Notes for introductory lecture, 12 January 2021

Norwegian University of Science and Technology

TPG4230 – Field development and operations

Spring Semester 2021

Information

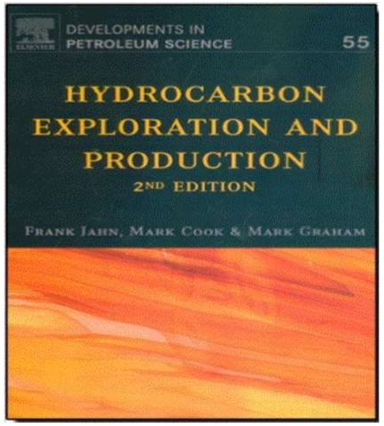
- Lecturer: Assoc. Prof. Milan Stanko (Production Tech) (milan.stanko@ntnu.no). Office 510.
- Teaching assistant: Ressi Bonti Mohammad (ressibm@stud.ntnu.no)
- Lecture schedule
  - Tuesdays, 10:15-12:00 (theory and exercises)
  - Thursdays, 12:15-15:00 (theory and exercises)
- Course description

Information

- Lectures until 27 April (breaking for Easter)
- Consultation time: preferably after class. Try to make an email appointment.
- Reference group – **any volunteers?**
  - Anonymous comment box (in blackboard)
- **Use Blackboard to navigate the course**
  - Use the forum for Q&A
  - Join a group before delivering the exercise (even if one person only!!)

Reference material

- Compendium
- Recommended
- Supplementary
- Hydrocarbon exploration and production (Jahn, Cook and Graham)



Evaluation

- 60% exam (digital home exam in Inspera 19-May, 9:00-12:00, all material allowed).
  - Previous years exams
  - Examples 2018, 2020
  - Make it nice, easy to understand and follow. When provided, use the Excel template

Evaluation

- 40% - assignments
  - All assignments must be delivered to get access to the exam, and at least get 20/40 (pass)
  - Home exercises (delivered in Inspera). Deadline probably in April. Groups of up to 3 people are allowed.
    - (maybe) ungraded partial deliveries in BB to check progress and give feedback
  - Codes of approval of **all** online quizes. (10/40)
  - **Let me know early if there is a deadline conflict with other courses**
  - **Work on the assignments during the semester!**

Teaching

- Pilot
  - Be understanding and provide constructive feedback
- Digital, until further notice
- «Sort of» flipped classroom
  - Some live classes (Class exercises, tutorials on software, Q&A, advanced topics) – weekly or bi-weekly

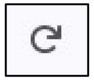
Teaching

- Participants watch by themselves pre-recorded videos (ca 45 min) (on youtube)
  - Watch at higher playback speed (1.5x -2x, Milan speaks slow)😅
  - At certain time stamps (**or at the end of the video**), the videos have embedded links to: other relevant videos, material and quizzes. Example link1 link2
  - It is recommended to go through the complete video and click on the links along the way
  - It helps if you make your own annotations while watching (with pen and paper or on the pdf)

Quizzes

- Supposed to help you remember better
- Embedded on videos link2
- When a quiz is completed, a completion code will be shown at the bottom of the quiz – **collect and save the code, this is a proof of completion**
  - Codes of completion will be submitted together with the home assignments in Inspera in an Excel sheet
  - Codes are individual and non-transferrable
  - Take the quiz using your computer
  - We have ways to detect if you generate codes for others, **don't do it!, both codes will be invalidated**

Quizzes

- No solution key will be given
- Known bugs
  - When there is a multiple-choice question, if you want to clear your selection, you have to refresh the page 
  - In some browsers one must scroll down sometimes to see the rest of the quiz and the result code
  - Be patient, give it time to load and process information

Course progress overview – Excel file

Tools

- Excel (VBA)
- Python (Jupyter Notebook) –using Google Colab
- Hysys (Aspentech, run on ntnu farm) or DWSIM
- IPM (Petex) – maybe?

Questions?

Notes for youtube video nr. 1

Field development and operations

Offshore oil and gas production (from fields in Norway)

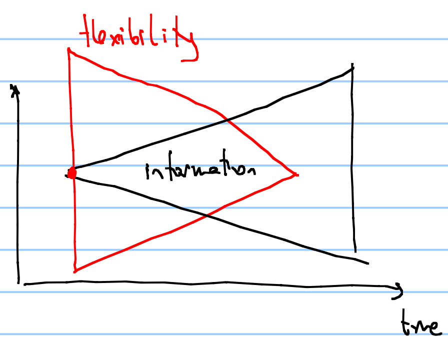
maximize economic value of HC exploitation project for shareholders, subjected to technical constraints (eng., petroleum engineering) HSE constraints

define KPI's

stuck with an existing system
reduce the impact of system defficiencies
exploit the advantages
optimize / "effectivize" production

Decide on main features of field

→ define KPI's for project (Key performance indicator)
→ collect information $
→ define alternatives
→ analyze data, evidence (modeling)
→ choose an alternative



life-cycle of hydrocarbon field:

Eriksen process

DG0 (Decision gate)

(5-40)

Pre-exploration → exploration → Appraisal → field planning → field construction → operations → decommissioning abandonment

discovery

(3-6)

DG1 (BoK) (Beslutning om Konkretisering)

DG2 (BoV) → Beslutning om videreføring

DG3 → BoG Beslutning om gjennomføring

feasibility studies → concept planing → preengineering

issue PDO plan for development and operations

detailed engineering — construction — testing and startup

DG4

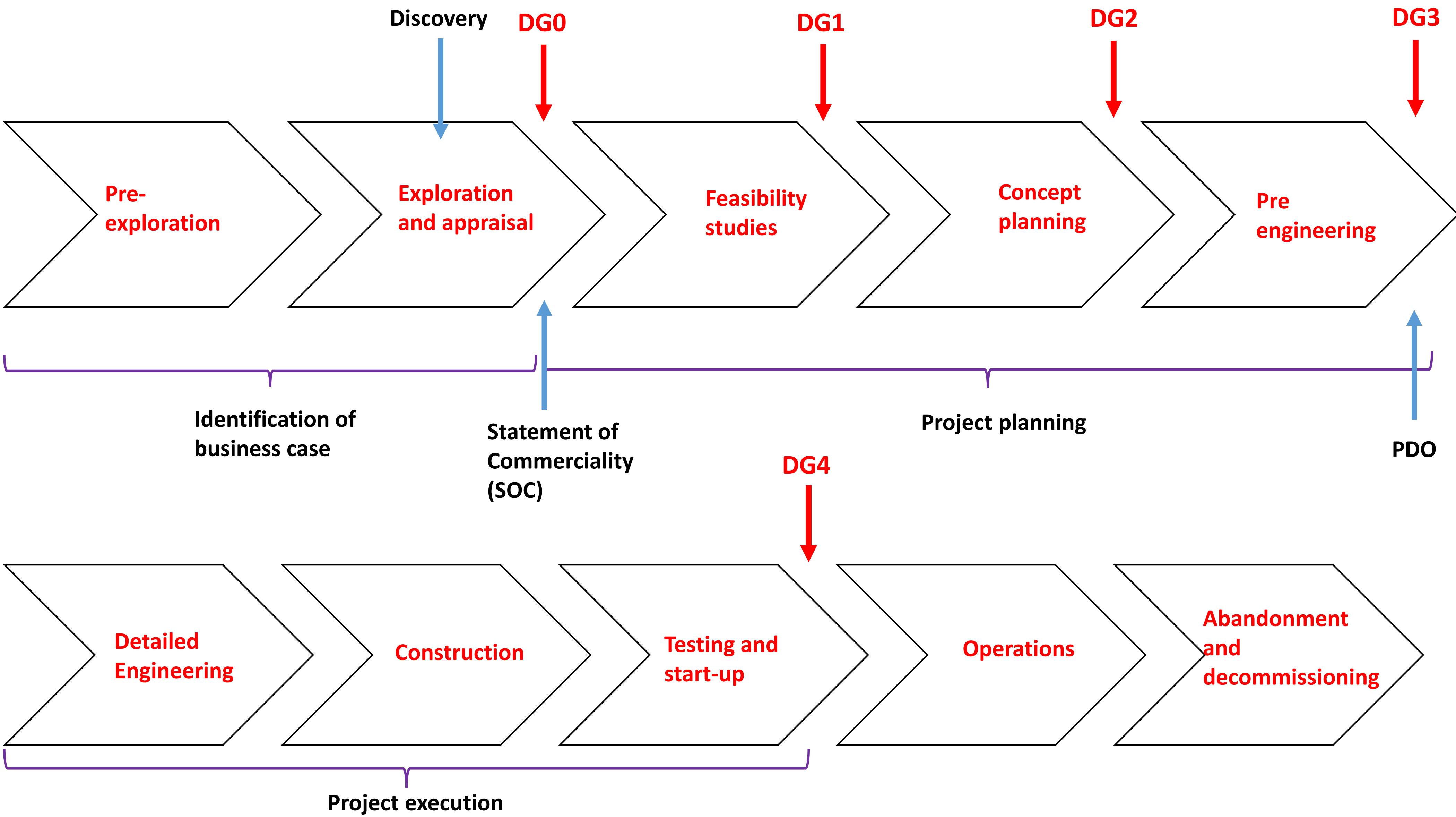
Topics to cover in the course:

- Overview of FD process, general considerations
  - Production modes
  - gas vs. oil
  - onshore vs. offshore
  - Production profile stages
- field production performance.
  - production scheduling
    - Material balance, IPR, TPR, choke, network, downhole network, boosting and AL, } model
    - Coupling with reservoir simulator
    - Plateau height vs. plateau length
  - production potential
  - Multi-reservoir scheduling
- Value chain model. NPV quantification (q vs t)
- flow assurance issues and considerations in FD
  - layout of subsea production systems
  - Modeling of wax (or hydrate)
- $\underbrace{\text{offshore structures}}_{\$}$, type and selection
- Uncertainty quantification using stochastic analyses and probability trees ← decision making
  - reserve estimation
  - appraisal

Notes for youtube video n. 2

THE FIELD DEVELOPMENT PROCESS

Prof. Milan Stanko (NTNU)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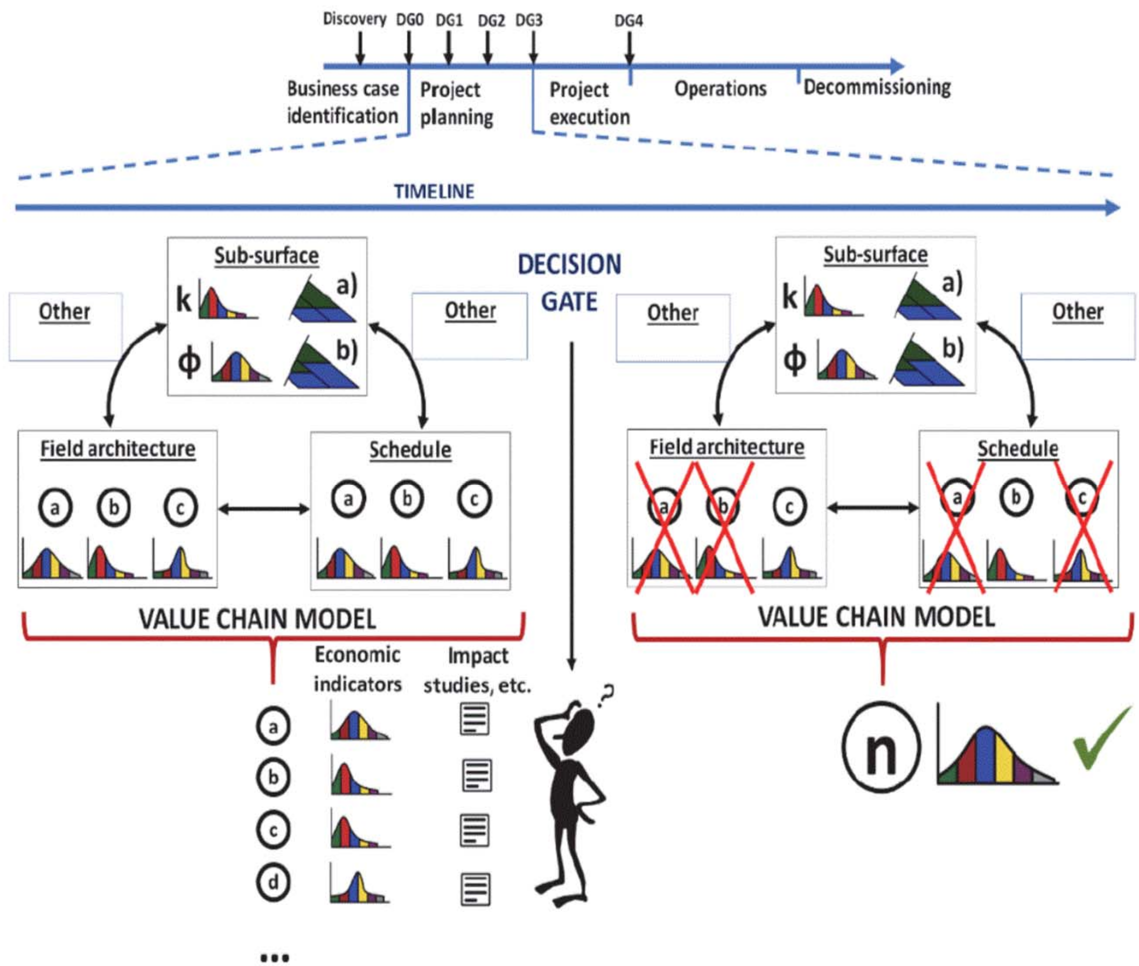
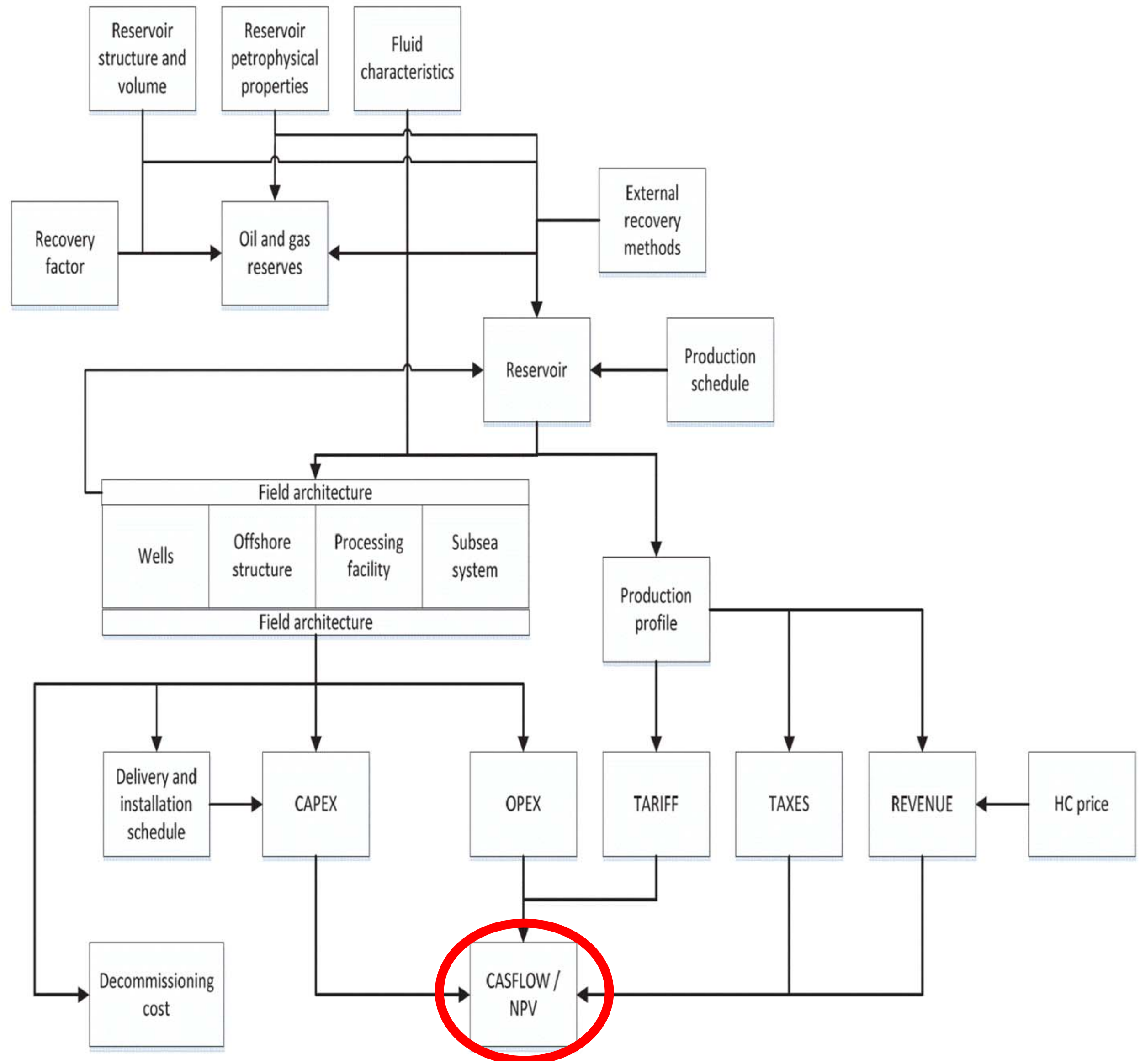
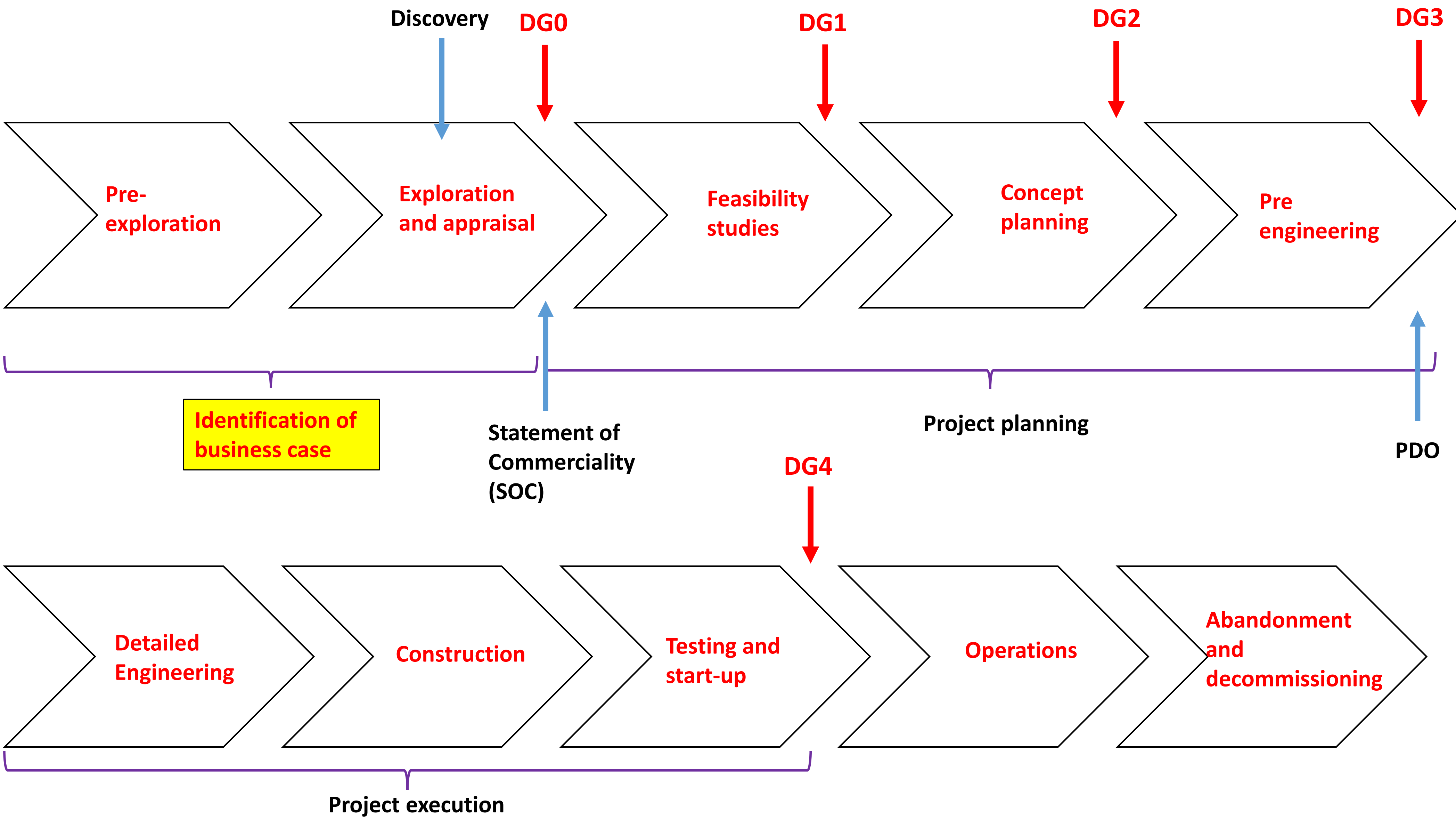
Project execution

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



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

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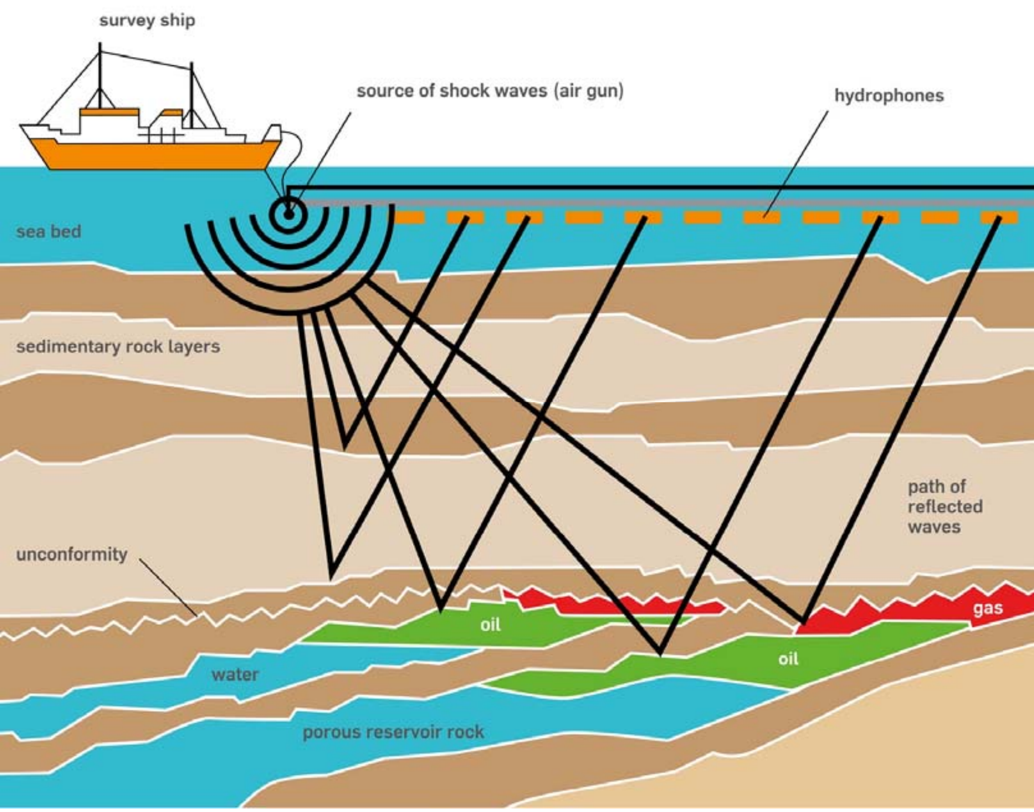
IDENTIFICATION OF BUSINESS CASE

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

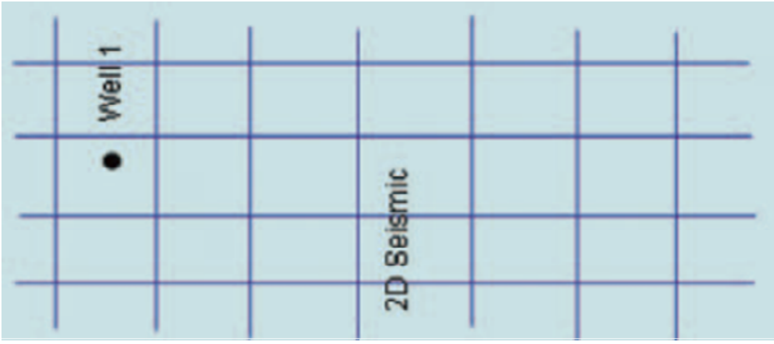
IDENTIFICATION OF BUSINESS CASE - TASKS

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

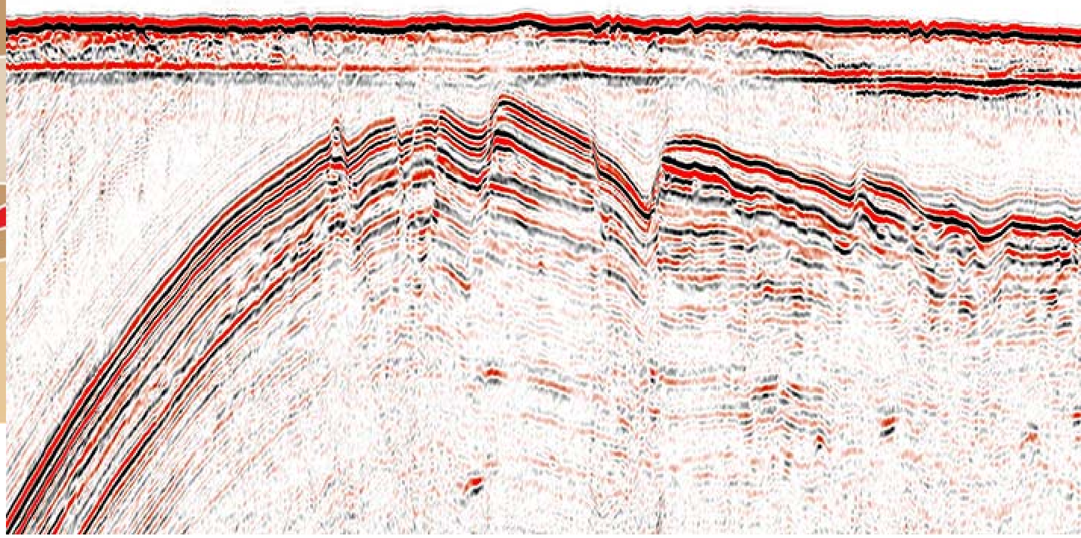
IDENTIFICATION OF BUSINESS CASE - TASKS



Ref: https://krisenergy.com/company/about-oil-and-gas/exploration/

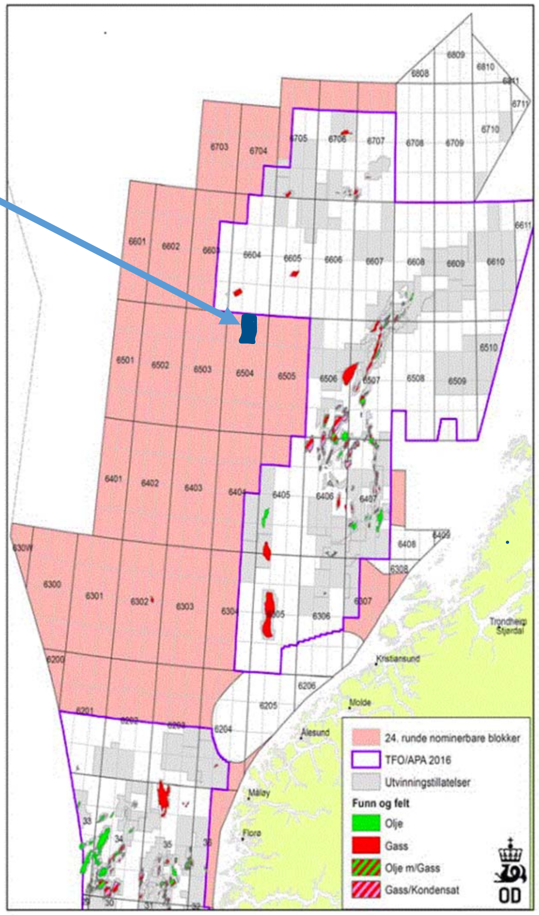


Seismic exploration



IDENTIFICATION OF BUSINESS CASE - TASKS

Ca 500 km^2



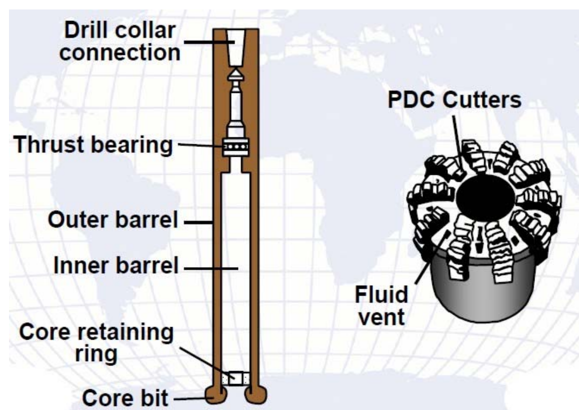
Ref: NPD

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

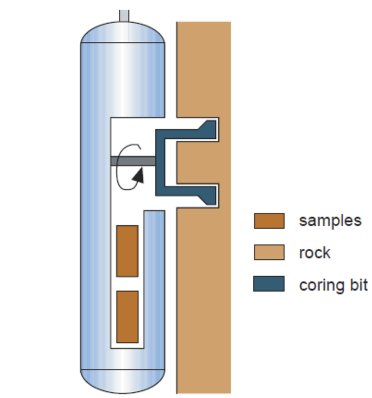
IDENTIFICATION OF BUSINESS CASE - TASKS

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

- Discovery!



Ref: https://www.spec2000.net/09-coremethods.htm



Ref: Hydrocarbon exploration and production, Jahn et al.

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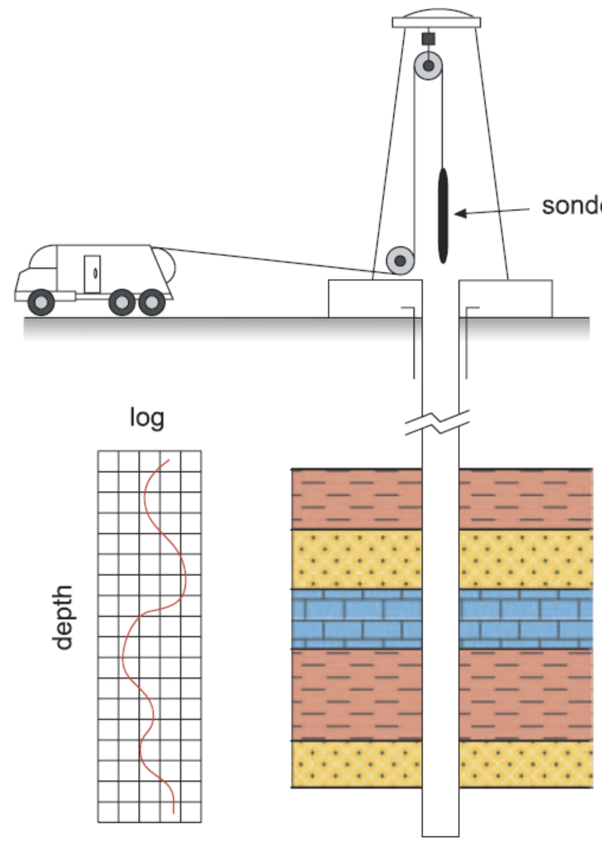

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IDENTIFICATION OF BUSINESS CASE - TASKS

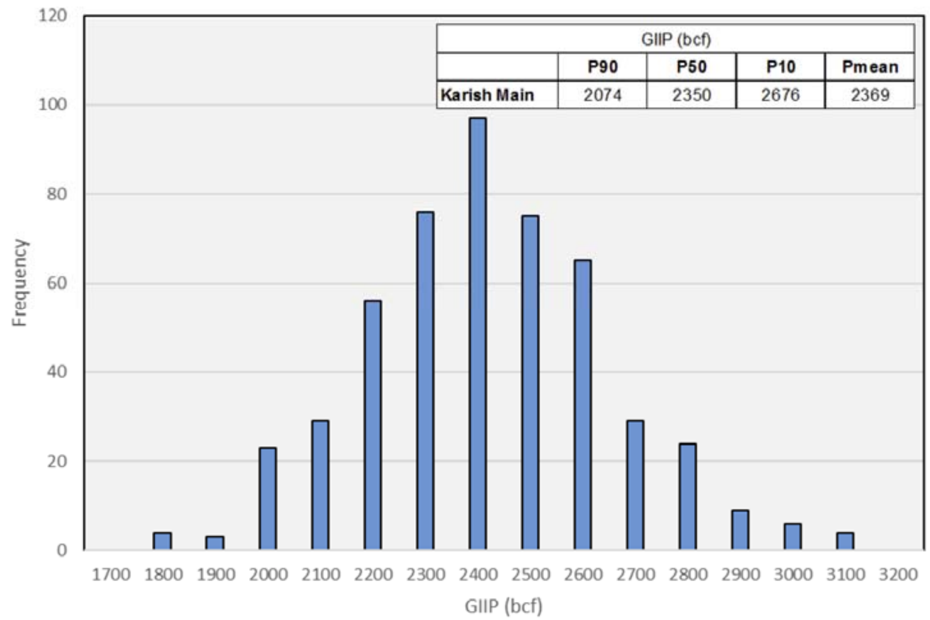
- Exploration. Perform geological studies, geophysical surveys, seismic, exploration drilling (Well cores, wall cores, cuttings samples, fluid samples, wireline logs, productivity test).

- Discovery!

https://www.youtube.com/watch?v=Qd7F8T0IVXU

IDENTIFICATION OF BUSINESS CASE - TASKS

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



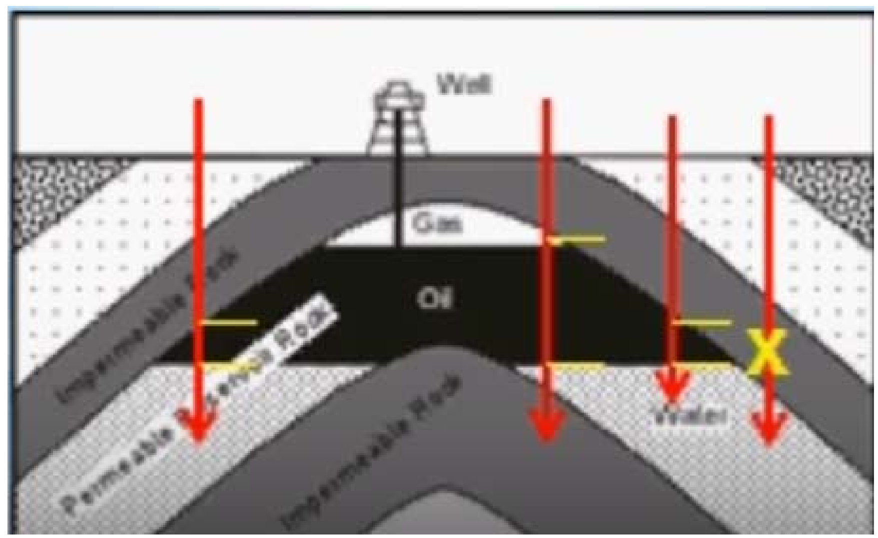
Ref: PDO Karish and Tanin. Energean

IDENTIFICATION OF BUSINESS CASE - TASKS

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

IDENTIFICATION OF BUSINESS CASE - TASKS

- Appraisal

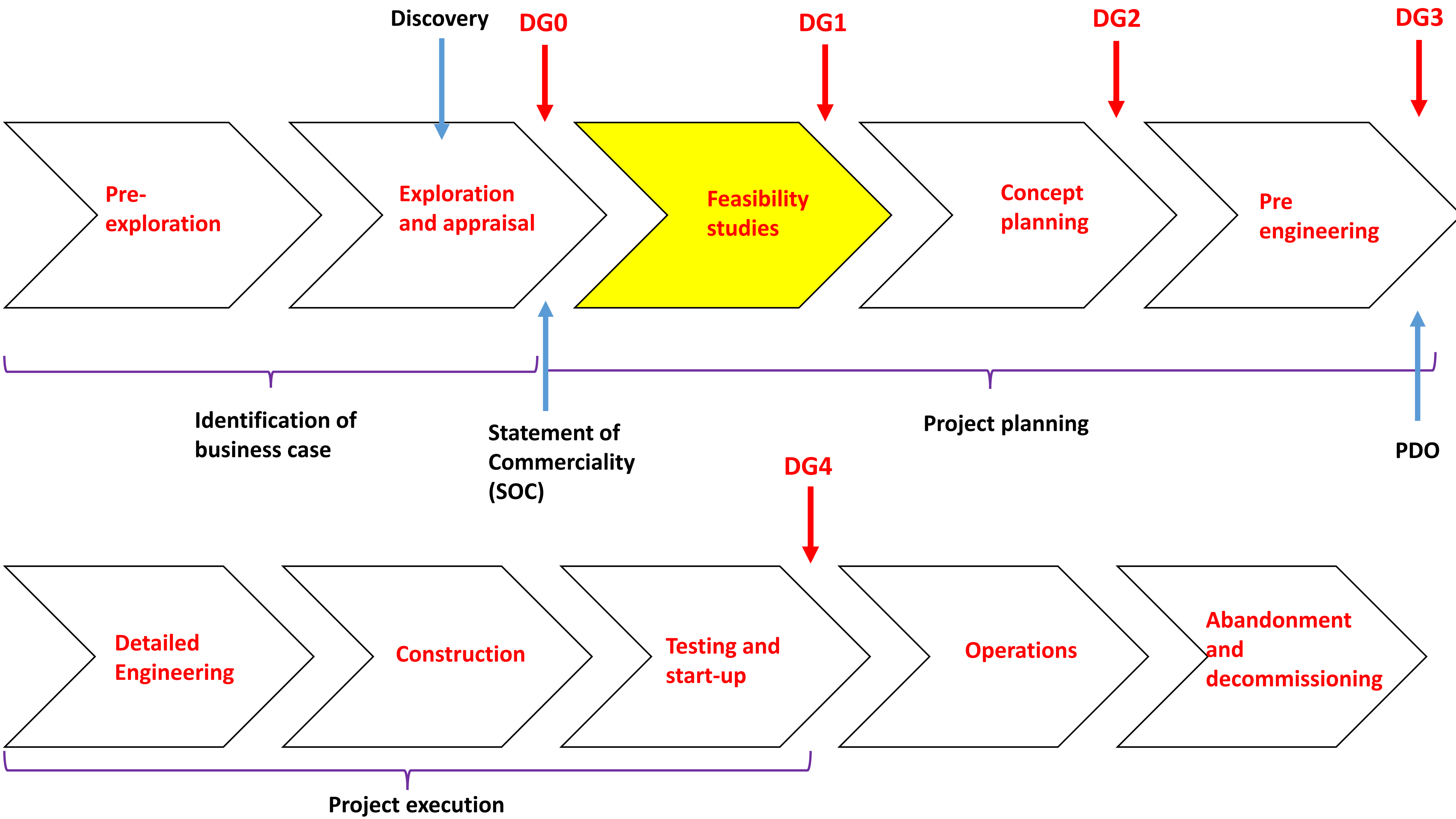


Ref: https://www.youtube.com/watch?v=-e9jjnsquGI

IDENTIFICATION OF BUSINESS CASE - TASKS

DG0:

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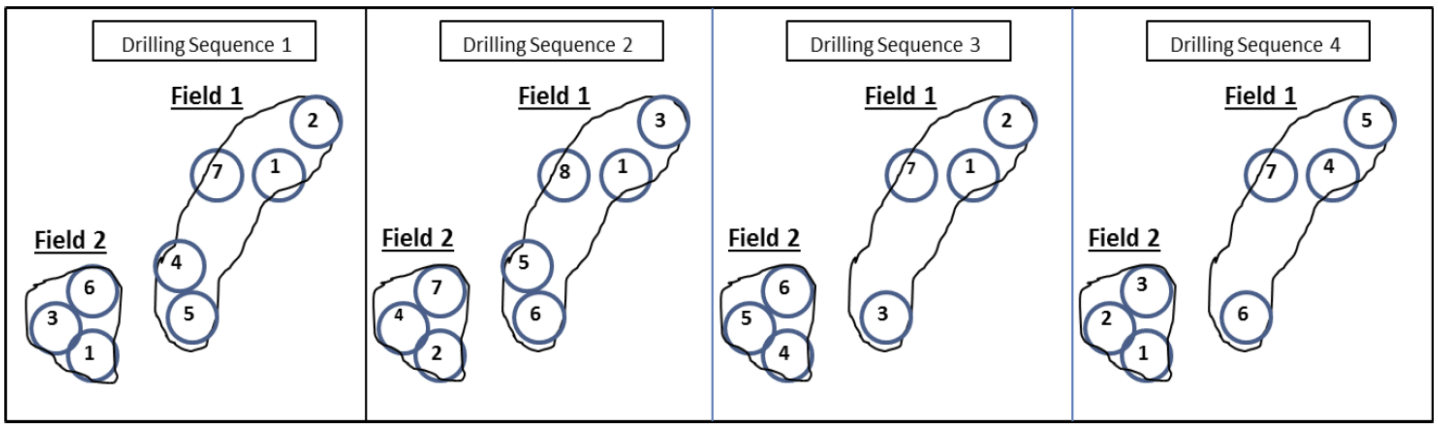
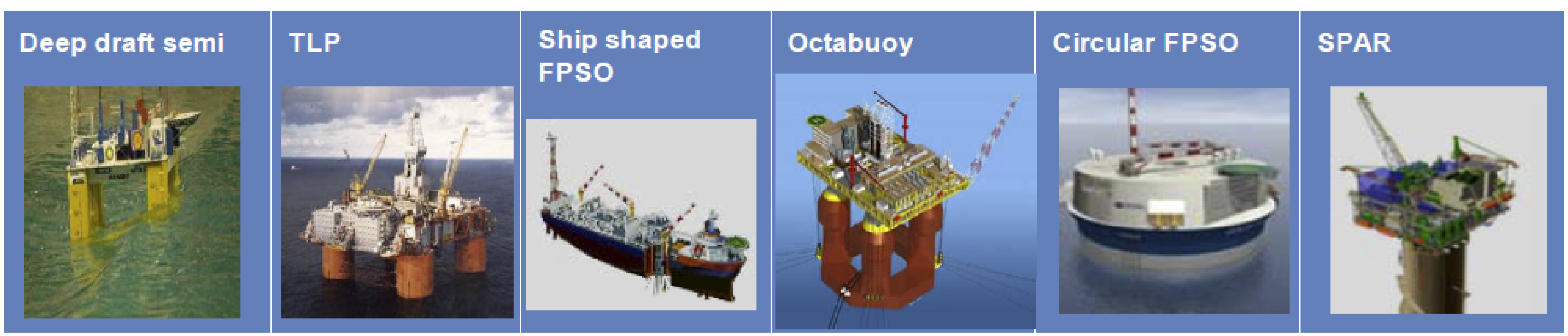
FEASIBILITY STUDIES - TASKS

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

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

FEASIBILITY STUDIES - TASKS

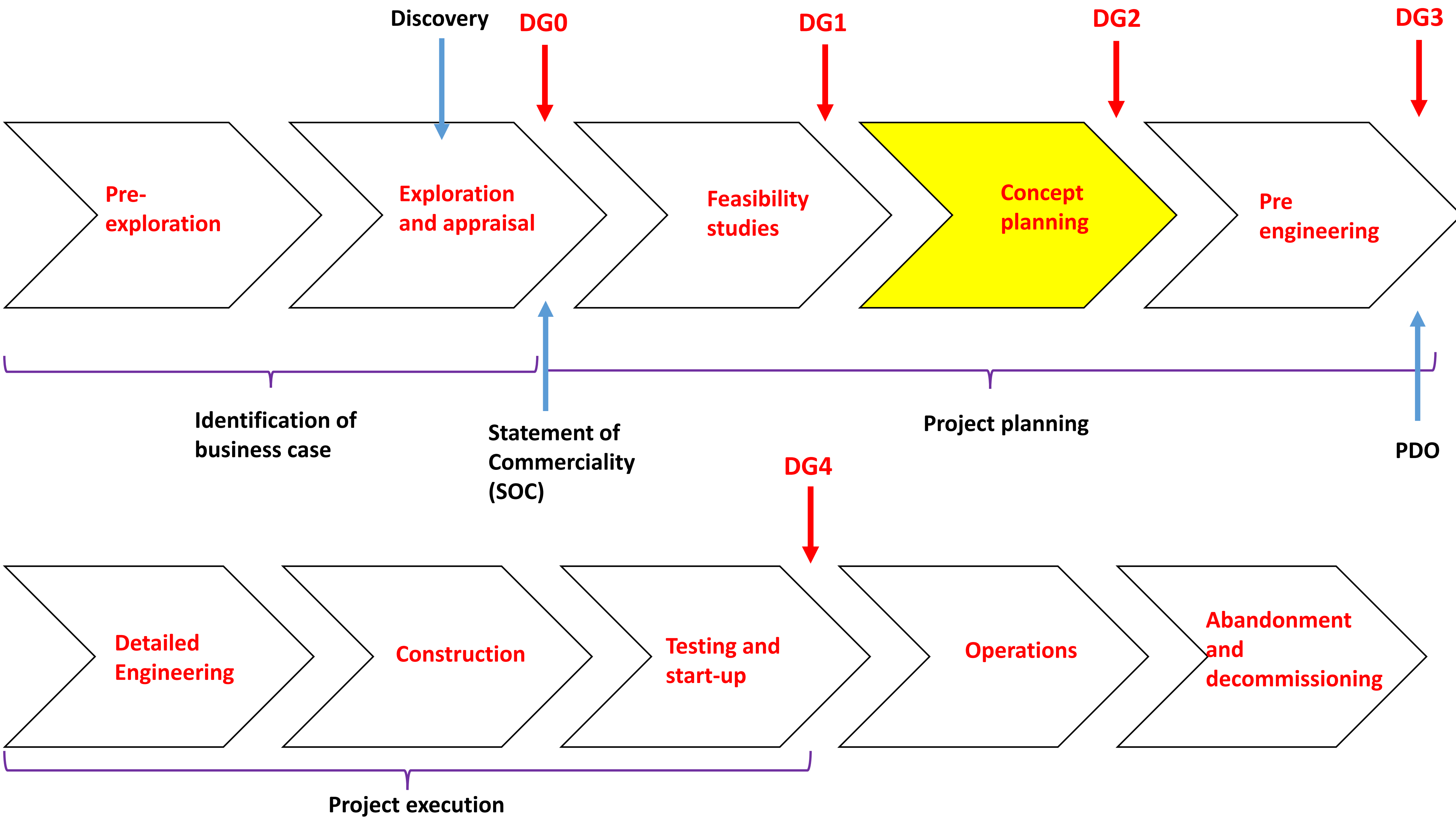




Ref: UTC 2017, Strategies, methods and tools for development of subsea fields, Skogvang and Løken.

FEASIBILITY STUDIES - TASKS

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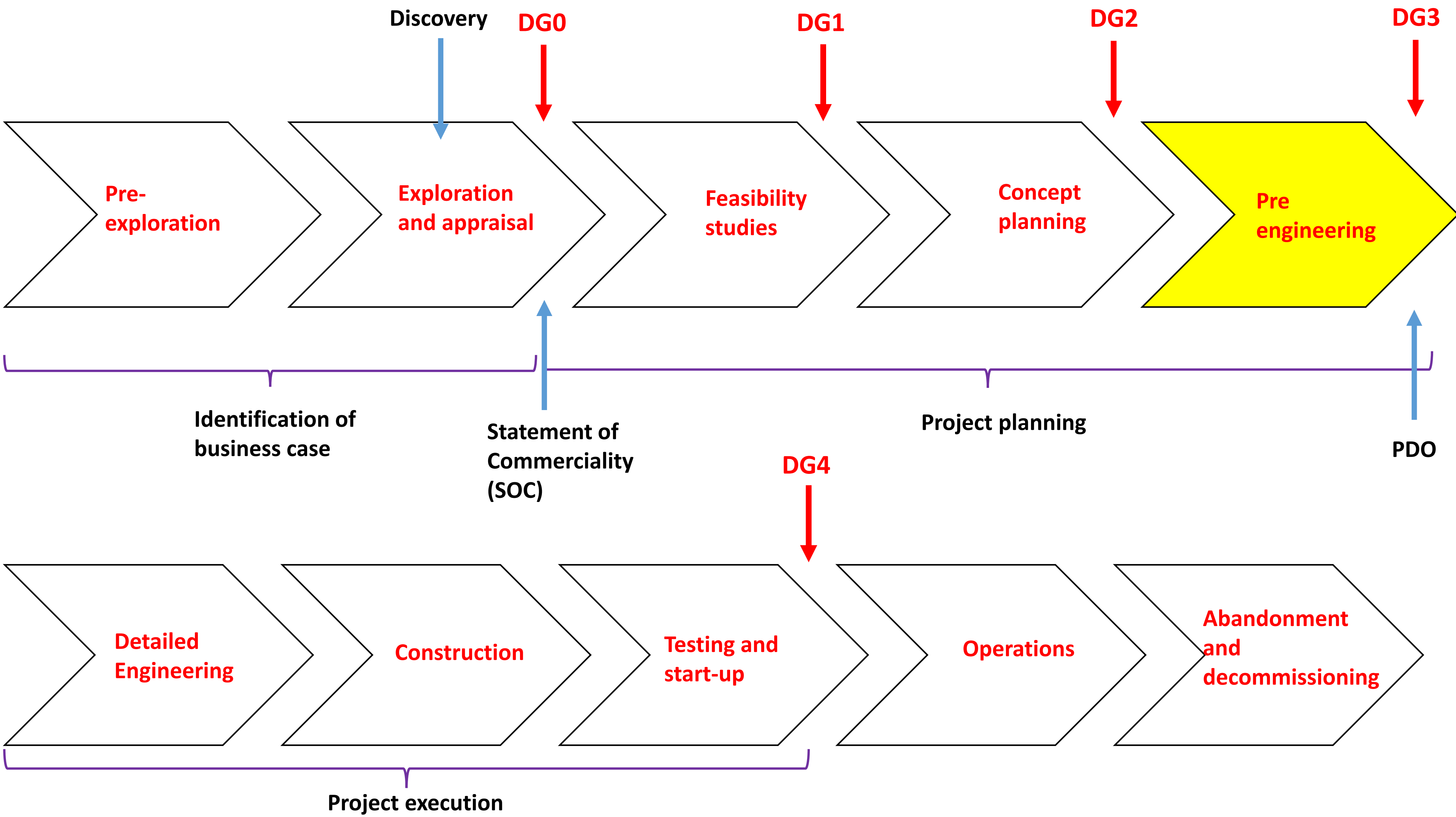
CONCEPT PLANNING - TASKS

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

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

CONCEPT PLANNING - TASKS

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

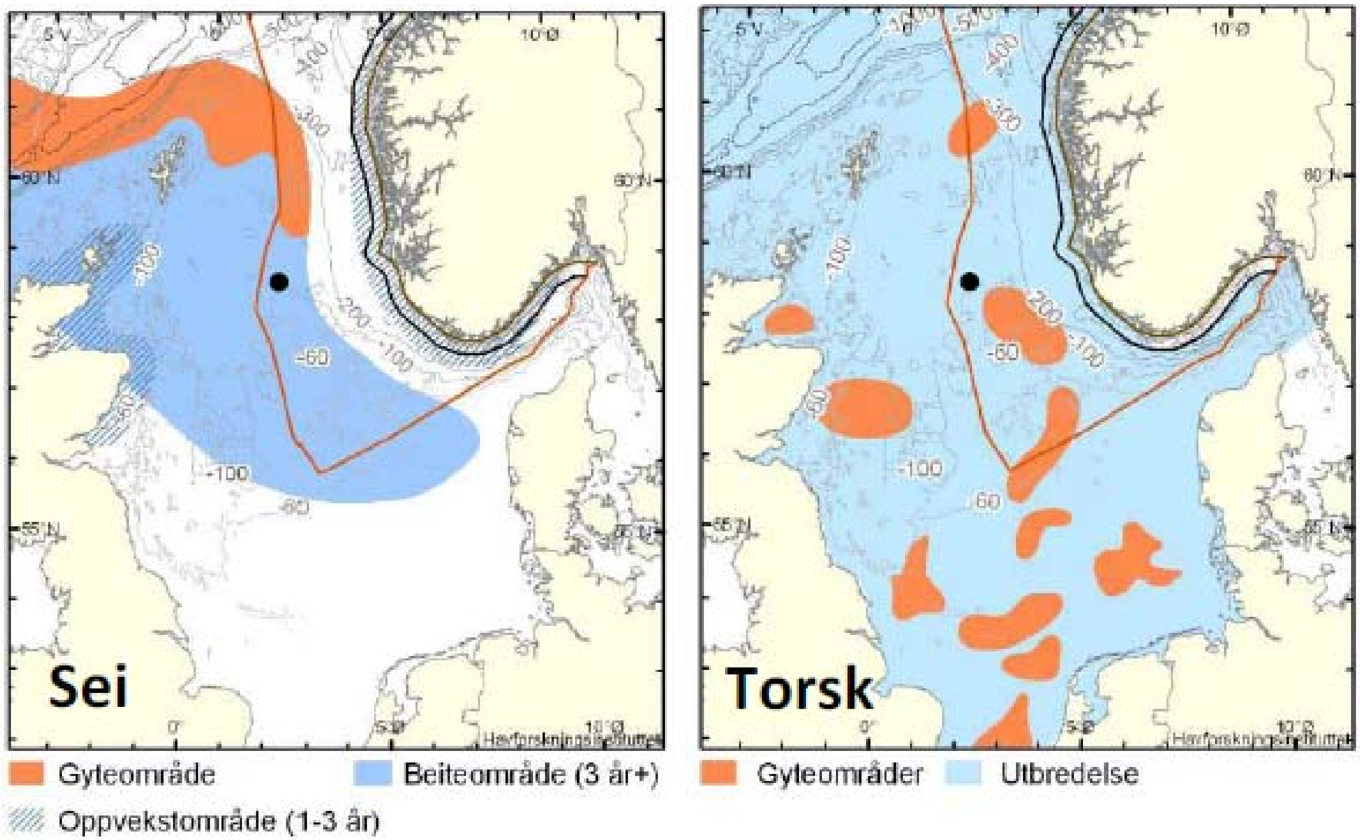
OBJECTIVE: Further mature, define and document the development solution based on the selected concept.

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

PRE-ENGINEERING - TASKS

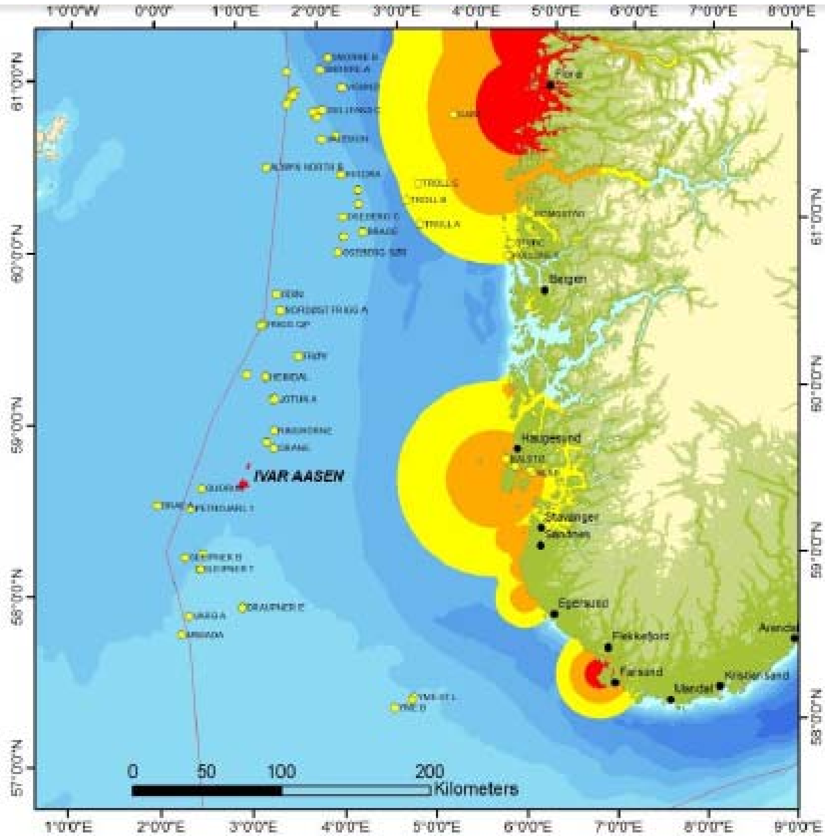
- Prepare for submission of the application to the authorities.
- Perform the Environmental impact assessment.
- Establish the basis for awarding contracts.
- Issue:
  - Plan for development and operations
  - Plan for installation and operations of facilities for transport and utilization of petroleum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

PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

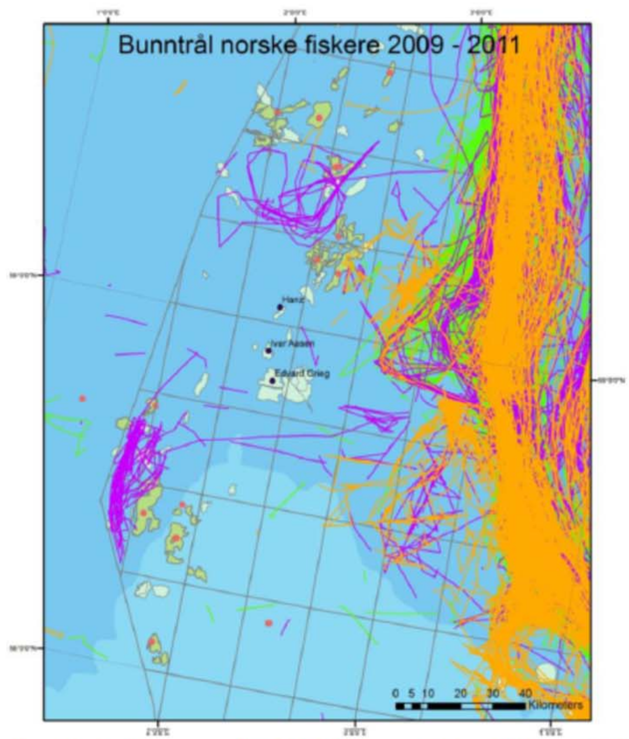
PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS



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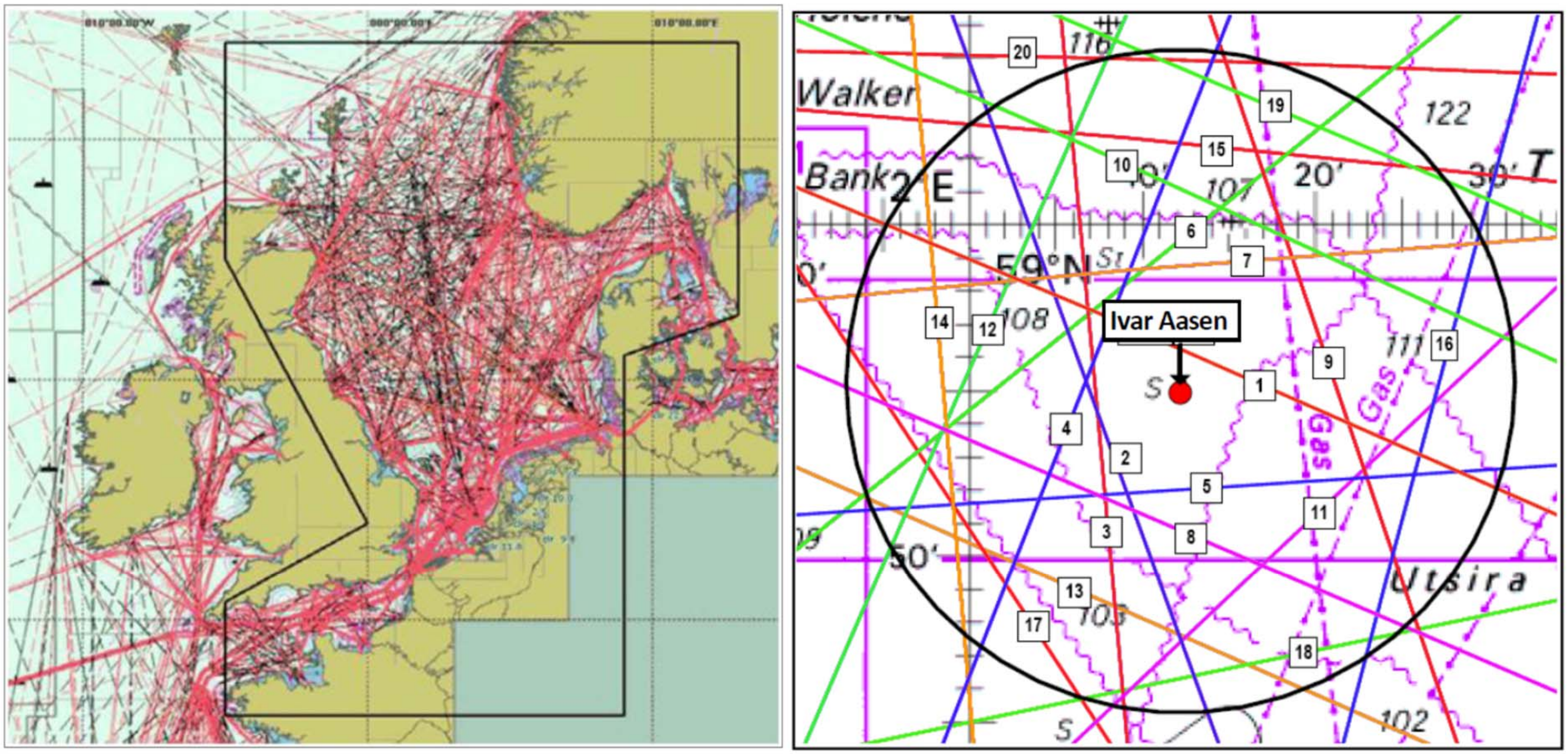
Figur 23. Registrert norsk fiskeriaktivitet med bunntrål i området omkring Aasen i 2009 (grønn), 2010 (fiolett) og 2011 (oransje). Figur utarbeidet på grunnlag av data fra Fiskeridirektoratets satellittsporing av større fiskefartøyer

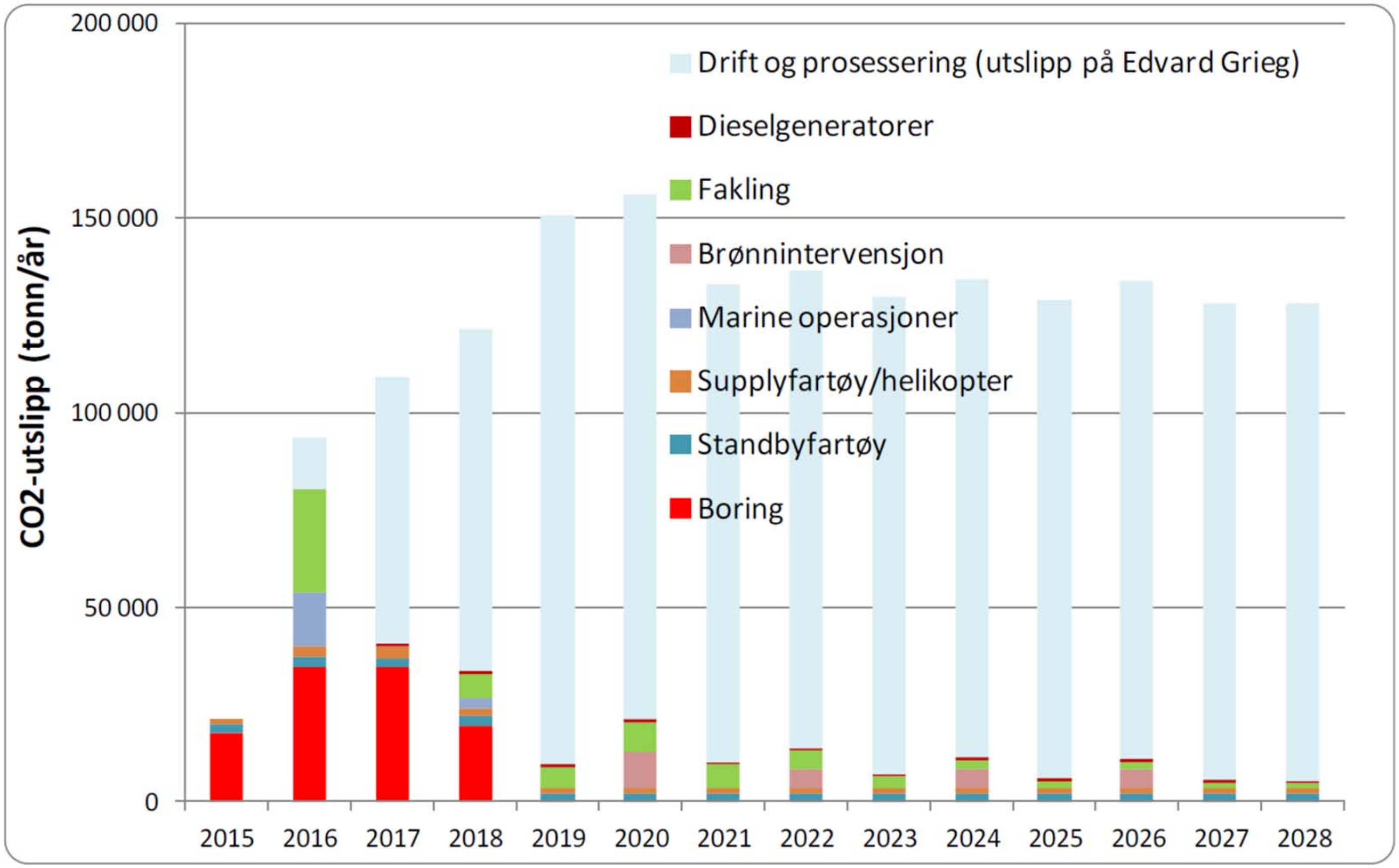
PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

