TPG 4230 – Field development and operations

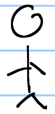
Prof. Milan Stanko   Associate professor Production engineering → { well construction and production systems }

Teaching hours : Mondays 14:15 - 17:00 } P11
Tuesday 10:15 - 12:00

2 student assistants :   . exercise sessions hold by student assistants every week

Martin Marthinussen   1 pending   Consultation → after class
↳ send me an email   milan.stanko@NTNU.NO

martinhm@stud.ntnu.no



Evaluation: 40% home exercises → 5 sets with 3-4 problems each.
In groups of ~ 3   to get approval to take the exam
- deliver all but one
- compound grade at least 20/40
- penalty for late delivery

60% exam. Digital exam 24.05.2018 JC23 Realfag.

Main tools are {
Excel → VBA visual basic for applications
be careful mac users! → check your version
has VBA functionality
↳ Install a virtual machine with windows
↳ computers in the computer lab

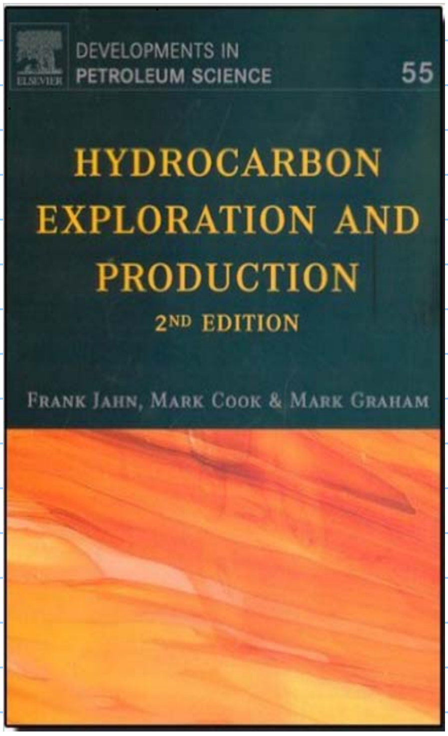
- IPM → intergrated petroleum management { Prosper Gap }
  make models of production system
  calculate rates, p, T,
- Hysys → process modeling → farm.ntnu.no

Reference group:
- Petra Bachhuber
- Fabian Barganski
- Abdul Saboor Khan

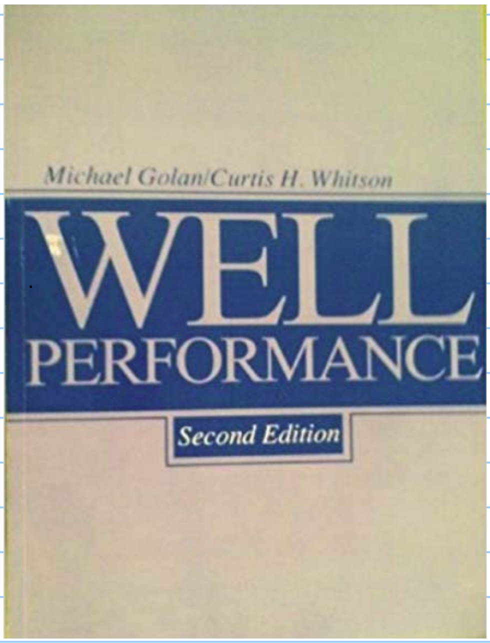
Some mondays we might get some guest lectures (14:15-1500)

to assist at least to 50% of them to take the exam.

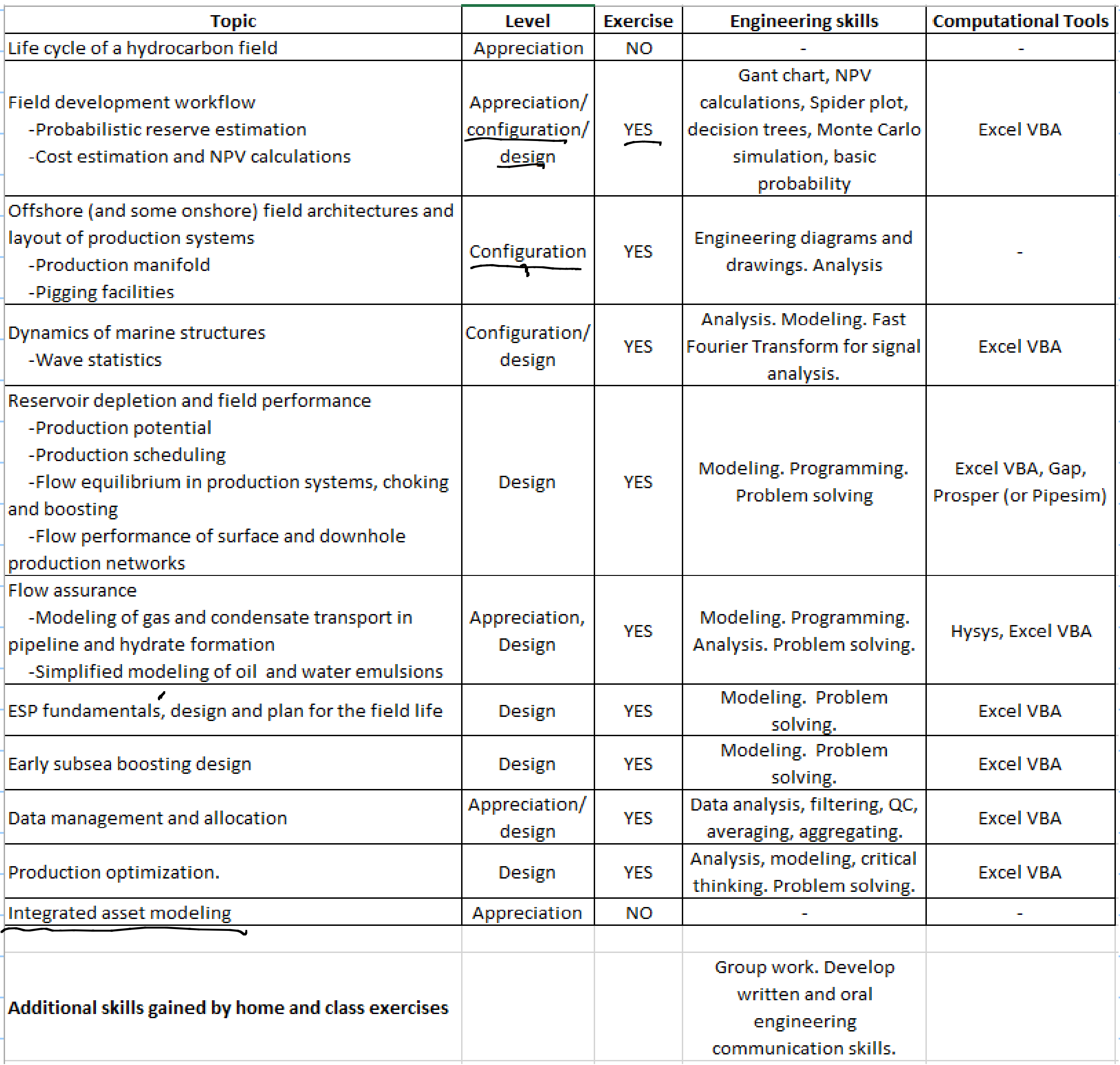
Reference material:



Well performance by Michael Golan



Compendium by Milan.

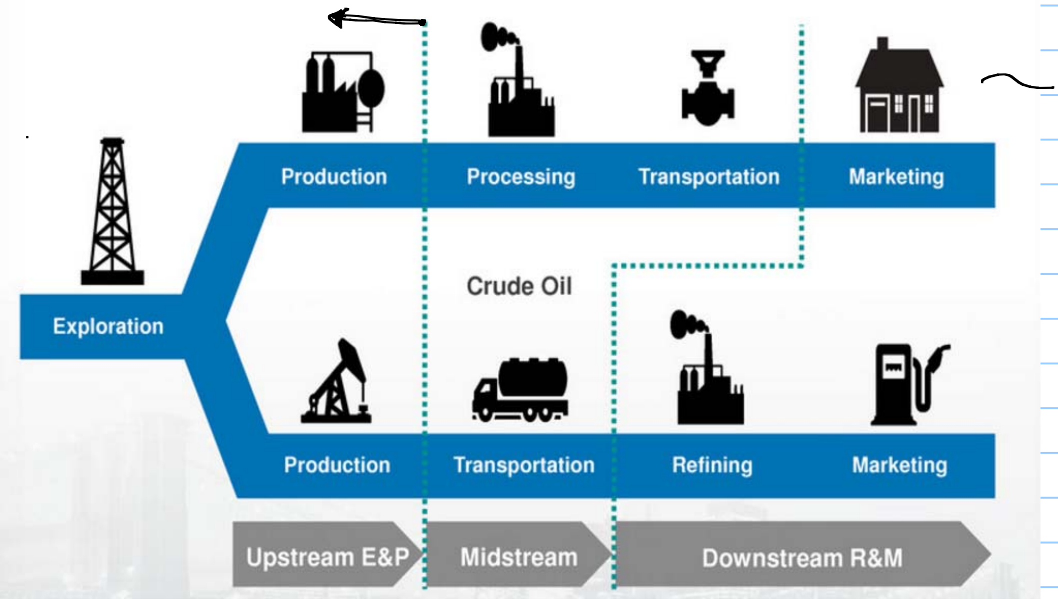


Topic	Level	Exercise	Engineering skills	Computational Tools
Life cycle of a hydrocarbon field	Appreciation	NO	-	-
Field development workflow -Probabilistic reserve estimation -Cost estimation and NPV calculations	Appreciation/ configuration/ design	YES	Gant chart, NPV calculations, Spider plot, decision trees, Monte Carlo simulation, basic probability	Excel VBA
Offshore (and some onshore) field architectures and layout of production systems -Production manifold -Pigging facilities	Configuration	YES	Engineering diagrams and drawings. Analysis	-
Dynamics of marine structures -Wave statistics	Configuration/ design	YES	Analysis. Modeling. Fast Fourier Transform for signal analysis.	Excel VBA
Reservoir depletion and field performance -Production potential -Production scheduling -Flow equilibrium in production systems, choking and boosting -Flow performance of surface and downhole production networks	Design	YES	Modeling. Programming. Problem solving	Excel VBA, Gap, Prosper (or Pipesim)
Flow assurance -Modeling of gas and condensate transport in pipeline and hydrate formation -Simplified modeling of oil and water emulsions	Appreciation, Design	YES	Modeling. Programming. Analysis. Problem solving.	Hysys, Excel VBA
ESP fundamentals, design and plan for the field life	Design	YES	Modeling. Problem solving.	Excel VBA
Early subsea boosting design	Design	YES	Modeling. Problem solving.	Excel VBA
Data management and allocation	Appreciation/ design	YES	Data analysis, filtering, QC, averaging, aggregating.	Excel VBA
Production optimization.	Design	YES	Analysis, modeling, critical thinking. Problem solving.	Excel VBA
Integrated asset modeling	Appreciation	NO	-	-
Additional skills gained by home and class exercises			Group work. Develop written and oral engineering communication skills.	

Material balance	TPG4145	~ Prof whitson
Reservoir simulation fundamentals, flow tables	TPG4160	→ Prof. Kleppe
Well inflow	TPG4245	→ Prof. Asheim
Fluid phase behavior	TPG4145	→ Prof whitson
Black oil model	TPG4145	→ Prof whitson
Single and multi phase fluid flow in pipes	TPG4135	→ Prof larsen → Prof. Nydal
(computation of pressure and temperature losses)	TPG4245	→ Asheim
Processing fundamentals, separation,	TPG4135	} Prof. larsen
Compression fundamentals	TPG4135	
Pumping fundamentals	TPG4135	

Introduction to subsea boosting	TPG4200	} Prof Sangesland / Gjersvik
Introduction to subsea systems	TPG4200	
Risk analysis, decision making, uncertainty	TPG4151	→ Prof Bratvold
Life cycle of an oil and gas field. Fundamentals	TPG4105	→ Prof Stovas

where is TPG4230 located? → E and P → exploration and production
→ upstream



Field development and operations

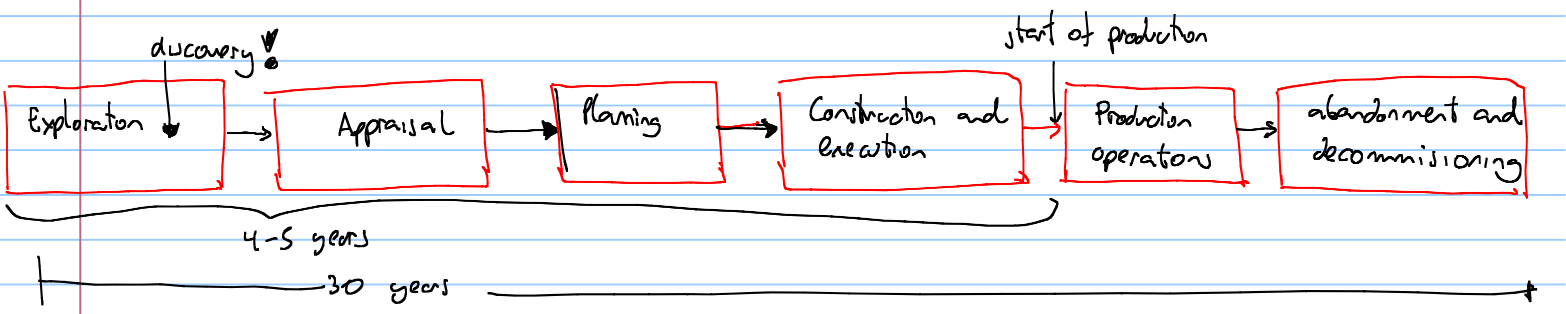
①

- high uncertainty
- empty start point { high flexibility / a lot of decisions to take.
- offshore production
- evaluation of several options
- find best suitable solution

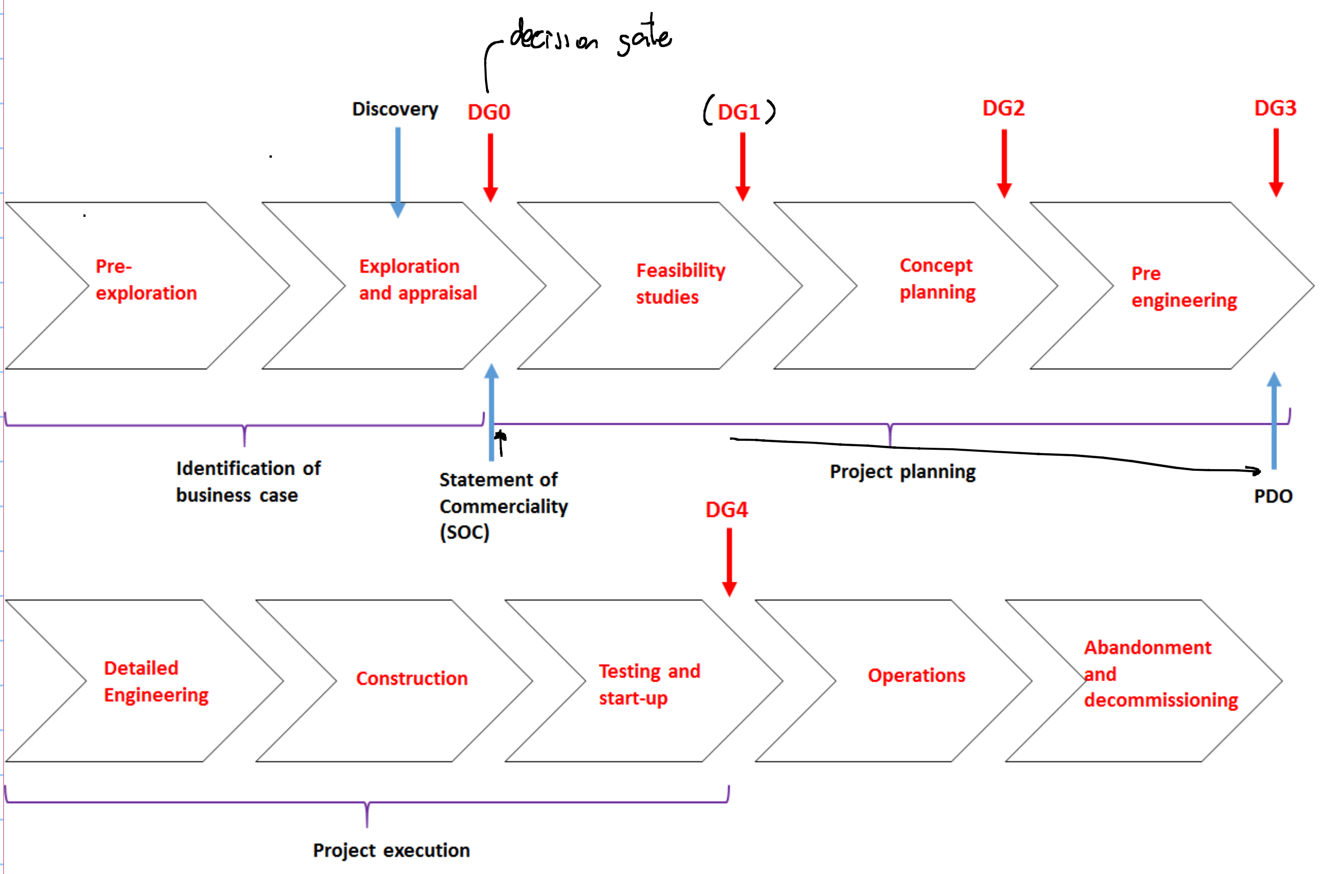
{ increase value to shareholders in a sustainable and environmentally friendly maner

- existing system
- cope with its deficiencies
take advantage of its characteristics
- optimize production { trouble shooting / maintenance / modifications.

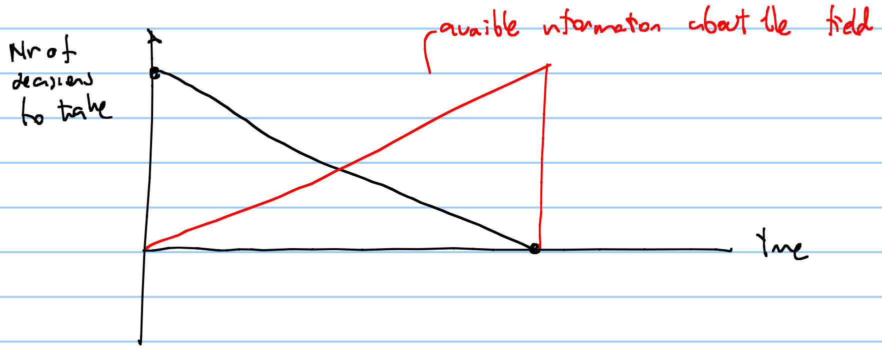
life cycle of a hydrocarbon field:



Field development process

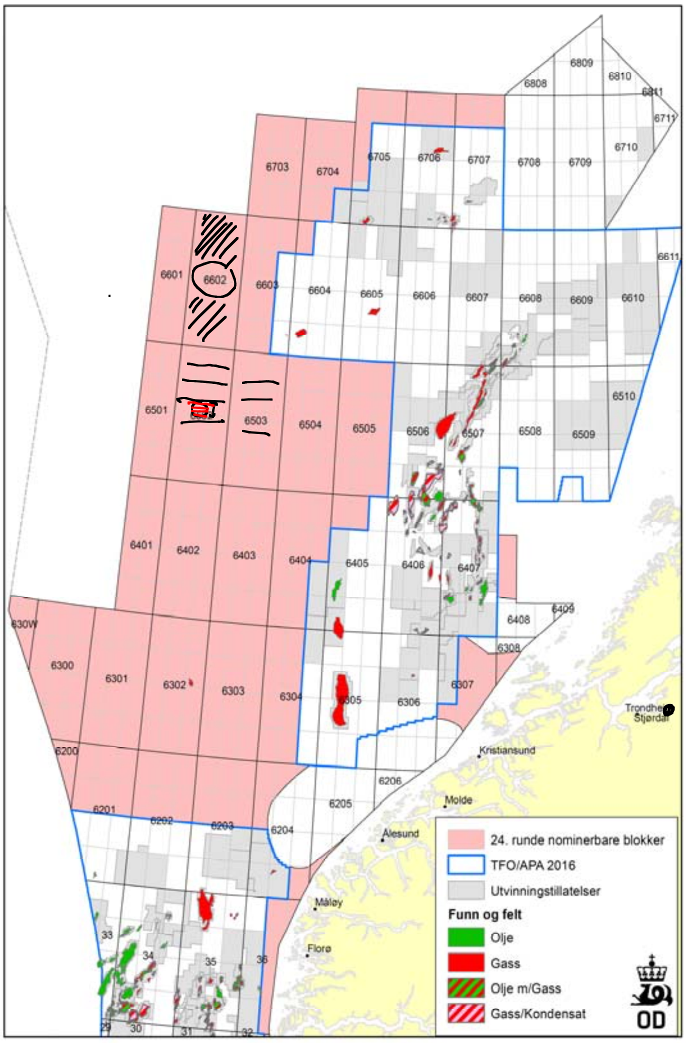


Project management process (strategy) (stage-gate process)



Business Case identification:

- pre exploration
  - scouting: collecting information about areas of interest.
    - politics
      - government
      - personel security
    - techical
      - geology
    - geographical
    - social
    - environmentals issues
    - taxation
    - previous experience
  - get pre-exploration access { seismic and drilling shallow wells
    - not done by oil company ~> scouting companies
  - identify prospects
  - get a production license → exclusive!



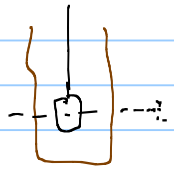
- licensing rounds. APA { Awards in predefined areas

Year 1: 34000 NOK/Km^2

Year 2: 68000 NOK/Km^2

Year 3: 137 000 NOK/Km^2

- exploration:
  - perform geological studies
  - geophysical surveys, seismic
  - exploration drilling
    - core sampling
    - wall sampling
    - cuttings
    - fluid samples
    - wireline logging
    - productivity test



- DISCOVERY!

- Assessment of the discovery
  - Probabilistic reserve estimation
  - Perform a simplified ecconomic valuaton of resources
  - Appraisal
    - drill more exploration wells
      - extent of reservoir
      - fault communication
      - aquifer type and behavior
      - WOC (water oil contact)
      - GOC (gas oil contact)
    - seismic

DGO
- issue a SOC Statement of commerciality
- perform more appraisal.
- sit and wait
- sell the discovery
- Relinquish to government.

if the field is declared SOC

- project planning phase main purpose :
  - is to identify and screen several options to develop the fied
    - feasibility
    - economical evaluation
  - select an define a development concept
  - document the final solution for delivery to the authorities.

- feasibility studies :
  - identify development options (Top level)
  - objectives of the development in line with corporate strategy
  - project timeline
  - identify possible stoppers / show blockers
  - Rough cost valuation of field

Concept planning

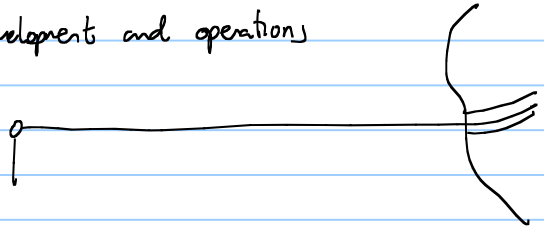
- compare alternatives for development, screen out less attractive /nonviable options
- PEP project for execution plan { describes project /management }
- defining the commercial aspects, legislation, taxation, agreements with partners / market
- ! Create static and dinamic reservoir model → production scheduling, production strategy
- HSE
- flow assurance issues (management strategy)
  - wax
  - hydrates
  - corrosion
  - scale
  - slugging
  - emulsion
  - erosion

- Planning drilling campaign (Location completion)
- Pre-design of facilities

Pre-engineering

- mature and expand the final development option

- Select the final technical solution
- Define technical requirements for each package FEED Front end engineering design
- establish the base for awarding contracts
- plan and prepare execution phase
- perform an environmental assessment)
- prepare PDO plan for development and operations
  PUD
  DP



Videos, lecture notes and class files can be found at :

http://folk.ntnu.no/stanko/Courses/TPG4230/2018/

Additional information here: http://www.ipt.ntnu.no/~stanko

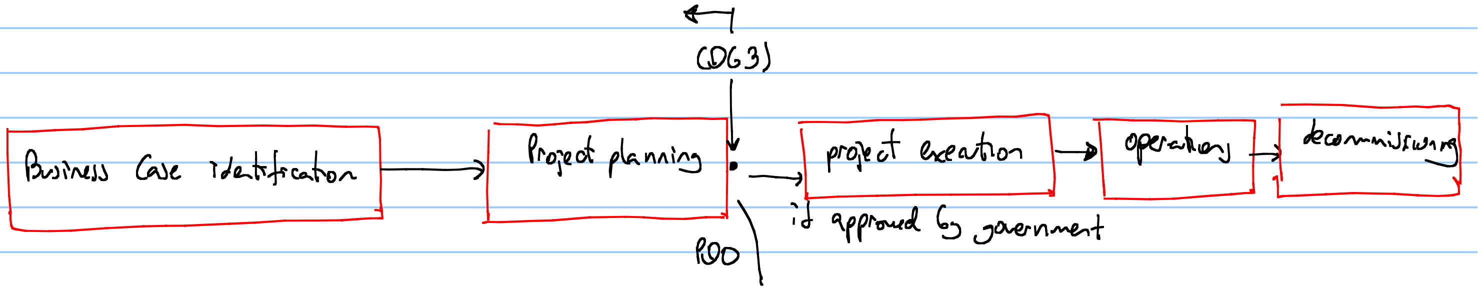
Class activity (and also problem 1 of Exercise set 1). Read quickly through the PDO of the Hebron field : http://folk.ntnu.no/stanko/Courses/TPG4230/2018/Class_files/20180109/PDO_Hebron_project.pdf

- List most activities that were performed prior to the PDO. Group them in categories:

Subsurface (reservoir)	Environmental impact	Offshore facilities	wells, drilling and completion	Subsea system (if any)
project management	timeline	operations personnel and supply logistics	Processing facilities	other...

- Compare them with the activities listed in the PDO description document from the NPD (Norwegian petroleum directorate : http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/Guidelines/PDO-PIO-guidelines_2010.

- Create a Gantt chart of the project (according to your interpretation, do not copy the one on the PDO). Create the Gantt in excel, showing the main activities, their start and end and the main milestones in the project. Example: http://www.excel-easy.com/examples/gantt-chart.html



NPD evaluates the PDO of field and gives comments, corrections.

- Impact assessment report. { environmental impact
  human/social

PIO { plan for installations and operations
transportation and utilization strategy.

Project execution: detailed design, procurement, construction, installation and commissioning. of all equipments and facilities of the field.

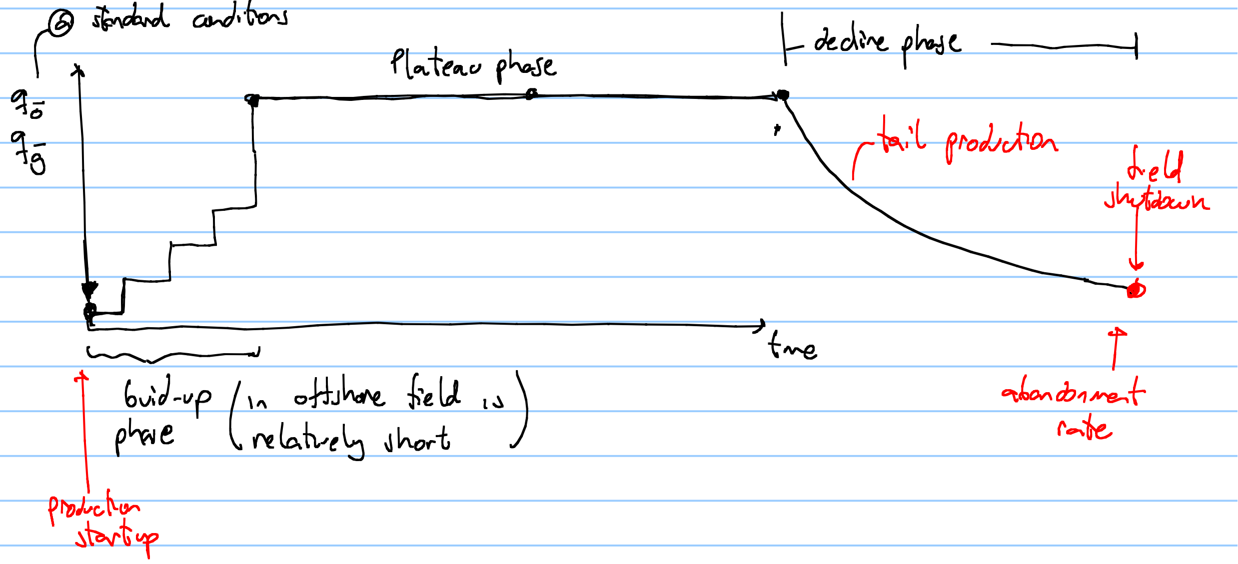
↳ individual contracts:
- Detailed engineering
- Bids, contracts
- construction, fabrication
- installation

- EPCM contract

Engineering, procurement, construction and management contract.

- Well drilling (well construction)
- System testing
- prepare hand-over to operations { courses
user manuals

Operations



- produce as planned as efficient as possible { low production costs }
- maintenance
- troubleshooting
- optimization
- implementation of EOR and IOR methods ⤳ { increase recovery factor / maintain production / increase production }
  enhanced oil recovery ↳ improved oil recovery

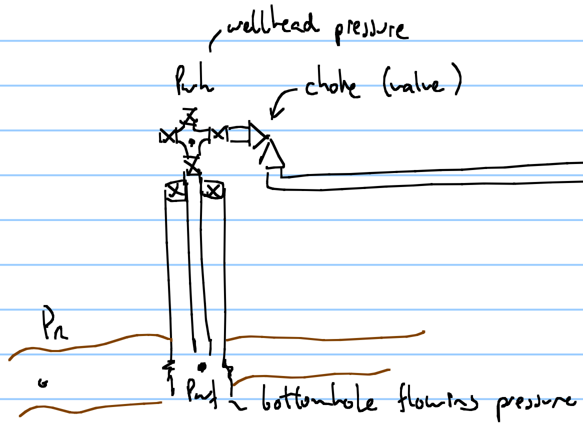
20180123. Class 3:

DECOMMISSIONING AND ABANDONMENT

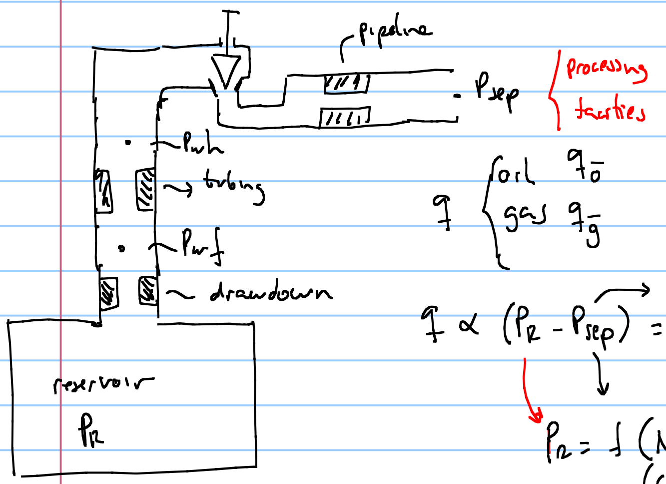
- Engineering “down and clean”: flushing and cleaning tanks, processing equipment, piping.
- Coordinate with relevant environmental and governmental authorities.
- Well plugging and abandonment (P&A) → drilling rigs
- Cut and remove well conductor and casing.
- Remove topside equipment. →
- Removal of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

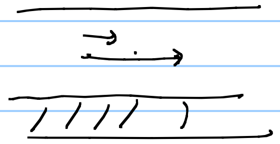
Decommissioning:
Overview of activities
https://www.youtube.com/watch?v=8Xm9VNZuI9M
Transport of platform and scrap yard
https://www.youtube.com/watch?v=1GA3EIu81rw

Field performance:



simple analog of field:





$$q \begin{cases} \text{oil} & q_o \\ \text{gas} & q_g \end{cases}$$

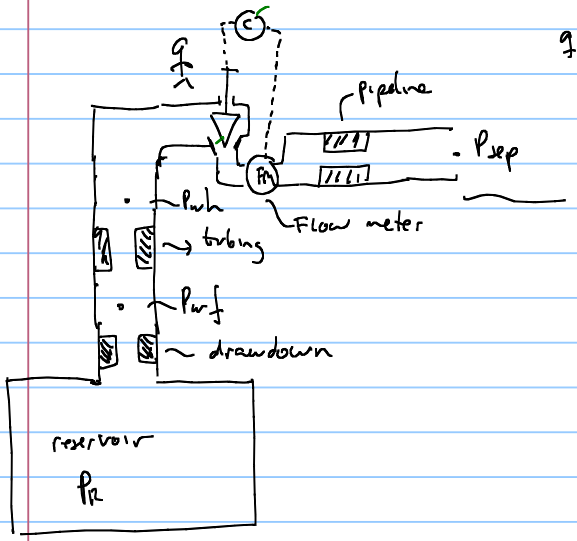
$$q \propto (P_R - P_{sep}) = \Delta p_{draw} + \Delta p_{tubing} + \Delta p_{pipeline} + \underbrace{\Delta p_{choke}}$$

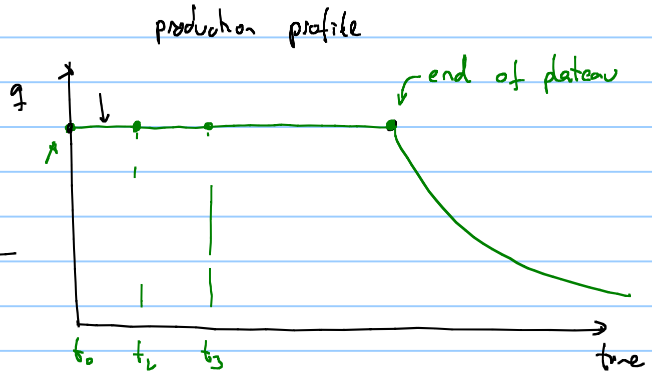
$$P_R = f\begin{pmatrix} N_p \\ G_p \end{pmatrix} \qquad N_p = \int_0^{t^*} q_o(t)\,dt$$

$$G_p = \int_0^{t^*} q_g(t)\,dt$$

operating modes of field

A - constant rate (plateau mode)



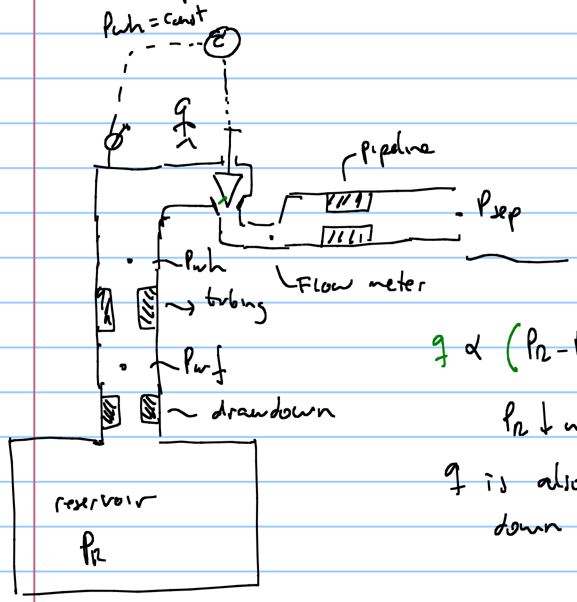


when is this production mode employed?

- in standalone developments with independent processing facilities and offshore structure
New fields with no neighboring fields with spare capacity

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

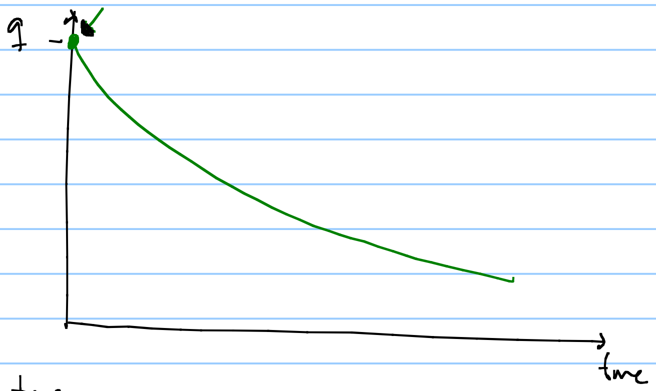
B - Constant pressure - rate decline mode



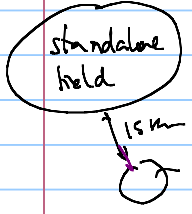
$q \propto (P_R - P_{wh})$

$P_R \downarrow$ with time

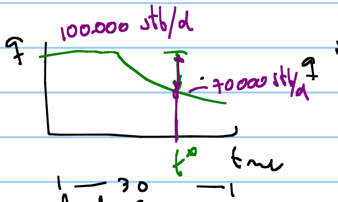
q is also going down with time



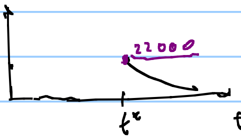
- produce as much as possible as fast as possible
- used for satellite field producing to an existing facility with spare capacity



satellite field produced as a tie-back to the standalone field



field 1
standalone



field 2
satellite

t* production startup date of satellite field http://folk.ntnu.no/stanko/Files/20170402_NCS_Production_Data.xlsx

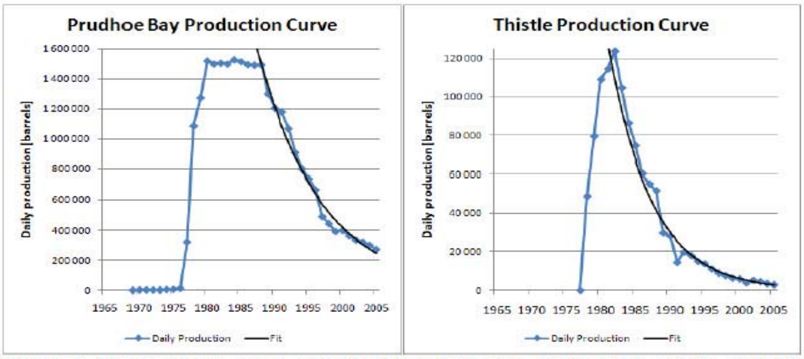
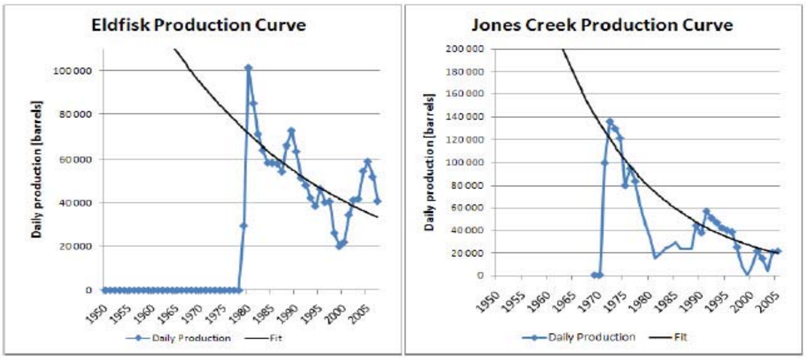
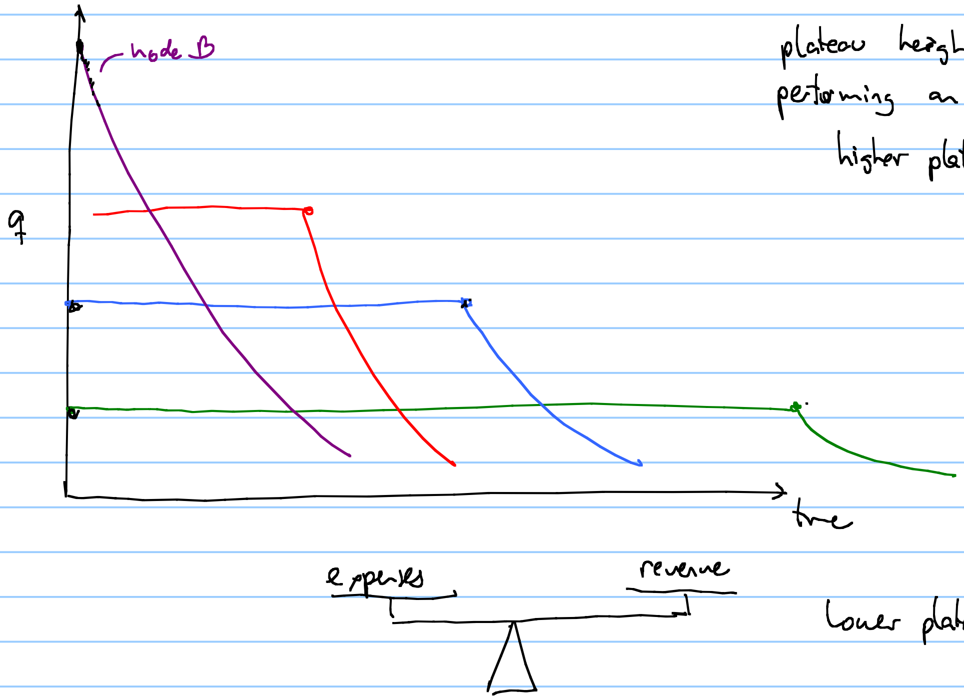


Figure 4: *The production curves of the land-based US giant Prudhoe Bay and the giant UK Thistle offshore field. The approximately exponential average decline rate is clearly seen in these two well-behaved fields.*



https://grandemotte.wordpress.com/oil-and-gas-5-production-decline-rates/

there is a close relationship between plateau height and length



plateau height is determined by performing an NPV analysis.

higher plateau → higher CAPEX { offshore structure, processing facility, pipelines
→ higher DRILLEX
→ quicker and higher revenue

lower plateau → lower capex
→ lower drillex
→ lower revenue
delayed "

the plateau height is usually found by performing sensitivity analysis to maximize NPV.

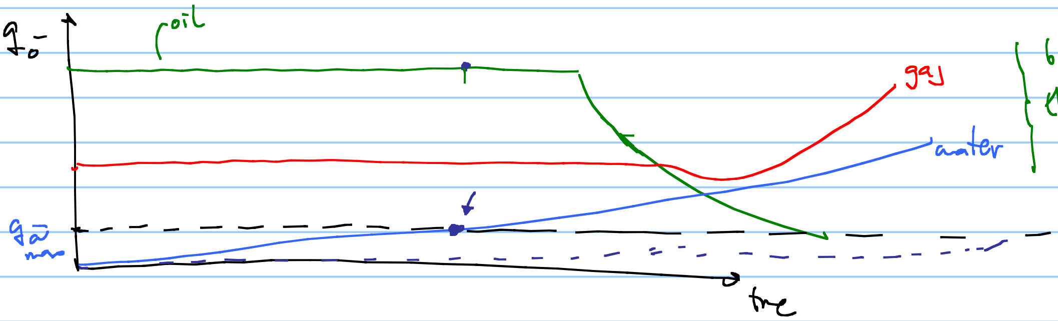
plateau height is usually something i can decide upon

plateu duration is defined by physics } ← proper forecast of production profile !

production scheduling ~ define the rates of field / well during the lifetime of field

reservoir management ~ define how much each well will produce {
reservoir characteristics (productivity of each well)
gas / water coning
sand production
target recovery factor
...

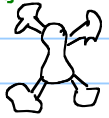
In the development process the associated products { $\bar{g}$ and $\bar{w}$ for oil field; $\bar{o}$ and $\bar{w}$ for gas field } must also be taken into account !

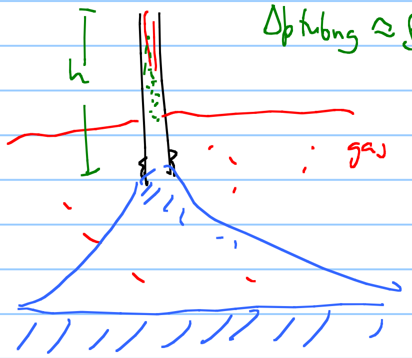


} big uncertainty in these profiles

when designing the processing facilities they are made for a maximum $q_{\bar{g}}$ and $q_{\bar{w}}$

for gas fields oil production is an extra source of revenue ! it can change completely the economy of field for good

water is  for gas field



$\Delta p_{tubing} \simeq \rho_{mixture}\, g\, h$

ρ_{gas} { 80 kg/m³ ↓ 300 kg/m³

1000 kg/m³

plateau length for gas fields ~ 10 – 30 years

plateau length for oil field ~ 2 → 5 years

20180129 Class 4:

when operating in plateau mode as a first approximation annual offtake of

$$q_p = \frac{0.1 \; N_{pu}}{\text{producing Nr. day in a year}}$$

: 10% of TRR for oil field

TOTAL recoverable reserves

N_{pu} ultimate cumulative oil production

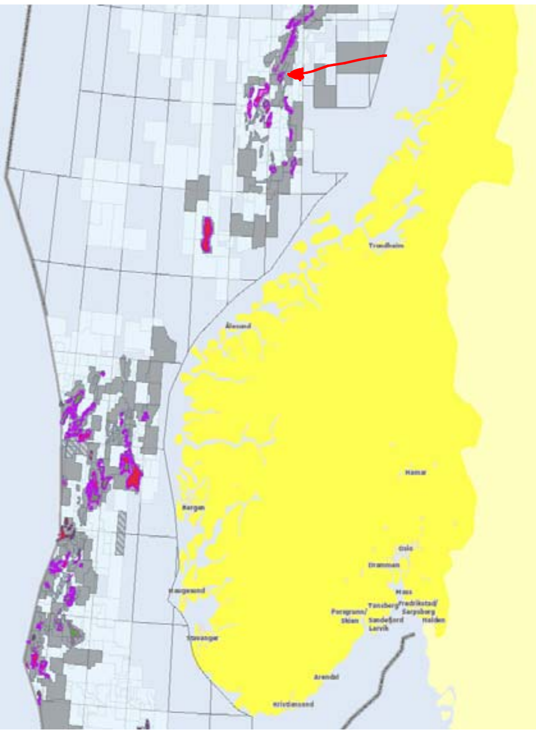
$$\text{uptime} = \frac{\text{Producing Nr. days per year}}{\text{Nr. days per year}} \cdot 100\%$$

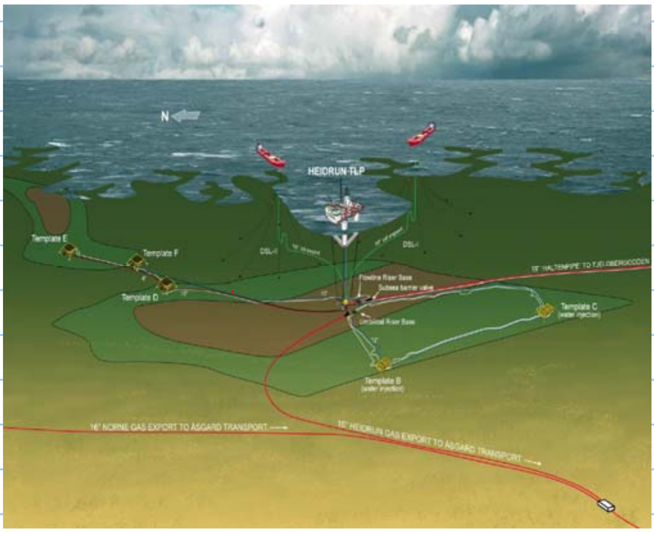
G_{pu}

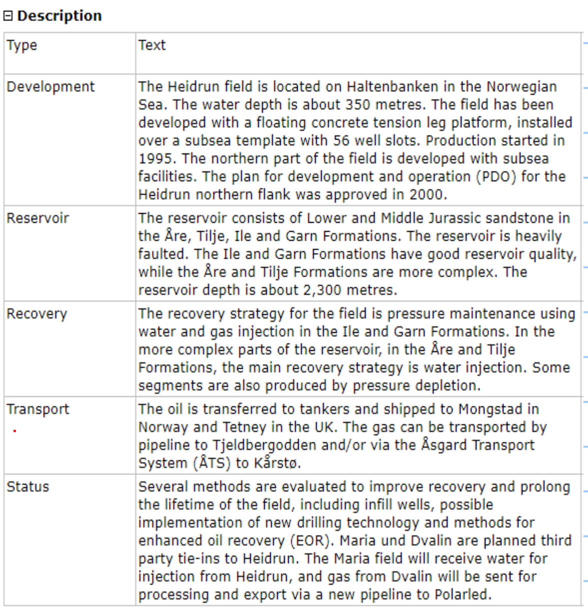
$$q_p = \frac{(0.02-0.05) \; G_{pu}}{\text{Producing Nr. days per year}}$$

; 2-5% of TRR

- Production limited by capacity of processing facilities - Heidrun

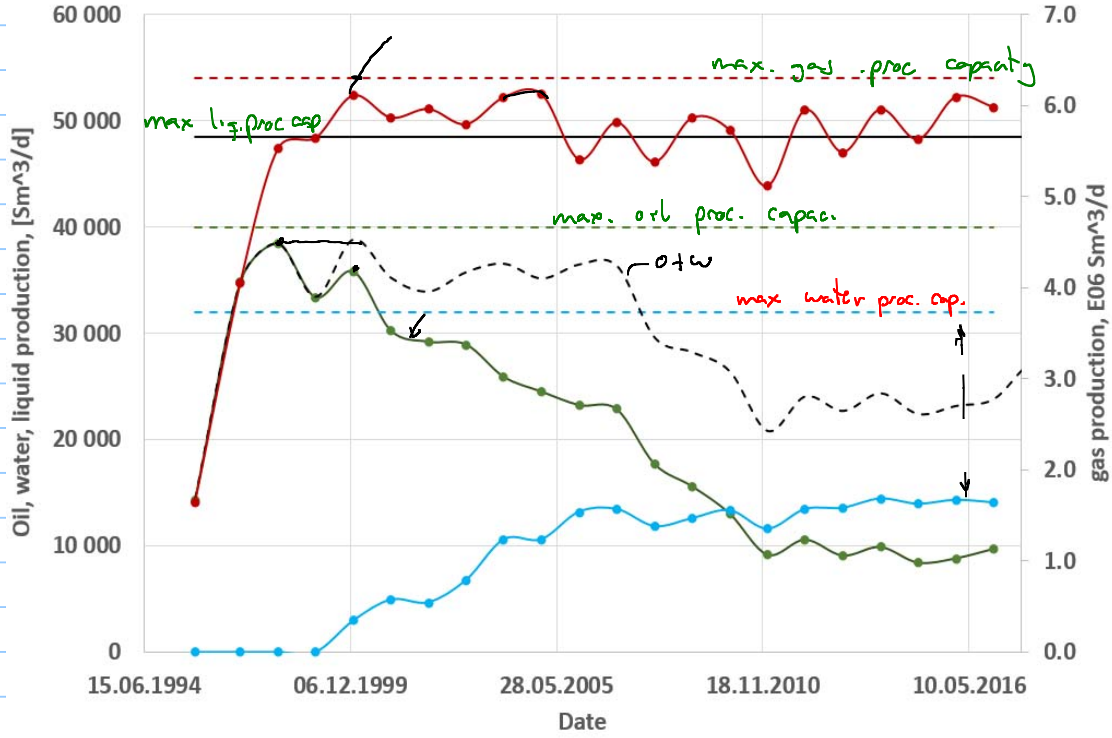


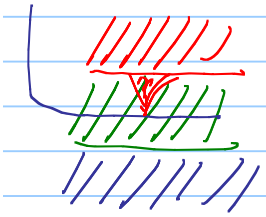


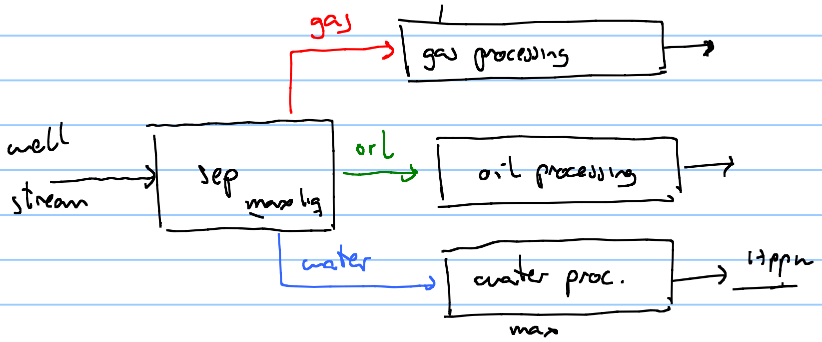


⊟ **Description**

Type	Text
Development	The Heidrun field is located on Haltenbanken in the Norwegian Sea. The water depth is about 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. Production started in 1995. The northern part of the field is developed with subsea facilities. The plan for development and operation (PDO) for the Heidrun northern flank was approved in 2000.
Reservoir	The reservoir consists of Lower and Middle Jurassic sandstone in the Åre, Tilje, Ile and Garn Formations. The reservoir is heavily faulted. The Ile and Garn Formations have good reservoir quality, while the Åre and Tilje Formations are more complex. The reservoir depth is about 2,300 metres.
Recovery	The recovery strategy for the field is pressure maintenance using water and gas injection in the Ile and Garn Formations. In the more complex parts of the reservoir, in the Åre and Tilje Formations, the main recovery strategy is water injection. Some segments are also produced by pressure depletion.
Transport	The oil is transferred to tankers and shipped to Mongstad in Norway and Tetney in the UK. The gas can be transported by pipeline to Tjeldbergodden and/or via the Åsgard Transport System (ÅTS) to Kårstø.
Status	Several methods are evaluated to improve recovery and prolong the lifetime of the field, including infill wells, possible implementation of new drilling technology and methods for enhanced oil recovery (EOR). Maria und Dvalin are planned third party tie-ins to Heidrun. The Maria field will receive water for injection from Heidrun, and gas from Dvalin will be sent for processing and export via a new pipeline to Polarled.

