}$$

$$P_2 = \sqrt{ \frac{P_1^2}{e^s} - \left(\frac{q_g}{C_T} \right)^2 }$$

Tubing flow Equation-Dry gas

K 15.56 + 273.15 K

C_T

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

Universal gas constant $R = 8.314 \frac{J}{kmol\,K}$

M = molecular weight

$MW_{air} = 28.97$

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

height difference

$9.81\ m/s^2$

$\frac{T_{wh} + T_{wf}}{2}$

$Z_{av} = \frac{Z_{wf} + Z_{wh}}{2}$

γ_g gas specific gravity

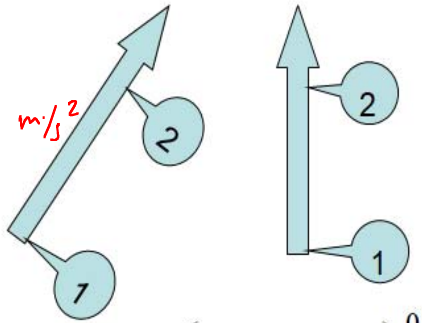
$\gamma_g = \frac{MW_g}{MW_{air}}$

CH_4 12+4 = 16

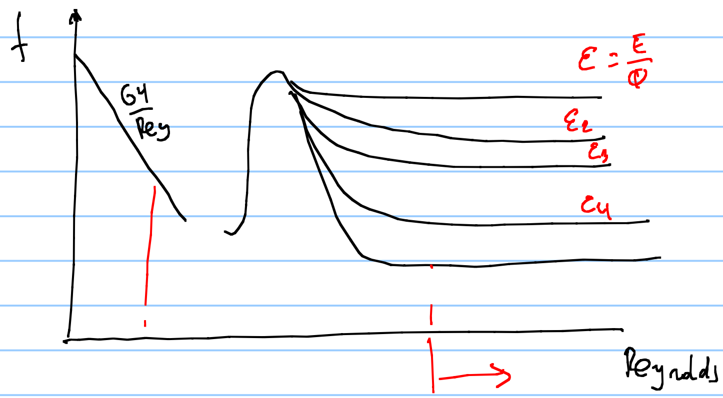
$\gamma_{g\,CH_4} = \frac{16}{28.97}$

$\gamma_{g\,CH_4} = 0.55$

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



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



$Re = \frac{V \rho \Phi}{\mu}$

Re are usually very high

V are high

μ are very low

liquid 1E-3 Pa s

gas 1E-5 Pa.s

gas is usually in the fully turbulent region

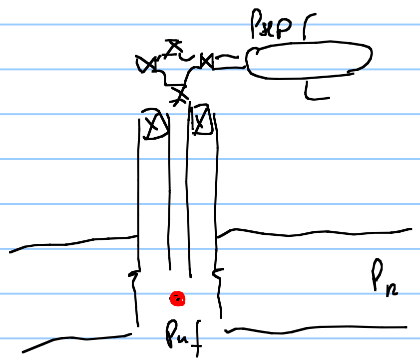
$f \neq F(Re)$

$f = F(\varepsilon)$

$\varepsilon = f(\Phi)$

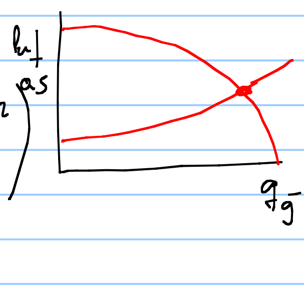
$$f_M = \frac{0.01748}{D^{0.224}\cdot\left(|1\,m|\cdot\left|\frac{39.37\,in}{1\,m}\right|\right)^{0.224}} = \frac{0.0077}{D^{0.224}}$$

Class exercise



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

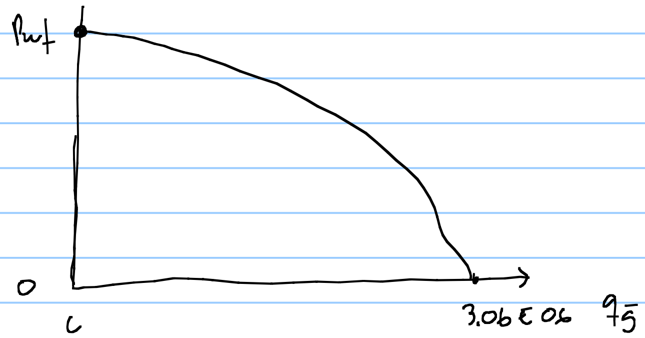
$P_{wf} = \left(P_R^2 - \left(\frac{q_g}{C_R}\right)^{1/n}\right)$

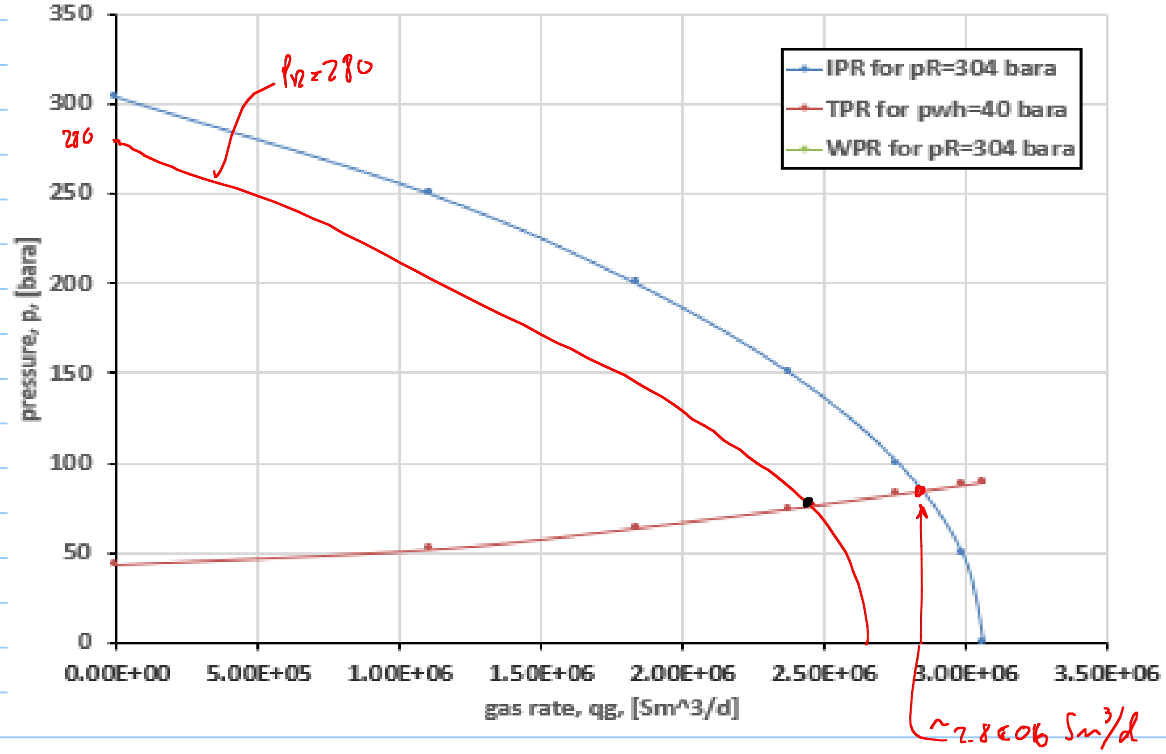


from pxp → P_{wf}

$$P_{wf} = \left[\left(\left(\frac{q_g}{C_T}\right)^2 + P_{wh}^2\right)e^S\right]^{0.5}$$

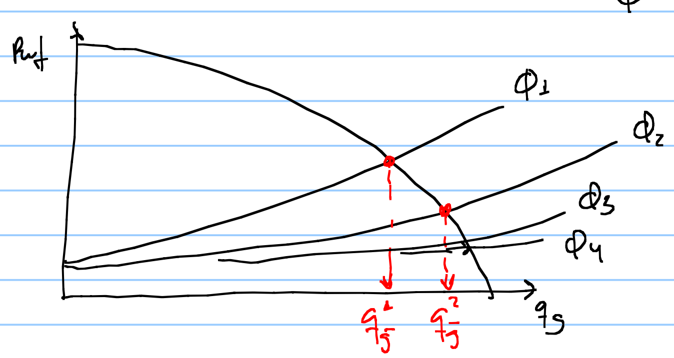
	IPR
pwf_avail	qg
[bara]	[Sm^3/d]
304	0.00E+00
250	1.11E+06
200	1.84E+06
150	2.38E+06
100	2.76E+06
50	2.99E+06
0	3.06E+06





How do we decide on tubing size (Φ) NOT POROSITY!

Φ ↑



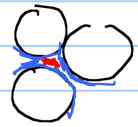
$\Phi_2 > \Phi_1$

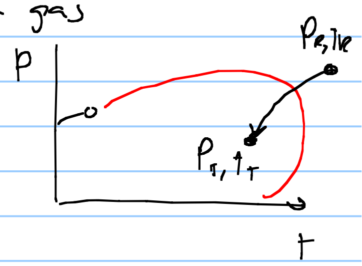
Φ↑ also costs more

Φ_3 and Φ_4 don't give a substantial increment in rate

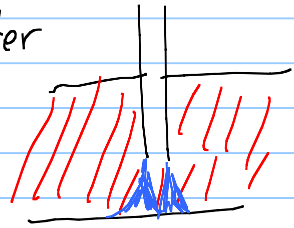
Usually wells produce not only gas, but liquid → oil condensing from gas

↳ water condensing out of gas





↳ coning from aquifer

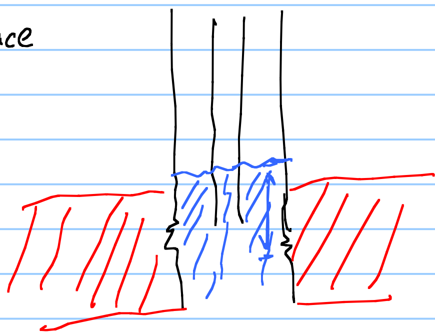


the gas must evacuate the liquid from well

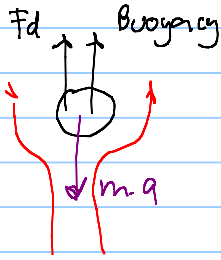
gas velocity V_g must be high enough to drag liquid out of well

$\uparrow \phi$ $V_g \downarrow$ then liquid dragging capacity will be reduced! ⇒ liquid loading

choose a diameter that assures liquid is carried to surface



V_g should be high enough



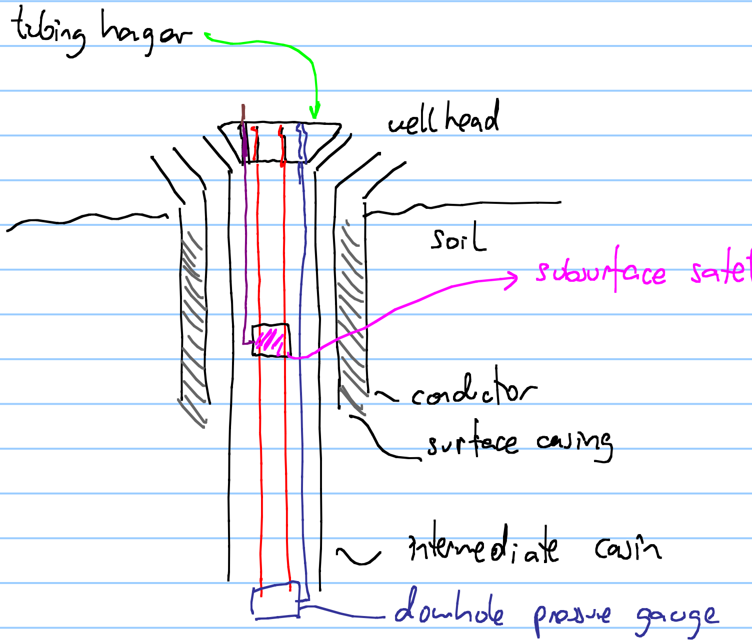
liquid droplet

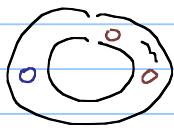
$$F_d + F_B = F_{weigh} \Rightarrow V_g^{Turner}$$

- Erosion usually wells produce particles and liquid, if ϕ is too small this can cause erosion.

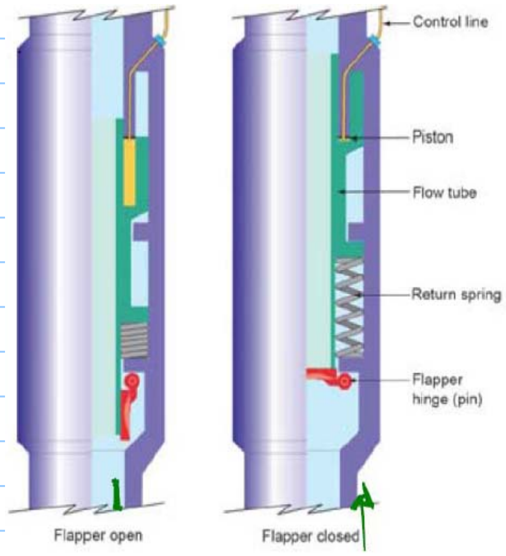
$$V_g < V_{erosional} \rightsquigarrow \text{API 14E}$$

- tubing hanger





leave enough space in the hanger



how to find the equlibrium point

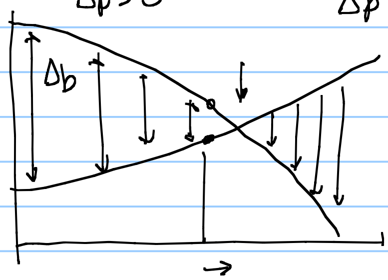
$f_1(x)$ find x^* such that $f_1(x^*) = f_2(x^*)$

$f_2(x)$

$f_3 = f_1 - f_2$ find x^* such that $f_3(x^*) = 0$

root finding

$\Delta p > 0$ $\Delta p < 0$



	IPR	TPR	
pwf_avail	qg	pwf_req	pwf_avail-pwf_req
[bara]	[Sm^3/d]	[bara]	[bara]
304	0.00E+00	43.2	260.8
250	1.11E+06	51.6	198.4
200	1.84E+06	63.7	136.3
150	2.38E+06	74.4	75.6
100	2.76E+06	82.5	17.5
50	2.99E+06	87.4	-37.4
0	3.06E+06	89.1	-89.1

the solution is between these two. When $P_{wf\,avail} - P_{wf\,req}$ equals zero

Goal seek

	IPR	TPR	
pwf_avail	qg	pwf_req	pwf_avail-pwf_req
[bara]	[Sm^3/d]	[bara]	[bara]
304	0.00E+00	43.2	260.8
250	1.11E+06	51.6	198.4
200	1.84E+06	63.7	136.3
150	2.38E+06	74.4	75.6
84.3784	2.85E+06	84.4	0.0
50	2.99E+06	87.4	-37.4
0	3.06E+06	89.1	-89.1

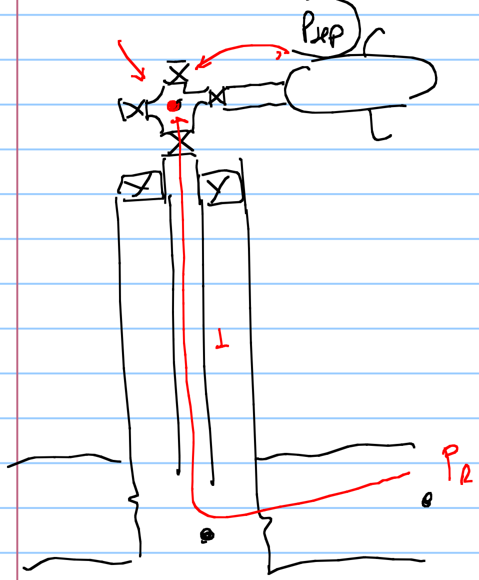
equilibrium rate $q_g = 1.85$ E06 Sm^3/d

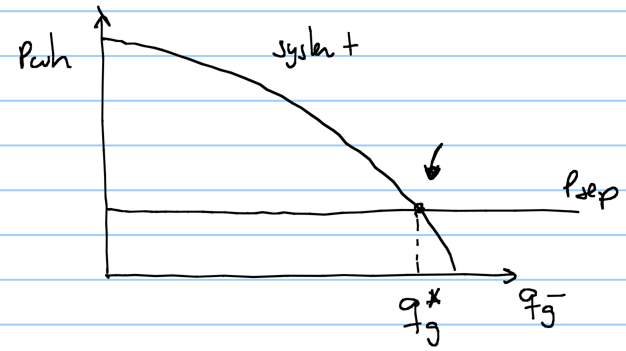
$P_{wf} = 84.37$ bara

$$q_g = C_R\left(P_R^2 - P_{wf}^2\right)^n \qquad q_g = C_T\left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$$

Two equations with two unknowns

• change equilibrium point ⤳ at wellhead



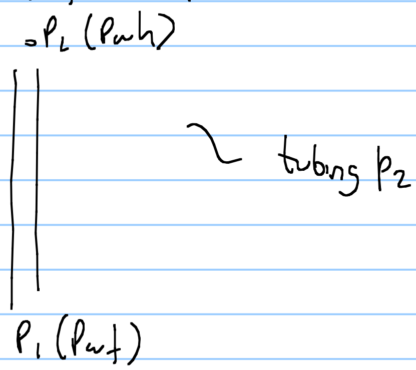


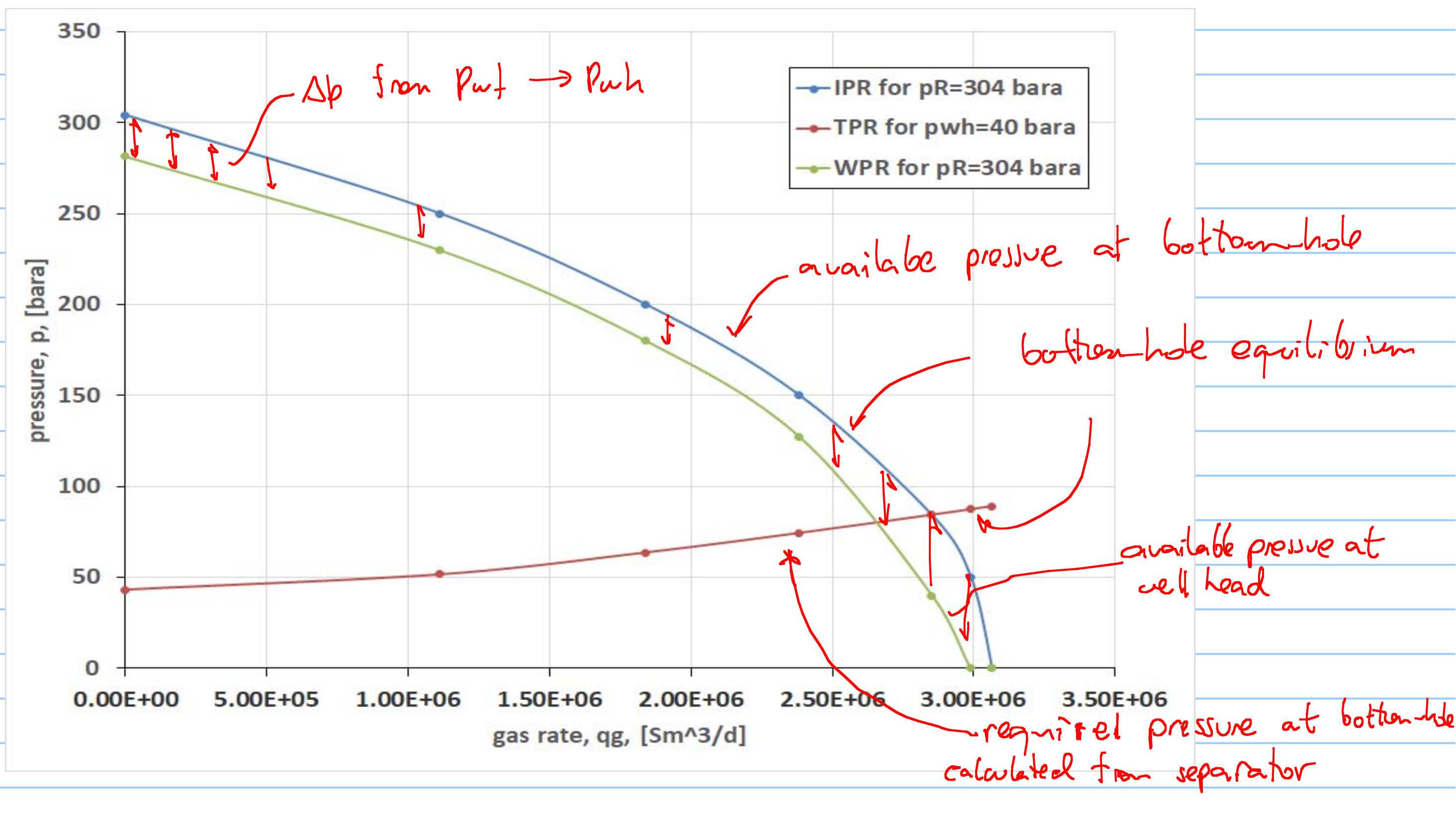
very close to wellhead, therefore Δp friction at flowline is neglected

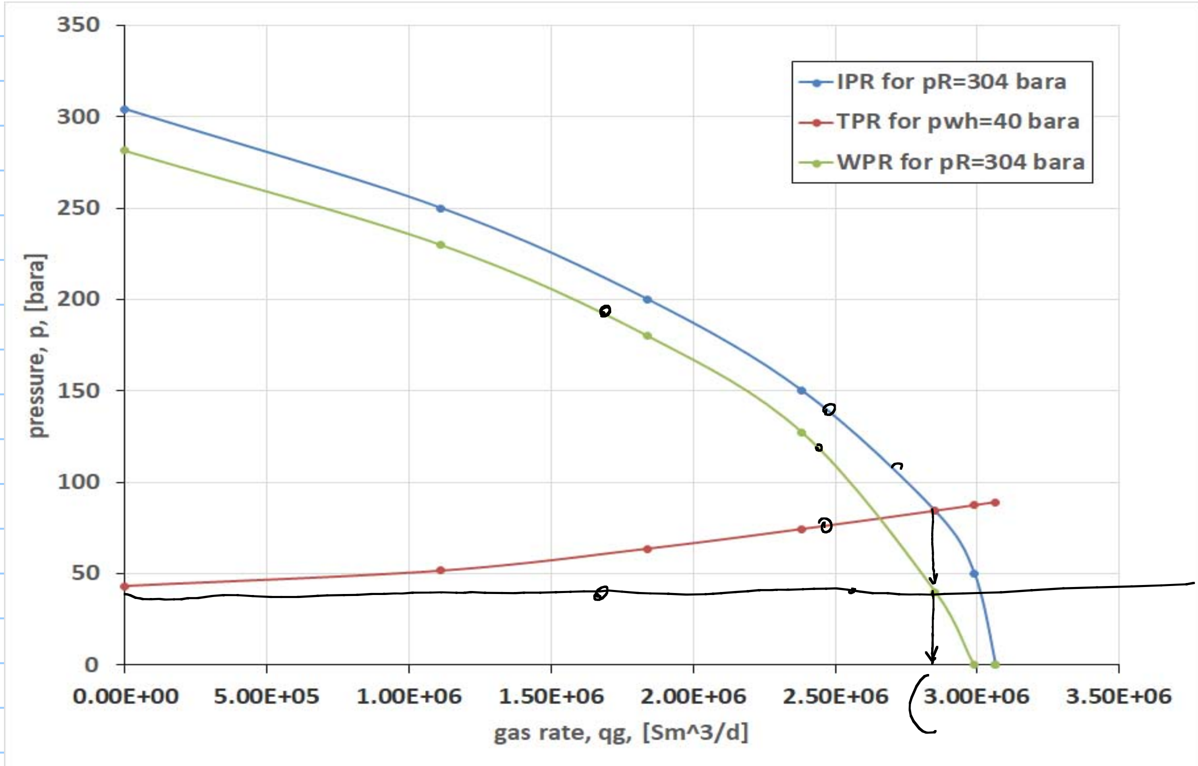
↳ 2.85 E06 Sm³/d same system!