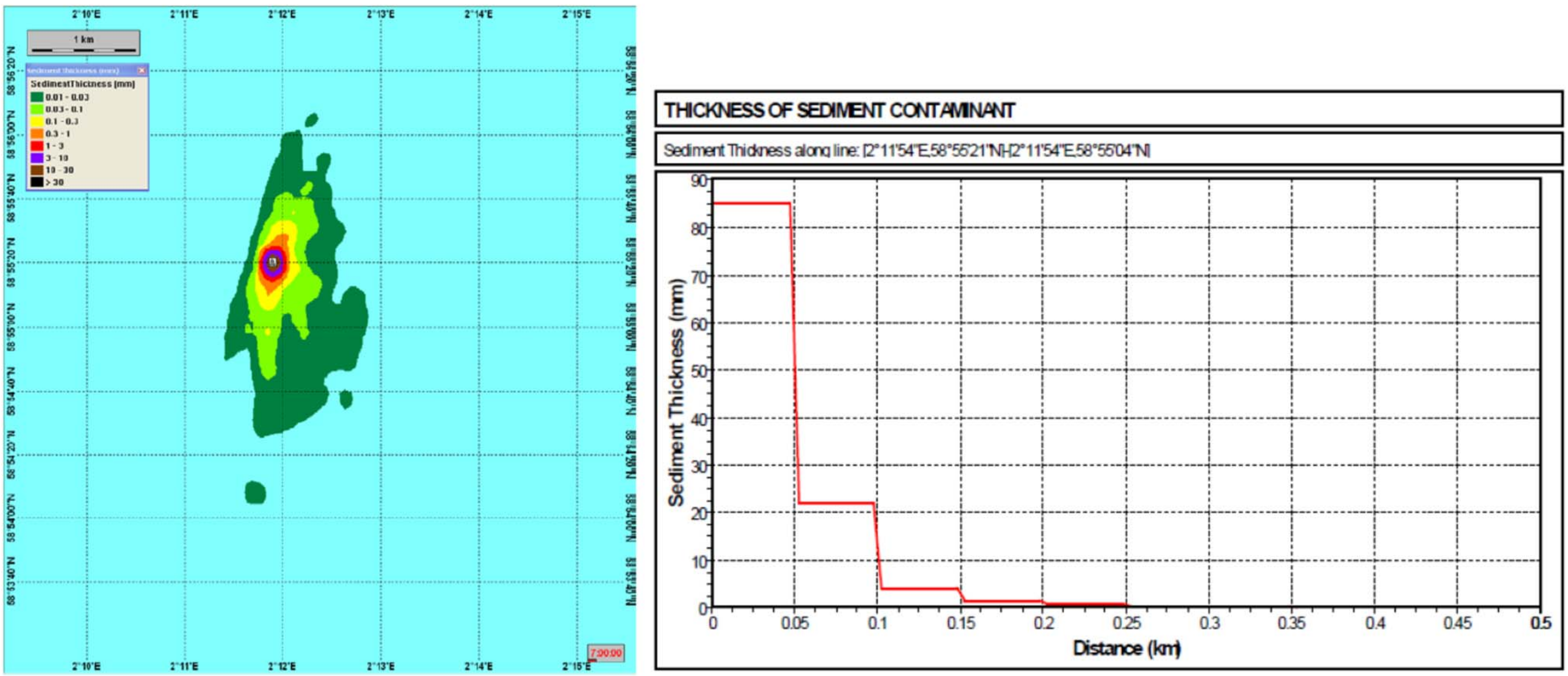
PRE-ENGINEERING - TASKS

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

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

Ref: PDO Ivar Aasen. Det Norske

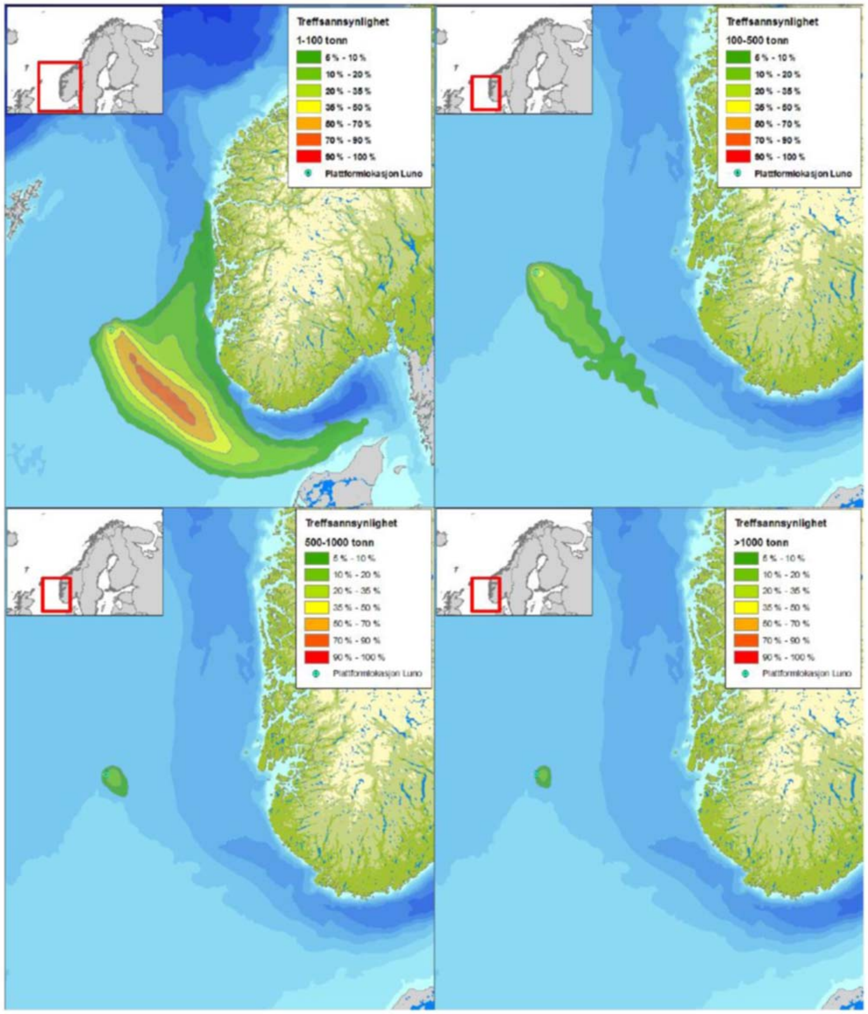
PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

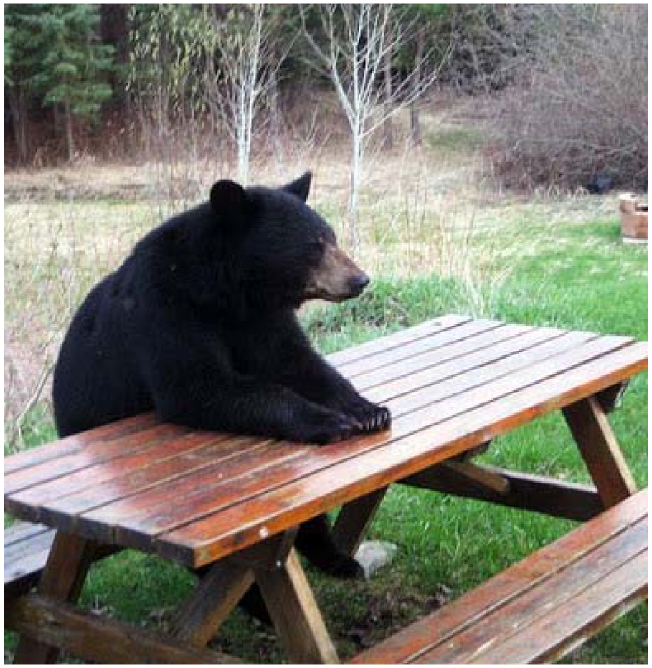


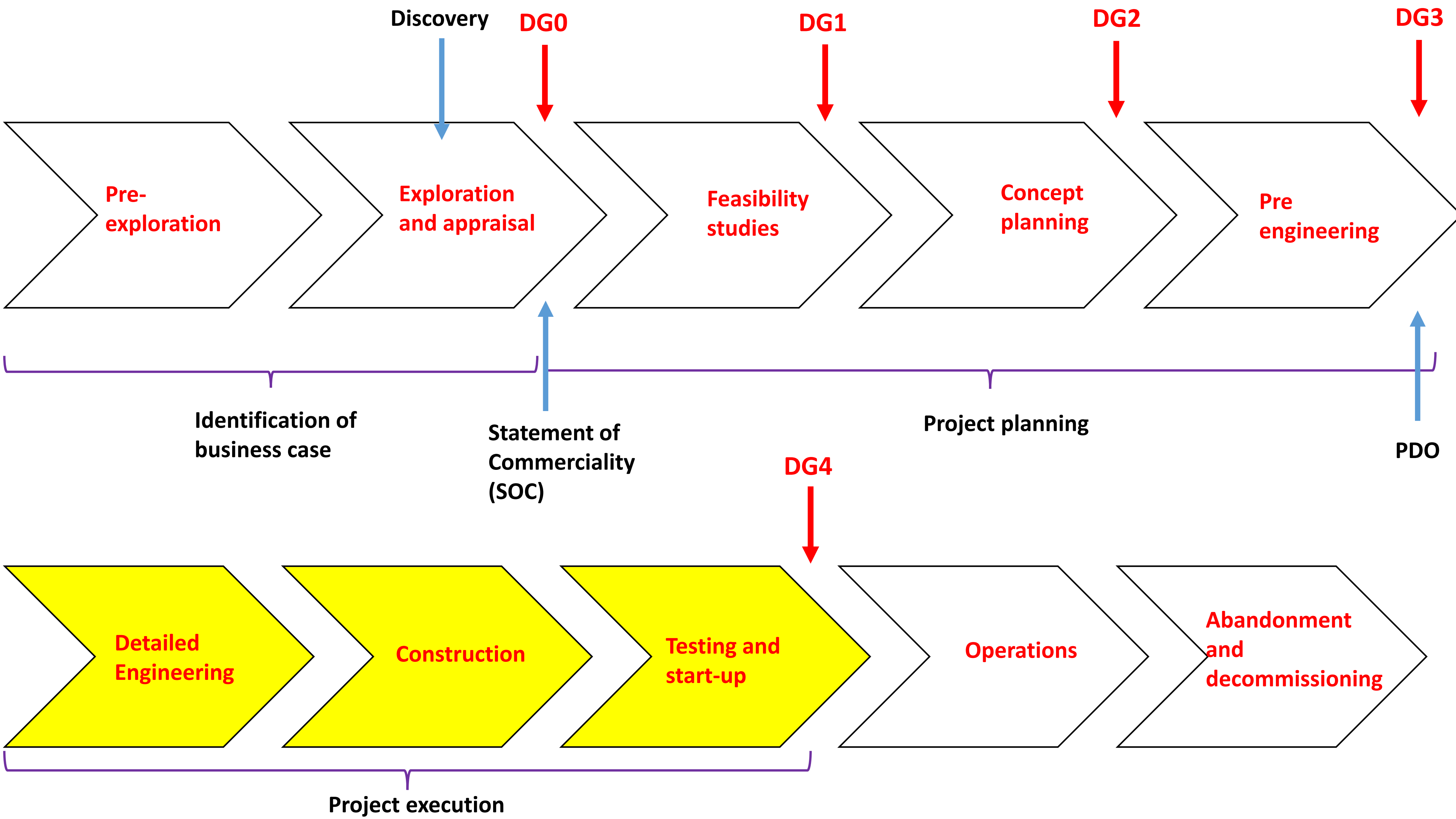
Figur 37. Sannsynligheten for treff av ulike mengdekategorier av olje i 10 × 10 km ruter gitt en sjøbunnsutblåsning fra Aasen/Grieg (helårsstatistikk). Influensområdet er basert på alle utslippsrater og varigheter og deres individuelle sannsynligheter. Merk at det markerte området ikke viser omfanget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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

- Wait for the government to study the proposal

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DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

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

Individual contracts

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

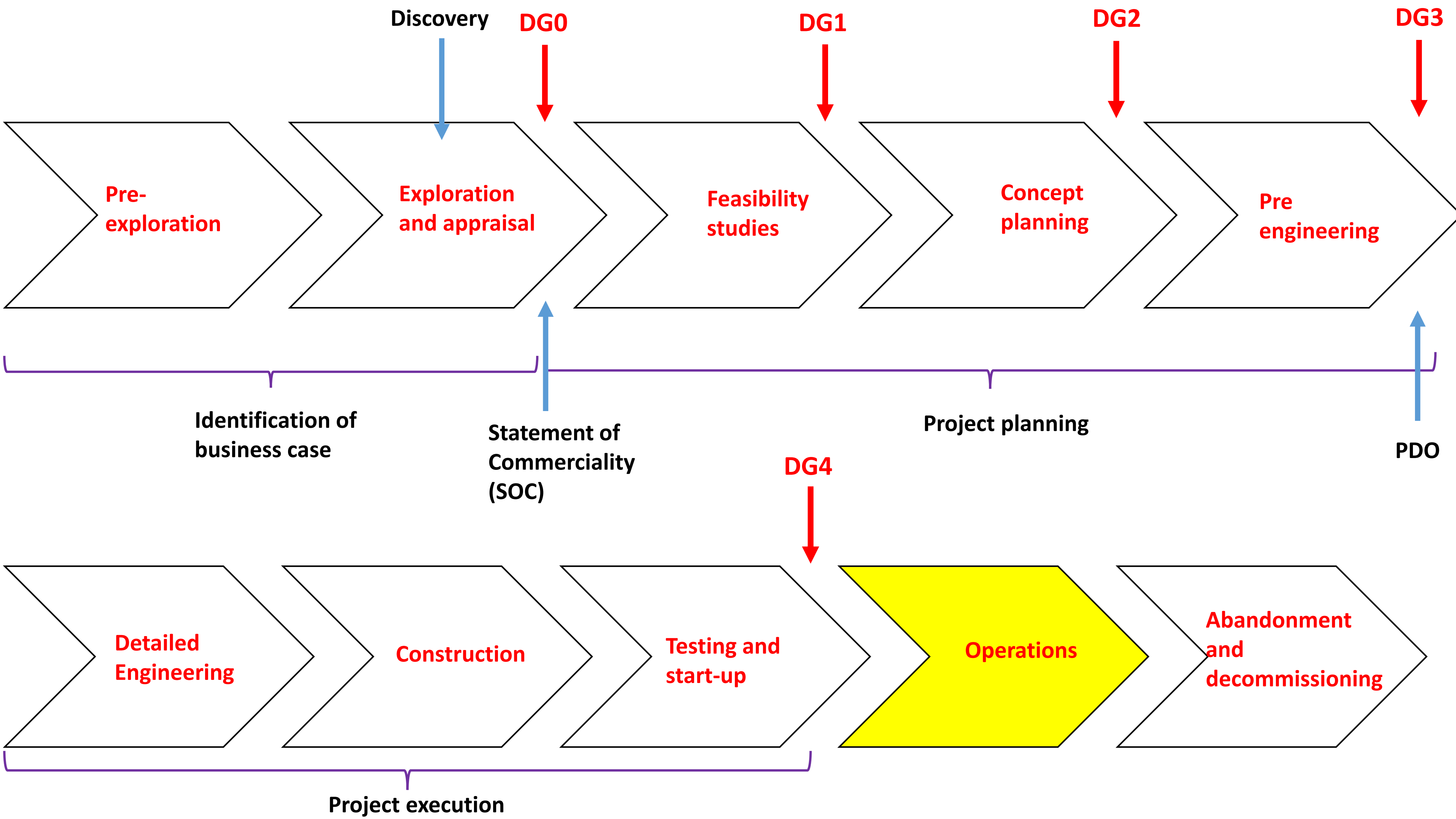
EPCM (Engineering, procurement, construction, and management contract) with one main contractor.

https://www.youtube.com/watch?v=TzLAfzhqVHc

https://www.youtube.com/watch?v=TiWOgTq0YD4

DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

- Constructing wells.
- Perform hand over to asset, operations
- Prepare for start-up, operation and maintenance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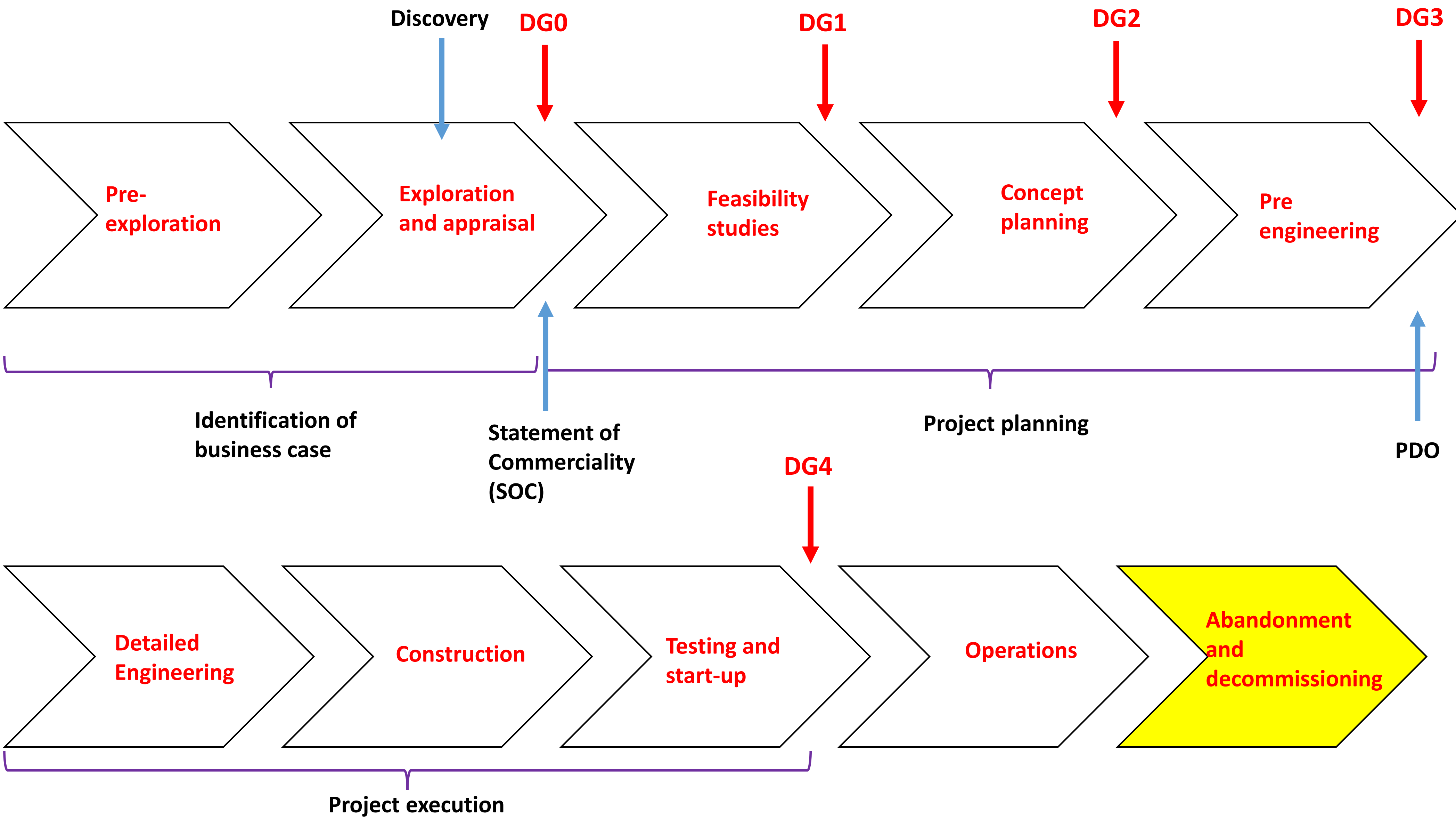
PDO
DG4
Detailed Engineering
Construction
Testing and start-up
Operations
Abandonment and decommissioning
Project execution

OPERATIONS

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


Discovery
DG0
DG1
DG2
DG3
Pre-exploration
Exploration and appraisal
Feasibility studies
Concept planning
Pre engineering
Identification of business case
Statement of Commerciality (SOC)
Project planning
PDO
DG4
Detailed Engineering
Construction
Testing and start-up
Operations
Abandonment and decommissioning
Project execution

DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

https://www.youtube.com/watch?v=SLO9uD5Ub_Y

DECOMISSIONING AND ABANDONMENT

https://www.youtube.com/watch?v=1GA3EIu81rw

Notes for Youtube video nr. 3

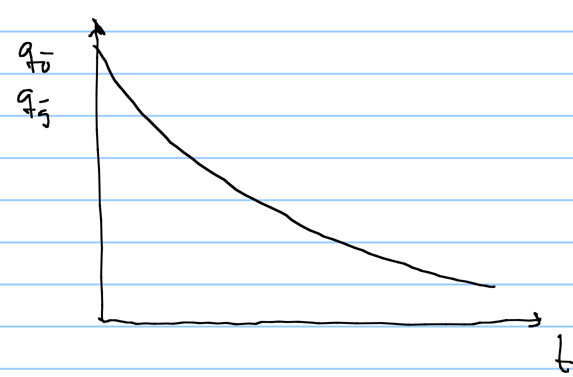
- Field production performance
  - production modes (production scheduling)
  - plateau height vs. plateau length
  - deciding plateau height

production scheduling : deciding / forecasting rates of {oil / gas} and associated products {oil, water / gas, water}

during the life of field

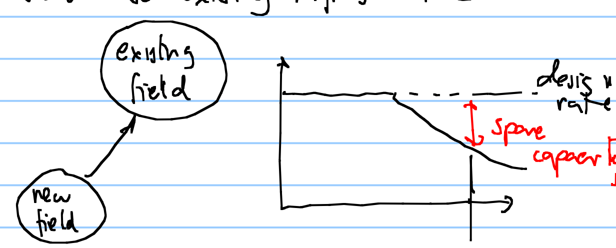
two ways to produce a field

Production mode A "plateau production" — Production mode "B" "decline production"

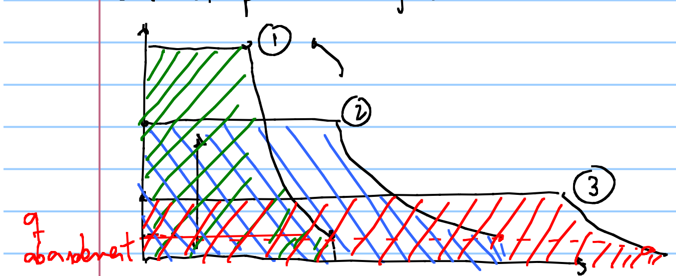


- typically used for gas fields with a contract
- Big-medium reservoir
- standalone development → requires its own facilities, offshore structure etc.

- produce as much as possible as early as possible
- satellite developments to existing fields that use existing infrastructure



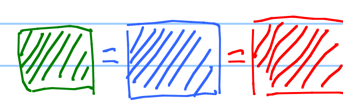
in mode "a" there is a relationship between plateau height and duration



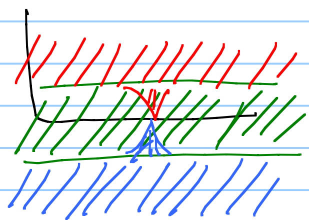
$$N_p = \int_0^t q(t)\,dt$$

↳ cumulative production

until abandonment N_{pu}



- for gas, plateau height / length is given by contract
- for oil/gas → there is a requirement by authorities to reach certain RF



higher rates can cause high GOR
high WC
sand production

to define plateau rate an economic analysis must be made

higher plateau ⟶ higher revenue

cash flow = revenue − expenses

NPV ⇝ net present value
$$NPV = \sum_{i=1}^{N} \frac{CF_i}{(1+c)^i}$$
year

↳ discounting rate (5% → 15%)
0.05 − 0.15

ΔQ_{P_i}: P_o^i production of oil/gas in year^n i

$$NPV = \underset{\text{wells, processing facilities, platform}}{\underset{(1-5)}{\text{Expenses}}} + \frac{\Delta Q_p^5 \cdot P_o^5 - OPEX^5}{(1+0.07)^5} + \frac{\Delta Q_p^6\, P_o^6 - OPEX^6}{(1+0.07)^8} + \ldots$$

start production

due to discounting, it makes sense to produce as much as possible, as early as possible

$DF = \frac{1}{(1+c)^i}$

year	
1	0.93457944
2	0.87343873
3	0.81629788
4	0.76289521
5	0.71298618
6	0.66634222
7	0.62274974
8	0.5820091
9	0.54393374
10	0.50834929
11	0.4750928
12	0.44401196
13	0.41496445
14	0.38781724
15	0.36244602

if plateau rate is higher → bigger processing facility
→ bigger offshore structure
→ more wells

"expenses" become very negative

but also revenues become bigger

for HC fields, plateau rate is usually decided by doing an economic evaluation and sensitivity analyses

exceptions { • Blending of crude

Rules of thumb for first iteration on plateau rate

for oil: 10% of $\underbrace{N_{pu}}$ per year

ultimate cumulative production (at abandonment)

TRR → total recoverable reserves

Example 180E06 stb → N initial oil in place (OOIP)

$$N_{pu} = \underbrace{R_{Fu}}_{(0.3-0.5)} \cdot N$$

$$N_{pu} = 0.4 \; 180E06 \text{ stb}$$

$$N_{pu} = 72E06 \text{ stb}$$

$$q_{plateau} = \frac{N_{pu} \cdot 0.1}{\text{Nr. producing day in year}} = \frac{72E06 \cdot 0.1}{0.9 \cdot 365} \approx 21900 \text{ stb/d}$$

[Sm³/d]

[stb/d]

↳ 95% uptime (0.95 · 365)

for gas (2-5)% of G_{pu}

Q is either oil or gas

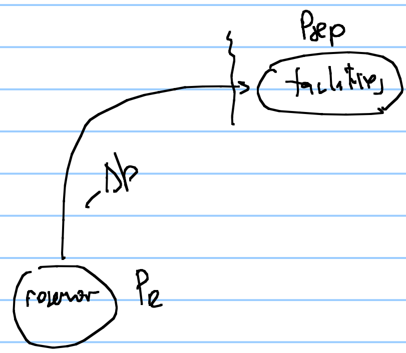
N is for oil

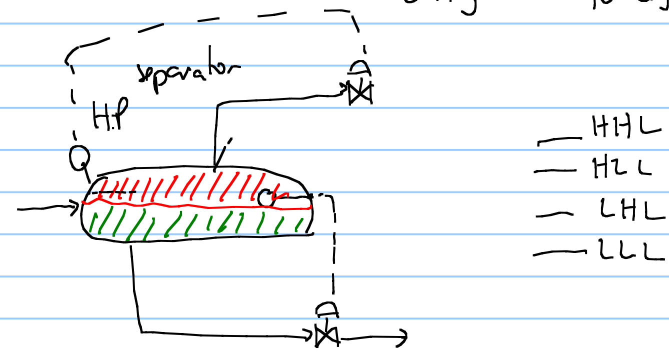
G is for gas

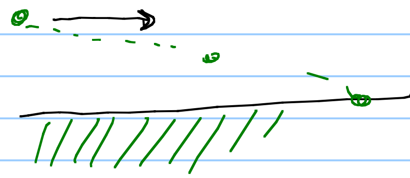
Notes for Youtube video nr. 4

separator pressure is kept constant during the life of field

why does plateau end?

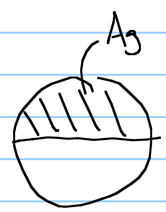






the operation of sep is dependent on $q_{local,g}$, V_g, residence time

Cross section view of the separator



$$V_g = \frac{q_g(p,T)}{(A_T/2)}$$

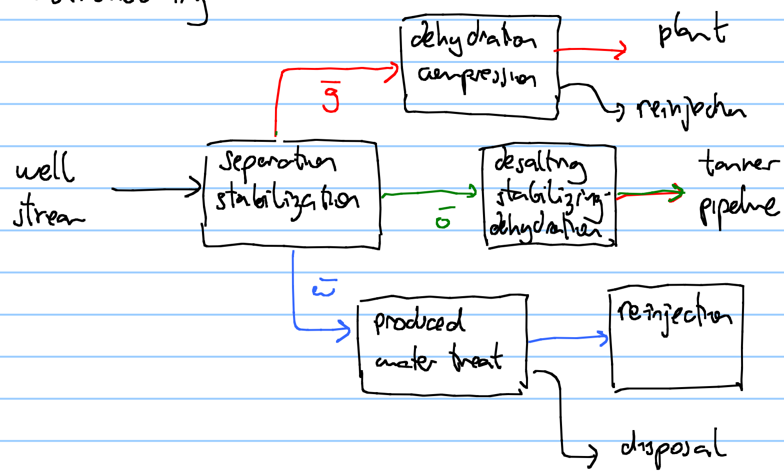
Psep must be kept ~~almost always~~ constant and of all downstream equipment and processes to esure proper functioning and acceptable performance

plateau ends because the system doesnt have enough energy to flow against Psep with the specified plateau rate

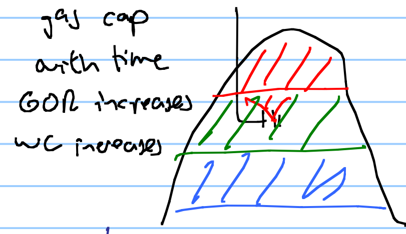
Reservoir $\xrightarrow{q_g}$ bottom-hole ⟶ wellhead ⟶ separator

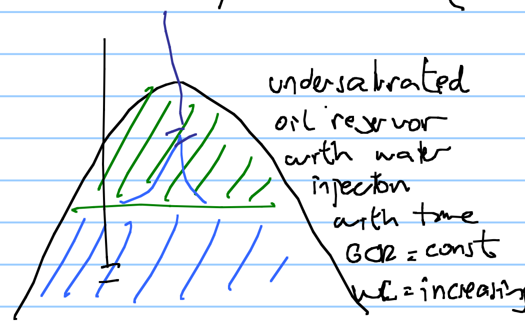
formation drawdown $-\Delta p$ | "pipe" tubing flow $-\Delta p$ | "pipe" gathering network $-\Delta p$

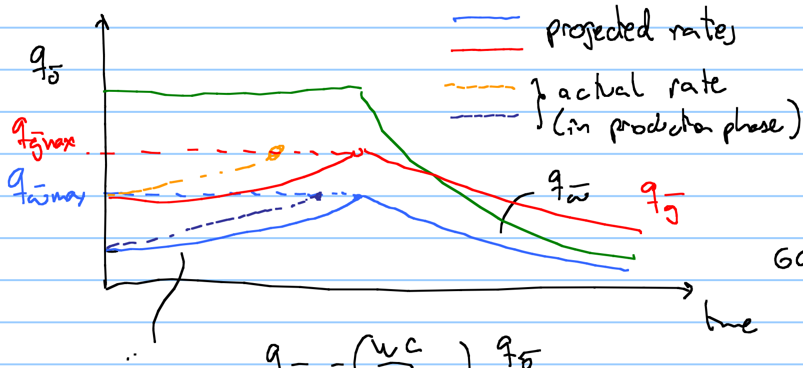
- Bottlenecking



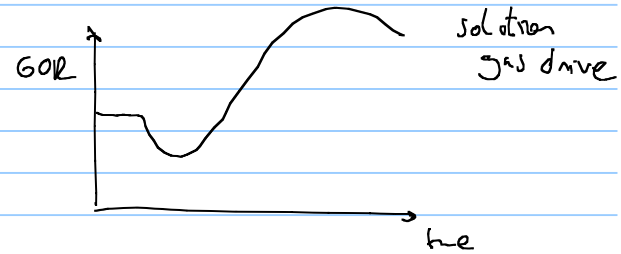
examples of variations of GOR and WC with time







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



$$WC = \frac{q_{\bar{w}}}{q_{\bar{L}}} = \frac{q_{\bar{w}}}{q_{\bar{w}} + q_{\bar{o}}}$$

$$q_{\bar{g}} = GOR \; q_{\bar{o}}$$

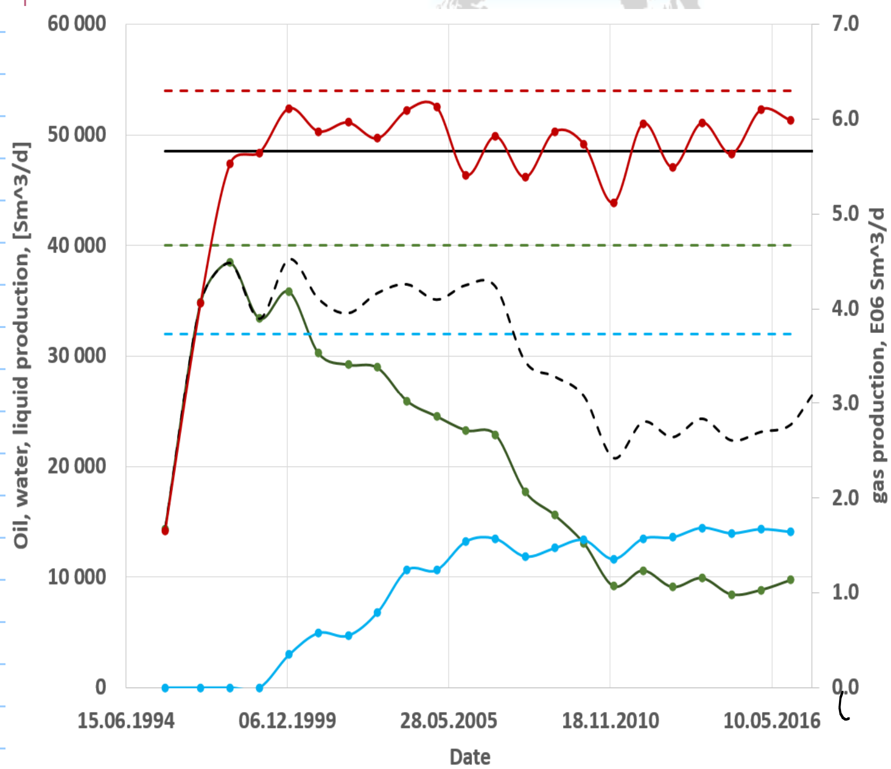
$q_{\bar{g}max}$ and $q_{\bar{w}max}$ are used to design facilities

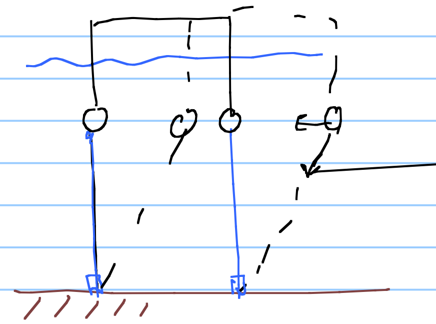
if $q_{\bar{g}}$ or $q_{\bar{w}}$ increase quicker than anticipated the the only choice is to reduce $q_{\bar{o}}$ (enter in decline phase)

$$q_{\bar{g}} = GOR \cdot q_{\bar{o}}$$

$$q_{\bar{w}} = \frac{WC}{1-WC} q_{\bar{o}}$$

Maybe? a case where bottlenecking caused a premature plateau end

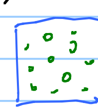




TLP tension leg platform

Bottlenecking can also occur due to problems in the process

- water injectors plugging
- gas injector problems
- higher than anticipated separation times → foam → fine dispersion of gas in liquid
  → emulsion → water-oil dispersion "fine"

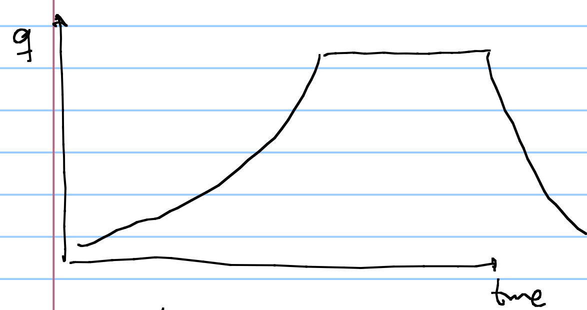


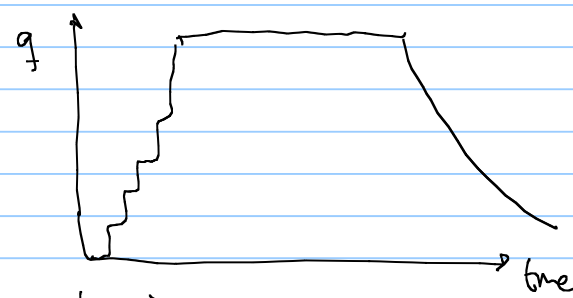
↳ can sometimes be mitigated with chemical or with different technology

- onshore vs. offshore

Onshore: if neighbouring facilities are available, it is possible to produce from few wells gather more information and then plan better field

Offshore: it is necessary to design, construct and install facilities before producing



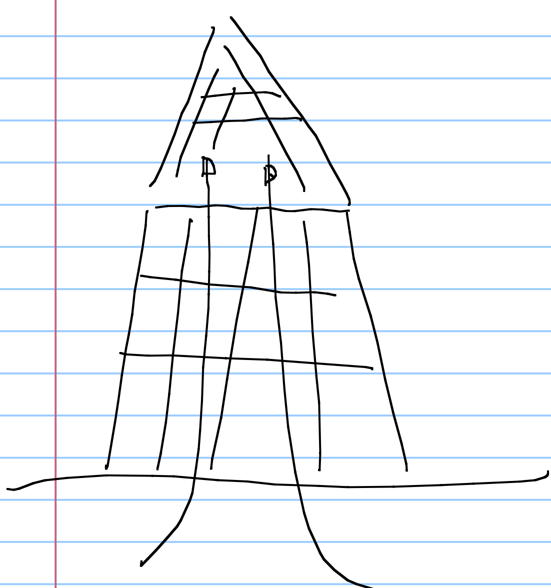


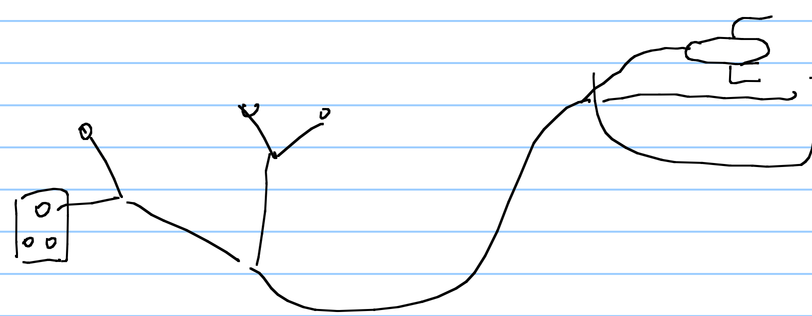
Longer build-up

build-up phase

- gain more information about reservoir
- finance development with initial wells

- start production asap { • shorter build-up, • pre-drilled wells }
- making decisions with big uncertainty

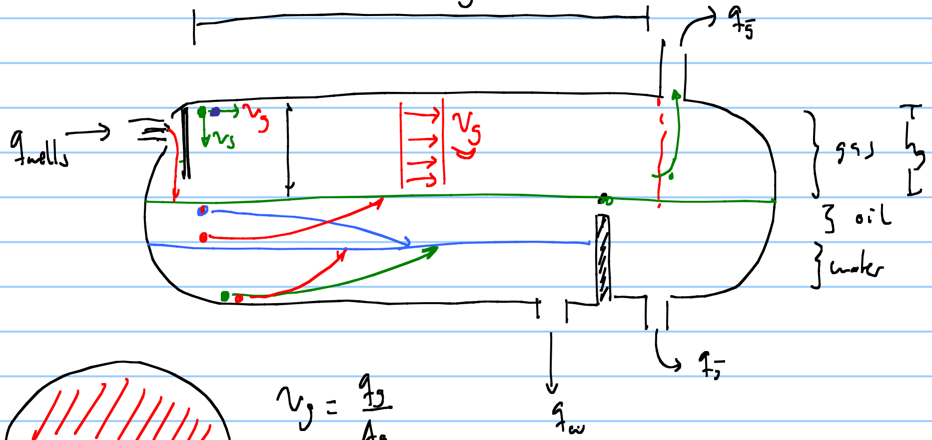




Alternatively, there can be onshore fields whose development resembles those in the offshore environment. One such field in the (aptly named) Empty Quarter of the Yemen was so remote that, by the time an oil production pipeline had been laid, all the appraisal and development wells had been drilled permitting only a static view of the reservoirs.

Notes for Intro to problem 1, 21 January 2021

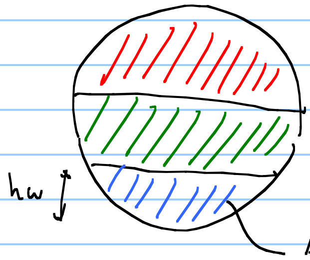
$$t_{res} = \frac{L}{v_g}$$



$$t_{set} = \frac{h_g}{v_s}$$

$$t_s \leq t_{res,g}$$

$$v_g = \frac{q_g}{A_g}$$



$$A_w = f(h_w)$$

$\bar{q}_o(t)$, P_{sep}, T_{sep}

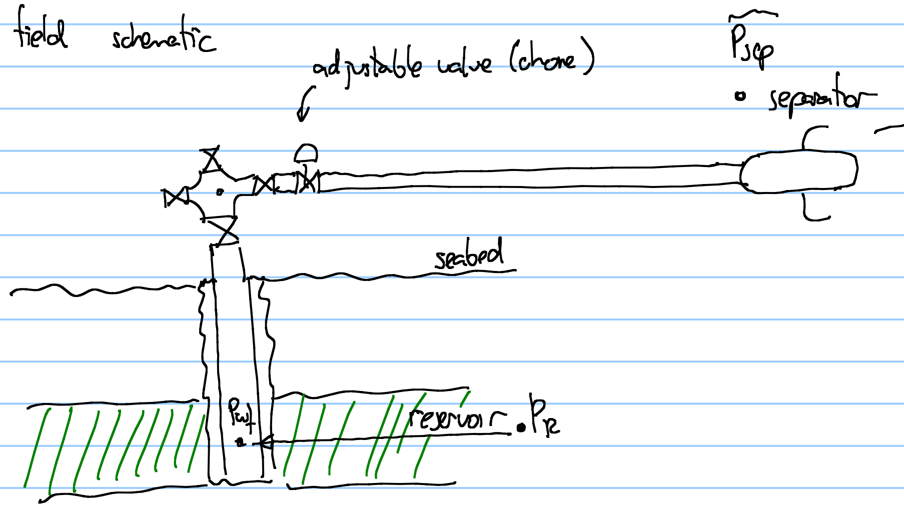
$$q_o(P,T) = \bar{q}_o \cdot B_o(P,T)$$

$$q_g(P,T) = \bar{q}_g \cdot B_g(P,T)$$

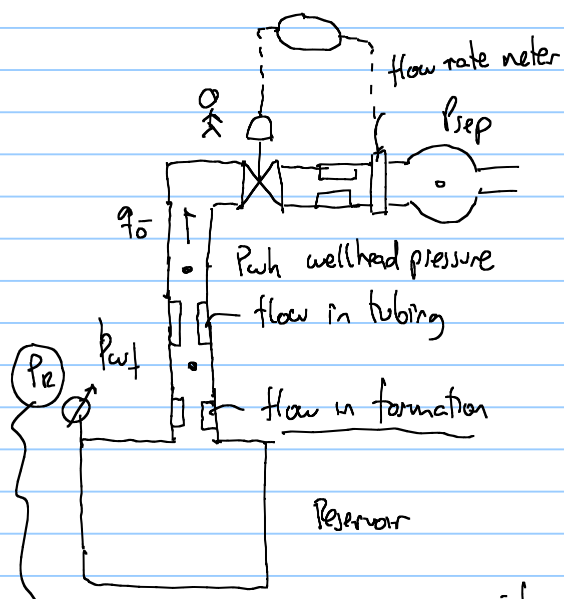
$$q_w(P,T) = \bar{q}_w \cdot B_w(P,T)$$

Notes for Youtube video nr. 5

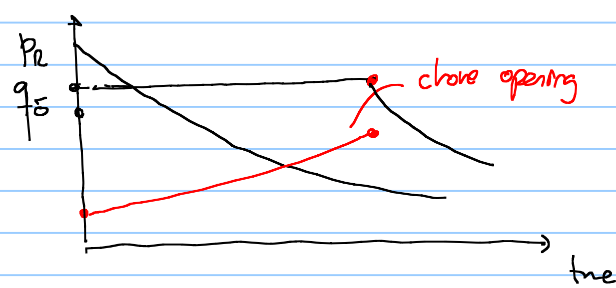
field schematic



Mechanical analogue of field

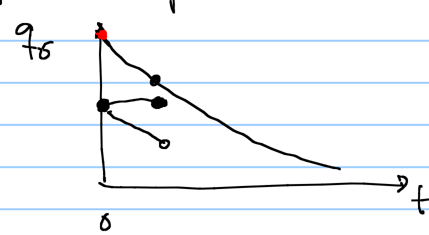


$q_o = f(P_R, P_{sep}, \text{choke opening})$

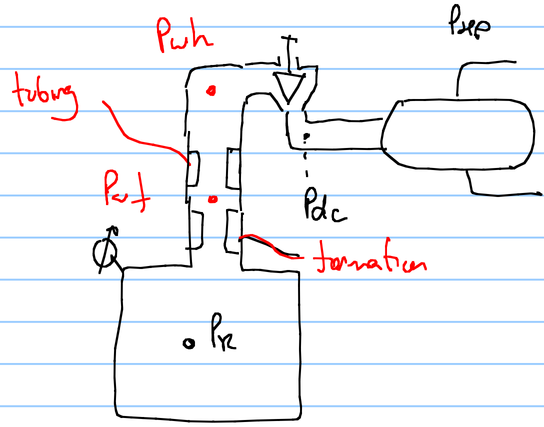


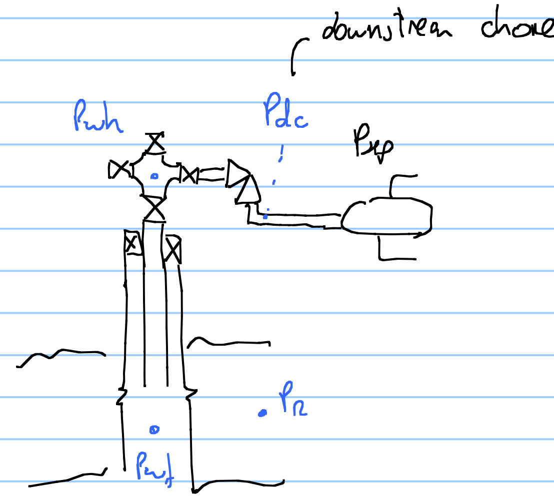
$q_o = (P_R, P_{sep}, \Delta p_{choke})$

if choke is open



mechanical analog of a field (dry gas)



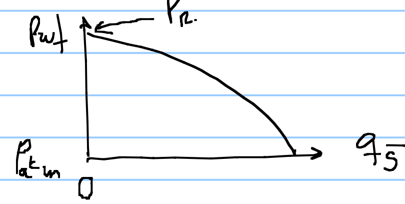


P_{wf} flowing bottom-hole pressure (BHP)

P_{wh} wellhead pressure (WHP)

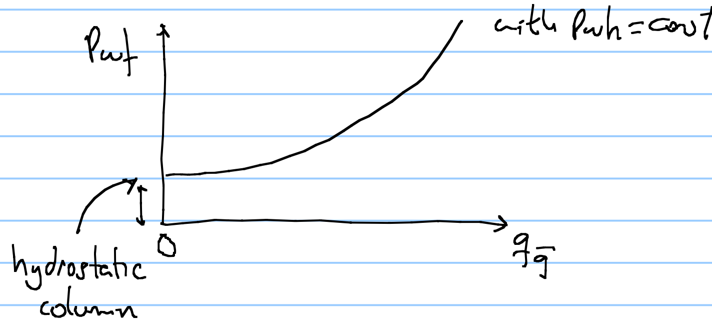
$P_R \to P_{wf}$ flow in formation (Drawdown) IPR inflow performance relationship

$$q_g = f_1(P_R, P_{wf})$$



$P_{wf} \rightsquigarrow P_{wh}$ flow in tubing $\rightsquigarrow$ TPR tubing performance relationship

$$q_g = f_2(P_{wf}, P_{wh})$$



$P_{wh} \to P_{dc}$ $\rightsquigarrow$ pressure drop in choke choke equation

$$q_g = f_3(P_{wh}, P_{dc}, \text{Opening})$$

- inaccurate model
- highly non-linear
- difficult to converge
- "many" models

$P_{dc} \rightsquigarrow P_{sep} \rightsquigarrow$ pressure drop in pipe

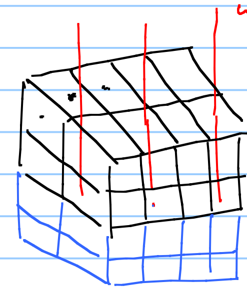
Pipeline/flowline performance relationship (FPR, PPR)

$q_g = f_y(P_{in}, P_{out})$

Production profiles (field performance) are typically estimated with:

examples of commercial software
- ECLIPSE
- CMG
- Intersect
- Nexus
- MRST
- OPM
- SENSOR

• Reservoir simulator.



well
- target rate q_T
- minimum bottom hole pressure →

try to produce target rate, if not, change to minimum bottom-hole pressure

in FD, a workflow that is typically used by oil companies to compute realistic production profiles is:

Reservoir engineering
- 3D reservoir model

q_{Target} rates (t) ~ $q(t)$

$P_{wf\,min}(t)$ $\quad P_{wf}(t)$

Production and facilities engineering

production simulator (steady-state)

check at each point in time is

$\left.\begin{matrix} q(t) \\ P_{wf}(t) \end{matrix}\right\}$ feasible?

↳ is it enough to reach separator?

If not, try to make it feasible

flag years in which it is not possible to produce the rates

example of commercial software
- Pipesim
- Prosper, gap
- Olga
- pipesoft
- ReO

send feedback to

At early FD, there is usually no information on wells, gathering network or facilities, thus they are typically neglected

- Reservoir simulator "coupled" with a well + gathering network simulator in a IAM software

  ↳ integrated asset management

examples of software
- Resolve
- Avocet
- Pipe-it (now Tieto)

- material balance single tank + Inflow performance relationship

P_R
S_o vs t
S_g
S_w

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

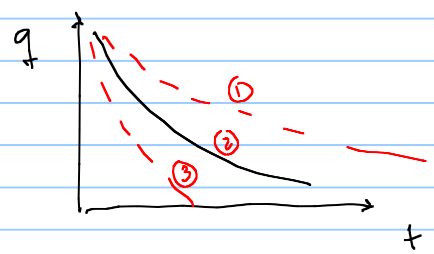
needs assumption on $P_{wf\,min}$

- material balance + well + network model

P_R
S_o vs t
S_g
S_w

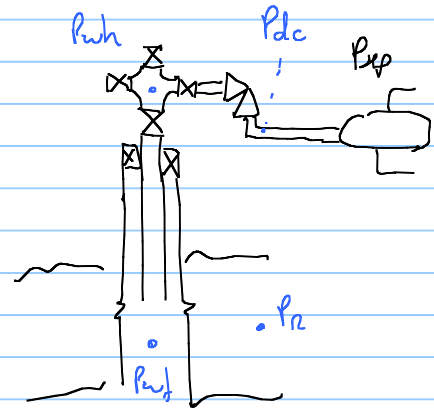
$$q = f(P_R, P_{sep})$$

- Decline or type curves { very early FD }

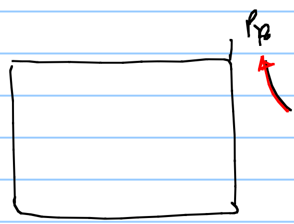


Notes for Youtube video nr. 6

Simplified dry gas production system



Reservoir model



Dry gas material balance

$$p_R = p_{Ri} \frac{z_R}{z_i} \left(1 - \underbrace{\frac{G_p}{G}}_{R_F \text{ recovery factor}} \right)$$

$G_p = f(q_g)$, $q_g = f(t)$

uncertain value

gas deviation factor

$$z = f(P_r, T_r)$$

$$P_r = \frac{P_R}{P_c}, \quad T_r = \frac{T_R}{T_c} \rightarrow f(\text{gas composition})$$

MB dry gas equation is implicit

- Given RF, assume P_R
- with P_R compute z_R
- verify that $\varepsilon = P_R - P_{Ri} \frac{z_R}{z_i} \left(1 - R_F\right) = 0 \leq$ Tolerance
- if not,

3.3.2 Z-Factor Correlations. Standing and Katz[4] present a generalized Z-factor chart (**Fig. 3.6**), which has become an industry standard for predicting the volumetric behavior of natural gases. Many empirical equations and EOS's have been fit to the original Standing-Katz chart. For example, Hall and Yarborough[21,22] present an accurate representation of the Standing-Katz chart using a Carnahan-Starling hard-sphere EOS,

$$Z = \alpha p_{pr}/y, \qquad (3.42)$$

Equation approximation to Z chart

where $\alpha = 0.06125t \exp[-1.2(1-t)^2]$, where $t = 1/T_{pr}$.

The reduced-density parameter, y (the product of a van der Waals covolume and density), is obtained by solving

$$f(y) = 0 = -\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3}$$
$$- (14.76t - 9.76t^2 + 4.58t^3)y^2$$
$$+ (90.7t - 242.2t^2 + 42.4t^3)y^{2.18+2.82t}, \qquad (3.43)$$

with

$$\frac{df(y)}{dy} = \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4}$$
$$- (29.52t - 19.52t^2 + 9.16t^3)y$$
$$+ (2.18 + 2.82t)(90.7t - 242.2t^2 + 42.4t^3)$$
$$\times y^{1.18+2.82t}. \qquad (3.44)$$

The derivative $\partial Z/\partial p$ used in the definition of c_g is given by

$$\left(\frac{\partial Z}{\partial p}\right)_T = \frac{\alpha}{p_{pc}}\left[\frac{1}{y} - \frac{\alpha p_{pr}/y^2}{df(y)/dy}\right]. \qquad (3.45)$$

to predict T_c, P_c we will use

Sutton correlations

Sutton[7] suggests the following correlations for hydrocarbon gas mixtures.

$$T_{pcHC} = 169.2 + 349.5\gamma_{gHC} - 74.0\gamma_{gHC}^2 \qquad (3.47a)$$

and

$$p_{pcHC} = 756.8 - 131\gamma_{gHC} - 3.6\gamma_{gHC}^2. \qquad (3.47b)$$

$$\gamma_g = \frac{M_{w\,gas}}{M_{w\,air}\,(28.97)}$$

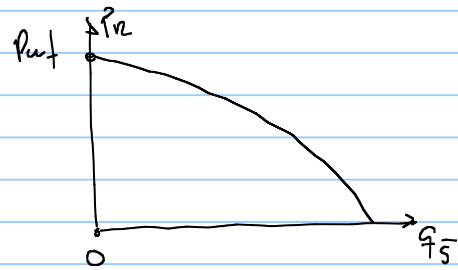
$$M_{w\,gas} = \sum_{i=1}^{N} z_i M_{w_i}$$

$P_R \rightarrow P_{wf}$ IPR equation low-pressure dry gas equation

$$q_g = \underbrace{C_R}_{\text{inflow coefficient}} \left(P_R^2 - P_{wf}^2\right)^{n} \leftarrow \text{backpressure exponent}$$

laminar $n \sim 1$
turbulent $n \to 0.5$

inflow coefficient $\left\{ T_R, K, h, s \text{ (skin factor)} \right.$



- pseudo-steady state regime (boundary dominated flow)
page 97 of compendium

- $p_{wf} \rightarrow p_{wh}$ Dry gas tubing equation

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

elevation coefficient (hydrostatic losses)

tubing coefficient (friction losses)

$$q_{\bar{g}} = 0 \qquad p_{wf} = p_{wh}\, e^{S/2}$$

Page 156, Appendix A of compendium

$$q_{sc} = \left(\frac{\pi}{4}\right)\cdot\left(\frac{R}{M_{air}}\right)^{0.5}\cdot\left(\frac{T_{sc}}{p_{sc}}\right)\cdot\left(\frac{D^5}{f_M\cdot L\cdot\gamma_g\cdot Z_{av}\cdot T_{av}}\right)^{0.5}\cdot\left[\left(p_{wf}^2 - p_t^2\cdot e^S\right)\cdot\left(\frac{S}{e^S-1}\right)\right]^{0.5}$$

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

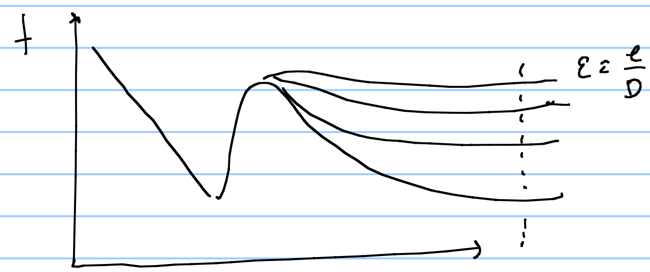
$$S = 2\cdot L\cdot C_a = 2\cdot\frac{M_g}{Z_{av}\cdot R\cdot T_{av}}\cdot L\cdot g\cdot\cos(\alpha)$$

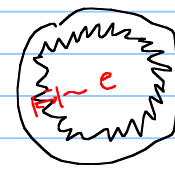
Comments about tubing equation

to compute C_T $\quad T_{av} \rightarrow \dfrac{T_{wf} + T_{wh}}{2}$ $\quad$ An estimate of T_{wh} is needed

$$z_{av} \sim \frac{z_{wf} + z_{wh}}{2}$$

f_M friction factor





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

μ_g is $<< \mu_L$

$Re_g >>$

always in fully turbulent regime

$v = f(q_{local})$

q_{local} $f(\rho)$

for gas $v \uparrow\uparrow$ $\quad \rho$ is low compared to liquid

liquid v - $[0.5 - 4]$ m/s

gas v - $[5 - 40]$ m/s

$f_M = f(\varepsilon)$ $\quad$ however $e = f(C, D)$ due to manufacturing

Valve equation for dry gas: (page 166)

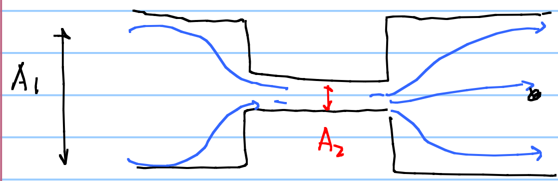
"opening" tuning factor $\frac{R_u}{MW_g}$ $k = \frac{c_p}{c_v}$

$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot \underbrace{A_2}_{\text{opening}} \cdot \underbrace{C_d}_{\text{tuning factor}}}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)}$$

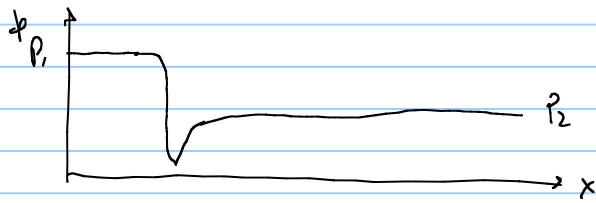
$p_{sc} = 1.01325$ bara

$T_{sc} = 15.56\ °C$

$y = \frac{p_2 \text{ (downstream)}}{p_1 \text{ (upstream)}}$



if $y > y_c \approx (0.6)$, there is critical flow at the throat



if $y > y_c$ $q_{\bar{g}} = q_{\bar{g}_c} =$

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

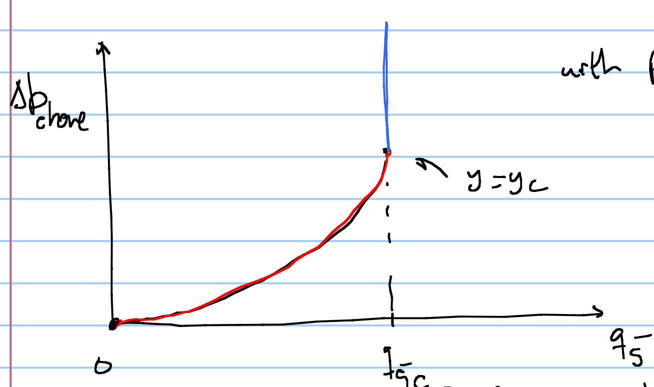
y_c y_c

in blue

if $y < y_c$

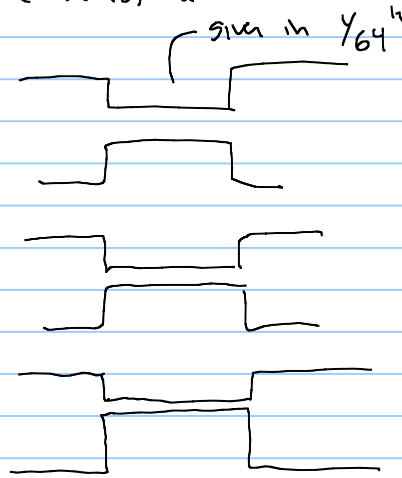
$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)}$$ in red

with p_1 = constant

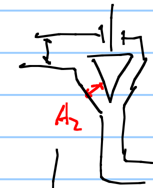


(flow is "choked", critical flow)

in onshore fields, bean choke are often used



offshore often adjustable chokes are used



→ P_{sep} flowline → tubing equation can be used for flowline

horizontal flowline, the tubing equation simplifies to

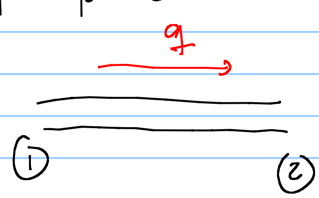
$$q_{\bar{s}} = C_{FL}\left(P_{dc}^2 - P_{sep}^2\right)^{0.5}$$

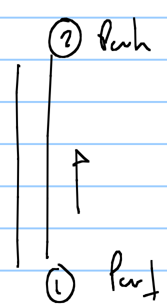
$S=0$ (L'Hopital)

VBA Visual basic for applications

for pipe equations in VBA ① is upstream

② is downstream





There were no notes for Youtube video 7, but check the video

Notes for TA session, clarifications to Prob 1 (28 Jan 2021)

Note Title 28.01.2021

	ϕ	Pdf	fd	fd	cfd
500	5	3	5	1+1+1+1 = 4	4/6	0.66
300	4	6			
10	4	7	250	1	1/6	5/6 0.83
5	1	8			
50	1		500	1	1/6	6/6
100	1				
				6		1.0