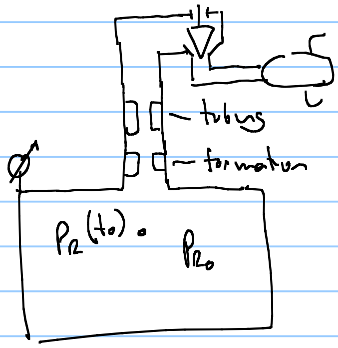


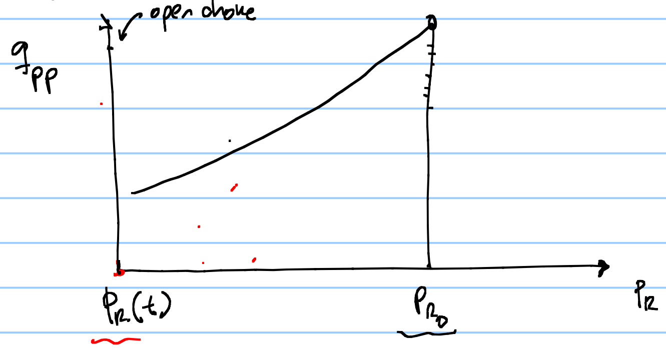




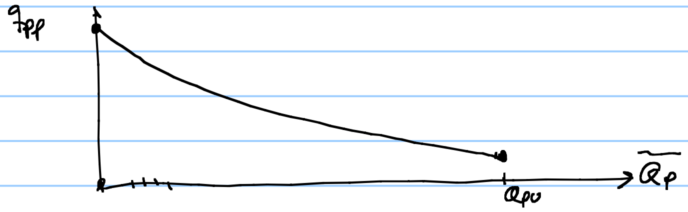
- Production potential

max production that can be obtained from my production system



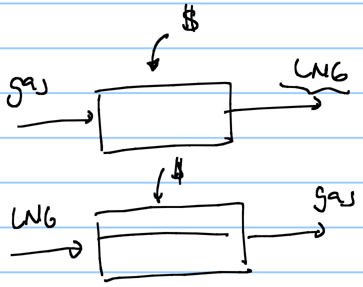


$$p_R = f\,(Q_p) \qquad Q_p = \int_0^t q\,(t)\,dt \;\begin{cases} N_p \\ G_p \end{cases}$$



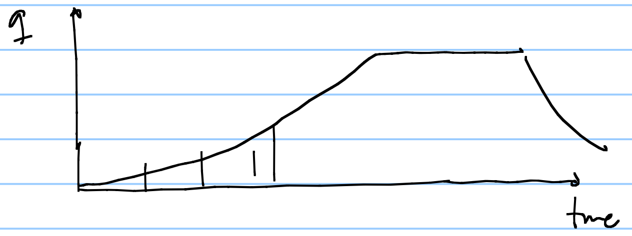
- Difference between oil / gas development.
  - transportability
    - oil tanker
    - gas relies on transportation by pipeline
      - an infrastructure
      - a customer
  - in gas one has to have a sales contract agreement. { 5 - 30 years }
    - DCQ
      - daily contract quantity
      - swing factor { 20% - 40% }
      - penalty clause

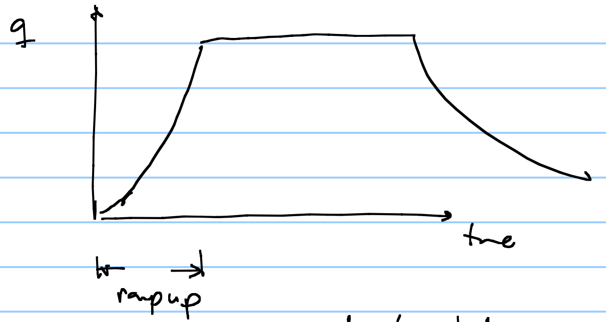
LNG liquified natural gas tries to make gas more like oil



one still needs an LNG plant and a LNG terminal

Onshore vs offshore





- long ramp-up / long and detailed appraisal
- produce with few wells to neighbouring facilities
- gather better information about the reservoir and make a better planning
- plan water / gas injection at a later stage
- fine tune reservoir models and use them for planning

- short ramp-up and limited appraisal → get revenue back as quick as possible

during exploration and appraisal the information gathered about the reservoir is limited and static

- ↳ extension
- ↳ depth
- ↳ k
- ↳ φ

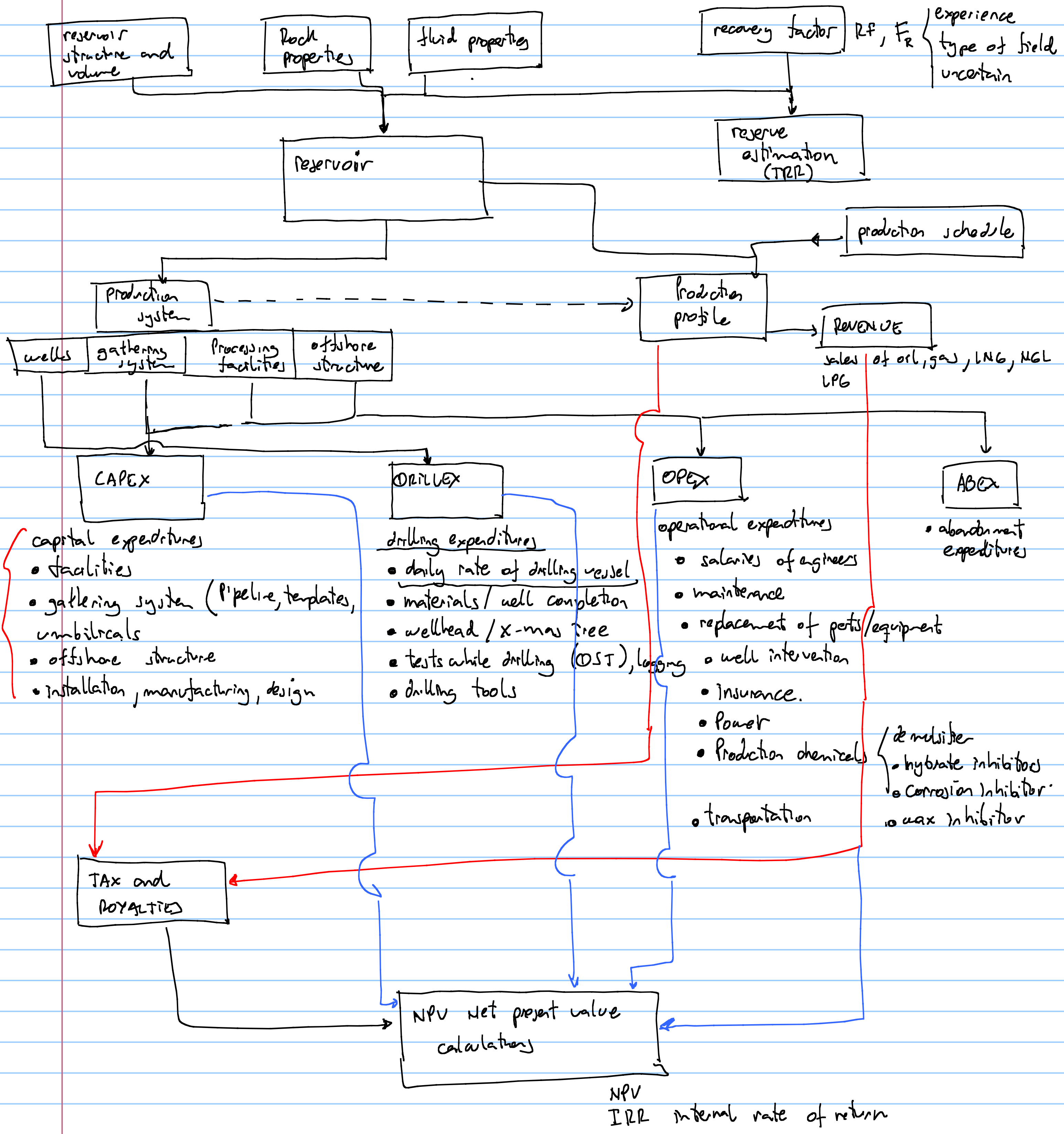
- hydraulic connectivity
- productivity of well
- type of aquifer
- sealing mechanism

- take big decisions with limited information
- plan water injection / gas injection from begining

- Very uncertain reservoir models {

- Remote onshore field { • desert, • jungle } behaves like offshore field

- Value chain model of asset / field



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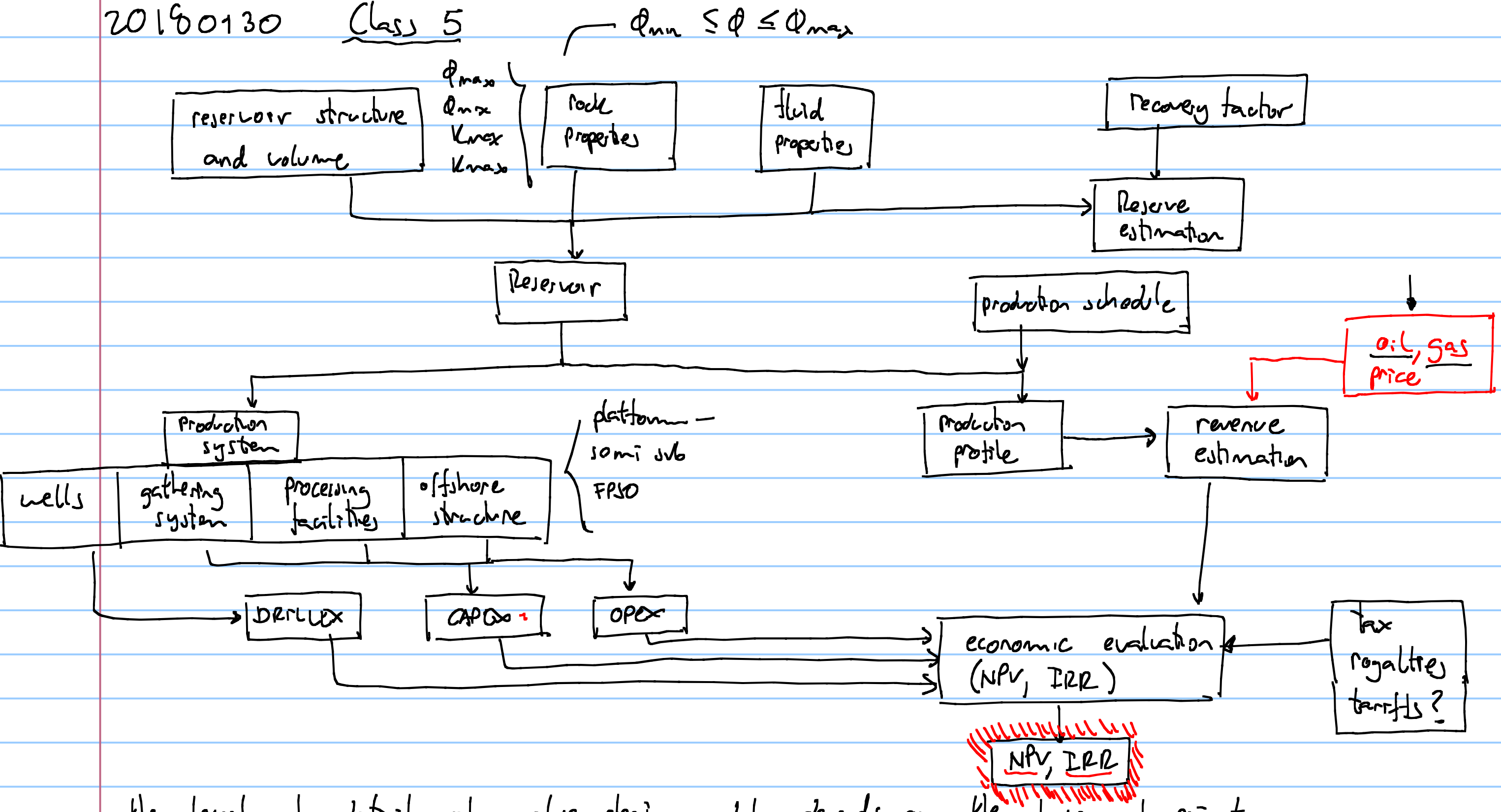
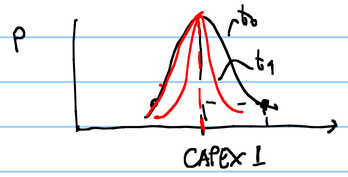


- the level of detail of value chain model depends on the phase of project

- CAPEX usually look like this



at initial stage CAPEX I 60%
40%

at later stage CAPEX ±20%

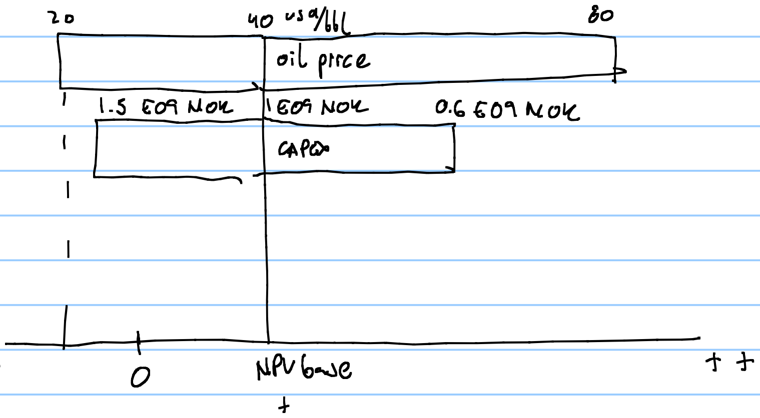
Field concept evaluation process

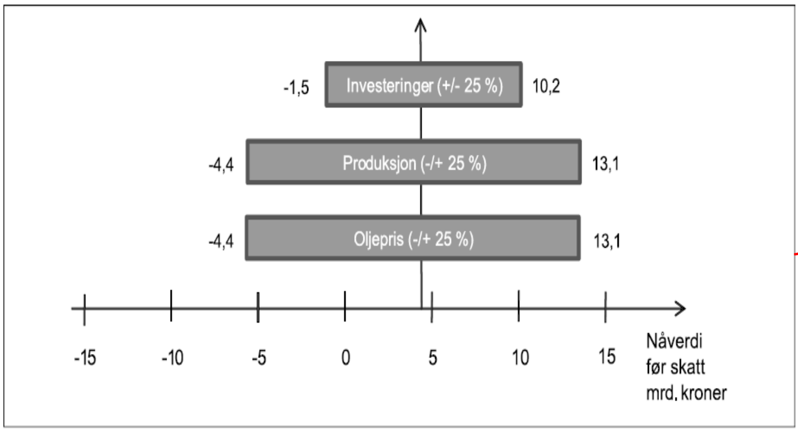
- Identify development scenarios and alternatives for each box
- Perform a pre-design of each scenario
- study and compute the economic value of each scenario
- Compare each scenario and choose the best option ① sensitivity analysis → "ceteris paribus"
all other the same

CAPEX min ≤ CAPEX I < CAPEX max
oil price min ≤ oil price I ≤ oil price max
$\phi_{max} \leq \phi \leq \phi_{max}$

	NPV_{min}	NPV_{base}	NPV_{max}
oil price ±20%			
CAPEX ±20%			
IRR ±20%	☐	☐	☐

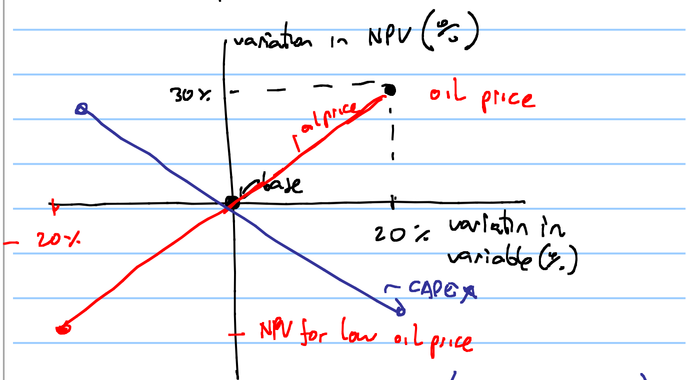
tornado chart





Figur 4.1 Sensitivitetsanalyse for prosjektet.

spider plot



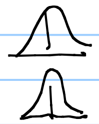
$$\text{variation } [\%] = \left(\frac{\text{value} - \text{value}_{\text{base case}}}{\text{value}_{\text{base case}}} \right) 100$$

② to study the effect of non-continuous variables { different options

TRR1 — 30% –
TRR2 → 50% –
TRR3 → 20% –
CAPEX 1 → 20%
CAPEX -2 → 60%
CAPEX 3 ~ 70%

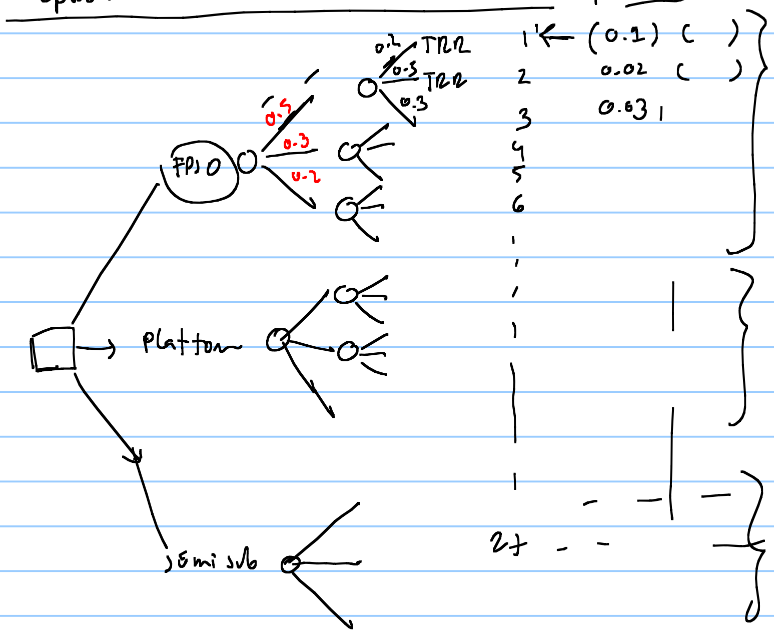
Decision trees TRR

CAPEX



development concept { FPSO –
platform –
semi-sb –

development option CAPEX



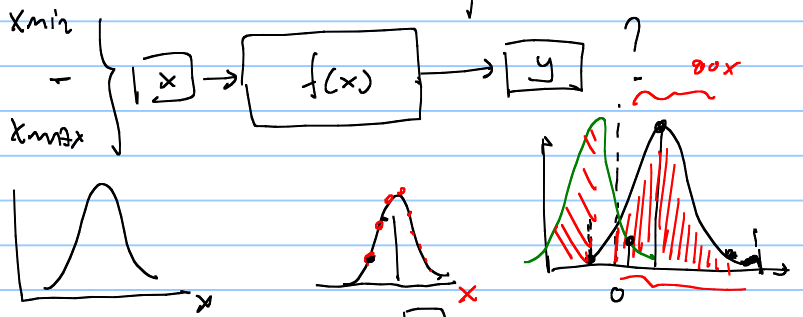
$\Sigma P_i \, NPV_i =$ compound NPV_{FPSO}

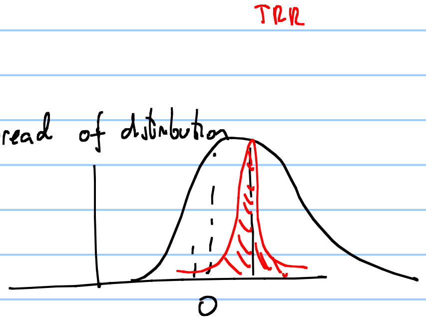
(3^{10})

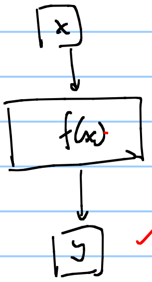
$\Sigma P_i \, NPV_i =$ compound NPV_{plat}

$\Sigma P_i \, NPV_i =$ compound $NPV_{semisub}$

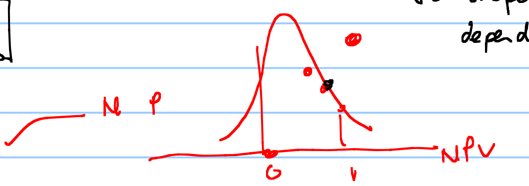
③ probabilistic analysis { monte Carlo method Stanislaw Ulam Los alamos lab



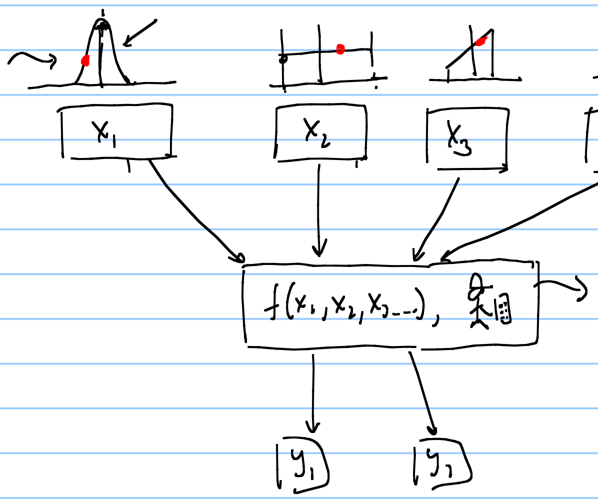




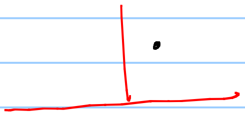
if x>100
y=1
if x≤100
y=0



the shape of the output distribution depends on: • input distribution(s)
• type of function

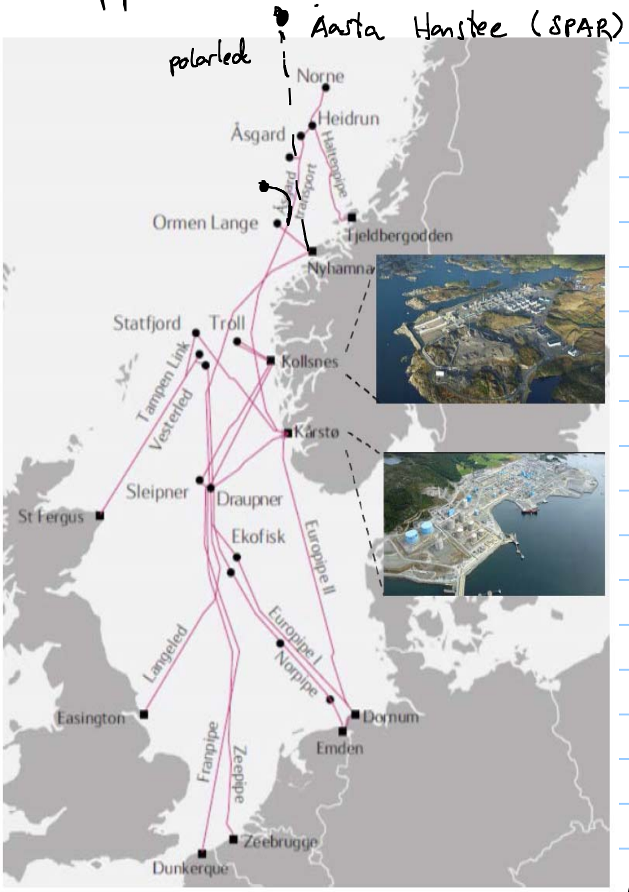


to perform monte carlo this process (function) has to run: automatically — fast

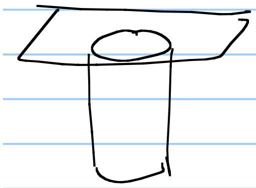


- opex has two parts: - fixed with production rate {
  - variable with production rate

In gas transportation (and sometimes when transporting oil) one has to include a pipeline tariff



the gas transportation system from Norway to EU/UK is managed GASSCO



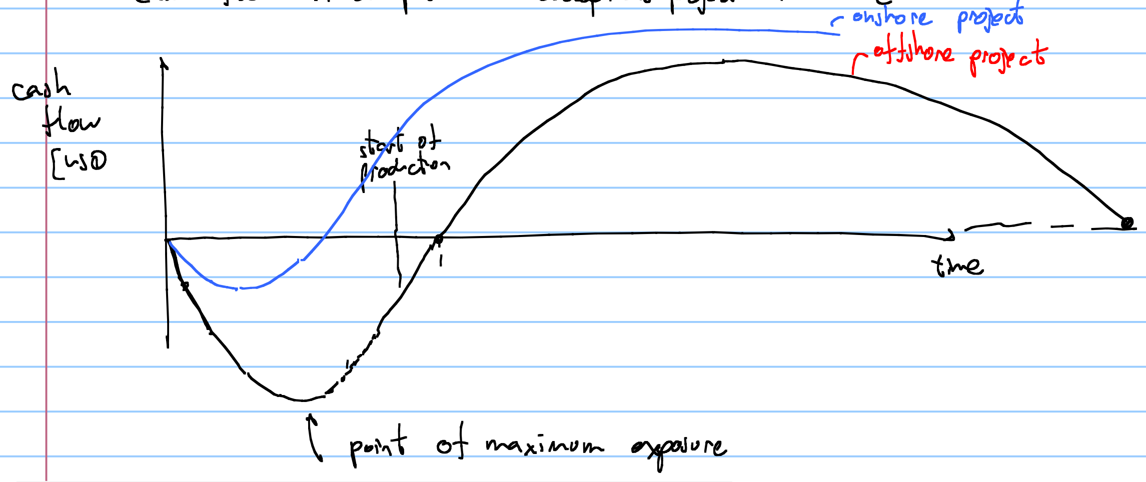
- to estimate cost / calculate NPV

{ • internal utilities developed by companies (based on previous projects)

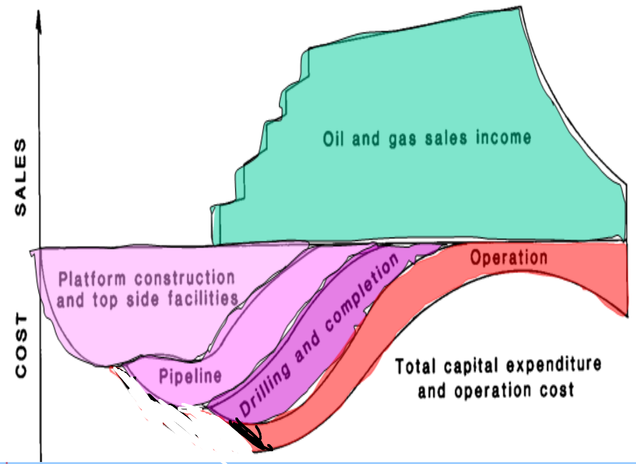
• commercial tools { • QUESTOR
• ACES (Acona)
• Siemens (oil and gas manager)

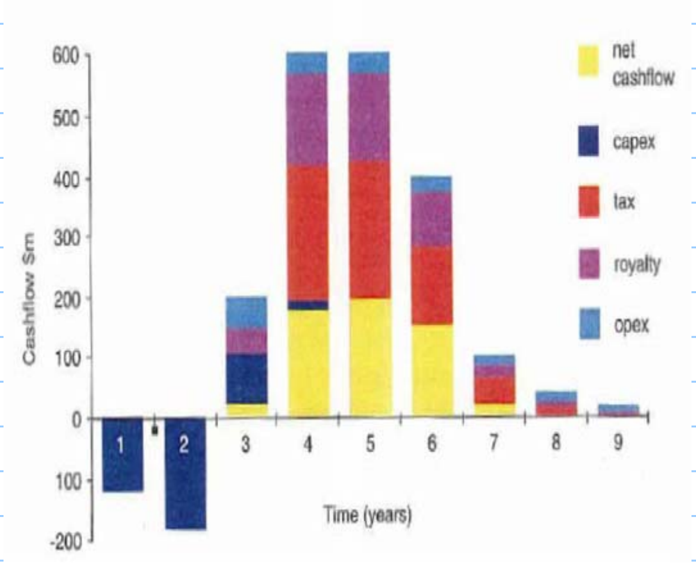
Petroleum economics Trygve Strøm (TPG5190) for more detailed information about NPV calculations

Cash flow in a petroleum development project with time



Revenue and Cost Profiles





Petroleum fiscal systems

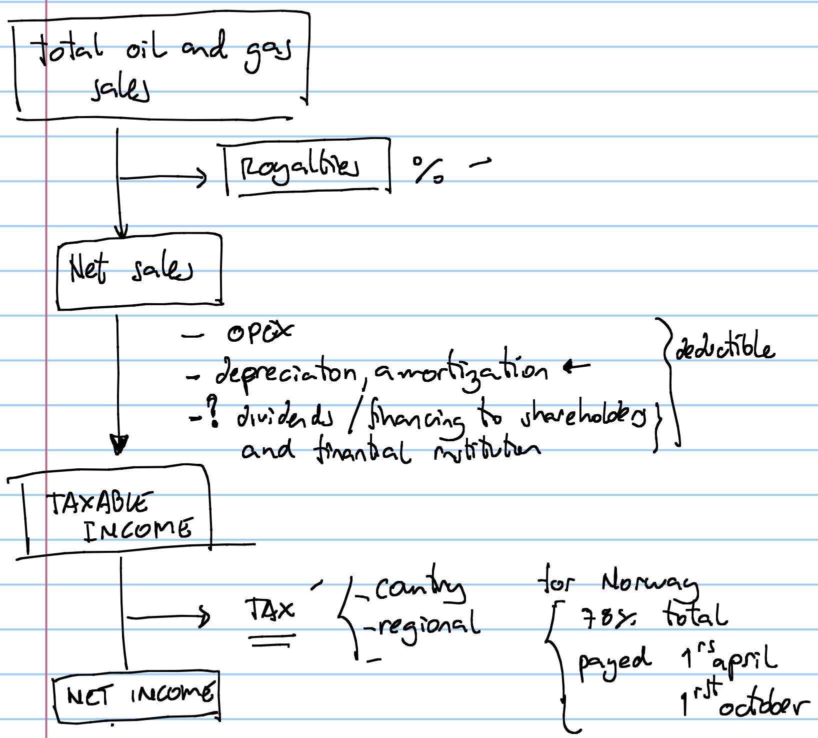
In almost any country the owner of the mineral resources is government except in onshore USA

royalty based system

contractual system

- the company get the mineral rights for a period of time 30 years
- full decision power on development of asset
- UK, France, Norway, Russia, Australia New Zealand, Colombia, Argentina

- A Royalty must be payed to government



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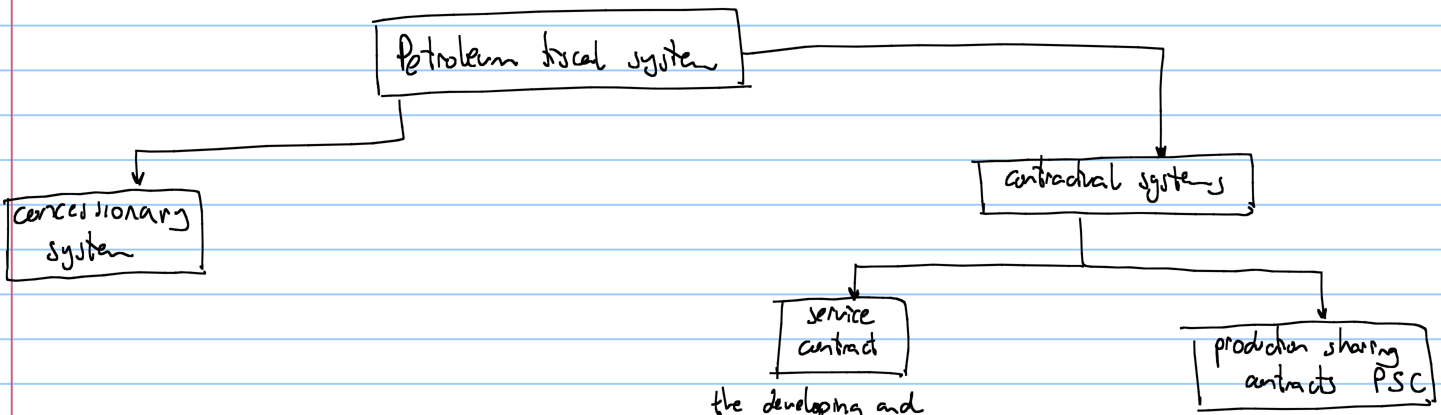
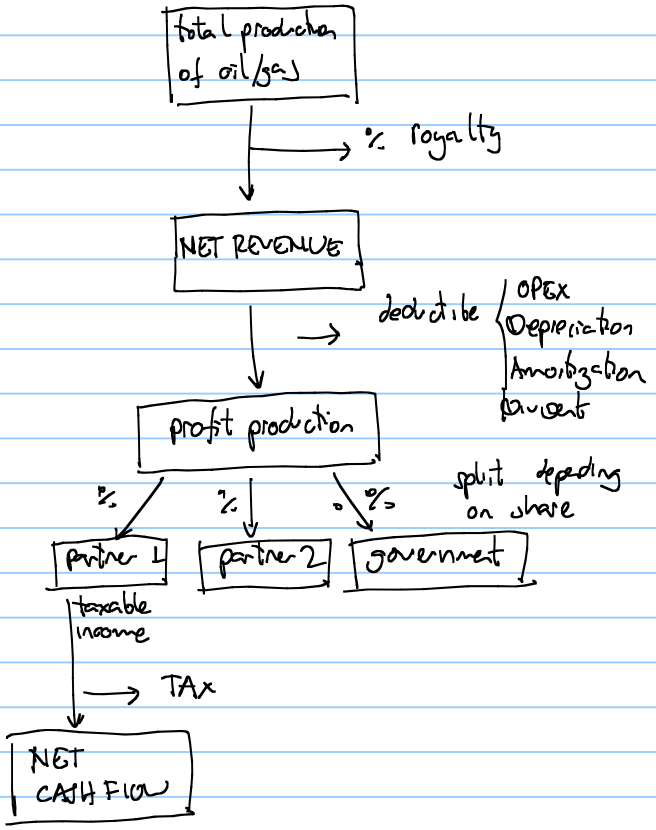


the developing and operating company is paid in cash

the company gets paid in production

- the government gets its share in oil/gas production
- the government is an equal partner in development/operation of field

Countries: Malaysia, India, Nigeria, Angola, Trinidad Algeria, Yemen, Egypt, China



Net Present Value (NPV) { there must be a minimum of information to be able to compute NPV

project start: year 0

end of project year	CAPEX [usd]	DRILLEX [usd]	OPEX [usd]	ROYALTIES TAXES [usd]	q_o q_g	USD/bbl	Revenues (usd)	CASH FLOW [usd]	discounted CASH FLOW
1			0		0			CF_1 = REVENUE$_1$ − EXPENSES$_1$	$\frac{CF_1}{(1+i)^j}$
2			0		0			CF_2	
3			0		0			CF_3 10	
.			0		0				
⋮			0		0				
			(OPEX$_1$		q_o				
⋮			OPEX$_2$		q_o				
⋮					q_o				

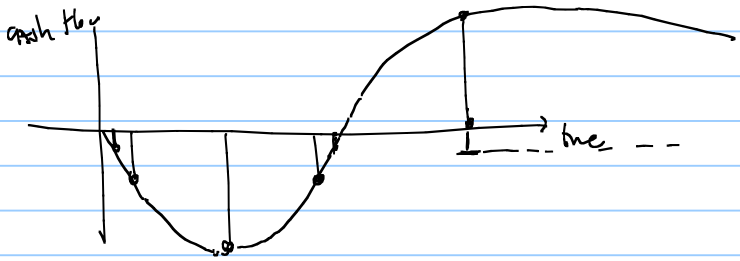
j: year measured from project startup

i: discount rate (inflation)

Σ( )

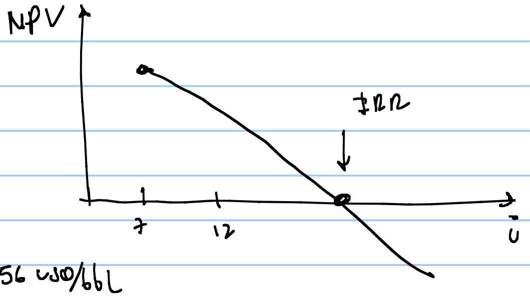
$$NPV = \sum_{j=1}^{N} \frac{CF_j}{(1+i)^j}$$

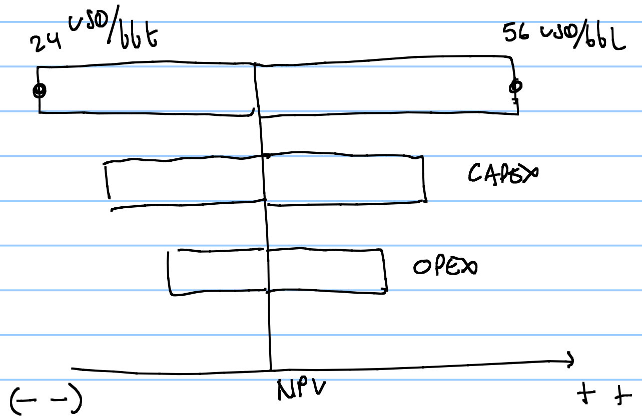
N: total number of years



i depends on company { 6 − 10% }

IRR internal rate of return is "i" that gives NPV = 0





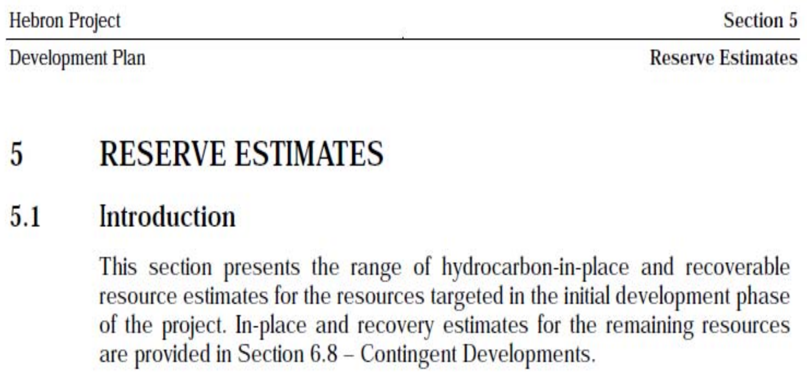
take points from an existing plot:

https://automeris.io/WebPlotDigitizer/

Quantifying uncertainty using Monte-Carlo method

Probabilistic estimation of hydrocarbon volumes / total recoverable reserves

suggestion: read Hebron PDO



Hebron Project Section 5

Development Plan Reserve Estimates

5 RESERVE ESTIMATES

5.1 Introduction

This section presents the range of hydrocarbon-in-place and recoverable resource estimates for the resources targeted in the initial development phase of the project. In-place and recovery estimates for the remaining resources are provided in Section 6.8 – Contingent Developments.

Oil in place: N, $\underbrace{OOIP}_{\text{original oil in place}}$, $\underbrace{IOIP}_{\text{initial oil in place}}$

G, $OGIP$, $IGIP$

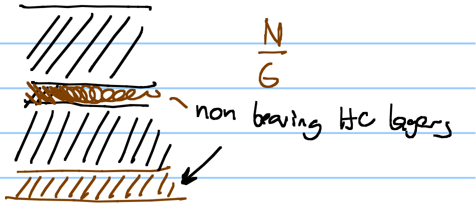
$$\frac{N_{pu}}{N} = F_{Ru} \quad \text{ultimate recovery factor}$$

$$F_{Ru} = \frac{G_{pu}}{G}$$

$$N_{pu} = TRR = \frac{\overbrace{V_R \cdot \phi}^{\text{pore volume}} \cdot \overbrace{S_o}^{(1-S_w)} \cdot \overbrace{N/G}^{\text{net to gross}}}{B_o} \cdot F_{Ru} \quad [Sm^3] \; [stb]$$

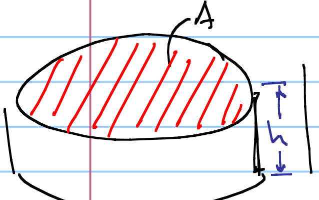
pore volume

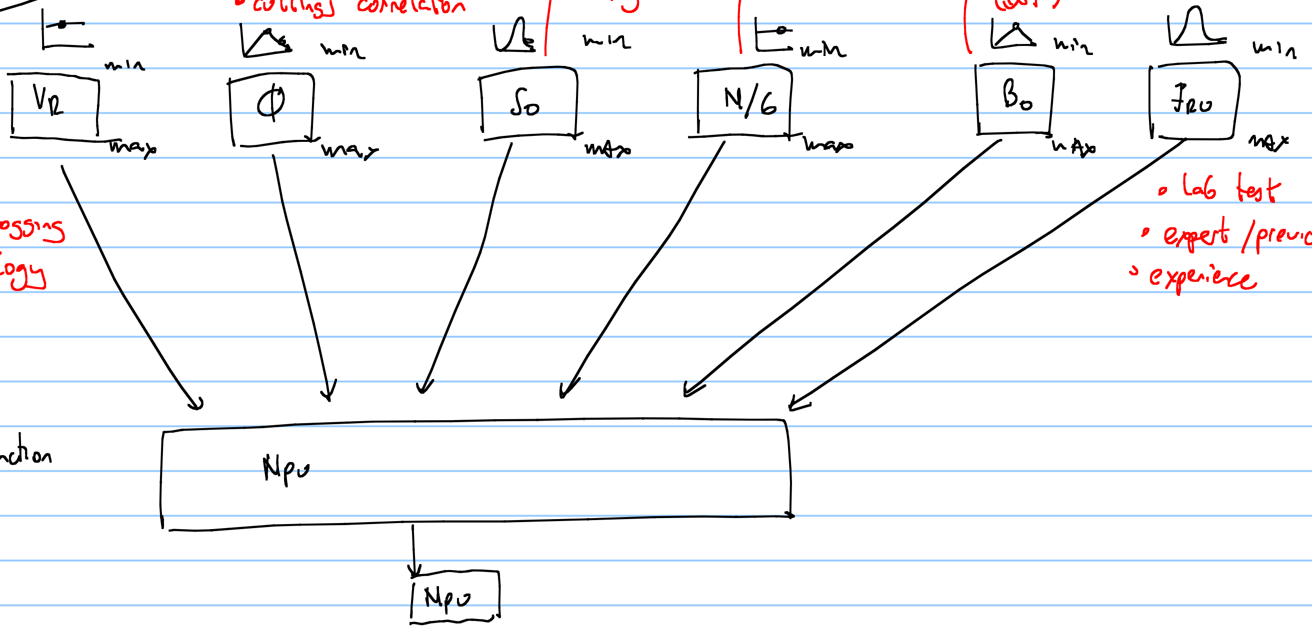
$\frac{\text{Pore volume}}{\text{Total volume}}$



$$B_o = \text{oil formation volume factor} = \frac{\text{volume in Reservoir}}{\text{volume @ s.c.}} \quad P_{sc} = 1.0325 \text{bar}$$

$$T_{sc} = 15.56 °C$$





- exploration drilling logging, coring
- cuttings correlation

- logging coring

logging

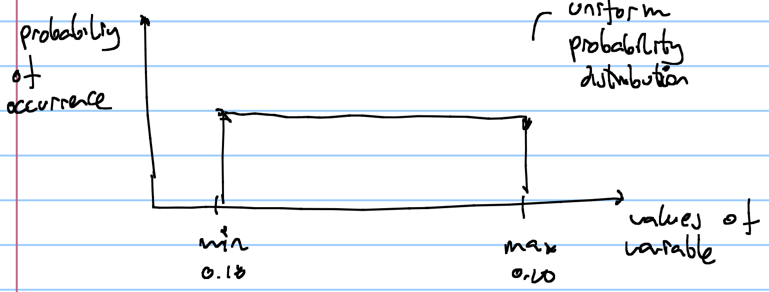
fluid sampling (DST)

- exploration drilling and logging
- regional geology

± 40%

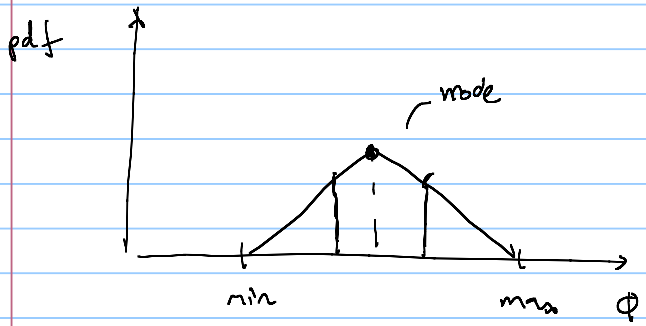
- lab test
- expert / previous
- experience

Usually we use a probability distribution function to describe the input parameters that are uncertain

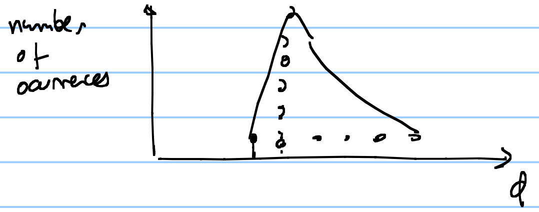


other types

triangle distribution



collecting more field data e.g. more exploration wells



- EXPERT

Monte Carlo - steps

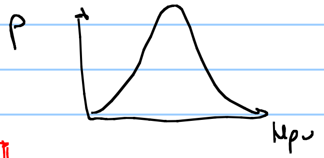
① Take a random sample of each input variable

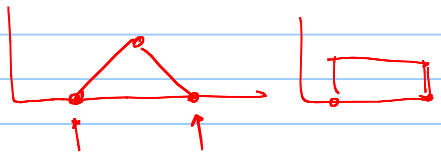
② Compute the Npo (using the equation)

③ if Nr. iterations ≤ Nmax → else → ④ make frequency diagram (pdf) with the results saved

↓ then

Save the result and repeat from ①





input output

it	φ	Vr	So	Bo	N/G	FRO	Npo
	[-]	[bbl]	[-]	[bbl/stb]	[-]	[-]	[stb]
1	○	○	○	○	○	○	compute → Npo
2	○	○	○	○	○	○	→ Np
3							
4							
5							
6							

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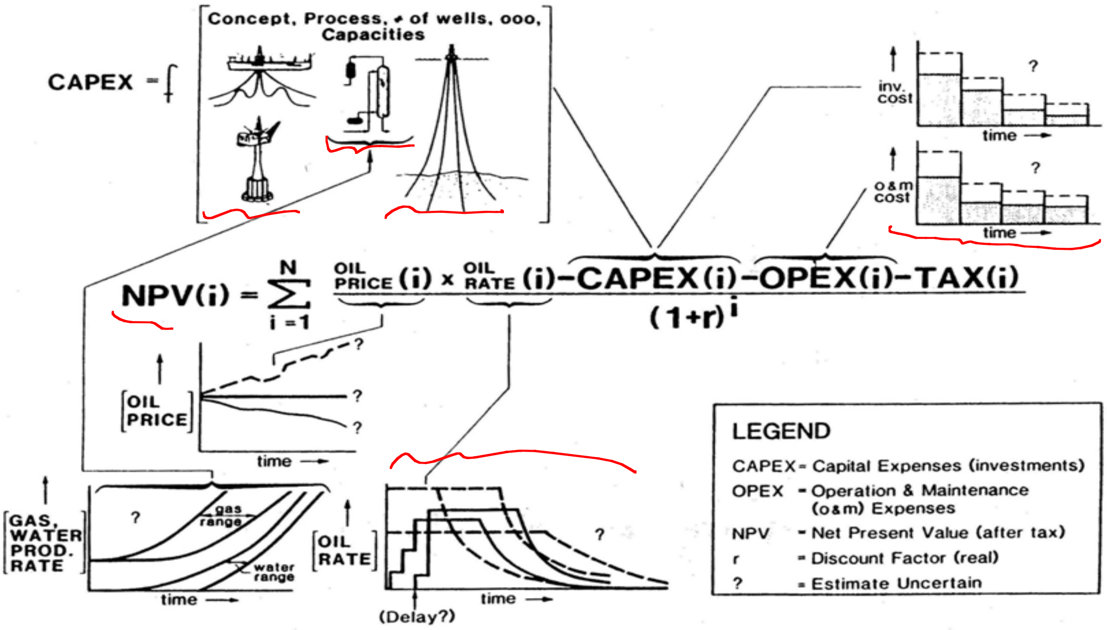
topics today :
- short comment on NPV calculations
- orientation for excel usage during the course
- Class exercise ~> estimation of OOIP(N) using Monte Carlo

What can we control?



supplementary material
article by Halvorsen.

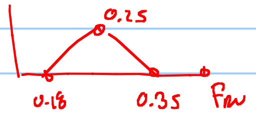
RECOMMENDATIONS WHEN DELIVERING THE EXERCISES

- -Attach all files used to perform your calculations (e.g. Excel files, Hysys files, etc.) to your delivery.

-Follow the "Excel etiquette" as explained in class. The excel sheets should be legible, understandable and usable for others besides yourself. It is encouraged to include text, sketches and comments to clarify the operations performed in the excel sheet. The plots should have a legible and proper size (e.g. 16 pt), axis titles in bold, depicting the variable name, variable symbol and units. Reservoir pressure, P_R, [bara]

-OPTIONAL: For clarity purposes, a summary document containing a small description about the methodology, results (on tables and graphs) and short conclusions may be delivered. When converting the word document to pdf make sure to use (in the pdf printer settings) a resolution high enough so figures and plots are still legible.

- Problem 3 of exercise set I



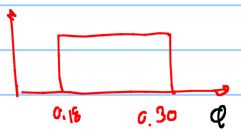
As part of the early development studies and as required by the Norwegian authorities, your first task is to perform a probabilistic estimation of the total recoverable reserves and the original oil in place of the Kobbe reservoir. The subsurface group has provided (in the excel sheet attached) information on the factors needed to calculate hydrocarbon pore volume (rock volume, net to gross, oil saturation, and the reservoir engineering group the formation volume factor (all based on a uniform probability distribution). The ultimate recovery factor is represented by a triangle distribution with a min value of 0.18, a max value of 0.35 and a mode of 0.25

There is disagreement within the company with respect to which porosity values to employ. A senior petrophysicist A says that a uniform porosity distribution should be employed with a min value of 0.18 and a max value of 0.30. Another senior petrophysicist B says that a skewed triangle distribution should be used with a min value of 0.18, a max value of 0.30 and a mode of 0.25.

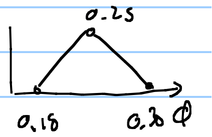
$$N_{pu} = \frac{V_R \cdot \phi \cdot S_o \, N_{TG} \, \overset{?!}{F_{RU}}}{B_o}$$

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

A expert

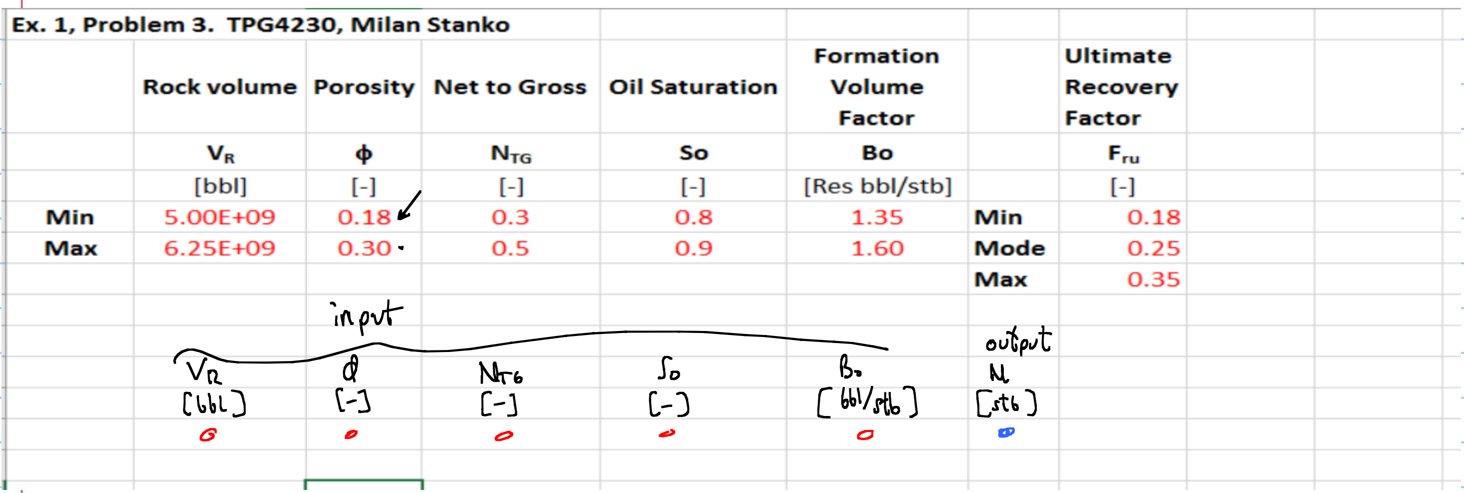


B



- Calculate TRR, N for expert A
  expert B

In class we are going to solve N for expert A.



Ex. 1, Problem 3. TPG4230, Milan Stanko

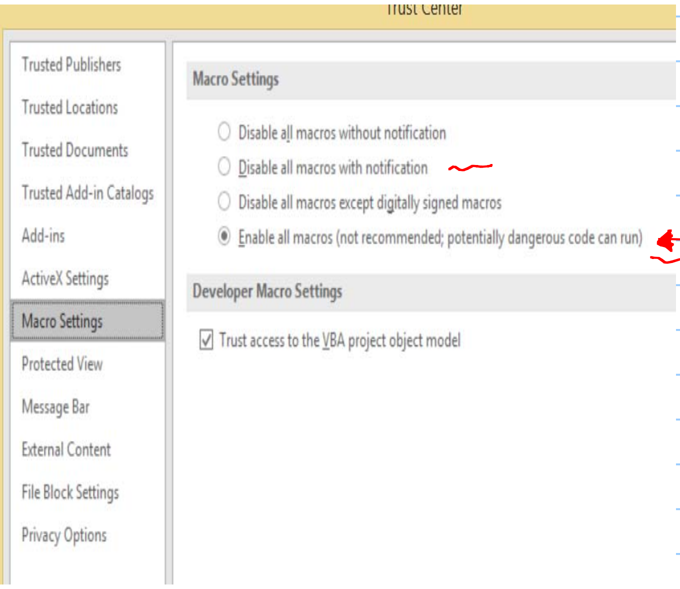
	Rock volume	Porosity	Net to Gross	Oil Saturation	Formation Volume Factor		Ultimate Recovery Factor
	V_R	ϕ	N_{TG}	So	Bo		F_{ru}
	[bbl]	[-]	[-]	[-]	[Res bbl/stb]		[-]
Min	5.00E+09	0.18	0.3	0.8	1.35	**Min**	0.18
Max	6.25E+09	0.30	0.5	0.9	1.60	**Mode**	0.25
						Max	0.35

input

V_R	ϕ	N_{TG}	S_o	B_o	output N
[bbl]	[-]	[-]	[-]	[bbl/stb]	[stb]

- Excel setup { lower macro security VBA visual basic for applications

File → options → trust center → trust center settings : on the left menu: "macro settings"



Trust Center

Macro Settings

○ Disable all macros without notification

○ Disable all macros with notification

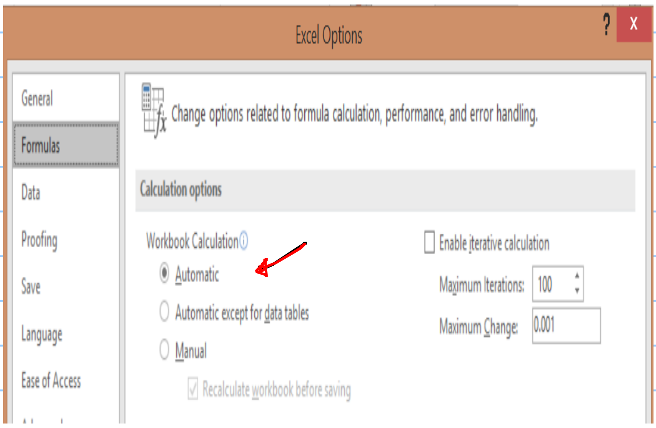
○ Disable all macros except digitally signed macros

● Enable all macros (not recommended; potentially dangerous code can run)

Developer Macro Settings

☑ Trust access to the VBA project object model

- enable automatic calculations in "File" → "options" → on the left menu → "Formulas"



Excel Options

Change options related to formula calculation, performance, and error handling.