the system is the same regardless of equilibrium point

move from Pwf ⤳ Pwh

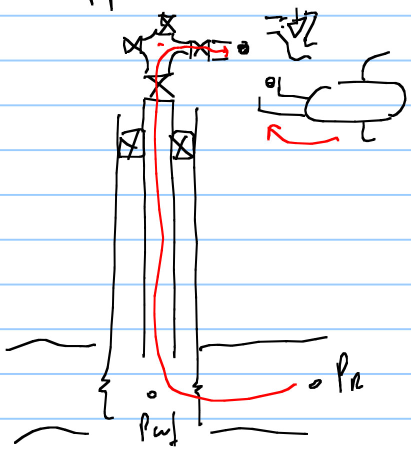




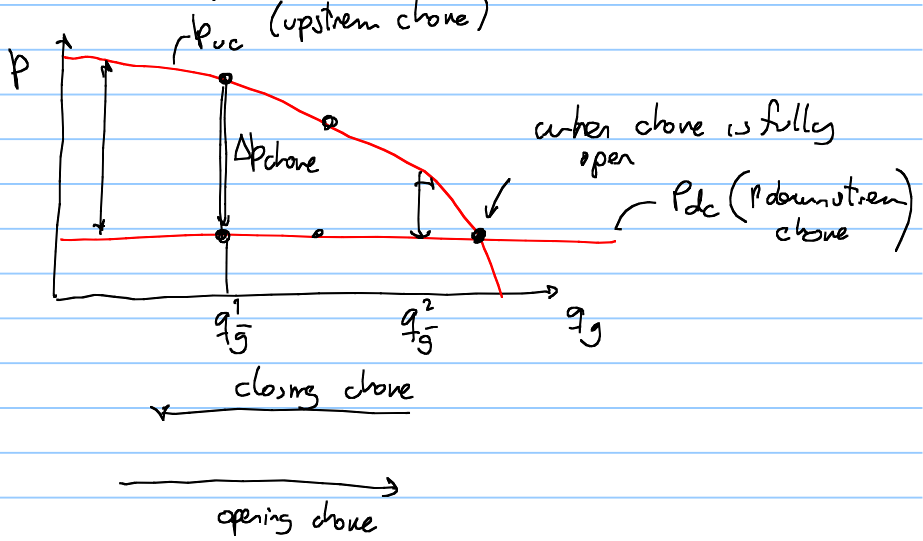


$P_{sep} = 40$ bara

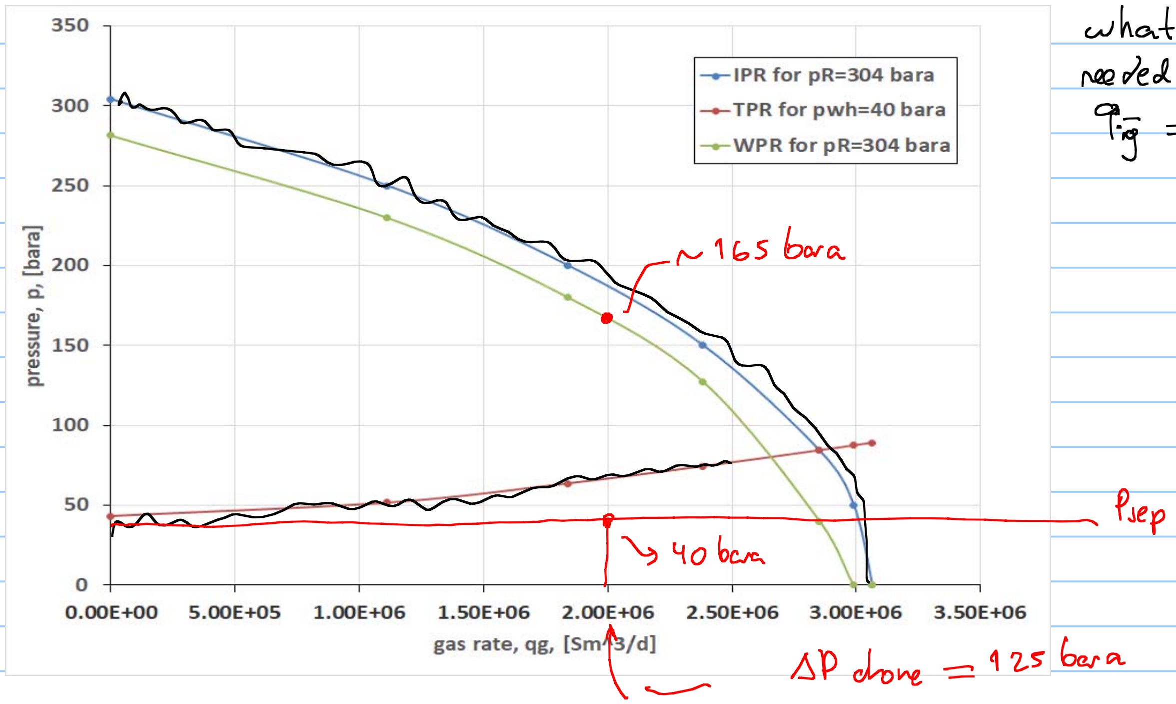
what happens when there is a choke?



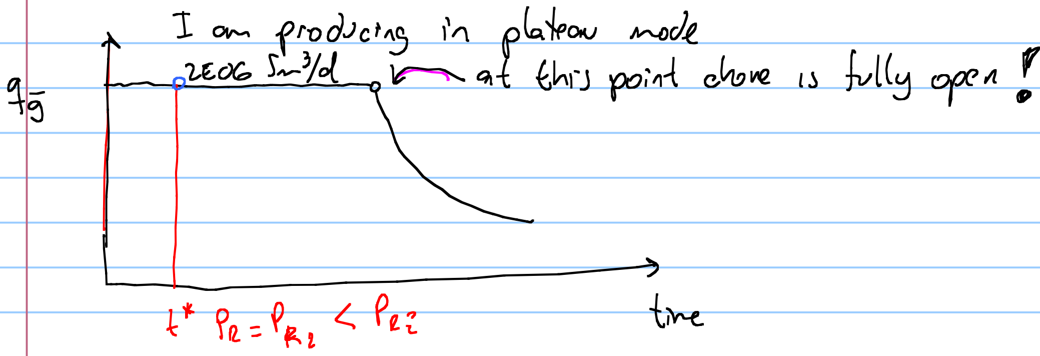
- remove choke
- compute available pressure at choke inlet and required pressure at choke outlet



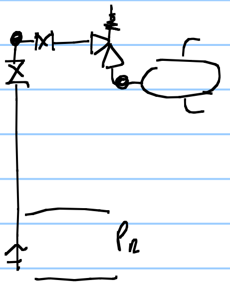
what choke Δp is needed to produce $q_g = 2E06$ Sm^3/d ?

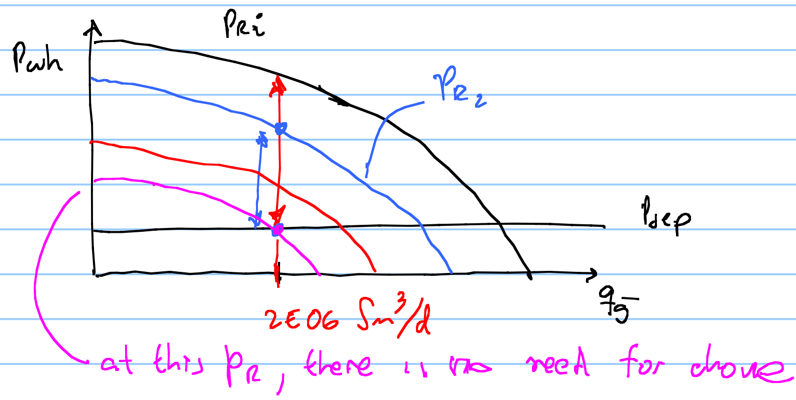


ΔP choke $= 125$ bara



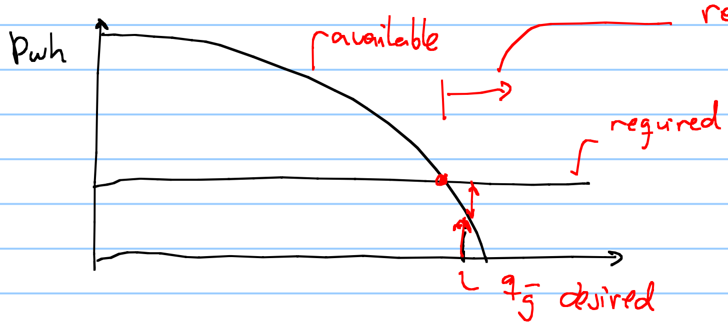
$\Delta p_{choke\,2} < \Delta p^{i}_{choke}$



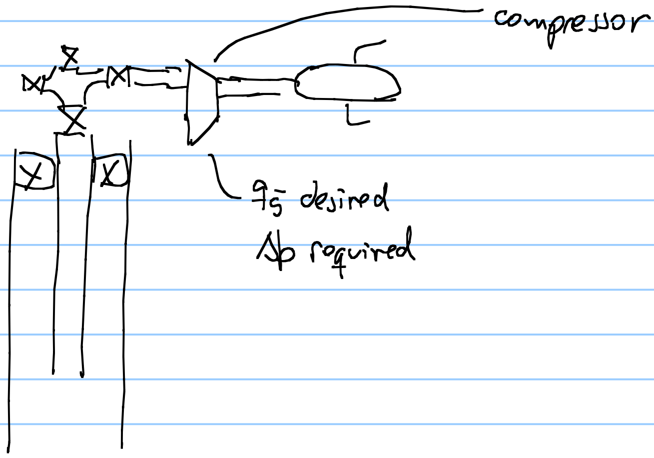


what if i need a rate bigger than equilibrium rate?

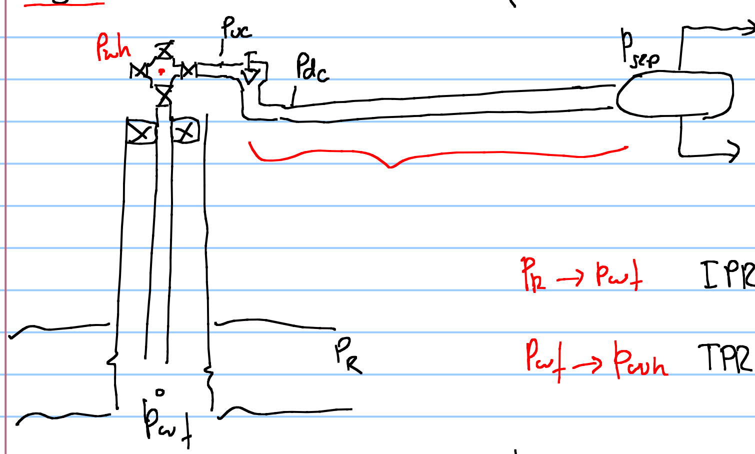
required energy is greater than available!

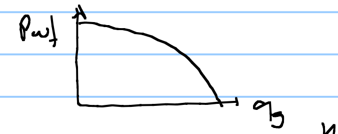


to place a component that gives energy, like a compressor or a pump


compressor
q_g desired
Δp required

Day 3 04.12.2019 (B2 Tanzania)





$P_R \to P_{wf}$ IPR equation $q_g = C_R\left(P_R^2 - P_{wf}^2\right)^n$

$P_{wf} \to P_{wh}$ TPR equation $q_g = C_T\left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$

$P_{uc} \to P_{dc}$ no equation, simply fix the rate and calculate available pressure upstream and required pressure downstream

$P_{dc} \longrightarrow P_{sep}$ FPR (flowline performance relationship)
assuming horizontal flowline $H = 0$

if $H=0$ $S=0$

e^S $e^0 = 1$

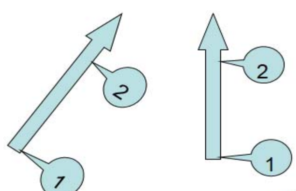
$\left(\frac{s\,e^S}{e^S - 1}\right)^{0.5}$ $S \to 0$?

Tubing flow Equation-Dry gas

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

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

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



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

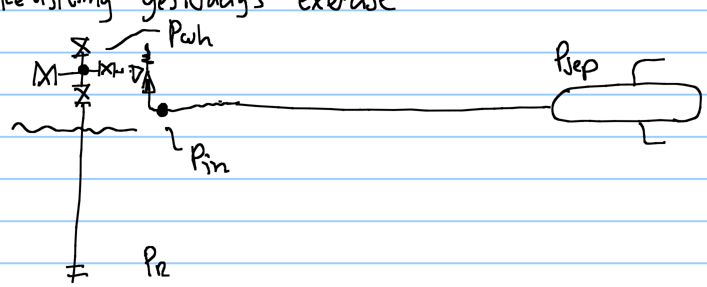
$\frac{0 \cdot 1}{1 - 1} \to \frac{0}{0}$ L'Hopital

$\lim_{S \to 0} \frac{S \cdot e^S}{e^S - 1} = \frac{e^S + e^S \cdot S}{e^S}$

if $S = 0$ $\frac{1 + 0}{1} = 1$

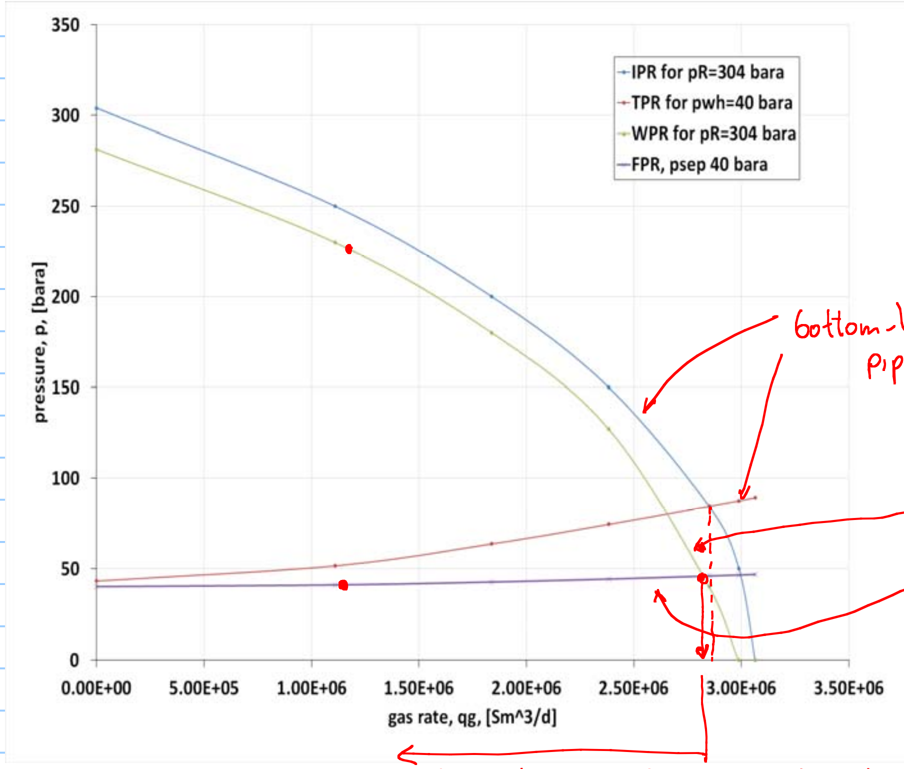
for horizontal flowline $q_g = C_{FL}\left(P_1^2 - P_2^2\right)^{0.5}$

Revisiting yesterdays exercise



$P_R \to P_{wf} \to P_{wh}$ available pressure at wellhead

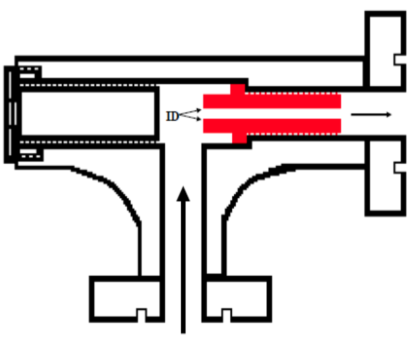
$P_{sep} \longrightarrow P_{in}$ required pressure at flowline inlet

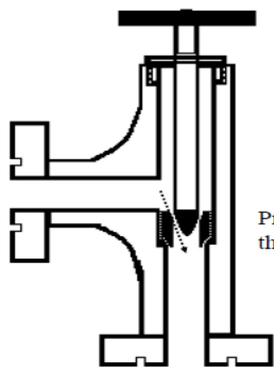


bottom-hole equilibrium, neglecting pipeline

wellhead equilibrium, including pipeline.

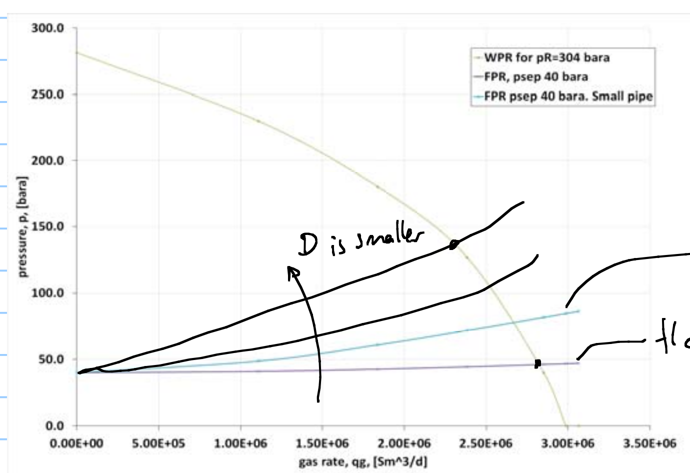
with a choke, p_{wh} is at the upstream and p_{in} is at downstream
therefore, I can obtain all rates to the left





it is challenging to operate the choke with high Δp → high velocities → high erosion

"newer" design to avoid excessive erosion



D is smaller

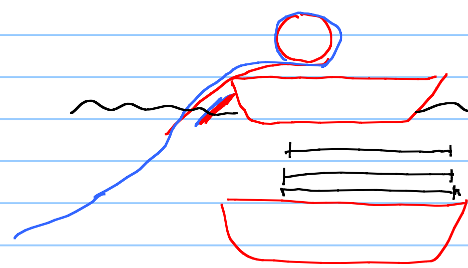
flowline with small pipe

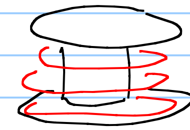
flowline with big pipe

how to decide on flowline diameter?

- provide desired rate → minimize pressure drop
- minimize pipe cost → large pipe is more costly to manufacture
  to transport
  to install

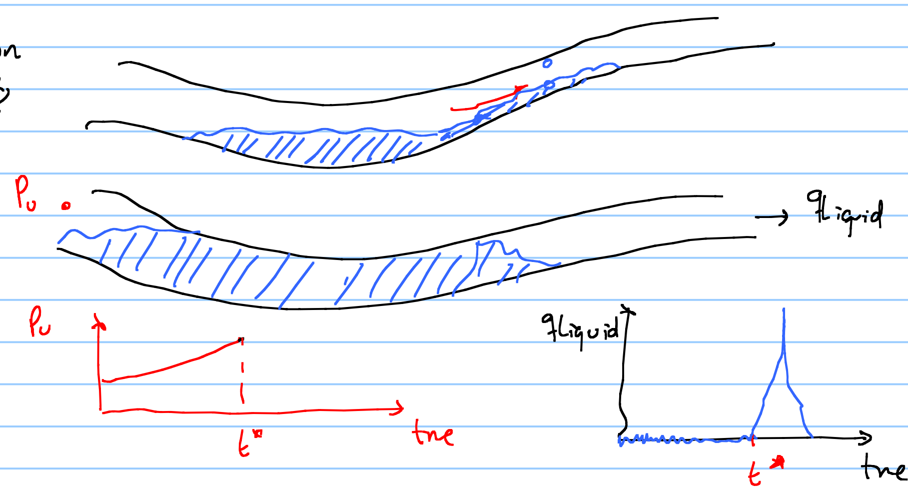
small diameter pipe can be reeled

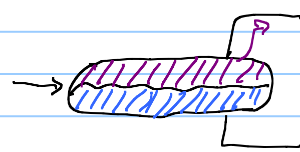




- avoid erosion
- avoid liquid accumulation
  increase v_g reducing ϕ

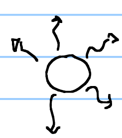
if slugging cannot be avoided a different type of separator is needed (slugcatcher)





- avoid excessive cooling

big diameter increases surface area, increases heat transfer



$$\dot{q} = U A (T_f - T_{amb})$$

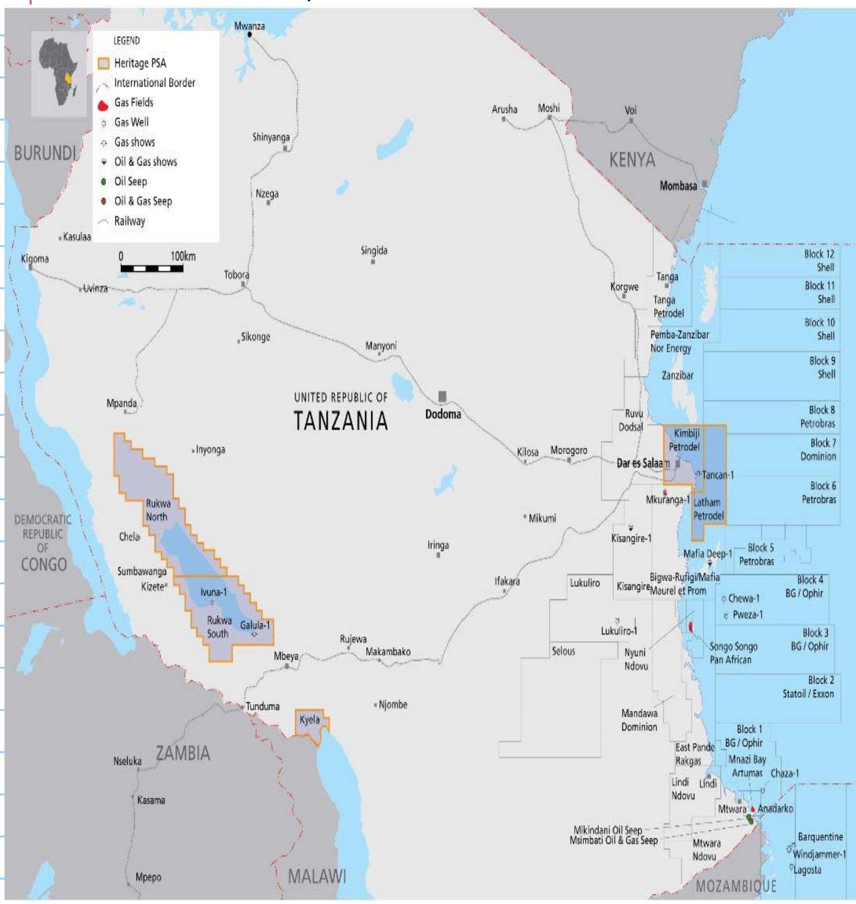
$\dot{q}$ → heat; U → universal heat transfer coefficient; T_f → fluid

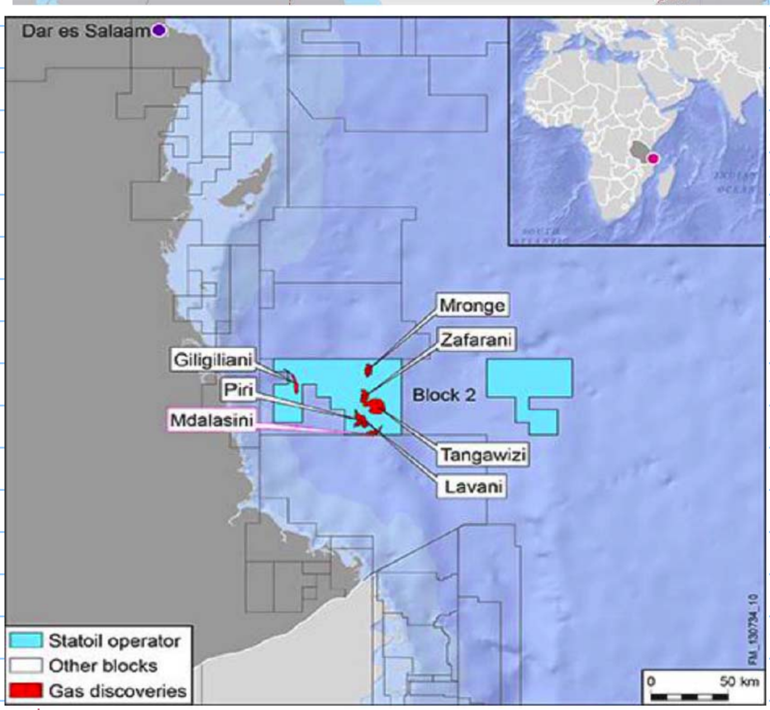
cooling and low temperatures can lead to hydrates, wax