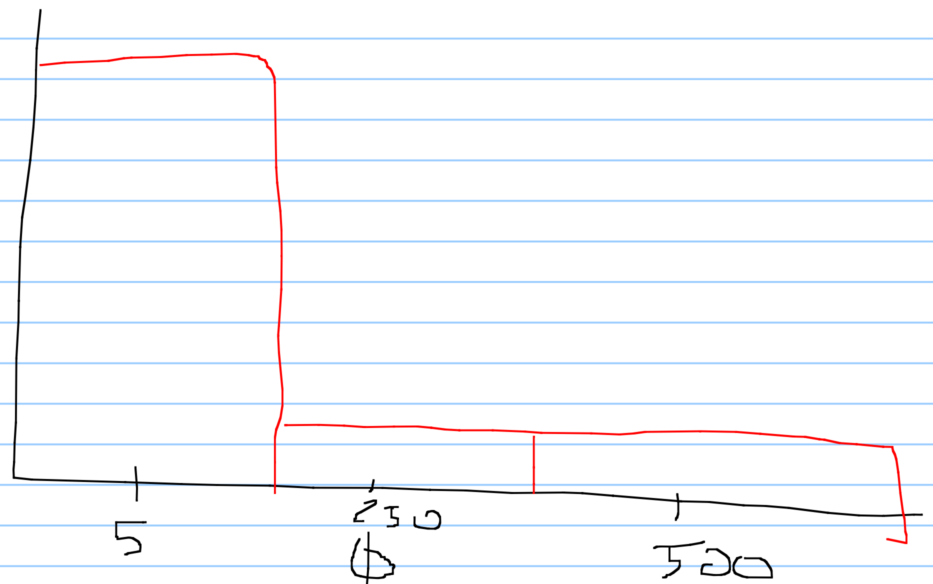
n.v

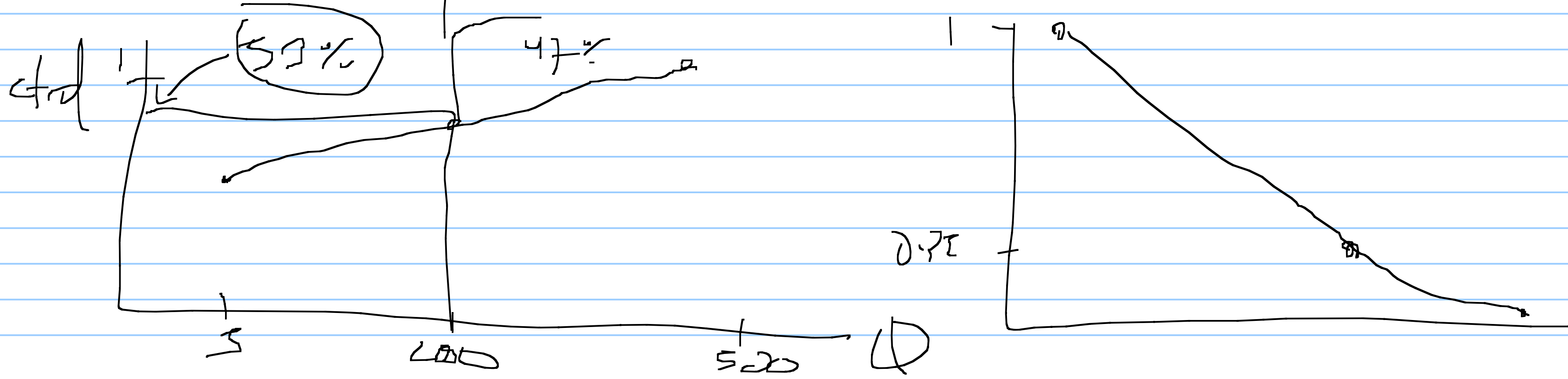
r.v.s

250 500

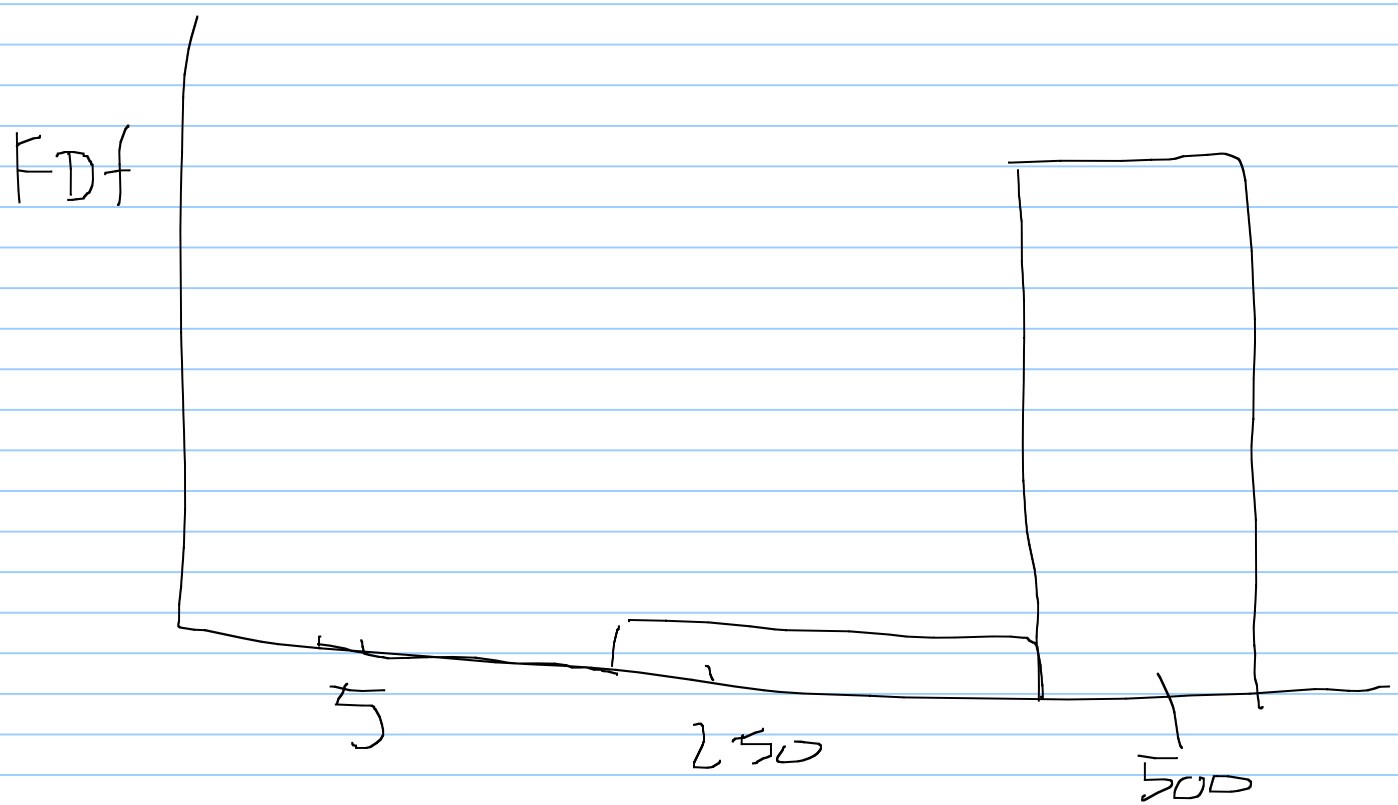
5 | 250 | 500

125 375

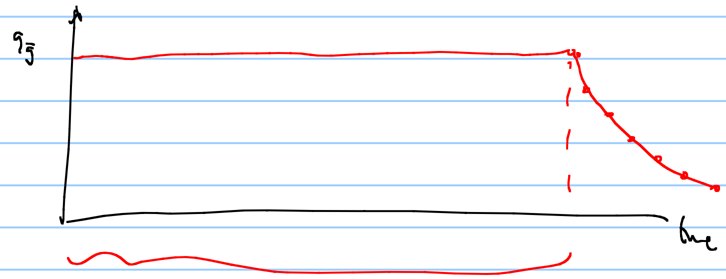

5
250
D
500

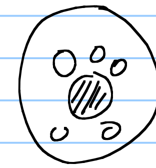

53%
47%
5
200
500
D
1
0.75

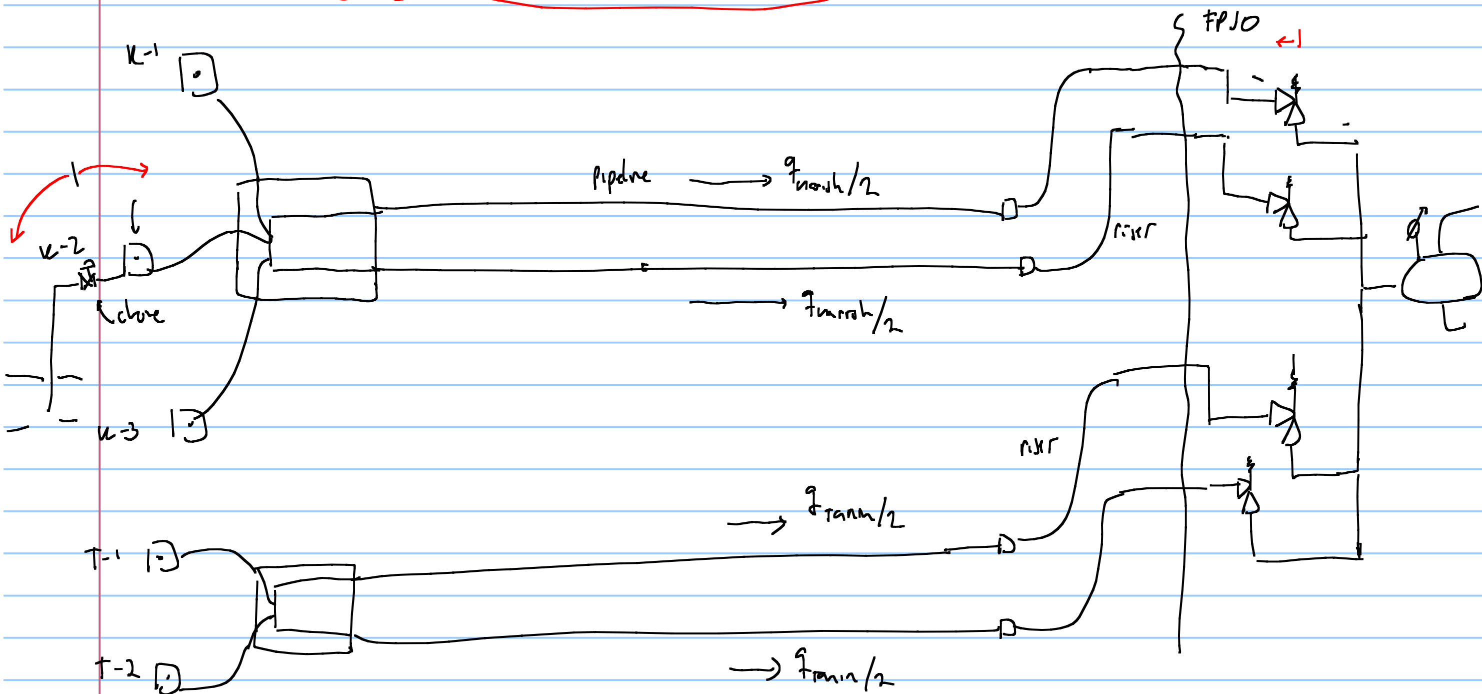
D		Vol oil
5	4	$4 \times \frac{\pi 5^3}{6} =$
250	1	$1 \times \frac{\pi 250^3}{6}$
500	1	$1 \times \frac{\pi 500^3}{6}$


PDf
5
250
500

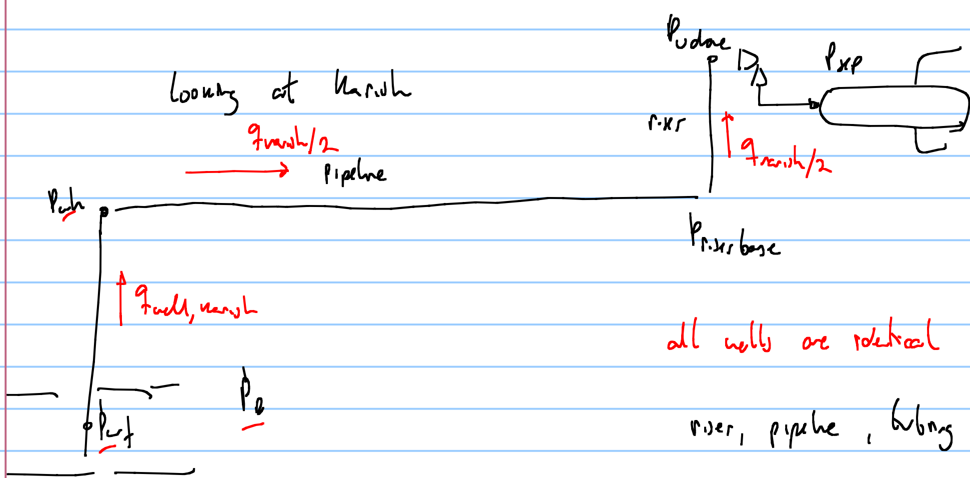
Notes for discussion of Problem 2 (02 Feb, 2021)







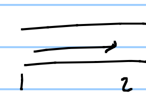
Looking at Karish



all wells are identical

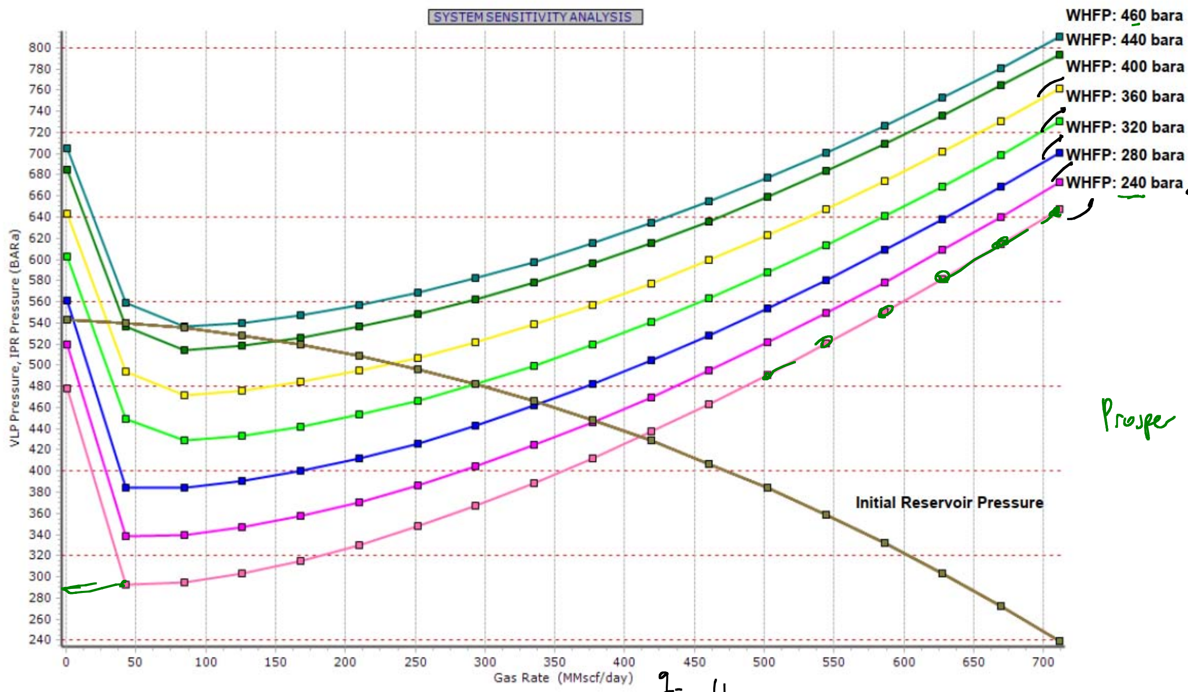
riser, pipeline, tubing

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



Pwf

vertical lift performance



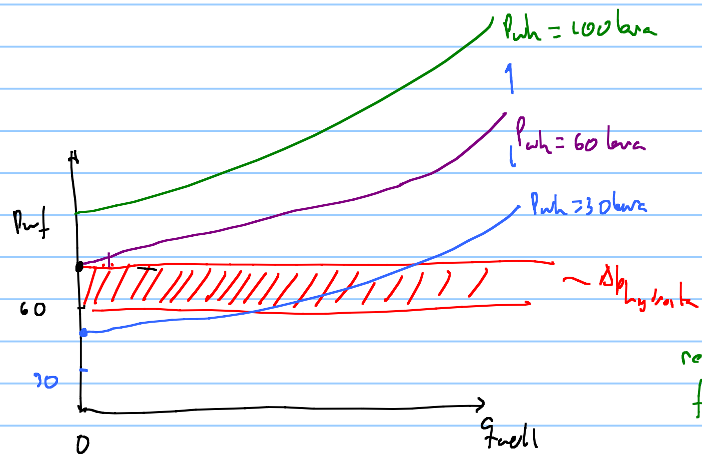
well head flowing pressure

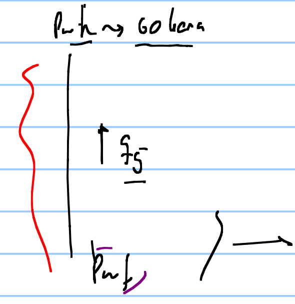
Pwh

Prosper (PETEX)

$q_{g\,well}$

Figure 6-21 Karish Well Analysis IPR/VLP at initial reservoir pressure





required pressure at bottom-hole (Pwf) to flow against a constant wellhead pressure

Comments about Problem 2. Zoom session 04.02.2021

for pipeline, flowline, riser, tubing

$$C = f(P_1, P_2, T_1, T_2)$$

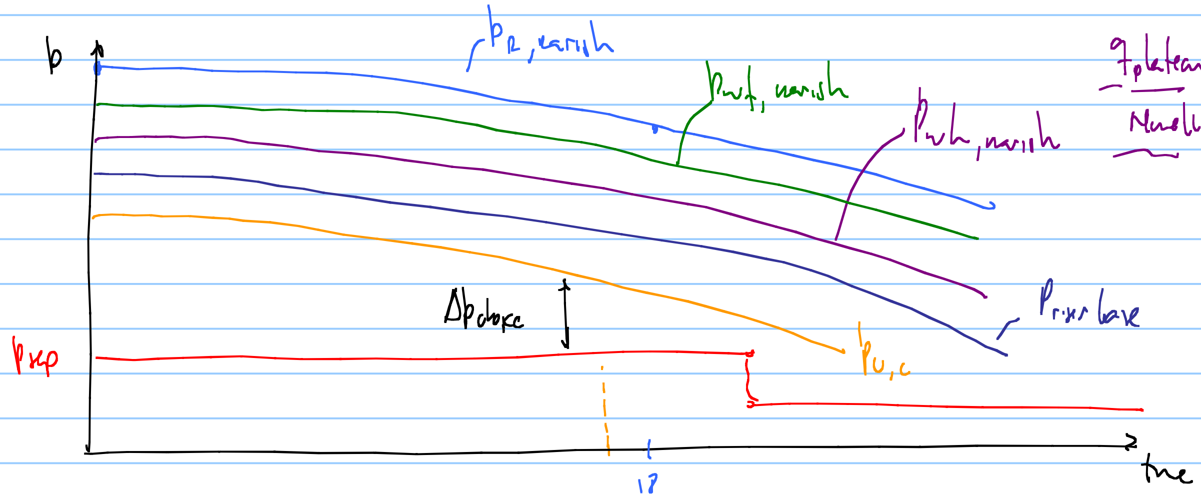
assume C → solve for P_1, P_2, q_g → recalculate C

We are neglecting this dependency in the course, we assume constant pipeline flow and elevation coefficients

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

Evolution of pressures in system

$$\frac{q_{plateau}}{N_{well}} = q_{well}$$



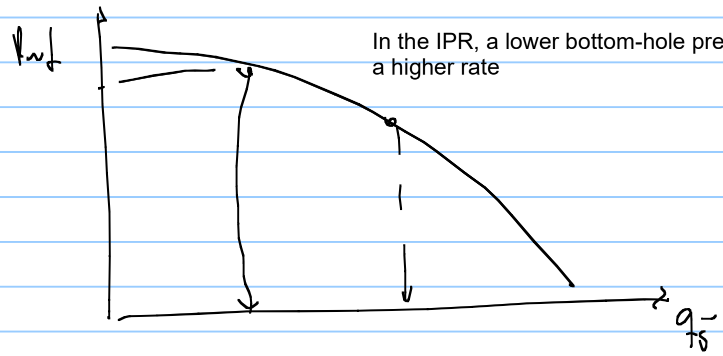
end of plateau

$$\Delta p_{choke} = 0$$

$$q_{well} = C_T\left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$$

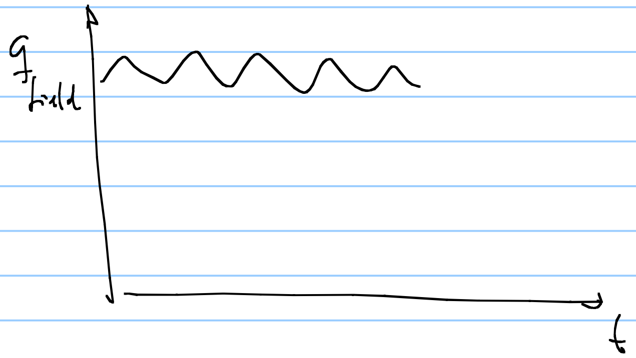
$$\frac{q_{manifold}}{2} = C_{PL}\left(P_{wh}^2 - P_{riser\,base}^2\right)^{0.5}$$

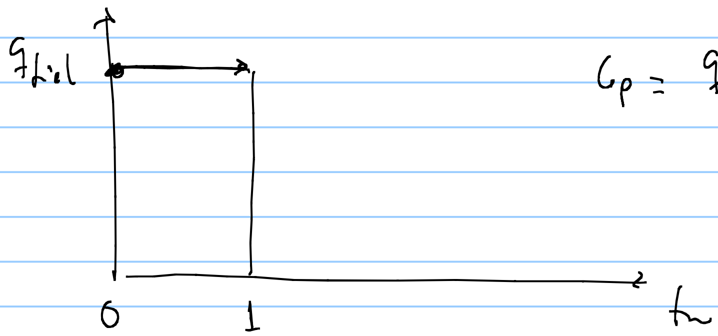
$$\frac{q_{manifold}}{2} = C_{riser}\left(\frac{P_{riser\,base}^2}{e^S} - P_{u\,choke}^2\right)^{0.5}$$



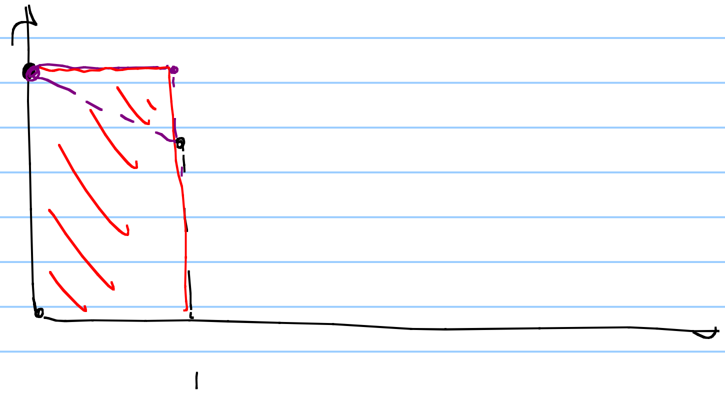
In the IPR, a lower bottom-hole pressure gives a higher rate

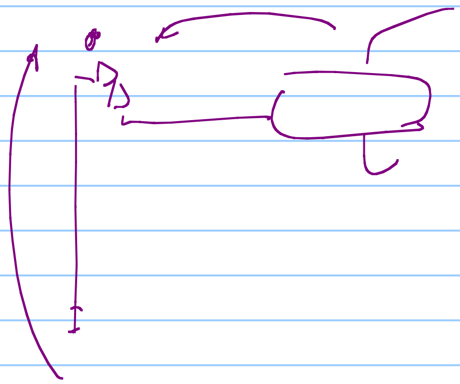
$$G_p = \int_0^t q_{field}\, dt$$

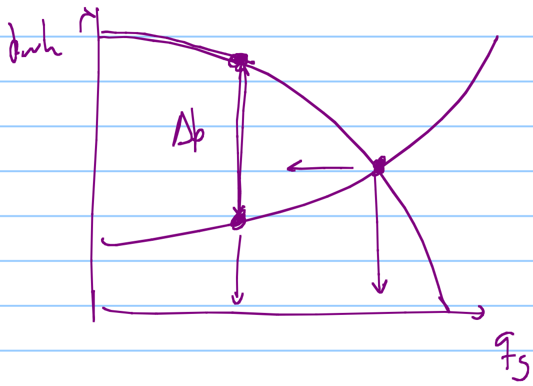




$$G_p = q_{field} \cdot t_{days/year}$$

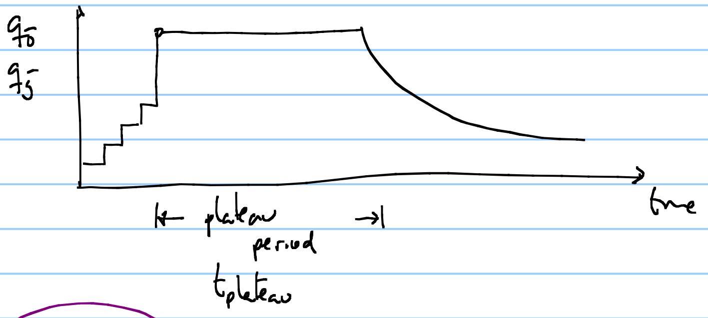


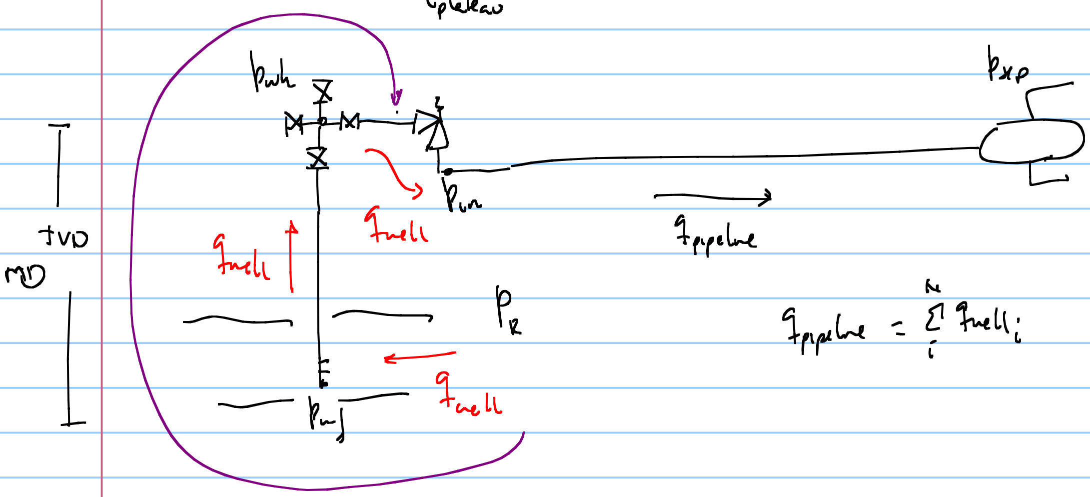



Δp
q_s

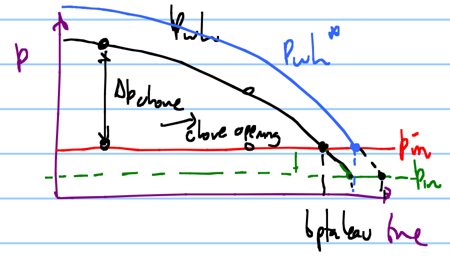
Notes to Youtube video nr. 8

Measure to prolong plateau duration





$$q_{pipeline} = \sum_{i}^{N} q_{well_i}$$



Reservoir → bottom-hole → wellhead → pipe inlet → separator

TYPE OF FLOW: formation, tubing, choke, pipeline

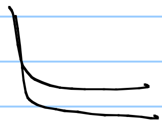
$\Delta p_{drawdown}$, Δp_{tubing}, Δp_{choke}, $\Delta p_{pipeline}$

measures to reduce Δp

$\Delta p_{drawdown}$
- stimulation
- acidizing
- fracking
- re completion
- side-tracking
- multi laterals
- reduce rate per well (drilling more well)

$$q_g = C_R \underbrace{\left(p_R^2 - p_{wf}^2\right)^n}_{\simeq \Delta p_{drawdown}}$$

q_g: constant; p_R: reducing



$$q_{field} \simeq q_{well} \cdot N_{well}$$

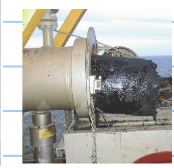
Δp_{tubing}
- "increase" C_T.
- increase the diameter

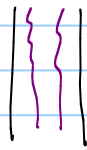
$$q_g = C_T \underbrace{\left(\frac{p_{wf}^2}{e^S} - p_{wh}^2\right)^{0.5}}_{\propto \Delta p_{tubing}}$$

- artificial lift → gas lift
  - → jet pump
  - → plunger lift
  - → rod pumping
  - → Progressive cavity pumps (PCP)
  - → Electric submersible pumps (ESP)

- measures to mitigate phenomena that causes tubing diameter to be reduced in time

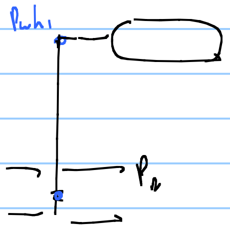
- scaling
- wax
- asphaltene





How to determine tubing size

- get more rate ↑Φ ↑q_g
- keep cost low ↑Φ ↑\$



$P_{wh} = const = P_{sep}$

big Φ, ↓ v_g, ↓ f, ↓ Δp

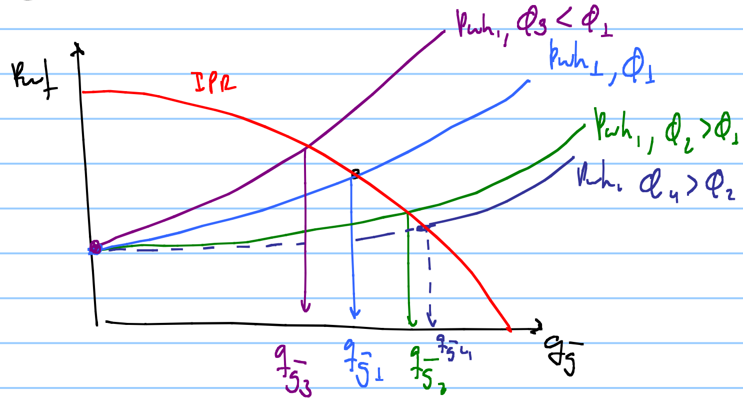
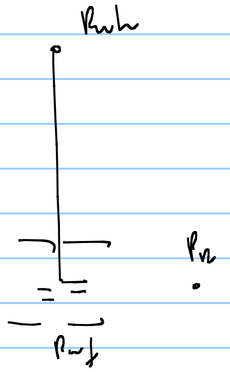
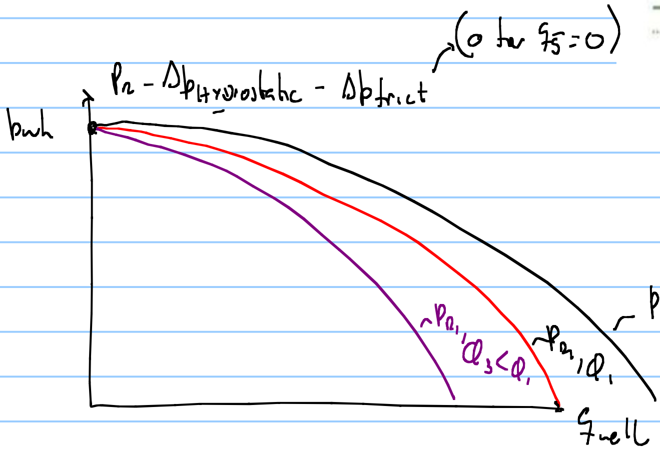


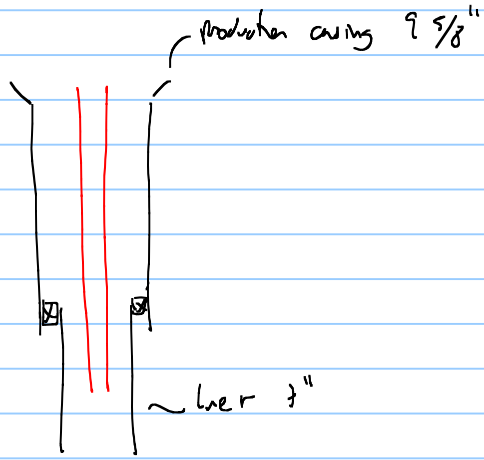
Figure 6-25 Karish PQ Curves





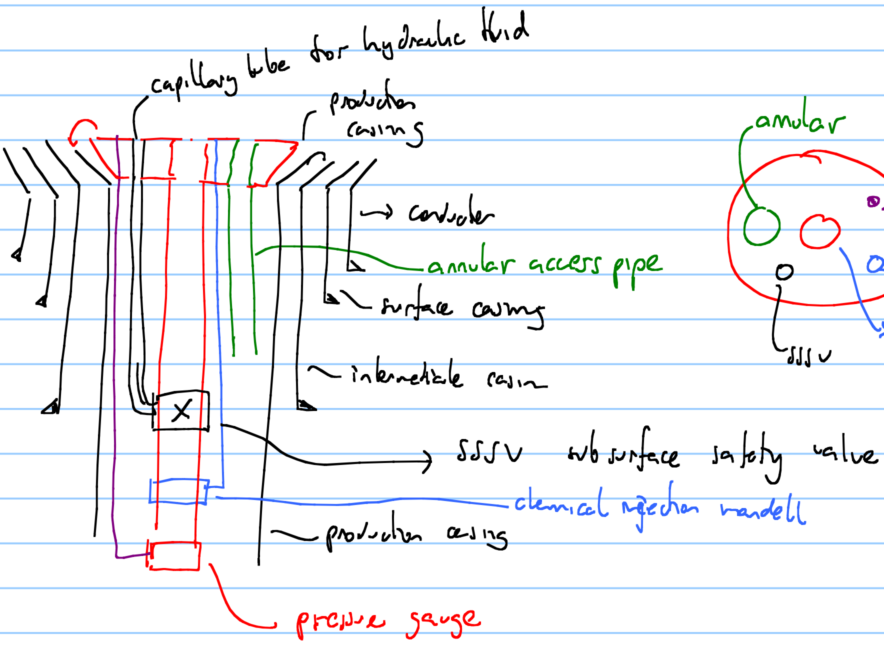
wellhead performance relationship

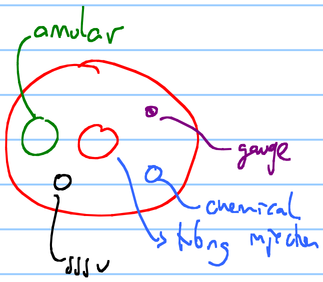
- completion considerations
  possible to run the tubing in well



- tubing hanger

due to structural integrity of tubing hanger, tubing diameter might be limited





- erosional velocity

$$v_g \leq \underline{v_{erosional}}$$

$$\frac{q_g(P,T)}{A} = v_{sg}$$

v_{sg} → superficial gas velocity

A → cross section area of tubing

$$q_g(P,T) = q_{\bar{g}}\, B_g(P,T)$$
$$q_o(P,T) = q_{\bar{o}}\, B_o(P,T)$$
$$q_w(P,T) = q_{\bar{w}}\, B_w(P,T)$$

standards to define $v_{erosional}$

→ API 14E

. DNV Recommended Practice RP O501)

(1) The velocity above which erosion may occur can be determined by the following empirical equation:

$$V_e = \frac{c}{\sqrt{\rho m}} \qquad \textbf{Eq. 2.14}$$

where:

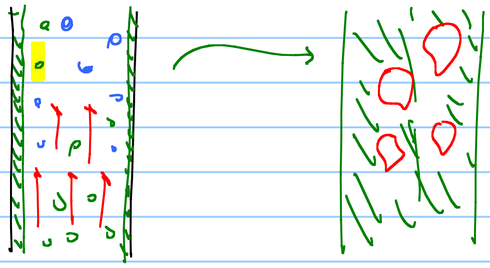
V_e = fluid erosional velocity, feet/second

c = empirical constant

pm = gas/liquid mixture density at flowing pressure and temperature, lbs/ft³

$$\rho_m = \rho_o\left(\frac{q_o}{q_o+q_g+q_w}\right) + \rho_g \cdot \frac{q_g}{(q_o+q_g+q_w)} + \rho_w\left(\frac{q_w}{q_o+q_g+q_w}\right)$$

- In gas wells, v_g must be higher than the critical liquid loading velocity

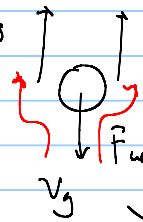


$\rho_{m1} > \rho_{m2}$

ρ_{m2}

Liquid loading

Turner criteria



v_{gc} critical gas velocity

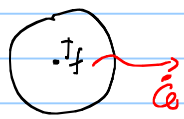
$v_g \geq v_{gc}$ for all points in the tubing

if ϕ is big, then v_g is small and then it could happen $v_g < v_{gc}$

$\Delta p_{pipeline}$
- increase diameter $
- parallel pipeline $

$$q_g = C_{PL} \left(\overbrace{P_{in}^2 - P_{out}^2}^{\propto \Delta p_{pipe}}\right)^{0.5}$$

Considerations for choosing pipe diameter
- erosion
- heat transfer



- T_{amb}

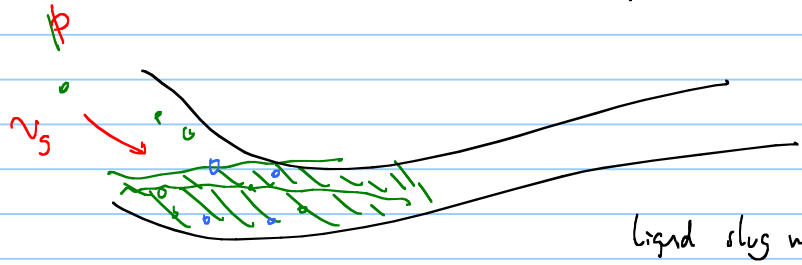
$$\dot{Q} = U \cdot \pi \phi \cdot L \, (T_f - T_{amb})$$

$U \rightarrow$ overall heat transfer coefficient

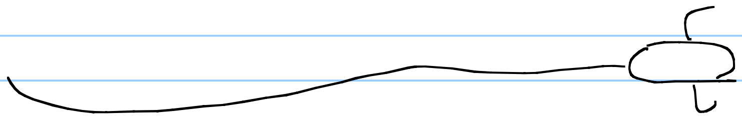
big ϕ $\rightarrow$ big $\dot{Q}$ $\rightarrow$ low T_f
- ↳ liquid dropout in gas systems
- ↳ wax appearance in oil pipes
- ↳ hydrate formation
- ↳ high oil viscosity

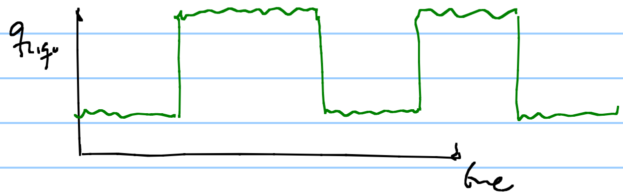
- liquid accumulation in gas pipelines

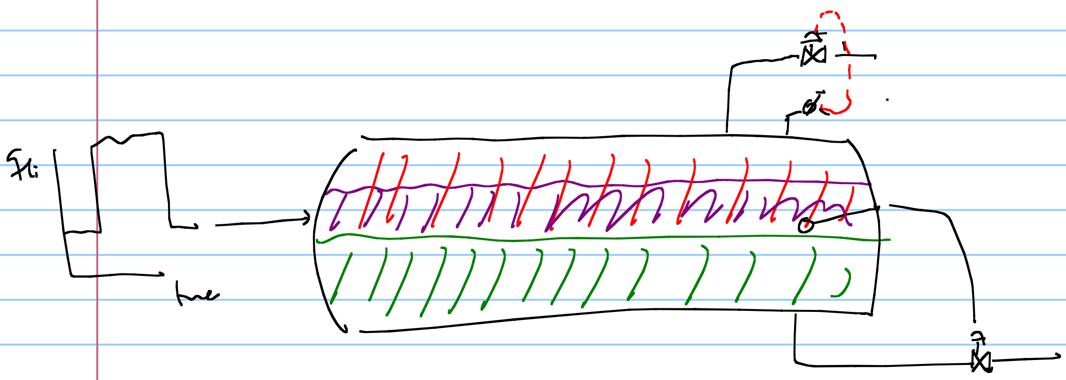
$\uparrow \Delta p_{pipe}$

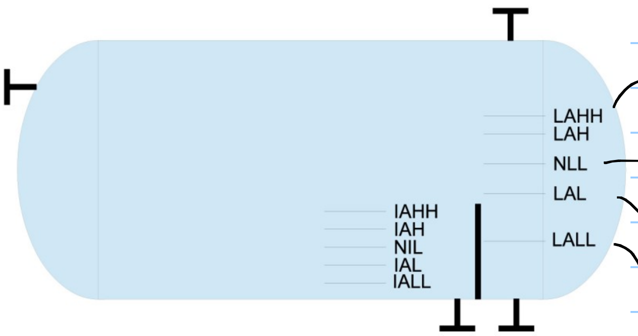


liquid slug might be created in the pipe









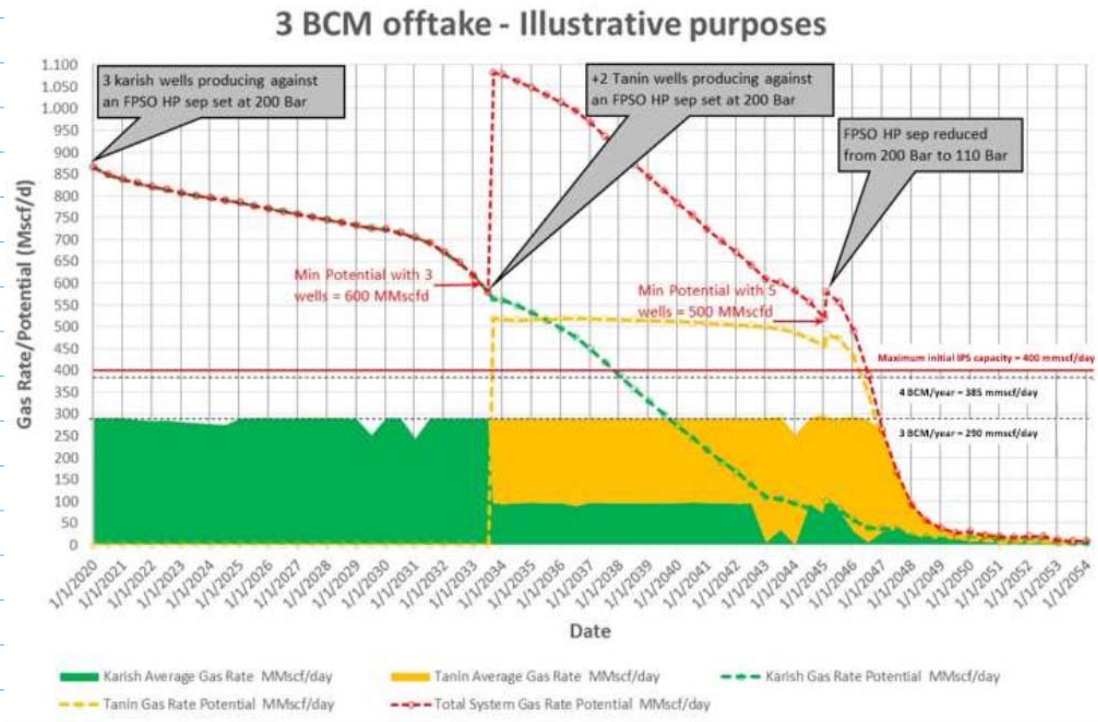
level alarm high high

Normal liquid level

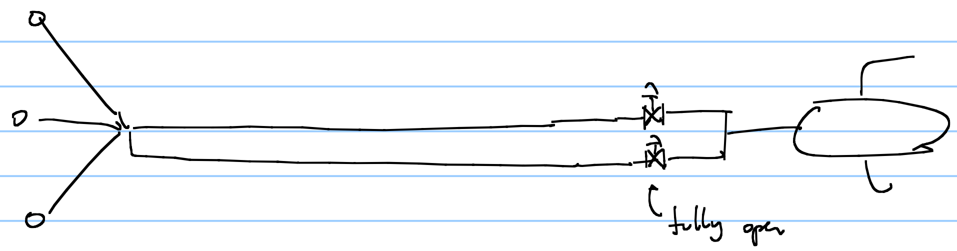
level alarm low

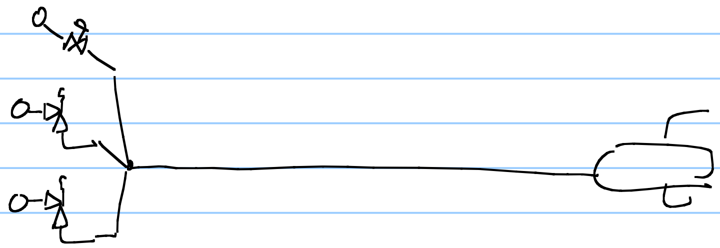
level alarm low low

Notes to Youtube video nr. 9

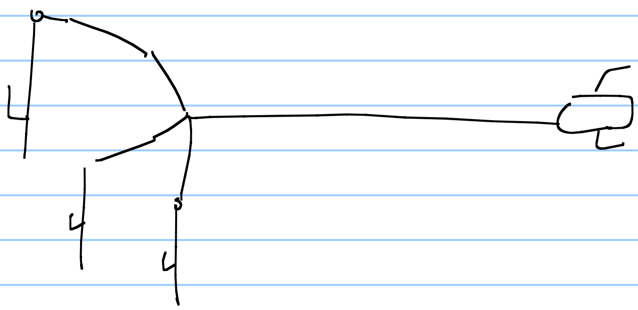


Production potential   maximum rate the production system can deliver at a given time



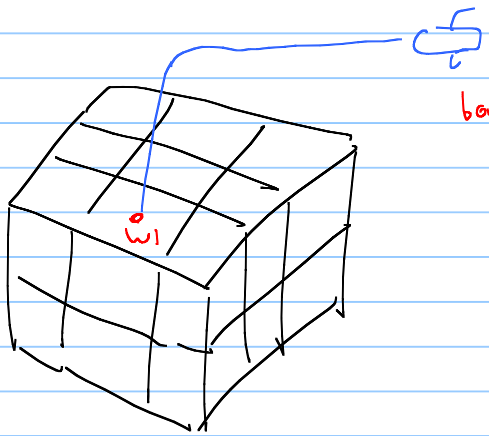


q_{pp} = fully open choke



max q_g by changing $q_{g\,inj\,1}$, $q_{g\,inj\,2}$, $q_{g\,inj\,3}$

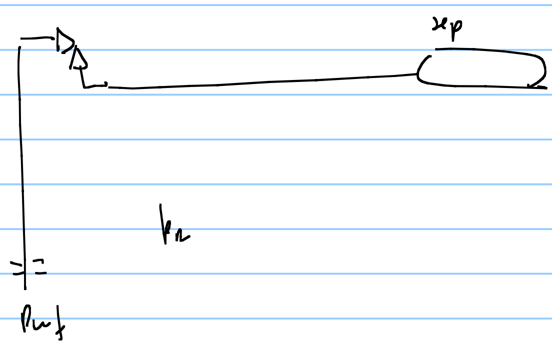
Production potential is also used in reservoir simulation

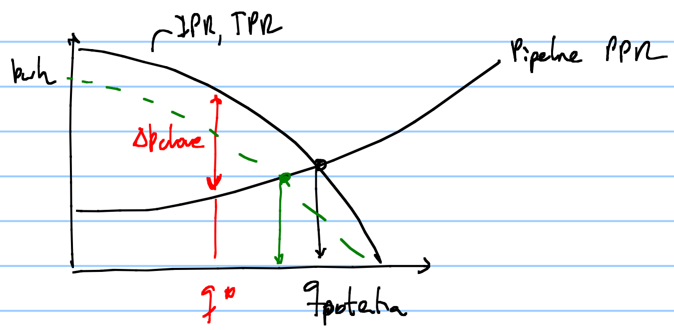


boundary conditions on well 1 → q_{target}
→ $p_{wf\,min}$

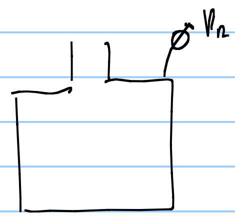
in each time step

- tries $p_{wf\,min}$ → $q_{potential}$
- if $q_{potential} > q_{target}$
  - → q_{target} can be produced
    increase p_{wf} until the $q_{well} = q_{target}$
  - → if $q_{pot} \leq q_{target}$
    → q_{target} cannot be produced
    $p_{wf} = p_{wf\,min}$
    $q_{well} = q_{potential}$





- Production potential is actually a function of p_R

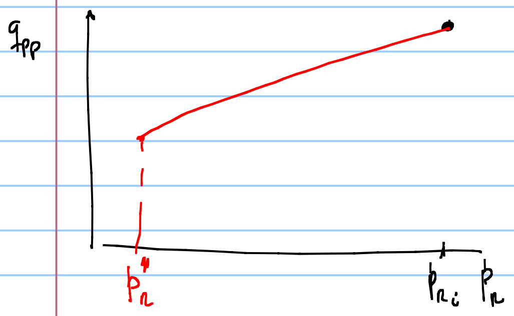


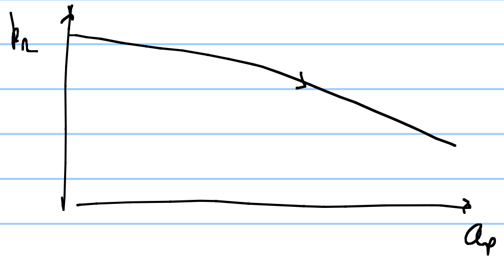
→ and p_R is usually a function of
Q_p → G_p (gas)
→ N_p (oil)

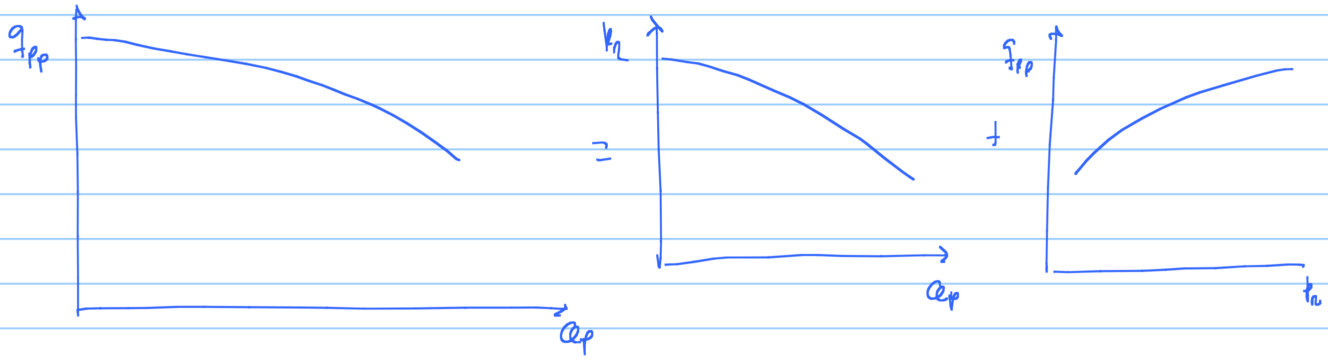
$$p_R = f(Q - Q_p)$$

$$p_R(t) = f(Q - Q_p(t))$$

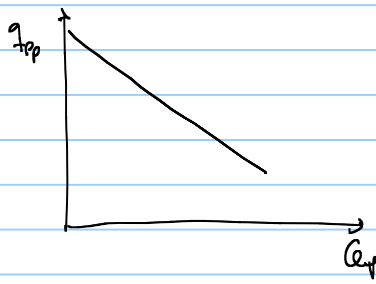
$$p_R = f(Q_p)$$



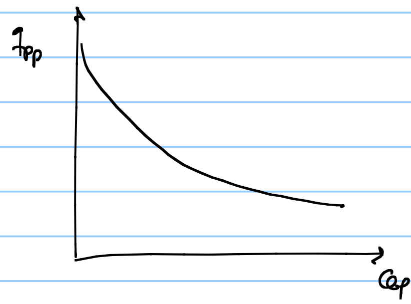




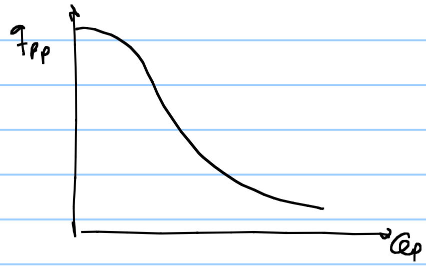
for dry gas and undersaturated oil



for saturated oil

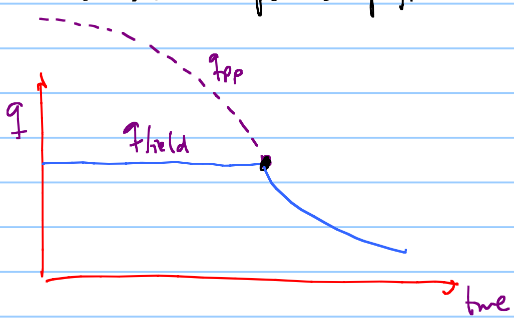


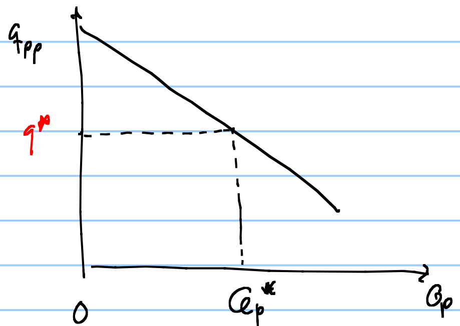
for oil water injection



Production potential curves can be used for

- determine plateau duration
- estimate production profile





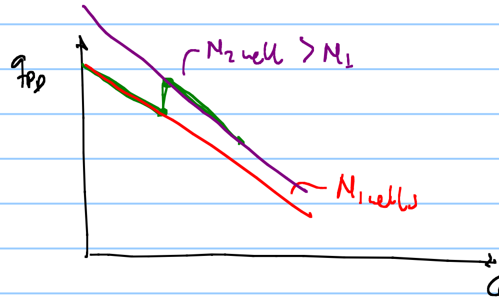
$q_{plateau} = q^*$

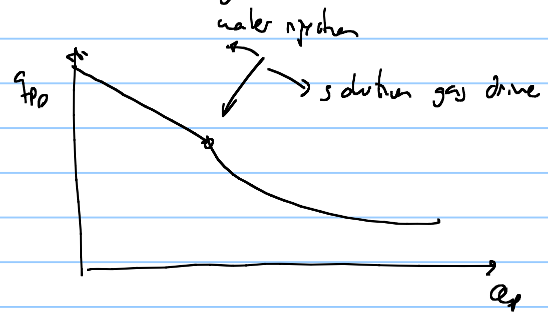
G_p^* ~ cumulative production at which the end of plateau will occur

$0 \rightarrow Q_p^*$ has been produced at constant rate q^*

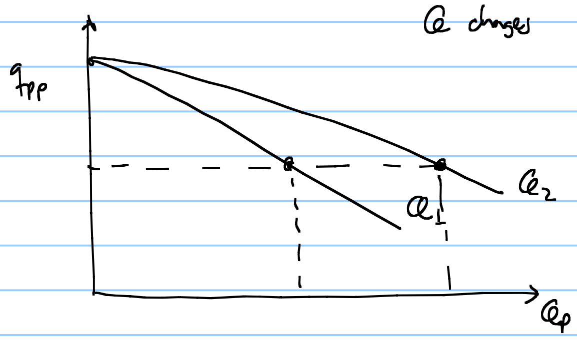
$$t_{plateau} = \frac{Q_p^* \, [Sm^3]}{q^* \, [Sm^3/d] \; t_{uptime}} \qquad t_{uptime} \longrightarrow \frac{\text{nr. operational days}}{\text{year}}$$

Production potential curve is affected by changes to the production system





Q changes



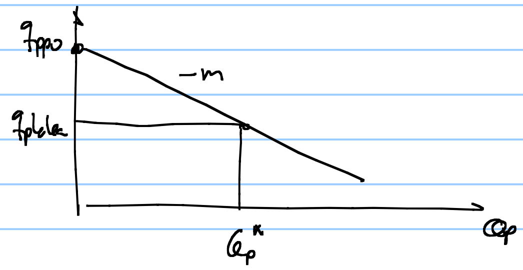
$p_R = f(R_f)$

$$R_{f_1} = \frac{Q_p}{Q_1} \qquad R_{f_2} = \frac{Q_p}{Q_2}$$

$R_{f_2} < R_{f_1}$

if curve q_{pp} is linear $q_{pp} = -m\, Q_p + q_{ppo}$

derive analitically $q_f(t)$ from q_{pp}



$$q_f(t) \begin{cases} q_{plateau} & \text{for } t \le t_{plateau} = \left(\frac{q_{ppo}}{q_{plateau}} - 1\right)\frac{1}{m} \\ q_{field} = q_{pp} & \text{for } t > t_{plateau} \end{cases}$$

$$q_{plateau} = q_{pp} = -m\, Q_p^* + q_{ppo}$$

$$Q_p^* = \frac{q_{ppo} - q_{plateau}}{m}$$

$$q_{pp} = -m\left(Q_p^* + \int_{t_{plateau}}^{t} q_{pp}\, dt\right) + q_{ppo}$$

$$t_{plateau} = \frac{Q_p^*}{q_{plateau}} = \left(\frac{q_{ppo}}{q_{plateau}} - 1\right)\frac{1}{m}$$

$$q_{pp} = -m\,\frac{(\cancel{q_{ppo}} - q_{plateau})}{m} - m\int_{t_{plateau}}^{t} q_{pp}\, dt + \cancel{q_{ppo}}$$

$$q_{pp} = q_{plateau} - m\int_{t_{plateau}}^{t} q_{pp}\, dt$$

$\longrightarrow$ a solution to this equation is

$$q_{pp} = q_{field} = q_{plateau} \cdot e^{-m(t - t_{plateau})}$$

$$q_f(t) \begin{cases} q_{plateau} & \text{if } t \le t_{plateau} = \left(\dfrac{q_{ppo}}{q_{plateau}} - 1\right)\dfrac{1}{m} \\ q_{plateau}\, e^{-m(t-t_{plateau})} & \text{if } t > plateau \end{cases}$$

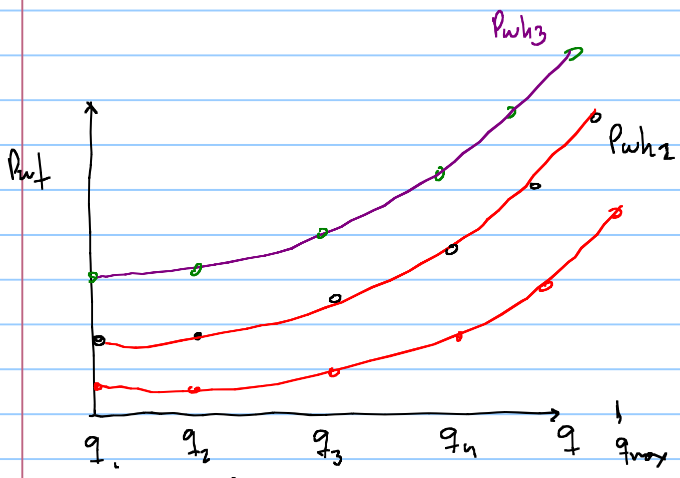
$$= e^{-\frac{1}{m}(t-t_{plateau})}$$

Notes for Youtube video 10

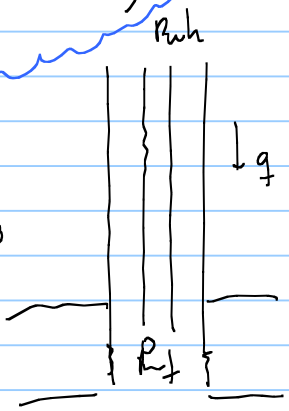
Discussion on TPR (tubing performance relationship)

In commercial software, instead of running Δp calculation along tubing each time is needed (flow equilibrium calculations), tubing tables are used instead (Δp tubing is precomputed for many operational conditions) and later on interpolation is made on table

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



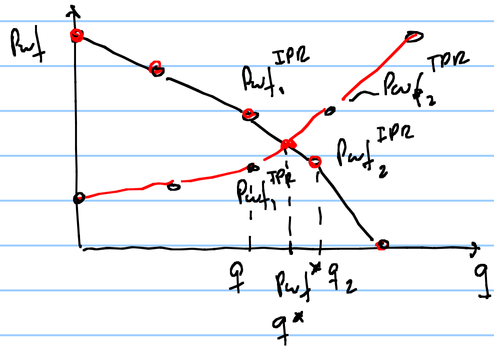
$P_{wh_2} < P_{wh_1} < P_{wh_3}$



	P_{wh_1}	P_{wh_2}	P_{wh_3}	-
q_1	$P_{wf_{11}}$	$P_{wf_{12}}$	-	
q_2	-	.	-	
q_3	-	.	-	
q_4				
q_5				

tubing table

interpolation on this table is much more computationally efficient than using the equation/method $\Delta p = f(q, P_{wh},)$ specially for multiphase flow, gas with liquid



IPR

task find equilibrium for $P_{wh} = P_{wh_1}$

go to tubing table and extract colum $P_{wh} = P_{wh_1}$

and impose on plot

from the table

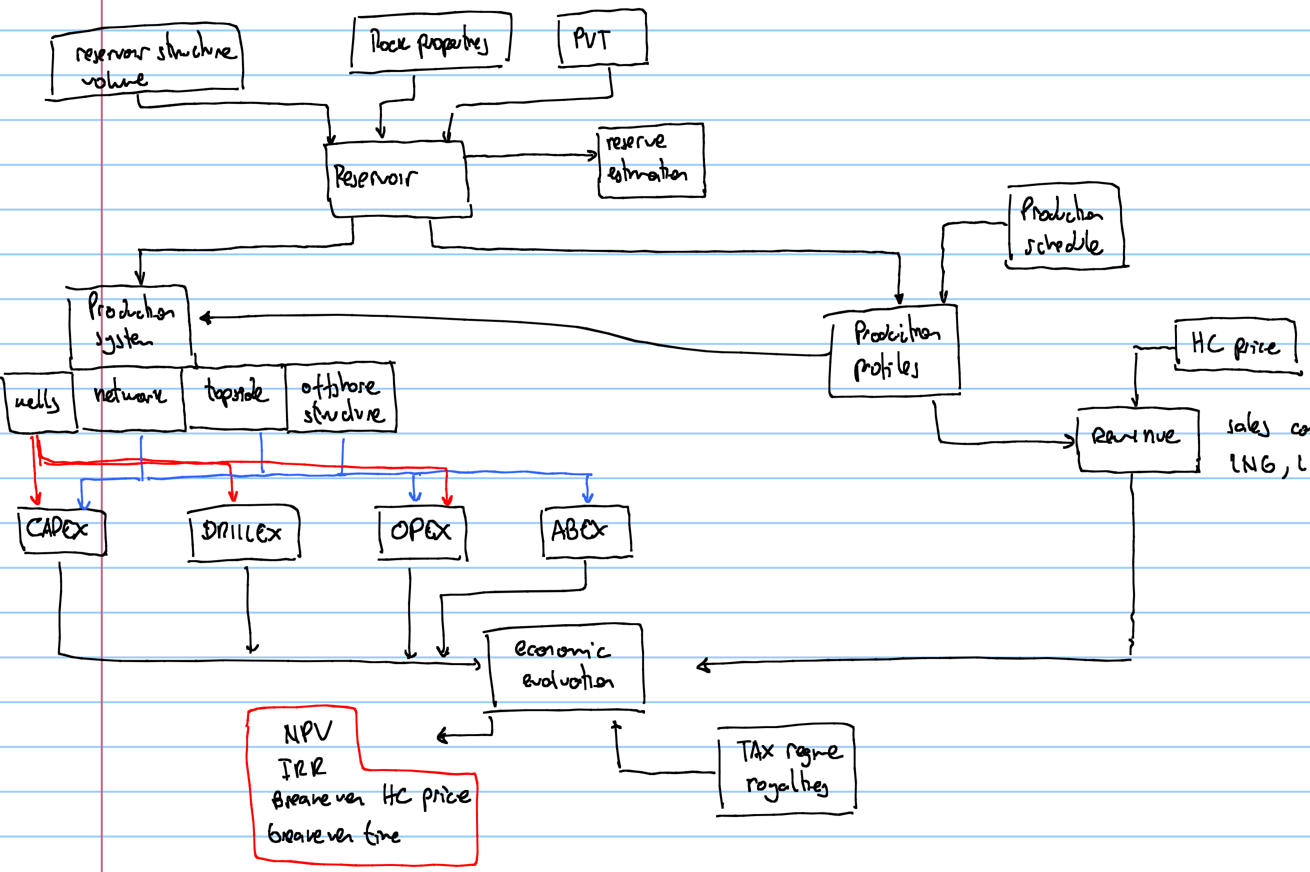
$$\frac{P_{wf_1}^{IPR} - P_{wf_2}^{IPR}}{q_1 - q_2} = \frac{P_{wf_1}^{IPR} - P_{wf}^*}{q_1 - q^*}$$

System of two linearequations with two unknowns

$$\frac{P_{wf_1}^{TPR} - P_{wf_2}^{TPR}}{q_1 - q_2} = \frac{P_{wf_1}^{TPR} - P_{wf}^*}{q_1 - q^*}$$

Notes for Youtube video 11

Value chain model



CAPEX:
- engineering studies (salaries, consultants, contractor)
- processing facilities (separators, pumps, compressor, heat exchangers, control system, injection, export, water, oil, gas treatment)
- offshore structure (cost of platform, FPSO, TLP, living quarters, auxiliary equipment, power equipment)
- Subsea system costs (template, flowline, pipeline, risers, umbilicals, control system, metering, boosting)
- export system

DRILLEX
- Drilling rate of vessel
- drilling materials (tubulars, cement, mud, completion, wellhead)
- test during drilling (DST, logging, pressure test, sampling)
- X-mas tree
- drilling tools

OPEX
- Important to estimate abandonment rate.
- workers' salaries
- insurance
- maintenance
- equipment
- well intervention
- Power consumption
- production chemicals
  - MEG
  - wax inhibitor
  - corrosion inhibitor
  - etc.
- Pigging
- transportation and export
- troubleshooting

ABEX
- well plugging
- removal of flowlines, pipelines, offshore structure
- cleaning
- monitoring

NPV calculations

$$NPV = \sum_{i=1}^{N} \frac{CF_i}{(1+d)^i}$$

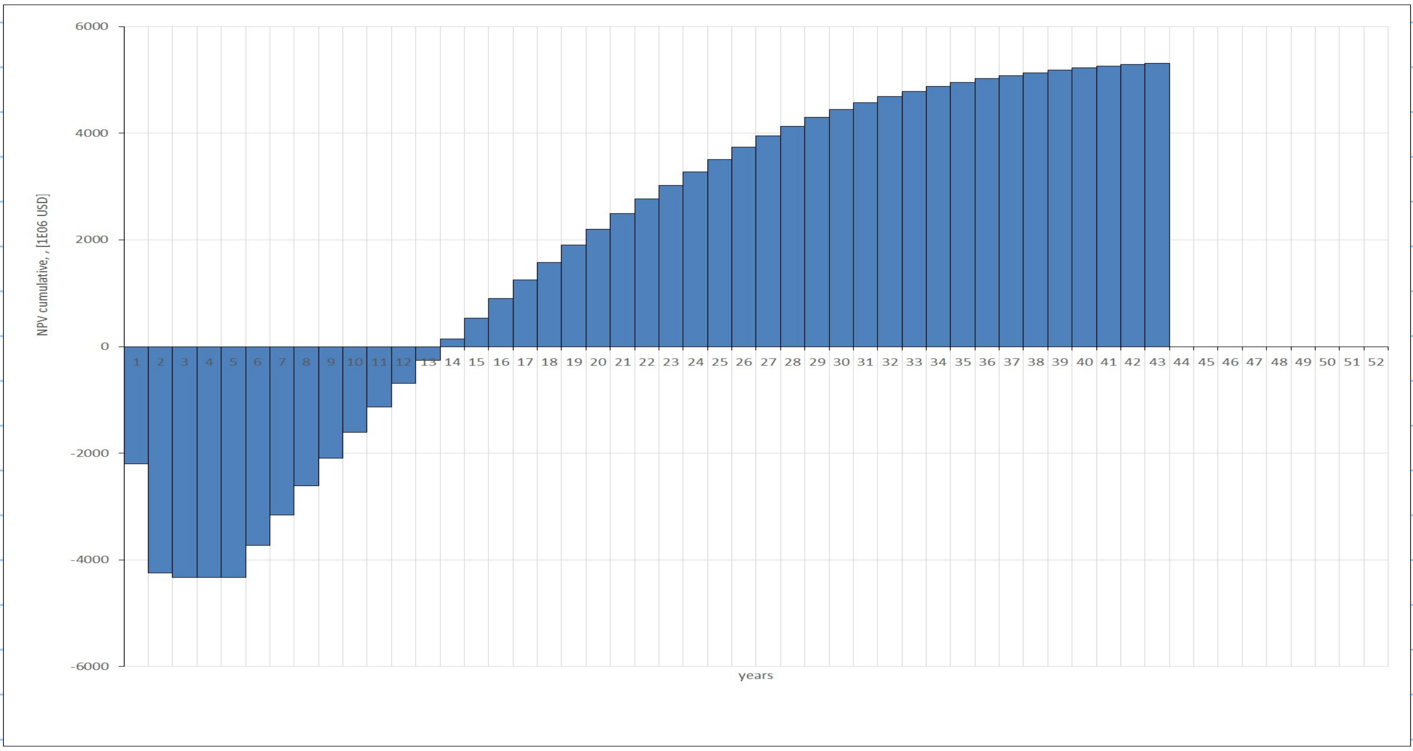
N: abandonment

CF_i = revenue – expenditures of year "i"

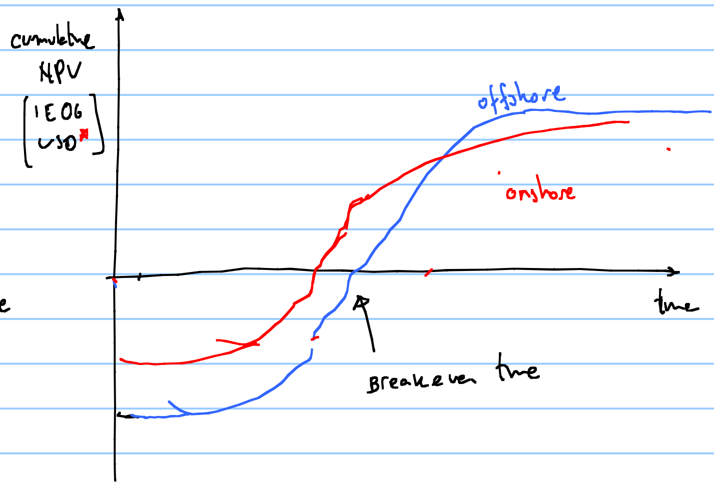
d: discount factor 5% → 12%

expenses are executed during early years so $\frac{1}{(1+d)^i}$ is close to "1"

discount factor	0.07
year	1/(1+d)^i
1	0.934579
2	0.873439
3	0.816298
4	0.762895
5	0.712986
6	0.666342
7	0.62275
8	0.582009
9	0.543934
10	0.508349
11	0.475093
12	0.444012



Output to present NPV calculations



*USD of each year

USD of time "0"

the effect of uncertainty on the project is typically studied using "Ceteris Paribus" "one at a time"

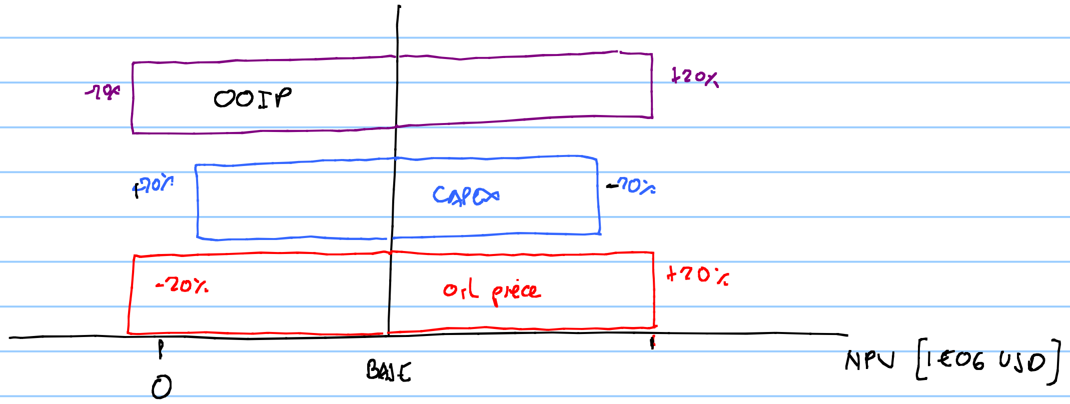
also called sensitivity analysis

- oil price uncertainty
- Cost uncertainty (±40% → DG3 ±20%)
- N

BASE CASE NPV =

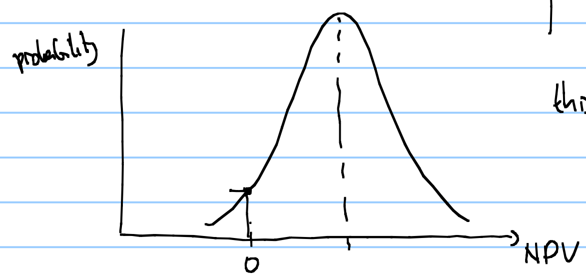
	min	max
Oil price	NPV	NPV
OOIP	NPV	NPV
CAPEX	NPV	NPV

Tornado chart

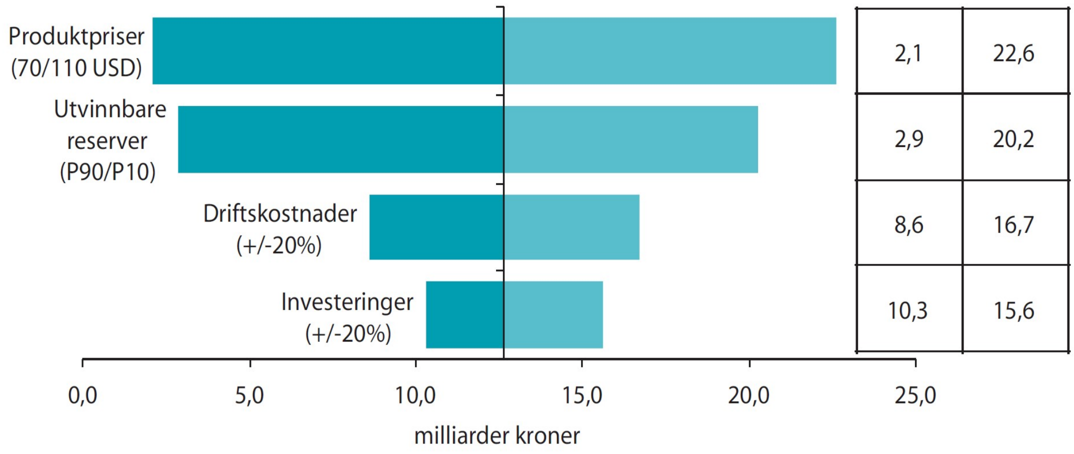


this is NOT a good way to evaluate/quantify uncertainty { we are neglecting other combinations }

a probabilistic evaluation is better!



this requires multiple { 100 500 1010 10000 } evaluations


Produktpriser
(70/110 USD)
Utvinnbare
reserver
(P90/P10)
Driftskostnader
(+/-20%)
Investeringer
(+/-20%)
2,1
22,6
2,9
20,2
8,6
16,7
10,3
15,6
0,0
5,0
10,0
15,0
20,0
25,0
milliarder kroner

There were no notes for the session 20210218, but check the video

How to deal and quantify uncertainty in field development

for example in our Snøhvit case

↳ G, N , $q_g = C_R(P_R^2 - P_{wf}^2)^n$

$

uptime 90 – 100%

$\left(\dfrac{\text{nr days producing in year}}{365} \right)$

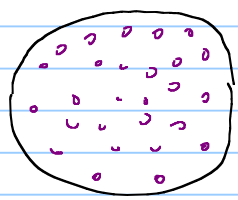
↳ cause additional OPEX

↳ cut in production → cut in Revenue

input variables used in engineering studies in FD are highly uncertain

$\Phi_{min} \leq \Phi \leq \Phi_{max}$ and affect the value of KPIs that are used to discriminate and select development alternatives.

