TPG4230 - Field development and operations

Associate Professor Milan Stanko (office 510). milan.stanko@ntnu.no
↳ 5th floor.

Lecture schedule Fridays 9-12 (P12)
Mondays 8-10 (P11)

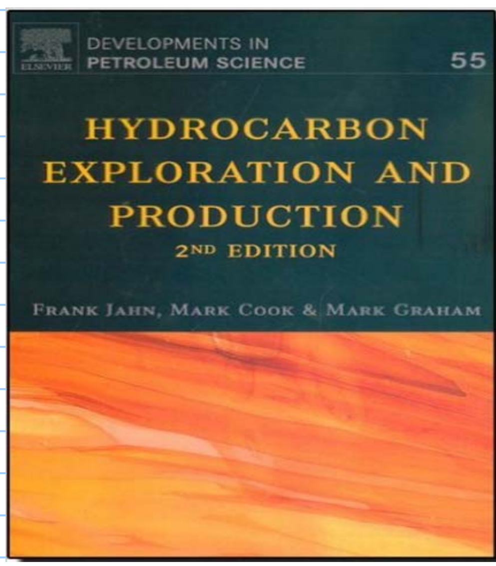
Consultation time Fridays after class (12-13). Try to make an email appointment before

Student assistant Salma Alkindira → arrange additional exercise sessions during the week.

Evaluation 60% digital exam 27.05.2020 (09:00)
40% Exercises
↳ (4-5), in groups 3-4 people (max)
Deliver all to get access to exam. (20/40)
Deliver late is allowed but penalty (-20%) every half-day late
for delivery in Blackboard, be aware a group must be created first

Maybe? Guest lectures from industry (1 hr) → will be notified in advance

- Tools: Excel (VBA), Hysys (AspenTech, process simulator), IPM (Petex), Python (Jupyter notebooks)
  - farm.ntnu.no
  - computer lab on ground floor
  - ↳ Visual Basic for Applications
  - IPM: Integrated petroleum management

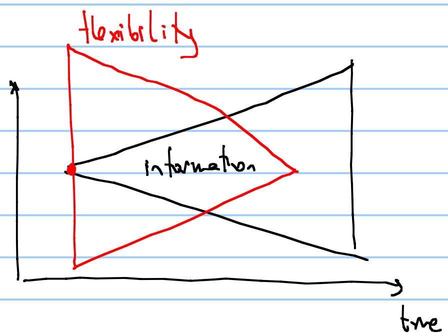


Field development and operations → offshore oil and gas production (from fields in Norway)

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

Operations: define KPI's
- stuck with an existing system
- reduce the impact of system deficiencies
- 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)

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

discovery

(3-6)

(5-40)

Beslutning om Konkretisering

Beslutning om videreføring

BoG Beslutning om gjennomføring

DG1 (BoK)   DG2 (BoV)   DG3

feasibility studies → concept planing → preengineering

issue PDO plan for development and operations

DG4

detailed engineering → construction → testing and startup

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)

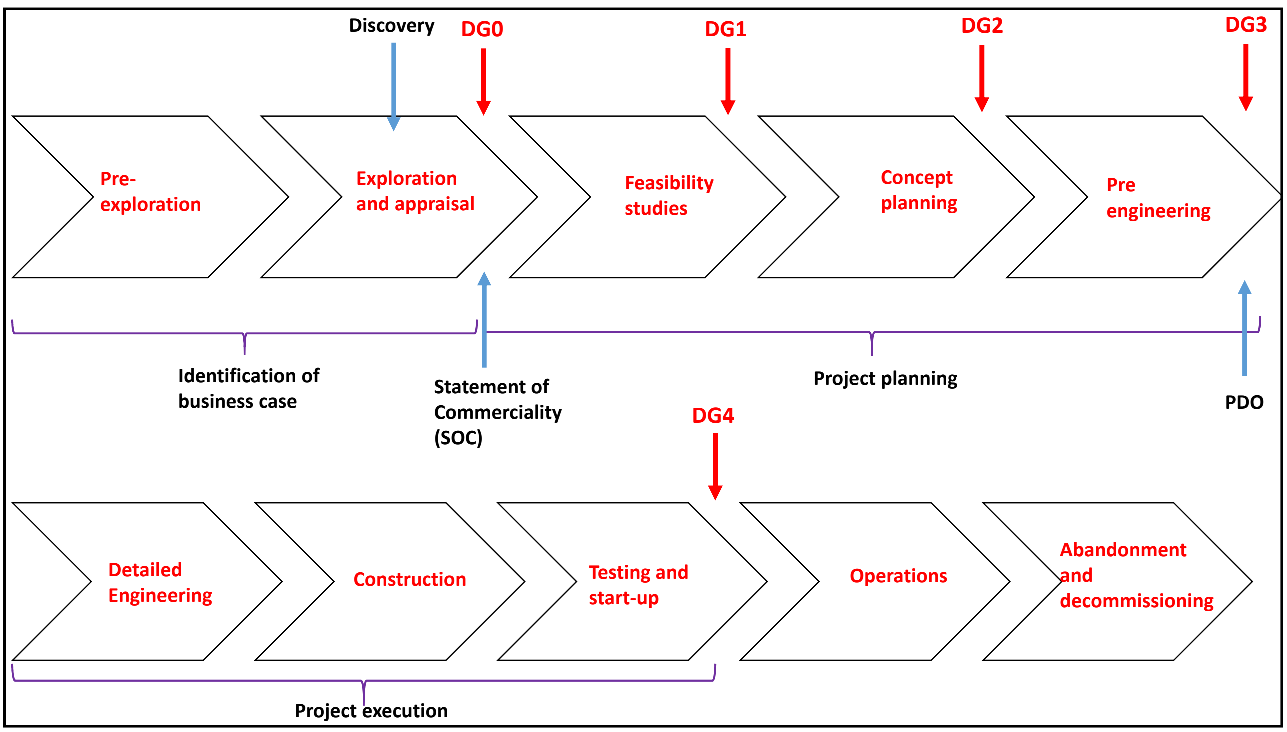
$

- offshore structures, type and selection

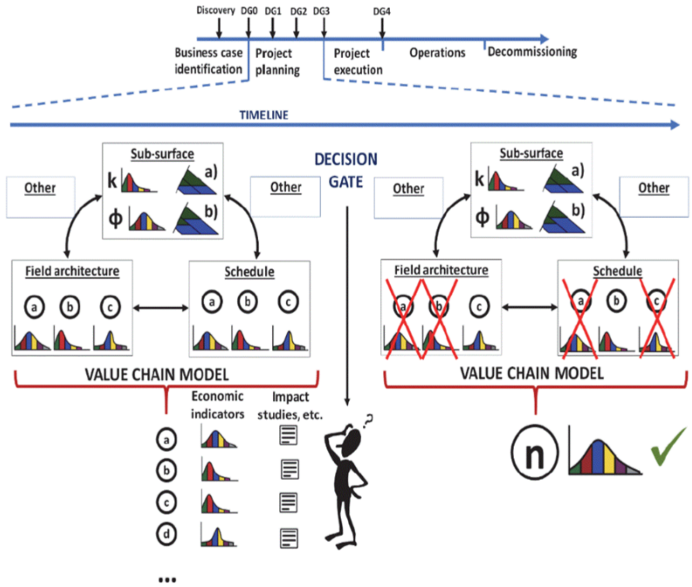
- Uncertainty quantification using Stochastic analyses and probability trees ← decision making
  { reserve estimation
  { appraisal

THE FIELD DEVELOPMENT PROCESS

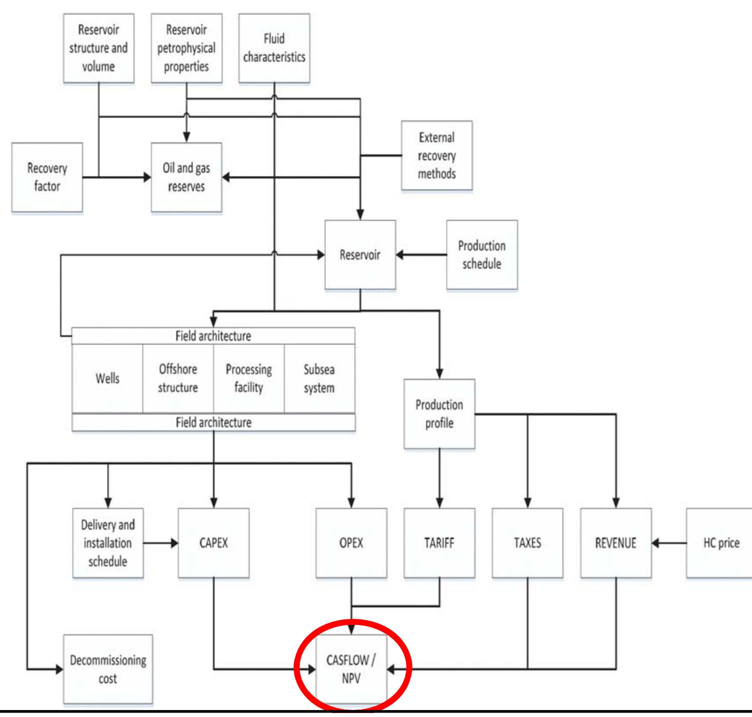
Prof. Milan Stanko (NTNU)

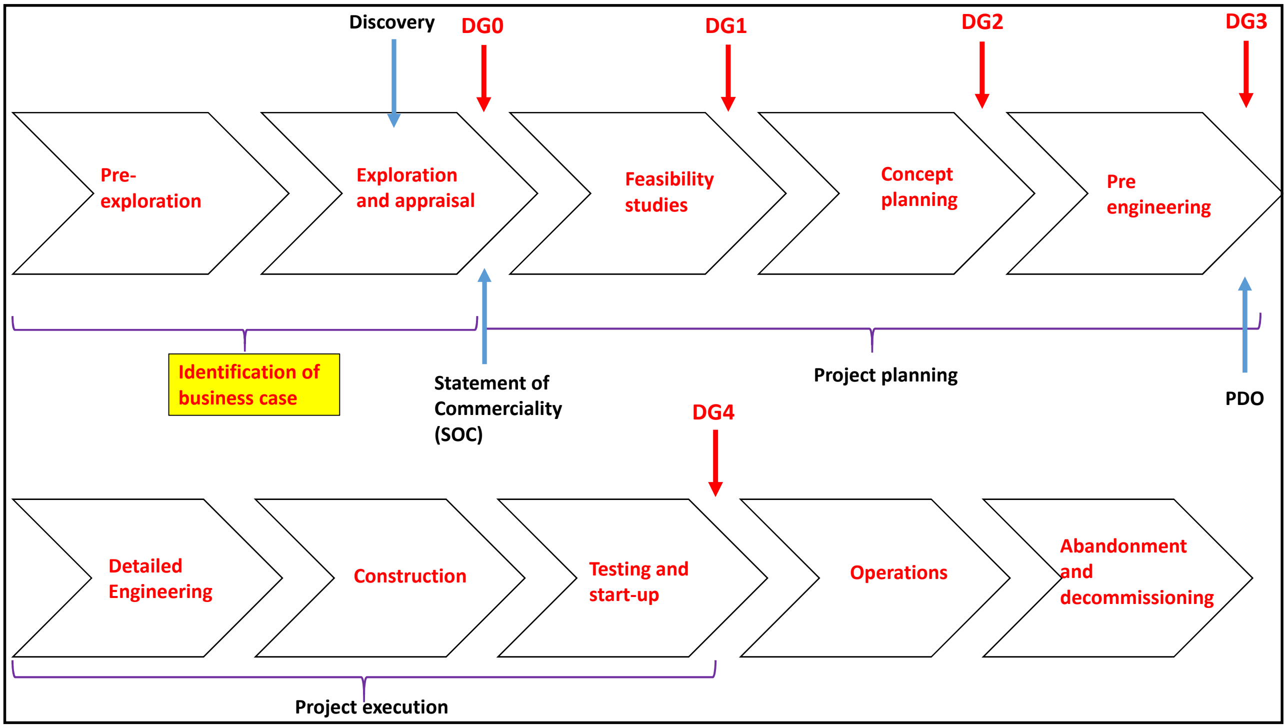


During the field development process a model of the value chain is made based on the disciplines involved and populated with information. Initially there are many alternatives and little information. As time progresses and decisions are taken, the model is expanded, there is more information but less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



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





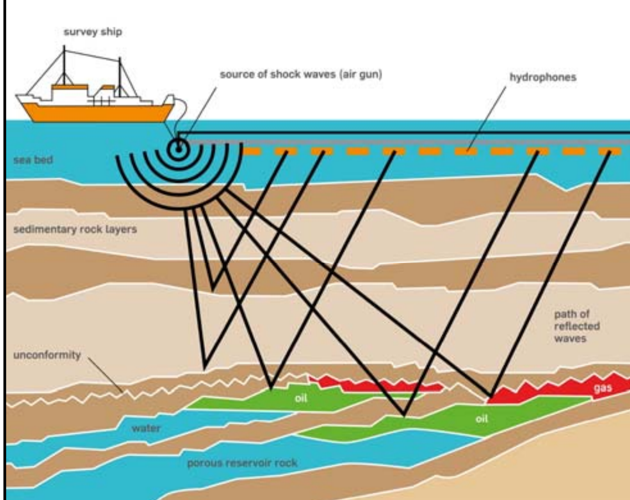
IDENTIFICATION OF BUSINESS CASE

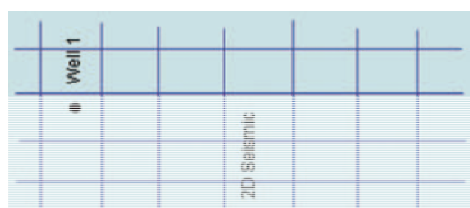
The main goal of this stage is to prove economic potential of the discovery and quantify and reduce the uncertainty in the estimation of reserves.

IDENTIFICATION OF BUSINESS CASE - TASKS

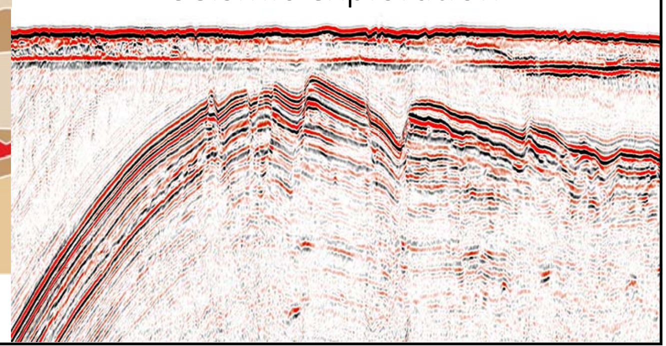
- Pre-exploration – scouting: collecting information on areas of interests. Technical, political, geological, geographical, social, environmental considerations are taken into account. E.g. expected size of reserves, political regime, government stability, technical challenges of the area, taxation regime,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

IDENTIFICATION OF BUSINESS CASE - TASKS





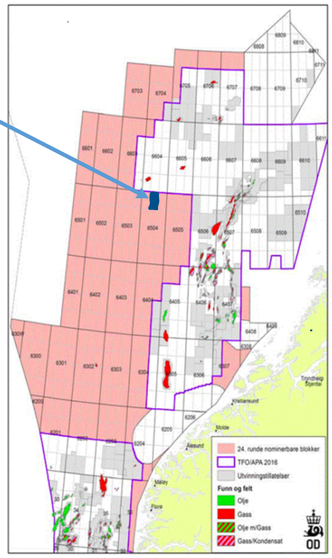
Seismic exploration



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

IDENTIFICATION OF BUSINESS CASE - TASKS

Ca 500 km²



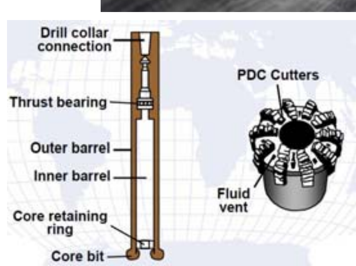
Ref: NPD

- 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 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.

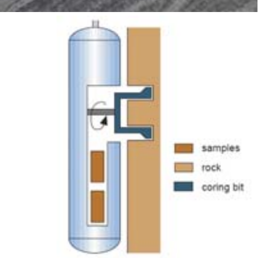
IDENTIFICATION OF BUSINESS CASE - TASKS

- 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

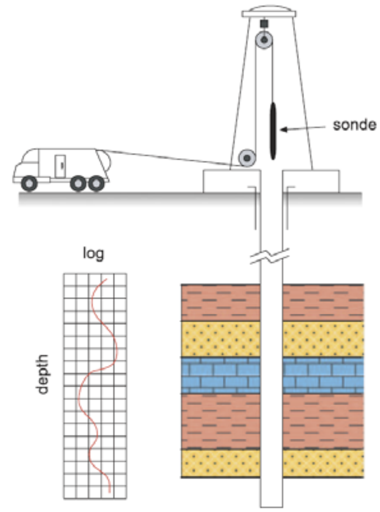


Ref: Hydrocarbon exploration and production, Jahn et al.

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: Hydrocarbon exploration and production, Jahn et al.

IDENTIFICATION OF BUSINESS CASE - TASKS

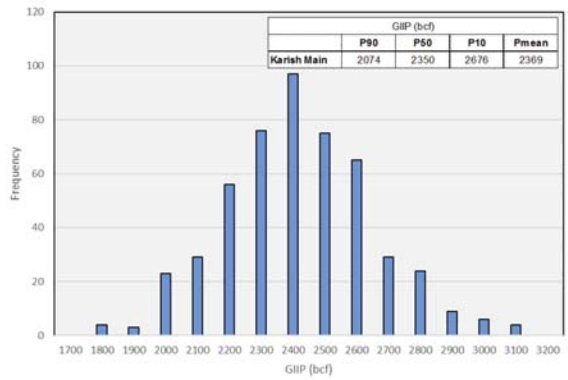
- Exploration. Perform geological studies, geophysical surveys, seismic, exploration drilling (Well cores, wall cores, cuttings samples, fluid samples, wireline logs, productivity test).

- 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.



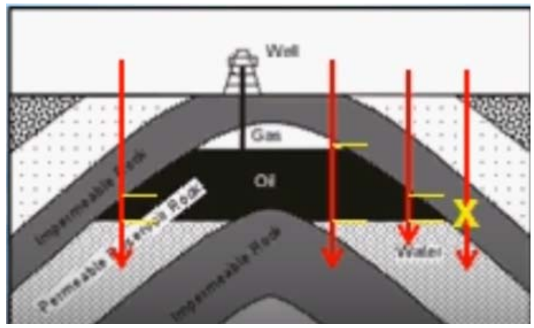
Ref: PDO Karish and Taning. Energean

IDENTIFICATION OF BUSINESS CASE - TASKS

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

IDENTIFICATION OF BUSINESS CASE - TASKS

- Appraisal

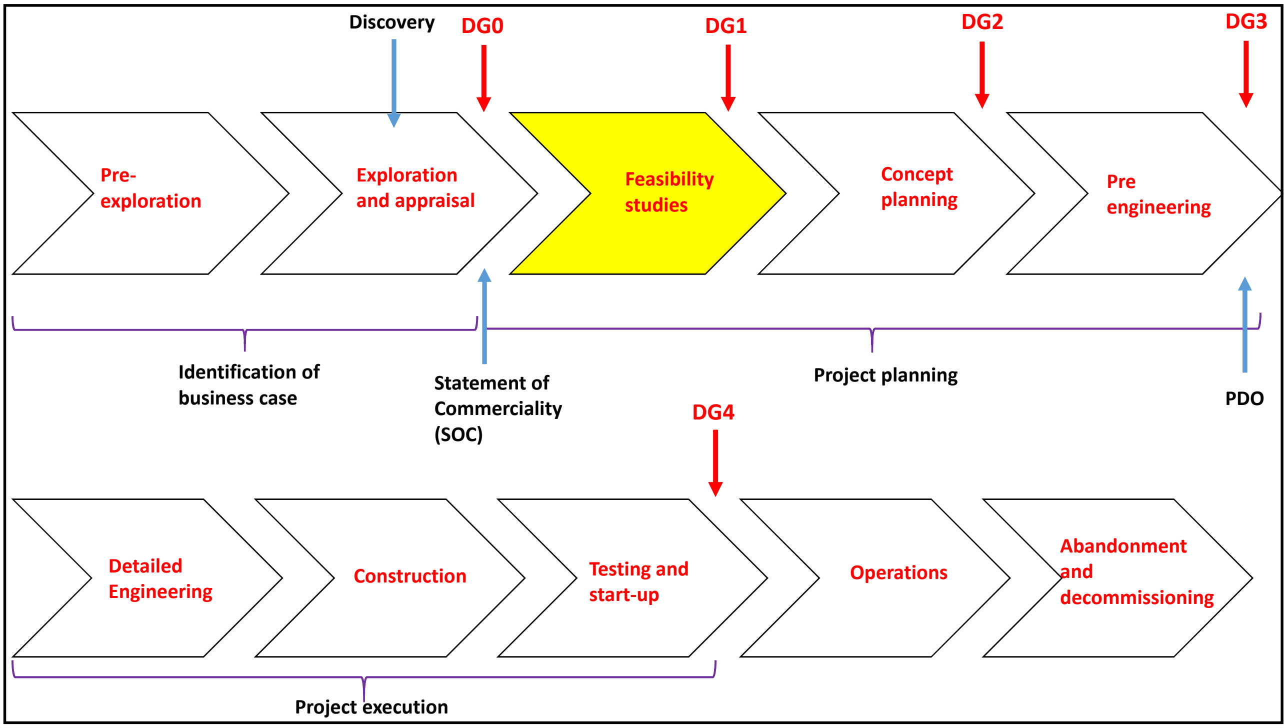


Ref: https://www.youtube.com/watch?v=-e9jjnsquGI

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

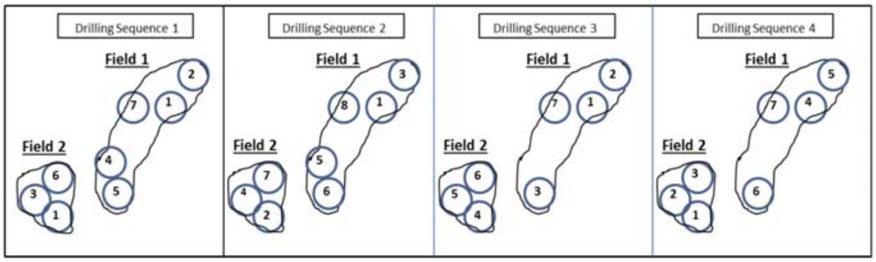


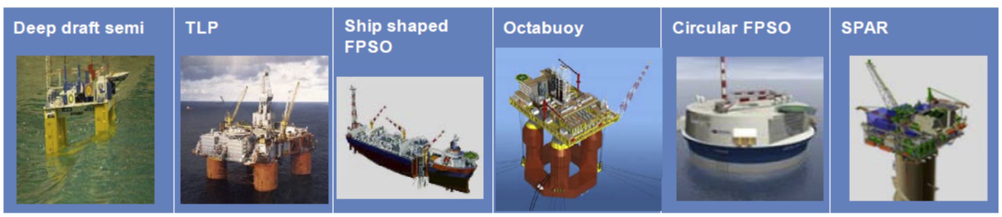
FEASIBILITY STUDIES - TASKS

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

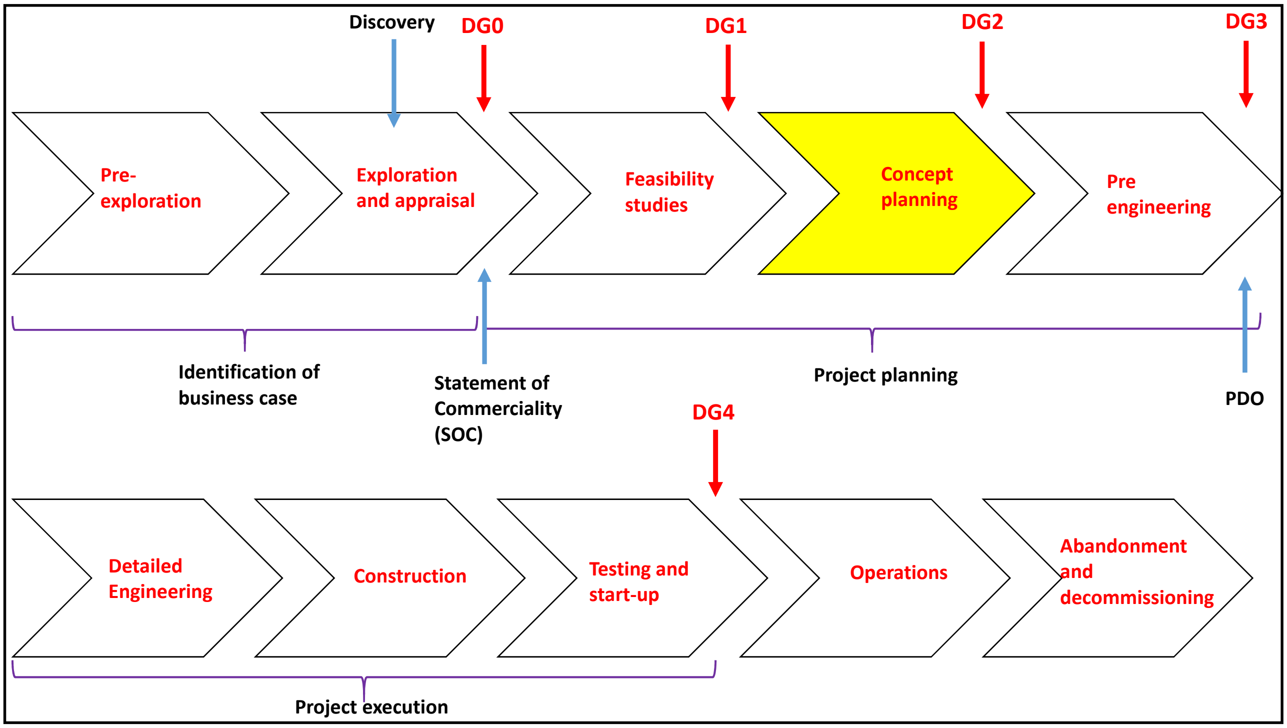




Ref: UTC 2017, Strategies, methods and tools for development of subsea fields, Skogvang and Løken.

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)



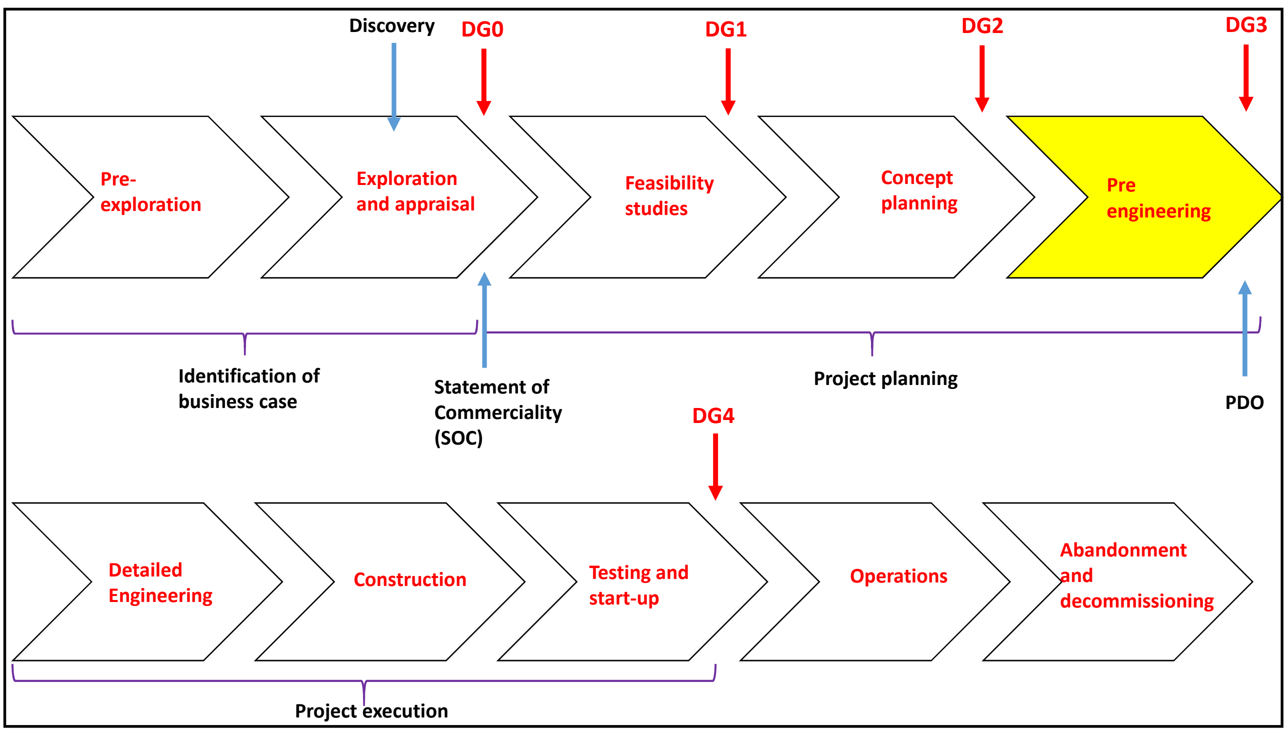
CONCEPT PLANNING - TASKS

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

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

CONCEPT PLANNING - TASKS

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



PRE-ENGINEERING - TASKS

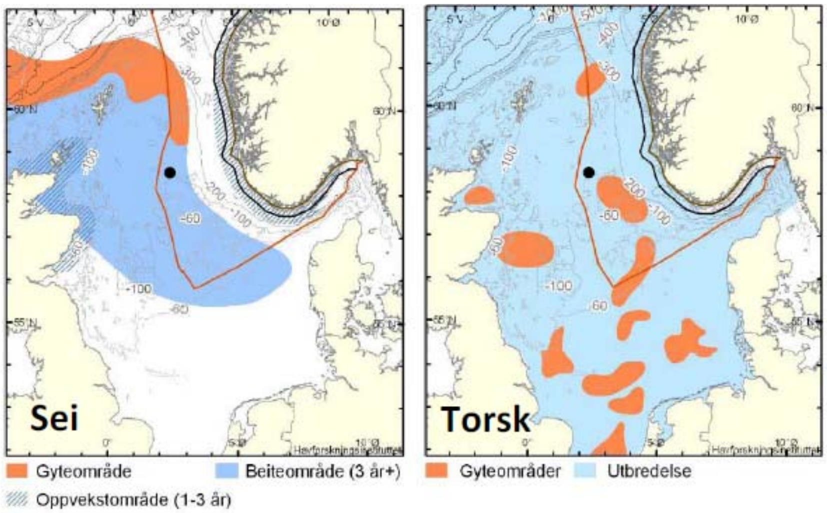
OBJECTIVE: Further mature, define and document the development solution based on the selected concept.

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

PRE-ENGINEERING - TASKS

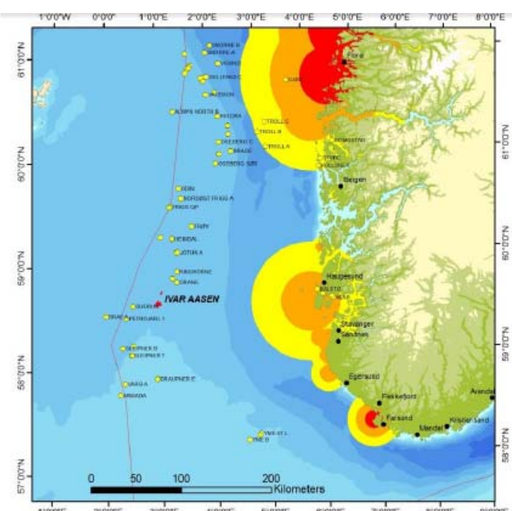
- Prepare for submission of the application to the authorities.
- Perform the Environmental impact assessment.
- Establish the basis for awarding contracts.
- Issue:
  - Plan for development and operations
  - Plan for installation and operations of facilities for transport and utilization of petroleum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

PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

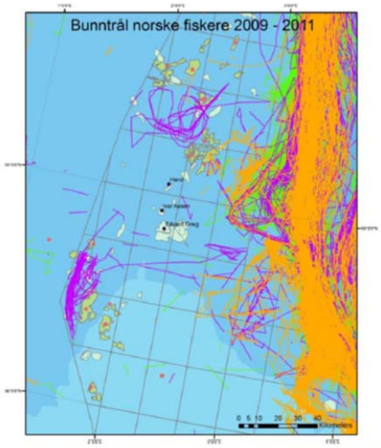
PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

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

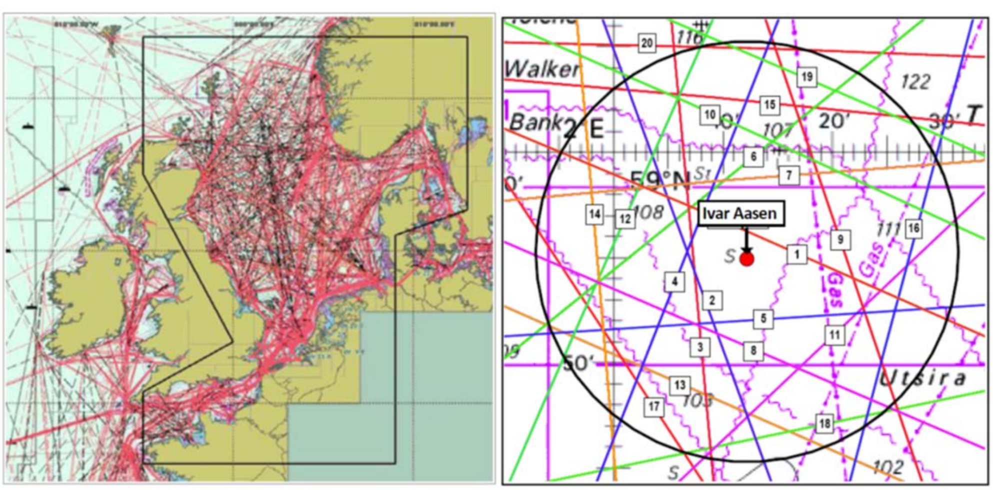
PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

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

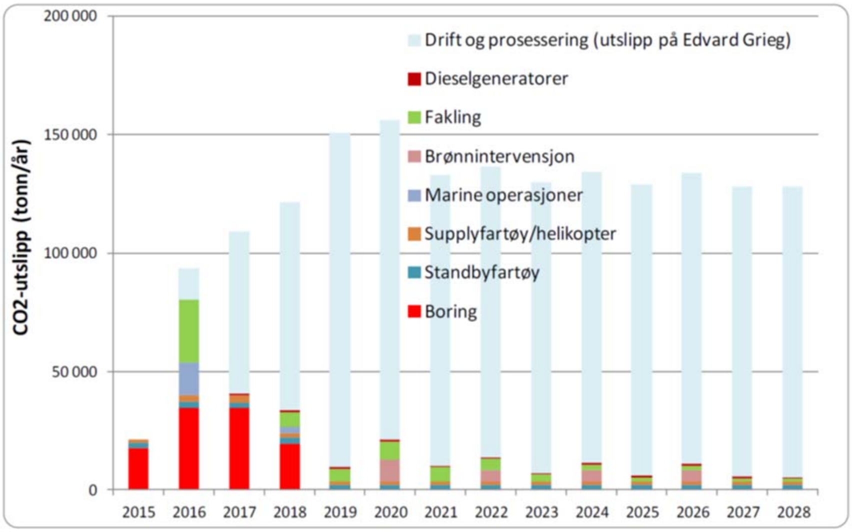
PRE-ENGINEERING - TASKS



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

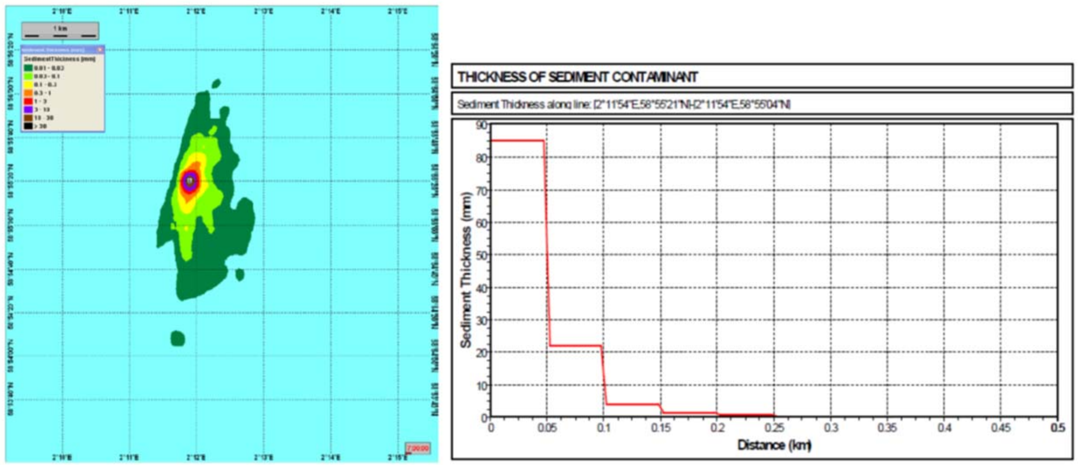
PRE-ENGINEERING - TASKS

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

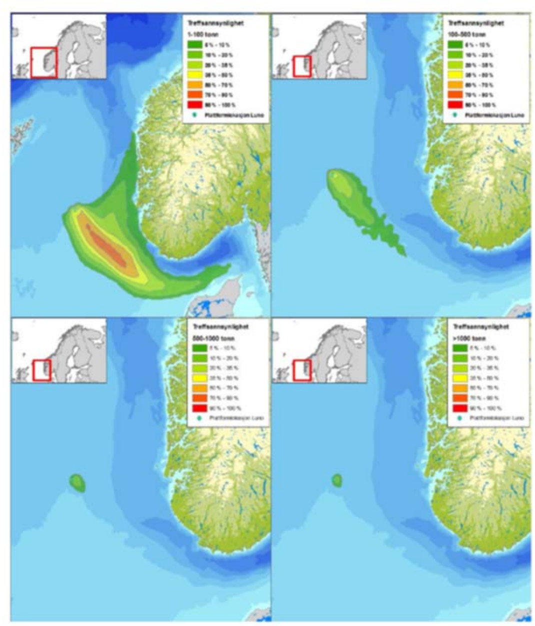
PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

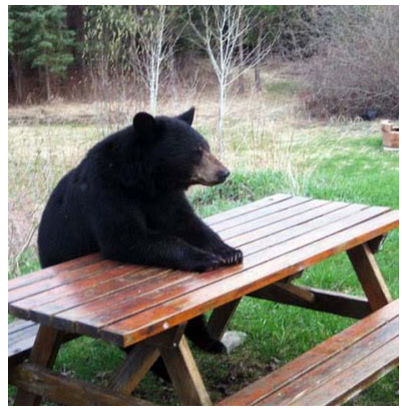


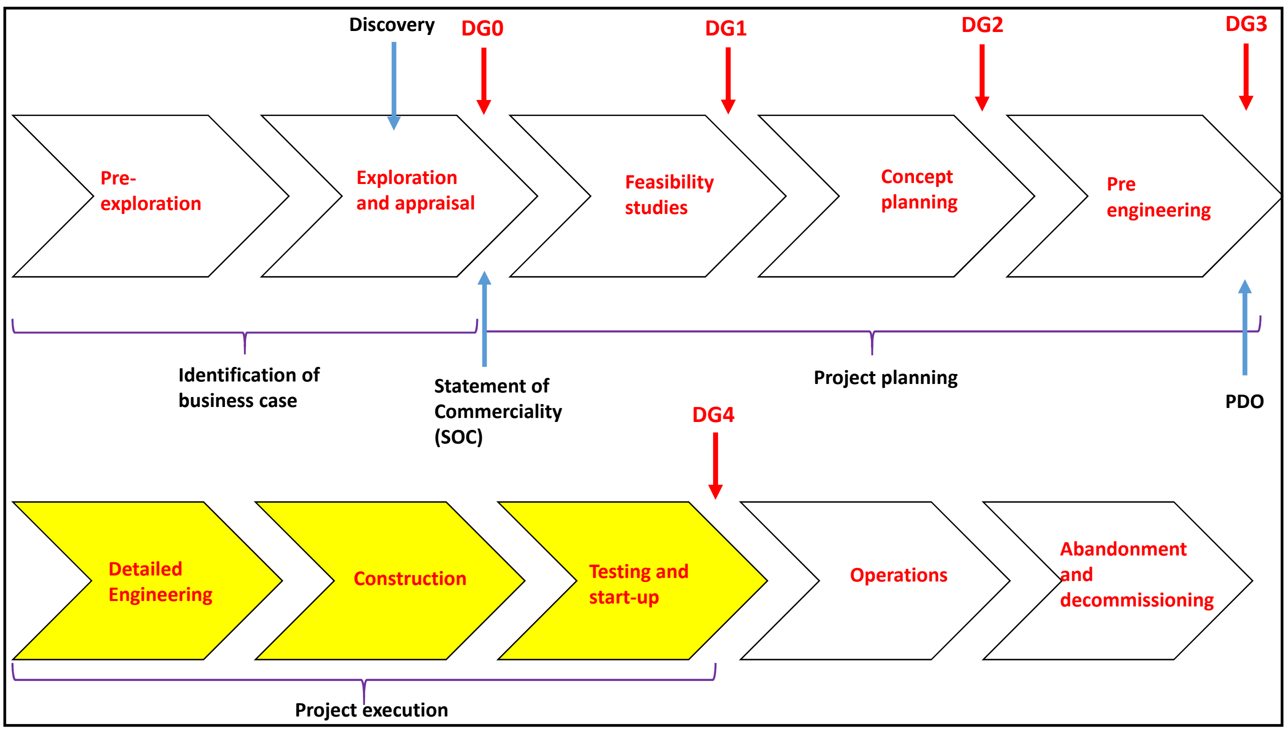
Figur 37. Sannsynligheten for treff av ulike mengdekategorier av olje i 10 × 10 km ruter gitt en sjøbunnsutblåsning fra Aasen/Grieg (helårsstatistikk). Influensområdet er basert på alle utslippsrater og varigheter og deres individuelle sannsynligheter. Merk at det markerte området ikke viser omfanget 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





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)

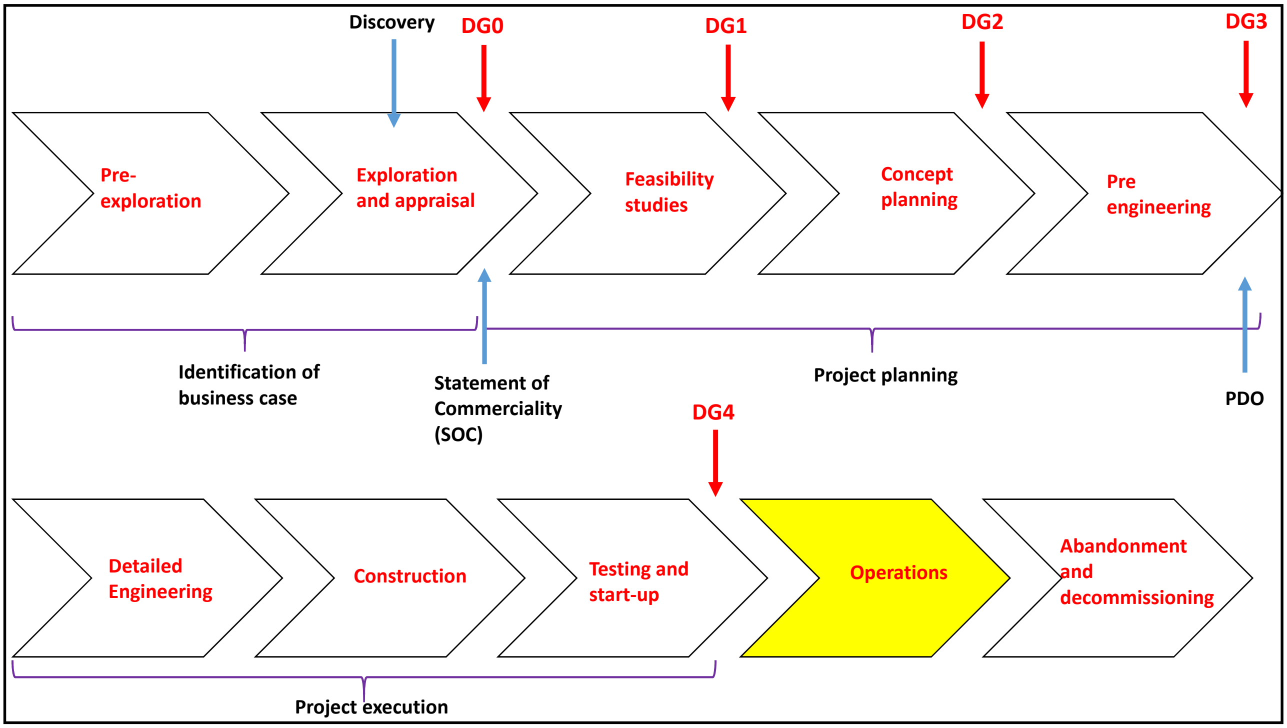
EPCM (Engineering, procurement, construction, and management contract) with one main contractor.

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

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

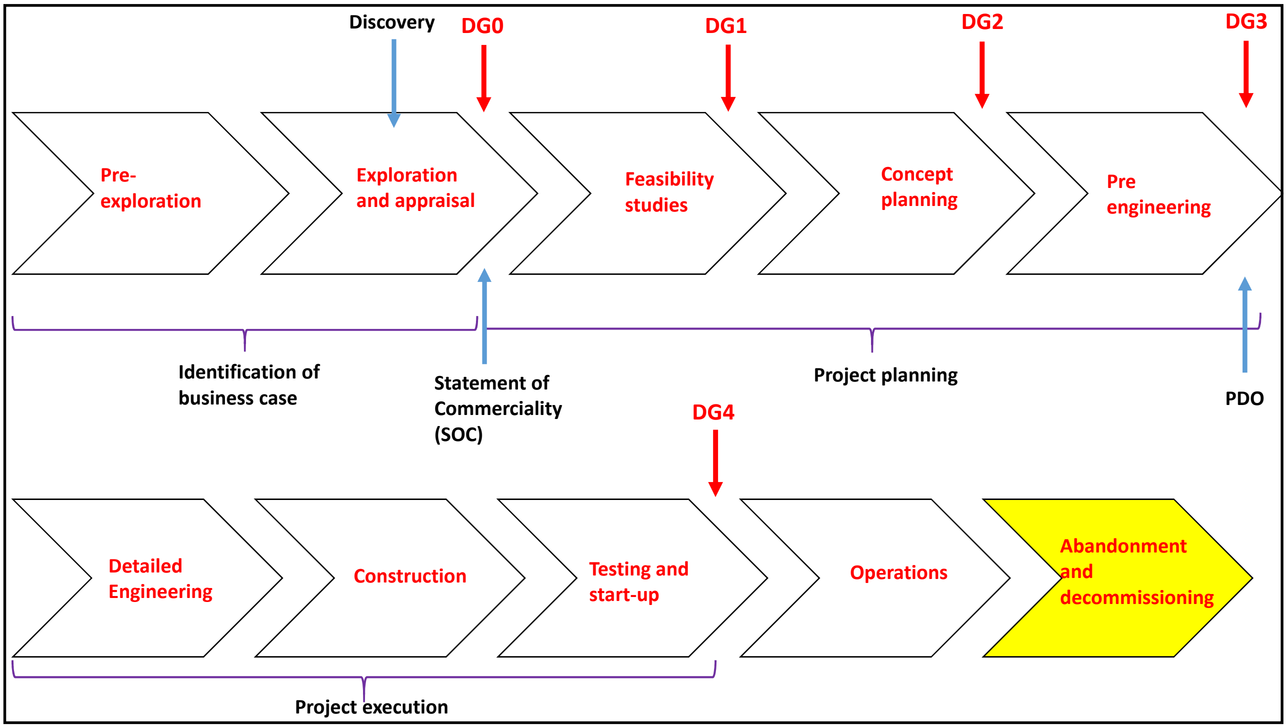
DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

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



OPERATIONS

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



DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

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

Class nr. 3

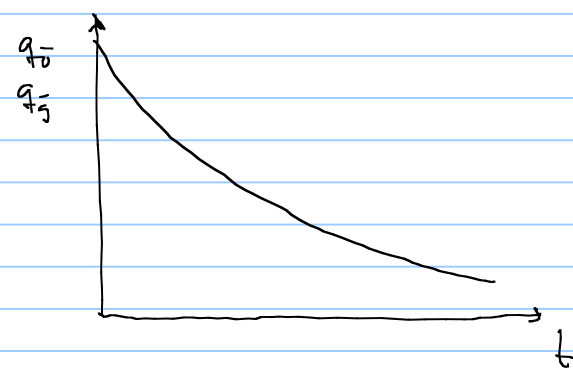
- Field production performance
  - production modes (production scheduling)
  - plateau height vs. plateau length
  - deciding plateau height
  - production of associated products (bottlenecking)
  - offshore vs. onshore
    oil vs. gas

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

during the life of field

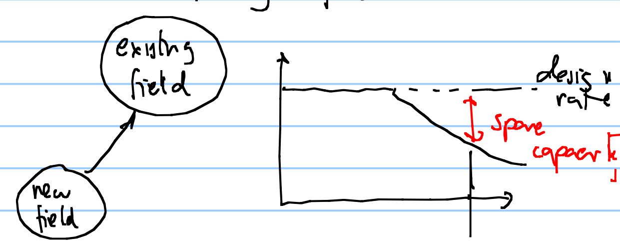
two ways to produce a field

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

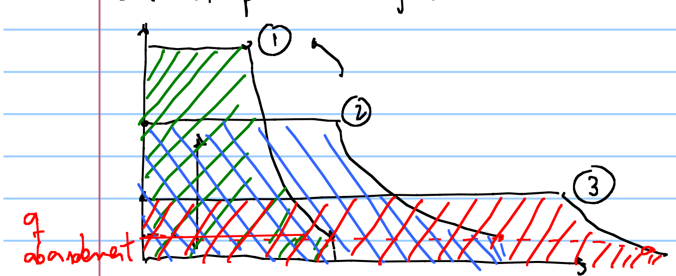


- typically used for gas fields with a contract
- Big-medium reservoir
- standalone development → requires its own facilities, offshore structure etc.