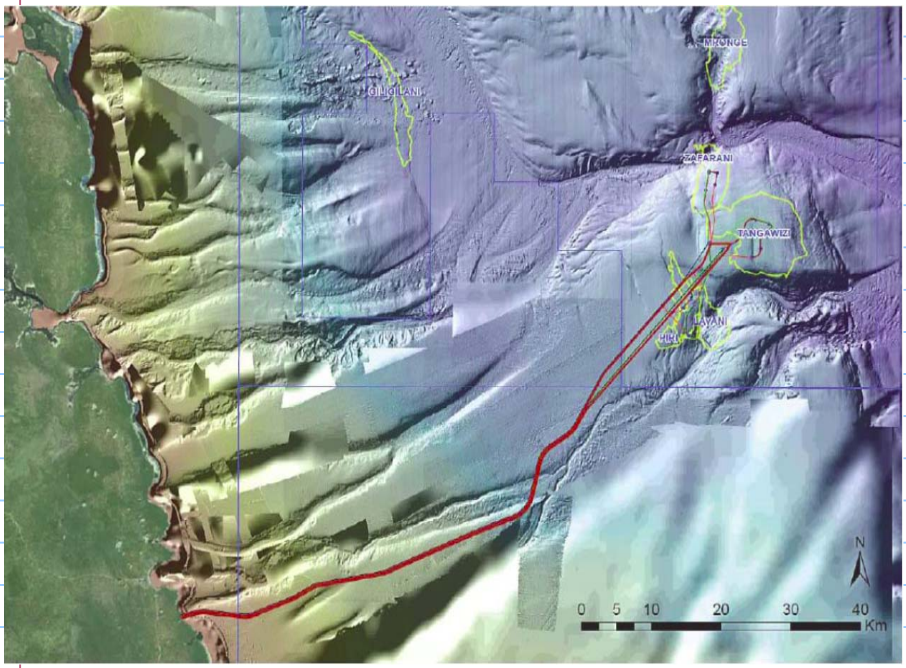
Production scheduling calculations for offshore gas field

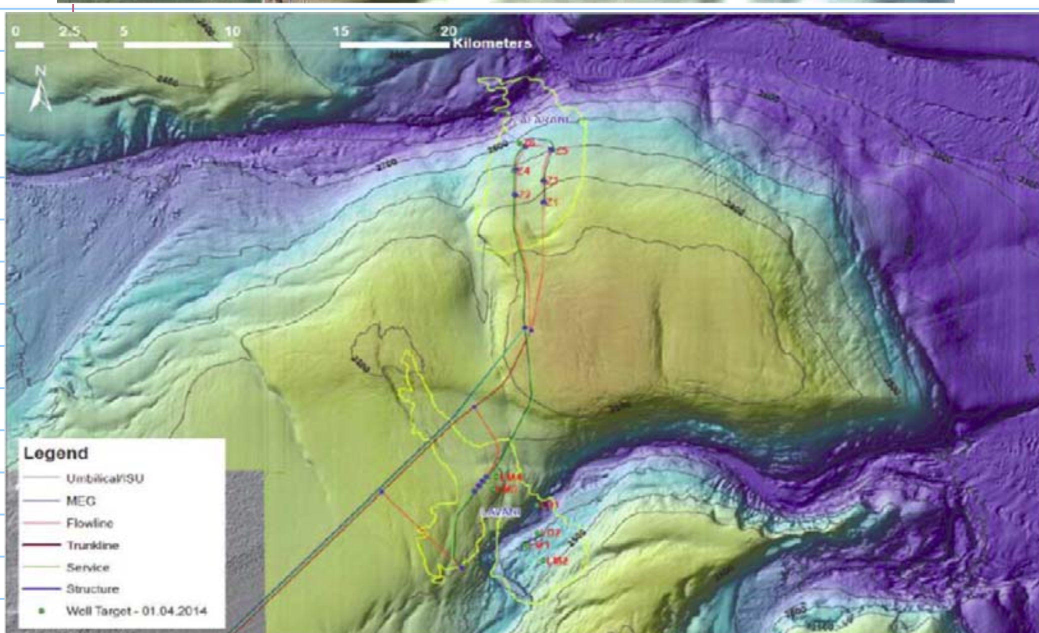
estimating q_{field} vs time (very important for revenue calculations
cost estimation
NPV calculations

Case: Block 2 offshore Tanzania



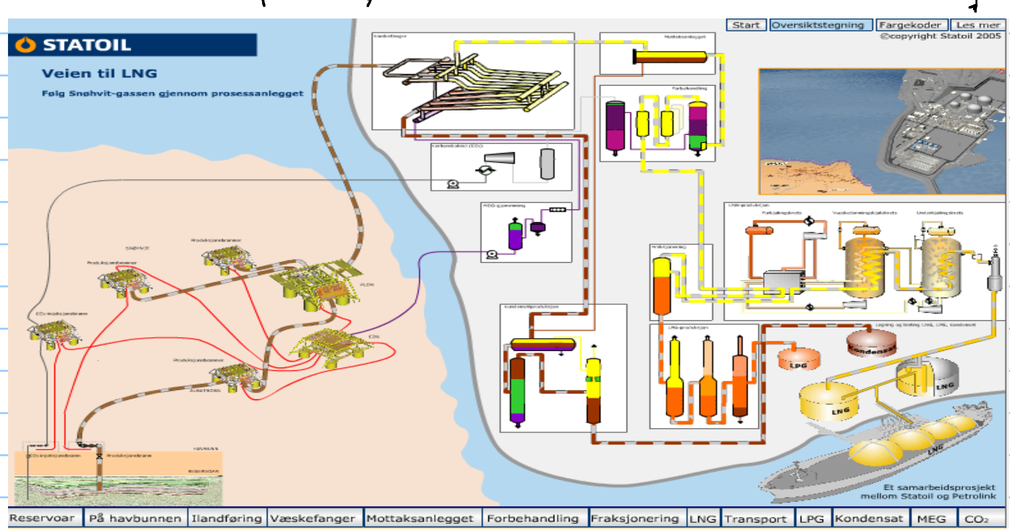


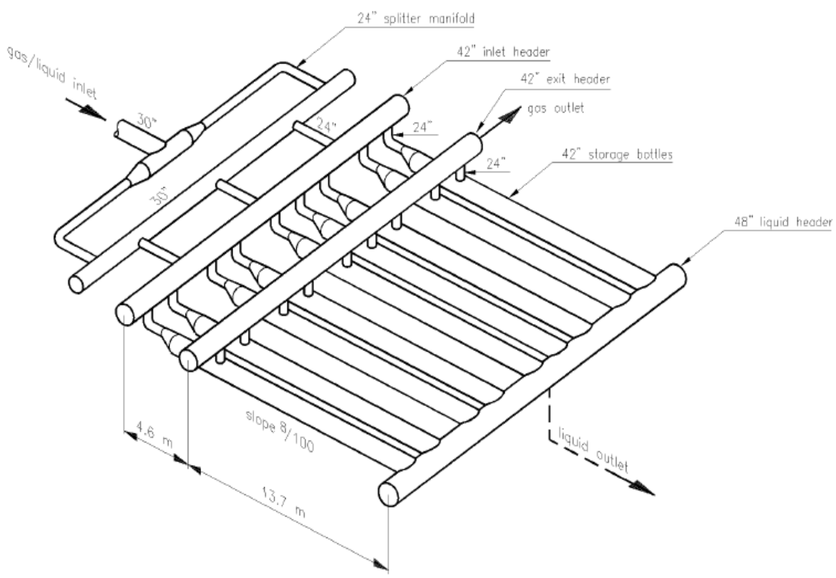


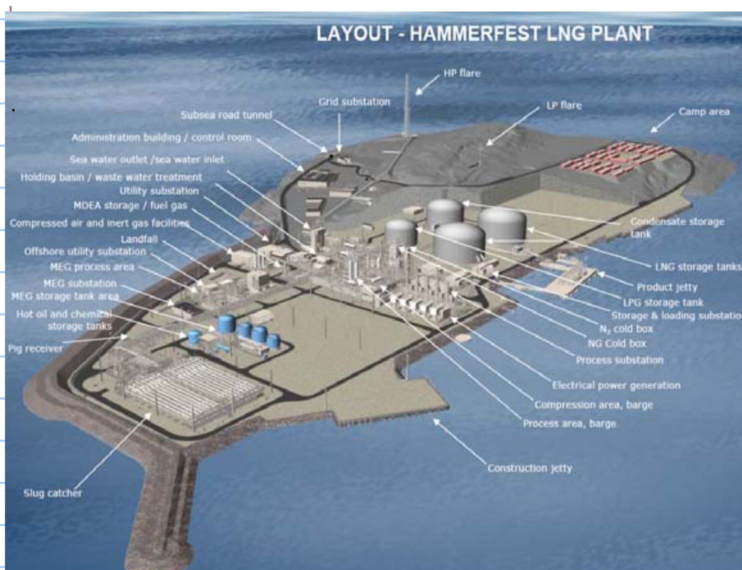


in Norway there is a field very similar to B2, Snøhvit (Snowhite)

Subsea to beach : subsea wells, no platform, no offshore structure and a long transportation pipeline to shore



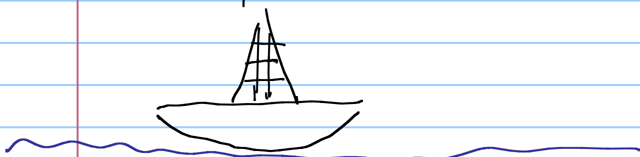

24" splitter manifold
42" inlet header
42" exit header
gas outlet
gas/liquid inlet
30"
30"
24"
24"
24"
42" storage bottles
48" liquid header
slope 8/100
4.6 m
13.7 m
liquid outlet


LAYOUT - HAMMERFEST LNG PLANT
HP flare
Grid substation
LP flare
Camp area
Subsea road tunnel
Administration building / control room
Sea water outlet /sea water inlet
Holding basin / waste water treatment
Utility substation
MDEA storage / fuel gas
Compressed air and inert gas facilities
Landfall
Offshore utility substation
MEG process area
MEG substation
MEG storage tank area
Hot oil and chemical storage tanks
Pig receiver
Condensate storage tank
LNG storage tanks
Product jetty
LPG storage tank
Storage & loading substation
N2 cold box
NG Cold box
Process substation
Electrical power generation
Compression area, barge
Process area, barge
Construction jetty
Slug catcher

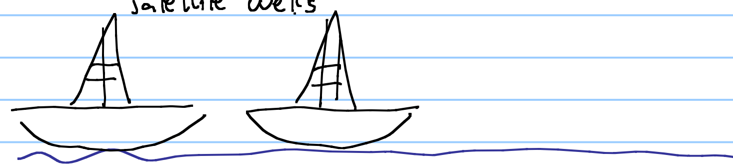
Subsea layout

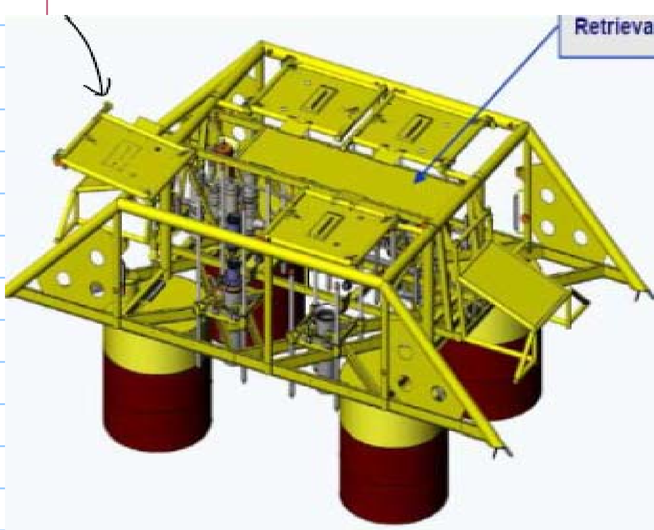
typically, wells are arranged in templates

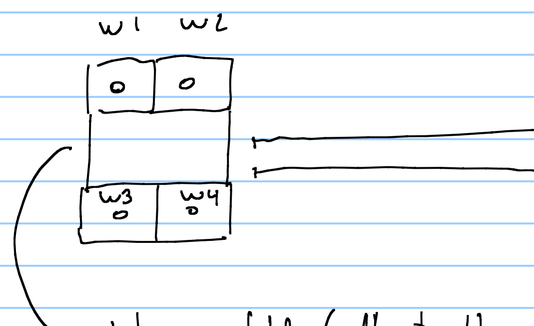
4-slot template



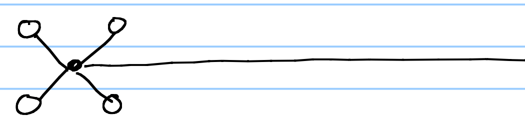
satellite wells



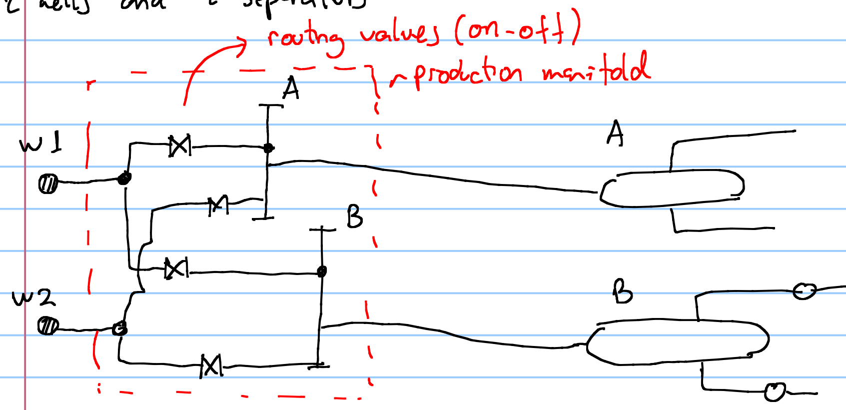




production manifold (collects the production of wells)



2 wells and 2 separators



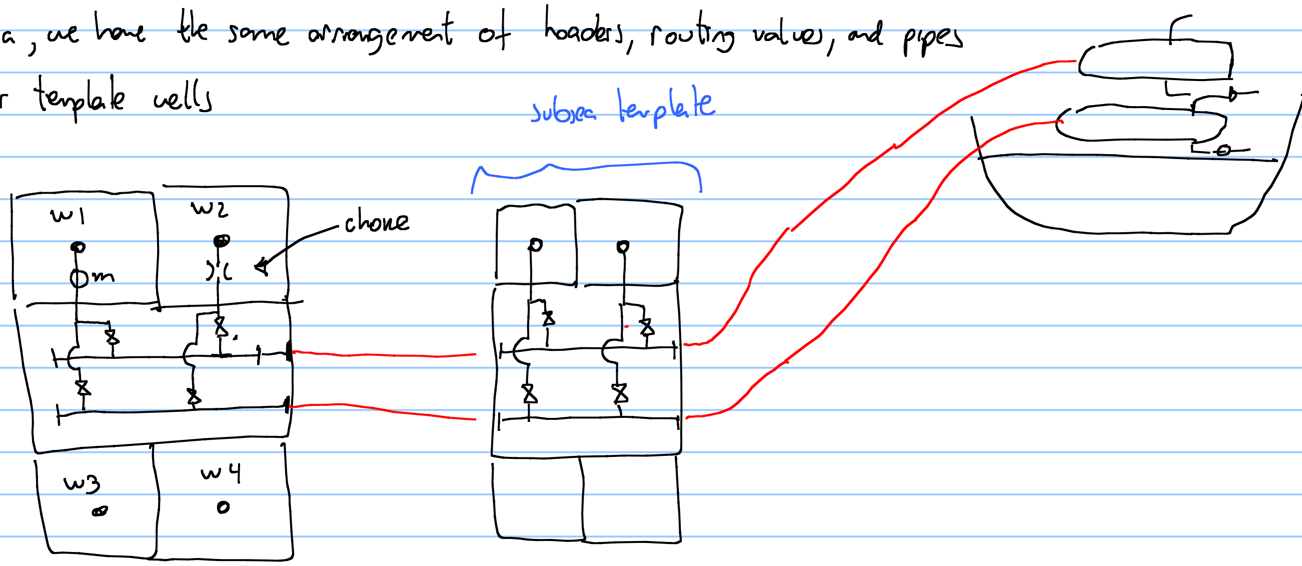
to have the option to send production from w1 to A or to B

include a header for each destination

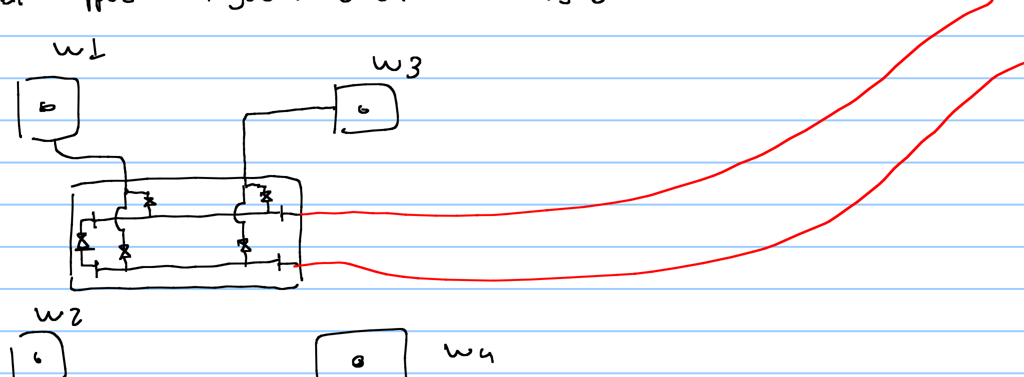
Reasons to use a production manifold : for well testing (allocation)
↳ to find out how much is the well producing and split production and revenue among partners

to improve models (production (reservoir history matching))

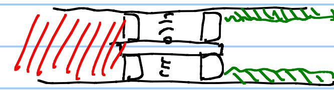
subsea, we have the same arrangement of headers, routing valves, and pipes for template wells

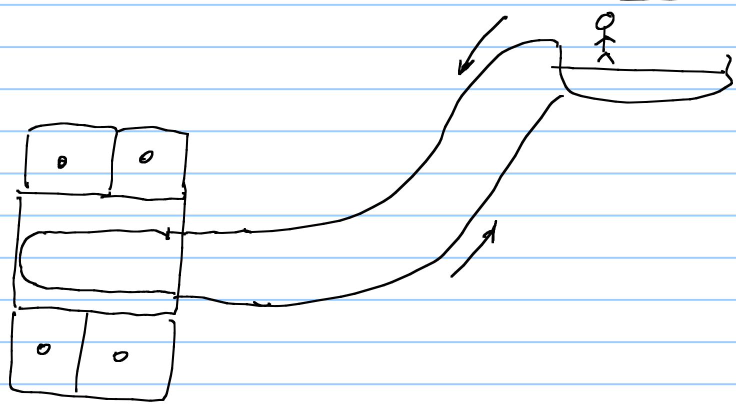


what happens when you have satellite wells?

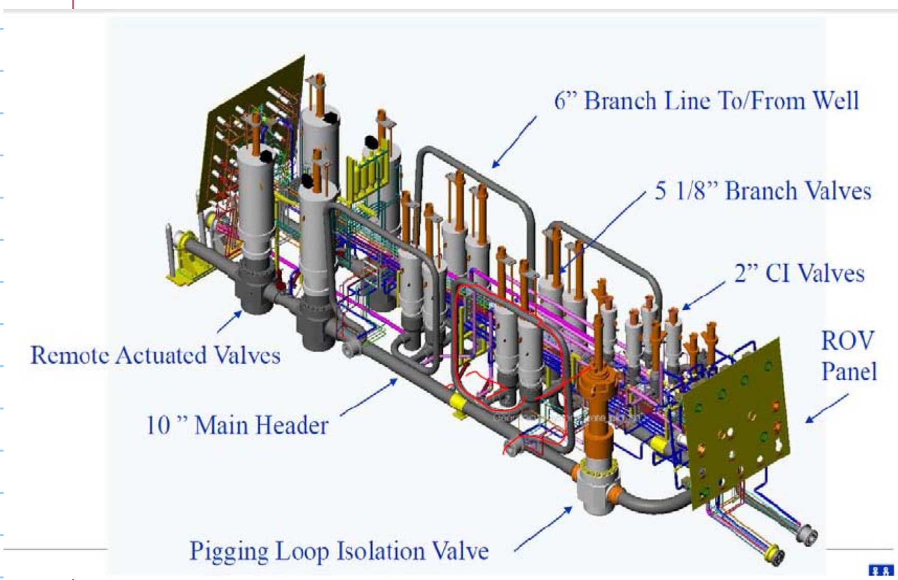


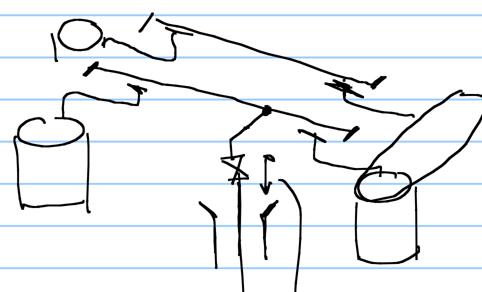
some reasons to have two flowlines:
- to meter rates topside (test separator)
- to use 2 separators and smaller pipelines (operational flexibility)
- to perform pigging.
  - inspection and monitoring pipe thickness
  - evacuate liquid e.g used hydrostatic pressure test
  - remove wax accumulations



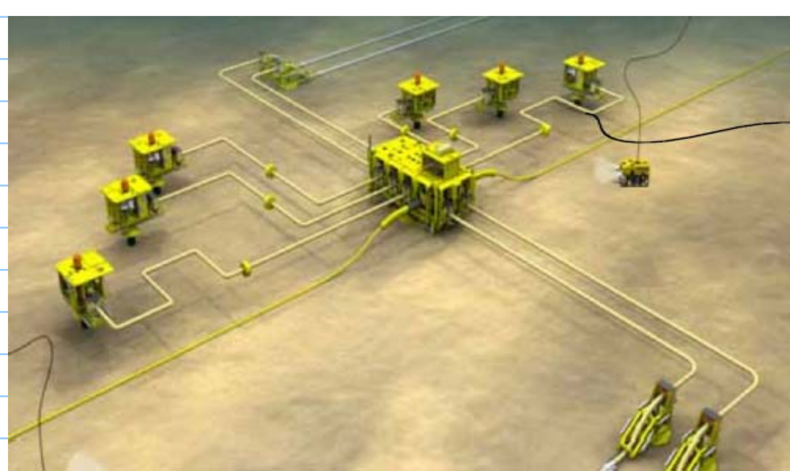


manifold module of 4 well subsea template

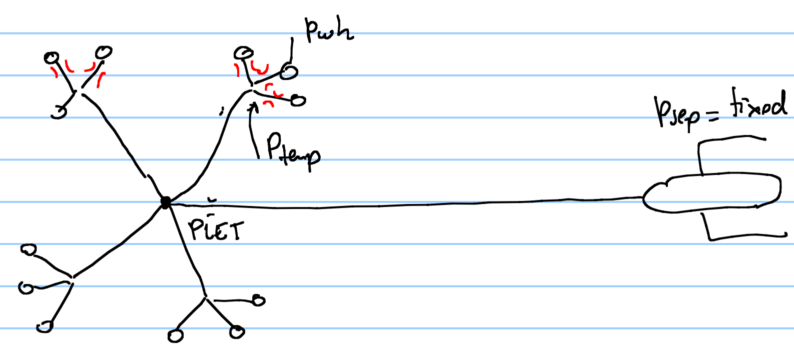


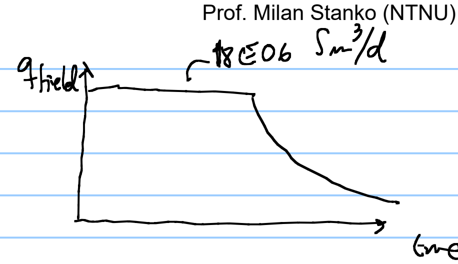


cooling and warming up of well



B2 problem (12 wells)





a long term gas contract produced mode A

$G = 311\,E9\ Sm^3$

set equilibrium point = choke

- All well are identical
- All template are identical
- All template are located symmetrical and same distance from PLET