Calculation options

Workbook Calculation

● Automatic

○ Automatic except for data tables

○ Manual

☑ Recalculate workbook before saving

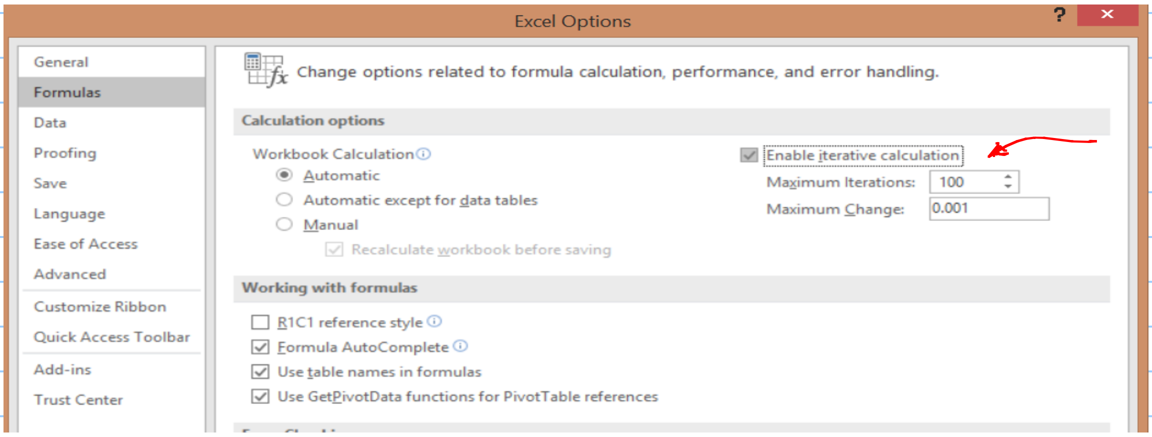
☐ Enable iterative calculation

Maximum Iterations: 100

Maximum Change: 0.001

- to execute all calculations on an excel sheet press "F9"

- enable "iterative calculations" (circular references)



Change options related to formula calculation, performance, and error handling.

Calculation options

Workbook Calculation
● Automatic
○ Automatic except for data tables
○ Manual
☑ Recalculate workbook before saving

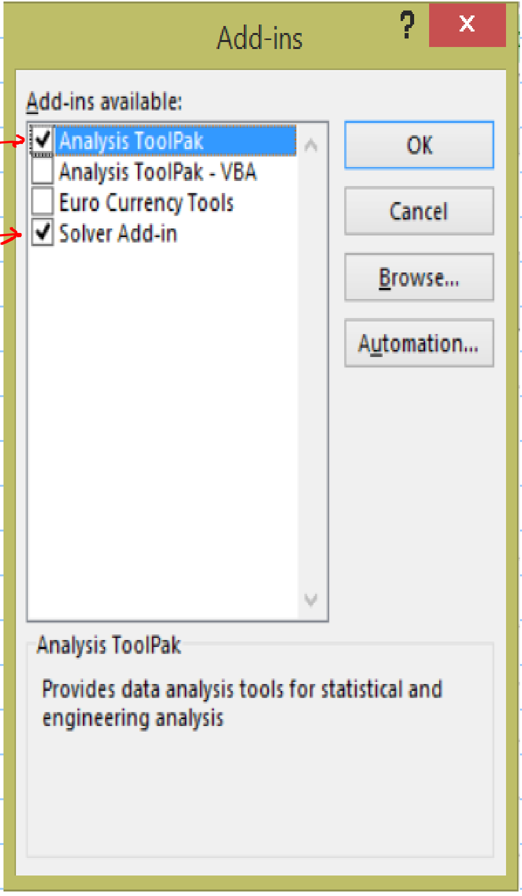
☑ Enable iterative calculation
Maximum Iterations: 100
Maximum Change: 0.001

Working with formulas

☐ R1C1 reference style
☑ Formula AutoComplete
☑ Use table names in formulas
☑ Use GetPivotData functions for PivotTable references

- Enable "solver" { root finding tool } Analysis toolpack

"File" → "options" → "add-ins" → "go"



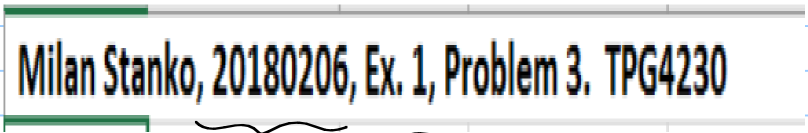
Add-ins available:
☑ Analysis ToolPak
☐ Analysis ToolPak - VBA
☐ Euro Currency Tools
☑ Solver Add-in

Analysis ToolPak

Provides data analysis tools for statistical and engineering analysis

Excel etiquette :

1: Identify your sheet !



Milan Stanko, 20180206, Ex. 1, Problem 3. TPG4230

Name

date
YYYYMMDD

title

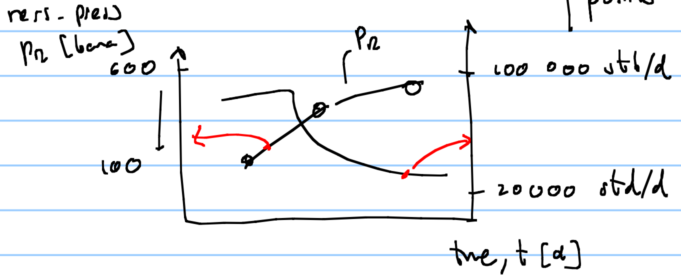
2: Use color code for cells : RED ~ user defined input (things that might potentially change)

blue ~ results / product of a calculations

violet ~ constants

for few input output follow the convention above
for long rows then use black

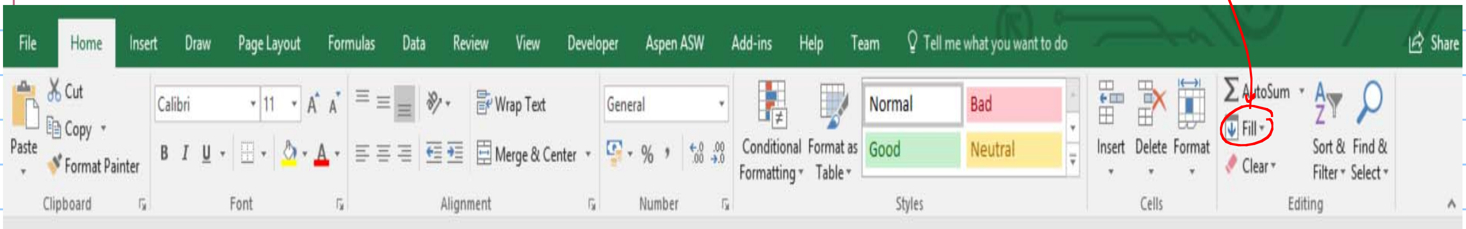
3: Figures/plots
- go in a separate sheet
- axis titles variable name, variable symbol, units
- font size (16-18 pt)
- points should be visible
  - scatter point with line
  - bar plot



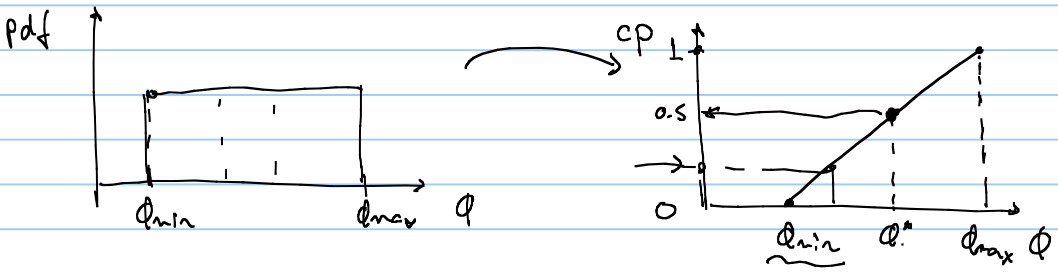
"plot series in secondary axis"

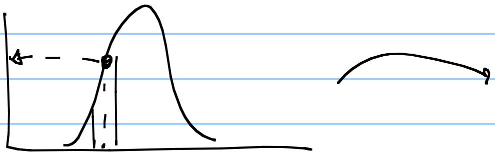
- Fill : fill a column automatically

"series"



the random sampling is usually made using the cumulative distribution, NOT the pdf (probability distribution function)



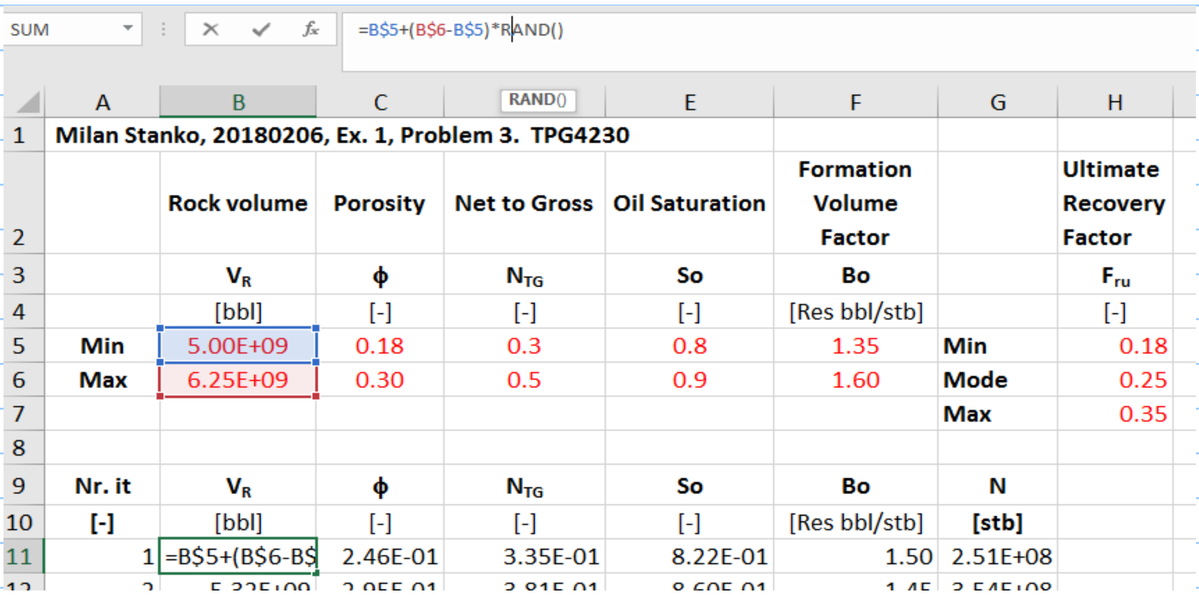


$$\text{rand}\begin{cases}0\\1\end{cases}$$

$$\frac{1-0}{Q_{max}-Q_{min}} = \frac{cp - 0}{Q^* - Q_{min}}$$

X_{max} X_{min}

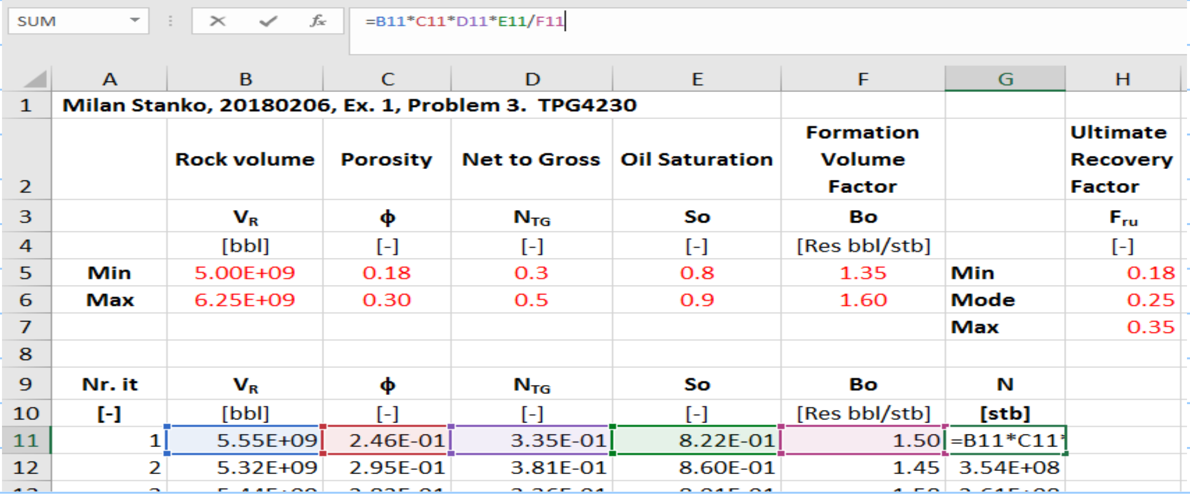
$$X = X_{min} + (X_{max} - X_{min}) \cdot \boxed{cp} \Big\{ \text{rand}(0-1)$$



SUM

`=B$5+(B$6-B$5)*RAND()`

	A	B	C	RAND()	E	F	G	H
1	**Milan Stanko, 20180206, Ex. 1, Problem 3. TPG4230**							
2		**Rock volume**	**Porosity**	**Net to Gross**	**Oil Saturation**	**Formation Volume Factor**		**Ultimate Recovery Factor**
3		V_R	ϕ	N_{TG}	So	Bo		F_{ru}
4		[bbl]	[-]	[-]	[-]	[Res bbl/stb]		[-]
5	**Min**	5.00E+09	0.18	0.3	0.8	1.35	**Min**	0.18
6	**Max**	6.25E+09	0.30	0.5	0.9	1.60	**Mode**	0.25
7							**Max**	0.35
8								
9	**Nr. it**	V_R	ϕ	N_{TG}	So	Bo	N	
10	**[-]**	[bbl]	[-]	[-]	[-]	[Res bbl/stb]	**[stb]**	
11	1	=B$5+(B$6-B$	2.46E-01	3.35E-01	8.22E-01	1.50	2.51E+08	



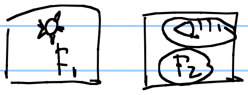
SUM

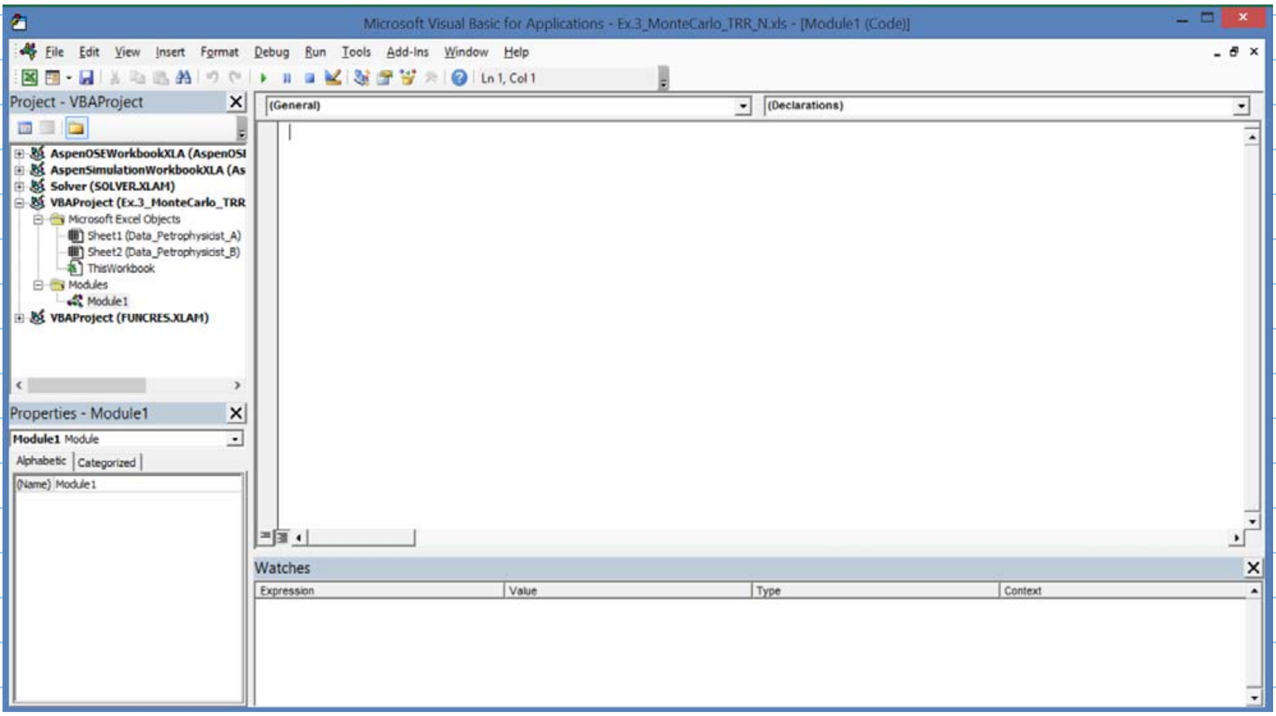
`=B11*C11*D11*E11/F11`

	A	B	C	D	E	F	G	H
1	**Milan Stanko, 20180206, Ex. 1, Problem 3. TPG4230**							
2		**Rock volume**	**Porosity**	**Net to Gross**	**Oil Saturation**	**Formation Volume Factor**		**Ultimate Recovery Factor**
3		V_R	ϕ	N_{TG}	So	Bo		F_{ru}
4		[bbl]	[-]	[-]	[-]	[Res bbl/stb]		[-]
5	**Min**	5.00E+09	0.18	0.3	0.8	1.35	**Min**	0.18
6	**Max**	6.25E+09	0.30	0.5	0.9	1.60	**Mode**	0.25
7							**Max**	0.35
8								
9	**Nr. it**	V_R	ϕ	N_{TG}	So	Bo	N	
10	**[-]**	[bbl]	[-]	[-]	[-]	[Res bbl/stb]	**[stb]**	
11	1	5.55E+09	2.46E-01	3.35E-01	8.22E-01	1.50	=B11*C11	
12	2	5.32E+09	2.95E-01	3.81E-01	8.60E-01	1.45	3.54E+08	

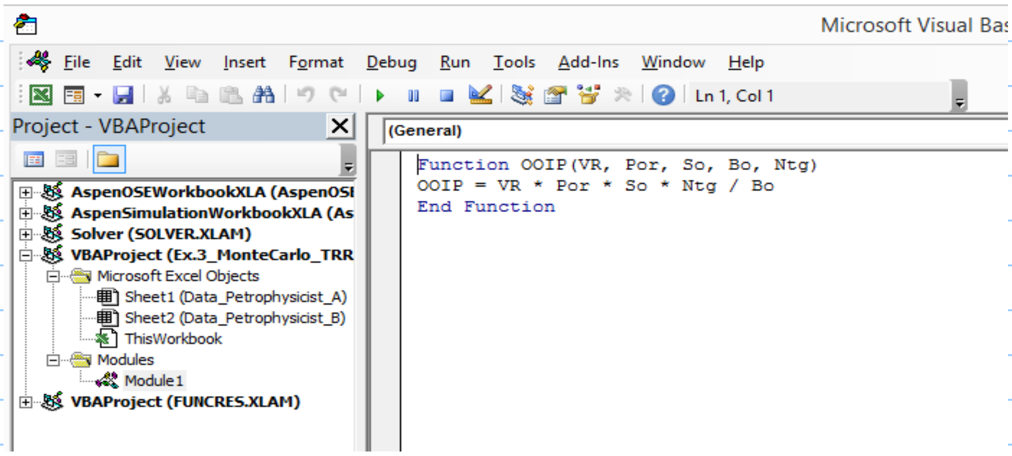
VBA Using VBA instead of a formula in Excel:

alt + F11 to access the VBA module:





Microsoft Visual Basic for Applications - Ex.3_MonteCarlo_TRR_N.xls - [Module1 (Code)]



```
Function OOIP(VR, Por, So, Bo, Ntg)
OOIP = VR * Por * So * Ntg / Bo
End Function
```

20180212:

menu:

- Continue example on estimation of N with input from petrophysicist "A"
- Results of Monte Carlo simulation: P90 – P50 – P10 }
- Some more excel "tricks" and considerations
- triangular distribution:
- discrete → continuous distribution
- required number of iterations for MC. method
- .

1= file format:

in Windows the newest file format of excel → .xslx — most use only for spreadsheet info, DOESN'T save any macros, VBA information

→ .xslm — macro-enabled workbook

if using the old format .xls (1997-2003)

↳ contains both spreadsheet and VBA/macro

2= Separator for function input:

in some computers the separator for function variables is not comma, is semicolon ;

```
function multiply (a,b,c)
multiply = a.b.c
end function
```

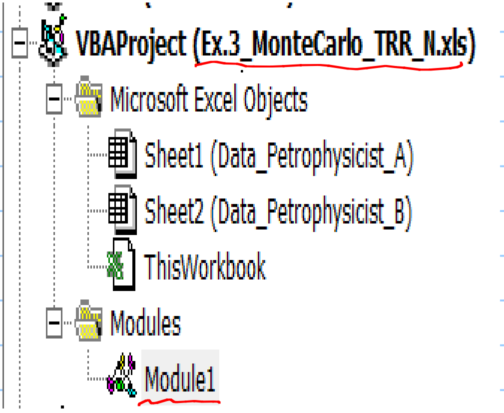
a = 1
b = 2
c = 3

[ ] ~ multiply (a,b,c)

or

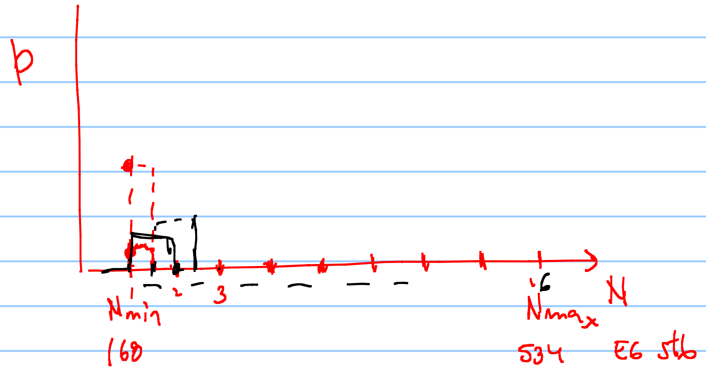
multply (a;b;c)

to make a VBA function available in a spreadsheet it must be located in the "module" of that particular spreadsheet



VBAProject (Ex.3_MonteCarlo_TRR_N.xls)
Microsoft Excel Objects
Sheet1 (Data_Petrophysicist_A)
Sheet2 (Data_Petrophysicist_B)
ThisWorkbook
Modules
Module1

pdf of N



$$N_i = N_{min} + \frac{(N_{max} - N_{min})}{N_{point}} \cdot i$$

i = {0 to 16 {

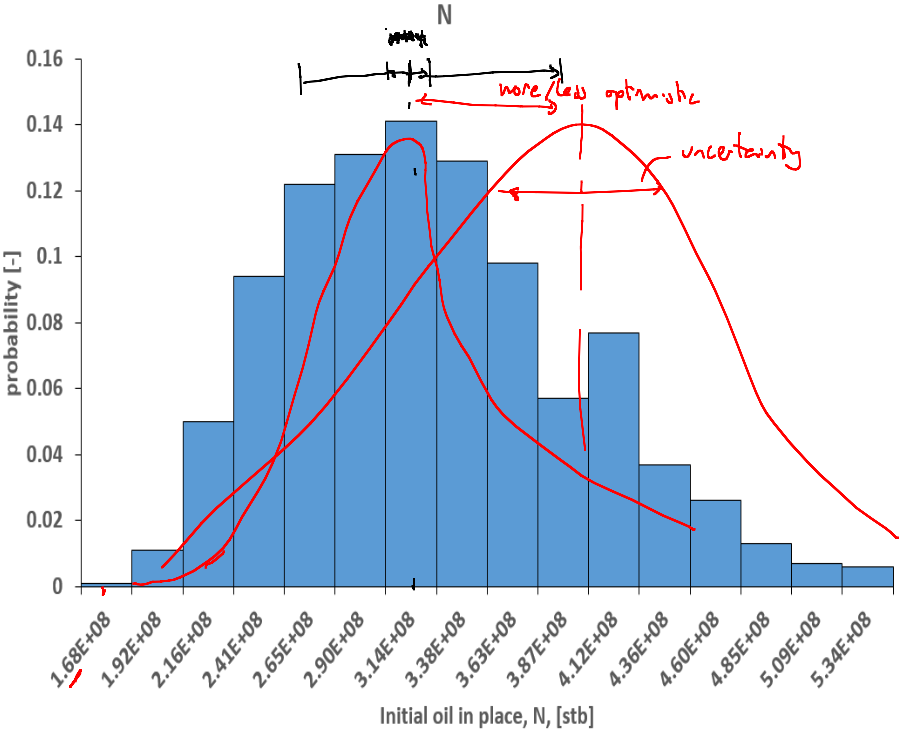
Count the number of occurrences (in column N) of

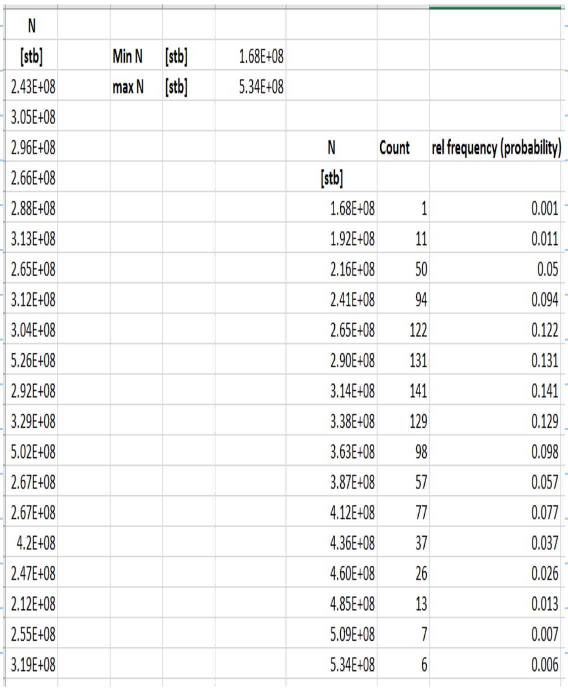
$$168 \rightarrow \left(168 \leftrightarrow 168 + \frac{(192-168)}{2} \right)$$

$$192 \rightarrow \left(192 - \frac{(192-168)}{2} \leftrightarrow 192 + \frac{(216-192)}{2} \right)$$

frequency is a vectorial function (gives back a vector) to apply it, follow the steps:

- Select the output column
- write the formula on the formula window
- provide input
- apply formula by pressing ctrl + shift + enter



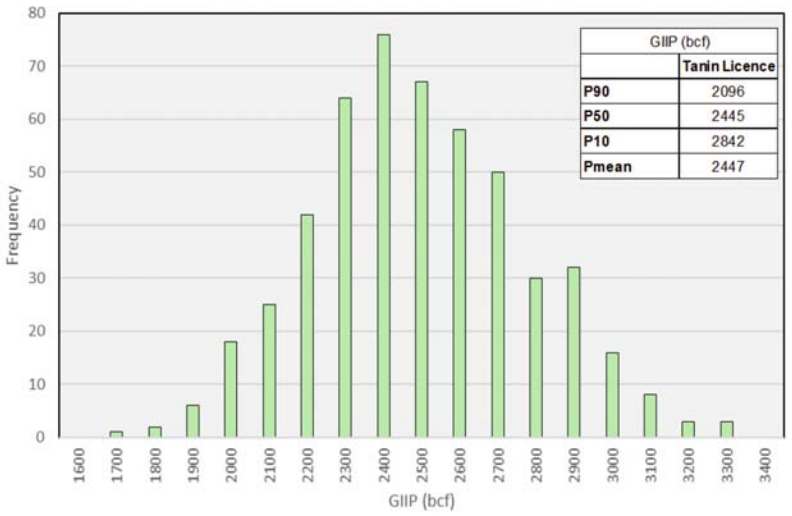


N							
[stb]		Min N	[stb]	1.68E+08			
2.43E+08		max N	[stb]	5.34E+08			
3.05E+08							
2.96E+08					N	Count	rel frequency (probability)
2.66E+08					[stb]		
2.88E+08					1.68E+08	1	0.001
3.13E+08					1.92E+08	11	0.011
2.65E+08					2.16E+08	50	0.05
3.12E+08					2.41E+08	94	0.094
3.04E+08					2.65E+08	122	0.122
5.26E+08					2.90E+08	131	0.131
2.92E+08					3.14E+08	141	0.141
3.29E+08					3.38E+08	129	0.129
5.02E+08					3.63E+08	98	0.098
2.67E+08					3.87E+08	57	0.057
2.67E+08					4.12E+08	77	0.077
4.2E+08					4.36E+08	37	0.037
2.47E+08					4.60E+08	26	0.026
2.12E+08					4.85E+08	13	0.013
2.55E+08					5.09E+08	7	0.007
3.19E+08					5.34E+08	6	0.006

check how the frequency function works:

https://support.office.com/en-us/article/frequency-function-44e3be2b-eca0-42cd-a3f7-fd9ea898fdb

example from PDO of Karish and Tanin field



GIIP (bcf)	
	Tanin Licence
P90	2096
P50	2445
P10	2842
Pmean	2447

100-66%

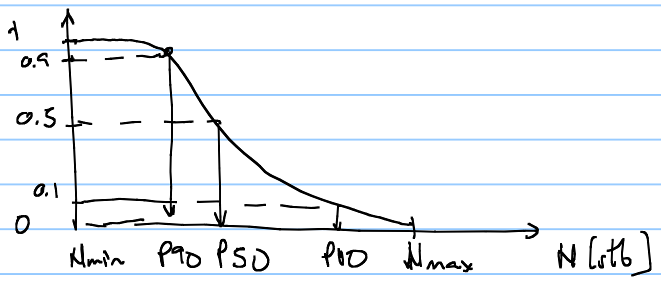
P90 (proven reserves): the quantity for which there is 90% probability that actual reserves are equal or higher

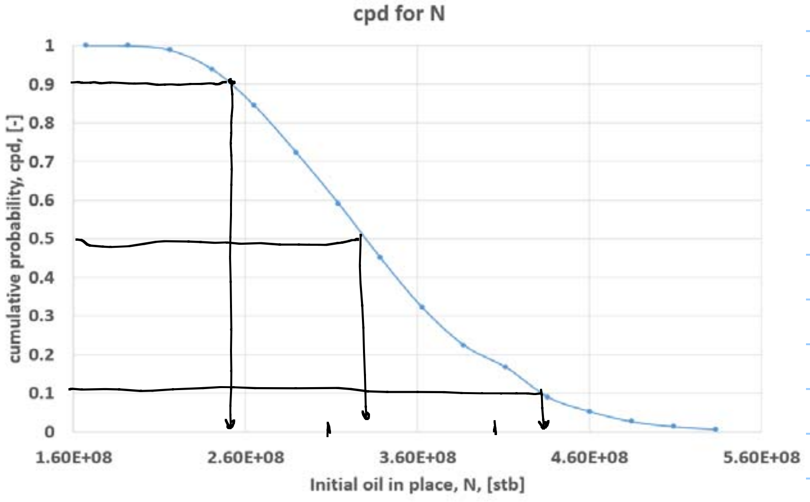
66-33

P50 proven + probable reserves: the quantity for which there is 50% probability that actual reserves are equal or higher

P10 proven + probable + possible: the quantity for which there is 10 probability that actual reserves are equal or higher

to obtain these number we have to compute cpf from pdf



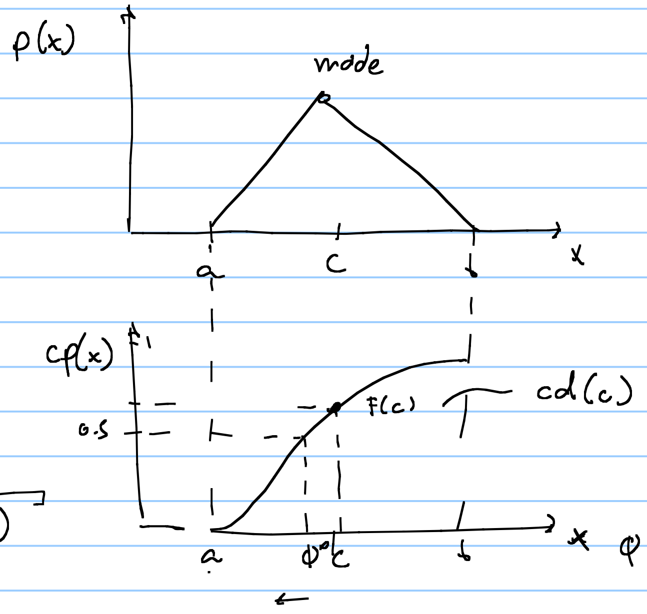


P90 ≃ 260 E6 stb

P50 ≃ 330 E6 stb

P10 ≃ 430 E6 stb

triangle distribution



random number (cp)

$0 \leq \omega \leq 1$

function (ω, a, b, c)

$F(c) = cd(c) = \frac{(c-a)}{(b-a)}$

for $0 \leq \omega \leq F(c)$

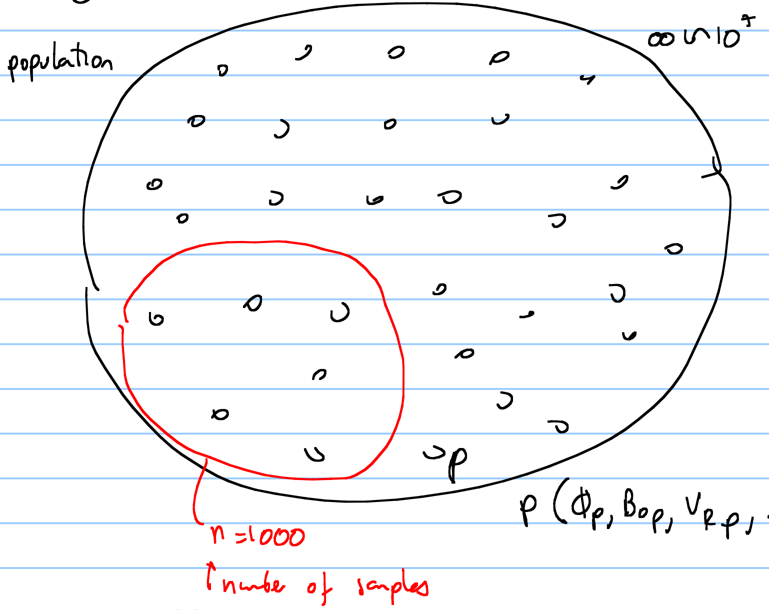
$\underset{\sim}{x} = a + \sqrt{\omega (b-a)(c-a)}$

for $F_c < \omega \leq 1$

$x = b - \sqrt{(1-\omega)(b-a)(b-c)}$

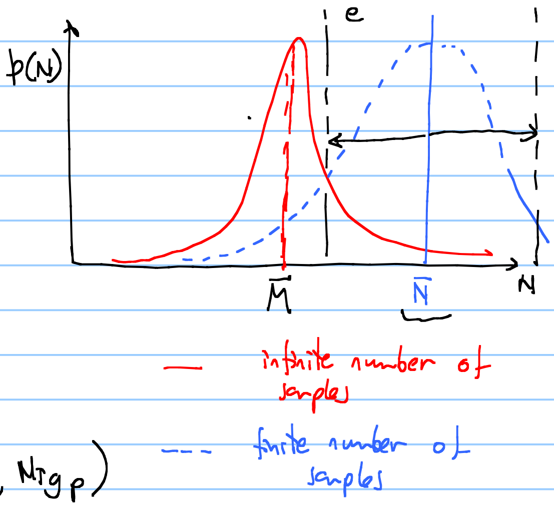
end function

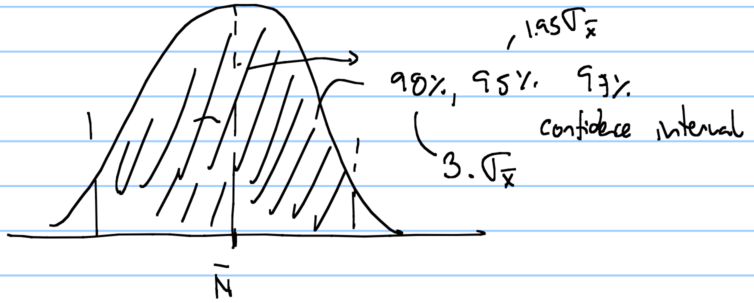
How many iterations are required in Monte Carlo?



$p(\Phi_p, Bo_p, V_{Rp}, So_p, N_{Tg\,p})$

N if number of samples is ∞ the N → normal distribution





real mean

$$\bar{N} + e \geq \bar{M} \geq \bar{N} - e$$

$$e = \underbrace{2\%\ \bar{N}} = \underbrace{0.02 \cdot \bar{N}}$$

$$\sigma_{\bar{x}} = \frac{S_x}{\sqrt{n}}$$

$$3 \cdot \sigma_{\bar{x}} = 0.02\ \bar{N}$$

$$3 \frac{S_x}{\sqrt{n}} = 0.02 \cdot \bar{N}$$

clearing n

$$n = \left(\frac{3 \cdot S_x}{0.02 \cdot \bar{N}}\right)^2$$

Exercise set 1 delivery date: 20 feb 2018, 23:59. Trd time.

2018 02 13 → menu :
- Additional comments on estimation of N, G, TRR (N_{pu}, G_{pu}) using Monte Carlo ⇝ exercise 4
- layout of production systems

if you have interest: http://www.spe.org/industry/docs/GuidelinesEvaluationReservesResources_2001.pdf


DISTINGUISHED AUTHOR SERIES

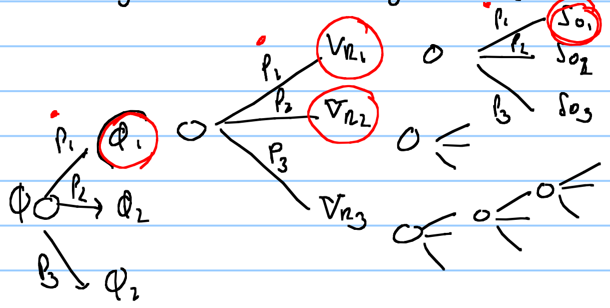
Reserves Estimation: The Challenge for the Industry

Ferruh Demirmen, SPE, Petroleum Consultant

Comment on problem 4 → exercise 1

$$N = \frac{\overset{1}{\phi}\,\overset{2}{V_R}\,\overset{3}{S_o}\,\overset{4}{N_{TG}}}{B_{o_5}}$$

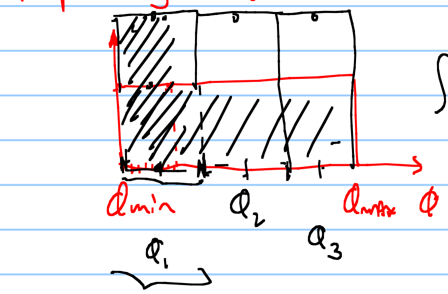
layer 1 (φ) layer 2 (V_R) layer 3 (S_o) layer 4 (N_{TG}) layer 5 (B_o



Nr. cases to evaluate

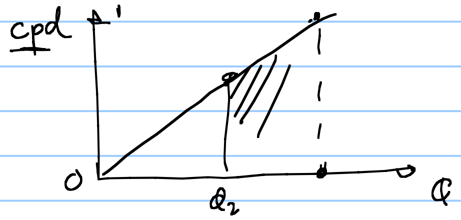
$3^5 = 2{,}73$ → N_1 – P_1
N_2

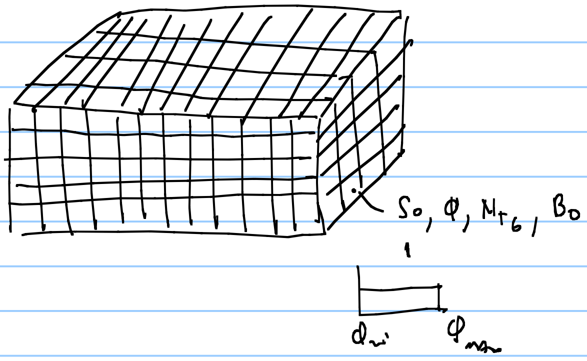
φ probability distribution



$$\int p\, d\phi = 1$$

Convert from continuous probability to discrete by integrating under curve



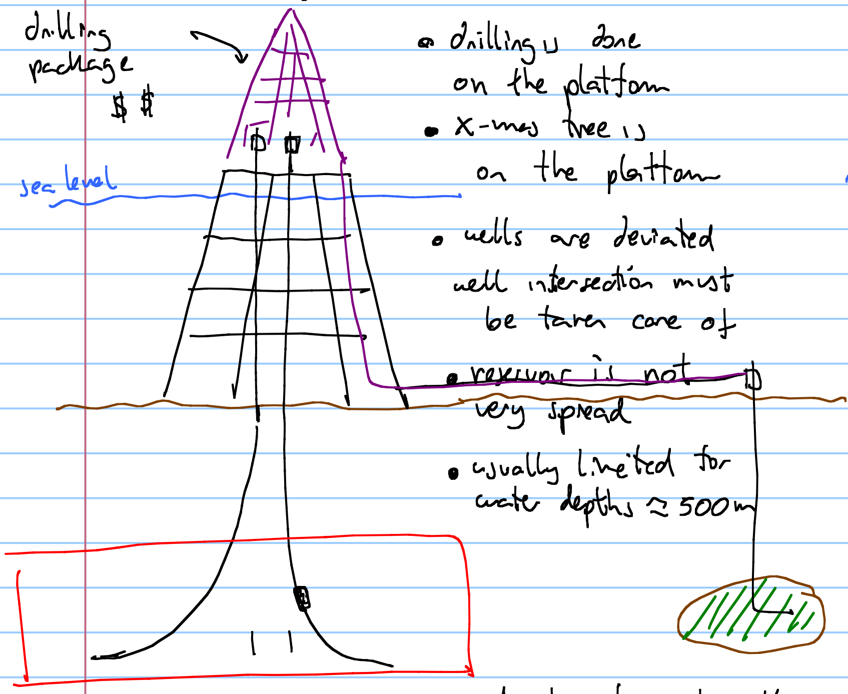


Read page 85 from compendium for more information about how we handle several reservoir realizations.

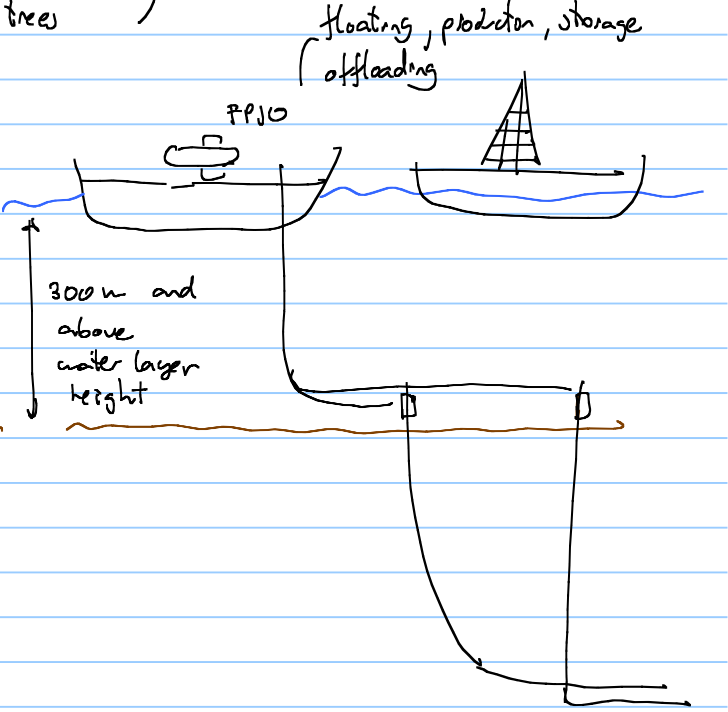
layout of offshore production systems → offshore Norway

platform wells
(dry X-mas trees)

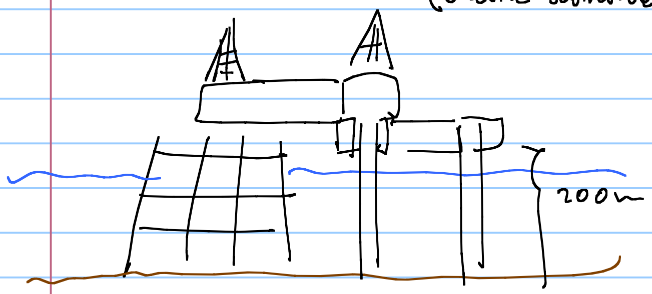
subsea wells
(wet X-mas trees)



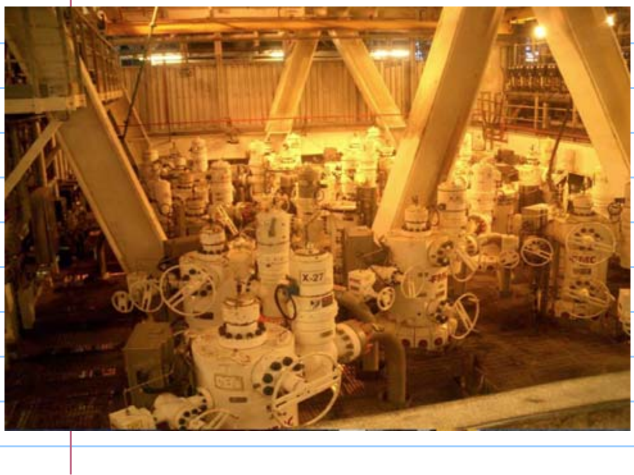
- drilling is done on the platform
- X-mas tree is on the platform
- wells are deviated
  well intersection must be taken care of
- reservoir is not very spread
- usually limited for water depths ≳ 500 m
- used when frequent well intervention is required (electric submersible pump)



drilling ins subsea wells usually performed by drilling ship
↳ semisubmersible drilling

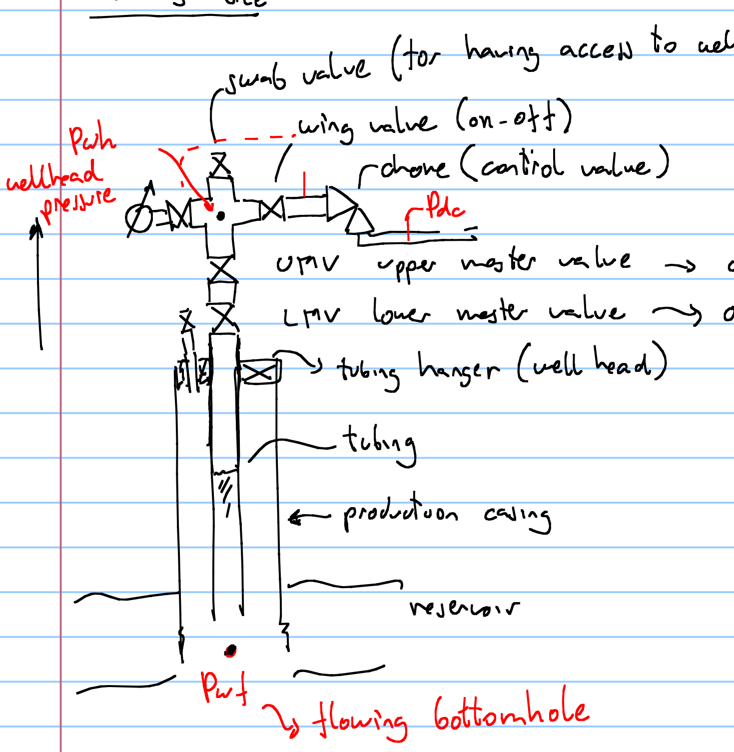


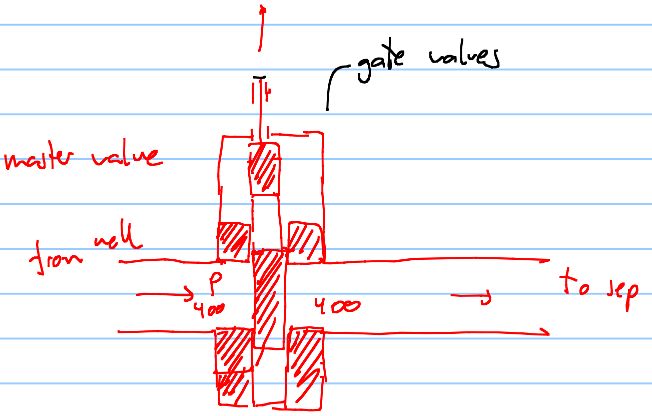
in platform well wells are contained
well bay

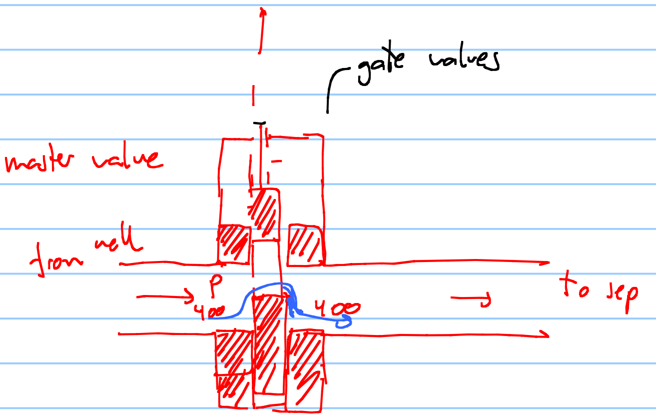


in platform well the operator has direct access to
X-mas tree → well closing change choke
↘ test well maintenance

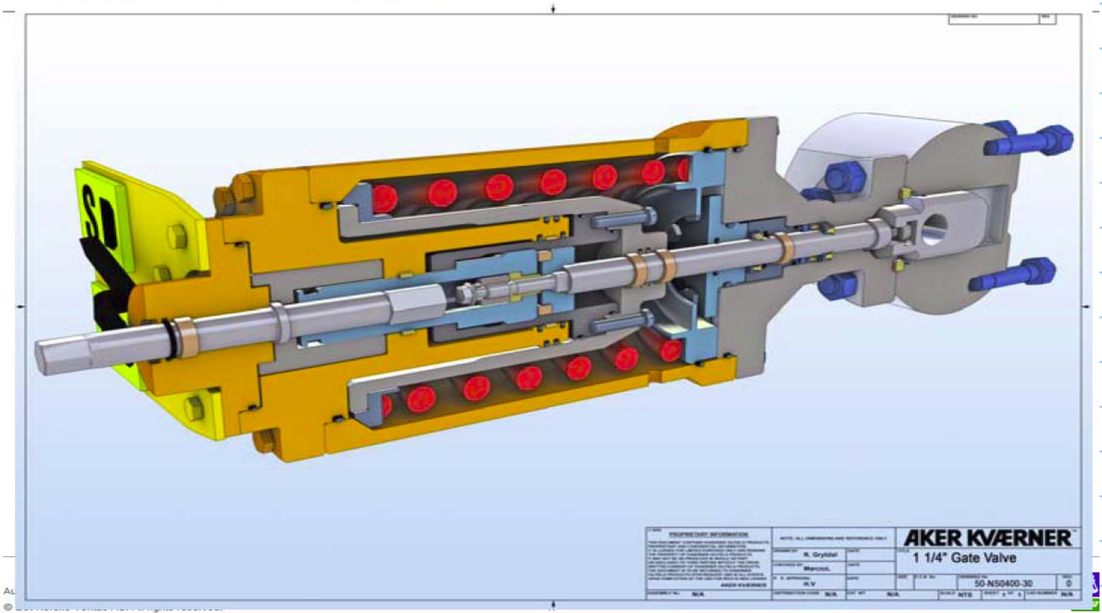
X-mas tree







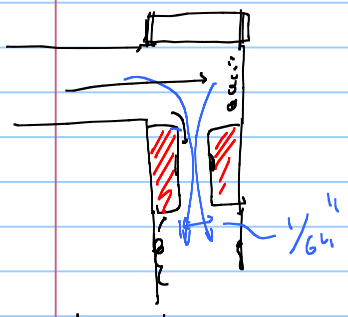
Xmas Tree Gate Valves



Choke

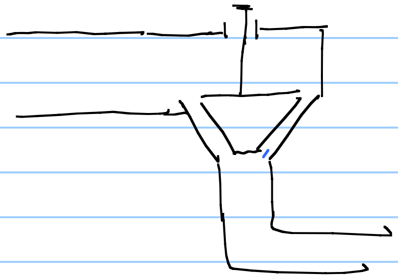
Fixed

adjustable



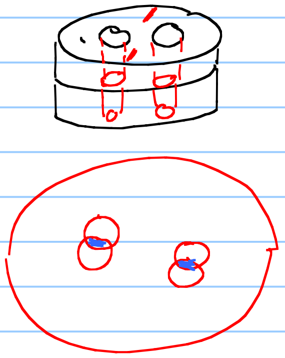
bean choke

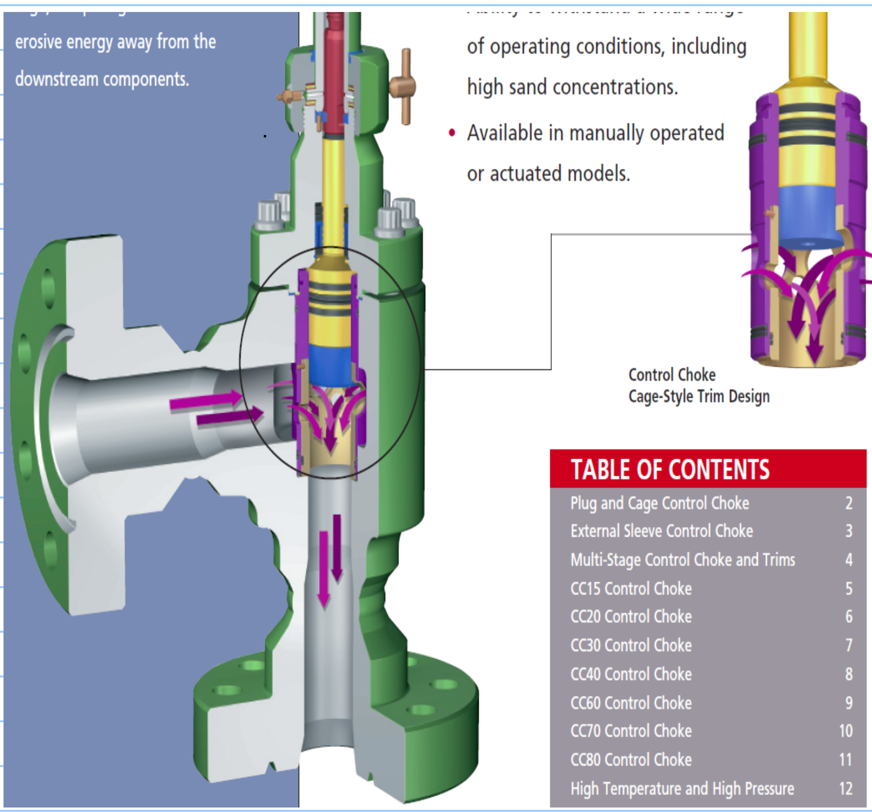
usually used on onshore wells
or platform wells



needle choke

willis choke
disk choke





erosive energy away from the downstream components.

of operating conditions, including high sand concentrations.