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



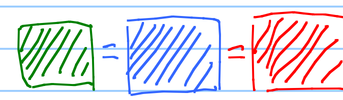
in mode "a" there is a relationship between plateau height and duration



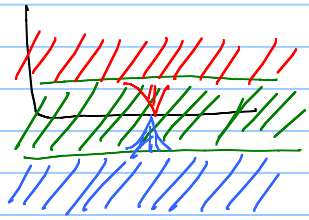
$$N_p = \int_0^t q(t)\,dt$$

↳ 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

NPV ⇝ net present value

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

year

cash flow = revenue − expenses

$\Delta Q_{p_i} \cdot P_o^i$ production of oil/gas in year "i"

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

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

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 with two fields

Rules of thumb for first iteration on plateau rate

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

ultimate cumulative production (at abandonment)

TRR → total recoverable reserves

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

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

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

$N_{pu} = 72E06$ stb

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

[Sm³/d]

[stb/d]

↳ 95% uptime (0.95 · 365)

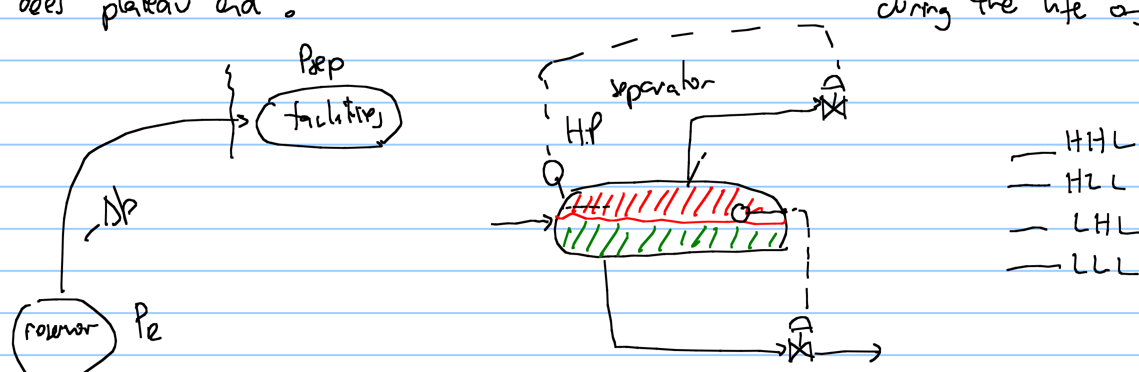
for gas (2-5)% of G_{pu}

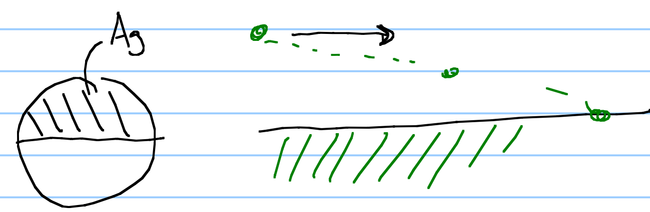
Q is either oil or gas
N is for oil
G is for gas

https://factpages.npd.no/factpages/Default.aspx?culture=en
http://www.ipt.ntnu.no/~stanko/files/Files/
} field production figures from NCS

why does plateau end?

separator pressure is kept constant during the life of field





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

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

$q_{\bar{g}} \sim \dot{m}_g$ $\qquad q_g(P_{sep}, T_{sep}) = \dfrac{\dot{m}_g}{\rho_g(P_{sep}, T_{sep})}$

P_{sep} must be kept (almost always) constant and of all downstream equipment and processes to esure proper functioning and acceptable performance

for $P_{sep} = 80$ bar $\rightsquigarrow \rho_g \sim 120\ kg/m^3$

$q_g(p=80)$

for $P_{sep} = 30$ bar $\rightsquigarrow \rho_g = 60\ kg/m^3$

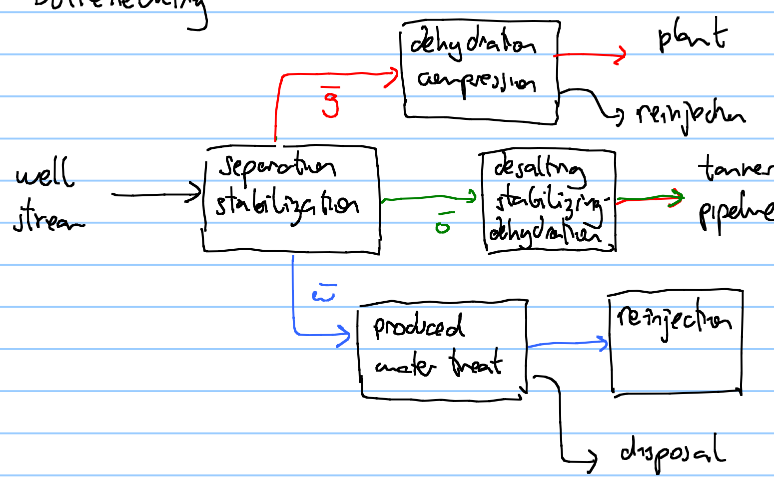
$q_g(p=30)$ $\qquad q_g(30) > q_g(80)$

plateau ends because the system doesn't have enough energy to flow against P_{sep} with the specified plateau rate

$$\text{Reservoir} \xrightarrow{q_{\bar{g}}} \text{bottom-hole} \longrightarrow \text{wellhead} \longrightarrow \text{separator}$$

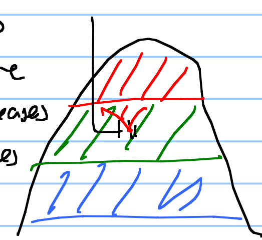
formation drawdown $-\Delta p$	"pipe" tubing flow $-\Delta p$	"pipe" gathering network $-\Delta p$

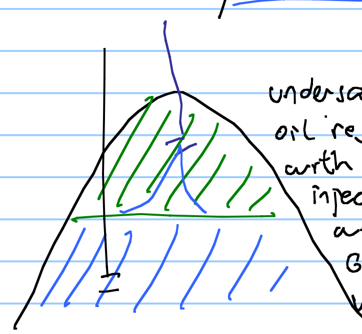
- Bottlenecking



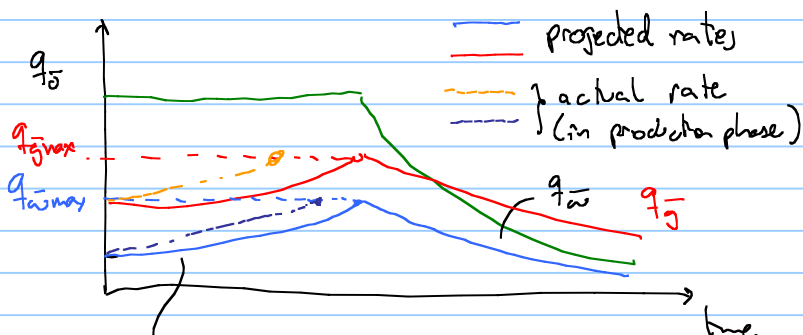
examples of variations of GOR and WC with time

saturated oil reservoir with gas cap with time GOR increases WC increases

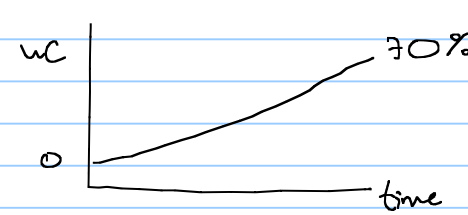




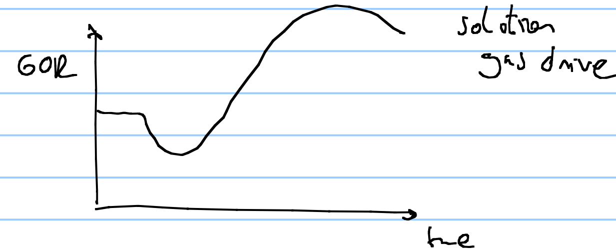
undersaturated oil reservoir with water injection with time GOR = const WC = increasing



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



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



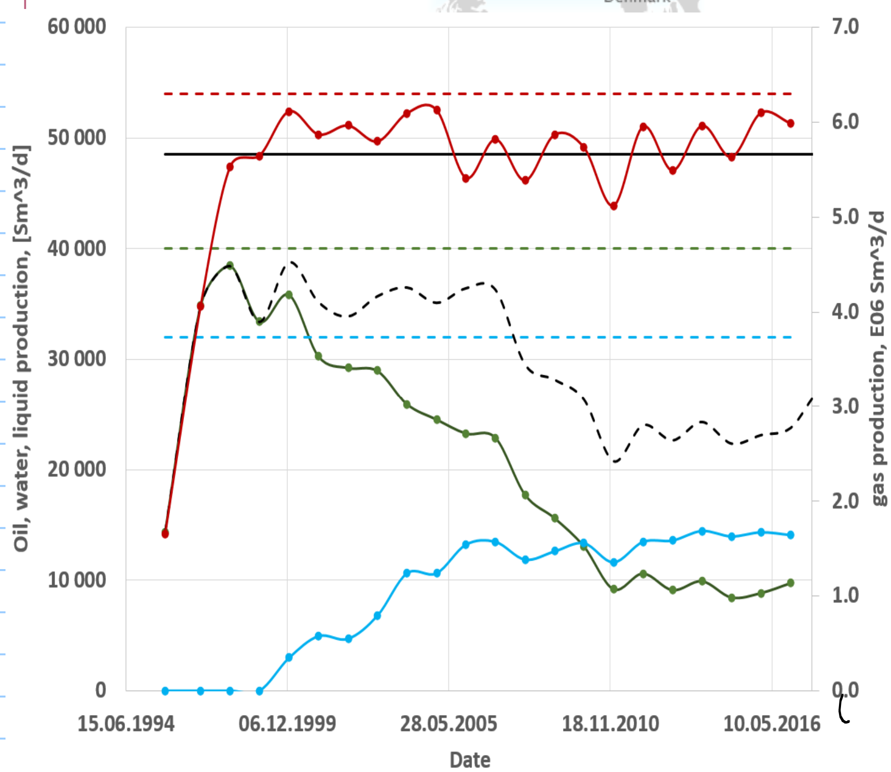
$$q_{\bar{g}} = GOR \; q_{\bar{o}}$$

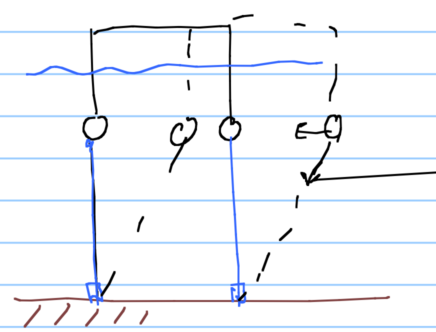
$q_{\bar{g}\,max}$ and $q_{\bar{w}\,max}$ are used to design facilities

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)

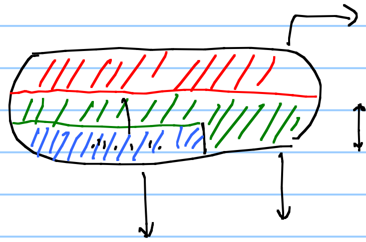
$$q_{\bar{g}} = GOR \cdot q_{\bar{o}}$$

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





TLP tension leg platform



$$t^{g}_{res} = \frac{V_g}{q_g(P_{sep}, T)}$$ ~ required time for good separation 3 - 5 min (horizontal)

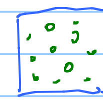
$$t^{o}_{res} = \frac{V_o}{q_o(P_{sep}, T)}$$

t^{w}_{res}

maximum liquid capacity is also important

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 "free"

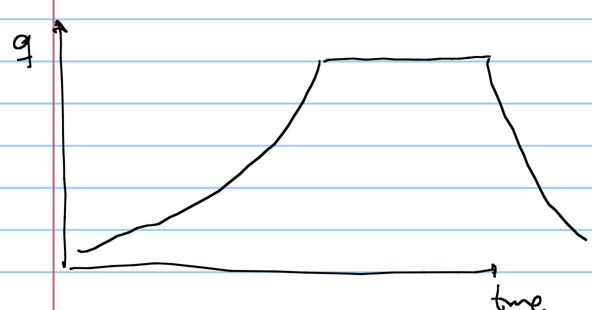


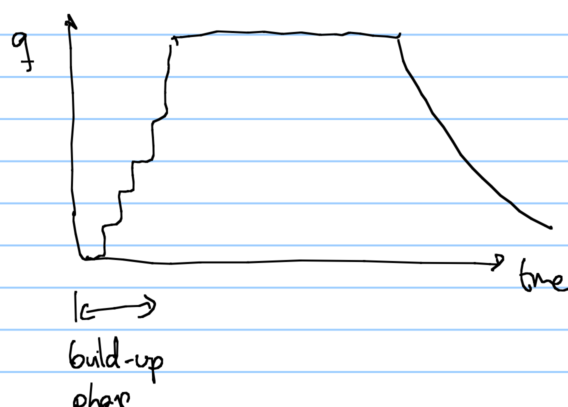
→ can sometimes be mitigated with chemical or with different techology

- onshore vs. offshore

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

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

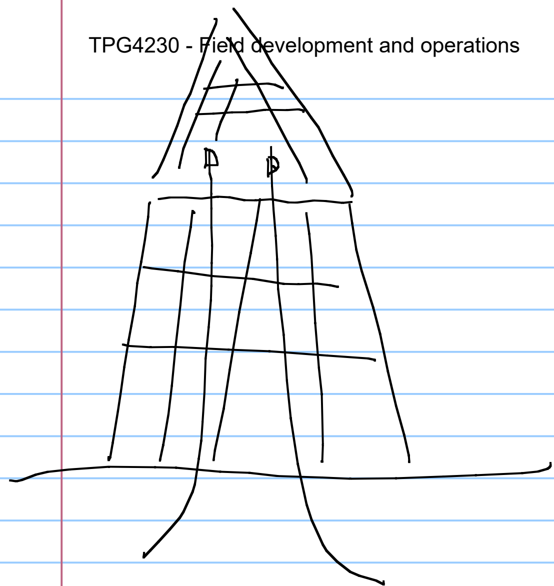


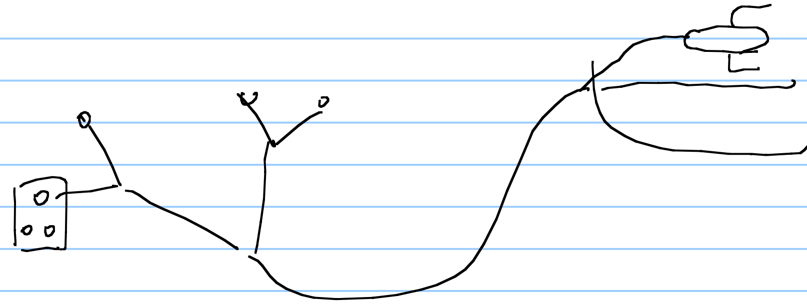


Longer build-up

- 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.

Class quiz

Hide answers

Q1: What does SOC stands for?

- Statement of Commitment

  This is a wrong answer

- Statement of Commerciality

  This is a correct answer

- Statement of Conflict

  This is a wrong answer

- Statement of Contribution

  This is a wrong answer

Q2: How many decision gates do we normally have in a field development process?

- 3

  This is a wrong answer

- 5

  This is a correct answer

- 4

  This is a wrong answer

- 6

  This is a wrong answer

Q3: How do we call the project management process that is commonly used in field development ?

- Status-gate

  This is a wrong answer
- Phase-gate

  This is a correct answer
- Waterfall

  This is a correct answer
- Stage-gate

  This is a correct answer

Q4: Which of the following activities are normally performed during a business case identification

- Scouting, pre-exploration, prospect identification , Seismic

  This is a correct answer
- Prepare the PDO

  This is a wrong answer
- Create a reservoir model

  This is a wrong answer
- Discovery assessment, appraisal, reserve estimation

  This is a correct answer

Q5: What subphases are in the project planning?

- Feasibility studies, concept planning, detailed engineering

  This is a wrong answer

- Feasibility studies, concept planning, pre-engineering

  This is a correct answer

- Business case identification, Feasibility studies, pre-eng

  This is a wrong answer

- Feasibility studies, concept planning, tech. requirements

  This is a wrong answer

Q6: Flow assurance issues are evaluated in the project planning phase

- True

  This is a correct answer

- False

  This is a wrong answer

Q7: The life cycle of a hydrocarbon field is comprised of

- Exploration, appraisal, planning

  This is a correct answer

- Construction and execution

  This is a correct answer

- Production and operations

  This is a correct answer

- Abandonment and decommisioning

  This is a correct answer

Q8:PDO stands for

- Plan for Design and Operations

  This is a wrong answer

- Plan for Development and Optimization

  This is a wrong answer

- Plan for Development and Operations

  This is a correct answer

- Plan for Utbygging og Drift

  This is a correct answer

Q9: In the field development process, what follows after the project planning?

- Appraisal

  This is a wrong answer

- Project execution

  This is a correct answer

- Identification of Business case

  This is a wrong answer

- Operations

  This is a wrong answer

Q10: What does FEED stand for?

- First End Engineering Design

  This is a wrong answer

- Field End Engineering design

This is a wrong answer

- Front End Established Design

This is a wrong answer

- Front End Engineering Design

This is a correct answer

Q11: What of the tasks below are not performed during decommissioning?

- Remove and bury subsea pipelines

This is a wrong answer

- well plugging and abandonment

This is a wrong answer

- debottlenecking

This is a correct answer

- recovery of material and recycling of equipment

This is a wrong answer

Q12:which of the following statements is false?

- Field production mode A is always followed by mode B

This is a wrong answer

- A field could be produced using mode b and then mode a

This is a wrong answer

- production mode B is typically used for standalone projects

This is a correct answer

- In production mode A, the wellhead choke is opened gradually

This is a wrong answer

Q13: Which one of the following tasks are performed during the business case identification phase?

- Probabilistic reserve estimation

  This is a correct answer

- simplified economic valuation of reserves

  This is a correct answer

- appraisal

  This is a correct answer

- Apply and obtain a production license

  This is a correct answer

Q14: As a rule of thumb, how much is the annual offtake of an oil field in the north sea?

- 10% of the TRR

  This is a correct answer

- 3% of the TRR

  This is a wrong answer

- 5% of the TRR

  This is a wrong answer

- 0.1% of the TRR

  This is a wrong answer

Q15: When is the reservoir pressure maintenance strategy planned in an offshore development?

- from the begginning

  This is a correct answer

- after some years producing the field

  This is a wrong answer

Q16:BONUS: what are the names of the members of the reference group?

Q17: During the feasibility studies one or more development concepts must be identified and analyzed

- true

  This is a correct answer

- false

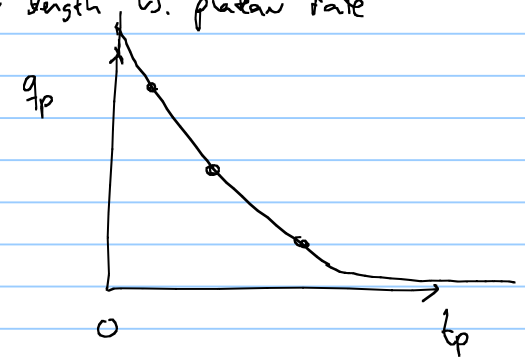
  This is a wrong answer

- Kahoot quiz for re-cap
- onshore vs offshore
- oil vs gas
- try online field simulator (dry gas) http://www.ipt.ntnu.no/~stanko/Field_Simulator.html

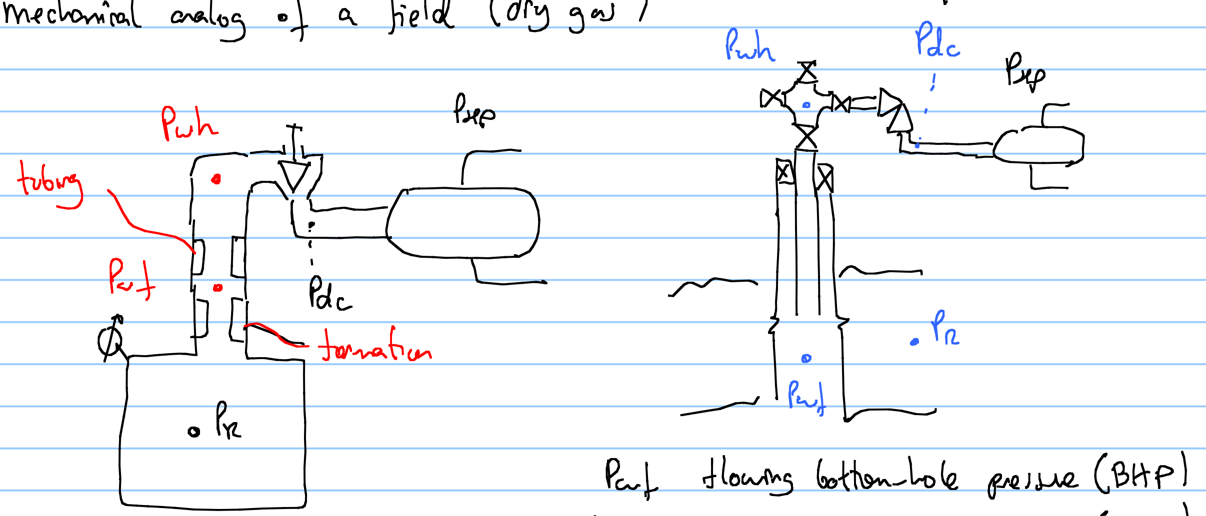
		7 wells	10 wells
plateau duration for	15 E06 Sm³/d	→ 7000 d	10000 d
	20 E06 Sm³/d	~ 3250 d	6000 d
	25 E06 Sm³/d	~ 1750 d	4100 d

- choke must be opened gradually to maintain plateau
- Adding number of wells increases plateau duration
- increasing wellhead deliverability coefficient prolongs plateau
  - re-completion
  - fracking
  - stimulation
  - ↑ tubing size
  - AL / boosting

Plateau length vs. plateau rate



mechanical analog of a field (dry gas)

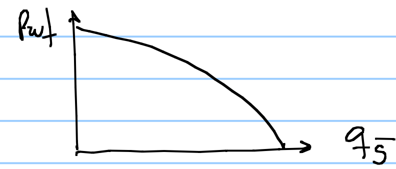


P_{wf} flowing bottom-hole pressure (BHP)

P_{wh} wellhead pressure (WHP)

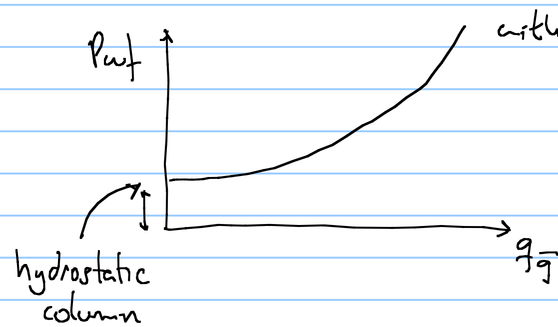
$P_R \rightarrow P_{wf}$ flow in formation (Drawdown) IPR inflow performance relationship

$q_{\bar{g}} = f_1(P_R, P_{wf})$



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

$q_{\bar{g}} = f_2(P_{wf}, P_{wh})$



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

$q_{\bar{g}} = f_3(P_{wh}, P_{dc}, \text{Opening})$

- 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)

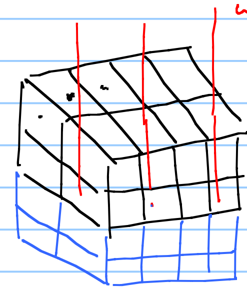
$q_{\bar{g}} = f_4(P_{in}, P_{out})$

- Production scheduling
- Dry gas equations
- introduction to excel VBA (functions)
- class exercise

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

$q_{Target\ rates}(t) \sim q(t)$

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

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)

- $\underbrace{\text{material balance single tank}}$ + $\underbrace{\text{Inflow performance relationship}}$

P_R, S_o, S_g, S_w vs t

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

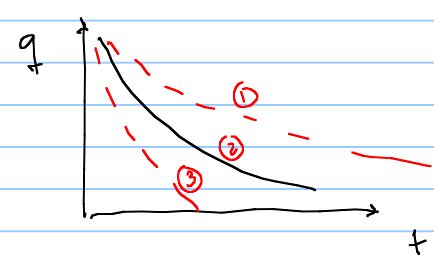
needs assumption on $P_{wf\,min}$

- material balance + well + network model

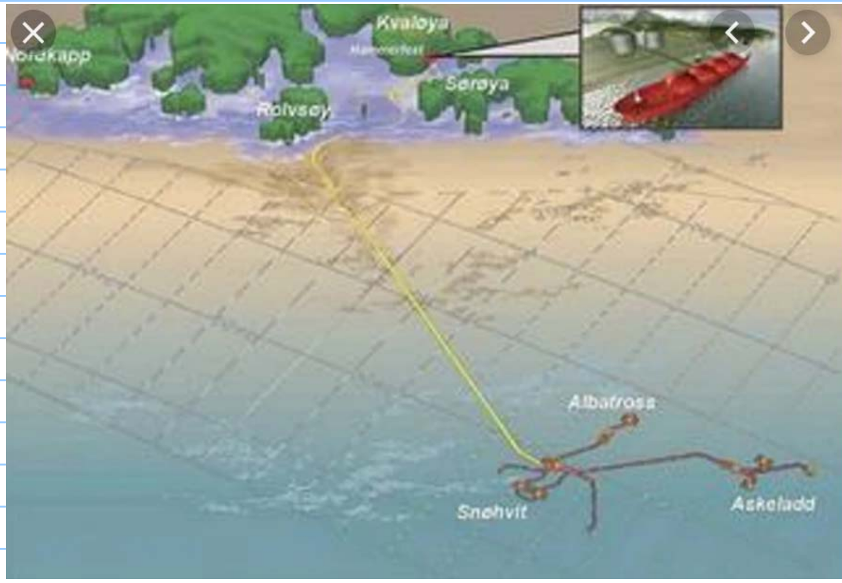
P_R, S_o, S_g, S_w vs t

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

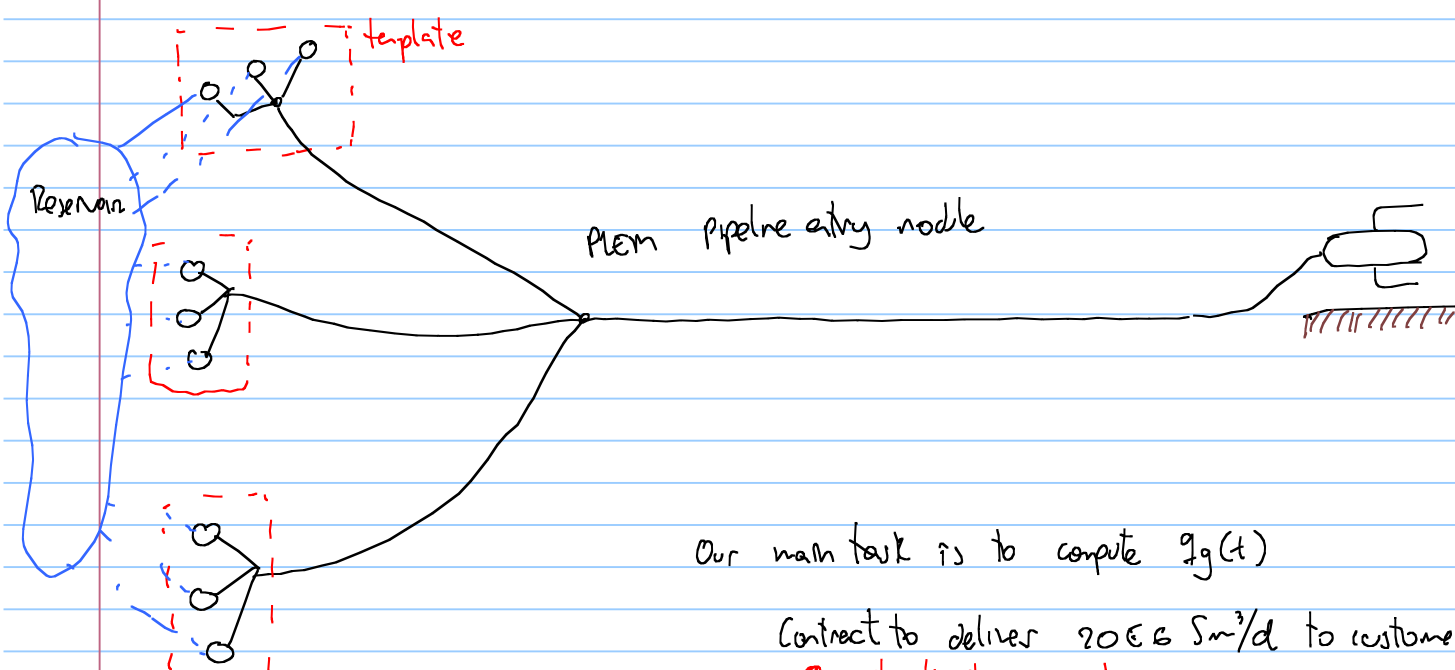
- Decline or type curves { very early FD }



Class exercise: Production scheduling of Snowhite field



Dry gas field



Our main task is to compute $q_g(t)$

Contract to deliver $20E6$ Sm^3/d to customer

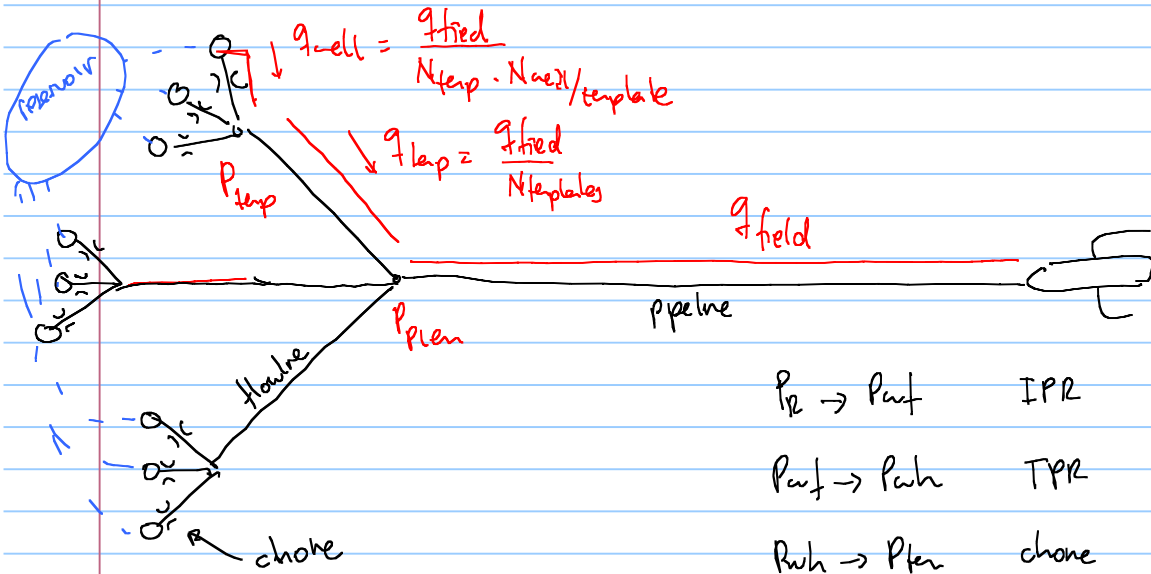
Our task, to compute

- plateau duration and post-plateau production

- Only dry gas, no liquid
  - no condensate
  - no water
  - no production chemicals

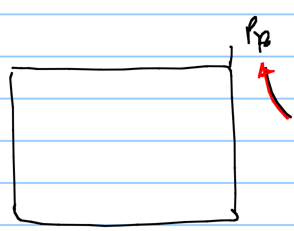
- all wells are identical (same production, same characteristics)

- templates are located symmetrically from the plem



$P_R \to P_{wf}$	IPR	$q_g = f(P_R, P_{wf})$
$P_{wf} \to P_{wh}$	TPR	$q_g = f(P_{wf}, P_{wh})$
$P_{wh} \to P_{tem}$	choke	$q_g = f(P_{wh}, P_{tem}, C_d)$
$P_{temp} \to P_{plem}$	FPR	$q_g = f(P_{tem}, P_{plem})$
$P_{plem} \to P_{sep}$	PPR	$q_g = f(P_{plem}, P_{sep})$

Reservoir model



Dry gas material balance

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

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

G: uncertain value

$\frac{G_p}{G}$: R_F recovery factor

z: gas deviation factor

$z\ f(P_r, T_r)$, $T_r = \frac{T_R}{T_c}$, $P_r = \frac{P_R}{P_c}$ → f(gas composition)

MB dry gas equation is implicit

- Given RF, assume P_R
- with P_R compute z_R
- verify that $\varepsilon = P_R - P_{Ri} \frac{z_R}{z_i}(1 - R_F) = 0 \leq$ 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,

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

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

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

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

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

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

to predict T_c, P_c we will use Sutton correlations

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

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

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

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

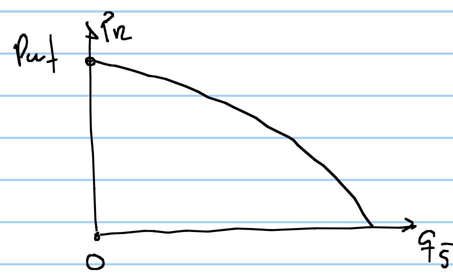
$$Mw_{gas} = \sum_{i=1}^{N} z_i Mw_i$$

$P_R \rightarrow P_{wf}$ IPR equation <u>low pressure</u> dry gas equation

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

← backpressure exponent
laminar $n \sim 1$
turbulent $n \rightarrow 0.5$

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



- pseudo-steady state regime (boundary dominated flow) page 37 of compendium

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

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

tubing coefficient (friction losses)

elevation coefficient (hydrostatic losses)

$q_g = 0 \qquad p_{wf} = p_{wh} \, e^{s/2}$

Page 156, Appendix A of compendium

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

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

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

$p_{wh} \rightarrow p_{template}$ choke no need for equation

$p_{temp} \rightarrow p_{plem}$ flowline $\rightarrow$ tubing equation can be used for flowline

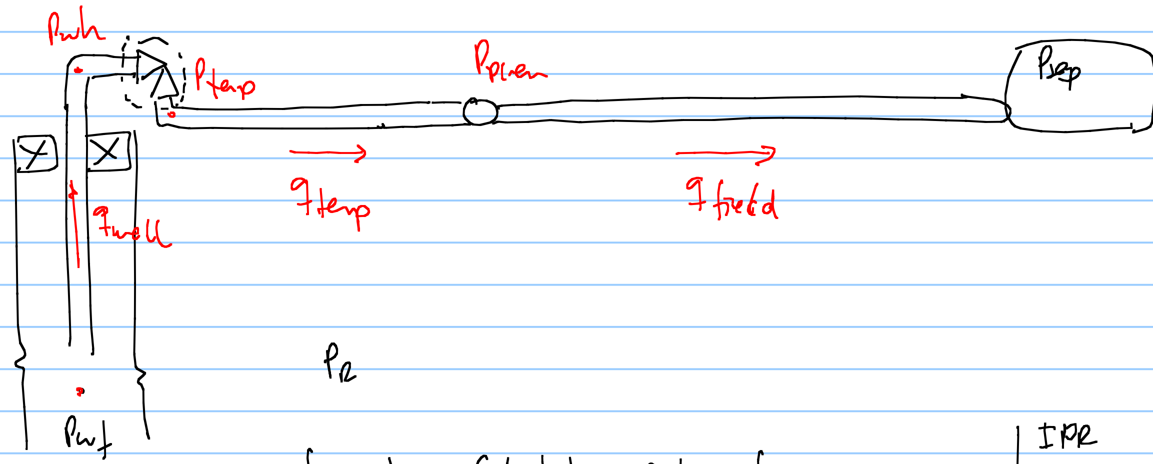
horizontal flowline, the tubing equation simplifies to

$$q_g = C_{FL} \left(p_{temp}^2 - p_{plem}^2 \right)^{0.5}$$

$S = 0$ (L'Hopital)

$p_{plem} \rightarrow p_{sep}$

$$q_g = C_{PL} \left(p_{plem}^2 - p_{sep}^2 \right)^{0.5}$$



fix rate. Calculate Pwh from reservoir { IPR, TPR

Calculate P_{temp} from sep { PPR, FPR

verify Pwh > Ptemp → rates is feasible

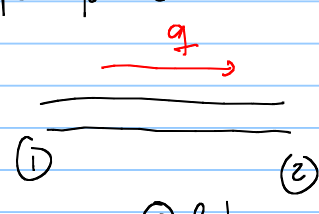
Pwh < Ptemp → rate not feasible, must be reduced

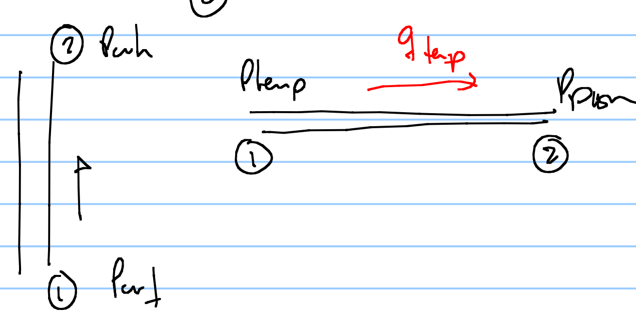
http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2020/Class_files/20200124/

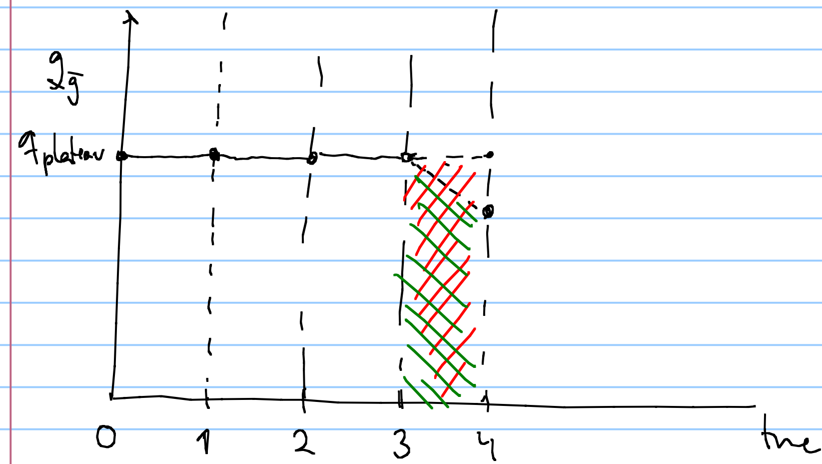
VBA Visual basic for applications

for pipe equations in VBA ① is upstream

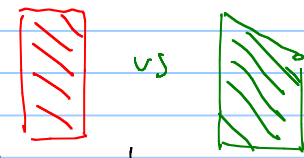
② is downstream







rectangular integration give a poor approximation of G_p when in decline phase



improvement
- use smaller time-step
- use a better integration

$$G_p = \int_0^1 q_{field}\, dt \longrightarrow R_F \longrightarrow P_R$$

$$\Delta G_p^{i} = \frac{\left(q^{i-1} + q^{i}\right)}{2} \Delta t$$

P_R

Approximation, q^{0}_{field} is constant between $0 \rightarrow 1$

G=IGIP	270E+09	Sm3
Annual production rate	0.027	fraction of IGIP
Production days per year	365	day
T_R	92	oC
Pi, initial Res pressure	276	bara
C, inflow Back pressure coefficient	1000	Sm3/bar^2n
n, backpressure, exponent	1	
Ct, Tubing coefficient (2100 MDx0.15	4.03E+04	Sm3/bar
Elevation coeff, S	0.155	
$C_{FL\ Flowline}$ Template-PLEM (5000x0.	2.83E+05	Sm3/bar
$C_{PL\ Pipeline}$ PLEM-Shore (158600x0.6	2.75E+05	Sm3/bar
Separator (slug catcher) pressure	30	bara
Gas molecular weight (Methane)	16	kg/kmole
Gas specific gravity	0.55	Gas specific gravity
Gas density at Sc	0.67	kg/m^3
Number of templates	3	
Number of wells	9	
Desired plateau	20	years
qfield	20.0E+6	[Sm^3/d]
Field gas rate for abandonment	5.00E+06	[Sm^3/d]

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

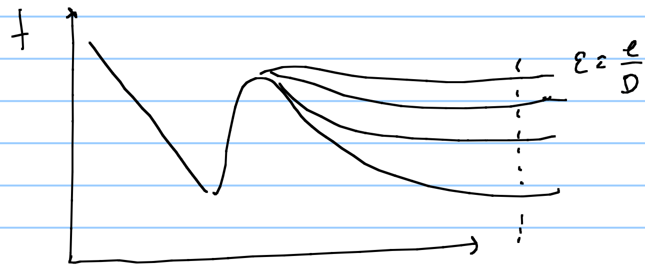
time	qfield	Gp	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke
												for each well
[years]	[Sm^3/d]	[Sm^3]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6	000.0E+0	0.967291	276.0E+0	2.2E+6	272.0	245.6	82.0	78.6	30.0	6.7E+6	164
1	20.0E+6	7.29E+09	0.962615	269	2.2E+6	264.4	238.4	82.0	78.6	30.0	6.7E+6	156
2	20.0E+6	1.46E+10	0.957442	260	2.2E+6	255.5	230.0	82.0	78.6	30.0	6.7E+6	148
3	20.0E+6	2.19E+10	0.952572	251	2.2E+6	246.6	221.5	82.0	78.6	30.0	6.7E+6	139
4	20.0E+6	2.92E+10	0.948138	242	2.2E+6	237.8	213.1	82.0	78.6	30.0	6.7E+6	131

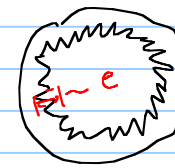
Comments about tubing equation

$T_{av} \rightarrow \frac{T_{wf} + T_{wh}}{2}$ An estimate of T_{wh} is needed to compute G_T