2–5% of TRR produced anually

$TRR = G \cdot \underbrace{R_{Fo}}_{0.8} = 311 \cdot 0.8\ 1E09 = 248\ E09$

calculate $q_w = \dfrac{q_{field}}{N_w}$

$q_{plateau} = \dfrac{TRR \cdot 0.02}{N_{day\ in\ year}} = \dfrac{248\ E09 \cdot 0.02}{365}$

$q_{plateau} = 13.6\,E6\ Sm^3/d$

compute available pressure at Pwh

$P_R - P_{wf}$ IPR equation with q_w

$P_{wf} \rightarrow P_{wh}$ TPR equation with q_w

compute required pressure downstream the choke (P_{temp})

$P_{sep} \rightarrow P_{PLET} \rightarrow$ pipeline equation with q_{field}

$PLET \rightarrow P_{temp} \rightarrow$ flowline equation with $q_{temp} = \dfrac{q_{field}}{N_{temp}}$

- verify $P_{wh} > P_{temp}$? $\xrightarrow{\text{if yes}}$ production is possible by choking
  $\xrightarrow{\text{if not}}$ production is not possible, rate must be reduced

IPR TPR FPR PPR (pipeline performance relationship)

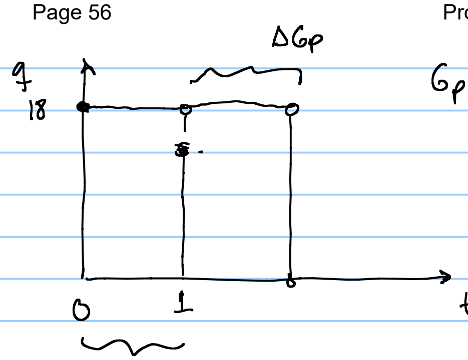
time	P_R	P_{wf}	P_{wh}	P_{temp}	P_{plet}	P_{sep}
→ 0						
1						

time 0 years means first day of year 1

time 1 years means first day of year 2

$P_R = P_{Ri} \dfrac{z_R}{z_{Ri}} \left(1 - \underbrace{\dfrac{G_P}{G}}_{RF}\right)$?

to calculate G_p for $t = 1$ i assume production remained constant from $t=0 \rightarrow t=1$



$$G_{p_2} = \Delta G_{p_1} + \Delta G_{p_2}$$

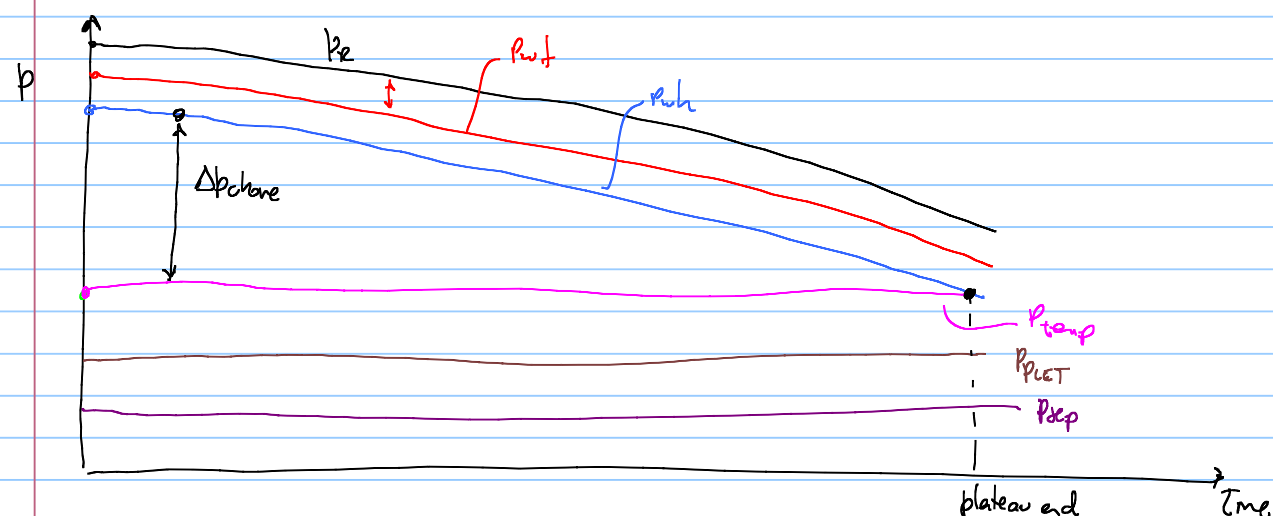
$$\Delta G_p = q_{field\,(t=0)} \cdot \Delta t \quad N_{day/year}$$

$$\left[Sm^3/\cancel{d} \right] \quad \left[\cancel{years} \right] \quad \left[\cancel{d}/\cancel{year} \right]$$

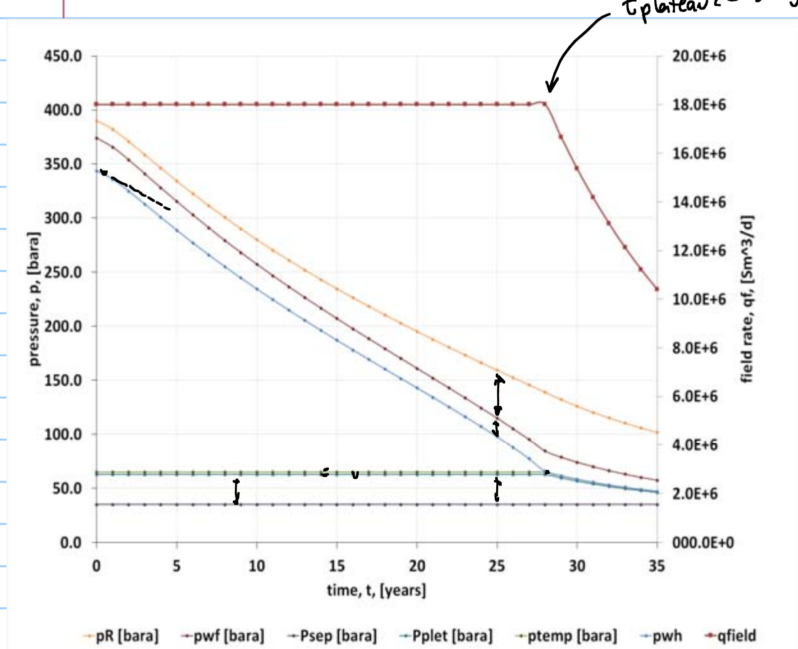
$$G_p = \sum_{i=0}^{N} \Delta G_p$$

usually the company doesn't operate all day in year

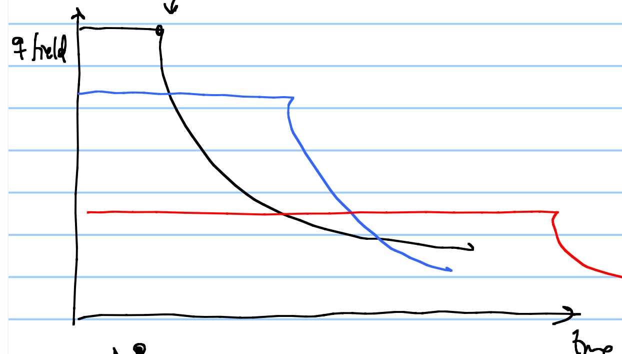
uptime = N producing days in a year < 365

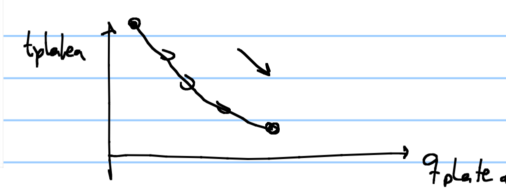


tplateau ~ 28 years



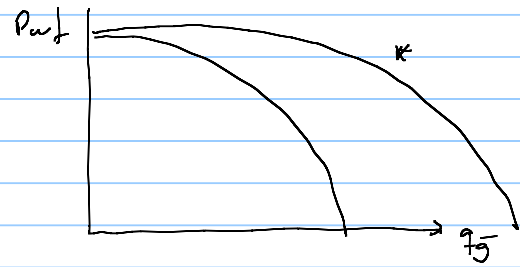
usually the higher the plateau rate, the shorter the plateau





How to extend the plateau?

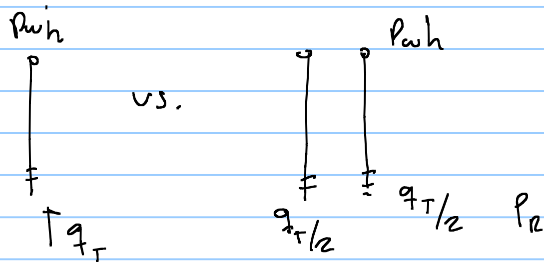
- make available pressure higher or make it decline "slower"
  - P_R ~ pressure support to reservoir injection? → for oil water/gas
    for gas not feasible
  - "enhance" IPR



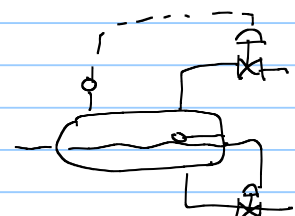
stimulation
fracking
acidizing (cleaning pores)

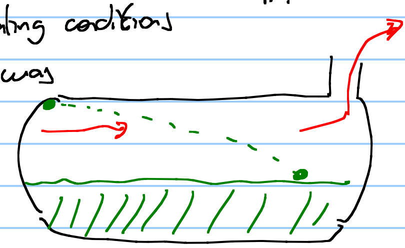
  - Increase tubing size. if oil reservoir { pumping in well artificial lift; gas lift }

  - Increase N_w → lower rate per well, lower pressure drop in formation and in tubing therefore higher P_{wh}



- making required pressure lower plateau?
  - lower P_{sep} → change separator set
    might not be desirable because it changes operating conditions for which equipment was designed





if P_{sep} is reduced v_g ↑

high pressure   low pressure

$$\dot{m}_g = \dot{m}_g$$

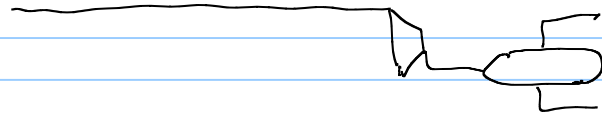
$$\rho_g q_g = \rho_g \cdot q_g$$

P is high ρ is also high   P is low, ρ_g is low

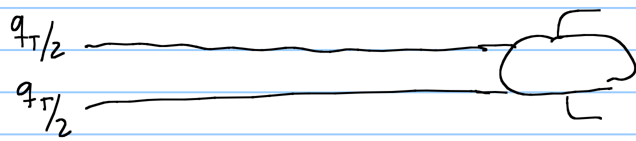
q_g for low pressure is higher than q_g for high pressure

$$v_g = \frac{q_g}{A_{sep}}$$

- add a compressor before separator



- increase pipeline diameter
- increase flowline diameter
- add another pipeline



- homework: repeat calculations for plateau rate of 25E06 Sm^3/d

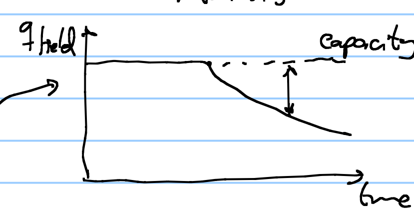
NPV calculations (Net present value): Sum expenses and revenue of project and refer all to a common date

operational expenditures (OPEX) (–) occur after field starts producing
- salaries
- power consumption
- maintenance of equipment
- well intervention
- insurance
- chemical usage: biocide, corrosion inhibitor, hydrate, wax
- transportation

field "X"

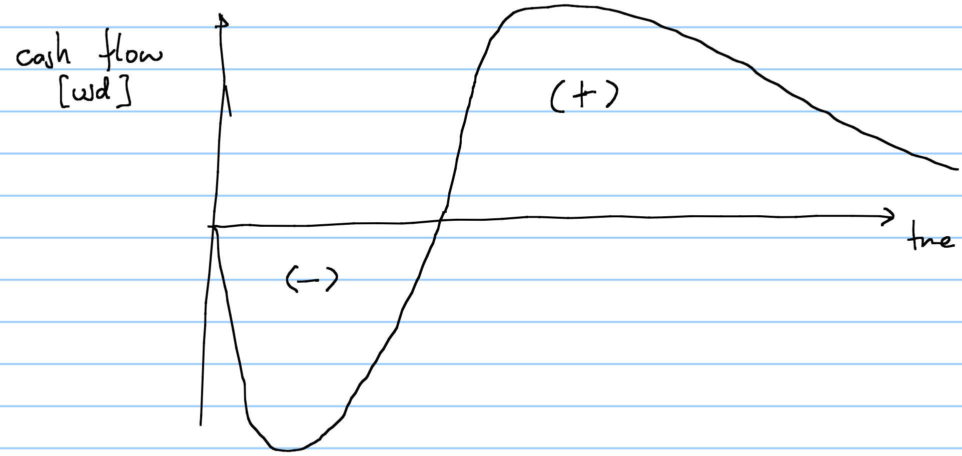
revenue? (+)
- sales of hydrocarbons: oil, gas
- rental of processing capacity

capital expenditures (CAPEX) (–) occur during first years
- drilling, completing wells (DRILLEX)
- processing facilities (separators, gas compressors, turbine, pumps, control system)
- offshore structure → FPSO, GBS, Jackup
- subsea system
- engineering studies
- export system → pipeline, tankers

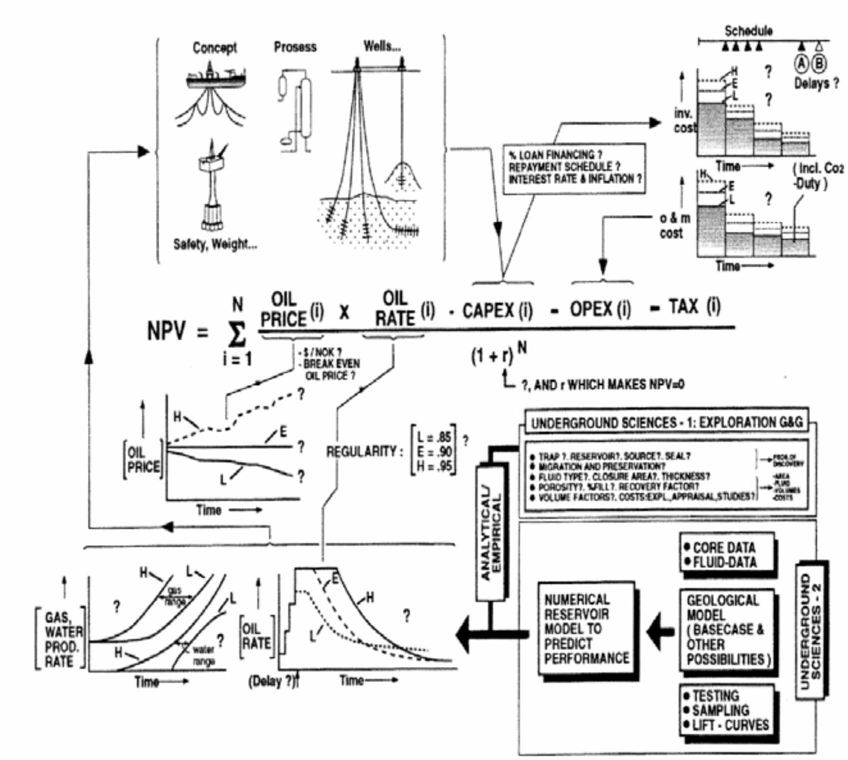


Cash flow calculation

time	CAPEX	DRILLEX	OPEX	Revenue [USD]	Cash flow
0	$\boxed{-}$	0	0	0	$\Sigma (+)(-)$
1	$\boxed{-}$	$\boxed{-}$	0	0	
2	$\boxed{-}$	$\boxed{-}$	0	0	
3	$\boxed{-}$	$\boxed{-}$	0	0	
4	$\boxed{-}$	$\boxed{-}$	0	0	
5	0	0	$\boxed{-}$	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$	



Day 4 05.12.2019 → NPV calculations
→ Reserve estimation
→ probability / decision trees



- Usually royalties and taxes must be considered in NPV calculations → will be covered more in detail in petroleum economics course (Trygve Strøm)

  royalties: fixed amount (%) of revenue

  taxes: (%) of net profit

- Other costs such as EXPEX (exploration expenditures)

  ABEX (Abandonment costs)

might be included in NPV calculations

$$NPV = \sum_{i=1}^{N} \frac{\text{Revenue}(i) - \text{expenses}(i)}{(1+d_c)^i} = \frac{P_o(i)\cdot\Delta N_p(i) + P_g(i)\cdot\Delta G_p(i) - CAPEX(i) - OPEX(i)}{(1+d_c)^i}$$

i: year counter

d_c discount factor ⇝ (6% → 12%)

$$\frac{1}{(1+d_c)^i}$$

for year 1 : 6% $\frac{1}{(1.06)^1} = 0.94$

for year 10 : 6% $\frac{1}{(1.06)^{10}} = 0.56$

class exercise

CAPEX+DRILLEX+OPEX

discounted cash flow

time	ΔG_p	Revenue	CAPEX	DRILLEX	OPEX	Expenses	Cash flow	DCF
1	0	0	(−)	(−)	0	(−)	Revenue − Expenses	$\frac{CF}{(1+d_c)^i}$
2	0	0	(−)	(−)	0	(−)		
3	0	0	(−)	(−)	0	(−)		
4	0	0	(−)	(−)	0	(−)		
5	0	0	(−)	(−)	0	(−)		
6	ΔG_{p6}	$\Delta G_p \cdot P_g$	0	0	(−)	(−)		
7	ΔG_{p7}	"	0	0	(−)	(−)		
8	"	"	0	0	(−)	(−)		
9	"	"	0	0	(−)	(−)		
10	"	"	0	0	(−)	(−)		
11			0	0	(−)	(−)		

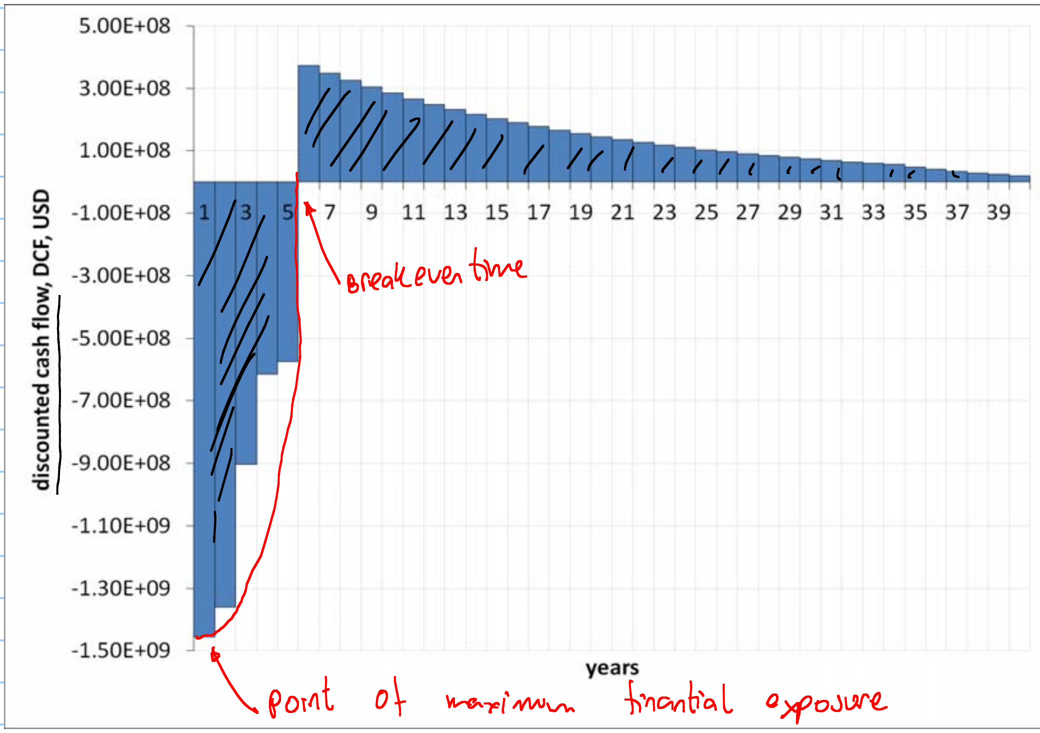
$$\sum \frac{CF}{(1+d_c)^i} = NPV$$

B2 example

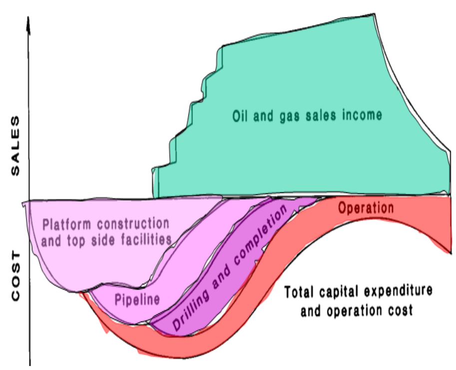
				Observations:
Well drilling cost	150	[1E6 USD]		Maximum 5 wells can be drilled per year
water depth	2500	[m]		all CAPEX is invested evenly during the first 5 years
Discount rate	0.07	[-]		
Uptime	360	days/year		
OPEX	1.20E+08	USD/year		
Gas price	0.11	[usd/Sm^3]		
$CAPEX_{LNG}$	3.48E+09	USD		
$CAPEX_{SUBSEA}$	5.58E+08	USD		

Time	Gas production in year	Revenue	DRILLEX	$CAPEX_{SUBSEA}$	$CAPEX_{LNG}$	OPEX	Total Cost	Cash Flow	Discounted Cash Flow: PV(i)
end of year	[Sm^3]	USD	USD	USD	USD	USD	USD	USD	USD
1	0	0.00E+00	7.50E+08	1.12E+08	6.95E+08	0	1.56E+09	-1.56E+09	-1.46E+09
2	0	0.00E+00	7.50E+08	1.12E+08	6.95E+08	0	1.56E+09	-1.56E+09	-1.36E+09
3	0	0.00E+00	3.00E+08	1.12E+08	6.95E+08	0	1.11E+09	-1.11E+09	-9.04E+08
4	0	0.00E+00	0.00E+00	1.12E+08	6.95E+08	0.00E+00	8.07E+08	-8.07E+08	-6.16E+08
5	0	0.00E+00	0.00E+00	1.12E+08	6.95E+08	0.00E+00	8.07E+08	-8.07E+08	-5.75E+08
6	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	3.73E+08
7	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	3.49E+08
8	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	3.26E+08
9	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	3.05E+08
10	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.85E+08
11	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.66E+08
12	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.49E+08
13	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.33E+08
14	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.17E+08
15	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	2.03E+08
16	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.90E+08
17	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.77E+08
18	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.66E+08
19	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.55E+08
20	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.45E+08
21	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.35E+08
22	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.26E+08
23	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.18E+08
24	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.10E+08
25	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	1.03E+08
26	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	9.65E+07
27	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	9.02E+07
28	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	8.43E+07
29	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	7.88E+07
30	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	7.36E+07
31	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	6.88E+07
32	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	6.43E+07
33	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	6.01E+07
34	6.5E+9	6.80E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.60E+08	5.62E+07
35	6.0E+9	6.30E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	5.10E+08	4.78E+07
36	5.5E+9	5.81E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	4.61E+08	4.03E+07
37	5.1E+9	5.36E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	4.16E+08	3.40E+07
38	4.7E+9	4.95E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	3.75E+08	2.87E+07
39	4.4E+9	4.58E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	3.38E+08	2.42E+07
40	4.0E+9	4.24E+08	0.00E+00	0.00E+00	0.00E+00	1.20E+08	1.20E+08	3.04E+08	2.03E+07
								NPV	1.92E+08

1) Homework: repeat NPV calculations for $q_{plateau} = 25$ E06 Sm^3/d



Revenue and Cost Profiles



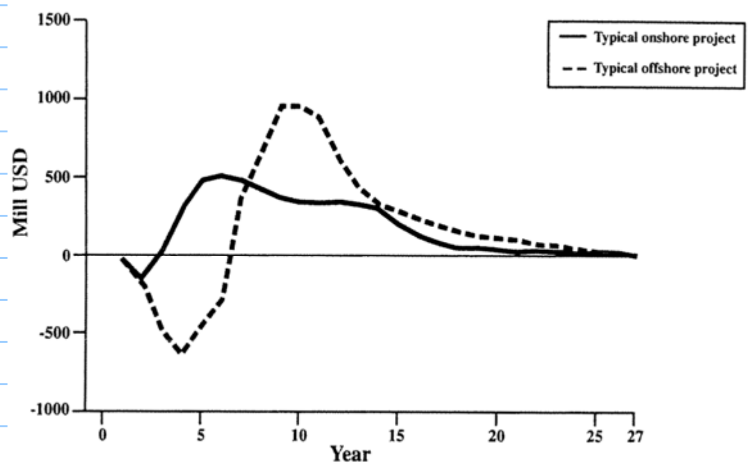


Fig. 9. Typical before tax cash flow profiles for offshore and onshore projects.