Φ



number sample	Φ
–	–
–	–
–	–
–	–
–	–

→ discrete frequency analysis

create bins min Φ_1 (0.15)

0.175

Φ_2 (0.20)

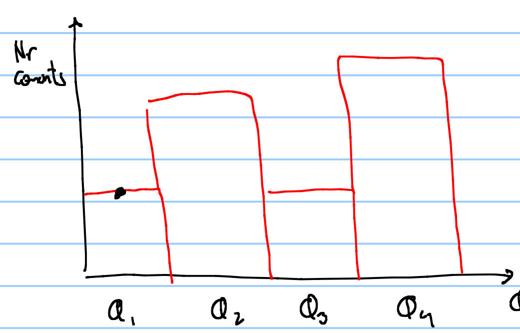
Φ_3 (0.25)

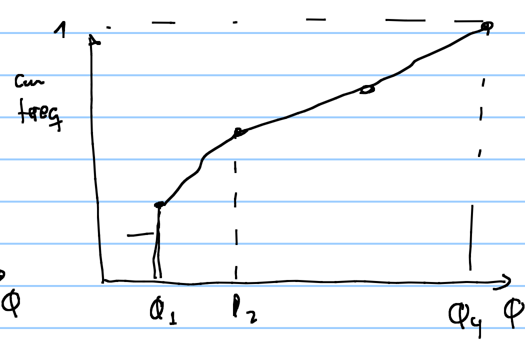
max Φ_4 (0.30)

if $\Phi_i = 0.18$

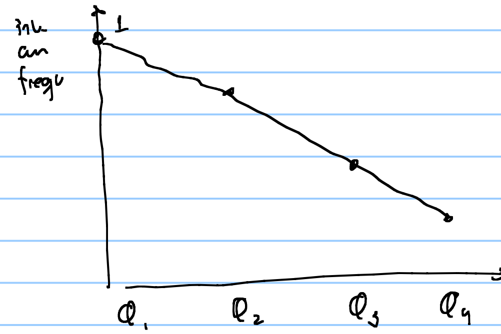
$\Phi_1 \leq \Phi_i \leq \Phi_2$

if $\Phi_i < \dfrac{(\Phi_2 - \Phi_1)}{2} + \Phi_1$ → counted as part of Φ_1





bin	Nr counts	rel. frequency	cum frequency	inv. cum frequency
Q_1	x	x/N	x/N	(x+w+z+y)/N → 1
Q_2	y	y/N	y/N + x/N	(w+z+y)/N
Q_3	z	z/N	y/N + x/N + z/N	(w+z)/N
Q_4	w	w/N	(x+y+z+w)/N	w/N
	N			



how to do frequency analysis in excel:

E7 {=FREQUENCY(A2:A20;D7:D11)}

	A	B	C	D	E	F	G
1	Variable			min	1		
2	10			max	10		
3	7			Nr bins	5		
4	2			delta	2.25		
5	6						
6	1			bins	nr counts		
7	8			1	4		
8	1			3.25	4		
9	7			5.5	1		
10	3			7.75	3		
11	9			10	7		
12	1						
13	4						
14	8						
15	2						
16	8						
17	1						
18	9						
19	3						
20	10						

to create bins:

find max
find min
define Nr bins
calculate $\text{delta} = \frac{(\max - \min)}{(\text{Nr bins} - 1)}$

compute each bin
$\text{bin}^{i} = \text{bin}^{i-1} + \text{delta}$

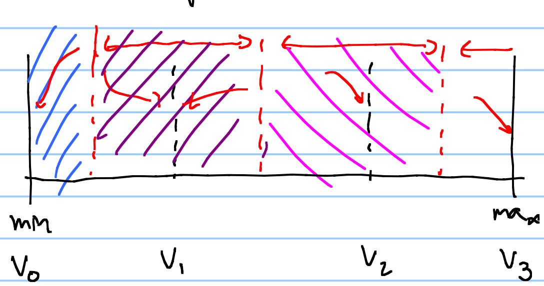
starting from $\text{bin}^{0} = \min$

to apply frequency function:

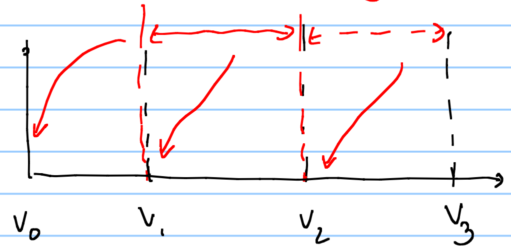
ctrl + shift + enter (in sequence and leave it pressed)

selecting bins must take into account

- nr data points



be careful how the frequency is accounted for



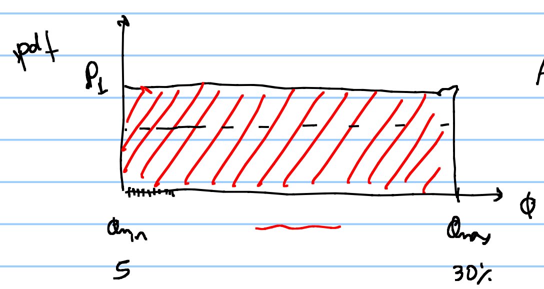
what happens if there are no measurements?

frequency ⇝ probability

rel frequency ⇝ pdf probability density function

cum frequency plot ⇝ cdf cumulative distribution function

poor boy, no data pdf ϕ continuous probability



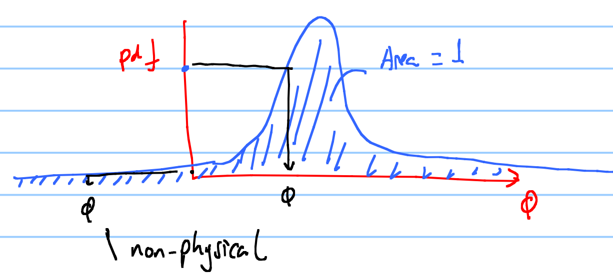
$$\text{Area} = (\phi_{max} - \phi_{min}) \cdot P_1 = 1$$

$$P_1 = \frac{1}{(\phi_{max} - \phi_{min})}$$

Continuous distributions are advantageous because:
-There is an analytical expression
-I need only few values to define the distribution
-There is no data to determine a discrete distribution

Warning: many continuous distributions go from $-\infty \rightarrow +\infty$

There are many parameters in FD that exhibit typical distributions:
-cost ---Normal
-Porosity --- Normal
-Initial oil/gas in place --- Log Normal



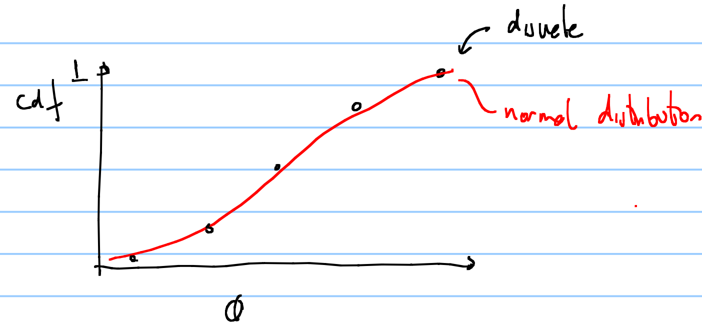
so bounding is necessary

discrete distribution ⟶ continuous distribution

- calculate directly using population data

$$\left.\begin{array}{c} \phi \\ \phi_1 \\ \phi_2 \\ \vdots \end{array}\right\} \begin{array}{l} \mu \\ \sigma \end{array} \rightarrow \text{parameters of a normal distribution}$$

- tune parameters in the continuous distribution to represent the discrete distribution

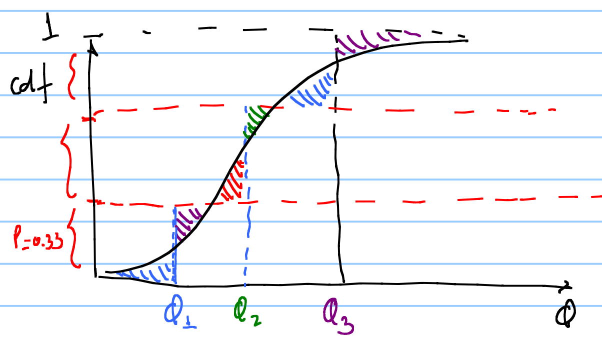


$$\frac{1}{\sigma\sqrt{2\pi}}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}$$

change μ, σ until diff discrete and continuous is minimal

continuous distribution → discrete distribution

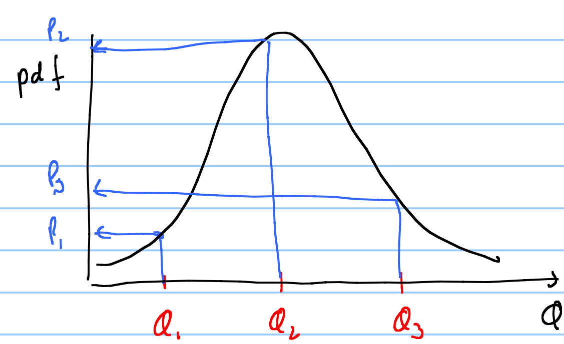
- Bracket mean
  - define nr bins
  - define probability of bins



Φ	P
Φ_1	0.33
Φ_2	0.33
Φ_3	0.33

find Φ_1, such that [purple area] = [blue area]

- value discretization
- pick nr. bins in Φ
- read probabilities from pdf



Φ	P
Φ_1	P_1^*
Φ_2	P_2^*
Φ_3	P_3^*

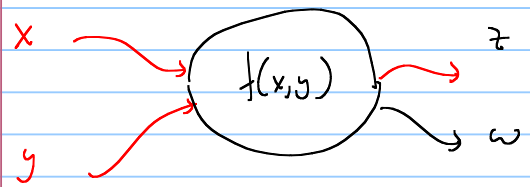
- Normalize probabilities using the sum

$$P_1^* = \frac{P_1}{P_1 + P_2 + P_3}$$

$$P_2^* = \frac{P_2}{P_1 + P_2 + P_3}$$

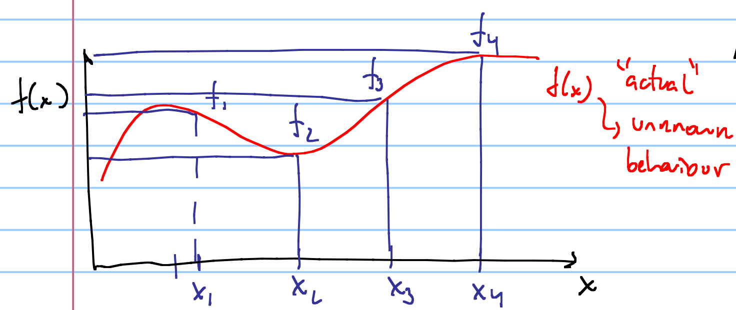
Notes to Youtube video 13

How to handle uncertain parameters in our FD calculations



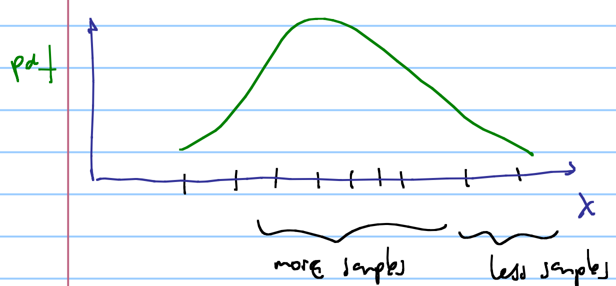
deterministic calculation: x and y have a unique known value

stochastic/probabilistic calculation: x and y exhibit a probabilistic distribution



Approach to deal with uncertainty:

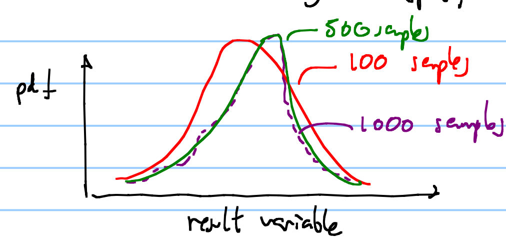
- create samples
- evaluate the function at samples
- calculate pdf and cdf of the results



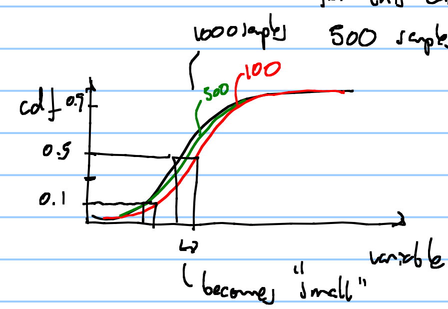
1: How many samples are needed?

2: How to generate the samples?

1: Increase the number of samples and see how the results change (pdf, cdf)



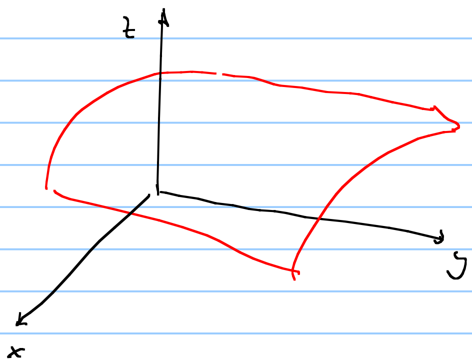
for this case, it seems 500 samples is enough

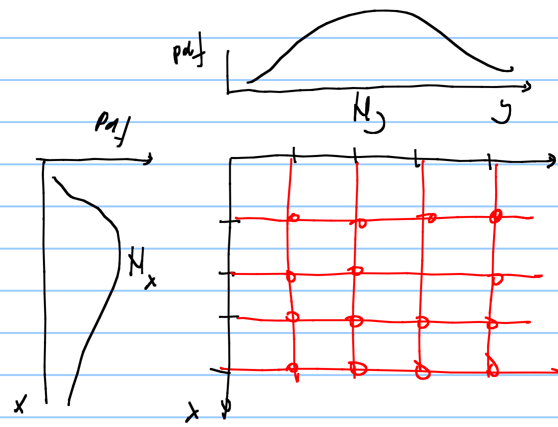


2: how to generate the samples

- Monte Carlo method
- Latin hypercube sampling

} efficient sampling → less number of samples to achieve convergence brute-force sampling

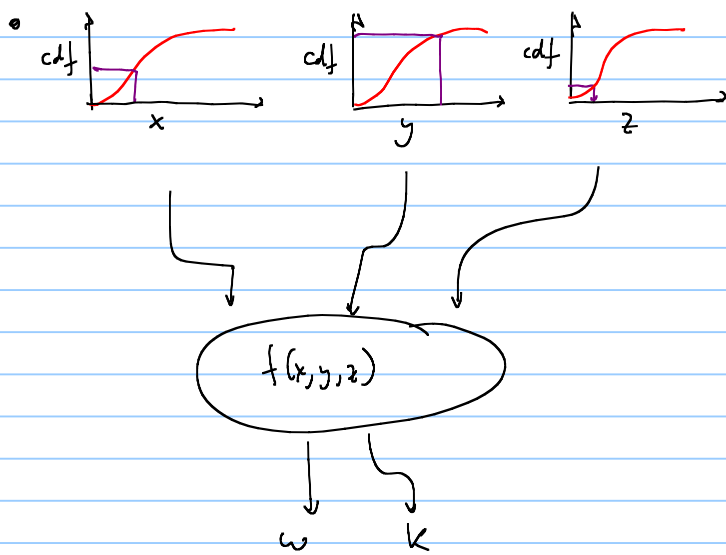




$N_{total} = N_x \cdot N_y$

It is impractical for large number of variables/samples

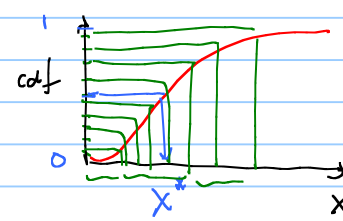
•



① For each variable

1.1 pick a random number between 0-1

1.2 enter cdf and read the value of the variable



② perform a simulation with the samples

③ repeat "many" times steps 1-2

④ perform a frequency analysis on the results → pdf cdf

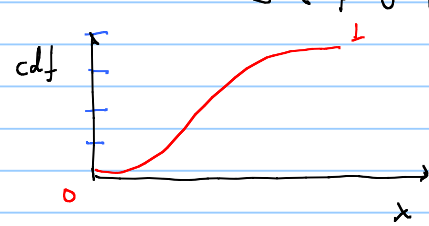
• Latin hypercube sampling (LHS)

① Define a number of samples "N"

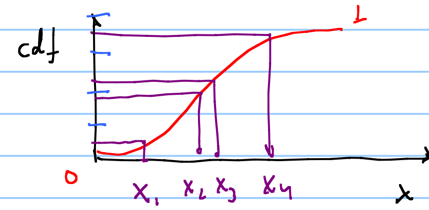
① For each variable

1.1. subdivide the cumulative probability in "N" intervals (equally-spaced)

$N=4$



1.2. Pick a random number in the interval
find the corresponding value of the variable



$$\begin{Bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{Bmatrix} \quad \begin{Bmatrix} y_1 \\ y_2 \\ y_3 \\ y_4 \end{Bmatrix} \quad \begin{Bmatrix} z_1 \\ z_2 \\ z_3 \\ z_4 \end{Bmatrix}$$

1.3. shuffle randomly the sample vector(s)

$$\begin{array}{l|c|c|c|} \text{sim 1} & x_3 & y_1 & z_3 \\ \text{sim 2} & x_1 & y_3 & z_2 \\ \text{sim 3} & x_4 & y_4 & z_1 \\ \text{sim 4} & x_2 & y_2 & z_4 \end{array}$$

2. perform simulations for samples variables that are in the same row

3. perform a frequency analysis on the results
↳ cdf, pdf

Notes to Youtube video 14

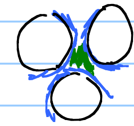
Reserve estimation : case undersaturated oil reservoir

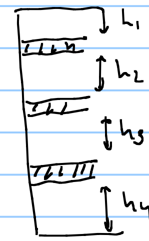
$$TRR = N_{pu} = \frac{V_R \cdot \phi \cdot N_{TG} \cdot S_o \cdot F_{RO}}{B_o}$$

TRR: total recoverable reserves

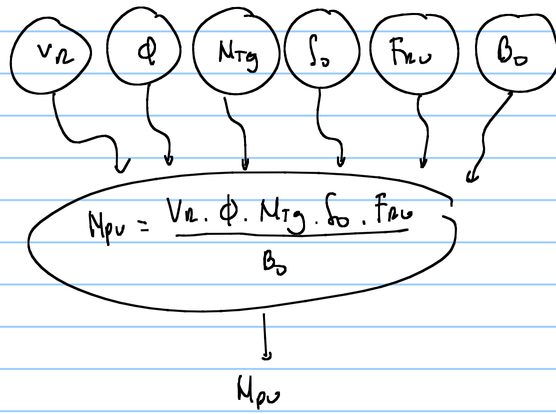
N_{pu}: ultimate cumulative production

F_{RO}: recovery factor

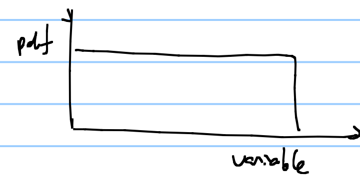




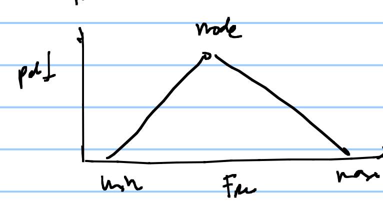
$$N_{TG} = \frac{h_1 + h_2 + h_3 + h_4}{h_{total}}$$

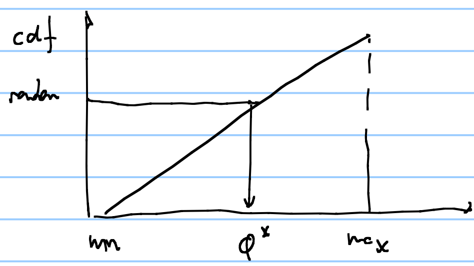


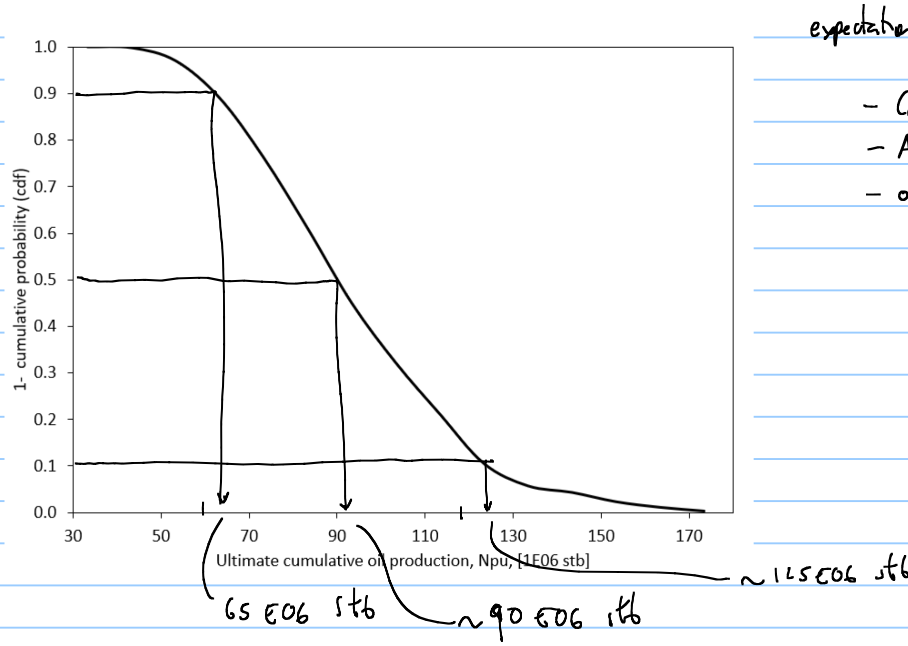
V_R, ϕ, N_{TG}, S_o, B_o have a uniform pdf



F_{RO}





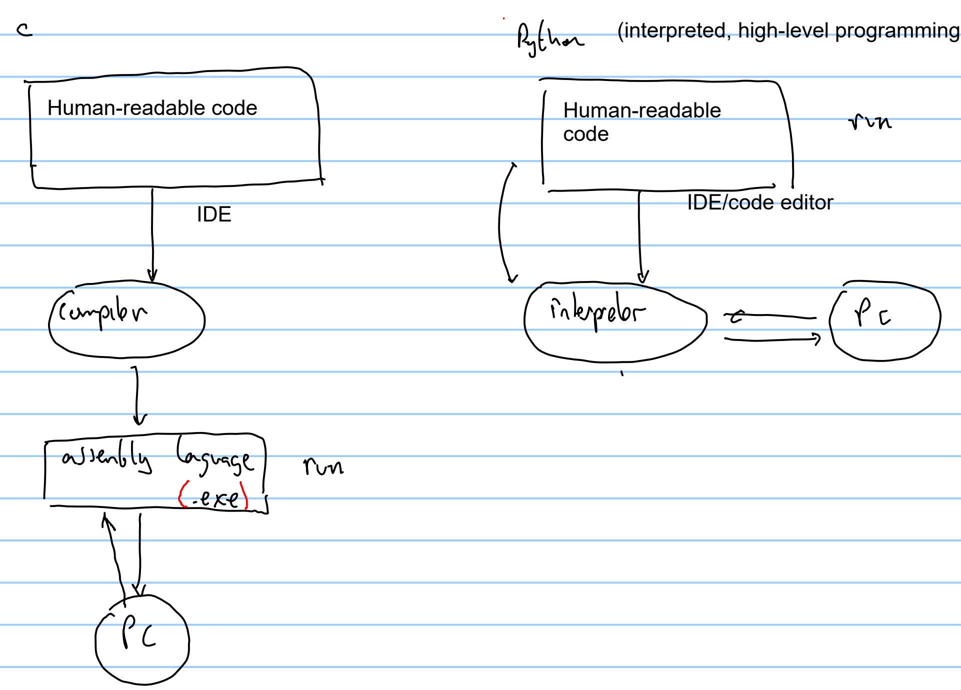


expectation curve

- Conservative estimate (90%) P90
- Average estimate (50%) P50
- optimistic estimate (10%) P10

Notes for lecture 20210302

Differences on how Python and "C" run



Python is open-source, free, with a lot of libraries (toolboxes) and there is a lot of help resources on the web. The sintax is somewhat similar to Matlab (e.g. variables do not need to be declared beforehand).
You can run Python on your computer by:
-Installing directly from https://www.python.org/ and then installing the libraries needed. Libraries are installed by calling Python from the command line. Once Python opens, use the command: "pip install name_of_package". You can also install a specific version of the package, if needed.
-Alternatively, you can download a "package" with Python and a lot of libraries, like anaconda (from https://anaconda.org/). In this case, to install additional libraries you must use anaconda's command line or interface.

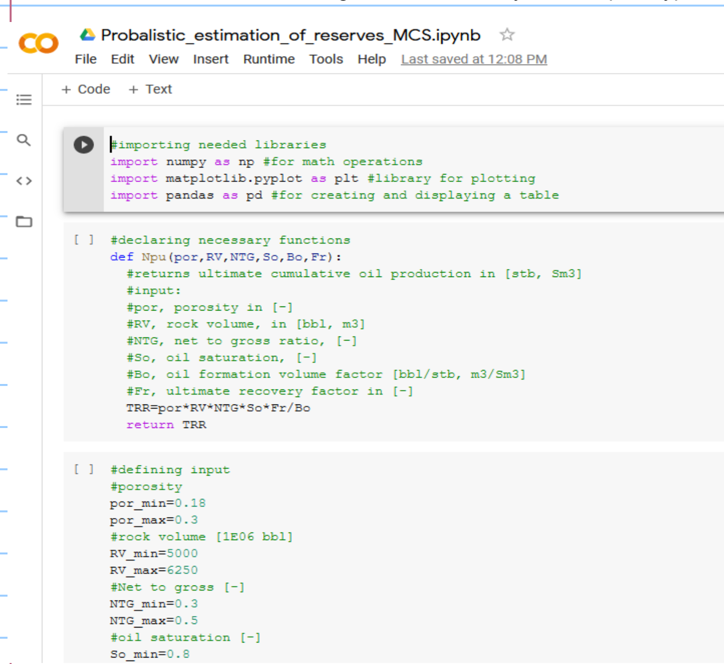
Some popular libraries are numpy and scipy (for math and scientific computing), matplotlib (for plotting), pandas for statistics, etc.

Typically, one uses a code editor or an IDE (Integrated development Environment) to write, debug and test code. For this, you typically need to:
-Install the programming language on your computer and libraries (if needed)
-Configure the editor to work with the programming language.

When you want to run parts of the code, you have to use the "debugging" mode that can allow you to run line by line or jump between sections

Some popular IDEs for Python are Pycharm and Visual studio code.

Jupyter notebook is sort of a code editor for Python. It is an application that uses your browser. It allows to run interactively blocks of code. You can also add annotations, images, etc, so it can work as a interactive document. It is mainly used for solving tasks interactively, and to "prototype" code.




```
#importing needed libraries
import numpy as np #for math operations
import matplotlib.pyplot as plt #library for plotting
import pandas as pd #for creating and displaying a table
```

```
#declaring necessary functions
def Npu(por,RV,NTG,So,Bo,Fr):
    #returns ultimate cumulative oil production in [stb, Sm3]
    #input:
    #por, porosity in [-]
    #RV, rock volume, in [bbl, m3]
    #NTG, net to gross ratio, [-]
    #So, oil saturation, [-]
    #Bo, oil formation volume factor [bbl/stb, m3/Sm3]
    #Fr, ultimate recovery factor in [-]
    TRR=por*RV*NTG*So*Fr/Bo
    return TRR
```

```
#defining input
#porosity
por_min=0.18
por_max=0.3
#rock volume [1E06 bbl]
RV_min=5000
RV_max=6250
#Net to gross [-]
NTG_min=0.3
NTG_max=0.5
#oil saturation [-]
So_min=0.8
```

You can install Jupyter notebook from their website (https://jupyter.org/), it is included on the Anaconda package. There are also some websites that allow you to run Jupyter notebooks in their servers. An example is google collaboratory (https://colab.research.google.com)

```python
#importing needed libraries
import numpy as np #for math operations
import matplotlib.pyplot as plt #library for plotting
import pandas as pd #for creating and displaying a table
```

```python
[3] #declaring necessary functions
def Npu(por,RV,NTG,So,Bo,Fr):
  #returns ultimate cumulative oil production in [stb, Sm3]
  #input:
  #por, porosity in [-]
  #RV, rock volume, in [bbl, m3]
  #NTG, net to gross ratio, [-]
  #So, oil saturation, [-]
  #Bo, oil formation volume factor [bbl/stb, m3/Sm3]
  #Fr, ultimate recovery factor in [-]
  TRR=por*RV*NTG*So*Fr/Bo
  return TRR
```

```python
[6] #defining input
#porosity
por_min=0.18
por_max=0.3
#rock volume [1E06 bbl]
RV_min=5000
RV_max=6250
#Net to gross [-]
NTG_min=0.3
NTG_max=0.5
#oil saturation [-]
So_min=0.8
So_max=0.9
#Oil formation volume factor [bbl/stb]
Bo_min=1.35
Bo_max=1.6
#recovery factor, Fr, [-]
Fr_min=0.18
Fr_max=0.35
Fr_mode=0.25
```

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

```python
[9] #creating random samples
n=1000  #number of samples
por=np.random.uniform(por_min,por_max,n)
RV=np.random.uniform(RV_min,RV_max,n)
NTG=np.random.uniform(NTG_min,NTG_max,n)
So=np.random.uniform(So_min,So_max,n)
Bo=np.random.uniform(Bo_min,Bo_max,n)
Fr=np.random.triangular(Fr_min,Fr_mode,Fr_max,n)
```

equivalent to

```vb
Function x_uniform(a, b)
    'value of the variable x for a uniform distribution
    'a is the minimum value of x
    'b is the maximum value of x
    'U is the the random number
    Application.Volatile (True)
    U = Rnd()
    x_uniform = a + (b - a) * U
End Function
```

equivalent to

```vb
Function x_Triangular(a, b, c)
    'value of the variable x for a Triangular distribution
    'a is the minimum value of x
    'b is the maximum value of x
    'c is the mode value of x
    'U is the the random number
    Application.Volatile (True)
    U = Rnd()
    F_c = (c - a) / (b - a)
      If F_c > U Then
        x_Triangular = a + Sqr((b - a) * (c - a) * U)
      Else
        x_Triangular = b - Sqr((b - a) * (b - c) * (1 - U))
      End If
End Function
```

```python
[13] #MC simulation
TRR=Npu(por,RV,NTG,So,Bo,Fr)
```

	Rock volume	Porosity	Net to Gros N/G	Oil Saturation So=(1-Sw)	Formation Volume Bo	Ultimate Recovery Factor Fr	
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	
Min	2000000000	0.18	0.3	0.8	1.35	0.42	
Max	2500000000	0.3	0.5	0.9	1.6	0.65	
MC it	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	Npu
[-]	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	[stb]
1	2012066161	0.18926	0.4099759	0.88329645	1.42513865	0.425175962	4.11E+07
2	2102438113	0.26087	0.4857407	0.807186328	1.354060909	0.611151706	9.71E+07
3	2227585607	0.23525	0.4005316	0.850604772	1.580405627	0.527296311	5.96E+07
4	2141227076	0.28532	0.3038112	0.877732837	1.477701936	0.514140587	5.67E+07
5	2200610567	0.29046	0.3220469	0.829377484	1.365998187	0.584485561	7.31E+07

```
[18] #frequency analysis on the results
     nr_bins=15
     bins=np.linspace(TRR.min(),TRR.max(),nr_bins)
     counts,bins=np.histogram(TRR,bins=bins)
     pdf=counts/n
     cdf=np.cumsum(pdf)
```

the function np.histogram works in the following way

– min 0

Counted as part of the 2nd bin (including min, excluding 1) 0<=X<1

– 1

Counted as part of the 3rd bin (including 1, excluding 2) 1<=X<2

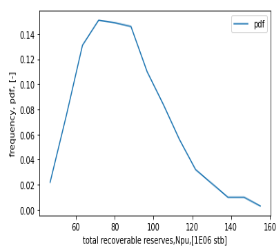
– 2

– 3

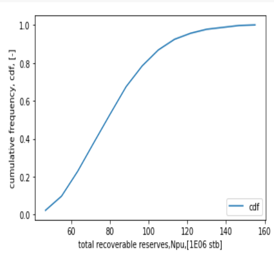
This is why

Number of elements in pdf vector = Number of elements in the bin vector - 1

```
[21] #plot pdf
     plt.xlabel("total recoverable reserves,Npu,[1E06 stb]")
     plt.ylabel('frequency, pdf, [-]')
     plt.plot(bins[1:],pdf,label='pdf')
     plt.legend(loc="upper right")
     plt.show()
```




```
[22] #plot cdf
     plt.xlabel("total recoverable reserves,Npu,[1E06 stb]")
     plt.ylabel('cumulative frequency, cdf, [-]')
     plt.plot(bins[1:],cdf,label='cdf')
     plt.legend(loc="lower right")
     plt.show()
```




```
[25] #create a summary table
     summary_table=pd.DataFrame({
         "Variable":['Mean [1E06 stb]','Mode [1E06 stb]','Minimum [1E06 stb]','Maximum [1E06 stb]','P90 [1E06 stb]','P50 [1E06 stb','P10 [1E06 stb]'],
         "Value":[TRR.mean(),83,TRR.min(),TRR.max(),np.percentile(TRR,10),np.percentile(TRR,50),np.percentile(TRR,90)]
     })
     summary_table
```

	Variable	Value
0	Mean [1E06 stb]	80.808664
1	Mode [1E06 stb]	83.000000
2	Minimum [1E06 stb]	38.385094
3	Maximum [1E06 stb]	155.068618
4	P90 [1E06 stb]	55.492273

BE CAREFUL
In petroleum engineering, P90 often refers to the the 90th percentile of the inverse cdf. Therefore, to calculate P90 from the regular cdf, you have to use the 10th percentile.

Continuation of class exercise: probabilistic reserve estimation using MC and Jupyter

pdf bins

		index
N_1	— min	0
N_2	—	1
N_3	—	2
		⋮
	—	i
	— max	n-1

$\{N_1, N_2, N_3, \dots, N_n\}$

bins[1:] = a

bins[:-1] = b

$$pdf\_bins = \frac{a+b}{2}$$

$\{(N_1 + N_2)/2, (N_2 + N_3)/2, \dots\}$

cdf_bins = bins[1:]

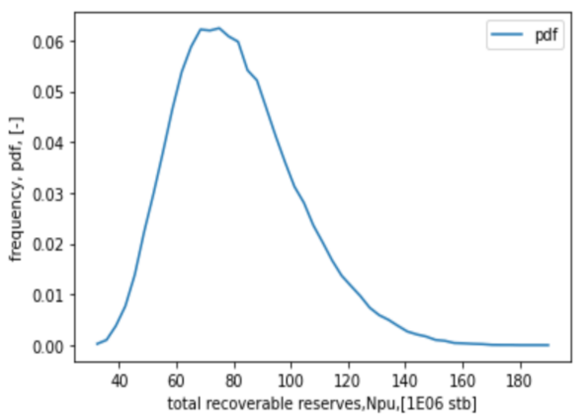
How to find the mode?

pdf_bins $\{N_0, N_1, N_2, \dots, N_{n-1}\}$

pdf $\{P_0, P_1, P_2, P_3, \dots, P_{n-1}\}$

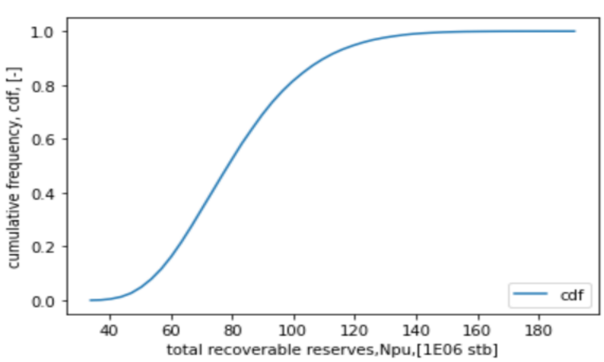
P_3 — max i=3 mode ~> pdf_bins[i]

```
pdf_bins[np.argmax(pdf)],
```



This looks very much like a log normal distribution (needs only mean and sigma)

https://en.wikipedia.org/wiki/Log-normal_distribution



The nr. of bins should be adjusted slightly with the number of samples, e.g. more samples ---> more bins. The pdf will look smoother.

Convergence study on the number of interations required for results not to vary significantly:

Nr iterations	1000	Change % wrt max iter	10000	Change % wrt max iter	100000	Change % wrt max iter	1000000
Mean [1E06 stb]	82.0	1.14	81.0	0.16	81.1	0.01	81.1
Mode [1E06 stb]	75.0	4.36	76.3	6.22	71.0	1.12	71.8
Minimum [1E06 stb]	33.7	21.22	30.7	10.45	31.3	12.51	27.8
Maximum [1E06 stb]	162.1	20.53	172.6	15.38	190.3	6.70	203.9
P90 [1E06 stb]	55.2	0.53	55.0	0.96	55.5	0.13	55.5
P50 [1E06 stb	79.4	0.86	78.7	0.06	78.6	0.07	78.7
P10 [1E06 stb]	111.7	1.46	109.9	0.12	110.1	0.08	110.1

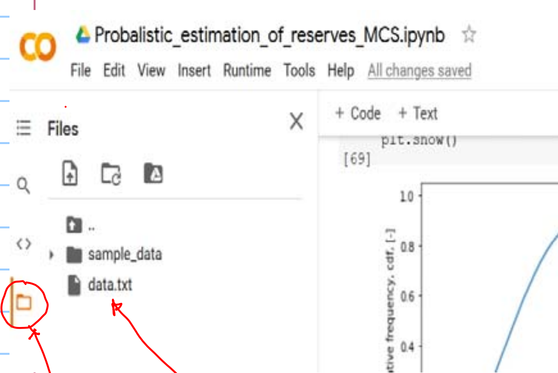
this variable depends on nr. bins and samples!

To output results to a text file:

```
output=np.vstack((pdf_bins,pdf))
np.savetxt('data.txt',output.T)
```

putting arrays together

printing to text file



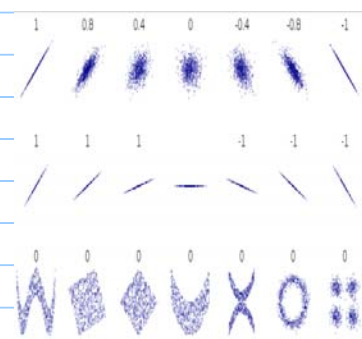
available here (1)

(1)

To find correlation between the variables and results and calculate sort of an "importance" for each parameter, the Pearson Correlation coefficient can be used.

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

$$\rho_{X,Y} = \frac{\mathrm{cov}(X,Y)}{\sigma_X \sigma_Y} \quad \text{(Eq.1)}$$



for our case:

```
PCC_por=np.corrcoef(por,TRR)[0,1]
print("PCC for Porosity is: ",PCC_por )
PCC_RV=np.corrcoef(RV,TRR)[0,1]
print("PCC for rock volume is: ",PCC_RV )
PCC_NTG=np.corrcoef(NTG,TRR)[0,1]
print("PCC for Net to gross is: ",PCC_NTG )
PCC_So=np.corrcoef(So,TRR)[0,1]
print("PCC for oil saturation is: ",PCC_So )
PCC_Bo=np.corrcoef(Bo,TRR)[0,1]
print("PCC for oil formation volume factor is: ",PCC_Bo )
PCC_Fr=np.corrcoef(Fr,TRR)[0,1]
print("PCC for ultimate recovery factor is: ",PCC_Fr )
```

```
PCC for Porosity is:  0.5450822680244062
PCC for rock volume is:  0.2429501735721322
PCC for Net to gross is:  0.547369047073988
PCC for oil saturation is:  0.13319591901184374
PCC for oil formation volume factor is:  -0.18644951517089872
PCC for ultimate recovery factor is:  0.5122102672675487
```

most important: ϕ, NTG, F_r

"intuition" because they are fractions and their range is relatively broad

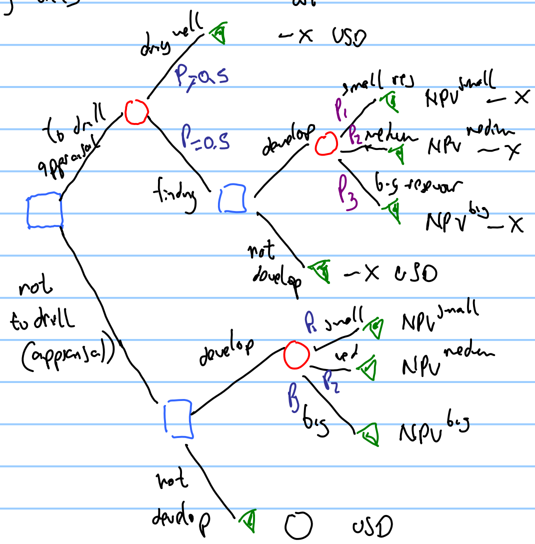
Clarifications about Python

```python
#How do we modify an existing array
#appending an array (adding values at the end)
a=np.linspace(1,6,10)
b=np.linspace(1,2,2)
c=np.append(a,b)
#concatenating arrays (order matters!!)
d=np.concatenate((a,b))
```

```python
#how to make a function run element-wise for all members of an array
def test_function(a):
  if a>0:
    result=0
  else:
    result=1
  return result
a=np.linspace(-6,6,10)
V_test_function=np.vectorize(test_function)
V_test_function(a)
```

∘ Probability trees

Probability trees are similar to sampling, but they allow us to include decision and integer variables



□ decision node

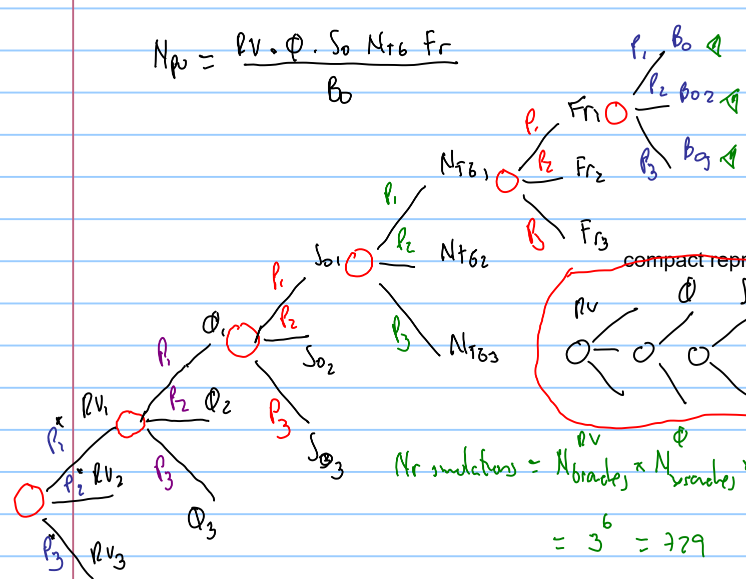
○ chance node ← this can be evaluated with Monte Carlo

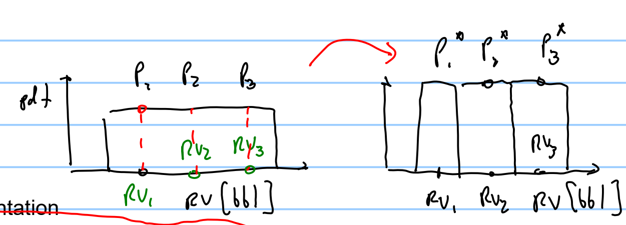
◁ end node

–x USD value of appraisal well

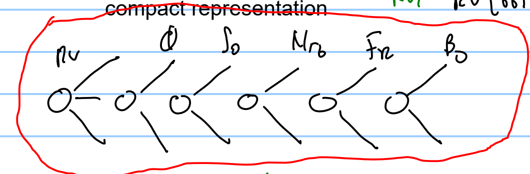
How to solve the previous example solved with Python with probability trees?

$$N_p = \frac{RV \cdot \Phi \cdot S_o \, N_{TG} \, F_R}{B_o}$$





compact representation



$$P_1^* = \frac{P_1}{(P_1+P_2+P_3)}$$

$$\text{Nr simulations} = N_{branches}^{RV} \times N_{branches}^{\Phi} \times N_{branches}^{S_o} \times N_{branches}^{NTG} \times N_{branches}^{F_R} \times N_{branches}^{B_o} = n$$

$$= 3^6 = 729$$

729 end nodes

each case (end node) will have an associated probability

Case RV_1, Φ_1, So_1, N_{TG_1}, Fr_1, Bo_1 $\longrightarrow$ TRR_1

$P_{RV_1} \cdot P_{\Phi_1} \cdot P_{So_1} \times P_{NG_1} \times P_{FR_1} \times P_{Bo_1} = P_{case_1}$

Case RV_1, Φ_1, So_1, N_{TG_1}, Fr_1, Bo_2 $\longrightarrow$ TRR_2

$P_{RV_1} \cdot P_{\Phi_1} \cdot P_{So_1} \times P_{NG_1} \times P_{FR_1} \times P_{Bo_2} = P_{cas_2}$

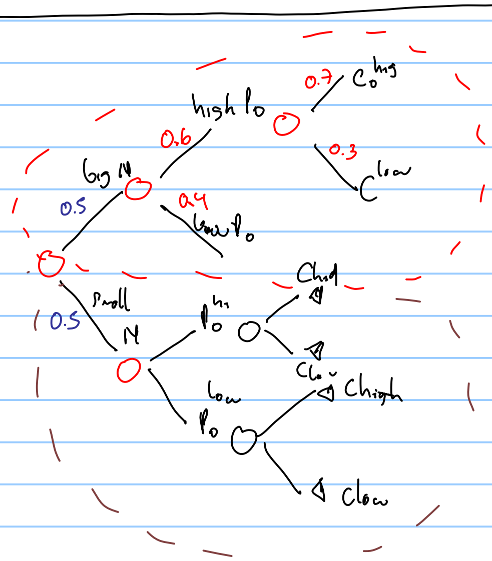
$$\left\{\begin{array}{ll} TRR_1 & P_{case\,1} \\ TRR_2 & P_{case\,2} \\ \vdots & \vdots \\ TRR_n & P_n \end{array}\right\}$$

a cdf can be calculated with these results
- sort TRR column
- calculate cum probabilities

"expected" value of the tree

$$\sum_{i=1}^{N} \left(TRR_i \, P_{cas_i} \right) = \text{expected TRR}$$

Spontaneous
Class example

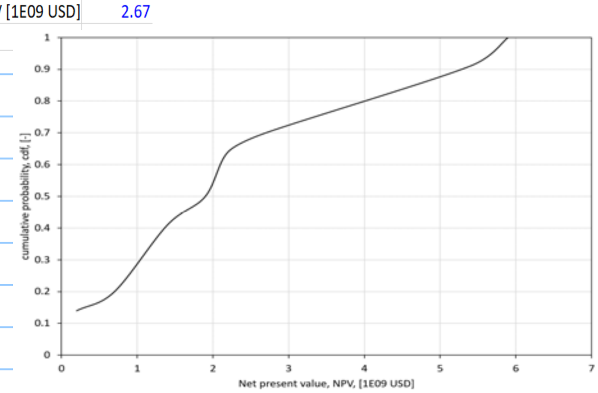


$2 \times 2 \times 2 = 8$

$NPV = N \cdot P_o - Cost$

CASE	N [1e06 stb]	Po [usd]	Cost [1e09 usd]	P _N	P _Po	P_ Cost	Pcase	NPV [1E09 USD]	Pcase*NPV		
1	30	80	1.00E+00	0.5	0.6	0.7	0.21	1.4	0.294		
2	30	80	5.00E-01	0.5	0.6	0.3	0.09	1.9	0.171		
3	30	40	1.00E+00	0.5	0.4	0.7	0.14	0.2	0.028		
4	30	40	5.00E-01	0.5	0.4	0.3	0.06	0.7	0.042		
5	80	80	1.00E+00	0.5	0.6	0.7	0.21	5.4	1.134		
6	80	80	5.00E-01	0.5	0.6	0.3	0.09	5.9	0.531		
7	80	40	1.00E+00	0.5	0.4	0.7	0.14	2.2	0.308		
8	80	40	5.00E-01	0.5	0.4	0.3	0.06	2.7	0.162	EV [1E09 USD]	2.67
							1				

NPV [1E09 USD]	P	cdf
0.2	0.14	0.14
0.7	0.06	0.2
1.4	0.21	0.41
1.9	0.09	0.5
2.2	0.14	0.64
2.7	0.06	0.7
5.4	0.21	0.91
5.9	0.09	1



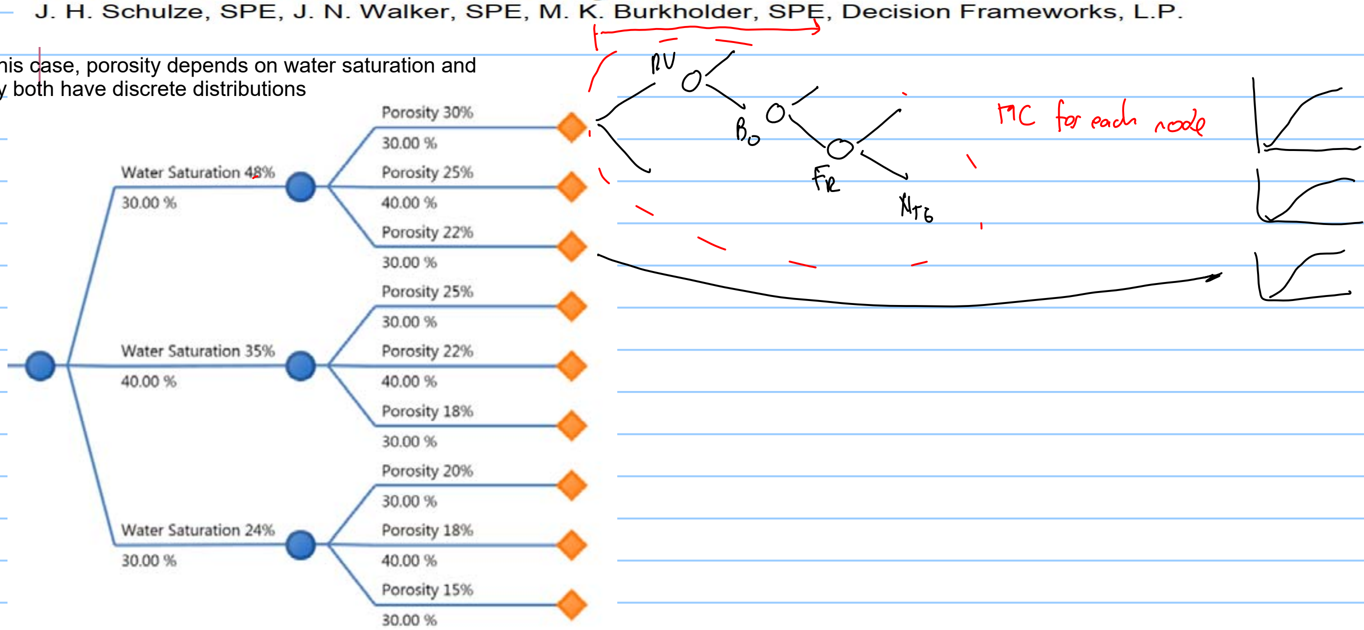
An example combining probability trees and monte carlo

SPE 162883

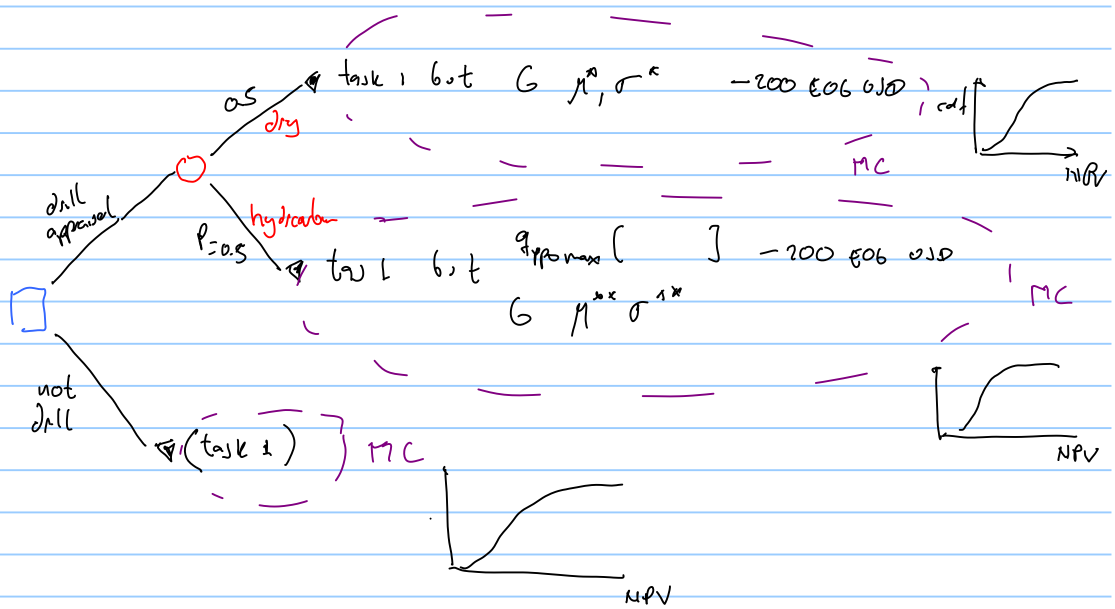
Integrating the Subsurface and the Commercial: A New Look at Monte Carlo and Decision Tree Analysis

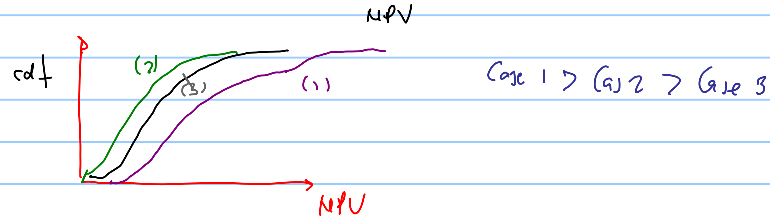
J. H. Schulze, SPE, J. N. Walker, SPE, M. K. Burkholder, SPE, Decision Frameworks, L.P.

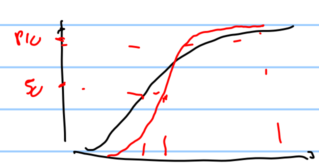
In this case, porosity depends on water saturation and they both have discrete distributions



Comments about problem 3







Notes for Youtube video nr. 15

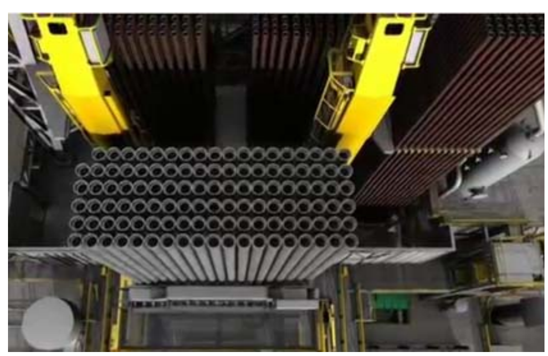
Offshore structures for oil and gas production

Prof. Milan Stanko (NTNU)

1

Components

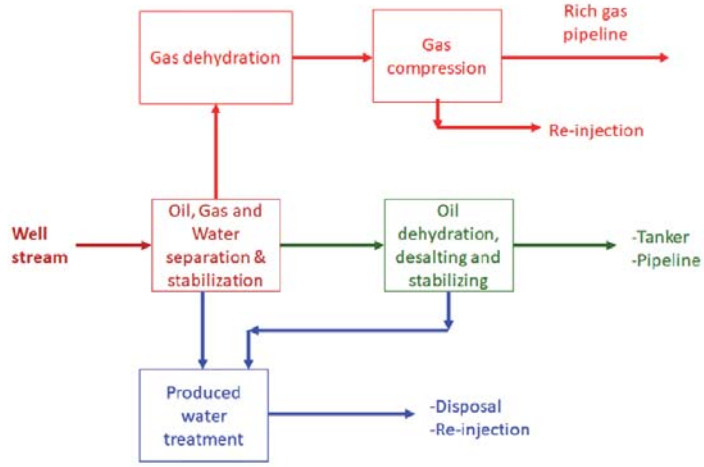
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers.