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

f_m friction factor





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

μ_g is << μ_L

Re_g >>

always in fully turbulent regime

$v = f(q_{local})$

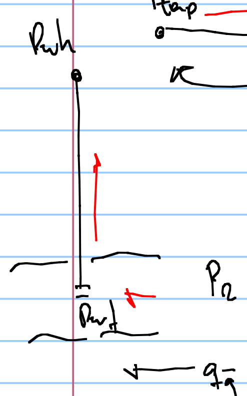
q_{local} $f(p)$

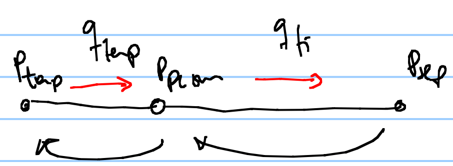
for gas $v \uparrow \uparrow$ ρ is low compared to liquid

liquid v - [0.5 - 4] m/s

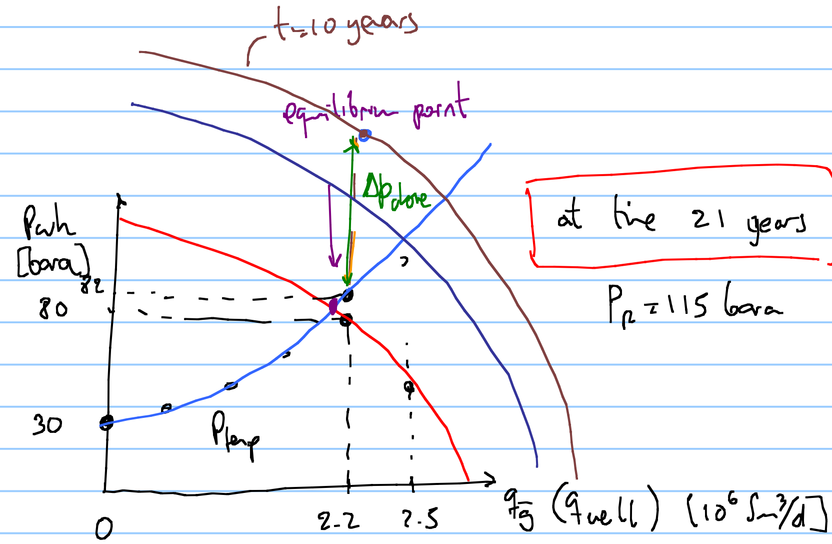
gas v - [5 - 40] m/s

$f_m = f(\varepsilon)$ however $e = f(D)$ due to manufacturing



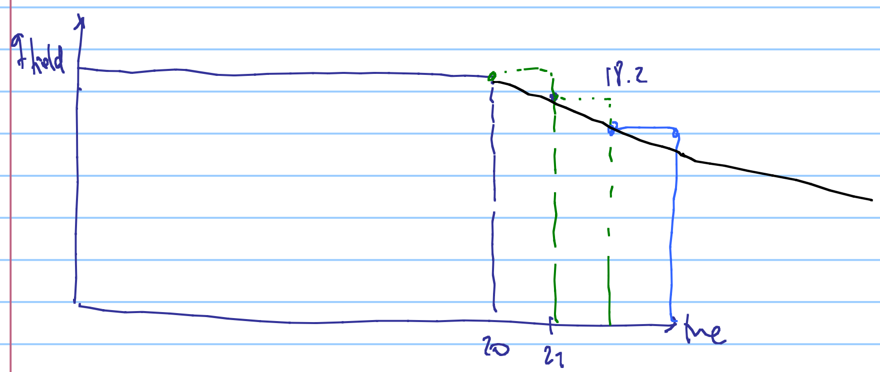


$q_{field} = 3\, q_{temp} = 9\, q_{well}$



$\boxed{\text{at time 21 years}}$

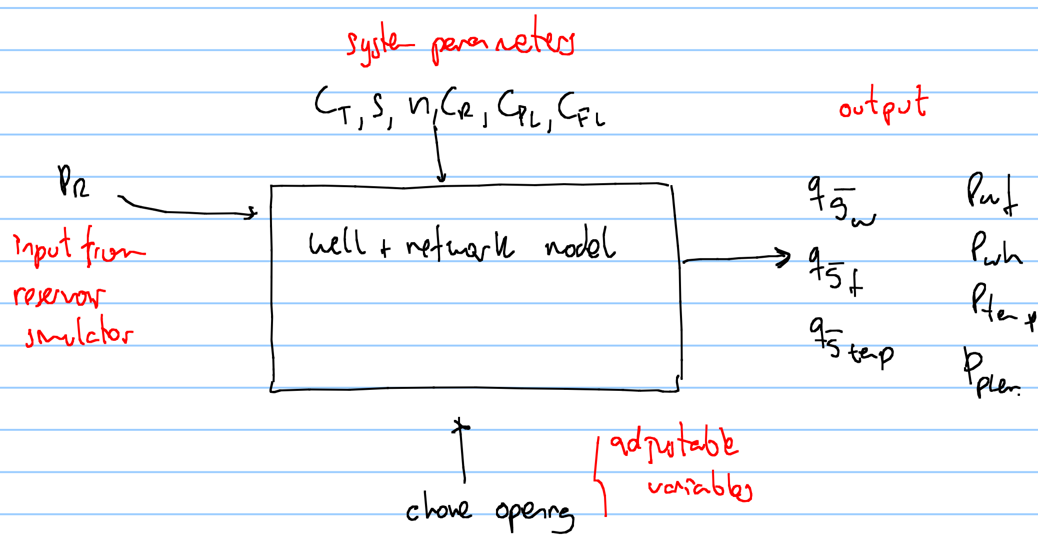
$P_R = 115$ bara

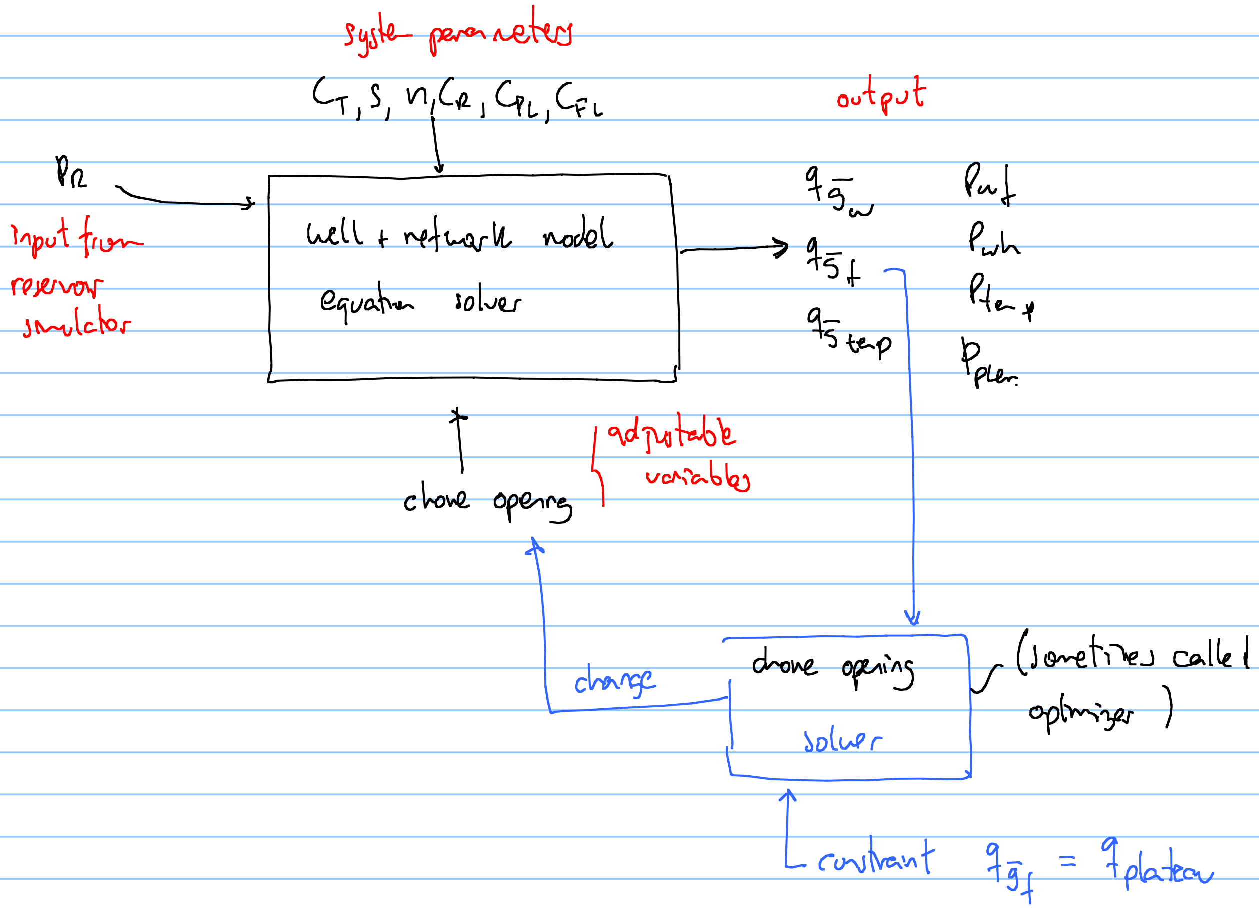


In reality the well + network simulator works differently, as a system of equations solver

for example

		EQUATIONS	UNKNOWNS
IPR	$q_{g_w} = C_R \left(P_R^2 - P_{wf}^2\right)^n$	1	2
TPR	$q_{g_w} = C_T \left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$	2	3
FPR	$q_{g_T} = C_{FL} \left(P_{Temp}^2 - P_{PLem}^2\right)^{0.5}$	3	6
PPR	$q_{g_f} = C_{PL} \left(P_{PLem}^2 - P_{sep}^2\right)^{0.5}$	4	7
choke	$q_{g_f} = f\left(P_{wh}, P_{temp}, \text{opening}\right)$	5	7 (if opening is given)
	$q_{g_w} = q_f / N_w$	6	7
	$q_{g_t} = q_f / N_{temp}$	7	7
		7 =	7





choke equation for dry gas: (page 166)

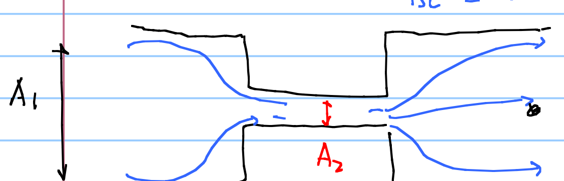
"opening" tuning factor $\frac{R_U}{MW_g}$ $k = \frac{C_P}{C_V}$

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

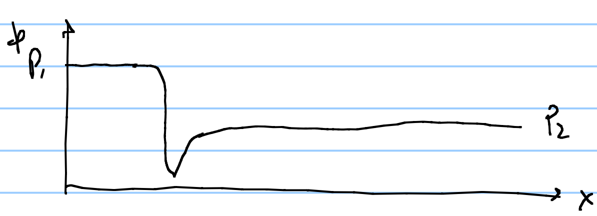
$p_{sc} = 1.01325$ bara

$T_{sc} = 15.56\ °C$

$y = \frac{P_2 \ \text{(downstream)}}{P_1 \ \text{(upstream)}}$



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



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

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

in blue

if $y < y_c$

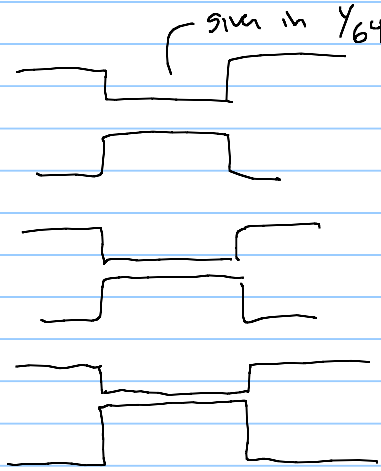
$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)}$$

in red

(flow is "choked", critical flow)

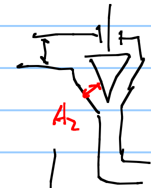
in onshore fields, bean choke are often used

given in 1/64"



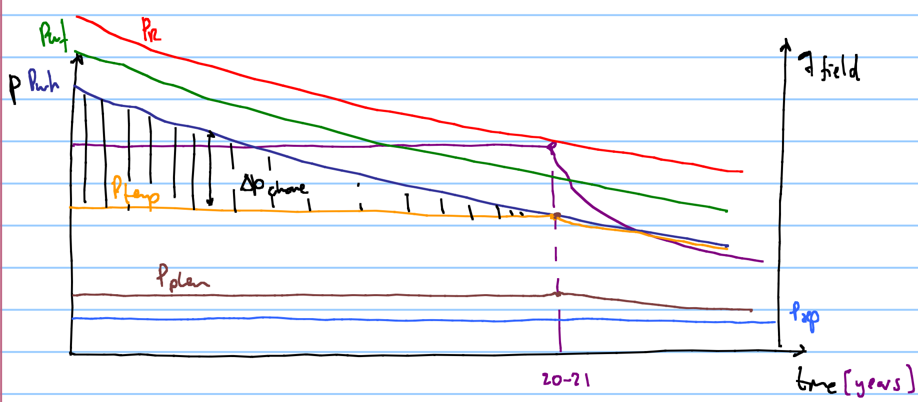
offshore often adjustable chokes are used

needle choke



adjustable throat area

time	qfield	Gp	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke
[years]	[Sm^3/d]	[Sm^3]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6	000.0E+0	0.967291	276.0E+0	2.2E+6	272.0	245.6	82.0	78.6	30.0	6.7E+6	164
1	20.0E+6	7.29E+09	0.962615	269	2.2E+6	264.4	238.4	82.0	78.6	30.0	6.7E+6	156
2	20.0E+6	1.46E+10	0.957442	260	2.2E+6	255.5	230.0	82.0	78.6	30.0	6.7E+6	148
3	20.0E+6	2.19E+10	0.952572	251	2.2E+6	246.6	221.5	82.0	78.6	30.0	6.7E+6	139
4	20.0E+6	2.92E+10	0.948138	242	2.2E+6	237.8	213.1	82.0	78.6	30.0	6.7E+6	131
5	20.0E+6	3.65E+10	0.944151	234	2.2E+6	229.2	204.9	82.0	78.6	30.0	6.7E+6	123
6	20.0E+6	4.37E+10	0.9406	226	2.2E+6	220.8	196.8	82.0	78.6	30.0	6.7E+6	115
7	20.0E+6	5.10E+10	0.937473	218	2.2E+6	212.5	188.8	82.0	78.6	30.0	6.7E+6	107
8	20.0E+6	5.83E+10	0.934759	210	2.2E+6	204.4	180.9	82.0	78.6	30.0	6.7E+6	99
9	20.0E+6	6.56E+10	0.932447	202	2.2E+6	196.3	173.1	82.0	78.6	30.0	6.7E+6	91
10	20.0E+6	7.29E+10	0.930524	194	2.2E+6	188.4	165.4	82.0	78.6	30.0	6.7E+6	83
11	20.0E+6	8.02E+10	0.928981	187	2.2E+6	180.6	157.8	82.0	78.6	30.0	6.7E+6	76
12	20.0E+6	8.75E+10	0.927809	179	2.2E+6	172.9	150.2	82.0	78.6	30.0	6.7E+6	68
13	20.0E+6	9.48E+10	0.926997	172	2.2E+6	165.2	142.6	82.0	78.6	30.0	6.7E+6	61
14	20.0E+6	1.02E+11	0.926538	165	2.2E+6	157.6	135.1	82.0	78.6	30.0	6.7E+6	53
15	20.0E+6	1.09E+11	0.926422	157	2.2E+6	150.1	127.5	82.0	78.6	30.0	6.7E+6	45
16	20.0E+6	1.17E+11	0.926642	150	2.2E+6	142.6	119.9	82.0	78.6	30.0	6.7E+6	38
17	20.0E+6	1.24E+11	0.927191	143	2.2E+6	135.1	112.2	82.0	78.6	30.0	6.7E+6	30
18	20.0E+6	1.31E+11	0.928061	136	2.2E+6	127.6	104.4	82.0	78.6	30.0	6.7E+6	22
19	20.0E+6	1.39E+11	0.929247	129	2.2E+6	120.0	96.5	82.0	78.6	30.0	6.7E+6	14
20	20.0E+6	1.46E+11	0.930741	122	2.2E+6	112.5	88.3	82.0	78.6	30.0	6.7E+6	6
21	19.6E+6	1.53E+11	0.93254	115	2.2E+6	105.1	80.8	80.8	77.4	30.0	6.5E+6	0
22	18.2E+6	1.60E+11	0.934597	108	2.0E+6	98.3	75.9	75.9	72.8	30.0	6.1E+6	0
23	16.9E+6	1.67E+11	0.936756	102	1.9E+6	92.1	71.3	71.3	68.5	30.0	5.6E+6	0
24	15.7E+6	1.73E+11	0.938977	96	1.7E+6	86.4	67.1	67.1	64.5	30.0	5.2E+6	0
25	14.6E+6	1.79E+11	0.941221	90	1.6E+6	81.0	63.3	63.3	60.9	30.0	4.9E+6	0



$$P_R = P_{Ri}\,\frac{z_R}{z_{Ri}}\left[1 - R_p\right]$$

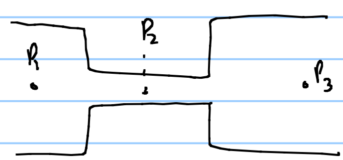
$$q_{well} = C_R\left(P_R^2 - P_{wf}^2\right)^n$$

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

$P_{plem} \rightarrow q_{field} = C_{PL}\left(P_{Plem}^2 - P_{sep}^2\right)^{0.5}$ $\qquad \Delta P_{choke} = P_{wh} - P_{temp}$

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

Critical flow occurs $\frac{P_2}{P_1} \leq (0.5-0.6)$ in our case $\frac{P_{temp}}{P_{wh}} \leq (0.5-0.6)$ y_c critical pressure ratio



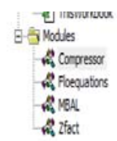
time	qfield	Gp	RF	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke	ptemp/pwh
[years]	[Sm^3/d]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]	[-]
0	20.0E+6	000.0E+0	0.000	0.967291	276.0E+0	2.2E+6	272.0	245.6	82.0	78.6	30.0	6.7E+6	164	0.33
1	20.0E+6	7.29E+09	0.027	0.962615	269	2.2E+6	264.4	238.4	82.0	78.6	30.0	6.7E+6	156	0.34
2	20.0E+6	1.46E+10	0.054	0.957442	260	2.2E+6	255.5	230.0	82.0	78.6	30.0	6.7E+6	148	0.36
3	20.0E+6	2.19E+10	0.081	0.952572	251	2.2E+6	246.6	221.5	82.0	78.6	30.0	6.7E+6	139	0.37
4	20.0E+6	2.92E+10	0.108	0.948138	242	2.2E+6	237.8	213.1	82.0	78.6	30.0	6.7E+6	131	0.38
5	20.0E+6	3.65E+10	0.135	0.944151	234	2.2E+6	229.2	204.9	82.0	78.6	30.0	6.7E+6	123	0.40
6	20.0E+6	4.37E+10	0.162	0.9406	226	2.2E+6	220.8	196.8	82.0	78.6	30.0	6.7E+6	115	0.42
7	20.0E+6	5.10E+10	0.189	0.937473	218	2.2E+6	212.5	188.8	82.0	78.6	30.0	6.7E+6	107	0.43
8	20.0E+6	5.83E+10	0.216	0.934759	210	2.2E+6	204.4	180.9	82.0	78.6	30.0	6.7E+6	99	0.45
9	20.0E+6	6.56E+10	0.243	0.932447	202	2.2E+6	196.3	173.1	82.0	78.6	30.0	6.7E+6	91	0.47
10	20.0E+6	7.29E+10	0.270	0.930524	194	2.2E+6	188.4	165.4	82.0	78.6	30.0	6.7E+6	83	0.50
11	20.0E+6	8.02E+10	0.297	0.928981	187	2.2E+6	180.6	157.8	82.0	78.6	30.0	6.7E+6	76	0.52
12	20.0E+6	8.75E+10	0.324	0.927809	179	2.2E+6	172.9	150.2	82.0	78.6	30.0	6.7E+6	68	0.55
13	20.0E+6	9.48E+10	0.351	0.926997	172	2.2E+6	165.2	142.6	82.0	78.6	30.0	6.7E+6	61	0.57
14	20.0E+6	1.02E+11	0.378	0.926538	165	2.2E+6	157.6	135.1	82.0	78.6	30.0	6.7E+6	53	0.61
15	20.0E+6	1.09E+11	0.405	0.926422	157	2.2E+6	150.1	127.5	82.0	78.6	30.0	6.7E+6	45	0.64
16	20.0E+6	1.17E+11	0.432	0.926642	150	2.2E+6	142.6	119.9	82.0	78.6	30.0	6.7E+6	38	0.68
17	20.0E+6	1.24E+11	0.459	0.927191	143	2.2E+6	135.1	112.2	82.0	78.6	30.0	6.7E+6	30	0.73
18	20.0E+6	1.31E+11	0.486	0.928061	136	2.2E+6	127.6	104.4	82.0	78.6	30.0	6.7E+6	22	0.79
19	20.0E+6	1.39E+11	0.513	0.929247	129	2.2E+6	120.0	96.5	82.0	78.6	30.0	6.7E+6	14	0.85
20	20.0E+6	1.46E+11	0.540	0.930741	122	2.2E+6	112.5	88.3	82.0	78.6	30.0	6.7E+6	6	0.93
21	19.6E+6	1.53E+11	0.567	0.93254	115	2.2E+6	105.1	80.8	80.8	77.4	30.0	6.5E+6	0	
22	18.2E+6	1.60E+11	0.594	0.934597	108	2.0E+6	98.3	75.9	75.9	72.8	30.0	6.1E+6	0	
23	16.9E+6	1.67E+11	0.618	0.936756	102	1.9E+6	92.1	71.3	71.3	68.5	30.0	5.6E+6	0	
24	15.7E+6	1.73E+11	0.641	0.938977	96	1.7E+6	86.4	67.1	67.1	64.5	30.0	5.2E+6	0	
25	14.6E+6	1.79E+11	0.662	0.941221	90	1.6E+6	81.0	63.3	63.3	60.9	30.0	4.9E+6	0	

choke is in critical flow
are in critical regime

subcritical

• in excel VBA

functions
• are called on each cell and fx button
• saved in "module"

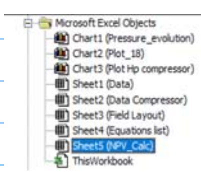


function namefunction(args 1, arg2, ...)
:
:
namefunction = f(args 1, args 2, ...)
end function

subs (scripts) set of instructions to execute
• are run from VBA module or by making buttons on spreadsheet
• can be saved in "module" or in each sheet

sub name_sub()
argument are optional

end sub




```
Sub GoalSeekVBA()
    sheetname = "Data"
    x = Worksheets(sheetname).Cells(2, 2).Value
    b = x / 2
    Worksheets(sheetname).Cells(2, 4).Value = b
End Sub
```

For debugging (for functions or subs)

↳ add a red point on the frame (gray zone)

F8 instruction by instruction

F5 to jump between points (if no more points, it will run until function end)

Code to run goal seek in several cells sequentially

```
Sub GoalSeekVBA()
    sheetname = "Data"
    x = Worksheets(sheetname).Cells(2, 2).Value
    Dim sh As Worksheet
    Set sh = ThisWorkbook.Sheets("Data")
    Dim target As Long
    target = 0#
    For i = 45 To 49
        OBJTAG = "O" & i
        VARTAG = "C" & i
        sh.Range(OBJTAG).GoalSeek Goal:=target, ChangingCell:=Range(VARTAG)
    Next
End Sub
```

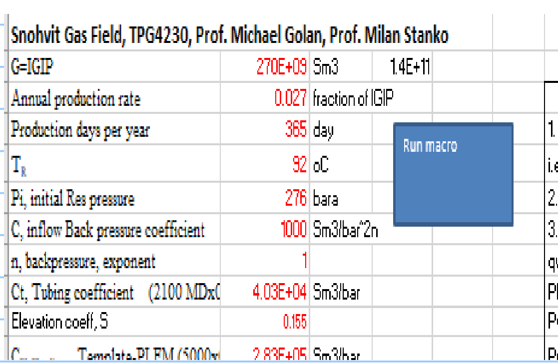
The initial seed for field rate must give a valid solution:

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

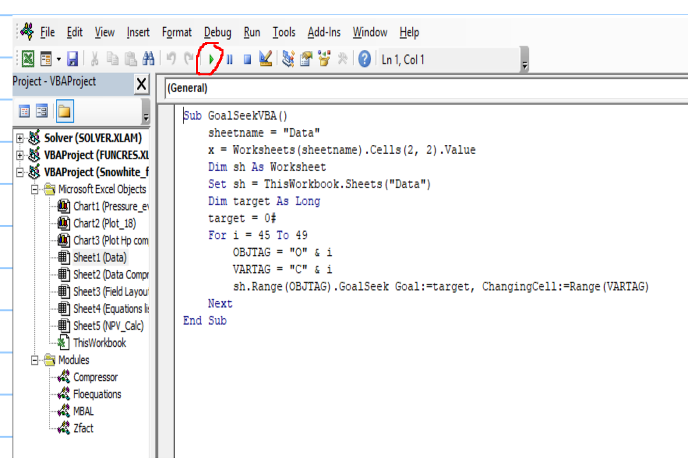
$$P_{wh} = \sqrt{\underbrace{\frac{P_{wf}^2}{e^S} - \left(\frac{q_g}{C_T}\right)^2}_{(-)}}$$

(−) ~ #VALUE ERROR IN EXCEL when q_g is "too big"

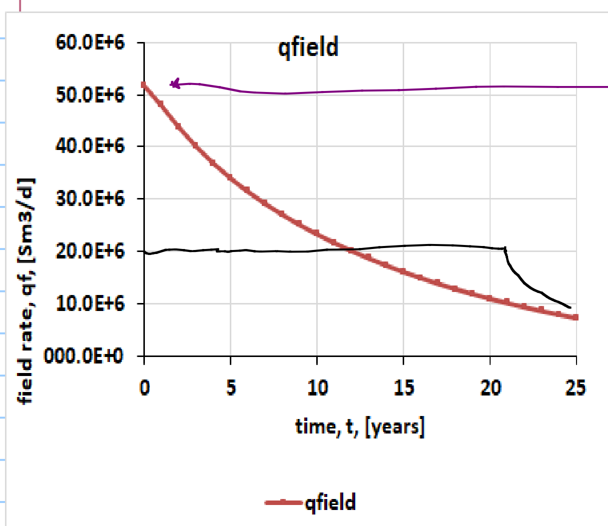
To run the macro, a button can be created (link it to a macro)..... or the VBA interface:



Snohvit Gas Field, TPG4230, Prof. Michael Golan, Prof. Milan Stanko			
G=IGIP	2.70E+09	Sm3	1.4E+11
Annual production rate	0.027	fraction of IGIP	
Production days per year	365	day	
T_R	92	oC	
Pi, initial Res pressure	276	bara	
C, inflow Back pressure coefficient	1000	Sm3/bar^2n	
n, backpressure, exponent	1		
Ct, Tubing coefficient (2100 MD...	4.03E+04	Sm3/bar	
Elevation coeff, S	0.155		



Producing Snowhite in mode "B" (decline)



theoretically max well rate is

$q_{well} = 5.7E06\ Sm^3/d$

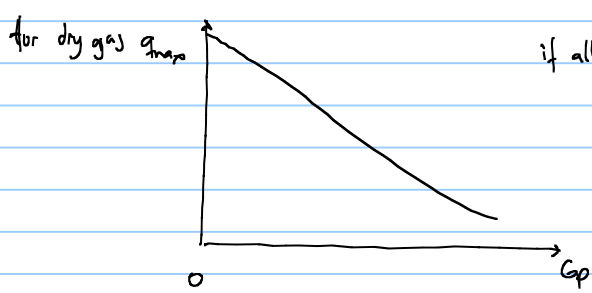
in reality it might not be feasible to produce

the biggest offshore gas wells produce at most $9\ E06\ Sm^3/d$

↳ tubing $\phi = 7-9''$

↳ sand production / formation collapse

Production potential (max rate of production system versus cumulative production), q_{pp}



if all else if constant, for example n wells, choke opening, n pipes, tubing size, etc

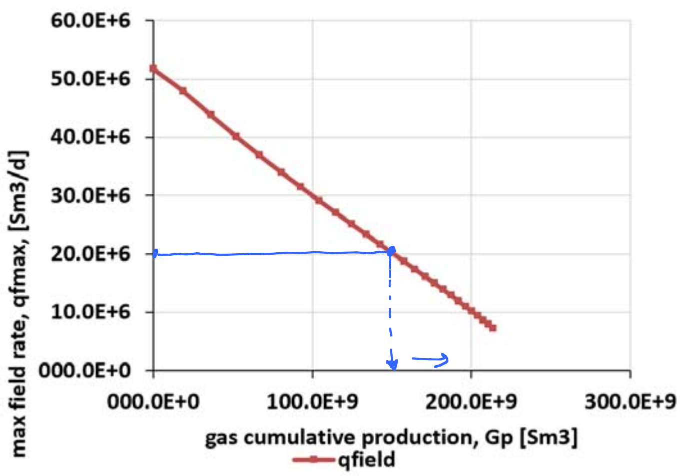
q_{max} is only a function of cumulative production

Because:

q_{max} is only a function of P_R

and P_R is only a function of G_p

in conclusion $q_{max} = f(G_p)$



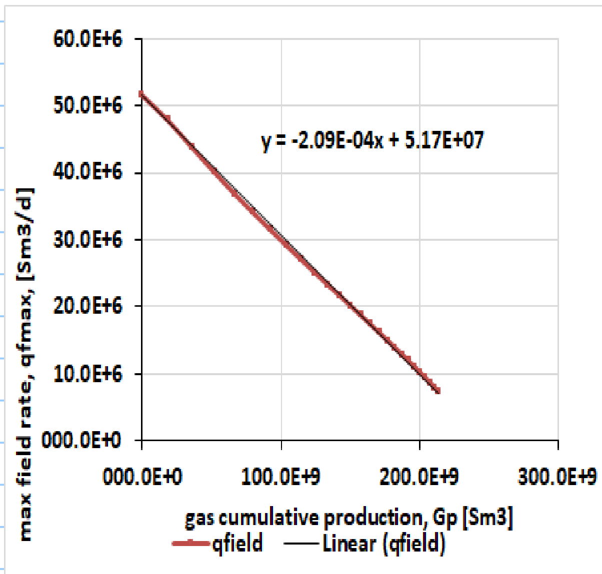
when producing in plateau rate

$t < t_{plateau}$ producing below potential

$t > t_{plateau}$ production at potential

if production 20E06 Sm^3/d.
when I reach $G_p \approx 150$ E09 Sm^3
the field enters in decline
for $G_p < 150$E09 Sm^3, it will be possible to produce at plateau rate

for Snowhite, this curve can be approximated $q_{pp} = -2.09E{-}04 \cdot G_p + 5.17E07$



$q_{pp} = -m\, G_p + \underbrace{q_{ppo}}_{}$
production at initial reservoir pressure

task: find G_p^* for wich $q_{pp} = q_{plateau} = 20E06$ Sm^3

$20E06 = -2.09E{-}04\ G_p^* + 5.17E07$

$G_p^* = \frac{5.17E07 - 20E06}{+2.09E{-}04} = 151.8E09\ Sm^3$

G_p { $0 \rightarrow G_p^*$ } production at constant rate

therefore

$G_p^* = q_{plateau} \cdot t_{plateau}$

$t_{plateau} = \frac{G_p^*}{q_{plateau}} = 7589\ d \,/\, 365 = 20.79$ years

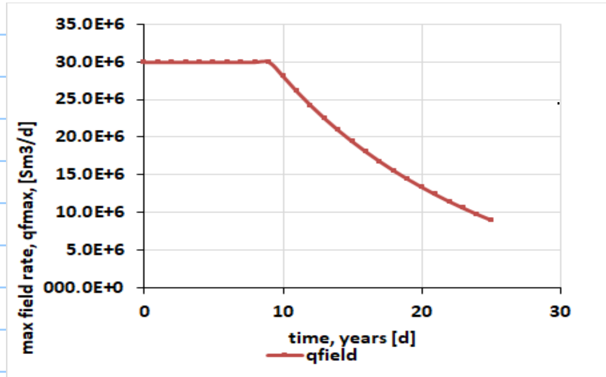
$\frac{[Sm^3]}{[Sm^3/d]} = [d]$

find plateau end for $q_{plateau} = 30E06\ Sm^3/d$

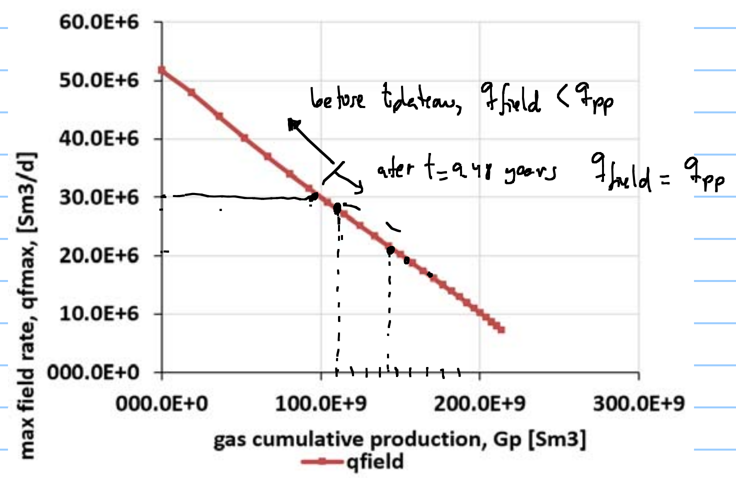
$q_{pp} = q_{plateau} = -m\, G_p^* + q_{ppo}$

$30E06 = -m\, G_p^* + q_{ppo}$

$t_{plateau} = 9.48$ years



time	qfield	Gp	RF	Z	PR	qwell	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	qtemp	DeltaPchoke	ptemp/pwh
[years]	[Sm^3/d]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]	[-]
0	30.0E+6	000.0E+0	0.000	0.967291	276.0E+0	3.3E+6	269.9	235.7	118.5	113.1	30.0	10.0E+6	117	0.50
1	30.0E+6	1.10E+10	0.041	0.960354	265	3.3E+6	258.4	224.4	118.5	113.1	30.0	10.0E+6	106	0.53
2	30.0E+6	2.19E+10	0.081	0.952966	252	3.3E+6	245.1	211.2	118.5	113.1	30.0	10.0E+6	93	0.56
3	30.0E+6	3.29E+10	0.122	0.946385	239	3.3E+6	231.7	197.9	118.5	113.1	30.0	10.0E+6	79	0.60
4	30.0E+6	4.38E+10	0.162	0.940794	226	3.3E+6	218.7	184.7	118.5	113.1	30.0	10.0E+6	66	0.64
5	30.0E+6	5.48E+10	0.203	0.936181	214	3.3E+6	206.1	171.8	118.5	113.1	30.0	10.0E+6	53	0.69
6	30.0E+6	6.57E+10	0.243	0.932506	202	3.3E+6	193.7	159.0	118.5	113.1	30.0	10.0E+6	41	0.75
7	30.0E+6	7.67E+10	0.284	0.929729	191	3.3E+6	181.6	146.3	118.5	113.1	30.0	10.0E+6	28	0.81
8	30.0E+6	8.76E+10	0.324	0.927813	179	3.3E+6	169.7	133.4	118.5	113.1	30.0	10.0E+6	15	0.89
9	30.0E+6	9.86E+10	0.365	0.926721	168	3.3E+6	157.9	120.4	118.5	113.1	30.0	10.0E+6	2	0.98
10	28.1E+6	1.10E+11	0.406	0.926423	157	3.1E+6	146.9	111.6	111.6	106.6	30.0	9.4E+6	0	1.00
11	26.1E+6	1.20E+11	0.444	0.926839	147	2.9E+6	136.9	104.2	104.2	99.6	30.0	8.7E+6	0	1.00
12	24.2E+6	1.29E+11	0.479	0.927805	138	2.7E+6	127.7	97.4	97.4	93.1	30.0	8.1E+6	0	1.00
13	22.5E+6	1.38E+11	0.512	0.929186	129	2.5E+6	119.2	91.2	91.2	87.2	30.0	7.5E+6	0	1.00
14	20.9E+6	1.46E+11	0.542	0.930877	121	2.3E+6	111.4	85.4	85.4	81.8	30.0	7.0E+6	0	1.00
15	19.4E+6	1.54E+11	0.570	0.932791	114	2.2E+6	104.2	80.1	80.1	76.8	30.0	6.5E+6	0	1.00
16	18.1E+6	1.61E+11	0.597	0.934861	107	2.0E+6	97.5	75.3	75.3	72.2	30.0	6.0E+6	0	1.00



if we have an analytical expression of q_{pp}, it is possible to find an analytical expression for q_{field}

If q_{pp} is linear (dry gas)

$$q_{pp} = -m\, G_p + q_{ppo}$$

$t_{plateau}$ occurs when $q_{plateau} = q_{pp} = -m\, G_p^* + q_{ppo}$

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

$$\underset{[d]}{t_{plateau}} = \left(\frac{q_{ppo}}{q_{plateau}} - 1\right)\frac{1}{m}$$

if $t < t_{plateau}$ the $q_{field} = q_{plateau}$

if $t \geq t_{plateau}$ then $q_{field} = q_{pp}$

$$q_{pp} = -m\,G_p + q_{ppo}$$

$$q_{pp} = -m \left[\int_0^t q_{field} \cdot dt \right] + q_{ppo}$$

$$q_{pp} = -m \left[q_{plateau} \cdot t_{plateau} + \int_{t_{plateau}}^{t} q_{field}\, dt \right] + q_{ppo}$$

$$q_{field} = -m \left[q_{plateau} \cdot t_{plateau} + \int_{t_{plateau}}^{t} q_{field}\, dt \right] + q_{ppo}$$

a solution to this equation is

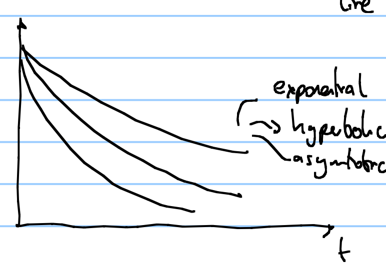
$$q_{field} = q_{plateau}\, e^{-m(t - t_{plateau})}$$

if $t < t_{plateau}$ $q_{field} = q_{plateau}$ $t_{plateau} = \left[\frac{q_{ppo}}{q_{plateau}} - 1 \right] \frac{1}{m}$

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

→ if production potential is a straight line, then decline rates are exponential

DCA (decline curve analysys)



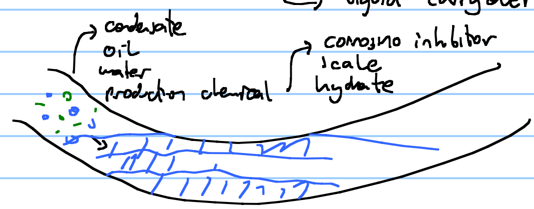
- how to prolong plateau:
  - "change" C_R $q_{well} = C_R (P_R^2 - P_{wf}^2)^n$
    - fracturing
    - acidizing (stimulation)
    - change completion → longer well, bigger bore hole, multi lateral
  - change C_T $q_{well} = C_T \left(\frac{P_{wf}^2}{e^s} - P_{wh}^2 \right)^{0.5}$
    - increase tubing diameter
  - change C_{PL}, C_{FL} $q_{field} = C_{PL} \left(P_{ple}^2 - P_{sep}^2 \right)^{0.5}$

increasing flowline and pipeline diameter might help

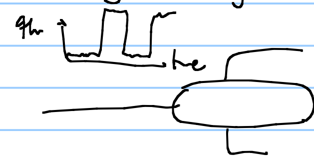
However keep in mind: big pipe → more costly to manufacture
to install

more CAPEX
less NPV

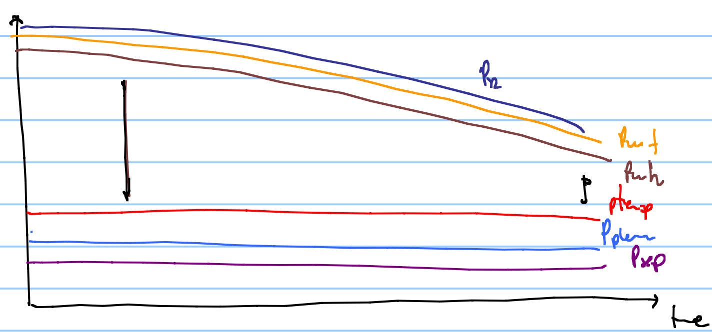
→ liquid carryover



gas must have enough velocity to carry this liquid



- number of wells



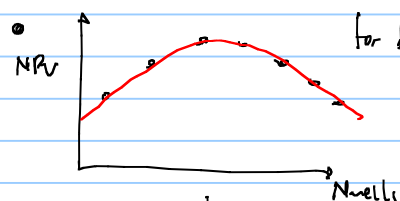
q_f

$$q_{well} = \frac{q_f}{N_{wells}}$$

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

$$P_{wf} = \left(P_R^2 - \left(\frac{q_w}{C_R}\right)^{1/n}\right)^{0.5}$$

choosing ideal number of wells:
- Recovery factor
- maximum allowable rate per well
  - coning (gas, water)
  - erosion
  - sand production



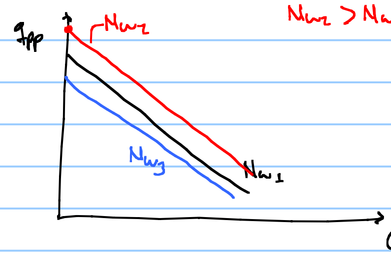
for fixed $q_{plateau}$

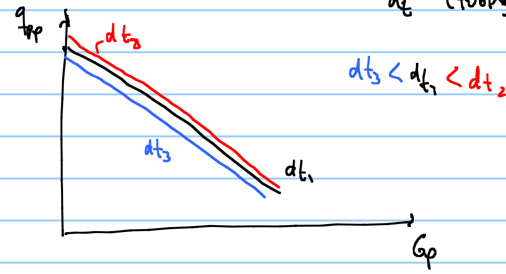
← the income of extra plateau duration is bigger than extra expenses

→ the income of plateau extensions is less than extra expenses

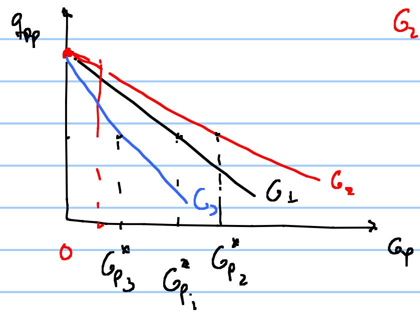
Some comments on production potential: changing nr. wells modifies the potential

d_t (tubing size)





changing G modifies the potential



$q_{plateau}$ which one gives me max $t_{plateau}$?

$$t_{plateau} = \frac{G_{p3}^*}{q_{plateau}} \qquad \frac{G_{p2}^*}{q_{plateau}} \qquad \frac{G_{p1}^*}{q_{plateau}}$$

there is a big uncertainty in G during field development

- how can we use q_{pp} vs Q_p to estimate q_{field} post plateau? (either N or G)

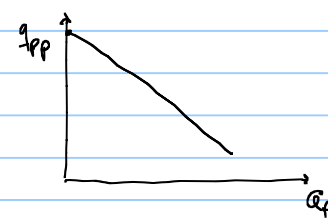
1) Analytical derivation, if q_{pp} vs Q_p is easy to integrate

2) time-wise calculation: for each time, with Q_p^t, read in (curve / table) $q_{pp}(Q_p^t)$

- if q_{pp}^t is greater than q_{target} then produce q_{target} and move to next time step $\Delta Q_p = \Delta t \cdot q_{target}$

- if $q_{pp}^t < q_{target}$ then produce q_{pp}^t and move to next time step $\Delta Q_p = \Delta t \, q_{pp}^t$

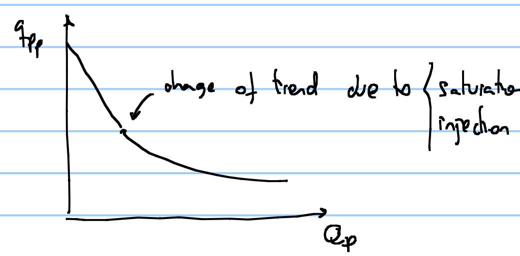
repeat



q_{pp} $y = -2.09E-04x + 5.17E+07$ (G_p)

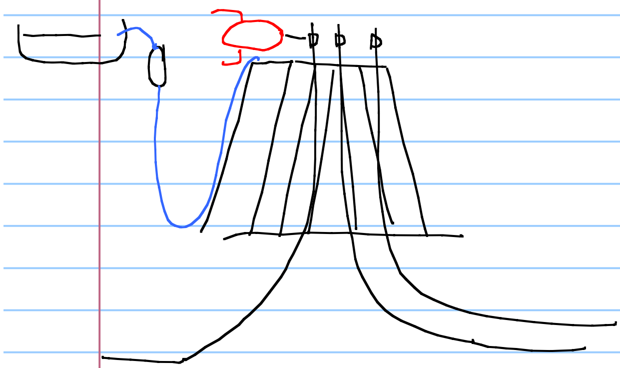
time	Gp [Sm3]	qplateau [Sm3/d]	qpp [Sm3/d]	qfield [Sm3/d]
0	0.00E+00	3.00E+07	5.17E+07	3E+07
1	1.10E+10	3.00E+07	4.94E+07	3E+07
2	2.19E+10	3.00E+07	4.71E+07	3E+07
3	3.29E+10	3.00E+07	4.48E+07	3E+07
4	4.38E+10	3.00E+07	4.25E+07	3E+07
5	5.48E+10	3.00E+07	4.03E+07	3E+07
6	6.57E+10	3.00E+07	3.80E+07	3E+07
7	7.67E+10	3.00E+07	3.57E+07	3E+07
8	8.76E+10	3.00E+07	3.34E+07	3E+07
9	9.86E+10	3.00E+07	3.11E+07	3E+07
10	1.10E+11	3.00E+07	2.88E+07	2.9E+07
11	1.20E+11	3.00E+07	2.66E+07	2.7E+07
12				

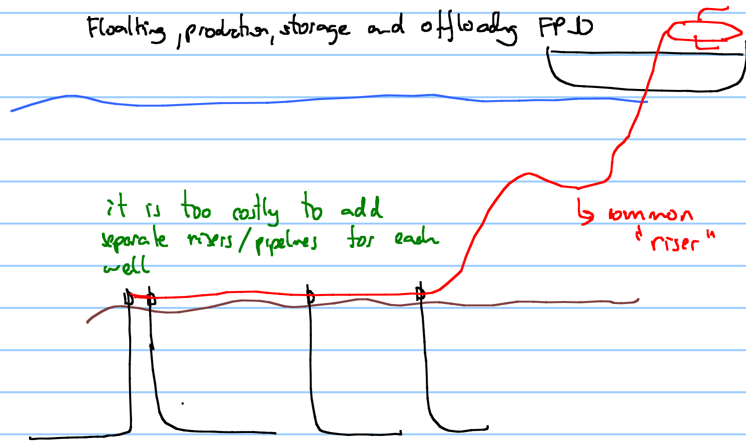
potential curves might have a non-linear behavior



Networks

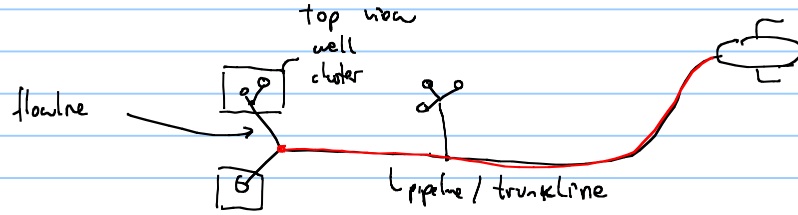
Floating, production, storage and offloading FPSO





subsea gathering network

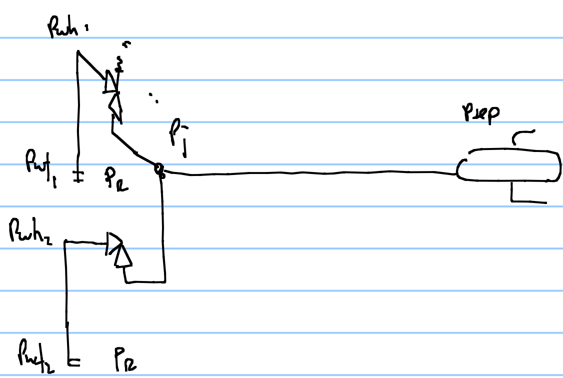
top view



each well depends / is affected by the production of other wells in the network

How to solve networks?

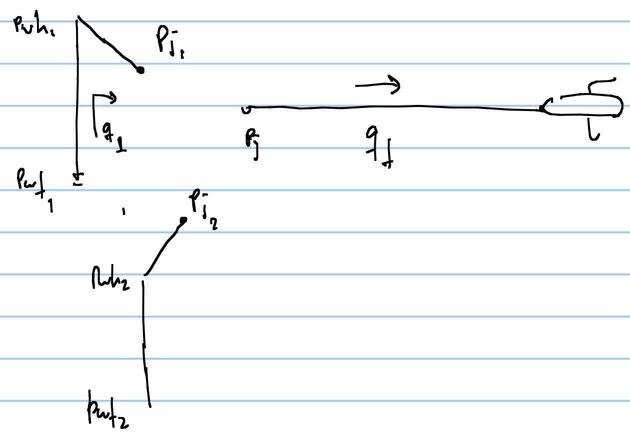
Dry gas networks

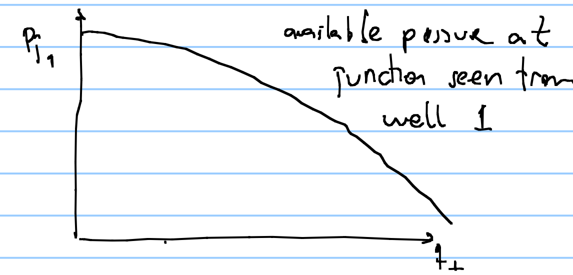


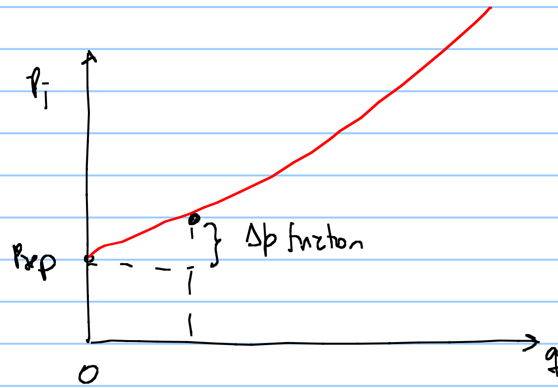
open choke

	nr. equations	nr. unknowns
IPR $q_{w1} = C_{R1}(P_R - P_{wf1})^n$	2	4
TPR $q_w = C_T\left(\frac{P_{wf}^2}{e^s} - P_{wh}^2\right)^{0.5}$	2	2
FPR $q_{field} = C_{PL}(P_j^2 - P_{sep}^2)^{0.5}$	1	2
mass conservation in junction $q_f = q_{w1} + q_{w2}$	1	0
pressure balance in junction $P_{wh1} = P_j$, $P_{wh2} = P_j$ (if open choke and 1 and 2 close to junction)	2	0
	8	8

to find rates, solve this system of equations







Task 1 (9 POINTS). Calculate the operating flow rates when the chokes are fully open. Verify if the H2S concentration of the field is higher than the maximum value allowed (5.7 mg/Sm^3)

Task 2. (6 POINTS) If the H2S constraint is violated, please find an operational point that does not violate the H2S constraint (by choking one or two wells). Hint: Fix the rate on both wells. Report the pressure drop across the chokes.

$q_1 = 0.8\text{E}06$ Sm³/d ?

$q_2 = 0.8\text{E}06$ Sm³/d

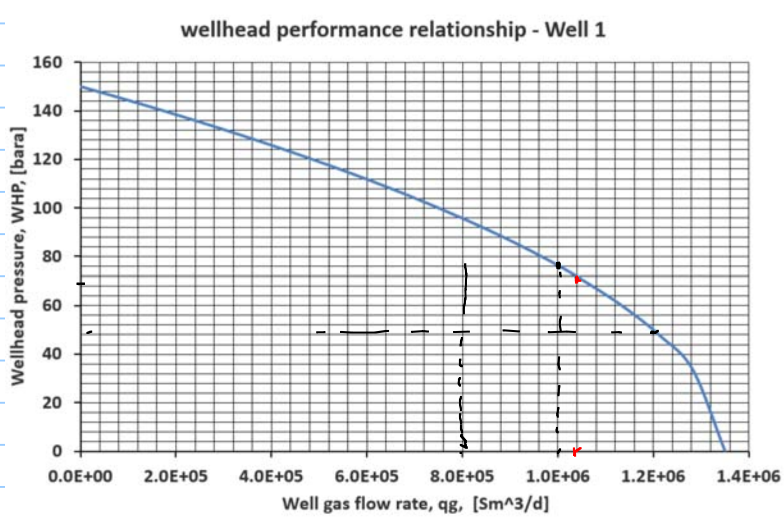
Is it possible to produce these rates?