we should always evaluate the effect of uncertainty { P_g, P_o / Cost figures / production rates

Sensitivity analysis

↳ change one variable at the time while keeping all others fixed

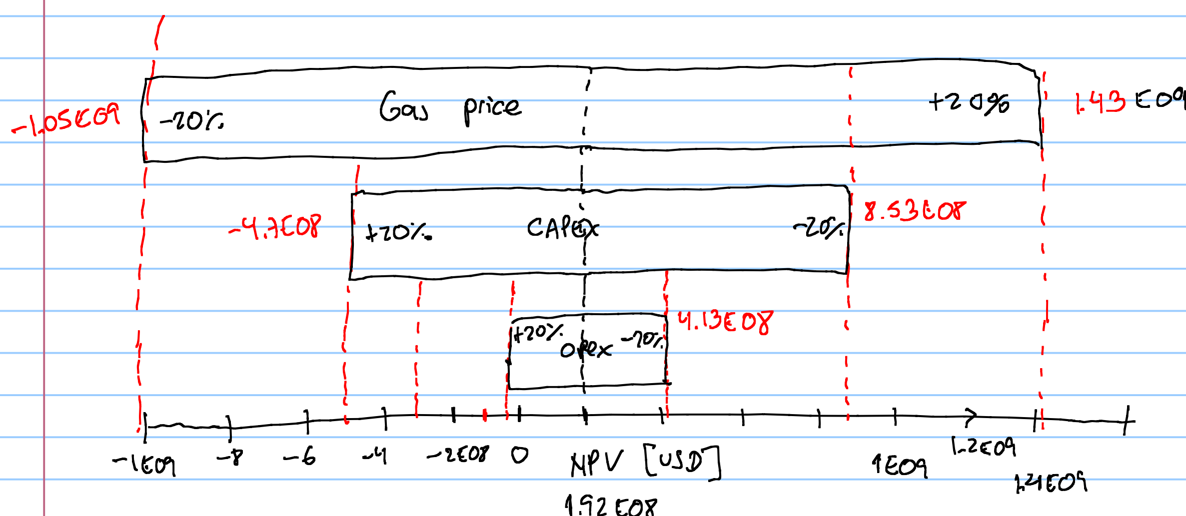
for gas price P_g → $1.2\ P_g$ (+20)%
→ $0.8\ P_g$ (−20)%

for our problem, evaluate the effect of uncertainty: ±20% gas price
±20% Capex values
±20% OPEX

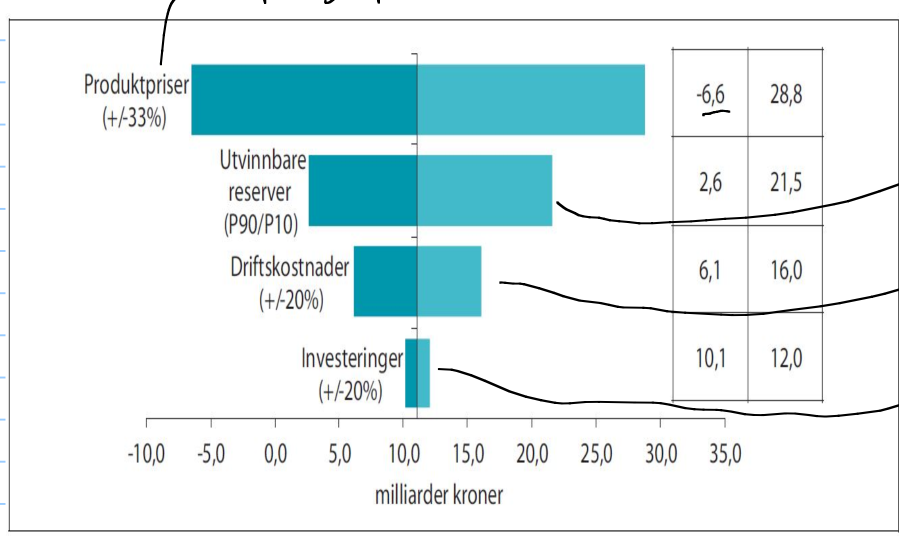
1) • Change $P_g \to P_g \cdot 1.2$ → Compute NPV → return to P_g
2) • change $P_g \to P_g \cdot 0.8$ → Compute NP → return to P_g

Variable	NPV -20%	NPV BASE CASE	NPV +20%
gas price	-1.05E9	1.92E8	1.43 E09
CAPEX	8.53 E08	1.92E8	-4.7E8
OPEX	4.13 E08	1.92 E8	-3E07

tornado chart



oil price/gas price



TRR size

OPEX

CAPEX

Petroleum fiscal systems

Concessionary system
- apply for production licence (30 years)
- operator

HC production
↓
Sales Revenue
↓ → Royalty (10% Tanzania?)
Net revenue
↓ → operating cost, depreciation / amortization
Taxable income
↓ → government TAX
Net income

Contractual system

Service contract
↳ get a fee service in production or in cash

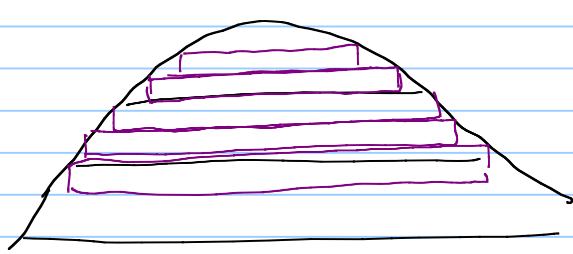
Production sharing contract (PSC)
conglomerate of several companies, one of them is typically government TPDC

HC Production
↓ → royalty (or part of production)
Net production
↓ → opex, depreciation
Profit production
↓ % → Partner → tax → net profit production
↓ % → Partner
↓ % → partner

Reserve estimation (D60, D61, D62)

↳ estimating N, G → N_{pu}, G_{pu}

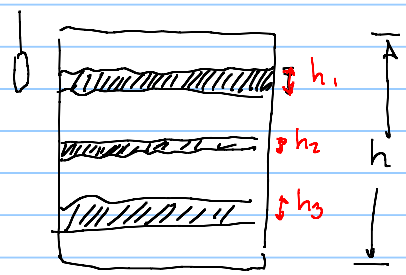
$$N_{pu} = N \cdot F_{RU}$$
$$G_{pu} = G \cdot \underbrace{F_{RU}}_{\text{ultimate recovery factor}}$$



$$N = \frac{V_R \, \phi \, S_o \, N_{TG}}{B_o}$$

N_{TG} --- Net to gross

reservoir rock layers which are not "clean" not "hydrocarbon-bearing" rock



$$N_{TG} = \frac{\sum h_i}{h} = \frac{h_1 + h_2 + h_3}{h}$$

is a multiplier to the total rock volume, to account for the presence of non productive layers.

$$N_{pu} = N \cdot F_{Ru} = \frac{V_R \cdot \phi \cdot S_o \cdot N_{TG} \cdot F_{Ru}}{B_o}$$

the input to this equation is not a single number!

$\phi \rightarrow$

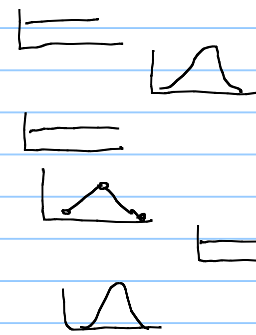
$V_R \rightarrow$

$S_o \rightarrow$

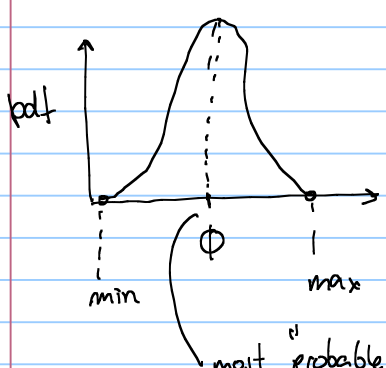
$B_o \rightarrow$

$N_{TG} \rightarrow$

$F_{Ru} \rightarrow$



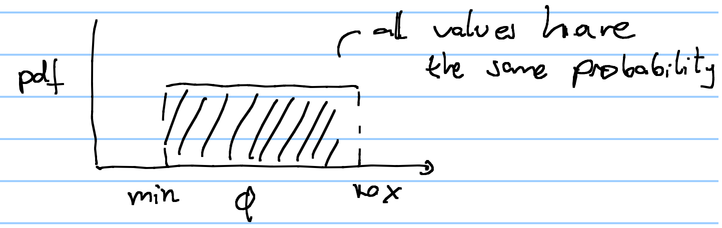
we are also interested in computing N_{pu} as a range, with associated probabilities



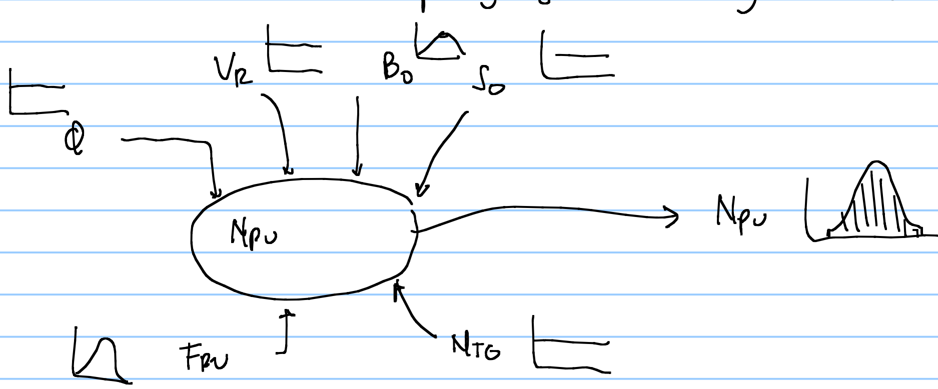
pdf probability density function

pdf probability distribution function

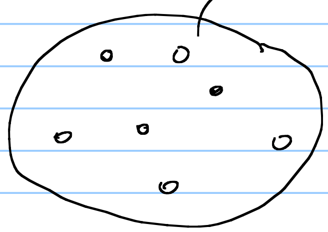
if i have no prior information



what i am interested in computing is the resulting distribution for N_{pu}



estimating probability distribution using measured data



"N" samples

Φ
Φ_1
Φ_2
Φ_3
Φ_4
$\vdots$
Φ_N

min
max

frequency analysis

- define certain number of bins n
  n should be much less than N (number of samples)

- determine minimum and maximum values of sample

Φ_{min} $\qquad$ $\Delta\Phi = \dfrac{\Phi_{max} - \Phi_{min}}{n-1}$

Φ_{max}

- generate bins

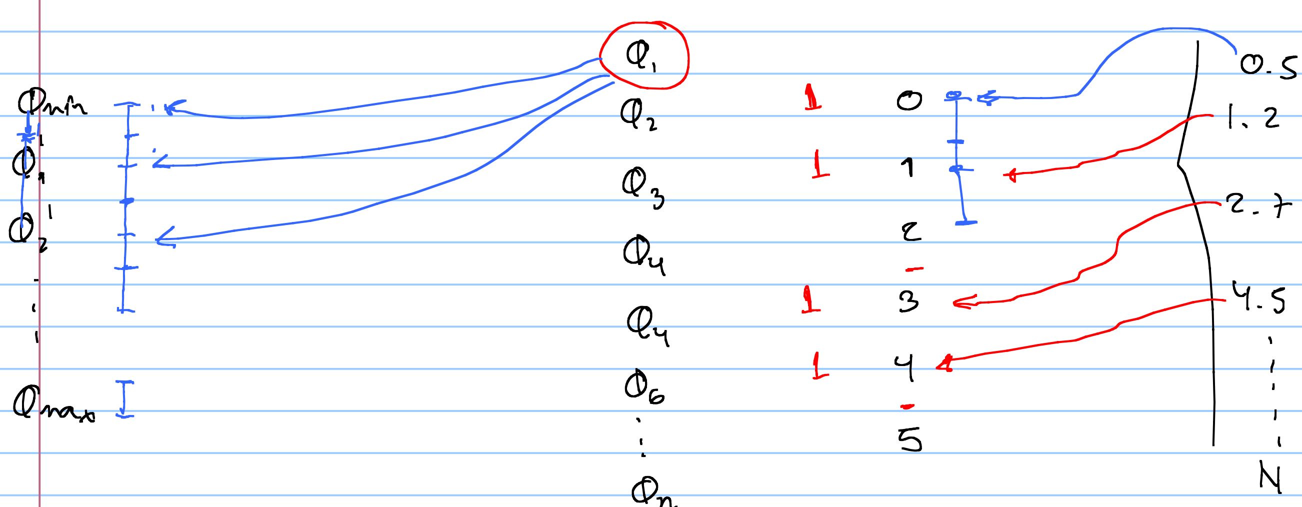
bins
$$\begin{cases} \Phi_{min} \\ \Phi_1 = \Phi_{min} + \Delta\Phi \\ \Phi_2 = \Phi_1 + \Delta\Phi \\ \vdots \\ \Phi_{max} = \Phi_{i-1} + \Delta\Phi \end{cases}$$

Φ_{min} $\qquad$ $\Delta\Phi = \dfrac{\Phi_{max} - \Phi_{min}}{2}$

Φ_1 –

Φ_{max} $\qquad$ $\Phi_1 = \Phi_{min} + \dfrac{(\Phi_{max} - \Phi_{min})}{2} =$

- look at each value in sample and assign it to a bin



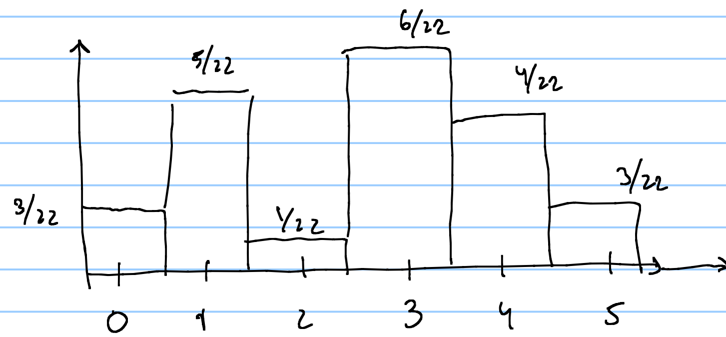
- count the number of samples assigned to each bin an

"probability"

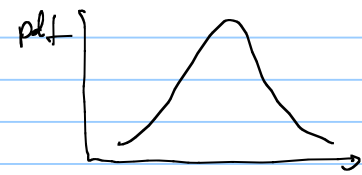
bin	Count	frequency
0	3	3/22
1	5	5/22
2	1	1/22
3	6	6/22
4	4	4/22
5	3	3/22

n = 6

N = 22

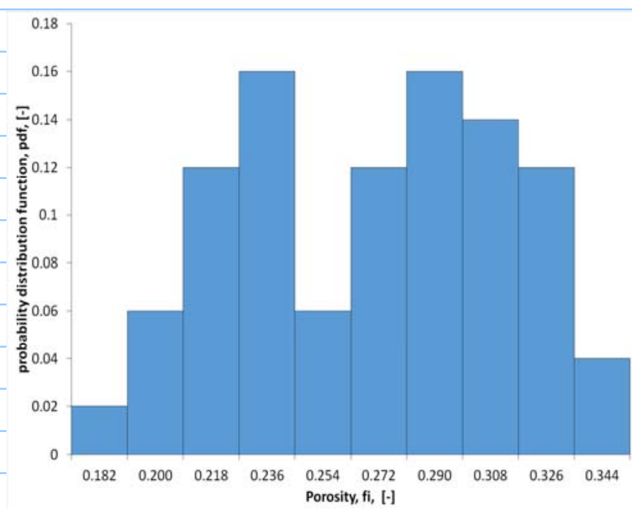


discrete probability distribution

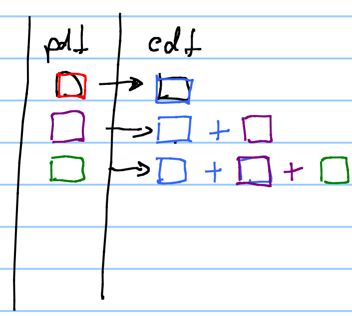


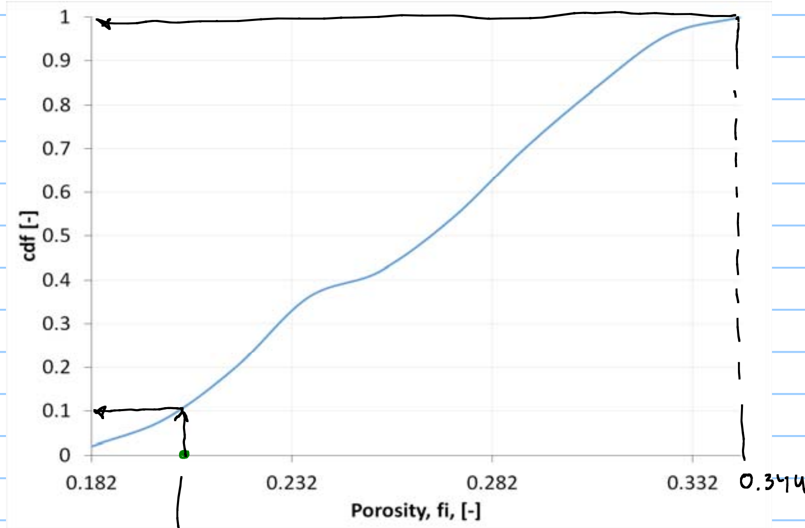
continuous probability distribution

Class exercise → generate discrete frequency distribution for measured porosity data



cumulative distribution function (cdf)

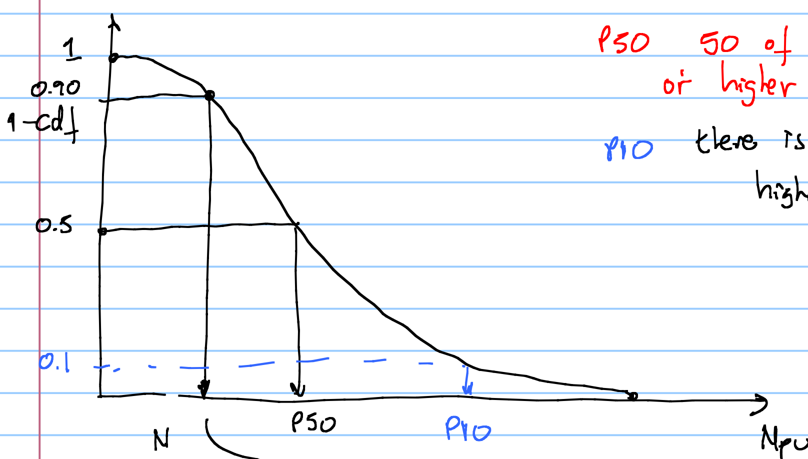




100% of the population has $\phi = 0.344$ or less

$\phi = 0.2 \rightsquigarrow cdf = 10\%$ there is 10% probability that the porosity of my population is equal to $\phi = 0.2$ or less

in reserves



P50 50 of the population will have Npu of P50 or higher

P10 there is 10% chance that Npu will be P10 or higher

each company uses their own percentiles
90 → 80
50 → 66
10 → 15, 5

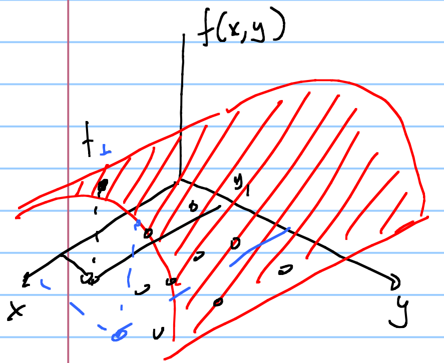
N P90 → 90% of the total population will have Npu of P90 or bigger

P10 P50 P90 P00 Hebron

Hebron Ben Nevis Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm^3	MBO	Mm^3	MBO	Mm^3
D-94 Fault Block	1601	255	1328	211	1077	171
I-13 Fault Block	252	40	187	30	141	22
Total Hebron Ben Nevis	1870	297	1515	241	1204	191
Total Hebron Ben Nevis Gas	**Upside Volumes**		**Best Estimate Volumes**		**Downside Volumes**	
	GCF	* GSm^3	GCF	GSm^3	GCF	GSm^3
Solution Gas D-94 Block	112	3.2	145	4.1	189	5.4
Solution Gas I-13 Block	10	0.3	14	0.4	22	0.6
Non-associated Gas	n/a	n/a	n/a	n/a	n/a	n/a
Gas Cap D-94 Block only	0	0	0	0	31	0.9

* $GSm^3 = 10^9$ cubic meters

to compute the pdf and cdf of Npu, we will use sampling method called Monte-Carlo



$f(x,y) = x^2 + y^2$ random sampling

$x_1, y_1 \rightsquigarrow f_1$

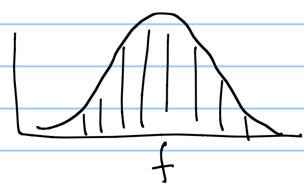
$x_2, y_2 \rightsquigarrow f_2$

$\vdots$

repeat for many random samples

$$\underbrace{\left(f_1, f_2 \, ------ \, f_N\right)}_{}$$

apply a frequency analysis to the results



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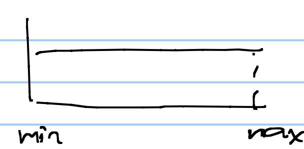
Number 247 SEPTEMBER 1949 *Volume 44*

THE MONTE CARLO METHOD

NICHOLAS METROPOLIS AND S. ULAM
Los Alamos Laboratory

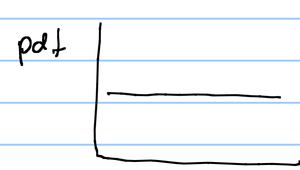
1) • Assign pdf for all input data

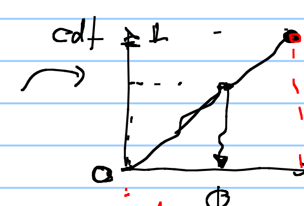
ϕ
V_R
B_o
S_o
N_{TG}
F_{RV}



2) • take a random sample for each variable in each range.

$$\text{cdf} = \frac{(X - X_{min})}{\underbrace{(X_{max} - X_{min})}_{1}}$$





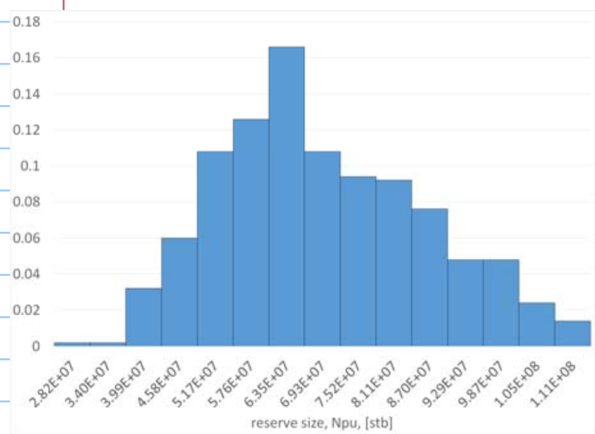
$$X = \text{RAND}(0\text{-}1)\left[X_{max} - X_{min}\right] + X_{min}$$

3) o compute Npu with all random input.