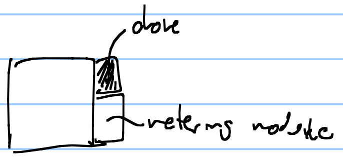
- Available in manually operated or actuated models.

Control Choke
Cage-Style Trim Design

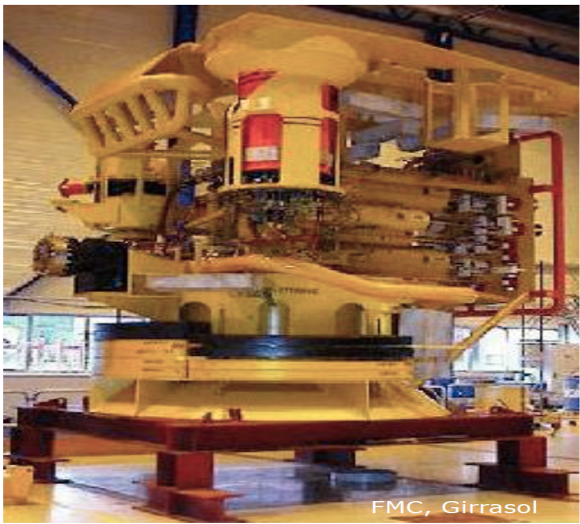
TABLE OF CONTENTS

Plug and Cage Control Choke 2
External Sleeve Control Choke 3
Multi-Stage Control Choke and Trims 4
CC15 Control Choke 5
CC20 Control Choke 6
CC30 Control Choke 7
CC40 Control Choke 8
CC60 Control Choke 9
CC70 Control Choke 10
CC80 Control Choke 11
High Temperature and High Pressure 12

cage-choke



in subsea wells the choke is placed in a special module to make it easy to retrieve

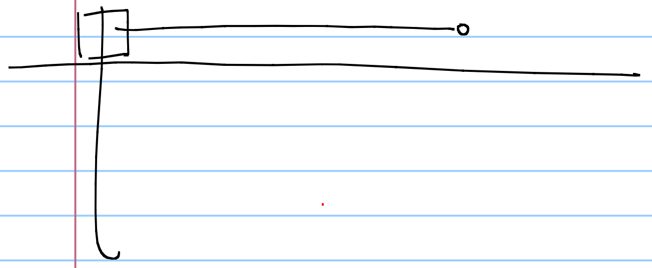


20180219

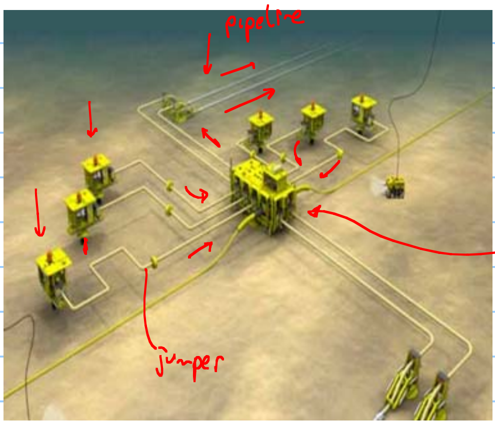
Subsea systems → TPG4200 Subsea system

arrangement of well on seabed

satellite



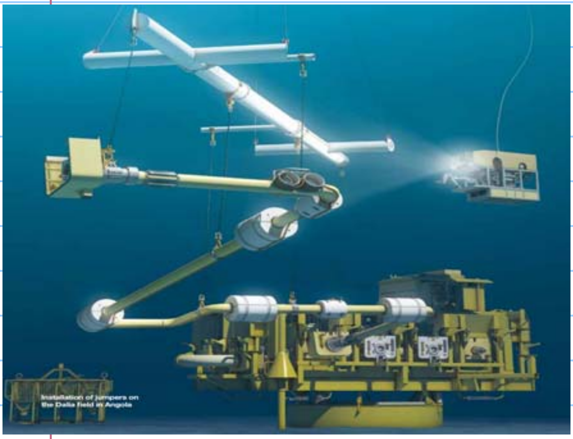
cluster

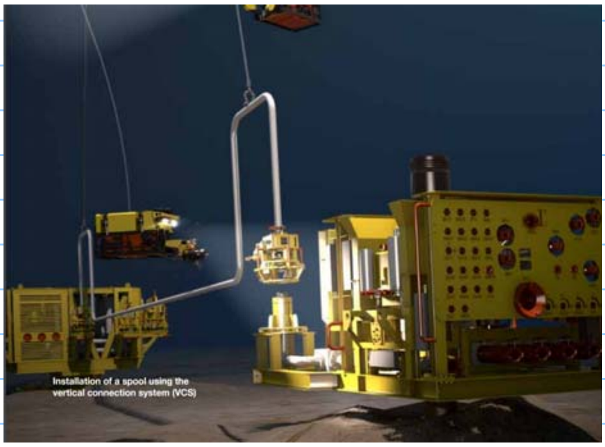


independent wells

manifold

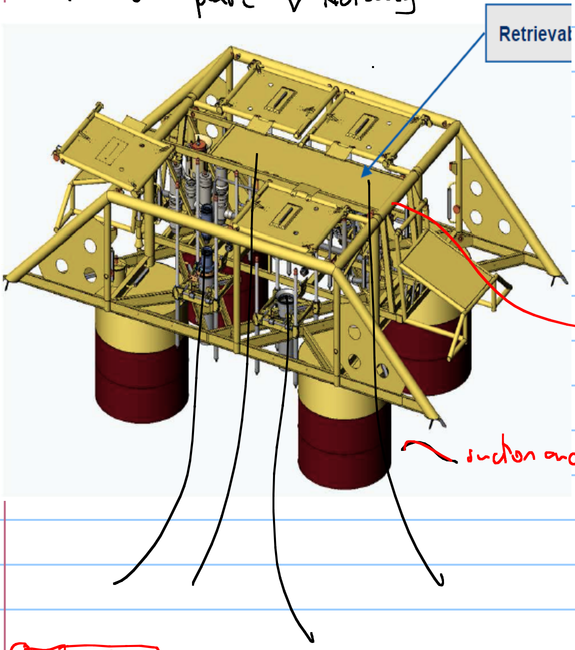
{ commingle the production of individual wells





template

4-well template ♡ Norway

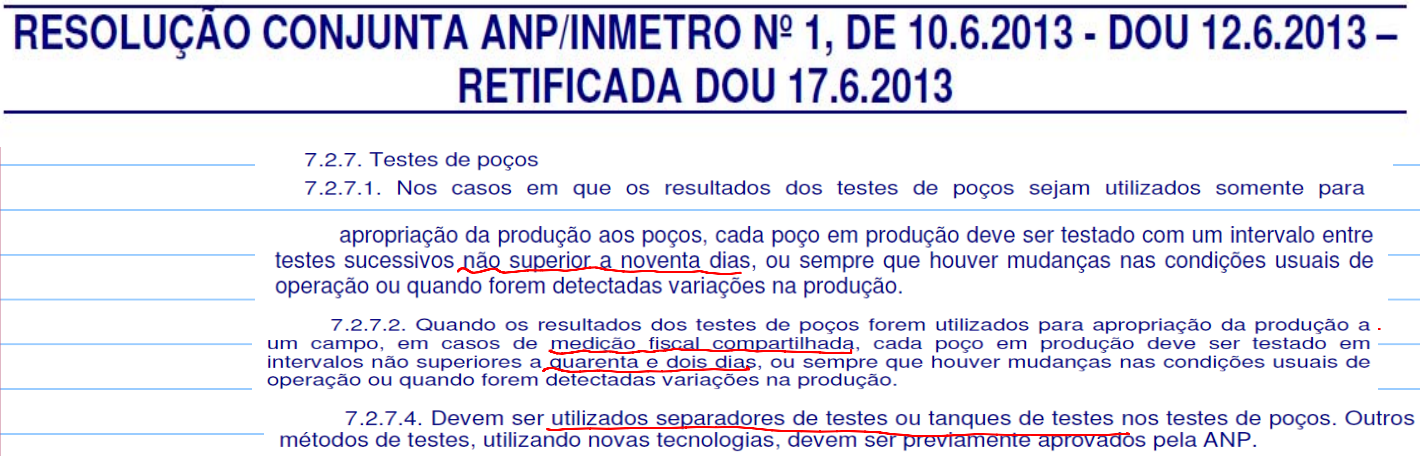


manifold

suction anchors support / weight protection structure

{ manifold
NOT wells / X-mT

How do we define the layout of subsea system?
- need for individual well metering {Fiscal metering {
  → accepted methods?
- need for pigging ?



RESOLUÇÃO CONJUNTA ANP/INMETRO Nº 1, DE 10.6.2013 - DOU 12.6.2013 – RETIFICADA DOU 17.6.2013

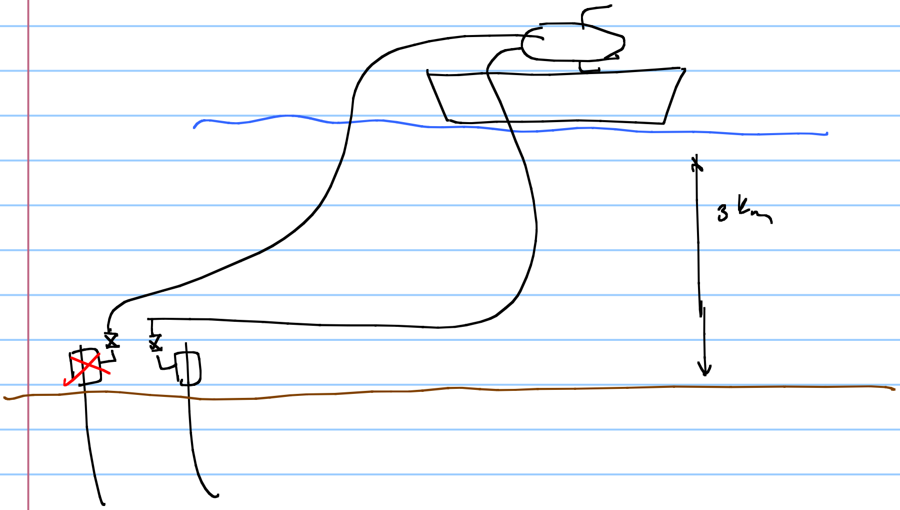
7.2.7. Testes de poços

7.2.7.1. Nos casos em que os resultados dos testes de poços sejam utilizados somente para apropriação da produção aos poços, cada poço em produção deve ser testado com um intervalo entre testes sucessivos não superior a noventa dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

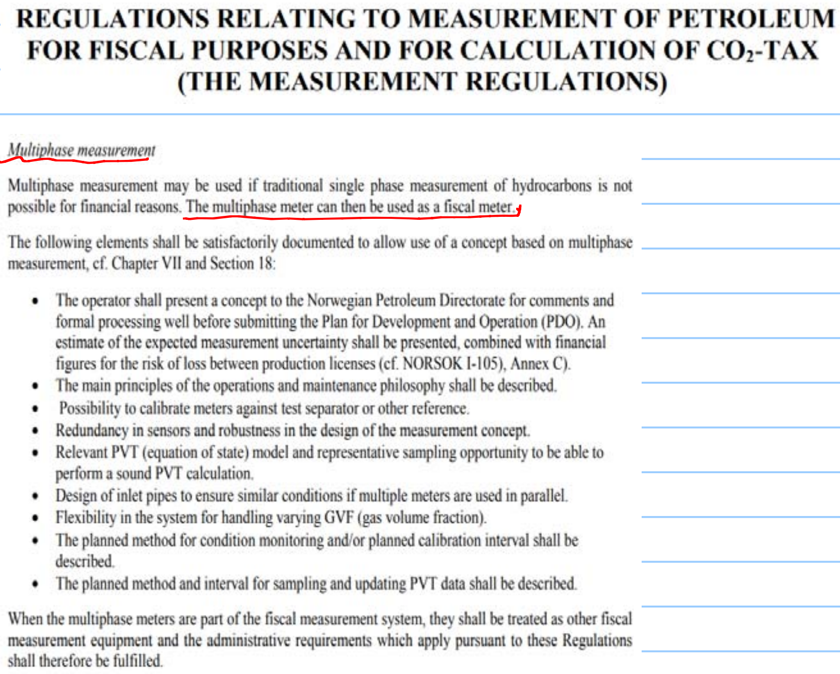
7.2.7.2. Quando os resultados dos testes de poços forem utilizados para apropriação da produção a um campo, em casos de medição fiscal compartilhada, cada poço em produção deve ser testado em intervalos não superiores a quarenta e dois dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

7.2.7.4. Devem ser utilizados separadores de testes ou tanques de testes nos testes de poços. Outros métodos de testes, utilizando novas tecnologias, devem ser previamente aprovados pela ANP.

http://www.anp.gov.br/wwwanp/?dw=66648



http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/NPD-regulations/Maaleforskriften_e.pdf



REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO_2-TAX (THE MEASUREMENT REGULATIONS)

Multiphase measurement

Multiphase measurement may be used if traditional single phase measurement of hydrocarbons is not possible for financial reasons. The multiphase meter can then be used as a fiscal meter.

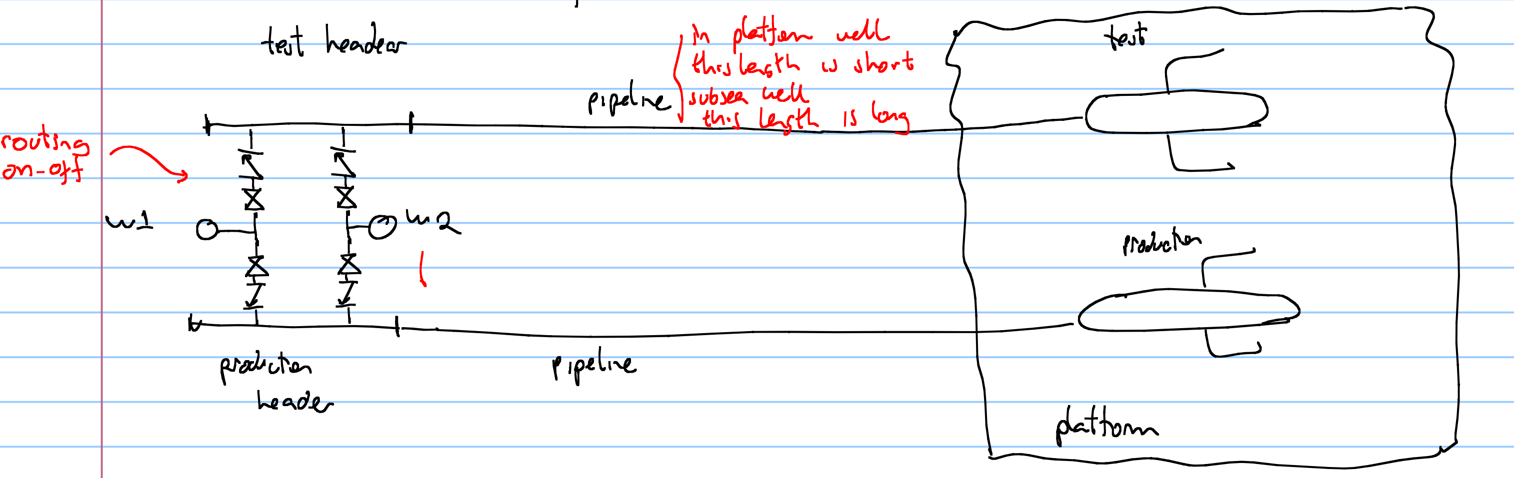
The following elements shall be satisfactorily documented to allow use of a concept based on multiphase measurement, cf. Chapter VII and Section 18:

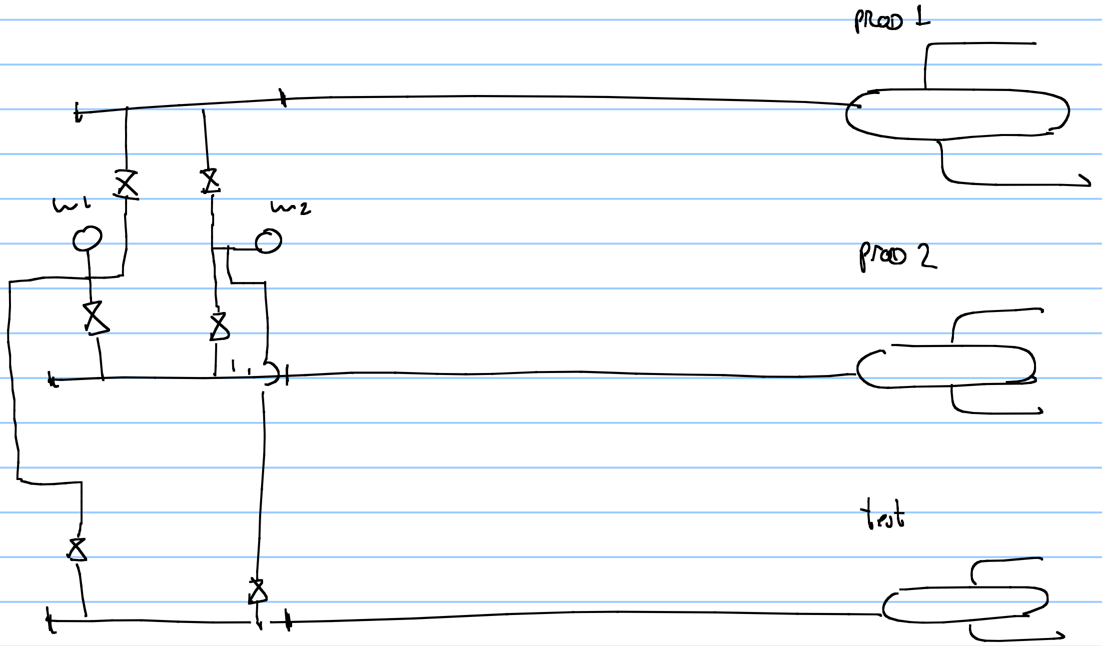
- The operator shall present a concept to the Norwegian Petroleum Directorate for comments and formal processing well before submitting the Plan for Development and Operation (PDO). An estimate of the expected measurement uncertainty shall be presented, combined with financial figures for the risk of loss between production licenses (cf. NORSOK I-105), Annex C).
- The main principles of the operations and maintenance philosophy shall be described.
- Possibility to calibrate meters against test separator or other reference.
- Redundancy in sensors and robustness in the design of the measurement concept.
- Relevant PVT (equation of state) model and representative sampling opportunity to be able to perform a sound PVT calculation.
- Design of inlet pipes to ensure similar conditions if multiple meters are used in parallel.
- Flexibility in the system for handling varying GVF (gas volume fraction).
- The planned method for condition monitoring and/or planned calibration interval shall be described.
- The planned method and interval for sampling and updating PVT data shall be described.

When the multiphase meters are part of the fiscal measurement system, they shall be treated as other fiscal measurement equipment and the administrative requirements which apply pursuant to these Regulations shall therefore be fulfilled.

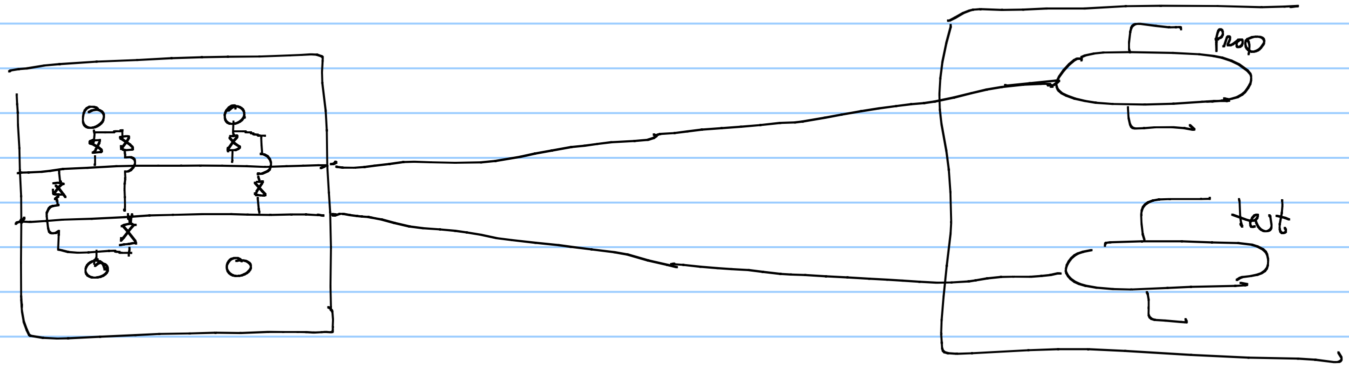
Production manifold

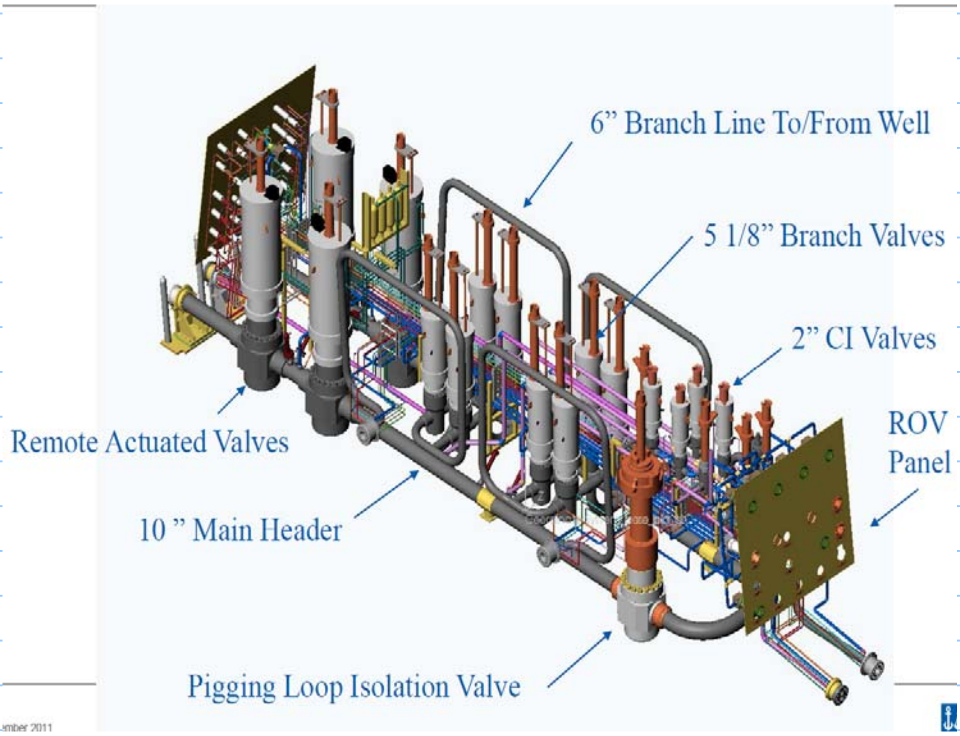
- commingle, merge, gather the production from different wells
- route the production of a given well to test or production separator
- if I have more than one production separator, route the production of each well to the one I choose





for template wells




6” Branch Line To/From Well

5 1/8” Branch Valves

2” CI Valves

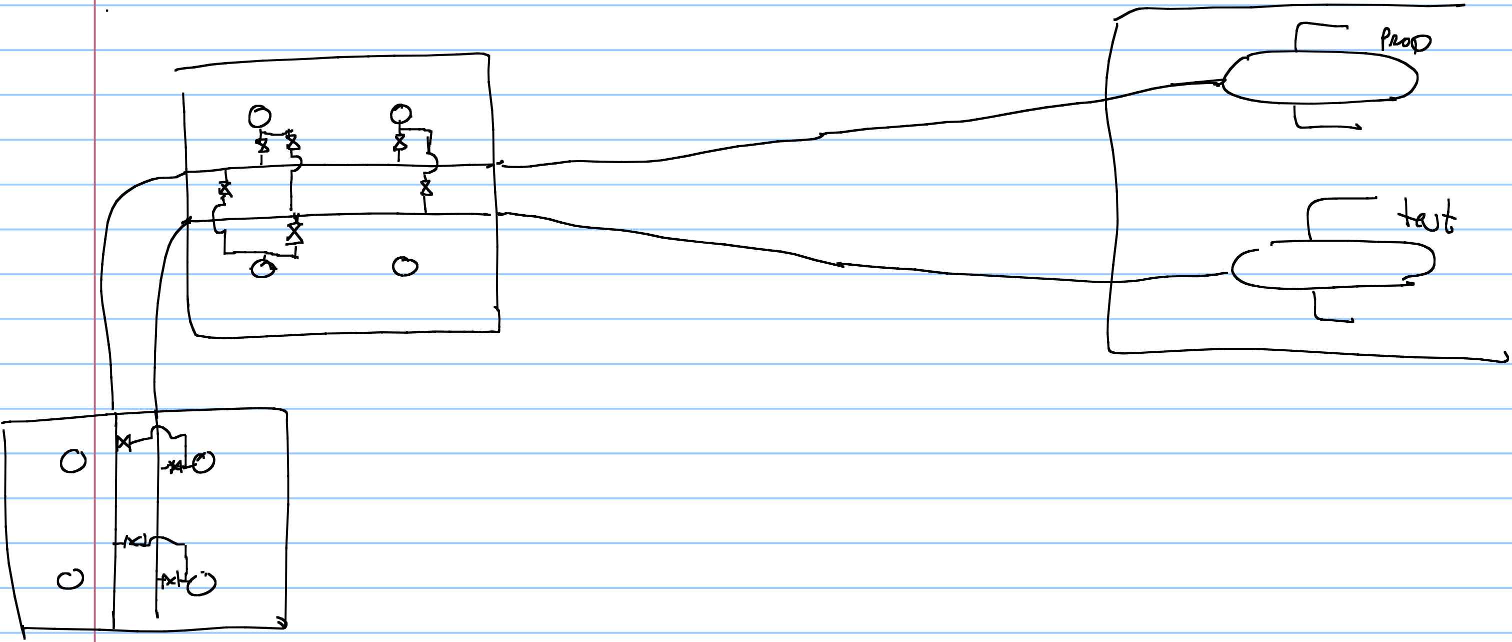
ROV Panel

Remote Actuated Valves

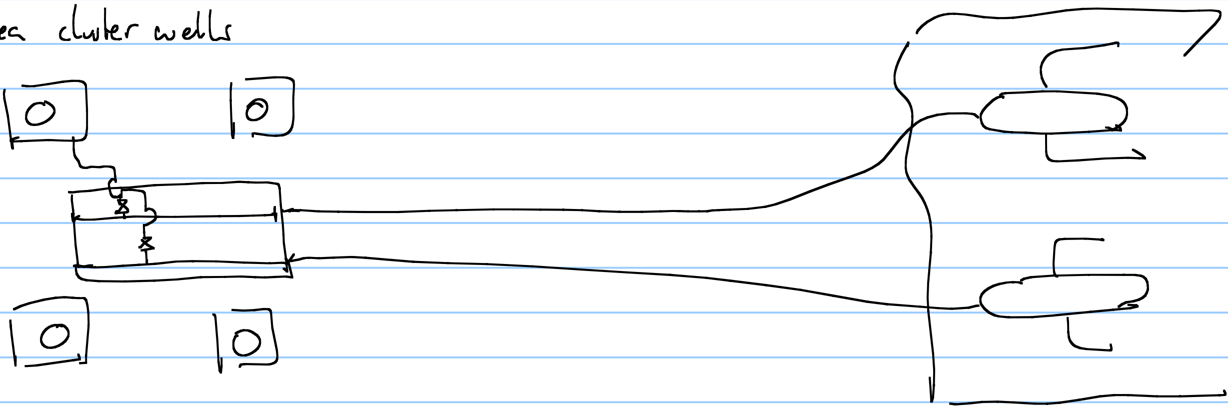
10 ” Main Header

Pigging Loop Isolation Valve

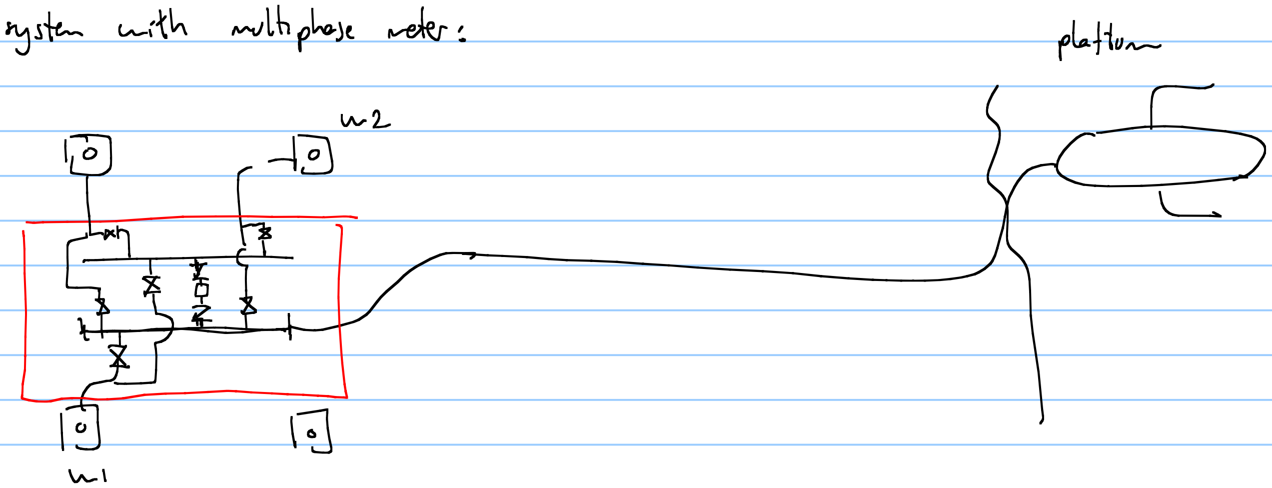
2 templates



subsea cluster wells



system with multiphase meter:



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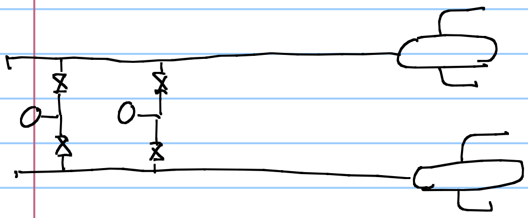
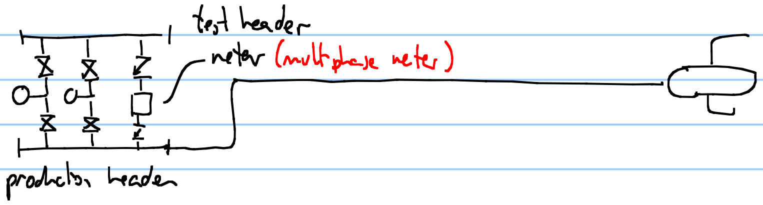
onshore systems

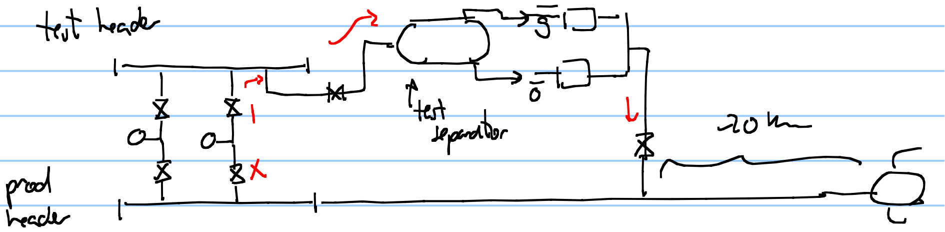
production manifold in lybia

field in Colombia, production manifold and liquid flow meter



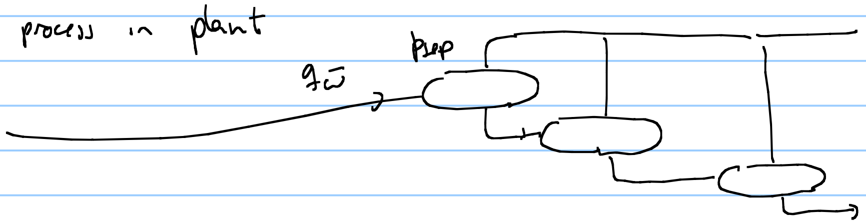


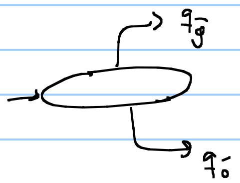
what happens if multiphase meter is too expensive and the transportation distance is far



be aware! the rates won't be the same one has to convert the rates

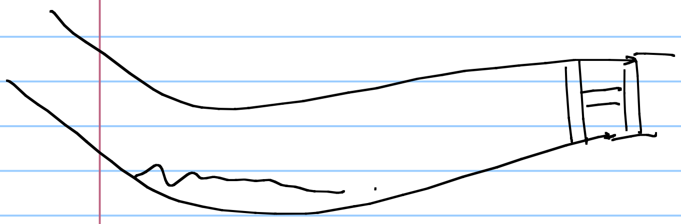
actual process in plant





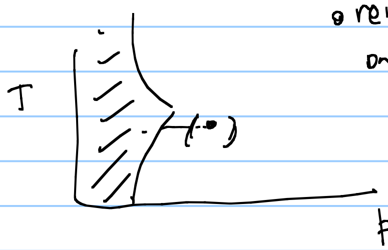
in subsea fields one has to take into account the need for pigging

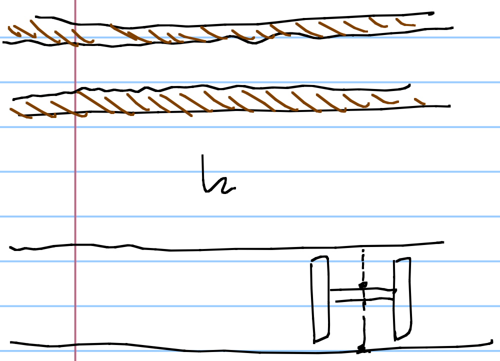
in gas lines : remove liquids
- avoid corrosion
- avoid slugging
- reduce Δp



in oil lines : • remove accumulated water
- avoid corrosion

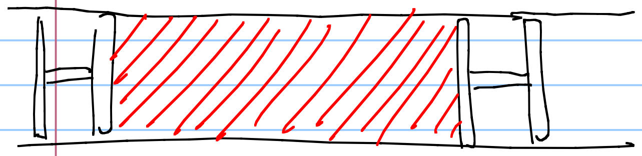
• remove wax accumulated on pipe wall
- reduces pipe cross section → $\Delta p \uparrow$
- affects the operation of components in the system (valve)
- block pipe

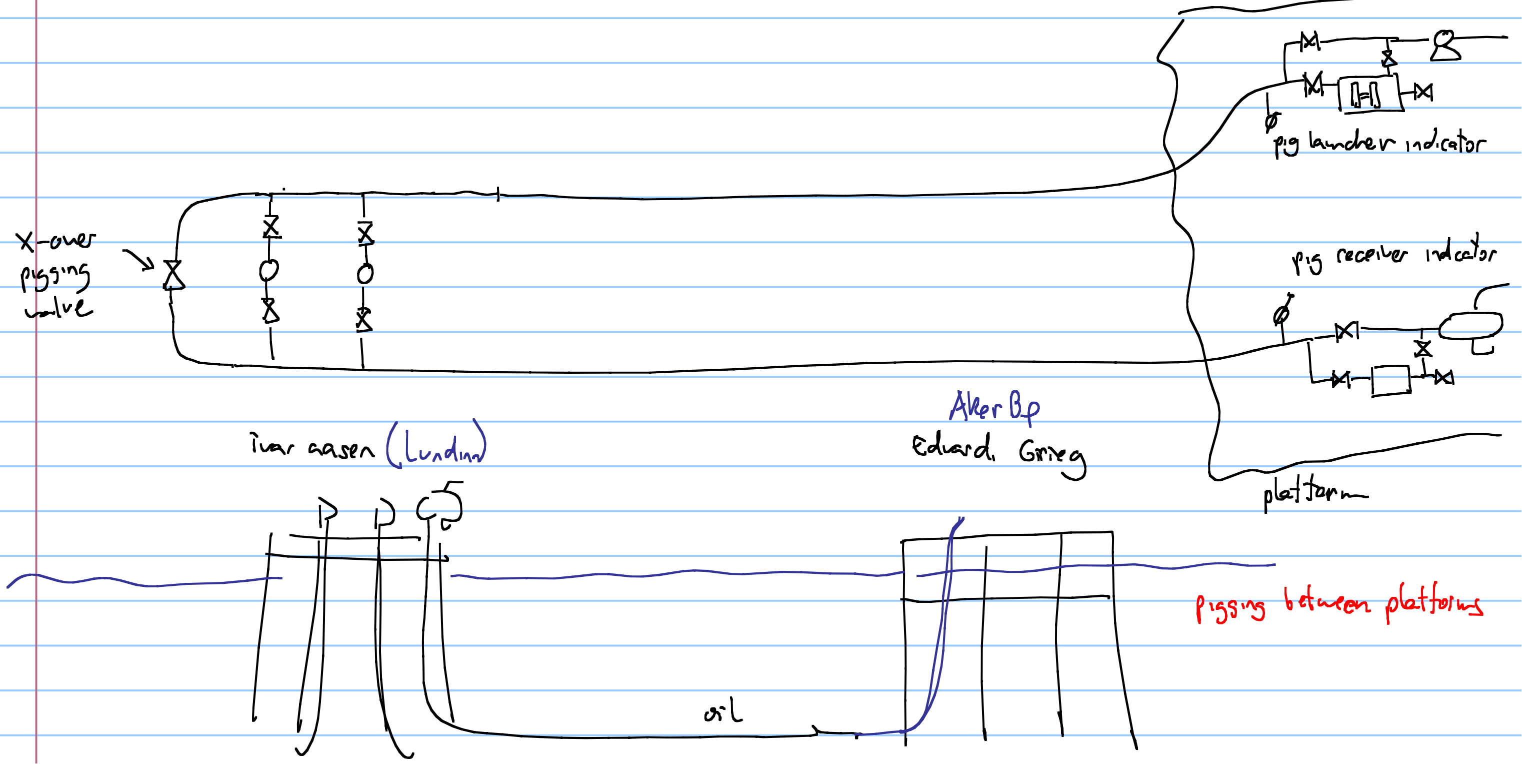




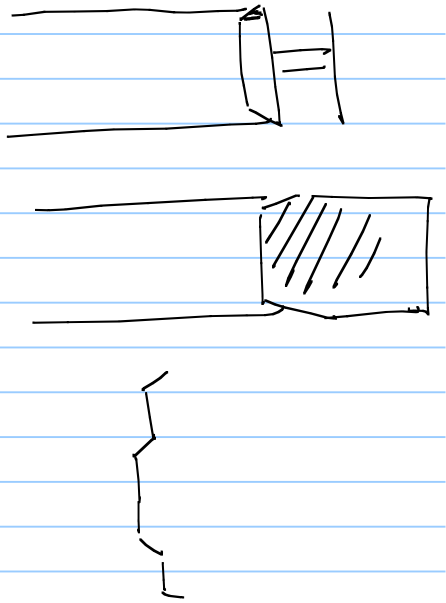
• pipeline inspection

• chemical treatment



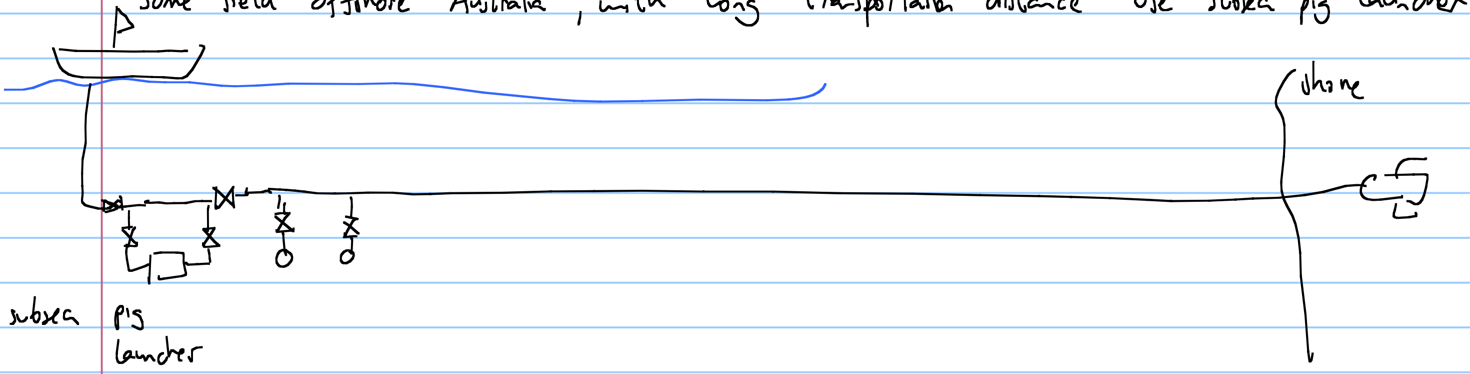


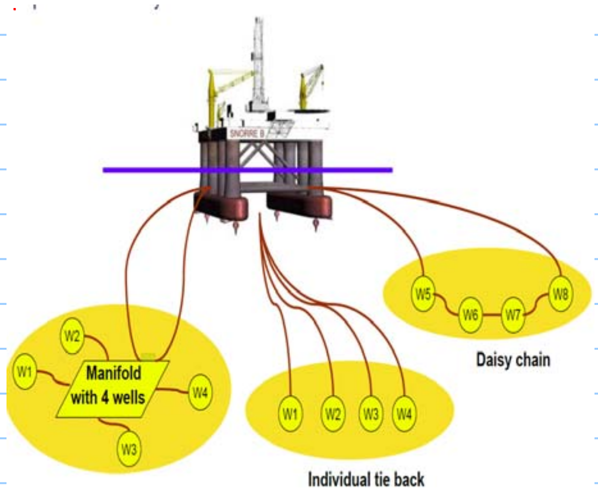
Various pig types



Wax plug-North Sea line pigging

Some field offshore Australia, with long transportation distance use subsea pig launcher



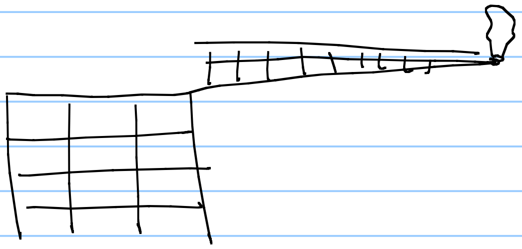


NOT ABOUT
- drilling jackup
- drilling vessels { ship / semi-subs
- intervention vessels
- pipe laying vessels

Offshore structures for oil and gas production"

what is included in these facilies? :

- facilities for well drilling/intervention (drilling package USD) hoisting system, tower, mud pumps, cements pumps storage, shale shakess
  - ↳ mud
  - ↳ pipe (tubulars)
- processing facilities for reservoir fluids
  - → main separation trains { 2 sep trains / 1 test
  - → gas processing module
  - ↳ water processing module
  - ↳ oil processing module
- Gas-lift facities
- Gas injection facilities ⇝ compressor (USD $)
- water injection facilites ⇝ pumps.
- well bay (X-mas tree / welhead)
- living quarters (helideck)
- power generation
- gas export compressors
- fire fighting system
- oil storage
- oil offloading system
- control system
- monitoring system
- system for storage, injection and recovery of production chemicals { hydrate inhibitors / wax inhibitors / corrosion inhibitors / scale inhibitor / emulsion inhib. / bacterial inh.
- communication system
- manifold well
- flare system
- Repair workshop
- utilities (hydraulic power fluid, compressed air, drinking water unit, air condition, ventilation)



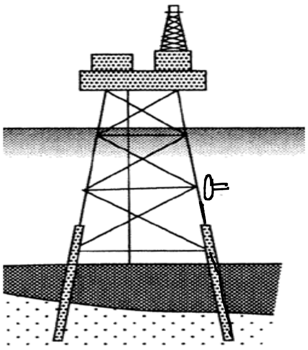
two categories

Bottom-supported

significant part ot load weight are transferred to soil

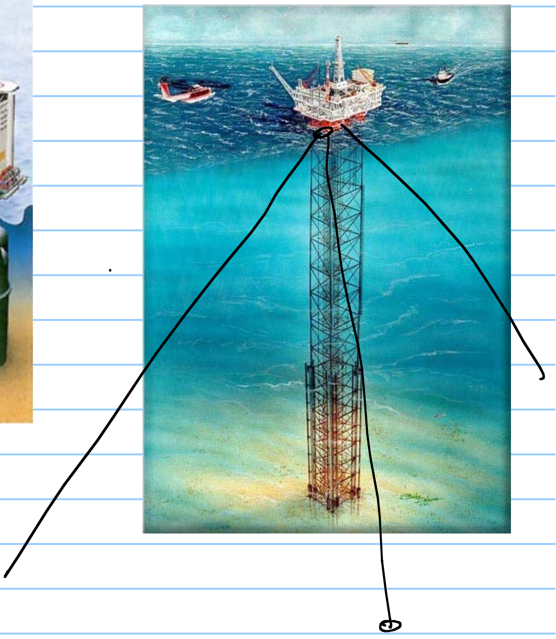
have limited movements in the vertical and horizontal direction

Jacket



Gravity Based structure (GBS)

Compliant tower (Guyed tower)

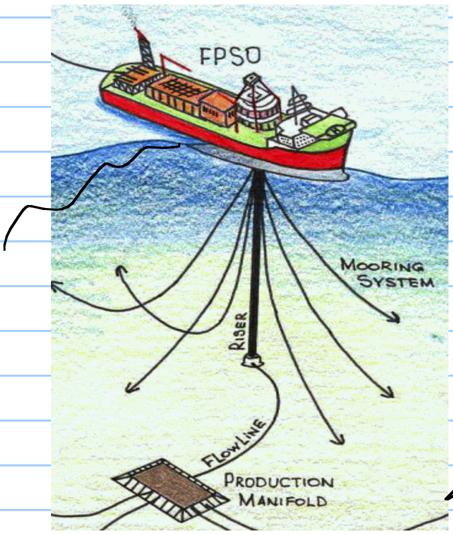


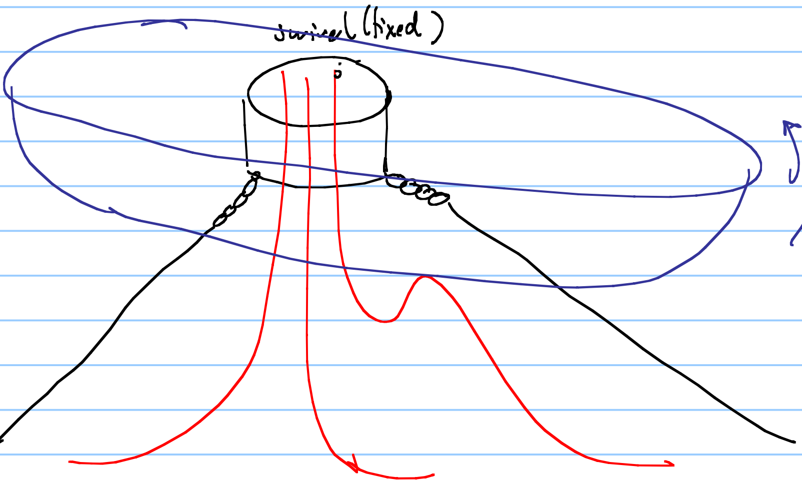
floating (using buoyancy to support its weight)

FPSO

naturally bouyant

Sevan FPSO

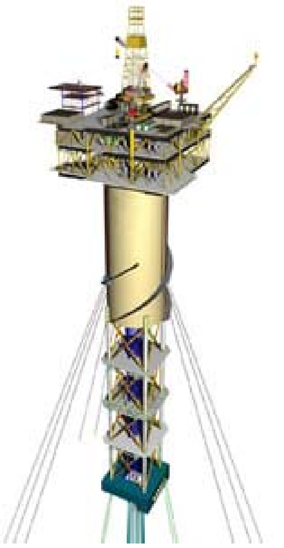


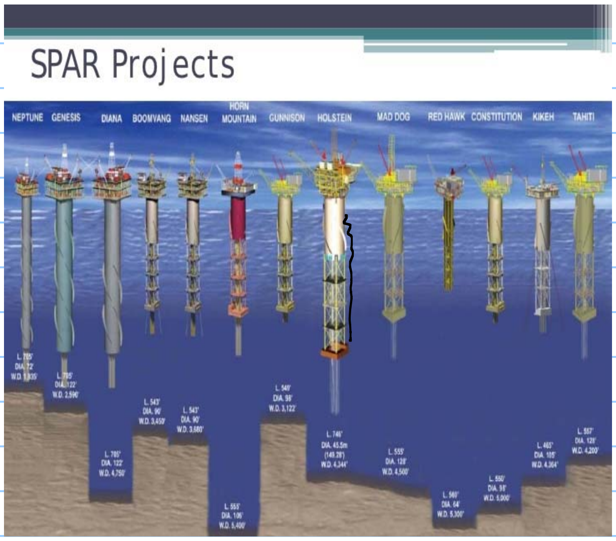


orient depending on wind /wave direction

SPAR

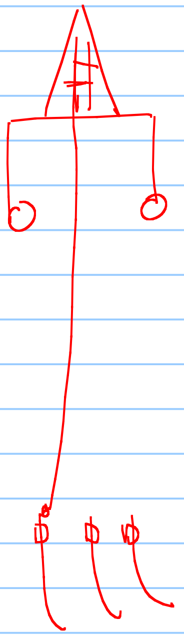
Asta Hansteen.




SPAR Projects

deep hull structure (limits movement in vertical and horizontal direction)

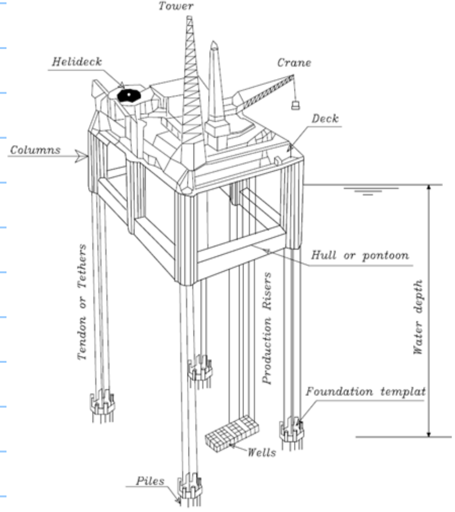
Semi-submersible

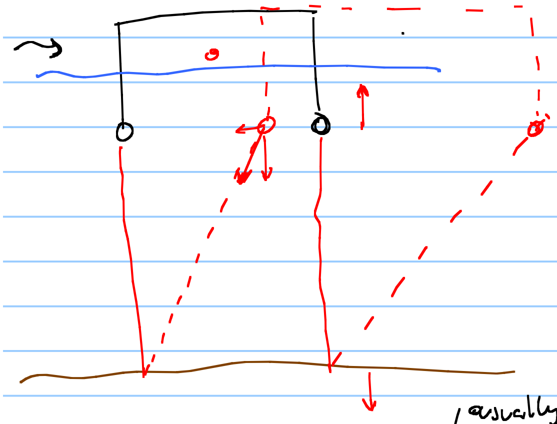


positively buoyant

TLP tension leg platform

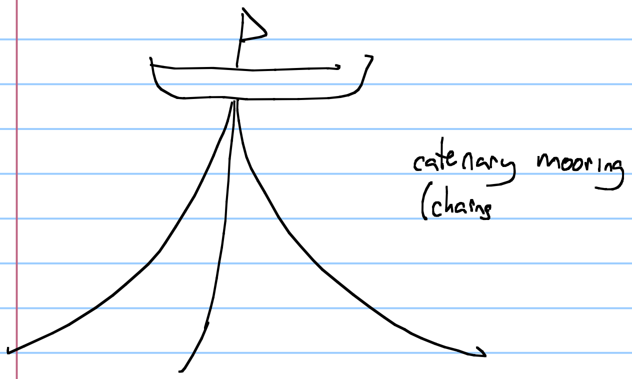
Heidrun

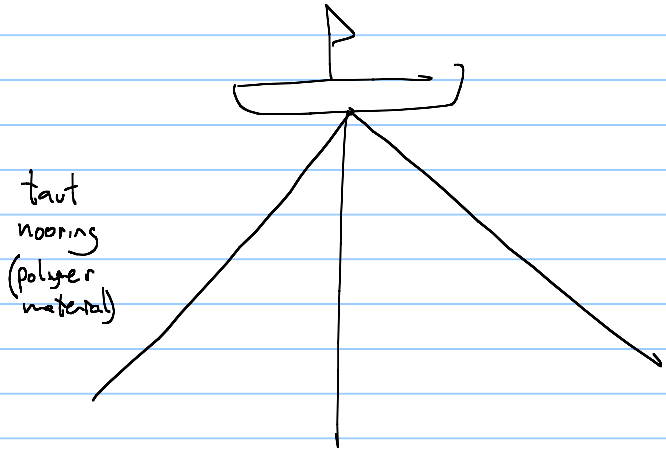




about buoyant structures
- usually exhibit "relevant" movement in horizontal/vertical direction
- require active regulation of ballast

they require mooring





20180226. Offshore structures for hydrocarbon production

TENTATIVE! reference group meeting on 05.03.2018

remember! delivery of ex. set 1 on Blackboard 28.02 KL 23:59.

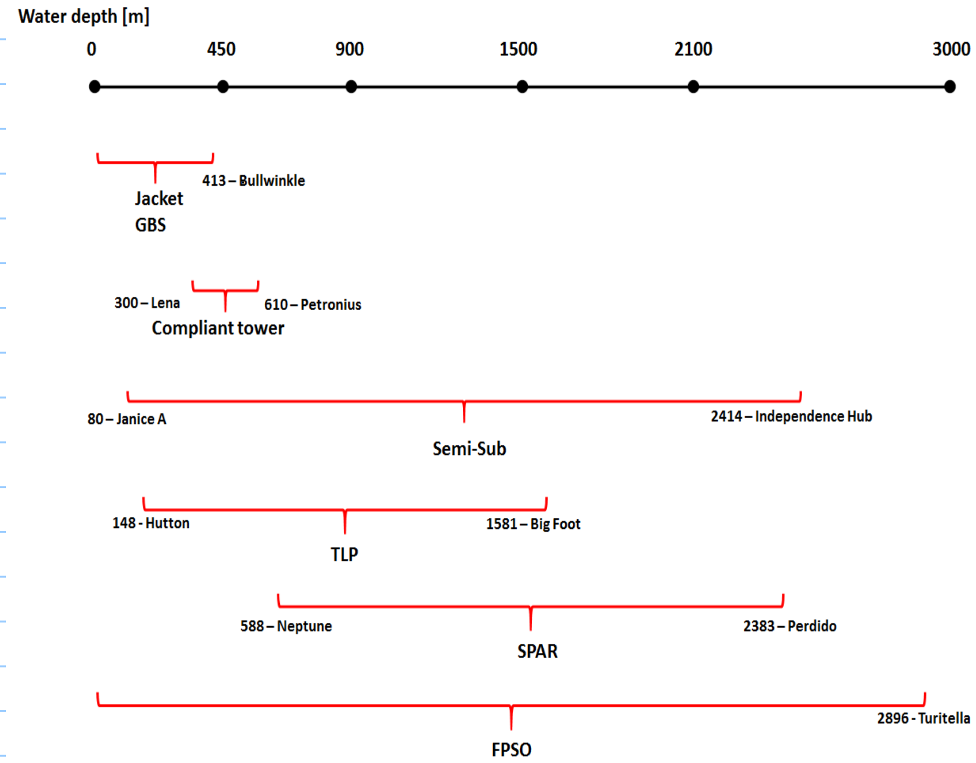
How do we select offshore structures for hydrocarbon production

- water depth
- X-mas tree type
  - wet
  - dry
- well intervention requirements
- Reservoir structure and extent
- future development and expansion plans
- storage needs (oil, condensate)
- marine environment
  - wind
  - currents
  - waves
- soil conditions
- cost / delivery time
- past experience

- water depth

bottom-supported structures bellow 500-600 m

floating structures → no restrictions



- Storage { if field is in a remote location that might be difficult to access. due to rough weather, etc.