2

Components

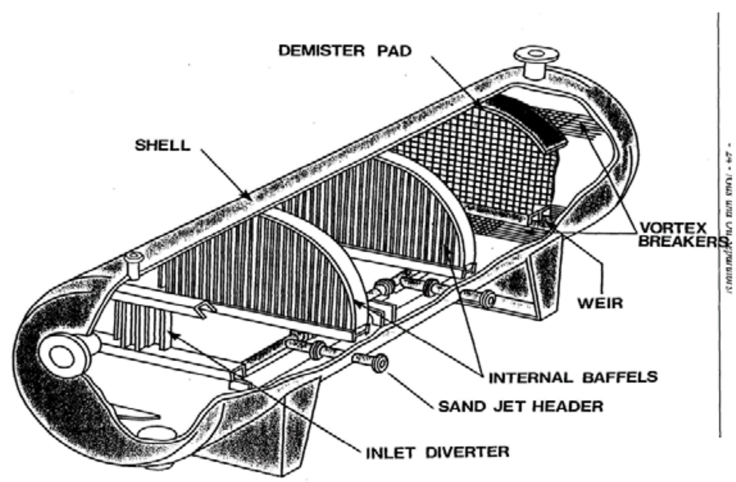
- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



3

Components

- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



4

Components

- Living quarters
- Helideck.
- Power generation.
- Flare system.
- Utilities (hydraulic power fluid, compressed air, drinking water unit, air condition system, ventilation and heating system)

5

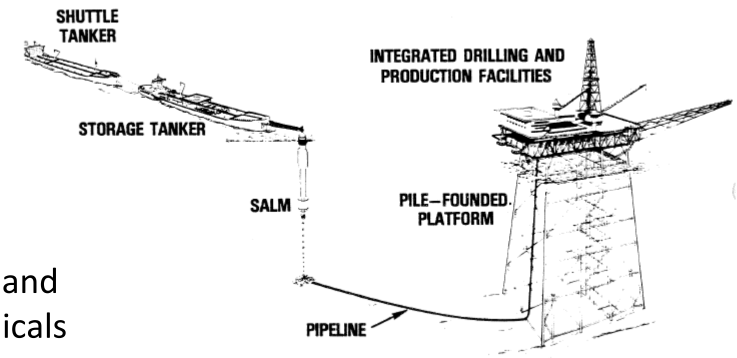
Components

- Bay for wellheads and X-mas trees
- Production manifolds
- Oil storage
- Facilities for oil offloading
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale, hydrate or corrosion inhibitors)
- Repair workshop

6

Components

- Bay for wellheads and X-mas trees
- Production manifolds
- Oil storage
- Facilities for oil offloading
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale, hydrate or corrosion inhibitors)
- Repair workshop



7

Components

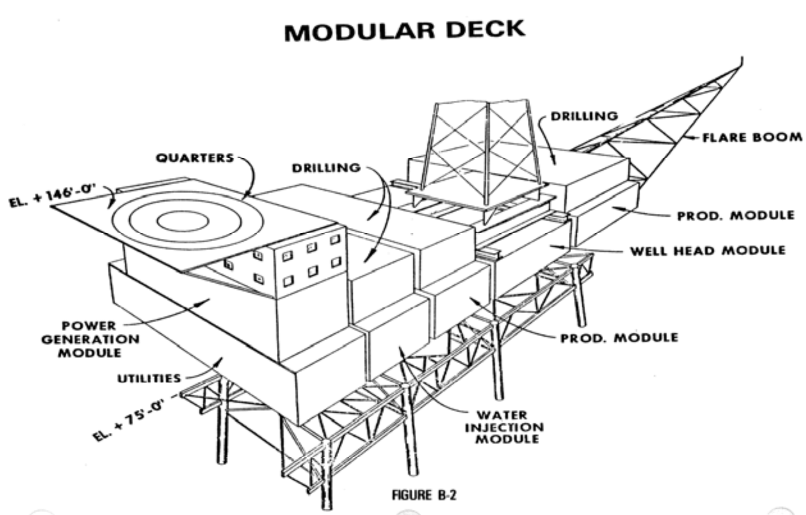


FIGURE B-2

8

Components – can be spread

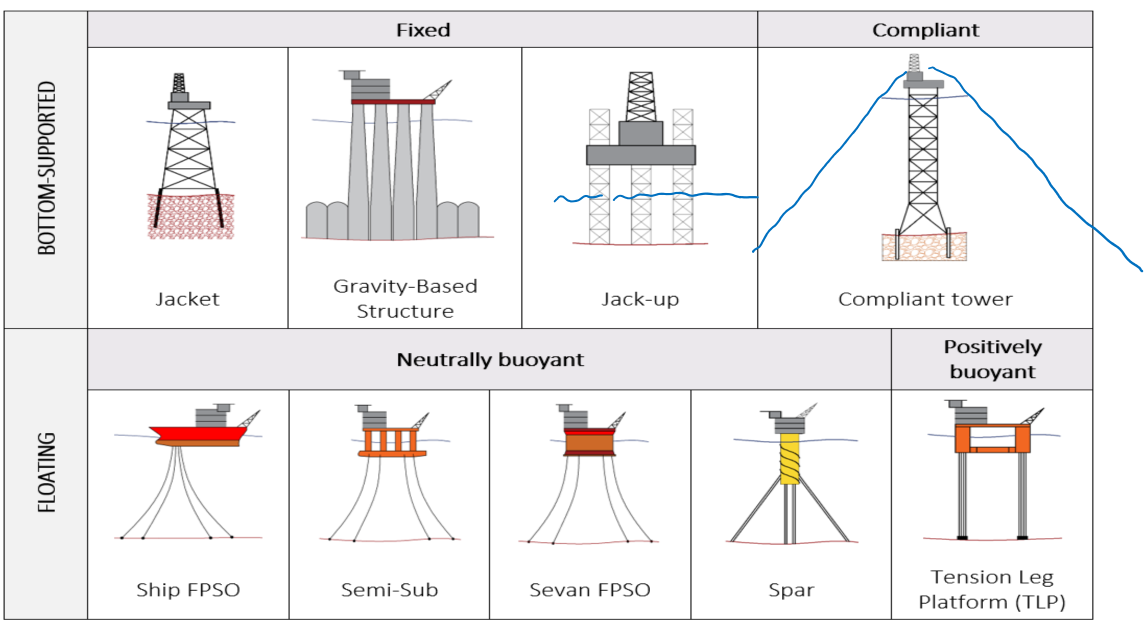
https://www.akerbp.com/produksjon/valhall/

9

Types

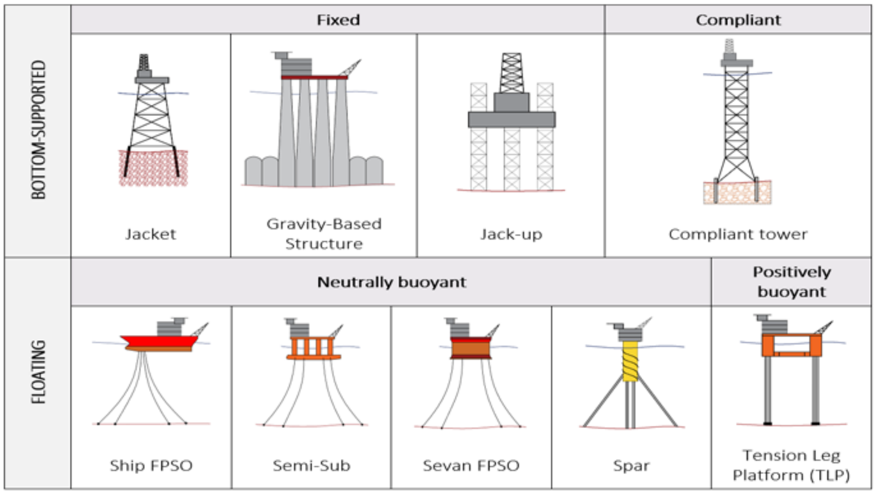
suction anchor

soil



10

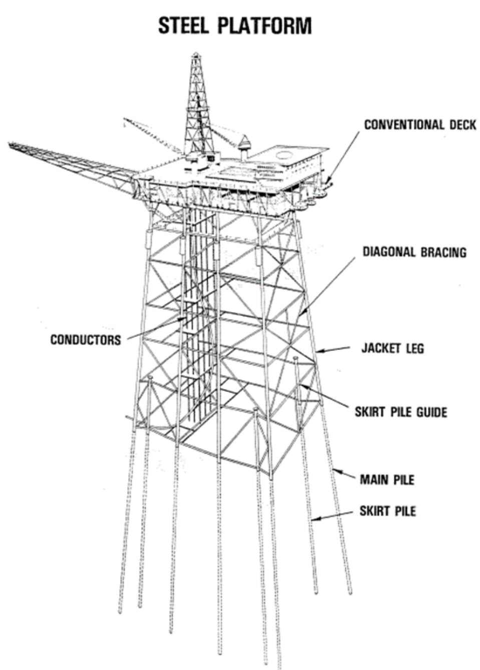
Types



- Have significant movement
- Are usually moored
- Buoyancy is controlled actively with ballast

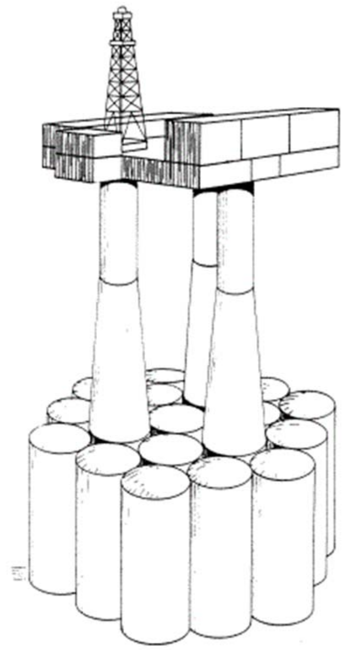
11

Jacket



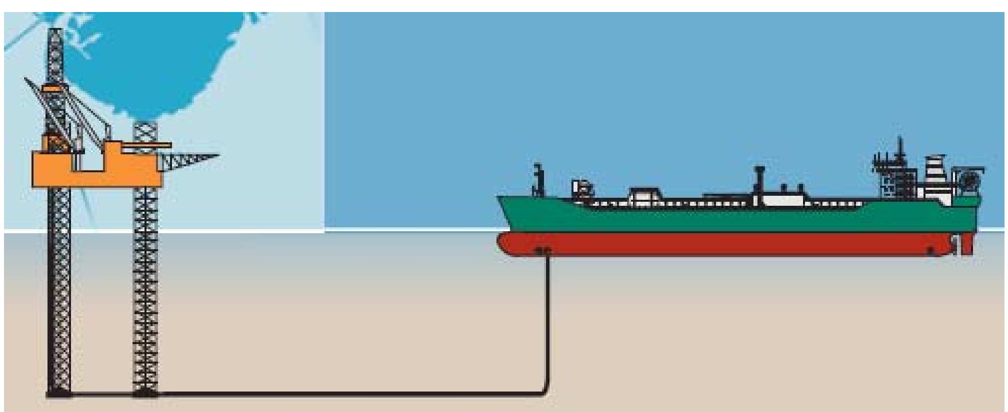
12

GBS



13

JACKUP



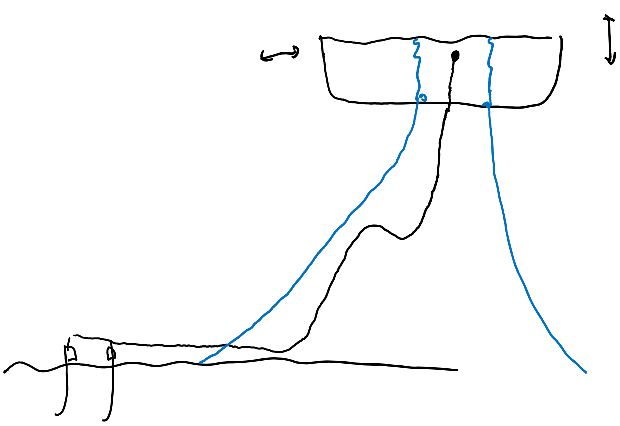
Taken from Volve PDO

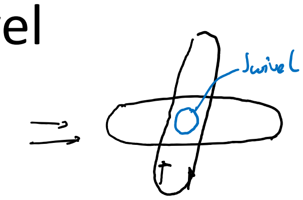
14

FPSO

15

FPSO - Comment about swivel





the swivel allows to adjust the orientation of the FPSO to wind, waves and current

16

FPSO - Swivel

https://www.youtube.com/watch?v=70XwYmmZFWs

17

FPSO - Swivel

https://www.youtube.com/watch?v=cCiUggjUhY0

https://www.youtube.com/watch?v=Sfjay0Rt3hU

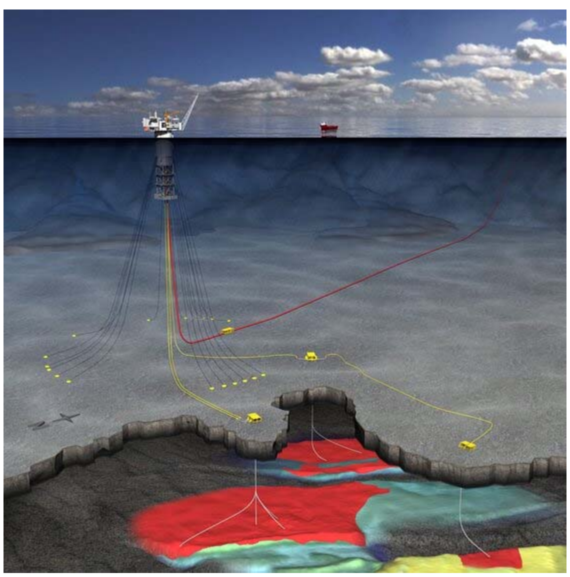
18

FPSO - Swivel

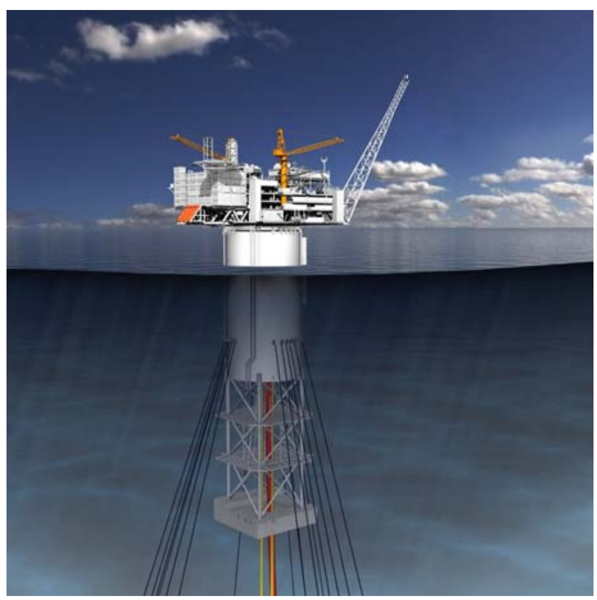
https://www.youtube.com/watch?v=HbJh1ar0u1s

19

SPAR



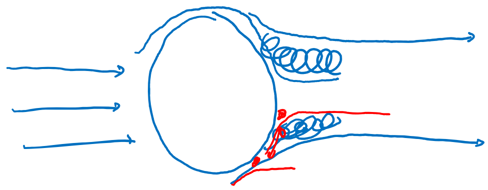
https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940



https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940

20

Vortex shedding



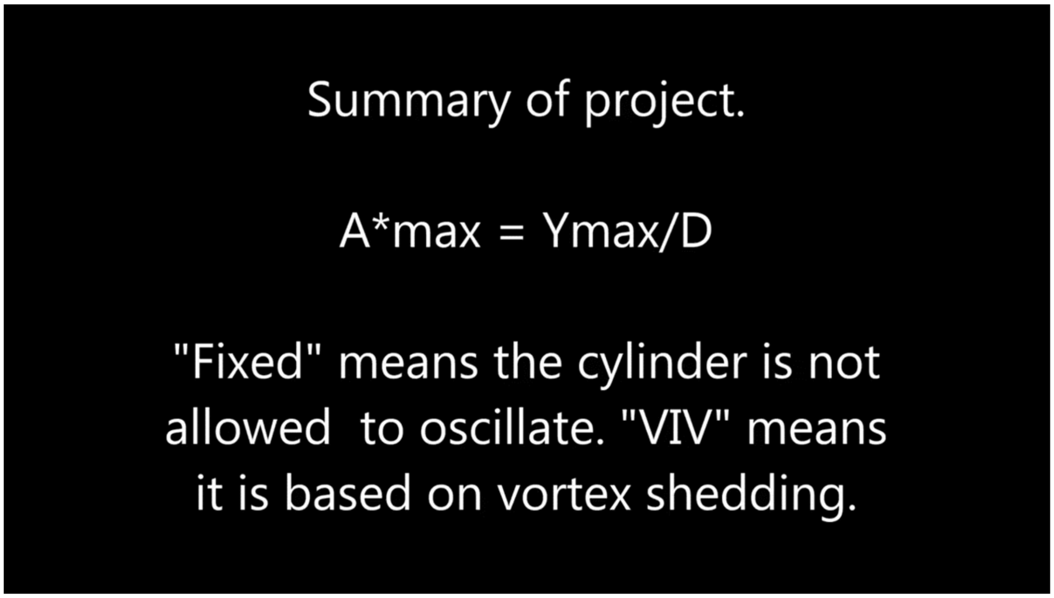
21

SPAR – Vortex induced vibrations

https://www.youtube.com/watch?v=_Hbbkd2d3H8&feature=youtu.be

22

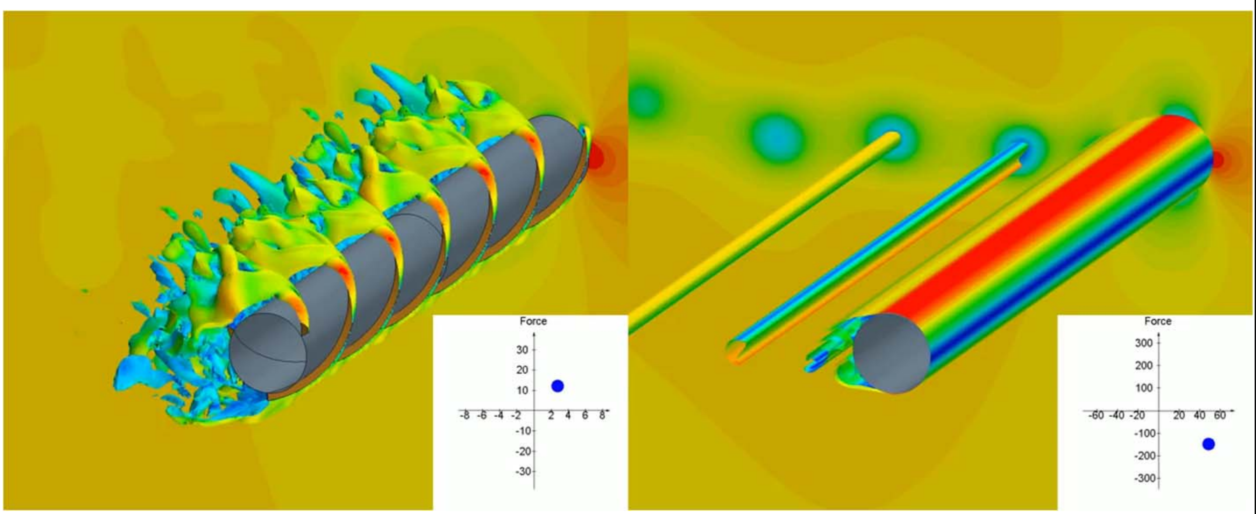
SPAR – Vortex induced vibrations



https://www.youtube.com/watch?v=24tBX_UD3fM

23

SPAR – Effect of helical strakes



https://www.youtube.com/watch?v=W-zXwPT2r14

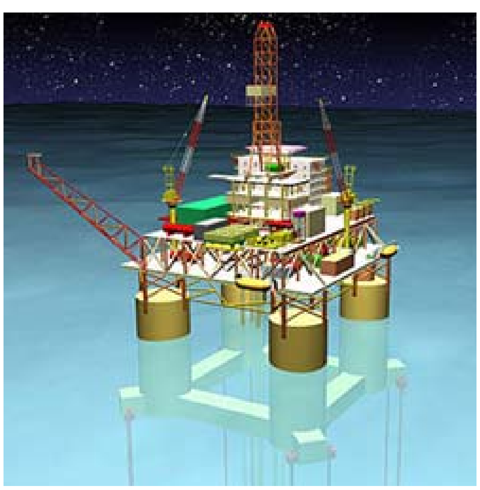
24

SEVAN FPSO

https://www.upstreamonline.com/epaper/sevan-fpso-selected-for-bream/1-1-1160389

25

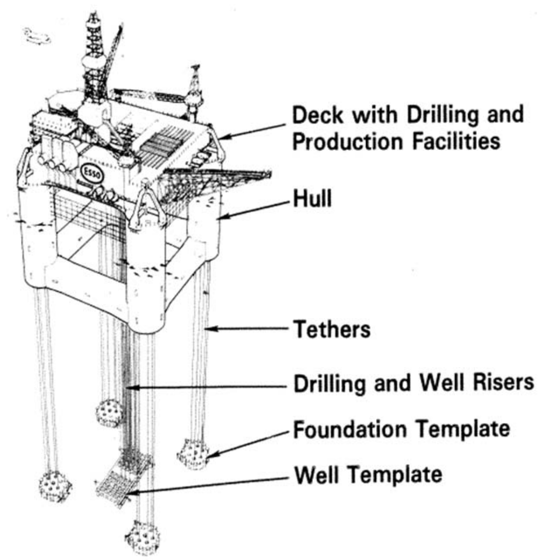
Tension leg platform



https://www.rigzone.com/training/insight.asp?insight_id=305&c_id=

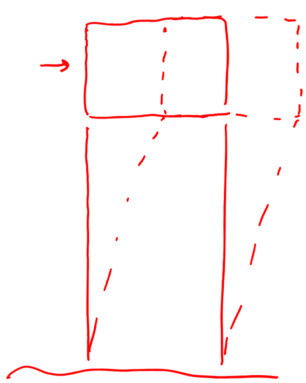
26

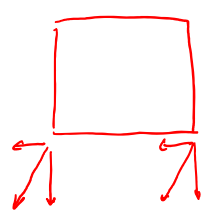
Tension leg platform



27

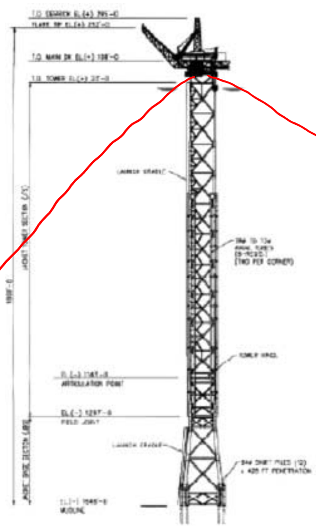
Comment about Tension leg platform





28

Compliant tower



https://www.sciencedirect.com/science/article/pii/S0951833914000148

29

Semi-Sub

https://www.oedigital.com/news/453987-jack-st-malo-flows-for-chevron

https://www.bairdmaritime.com/work-boat-world/offshore-world/offshore-extraction-and-processing/offshore-drilling/awilco-orders-second-semi-submersible-drilling-rig-from-keppel-fels/

30

Some selection criteria for offshore structures

- Water depth
- Type of X-mas tree
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads Oceanographic environment
  - Wind, waves, current

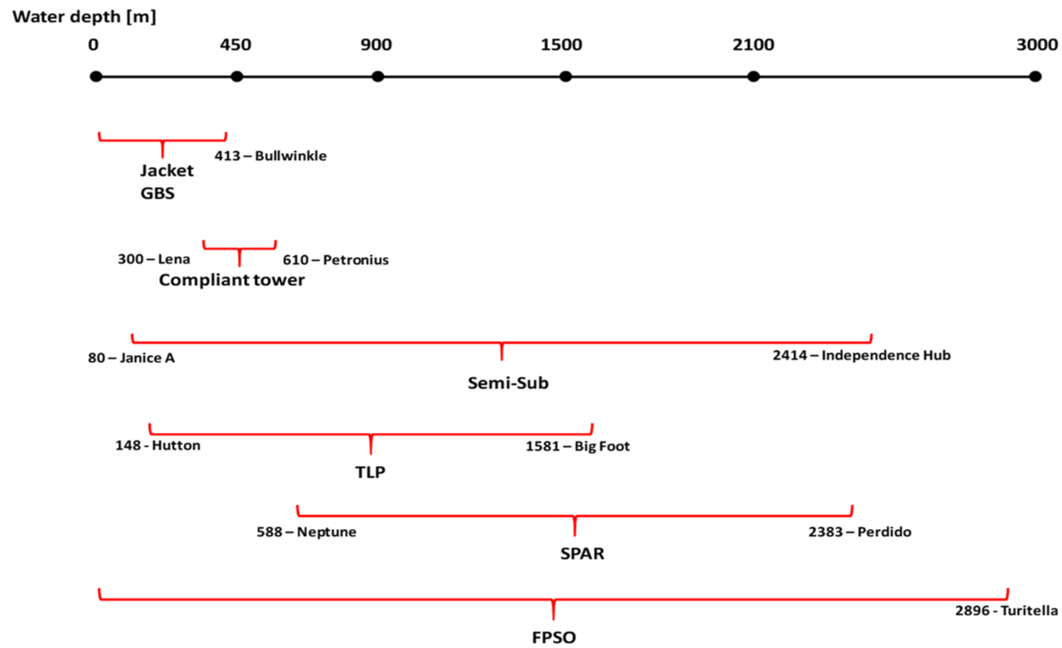
31

Some selection criteria for offshore structures

- **Water depth**
- Type of X-mas tree
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads Oceanographic environment
  - Wind, waves, current

32

Water depth



Some selection criteria for offshore structures

- Water depth
- **Type of X-mas tree**
  - Well intervention needs
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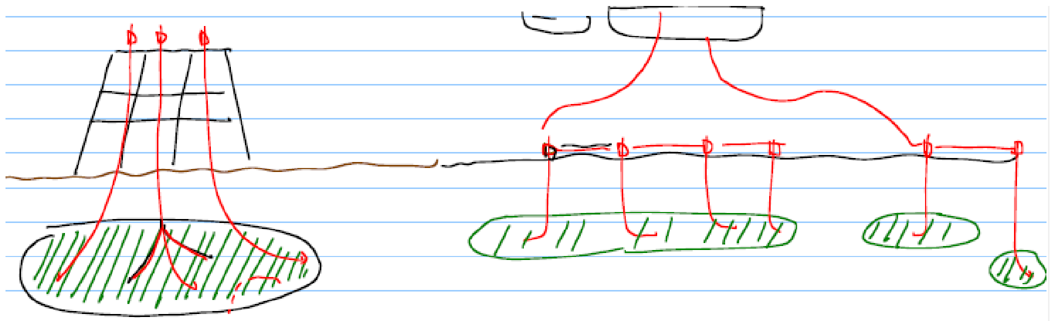
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads – Oceanographic environment
  - Wind, waves, current

Reservoir spread and structure

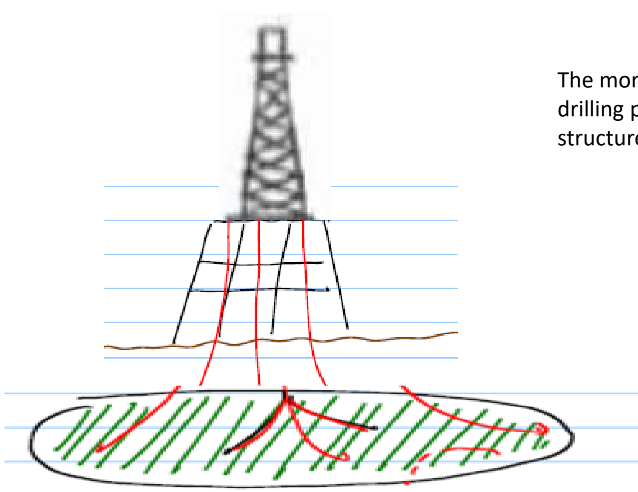


- Long deviated wells ($$$)
- Wells are drilled from one location, no need to spend mobilization time ($$)
- Production startup must be delayed until all wells are drilled

- Shorter, vertical wells ($)
- The drilling rig must be mobilized often which costs money ($$$)
- Production can start in ramp up mode (if topside is in place)

35

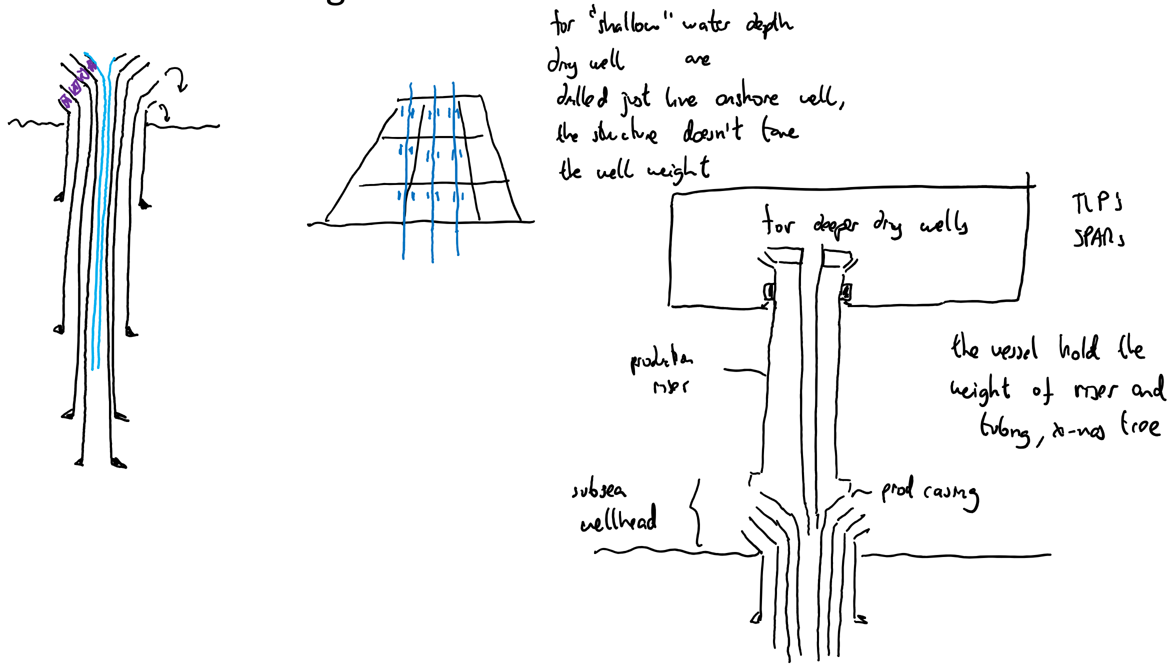
Reservoir spread and structure



The more spread - requires a bigger and more costly drilling package – more weight on the structure, bigger structure ($$$)

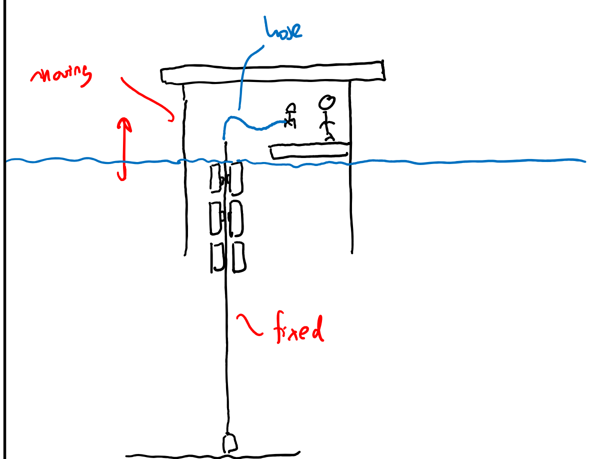
36

Transfer of well weight to soil and to offshore structure



37

Transfer of well weight to soil and to offshore structure



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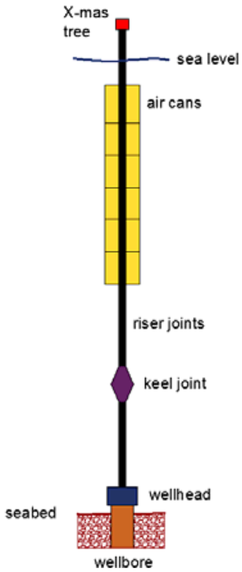
Support system for dry X-mas trees – deep water



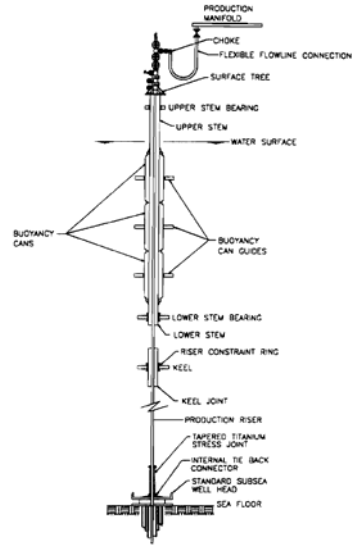


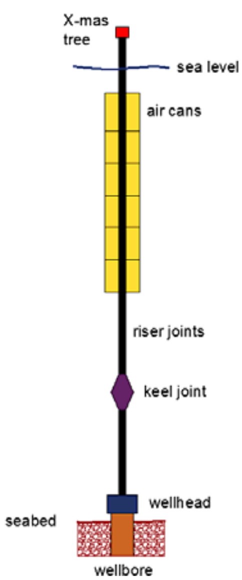
Figure 6 - Well System

OTC 8382

Neptune Project: Spar History and Design Considerations
R.S. Glanville, J.E. Halkyard, R.L. Davies, A. Steen, F. Frimm, Deep Oil Technology, Inc.

39

Support system for dry X-mas trees – deep water



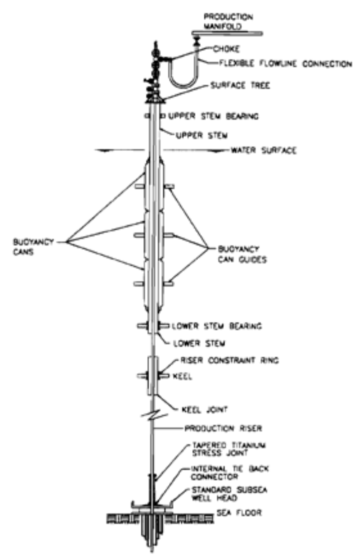


Figure 6 - Well System

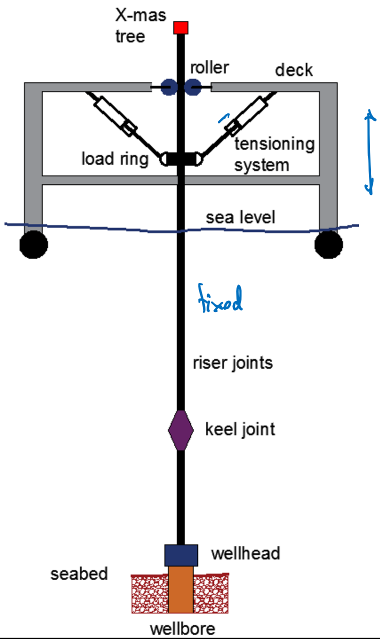
OTC 8382

Real State on offshore structure is critical, not more slots than what is needed!

Neptune Project: Spar History and Design Considerations
R.S. Glanville, J.E. Halkyard, R.L. Davies, A. Steen, F. Frimm, Deep Oil Technology, Inc.

40

Support system for dry X-mas trees – deep water



41

Some selection criteria for offshore structures

- Water depth
- **Type of X-mas tree**
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads – Oceanographic environment
  - Wind, waves, current

Only floating structures SPAR, TLPs and Semi-subs have "small" movement ranges suitable for dry X-mas trees

42

Possibility for jackets without drilling package

https://www.youtube.com/watch?v=-vJmAvqn6dU

43

Possibility for jackets without drilling package

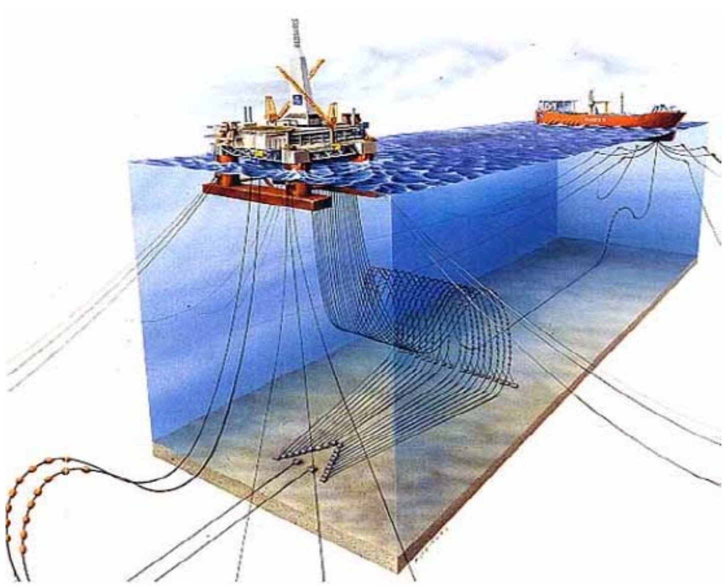
44

Possibility for jackets without drilling package

https://www.offshoreenergytoday.com/offshore-safety-watchdog-to-investigate-maersk-invincible-incident/

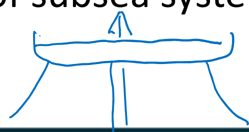
45

Njord: subsea wells with well intervention possibility



46

Layout of subsea systems – template wells



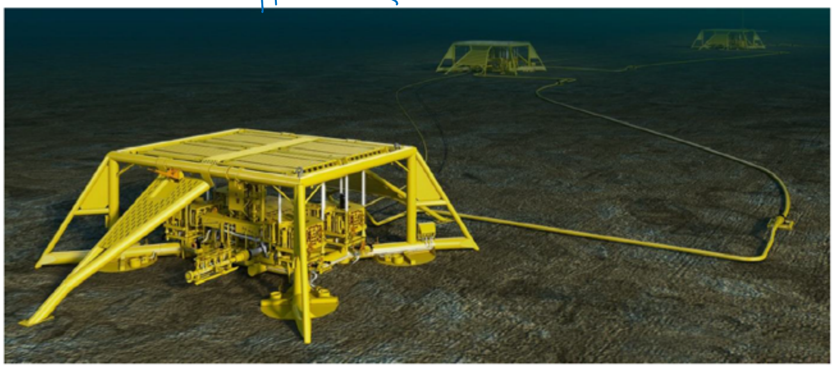
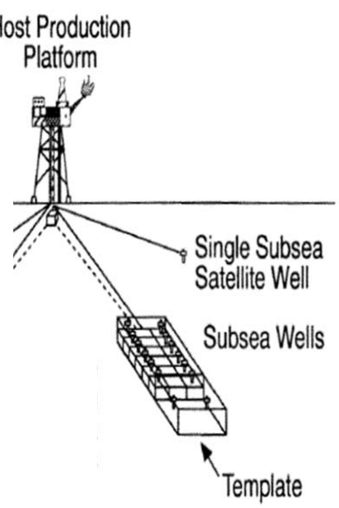


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

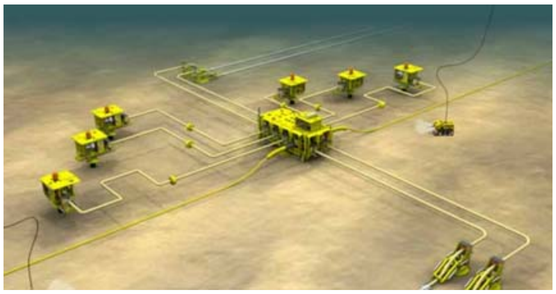
47

Layout of subsea systems – template wells



48

Satellite wells



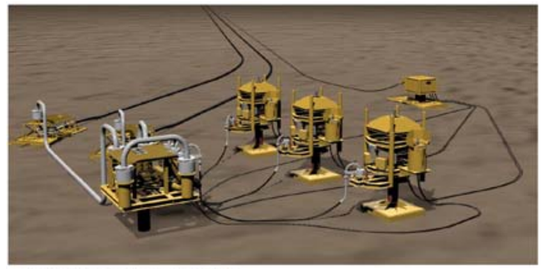


Figure 3.4 Typical GOM subsea tie-back

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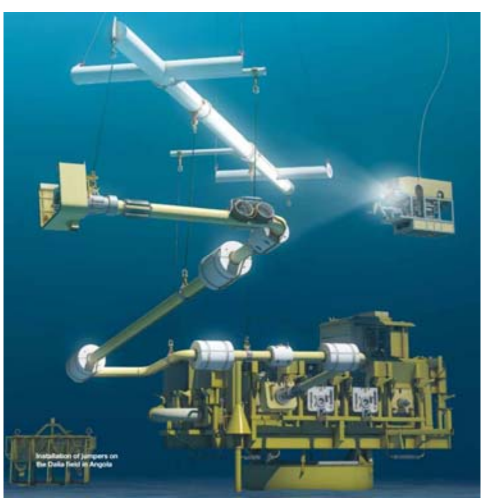
Jumpers for satellite wells (if close)



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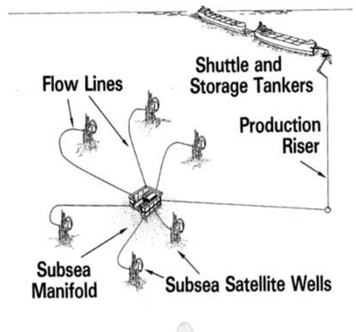
Template wells vs satellite wells – similar dilemma to dry versus wet X-mas tree


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

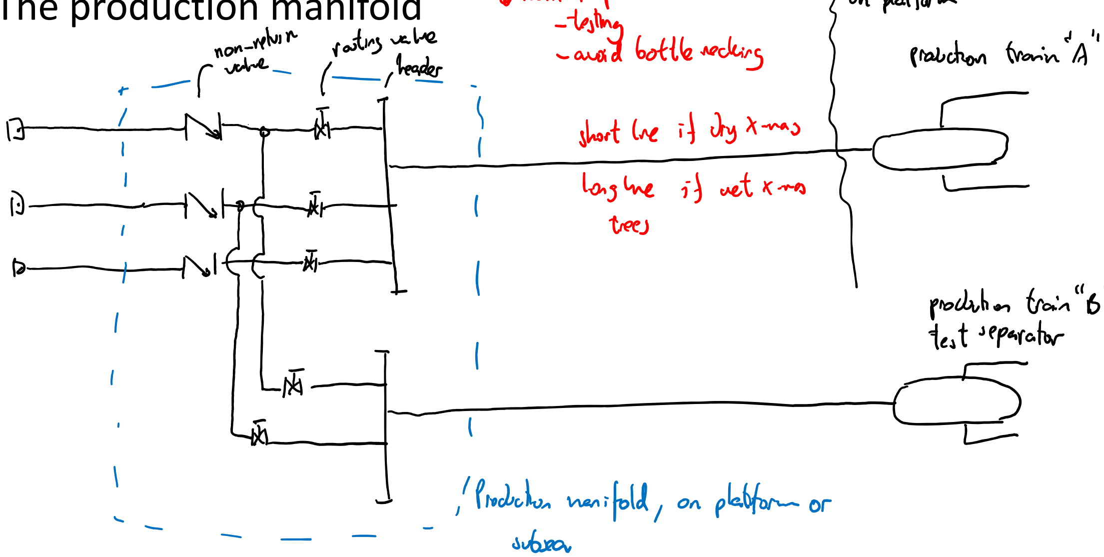
- Long deviated wells
- Wells are drilled from one location, no need to spend rig mobilization time
- Less subsea equipment



- Shorter, vertical wells
- The drilling rig must be mobilized often which costs money
- More flowlines, pipelines. Manifolds are required

The production manifold

- Commingle production
- redirect production
  - testing
  - avoid bottlenecking



The production manifold

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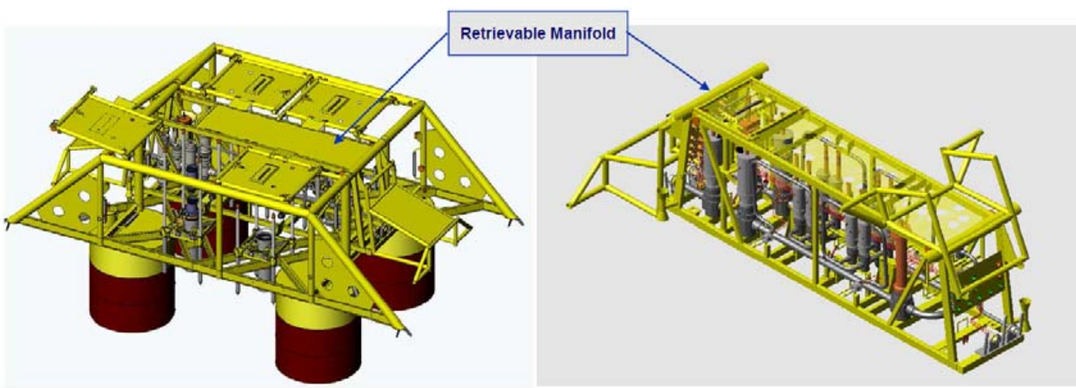
4 well template – the production manifold



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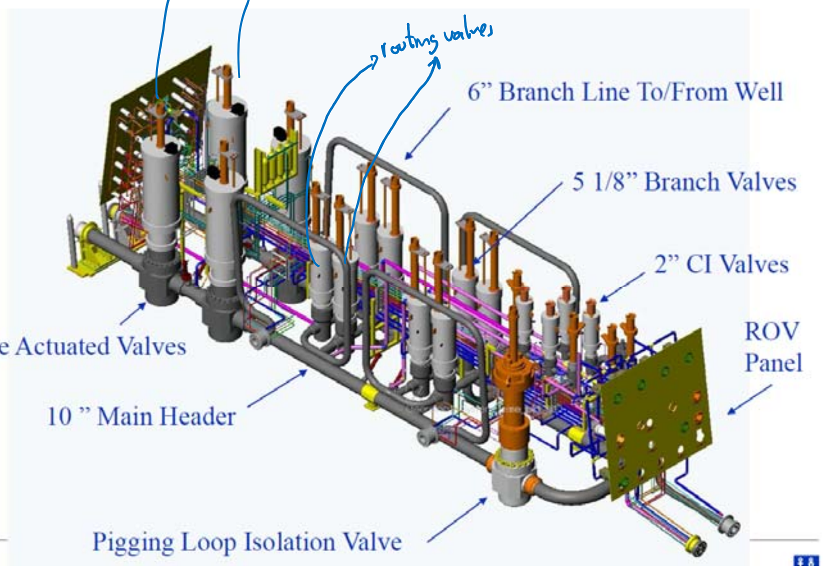
The manifold

integrity

HIPPS (high pressure protection system)

routing valves



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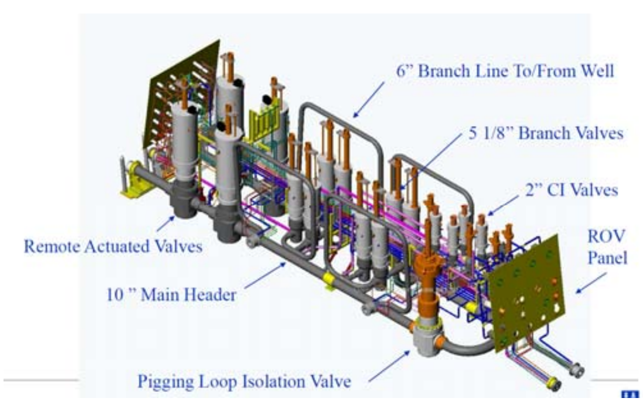
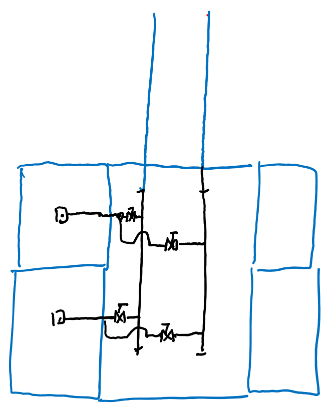
The manifold – reality vs sketch





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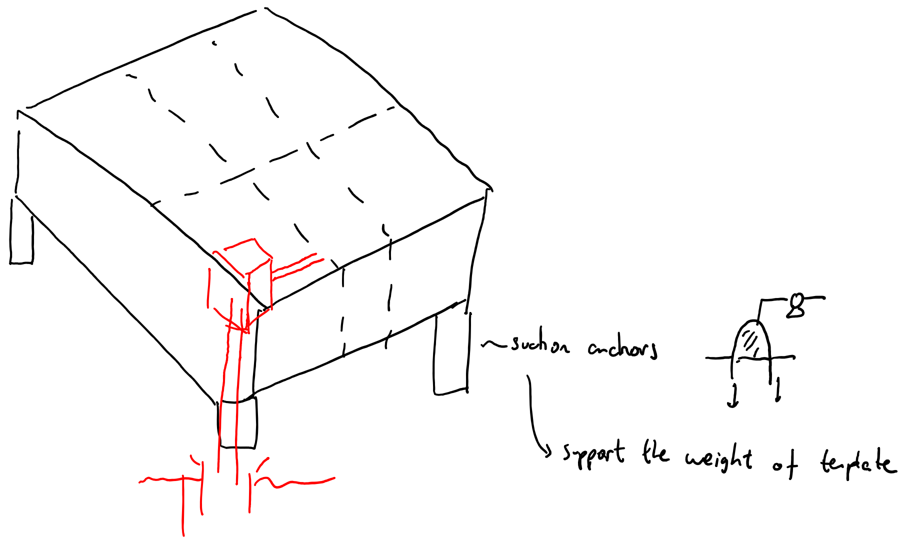
4 well template – weight transfer



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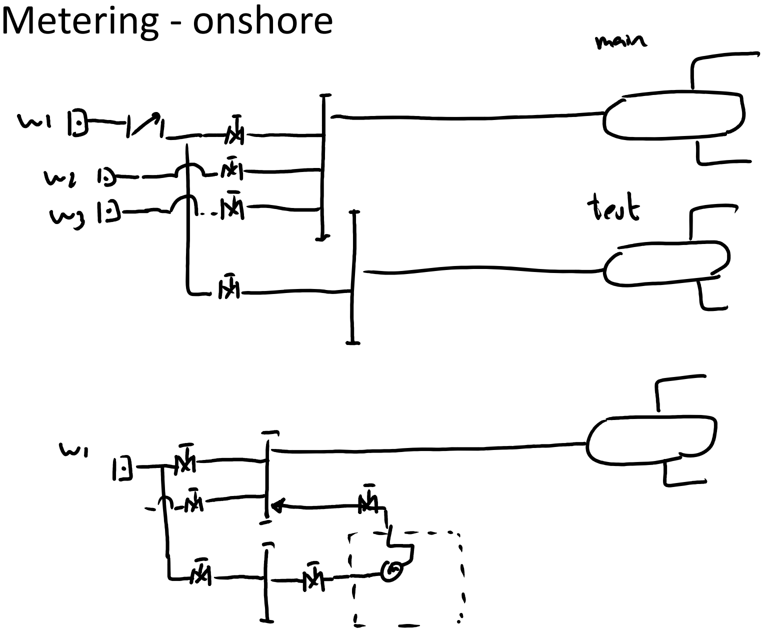
notes for Youtube video 16

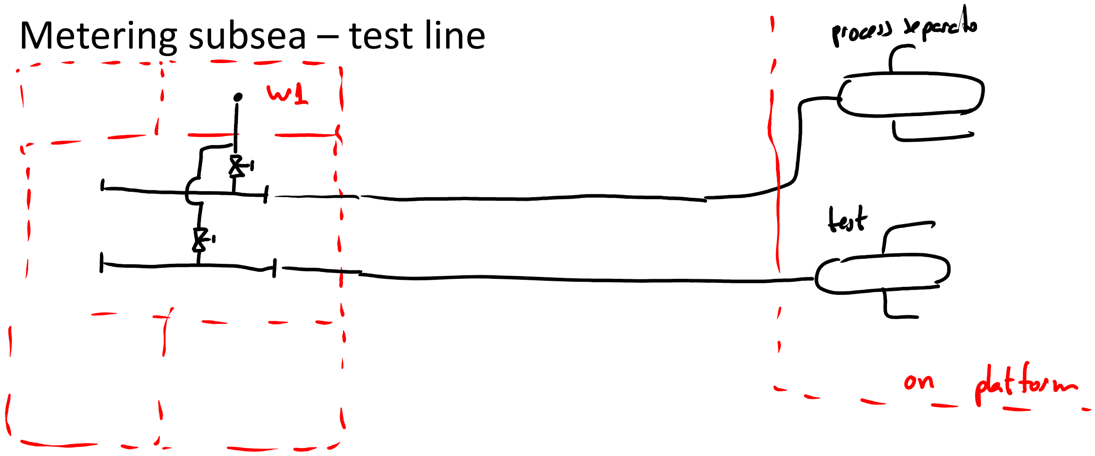
Metering - onshore



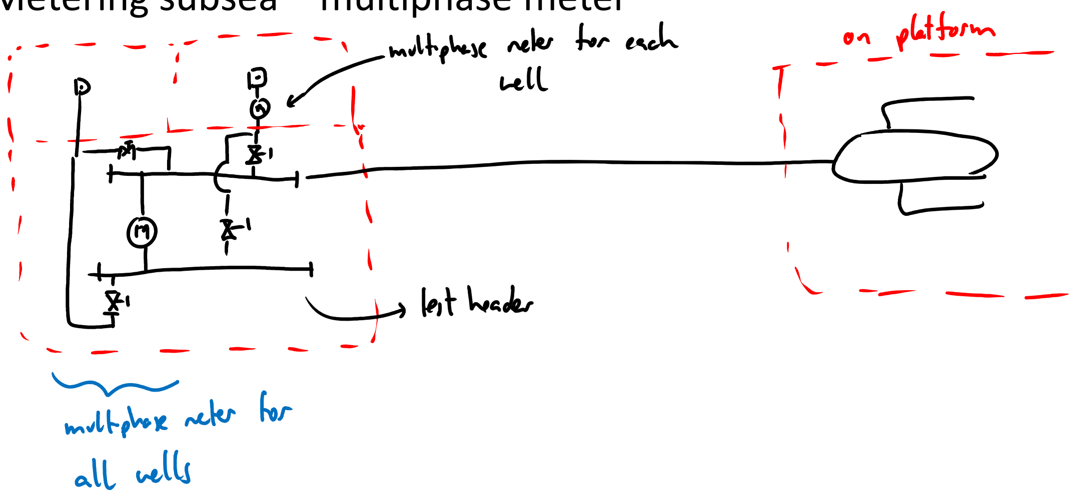
instead of separating, a multiphase meter can also be used, instead of a test separator

Metering onshore – test separator

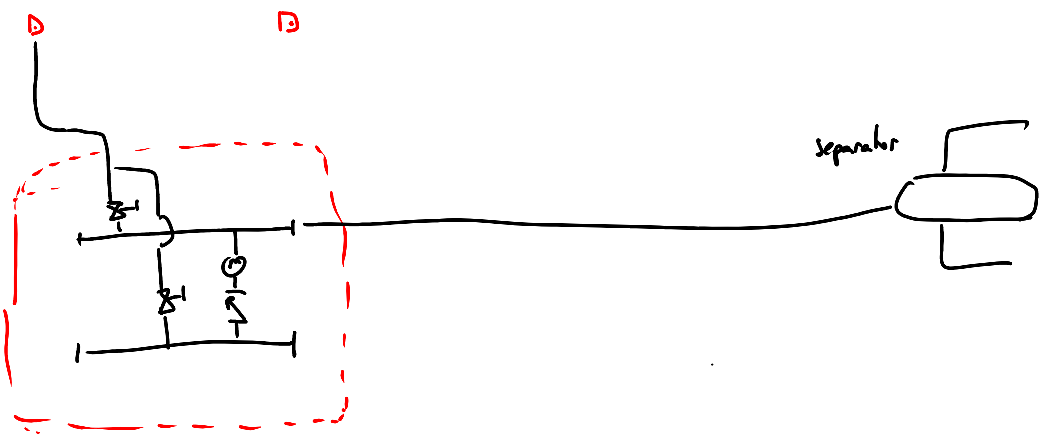
Metering subsea – test line



Metering subsea – multiphase meter



multiphase meter - satellite wells



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Metering requirements affect field layout - Brazil

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

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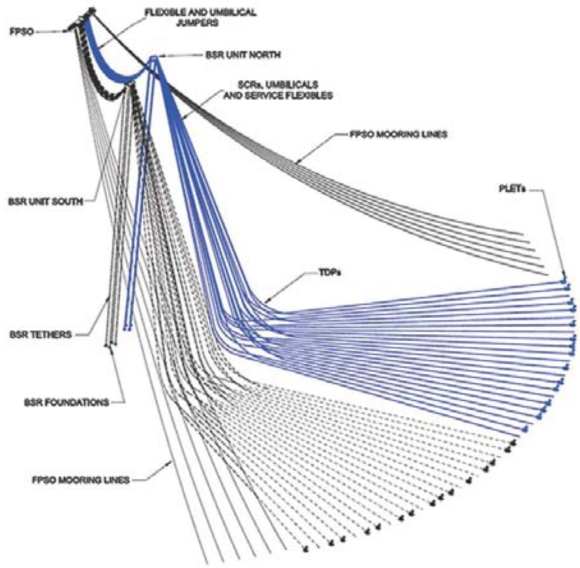
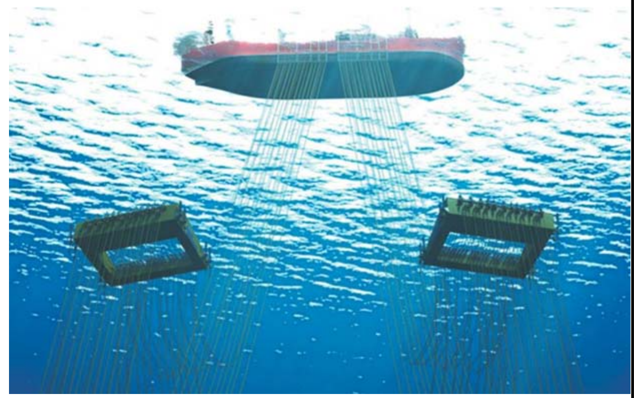
Metering requirements - Brazil

$$$





https://www.marinetechnologynews.com/news/reviewing-sapinho-system-564661

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Metering requirements - Norway

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.