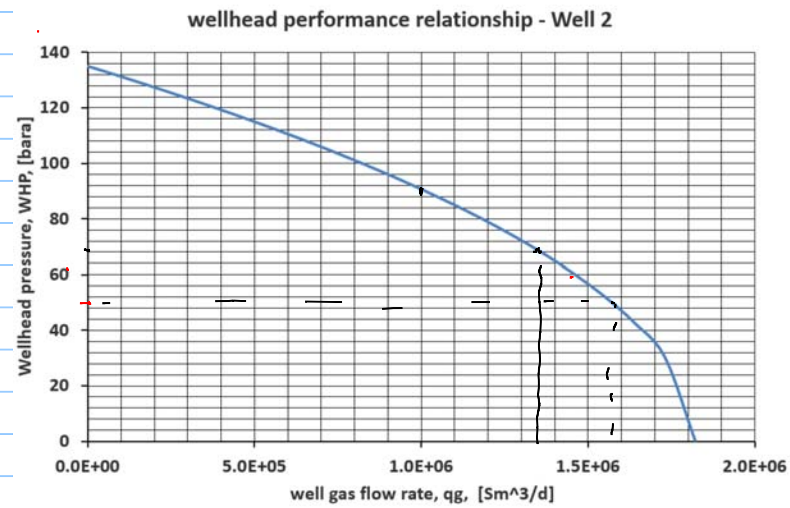
one possible option

guess $q_1 = 1\text{E}06$ Sm³/d $P_{j1} = 76$ bara

$q_2 = 1\text{E}06$ Sm³/d $P_{j2} = 90$ bara

$q_f = 2\text{E}06$ Sm³/d $p_j = 54$ bara



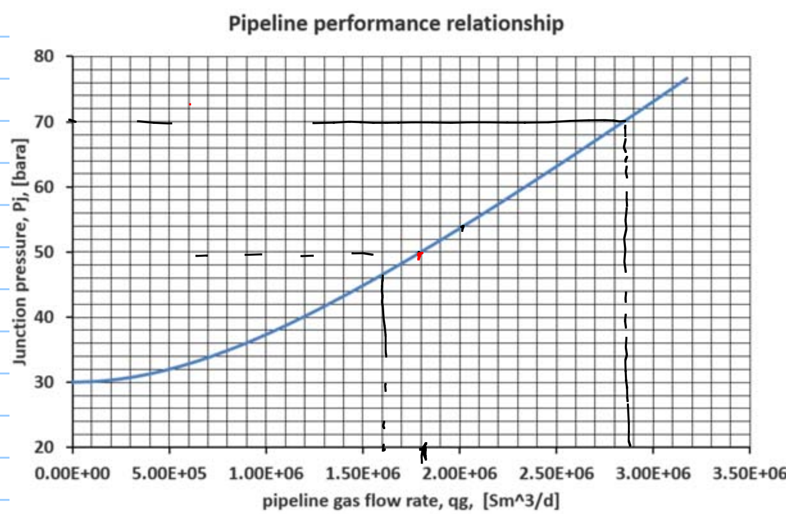


much better to iterate with p_j

$p_j = 50$ bara

$q_1 = 1.2\,E06$ Sm³/d

$q_2 = 1.57\,E06$ Sm³/d



$q_f = 1.8\,E06$ Sm³/d

~ 1 E06 Sm³/d

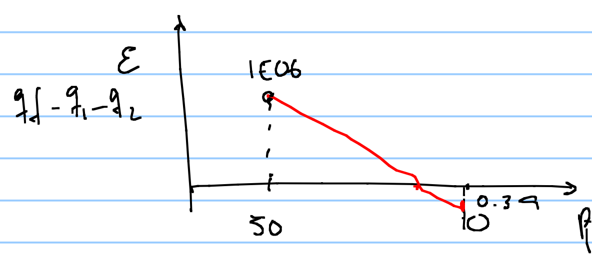
$p_j = 70$ bara

$q_1 = 1.06\,E06$

$q_2 = 1.35\,E06$

2.8 E06

− 0.39



$$\frac{1\,E06 - (-0.39\,E06)}{50 - 70} = \frac{1E06 - 0}{50 - p_j^*}$$

the solution is $p_j = 64$ bara

$q_1 = 1.1\,E06$ Sm³/d

$q_2 = 1.45\,E06$ Sm³/d

impose rate $q_1 = 0.8E06$ Sm^3/d

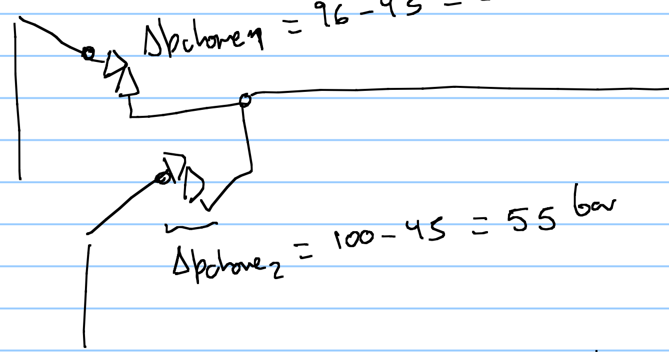
$q_2 = 0.8E06$ Sm^3/d

calculate available pressure and required pressure at junction.

$P_{J1} = 96$ bara $\rightarrow P_{wh_1}$

$P_{J2} = 100$ bara.

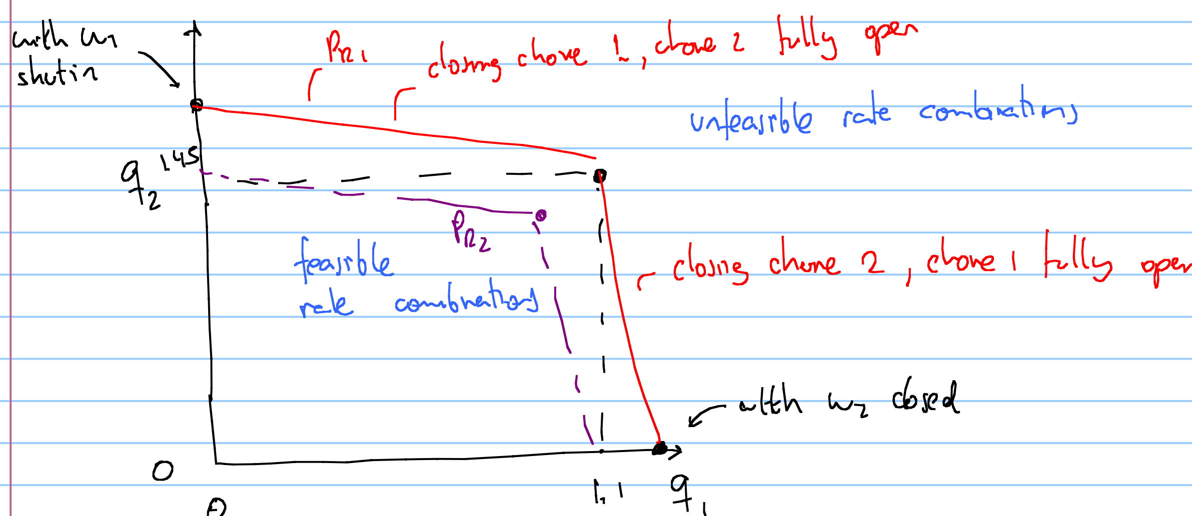
$P_J = 45$ bara $\rightarrow P_{wh_2}$



$\Delta p_{choke1} = 96 - 45 = 51$ bar

$\Delta p_{choke2} = 100 - 45 = 55$ bar

with depletion $P_{R_1} \rightarrow P_{R_2}$ the feasible area "shrinks"

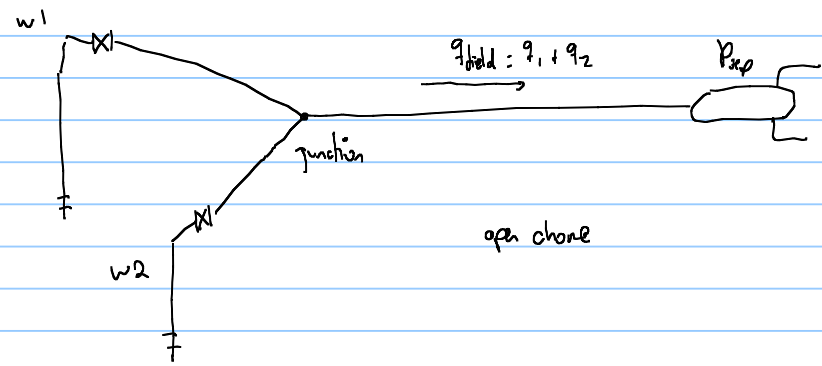


Class exercise on Dry gas network

Not secure | ipt.ntnu.no/~stanko/files/Courses/TPG4230/2020/Class_files/20200207/

Index of /~stanko/files/Courses/TPG4230/2020/Class_files/20200207

Name	Last modified	Size	Description
Parent Directory		-	
Network_two_gas_wells.xls	07-Feb-2020 08:43	44K	



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

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

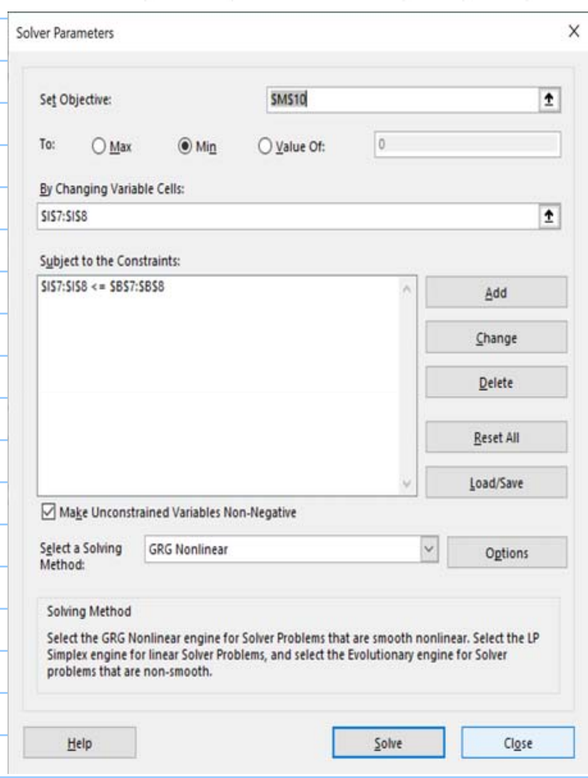
OR: P_{wf_1}, P_{wf_2} ← $P_{wf} < P_R$

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

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

i don't know q_{max}, and can give problems in eq.

Component Name	p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	pjunc	error
		IPR			Tubing	Flowline						
	[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
W_2	120	40	0.75	0.11	8600	7563		34	4.95E+04	31	31	9E-1
Pipeline						14080	28.6		1.51E+05		31	2E-0
										Average=	31	4E-0



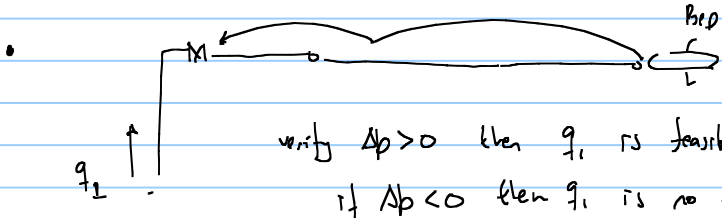
If solver is not available

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)

for Snøhvit; we choose the wellhead as equilibrium point

- 

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

$$\begin{cases} q_1 = 80000 \ Sm^3/d \\ q_2 = 40000 \ Sm^3/d \end{cases}$$

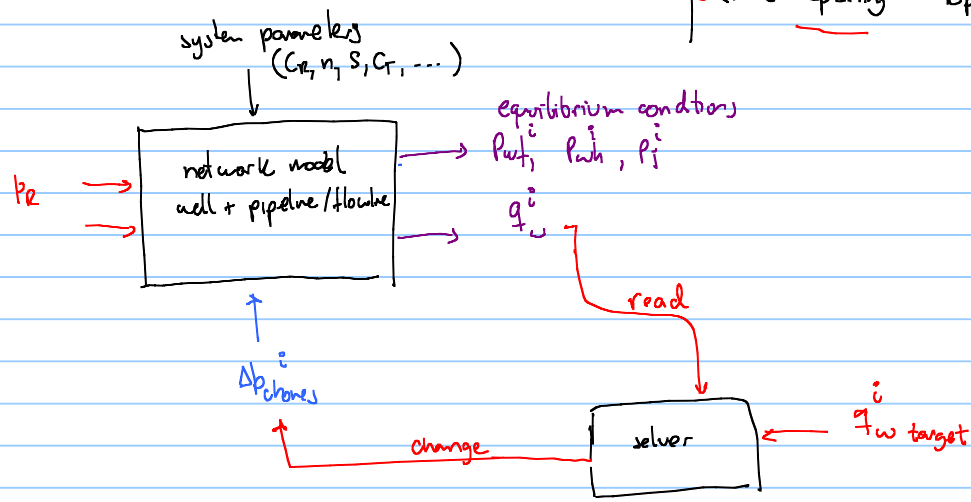
		IPR		Tubing		Flowline							
Component Name	p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc
	[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]
W_1	120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30
W_2	120	40	0.75	0.11	8600	7563		66	4.00E+04	63	32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

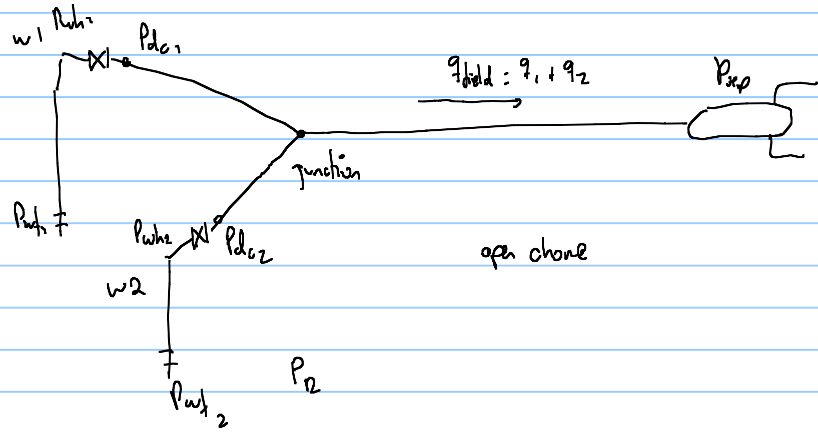
IPM (PETEX)

Next week: tutorial on predicting production and production profiles using Prosper (well), MBAL (material balance), GAP (network)

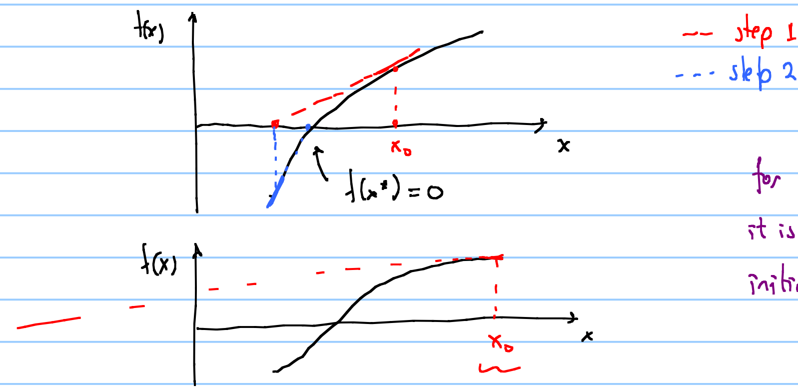
remake the snowhite (Snøhvit) field

- option 2: include the choke "model" → 2 options
  - Δp_{choke} ← this option will be discussed next
  - choke opening $\Delta p_{choke} = f(q_g, \text{Opening}, p_1)$





pR	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
	IPR			Tubing	Flowline								
[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

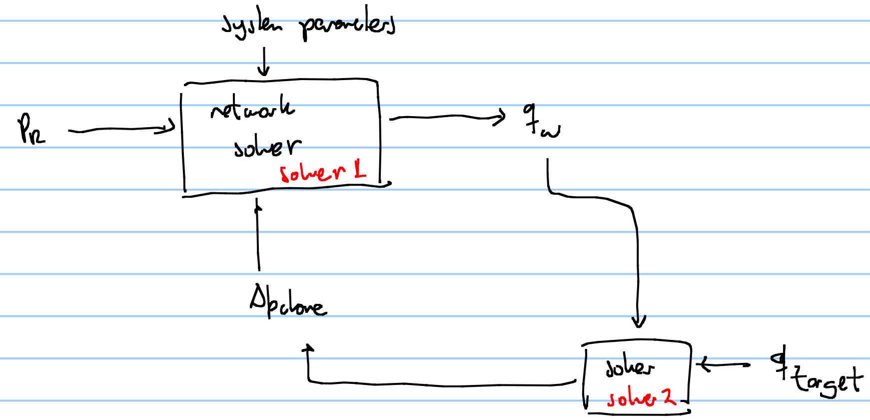


for derivative based solver it is necessary to give a good initial seed

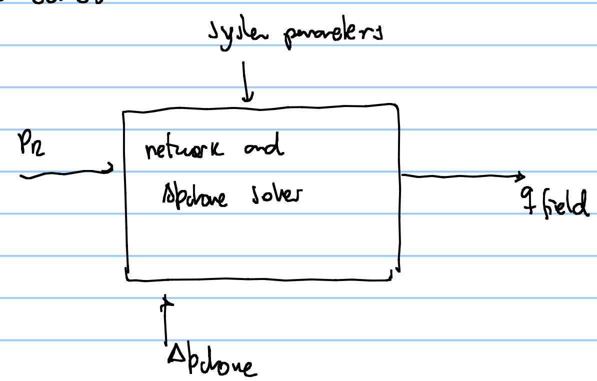
pR	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
	IPR			Tubing	Flowline								
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)
120	52	0.8	0.13	7680	8673		57	9.01E+04	52	20	32	30	1E-09
120	40	0.75	0.11	8600	7563		54	4.44E+04	51	20	31	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 $q_1 = 80000\ Sm^3/d$
  $q_2 = 40000\ Sm^3/d$

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}

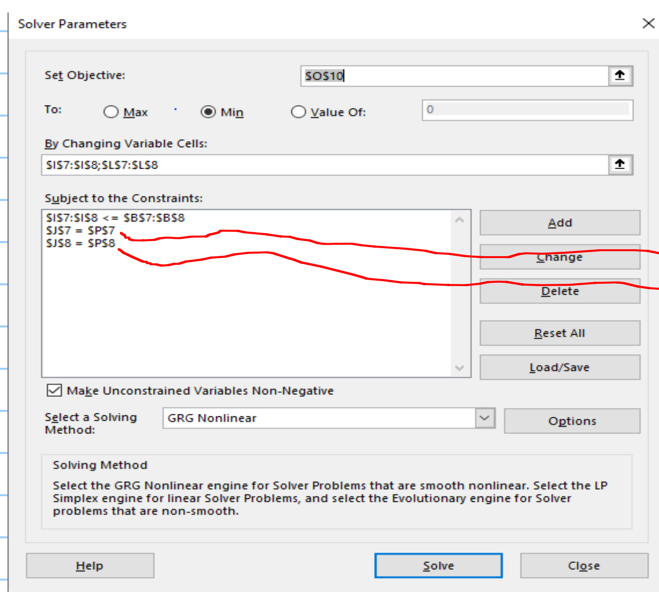
Δp_{choke} 1

Δp_{choke} 2

constraints

$q_1 = q_{1\,target}$

$q_2 = q_{2\,target}$


Solver Parameters

Set Objective: $O$10

To: Max Min Value Of: 0

By Changing Variable Cells:
$I$7:$I$8,$L$7:$L$8

Subject to the Constraints:
$I$7:$I$8 <= $B$7:$B$8
$J$7 = $P$7
$J$8 = $P$8

Add
Change
Delete
Reset All
Load/Save

Make Unconstrained Variables Non-Negative

Select a Solving Method: GRG Nonlinear Options

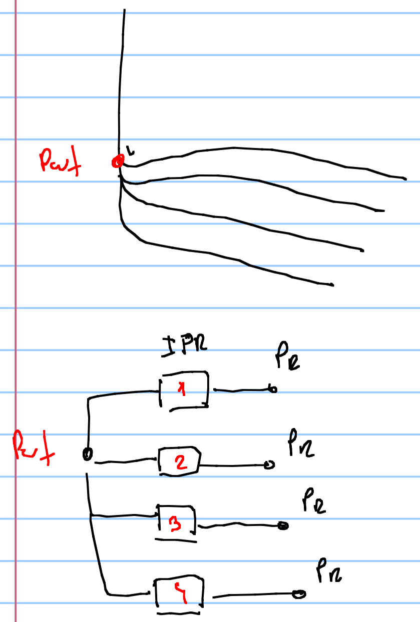
Solving Method
Select the GRG Nonlinear engine for Solver Problems that are smooth nonlinear. Select the LP Simplex engine for linear Solver Problems, and select the Evolutionary engine for Solver problems that are non-smooth.

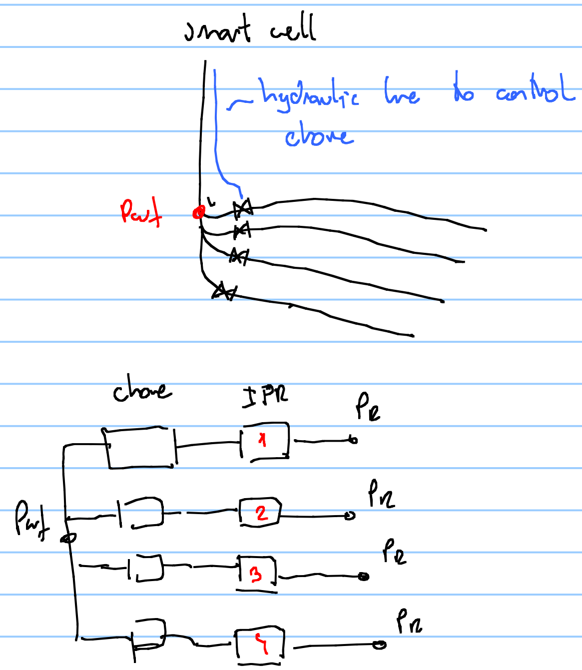
Help Solve Close

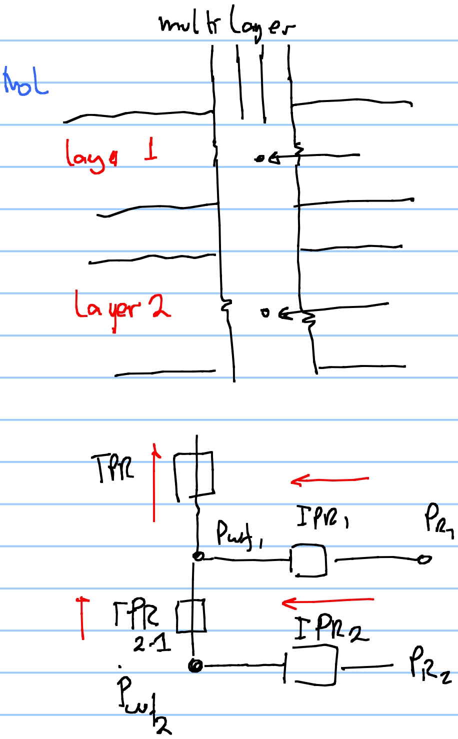
	IPR			Tubing	Flowline									
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error	qtarget
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)	[Sm3/d]
120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30	9E-11	80000
120	40	0.75	0.11	8600	7563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

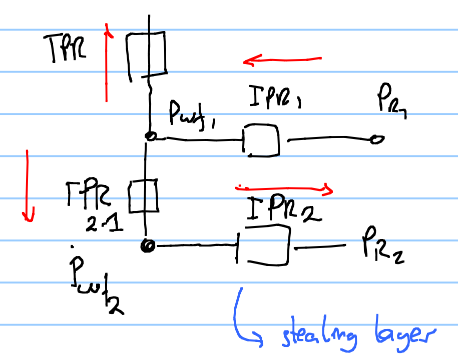
Downhole networks

multi-lateral wells

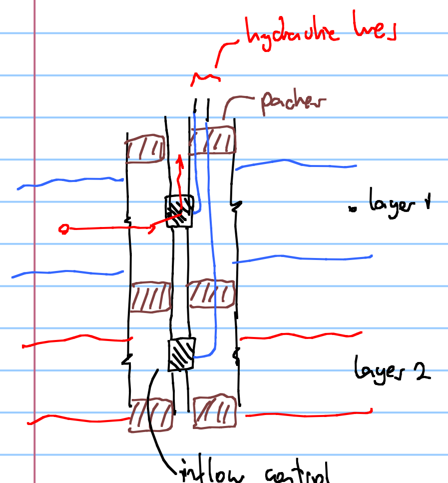


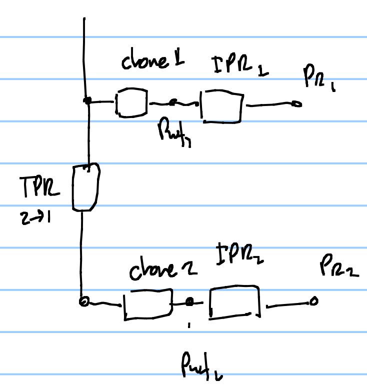




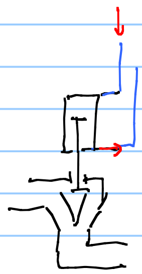


multi layer with inflow control



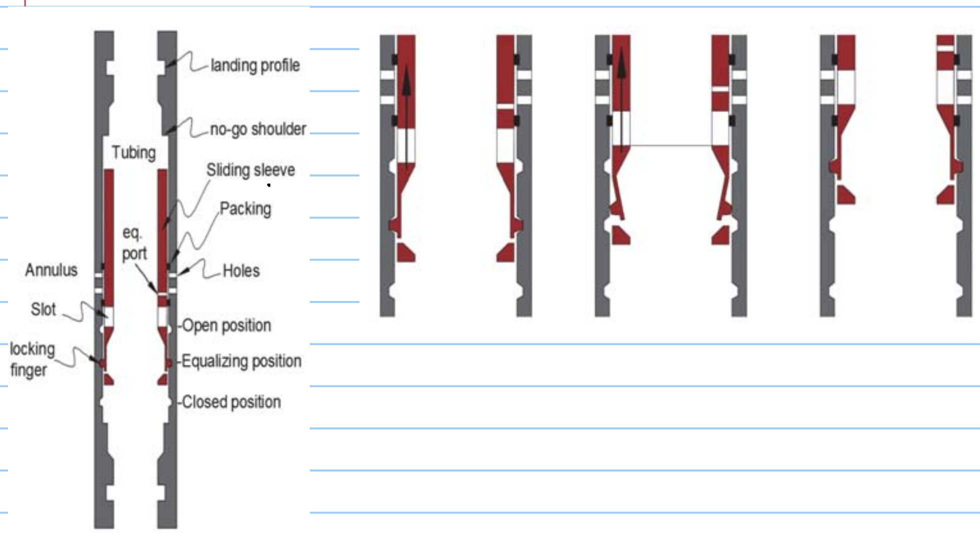


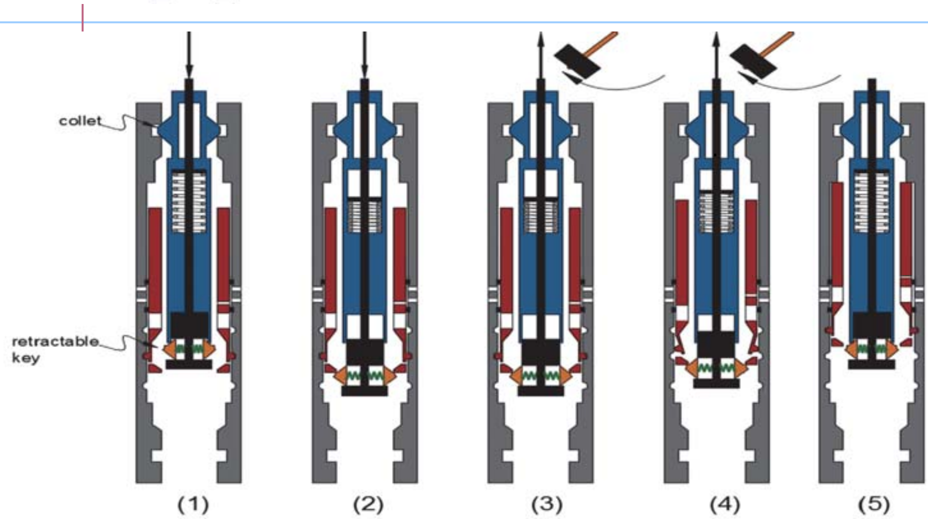
these chokes can be actuated from surface ($$$) or mechanically ($$)
actuated for example with wire line, coil tubing

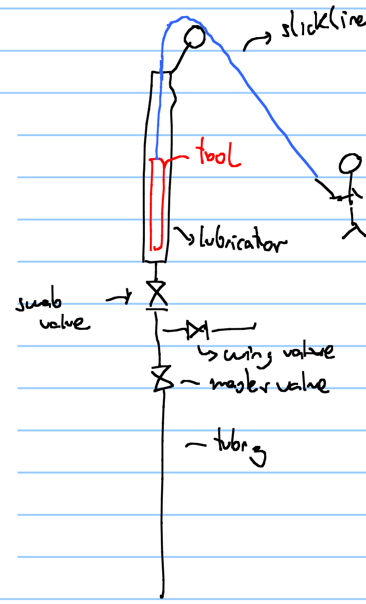


example of
hydraulic activation of choke

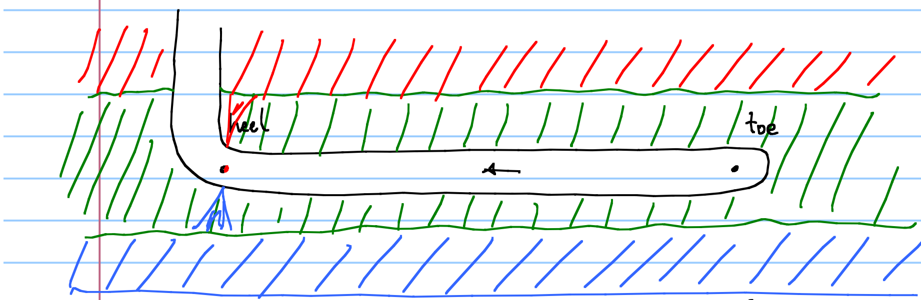
sliding sleeve functionality page 71 of compendium

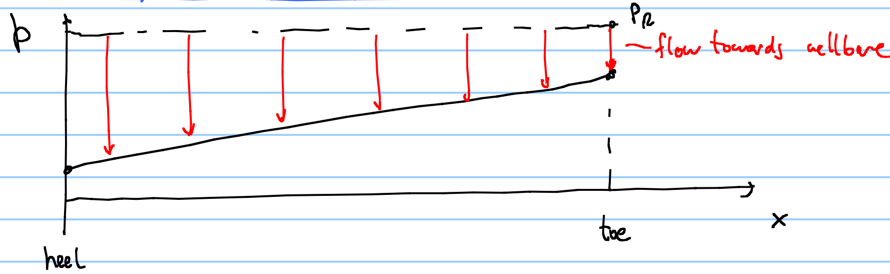




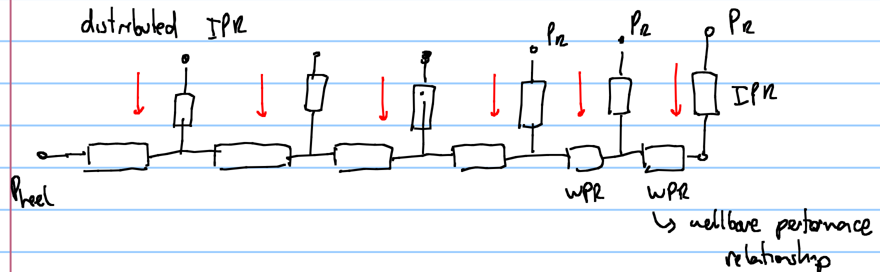


Networks to study a long horizontal well

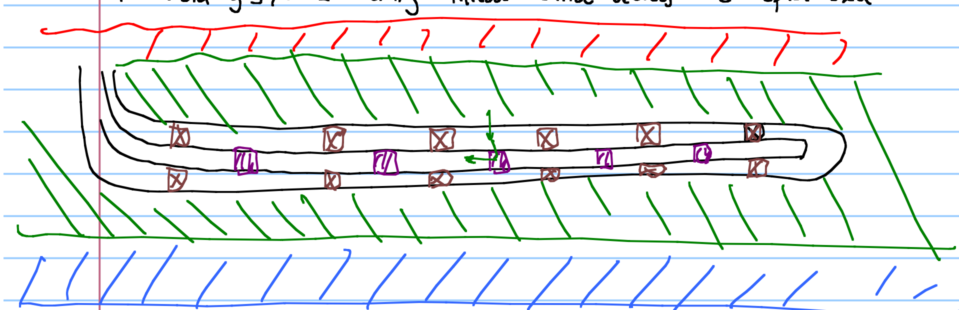


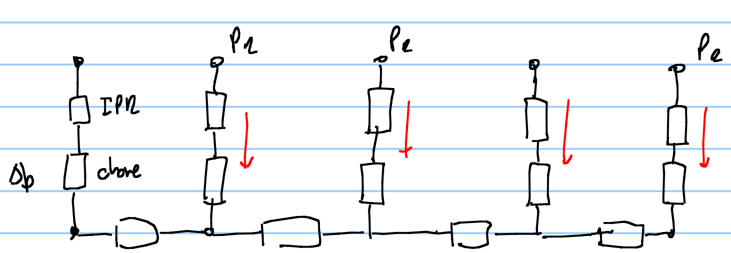


$q \propto (P_R - P_{wf})$



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



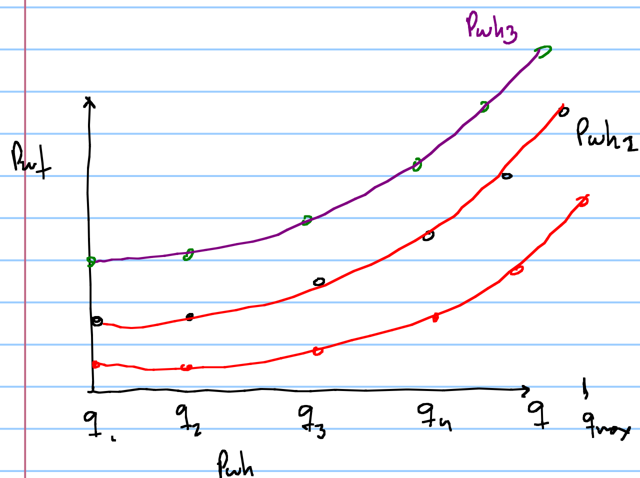


the chokes are used to even the rate profile along well. to ensure even depletion and high recovery factor

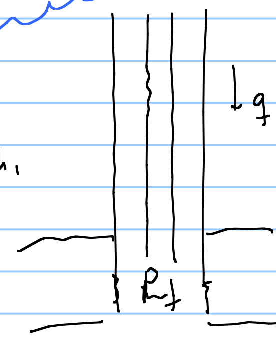
Discussion on TPR (tubing performance relationship)

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

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



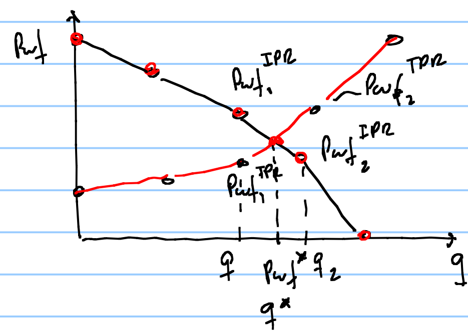
$p_{wh3} < p_{wh2} < p_{wh1}$



	p_{wh1}	p_{wh2}	p_{wh3}	-
q_1	p_{wf11}	p_{wf12}	-	
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 $p_{wh} = p_{wh1}$

go to tubing table and extract colum $p_{wh} = p_{wh1}$

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

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

1. Snohvit subsea gas well modeling in Prosper

Fluid information:

Use the black oil model for your PVT behavior.

WGR = 0 Sm^3/Sm3
CGR = 0 Sm^3/Sm^3
Condensate density = 751 Kg/m3
Gas gravity = 0.55
Formation Water salinity = 0 ppm
No H2S, CO2, N2.

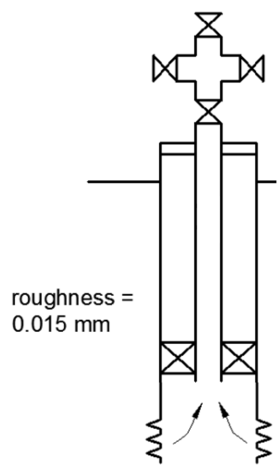
Well layout:

Deviation survey

MD [m]	TVD [m]
0	0
2100	2100

Geothermal gradient

MD [m]	T [C]
0	4
2100	92



Flow in tubing, tubing diameter 0.15 m

Overall wellbore heat transfer coefficient = 45 W/m^2 K

Reservoir info:

Producing from a single layer
Reservoir pressure = 276 bara
Reservoir temperature = 92 C
Backpressure coefficient = 1000 Sm^3/d/bara
Backpressure exponent = 1

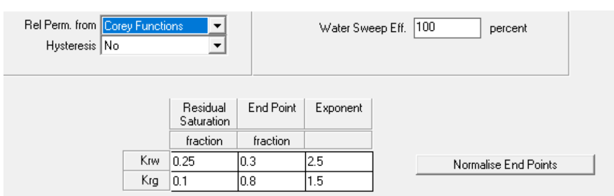
Tasks:

- Set up a prosper model of a subsea oil well.
- Estimate the producing rate using flow equilibrium assuming that the well is producing against a constant wellhead pressure of 100 bara
- Generate and export lift curves to be used in GAP (in the following exercise). p_{wh} range: 30-276 bara

1. **<u>Creating MBAL file of Snohvit reservoir</u>**

<u>Fluid information:</u>

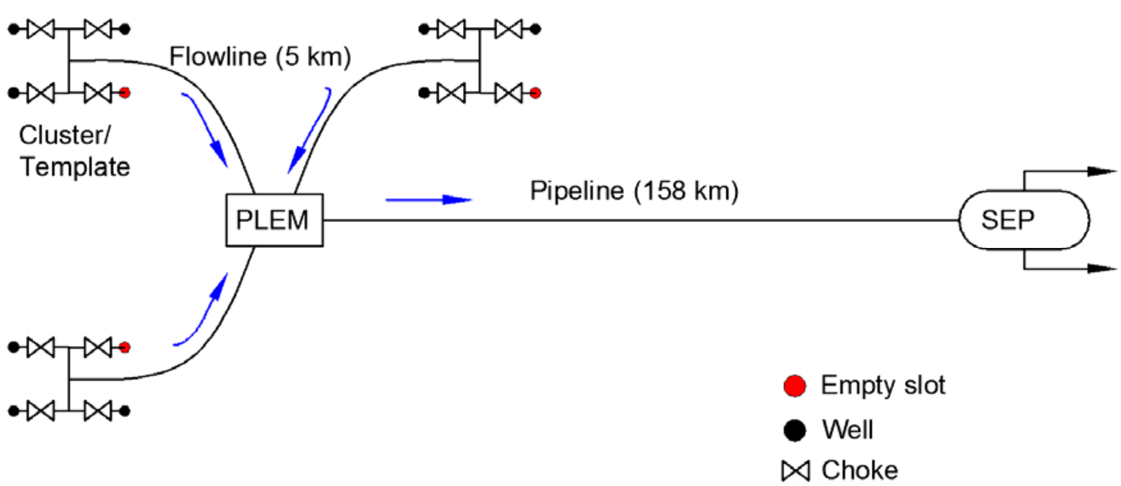
Use the black oil model to represent your PVT behavior.
Gas gravity = 0.55
Condensate gravity = 751 Kg/m^3
At initial conditions no water.
Formation Water salinity = 0 ppm
No H2S, CO2, N2.
Temperature: 92 C
Initial pressure: 276 bara
Porosity: 0.15
Connate water saturation: 0.25
Original oil in place: 270 000 E6 Sm^3
Start of production: 10.02.2020
Water influx: No aquifer
Rel Perm: Corey Functions



	Residual Saturation	End Point	Exponent
	fraction	fraction	
Krw	0.25	0.3	2.5
Krg	0.1	0.8	1.5

2. **<u>Modeling of a subsea network with nine gas wells in GAP</u>**

The layout of the production network layout is shown below.



All wells are identical
Pipeline and flowline heat transfer coefficient: 5 W/m2 K
Pipeline ID: 0.680 m, roughness 1.5e-5 m
Flowline ID: 0.355 m, roughness 1.5e-5 m

Tasks:

- Build the GAP model of three subsea wells producing to the LNG plan in Melkøya.
- Adding a rate constraint to the separator of 20E06 Sm3/d, and run an “optimization”.
- Run in prediction mode to find field rate with time.

NTNU

Kunnskap for en bedre verden

Introduction to PETEX

10 February 2020

Prepared by:
- Agung Gedde Angga
- Milan Stanko
- Salma Alkindira

1

NTNU

Outline

- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

2

2

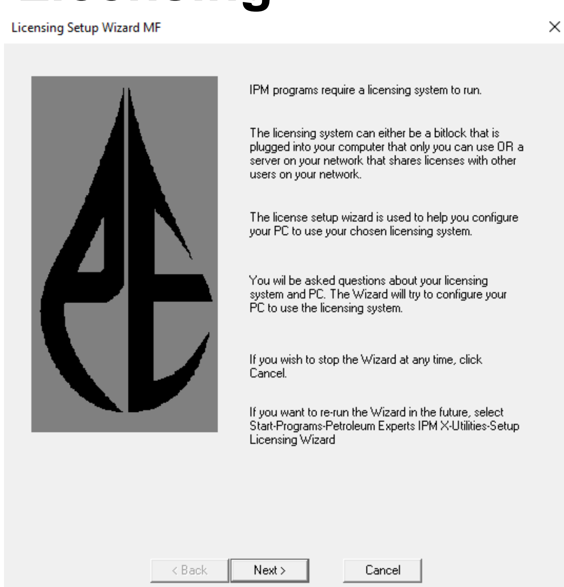
Outline

- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

3

3

Licensing



-only 10 licenses are available
-please work in groups (9)

4

4

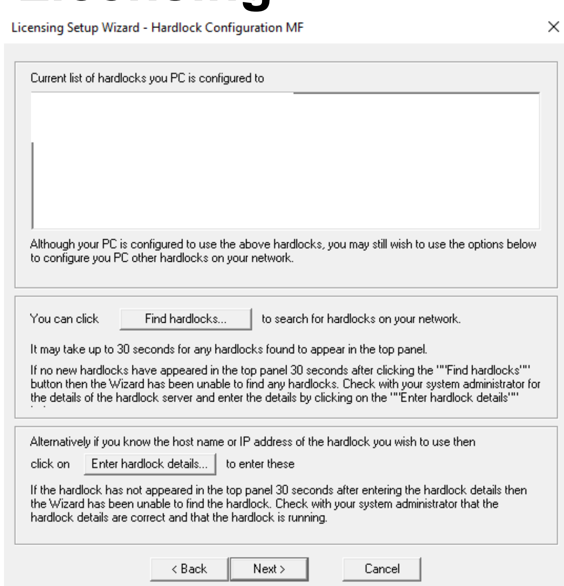
Licensing

-only 10 licenses are available
-please work in groups (9)

5

5

Licensing



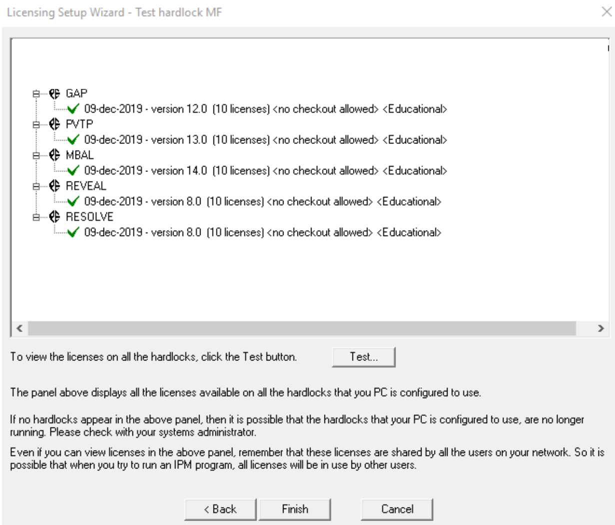
-only 10 licenses are available
-please work in groups (9)

6

6

NTNU

Licensing



-only 10 licenses are available
-please work in groups (9)

7

7

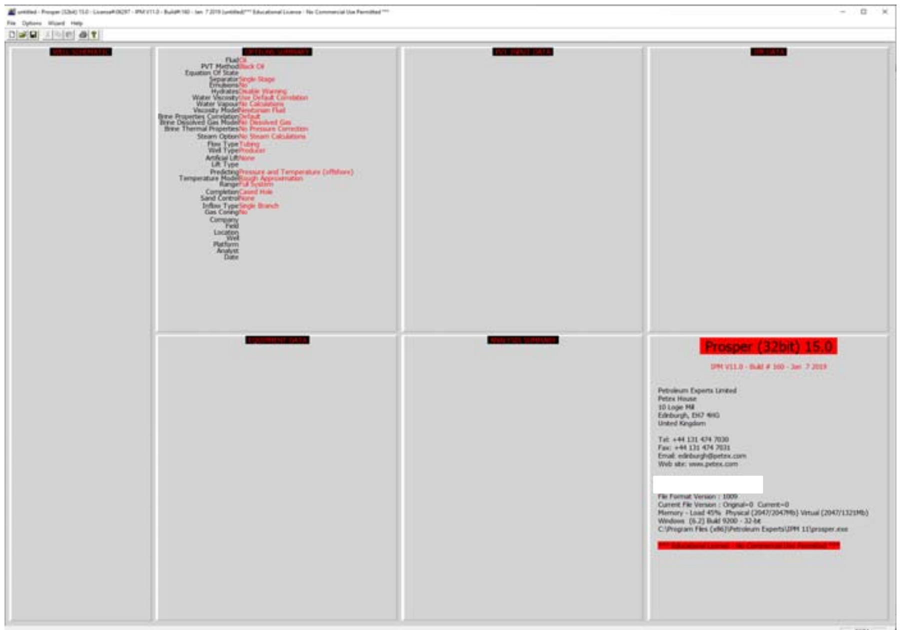
NTNU

Outline

- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

8

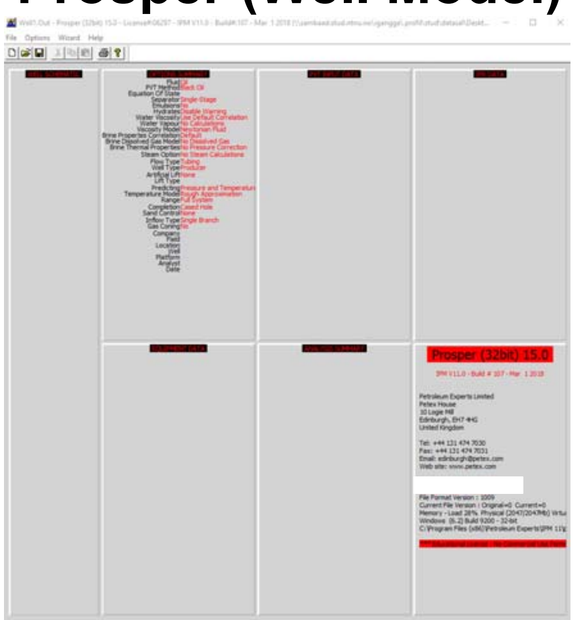
8



9

9

Prosper (Well Model)

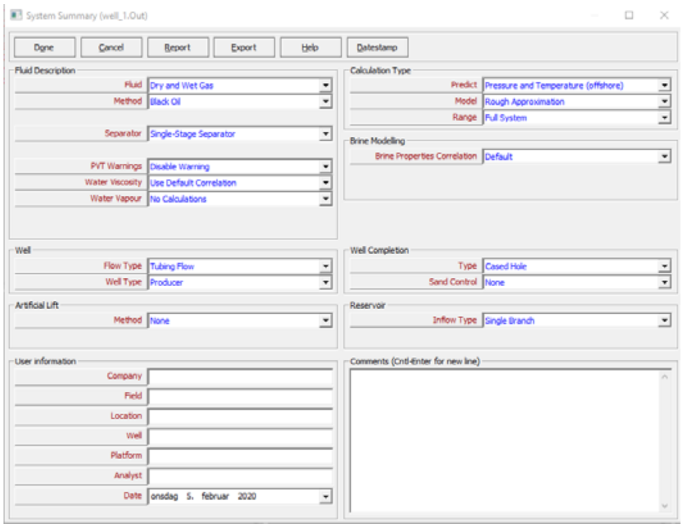


-open PROSPER
-save as

10

10

Prosper – System Summary

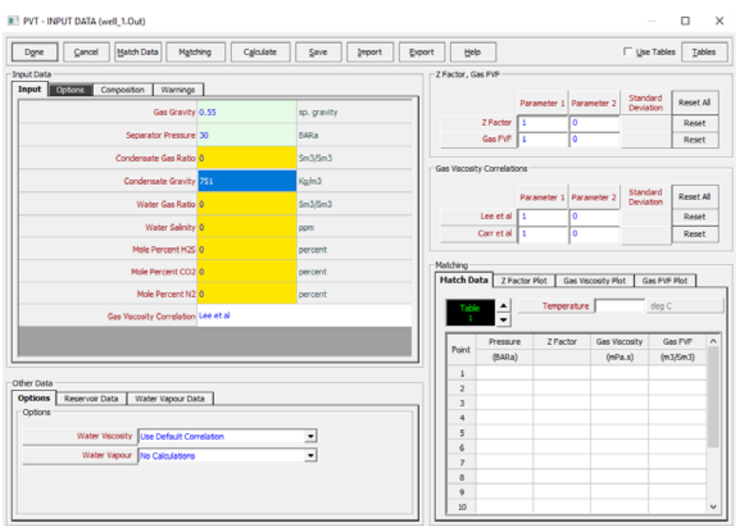


-use default setting
-Fluid: dry and wet gas
-Method: Black Oil
-change unit system to Norwegian S.I.