FPSO storage (1 E6 - 3 E6) stb

GBS (300000 stb)

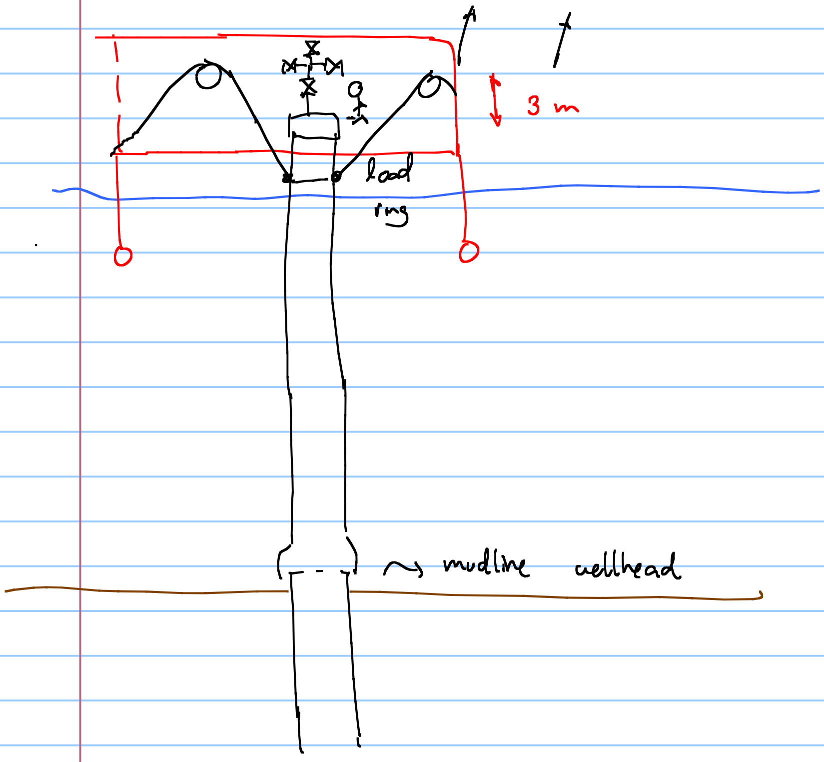
Asta Hansteen first SPAR with storage (150 000 stb)

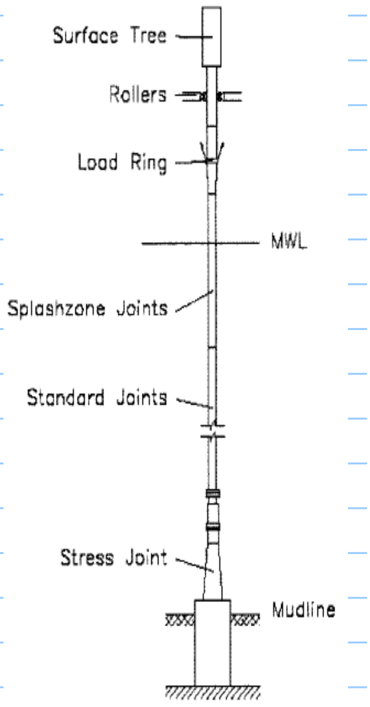
- X-mas tree type:
  - Reservoir extent and structure (depends also on Capacity of drilling package)
  - Current record for dry X-mas trees: 1700 m water depth
  - Intervention requirements { artificial lift → dry X-mas trees
    e.g. ESP lifetime is 6 mts
    1-5 years
  - future field expansion plans (infill drilling)

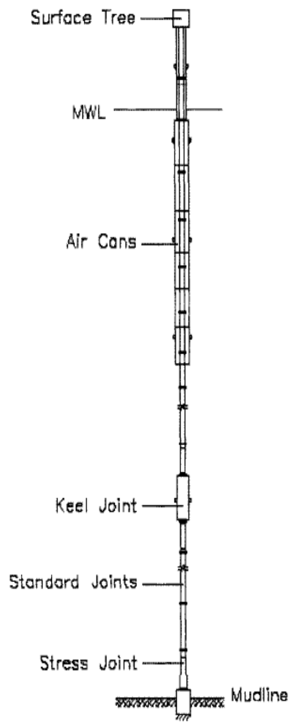
    Dry X-mas trees are drilled from well bay, and it has limited tree slots for this purpose.
  - severity of flow assurance issues

Dry X-mas trees can only be installed in: GBS, Jacket, compliant tower SPAR, TLP

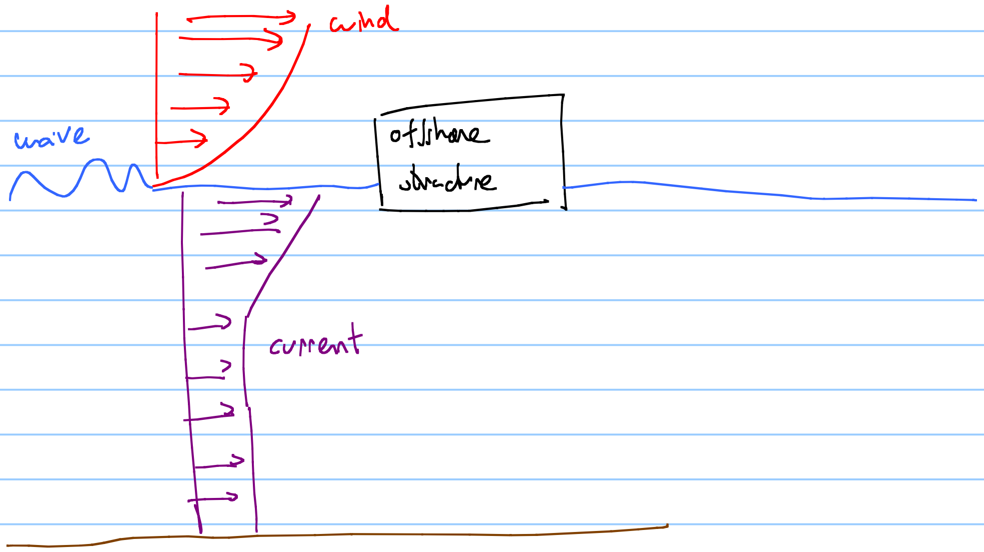
wells are drilled just like onshore



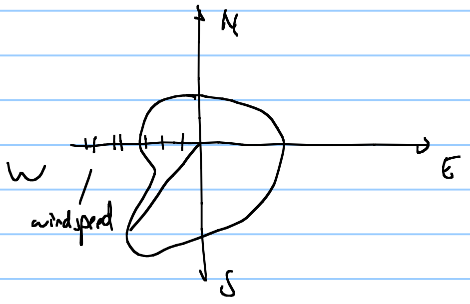


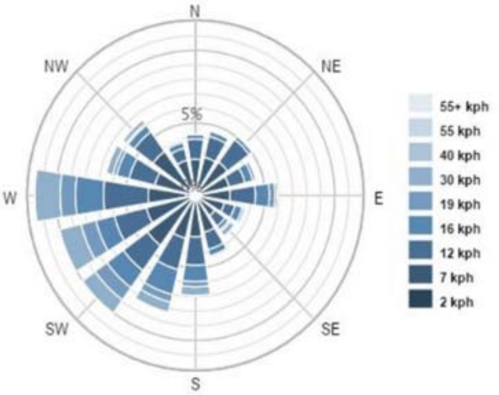


- Marine loads on offshore structure
  - wind



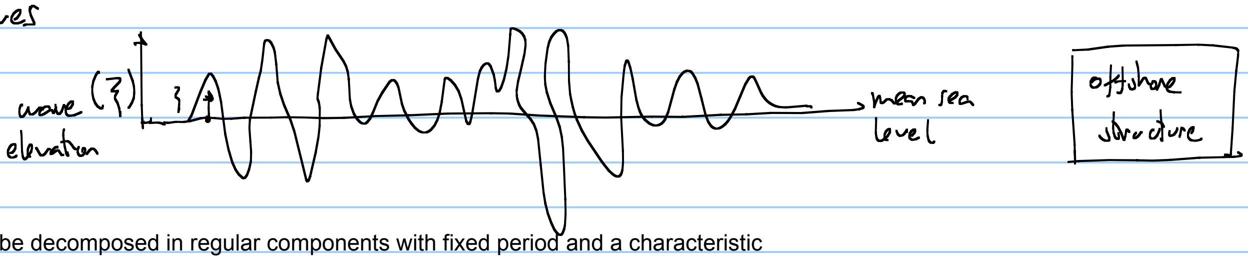
- usually wind is considered constant except for some floating structures, Direction must be taken into account



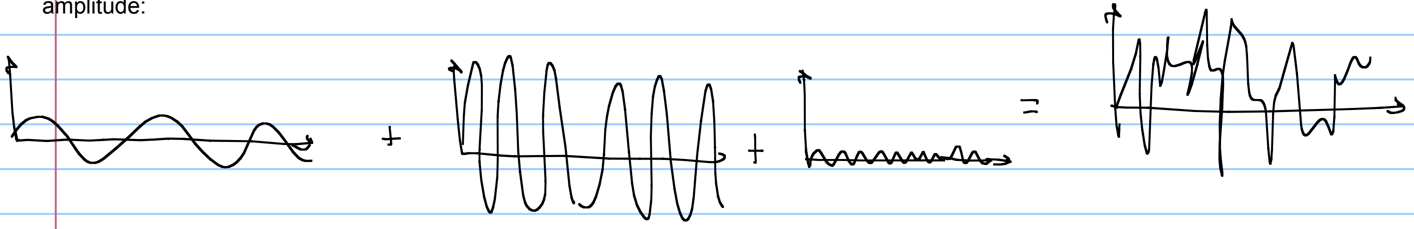


- currents the variation with depth is considered. Slow variation with time. a constant value is used, for example 100 year current

- waves



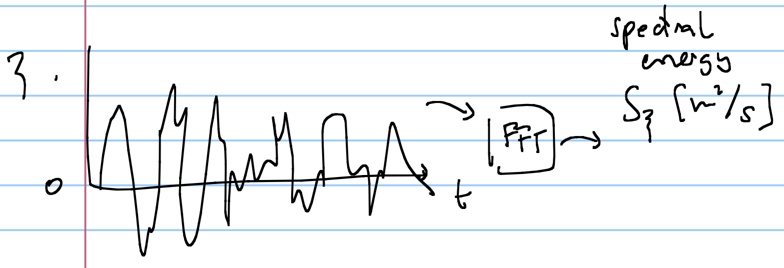
waves can be decomposed in regular components with fixed period and a characteristic amplitude:

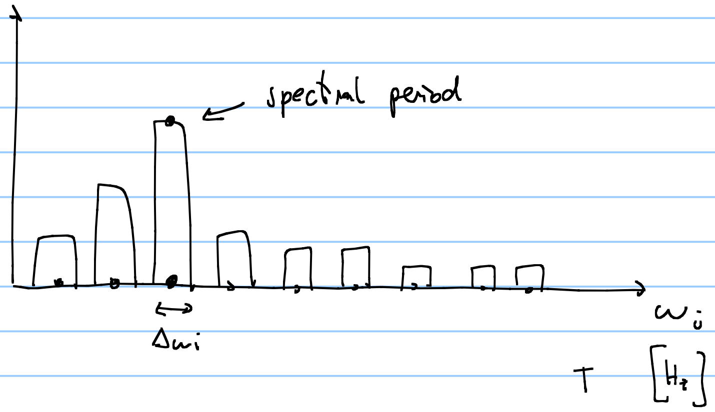


$$\zeta(t) = \sum_{i=1}^{N} \zeta_i \sin(\omega_i t + \varepsilon_i)$$

FFT Fast Fourier Transform

$$\zeta_i = \sqrt{2\, S_{\zeta_i} \cdot \Delta\omega_i}$$



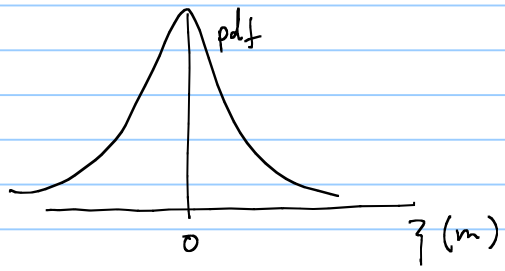


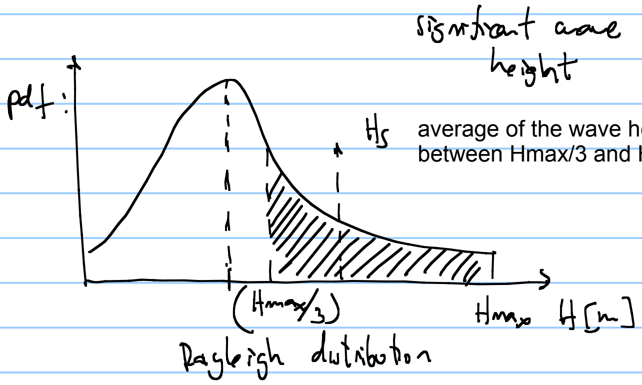
for a given sea state (3 hrs.) it will have a clear dominant period

wave data is usually collected
- observations
- buoys attached to ship (merchant, exploration)
- weather

at least two years.

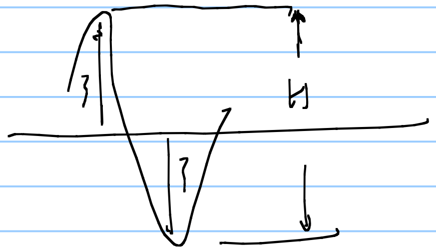
in a given sea state, wave elevation is distributed normally around zero "0"





average of the wave height between Hmax/3 and Hmax

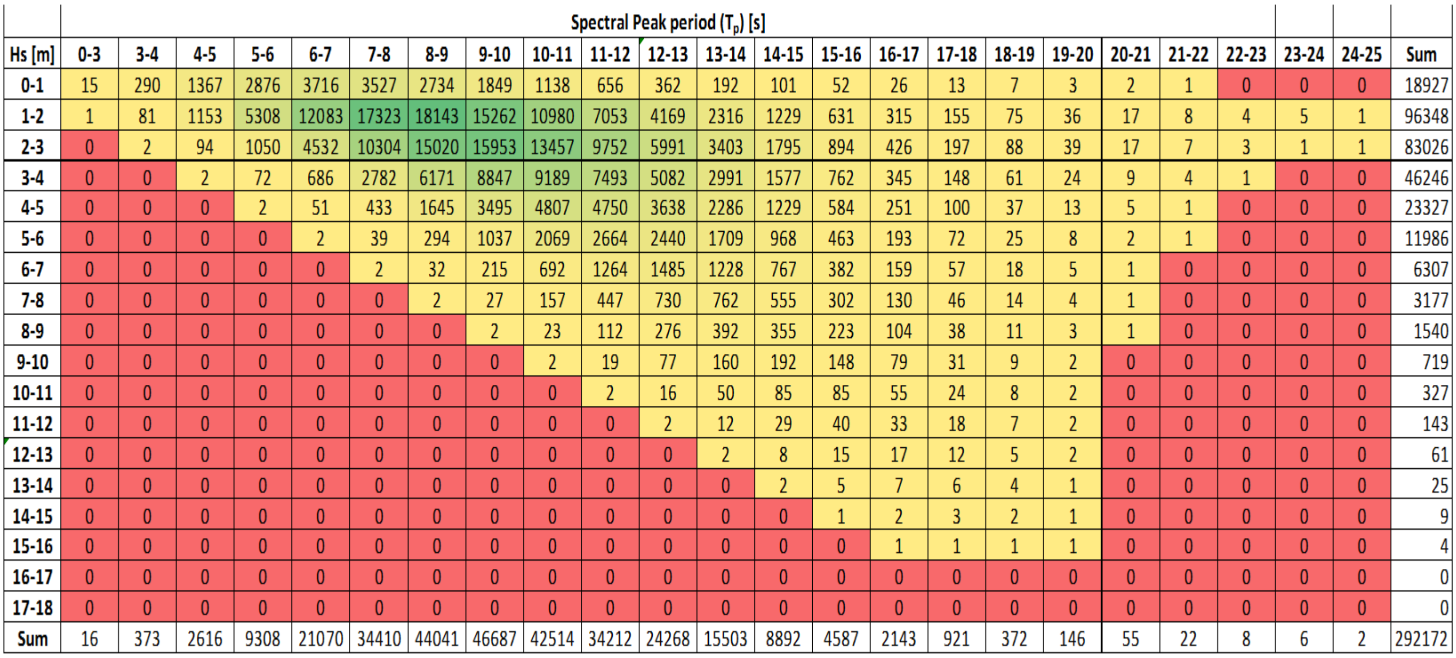
wave height distance between two consecutive crests and valley



each sea state has an associated period T_p and significant wave height (Hs)

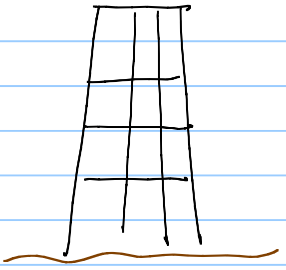
Tp (s)

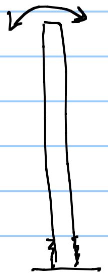
Hs (m)	0-3	3-4	5-6			24-25
0-1			||||	||	|	
1-2						
⋮						
17-18						

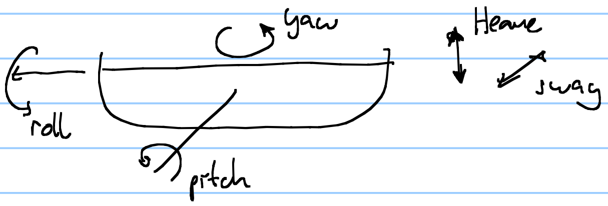


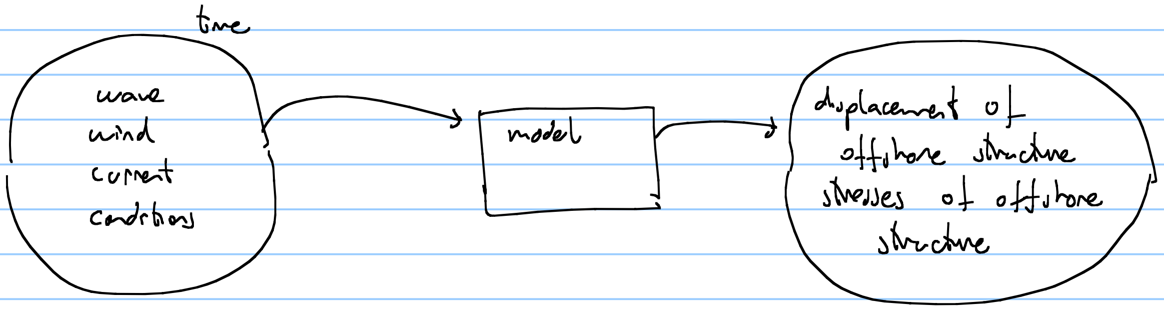
	Spectral Peak period (T_p) [s]																							
Hs [m]	**0-3**	**3-4**	**4-5**	**5-6**	**6-7**	**7-8**	**8-9**	**9-10**	**10-11**	**11-12**	**12-13**	**13-14**	**14-15**	**15-16**	**16-17**	**17-18**	**18-19**	**19-20**	**20-21**	**21-22**	**22-23**	**23-24**	**24-25**	**Sum**
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1	96348
2-3	0	2	94	1050	4532	10304	15020	15953	13457	9752	5991	3403	1795	894	426	197	88	39	17	7	3	1	1	83026
3-4	0	0	2	72	686	2782	6171	8847	9189	7493	5082	2991	1577	762	345	148	61	24	9	4	1	0	0	46246
4-5	0	0	0	2	51	433	1645	3495	4807	4750	3638	2286	1229	584	251	100	37	13	5	1	0	0	0	23327
5-6	0	0	0	0	2	39	294	1037	2069	2664	2440	1709	968	463	193	72	25	8	2	1	0	0	0	11986
6-7	0	0	0	0	0	2	32	215	692	1264	1485	1228	767	382	159	57	18	5	1	0	0	0	0	6307
7-8	0	0	0	0	0	0	2	27	157	447	730	762	555	302	130	46	14	4	1	0	0	0	0	3177
8-9	0	0	0	0	0	0	0	2	23	112	276	392	355	223	104	38	11	3	1	0	0	0	0	1540
9-10	0	0	0	0	0	0	0	0	2	19	77	160	192	148	79	31	9	2	0	0	0	0	0	719
10-11	0	0	0	0	0	0	0	0	0	2	16	50	85	85	55	24	8	2	0	0	0	0	0	327
11-12	0	0	0	0	0	0	0	0	0	0	2	12	29	40	33	18	7	2	0	0	0	0	0	143
12-13	0	0	0	0	0	0	0	0	0	0	0	2	8	15	17	12	5	2	0	0	0	0	0	61
13-14	0	0	0	0	0	0	0	0	0	0	0	0	2	5	7	6	4	1	0	0	0	0	0	25
14-15	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0	9
15-16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	4
16-17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17-18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	16	373	2616	9308	21070	34410	44041	46687	42514	34212	24268	15503	8892	4587	2143	921	372	146	55	22	8	6	2	292172

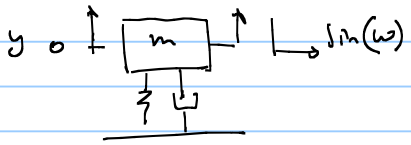
- for platforms, height of deck must be defined based on 100-year wave H_{s100}
  - use Tp - Hs to calculate loads on offshore structure









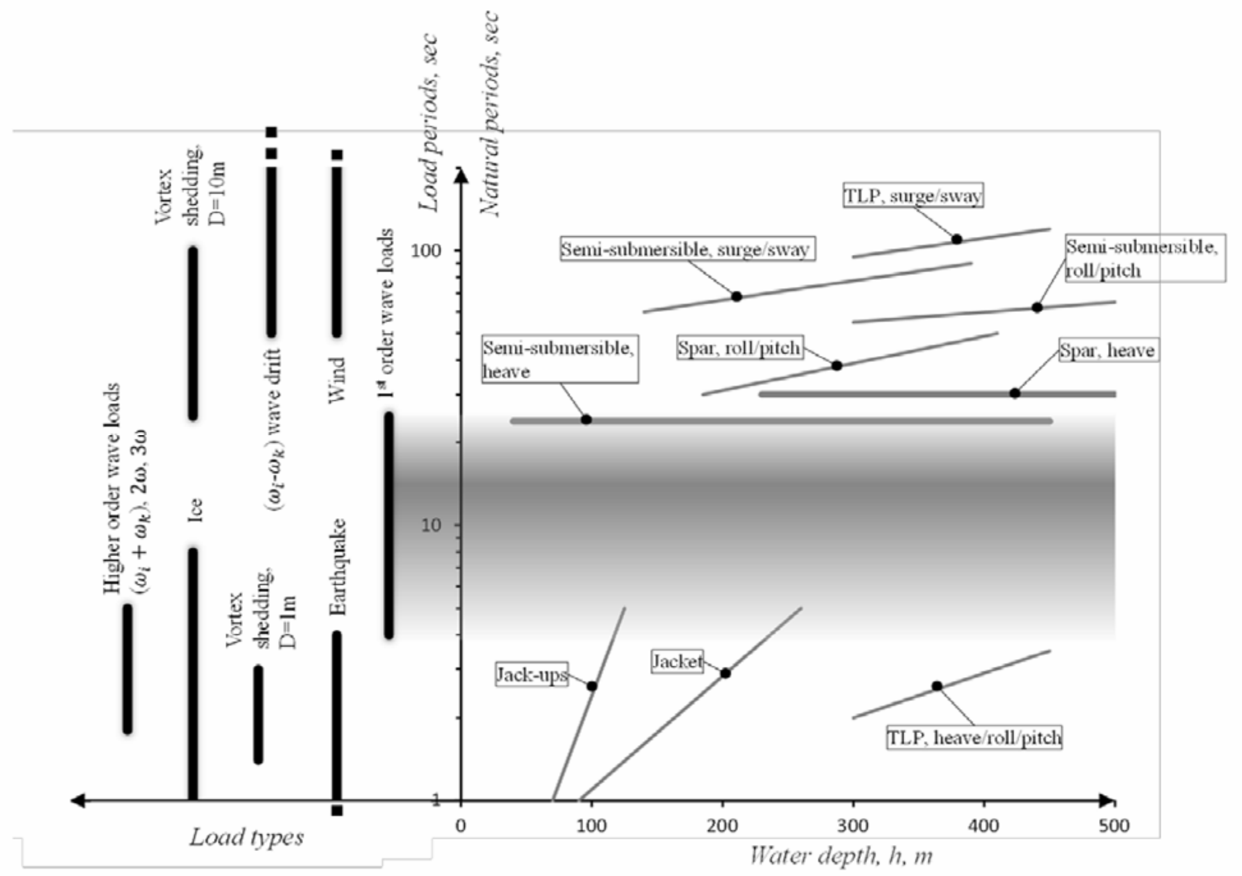


mechanical system analog of a offshore structure

resonance (natural frequency)

Resonance will occur when the excitation frequency is equa
to the natural frequency of the structure (maximum amplituc

Example: natural frequencies of some offshore structures



previous section and applied on the structure. Due to the variability of these loads, there are usually three main design approaches:

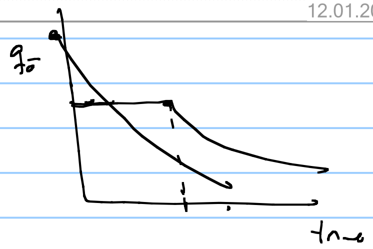
- **Design wave:** perform the analysis using the 100 year significant wave height ($H_{S,100}$) and a suitable range of wave periods. If more accurate estimates are not available, the Norwegian standard NORSOK N-003 suggests to take $H_{S,100}$ = 1.9 · H_S and vary the wave period between $\sqrt{6.5 \cdot H_{S,100}} \leq T \leq \sqrt{11 \cdot H_{S,100}}$.
- **Short term design:** perform the analysis for a 100 year storm of specified duration (3-6 h) with an associated frequency spectrum. This is usually done to predict dynamic loads and stresses on critical load-bearing components.
- **Long term design:** This analysis takes into account the long term varying weather conditions. This is important for fatigue design.

20180227

Flow performance of production systems

$$\downarrow$$

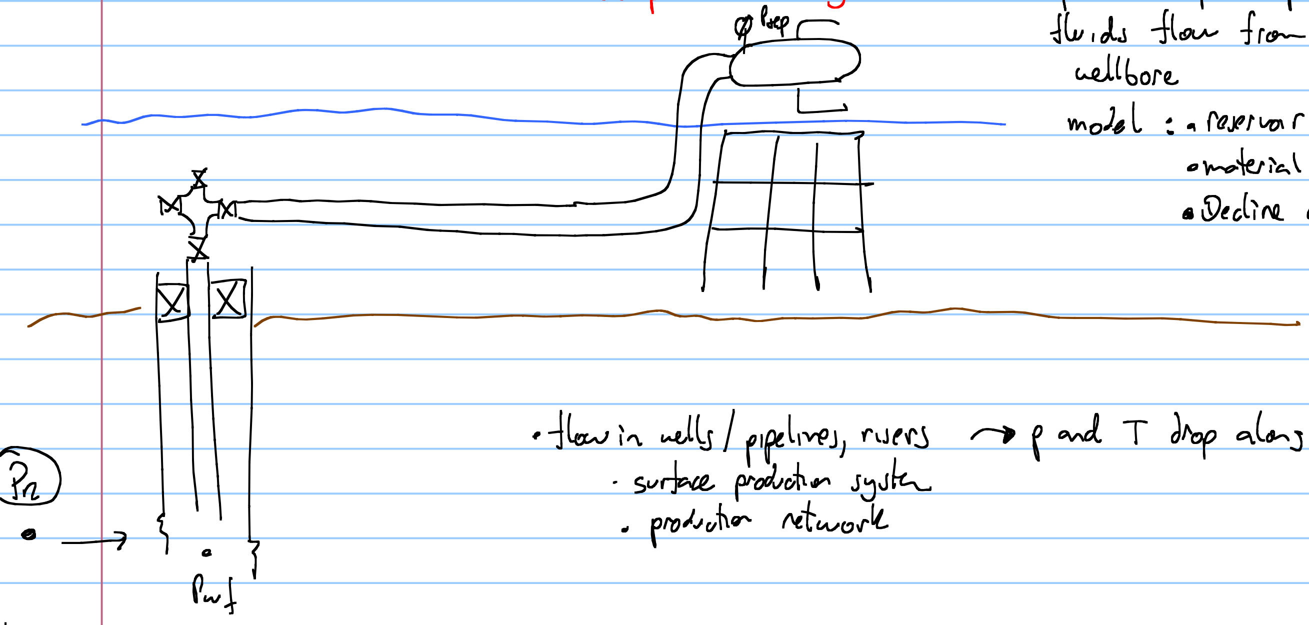
$$NPV \quad f\left(\underline{q_o(t)}\right)$$



- Depends on : · deliverability of formation → storability of formation p vs time

  discipline: Res. eng. → pressure drop in porous media when fluids flow from formation to wellbore

  model : • reservoir simulator
  - material balance 0D
  - Decline curve analysis



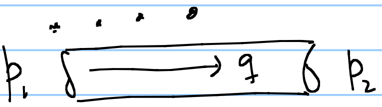
- flow in wells / pipelines, risers → p and T drop along the system
  - surface production system
  - production network

Pr is a function of time,

In early development stages only reservoir model is used for production forecast

<u>Flow equilibrium:</u>

horizontal pipe with single phase fluid



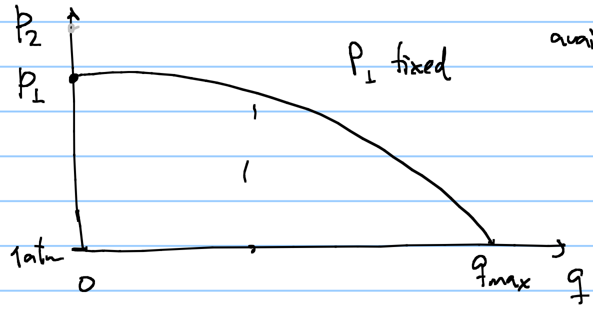
$$P_2 = P_1 + \Delta p$$

$$\Delta p = \Delta p_g + \Delta p_f$$

1: with P_1 fixed and q

↳ calculate P_2

upstream to downstream calculation
co-current

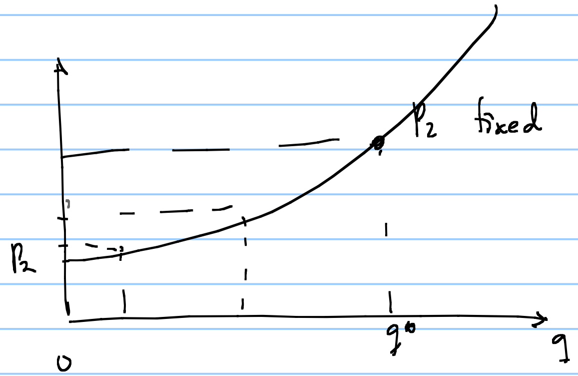


available pressure at pipe outlet

2: with P_2 fixed and q

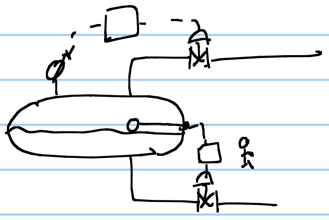
calculate P_1

downstream to upstream calculation
counter-current

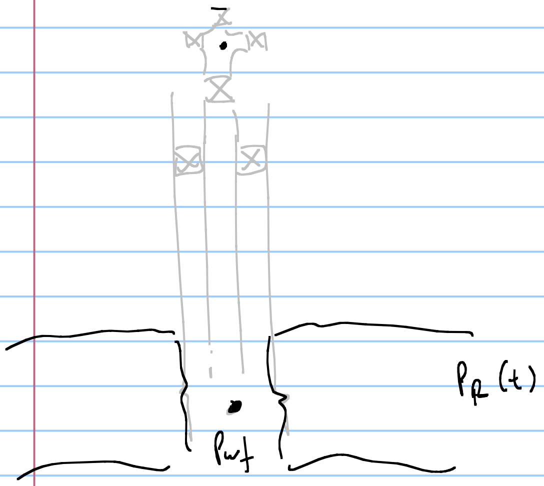


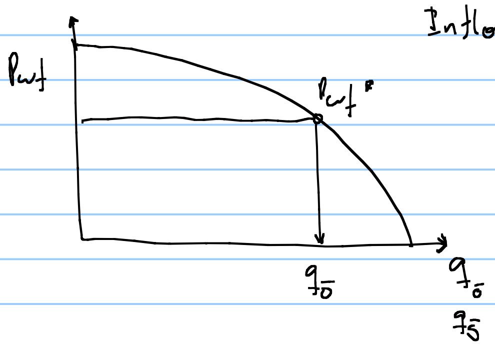
required pressure at pipe inlet

3: provide P_1, P_2 ~> calculate q



the same curves can be used to characterize parts of the production system





Inflow performace relationship (IPR)

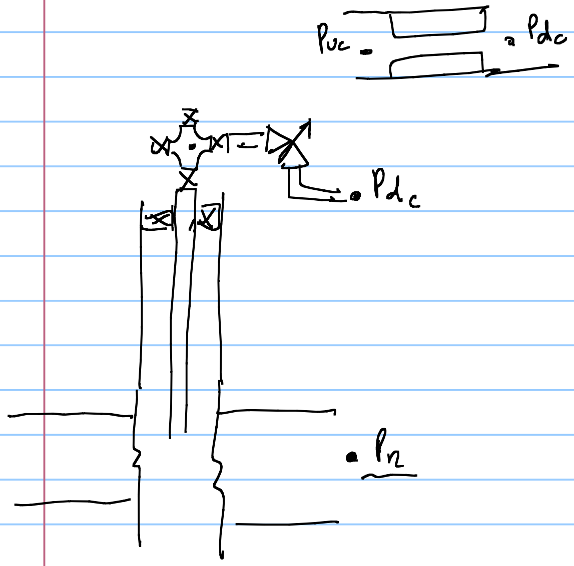
for undersaturated oil wells

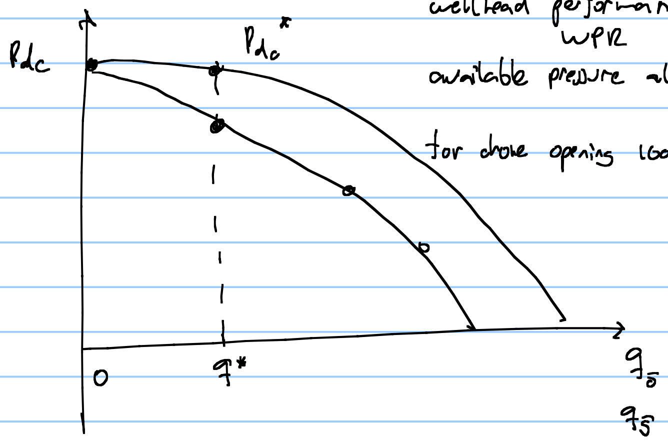
$q_o = J(P_R - P_{wf})$

$q_{\bar{o}}$ ~> standard conditions rate

for dry gas low pressure

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





wellhead performance relationship WPR

available pressure at wellhead

for choke opening 100%

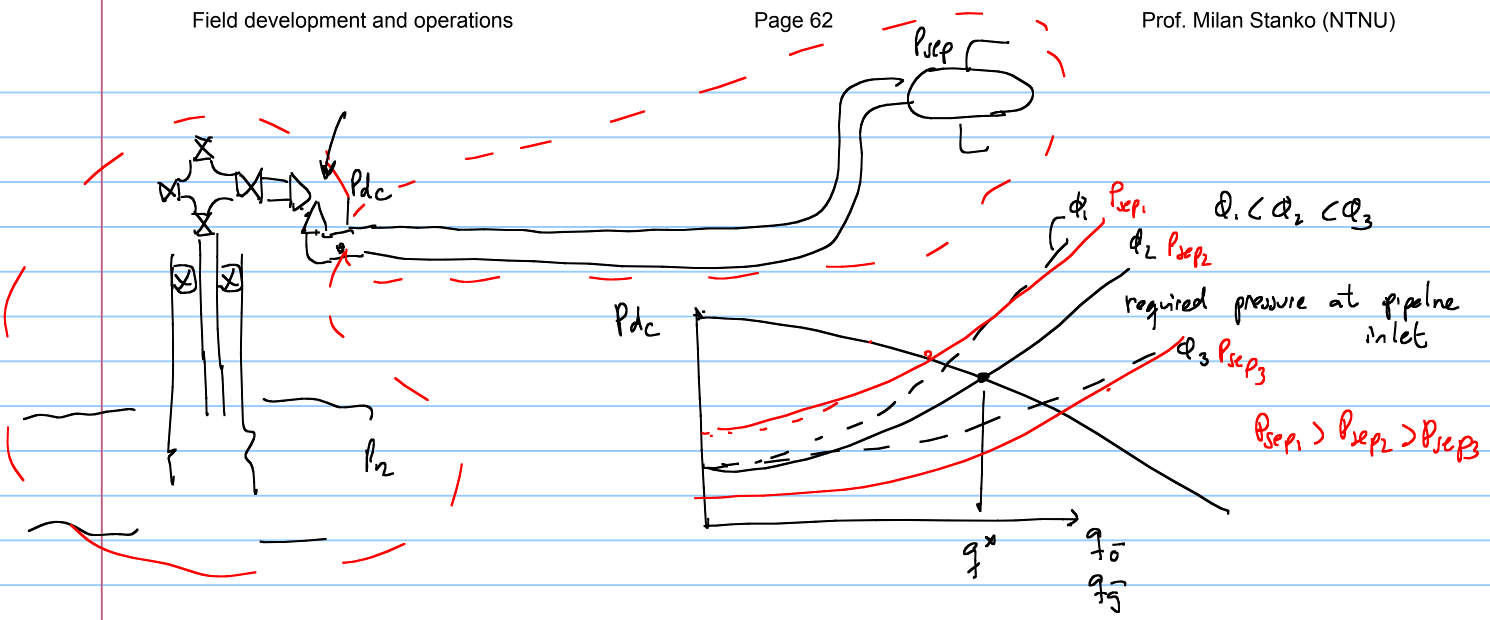
$P_{dc} = P_R - \Delta p_{res} - \Delta p_{tubing} - \Delta p_{choke}$

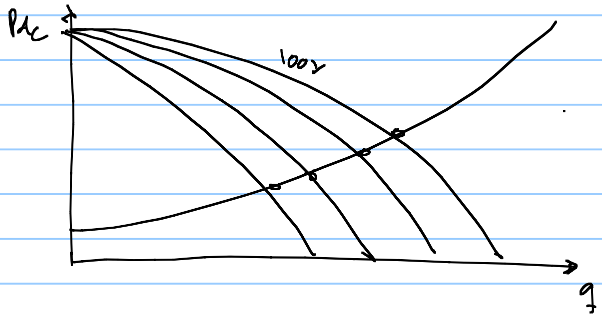
for 100% choke opening $\Delta p_{choke} = 0$

$P_{dc} = P_R - \Delta p_{res} - \Delta p_{tub}$

for 80% choke opening $\Delta p_{cho} \neq 0$

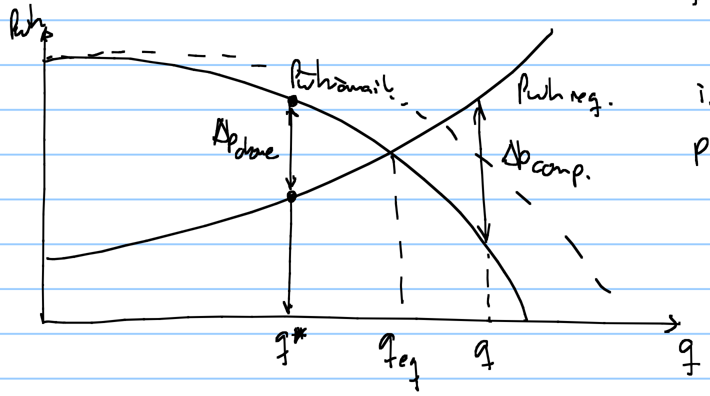
$P_{dc} = P_R - \Delta p_{res} - \Delta p_{tubing} - \Delta p_{cho}$





analysis useful for performance evaluation

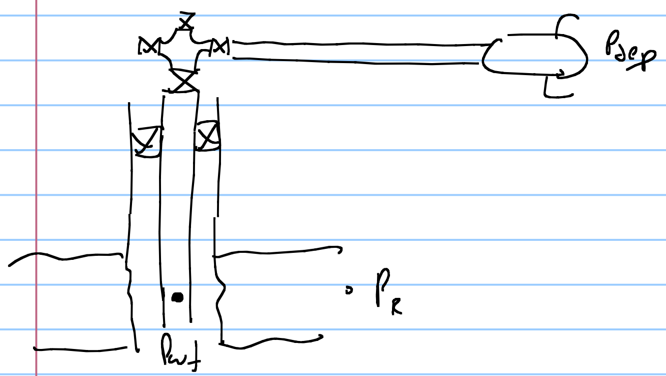
- remove the choke from system (assume open choke)

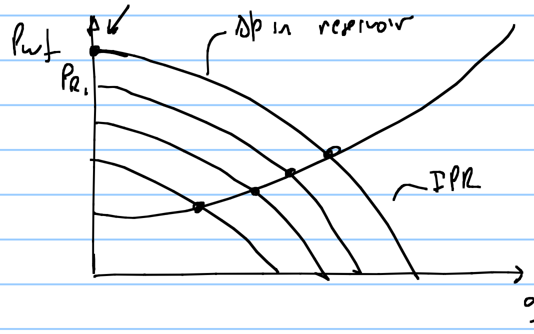


is useful for design phase

for design-type analysis, the equilibrium point must be at location of equipment.

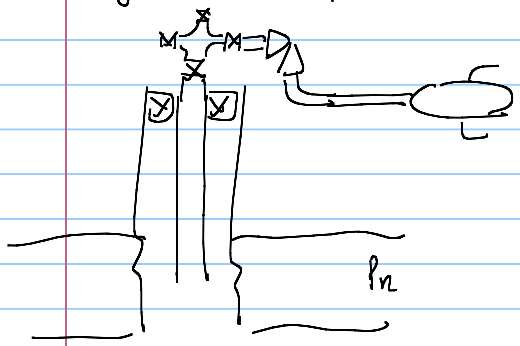
Depletion effect (time effect)

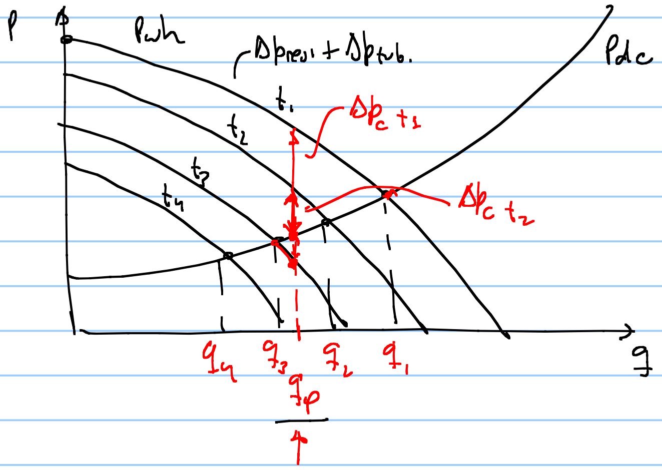


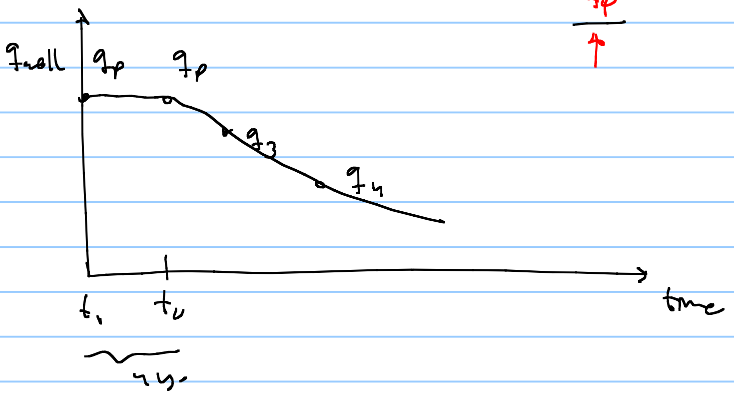


$$q_o = J\,(\underline{P_R} - P_{wf})$$

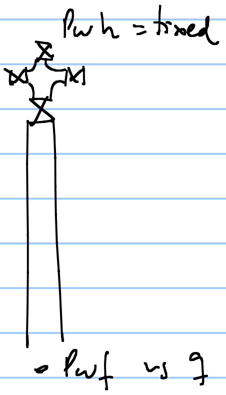
System with depletion and adjustable choke

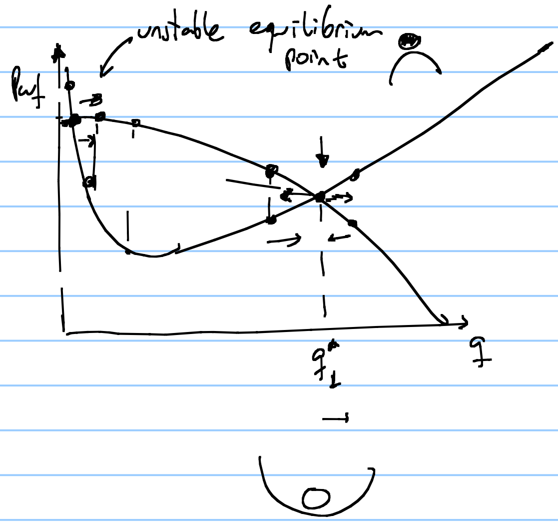






when the flow is multiphase G + liquid the pressure curve looks slightly
O + gas + water different

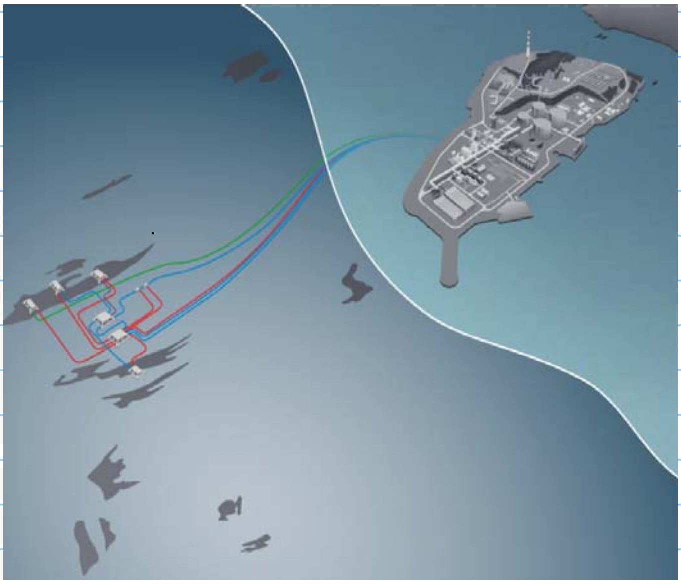




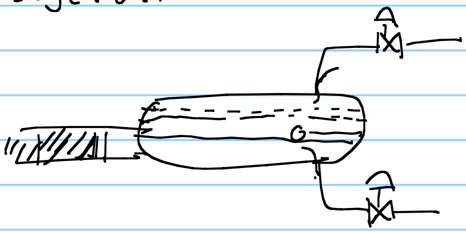
20180305 Production scheduling calculations for Snowhite field
Snøhvit

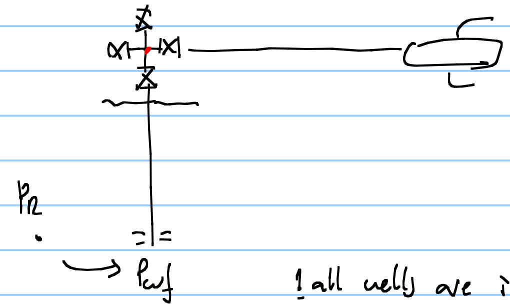
$q_{field} = 20\ E6\ Sm^3/d$ for 20 years

(by contract)

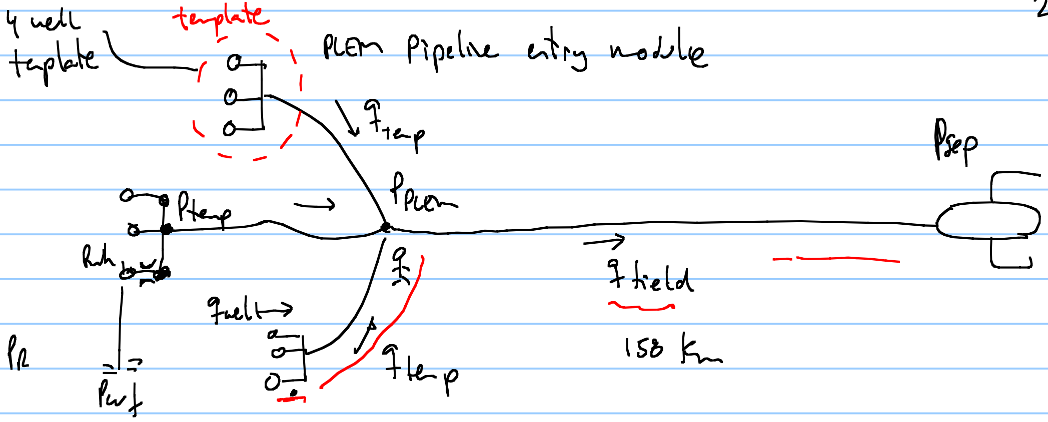


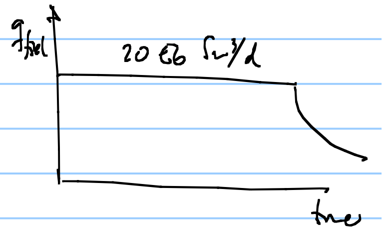
slug catcher





1 all wells are identical
2: the system is symmetric
3: q_{well} is same
q_{temp} is sample





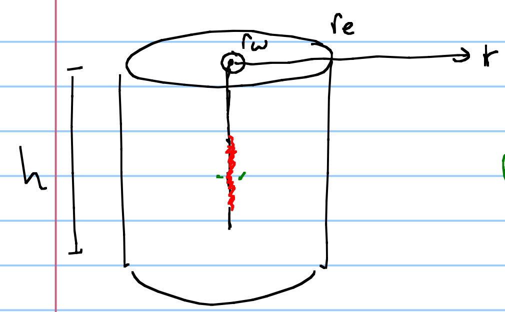
- Equilibrium point is choke

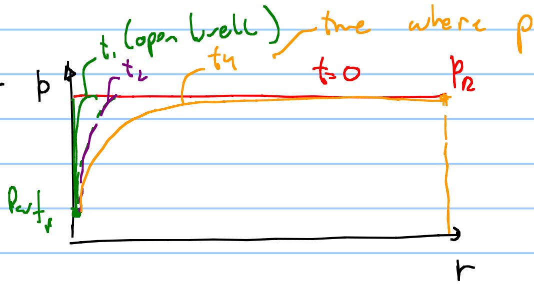
- Dry gas

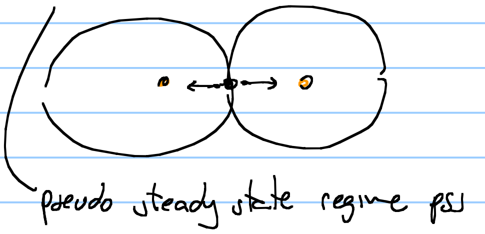
Inflow performance relationship:

- Backpressure equation $q_{well} = C_R \left(p_R^2 - p_{wf}^2\right)^{\boxed{n}}$ is valid for low pressures (100 bara >)

↳ accounts for non-Darcy flow n=1 darcy flow n=0.5 turbulent flow







the backpressure equation is derived by applying Darcy law on radial homogeneous single well geometry

$$q_g = \frac{2\pi k h}{\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S + Dq\right]} \frac{T_{sc}}{p_{sc} T_R} \int_{p_{wf}}^{p_R} \frac{p}{\mu z} dp \Big\}$$

- Dry gas tubing equation (derivation in page 164 of compendium)

$$q_{well} = C_T \left(\frac{p_{wf}^2}{e^S} - p_2^2\right)^{0.5} \qquad S = \frac{28.97 \cdot \gamma_g \, g \, H}{z_{av} \cdot R \cdot T_{av}}$$

H ← height difference between wf and wh

$$C_T = \frac{\pi}{4} \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \left(\frac{T_{sc}}{p_{sc}}\right) \left[\frac{D^5}{\gamma_g \cdot f_m \cdot z_{av} T_{av} \cdot L}\right]^{0.5} \left[\frac{S e^S}{e^S - 1}\right]^{0.5}$$

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

- flowline and pipeline → 1: horizontal pipe

$$q_g = C_{FL} \left(P_{in}^2 - P_{OUT}^2\right)^{0.5}$$

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

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

Solve system of equations :

$$\overset{?}{q_w} = \overset{\checkmark}{C_R}\left(\overset{\checkmark}{P_R}^2 - \overset{?}{P_{wf}}^2\right)^{\overset{\checkmark}{n}}$$ 2 unknown

$$\overset{?}{q_w} = \overset{\checkmark}{C_T}\left(\frac{\overset{?}{P_{wf}}^2}{e^S} - \overset{?}{P_{wh}}^2\right)^{0.5}$$ 1 add. unknown