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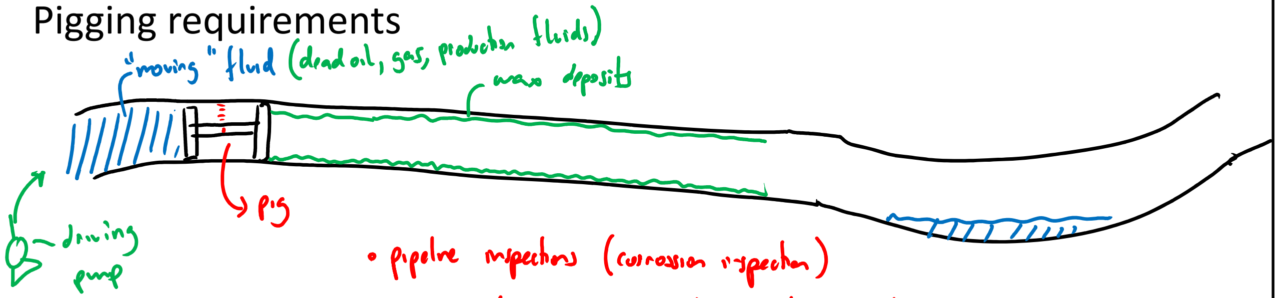
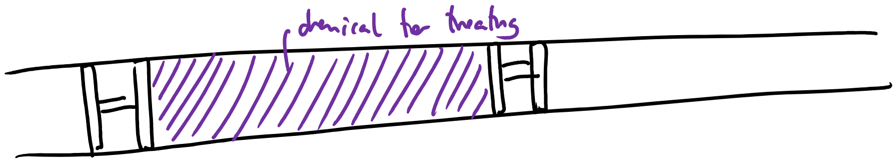
Pigging requirements



- pipeline inspections (corrosion inspection)
- remove liquid accumulated in low points
- chemical treatment
- wax scraping



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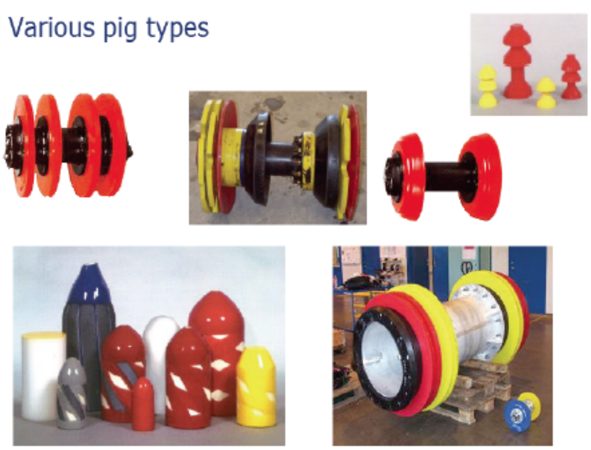
Pigs

Various pig types



Wax plug-North Sea line pigging

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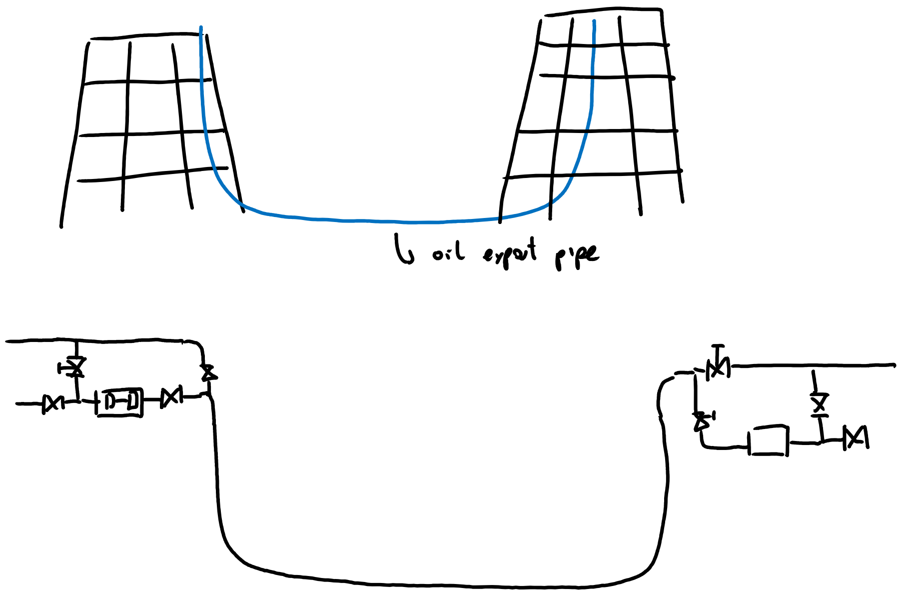
Pigging loop and subsea pig launcher



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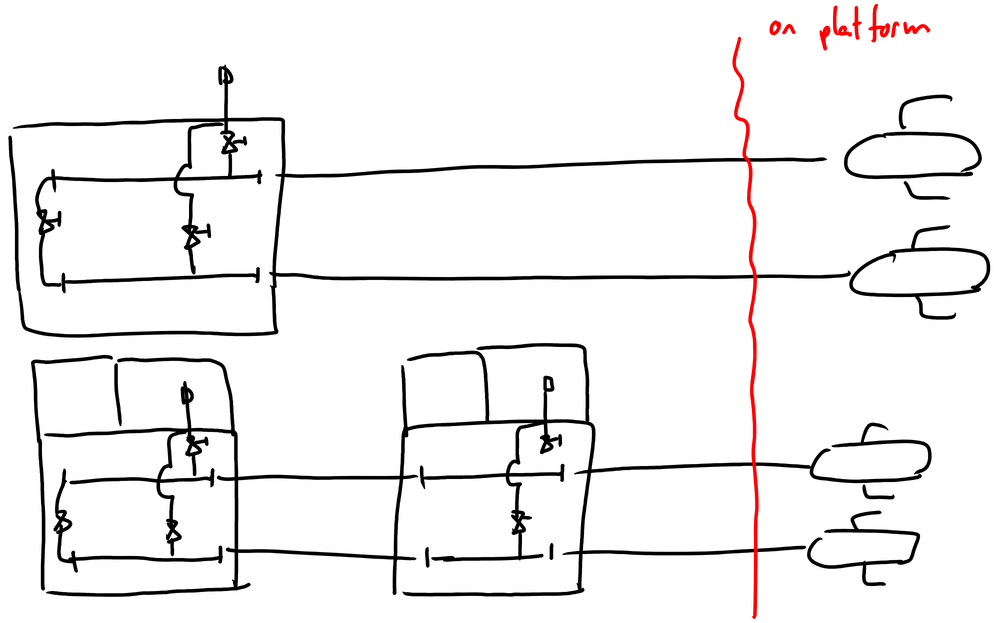

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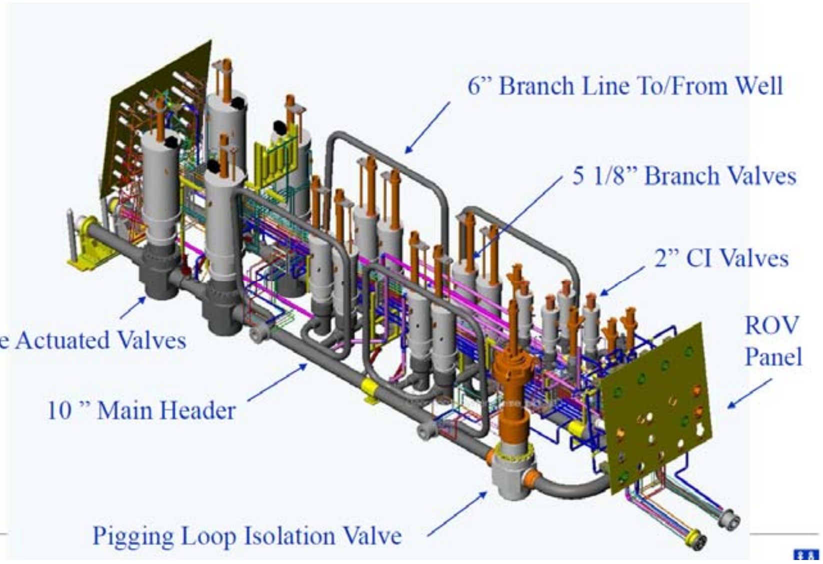
The pigging valve



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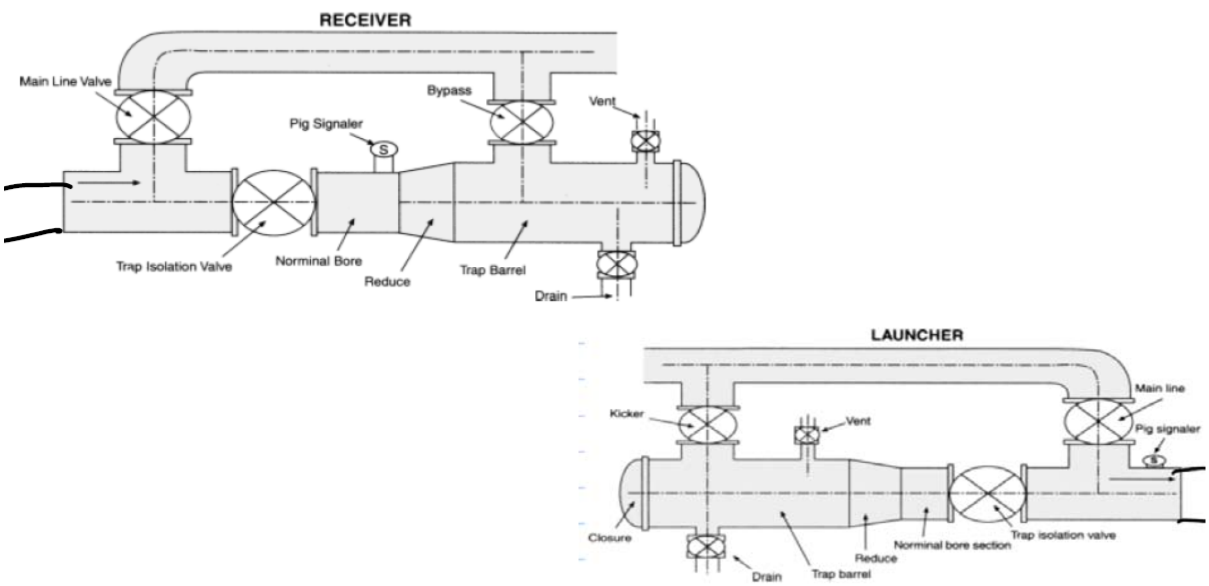
Pig launcher and receiver



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Pigging - video

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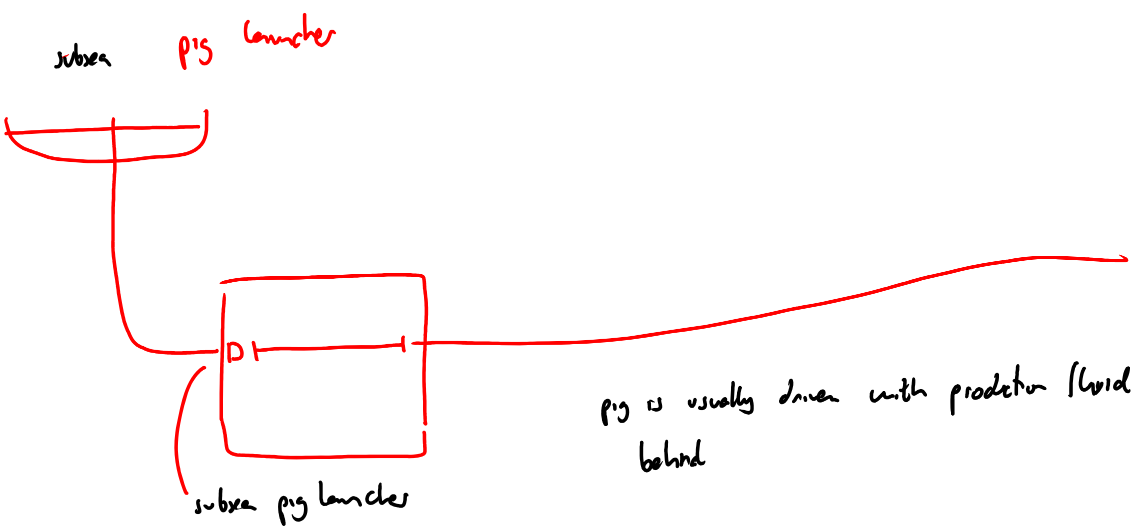

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Summary table

	Dry X-mas trees	Wet X-mas trees
Deep water (1700 m+)		X
Reservoir is “spread” or multiple reservoirs		X
Frequent well intervention	X	
Flow assurance concerns	X	
Plans for infill drilling (and coping with reservoir uncertainty)*	X	X
Progressive production startup		X

Jacket, GBS, SPAR, TLP

ALL

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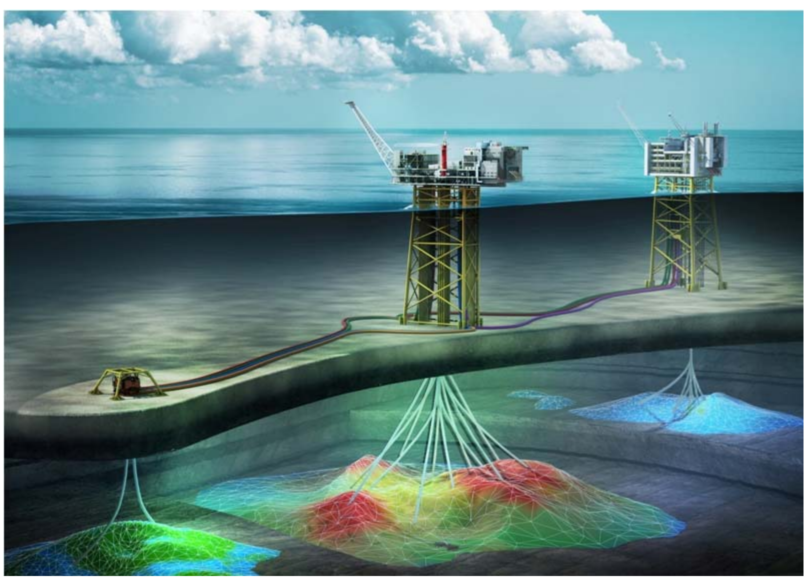
Combinations can be used



https://www.akerbp.com/en/our-assets/production/ivar-aasen/the-development-solution/

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Some selection criteria for offshore structures

- Water depth
- Type of X-mas tree
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- **Need for oil/condensate storage**
- Marine loads – Oceanographic environment
  - Wind, waves, current

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Need for liquid storage

No or limited storage	Steel Jackets, Semi-subs, TLPs, Spars[20]
Medium - Large storage (up to 2.5000.000 STB)	FPSOs, GBS

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Other selection criteria for offshore structures

- Previous experience
- Riser issues
- Topside upgrade flexibility
- Manufacturing workshop availability
- Maturity of technology
- Maintenance and OPEX

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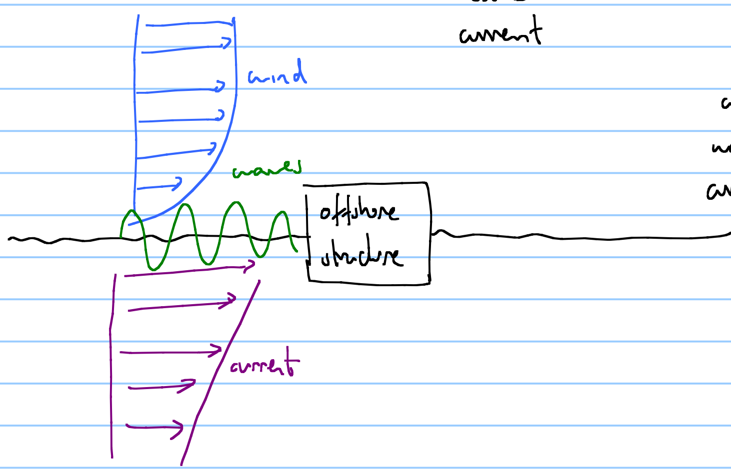
Notes for Youtube video nr. 17

Offshore structures for oil and gas production

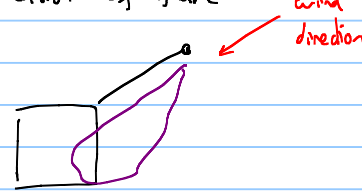
• effect of oceanographic environment : wind
waves
current



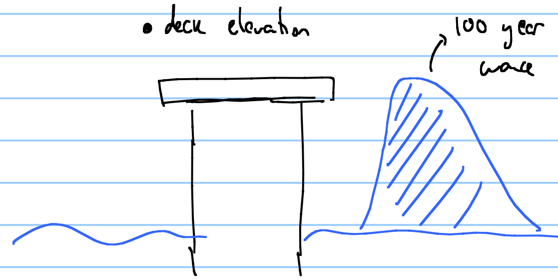
wind
waves
current

must be taken into account when designing the offshore structure

• Location of flare



• deck elevation



• design wave, for a range of periods
↳ most lively in the area

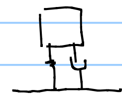
• storm (100 year storm)

• long term variations ⇝ fatigue

forces and marine loads on structure (t) → structure (mechanical system) → movement (t)
stress (t) → maximum stress
fatigue design

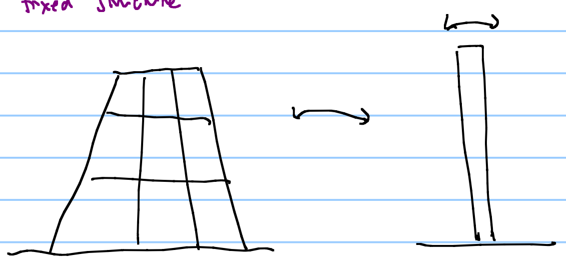
• magnitude
• frequency
• direction

each structure, depending on it characteristics (mass, flexibility, dampening)

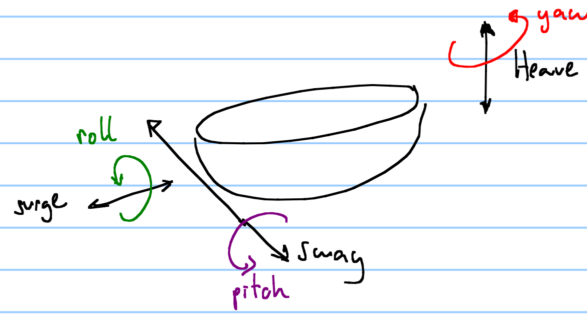


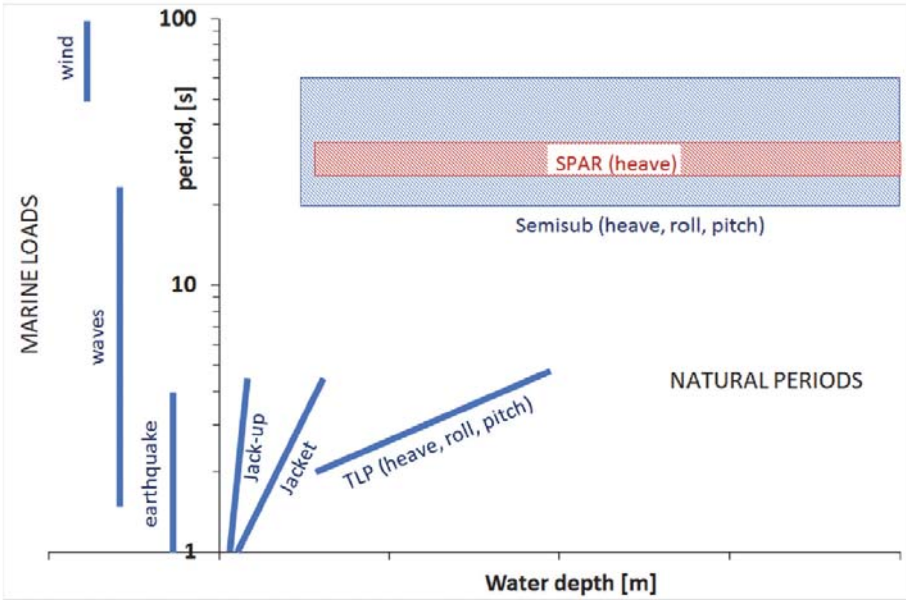
will have a natural frequency that if excited at this frequency might exhibit maximum movement and stress.

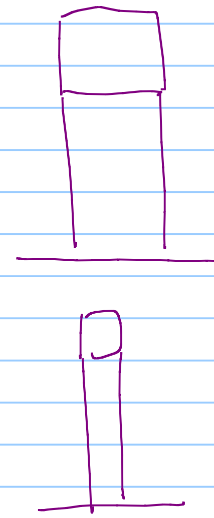
fixed structure

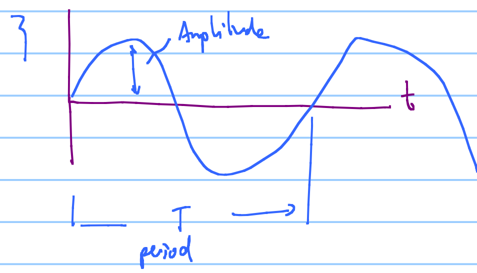


floating structure





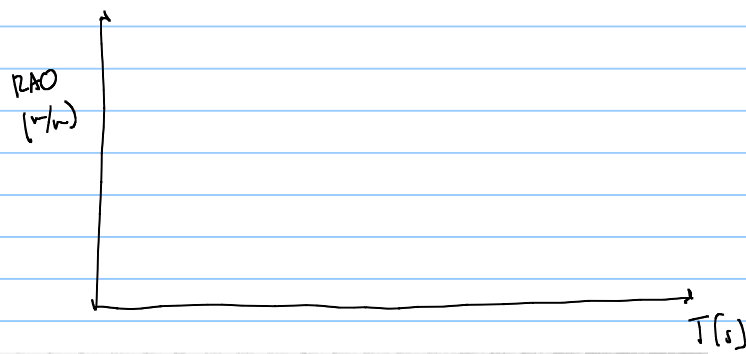




Response amplitude operator (RAO) $= \dfrac{\text{amplitude of response}}{\text{amplitude of excitation}} = \dfrac{\text{Heave [m]}}{\text{wave amplitude [m]}}$

$f = \dfrac{1}{T}$ $\dfrac{\text{cycle}}{\text{s}}$

RAO = 2



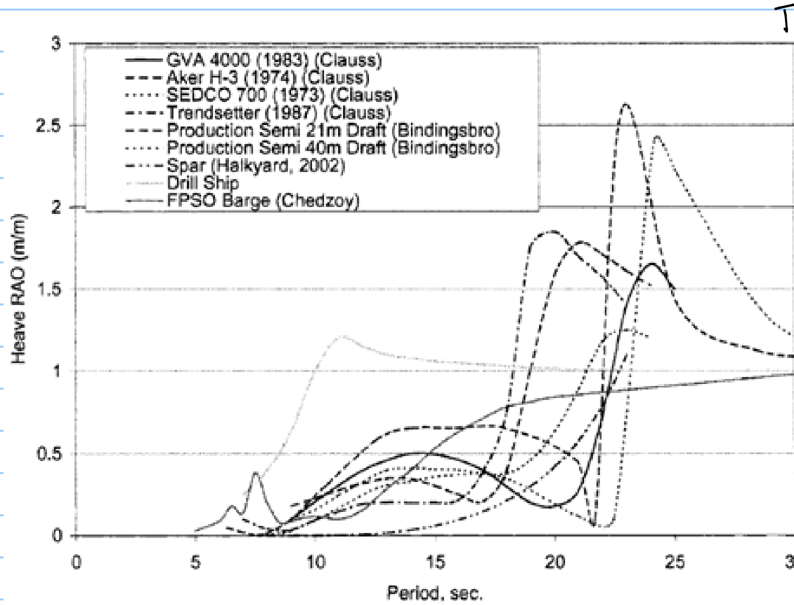
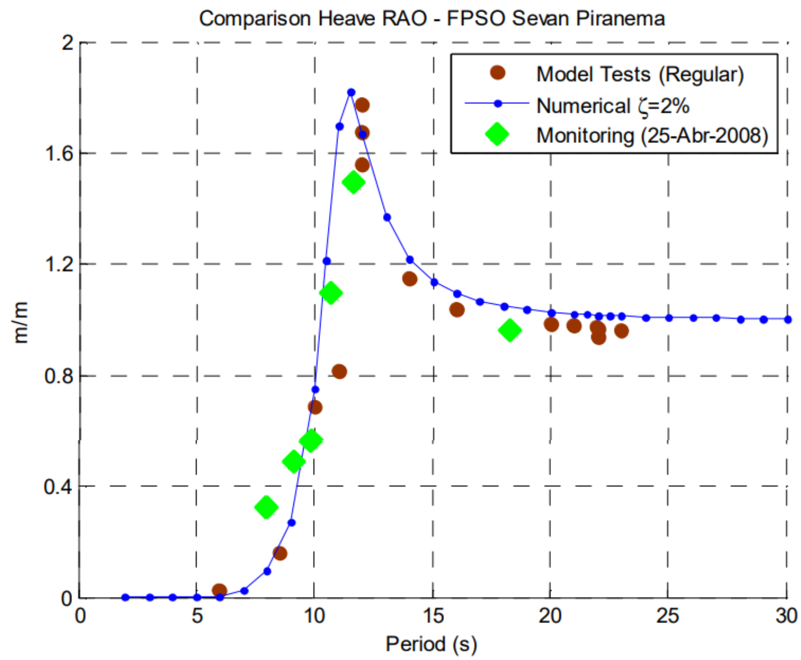


Figure 7.3 Example heave RAOs of various floaters



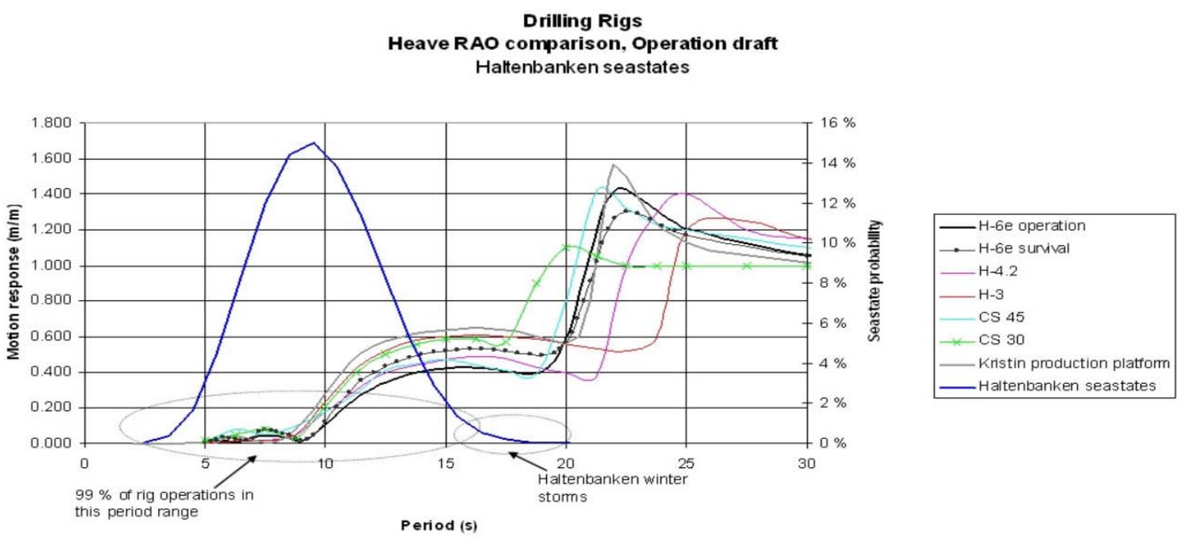


Figure 16.2: *RAO published on the AKER Drilling website.*

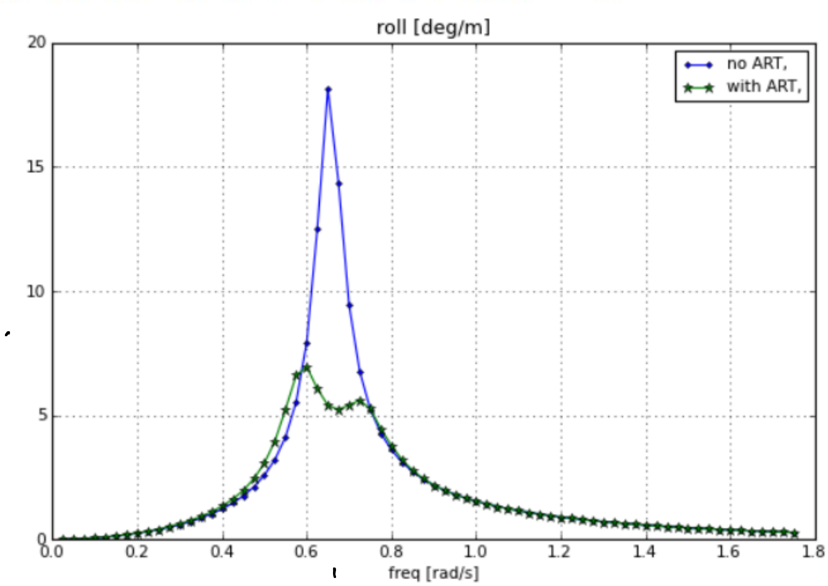
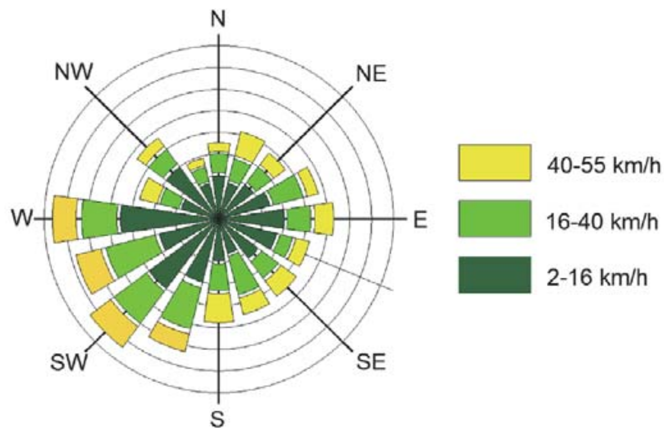


Figure 1: Typical RAO of roll of a ship with and without ART.

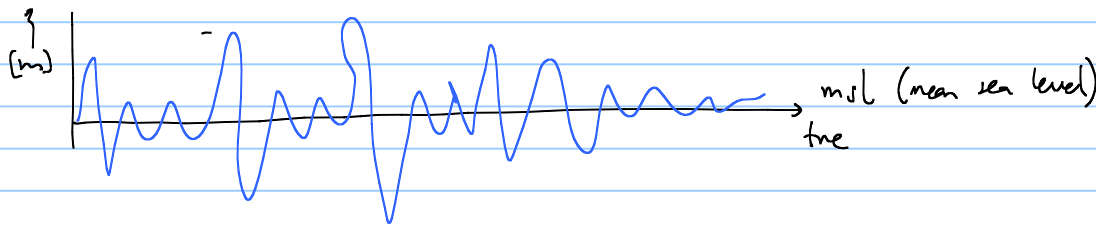
Wind



wind rose

wind and current are typically assumed constant and using the maximum value. (wind direction also must be taken into account)

Waves

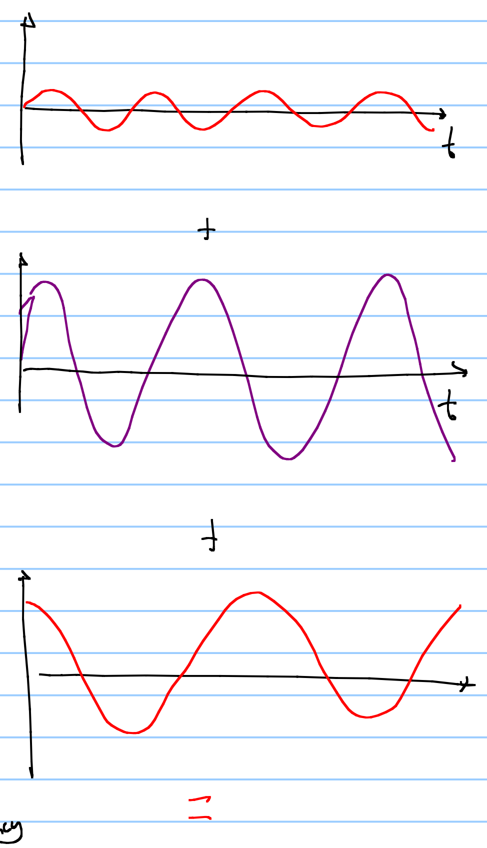


Fourier

$$f(t) = \sum_{i=1}^{N} \underbrace{A_i}_{\text{amplitude (m)}} \sin(\omega_i t + \overbrace{\phi_i}^{\text{phase shift}})$$

angular frequency $\omega_i = 2\pi f_i$

$\omega_i = \frac{rad}{s}$ $\left[\frac{\cancel{cycle}}{s}\right]\left[\frac{2\pi \; rad}{1 \; \cancel{cycle}}\right]$



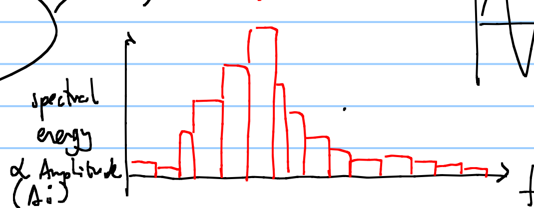
Discrete Fourier transform

FFT Fast fourier transform

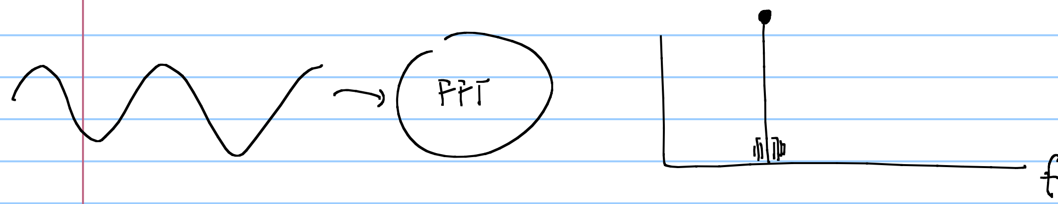
t	value
□	□
□	□
□	□
□	□

→ FFT →

spectral peak period
dominant frequency



→ sometimes analytical equations are used
Pierson Moskowitz, JONSWAP



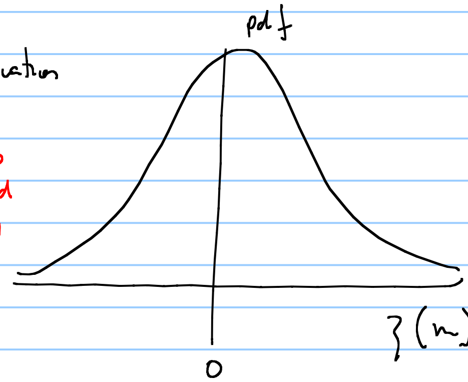
to deal with the variability of waves in time, we apply FFT on the signal and report spectral peak period

the spectral peak period does not change significantly in 3 hours

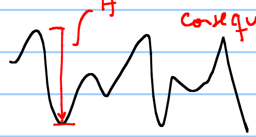
sea state

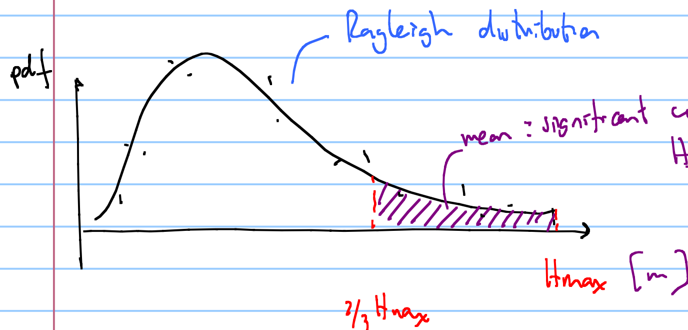
what to do with amplitudes?

statistics on wave elevation



wave height



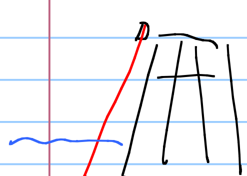


to characterize a sea state (3 hrs) Hs and Tp are used

wave Data must be gathered for at least 2 years to obtain a representative sample of wave conditions in the area

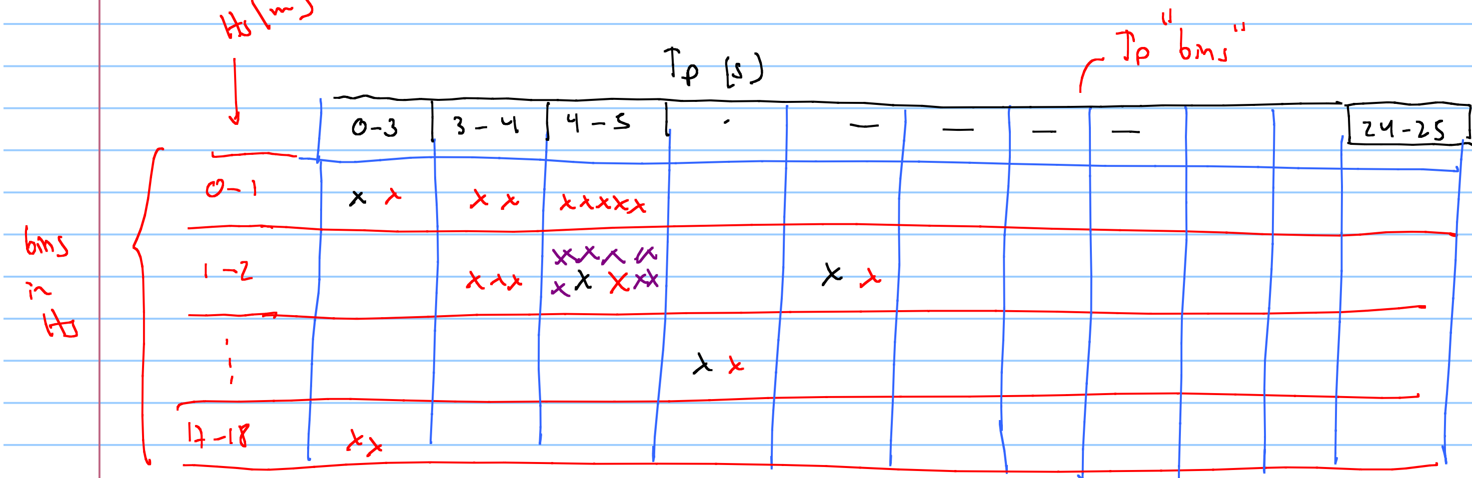
How many sea states are in 2 years

$2 \text{ years} \cdot \frac{365 \text{ day}}{\text{year}} \cdot \frac{24 \text{ hrs}}{1 \text{ day}} \cdot \frac{1 \text{ sea state}}{3 \text{ hr}} = 5840$



with all measured data, compute Tp, Hs for all

Scatter diagram of long term wave statistics



classify each data point I have in each box

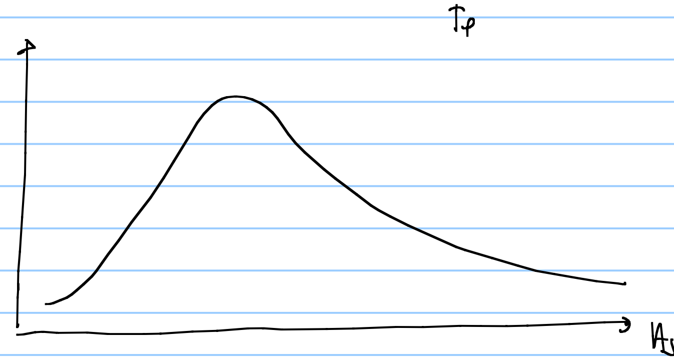
Hs [m]	Spectral Peak period (T_p) [s]																							Sum
	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	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	9139	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

FIGURE 6-18. SCATTER DIAGRAM OF LONG TERM WAVE STATISTICS

$$\frac{292172}{2920\left(\frac{\text{states}}{1\,\text{year}}\right)} \approx 100\ \text{years}$$

for a fixed wave Hs

for a fixed Tp



There were no notes for the session 20210318, but check the video

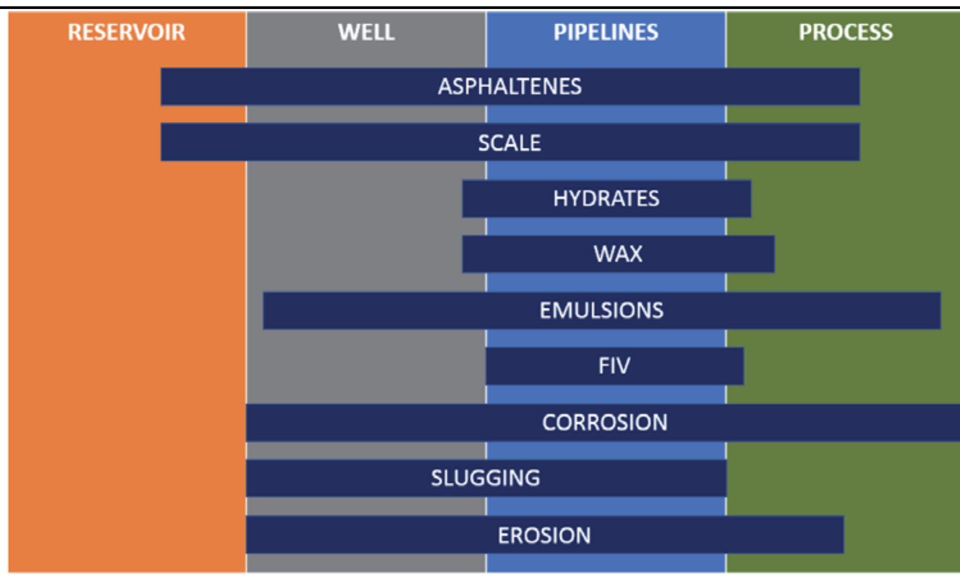
Notes for Youtube video nr. 18

Flow assurance considerations in hydrocarbon field development and planning

Prof. Milan Stanko (NTNU)

1

Issues



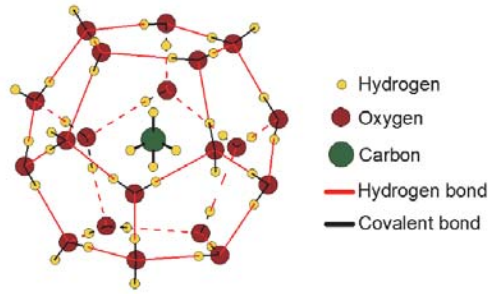
Naphtenates

Foam

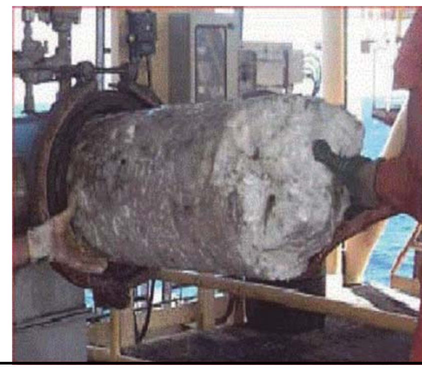
- microorganism growth

2

Hydrates



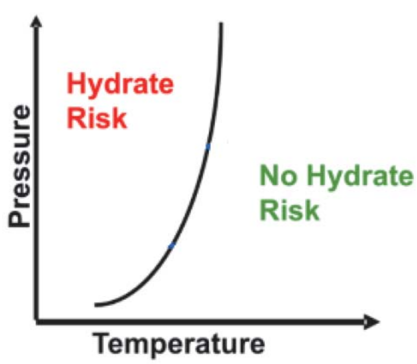
https://www.youtube.com/watch?v=Oz4NLXfdqpA



3

Hydrates - conditions

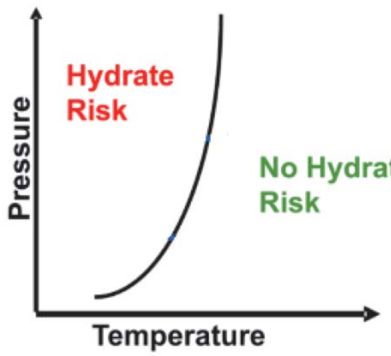
- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

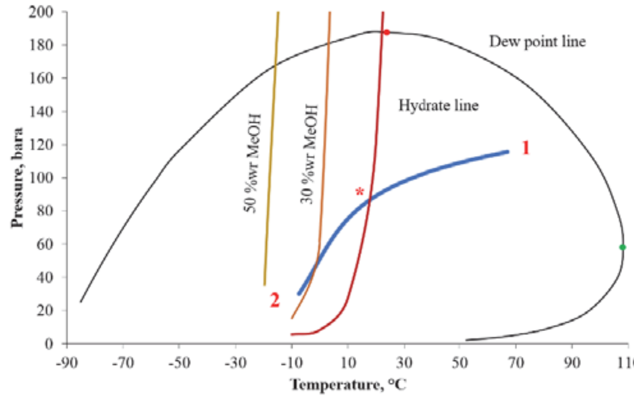


4

Hydrates - conditions

- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

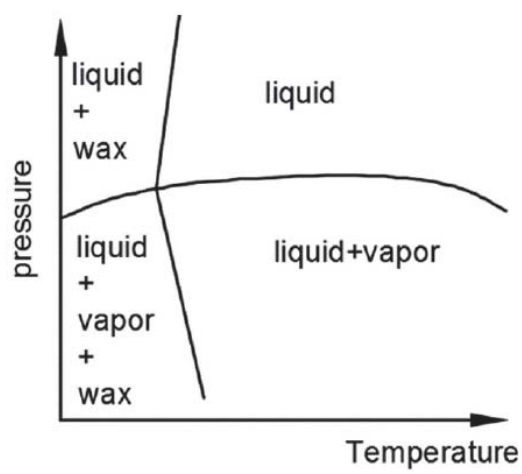




5

Wax

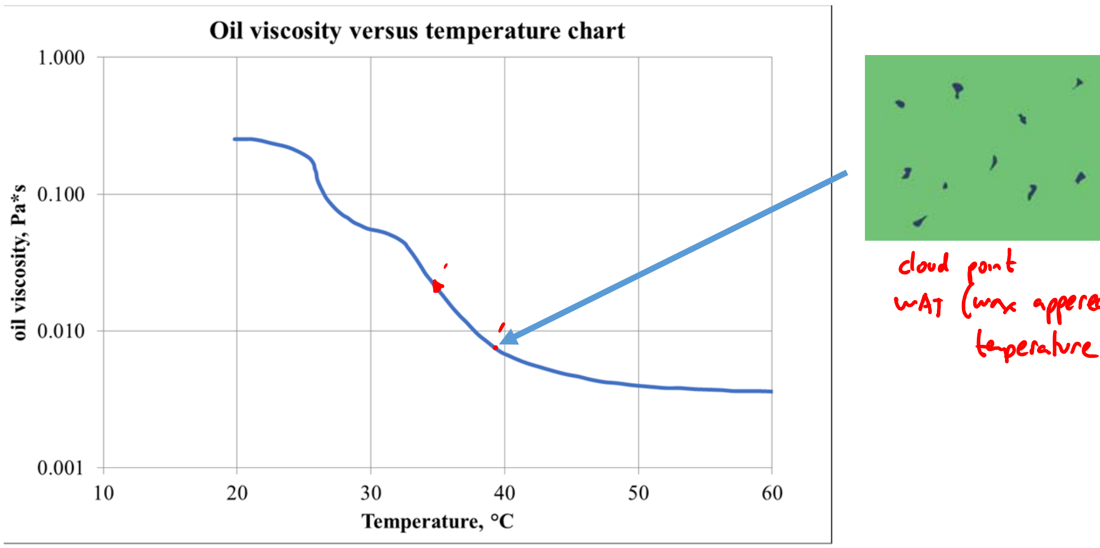
TAKEN FROM EQUINOR



Paraffins (C18 - C36)

6

Wax

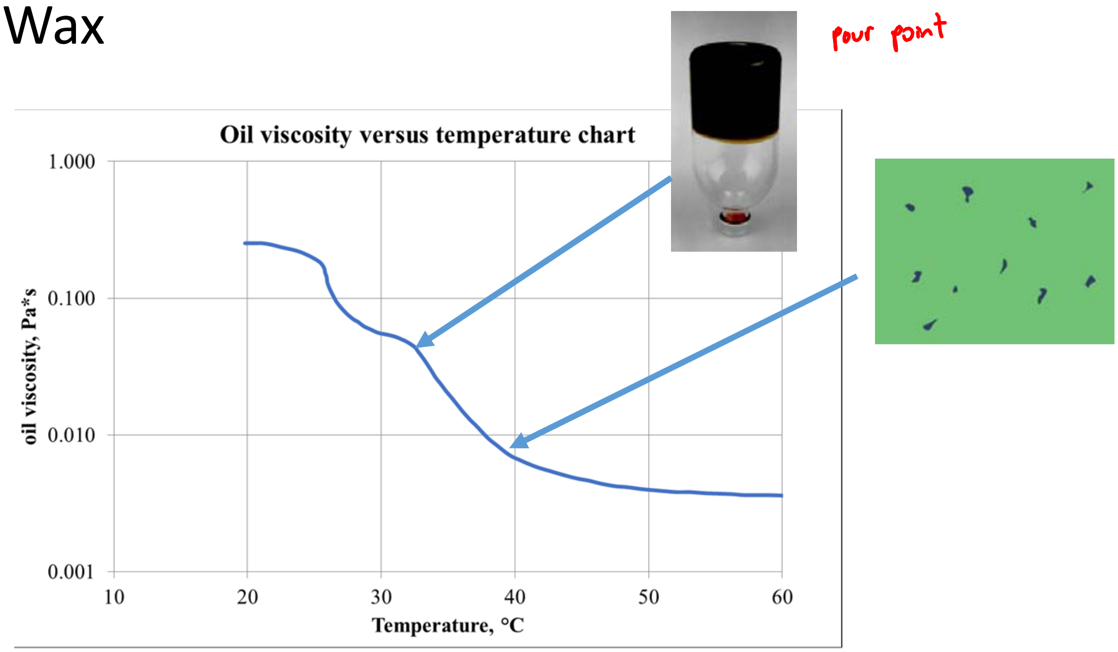


cloud point
WAT (wax apperance temperature)

7

Wax

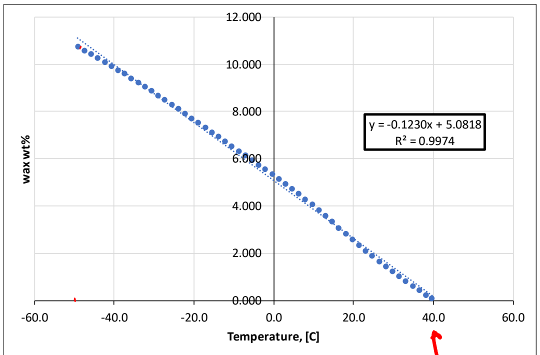
pour point



8

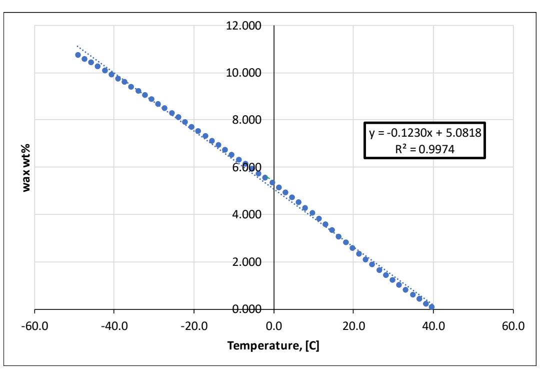
Wax

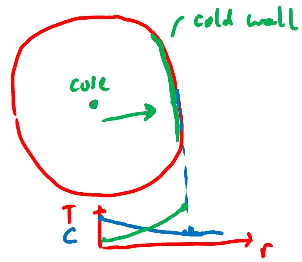
$$\frac{\text{weight of wax particles}}{\text{total weight}} \times 100$$

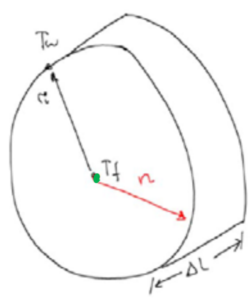


WAT

Wax



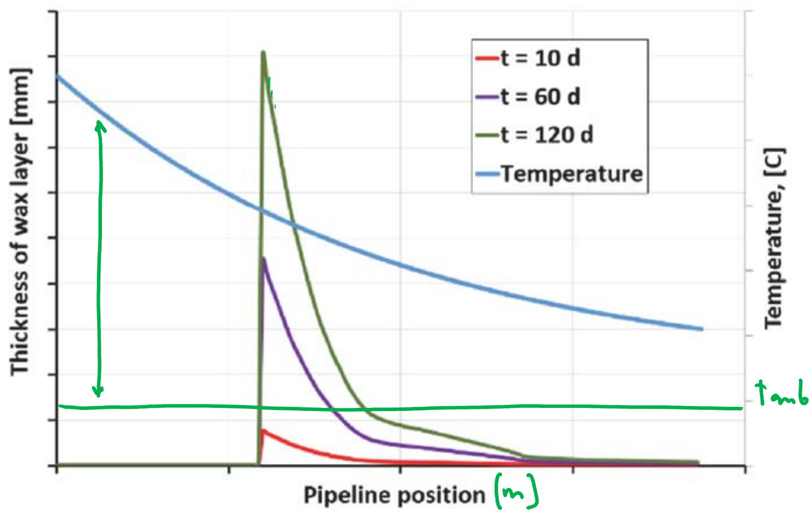




r_i: internal pipe diameter
T_f: fluid temperature
T_w: wall Temperature
n: mass flux of wax from fluid to wall [Kg/s.m²]
$dA = 2\pi r_i \, dL$
total mass flow of wax (m_w) deposited in a section
$m_w = n \cdot dA$

$$n = \rho_{wax} \cdot \frac{B}{\mu_o} \cdot \frac{dC}{dT} \cdot \frac{dT}{dr}$$

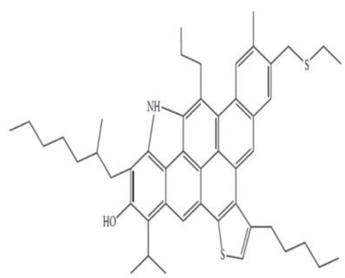
Wax

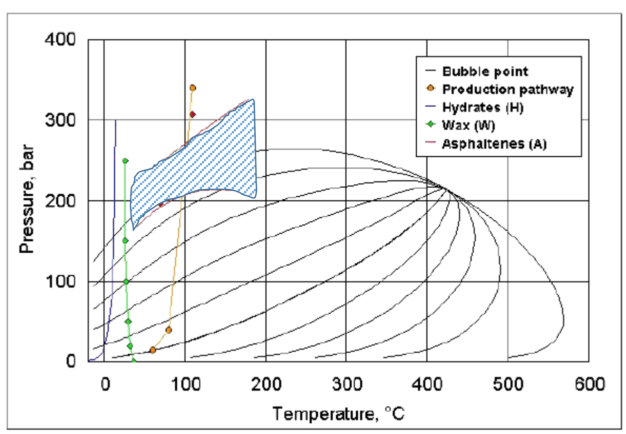


11

Asphaltenes

TAKEN FROM EQUINOR (KALLEVIK)





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Scale

Ion	Formasjonsvann [mg/l]
Na	14 800
K	520
Mg	13
Ca	378
Ba	410
Sr	228
Fe	58
Cl	23 600
SO4	0

+

Ion	Seawater [mg/l]
Na	10 680
K	396
Mg	1 279
Ca	409
Ba	8
Sr	0
Fe	0
Cl	19 220
SO4	2 689

$$Ba^{2+} + SO_4^{2-} = BaSO_4(s)$$

$$Ca^{2+} + CO_3^{2-} = CaCO_3(s)$$

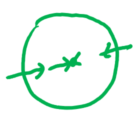
$p\downarrow$
$T\uparrow$

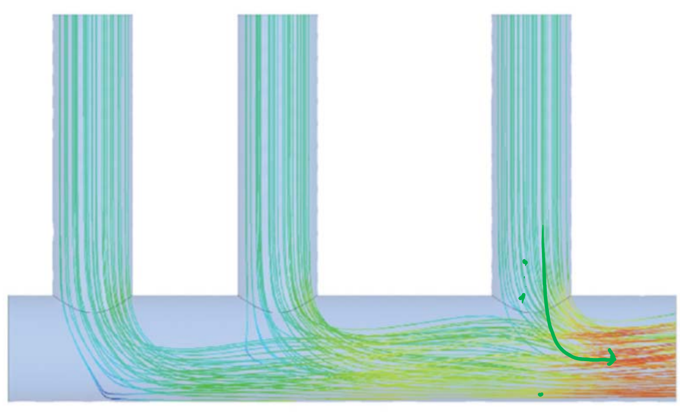
$BaSO_4$ $CaCO_3$ NaCl

TAKEN FROM EQUINOR (SANDENGEN)

13

Erosion





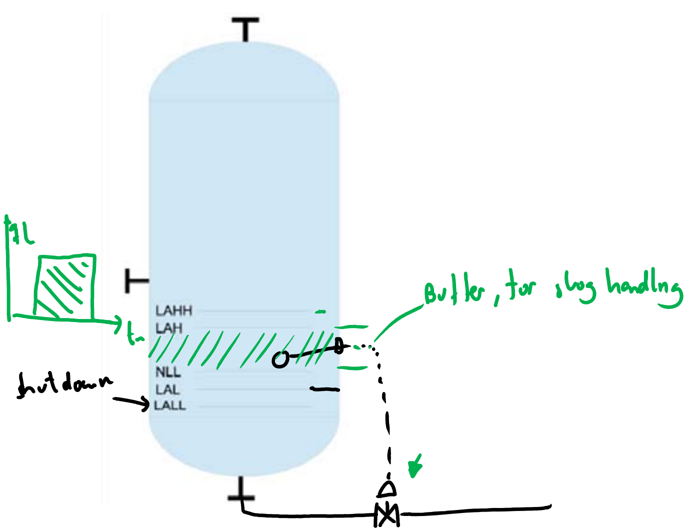
14

Slugging

https://www.youtube.com/watch?v=j59QLHsTs_c

15

Slugging – impact on separator operation



LAL: Level alarm low
LAH: Level alarm high
LALL: Level alarm low low
LAHH: Level alarm high high

https://pubs.spe.org/en/ogf/ogf-article-detail/?art=1028

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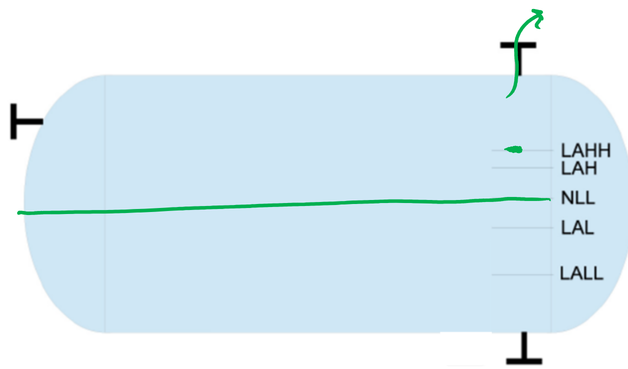
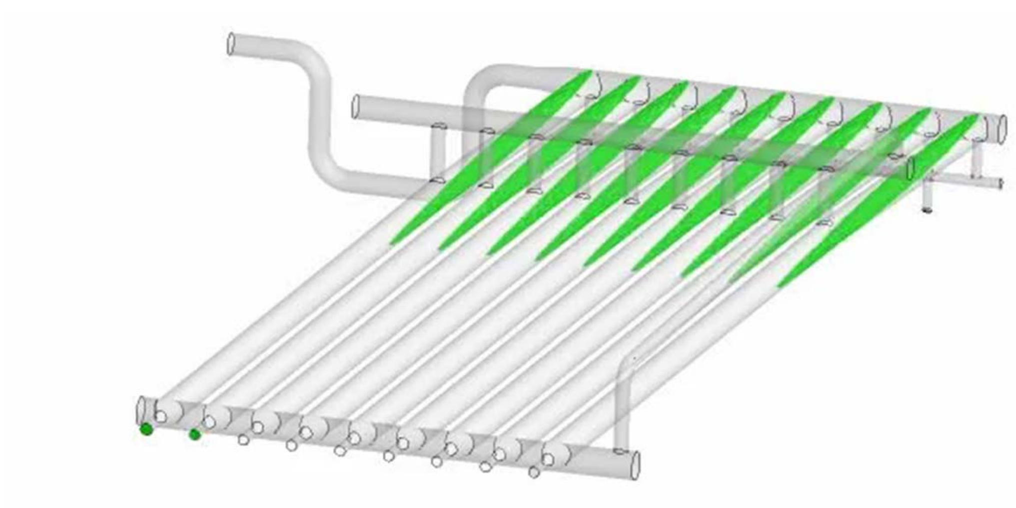
Slugging – impact on separator operation



17

Slugging – slugcatcher handling slugs



https://www.youtube.com/watch?v=LKLW5284adI

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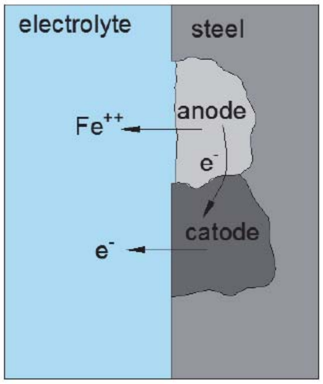
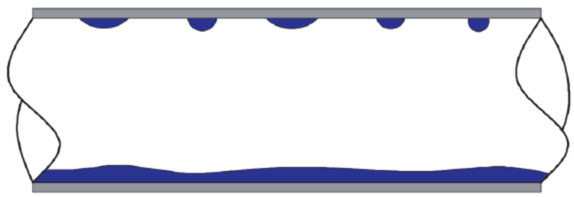
Corrosion





TOP of line corrosion

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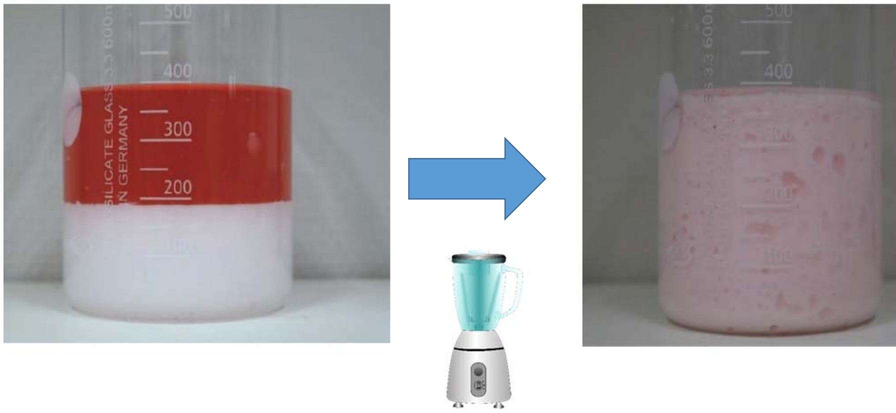
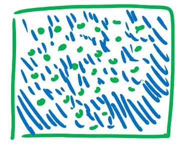
Oil-water emulsions

20

Oil-water emulsions



fine and stable dispersion



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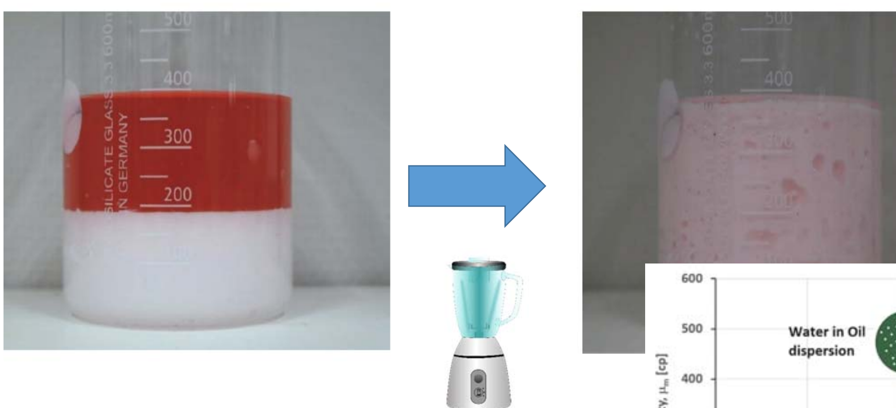
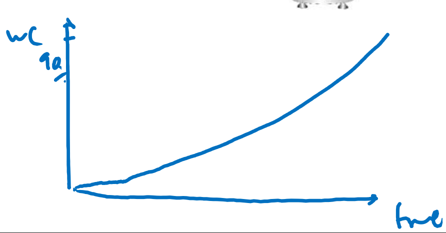
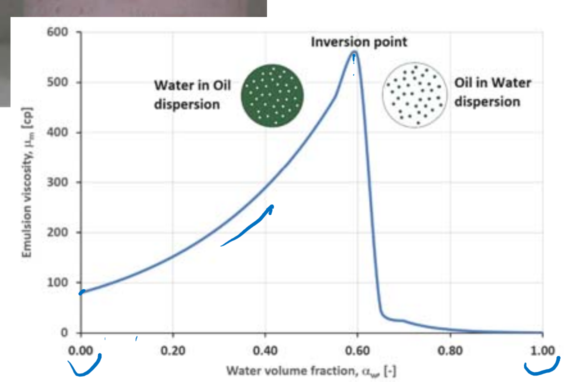
Oil-water emulsions







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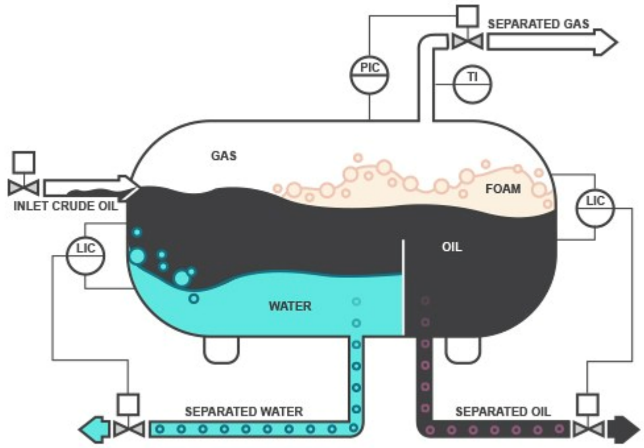
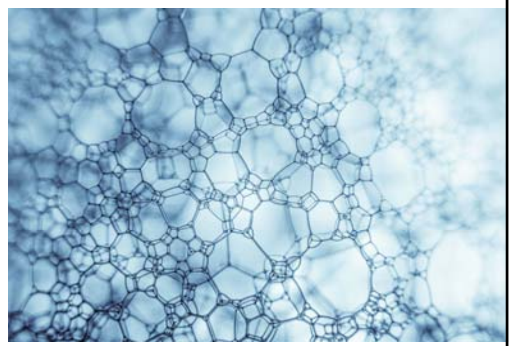
Foam



https://www.arab-oil-naturalgas.com/foam-in-oil-gas-separators/



https://www.crodaoilandgas.com/en-gb/discovery-zone/functions/foamers

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Flow assurance issue	Causes	Potential Consequences	Prevention/solution	Tools available for analysis
Hydrates	• Small gas HC molecules • Free water • Begin to form at a given p and T (low T, high P) given by thermodynamic equilibrium of the hydrate phase.	• Blockage of flowlines and pipelines	Reduce the hydrate formation region: •Continuous or on-demand injection of chemical inhibitor (MEG or MEOH) Stay out of hydrate formation region: •Improve thermal insulation •Electric heating Others: •Cold flow* •Water removal and gas dehydration*	To determine Hydrate formation conditions: •Laboratory tests •Empirical correlations •Thermodynamic simulators (e.g. Hysys, PVTsim, Unisim) To determine p and T along the pipe: •Multiphase simulator (Olga, LedaFlow). •Computational fluid dynamics (CFD)
Wax	• Composition of the crude oil • Begins to form at given p and T due to changes in solubility • Cold wall	In wells, flowlines and pipelines: •Increase pressure drop (pipe roughness) •Reduction of cross section area •Pipe blockage •Changes fluid rheology •Gelling (problem for startup)	• Pigging • Thermal insulation • Electric heating • Chemical inhibitors • Chemical dissolvers • Pipe coating • Cold flow*	• Laboratory tests • Transient multiphase simulators (e.g. Olga, LedaFlow) • Computational fluid dynamics (CFD)
Slugging	• Dynamics of multiphase flow of liquid and gas • Reduction of rate • Liquid accumulation on low points	• Fluctuating liquid and gas input to processing facilities In flowlines and pipelines: • Vibration • Added pressure drop • Fatigue	• Change separator size • Pipeline dimensioning • Maintain flow above minimum flow rate • Gas lift in riser base • Choking topside • Pipeline re-routing • Subsea separation*	• Transient multiphase simulator (OLGA, LEDA) • Structural analysis (usually with FEA, e.g. Ansys) • Laboratory experiments
Scaling	• Changes in solubility (e.g. changes in P and T conditions, changes in pH, mixture of incompatible water, CO2 injection).. • Irregularities on surface	In wells, pipelines and flowlines: •Reduction of cross section area •Pipe blockage •Malfunctioning of valves and equipment	• Continuous injection of chemical inhibitors • Dilution by adding more water • Chemical dissolvers • Mechanical removal • Coating	• Laboratory tests • Simulation tools

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Flow assurance issue	Causes	Potential Consequences	Prevention/solution	Tools available for analysis
Erosion	• Sand production • High flow velocities • Liquid droplets in the gas • Gas droplets in the liquid	In wells, pipelines and flowlines: •Structural damage •Vibration •Leaks •Corrosion	• Change geometry • Replacement and maintenance of components • Reduce flow rate (reduce formation drawdown) • Sand separation* • Coatings	• Standards (DNV-RP-0501) • Computational fluid dynamics • Laboratory testing
Corrosion	• Water • O_2 • CO_2 • H_2S	• Leaks • Integrity	• Coatings • Material selection • Surface passivation	• Laboratory testing
Emulsions	• Emulsification agents in the crude • Mixing, shear when flowing through valves, chokes, etc	• Added pressure drop • Increased separation time	• Injection of demulsifiers • Heating	• Laboratory tests • Multiphase models
Asphaltenes	• Crude with asphaltenes • Pressure reduction • Addup of light hydrocarbon components	• Blockage of formation, well, flowline and pipeline • Loss of equipment functionality • Emulsification and foamification	• Mechanical removal • Chemical injection	• Laboratory tests • Some simulation tools

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Measures and consequences

- **Chemical injection**
- System design, e.g.
  - pipe and component insulation
  - heat tracing
  - dead legs
  - pipeline routing
- Well intervention needs
- Water injection strategy
- Define procedures when shutting down and starting up
- Ensure proper distribution of chemicals

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Example of chemical injection program

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.

27

Release and disposal of chemicals

Tabell 7-1 Klassifisering av kjemikalier i henhold til OSPAR

	Svart kategori: Stoffer som er lite nedbrytbare og samtidig viser høyt potensial for bioakkumulering og/eller er svært akutt giftige. I utgangspunktet er det ikke er lov å slippe ut kjemikalier i svart kategori. Tillatelse til bruk og utslipp til spesifikke kjemikalier gis dersom det er nødvendig av sikkerhetsmessige og tekniske grunner.
	Rød kategori: Stoffer som brytes sakte ned i det marine miljøet, og viser potensiale for bioakkumulering og/eller er akutt giftige. Kjemikalier i rød kategori kan være miljøfarlige og skal derfor prioriteres for utskifting med mindre miljøfarlige alternativer. Tillatelse til bruk og utslipp gis kun av sikkerhetsmessige og tekniske hensyn.
	Gul kategori: Kjemikalier i gul kategori omfatter stoffer som ut ifra iboende egenskaper ikke defineres i svart eller rød kategori og som ikke er oppført på PLONOR-listen (se under). Ren gul kategori er uorganiske kjemikalier med lav giftighet eller kjemikalier som brytes ned >60% innen 28 dager. Gul-Y1 er 20-60% nedbrutt og forventes å brytes ned fullstendig over tid. Gul-Y2 er moderat nedbrytbare til ikke giftige og ikke-nedbrytbare komponenter. Y2 skal forsøkes substituert på lik linje med røde kjemikalier.
	Grønn kategori: Stoffer som er oppført på OSPAR-konvensjonens PLONOR-liste (Substances used and discharged offshore which are considered to Pose Little Or No Risk to the Environment). Disse kjemikaliene vurderes å ha ingen eller svært liten negativ miljøeffekt. Kjemikalier i grønn kategori omfatter også vann som inngår i kjemikaliene.

From Ivar Aasen PDO, Del 2

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Release and disposal of chemicals

Tabell 7-4 Miljømessige egenskaper til produksjonskjemikalier som vil følge produsert vann fra Johan Castberg-feltet

Type kjemikal	Vannfase/oljefase	Klassifisering
Avleiringshemmer	Vannløselig. Følger produsert vann.	Det er antatt at gult kjemikalie (i klassen Y2) kan velges. Kjemikaliet er moderat bionedbrytbart til ikke bionedbrytbart Det er ikke giftig og vil ikke bioakkumuleres i næringskjeden.
Emulsjonsbryter	Oljeløselig. Følger hovedsakelig oljefasen (95%). 5% følger produsert vann.	Alle disse kjemikaliene er klassifisert som røde, pga det ikke er bionedbrytbart. De er ikke giftige og vil ikke bioakkumulers i næringskjeden.
Vokshemmer	Oljeløselig. Følger oljefasen.	
Skumdemper	Oljeløselig. Følger i all hovedsak oljefasen, lave konsentrasjoner i produsert vann.	
Flokkulant	Vannløselig, men binder seg til oljedråper. Følger hovedsakelig oljefasen (80%). 20% er antatt å følge produsert vann.	
Biocid/Glutaraldehyd	Vannløselig. Følger injeksjonsvannet eller produsert vann.	Kjemikalie er klassifisert som gult pga giftighet. Det er ikke nedbrytbart og vil ikke bioakkumuleres i næringskjeden.