11

11

Prosper – PVT Input Data



-input PVT data (gas gravity, psep, condensate gravity)
-choose PVT correlation

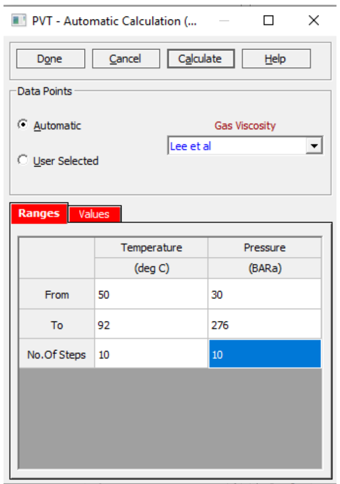
12

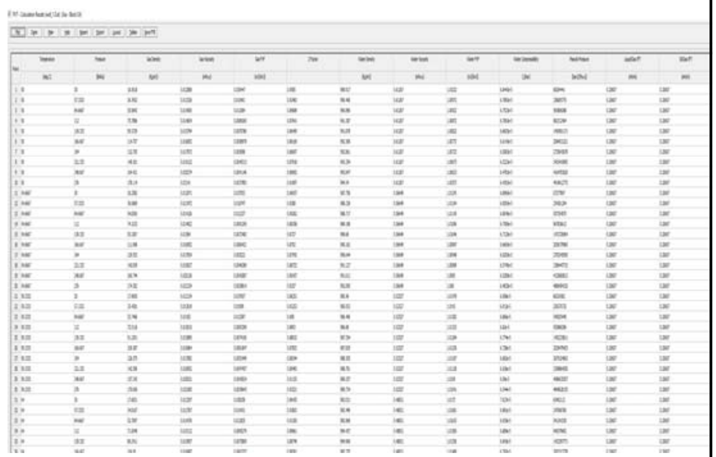
12

07.02.2020

Prosper – PVT Input Data

-calculate PVT properties
-input Tres & Pres



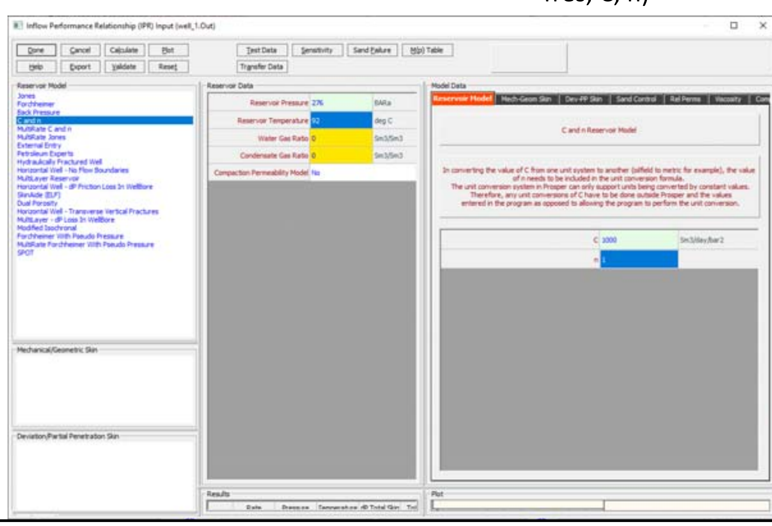


13

13

Prosper – IPR Data

-Reservoir model: C and n
-input reservoir data (Pres, Tres, C, n)

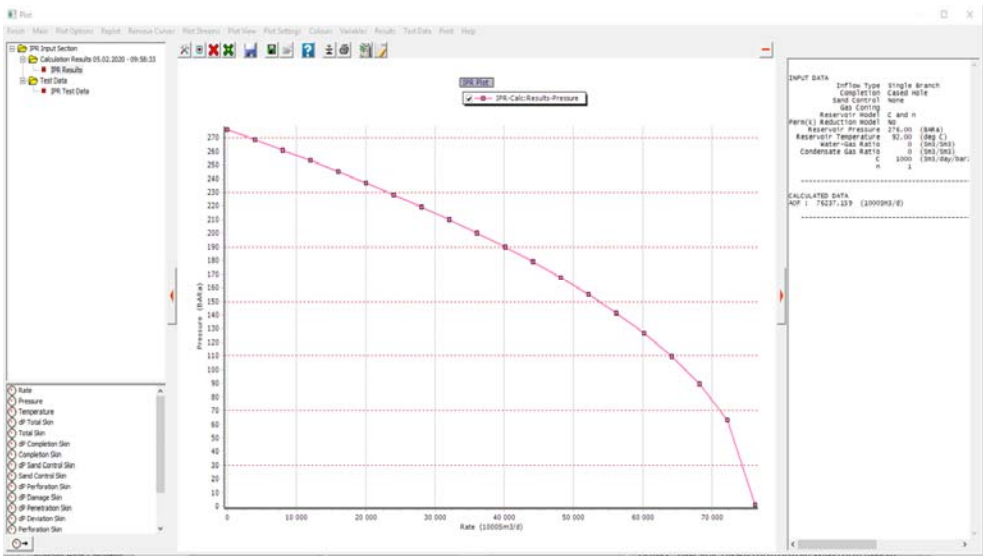


14

14

Prosper – IPR Data

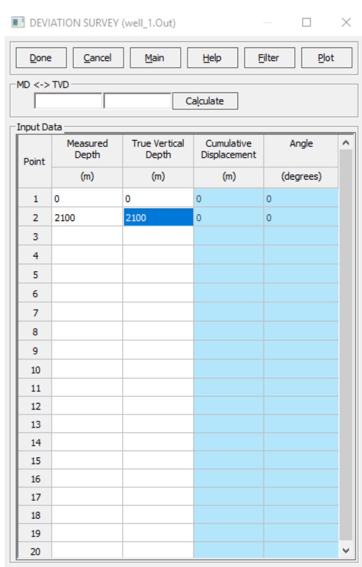
-calculate & plot



15

15

Prosper – Equipment Data



-input deviation survey
-neglect surface equipment (since we only consider the flow to wellhead)

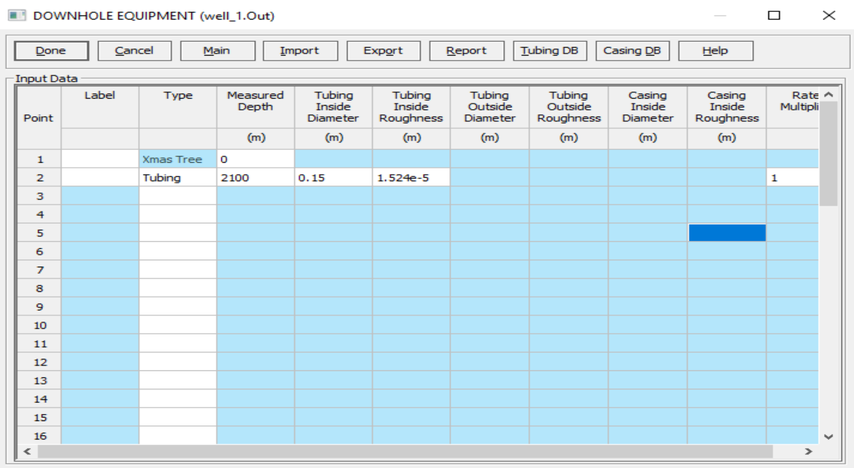
16

16

NTNU

Prosper – Equipment Data

-input downhole equipment
-pay attention with the measured depth, unit of tubing ID, & roughness



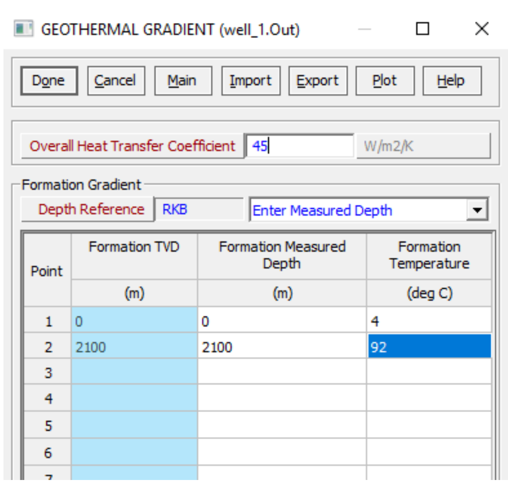
17

17

NTNU

Prosper – Equipment Data

-input geothermal gradient & overall heat transfer coefficient

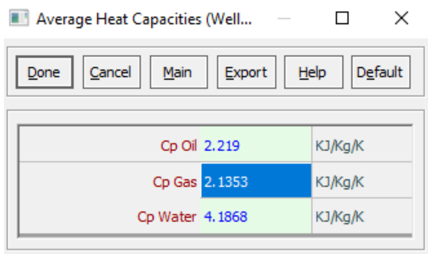


18

18

Prosper – Equipment Data

-input average heat capacities
-neglect gauge details



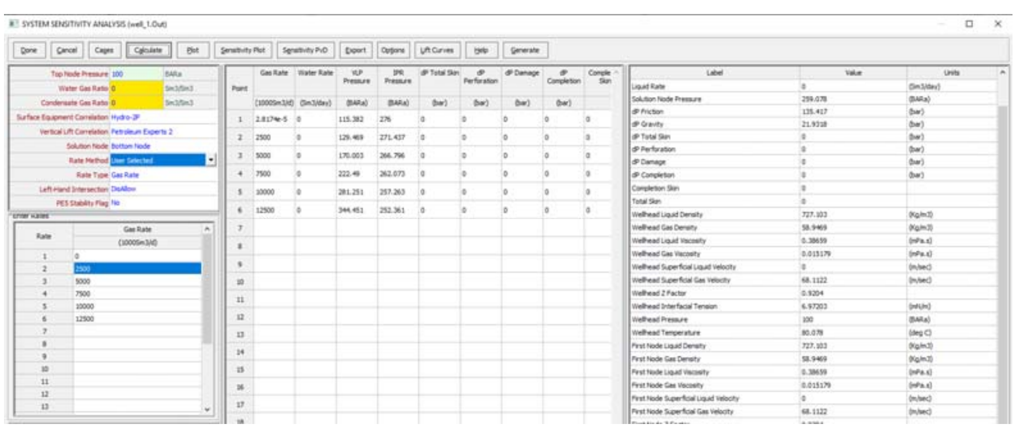
19

19

Prosper – Analysis Summary

- Estimate the producing rate using flow equilibrium assuming that the well is producing against a constant wellhead pressure of 100 bar.

-select "system" option
-input Pwh,
-use default tubing equation
-"Rate method"---User selected



20

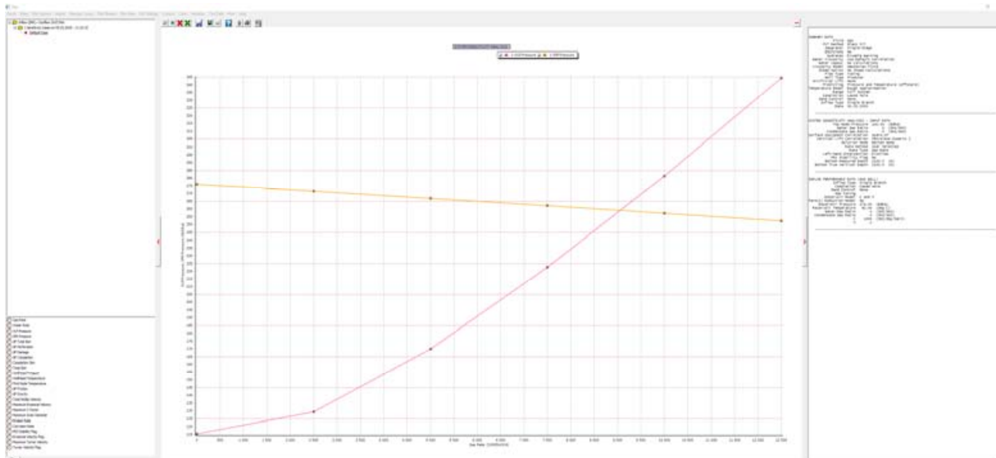
20

Prosper – Analysis Summary

NTNU

- Estimate the producing rate using flow equilibrium assuming that the well is producing against a constant wellhead pressure of 100 bar.

-calculate
-plot → system plot → plot all cases → X-axis: liquid rate, Y-axis: VLP & IPR pressure



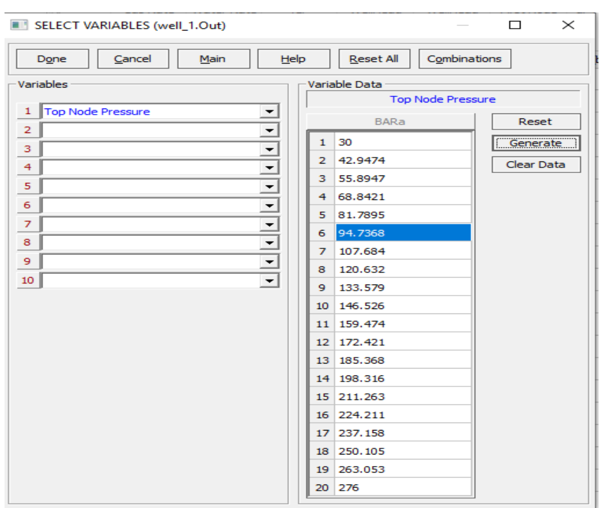
21

21

Prosper – Analysis Summary

NTNU

- Generate and export lift curves to be used in GAP (in the following exercise). p_{wh} range: 30-276 bara



-generate VLP table
-select "VLP" option
-go to "cases"
-select variables & generate variable data (you can use linear spacing & 20 breakpoints). Then you have 20 cases

22

22

NTNU

Prosper – Analysis Summary

-input Pwh = 100 bara (just to avoid it complaining)
-calculate
-select “export lift curve” → choose “Petroleum Experts – GAP/MBAL” → save in the same directory as your prosper file, and with the same name
-done

23

23

NTNU

Outline

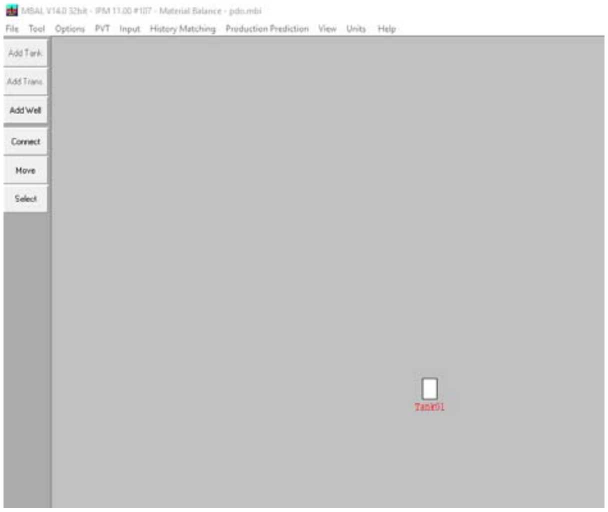
- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

24

24

NTNU

MBAL (Reservoir Model)



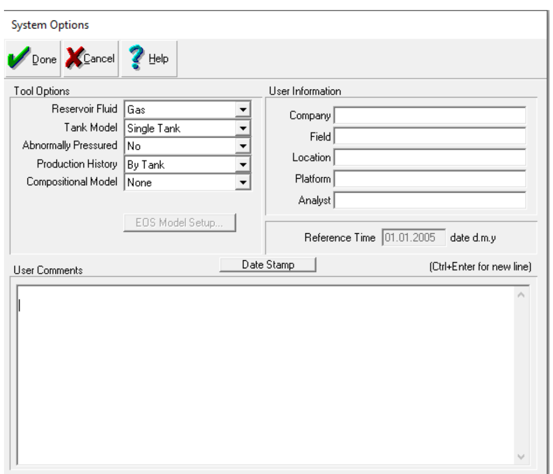
-open MBAL
-save as
-select “tool” → “material balance”

25

25

NTNU

MBAL - Options



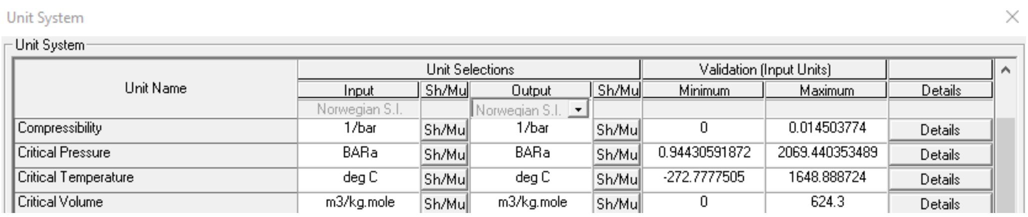
-select “options”
-use default setting

26

26

MBAL – Unit System

-select “Units”
-change unit system to Norwegian S.I.

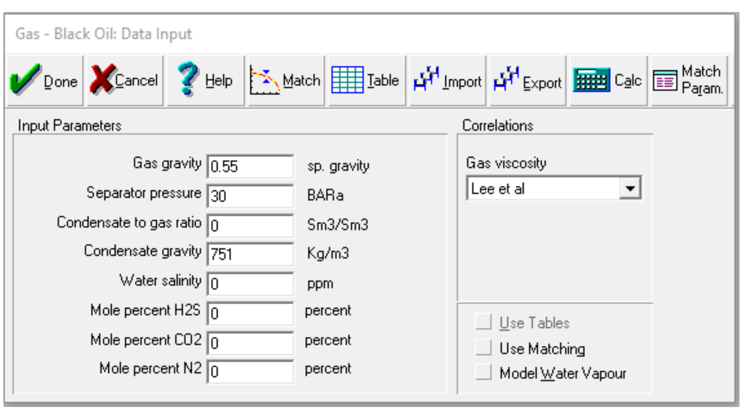


27

27

MBAL - PVT

-select “PVT” → fluid properties
-input PVT data
-select PVT correlations

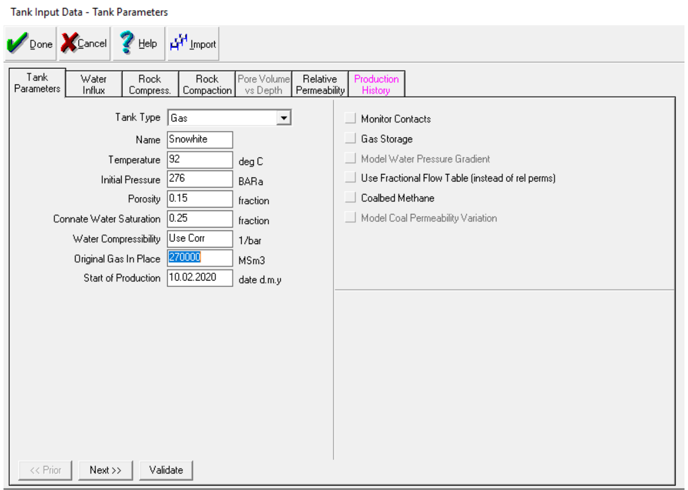


28

28

MBAL - Input

-select “Input” → tank data
-input tank parameters
-be careful with the unit of OOIP

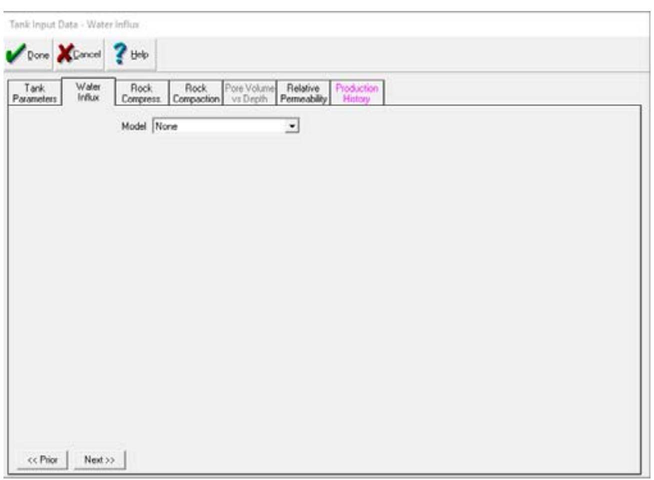


29

29

MBAL - Input

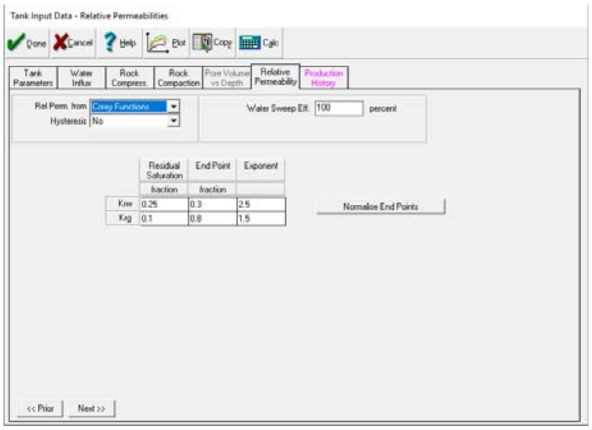
-input water influx



30

30

MBAL - Input



-input relative permeability

31

31

Outline

- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

32

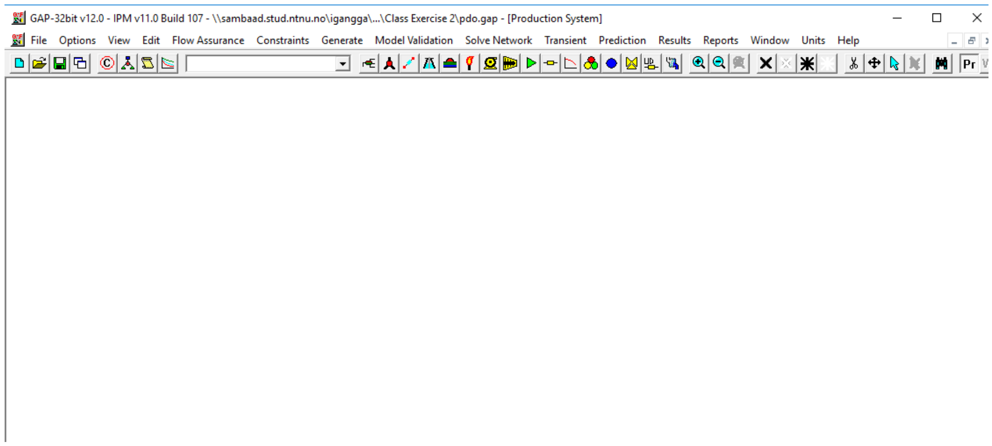
32

07.02.2020

NTNU

GAP (Network Model)

-open GAP
-save as

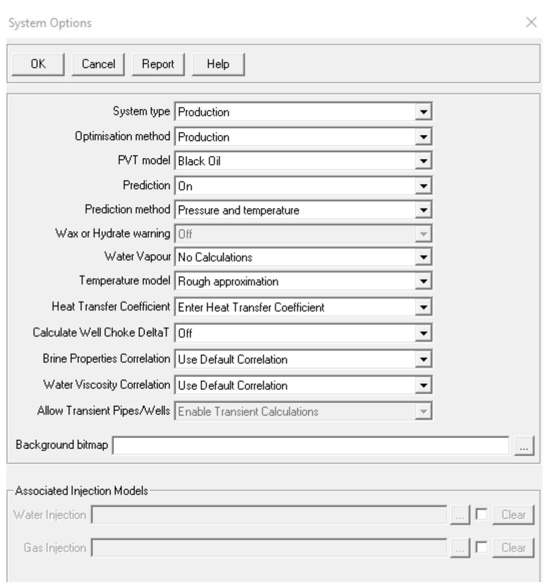


33

33

NTNU

GAP

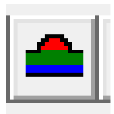


-open “options” → “method”
-system type: production
-PVT model: black oil
-for the rest, use default setting
-change unit system to Norwegian S.I.

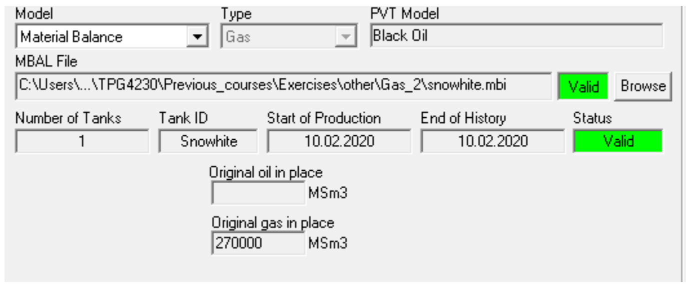
34

34

GAP: Reservoir: Summary tab



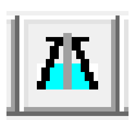
-add tank icon → rename the tank
-double click to edit tank properties
-include MBAL model
-done



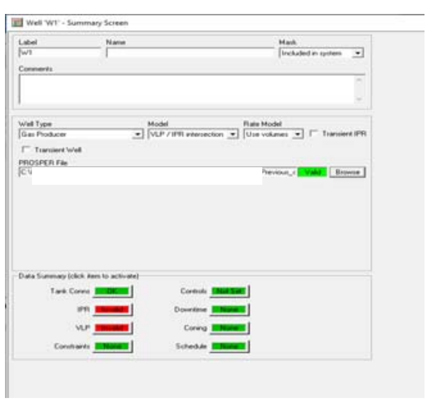
35

35

GAP: Well: Summary tab



-add well icon → rename the well
-double click to edit well properties
-'summary' tab → change welltype and add path to prosper file

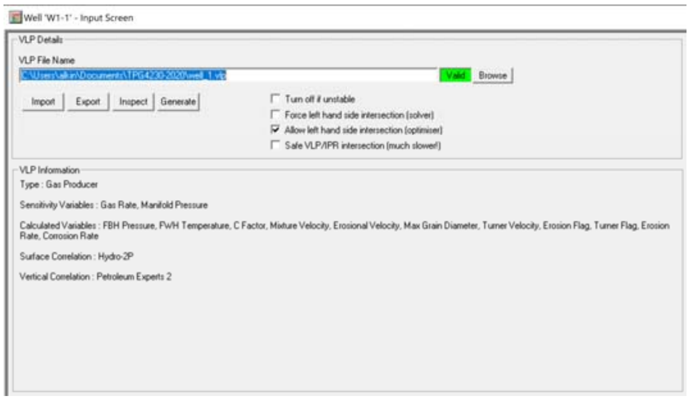


36

36

NTNU

GAP: Well: Input tab: VLP Tab



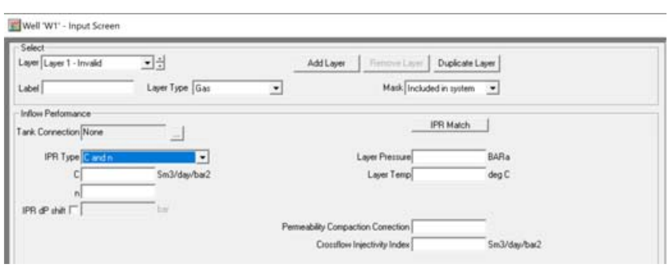
-'input' tab → 'VLP' tab → 'import' VLP table in **TPD format**
-done

37

37

NTNU

GAP: Well: Input tab: IPR Tab



- 'input' tab → '"IPR" tab
- Choose IPR type to "C and n" to have the same correlation in PROSPER

38

38

GAP: Well

Transfer IPR data

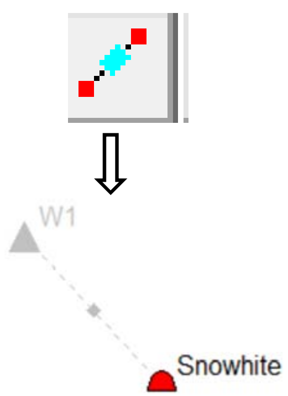
Menu: generate – well IPR from Prosper –All - Generate

39

39

GAP: Well

-add connection between reservoir and well

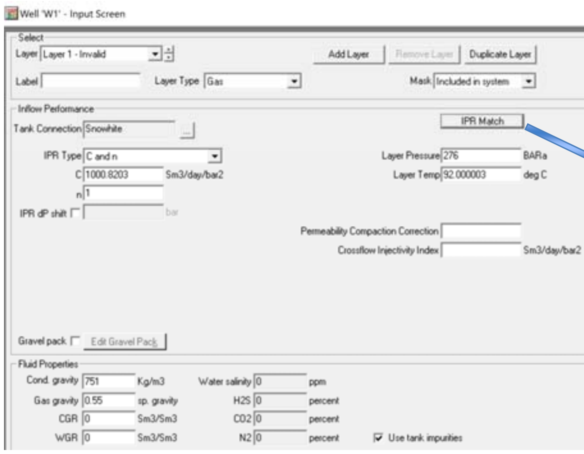


40

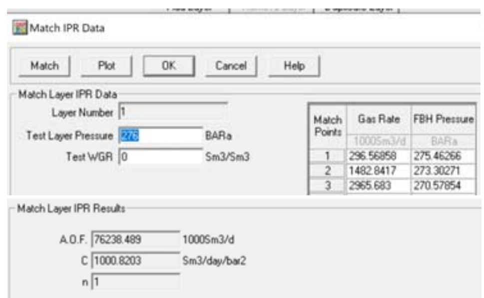
40

NTNU

GAP: Well: Input tab: IPR Tab



Checking the IPR quality:
- 'input' tab → "IPR" tab -> IPR Match

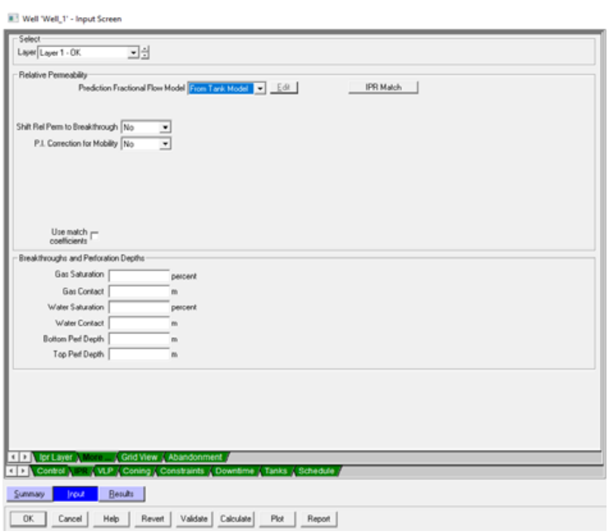


41

41

NTNU

GAP: Well: Input tab: IPR Tab

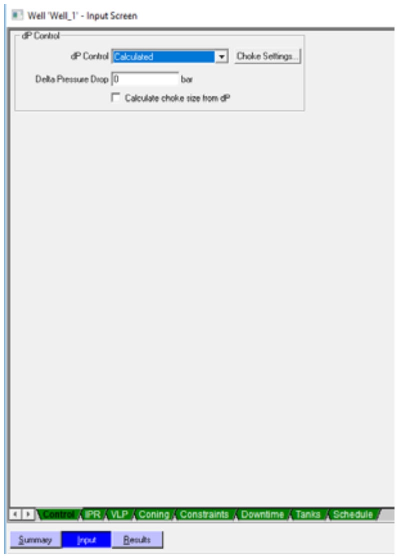


-'input' tab → 'IPR' tab → 'More' sub-tab
-use permeability curve as for MBAL model ('From Tank Model')

42

42

GAP: Well: Input tab: Control Tab

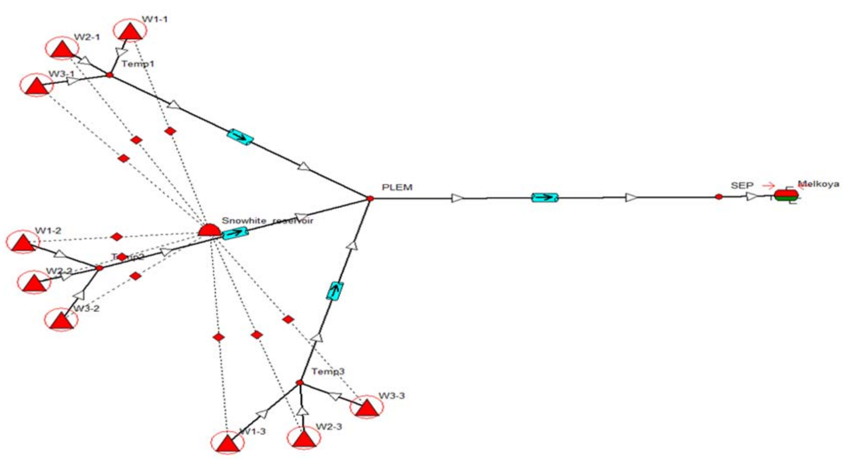


-'input' tab → 'control' tab
-change dp Control to allow well choking
-done

43

43

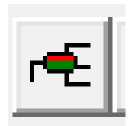
GAP: Production Layout



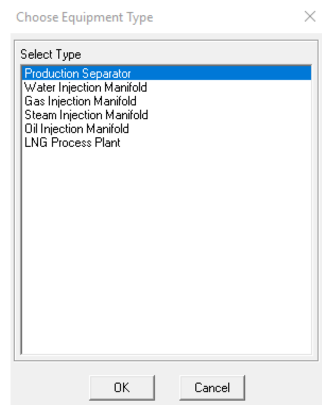
44

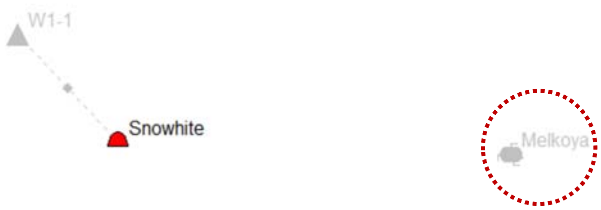
44

GAP: Separator



-add separator icon → choose 'production separator' → rename it
-connect the system with the separator

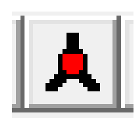




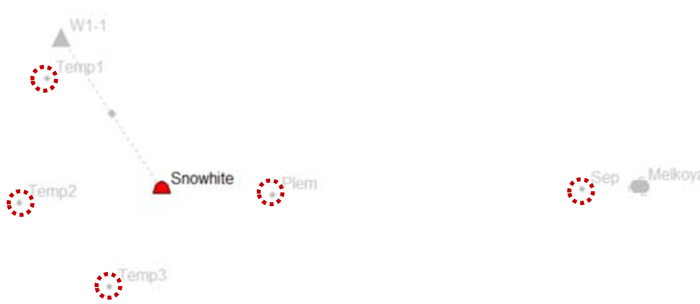
45

45

GAP: Joint (Xtree, Manifold, etc)



-add joint icon
-Rename the joint label
-pipeline is modelled between 2 joints

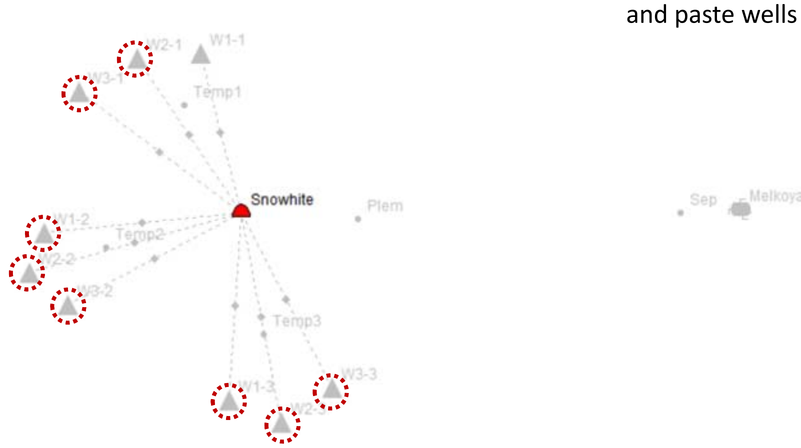


46

46

GAP: Adding more wells

-All wells are identical, thus, copy and paste wells (8 times)

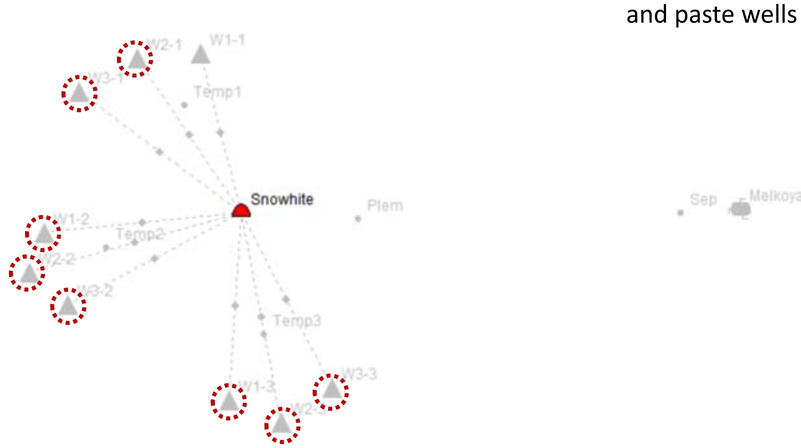


47

47

GAP: Adding more wells

-All wells are identical, thus, copy and paste wells (8 times)

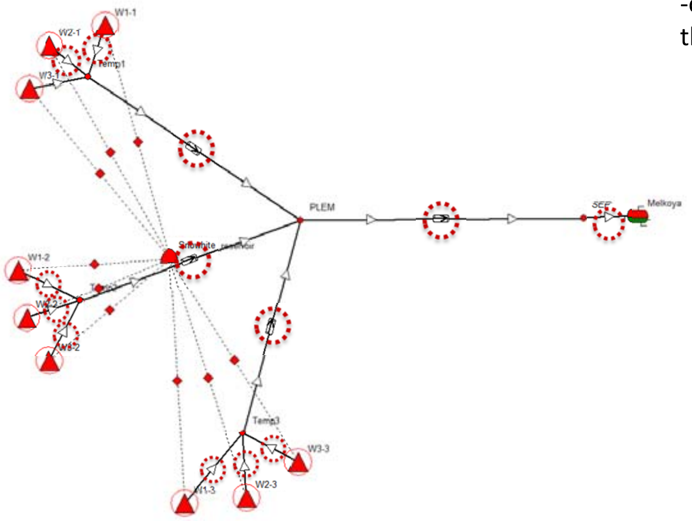


48

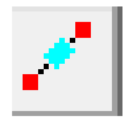
48

NTNU

GAP: Joint (Xtree, Manifold, etc)



-connect the joints
-connect wells and separator to the joints



49

49

NTNU

GAP: Pipeline: Summary tab

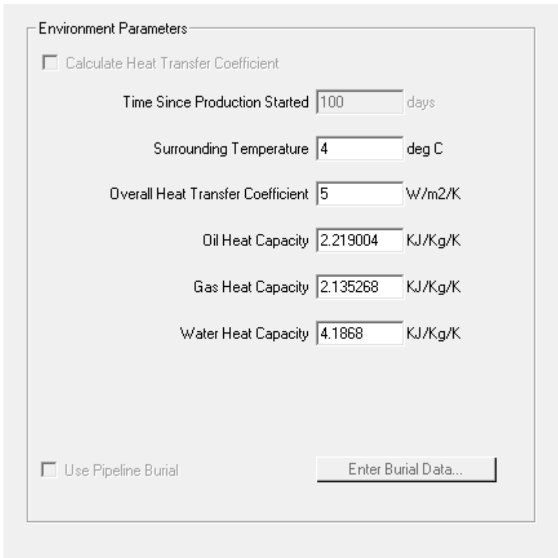
-double click in the selected pipeline
-open 'summary' tab → select PVT correlations
-leave the other things as defaults

50

50

NTNU

GAP: Pipeline: Input tab



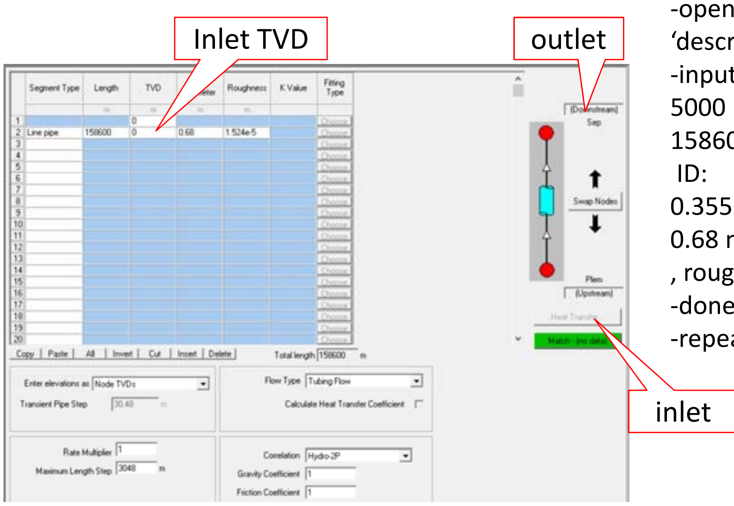
-open ’input’ tab → open ‘environtment’ sub-tab
-input ambient temperature (= 4 degC)
-input U (= 5 W/m2/K)

51

51

NTNU

GAP: Pipeline: Input tab



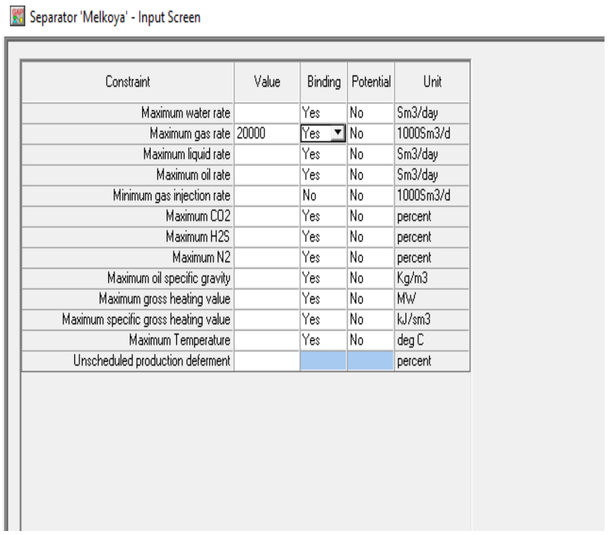
-open ’input’ tab → open ‘description’ sub-tab
-input pipeline properties: length:
5000 m for flowline
158600 m for pipeline
ID:
0.355 for flowline
0.68 m for pipeline
, roughness (=0.015 mm)
-done
-repeat for the other pipelines

52

52

GAP: Separator

Setting up constraint



Separator 'Melkoya' - Input Screen

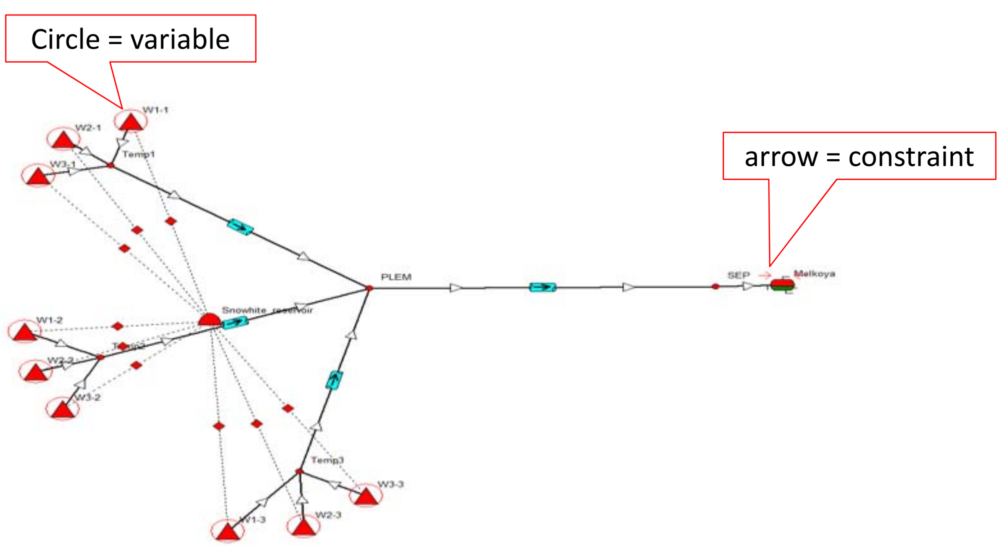
Constraint	Value	Binding	Potential	Unit
Maximum water rate		Yes	No	Sm3/day
Maximum gas rate	20000	Yes	No	1000Sm3/d
Maximum liquid rate		Yes	No	Sm3/day
Maximum oil rate		Yes	No	Sm3/day
Minimum gas injection rate		No	No	1000Sm3/d
Maximum CO2		Yes	No	percent
Maximum H2S		Yes	No	percent
Maximum N2		Yes	No	percent
Maximum oil specific gravity		Yes	No	Kg/m3
Maximum gross heating value		Yes	No	MW
Maximum specific gross heating value		Yes	No	kJ/sm3
Maximum Temperature		Yes	No	deg C
Unscheduled production deferment				percent

-double click on the separator icon
-open 'input' tab → open 'constraints' tab
-input the gas plateau rate

53

53

GAP: All System



54

54

NTNU

Outline

- Licensing
- PROSPER
- MBAL
- GAP: Set up Production Network
- GAP: Solve Production Network

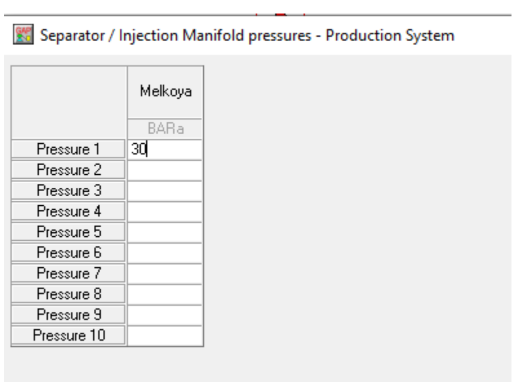
55

55

NTNU

GAP: Solve Network

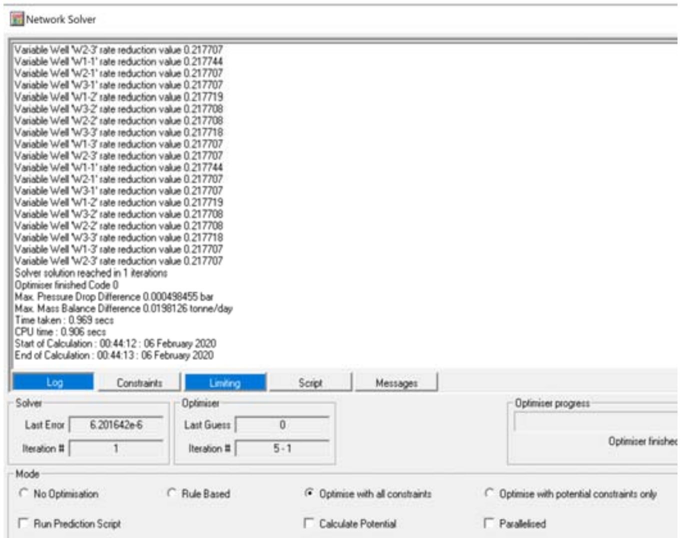
-open 'solve network' to solve the production network at t = 0
-run network solver
-input separator pressure