$q_{temp} = 3 . q_w$

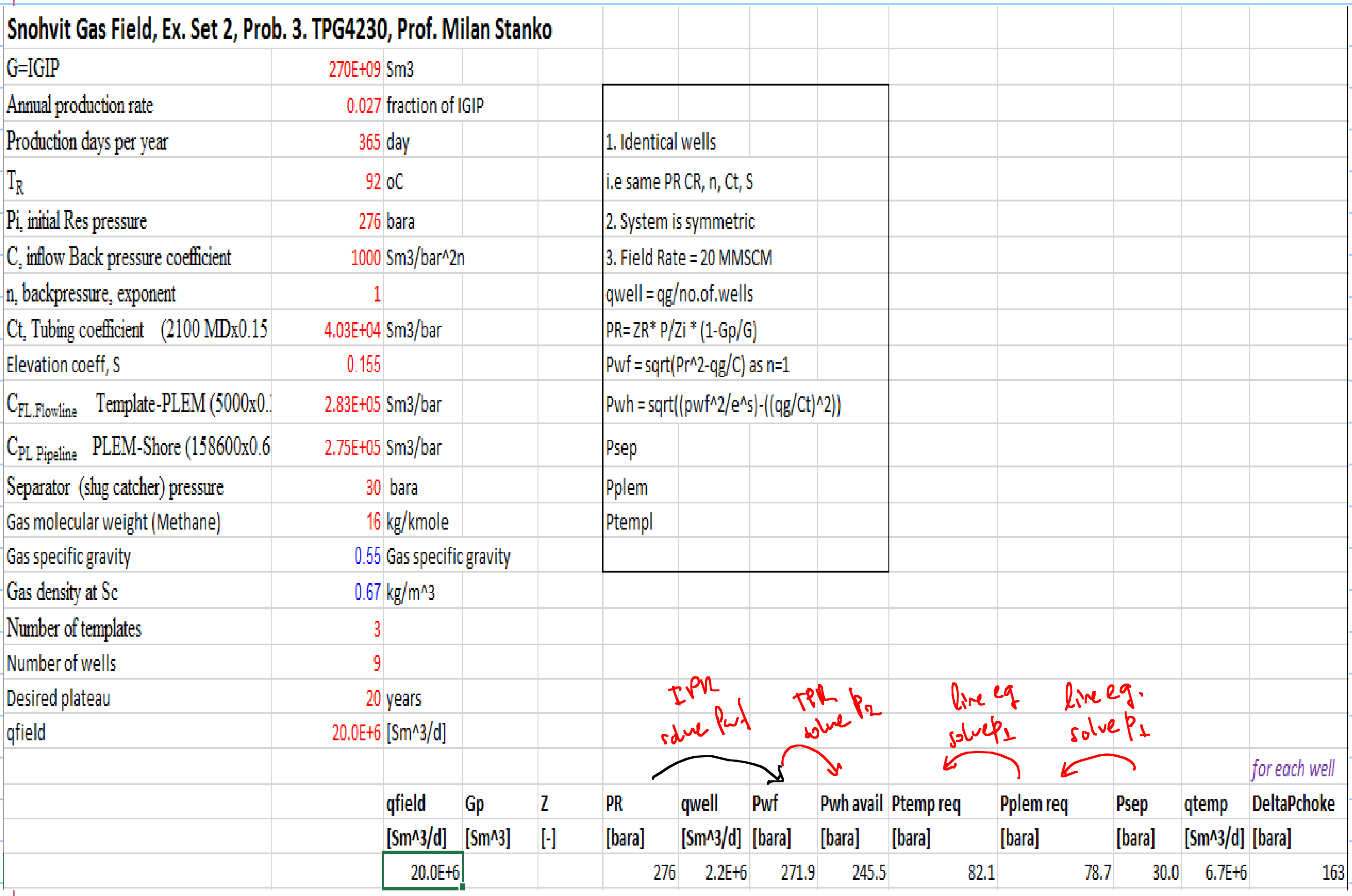
$$q_{Temp} = \overset{\checkmark}{C_{FL}}\left(\overset{?}{P_{Tem}}^2 - \overset{?}{P_{PLEM}}^2\right)^{0.5}$$ 2 add unknowns

$$q_{field} = \overset{\checkmark}{C_{PL}}\left(\overset{?}{P_{PLEM}}^2 - \overset{\checkmark}{P_{Sep}}^2\right)^{0.5}$$

4 equations. 5 unknowns

if calculation natural equ → for open choke $\boxed{P_{wh} = P_{Temp}}$ 5 eq, 5 unk.

plateau calculations → $q_{field} = 20E6$ Sm³/d 4 eq, 4 unk



Snohvit Gas Field, Ex. Set 2, Prob. 3. TPG4230, Prof. Milan Stanko

G=IGIP	270E+09	Sm3
Annual production rate	0.027	fraction of IGIP
Production days per year	365	day
T_R	92	oC
Pi, initial Res pressure	276	bara
C, inflow Back pressure coefficient	1000	Sm3/bar^2n
n, backpressure, exponent	1	
Ct, Tubing coefficient (2100 MDx0.15	4.03E+04	Sm3/bar
Elevation coeff, S	0.155	
$C_{FL\ Flowline}$ Template-PLEM (5000x0.	2.83E+05	Sm3/bar
$C_{PL\ Pipeline}$ PLEM-Shore (158600x0.6	2.75E+05	Sm3/bar
Separator (slug catcher) pressure	30	bara
Gas molecular weight (Methane)	16	kg/kmole
Gas specific gravity	0.55	Gas specific gravity
Gas density at Sc	0.67	kg/m^3
Number of templates	3	
Number of wells	9	
Desired plateau	20	years
qfield	20.0E+6	[Sm^3/d]

1. Identical wells
i.e same PR CR, n, Ct, S
2. System is symmetric
3. Field Rate = 20 MMSCM
qwell = qg/no.of.wells
PR= ZR* P/Zi * (1-Gp/G)
Pwf = sqrt(Pr^2-qg/C) as n=1
Pwh = sqrt((pwf^2/e^s)-((qg/Ct)^2))
Psep
Pplem
Ptempl

IPR solve Pwf

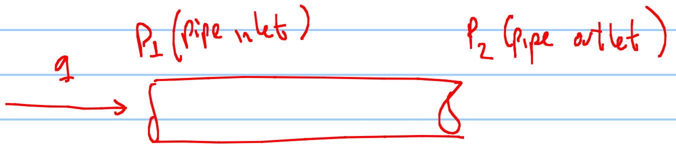
TPR solve P2

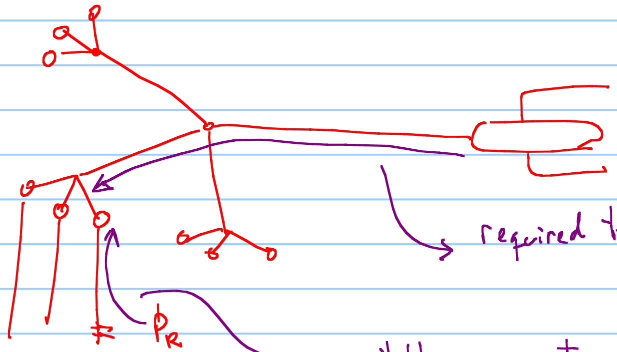
line eq solve P1

line eq. solve P1

for each well

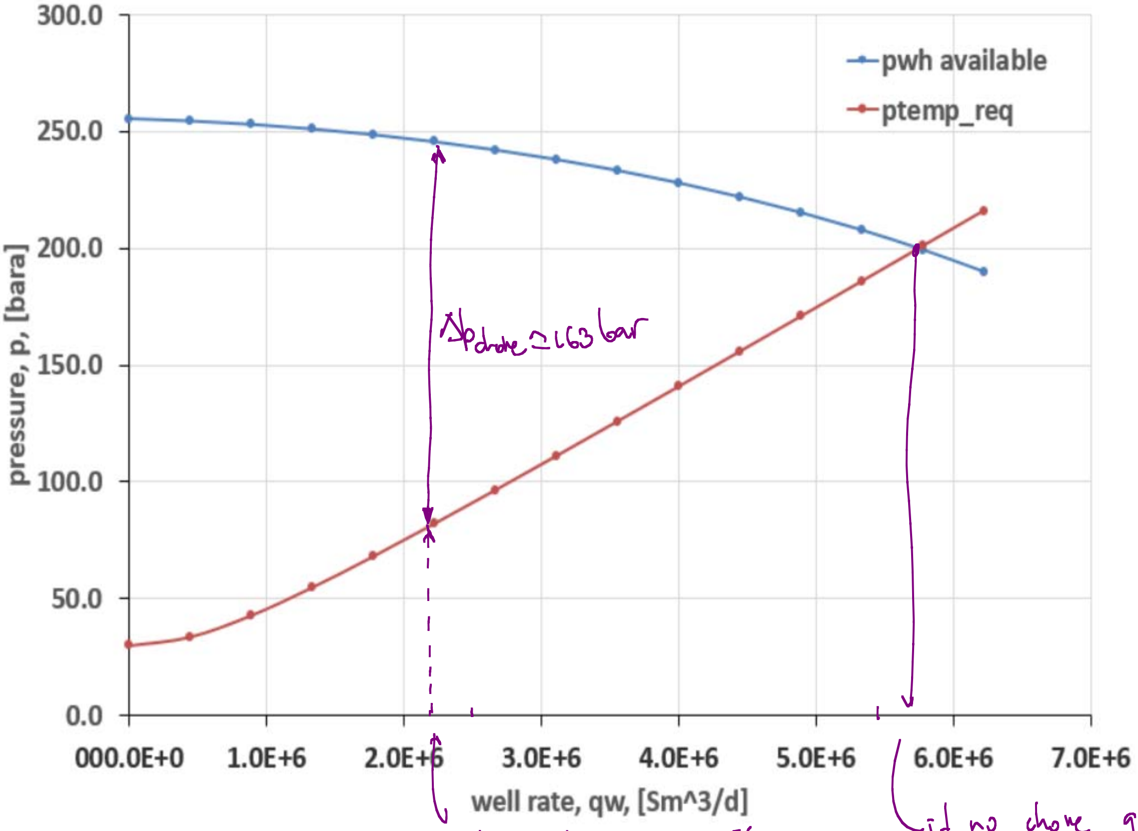
qfield	Gp	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke
[Sm^3/d]	[Sm^3]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bara]
20.0E+6			276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163





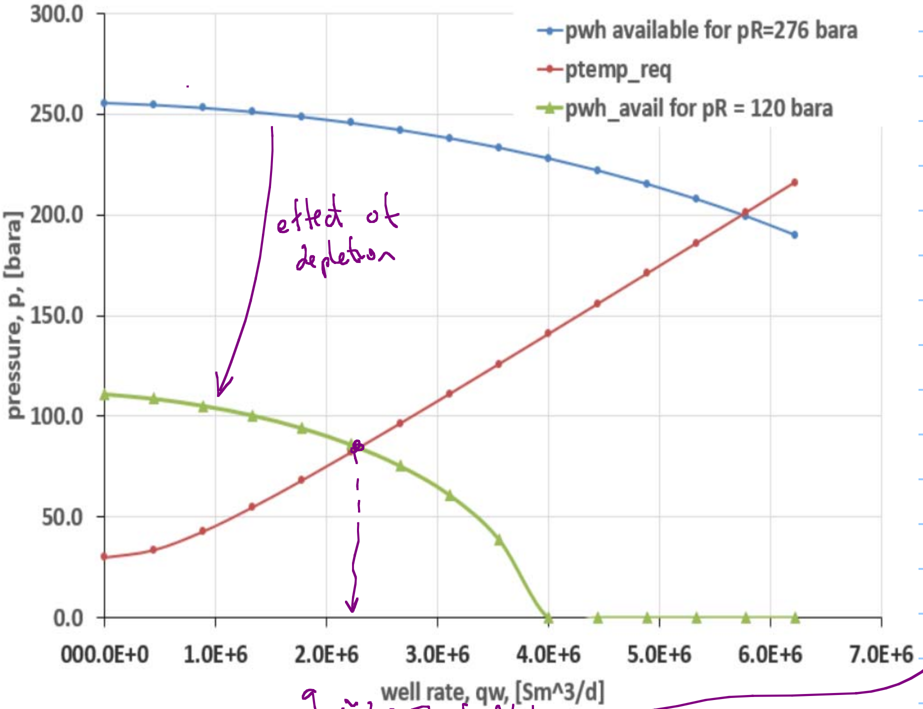
required template pressure (downstream choke)

available pressure at wellhead (upstream choke)



plateau rate $q_w = \frac{20 E6}{9} = 2.2 E6\ Sm^3/d$

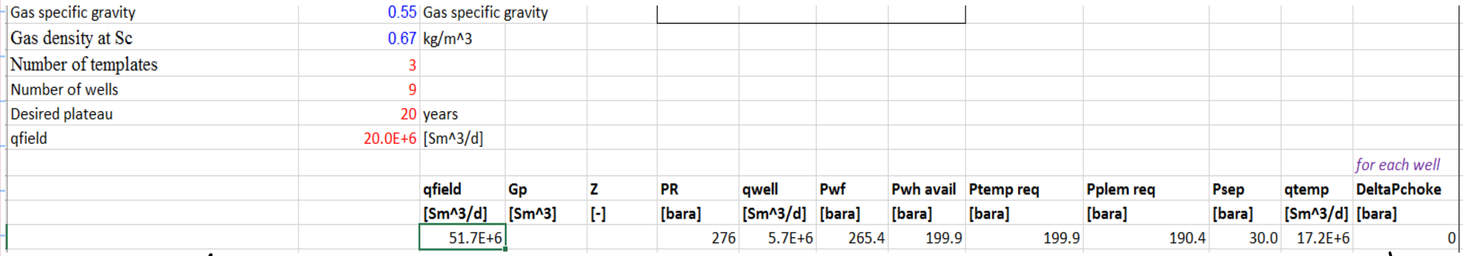
if no choke $q_{well} \simeq 5.75 E6\ Sm^3/d$



$q_w \simeq 2.2 E6\ Sm^3/d$

the end of plateau will be (approx.) when $p_R \simeq 120$ bara

20180306



Gas specific gravity	0.55	Gas specific gravity
Gas density at Sc	0.67	kg/m^3
Number of templates	3	
Number of wells	9	
Desired plateau	20	years
qfield	20.0E+6	[Sm^3/d]

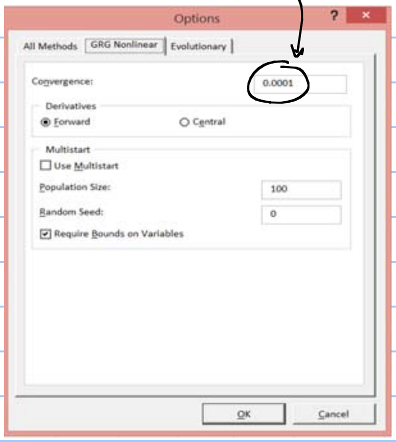
											for each well
qfield	Gp	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke
[Sm^3/d]	[Sm^3]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bara]
51.7E+6			276	5.7E+6	265.4	199.9	199.9	190.4	30.0	17.2E+6	0

how to find equilibrium rate when choke is fully open

→ change this to drive to "zero"

AKA production potential of field

$0 \pm (\varepsilon)$ tolerance

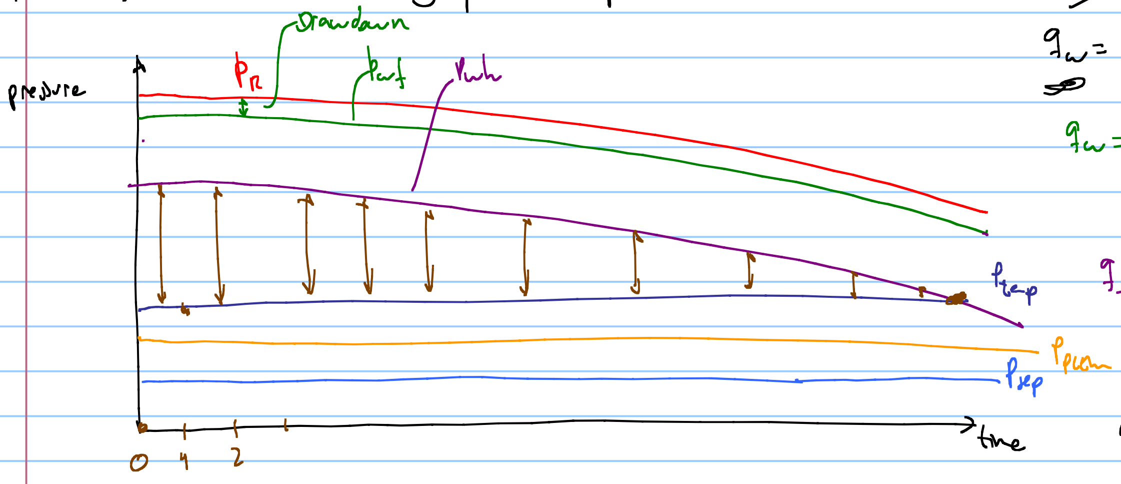


Convergence: 0.0001

Derivatives
● Forward ○ Central

Multistart
☐ Use Multistart
Population Size: 100
Random Seed: 0
☑ Require Bounds on Variables

Depletion effect when estimating production profile



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

$$q_w = C_T \left(\frac{P_{wf}^2}{e^s} - P_{wh}^2\right)^{0.5}$$

$$q_{field} = C_R \left(P_{Plem}^2 - P_{sep}^2\right)^{0.5}$$

$$q_{temp} = C_{PL} \left(P_{temp}^2 - P_{Plem}^2\right)^{0.5}$$

we need an equation to compute P_R vs time

Dry gas material balance equation: $P_R = \frac{P_i \cdot z_R}{z_i}\left(1 - \frac{G_p}{G}\right)$

recovery factor

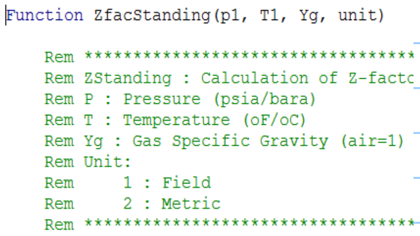
cumulative production

(1)

initial gas in place

VBA function zfac_Standing(p, T, γ_g, unit)

$$G_p = \int_0^t q_{field}\,dt = \underbrace{q_{plateau}}_{Sm^3/d}\,\underbrace{[t-0]}_{years}\,\underbrace{\frac{N_{days}}{year}}_{uptime}$$



```
Function ZfacStanding(p1, T1, Yg, unit)

    Rem *********************************
    Rem ZStanding : Calculation of Z-factc
    Rem P : Pressure (psia/bara)
    Rem T : Temperature (oF/oC)
    Rem Yg : Gas Specific Gravity (air=1)
    Rem Unit:
    Rem     1 : Field
    Rem     2 : Metric
    Rem *********************************
```

$$\boxed{PV = ZRT}$$

to solve eq. 1 (implicit)

- assume p_R
- Calculate Z_R
- use eq. to compute "real" p_R
- Compare $P_{R\,assume} \simeq P_{R\,real}$

same? NOT

Yes

achieved solution

in the exercise use Z_R previous time instead of current to avoid performing this process

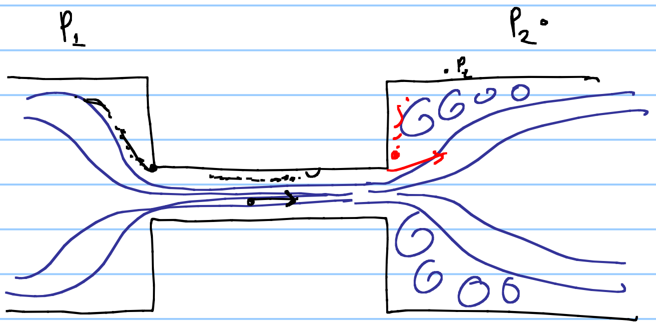
for year "0" we found we need a choke such as: $\Delta p = 163$ bar Pinlet = 245.5 bara

$q = 7.2\,E06\ Sm^3/d$

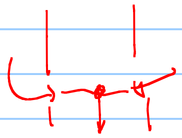
$\gamma_g = 0.55$

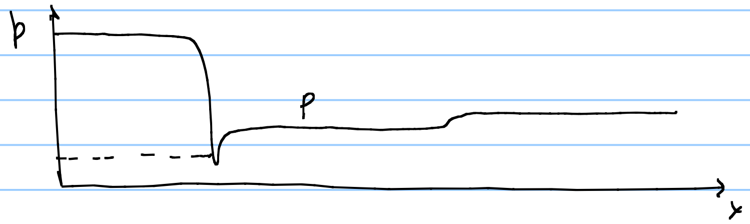
- erosion high Δp → higher velocities → higher wear

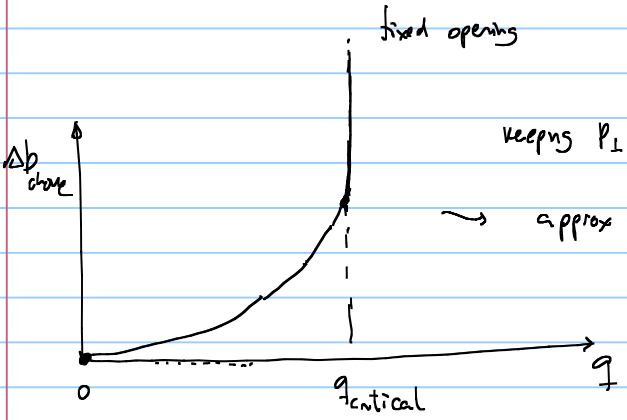
if Δp is too high, two chokes in series must be employed.



$\Delta p = P_1 - P_2$



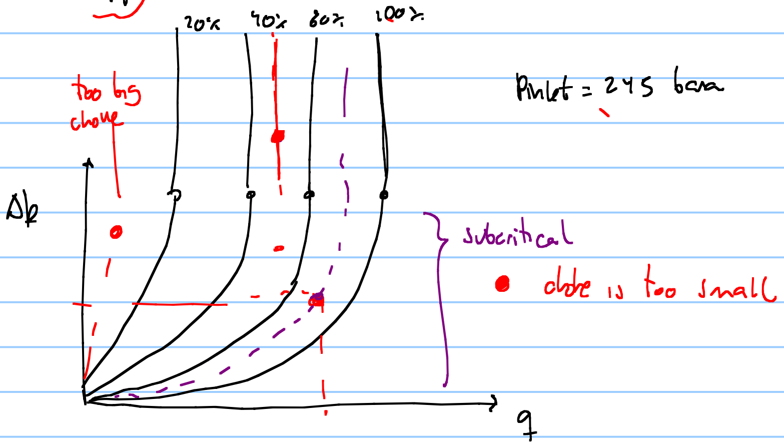




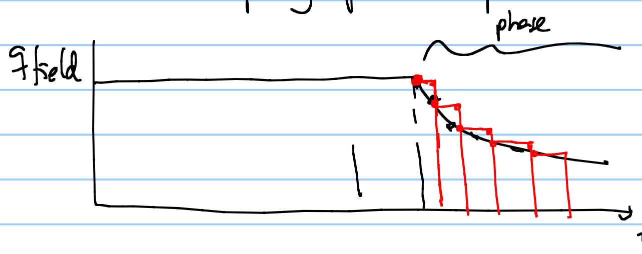
keeping P_1 fixed

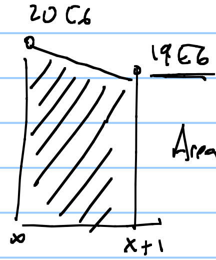
→ approx when $\frac{P_2}{P_1} \simeq 0.5 - 0.6$

at this point the flow becomes critical at choke throat



- Note : when computing production profile in decline mode :



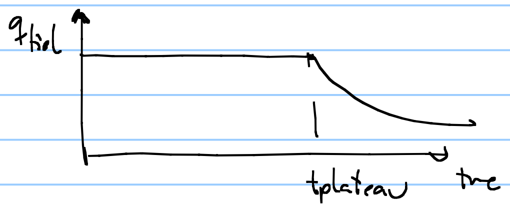


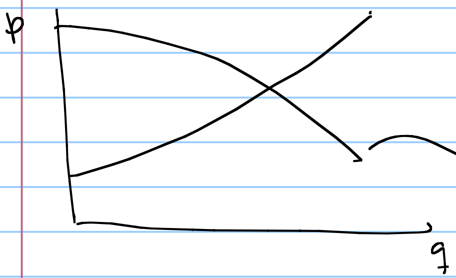
$$Area = \frac{(q_x + q_{x+1})(x+1-x)}{2}$$

time	q_{field}	G_p	P_R	P_{wf}	P_{wh}	P_{temp}	P_{plem}	P_{sep}	Δp_{choke}
x	20 E6		P_R						0
x+1	19 E6	○	P_{R*}						6

reducing the time-step improves the rectangular approximation.

how can we prolong the plateau

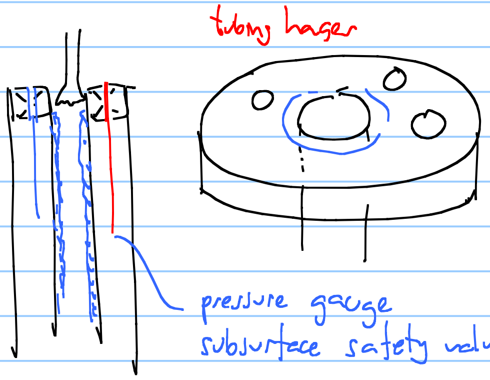




available pressure curve (reservoir + well + tubing)

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

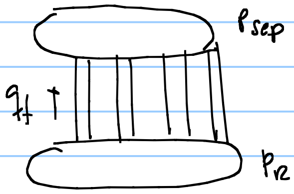
- increase well deliverability (re-perforate, fracking, stimulation, acidizing)



- increase ϕ $ and ϕ might be limited by tubing hanger size
- remove deposits.

required pressure curve (pipeline , flowline)

- increase ϕ $ ☹
- reduce separator pressure (if possible)
- deploy parallel lines



- add more wells $
- add boosting (subsea boosting) $

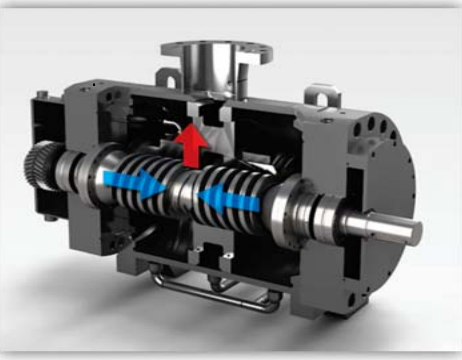
Surface boosting: → multiphase boosting

- twin screw pumps. } wide operation range
- helico-axial pump } low gas content / high gas content
- wet gas compressor ↳

↳ single phase boosting

typically requires separation before

{ ° Åsgard subsea compression




(a) Impeller (b) Diffuser

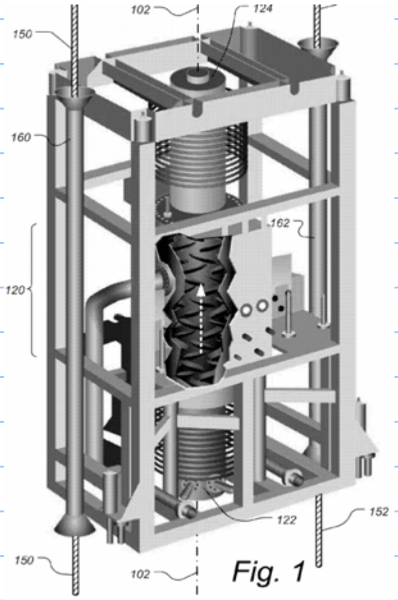
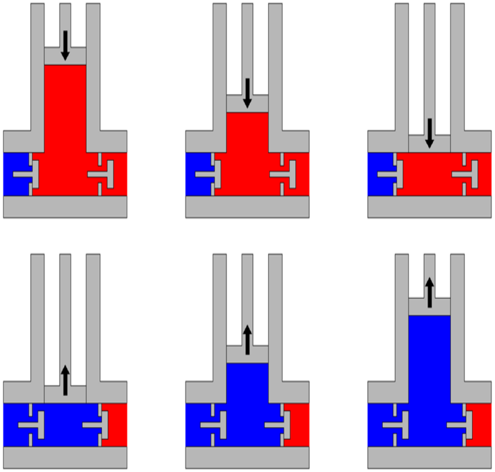


Fig. 1

based on positive displacement



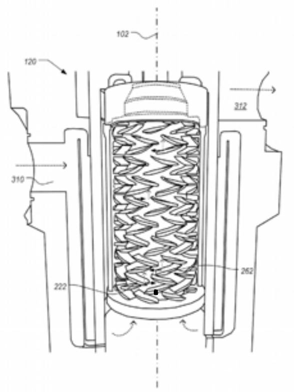
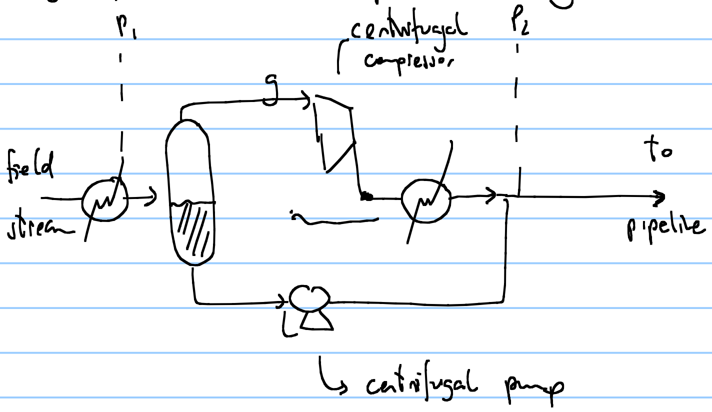
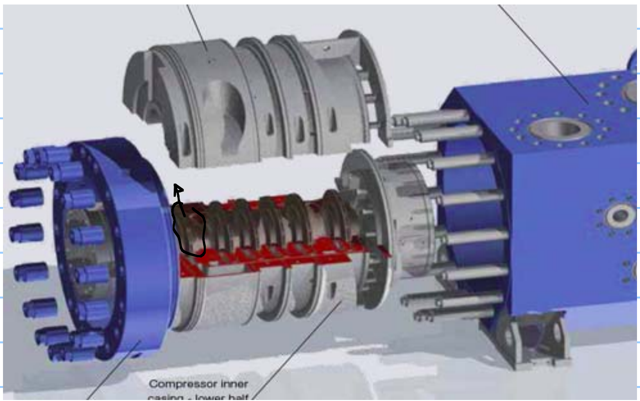
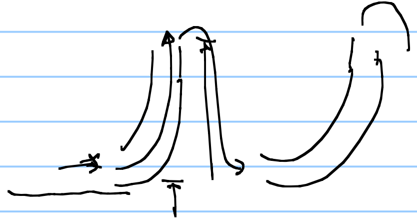


Fig. 3A

Single phase subsea compression/boosting







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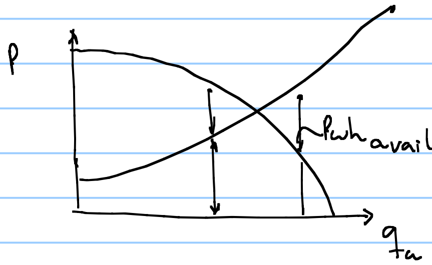
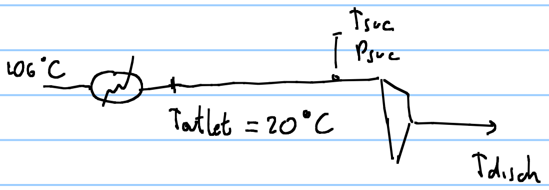


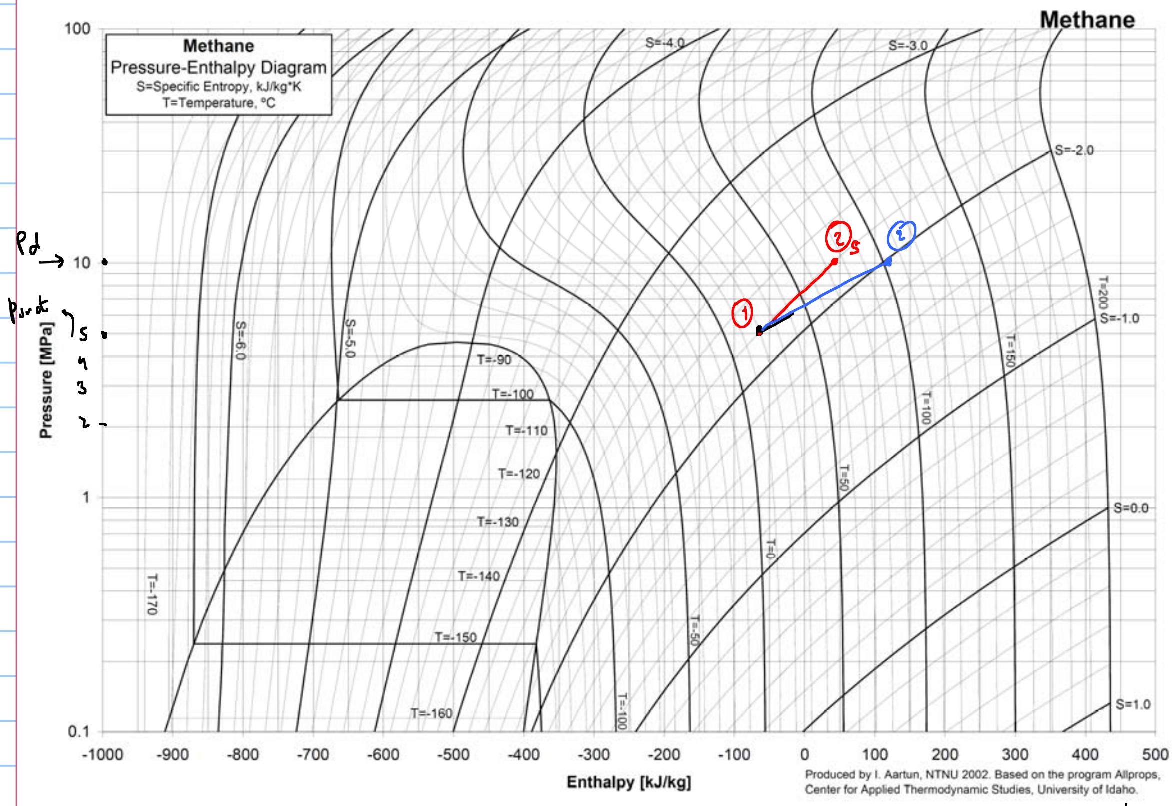
Åsgard subsea compression

$T_{wellstream} = 106°C$

$P_{suct} = 50$ bara

$P_{dis} = 100$ bara





ideally, the most efficient compression process is isentropic

S = const

if isentropic

$T_{disc} \simeq 75°C$

$P_s = \dot{m}(h_{2s} - h_1)$

$h_{2s} = 50 \text{ kJ/kg}$

$h_1 \simeq -65 \text{ kJ/kg}$

$q_g = 20 \text{ E6 Sm}^3\text{/d}$

$P_{sc} = 1.01325$ bara

$T_{sc} = 15.56°C$

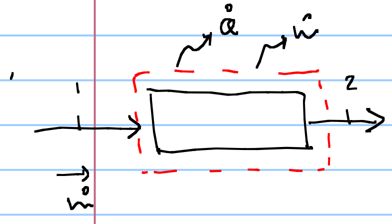
$\dot{m} = q_g \cdot \underbrace{\rho_{sc}} =$

$\rho_{sc} \simeq 0.68 \text{ kg/m}^3$

$\dot{m} = 157 \text{ kg/s}$

$P_{is} = 157 \cdot (115 \text{ kJ/kg})$

$P_{is} = 18101 \text{ KW}$



$$\dot{Q} - \dot{W} = \dot{m}(e_2 - e_1)$$

$$\overset{no}{\cancel{\dot{Q}}} - \dot{W} = \dot{m}\left(h_2 + \cancel{\frac{v_2^2}{2g}} + \cancel{z_2} - h_1 - \cancel{\frac{v_1^2}{2g}} - \cancel{z_1}\right)$$

in a compressor $\dot{W} = \dot{m}(h_2 - h_1)$

Approximate the real compression process with a polytropic compression

$p \cdot v^n = \text{constant}$ $n = k$ $k = \frac{C_p}{C_v}$

↳ isentropic methane $k \approx 1.3$

For a real compression process, the output temperature can be predicted by

$r_p = \frac{P_2}{P_1}$ for the plot $n = 1.46$

$$\frac{T_2}{T_1} = (r_p)^{\frac{n-1}{n}}$$

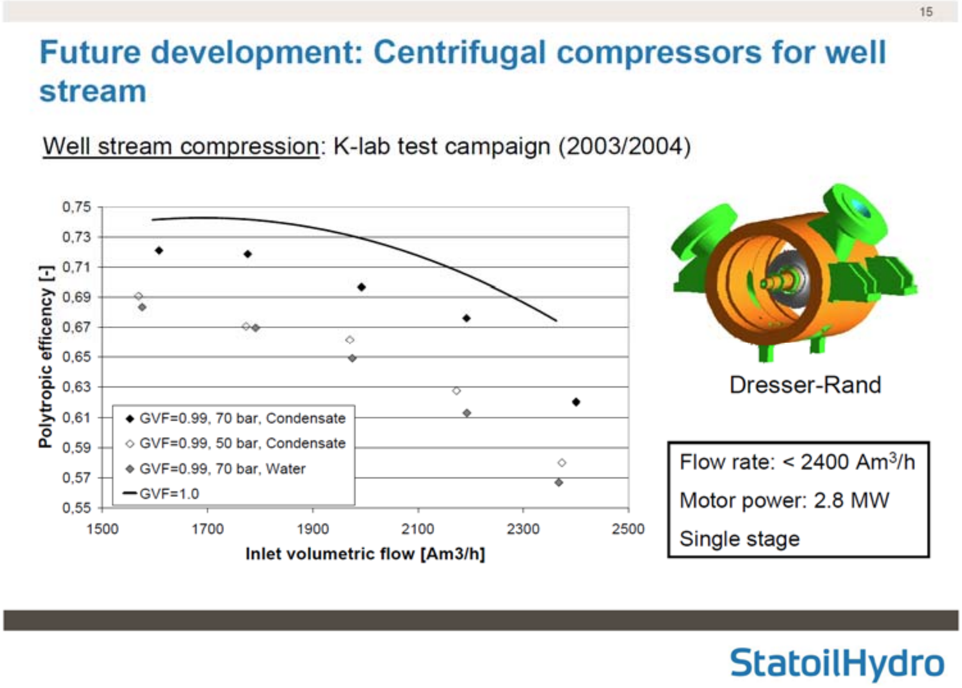
polytropic exponent

$$T_2 = T_1 \, r_p^{\frac{n-1}{n}}$$

absolute [K] [°R]

$$\eta_p = \cdot \frac{k-1}{k}\left(\frac{n}{n-1}\right)$$

$$\eta_p = 0.73$$



Future development: Centrifugal compressors for well stream

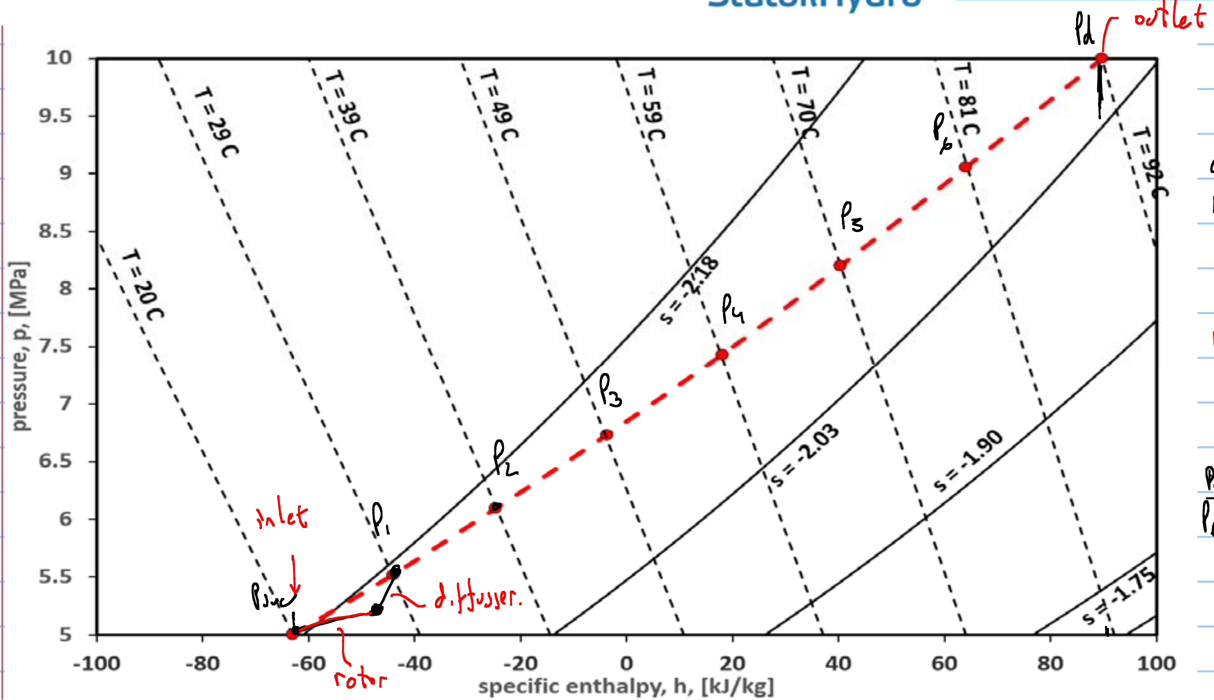
Well stream compression: K-lab test campaign (2003/2004)

Flow rate: < 2400 Am³/h

Motor power: 2.8 MW

Single stage

StatoilHydro



n_{stages} 7

assume that

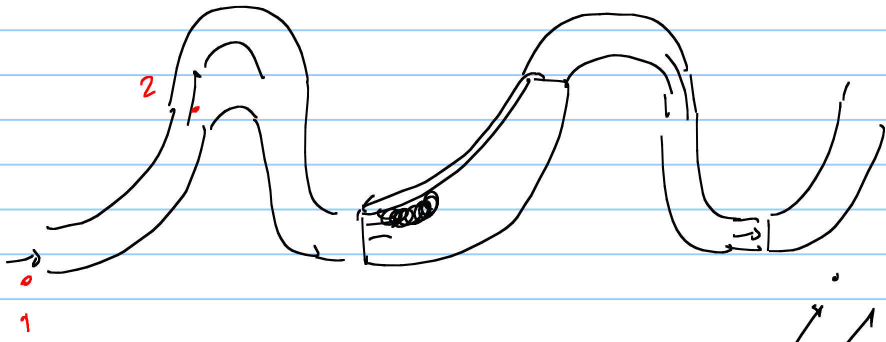
$\eta_{p_{stage}} = \eta_{p_{compressor}}$

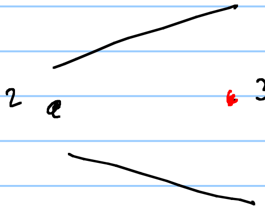
$r_{p_{stage}}$ is constant for each stage

$$\frac{P_{disc}}{P_6} \cdot \frac{P_6}{P_5} \cdot \frac{P_5}{P_4} \cdot \frac{P_4}{P_3} \cdot \frac{P_3}{P_2} \cdot \frac{P_2}{P_{suc}} \cdot \frac{P_5}{P_{suc}}$$

$$(r_{p,stage})^N = r_{p_{compressor}}$$

$$r_{p,stage} = \sqrt[N]{r_{p_{compressor}}}$$





$$\cancel{\dot{Q}} - \cancel{\dot{W}} = \dot{m}\left(h_3 + \frac{v_3^2}{2g} - h_2 - \frac{v_2^2}{2g}\right)$$

$$Power = \frac{\dot{m}\,(\Delta h_p)}{\underbrace{\eta_p}_{0.6-0.75} \cdot \eta_m} = \frac{(h_{disc\_p} - h_{suc\_p})\cdot \dot{m}}{\eta_p \cdot \eta_m}$$

η_m: mechanical effirient (95%-98%)

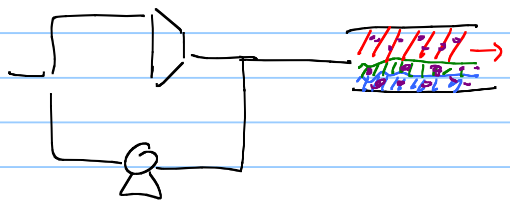
$$\Delta h_p = T_{suc} \cdot \overset{\frac{z_{suc}+z_{dis}}{2}}{z_{av}} \cdot R \cdot \frac{n}{n-1}\left(r_p^{\frac{n-1}{n}} - 1\right)$$

$$R = \frac{R_u}{MW}$$

- Simplified method to estimate subsea compression requirements

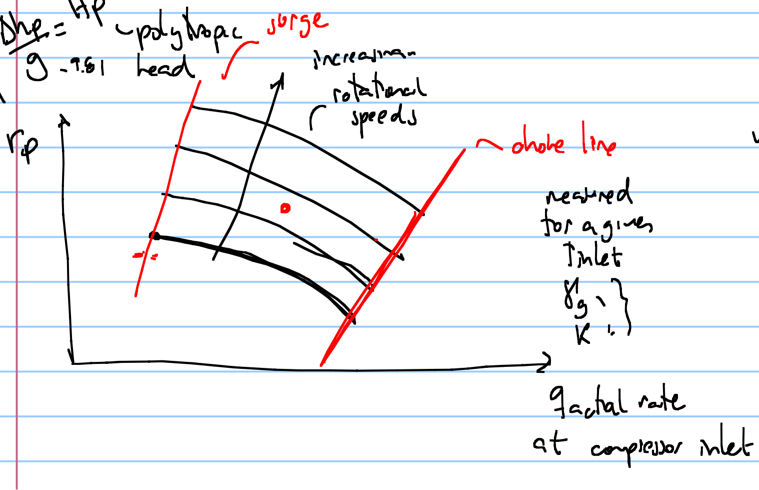
1. Limit on required compression power ≈ 11.5 MW per unit. (current)

2: limitation in outlet temperature:
- operating temperature of downstream pipelines < 150 °C
- max operating temperature of compressor seals
- max temperature to avoid vaporization of hydrate inhibitor. (MEG, TEG, MeOH)



3: minimum suction pressure. (10-20 bara)

$\frac{\Delta h_p}{g_{\sim 9.81}} = H_p$ ~polytropic head



4: if map is available ~> operating point must fall on the performace map. beware of choke line and surge line!

if the map is not available?

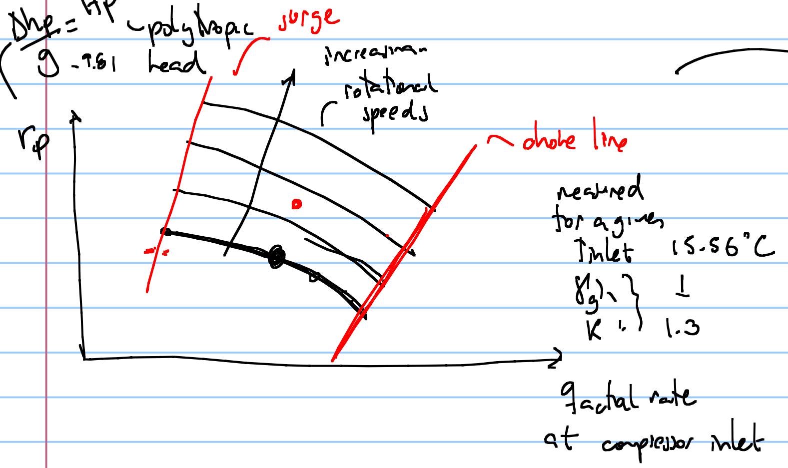
↳ $r_{p\,max} \approx 3.0$*

$\Delta p_{max} \approx 50$ bara*

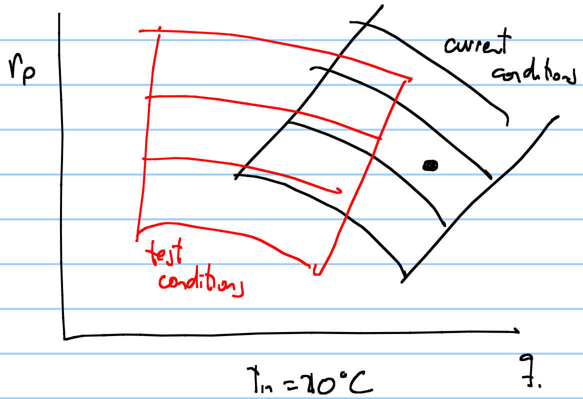
* current limitations

$\frac{\Delta h_p}{g} = H_p$ ← polytropic head

$g = 9.81$



for my current conditions



$T_{in} = 20°C$

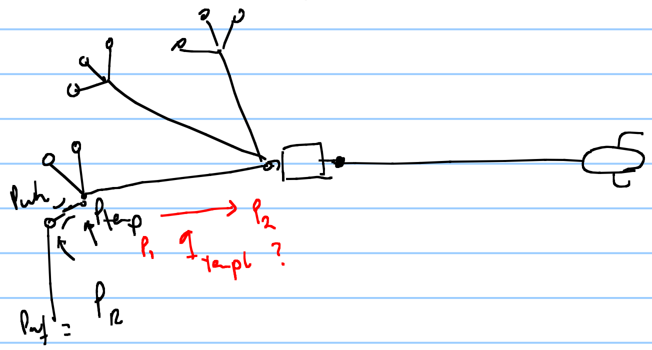
$\gamma_g = 0.55$

$k = 1.3$

$$q_{current} = q_{test} \sqrt{\frac{K_{curr}}{K_{test}}} \sqrt{\frac{MW_{test}}{MW_{current}}} \sqrt{\frac{T_{current}}{T_{test}}}$$

$$H_{p\,current} = H_{p_{test}} \frac{K_{current}}{K_{test}} \cdot \frac{MW_{test}}{MW_{current}} \frac{T_{current}}{T_{test}}$$

2018 03 13 Plan for today { brief on Snøhvit compressor calculations
- Surface networks
  - class exercise
- downhole networks



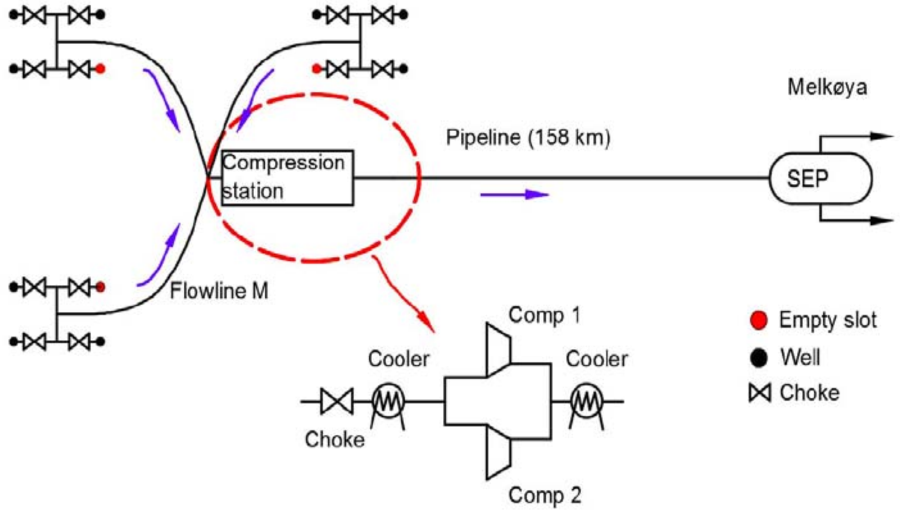
Calculate actual volume rate at compressor inlet

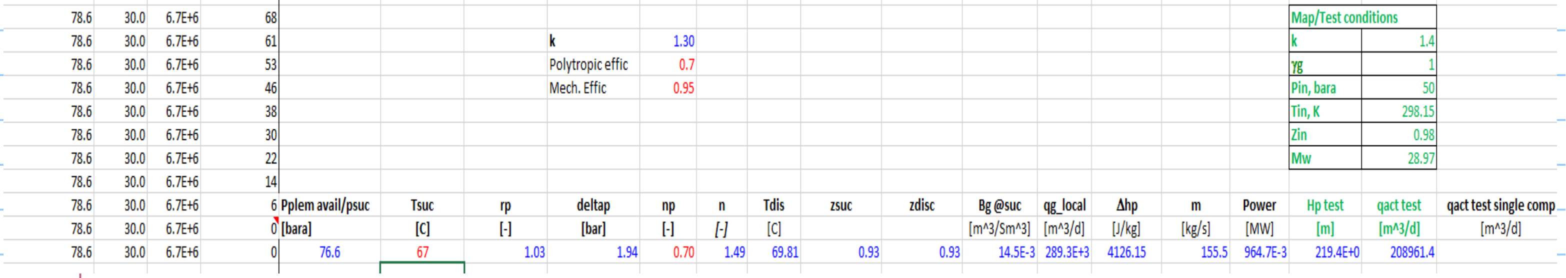
$$B_g(p,T) = \frac{V(p,T)}{V(p_{sc},T_{sc})}$$

$$B_g(p,T) = \frac{q(p,T)}{q_g}$$

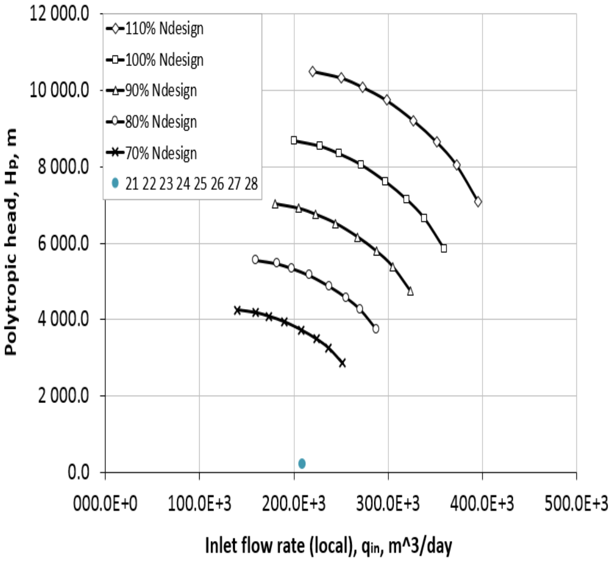
$$q(p_{suc},T_{suc}) = B_g(p_{suc},T_{suc}) \cdot q_g$$

Orientation about how to solve Task 4, exercise set 2.