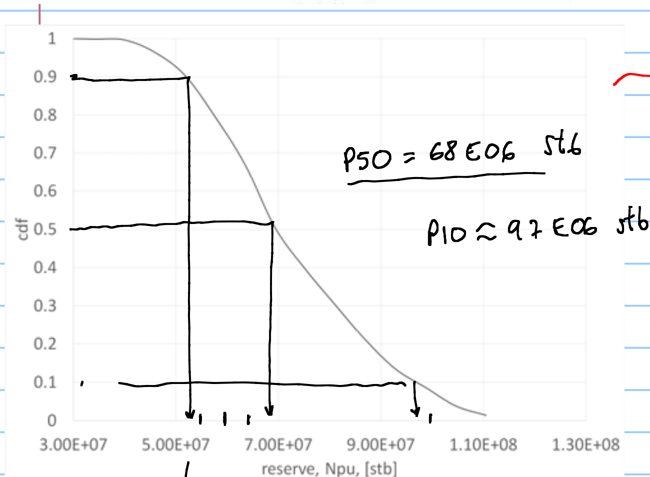
4) o Record Npu value

5) o repeat from step 2. "Many" times (500)

Class exercise



			Net to Gros	Oil Saturation	Formation Volume F	Ultimate Recovery Factor	
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	
Min	2.00E+09	0.18	0.3	0.8	1.35	0.42	
Max	2.50E+09	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	2.16E+09	1.94E-01	4.97E-01	8.25E-01	1.39E+00	6.10E-01	7.51E+07
2	2.28E+09	2.51E-01	4.17E-01	8.06E-01	1.46E+00	5.76E-01	7.59E+07
3	2.44E+09	2.77E-01	4.31E-01	8.23E-01	1.52E+00	5.77E-01	9.12E+07

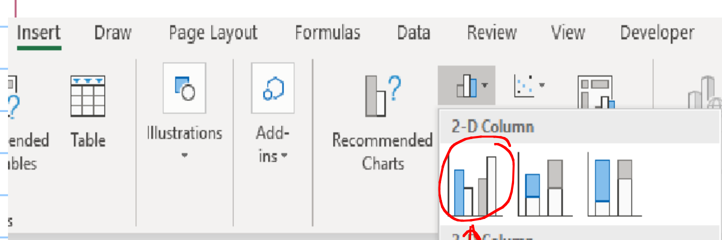


P90 ≈ 52.5 E6 Stb

cdf

nr	bin	count	pdf	cdf
1	2.82E+07	1	0.002	1
2	3.40E+07	1	0.002	0.998
3	3.99E+07	16	0.032	0.996
4	4.58E+07	30	0.06	0.964
5	5.17E+07	54	0.108	0.904
6	5.76E+07	63	0.126	0.796
7	6.35E+07	83	0.166	0.67
8	6.93E+07	54	0.108	0.504
9	7.52E+07	47	0.094	0.396
10	8.11E+07	46	0.092	0.302
11	8.70E+07	38	0.076	0.21
12	9.29E+07	24	0.048	0.134
13	9.87E+07	24	0.048	0.086
14	1.05E+08	12	0.024	0.038
15	1.11E+08	7	0.014	0.014

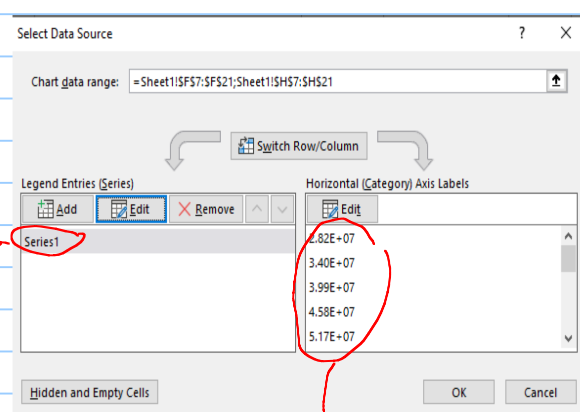
0.038 = 0.024 + 0.014



② Homework make plots of pdf / cdf

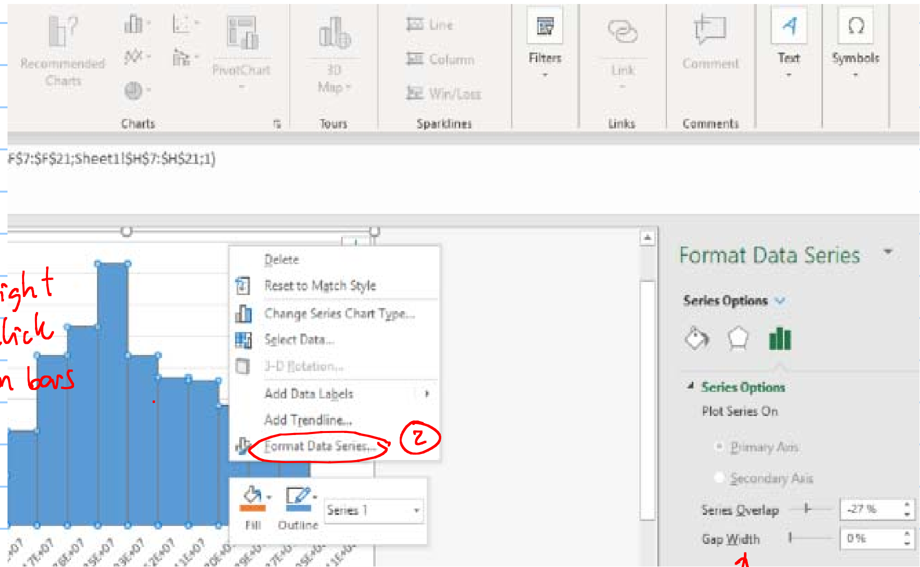
Npu

pdf



select bins

① right click on bars



②

③ set to zero "0"

Tool useful → : An easier way / faster way to quantify the effect of uncertainty instead of using : monte Carlo

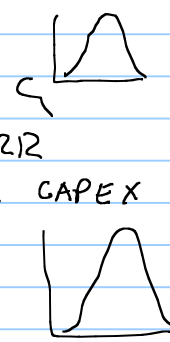
: to provide support when taking decision

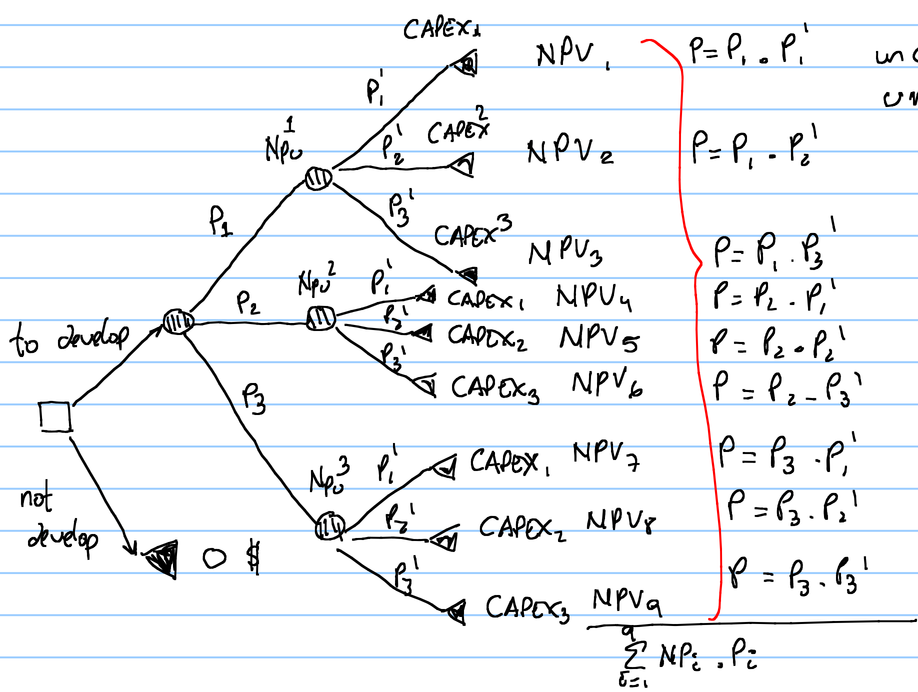
Probability trees / decision trees

□ choice node / decision node

chance

end node





uncertainties TRR

uncertainties in CAPEX

to compare branches, one can use EMV expected monetary value of branch

Class exercise

08_decision_Tree	xlsx
08_Decision_tree_exercise	docx

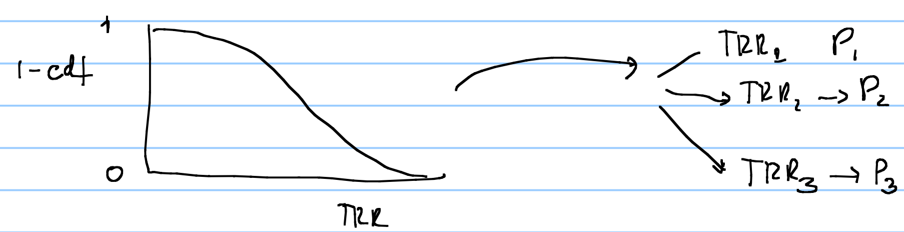
Your company is deciding whether to develop a reservoir or not in the Rovuma region. To help them take the decision, you have proposed to use a probability tree.
The value of the development can be estimated using the simplified equation:

$$NPV = TRR*60*0.4-CAPEX.$$

- What is the mean expected value of the development? Is it worth to look further into developing this field?

- The capex values exhibit a normal probability distribution. However, it has already been discretized by a colleague:
    - CAPEX1: 0.7 E9 USD, P1: 0.3
    - CAPEX2: 1.1 E9 USD, P2: 0.4
    - CAPEX3: 1.5E9, P3: 0.3.

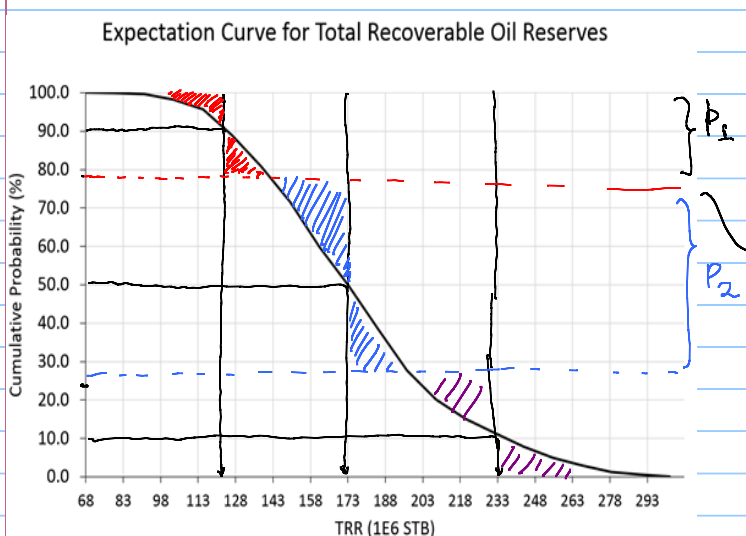
how to discretize TRR



$P90 = 122 E06$ stb

$P50 = 173 E06$ stb

$P10 = 233 E06$ stb



move the line until two red areas are same

from chart $P_1 = 0.2$

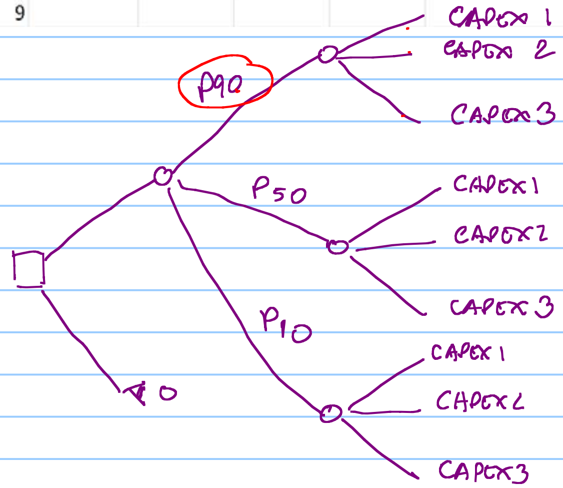
$P_2 = 0.55$

$P_3 = 1 - 0.2 - 0.55 = 0.25$

$P_1 + P_2 + P_3 = 1$

let's make the tree in excel

OPTION	TRR	P_TRR	CAPEX	P_capex	MV = TRR*60*0.4-CAPEX	P=P_capex*P_TRR	MV*P
[-]	[stb]	[-]	[USD]	[-]	[USD]	[-]	[USD]
1	P90	0.2	CAPEX1	0.3	NPV1	0.2 . 0.3	0.0
2	P90	0.2	CAPEX2	0.4	NPV2	0.2 . 0.4	
3	P90	0.2	CAPEX3	0.3	NV3	0.2 . 0.3	
4							
5							
6							
7							
8							
9							



$EMV = \Sigma(\quad)$

OPTION	TRR	P_TRR	CAPEX	P_capex	NPV = TRR*60*0.4-CAPEX	P=P_capex*P_TRR	MV*P
[-]	[stb]	[-]	[USD]	[-]	[USD]	[-]	[USD]
1	1.22E+08	0.2	7.00E+08	0.3	2.23E+09	0.06	1.34E+08
2	1.22E+08	0.2	1.10E+09	0.4	1.83E+09	0.08	1.46E+08
3	1.22E+08	0.2	1.50E+09	0.3	1.43E+09	0.06	8.57E+07
4	1.73E+08	0.55	7.00E+08	0.3	3.45E+09	0.165	5.70E+08
5	1.73E+08	0.55	1.10E+09	0.4	3.05E+09	0.22	6.71E+08
6	1.73E+08	0.55	1.50E+09	0.3	2.65E+09	0.165	4.38E+08
7	2.33E+08	0.25	7.00E+08	0.3	4.89E+09	0.075	3.67E+08
8	2.33E+08	0.25	1.10E+09	0.4	4.49E+09	0.1	4.49E+08
9	2.33E+08	0.25	1.50E+09	0.3	4.09E+09	0.075	3.07E+08
						EMV	3.17E+09

it is worth to develop the field !

③ Homework : do this exercise by yourselves

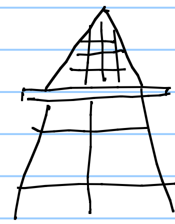
Day 5 06.12.2019

- offshore structures for oil and gas production. what component does the structure must have?

some of components I need

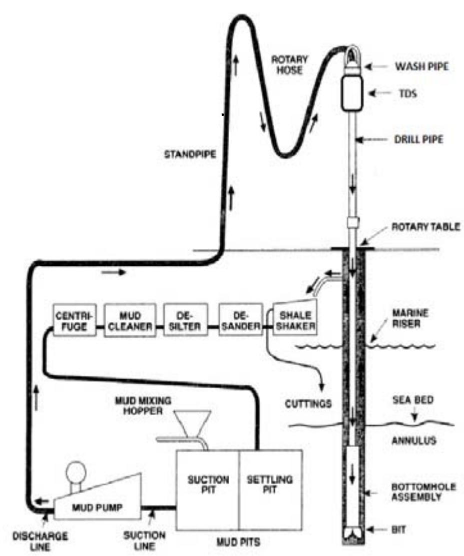
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers.

→ drilling package ($)



drilling tower

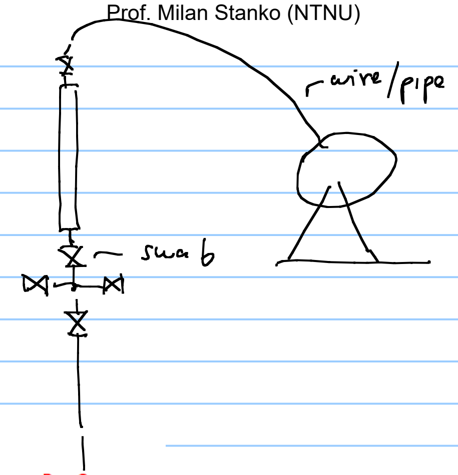
- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system
- Living quarters
- Helideck.
- Power generation. → gas turbine (20 - 70 MW)
- Flare system.
- Utilities (hydraulic power fluid, compressed air, drinking water unit, air condition system, ventilation and heating system)
- Bay for wellheads and christmas trees
- Production manifolds
- Oil storage
- Facilities for oil offloading
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale , hydrate or corrosion inhibitors)
- Repair workshop

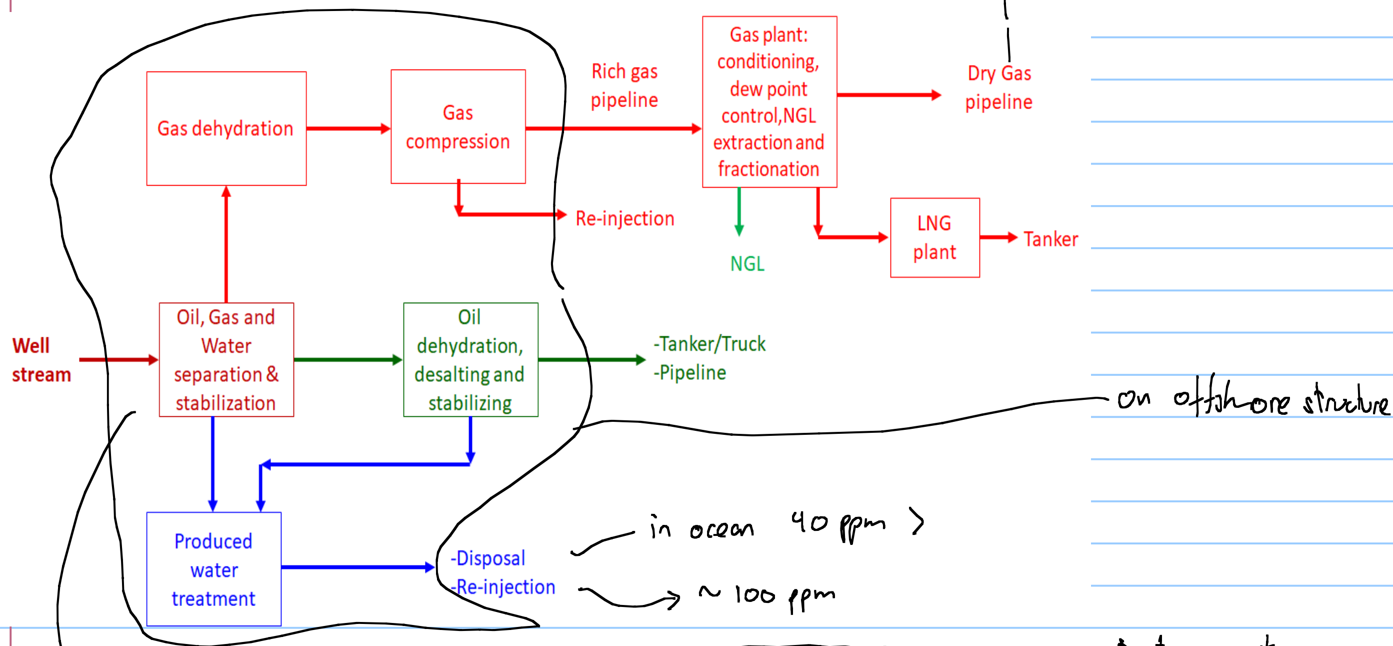


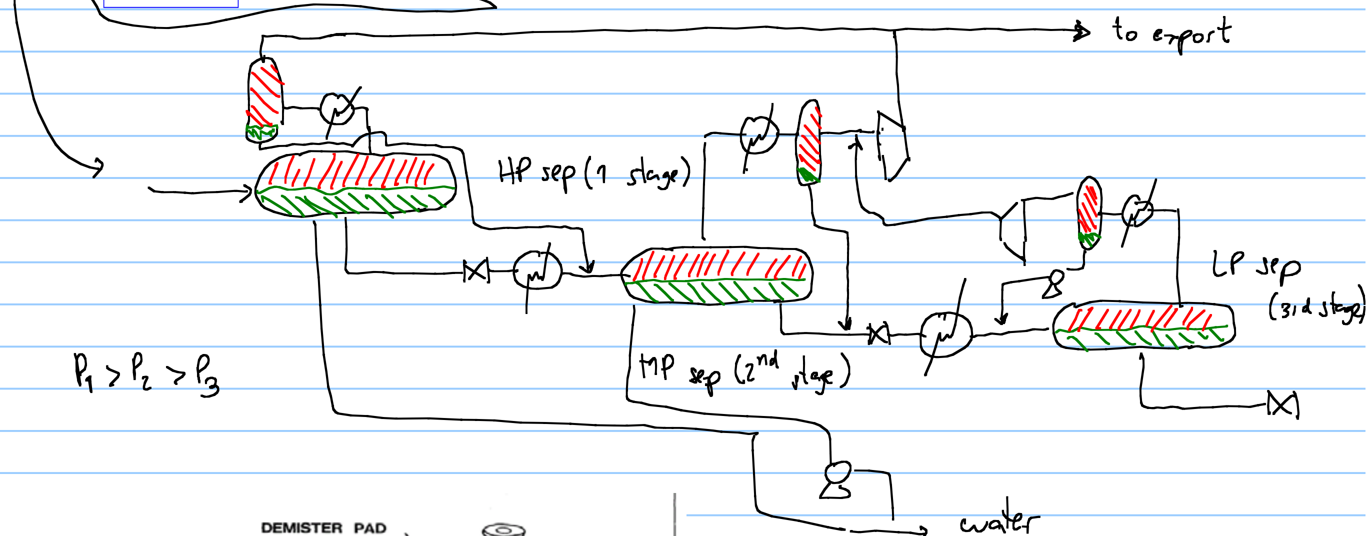
mud package

→ drilling pipe
tubing
casing
} storage

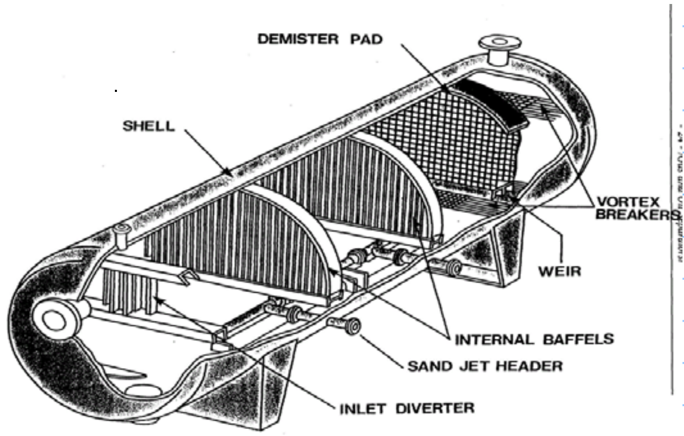
"Light" well intervention: → wireline / slickline
→ coiled tubing

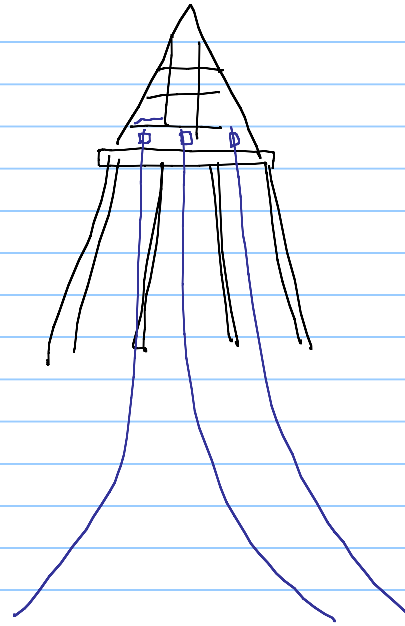


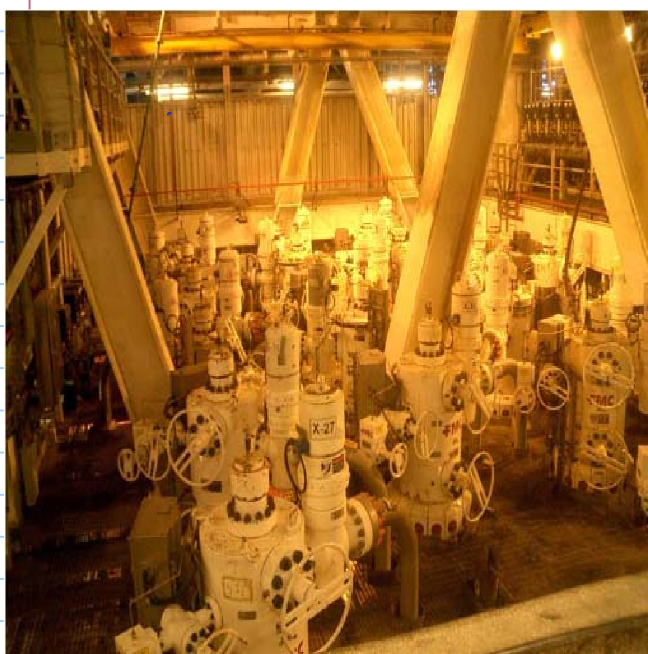




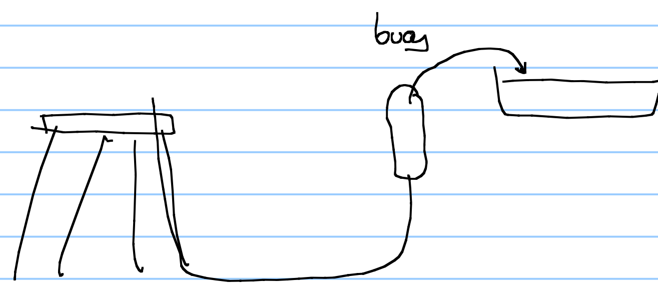
$P_1 > P_2 > P_3$



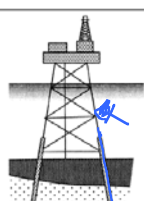
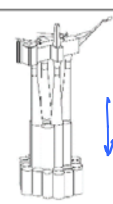