56

56

GAP: Solve Network

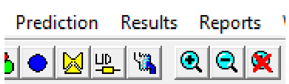


-since we have a constraint to be satisfy, choose 'optimise with all constraints' mode
-calculate

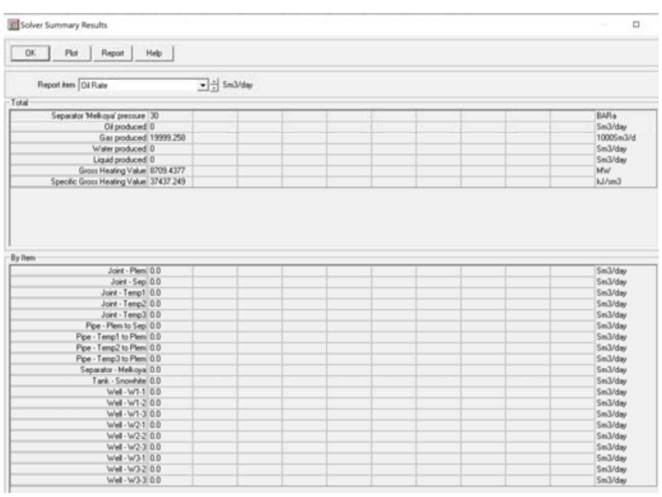
57

57

GAP: Solve Network



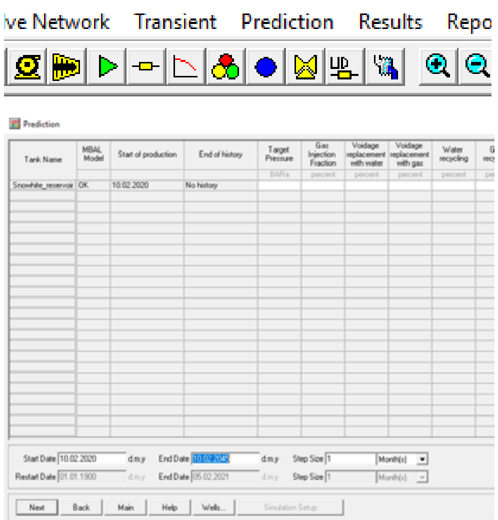
-to see the results, open 'results' tab → 'summary' → 'all items'



58

58

GAP: Prediction

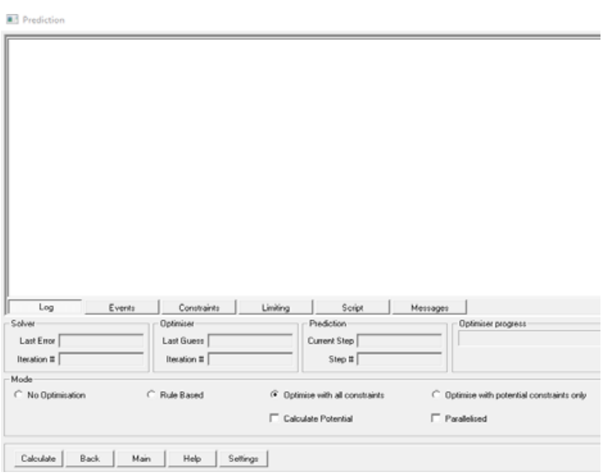


-to generate the production profile, go to 'prediction' → 'Run prediction'
-set prediction timespan & timestep size (in this exercise, you can use dt = 1 year)

59

59

GAP: Prediction



-input separator pressure
-since we have a constraint to be satisfy, choose 'optimise with all constraints' mode
-calculate

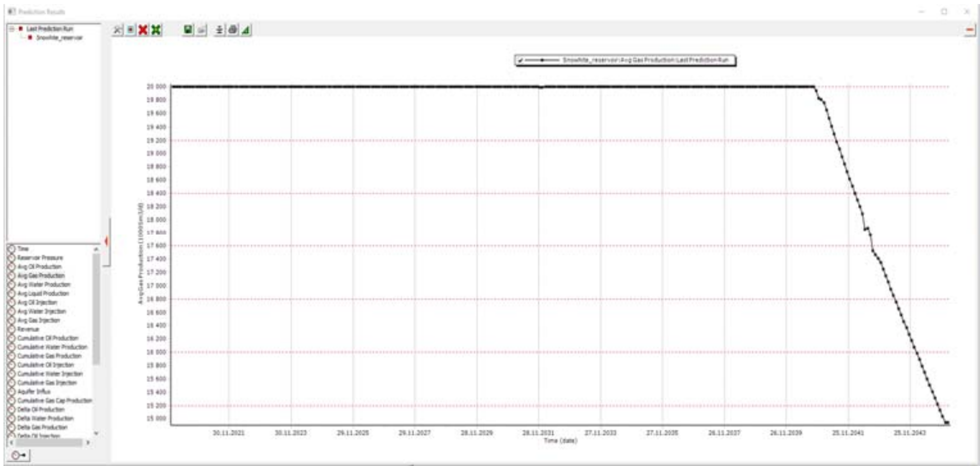
60

60

NTNU

GAP: Prediction

-to see the results, open ‘prediction’ → ‘plot nodes prediction results’ → select all equipment types → plot



61

61

NTNU

Questions

62

62

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 | Production simulator

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

Analytical model for IPR

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

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

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

generated "IPR's"

q^i_{target}

network model (optimization)

choke opening

esp frequency

gas lift rates

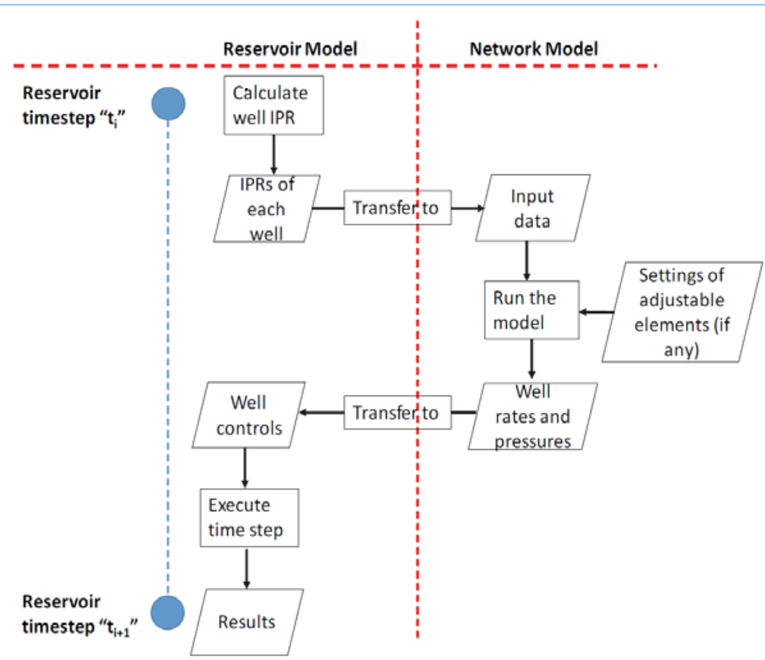
$q_w^i,\ P_{wf}^i$

compute

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

transfer IPR

and repeat...

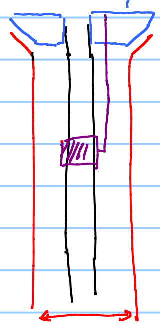


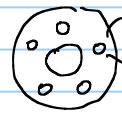
page 19 of compendium

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

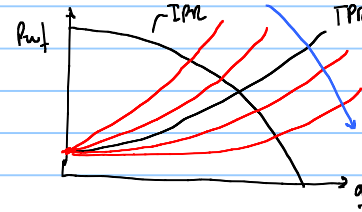
How to choose tubing size ?

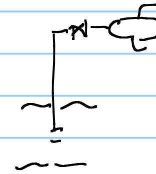
- maximize production
- reduce well costs
- fit the production casing 9 5/8"
- depends on tubing hanger





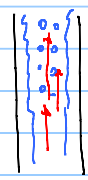
for dry gas, bottomhole equilibrium





compare production gain against tubing cost

- liquid loading



$$V_{sg} = \frac{q_g}{A}$$ (local rate of gas)

$V_{sg} \geq V_{cr}$ ↳ critical velocity

- erosional velocity

$V_{sg} < V_{erosional}$ → API 14E

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

$$V_e = \frac{c}{\sqrt{pm}} \qquad \text{Eq. 2.14}$$

where:

V_e = fluid erosional velocity, feet/second

c = empirical constant

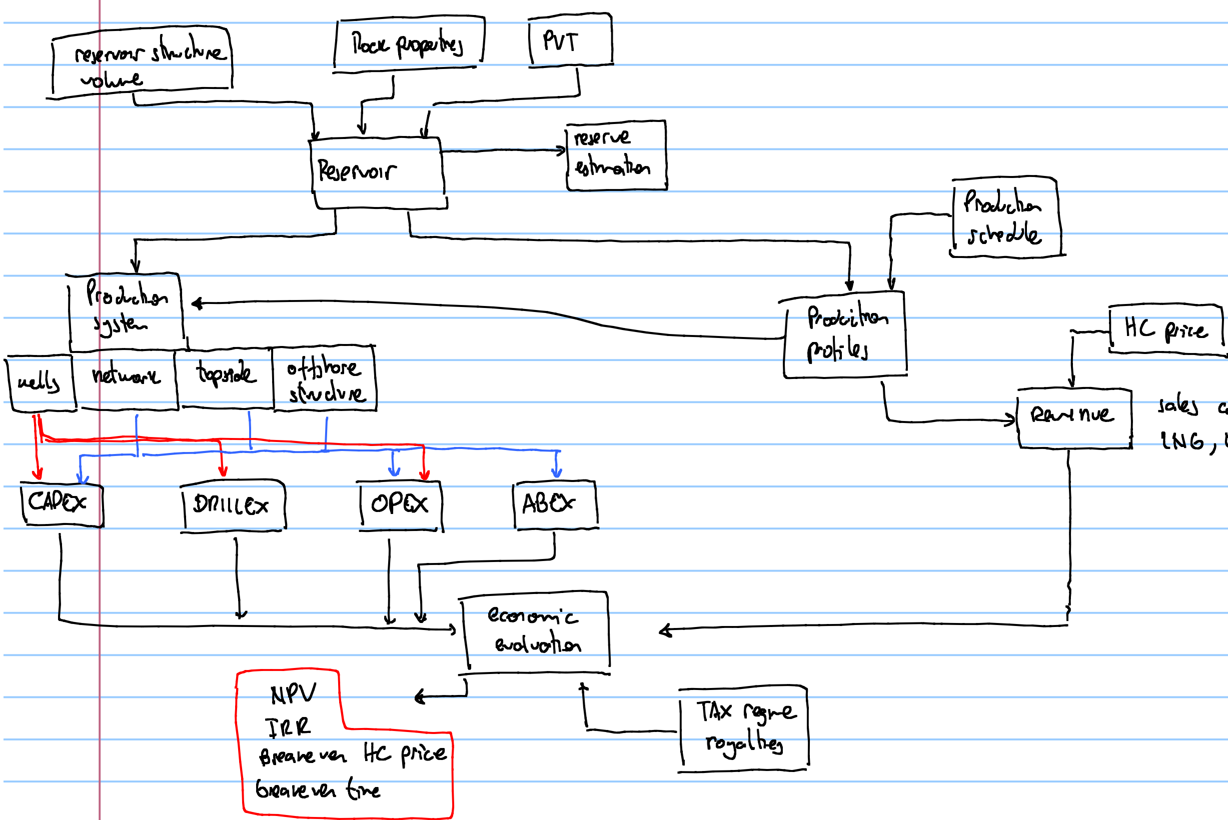
pm = gas/liquid mixture density at flowing pressure and temperature, lbs/ft³

in Norway

. DNV Recommended Practice RP O501)

- to make decisions during field development the company usually employs some economic indicator
  - NPV net present value (KPI) → TPG 5110 petroleum economics Trygve Strøm

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 inhibitors, etc.
- pigging
- transportation and export
- troubleshooting

ABEX

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

NPV calculations

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

CF_i = revenue − expenditures of year "i"

↳ discount factor $\underbrace{5\% \rightarrow 12\%}$

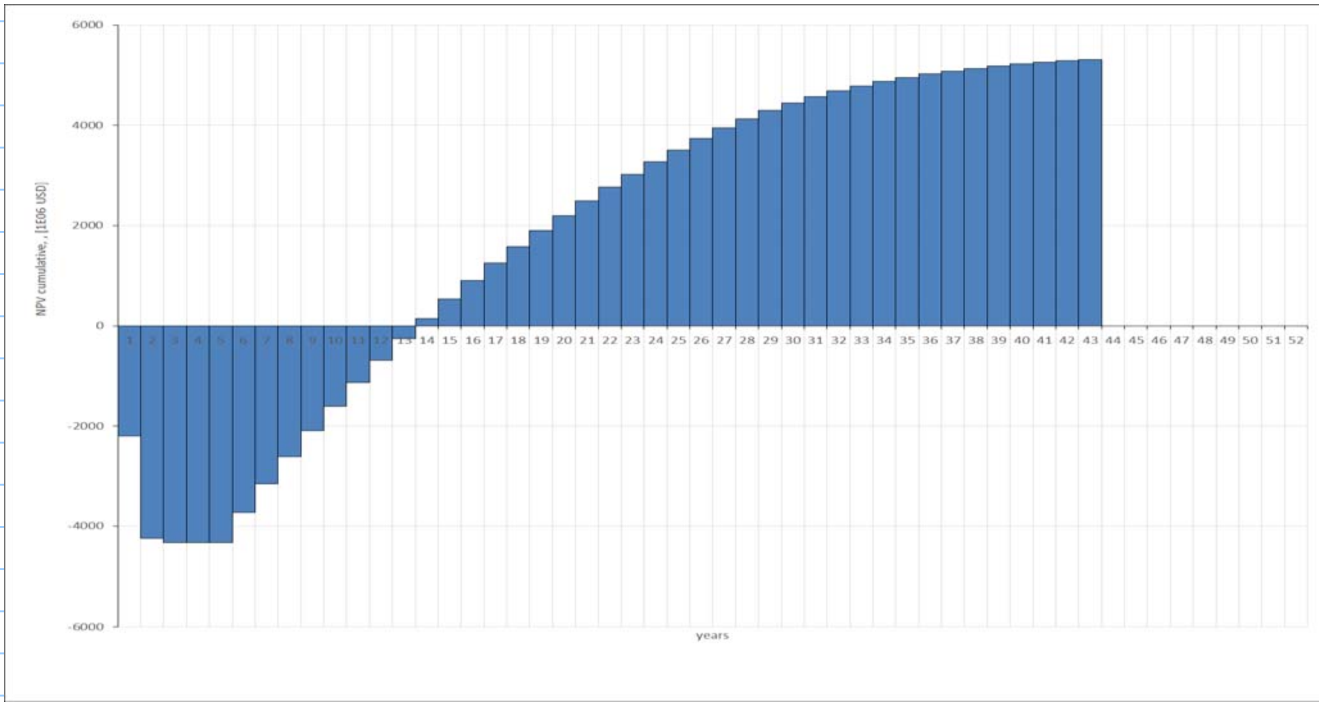
expenses are executed during early years so $\frac{1}{(1+d)^i}$ is close to "1"

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

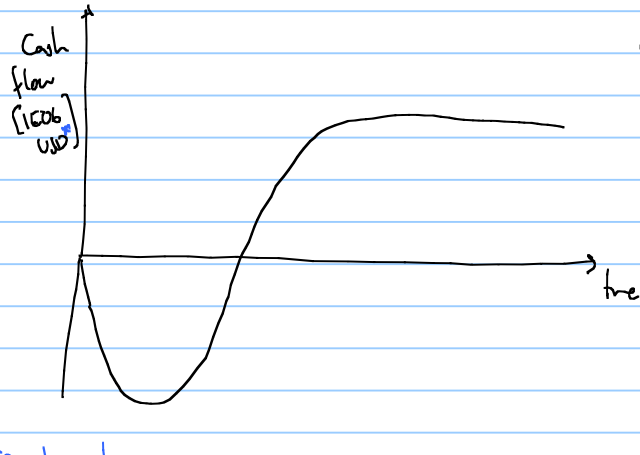
Gas price	0.11	[usd/Sm^3]	
Discount rate	5	[%]	
LNG plant CAPEX	160	[usd/ Sm^3/d]	
well cost	1.00E+02	[1E06 USD]	(paid in years 1 and 2)
LNG carrier cost	2.00E+02	[1E06 USD]	(each carrier has a capacity of 145000 Sm3 LNG, or 86E06 Sm3 og gas, can do 22 trips in a year, amount paid evenly during the first two years)
Subsea manifold cost	2.00E+01	[1E06 USD]	
Pipeline and umbilicals	5.00E+02	[1E06 USD]	(paid in years 1 and 2)

NPV [1E06 USD]: 5316

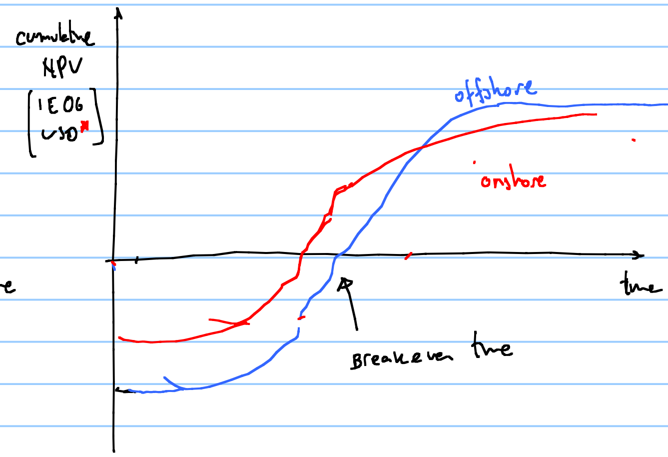
	CAPEX									
End of year	DRILLEX	Subsea	LNG Plant	LNG vessels	TOTAL CAPEX	Yearly gas offtake	Revenues	Cash flow	Discounted cash flow	NPV
[-]	[1E06 USD]	[1E06 USD]	[1E06 USD]	[1E06 USD]	[1E06 USD]	[Sm^3]	[1E06 USD]	[1E06 USD]	[1E06 USD]	[1E06 USD]
1	400	310	1600		2310	0.00E+00	0	-2310	-2200	-2200
2	400	250	1600		2250	0.00E+00	0	-2250	-2041	-4241
3	100	0	0		100	0.00E+00	0	-100	-86	-4327
4	0	0	0		0	0.00E+00	0	0	0	-4327
5	0	0	0		0	0.00E+00	0	0	0	-4327
6	0	0	0		0	7.30E+09	803	803	599	-3728
7	0	0	0		0	7.30E+09	803	803	571	-3157
8	0	0	0		0	7.30E+09	803	803	544	-2614
9	0	0	0		0	7.30E+09	803	803	518	-2096
10	0	0	0		0	7.30E+09	803	803	493	-1603
11	0	0	0		0	7.30E+09	803	803	469	-1134
12	0	0	0		0	7.30E+09	803	803	447	-687
13	0	0	0		0	7.30E+09	803	803	426	-261
14	0	0	0		0	7.30E+09	803	803	406	145
15	0	0	0		0	7.30E+09	803	803	386	531
16	0	0	0		0	7.30E+09	803	803	368	899
17	0	0	0		0	7.30E+09	803	803	350	1249
18	0	0	0		0	7.30E+09	803	803	334	1583
19	0	0	0		0	7.30E+09	803	803	318	1901
20	0	0	0		0	7.30E+09	803	803	303	2203
21	0	0	0		0	7.30E+09	803	803	288	2492
22	0	0	0		0	7.30E+09	803	803	275	2766
23	0	0	0		0	7.30E+09	803	803	261	3028
24	0	0	0		0	7.30E+09	803	803	249	3277
25	0	0	0		0	7.30E+09	803	803	237	3514
26	0	0	0		0	7.30E+09	803	803	226	3740
27	0	0	0		0	7.15E+09	786	786	211	3950
28	0	0	0		0	6.64E+09	731	731	186	4136
29	0	0	0		0	6.17E+09	678	678	165	4301
30	0	0	0		0	5.72E+09	630	630	146	4447
31	0	0	0		0	5.31E+09	584	584	129	4576
32	0	0	0		0	4.92E+09	542	542	114	4689
33	0	0	0		0	4.56E+09	502	502	100	4790
34	0	0	0		0	4.22E+09	464	464	88	4878
35	0	0	0		0	3.90E+09	429	429	78	4956
36	0	0	0		0	3.60E+09	396	396	68	5024
37	0	0	0		0	3.32E+09	365	365	60	5084
38	0	0	0		0	3.06E+09	336	336	53	5137
39	0	0	0		0	2.81E+09	309	309	46	5183
40	0	0	0		0	2.58E+09	284	284	40	5224
41	0	0	0		0	2.36E+09	260	260	35	5259
42	0	0	0		0	2.16E+09	237	237	31	5289
43	0	0	0		0	1.97E+09	216	216	27	5316


6000
4000
2000
0
-2000
-4000
-6000
NPV cumulative, [1E06 USD]
years

Output to present NPV calculations



*USD of each year



USD of time "0"

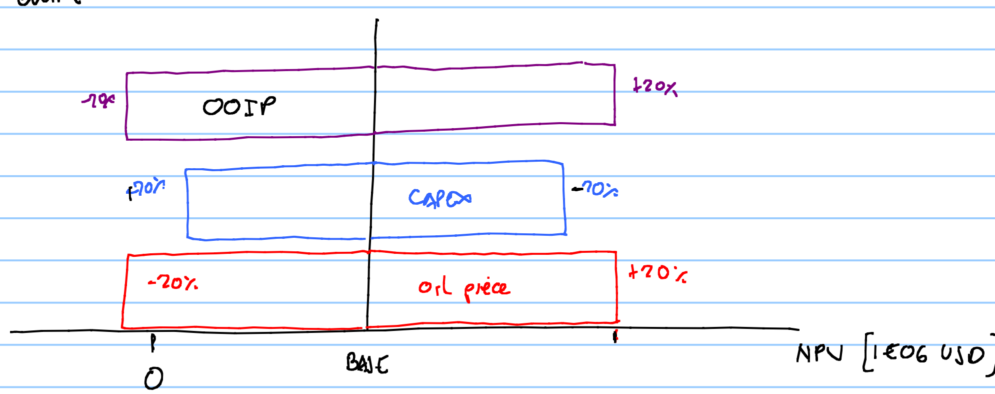
the effect of uncertainty on the project is typically studied using "Ceteris Paribus" "one at a time"

- oil price uncertainty OG3 also called sensitivity analysis
- cost uncertainty (±40% → ±20%)
- N

BASE CASE NPV =

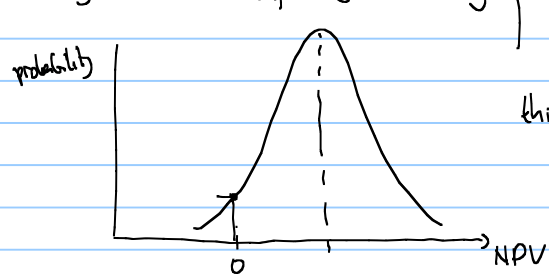
	min	max
Oil price	NPV	NPV
OOIP	NPV	NPV
CAPEX	NPV	NPV

tornado chart

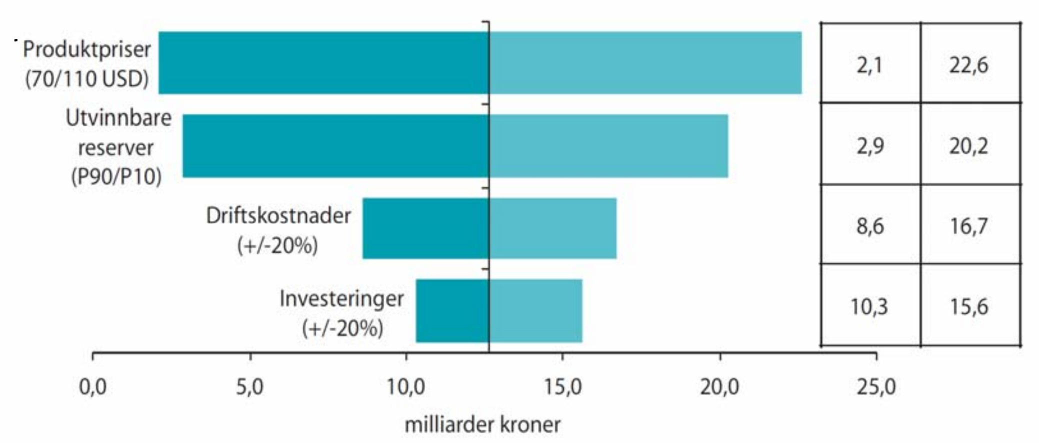


this is NOT a good way to evaluate/quantify uncertainty {we are neglecting other combinations}

a probabilistic evaluation is better!

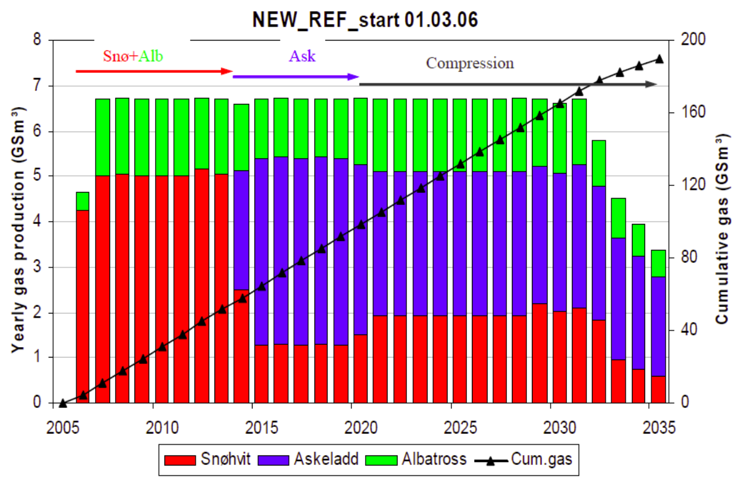


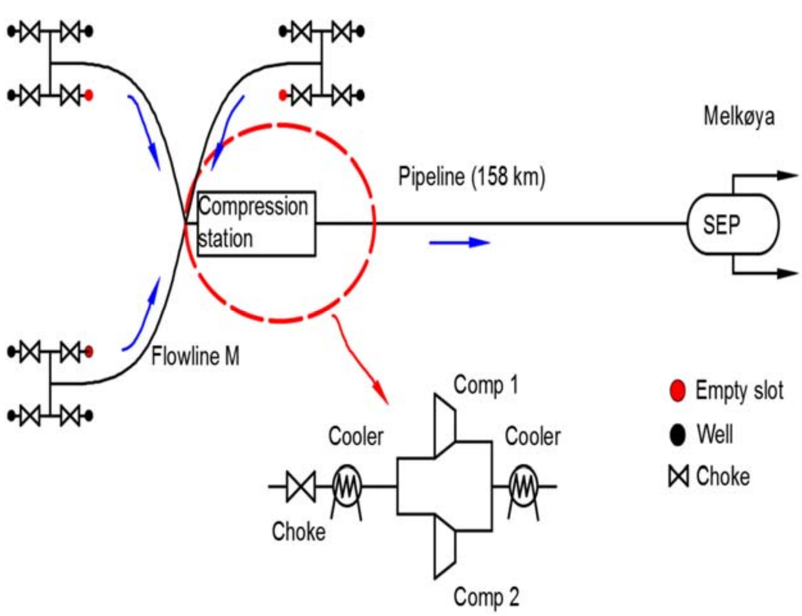
this requires multiple {100, 500, 1000, 10000} evaluations

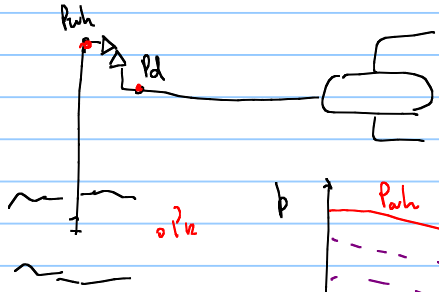


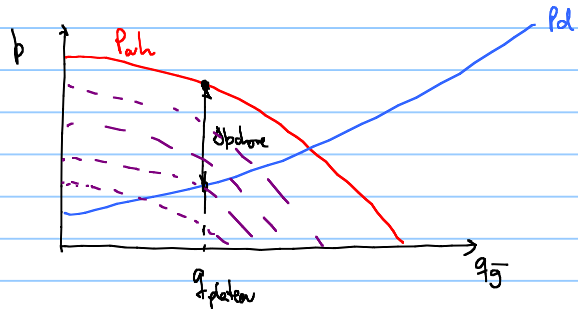
Boosting (Dry gas compression)

Production profile (20,8mill. Sm³/sd – 6,7 GSm³/år)





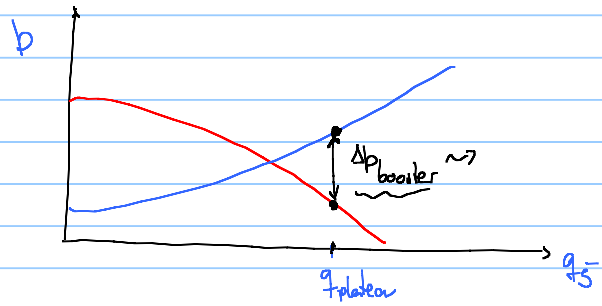




When Δp_{choke} is positive

it is always possible to achieve Δp for a given rate

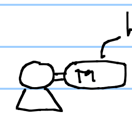
- choke wear
- cooling hydrate/ice formation



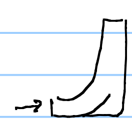
with boosters it isn't always possible to achieve the desired Δp

- equipment has maximum Δp
- Power constraints

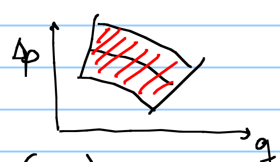
$$P^{pump} = \frac{q(\Delta p)}{\eta_H}$$



- minimum suction pressure
  - sealing
  - balancing loads on impeller (reducing loads on bearings)
  - cavitation



- operational map



- outlet temperature (gas)
  - deterioration of seals
  - damage to material

82.1	78.7	30.0	6.7E+6	22	0.79	1.31E+11	24.2E+6	20.0E+6	COMPRESSION STARTS			
82.1	78.7	30.0	6.7E+6	14	0.85	1.39E+11	22.7E+6	20.0E+6	Pcomp dis	Tsuc	rp	deltap
82.1	78.7	30.0	6.7E+6	6	0.93	1.46E+11	21.2E+6	20.0E+6	[bara]	[C]	[-]	[bar]
79.6	76.1	30.0	6.7E+6	0	1.00				78.7			2.6
70.8	66.8	30.0	6.7E+6	0	1.00				78.7			11.9
61.4	56.7	30.0	6.7E+6	0	1.00				78.7			22.0
51.0	45.3	30.0	6.7E+6	0	1.00				78.7			33.4
39.0	31.1	30.0	6.7E+6	0	1.00				78.7			47.5
22.9	#VALUE!	30.0	6.7E+6	0	1.00				78.7			#VALUE!
#VALUE!	#VALUE!	30.0	6.7E+6	#VALUE!	#VALUE!				78.7			#VALUE!
#VALUE!	#VALUE!	30.0	6.7E+6	#VALUE!	#VALUE!				78.7			#VALUE!

$T_{in} = 67\,°C$

$P_{in} = 56.7$ bara — 5.67 MPa

$P_{dis} = 78.7$ bara

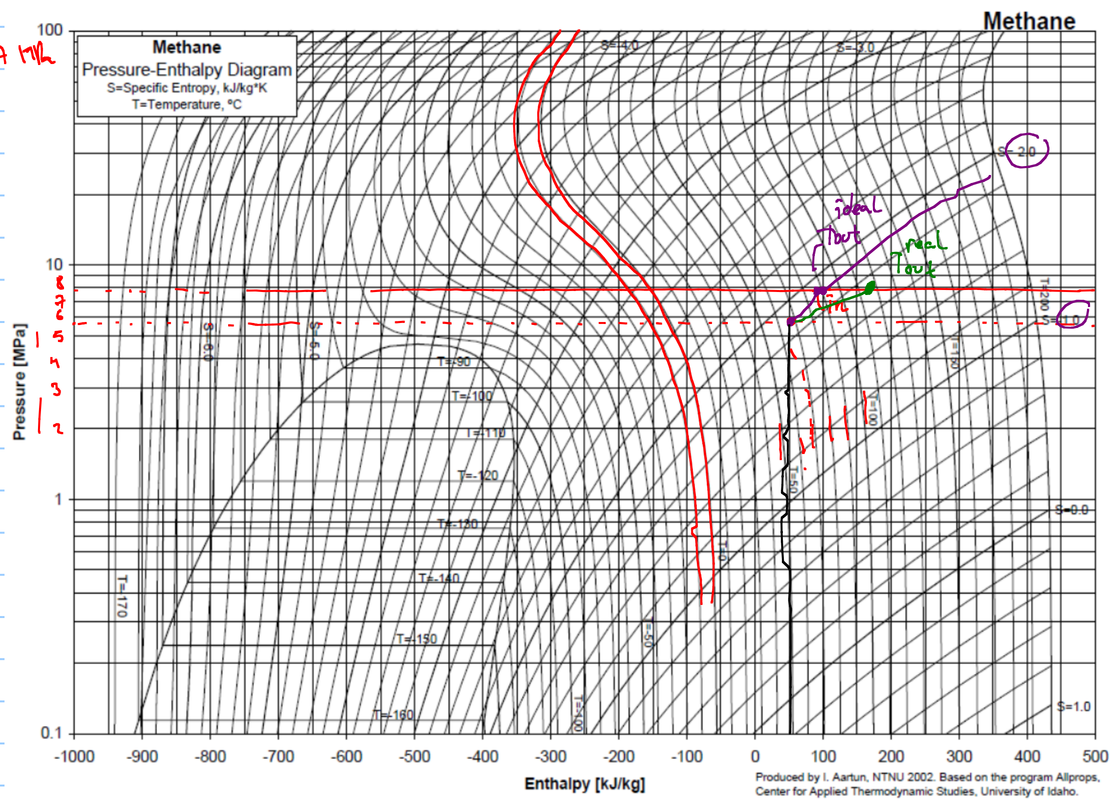
$S_{in} = -1.9$ kJ/kg K

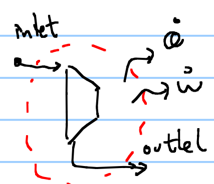
ideal $T_{out} = 90°C$

$h_{inlet} = 50$ kJ/kg

ideal $h_{outlet} = 100$ kJ/kg

ideal ~ isentropic





first law of thermodynamics for open systems

$$\cancel{\dot{Q}} - \dot{W} = \dot{m}\,(e_{inlet} - e_{outlet})$$

$$e = h + \cancel{\frac{v^2}{2g}} + \cancel{z}$$

$$-\dot{W} = \dot{m}\,(h_{inlet} - h_{outlet})$$

$$\underbrace{-\dot{W}}_{W\ [J/s]} = (50 - 100)\,\frac{kJ}{kg} \cdot 13.4\,E06\ kg/d \cdot \frac{1\,d}{24 \cdot 3600} = 7.7\ \frac{MJ}{s}$$

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

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

$$\frac{p_{sc}}{\rho_{sc}} = R\,T_{sc}$$

$$\dot{m} = 20\,E06\ Sm^3/d \cdot \underbrace{\rho_{sc}}_{0.67\ kg/m^3}$$

$$\rho_{sc} = \frac{P_{sc}}{R \cdot T_{sc}} =$$

$$\dot{m} = 13.4\,E06\ kg/d$$

ideal power required $P^{ideal} = 7.7$ MW

polytropic exponent

real compression $\left(\frac{T_{out}}{T_{in}}\right) = \underbrace{\left(\frac{P_{out}}{P_{in}}\right)}_{\text{pressure ratio}}^{\frac{n-1}{n}}$

properties of fluid

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

ideal compression $\left(\frac{T_{out}}{T_{in}}\right) = \left(\frac{P_{out}}{P_{in}}\right)^{\frac{k-1}{k}}$

for our case $k = 1.30 - 0.31(\gamma_g - 0.55)$

$\gamma_g = 0.55$

$k = 1.3$

always input in K kelvin

$T_{out}^{ideal} = T_{in}\left(\frac{P_{out}}{P_{in}}\right)^{\frac{1.3-1}{1.3}}$

$T_{out}^{ideal} = (67 + 273.15)\left(\frac{78.7}{56.7}\right)^{\frac{0.3}{1.3}} =$

$$\boxed{T_{out}^{ideal} = 93.73 \ ^\circ C}$$

Note Title 24.02.2020

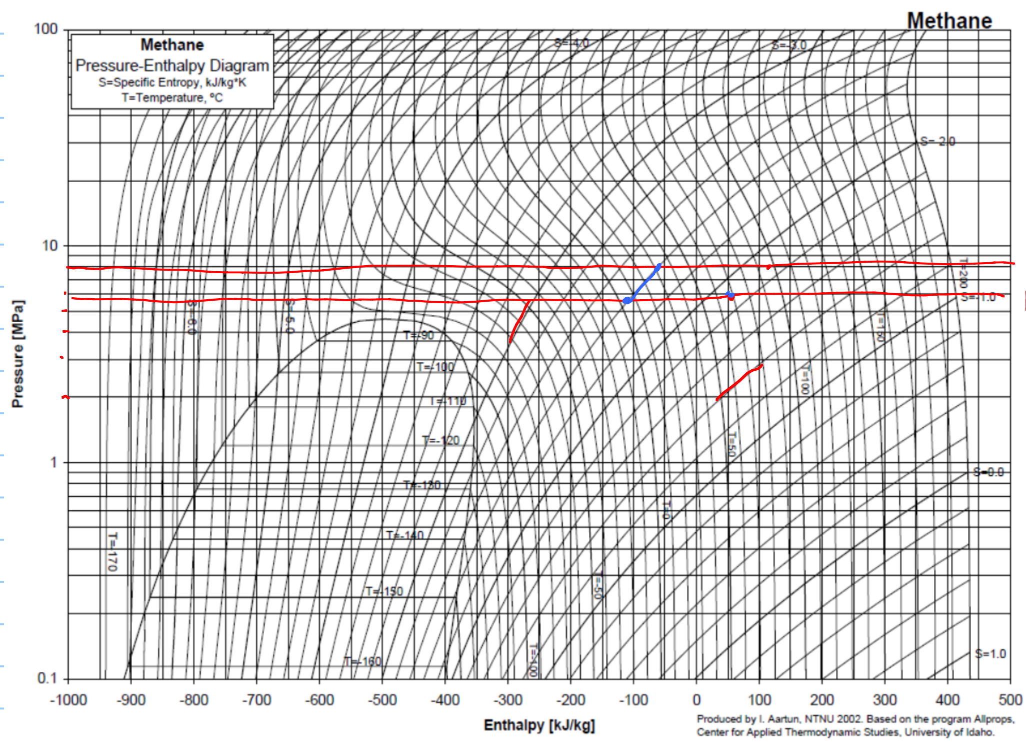
$$n = \frac{1}{1-\left(\frac{k-1}{k\,\eta_p}\right)}$$

$$\eta_p = \left(\frac{k-1}{k}\right)\left(\frac{n}{n-1}\right) \rightarrow (0.6 - 0.8)$$

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

$$\frac{T_{out}}{T_{in}} = r_p^{\frac{n-1}{n}}$$

Due to the shape of the isoentropy lines, lower inlet temperatures require less energy (Δh) for same Δp



- Estimate required compression power $P = \frac{H_p \cdot g \cdot \dot{m}}{\eta_p \cdot \eta_m}$ (polytropic head on

252 in compendium

$g = 9.81\ m/s^2$

$\eta_m = 95 - 99\%$

In pumps head $h = \frac{\Delta p}{\rho g}$

$$H_p = \frac{T_{suc}\, Z_{av}\, R}{g}\, \frac{n}{n-1}\left(r_p^{\frac{n-1}{n}} - 1\right)$$

$$Z_{av} = \frac{Z_{in} + Z_{out}}{2}$$

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

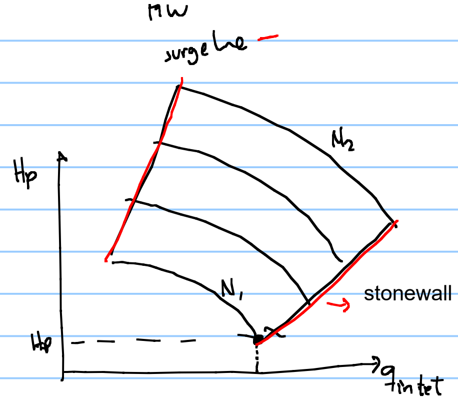
Operation map compressor

given

usually generated with certain gas → MW, k (air)

↳ T_{in}, P_{in} ↳ 1.01325 bara

($T_{amb} = 20°C$)



N rotational speed

(sonic velocity in blade passage)

test conditions are typically not equal to actual operating conditions

therefore it is necessary to convert from test conditions to actual conditions

$$q_{new} = q_{test} \sqrt{\frac{k_{new}}{k_{test}}} \cdot \sqrt{\frac{MW_{test}}{MW_{new}}} \cdot \sqrt{\frac{T_{new}}{T_{test}}}$$

$$H_{p\,new} = H_{p\,test} \frac{k_{new}}{k_{test}} \frac{MW_{test}}{MW_{new}} , \frac{T_{new}}{T_{test}}$$

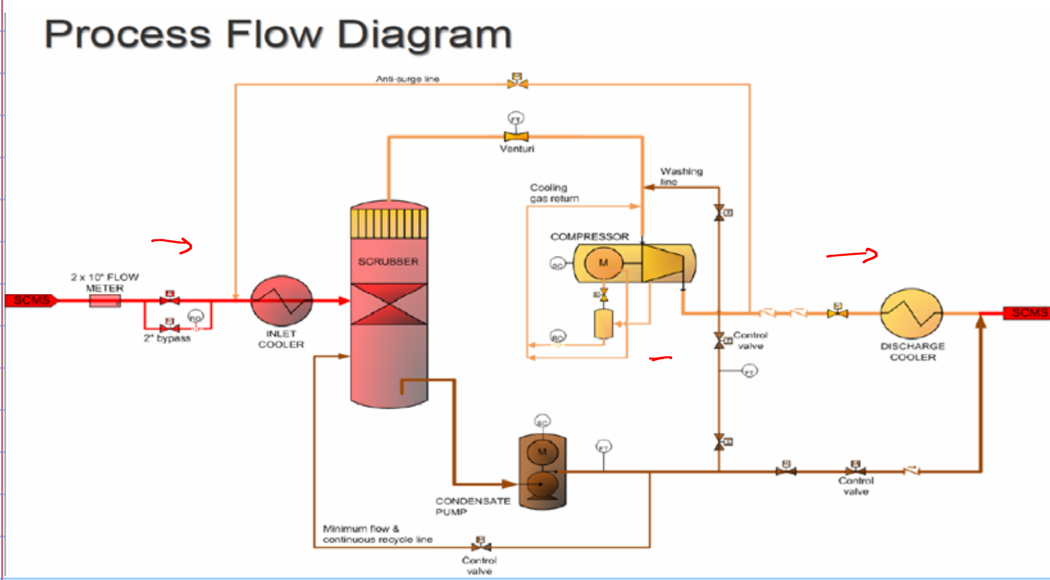
for our case we will convert the operational point to compressor test condition

$$H_{p\,test} = H_{p\,new} \frac{k_{test}}{k_{new}} \cdot \frac{MW_{new}}{MW_{test}} \cdot \frac{T_{test}}{T_{new}}$$

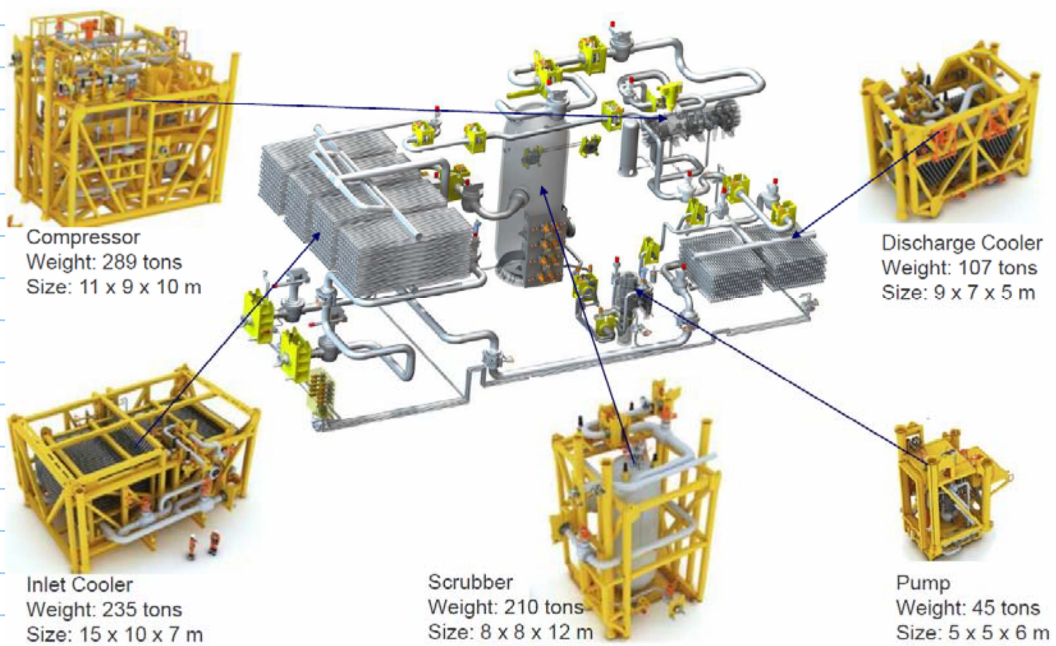
$$q_{test} = q_{new} \sqrt{\frac{k_{test}}{k_{new}}} \sqrt{\frac{MW_{new}}{MW_{test}}} \sqrt{\frac{T_{test}}{T_{new}}}$$

$$B_g(p,T) = \frac{q_g(p,T)}{q_{\bar{g}}(p_{sc}, T_{sc})} \qquad q_g = q_{\bar{g}} \cdot B_g$$

$$B_g = \frac{V_g(p,T)}{V_{\bar{g}}(p_{sc}, T_{sc})}$$

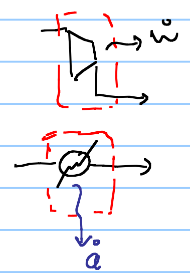


Process Modules- Sizes and Dry Weights



Cooler duty $\dot{Q} = \dot{m}(h_{inlet} - h_{outlet})$

11 MW 67°C



http://www.ipt.ntnu.no/

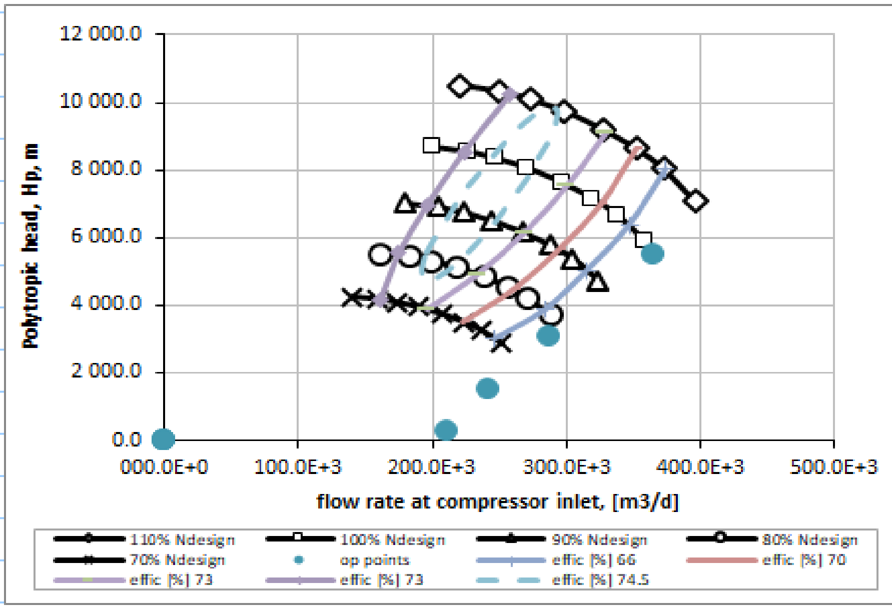
COMPRESSION STARTS

Deltap choke comp [bar]	p_suc [bara]	pcomp dis [bara]	Tplem [C]	DT inlet cooler [C]	Tsuc [C]	rp [-]	deltap [bar]	np -eff [-]	n [-]	Tdis [C]	DT outlet cooler [C]	Tin_pipeline [C]	zsuc	zdisc	Bg @suc [m^3/Sm^3]	qg_local [m^3/d]	Hp [m]
0	76.1	78.7	67	0	67	1.03	2.6	0.7	1.49	70.8	0	70.8					
0	66.8	78.7	67	0	67	1.18	11.9	0.7	1.49	85.9	0	85.9					
0	56.7	78.7	67	0	67	1.39	22.0	0.7	1.49	105.7	0	105.7					
0	45.3	78.7	67	0	67	1.74	33.4	0.7	1.49	134.8	0	134.8					
0	31.1	78.7	67	0	67	2.53	47.5	0.7	1.49	188.3	0	188.3					
0	#VALUE!	78.7	67	0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!					
0	#VALUE!	78.7	67	0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!					
0	#VALUE!	78.7	67	0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!					