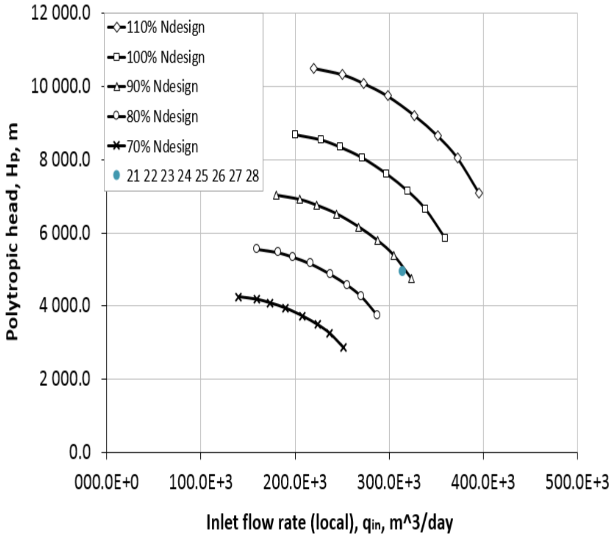


78.6	30.0	6.7E+6	68															Map/Test conditions		
78.6	30.0	6.7E+6	61				k	1.30										k	1.4	
78.6	30.0	6.7E+6	53				Polytropic effic	0.7										γg	1	
78.6	30.0	6.7E+6	46				Mech. Effic	0.95										Pin, bara	50	
78.6	30.0	6.7E+6	38															Tin, K	298.15	
78.6	30.0	6.7E+6	30															Zin	0.98	
78.6	30.0	6.7E+6	22															Mw	28.97	
78.6	30.0	6.7E+6	14																	
78.6	30.0	6.7E+6	6	Pplem avail/psuc	Tsuc	rp	deltap	np	n	Tdis	zsuc	zdisc	Bg @suc	qg_local	Δhp	m	Power	Hp test	qact test	qact test single comp
78.6	30.0	6.7E+6	0	[bara]	[C]	[-]	[bar]	[-]	[-]	[C]			[m^3/Sm^3]	[m^3/d]	[J/kg]	[kg/s]	[MW]	[m]	[m^3/d]	[m^3/d]
78.6	30.0	6.7E+6	0	76.6	67	1.03	1.94	0.70	1.49	69.81	0.93	0.93	14.5E-3	289.3E+3	4126.15	155.5	964.7E-3	219.4E+0	208961.4	

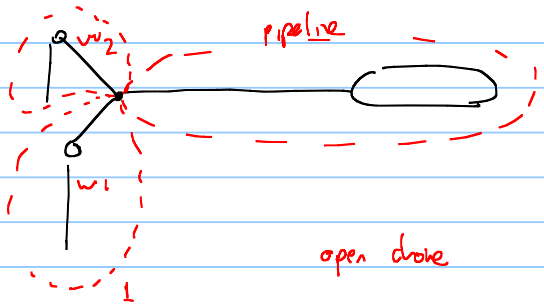


The point falls outside the operational map. We could use the inlet choke and inlet cooler to change the inlet conditions and try to move the point inside.

By choking at the inlet with DP = 30 bar and using the cooler such as Tsuc=20 C-->

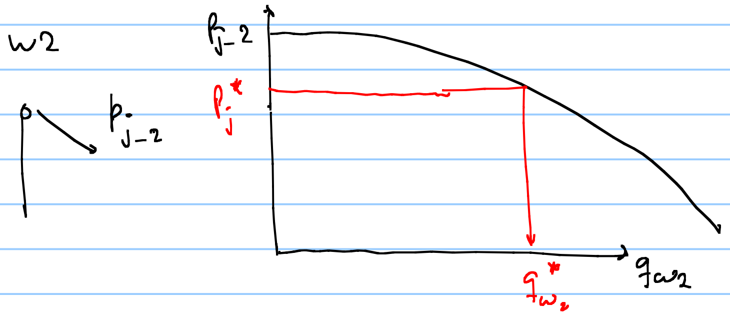


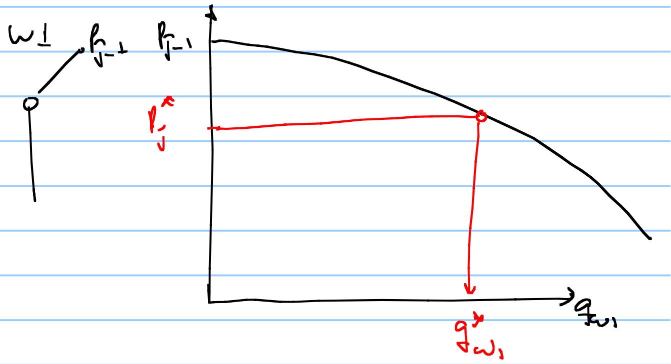
Surface networks

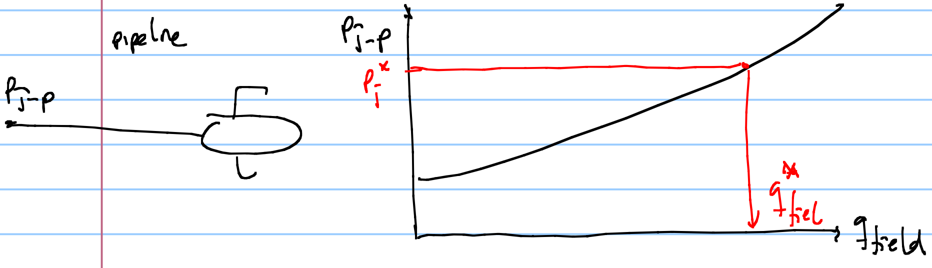


the assumption $q_w = \frac{q_f}{2}$ is NOT valid

how to compute the natural equilibrium point of this system?







$q_{field} = q_{w_1} + q_{w_2}$

assume p_J → calculate $q_{w_1}, q_{w_2}, q_{field}$

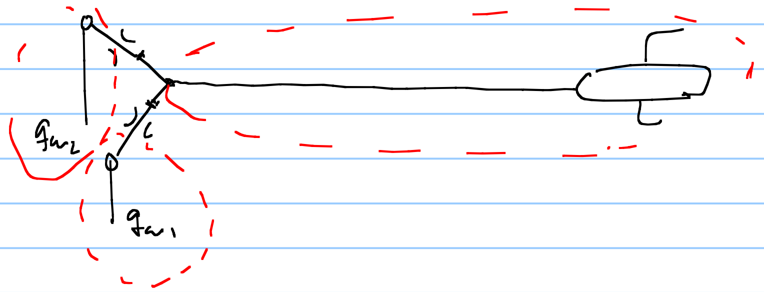
verify if $q_{w_1} + q_{w_2} = q_{field}$

NO yes → solution

		Nr unknowns	Nr equations
IPR_1	$q_{w_1} = C_1 (P_{R_1}^2 - P_{wf_1}^2)^n$	2	1
IPR_2	$q_{w_2} = C_2 (P_{R_2}^2 - P_{wf_2}^2)^n$	2	1
TPR_2	$q_{w_2} = C_{T_2}\left(\frac{P_{wf_2}^2}{e^{S_2}} - P_{wh_2}^2\right)^{0.5}$	1	1
TPR 1	$q_{w_1} = C_{T_1}\left(\frac{P_{wf_1}^2}{e^{S_1}} - P_{wh_1}^2\right)^{0.5}$	1	1
FPR_1	$q_{w_1} = C_{FL_1}(P_{wh_1}^2 - P_J^2)^{0.5}$	1	1
FPR_2	$q_{w_2} = C_{FL_2}(P_{wh_2}^2 - P_J^2)^{0.5}$	0	1
PPR	$q_f = C_{PL}(P_J^2 - P_{sep}^2)^{0.5}$	1	1
	$q_{field} = q_{w_1} + q_{w_2}$	0	1
		8	8

Fixed rate calculations for network

Flowline length is very short such as $P_{downstream\ choke} \approx P_J$



$q_{w_1}^*$ given by reservoir engineer.
$q_{w_2}^*$

for well 1

for well 2

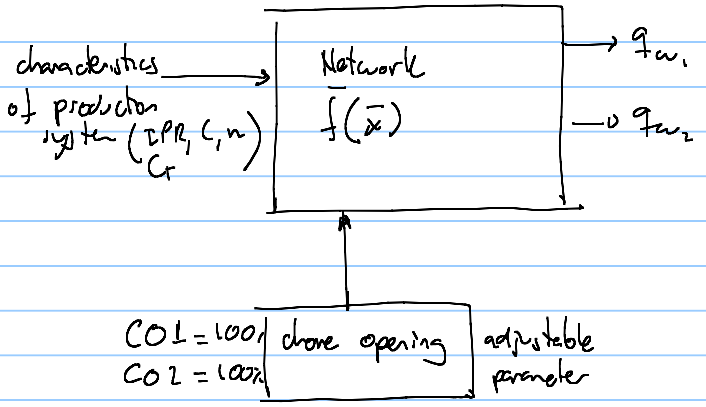
for pipeline

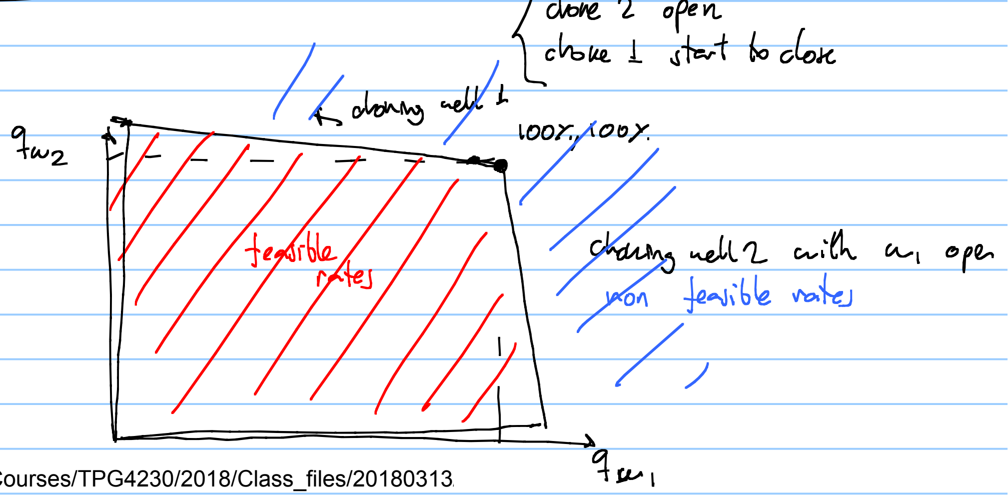
the rates will be feasible if

$P_{wh_1}^* > P_J^*$

$P_{wh_2}^* > P_J^*$

when I have chokes in the system, there are multiple combinations of q_{w_1}, q_{w_2} that can be achieved

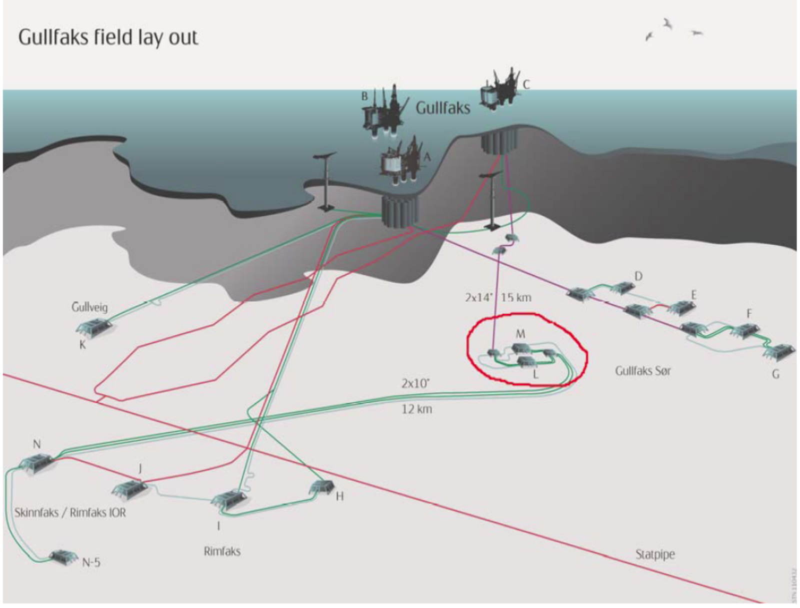




Class exercise: folk.ntnu.no/stanko/Courses/TPG4230/2018/Class_files/20180313

Problem 2: Production network calculations for the Gullfaks South field.

Two reservoir units in Gullfaks South field (Block 13 and Block 14) have been producing oil and gas since 1999 by two subsea templates (Template L and M). Template L has 4 wells and template M has 3 wells. For the purpose of this exercise, consider that all wells in a given template are identical (**However, the production of one well in the L template is not the same as the production of one well in the M template**). The production of the two templates is commingled in a towhead (junction) and transported further with a pipeline to the platform of Gullfaks C.

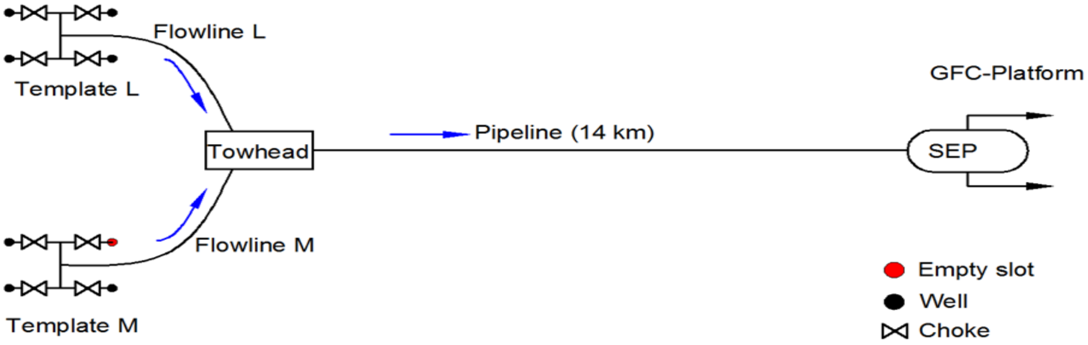


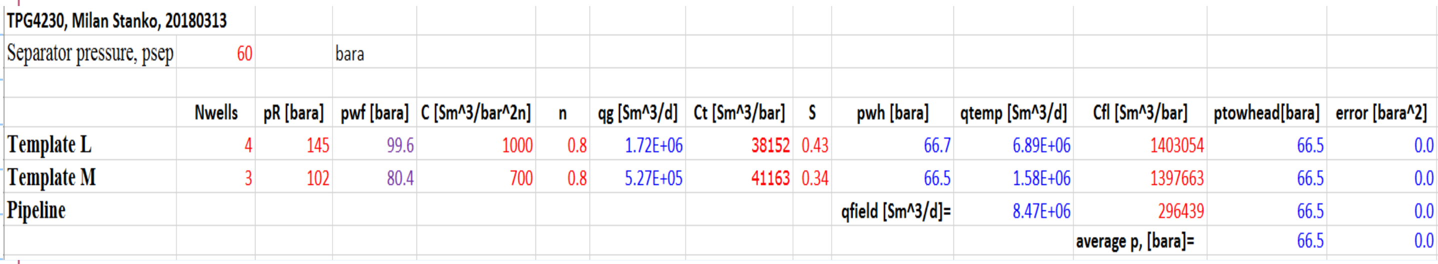
Issue on the choosing of the independent variable for the solving process: rate might give a problem of complex numbe if a too high value is used

IPR

$$\underline{q_{w_1}} = C_1 \left(P_{R_1}^2 - P_{wf_1}^2\right)^n$$

$$P_{wf_1} = \left(P_{R_1}^2 - \left(\frac{q_{w_1}}{C_1}\right)^{1/n}\right)^{0.5}$$





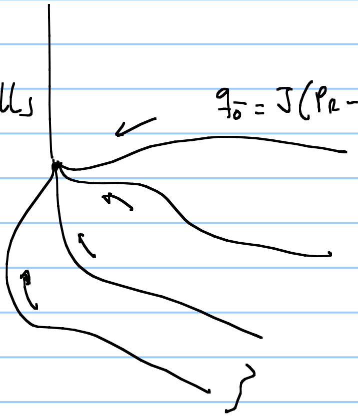
TPG4230, Milan Stanko, 20180313													
Separator pressure, psep	60		bara										
	Nwells	pR [bara]	pwf [bara]	C [Sm^3/bar^2n]	n	qg [Sm^3/d]	Ct [Sm^3/bar]	S	pwh [bara]	qtemp [Sm^3/d]	Cfl [Sm^3/bar]	ptowhead[bara]	error [bara^2]
Template L	4	145	99.6	1000	0.8	1.72E+06	38152	0.43	66.7	6.89E+06	1403054	66.5	0.0
Template M	3	102	80.4	700	0.8	5.27E+05	41163	0.34	66.5	1.58E+06	1397663	66.5	0.0
Pipeline									qfield [Sm^3/d]=	8.47E+06	296439	66.5	0.0
											average p, [bara]=	66.5	0.0

2018 03 19

- downhole networks
- flow of undersaturated oil and water in pipes
- ESP flow design

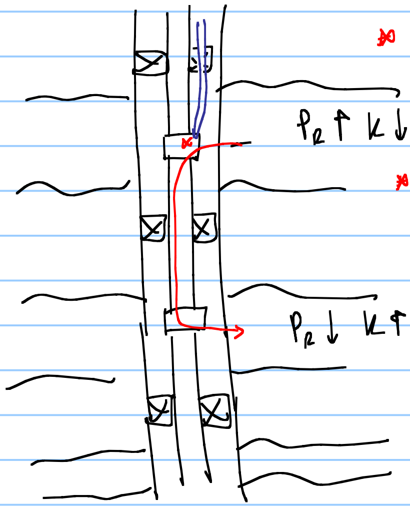
Downhole networks can occur in:

multilateral wells



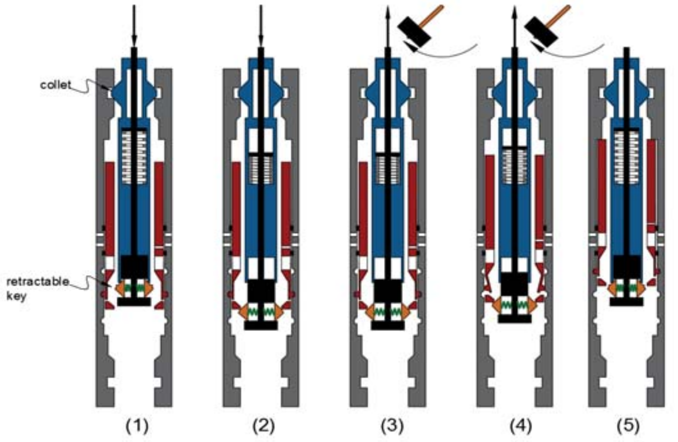
$q_o = J(P_R - P_{wf})$

- multilayer

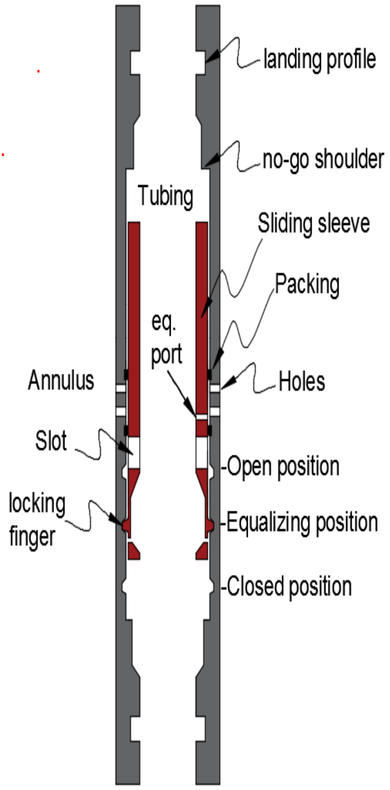


* opening
* sliding sleeve
shift to open or close
* downhole valve
Inflow control valve

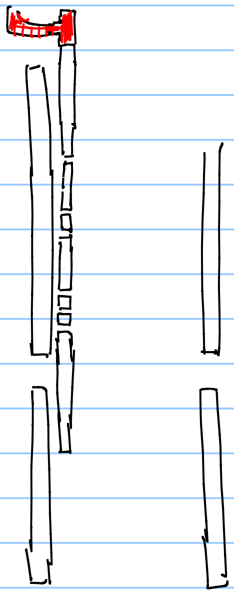
Shifting tool and sequence for sliding sleeve with wireline



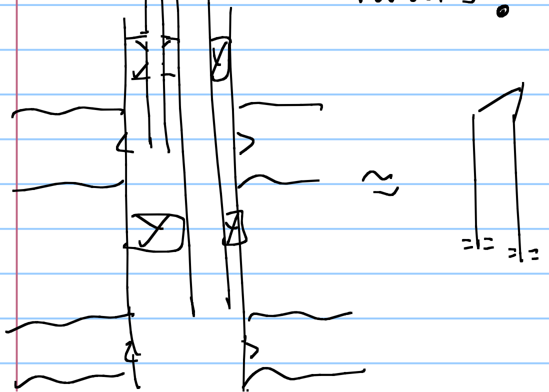
Sliding sleeve



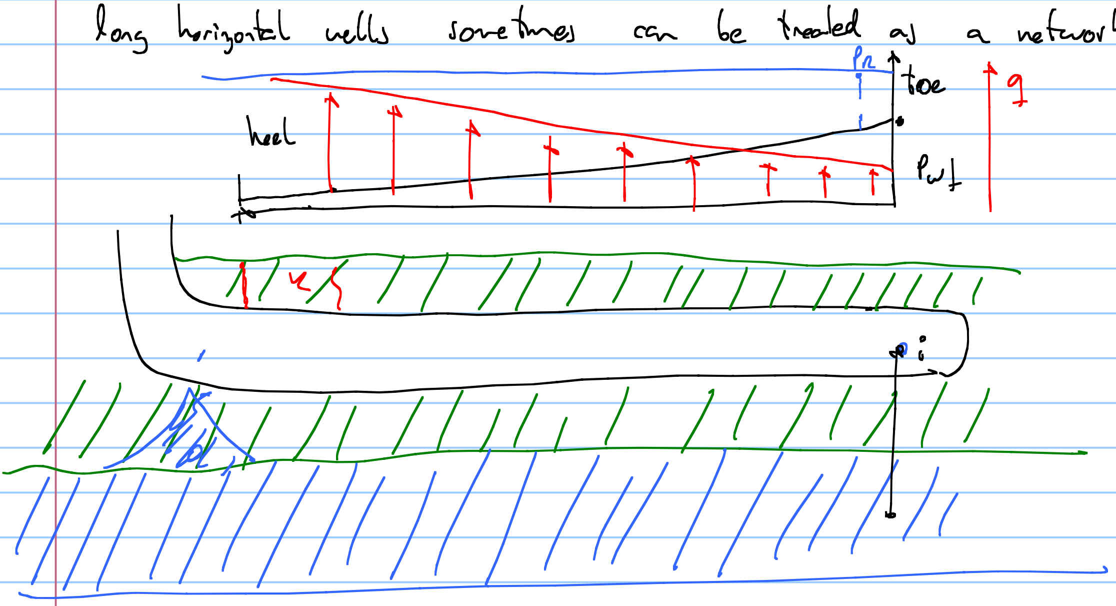
Inflow control Valve (ICV), 4 positions.
I need a hydraulic line to chang the opening without having to run wireline



dual -tubing completions are usually not networks !



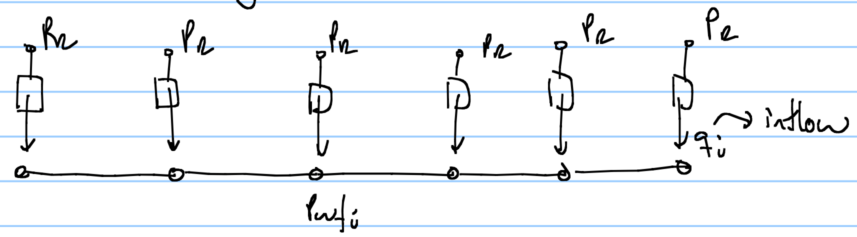
long horizontal wells sometimes can be treated as a network

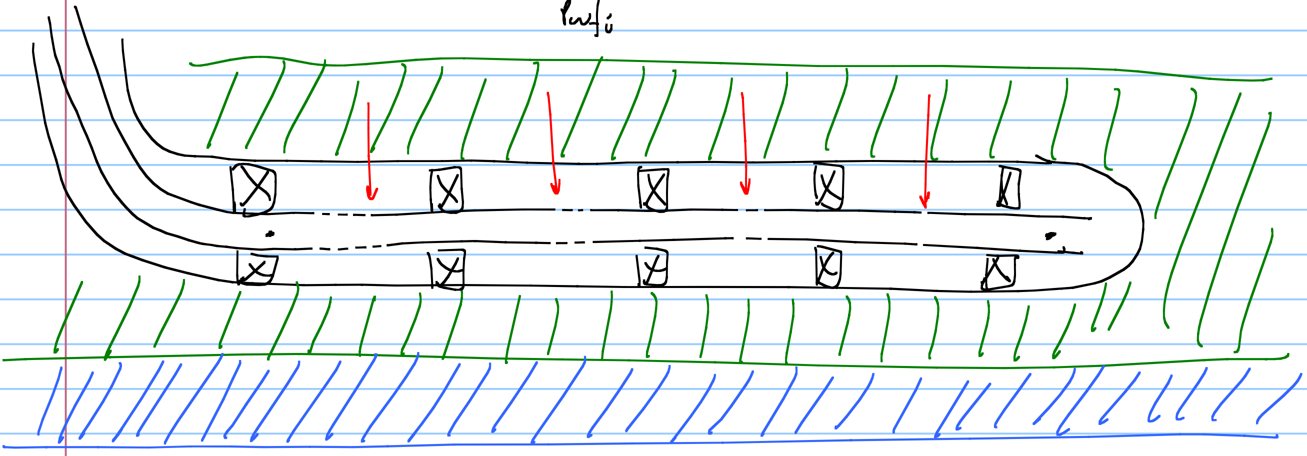


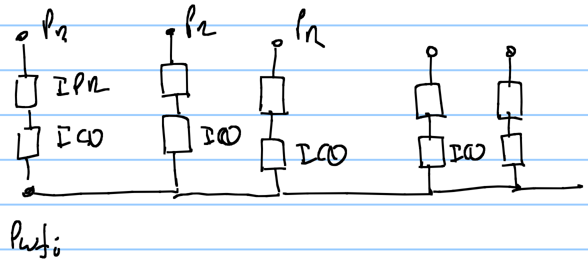
$$q_i \propto (P_R - P_{wf_i})\, J$$

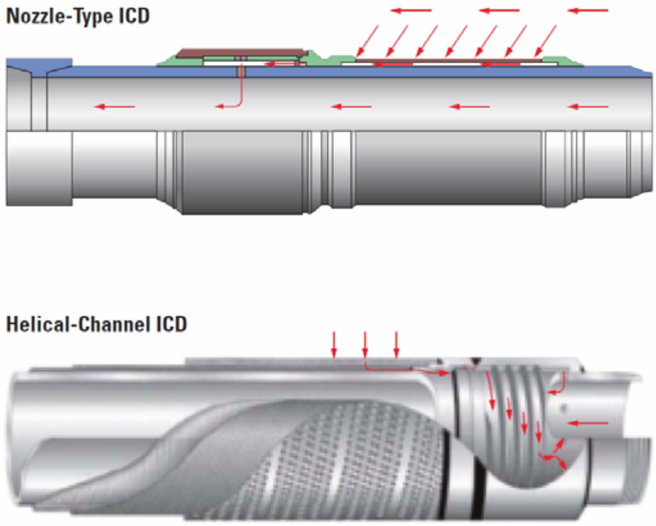
$$\propto f(k)$$

approximate the well by a network



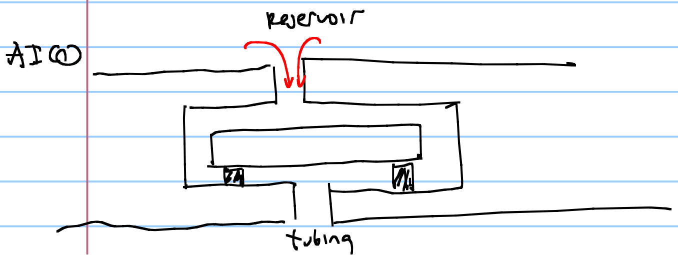






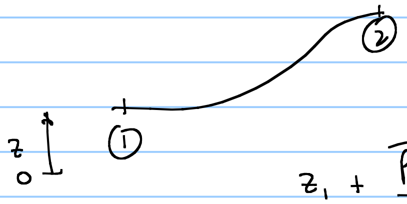
^ Leading ICD types. Fluid from the formation (red arrows) flows through multiple screen layers mounted on an inner jacket, and along the annulus between the solid basepipe and the screens. It then enters the production tubing through a restriction in the case of nozzle- and orifice-based tools (*top*), or through a tortuous pathway in the case of helical- and tube-based devices (*bottom*).

ICD	inflow control device
ICV	inflow control valve
AICD	Autonomous inflow control device



NetTool → Halliburton for analizing downhole networks.

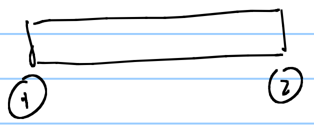
- pressure drop calculations for undersaturated oil + water



$$\underset{\sim}{h_1} = h_2 + \Delta h_L$$

localized loss coefficient

$$z_1 + \frac{p_1}{\rho \cdot g} + \frac{v_1^2}{2g} = z_2 + \frac{p_2}{\rho \cdot g} + \frac{v_1^2}{2g} + \underbrace{f \frac{L}{D} \frac{v^2}{2g}}_{\text{friction}} + K \frac{V^2}{2g}$$



$$V = \frac{q}{Area} \rightarrow$$ local volumetric rate @ p, T

$q_{\bar{o}}$ $q_{\bar{w}}$

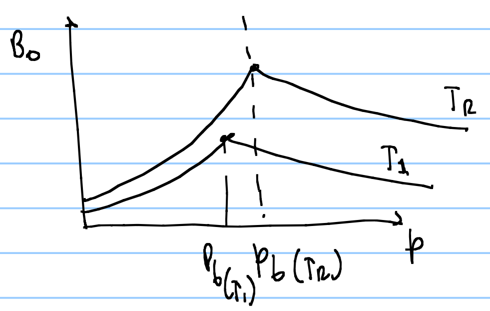
calculation modes:

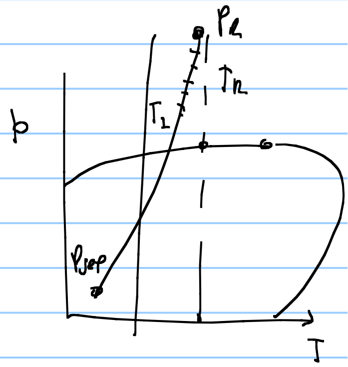
① p_1 fixed → calculate p_2
q

② p_2 fixed → calculate p_1
q

$$\underline{B_o(p,T)} = \frac{q@p,T}{q_{\bar{o}}}$$

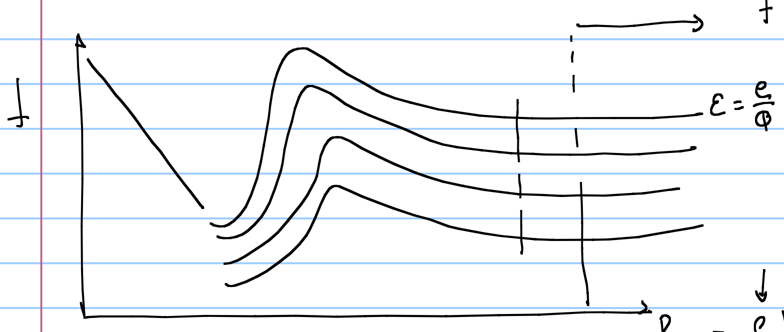
$$B_w(p,T) = \frac{q@p,T}{q_{\bar{w}}}$$





ρ is also a function of p, T

f friction factor



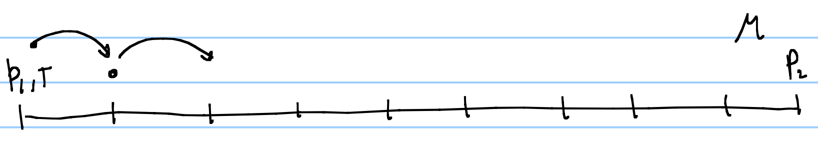
$$f \neq F(Re)$$

$$f = F(\varepsilon)$$

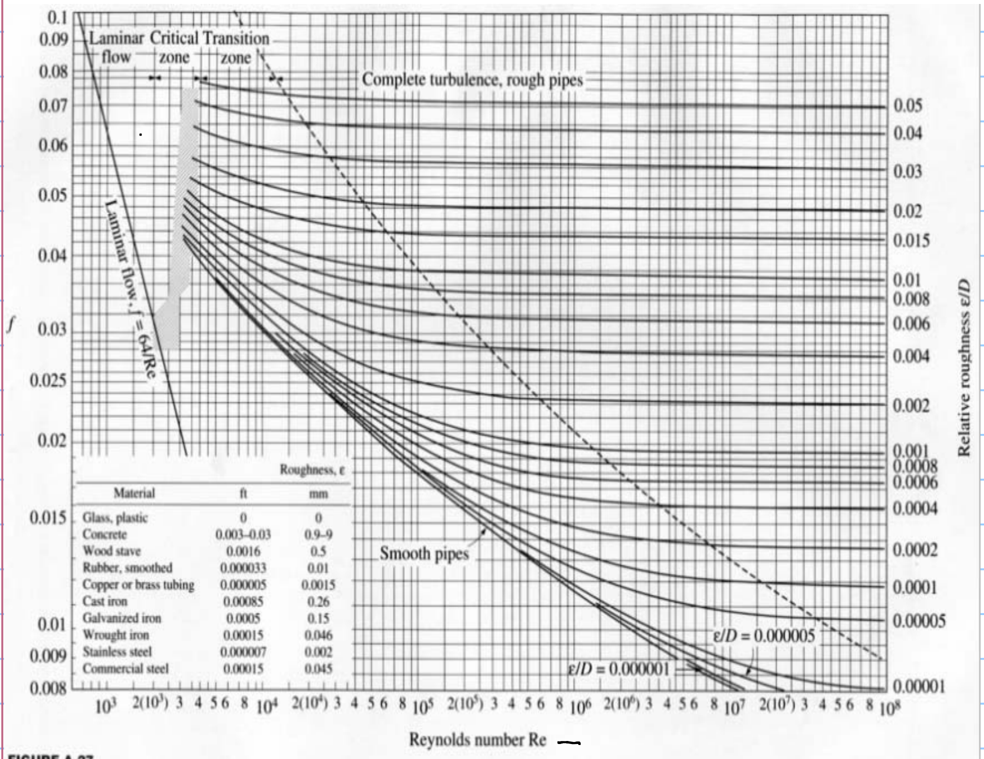
$$Re = \frac{\rho V D}{\mu}$$

Because of changes in p and T along the pipe, q@p,T will change
ρ " "
μ " "

pressure drop calculations in well, in pipes should be done in a stepwise manner.



$$\frac{\Delta p}{\frac{1}{2}\rho\frac{v^2}{2}}$$



Material	Roughness, ε ft	mm
Glass, plastic	0	0
Concrete	0.003–0.03	0.9–9
Wood stave	0.0016	0.5
Rubber, smoothed	0.000033	0.01
Copper or brass tubing	0.000005	0.0015
Cast iron	0.00085	0.26
Galvanized iron	0.0005	0.15
Wrought iron	0.00015	0.046
Stainless steel	0.000007	0.002
Commercial steel	0.00015	0.045

FIGURE A-27

The Moody chart for the friction factor for fully developed flow in circular tubes.

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

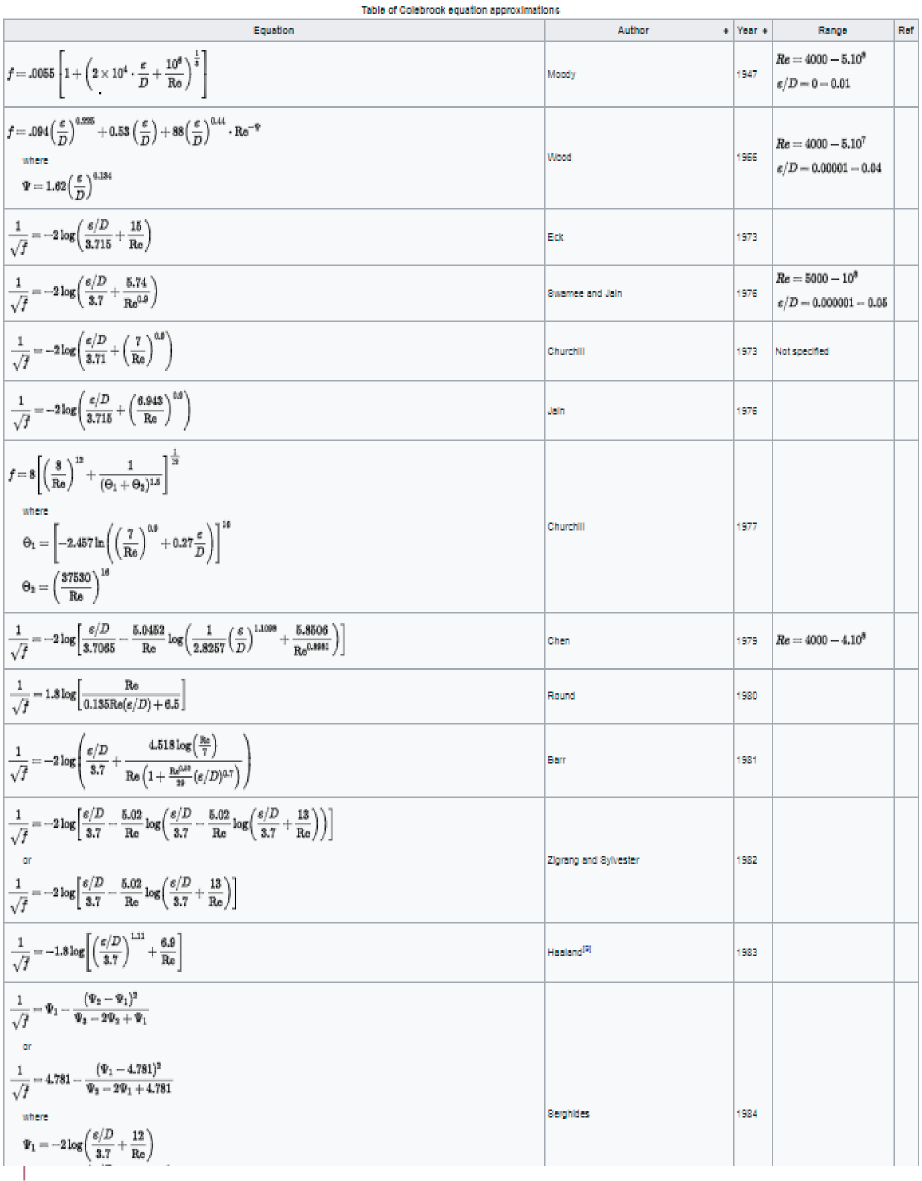


Table of Colebrook equation approximations

Equation	Author	Year	Range	Ref
$f = .0055\left[1+\left(2\times10^4\cdot\frac{\varepsilon}{D}+\frac{10^6}{\mathrm{Re}}\right)^{\frac{1}{3}}\right]$	Moody	1947	$Re = 4000 - 5.10^8$ $\varepsilon/D = 0 - 0.01$	
$f = .094\left(\frac{\varepsilon}{D}\right)^{0.225}+0.53\left(\frac{\varepsilon}{D}\right)+88\left(\frac{\varepsilon}{D}\right)^{0.44}\cdot\mathrm{Re}^{-\Psi}$ where $\Psi = 1.62\left(\frac{\varepsilon}{D}\right)^{0.134}$	Wood	1966	$Re = 4000 - 5.10^7$ $\varepsilon/D = 0.00001 - 0.04$	
$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.715}+\frac{15}{\mathrm{Re}}\right)$	Eck	1973		
$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.7}+\frac{5.74}{\mathrm{Re}^{0.9}}\right)$	Swamee and Jain	1976	$Re = 5000 - 10^8$ $\varepsilon/D = 0.000001 - 0.05$	
$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.71}+\left(\frac{7}{\mathrm{Re}}\right)^{0.9}\right)$	Churchill	1973	Not specified	
$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.715}+\left(\frac{6.943}{\mathrm{Re}}\right)^{0.9}\right)$	Jain	1976		
$f = 8\left[\left(\frac{8}{\mathrm{Re}}\right)^{12}+\frac{1}{(\Theta_1+\Theta_2)^{1.5}}\right]^{\frac{1}{12}}$ where $\Theta_1 = \left[-2.457\ln\left(\left(\frac{7}{\mathrm{Re}}\right)^{0.9}+0.27\frac{\varepsilon}{D}\right)\right]^{16}$ $\Theta_2 = \left(\frac{37530}{\mathrm{Re}}\right)^{16}$	Churchill	1977		
$\frac{1}{\sqrt{f}} = -2\log\left[\frac{\varepsilon/D}{3.7065}-\frac{5.0452}{\mathrm{Re}}\log\left(\frac{1}{2.8257}\left(\frac{\varepsilon}{D}\right)^{1.1098}+\frac{5.8506}{\mathrm{Re}^{0.8981}}\right)\right]$	Chen	1979	$Re = 4000 - 4.10^8$	
$\frac{1}{\sqrt{f}} = 1.8\log\left[\frac{\mathrm{Re}}{0.135\mathrm{Re}(\varepsilon/D)+6.5}\right]$	Round	1980		
$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.7}+\frac{4.518\log\left(\frac{\mathrm{Re}}{7}\right)}{\mathrm{Re}\left(1+\frac{\mathrm{Re}^{0.52}}{29}(\varepsilon/D)^{0.7}\right)}\right)$	Barr	1981		
$\frac{1}{\sqrt{f}} = -2\log\left[\frac{\varepsilon/D}{3.7}-\frac{5.02}{\mathrm{Re}}\log\left(\frac{\varepsilon/D}{3.7}-\frac{5.02}{\mathrm{Re}}\log\left(\frac{\varepsilon/D}{3.7}+\frac{13}{\mathrm{Re}}\right)\right)\right]$ or $\frac{1}{\sqrt{f}} = -2\log\left[\frac{\varepsilon/D}{3.7}-\frac{5.02}{\mathrm{Re}}\log\left(\frac{\varepsilon/D}{3.7}+\frac{13}{\mathrm{Re}}\right)\right]$	Zigrang and Sylvester	1982		
$\frac{1}{\sqrt{f}} = -1.8\log\left[\left(\frac{\varepsilon/D}{3.7}\right)^{1.11}+\frac{6.9}{\mathrm{Re}}\right]$	Haaland[3]	1983		
$\frac{1}{\sqrt{f}} = \Psi_1-\frac{(\Psi_2-\Psi_1)^2}{\Psi_3-2\Psi_2+\Psi_1}$ or $\frac{1}{\sqrt{f}} = 4.781-\frac{(\Psi_1-4.781)^2}{\Psi_2-2\Psi_1+4.781}$ where $\Psi_1 = -2\log\left(\frac{\varepsilon/D}{3.7}+\frac{12}{\mathrm{Re}}\right)$	Serghides	1984		

Haaland (from NTNU) ~ 1983

$$f = \left[-1.8\log\left[\left(\frac{\varepsilon/D}{3.7}\right)^{1.11}+\left(\frac{6.9}{Re}\right)\right]\right]^{-2}$$

beware ! ! !

- Moody (Darcy-Weisbach) friction factor

$$f_{DARCY} = \frac{\tau}{\frac{1}{8}\rho v^2}$$

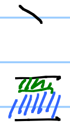
- Faning friction factor

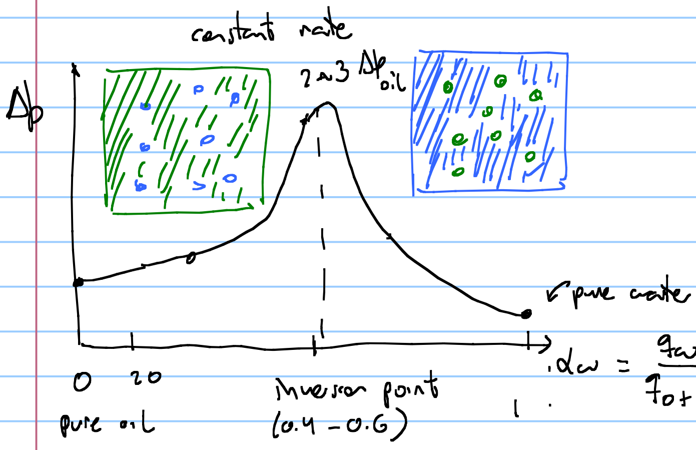
$$f_{FANNING} = \frac{\tau}{\frac{1}{2}\rho v^2}$$

$$\underline{f_{DARCY} = 4 f_{FANNING}}$$

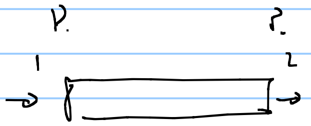
Oil-water flows can be modeled using liquid pressure drop equation

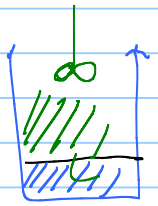
In oil and water flow we have formation of emulsions! fine and stable





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





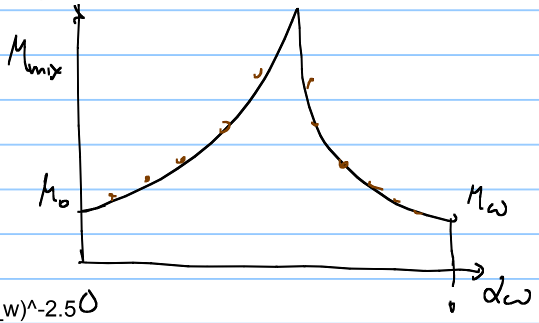
we can apply the same equation that for liquids

$$z_1 + \frac{P_1}{\rho_m g} + \frac{v_1^2}{2g} = z_2 + \frac{P_2}{\rho_m g} + \frac{v_2^2}{2g} + f\,\frac{L}{\phi}\,\frac{v^2}{2g}$$

$$\rho_m = \rho_w \cdot \alpha_w + \rho_o \underbrace{(1-\alpha_w)}_{\alpha_o}$$

μ

effective viscosity of mixture



- Some equations used to describe emulsion viscosity are
  - Brinkman mu_m=mu_o*(1-alpha_w)^-2.5
    mu_m=mu_w*(alpha_w)^-2.5
  - Richardson

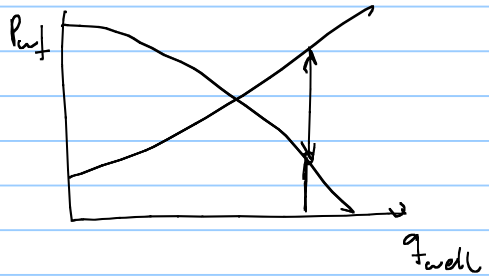
in the left $C\alpha_w$

$$M_m = M_o \cdot e$$

to the right

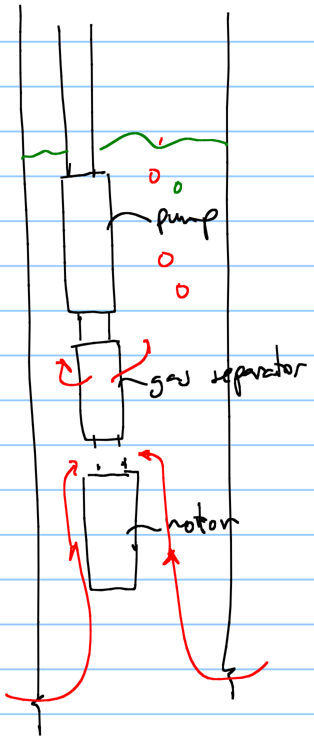
$$M_m = M_w \cdot e^{C_o(1-\alpha_w)}$$

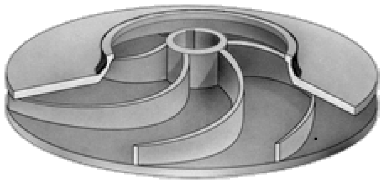
- Electric submersible pump (ESP)

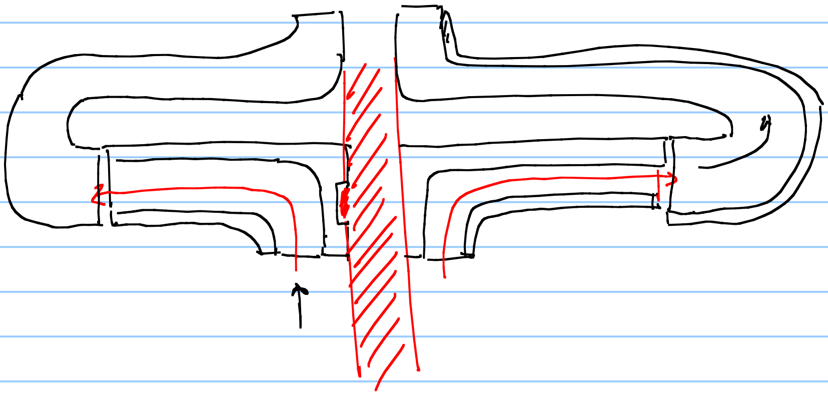


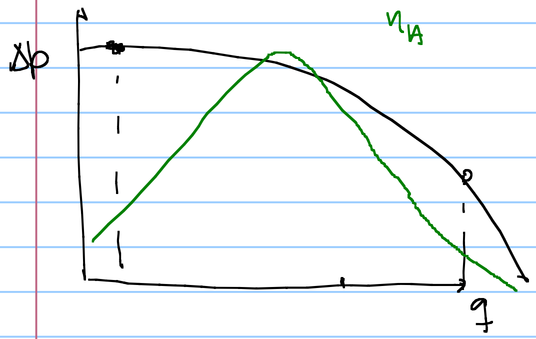
. P_R

inventor
Armais Arutunoff

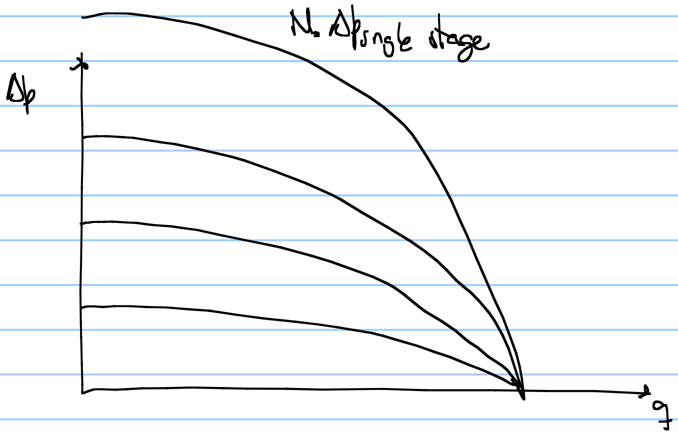








$$\overline{P}_{power} = \frac{\Delta p \cdot q}{\eta_H \cdot \eta_{mech}}$$



$$\Delta p_{required} = \overline{N_{stages}}\ \Delta p_{one\ stage} \cdot F_{pancake\ factor} \quad ✓$$

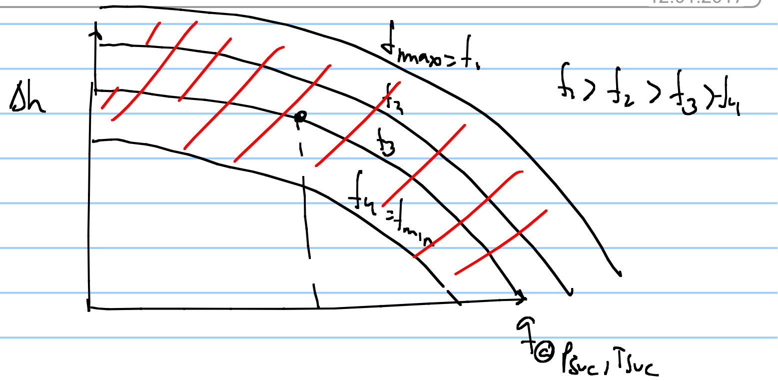
20180320 Lead $\Delta h = \frac{\Delta p}{\rho \cdot g}$

pure oil $\rho_o = 790$ kg/m³

$\Delta p = \Delta h \cdot 790$ kg/m³

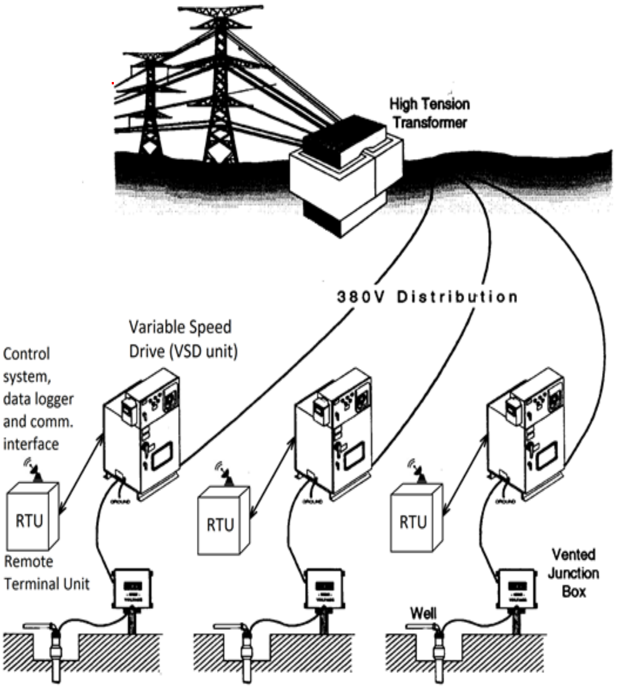
pure water $\rho_w = 1024$ kg/m³

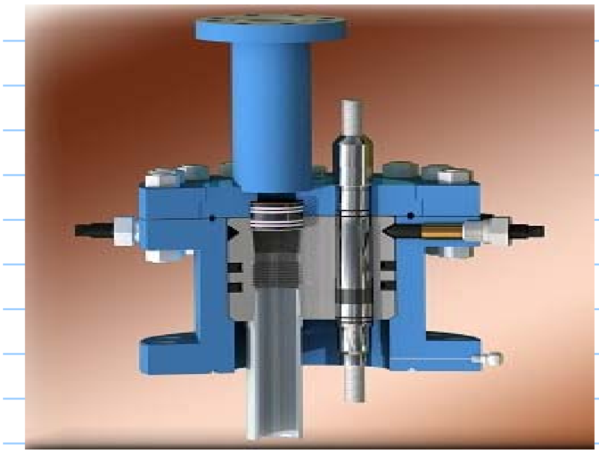
$\Delta p_{water} = \Delta h \cdot 1024$ kg/m³

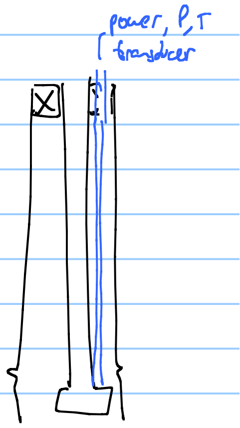


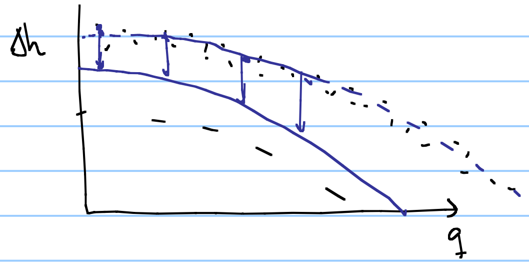
to control performance ESP one can change the rotational speed of pump (impeller) frequency hz

30 – 70









$$\Delta h = a \cdot q^4 + b q^3 + c q^2 + d q + e$$

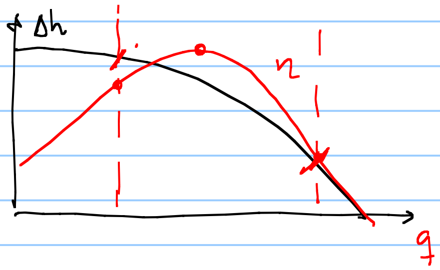
manufacturers usually measure for a ref fluid (water) at reference frequency (60 hz)