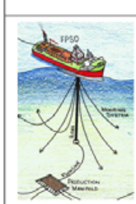
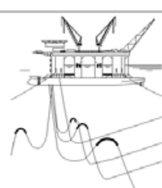
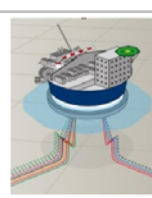
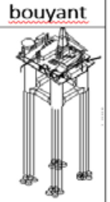


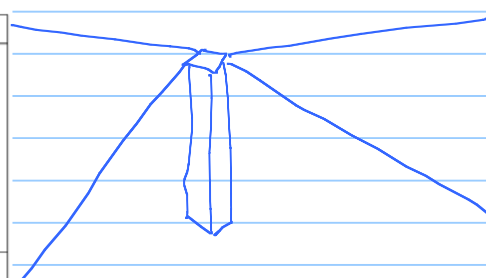
oil offloading

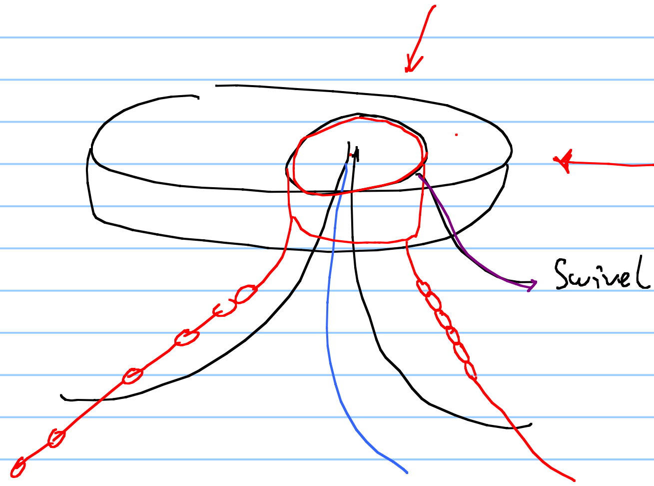


type of offshore structures

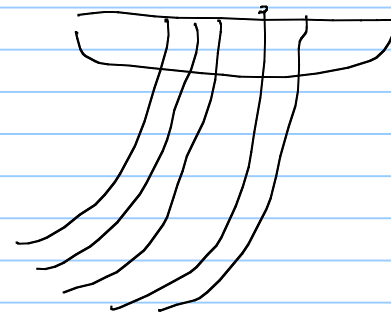
Bottom-supported	Fixed		Compliant
			
	Jacket	Gravity-Based Structure	Compliant tower

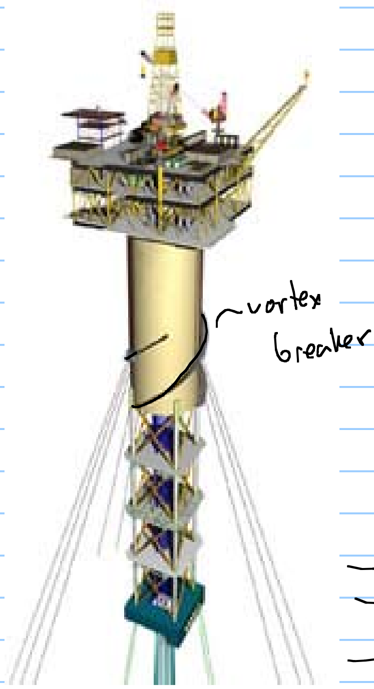
Floating	Neutrally bouyant				Positively bouyant
					
	Ship FPSO	Semi-Sub	Sevan FPSO	Spar	Tension Leg Platform (TLP)



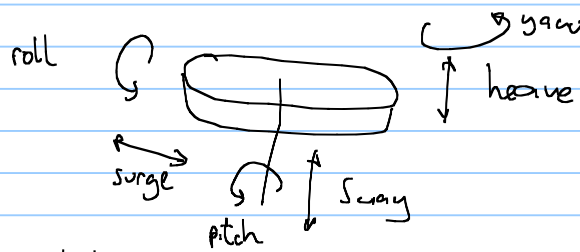


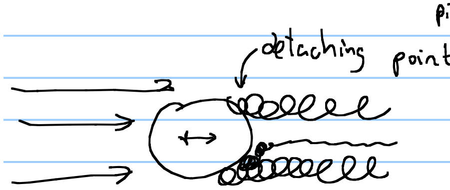
if weather conditions are not harsh and are not changing, we don't need swivel





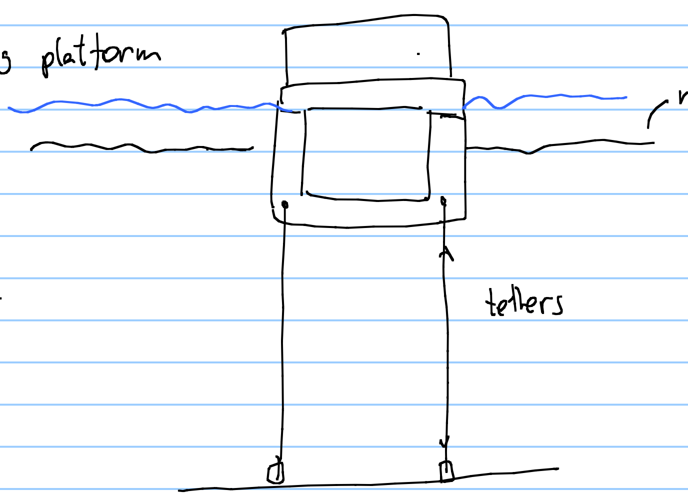
the big draft hinders movement



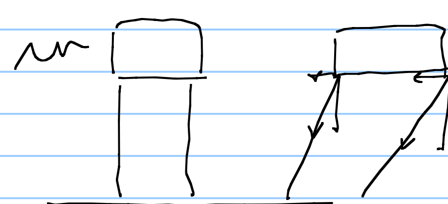


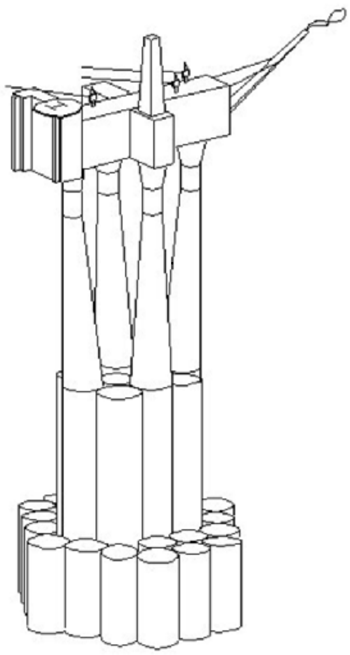
Vortex shedding

Tension leg platform

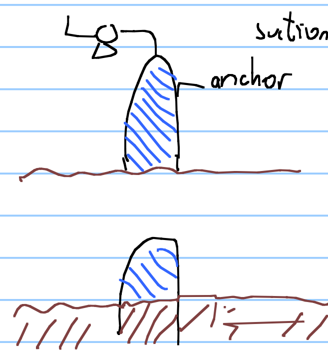


limit movement





suction anchor



storage tanks

buffer to avoid interrupting production in case of bad weather

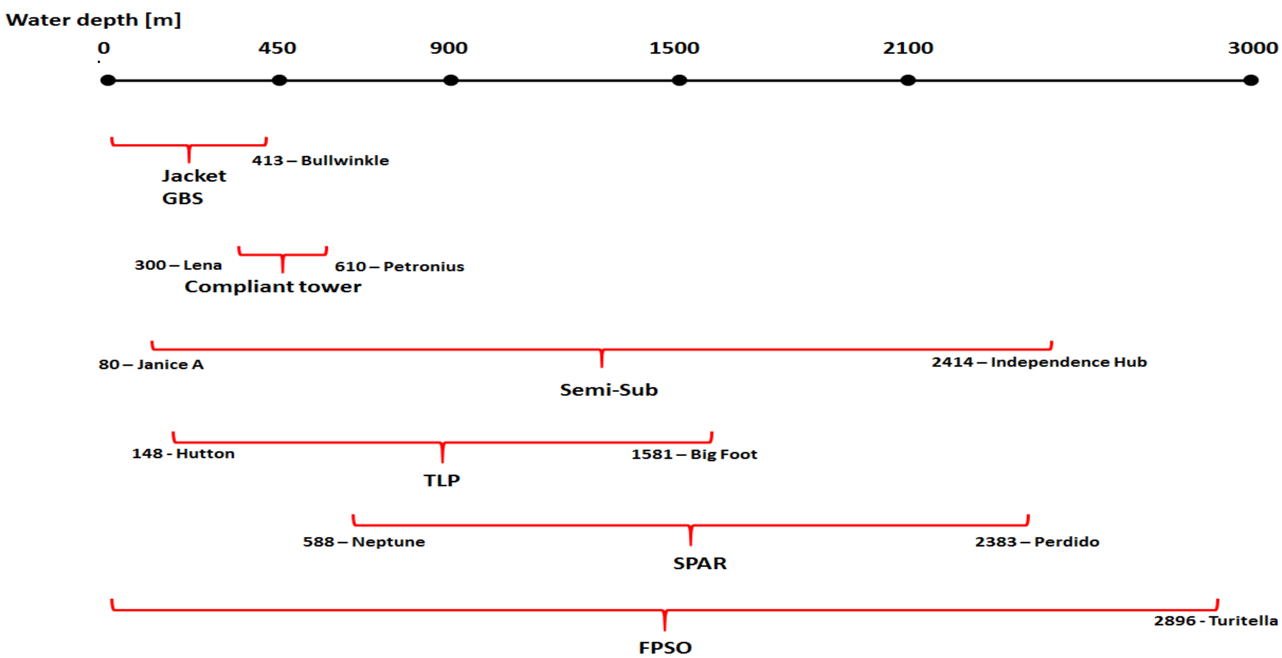
Semi submersible

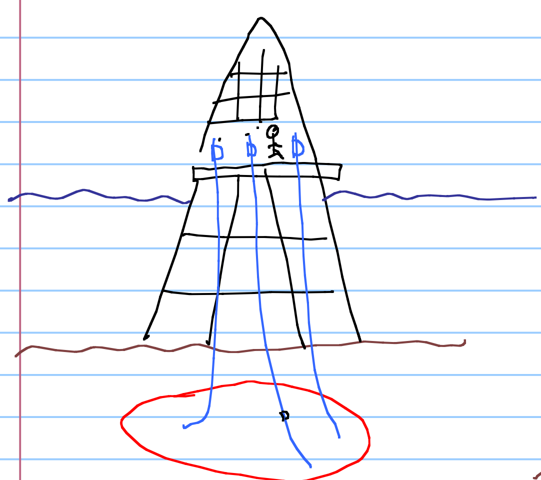
How do we select offshore structures?

1) water depth

bottom supported structures are used for water depths below 600 m

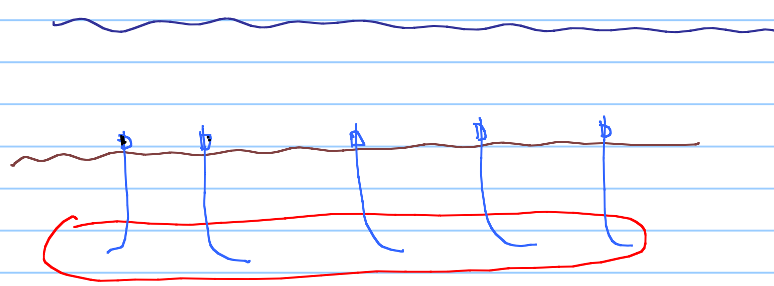
floating structures are used for any water depth but typically for > 600 m

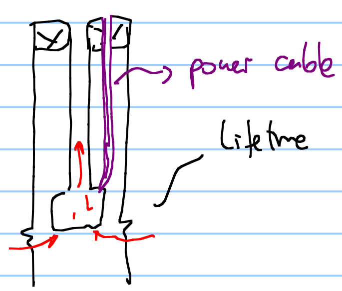




2) location of X-mas tree → dry (platform)
→ wet (subsea)

→ spread of reservoir
Can I reach all reservoir targets from same location?
reservoir structure and spread



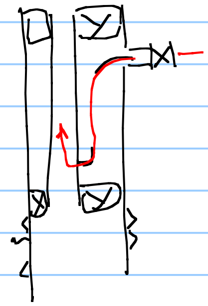


Lifetime (6months → 2 years)

→ water depth. Dry wells have a limit up to 1500 m

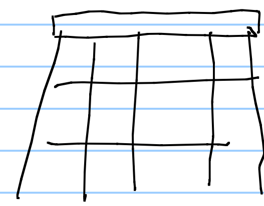
→ well intervention needs:

if Artificial Lift (electric submersible pumps or gas lift, then I prefer to have dry wells



gas lift. by injecting gas, ρ_{mix} is reduced, Δp is also reduced.

↳ infill drilling (to prolong plateau, high uncertainty in subsurface)

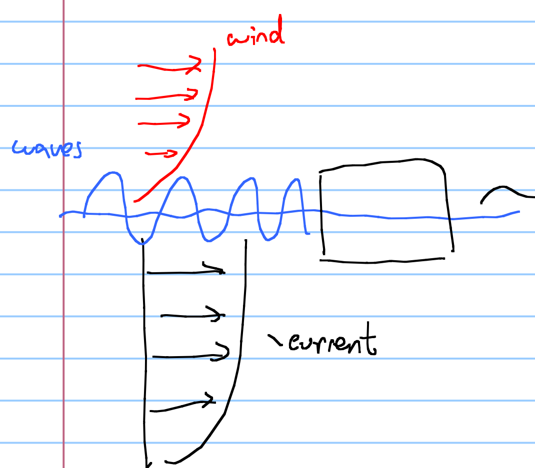


to have spare slots on platform will be very expensive. therefore it is preferred to use subsea wells.

there are only a few structures that allow dry X-mas → Jacket, GBS, compliant tower TLP, (semi-sub), SPAR

- oil storage { harsh weather conditions, social / political uncertainty } that might interrupt regular tanker schedule

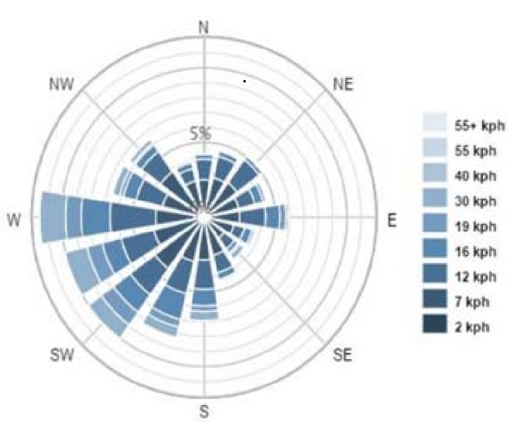
GBS → 300 000 → 500 000 stb
SPAR → 150000 stb
FPSO → 1.000.000 - 3000.000 stb



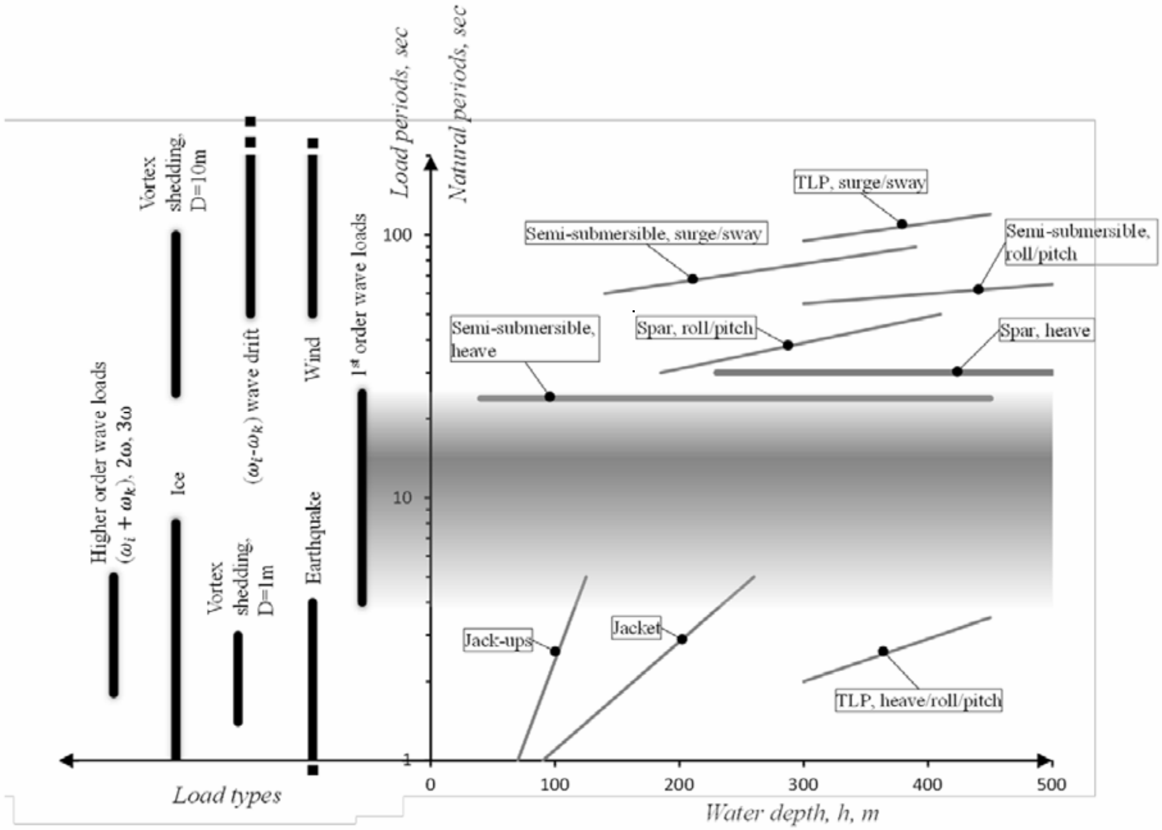
- Loads caused by • wind • waves • currents } each offshore location has some characteristic

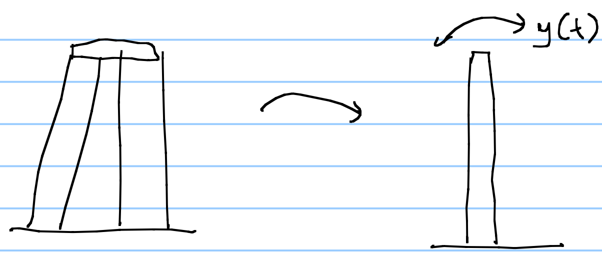
wave, wind, current } magnitude, direction, frequency/period

Causing movement ↳ heave (t), surge (t), sway (t), roll (t), pitch (t), yaw (t)



each structure has a natural frequency which give maximum movement, therefore I have to avoid using structures which their natural frequency coincides with excitation frequency

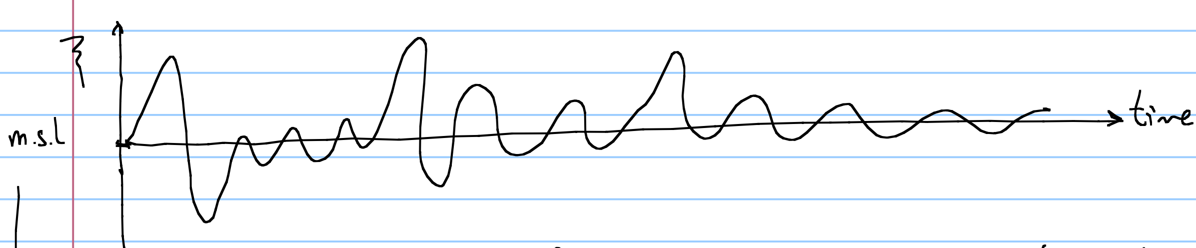




How do we characterize the conditions of wave, wind, current of an offshore location?

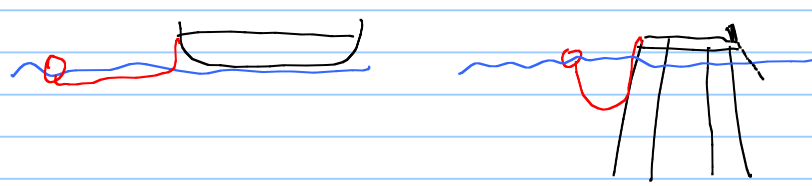
Waves

usually considered fixed in magnitude and direction



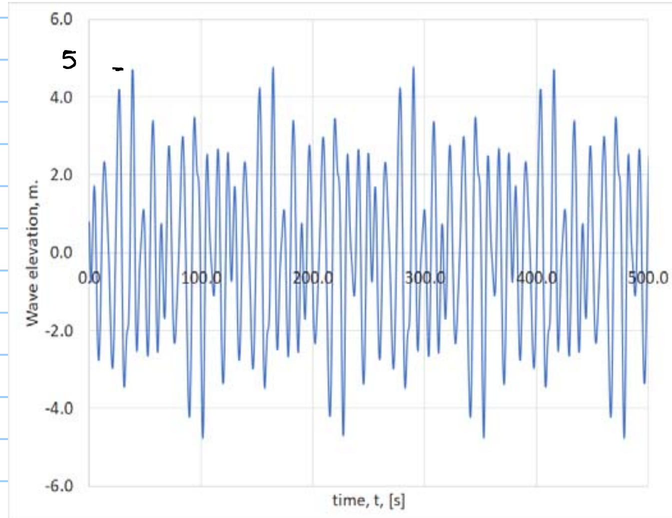
Surveys are made in the area for a few years (2 years)

mean sea level



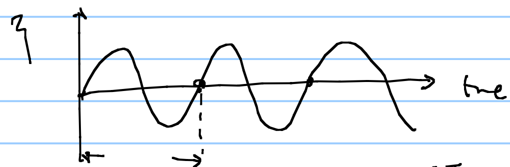
Exercise 9

Time [s]	Elevation [m]
0.0	0.8
0.5	0.0
1.0	-0.5
1.5	-0.8
2.0	-0.6
2.5	-0.1
3.0	0.5
3.5	1.1
4.0	1.6



our intention is to determine a characteristic period / frequency

Fourier (french mathematician)



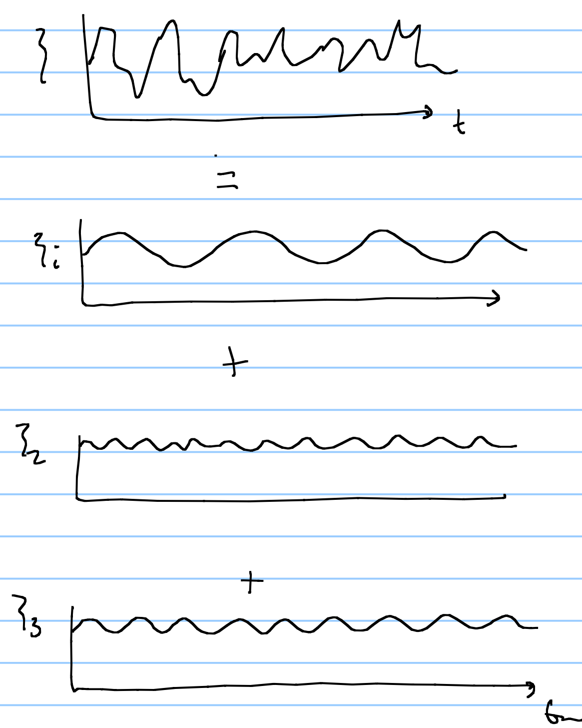
T $\quad f = \frac{1}{T} \quad \omega = \frac{2\pi}{T}$