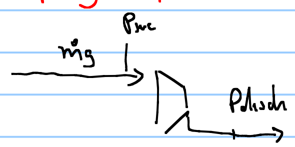
Tsc	288.71	K
k	1.30	
Polytropic effic	0.7	
Mech. Effic	0.95	

Pin, bara	50
Tin, K	298.15
Zin	0.98
Mw	28.97

zsuc	zdisc	Bg @suc [m^3/Sm^3]	qg_local [m^3/d]	Hp [m]	m [kg/s]	Power [MW]	Hp test [m]	qact test [m^3/d]	qact test single comp [m^3/d]
0.928	0.930	1.46E-02	292.0E+3	565.1	155.7E+0	1.30	294.8	210883.7638	
0.935	0.942	1.68E-02	335.2E+3	2851.9	155.7E+0	6.55	1487.9	242119.9827	
0.944	0.955	1.99E-02	398.4E+3	5924.7	155.7E+0	13.61	3091.0	287755.5395	
0.954	0.970	2.52E-02	504.1E+3	10505.5	155.7E+0	24.13	5480.9	364116.1919	
0.967	0.988	3.72E-02	743.8E+3	19107.5	155.7E+0	43.89	9968.8	537247.0699	

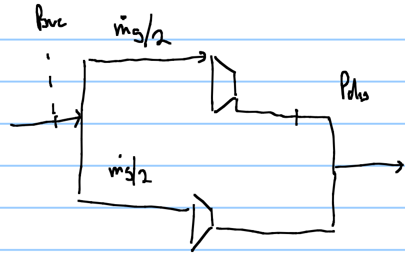

12 000.0
10 000.0
8 000.0
6 000.0
4 000.0
2 000.0
0.0
Polytropic head, Hp, m
000.0E+0
100.0E+3
200.0E+3
300.0E+3
400.0E+3
500.0E+3
flow rate at compressor inlet, [m3/d]
110% Ndesign
100% Ndesign
90% Ndesign
80% Ndesign
70% Ndesign
op points
effic [%] 66
effic [%] 70
effic [%] 73
effic [%] 73
effic [%] 74.5

Comment when planning compressors in parallel.

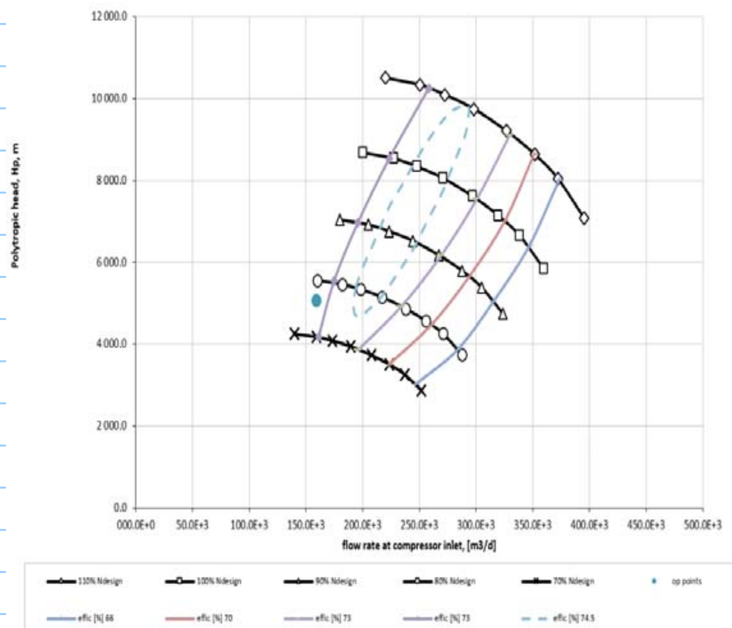


$\underline{P}_1$

$$\underline{P} = \frac{Hp \cdot g\, \dot{m}}{\eta_p \cdot \eta_m}$$



$\underline{P}$ per compressor is $\underline{P}_1/2$ because the mass flow was halved. BUT in reality η_p changes with $\dot{m}$ because qactual at compressor inlet is reduced



DT inlet cooler	Tsuc	rp	deltap	np -eff	n	Tdis	DT outlet cooler	Tin_pipeline	zsuc
[C]	[C]	[-]	[bar]	[-]	[-]	[C]	[C]	[C]	
47	20	1.71	32.6	0.73	1.46	73.9	0	73.9	0.916
0	67	1.18	11.9	0.7	1.49	85.9	0	85.9	0.935
0	67	1.39	22.0	0.7	1.49	105.7	0	105.7	0.944
0	67	1.74	33.4	0.7	1.49	134.8	0	134.8	0.954
0	67	2.53	47.5	0.7	1.49	188.3	0	188.3	0.967
0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!	#VALUE!
0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!	#VALUE!
0	67	#VALUE!	#VALUE!	0.7	1.49	#VALUE!	0	#VALUE!	#VALUE!

for 1st year of compression

$\Delta p_{choke} = 30$ bara

$\Delta T_{cooler} = 47\,°C$

k	1.30
Polytropic effic	0.7
Mech. Effic	0.95

Tin, K	298.15
Zin	0.98
Mw	28.97

zdisc	Bg @suc	qg_local	Hp	m	Power	Hp test	qact test	qact test single comp
	[m^3/Sm^3]	[m^3/d]	[m]	[kg/s]	[MW]	[m]	[m^3/d]	[m^3/d]
0.933	2.05E-02	409.9E+3	8366.0	155.7E+0	18.43	5064.5	318899.1772	159449.5886
0.942	1.68E-02	335.2E+3	2851.9	155.7E+0	6.55	1487.9	242119.9827	121059.9913
0.955	1.99E-02	398.4E+3	5924.7	155.7E+0	13.61	3091.0	287755.5395	143877.7697
0.970	2.52E-02	504.1E+3	10505.5	155.7E+0	24.13	5480.9	364116.1919	182058.096
0.988	3.72E-02	743.8E+3	19107.5	155.7E+0	43.89	9968.8	537247.0699	268623.535
#VALUE!	#VALUE!	#VALUE!	#VALUE!	155.7E+0	#VALUE!	#VALUE!	#VALUE!	#VALUE!
#VALUE!	#VALUE!	#VALUE!	#VALUE!	155.7E+0	#VALUE!	#VALUE!	#VALUE!	#VALUE!
#VALUE!	#VALUE!	#VALUE!	#VALUE!	155.7E+0	#VALUE!	#VALUE!	#VALUE!	#VALUE!

lets estimate cooler duty

$\dot{Q} = \dot{m}(h_{in} - h_{out})$

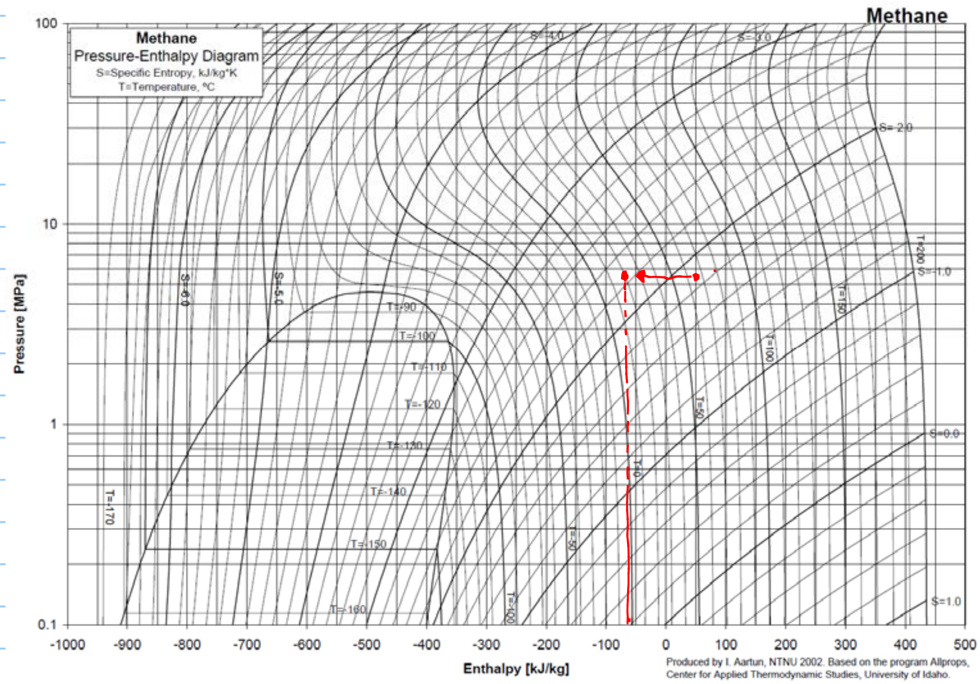
$\dot{Q} = 155\,kg/s\,(50-(-60)) = 155 \cdot 110000$

$= 17\,MW$

required cooling duty in year 1 of compression must be bigger than Asgard's

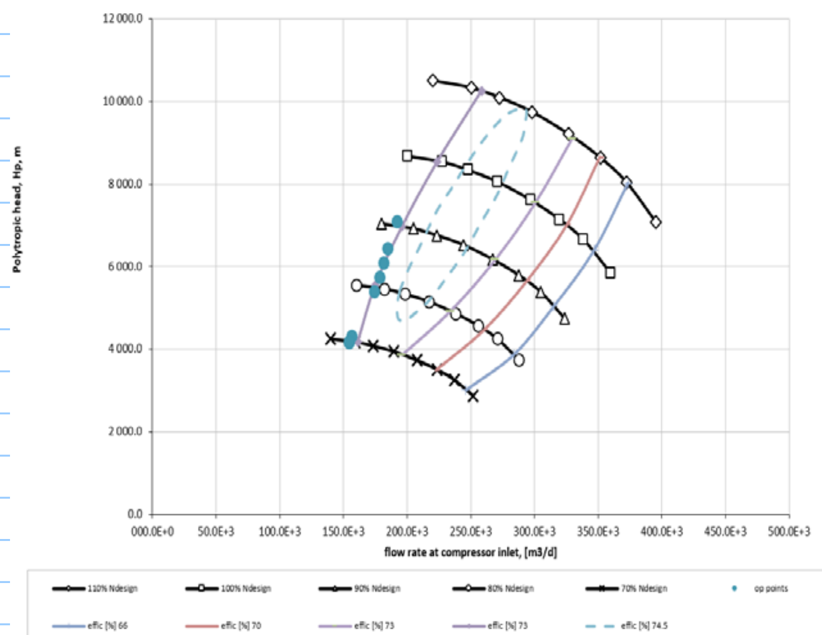
Cooler inlet
T = 67°C
p = 4.6 MPa

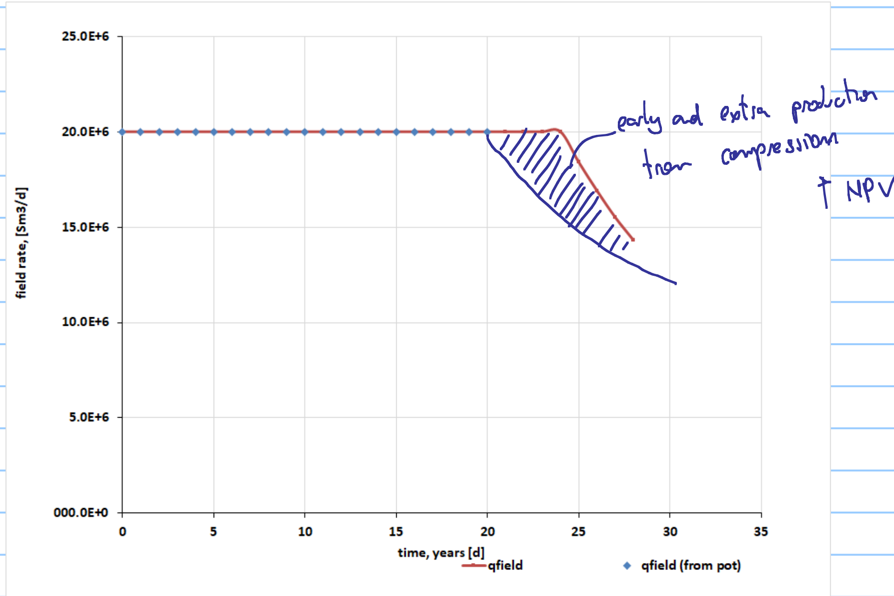
$h_{in} \approx 50$ kJ/kg
$h_{out} = -60$ kJ/kg
$T_{out} = 20$°C
$p_{out} = p_{in} = 4.6$ MPa



The inlet cooler seems to have a too high duty (17) compared to Aasgard (11 MW).
two options:
- make bigger / more efficient cooler $$$
- ΔTcooler must be reduced ~> more power is required, Tout will be higher

ΔTcooler of 20°C still works!

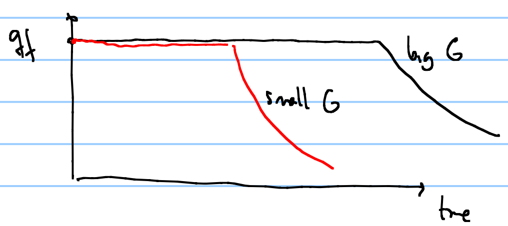




How to deal and quantify uncertainty in field development

for example in our Snøhvit case

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



$

uptime 90 – 100%

$\left(\frac{\text{nr day producing in year}}{365} \right)$

↳ cause additional OPEX

↳ cut in production → cut in Revenue

Input variables used in engineering studies in FD are highly uncertain

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

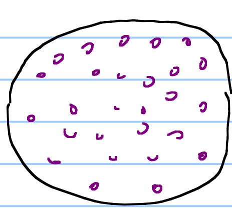
$$TRR = N_{pu} = \frac{\overbrace{V_R \cdot \Phi \cdot N_{tg} \cdot S_o}^{\text{volume of oil at local reservoir condition}}}{B_o}$$ total recoverable reserves

deterministic calculation: all input is known

$V_R \; \{ V_{Rmin} - V_{Rmax} \}$

probabilistic calculation: input is uncertain

Φ



number sample	Φ
–	–
–	–
–	–
–	–
–	–

→ discrete frequency analysis

create bins

min Φ_1 (0.15) — 0.175

Φ_2 (0.20)

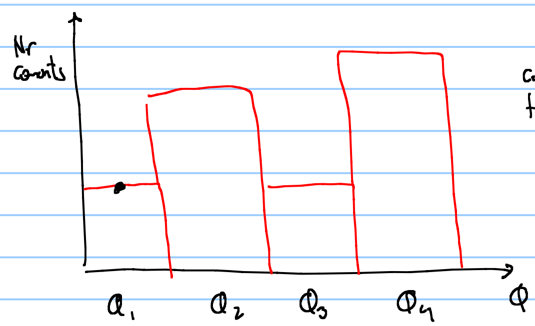
Φ_3 (0.25)

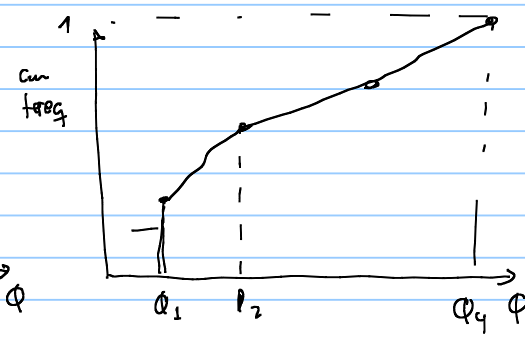
max Φ_4 (0.30)

if $\Phi_i = 0.18$

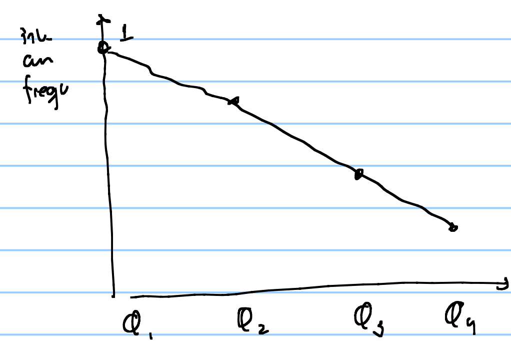
$\Phi_1 \le \Phi_i \le \Phi_2$

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





bin	Nr counts	rel. frequency	cum frequency	inv. cum frequency
Φ_1	x	x/N	x/N	$(x+w+z+y)/N$ → 1
Φ_2	y	y/N	$y/N + x/N$	$(w+z+y)/N$
Φ_3	z	z/N	$y/N + x/N + z/N$	$(w+z)/N$
Φ_4	w	w/N	$\frac{x+y+z+w}{N}$	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 $\text{delta} = \frac{(\text{max} - \text{min})}{(\text{Nr bins} - 1)}$

compute each bin

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

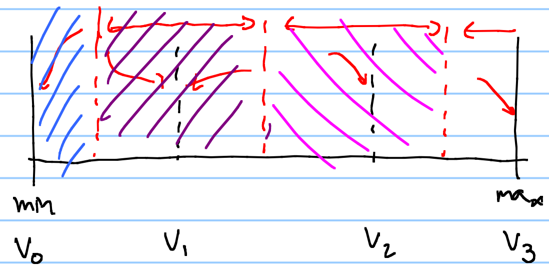
starting from $\text{bin}^0 = \text{min}$

to apply frequency function:

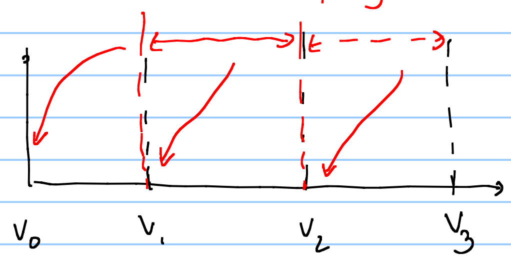
ctrl + shift + enter (in sequence and leave it pressed)

selecting bins must take into account
- nr data points

Courtesy of "Peng Li"



be careful how the frequency is accounted for



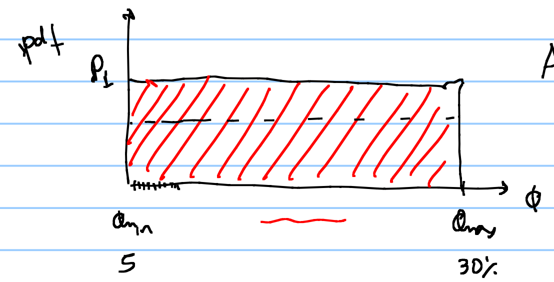
what happens if there are no measurements?

frequency ~> probability

rel frequency ~> pdf probability density function

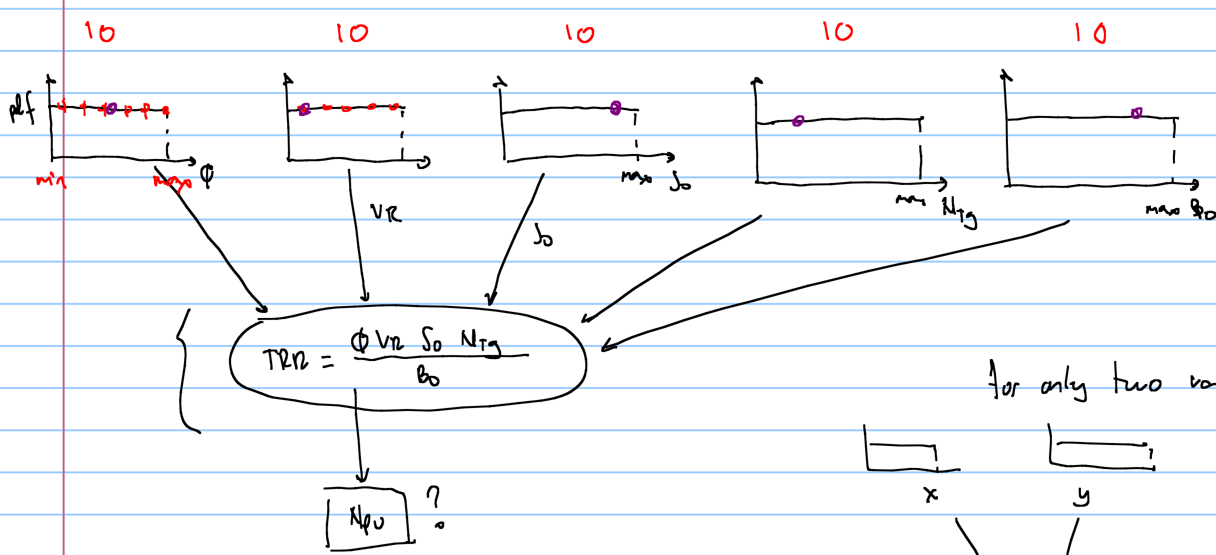
cum frequency plot ~> cdf cumulative distribution function

poor boy, no data pdf ϕ continuous probability

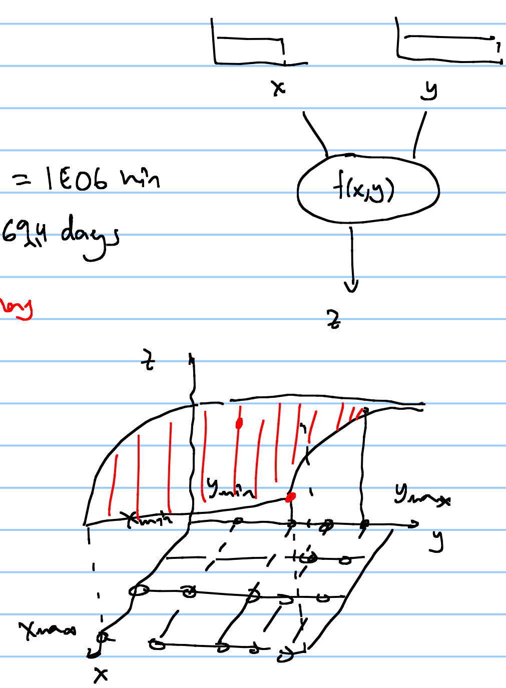


$$Area = (\phi_{max} - \phi_{min}) \cdot P_1 = 1$$

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



for only two variables:



$10^5 \cdot 10\,min = 1E06\,min$

694 days

uniform sampling requires

$10 \times 10 \times 10 \times 10 \times 10 = 10^5$ simulations

for many variables we use "sampling methods" evaluate many combinations of (x_i, y_i) and the do a frequency analysis on the results

x	y	z
x_1	y_1	$z_{1,1}$
x_1	y_2	$z_{1,2}$

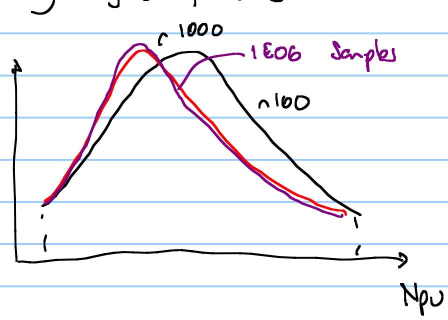
Monte Carlo sampling

1: take a random value of the variable in the interval for each variable

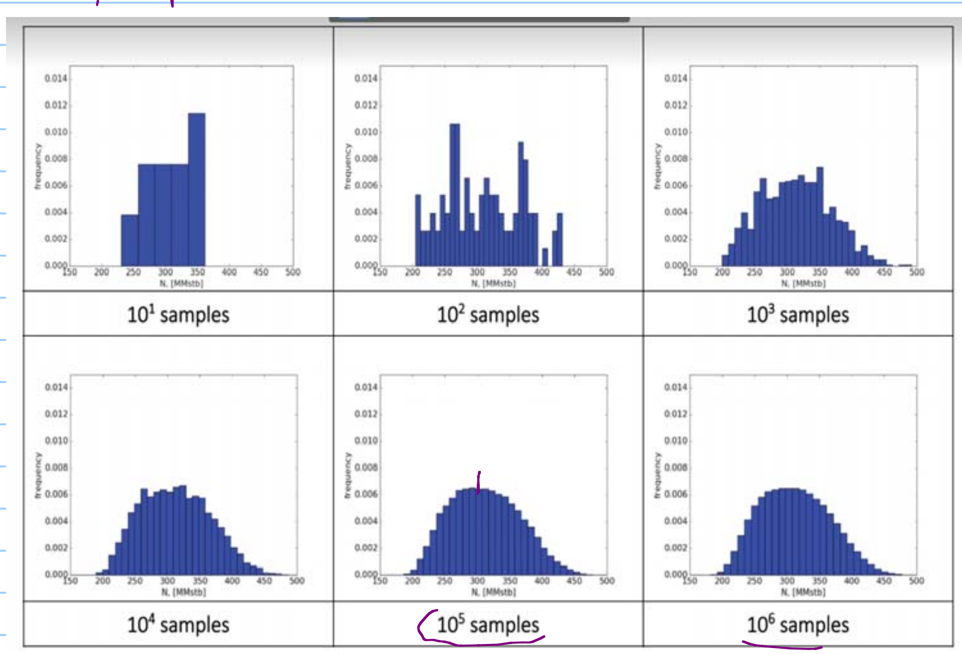
2: Compute the output variable → record result

3: repeat 1-2 many times

4: frequency analysis of results

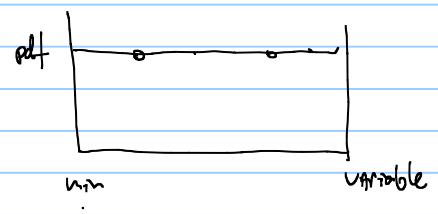


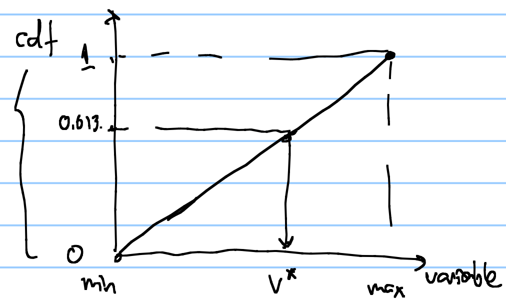
Page 110 of compendium



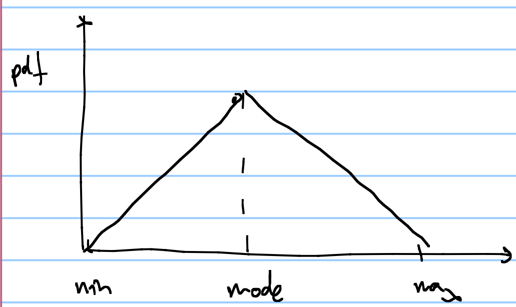
number of required iterations (page 113)

Sampling is made on cdf





$$Var = min + \frac{(max - min)}{(1 - 0)}(rand - 0)$$




```
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 random number
    Application.Volatile (True)
    U = Rnd()
    x_uniform = a + (b - a) * U
End Function
```

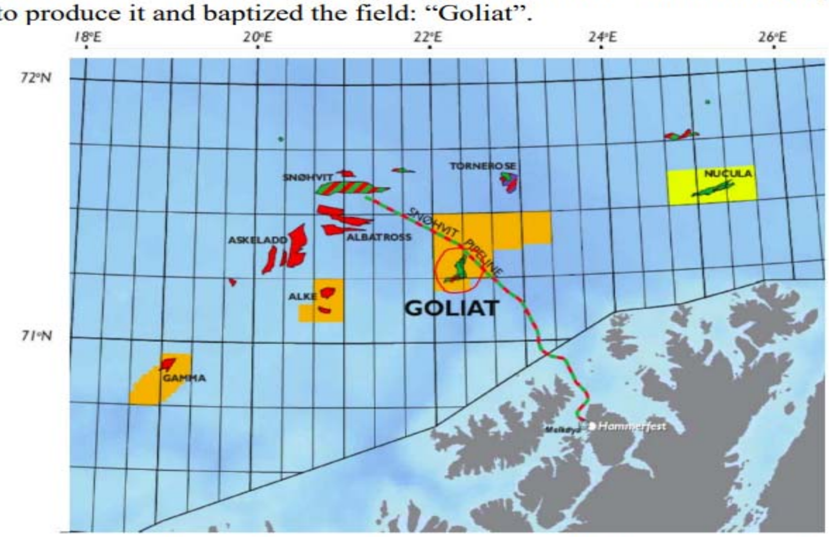
```
Function x_Triangular(a, b, c)
    'value of the variable x for a Triangular distribution
    'a is the minimum value of x
    'b is the maximum value of x
    'c is the mode value of x
    'U is the random number
    Application.Volatile (True)
    U = Rnd()
    F_c = (c - a) / (b - a)
      If 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
```

```
Function Npu(Bo, Fr, RV, Por, Ntg, So)
'total recoverable reserves, in stb or Sm3
'por porosity, fraction
'Ntg Net to gross, fraction
'So oil saturation, fraction
'Bo oil formation volume factor, (m3/Sm3 or bbl/stb)
'Fr ultimate recovery factor, fraction
Npu = RV * Por * Ntg * So * Ntg / Bo
End Function
```

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2020/Class_files/20200302/

Probabilistic estimation of Original oil in place and Total Recoverable Reserves of the Kobbe Formation

The company ENI has found a reservoir in the Barents sea, Kobbe, 50 km south of the Snøhvit field and 80 km from the LNG plant of Snøhvit in Hammerfest (Melkøya). The water depth in the area is 360 – 420 metres and, luckily, is an "ice-free" area. The company is evaluating to produce it and baptized the field: "Goliat".



The reservoir contains oil with a thin overlying gas cap and it lies approximately 1800 meters beneath the seabed. The static reservoir pressure is 190 bar.

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

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

Tasks:

-Perform a Monte Carlo Simulation Study (using 1000 simulations) to obtain the expected value of the Total Recoverable Oil Reserves and the initial oil in place. Report the outcome as:

- Expected value (Mean or Average)
- Most probable value (mode)
- Median (P50), P10, P90
- Expectation curve for the Total Recoverable Oil Reserves (Plot of Cumulative Probability) and the initial oil in place

-Estimate the required number of iterations for the Monte Carlo method using the values calculated above. Assume that the desired error is 2% of the average, and the desired confidence level is 98%. Do you have to run more iterations?

Class example TPG4230, Michael Golan and Milan Stanko							
			Net to Gros	Oil Saturation	Formation Volume F	Ultimate Recovery Factor	
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	
Min	5.00E+09	0.18	0.3	0.8	1.35	0.18	
Max	6.25E+09	0.3	0.5	0.9	1.6	0.35	
Mode						0.25	
MC it	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	Npu
[-]	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	[stb]

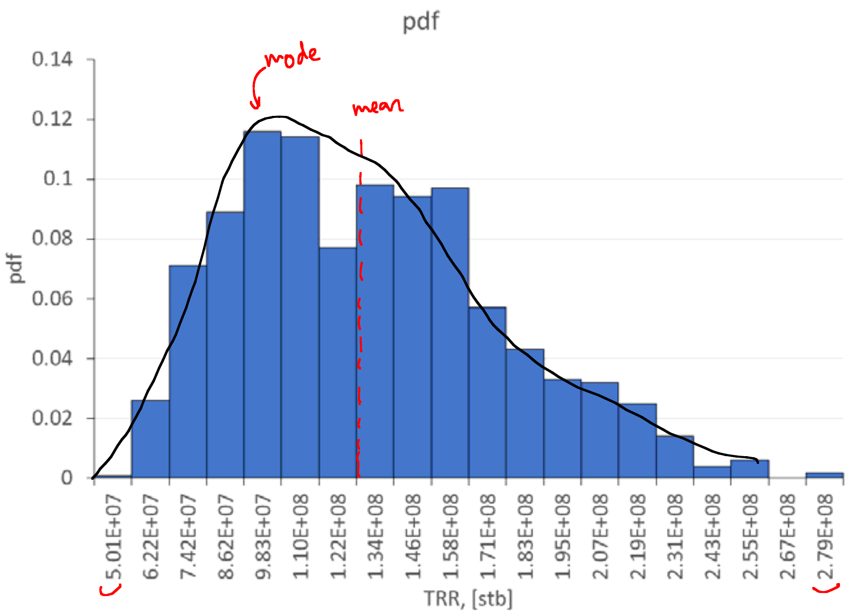
Class example TPG4230, Michael Golan and Milan Stanko							
			Net to Gros	Oil Saturation	Formation Volume F	Ultimate Recovery Factor	
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	
Min	5.00E+09	0.18	0.3	0.8	1.35	0.18	
Max	6.25E+09	0.3	0.5	0.9	1.6	0.35	
Mode						0.25	
MC it	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr	Npu
[-]	bbl	fraction	fraction	fraction	Res bbl/STB	fraction	[stb]
1	5.68E+09	0.24	0.36	0.90	1.45	0.25	1.13E+08
2	5.67E+09	0.26	0.37	0.86	1.53	0.28	1.14E+08
3	5.19E+09	0.28	0.43	0.86	1.56	0.25	1.49E+08
4	5.56E+09	0.19	0.45	0.83	1.52	0.28	1.19E+08
5	5.76E+09	0.23	0.37	0.88	1.54	0.23	1.08E+08

lock row only

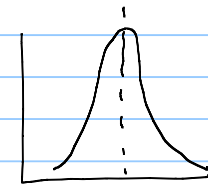
C$4

mean 1.27E08 stb

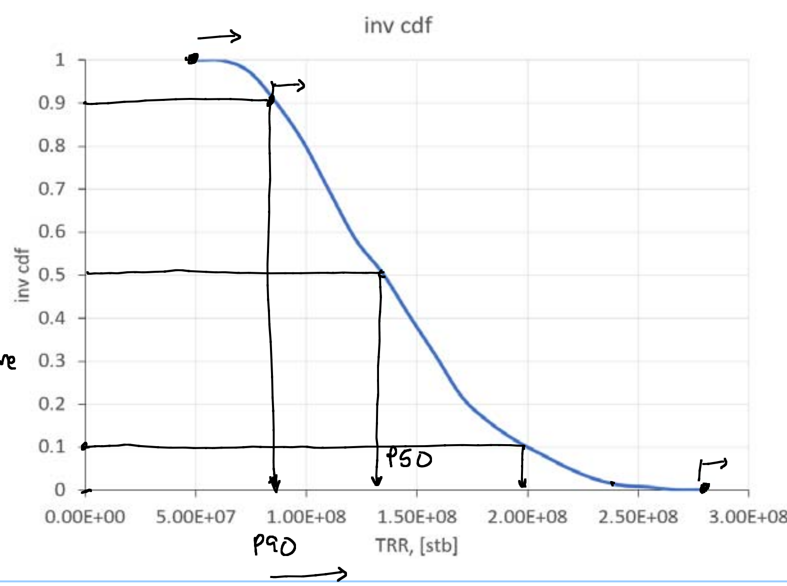
Npu		min	5.01E+07			
[stb]		max	2.79E+08			
1.04E+08		nr bins	2.00E+01			
1.36E+08		delta	1.20E+07			
92071991				frequency		
98955495			bins	counts	pdf	inv cdf
1.56E+08			[stb]			
1.29E+08			5.01E+07	1	0.001001	1
1.35E+08			6.22E+07	26	0.026026	0.998999
1.41E+08			7.42E+07	71	0.071071	0.972973
1.09E+08			8.62E+07	89	0.089089	0.901902
78525811			9.83E+07	116	0.116116	0.812813
1.86E+08			1.10E+08	114	0.114114	0.696697
88164376			1.22E+08	77	0.077077	0.582583
2.09E+08			1.34E+08	98	0.098098	0.505506
72468418			1.46E+08	94	0.094094	0.407407
70193843			1.58E+08	97	0.097097	0.313313
73626560			1.71E+08	57	0.057057	0.216216
62974381			1.83E+08	43	0.043043	0.159159
1.48E+08			1.95E+08	33	0.033033	0.116116
1.41E+08			2.07E+08	32	0.032032	0.083083
1.44E+08			2.19E+08	25	0.025025	0.051051
78948521			2.31E+08	14	0.014014	0.026026
1.42E+08			2.43E+08	4	0.004004	0.012012
1.48E+08			2.55E+08	6	0.006006	0.008008



resembles a log normal distribution



expectation curve of TRR



P90 → 90% probability that the field has reserves equal or greater than P90

aka
- proven reserves
- Downside estimates

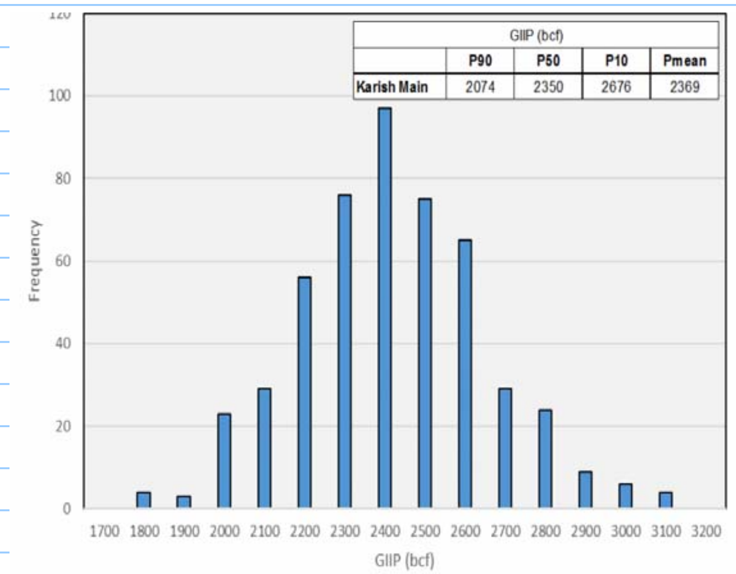
P50 → 50% probability that the field has reserves are equal or greater than P50
- proven + probable reserves
- Best estimate

P10 there is 10% probability that reserves are equal or greater than P10
- proven + probable + possible
- Upside / optimistic.

each company/country uses different %

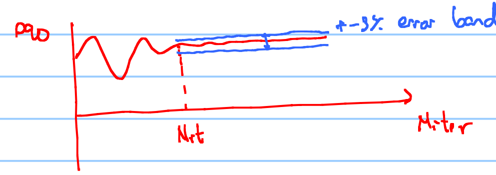
Table 5.2-1: Hebron Ben Nevis (Pool 1) In-Place Volumes Range

Hebron Ben Nevis Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm^3	MBO	Mm^3	MBO	Mm^3
D-94 Fault Block	1601	255	1328	211	1077	171
I-13 Fault Block	252	40	187	30	141	22
Total Hebron Ben Nevis	1870	297	1515	241	1204	191



how many iterations : • convergence study

Nit	P90	P50	P10	mean	mode



• Having results of at least one simulation with "N" samples

$$n_{it} = \left(\frac{F \; S_x}{error} \right)^2$$

depends on confidence level 2-3

standard deviation of sample

error = average · 0.03 ~ desired error (in this case 3%)

of sample

	confidence	
	98%	92%
F	3	1.8

more details : Page 113 of compendium.

if $N > n_{it}$ then N is appropriate

if $N < n_{it}$ then N must be increased

Now, with Python

cocalc.com.

File Edit View Insert Cell Kernel Help

tab Code Snippets Halt Validate

In [2]:
```python
#importing needed libraries
import matplotlib.pyplot as plt  #library for plotting
import numpy as np  #for math operations
import pandas as pd #for creating tables
```

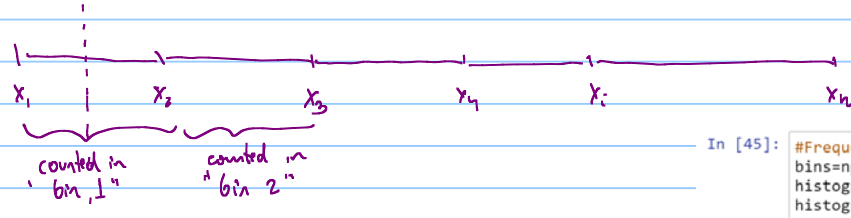
In [3]:
```python
#declare functions
def Npu(por,RV,NTG,So,Bo,Fr):
    #por porosity in fraction
    #RV rock volume in stb or Sm3
    #NTG net to gross, in fraction
    #So oil saturation, in fraction
    #Bo oil formation volume factor, bbl/stb or m3/Sm3
    #Fr recovery factor, in fraction
    TRR=por*RV*NTG*So*Fr/Bo
    return TRR
```

In [4]:
```python
#input data
por_min=0.18
por_max=0.3
RV_min=5e3   # in million bbl
RV_max=6.25e3
NTG_min=0.3
NTG_max=0.5
So_min=0.8
So_max=0.9
Bo_min=1.35
Bo_max=1.6
Fr_min=0.18
Fr_max=0.35
Fr_mode=0.25
```

In [9]:
```python
#MC simulation
#random sampling
n=1000
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)
#MC simulation, compute Npu for all samples
TRR=Npu(por,RV,NTG,So,Bo,Fr)
```

In [ ]:
```python
#Frequency analysis
```

a comment in python about bins




```
In [45]: #Frequency analysis of results
bins=np.linspace(TRR.min(),TRR.max(),20)
histogram,bins=np.histogram(TRR,bins=bins)
histogram=histogram/n
bin_centers=0.5*(bins[1:]+bins[:-1])
cdf=np.cumsum(histogram)
```

```
In [46]: #plotting pdf
plt.xlabel('Npu, [MMstb]')
plt.ylabel('frequency')
plt.plot(bin_centers,histogram)
plt.show()
```

. for plotting

$x_{1.5}$ $x_{2.5}$ $x_{3.5}$

```
bin_centers=0.5*(bins[1:]+bins[:-1])
```

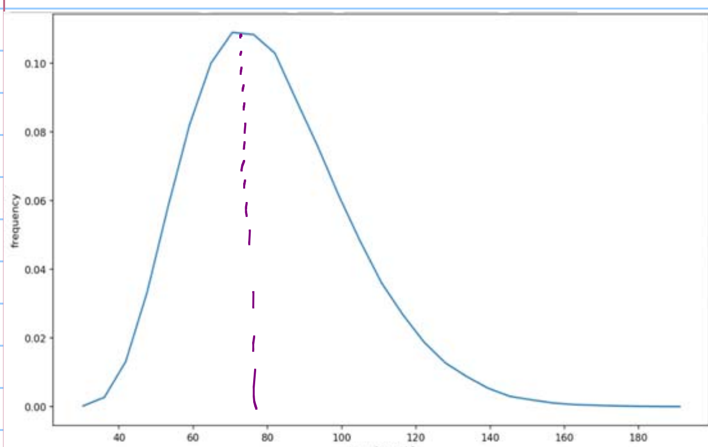
index: 0 1 2 3

bins $[a_1 \quad a_2 \quad a_3 \quad a_4]$

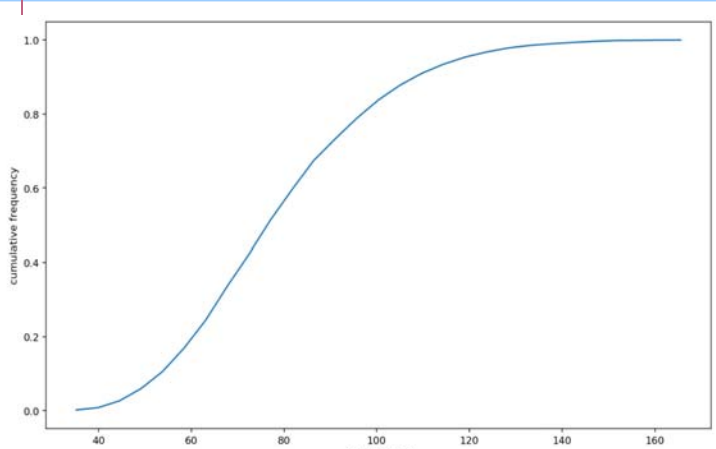
bins[1:] $\therefore [a_2 \quad a_3 \quad a_4]$

bins[:-1] $\therefore [a_1 \quad a_2 \quad a_3]$

bin centers: $\frac{a_1+a_2}{2}$ $\frac{a_3+a_3}{2}$ $\frac{a_4+a_3}{2}$



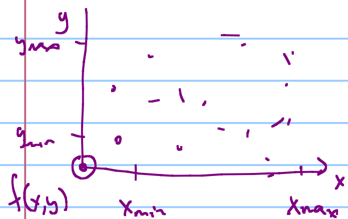
pdf

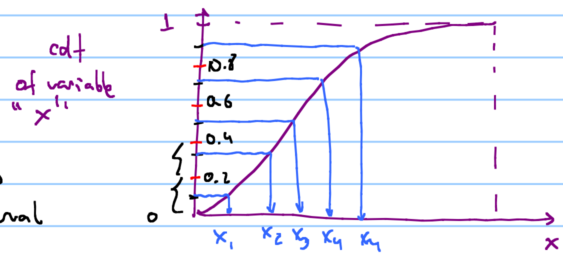



```
In [47]: #plotting cdf
plt.xlabel('Npu, [MMstb]')
plt.ylabel('cumulative frequency')
plt.plot(bin_centers,cdf)
plt.show()
```

Other methods to quantify uncertainty:

Latin Hypercube Sampling (LHS) like Monte Carlo but instead of random sampling, a more intelligent sampling is made





1: divide cdf in "n" intervals

2: sample randomly from each interval

0 → 0.2
0.2 → 0.4
0.4 → 0.6
0.6 → 0.8
0.8 → 1

3: find corresponding "x"s

x_1
x_2
x_3
x_4
x_5

4. Shuffle (random)

x_3
x_2
x_5
x_1
x_4

5: Repeat steps 1 – 4 for each variable

		LHS simulations
x_3	Y_1	$f(x_3, Y_1)$
x_2	Y_5	$f(x_2, Y_5)$
x_5	Y_4	$f(x_5, Y_4)$
x_1	Y_3	$f(x_1, Y_3)$
x_4	Y_2	$f(x_4, Y_2)$

6: do frequency analysis on results

interval_start : $\begin{Bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{Bmatrix}$

— x_5 end
— x_4
— x_3
— x_2
— x_1 start

interval_end $\begin{Bmatrix} x_2 \\ x_3 \\ x_4 \\ x_5 \end{Bmatrix}$

function vectorization

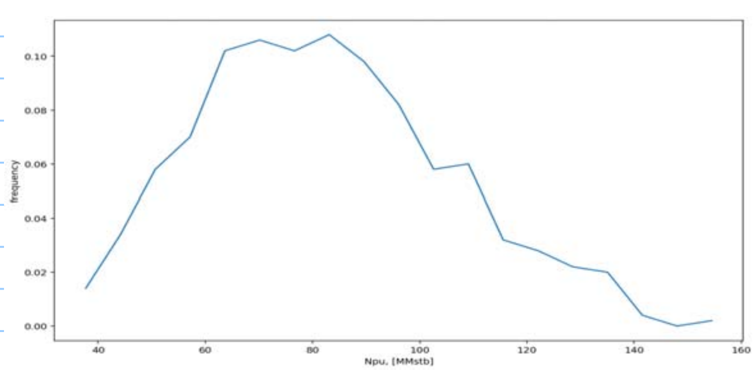
np.random.uniform $\left(\begin{Bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{Bmatrix}, \begin{Bmatrix} x_2 \\ x_3 \\ x_4 \\ x_4 \end{Bmatrix} \right) \longleftrightarrow$ np.random.uniform $(x_1, x_2) \longrightarrow x^*$