From Johan Castberg PDO, Del 2

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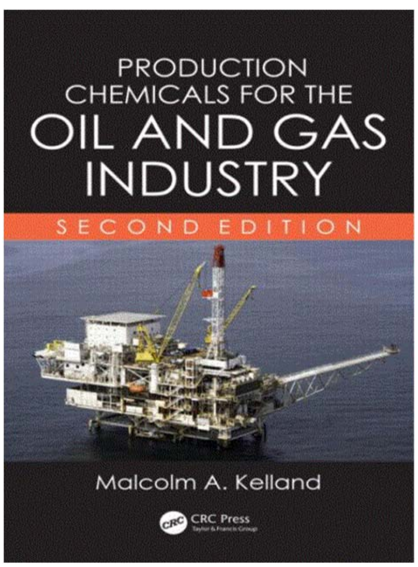
More about production chemicals



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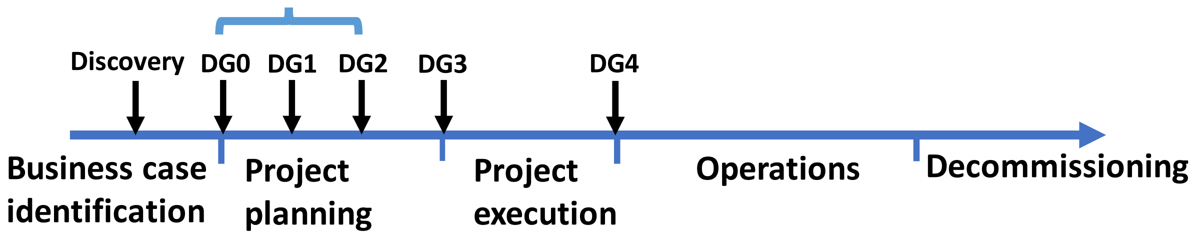
Flow assurance evaluation during field planning

- Detect potential showstoppers and communicate technical constraints and repercussions to field planner
- Laboratory tests



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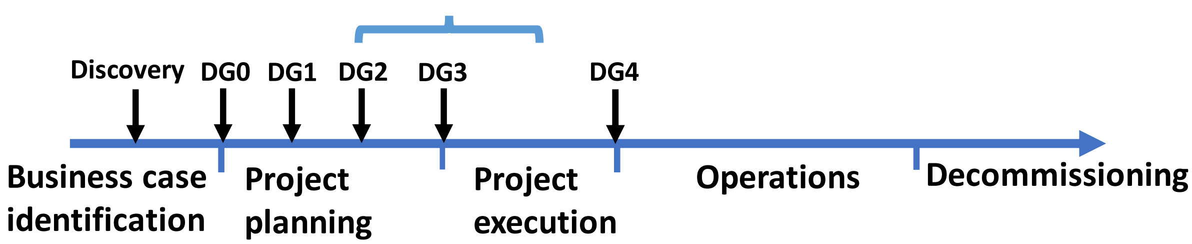
Flow assurance evaluation during field planning

Refine the flow assurance strategy
-More laboratory tests
-Management plan
-prediction of p and T
-Study of startup and shutdown
-System design and verification
-FIV



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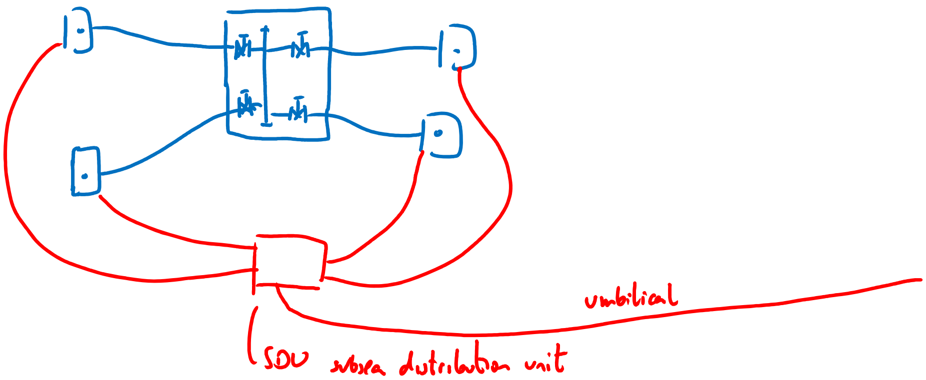
Injection of production chemicals subsea



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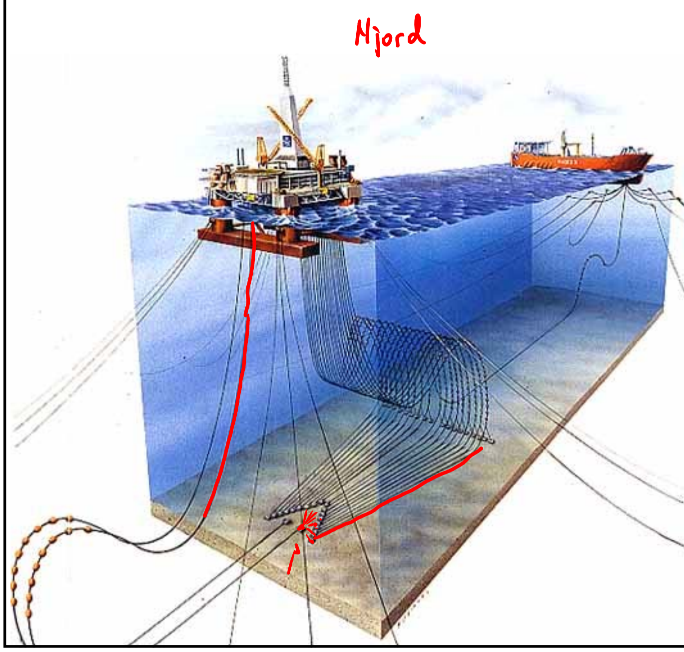
Injection of production chemicals



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Umbilicals, injection of production chemicals

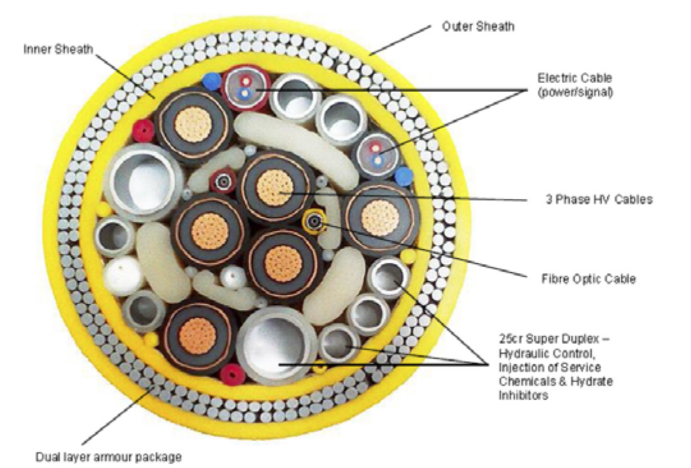

Figure 3 – Umbilical Cross Section Example

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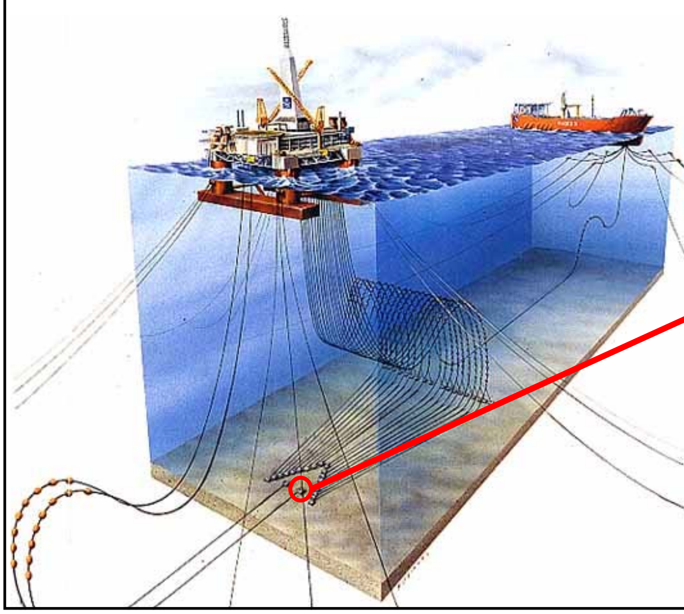
Umbilicals, injection of production chemicals



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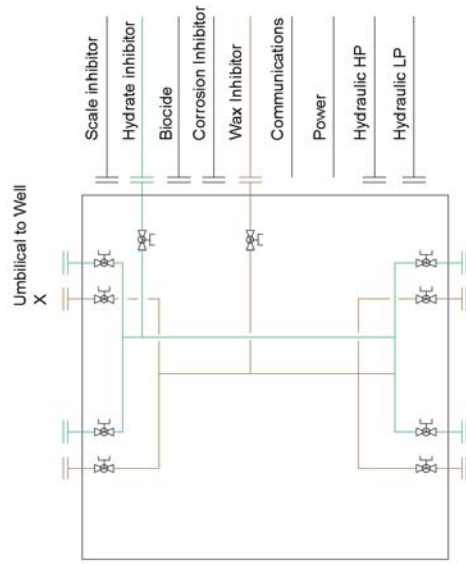
Release and disposal of chemicals



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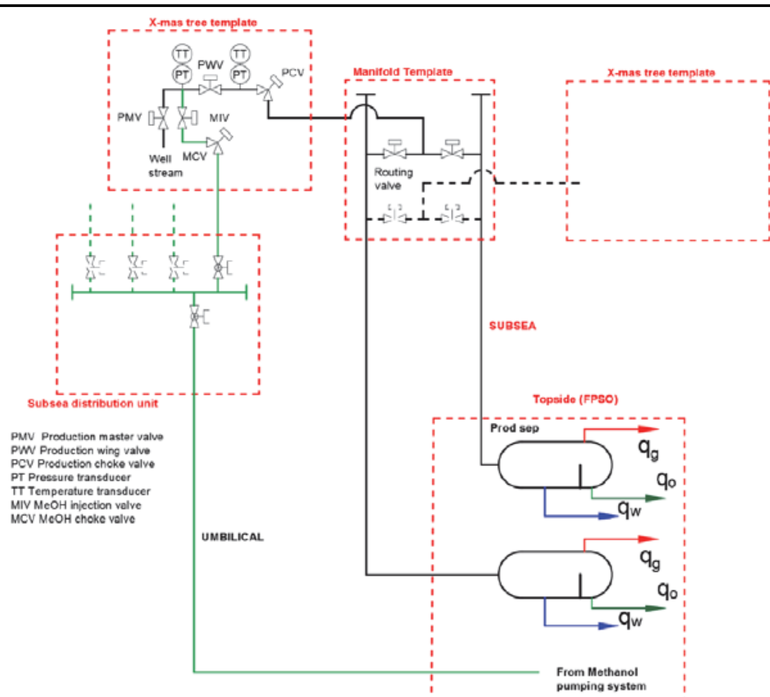

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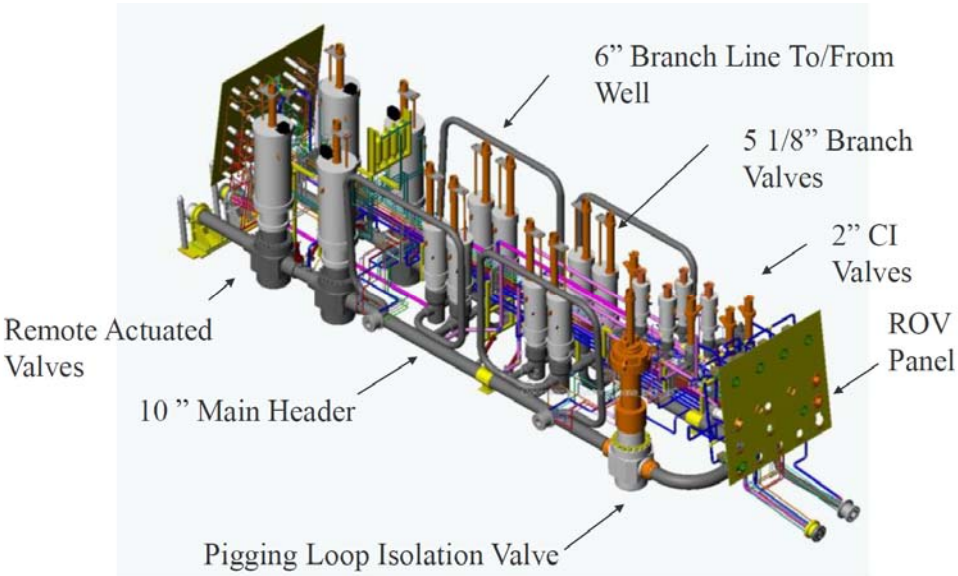
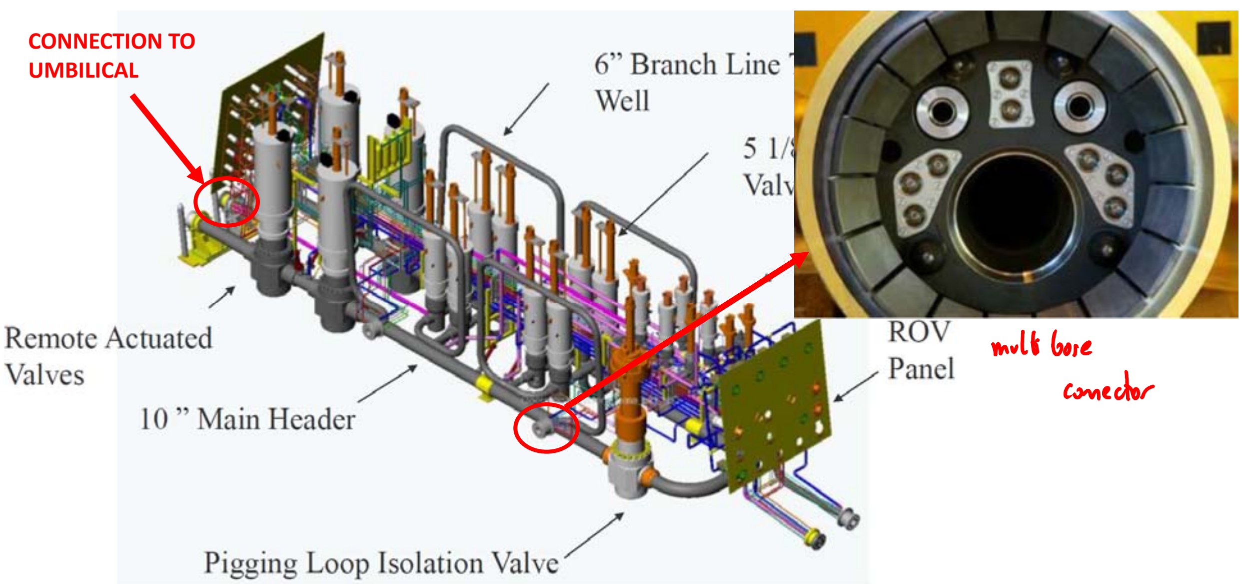
Injection of production chemicals – template wells



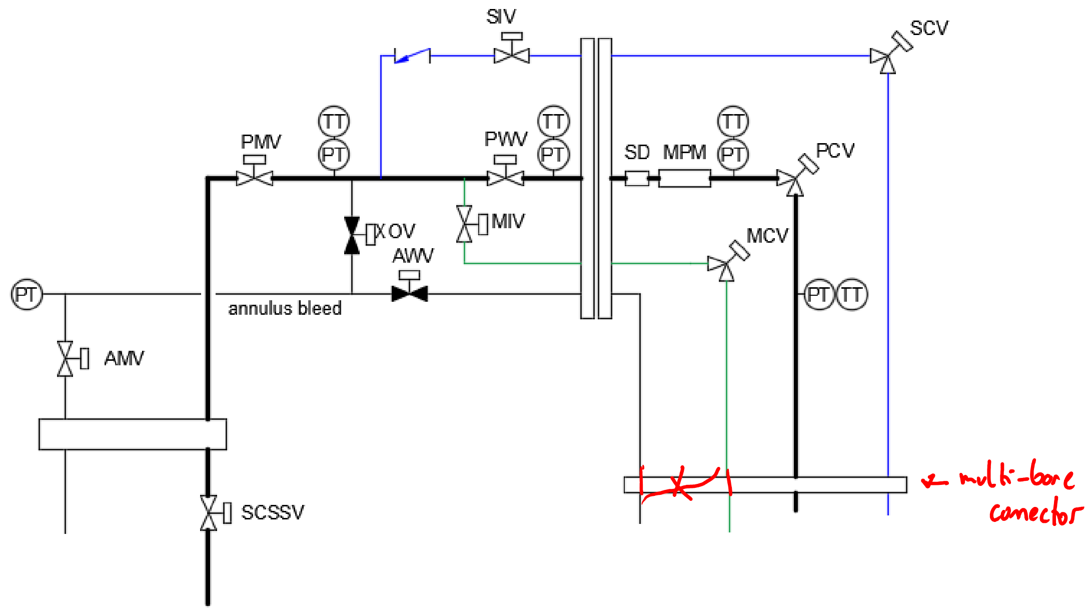
39

Injection of production chemicals – template wells



mult bore conector

40



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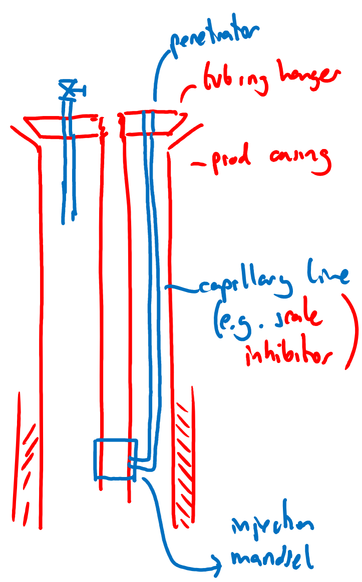
Injection of production chemicals in well



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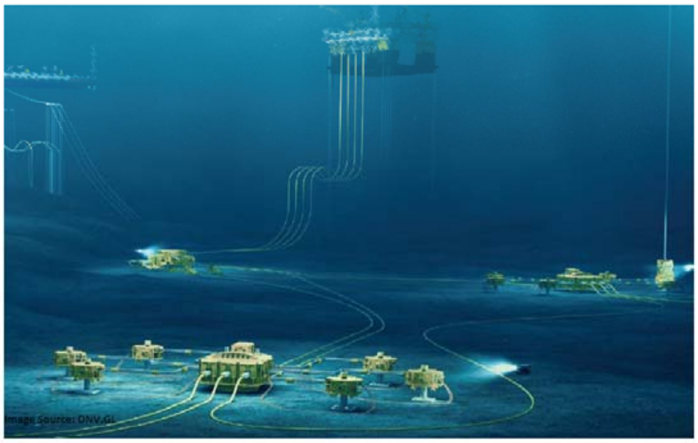
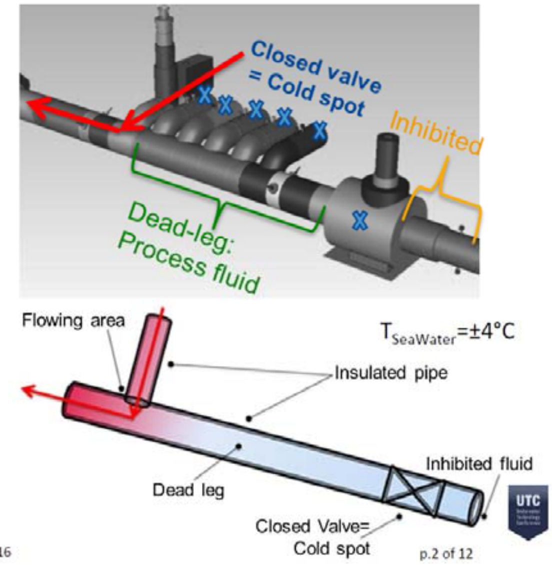
Subsea manifold and dead-leg geometry

- Dead-legs are inherently present





UTC Bergen - 16th June 2016

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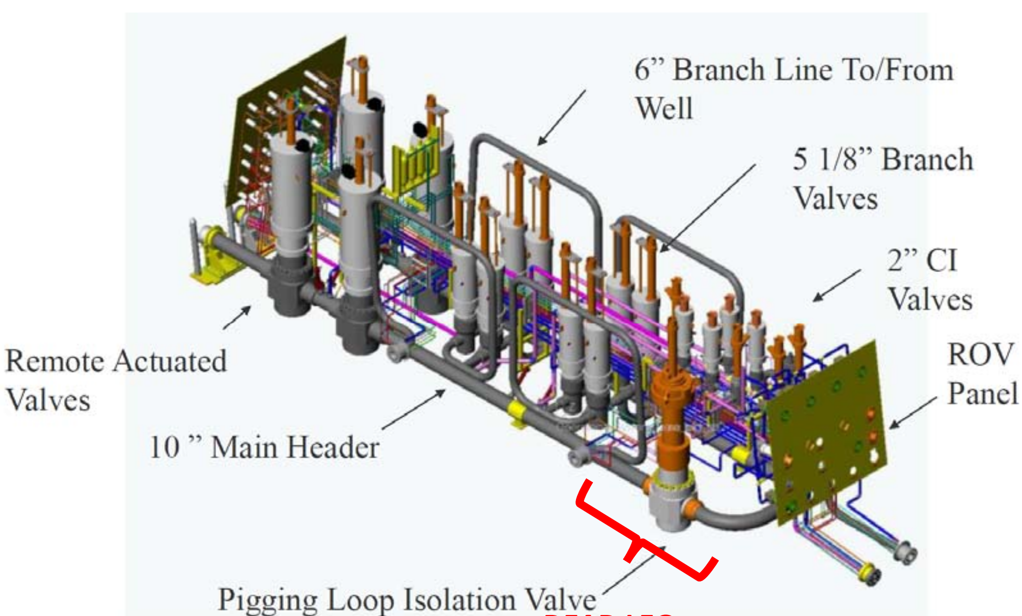

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Tools for analysis

- Laboratory tests of fluids (oil, gas, water)
- Steady state flow simulators (Hysys, Gap, Pipesim, Olga, Leda, FlowManager)
- Transient flow simulators (Olga, LedaFlow, FlowManager, Hysys)
- Thermodynamic or PVT simulators (PVTsim, Hysys)
- Standards (DNV, API)
- CFD simulation for 3D flow analysis of pressure and temperature (Comsol, Ansys)
- Finite element analysis for structural analysis and heat transfer in solids (Abacus, Ansys)

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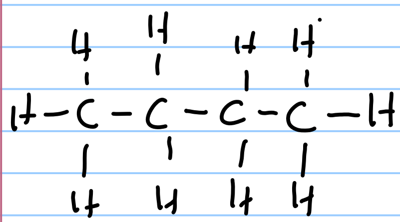
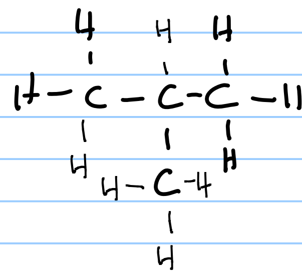
Notes for session 20210325

AGENDA:
-Introduction to Hysys
-Modeling part of the topside facilities of the Karish and Tanin field with Hysys
Evaluate Temperature change, liquid dropout
Assess hydrate formation vulnerability

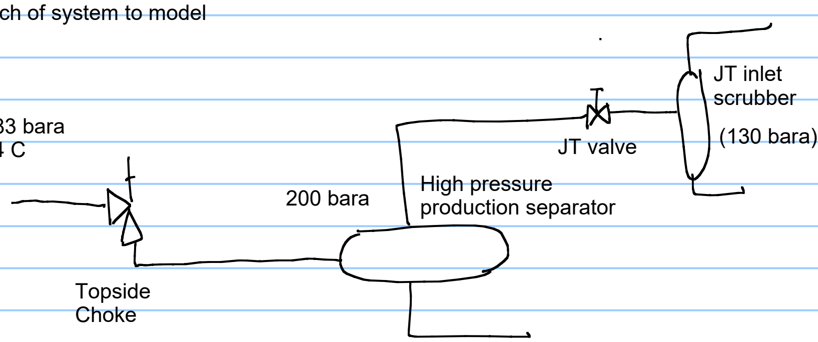
Comment about difference between normal butane and iso-butane



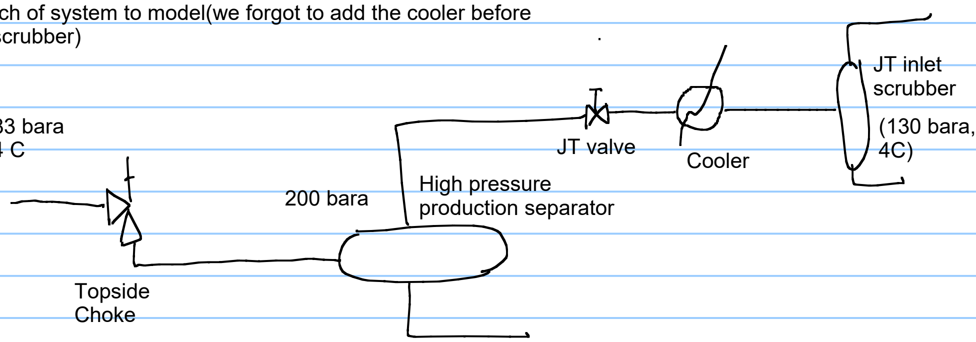


Isomer

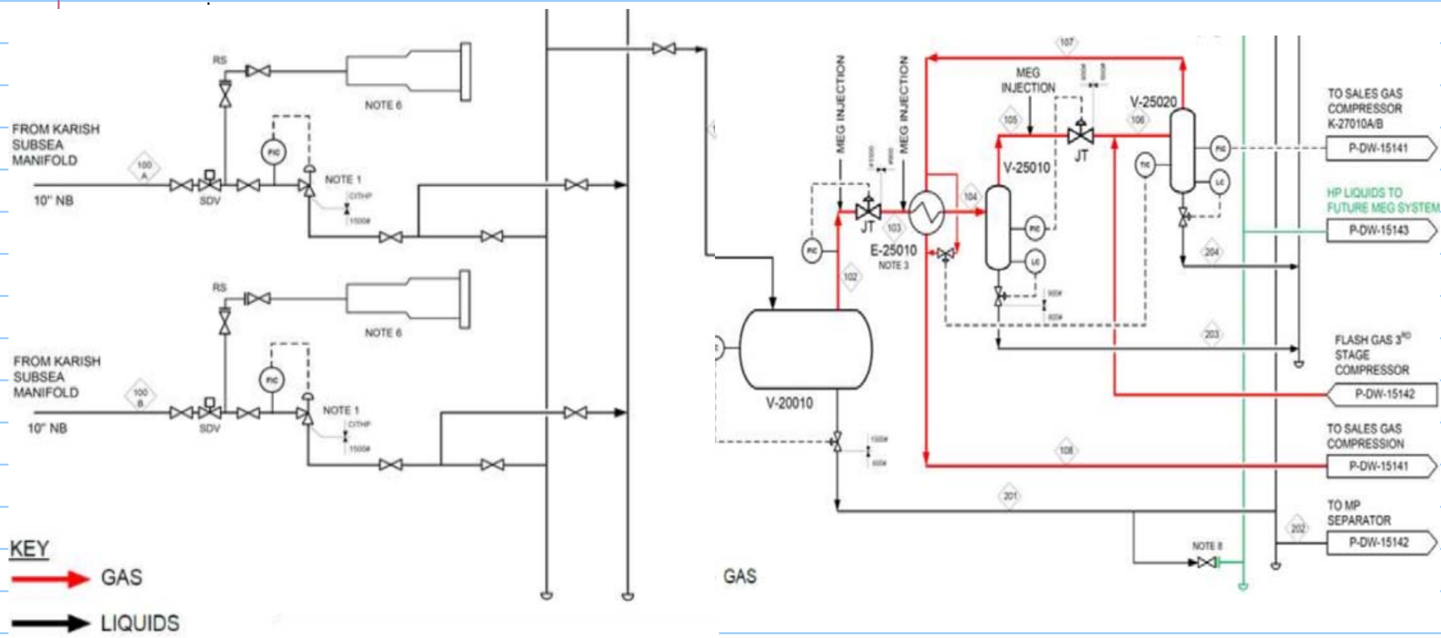
Sketch of system to model



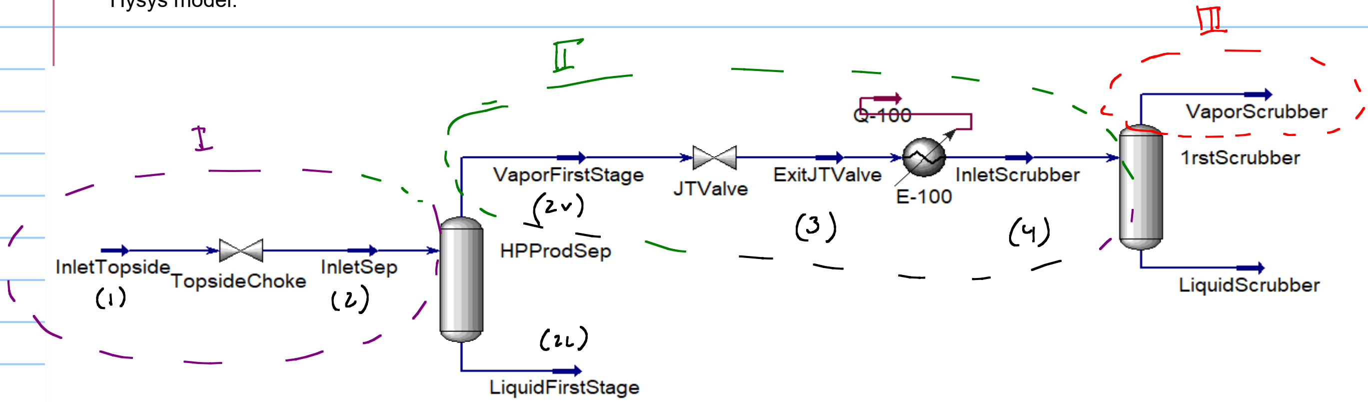
Sketch of system to model(we forgot to add the cooler before the scrubber)

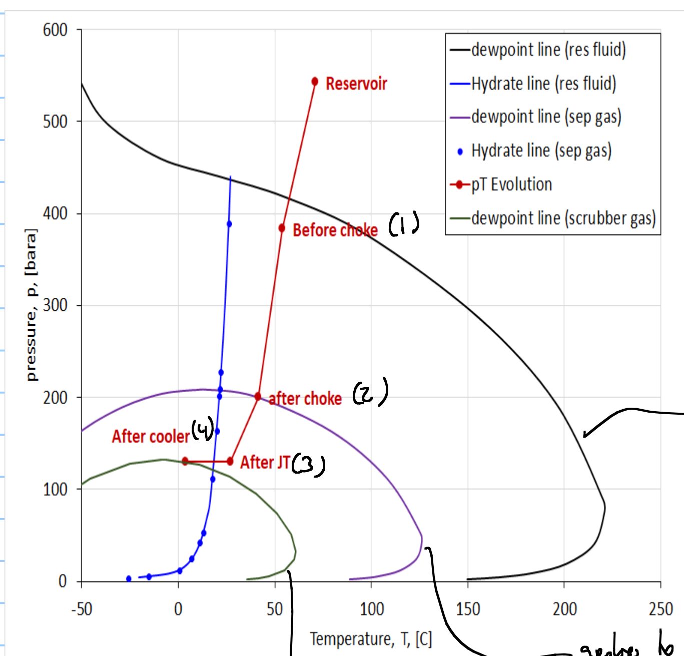


Modeling the topside facilities of the Karish and Tanin field in Hysys



Hysys model:





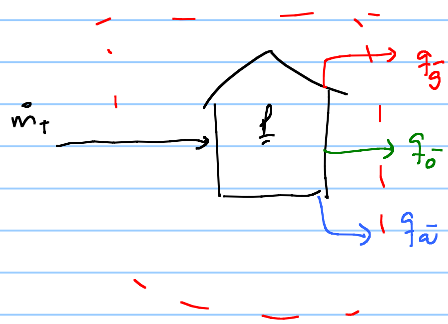
(2), (2v) and (2L) have the same p, T conditions

applies to region I

applies to region II

applies to region III

Estimating inlet mass flow to the processing facilities:



$$\dot{m}_T = \underbrace{q_g}_{m^3/d} \underbrace{\rho_g}_{kg/m^3} + q_o \cdot \rho_o + q_w \cdot \rho_w$$

assume q_o and $q_w << q_g$

gives:

$$\dot{m}_T \approx q_g \rho_g$$

$$\frac{p_{sc}}{\rho_{sc}} = \frac{R_u}{MW} \cdot T_{sc}$$

$$\rho_g = \rho_{sc} = \frac{p_{sc}\, MW}{R_u\, T_{sc}}$$

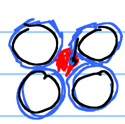
B11 =1.01325/(0.08314*(15.56+273.15)/(B4*28.97))

	A	B	C
1	Class exercise, TPG4230, Prof. Milan Stanko (NTNU)		
2			
3	Initial separator pressure	200	bara
4	Gas specific gravity	0.612	[-]
5	Reservoir Temperature, T_R	71	°C
6	Initial reservoir pressure, p_{Ri}	542.5	bara
7	$p_{downstreamJTvalve}$	130	bara
8	$T_{arrivalFPSO}$	54	°C
9			
10	q_{Karish}	8.33E+06	[Sm3/d]
11	sc gas density	7.48E-01	[kg/m3]
12	massflow	6.24E+06	[kg/d]

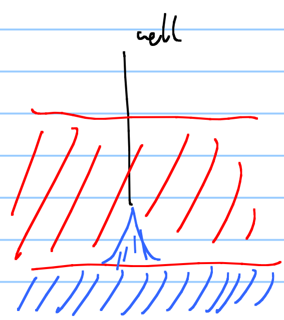
q_{Karish}	8.33E+06	[Sm3/d]
sc gas density	7.48E-01	[kg/m3]
massflow	6.24E+06	[kg/d]

- water content in natural gas

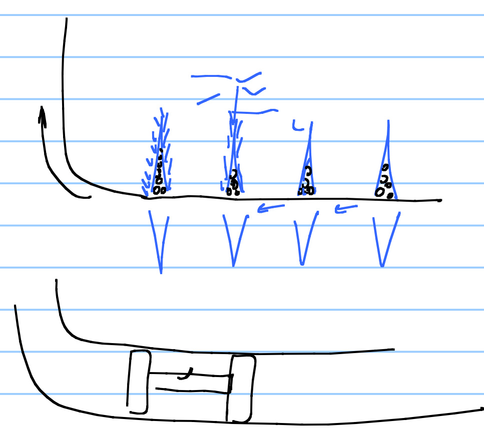
Sources of water in gas wells



Saturation from connate water



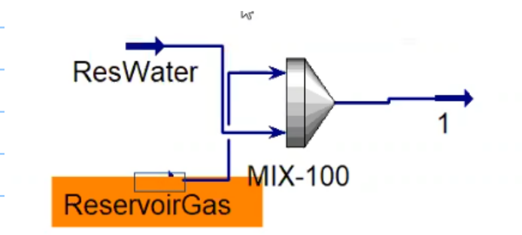
From aquifer (dangerous!)



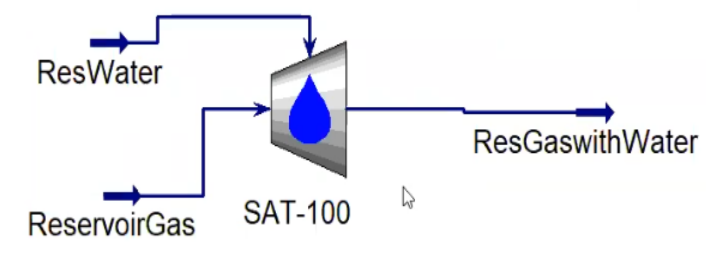
From frack jobs (shale gas)

In this field we assume water comes from saturation by connate water only

How to do it in Hysys?
OLD approach:
-Two streams, reservoir water and reservoir gas at same p and T
-Increase molar rate of res water until stream 1 just becomes two phase.
-Read the composition of stream 1

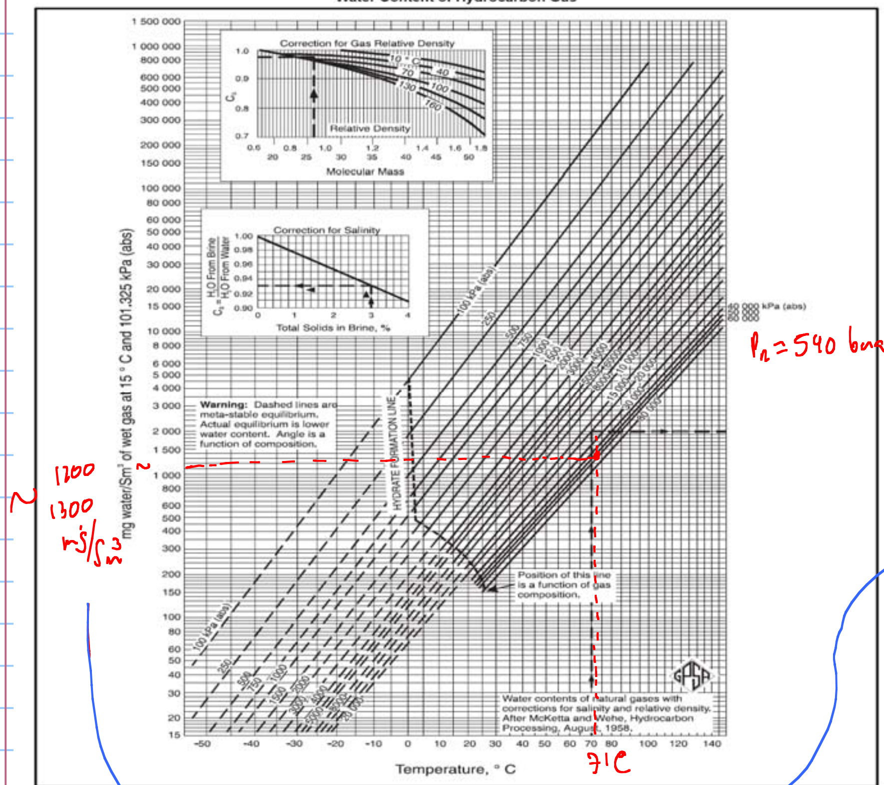


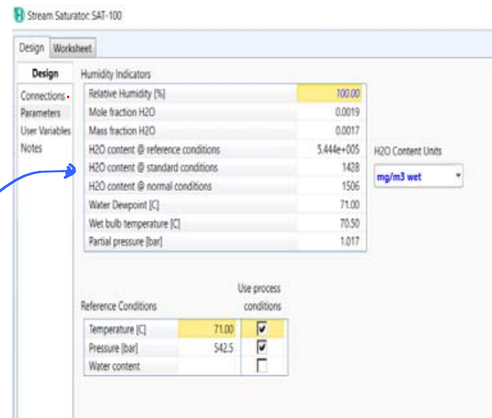
How to do it in Hysys?
NEW approach, use the saturation unit



Quality control of the result of the saturation unit:

FIG. 20-4
Water Content of Hydrocarbon Gas



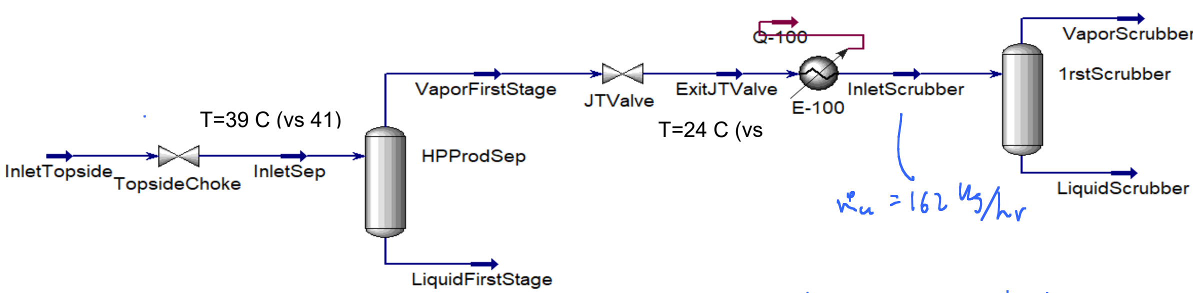


20-5
Similar to:

Component	Mole fraction (res gas)	Mole fraction (res gas sat with water)
N2	6.27E-03	6.26E-03
CO2	7.60E-04	7.59E-04
C1	9.42E-01	0.940683628
C2	1.56E-02	1.56E-02
C3	9.44E-03	9.42E-03
iC4	2.75E-03	2.74E-03
C4	2.97E-03	2.96E-03
iC5	1.80E-03	1.80E-03
C5	1.14E-03	1.14E-03
C6	1.90E-03	1.90E-03
C7	2.77E-03	2.76E-03
C8	1.78E-03	1.78E-03
C9	1.16E-03	1.16E-03
C10	1.00E-03	9.98E-04
C11	9.60E-04	9.58E-04
C12	8.90E-04	8.88E-04
C13	1.11E-03	1.11E-03
C14	6.20E-04	6.19E-04
C15+	4.65E-03	4.64E-03
H2O	0.00E+00	1.87E-03

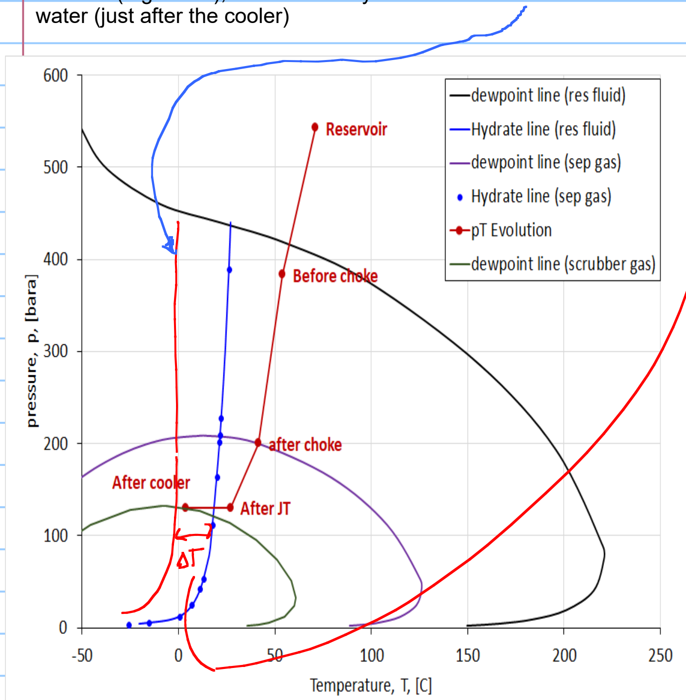
New composition considering saturation with water

How does it affect our previous results?



→ ~ 291 kg/h water ≃ 7 1E03 kg/d

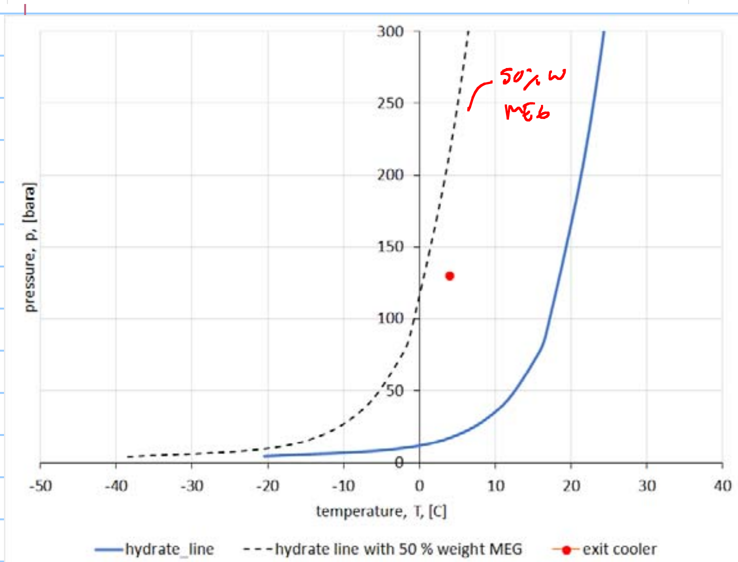
We have free water in the separator gas line, and after the cooler there is a risk of hydrate formation. Therefore it is necessary to inject an inhibitor (e.g. MEG), to move the hydrate line to the left. There should be enough MEG to suppress hydrates in the place where there is most water (just after the cooler)



$$wt\%\,MEG = \frac{\dot{m}_{MEG}}{\dot{m}_{MEG} + \dot{m}_{H_2O}}$$

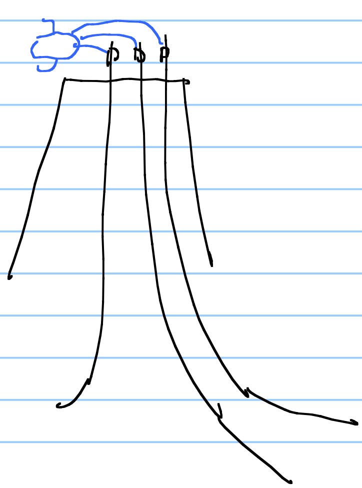
Can be calculated from Hammerschmidt equation

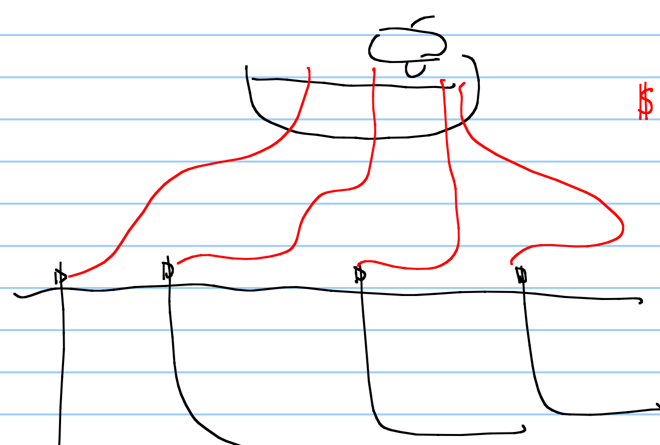
We can use the excel sheet of question 4, quiz 18:
http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2021/Quizzes/Quiz18.html
We substitute our hydrate line and calculate the amount of weight % of MEG required such that the outlet of the cooler is outside the hydrate formation zone

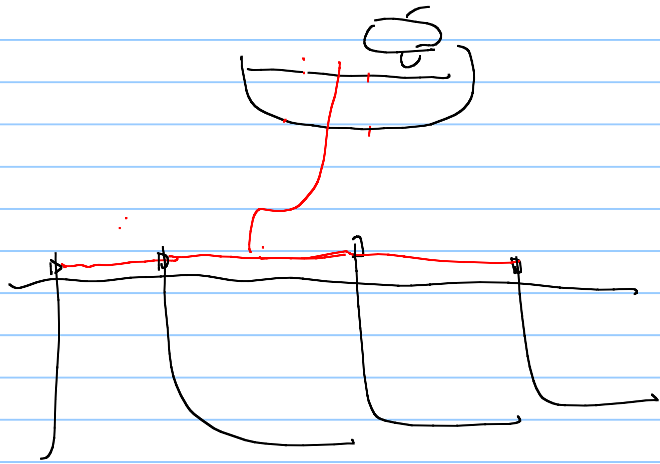


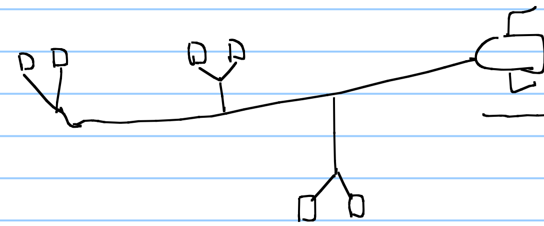
So approximately 162 kg/hr of MEG is needed

• Networks collection of pipes, flowline, pipeline, valves, pumps, take the fluids from wells to the processing facilities.

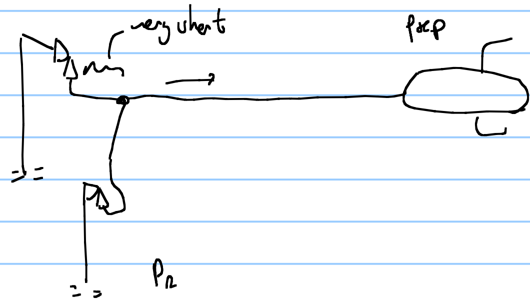








Example: 2 Dry gas wells

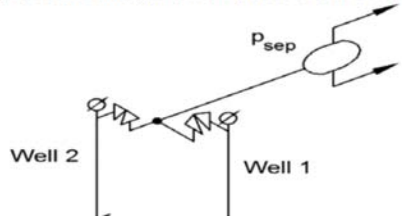


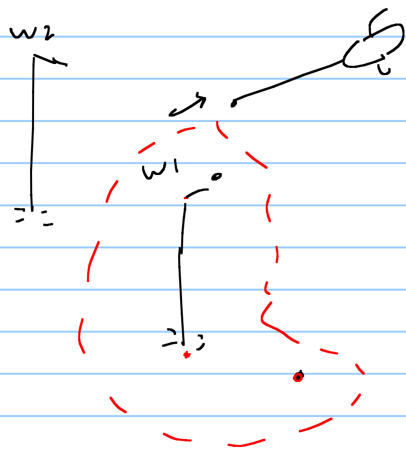
open choke $\Delta p_{c_1} = 0$ $\Delta p_{c_2} = 0$

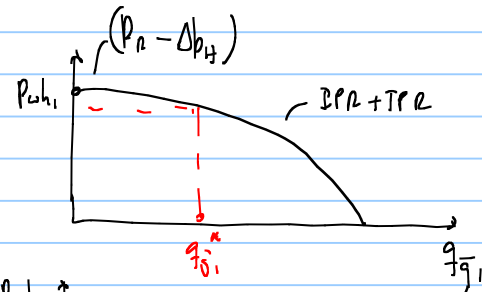
	Equations	Nr equations	Nr unknowns
IPR	$q_{g_1} = C_{R_1}(P_{R_1}^2 - P_{wf_1}^2)^{n_1}$ $q_{g_2} = C_{R_2}(P_{R_2}^2 - P_{wf_2}^2)^{n_2}$	2	4
TPR	$q_{g_1} = C_{T_1}\left(\frac{P_{wf_1}^2}{e^{s_1}} - P_{wh_1}^2\right)^{0.5}$ $q_{g_2} = C_{T_2}\left(\frac{P_{wf_2}^2}{e^{s_2}} - P_{wh_2}^2\right)^{0.5}$	2 ⌊4	2 ⌊6
PPR	$q_{g_1} + q_{g_2} = C_{PL}(P_j^2 - P_{sep}^2)^{0.5}$	1 ⌊5	1 ⌊7
	$\Delta p_{c_1} = 0$ $P_{wh_1} = P_j$	1 ⌊6	0 ⌊7
	$\Delta p_{c_2} = 0$ $P_{wh_2} = P_j$	1 ⌊7	0 ⌊7

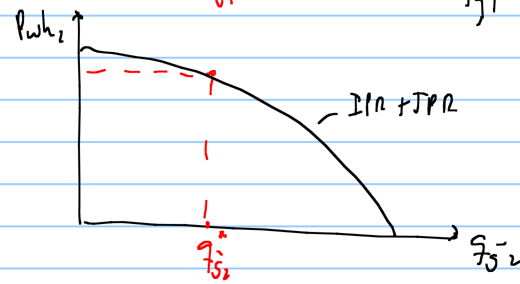
PROBLEM 4 (18 POINTS). Network solving. (2017) exam

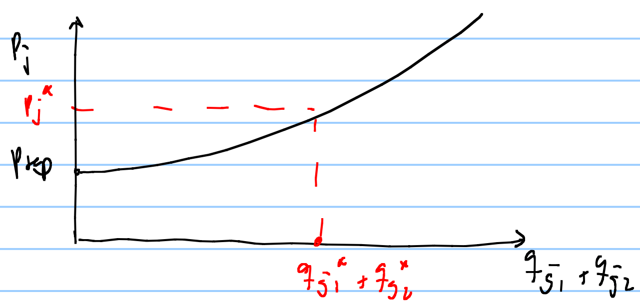
Consider the gas field with two wells, a manifold a pipeline and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal when the choke is open.











approach nr. 1

1: assume $q_{g_1}^*$ $q_{g_2}^*$

2: Read $p_{wh_1}^*$, $p_{wh_2}^*$, p_j^*
(WPR$_1$) (WPR$_2$) (PPR)

3: Verify $p_{wh_1}^* = p_{wh_2}^* = p_j^*$ — not

yes

$q_{g_1}^*$, $q_{g_2}^*$ are solution

approach nr. 2

1. assume $p_j^* = p_{wh_1}^* = p_{wh_2}^*$

2. Read $q_{g_1}^*$ (WPR$_1$), $q_{g_2}^*$ (WPR$_2$), $q_{pipeline}^*$ (PPR)

3. Verify

$q_{g_1}^* + q_{g_2}^* = q_{pipeline}^*$ — not

yes

solution

1st iteration

$p_j = 50$ bara

$q_{g_1}^* = 1.2E06\ Sm^3/d$

$q_{g_2}^* = 1.57E06\ Sm^3/d$ + $2.77E6\ Sm^3/d$ $\varepsilon = 0.97\ 1E06\ Sm^3/d$

$q_{pipeline}^* = 1.8E06\ Sm^3/d$ $1.8E06\ Sm^3/d$

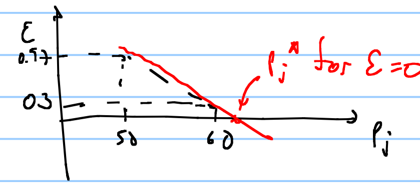
2nd

$p_j = 60$ bara

$q_{pipeline}^* = 2.3E06\ Sm^3/d$ $2.3E06\ Sm^3/d$ $\varepsilon = 0.3\ 1E06\ Sm^3/d$

$q_{g_2}^* = 1.45E06\ Sm^3/d$ + $2.60E06\ Sm^3/d$

$q_{g_1}^* = 1.15E06\ Sm^3/d$



$$\frac{\varepsilon_1 - \varepsilon_2}{p_{j_1} - p_{j_2}} = \frac{\varepsilon_1 - 0}{p_{j_1} - p_j^*}$$

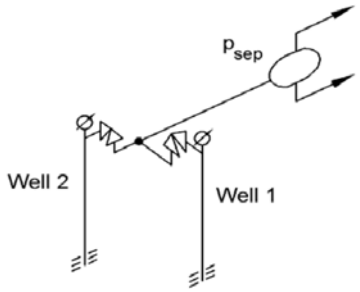
$p_j^* = \sim$

Youtube video nr. 19

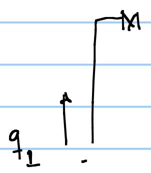
Exercise: using data from Problem 4 of the Exam 2017:

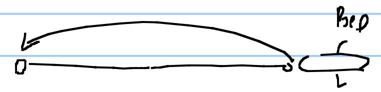
PROBLEM 4 (18 POINTS). Network solving.

Consider the gas field with two wells, a manifold a pipeline and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal when the choke is open.



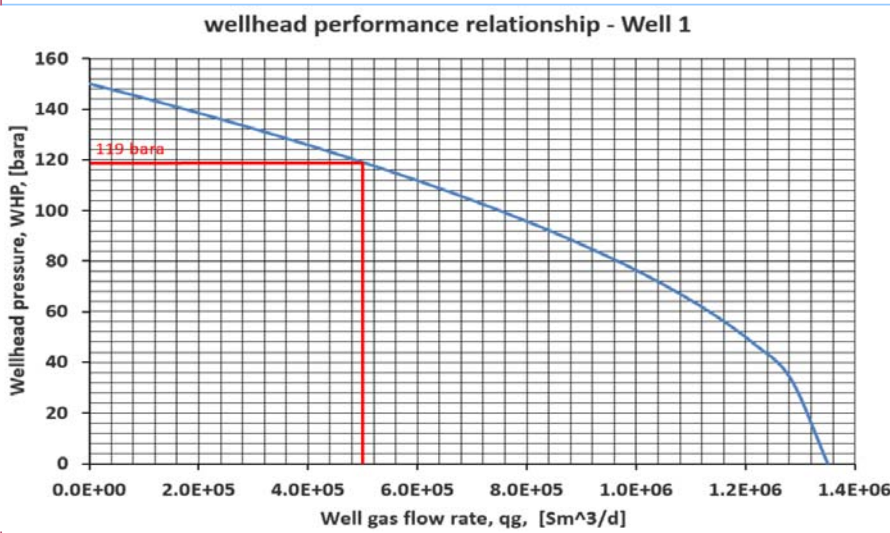
Will it be possible to produce 0.5 E06 Sm3/d from each well? if so, what is the choke deltap required in each well?

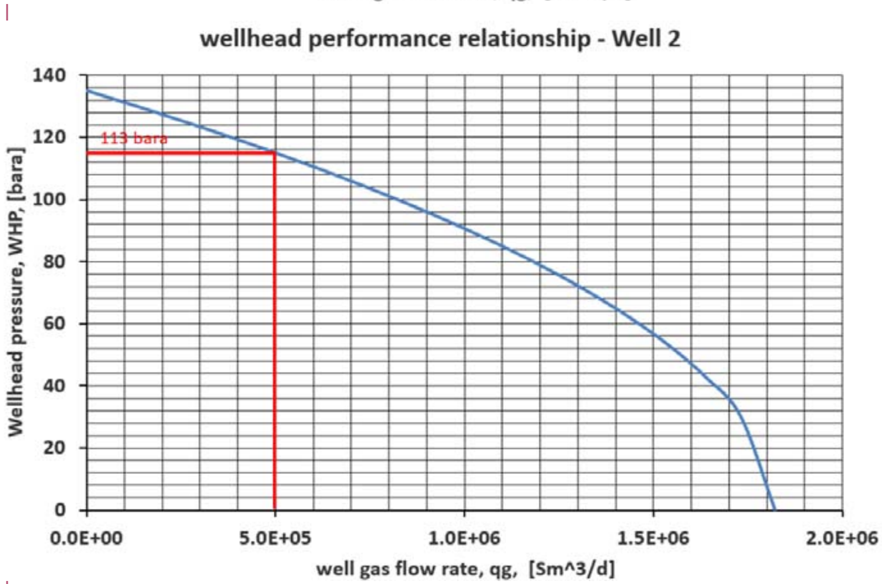


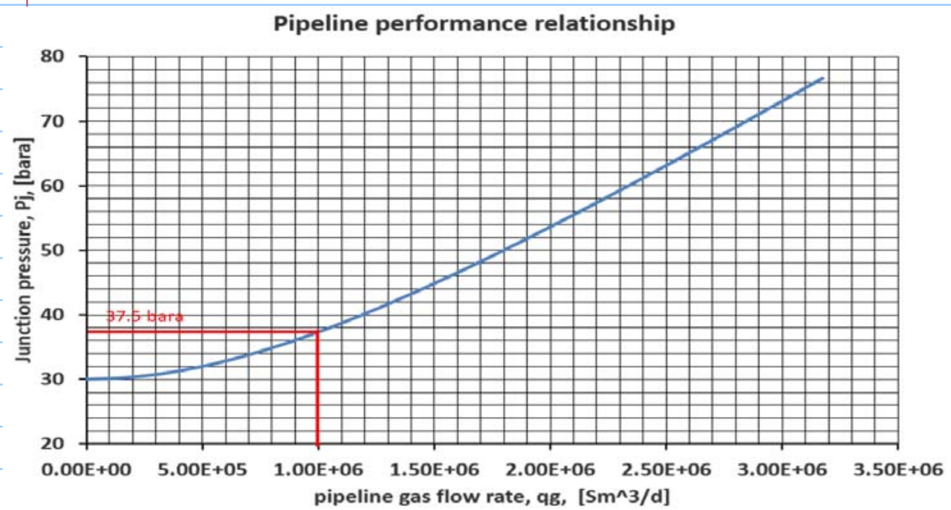


verify $\Delta p > 0$ then q_1 is feasible

if $\Delta p < 0$ then q_1 is no feasible



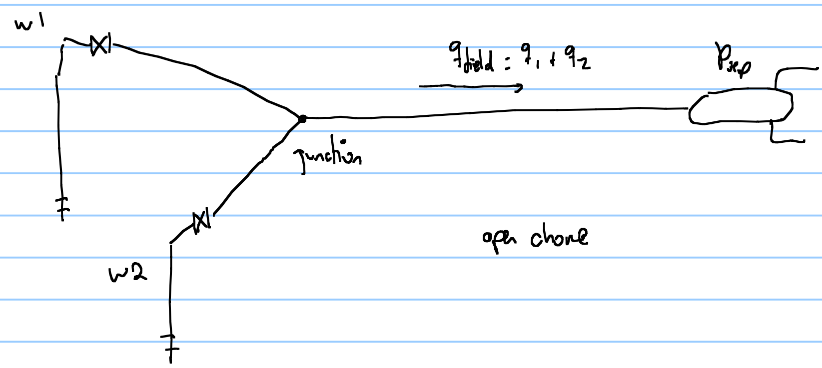




Deltap_choke1 = 119 - 37.5 = 81.5 bara
Deltap_choke2= 113-37.5 = 75.5 bara

Yes, it is possible to produce 0.5 E06 Sm3/d from well 1 and 2.