[s] $\quad \frac{1}{s} = Hz \quad \left[\frac{rad}{s}\right]$

$\frac{cycles}{s} \quad \frac{2\pi\ rad}{1\ cycle}$

all signals can be expressed as a sum of sinusoidal functions

$$\zeta(t) = \sum_{i=1}^{N} A_i \sin(\omega_i t + \delta_i)$$

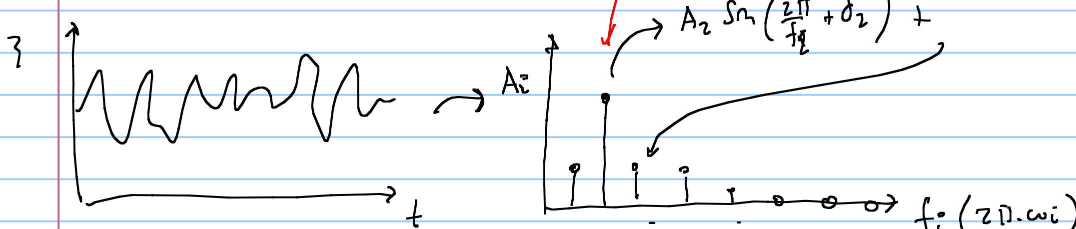


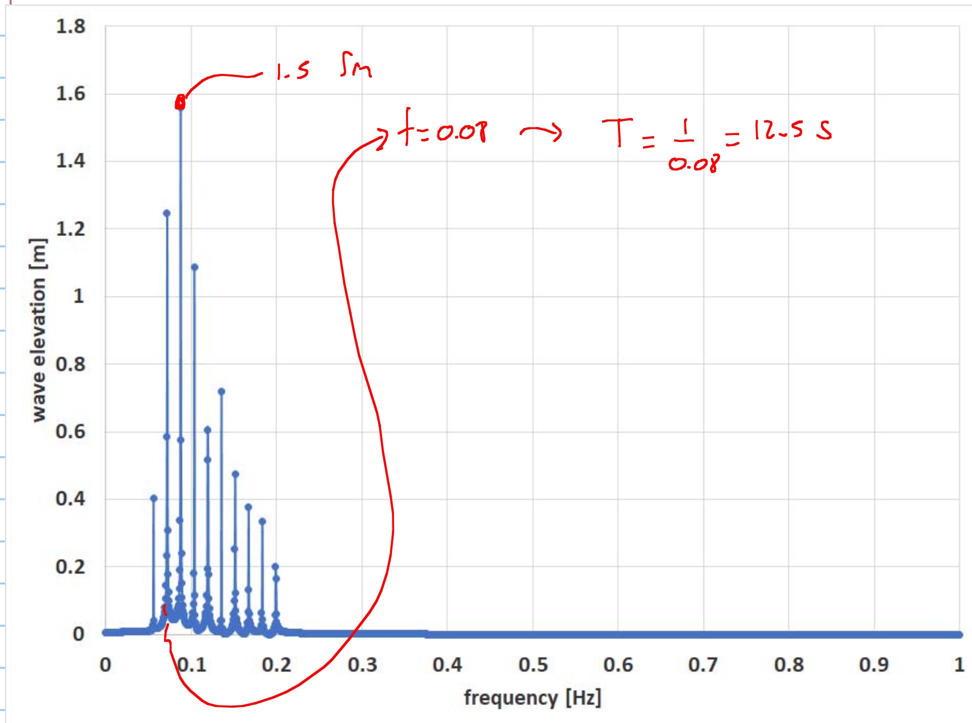
to process wave signals, we typically use Fourier transform (FFT) fast fourier transform

ζ vs t $\rightarrow \{ A_i \quad \omega_i \quad \delta_i$

dominant frequency in the signal

$A_2 \sin\left(\frac{2\pi}{f_2} + \delta_2\right) +$





this frequency analysis is typically made for "sea states" (periods of time of about 3hrs) during which it is assumed they exhibit a dominant magnitude and period

3h → A T
3h → A, T
3h → A, T

repeat this analysis for 2 years

Apply a frequency analysis on the results

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

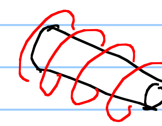
Flow assurance considerations in field development

ensure the uninterrupted flow of hydrocarbons from reservoir to processing facilities

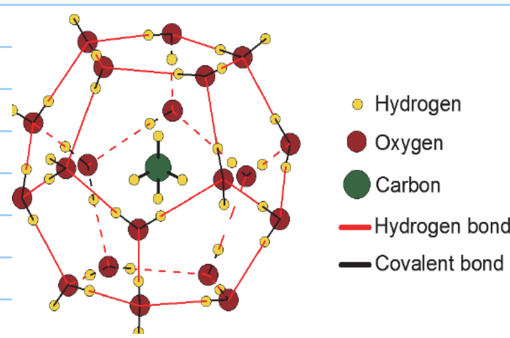
- wax $C12 \rightarrow$ long chain alcanes that precipitate from oil at low temperature

cause plugging of pipelines, cause malfunctioning of equipment.

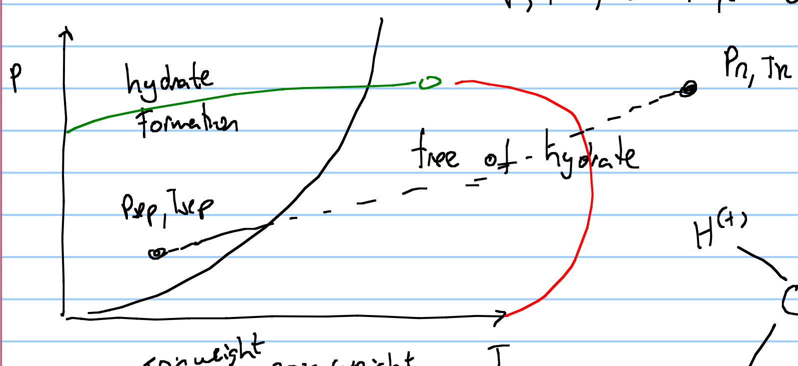
to avoid wax:
- wax inhibitor
- use better pipe insulation
- use pipe heating

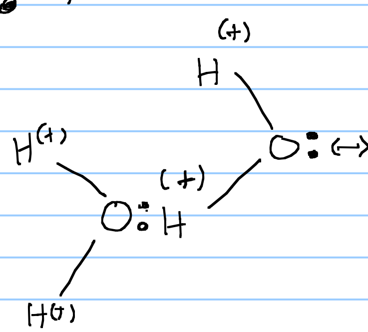


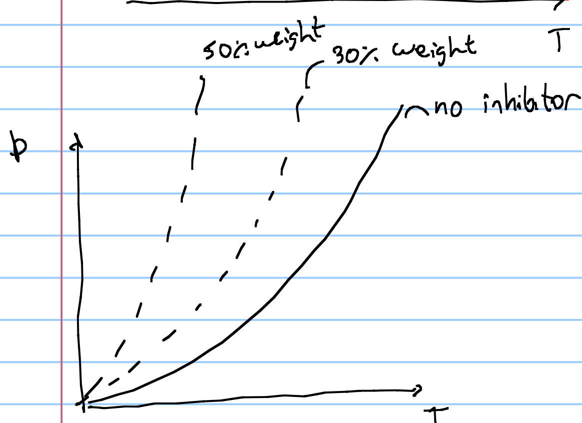
- hydrates



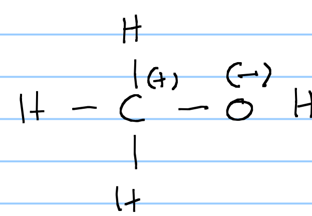
- free water
- small molecules of HC, C_1, C_2, CO_2 9 Å
- P, T, low temperature, high pressure







How to avoid hydrates?
- avoid cooling fluid
- heat the fluid
- chemical inhibitor → MeOH (methanol), MEG (mono ethylene glycol)

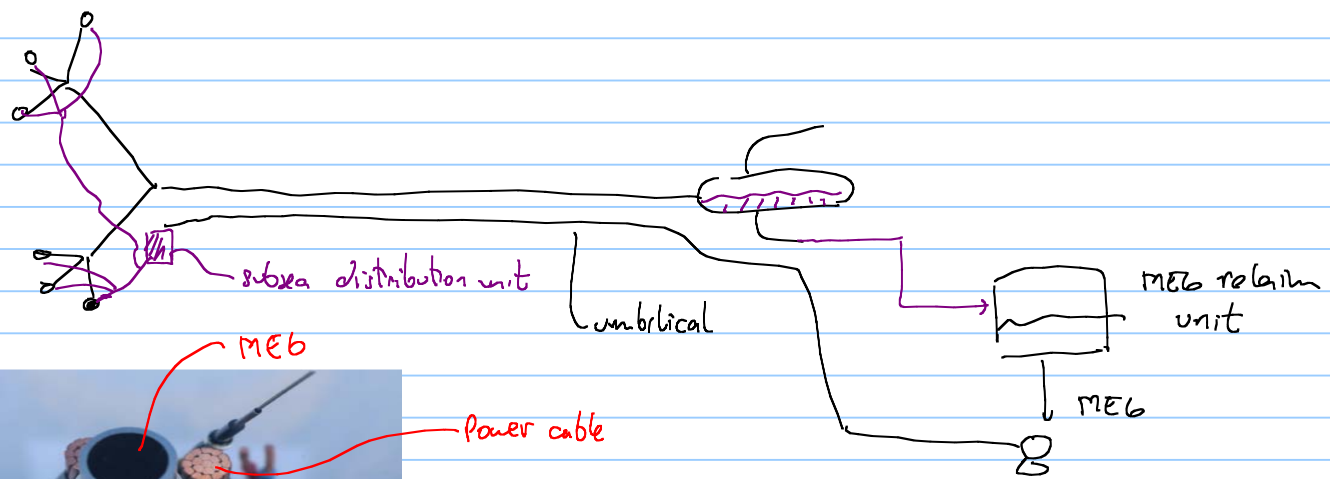


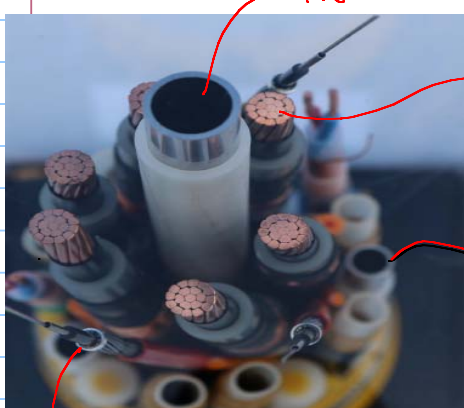
$$\text{weight\%} = \frac{\text{mass of inhibitor}}{\text{mass of inhibitor} + \text{mass water}}$$

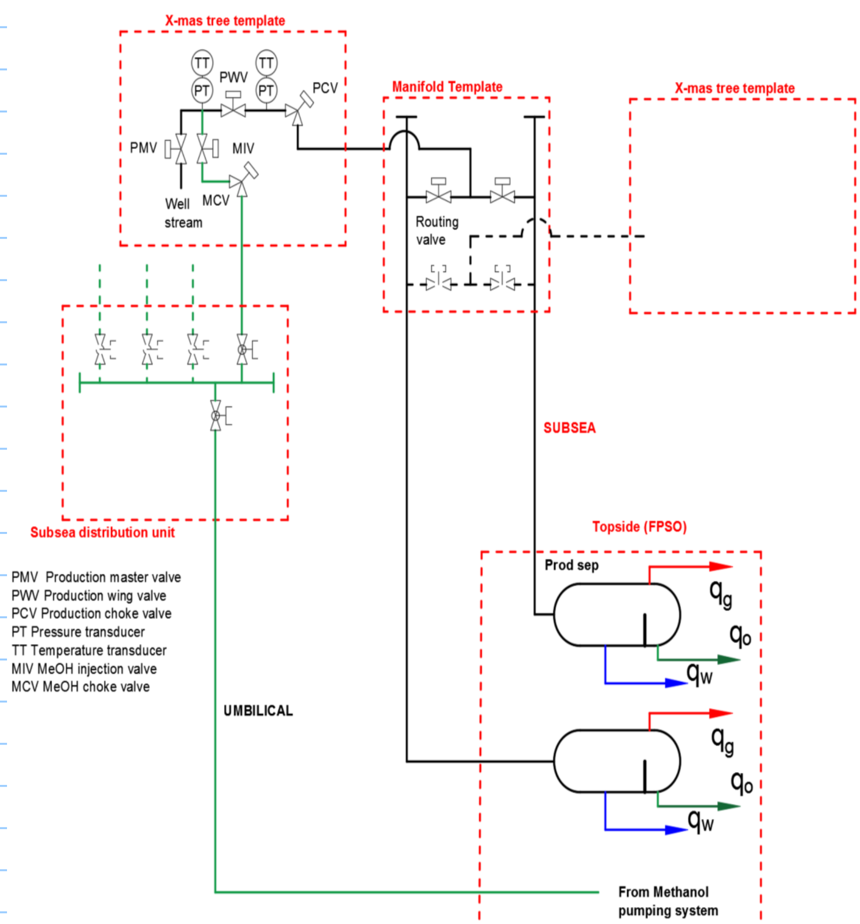
50 bbls of water ~ 50 bbls of MEG

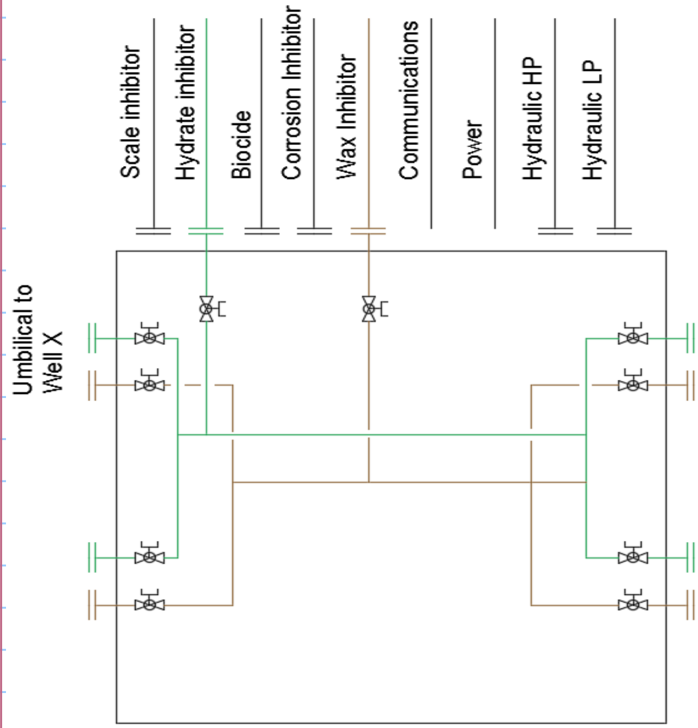
if MEG or MeOH are not recovered (reclaim) this can lead to huge expenses!

So usually this fluid is recovered from the production stream





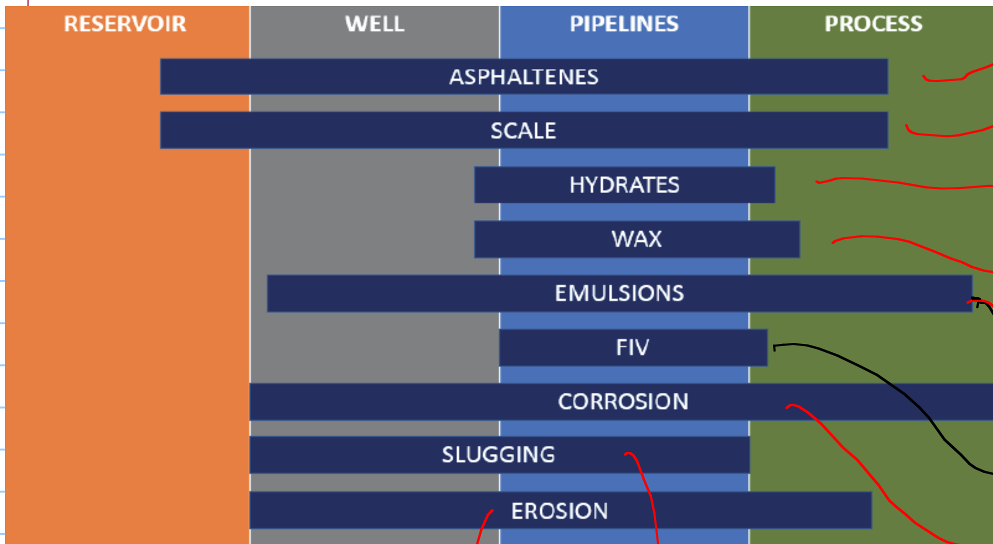




- scale → precipitation of minerals from water

- changes in solubility of these minerals
- changes in T, p, mixing water from different sources (formation water + sea water)

preventive action:
- scale inhibitor
- proper design of injection strategy
- mechanical removal



chemical management
opex

chemical management

chemical management /
insulations

insulation, heating, chemical
management

q vs t, chemical
management

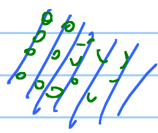
flow induced vibration

material selection
chemical management

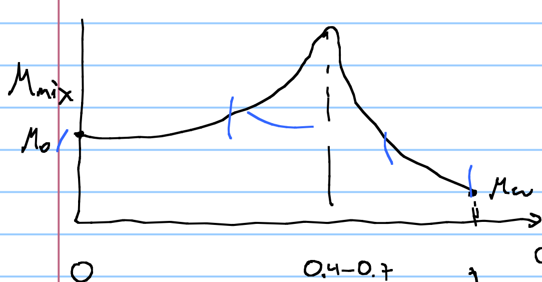
pipeline design
D, routing and trajectory

design of system, D, geometry

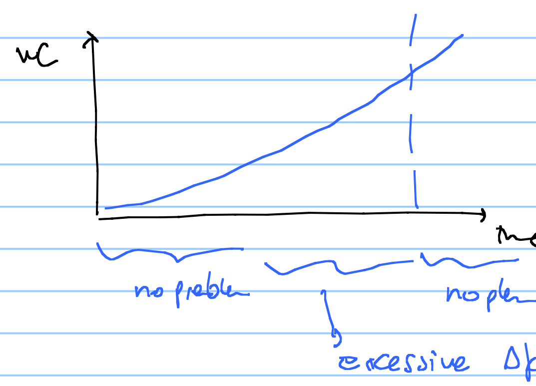
Emulsions: stable small size dispersion of oil in water
water in oil



longer separation time required
bottlenecking the system

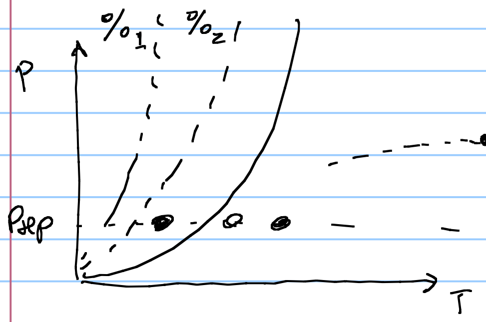


$$\alpha_w = \frac{V_w}{V_o + V_w}$$



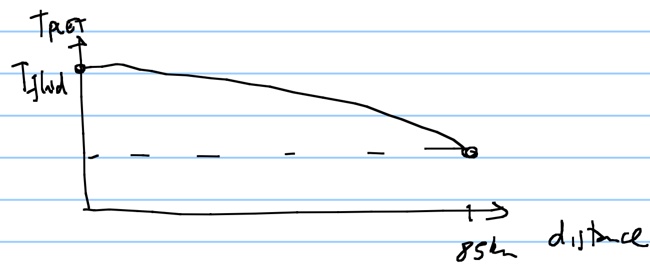
to deal with emulsions we use
demulsifiers → breaks stability of emulsions

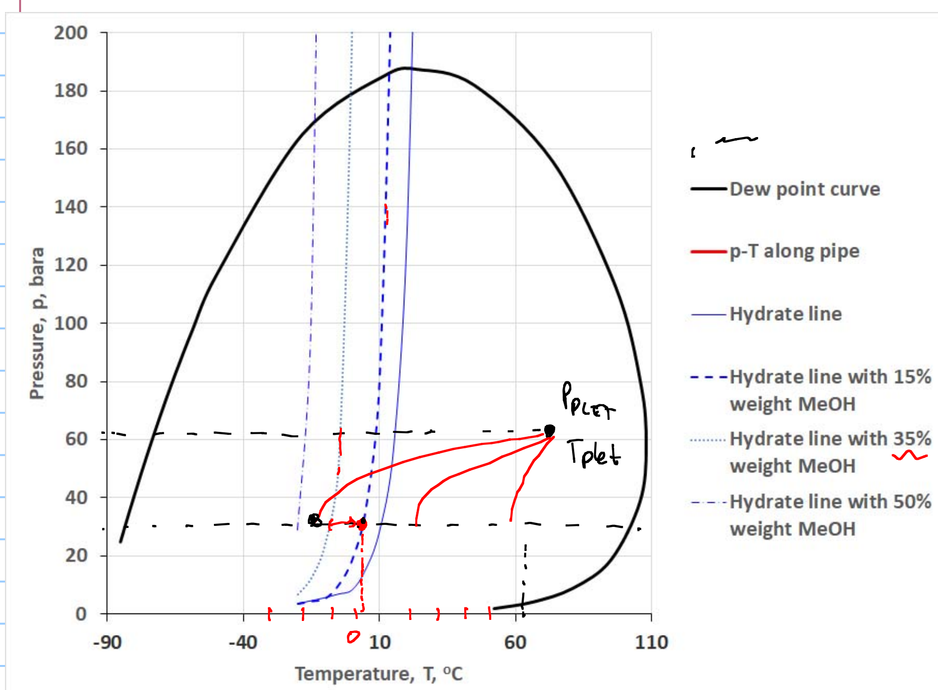
Class exercise: Analyzing hydrate risk in transportation pipeline of B2. Estimate amounts of inhibitor required. (nr. 3)

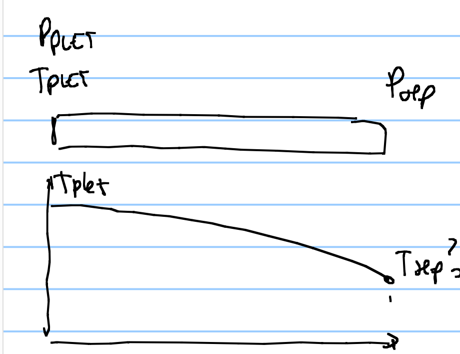


required information: hydrate line without inhibitor
with inhibitor

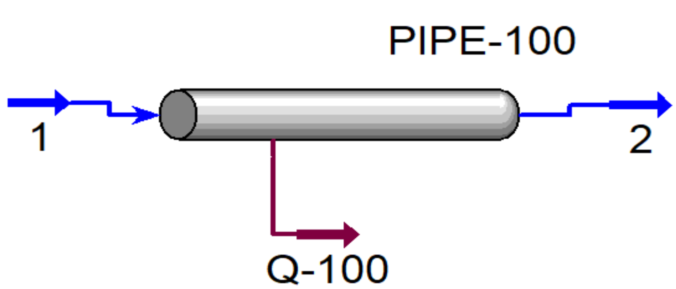
- inlet conditions to pipeline
  p_{PLET}
  T_{PLET}
- p_{sep}
- gas rate
- pipe diameter, length, heat transfer coefficient, T_{amb} (subsea)

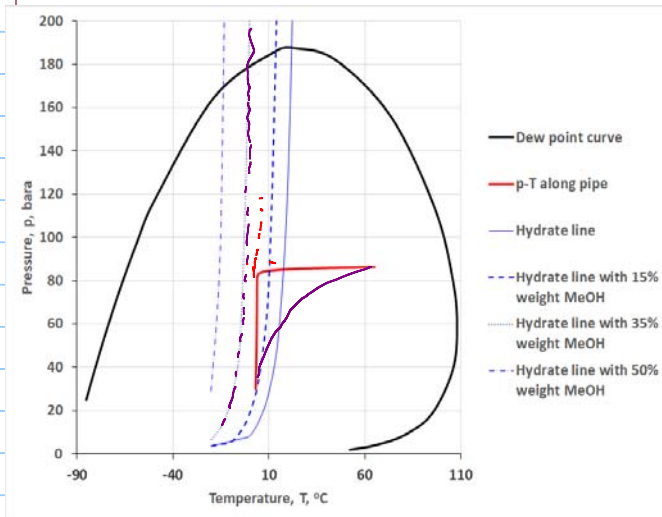






$T_{sep} = 3°C$, therefore, there is hydrate formation risk!





Solution: inject 35 % w of MeOH

THE END