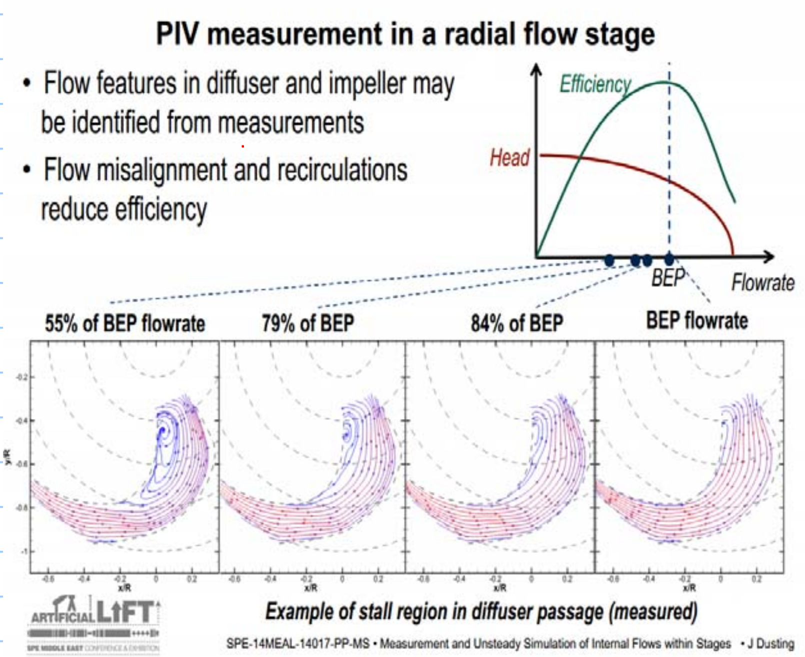
$$\frac{\Delta h_1}{\Delta h_{ref}} = \left(\frac{f_1}{f_{ref}}\right)^2 \qquad \frac{q_1}{q_{ref}} = \frac{f_1}{f_{ref}} \qquad q_{ref} = q_1 \left(\frac{f_{ref}}{f_1}\right)$$

$$\Delta h_{@f} = \left(a q^4 + b q^3 + c q^2 + d q + e\right)\left(\frac{f}{f_{ref}}\right)^2$$

$$\Delta h_{@f} = a\left[q_1\left(\frac{f_{ref}}{f_1}\right)\right]^4 + b\left[q_1 \frac{f_{ref}}{f_1}\right]^3 + c\left[q_1 \frac{f_{ref}}{f_1}\right]^2 + d\left[q_1 \frac{f_{ref}}{f_1}\right] + e$$

other operational constraints :





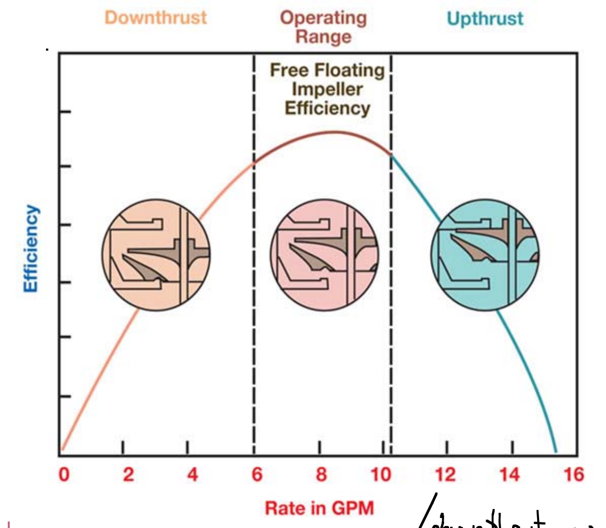
PIV measurement in a radial flow stage

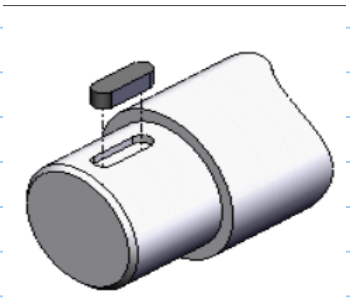
- Flow features in diffuser and impeller may be identified from measurements
- Flow misalignment and recirculations reduce efficiency

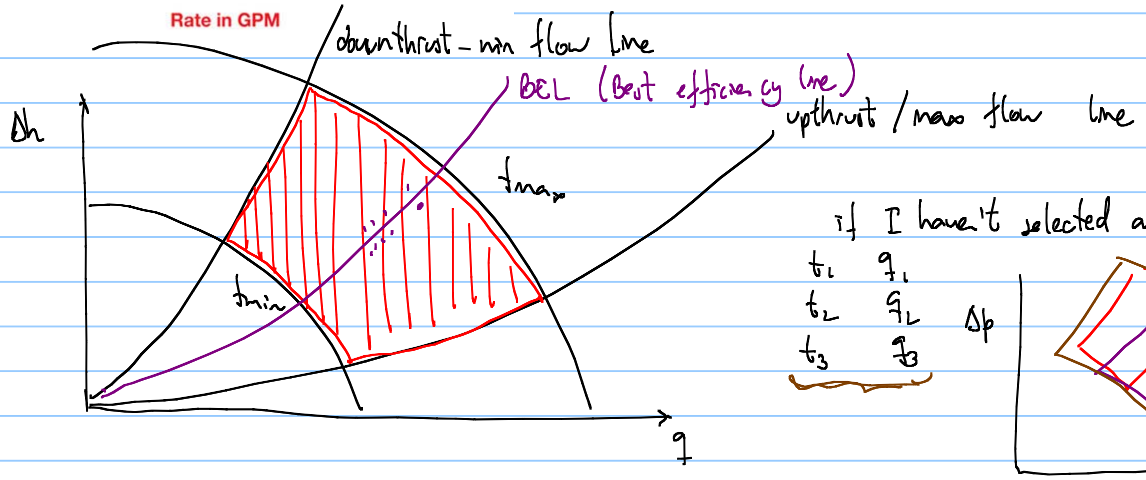
Example of stall region in diffuser passage (measured)

SPE-14MEAL-14017-PP-MS • Measurement and Unsteady Simulation of Internal Flows within Stages • J Dusting

upthrust and downthrust

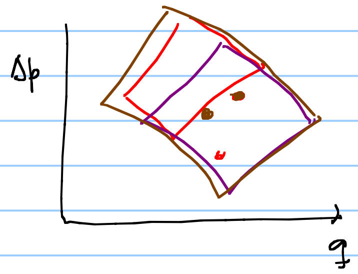


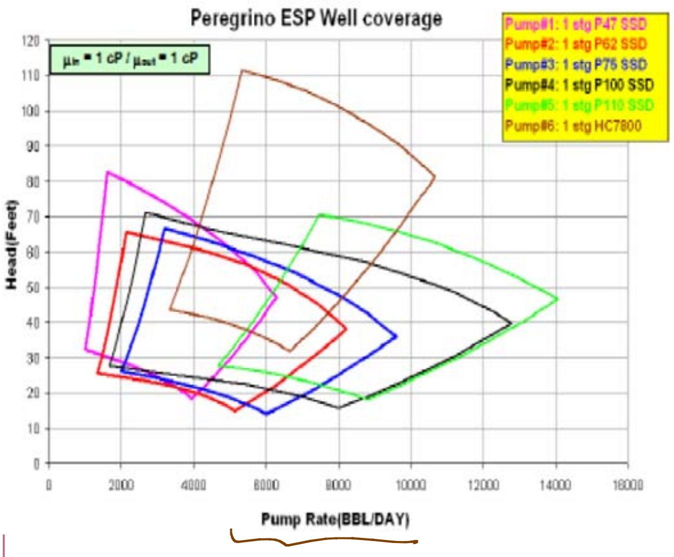




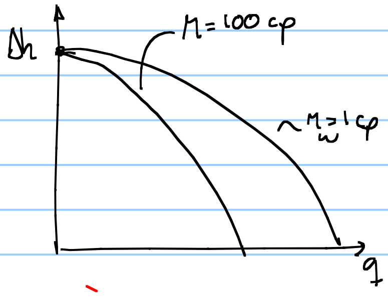
if I haven't selected an ESP get

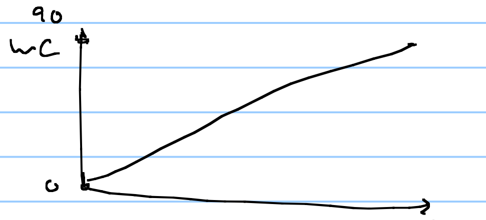
t_1	q_1
t_2	q_2
t_3	q_3

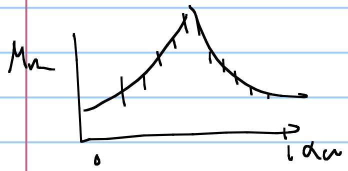




the performance of ESP is reduced by increased viscosity !

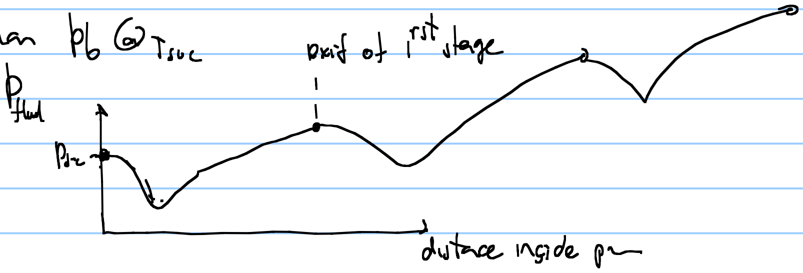






to estimate performance for a different viscosity ⇝ measurements
⇝ American national standard (Hydraulic Institute)
ANSI/HI 9.6.7 - 2015

- $P_{suction}$ has to be greater than p_b @ T_{suc}

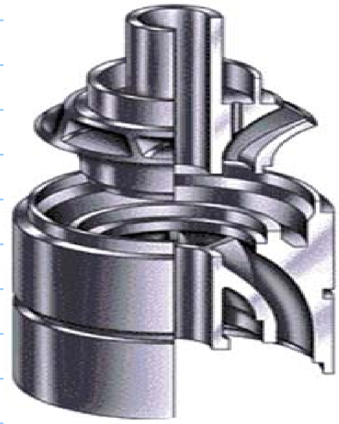


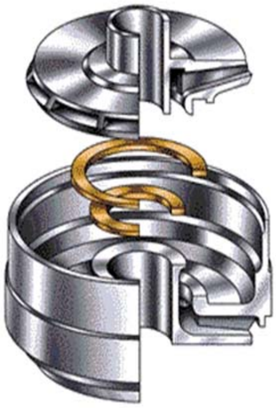
$$P_{suc} > F \cdot P_b @ T_{suc}$$

└ safety factor

- Power ≤ Power capacity motor

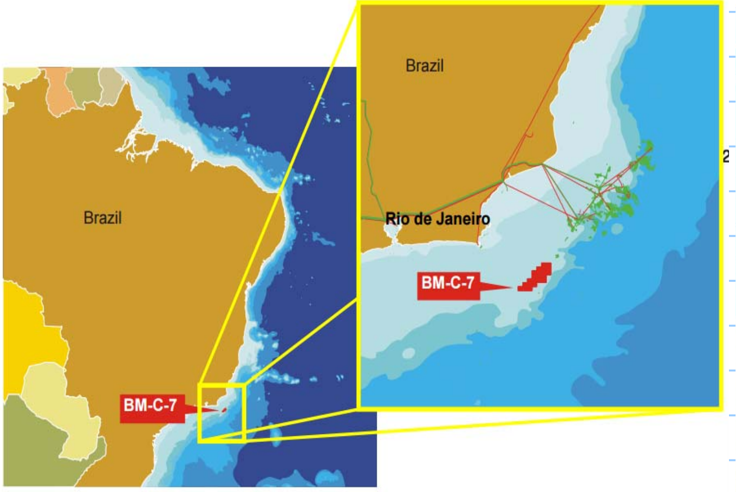
$$Power_{pump} = \boxed{\frac{\Delta p \cdot q}{\eta_m \eta_H}}$$

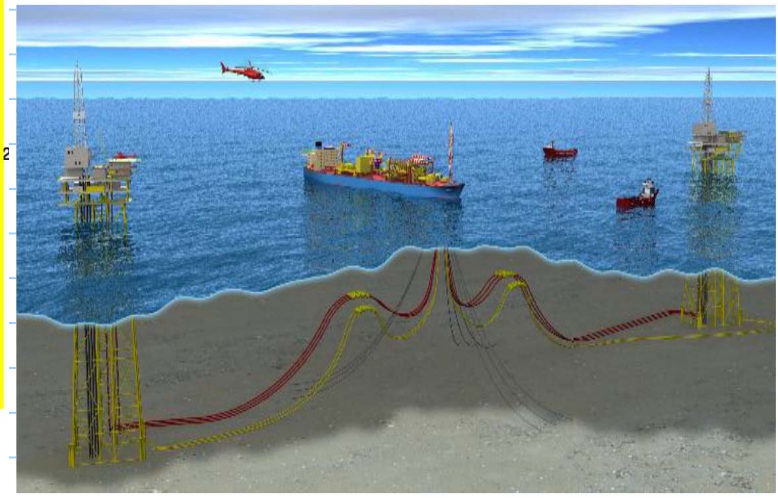


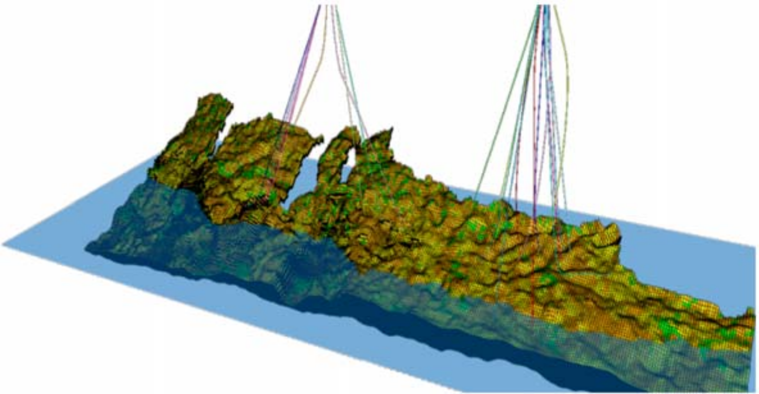


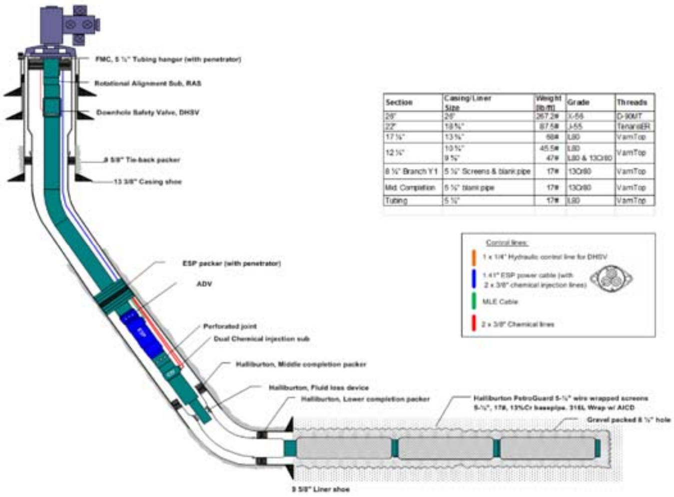
Class exercise:

http://folk.ntnu.no/stanko/Courses/TPG4230/2018/Class_files/20180320/

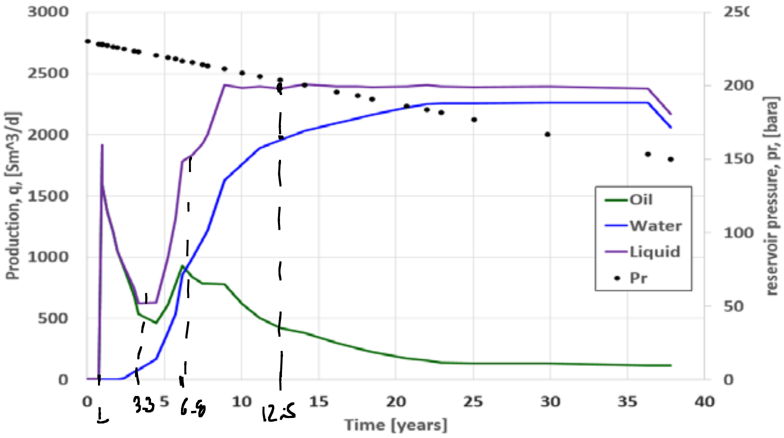


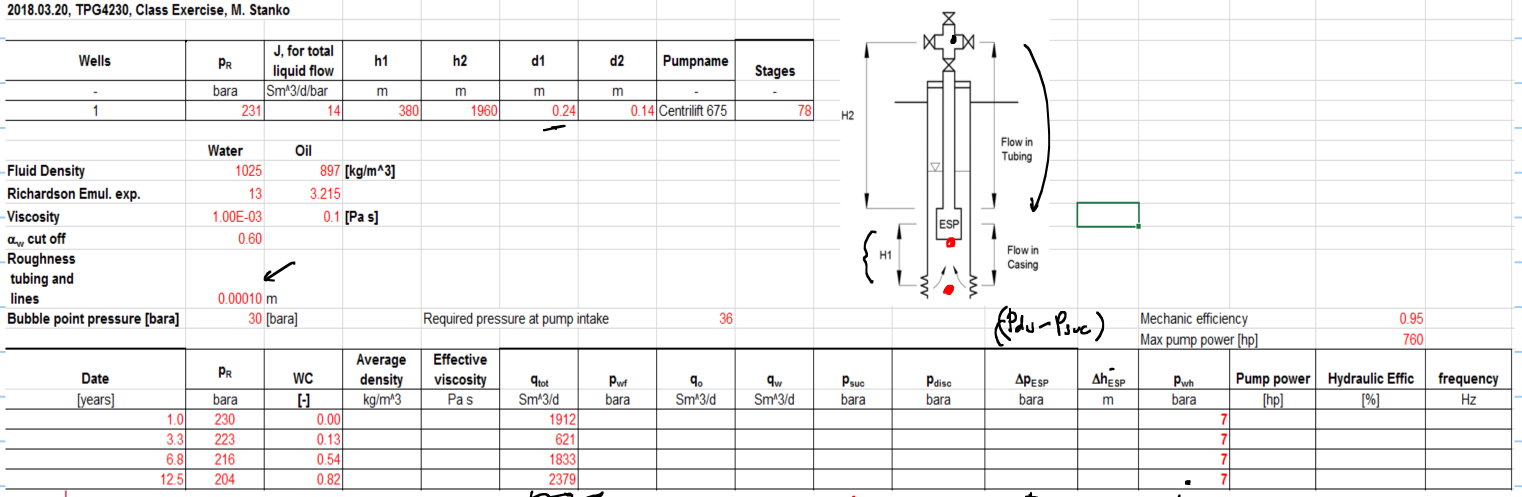






Section	Casing/Liner Size	Weight [lb/ft]	Grade	Threads
26"	26"	267.2#	X-56	D-90MT
22"	18 ⅝"	87.5#	J-55	TenarisER
17 ½"	13 ⅝"	88#	L80	VamTop
12 ¼"	10 ¾" 9 ⅝"	45.5# 47#	L80 L80 & 13Cr80	VamTop
8 ½" Branch Y1	5 ½" Screens & blank pipe	17#	13Cr80	VamTop
Mid. Completion	5 ½" blank pipe	17#	13Cr80	VamTop
Tubing	5 ½"	17#	L80	VamTop





2018.03.20, TPG4230, Class Exercise, M. Stanko

Wells	p_R	J, for total liquid flow	h1	h2	d1	d2	Pumpname	Stages
-	bara	Sm^3/d/bar	m	m	m	m	-	-
1	231	14	380	1960	0.24	0.14	Centrilift 675	78

	Water	Oil	
Fluid Density	1025	897	[kg/m^3]
Richardson Emul. exp.	13	3.215	
Viscosity	1.00E-03	0.1	[Pa s]
α_w cut off	0.60		
Roughness tubing and lines	0.00010	m	
Bubble point pressure [bara]	30	[bara]	

Required pressure at pump intake 36

$(p_{dis} - p_{suc})$

Mechanic efficiency 0.95

Max pump power [hp] 760

Date	p_R	WC	Average density	Effective viscosity	q_{tot}	p_{wf}	q_o	q_w	p_{suc}	p_{disc}	Δp_{ESP}	Δh_{ESP}	p_{wh}	Pump power	Hydraulic Effic	frequency
[years]	bara	[-]	kg/m^3	Pa s	Sm^3/d	bara	Sm^3/d	Sm^3/d	bara	bara	bara	m	bara	[hp]	[%]	Hz
1.0	230	0.00			1912								7			
3.3	223	0.13			621								7			
6.8	216	0.54			1833								7			
12.5	204	0.82			2379								7			

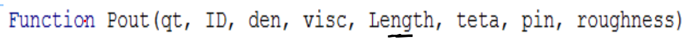
IPR

$q_L = J_L (p_R - p_{wf})$

$h_1 = h_2 + \Delta h_1$

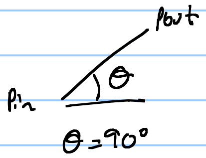
$p_{in}(-,-,-)$

$\frac{\Delta p}{\bar{\rho} g}$

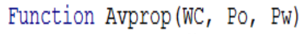


```
Function Pout(qt, ID, den, visc, Length, teta, pin, roughness)
```

$\rho_m = \alpha_w \rho_w + (1-\alpha_w)\rho_o$



$\theta = 90°$



```
Function Avprop(WC, Po, Pw)
```

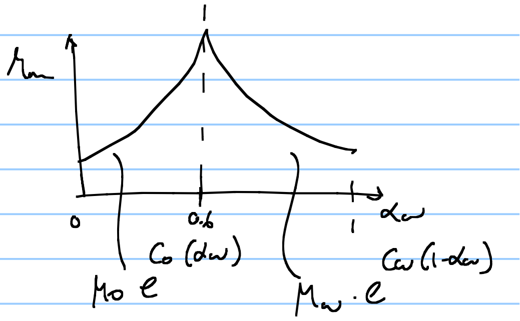
assume $B_o \approx 1$

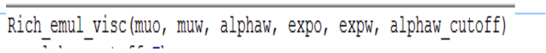
$B_w \approx 1$

$q_{\bar{o}} = q_{o @ p,T}$

$q_{\bar{w}} = q_{w @ p,T}$

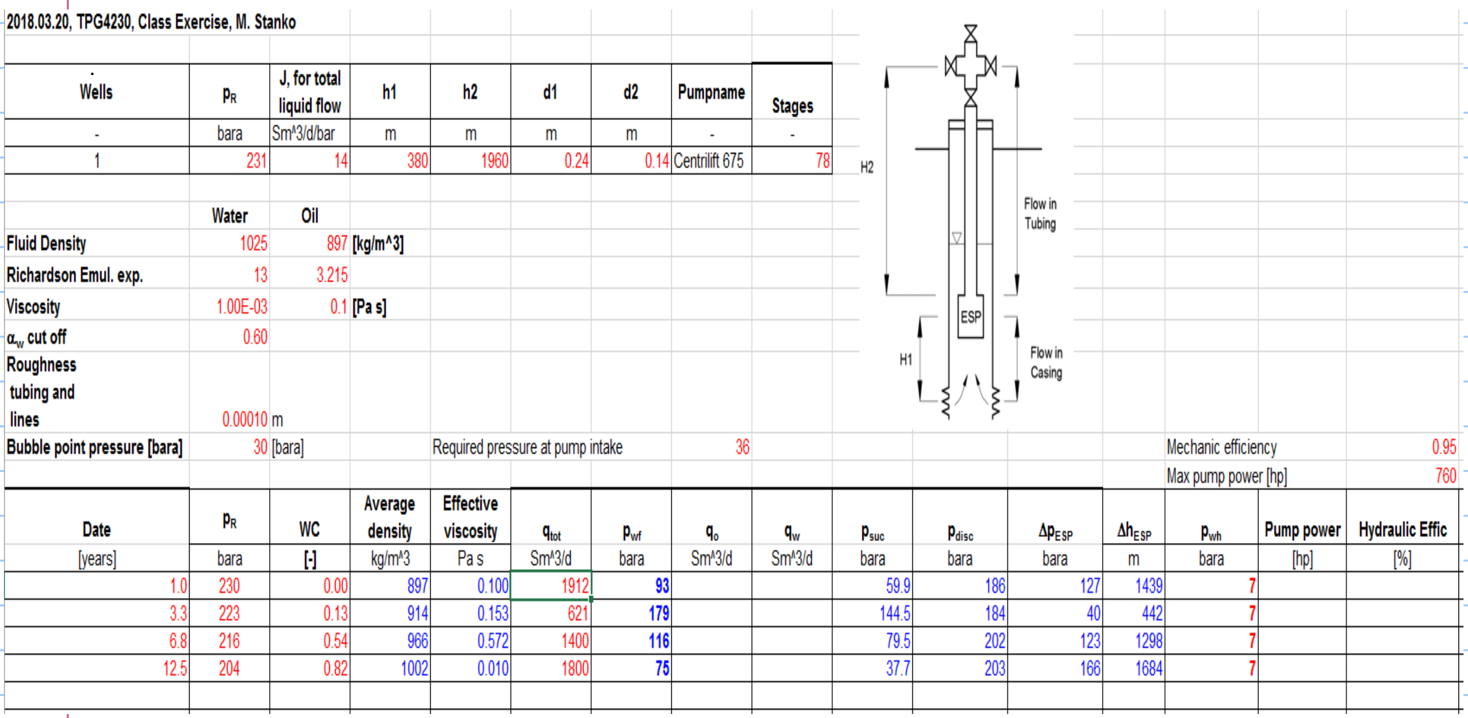
$WC = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}} = \alpha_w = \frac{q_w}{q_o + q_w}$





```
Rich_emul_visc(muo, muw, alphaw, expo, expw, alphaw_cutoff)
```

final operating points after adjustments



2018.03.20, TPG4230, Class Exercise, M. Stanko

Wells	p_R	J, for total liquid flow	h1	h2	d1	d2	Pumpname	Stages
-	bara	Sm^3/d/bar	m	m	m	m	-	-
1	231	14	380	1960	0.24	0.14	Centrilift 675	78

	Water	Oil	
Fluid Density	1025	897	[kg/m^3]
Richardson Emul. exp.	13	3.215	
Viscosity	1.00E-03	0.1	[Pa s]
α_w cut off	0.60		
Roughness tubing and lines	0.00010	m	
Bubble point pressure [bara]	30	[bara]	

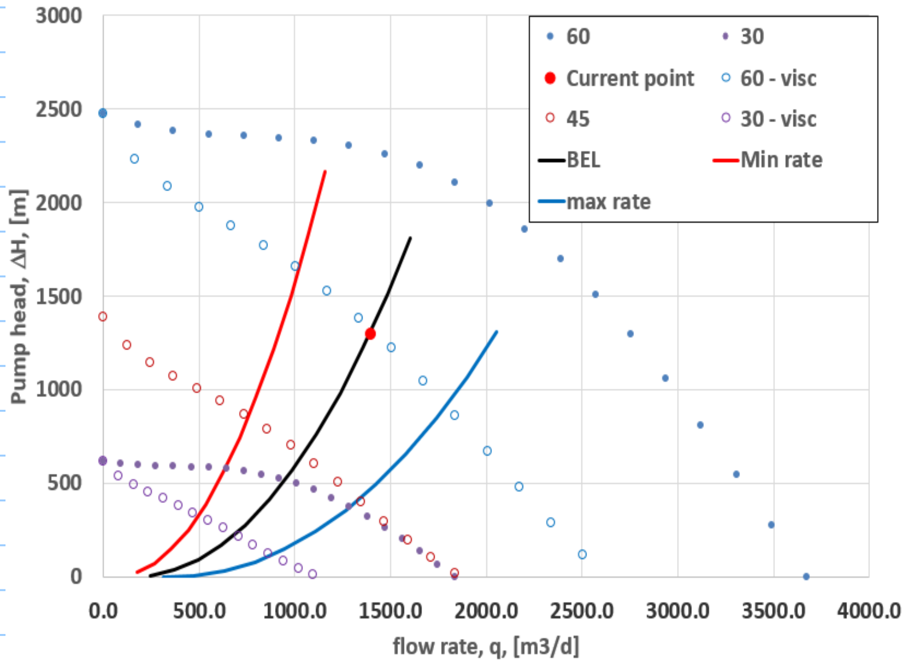
Required pressure at pump intake 36

Mechanic efficiency 0.95

Max pump power [hp] 760

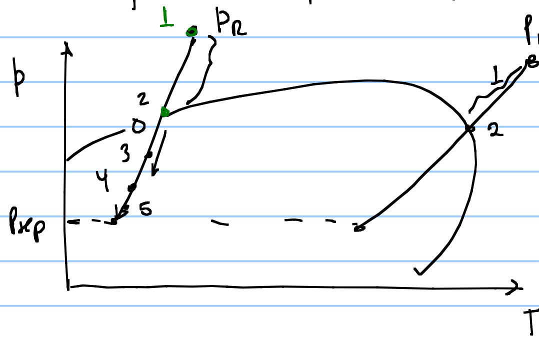
Date	p_R	WC	Average density	Effective viscosity	q_{tot}	p_{wf}	q_o	q_w	p_{suc}	p_{disc}	Δp_{ESP}	Δh_{ESP}	p_{wh}	Pump power	Hydraulic Effic
[years]	bara	[-]	kg/m^3	Pa s	Sm^3/d	bara	Sm^3/d	Sm^3/d	bara	bara	bara	m	bara	[hp]	[%]
1.0	230	0.00	897	0.100	1912	93			59.9	186	127	1439	7		
3.3	223	0.13	914	0.153	621	179			144.5	184	40	442	7		
6.8	216	0.54	966	0.572	1400	116			79.5	202	123	1298	7		
12.5	204	0.82	1002	0.010	1800	75			37.7	203	166	1684	7		

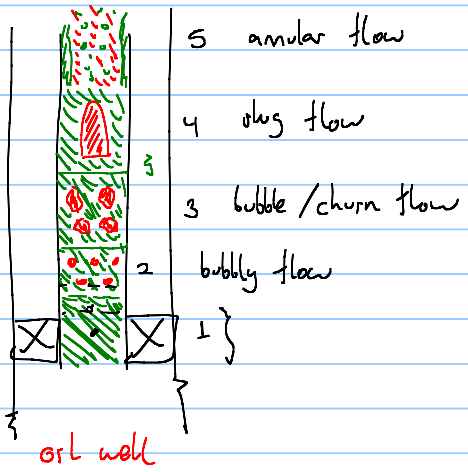
for year 6,8 :

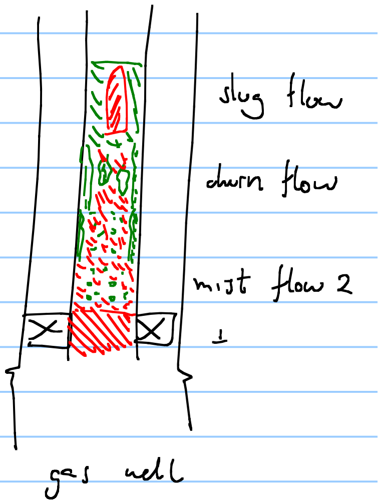

Pump head, ΔH, [m]
3000
2500
2000
1500
1000
500
0
0.0
500.0
1000.0
1500.0
2000.0
2500.0
3000.0
3500.0
4000.0
flow rate, q, [m3/d]
60
30
Current point
60 - visc
45
30 - visc
BEL
Min rate
max rate

20180403 4 exercise sets.

flow equilibrium (pressure drop) calculations with multiphase flow







If you are interested on multiphase flow → TEP4250 Ole Jørgen Nydal

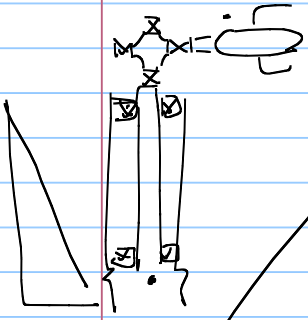
purpose: Δp along a conduit (well, tubing, pipeline, flow line, etc.)

due to the variation in flow pattern, I have to perform this calculation in a stepwise manner.

Steps

1: Depart from a point with known p, T.

2: assume a rate ($q_{\bar o}$, $q_{\bar g}$), GOR, wc → $q_{\bar g}$, $q_{\bar w}$

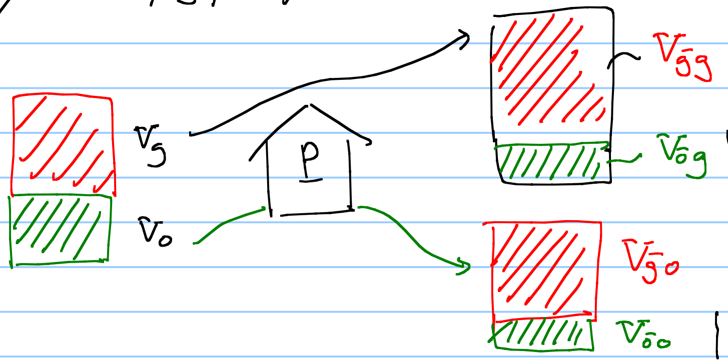


3: Calculate local rates / fluid properties

↓

BO properties

B_o, B_g, R_s, r_s



$B_o = \frac{V_o}{V_{\bar o o}}$

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

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

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

$\mu_o(p,T)$

$\mu_g(p,T)$

$\sigma_{og}(p,T)$

$\sigma_{ow}(p,T)$

$\sigma_{wg}(p,T)$

$$\begin{bmatrix} q_g \\ q_o \\ q_w \end{bmatrix}_{p,T} = \begin{bmatrix} \frac{B_g}{1-R_s \cdot r_s} & \frac{-B_g R_s}{1-R_s \cdot r_s} & 0 \\ \frac{-B_o r_s}{1-R_s r_s} & \frac{B_o}{1-R_s \cdot r_s} & 0 \\ 0 & 0 & B_w \end{bmatrix}_{@p,T} \cdot \begin{bmatrix} q_{\bar g} \\ q_{\bar o} \\ q_{\bar w} \end{bmatrix}$$

Bo properties come from:

- measured data (lab)
- BO correlations
- generate from EOS

EOS

calculate $\dot{m}_T$ $\dot{m}_T = q_{\bar{o}} \rho_{\bar{o}} + q_{\bar{g}} \cdot \rho_{\bar{g}} + q_{\bar{w}} \cdot \rho_{\bar{w}}$

need composition z_i C_1

C_2

C_3

CO_2

$\vdots$

perform a flash calculation @ P, T

↳ $\rho_g, \rho_o, \rho_w, \mu_g, \mu_o, \sigma_{og}, \sigma_{ow}, \sigma_{wg}$

↳ $X_g \sim$ mass fraction of gas $X_g = \frac{\dot{m}_g}{\dot{m}_g + \dot{m}_o}$

$\dot{m}_g$

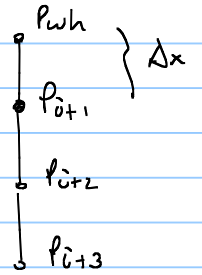
$\dot{m}_o$

$q_g = \frac{\dot{m}_g}{\rho_g}$ $q_o = \frac{\dot{m}_o}{\rho_o}$

4: calculate $\left\{ \frac{dP}{dx} \right.$ at that position $\rho_o, \rho_g, \rho_w, \mu_g, \mu_o, \mu_w, \sigma_{og}, \sigma_{ow}, \sigma_{wg}, \underset{\downarrow \frac{q_o}{A}}{U_{SL}}, \underset{\downarrow \frac{q_g}{A}}{U_{SG}}, \phi, \overset{\text{pipe inclination}}{\theta}, \underset{\downarrow \text{roughness}}{\varepsilon}$

- ↳ correlation ✓
- ↳ mechanistic model
- ↳ homogeneous model $\frac{dp}{dL} = \underset{\sim}{\rho_m} g + \frac{f}{\phi} \frac{v_m^2}{2g}$
- ↳ drift flux model

5: Integrate and find P_{i+1}



$\frac{dP}{dx}$ = constant

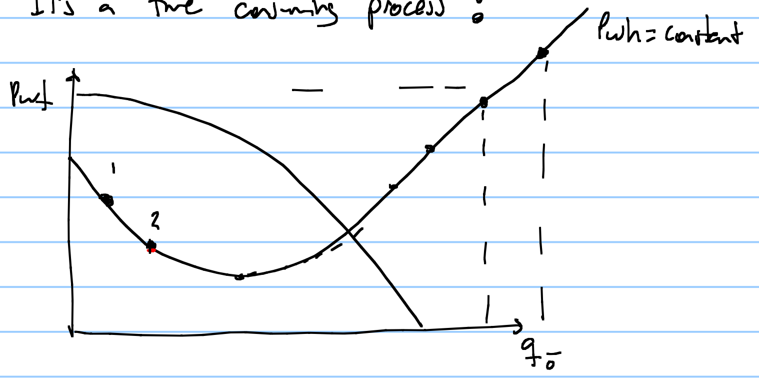
$P_{(x=0)} = P_{wh}$

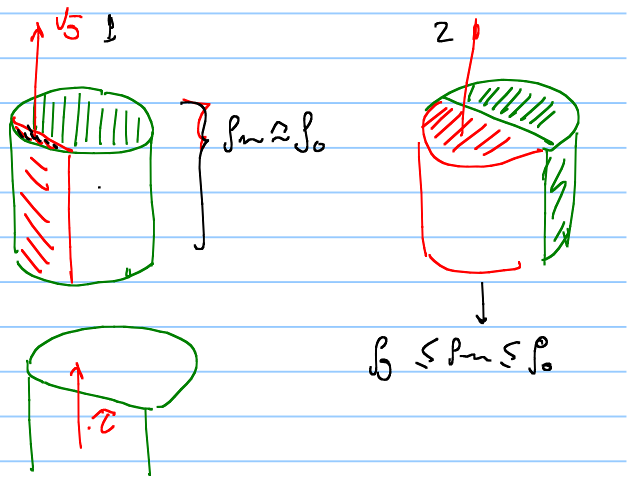
$P_{i+1} = ?$

$P_{i+1} = P_{wh} - \frac{dP}{dx} \Delta x$ EULER

or other implicit explicit methods

It's a true converging process!

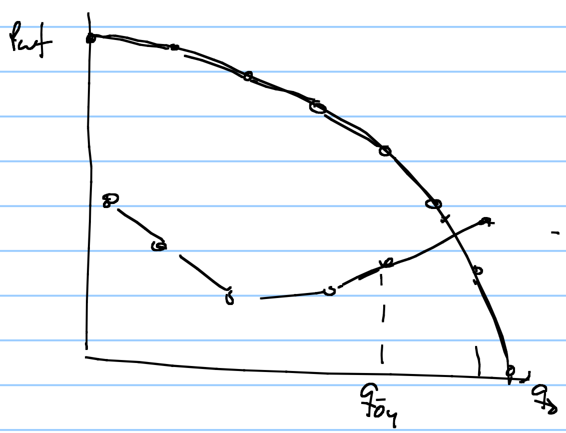




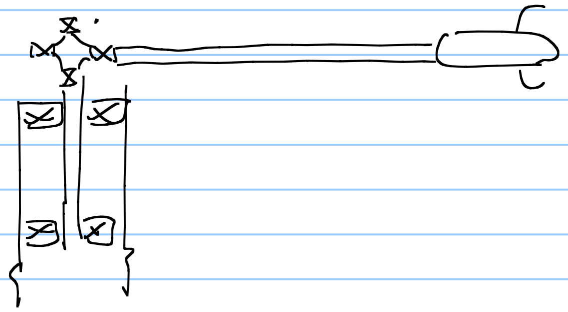
Pressure drop in multiphase flow is typically pre-computed and stored in "flow tables"

$P_{wh} = P_{wh1}$ $WC = WC_1$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf1}			
q_{o2}	P_{wf2}			
q_{o3}	P_{wf3}			
q_{o4}	P_{wf4}			
q_{o4}	P_{wf5}			



there are some situations where P_{wh} is not known a priori



perform calculations for P_{wh1}, P_{wh2}, P_{wh3}

during the life of well WC will change, GOR also changes

↳ perform calculations for GOR_1 GOR_2, GOR_3, GOR_4
WC_1 WC_2, WC_3, WC_4 -

$P_{wh} = P_{wh1}$ $WC = WC_1$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf1}			
q_{o2}	P_{wf2}			
q_{o3}	P_{wf3}			
q_{o4}	P_{wf4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh2}$ $WC = WC_1$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf1}			
q_{o2}	P_{wf2}			
q_{o3}	P_{wf3}			
q_{o4}	P_{wf4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh3}$ $WC = WC_1$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf1}			
q_{o2}	P_{wf2}			
q_{o3}	P_{wf3}			
q_{o4}	P_{wf4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh4}$ $WC = WC_1$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf1}			
q_{o2}	P_{wf2}			
q_{o3}	P_{wf3}			
q_{o4}	P_{wf4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh_1}$, $WC = WC_2$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf_1}			
q_{o2}	P_{wf_2}			
q_{o3}	P_{wf_3}			
q_{o4}	P_{wf_4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh_1}$, $WC = WC_3$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf_1}			
q_{o2}	P_{wf_2}			
q_{o3}	P_{wf_3}			
q_{o4}	P_{wf_4}			
q_{o4}	P_{wf5}			

$P_{wh} = P_{wh_1}$, $WC = WC_4$, $GOR = GOR_1$

$q_{\bar{o}}$	P_{wf}	$q_{\bar{g}}$	$q_{\bar{w}}$	T_{wh}
q_{o1}	P_{wf_1}			
q_{o2}	P_{wf_2}			
q_{o3}	P_{wf_3}			
q_{o4}	P_{wf_4}			
q_{o4}	P_{wf5}			

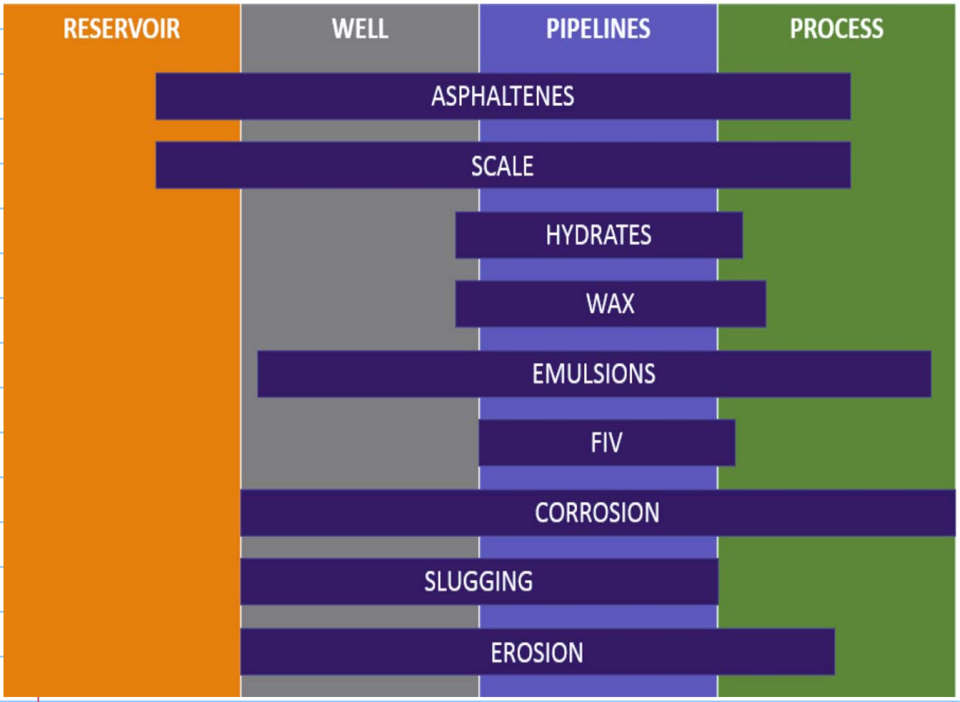
$$N_{runs\ to\ make} = \underbrace{N_{rates}}_{(5-10)} \cdot N_{P_{wh}} \cdot N_{GOR} \cdot N_{WCs} \approx 10^4$$

Flow assurance issues:

① Increased Δp, flow restriction, → blockage
② integrity problems
③ loss in functionality of components

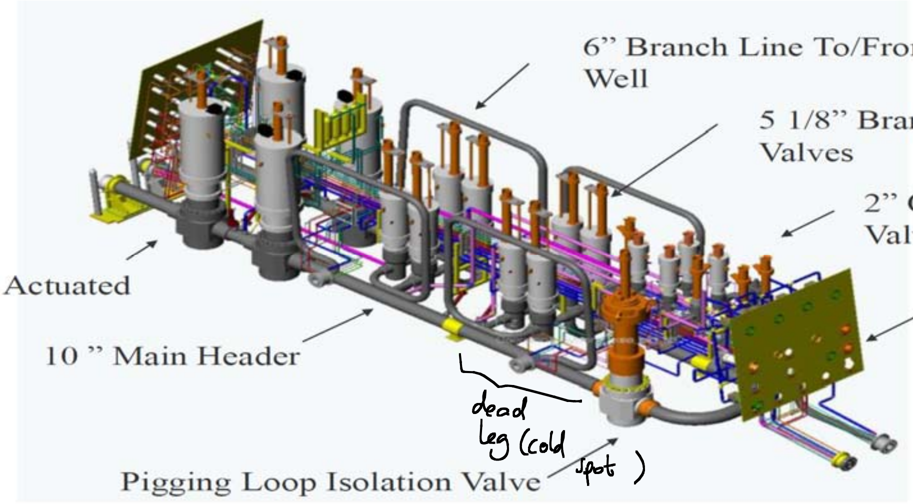
flow assurance issue	consequence	corrective measures
wax	①	pigging, insulation, heat tracing ↓ pigging loop requirement chemical inhibitors ↳ chemical injection system
hydrate	①, ③	• inhibitor → chemical injection system • insulation • heat tracing
asphaltenes	①, ②	• chemical inhibitor, removals • mechanical removal
emulsion	①, ③* *topside separation	• demulsifiers

Scale	①, ③	scale inhibitor, remover mechanical removal
erosion	②, ③	• proper dimensioning of pipes/components • reduce rate
Corrosion	②, ③	• material selection • corrosion inhibitor
Slugging	①, ③, ②	• choke control • gas injection • dimensioning of pipes • use a slug catchers instead of separator,



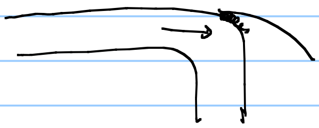
flow assurance considerations during field development:

- early studies: detect and flag possible show-stoppers { slugging, hydrate ←, wax
- FEED → • a specific development alternative is selected
  in detail study → hydrate management plan
  ↳ wax " "
  ↳ scale " "
  ↳ prediction of T, p, velocities in production system → pipelines, flowlines
  equipment
  dead leg
- EPC



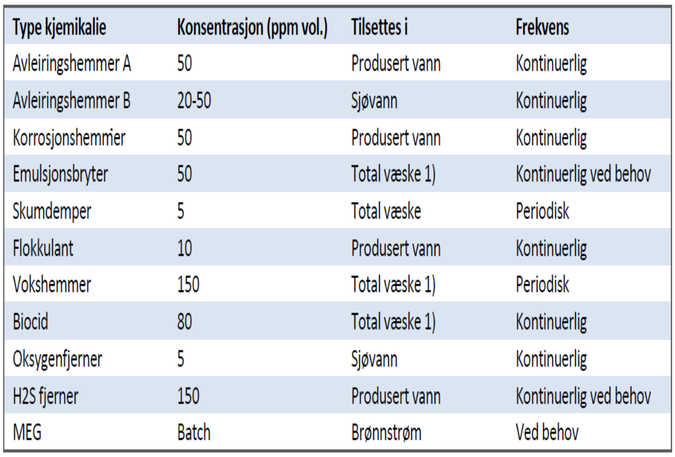
Engineering tools commonly used :

- multiphase flow simulator p, T along pipe { gap, pipesim, hysys
- transient flow simulator { OLGA, ledaflow — slugging, shutin, startup
- PVT and lab test { Hydrate, wax, scale, emulsion, erosion
- CFD computational fluid dynamics



- FEA Finite element analysis stresses
- standards

Tabell 5-2. Foreløpig oversikt over kjemikalietyper



Type kjemikalie	Konsentrasjon (ppm vol.)	Tilsettes i	Frekvens
Avleiringshemmer A	50	Produsert vann	Kontinuerlig
Avleiringshemmer B	20-50	Sjøvann	Kontinuerlig
Korrosjonshemmer	50	Produsert vann	Kontinuerlig
Emulsjonsbryter	50	Total væske 1)	Kontinuerlig ved behov
Skumdemper	5	Total væske	Periodisk
Flokkulant	10	Produsert vann	Kontinuerlig
Vokshemmer	150	Total væske 1)	Periodisk
Biocid	80	Total væske 1)	Kontinuerlig
Oksygenfjerner	5	Sjøvann	Kontinuerlig
H2S fjerner	150	Produsert vann	Kontinuerlig ved behov
MEG	Batch	Brønnstrøm	Ved behov

1) Olje og produsert vann.

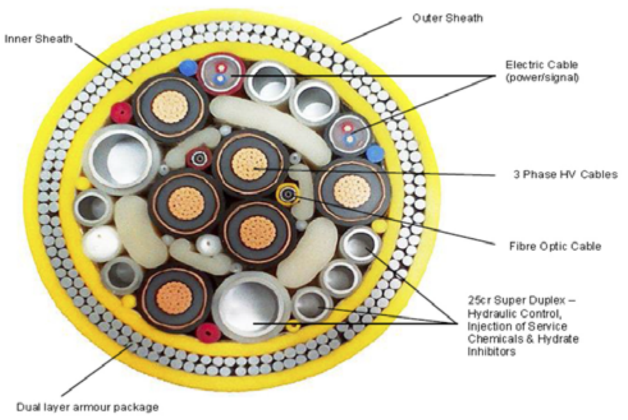
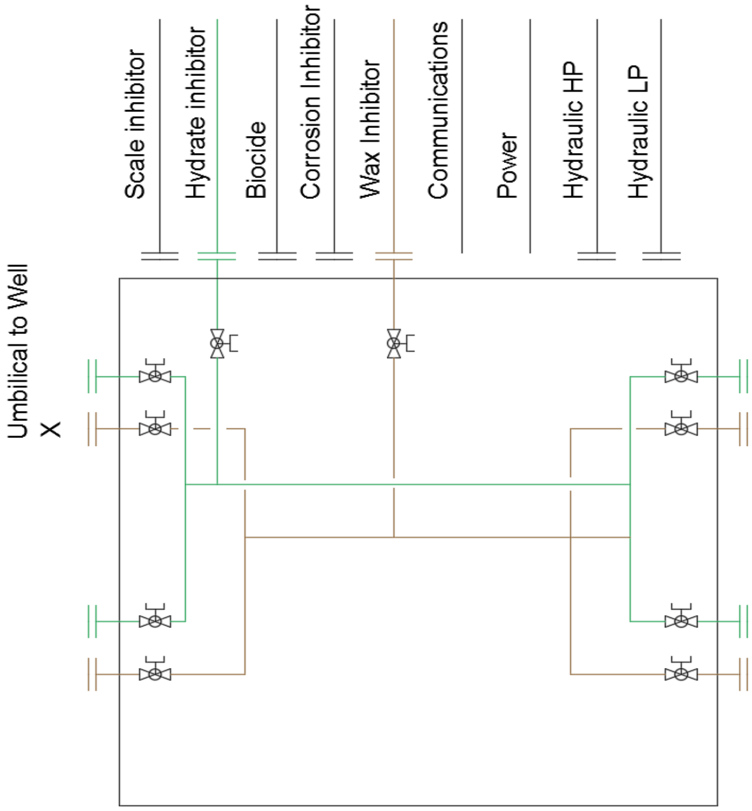
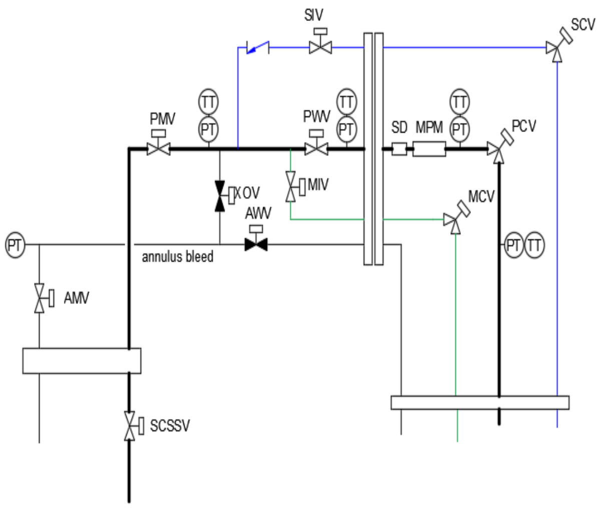
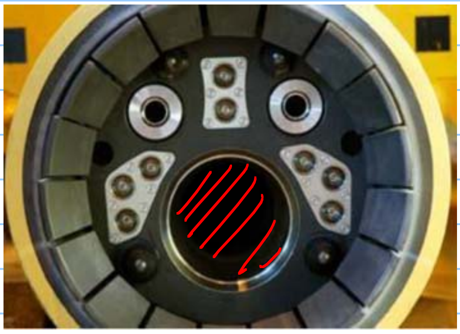


Figure 3 – Umbilical Cross Section Example







multi-bore connector.

Temperature calculations are performed based on energy conservation equation

$$\frac{d\dot{q}}{dL} = \dot{m}\left[\underbrace{\frac{dh}{dL}} + \sin\theta . g + v\frac{dv}{dL}\right]_{//}$$

$h = f(T)$ if liquid $dh = \underline{C_p . dT}$

if gas $dh = C_p\, dT + \underline{\mu_T} . dP$

for liquid

$$\frac{dT}{dL} + T\cdot\frac{1}{A} - \frac{T_{amb}}{A\cdot} - \frac{\sin(\theta)\cdot g}{c_p} = 0$$

$$u\cdot\frac{dT}{dL} + u\cdot T\cdot\frac{1}{A} = u\cdot\left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)$$

$$u = e^{\frac{x}{A}}$$

$$e^{\frac{x}{A}}\cdot\frac{dT}{dL} + e^{\frac{x}{A}}\cdot T\cdot\frac{1}{A} = e^{\frac{x}{A}}\cdot\left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)$$

$$\frac{d\left(e^{\frac{x}{A}}\cdot T\right)}{dL} = e^{\frac{x}{A}}\cdot\left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)$$

$$e^{\frac{x}{A}}\cdot T\Big|_{T_0}^{T(x)} = \left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)\cdot A\cdot e^{\frac{x}{A}}\Big|_{0}^{x}$$

$$e^{\frac{x}{A}}\cdot T(x) - T_0 = \left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)\cdot A\cdot\left(e^{\frac{x}{A}} - 1\right)$$

$$T(x) = T_0\cdot e^{\frac{-x}{A}} + \left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)\cdot A\cdot\left(1 - e^{\frac{-x}{A}}\right)$$

Incompressible fluid

$dh = C_p\, dT$

$$A = \frac{\dot{m}\ C_p}{2\pi r_{out}\cdot U}$$