Exercise on Dry gas network using Excel



we have to assume either $\bar{q}_1$, $\bar{q}_2$

OR: P_{wf_1}, P_{wf_2} ← $P_{wf} < P_R$

↳ we prefer to assume P_{wf} because I know the upper bound

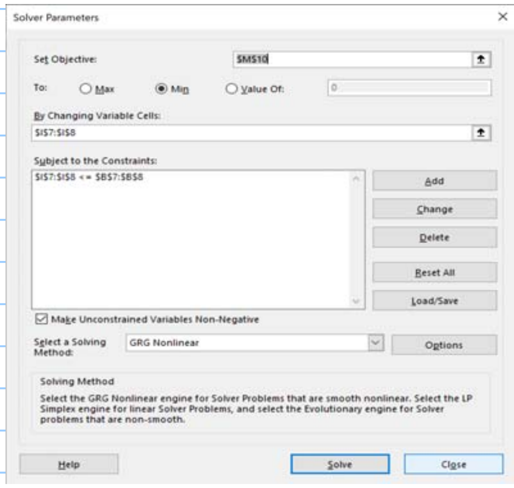
$$q = C_R \left(P_R^2 - P_{wf}^2\right)^n$$

$$P_{wf} = \sqrt{\underbrace{P_R^2 - \left(\frac{q}{C_R}\right)^{1/n}}_{\text{i don't know } q_{max}\text{, and can give problems in eq.}}}$$

objective variable:

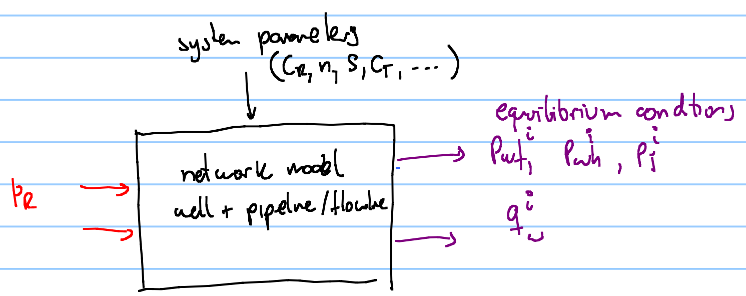
$$\left(P_{j_{av}} - P_{j_1}\right)^2 + \left(P_{j_{av}} - P_{j_2}\right)^2 + \left(P_{j_{av}} - P_{j_{sep}}\right)^2$$

		IPR		Tubing		Flowline						
Component Name	p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	pjunc	error
	[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bara]	(bara^2)
W_1	120	52	0.8	0.13	7680	8673		38	1.02E+05	33	31	1E-0[illegible]
W_2	120	40	0.75	0.11	8600	7563		34	4.95E+04	31	31	9E-1[illegible]
Pipeline						14080	28.6		1.51E+05		31	2E-0[illegible]
										Average=	31	4E-0[illegible]



If solver is not available

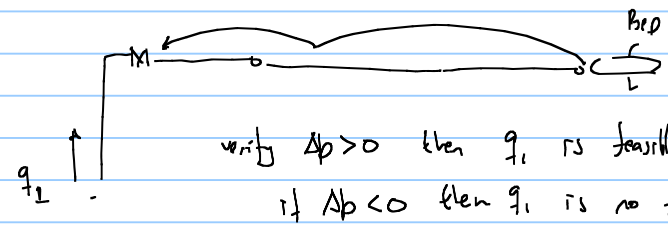
Activate solver → excel menu → options → Add in → "go" → tick on "solver" or "problem solver"



solving the network
with choke

- option 1, fixing rates

(option usually not available in commercial software)



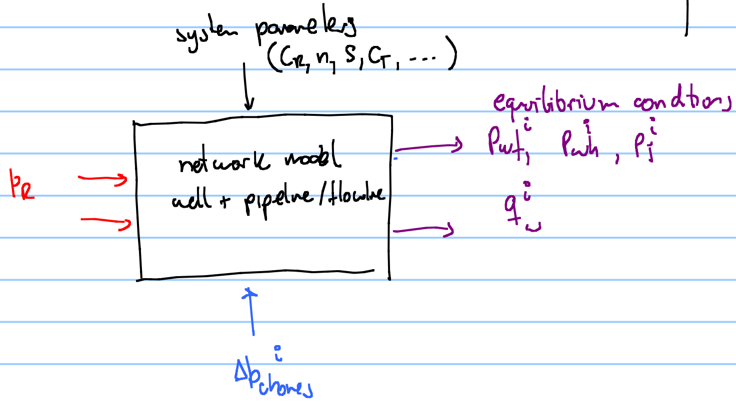
verify $\Delta p > 0$ then q_1 is feasible

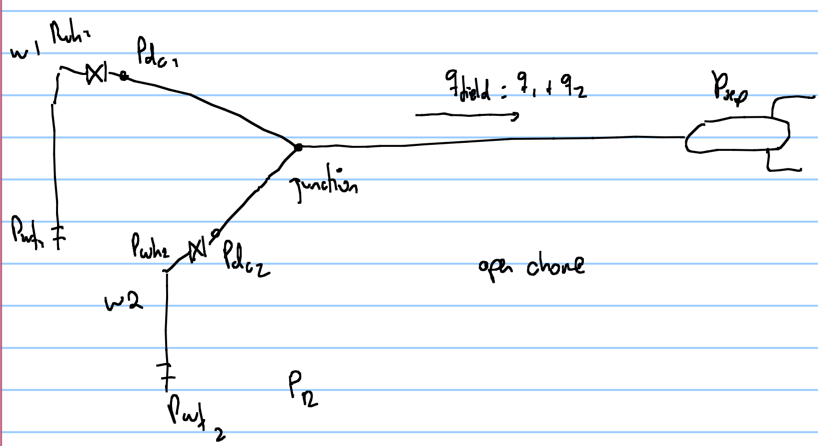
if $\Delta p < 0$ then q_1 is no feasible

for example, it is desirable to produce
$$\begin{cases} q_1 = 80000 \ Sm^3/d \\ q_2 = 40000 \ Sm^3/d \end{cases}$$

Component Name	p_R	IPR: C	IPR: n	IPR: S	Tubing: Ct	Flowline: Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc
	[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]
W_1	120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30
W_2	120	40	0.75	0.11	8600	7563		66	4.00E+04	63	32	30	30
Pipeline						14080	28.6		1.20E+05				30

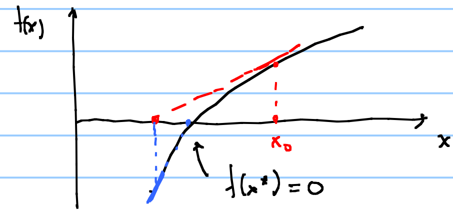
- option 2: include the choke "model" → 2 options
  - Δp_{choke}. ← this option will be discussed next
  - choke opening $\quad \Delta p_{choke} = f(q_g, \text{Opening}, P_1)$

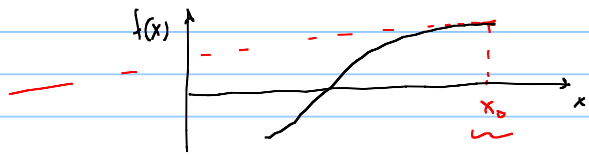




open choke

	IPR		Tubing		Flowline								
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)
120	52	0.8	0.13	7680	8673		42	9.92E+04	38	5	33	30	3E-10
120	40	0.75	0.11	8600	7563		39	4.84E+04	36	5	31	30	1E-09
					14080	28.6		1.48E+05				30	3E-09
									Average=			30	4E-09





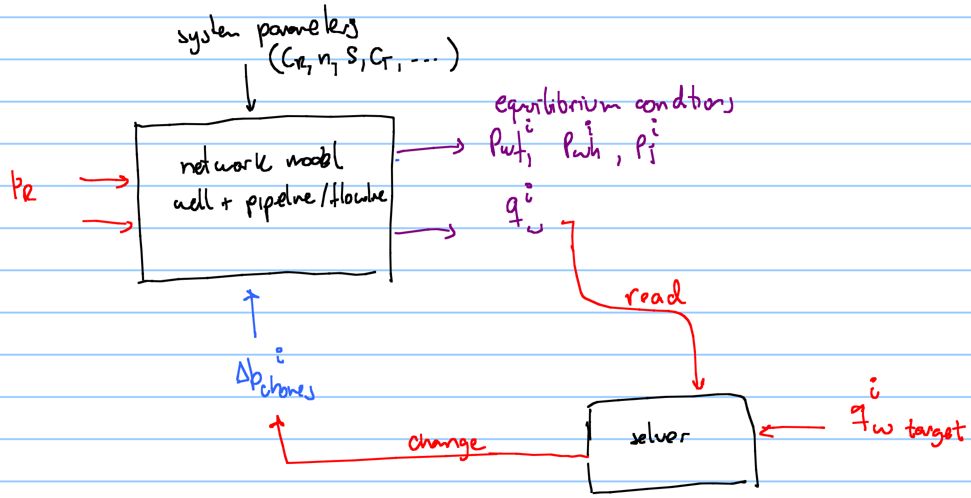
--- step 1

--- step 2

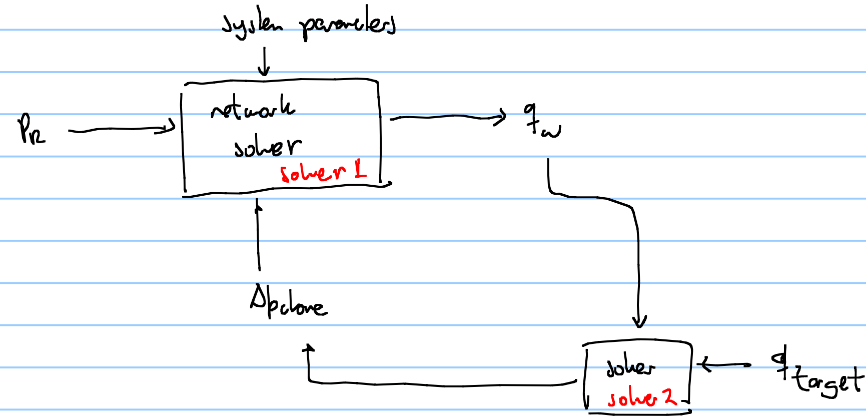
for derivative based solver it is necessary to give a good initial seed

	IPR		Tubing		Flowline								
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)
120	52	0.8	0.13	7680	8673		57	9.01E+04	52	20	32	30	1E-09
120	40	0.75	0.11	8600	7563		54	4.44E+04	51	20	31	30	8E-10
					14080	28.6		1.35E+05				30	4E-09
									Average=			30	6E-09

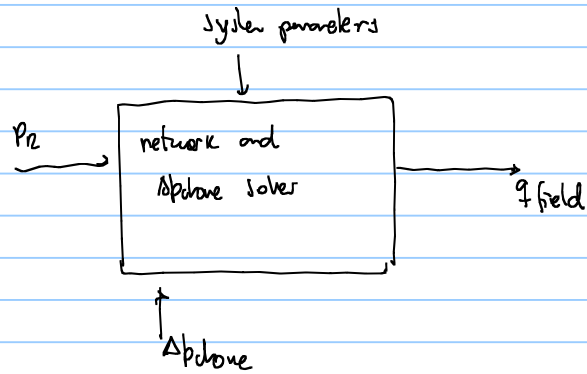
- How to use this model to find Δp_{choke} such that $q_1 = 80000$ Sm³/d
  $q_2 = 40000$ Sm³/d



in excel it is not possible to have two levels of solver



"Merging the two solvers"

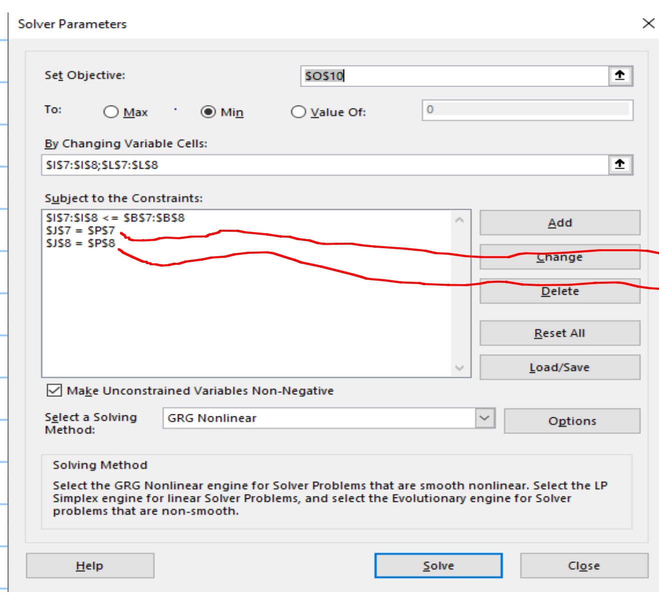


objective variable :

$$\left(P_{j_{av}} - P_{j_1}\right)^2 + \left(P_{j_{av}} - P_{j_2}\right)^2 + \left(P_{j_{av}} - P_{j_{sep}}\right)^2$$

variables

changing P_{wf_1}
P_{wf_2}
$\Delta p_{choke\,1}$
$\Delta p_{choke\,2}$



constraints

$q_1 = q_{1\,target}$

$q_2 = q_{2\,target}$

	IPR		Tubing		Flowline									
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error	qtarget
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)	[Sm3/d]
120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30	9E-11	80000
120	40	0.75	0.11	8600	7563		87	3.00E+04	82	52	30	30	5E-11	30000
					14080	28.6		1.10E+05				30	7E-12	
									Average=			30	2E-10	

Youtube nr. 20

Coupling reservoir + production simulators
network
well

- porous media
- wellbore flow can be included with tubing tables
- transient

- flowline + pipeline + wellbore flow
- steady state ($\partial/\partial t = 0$)
- Runs with IPR as boundary conditions on well

Example of explicit coupling strategy

Reservoir simulator

t_1, P_R^i, S_o^i, S_w^i, S_g^i, K_{rg}, K_{ro}

Production simulator

Analytical model for IPR

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

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

$$\frac{q_o}{q_{max}} = 1 - 0.2\frac{P_{wf}}{P_R} - 0.8\frac{P_{wf}^2}{P_R^2}$$

generated "IPR's"

q^i_{Target}

network model (optimization)

choke opening

esp frequency

gas lift rates

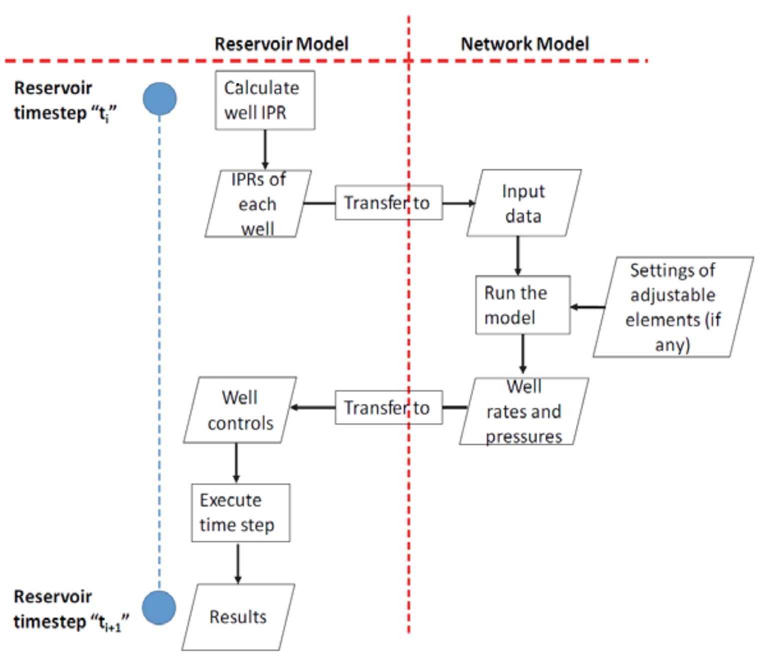
q_w^i, P_{wf}^i

compute

t_2, P_R, S_o, S_w, S_g, K_{rg}, K_{ro}

transfer IPR

and repeat...



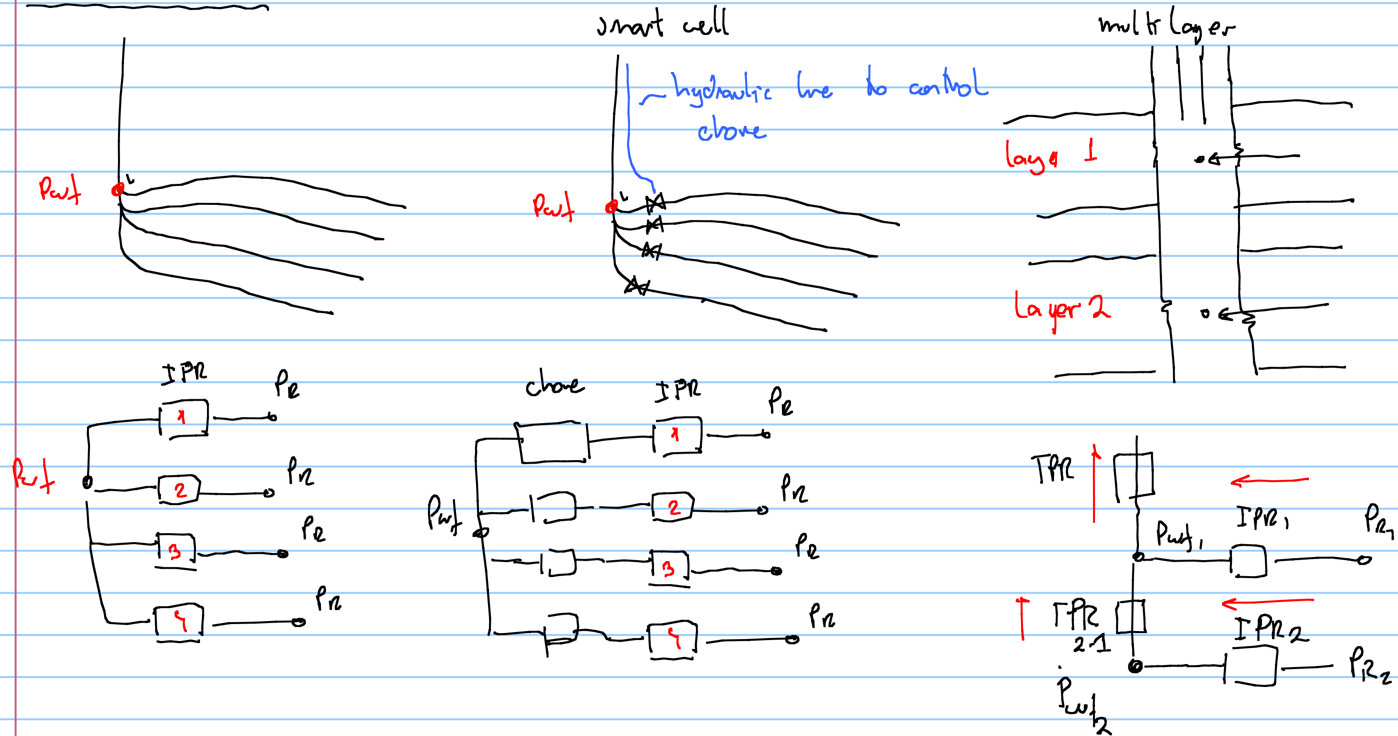
page 19 of compendium

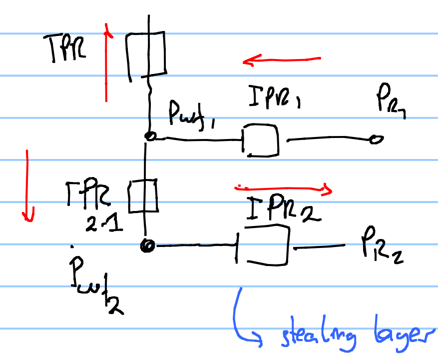
implicit coupling: requires either
- solving all equations simultaneously
- re-run the step until some convergence is achieved

Youtube n. 21

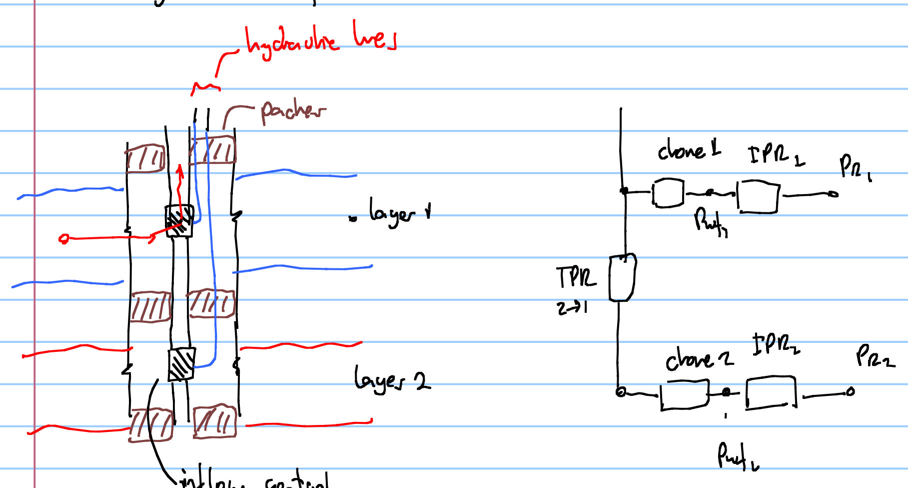
Downhole networks

multi-lateral wells



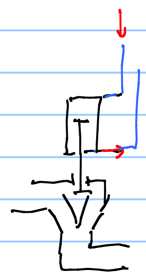


multi layer with inflow control

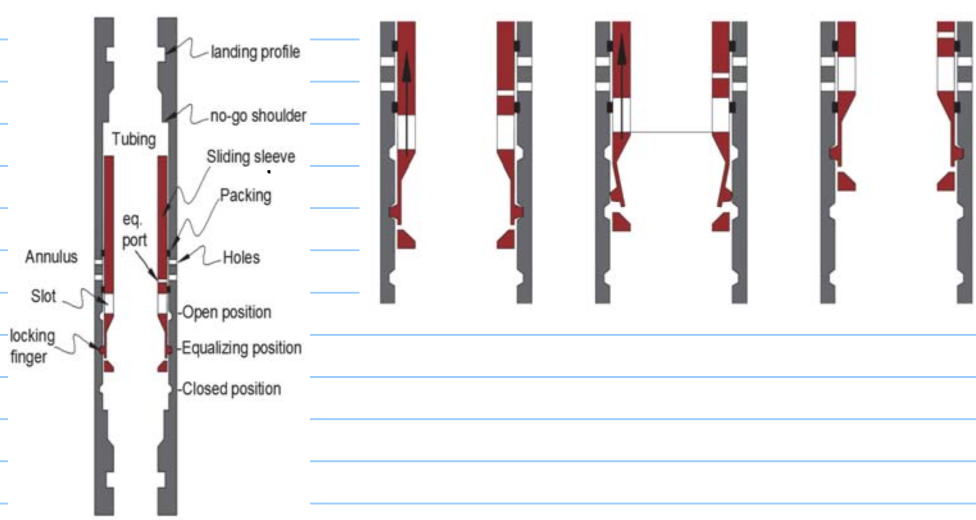


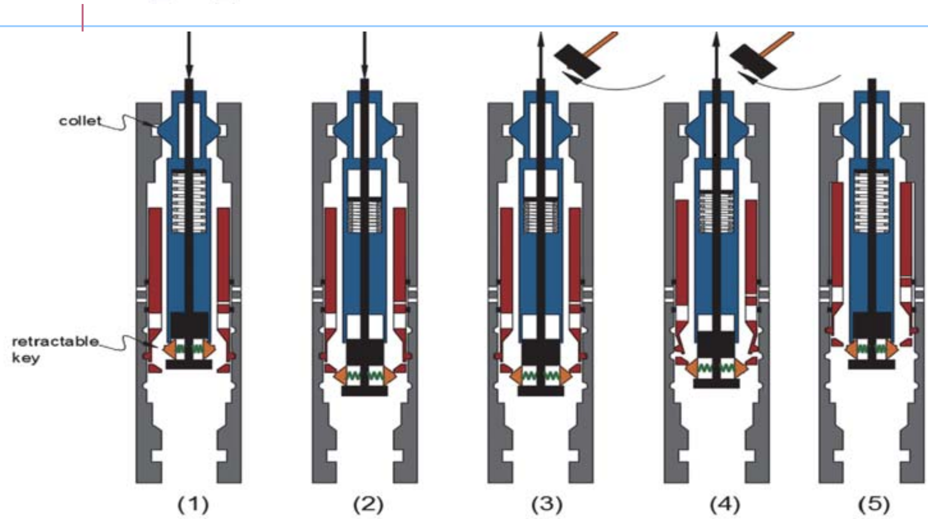
These chokes can be actuated from surface ($$$) or mechanically ($$) actuated for example with wire line, coil tubing

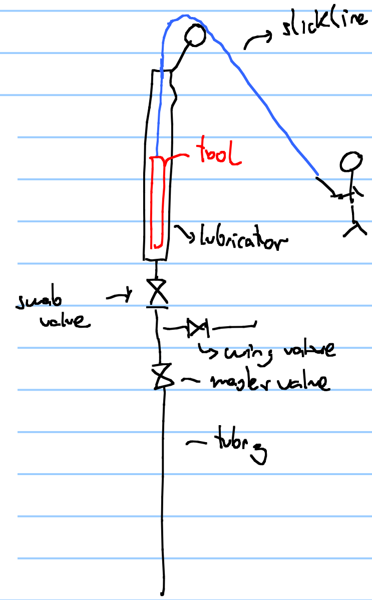
example of
hydraulic activation of choke



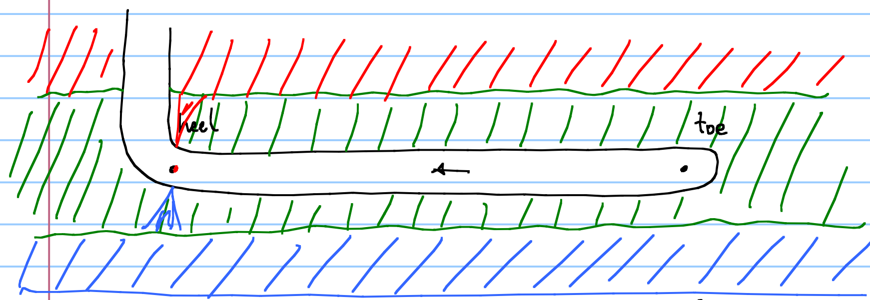
sliding sleeve functionality page 71 of compendium





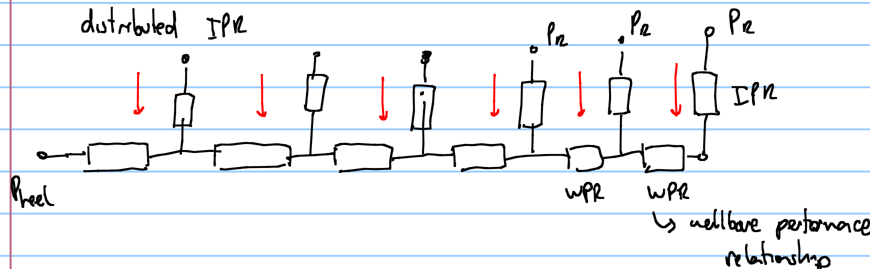


Networks to study a long horizontal well

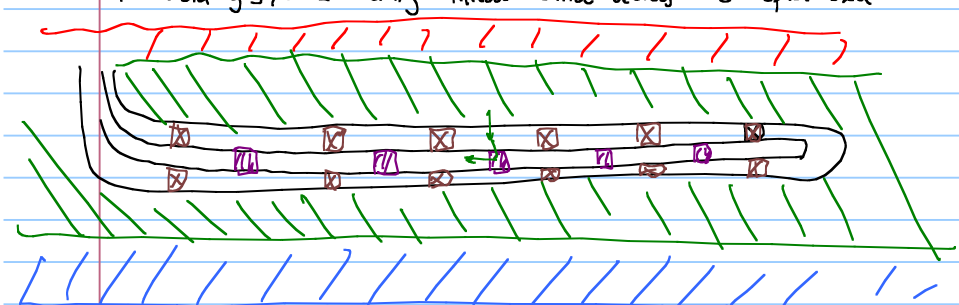


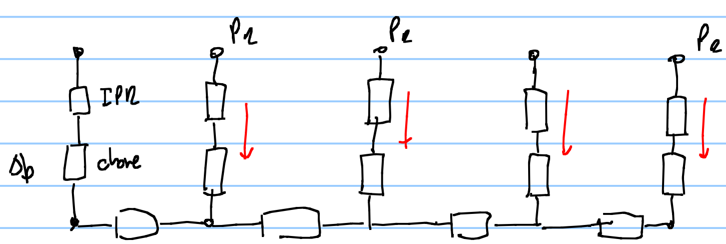
$q \propto (P_R - P_{wf})$

distributed IPR



to avoid gas/water coning inflow control devices are often used

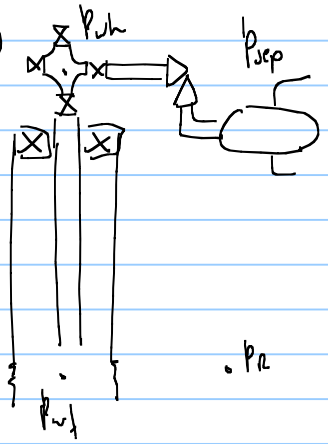




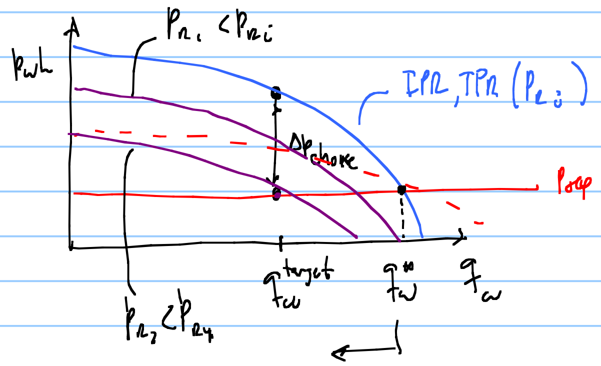
the chokes are used to even the rate profile along well. to ensure even depletion and high recovery factor

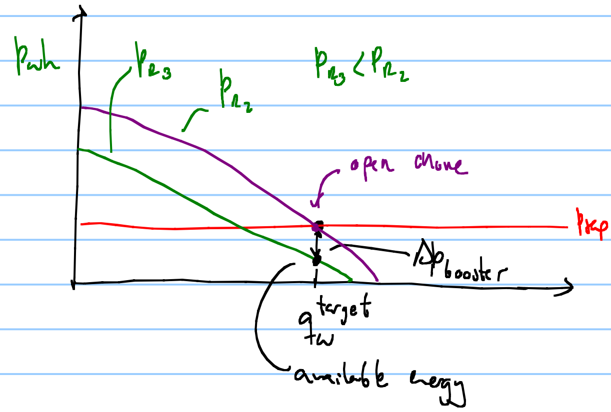
Notes of class 20210420

Class 20210420: Boosting



wellhead equilibrium





remember: another option, instead of using a booster is to modify the available and required pressure curves (e.g. fracking, stimulation, tubing ϕ change, gas-lift, Psep lowering)

when $P_R \downarrow \longrightarrow \Delta p_{booster} \uparrow$

find "something" (equipment) to provide @ $q_{fw}^{target} \rightarrow \Delta p_{booster}$

is this combination feasible?
- technically?/physically
- $
- equipment available on market
- others

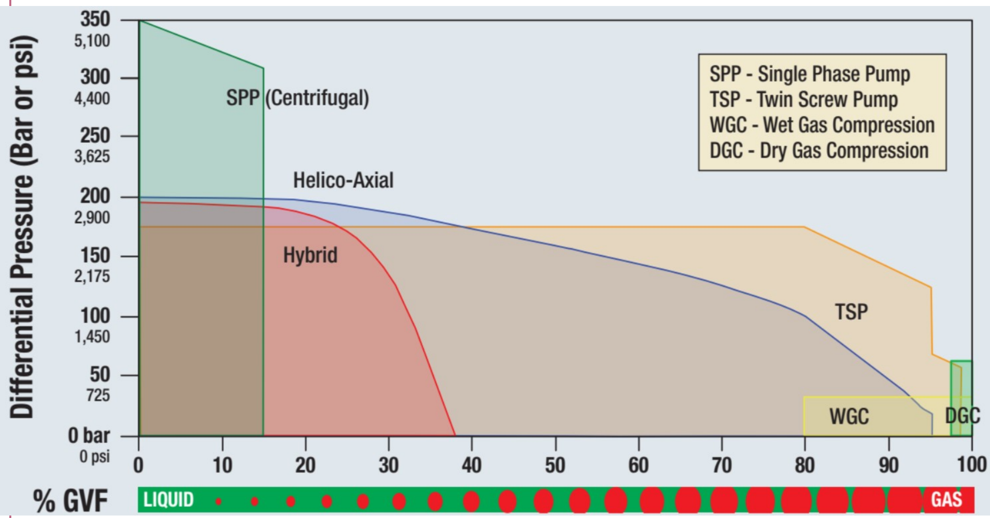
- Boosters
  - in well (Artificial lift)
    - ESP (electric submersible pump) ← offshore (screwed at end of tubing)
    - Jet pump
    - rod pumps
    - other

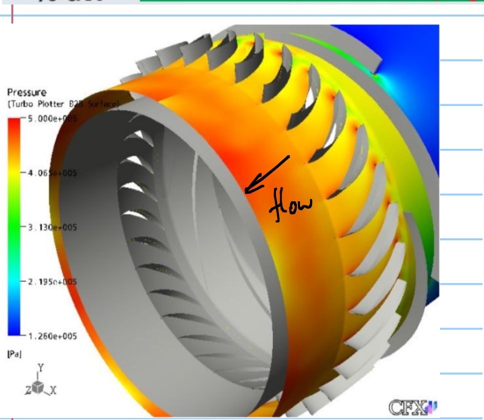
    mostly onshore (not very common in NCS)

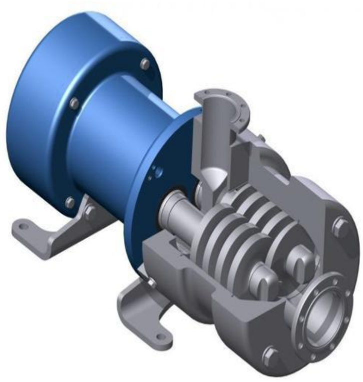
    reasons
    - "short" life time (6m - 2 years)
      ↑ intervention costs
    - if dry x-mas tree well
      the offshore structure should have a drilling package
    - if wet x-mas tree
      $ ↑
  - outside of well (typically subsea)
    - centrifugal pump GVF ≤ 0.1
    - helico-axial pumps. (GVF, gas volume fraction) @ inlet $\frac{q_g}{q_g+q_L}$

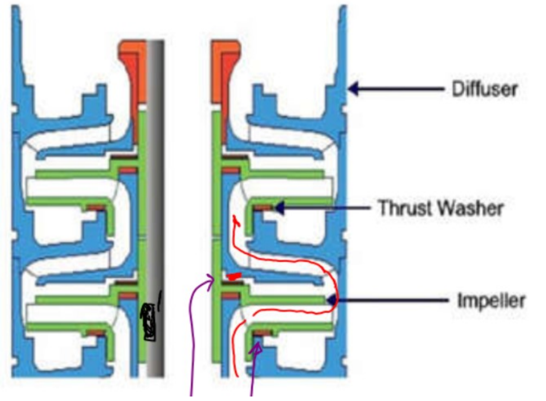
      0.1 ≤ GVF < 0.9
    - twin screw pump
    - Wet gas compressor (Gullfaks ?)

      0.9 ≤ GVF
    - Dry gas compressor GVF > 0.97 (Åsgard 1)





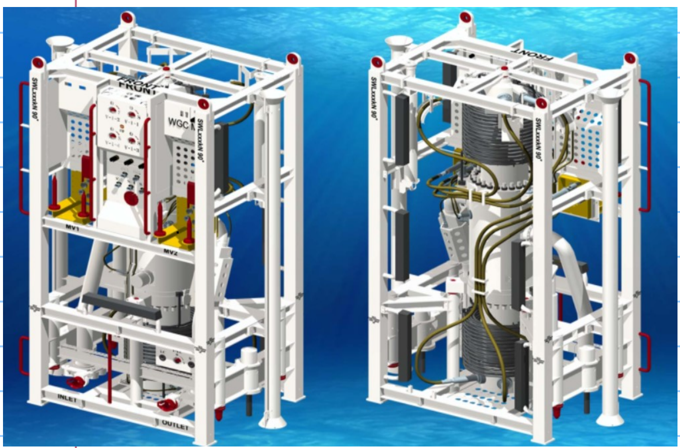




Helico-axial

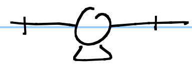
twin-screw pump

ESP



WGC

(1) suc (2) dis



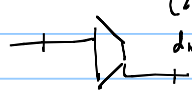
Determining <u>technical</u> feasibility of booster

if single phase pump (liquid only) $p_{suc} > p_b(T_{suc}) \cdot F_{safety}$

otherwise → multiphase pump ↑\$
↳ upstream separation

(1) suc

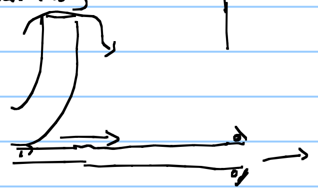
(2) dis



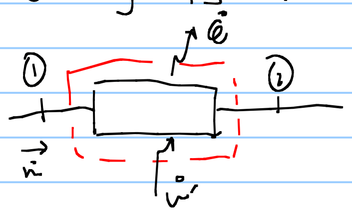
if single phase compressor $p_{suc} > p_d(T_{suc}) \cdot F_{safety}$

- for all machines

$p_{suc} \geq p_{min}$ for mechanical purposes, rotor balancing, seals



first law of thermodynamics for open systems:



$$\cancel{\dot{e}} - \dot{w} = E_1 - E_2$$

$$\dot{w} = E_2 - E_1 = \dot{m}(e_2 - e_1)$$

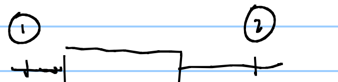
neglecting kinetic potential

$$P = \dot{w} = \dot{m}(h_2 - h_1)$$

Δh ?

$h \rightarrow f(p, T)$

$h, p \rightarrow T$

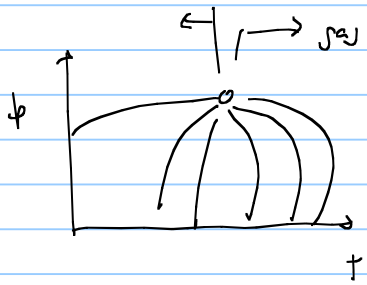


$p = 50$ bara, $T = 50°C$ → h_1

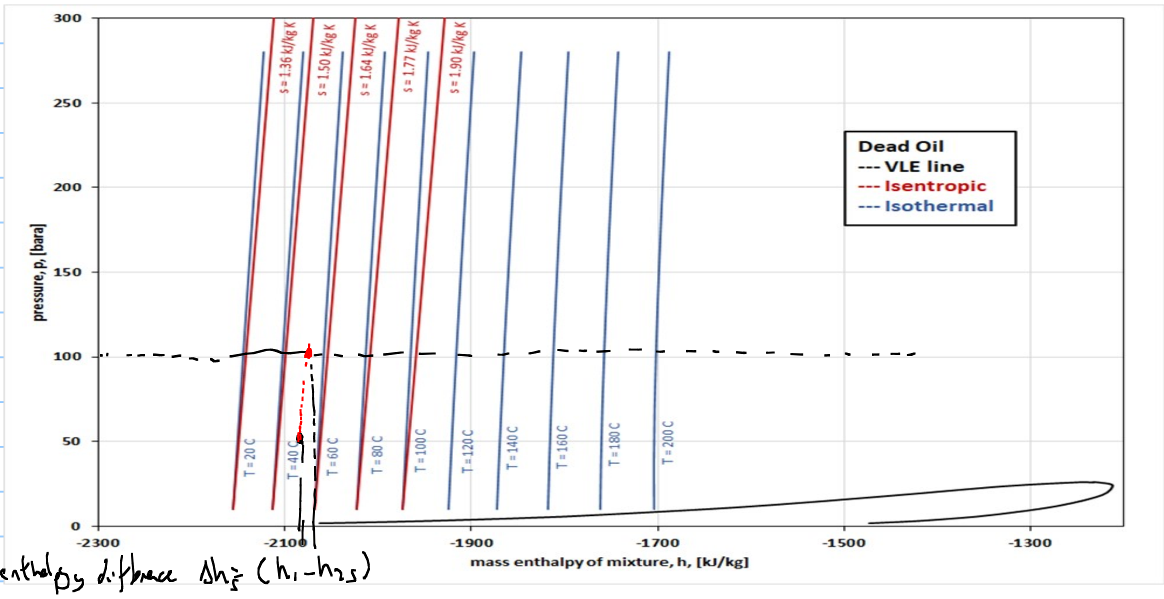
100 bara, $T = ?$

pressure-enthalpy diagram

water - Mollière diagram



Case: dead oil



ideal enthalpy difference $\Delta h_s = (h_1 - h_{2s})$

$$\Delta h_{real} = (h_2 - h_1) = \frac{(h_{2s} - h_1)}{\eta_{adiabatic}}$$

adiabatic efficiency (0 - 1)

in boosters (0.3 - 0.8)

$\Delta h_{real} > \Delta h_{ideal}$

$$\dot{w} = \dot{m} \cdot \frac{\Delta h_s}{\eta_{adiabatic}}$$

$\eta = 0.6$ (assumed)

example

$q_{\bar{o}} = 50000$ stb/d $\qquad \rho_{\bar{o}} = 800$ kg/m^3

$\dot{m} = q_{\bar{o}} \cdot \rho_{\bar{o}}$ kg/s

$$= \underbrace{\frac{50000}{6.29} \cdot \frac{1}{(24 \cdot 3600)}}_{7.} \cdot 800 = 7.4 \text{ kg/s}$$

Δh_s = instead of reading from chart, i use an approximation

for liquids $\qquad \Delta h_s \simeq \dfrac{\Delta p}{\rho} = \dfrac{(100-50) \cdot 10^5}{800} = 6250$ J/kg

ρ = constant = 800

from chart

(1) -2087.298387096774, 50.47013977128336

(2) -2080.040322580645, 100.78780177890721

$\Delta h_s \simeq 7.2$ kJ/kg

$$\left(-2080 - (-2087)\right) = 7.2 \text{ kJ/kg}$$

$$h_{(p,T)} = (h_{p,T} - h_{ref})$$

$h_{ref} > h_{p,T}$

$h_{ref} < h_{p,T}$

$$\dot{w} = \dot{m} \cdot \frac{(\Delta h_s)}{\eta_{adiab}} = \frac{7.4 \cdot 6250}{0.6 \cdot 1000} = 77 \qquad [kW]$$

ideal power = 46.3 kW

nadiab	required power [kW]
0.3	154.2
0.4	115.6
0.5	92.5
0.6	77.1
0.7	66.1
0.8	57.8

Class 20210422 : Boosting part 2

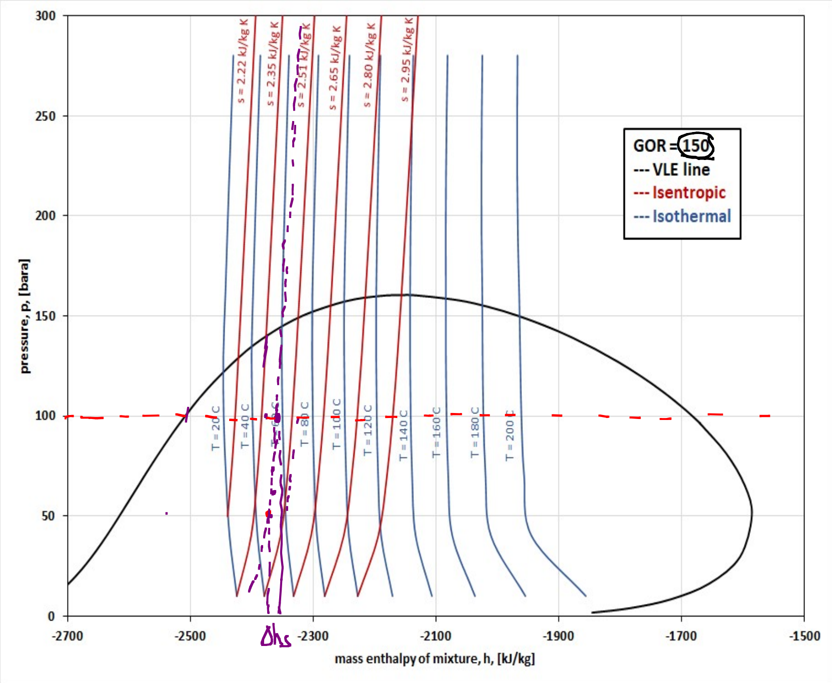
inlet: -2372.68, 50.
outlet (s): -2358.75, 99.5

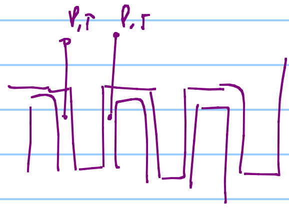
$(h_{2s}-h_1) = 14 \text{ kJ/kg}$

$P = \dot{m} \cdot \frac{\Delta h_s}{\eta_{adiab}}$

$= 7.2 \text{ kg/s} \cdot \frac{14}{0.6}$

$= 168 \text{ kW}$



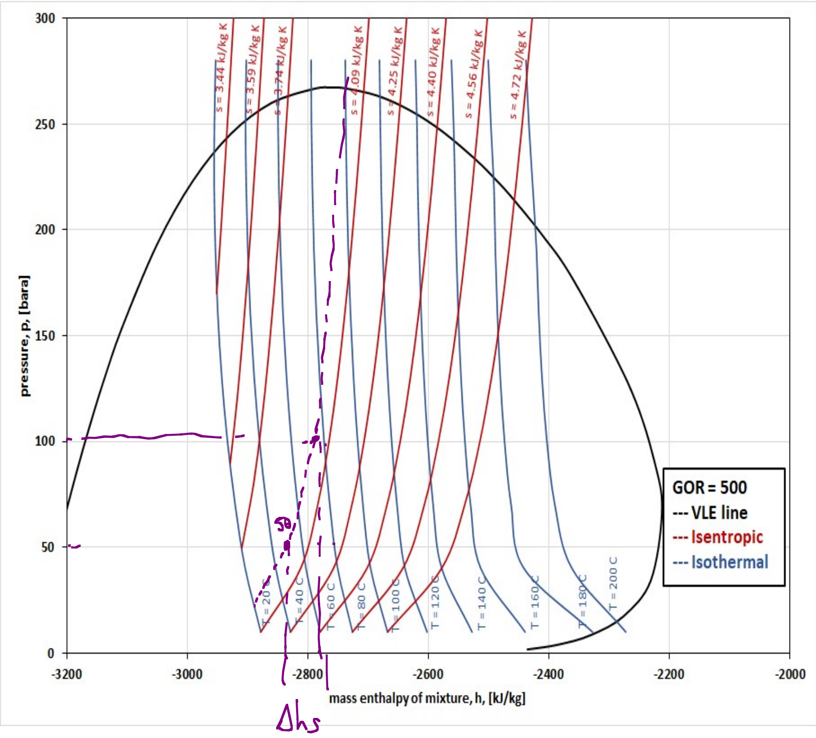


$T_{outs} \approx 57°C$
$T_{in} = 50°C$
Δh_s

inlet: -2831.8, 50.3
outlet (s): -2799.56, 99.7

$\Delta h_s \approx 31 \text{ kJ/kg}$

$P \approx 372 \text{ kW}$



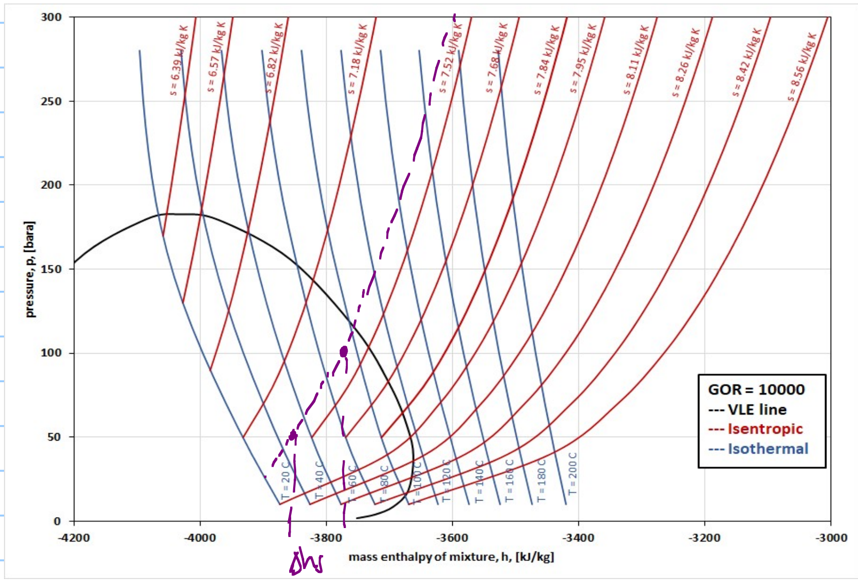
$T_{outs} = 70 C$
$T_{in} = 50°C$

inlet: -3853.71, 50.7
outlet (s): -3774.67, 99.5

$\Delta h_s \approx 79 \text{ kJ/kg}$

$P = \frac{7.2 \cdot 79}{0.6}$

$P = 948 \text{ kW}$

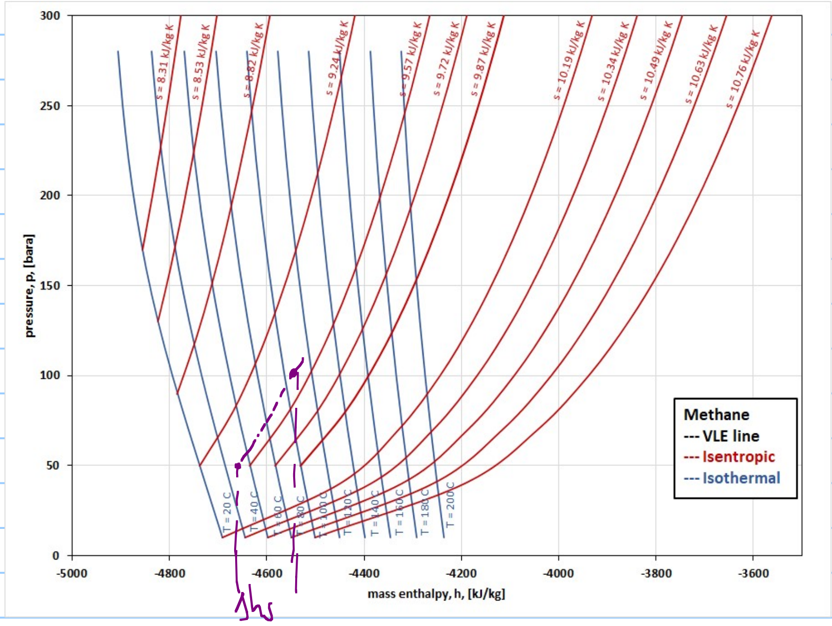


$T_{outs} \approx 93°C$
$T_{in} = 50°C$

inlet: -4661.43, 50.7
outlet (s): -4544.75, 99.5

$\Delta h_s = 117$ kJ/kg

$\underline{P} = 1404$ kW



$T_{out_s} = 105$ °C

$T_{in} = 50$ °C

Power required to compress 7.2 kg/s of the fluid from 50 bara, 50 °C to 100 bara, assuming an adiabatic efficiency of 0.6, and for different fluids:

fluid	$\underline{P}$ (kW)	T_{out_s}	q_o	q_g
Dead oil	77	51	50000 stb/d	0
GOR = 150	168	57		
GOR = 500	372	75		
GOR = 10000	948	93		
methane	1404	105		

$\rho_o = 800$ kg/m³

$\rho_g = 0.8$ kg/m³

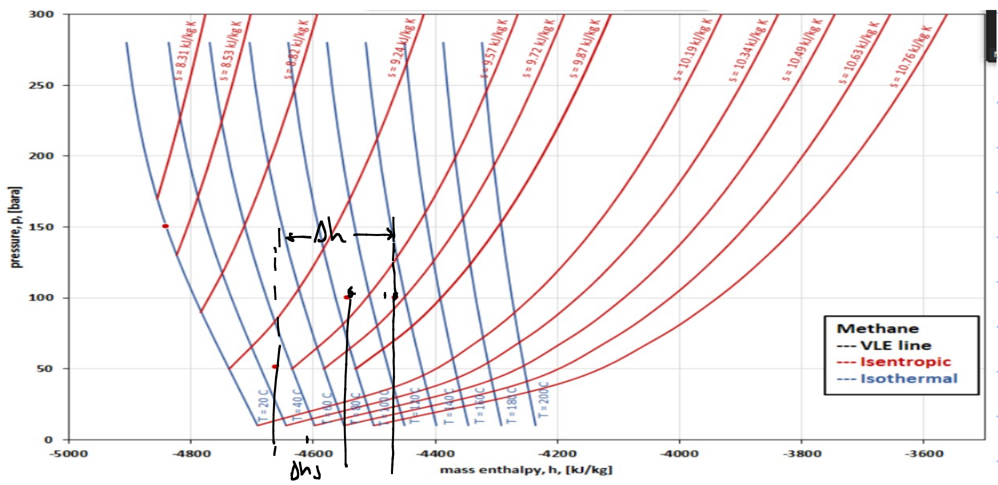
$\dot{m} = q_o \cdot \rho_o + q_g \cdot \rho_g$

$GOR = \frac{q_g}{q_o}$

$\dot{m} = q_o \rho_o + q_o GOR \cdot \rho_g$

$\dot{m} = q_o^{?} (\rho_o + GOR\, \rho_g)$

$7.2 = q_o (800 + \underbrace{GOR}_{500,\ 150,\ 10000} \cdot 0.8)$



$\Delta h_r = \frac{\Delta h_s}{0.6}$

$\Delta h = (\Delta h_s) \cdot 1.66$

$T_{out} \simeq 135$ °C

read from chart

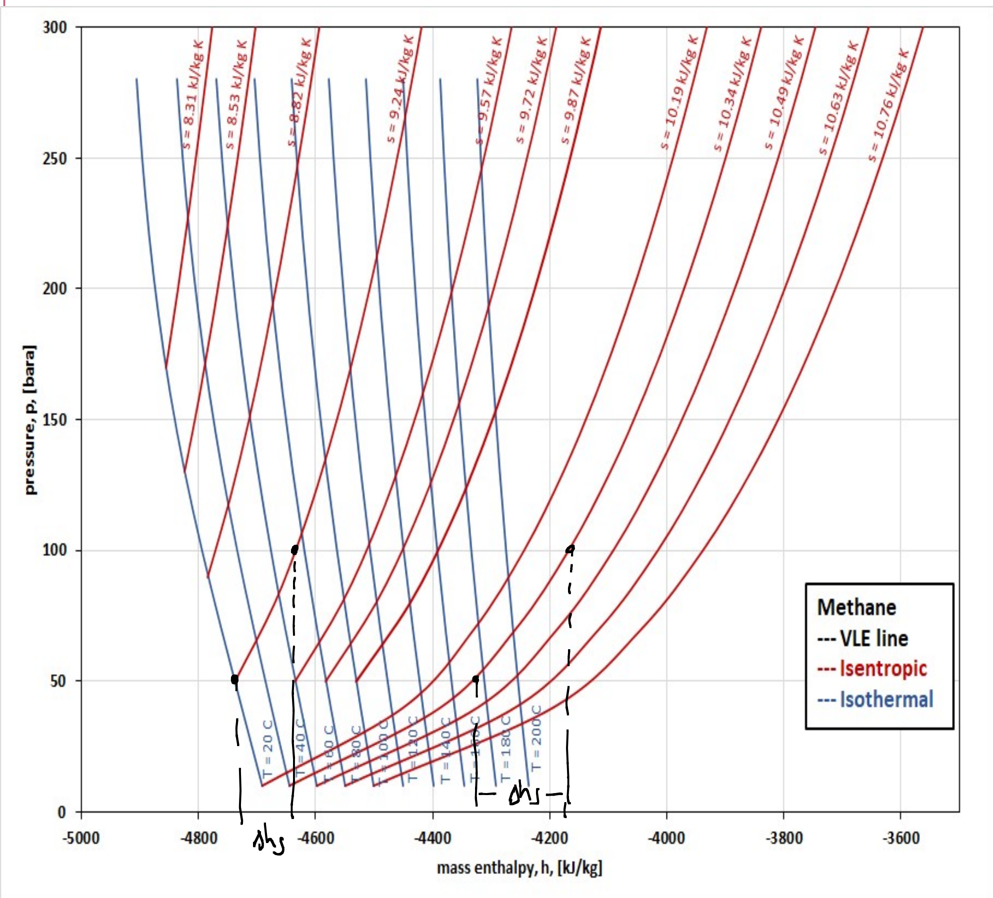
calculate from $\Delta h = \Delta h_s / \eta$

read from charts

calculate $h_{out} = h_{in} + \Delta h$

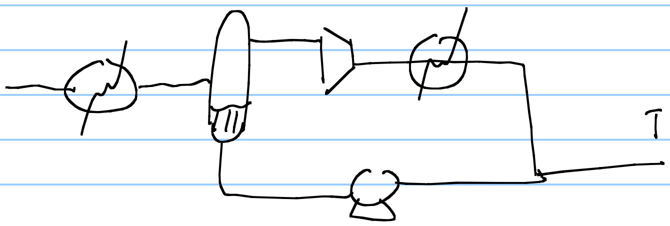
η_{adiab}	0.6 [-]					
Power	**$T_{out,s}$**	**Δh_s**	**Δh**	**h_{in}**	**h_{out}**	**T_{out}**
[kW]	**[C]**	**[kJ/kg]**	**[kJ/kg]**	**[kJ/kg]**	**[kJ/kg]**	**[C]**
77	51	6.4	11	-2087.9	-2077.2	51
168	57	14.0	23	-2372.7	-2349.4	60
372	70	31.0	52	-2831.8	-2780.1	78
948	93	79.0	132	-3853.7	-3722.0	110
1404	105	117.0	195	-4661.4	-4466.4	135

read from chart with $P_{out} = 100$ bara, h_{out}



Compression at lower inlet temperatures require a smaller Δh_s

Therefore, to avoid high outlet temperatures and reduce compression power, coolers are sometimes installed upstream and downstream the compressor (Example Aasgard



$T < 120°C$

Performance map of boosters

$q_1, \Delta p_1$ (should fall inside the performance map of the booster)

$q_2, \Delta p_2$

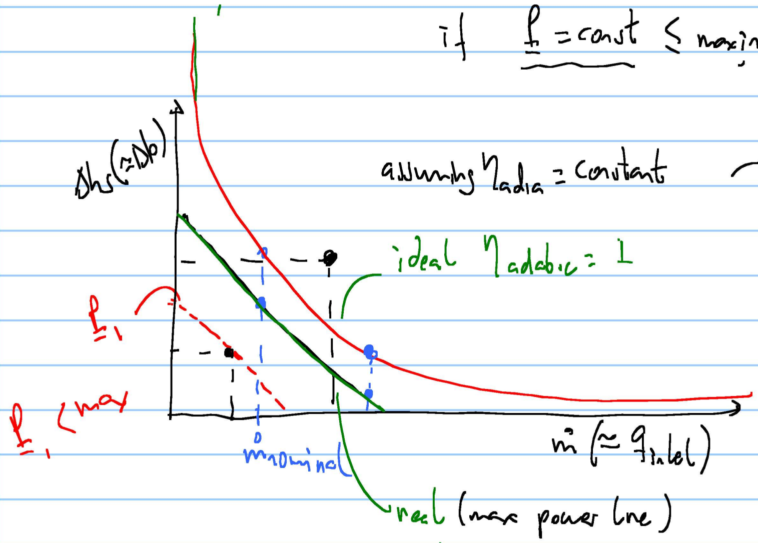
$q_3, \Delta p_3$

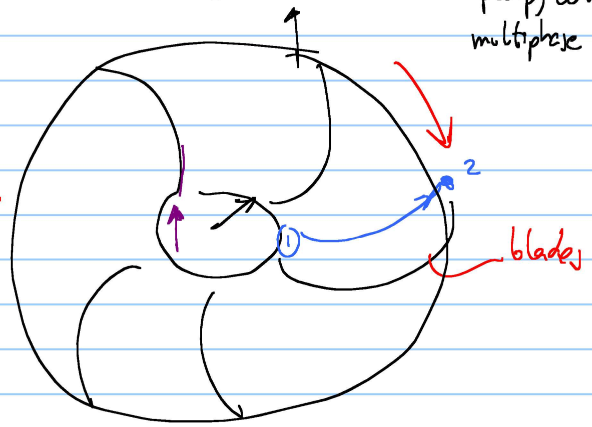
⋮

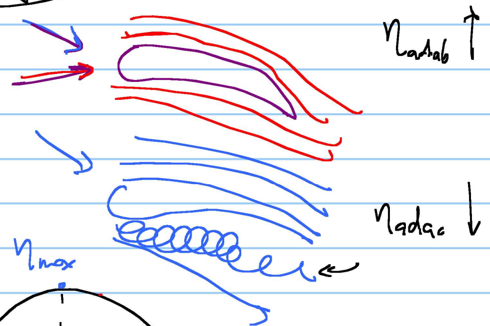
$$\underline{P} = \overset{\sim q_{inlet}}{\dot{m}} \; \frac{\Delta h_s}{\eta_{adia}} \sim \propto \Delta p$$

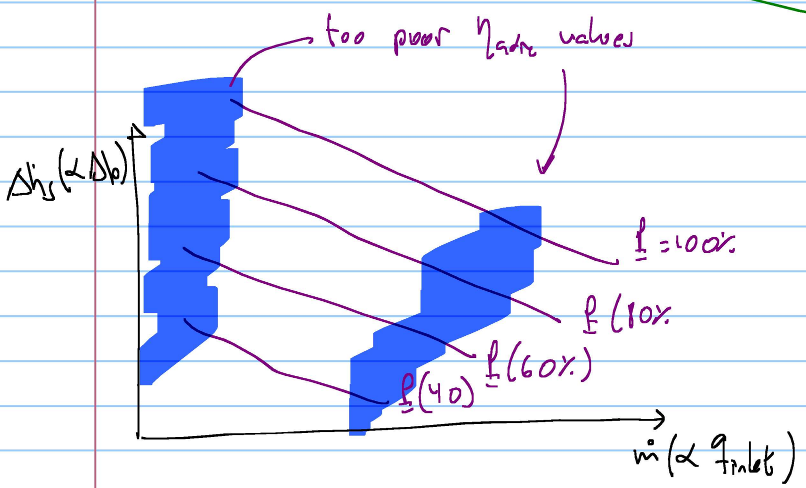
if $\underline{P} = const \leq$ maximum capacity

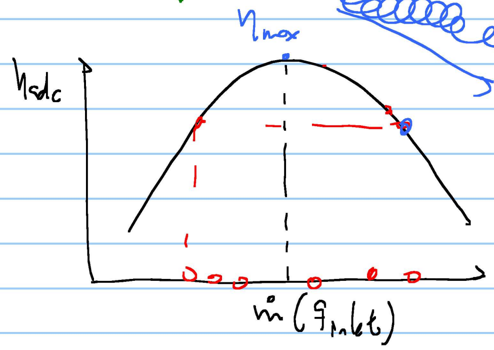
assuming $\eta_{adia} = constant \rightarrow$ rotor-dynamic machines ⇝ centrifugal, axial pump, compressor multiphase boosters





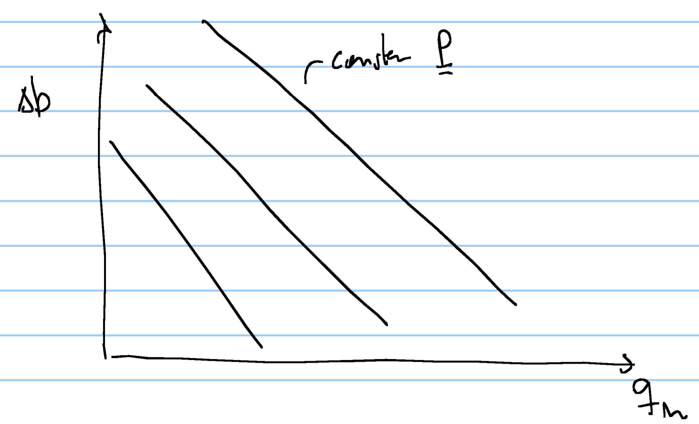




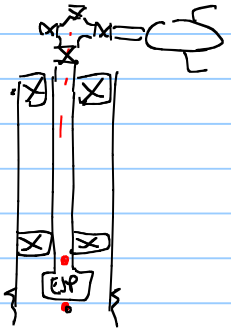


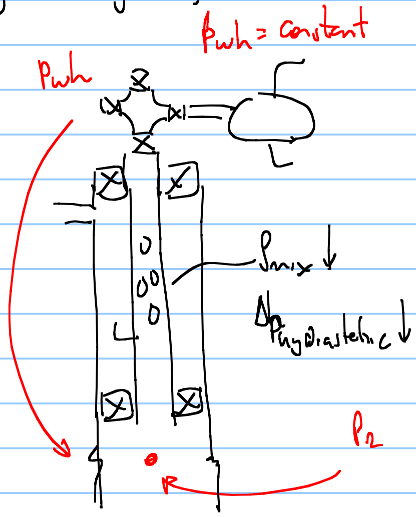
$\eta_{adiabatic} = f(\dot{m})$

for a liquid pump $\Delta h_s = \frac{\Delta p}{\rho}$ $\dot{m} = q_{in} \cdot \rho_{in} = q_{in} \cdot \rho$



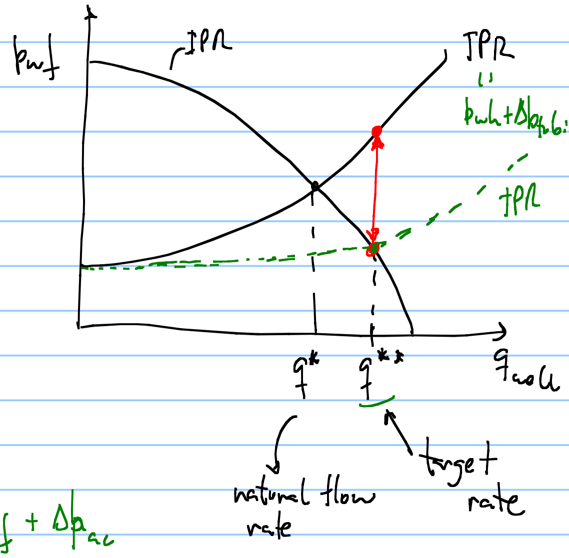
difference between boosting and gas lift





without any artifical lift

Bottomhole equilibrium



$$p_{wf} = p_{wh} + \Delta p_{tubing}$$

$$p_{wf} = p_{wh} + \underbrace{\Delta p_h}_{\downarrow} + \underbrace{\Delta p_f}_{\uparrow} + \Delta p_{ac}$$

$$v = \frac{q}{A} = \frac{\overbrace{q_o + q_g}^{q_{res} + q_{gas\,lift}}}{A}$$

In gas lift $\Delta p_f \uparrow << \Delta p_h \downarrow$

PENSUM:

- Field development workflow.
    - Lifecycle of a hydrocarbon field
    - Overview – The field development process (ppt)
    - Production modes
    - Discounting (Quiz exercise)
    - Relationship between plateau height and length
    - Rule of thumb between plateau height and TRR (Quiz exercise)
    - Bottlenecking and processing capacity (Quiz exercise, Home exercise)
    - Onshore vs offshore
    - Oil vs gas (Quiz exercise)
- Home exercise (frequency analysis, relative frequency and cumulative frequency, gravity separation and separation capacity)
- Field production performance
    - Estimation of production profiles
    - Dry gas production system: material balance, IPR, TPR, FPR, choke, flow equilibrium. (Quiz exercise)
    - Excel VBA, functions and routines.
    - Dry gas production system: production scheduling (Home Exercise)
    - Measures to prolong the plateau. Discussion on tubing size considerations, pipeline size considerations. (Quiz exercise)
    - Production potential. (Quiz exercise: production scheduling using the production potential)
    - Tubing tables (Quiz exercise)
- Value chain model, cost estimation and NPV calculations (Class exercise, Quiz exercises)
- Probabilistic reserve estimation
    - Monte Carlo (Class exercise in Excel and Jupyter notebook)
- Decision and probability tree analysis (Class exercise in Excel, Quiz exercise)
- Home exercise: quantification of uncertainty in NPV - early field development
- Offshore structures
    - Overview (ppt)
    - Layout of production systems (ppt)
    - Marine loads on offshore structures (Class exercise in Jupyter notebook, Quiz exercises)
- Flow assurance considerations (ppt)
    - General overview
    - Inhibitor subsea system. Disposal.
    - Class exercise: Modeling of topside facilities of Karish and Tanin field (p and T calculations on JT valve). Estimation of MEG injection requirements. (Quiz exercise)
- Field production performance
    - Dry gas networks. (Class exercise, Quiz Exercises)
    - Downhole networks (Quiz exercise)
    - Boosting (Class exercise)

Tools:

-Excel with VBA, Excel solver, Jupyter Notebook (Python), Hysys

Generic Skills and topics

-Sampling with Monte Carlo, Latin Hypercube
-Probability trees
-Statistics
-FFT
-Thermodynamics
-Economic calculations