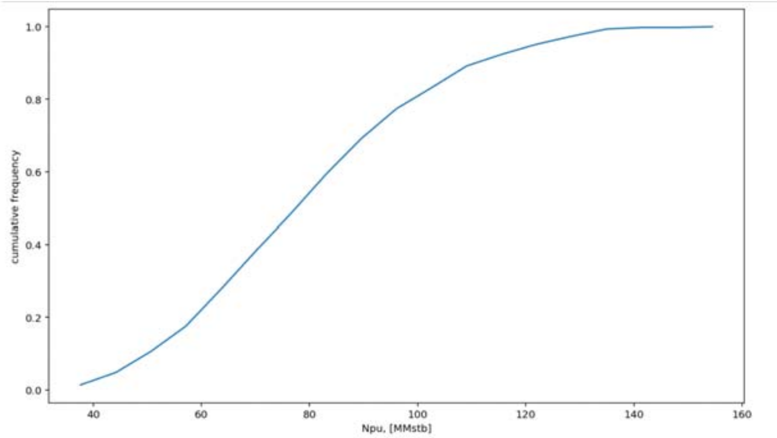
np.random.uniform $(x_2, x_3) \longrightarrow$

In [5]:
```python
#declare functions
def Npu(por,RV,NTG,So,Bo,Fr):
    #por porosity in fraction
    #RV rock volume in stb or Sm3
    #NTG net to gross, in fraction
    #So oil saturation, in fraction
    #Bo oil formation volume factor, bbl/stb or m3/Sm3
    #Fr recovery factor, in fraction
    TRR=por*RV*NTG*So*Fr/Bo
    return TRR
def LHS_samples_uniform(min_val,max_val,n):
    #returns a list of random values from a uniform distribution using LHS
    #n: number of samples to generate
    #min_val minimum value of the variable
    #max_val maximum value of the variable
    len_int=1/n  #delta in cdf
    interval_start=np.linspace(0,1-len_int,n)
    interval_end=np.linspace(len_int,1,n)
    cdf_samples=np.random.uniform(interval_start,interval_end)
    samples=scpstat.uniform.ppf(cdf_samples,loc=min_val,scale=(max_val-min_val))
    np.random.shuffle(samples)
    return samples
```

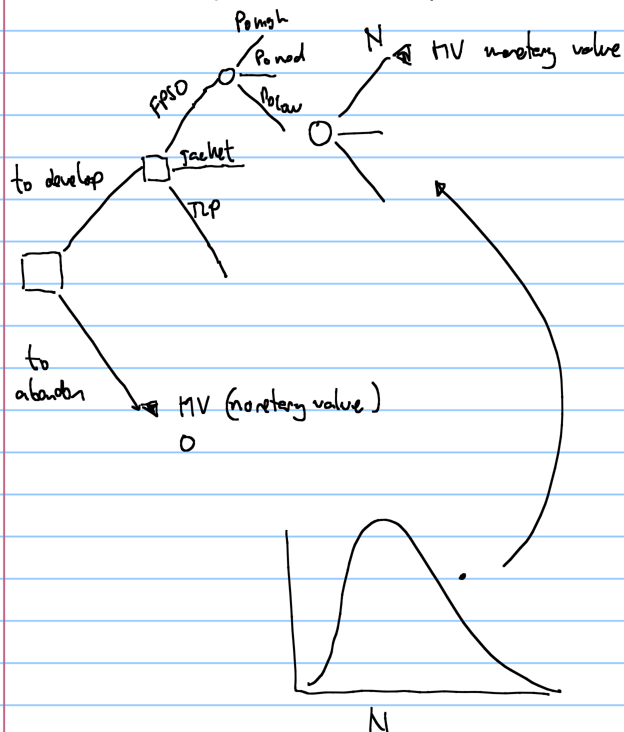
In [6]:
```python
#input data
por_min=0.18
por_max=0.3
RV_min=5e3   # in million bbl
RV_max=6.25e3
NTG_min=0.3
NTG_max=0.5
So_min=0.8
So_max=0.9
Bo_min=1.35
Bo_max=1.6
Fr_min=0.18
Fr_max=0.35
```

In [12]:
```python
#LHS simulation
n=500
por=LHS_samples_uniform(por_min,por_max,n)
RV=LHS_samples_uniform(RV_min,RV_max,n)
NTG=LHS_samples_uniform(NTG_min,NTG_max,n)
So=LHS_samples_uniform(So_min,So_max,n)
Bo=LHS_samples_uniform(Bo_min,Bo_max,n)
Fr=LHS_samples_uniform(Fr_min,Fr_max,n)
#LHS simulation, compute Npu for all samples
TRR=Npu(por,RV,NTG,So,Bo,Fr)
```





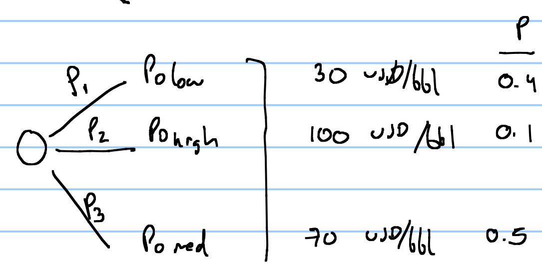
• to reduce even further computational time, and to include integer / discrete variables it is possible to use probability trees



□ decision node

○ chance node

◄ end node

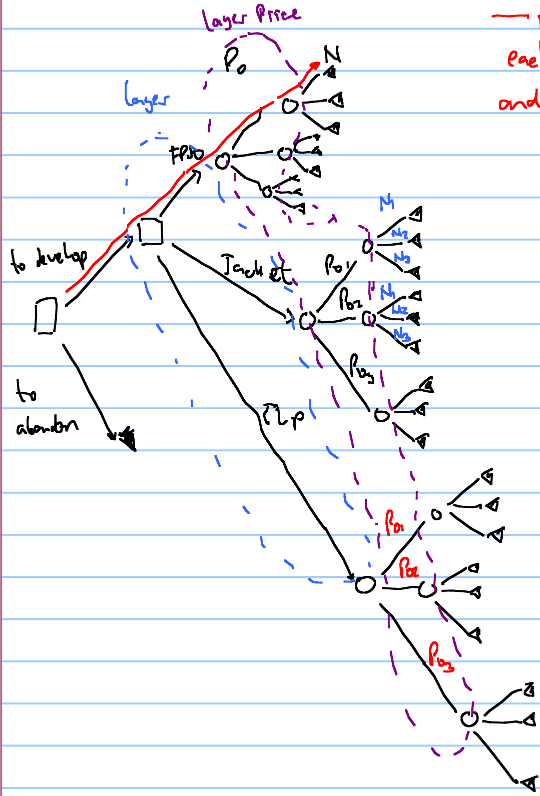


Case nr.	topside type	P_o	N	MV	Probability
1	FPSO	HIGH	SMALL	( )	$P_{Po\,high} \cdot P_{N\,small}$
2	FPSO	HIGH	MED	( )	
3	FPSO	HIGH	HIGH		
4	FPSO	MED	SMALL		
5	FPSO	MED	MED		
6	FPSO	MED	HIGH		
7	FPSO	LOW	SMALL		
8	FPSO	LOW	MED		
9	FPSO	LOW	HIGH		

and similar for Jacket and TLP (tension leg platform)

$$9 : \underset{\text{cases}}{\overset{\text{oil price}}{3}} \times \underset{\text{cases}}{\overset{N}{3}}$$

(Cont.) Probability / decision trees



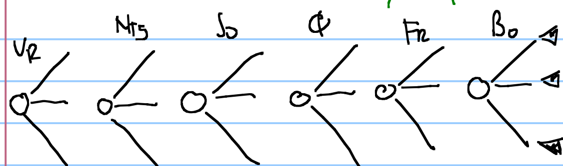
— path
each path has an economic value and a probability

$$P_{path} = P_{P_o} \cdot P_N$$

Lets solve the previous problem ($TRR = \frac{VR \cdot N_{tg} \cdot S_o (\phi) F_r}{B_o}$ using probability trees:

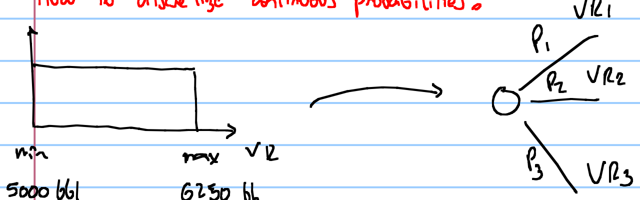
prob tree (compact view)

Not uniform



$3 \times 3 \times 3 \times 3 \times 3 \times 3 = 3^6 = 729$ paths

How to discretize continuous probabilities? (to use in decision trees)



?

there are many methods:

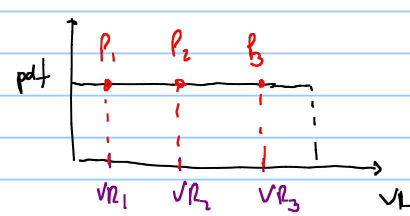
1) Value discretization

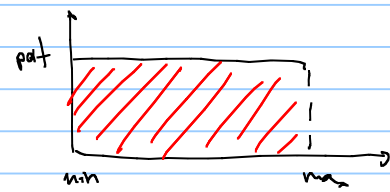
a) define "arbitrarily" "n" values of variable (e.g. uniformly spaced)

b) read from pdf its associated probability

$P_1, P_2, P_3 = 8E-4$

c) normalize probability





$$P_o(\max - \min) = 1$$

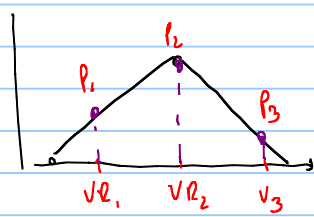
$$P = \frac{1}{(6250 - 5000)} = 8E{-4}$$

c) $P_1 = \frac{P_{old}}{\sum P_i} = \frac{8E{-4}}{3.8E{-4}} = 0.333$ ✓

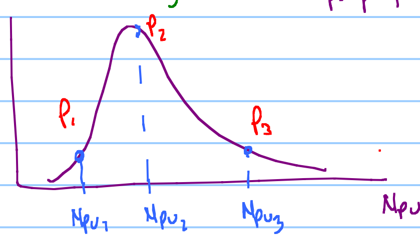
$P_2 = 0.333$ ✓

$P_3 = 0.333$ ✓

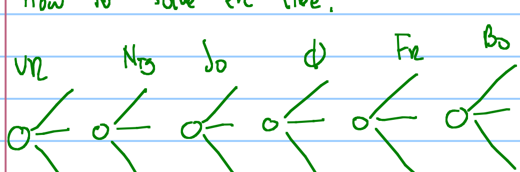
what if the distribution was not uniform pdf



we can also apply this method to discretize our "Npu" pdf



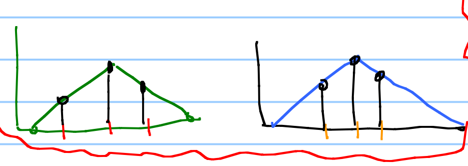
How to solve the tree?



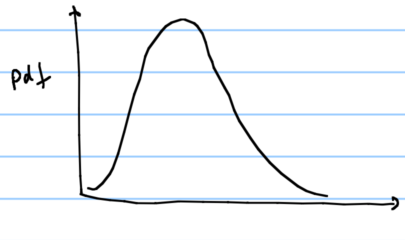
1) in excel

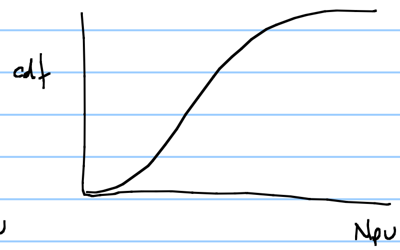
Case	VR	NTG	So	Φ	FR	Bo	Npu	P
1	VR_1	N_{TG1}	So_1	$Φ_1$	FR_1	Bo_1	A	B
2	VR_1	N_{TG1}	So_1	$Φ_1$	FR_1	Bo_2		
3	VR_1	N_{TG1}	So_1	$Φ_1$	FR_1	Bo_3		
4	VR_1	N_{TG1}	So_1	$Φ_1$	FR_2	Bo_1		
5	VR_1	N_{TG1}	So_1	$Φ_1$	FR_2	Bo_2		
6	VR_1	N_{TG1}	So_1	$Φ_1$	FR_2	Bo_3		

if all input probabilities are uniform, then the probability of each case (path) is the same, but, if not, they could be different



with MC (or LHS) we obtain a distribution





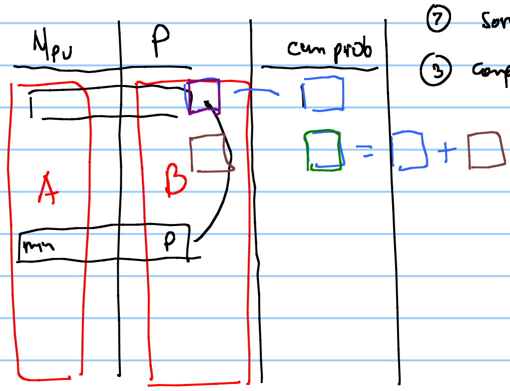
BUT with decision trees ?

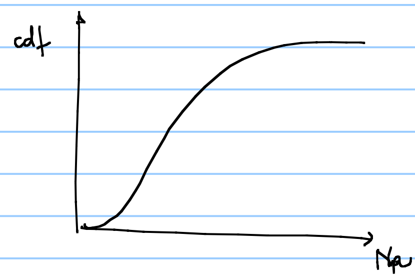
if there are many paths on the tree, we can also compute a distribution:

① take column A and B from above

② Sort values using column "A", e.g. from min to max

③ compute cummulative probability



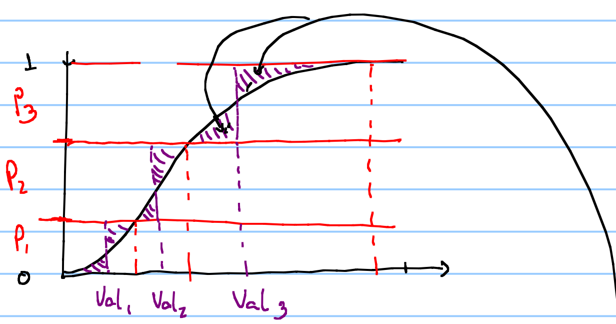


if not enough cases i just report all discrete cases with their associated probability

NPV	P

there are other methods to discretize continuous distributions

1) • on the cdf
• define desired probabilities (e.g. P_1, P_2, P_3)

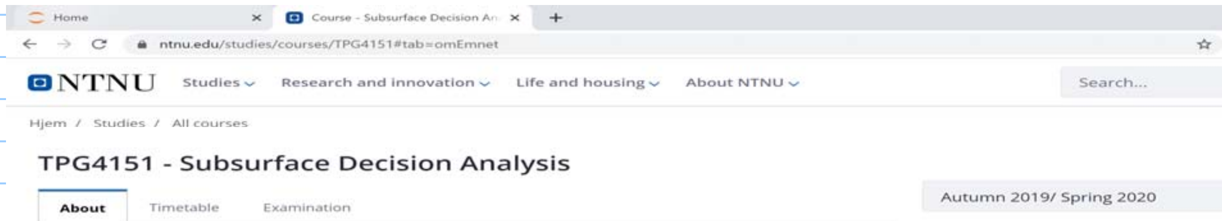


2) change the location of Val_1, Val_2, Val_3 until areas are the same

the discrete distribution (can be done graphically, with the eye or analytically)

Val_1	P_1
Val_2	P_2
Val_3	P_3

for more information about uncertainty quantification, MC simulation, decision trees, take the course:



Several discretization methods are available.

- 3-Point Shortcuts
  - Extended Pearson-Tukey
  - McNamee-Celona
  - Extended Swanson-Megill
- Moment Matching
- CDF Discretization
  - Bracket Mean
  - Bracket Median
- Value Discretization (High Resolution Probability Tree)

2019 HØST IØ8810 Vinterskole - Planlegging under usikkerhet 24

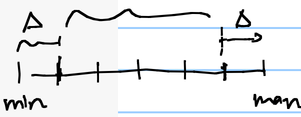
Prof Reidar Bratvold
Aojie Hong

Example, solving the TRR problem with probability tree in python:

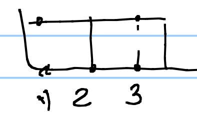
In [8]:
```python
#importing needed libraries
import matplotlib.pyplot as plt
import numpy as np
import scipy.stats as scpstat
```

In [9]:
```python
 #declaring necessary functions
def Npu(a):
    #returns N in [stb or Sm3]
    #input:
    #por, porosity, [-]
    #RV, rock volume, [m3 or bbl]
    #NTG, net to gross, [-]
    #So, oil saturation, [-]
    #Bo, oil formation volume factor [m3/Sm3]
    por=a[0]
    RV=a[1]
    NTG=a[2]
    So=a[3]
    Bo=a[4]
    Fr=a[5]
    TRR=por*RV*NTG*So*Fr/Bo
    return TRR
```

```
def total_prob(a):
    #calculates the probability of a particular combination of branches
    prob_1=a[0]
    prob_2=a[1]
    prob_3=a[2]
    prob_4=a[3]
    prob_5=a[4]
    prob_6=a[5]
    b=prob_1*prob_2*prob_3*prob_4*prob_5*prob_6
    return b
def branches(min_val,max_val,nr):
    delta=(max_val-min_val)*0.5/nr
    a=np.linspace(min_val+delta,max_val-delta,3)
    return a
def discrete_prob_uniform(min_val,max_val,val):
    #discretizes a uniform probability function using the value discretization method
    a=scpstat.uniform.pdf(val,loc=min_val,scale=(max_val-min_val))
    a=a/np.sum(a)
    return a
```



$\Delta = \frac{max - min}{n} \cdot 0.5$



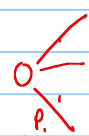
normalization

gets pdf

```
#input data
#porosity
por_min=0.18
por_max=0.3
```

```
#input data
#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_min=0.18
Fr_max=0.35
```

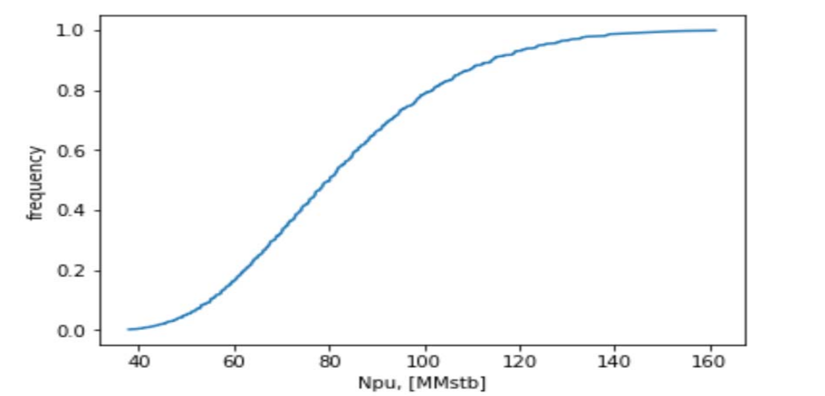
```
#nr. branches per variable
nb=3
#calculating branches
por=branches(por_min,por_max,nb)
RV=branches(RV_min,RV_max,nb)
NTG=branches(NTG_min,NTG_max,nb)
So=branches(So_min,So_max,nb)
Bo=branches(Bo_min,Bo_max,nb)
Fr=branches(Fr_min,Fr_max,nb)
#calculating probabilities of each branch (using value discretization)
prob_por=discrete_prob_uniform(por_min,por_max,por)
prob_RV=discrete_prob_uniform(RV_min,RV_max,RV)
prob_NTG=discrete_prob_uniform(NTG_min,NTG_max,NTG)
prob_So=discrete_prob_uniform(So_min,So_max,So)
prob_Bo=discrete_prob_uniform(Bo_min,Bo_max,Bo)
prob_Fr=discrete_prob_uniform(Fr_min,Fr_max,Fr)
```



```
nr_variables=6
#create an element-wise combination of all branches
combination_vector=np.array(np.meshgrid(por,RV,NTG,So,Bo,Fr)).T.reshape(-1,nr_variables)
combination_prob=np.array(np.meshgrid(prob_por,prob_RV,prob_NTG,prob_So,prob_Bo,prob_Fr)).T.reshape(-1,nr_variables)
N_comb=len(combination_vector)
results_val=[]   ← vector to gather results
results_prob=[]
for i in range(0,N_comb-1):
    results_val.append(Npu(combination_vector[i]))     → applying Npu function on each line
    results_prob.append(total_prob(combination_prob[i]))   → calculating prob of each path
results=np.vstack((results_val,results_prob))
results=results.T
results=np.sort(results,axis=0)   → sort from min to max
cdf=np.cumsum(results[:,1])       → calculate cummulative prob
```

$$\begin{bmatrix} (VR_1 & NTG_1 & So_1 & \Phi_1 & Fr_1 & Bo_1) \\ VR_1 & NTG & So_1 & \Phi_1 & Fr_1 & Bo_2 \\ \vdots & & & & & \end{bmatrix} \quad \begin{bmatrix} P_{VR_1} & P_{NTG_1} & P_{S_1} & P_{\Phi_1} & P_{Fr_1} & P_{Bo_1} \\ P_{VR_1} & P_{NTG_1} & P_{S_1} & P_{\Phi_1} & P_{Fr_1} & P_{Bo_2} \end{bmatrix}$$

```python
#plot cdf
plt.xlabel('Npu, [MMstb]')
plt.ylabel('frequency')
plt.plot(results[:,0],cdf,label="cdf")
plt.show()
```



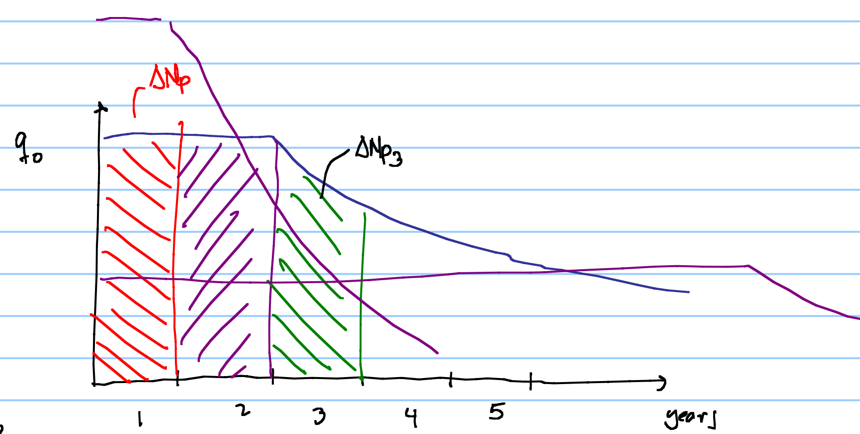
pending topics:
- offshore structures for oil and gas production
  - important part of CAPEX → affect NPV
  - technical constraints
- flow assurance: wax, hydrate, scale, emulsion, asphaltenes, corrosion, erosion, vibration, slugging
- Electric submersible pumps (ESPs)
- production optimization

(ESPs and production optimization: tentative)

Monday	Friday
	13.03 offshore struc
16.03 offshore struc	20.03 offshore flow assurance
23.03 flow ass.	27.03 flow assure LedaFlow (transient multiphase flow simulator)
30.03 LedaFlow (transient multiphase flow simulator) Production optimization	04.04 Exercise session
	17.04 prod. optimization
20.04 • Consultation • Course summary	

- Exercise 2 will be merged with exercise set 1 with delivery date after Easter (please keep working on it ☺ ≥) !
  there will be one exercise using LedaFlow.

Clarifications problem 6, exercise set 1



$$NPV_{revenue} = \sum_{i=1}^{N} \frac{\Delta Q_{pi} \cdot P_o}{(1+d_f)^i}$$

$$N_{pu} \cdot P_o \cdot F_D = NPV_{revenue} = \underbrace{\frac{\Delta N_{p1} \cdot P_o}{(1+d_f)^1} + \frac{\Delta N_{p2} \cdot P_o}{(1+d_f)^2} + \frac{\Delta N_{p3} \cdot P_o}{(1+d_f)^3} + \ldots}$$

$$N_{pu} = \sum_{i=1}^{N} \Delta N_{pi}$$

Use data from your Snohvit exercise to see the range of variation of Fd!!!

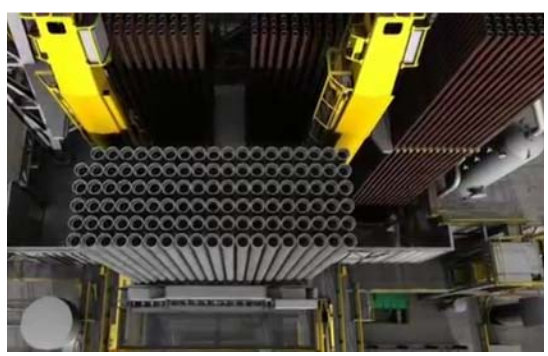
Offshore structures for oil and gas production

Prof. Milan Stanko (NTNU)

1

Components

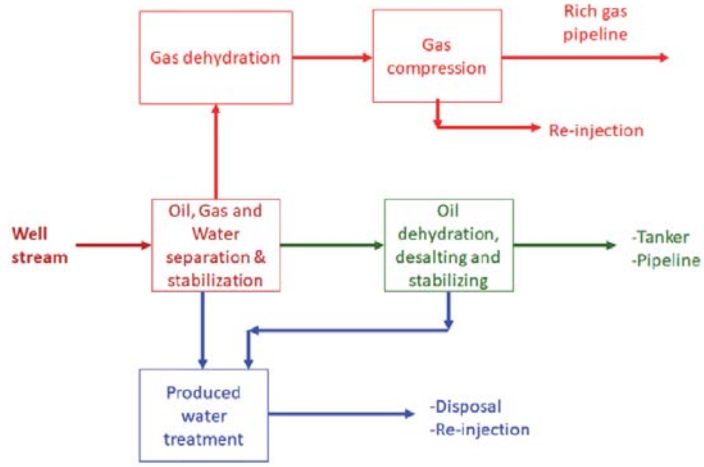
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers.



2

Components

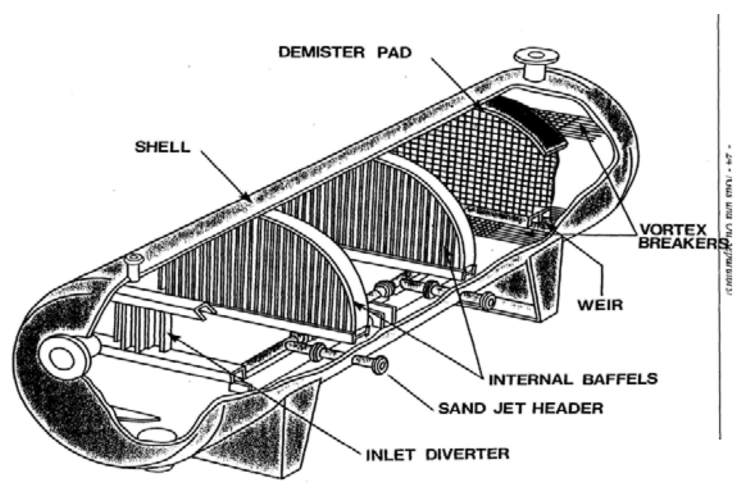
- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



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

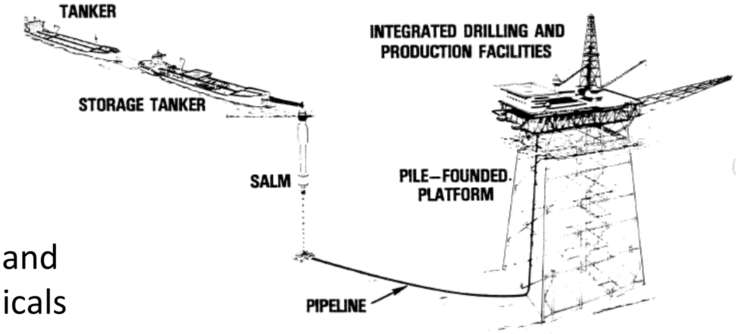
Components

- 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

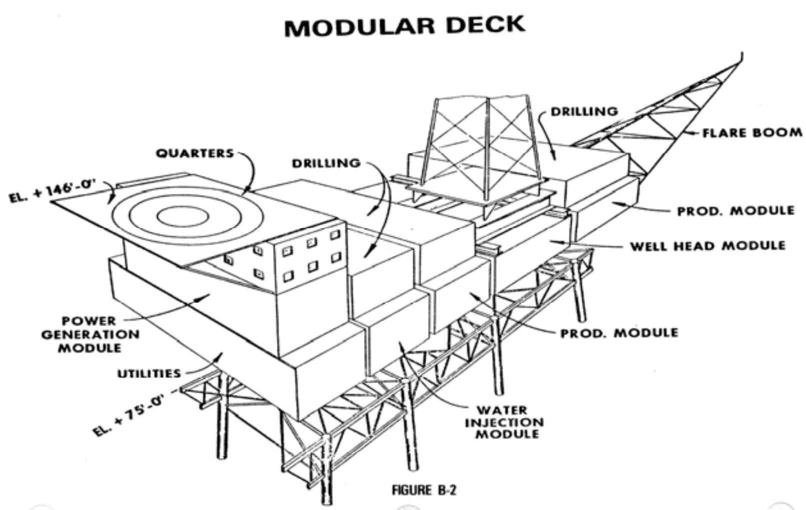


FIGURE B-2

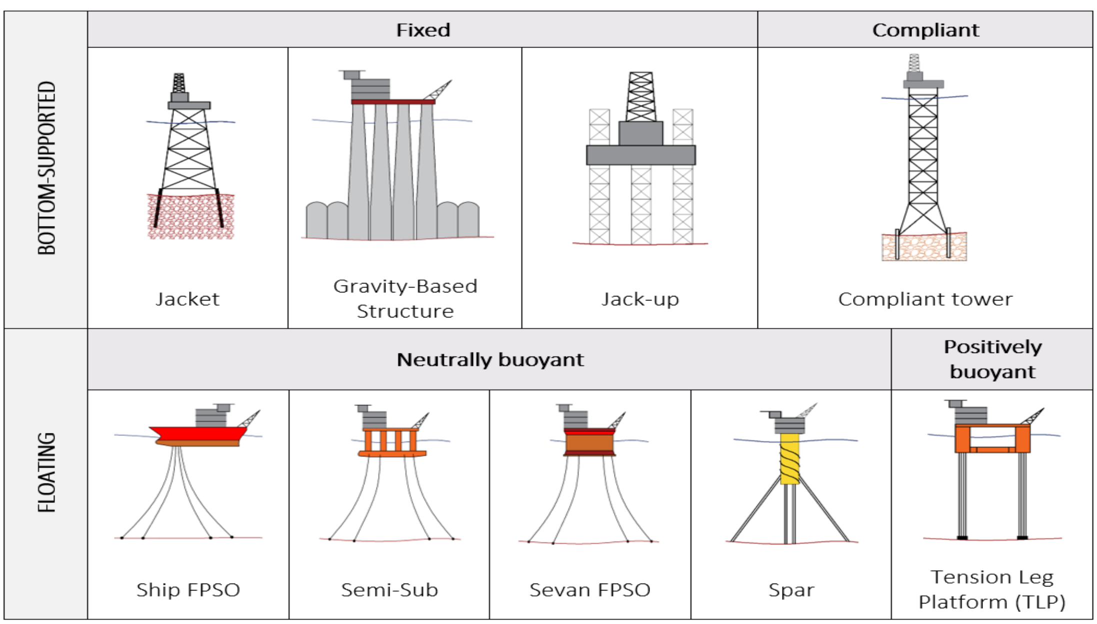
8

Components – can be spread

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

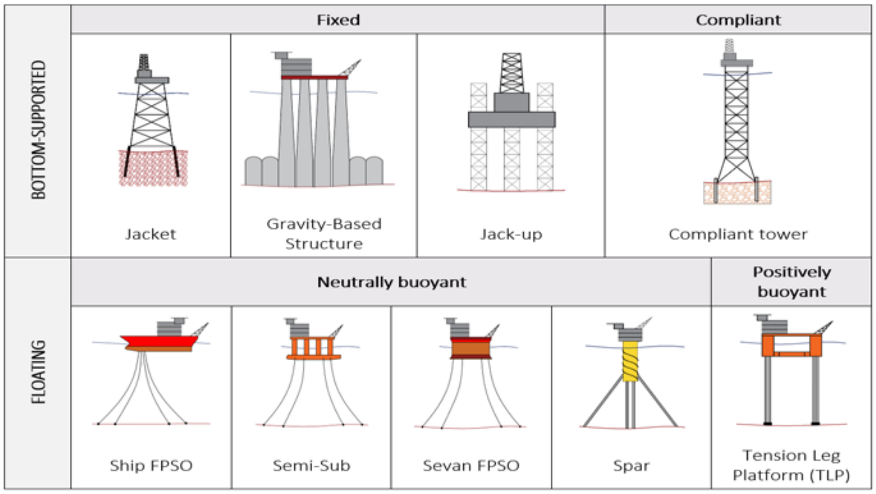
9

Types



10

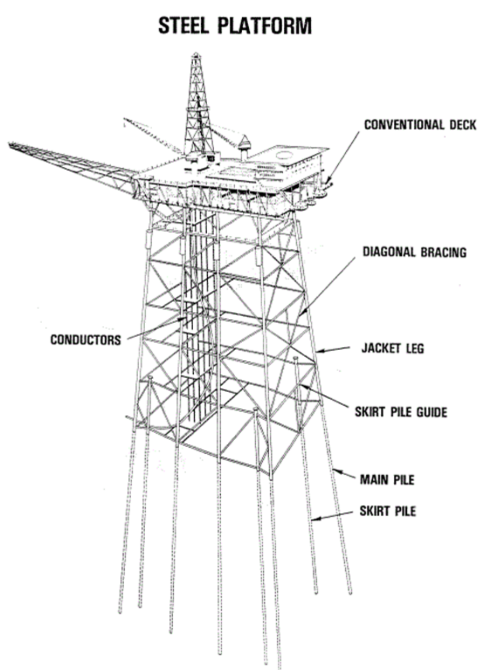
Types



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

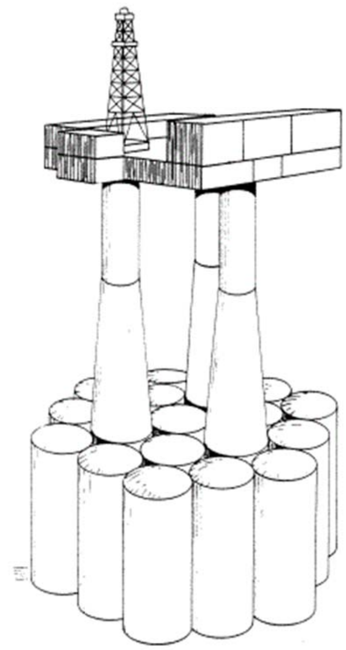
11

Jacket



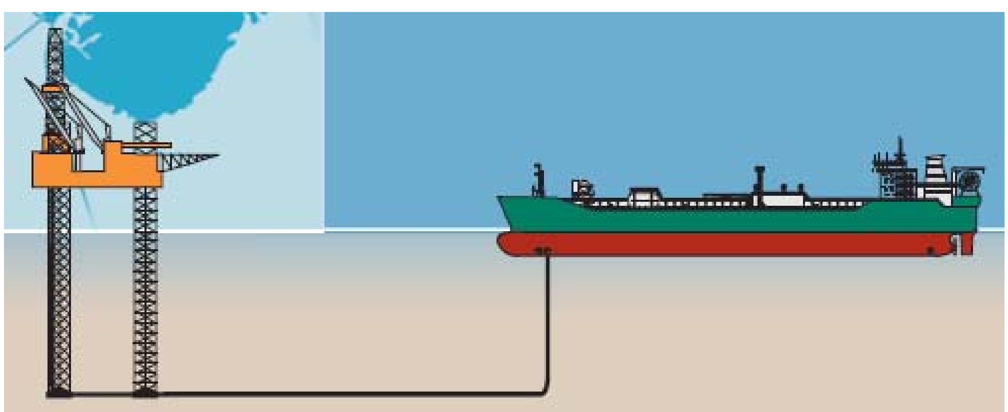
12

GBS



13

JACKUP



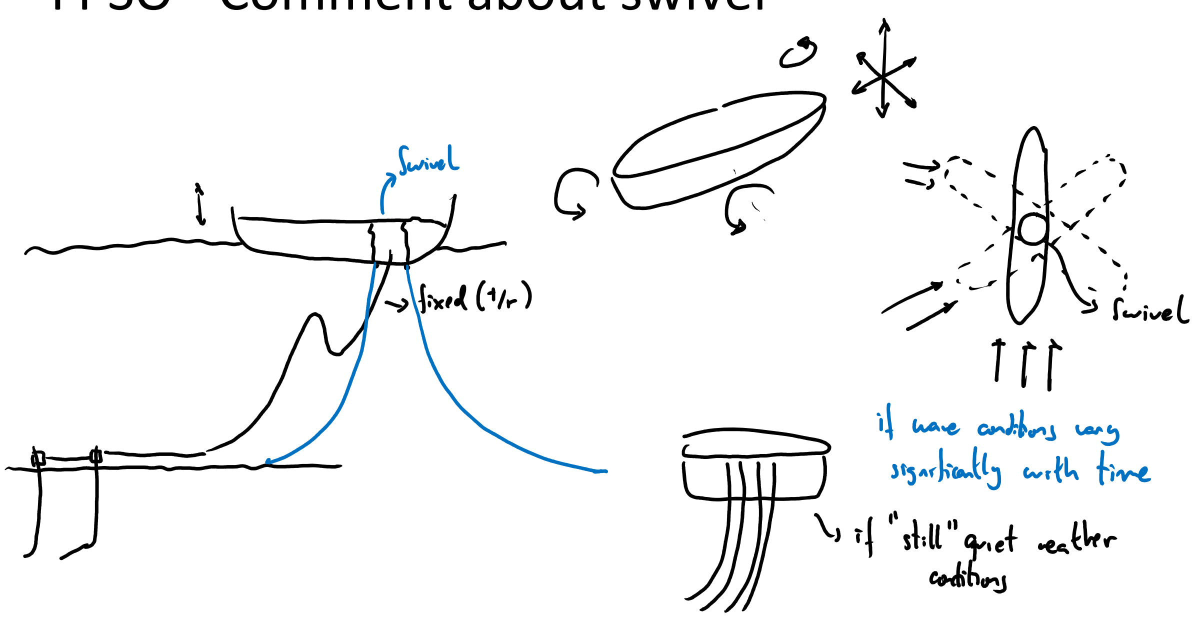
Taken from Volve PDO

14

FPSO

15

FPSO - Comment about swivel



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

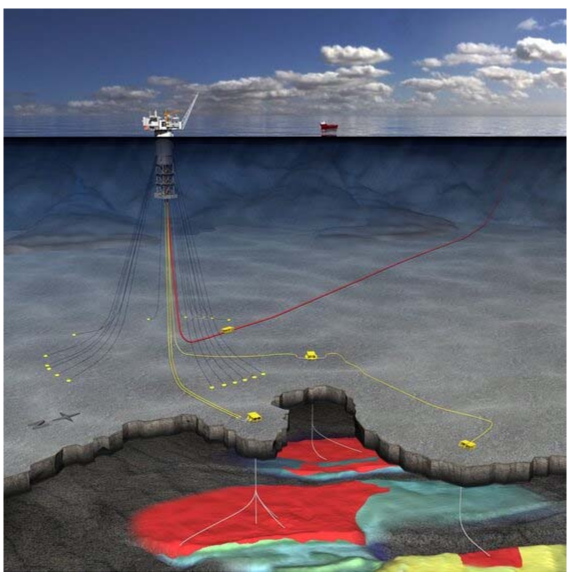
FPSO - Swivel

Swivel might be bottlenecked

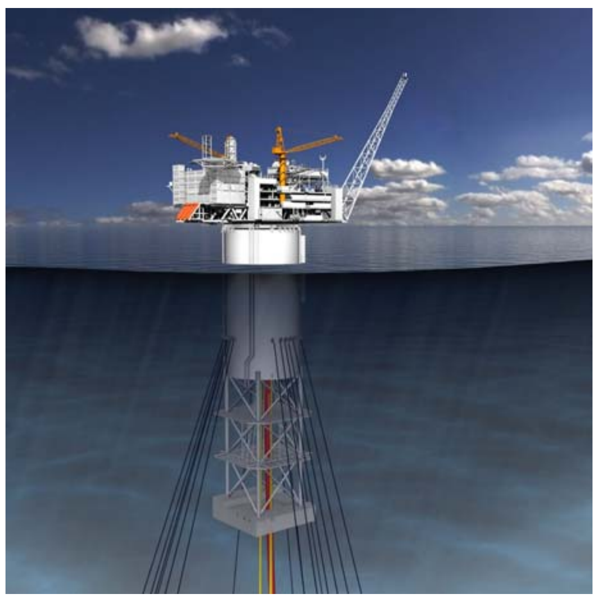
https://www.youtube.com/watch?v=HbJh1ar0u1s

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

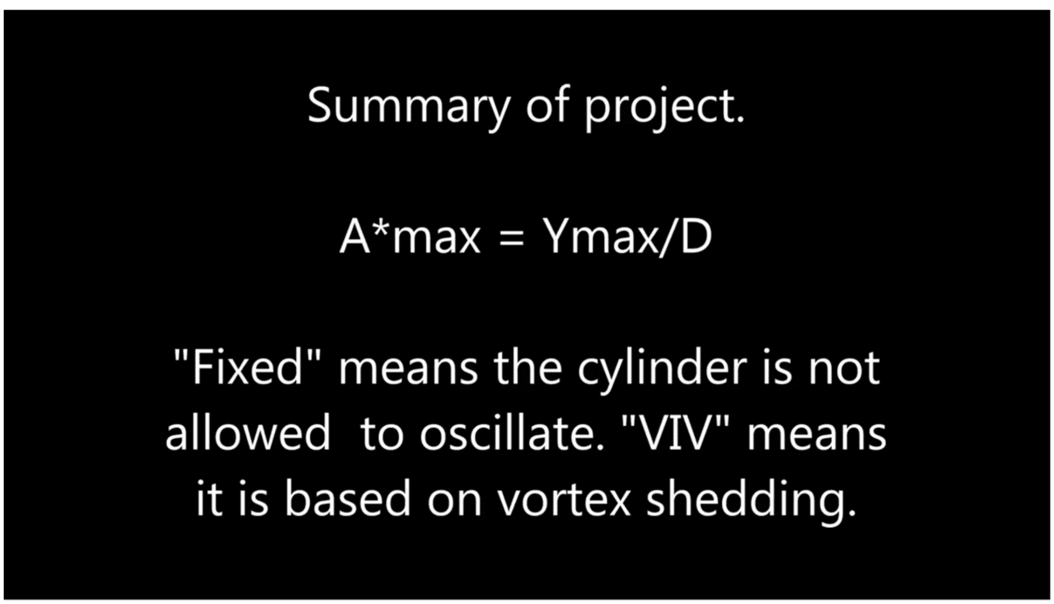
20

SPAR – Vortex induced vibrations

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

21

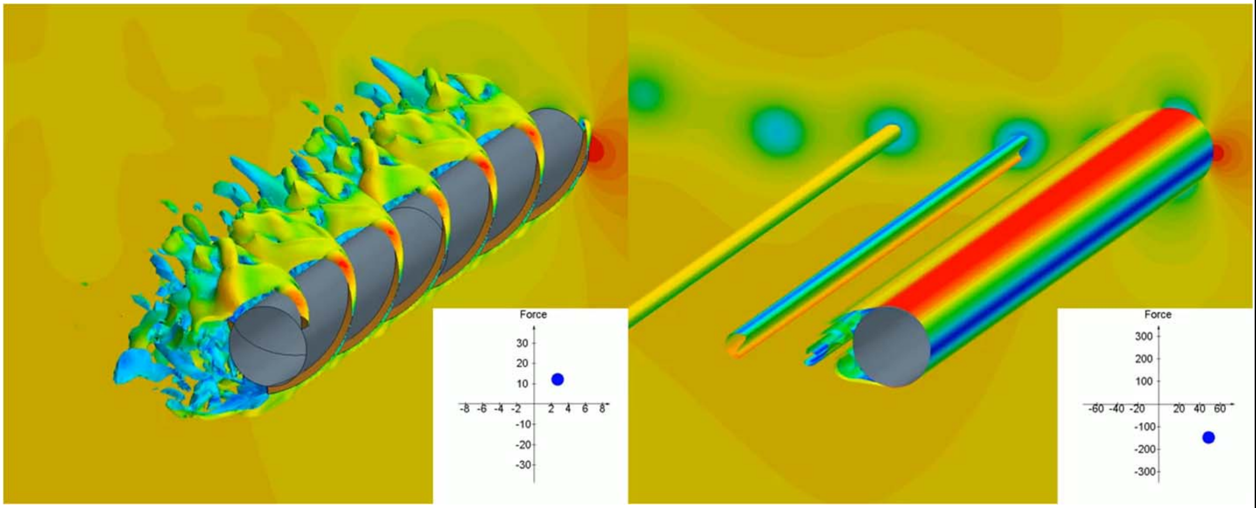
SPAR – Vortex induced vibrations



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

22

SPAR – Effect of helical strakes



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

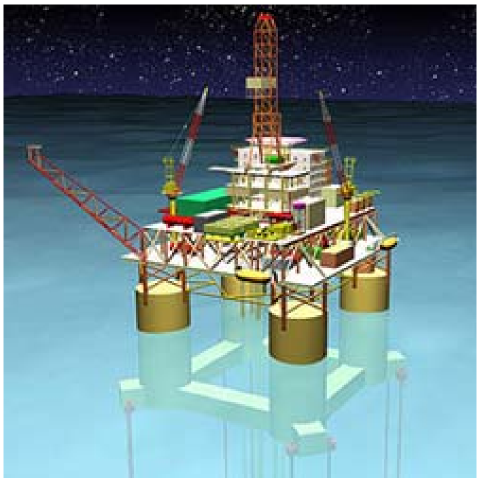
23

SEVAN FPSO

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

24

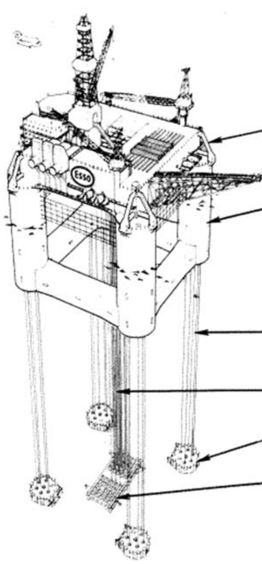
Tension leg platform



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

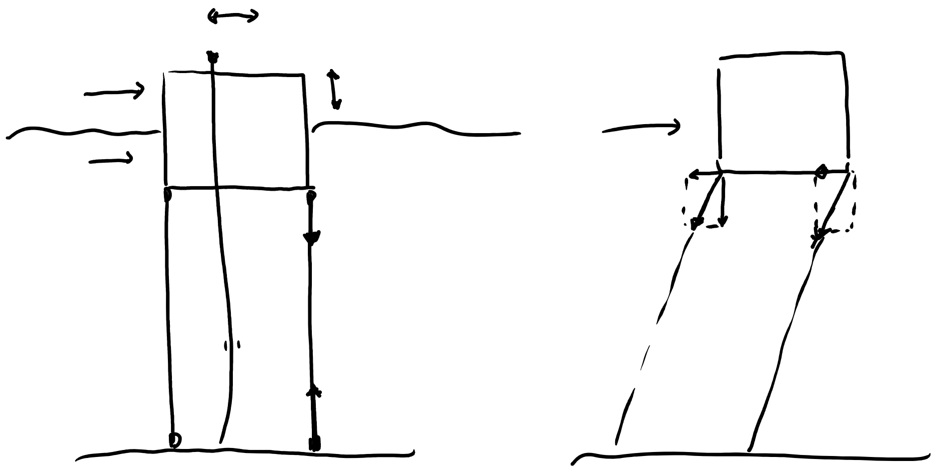
25

Tension leg platform



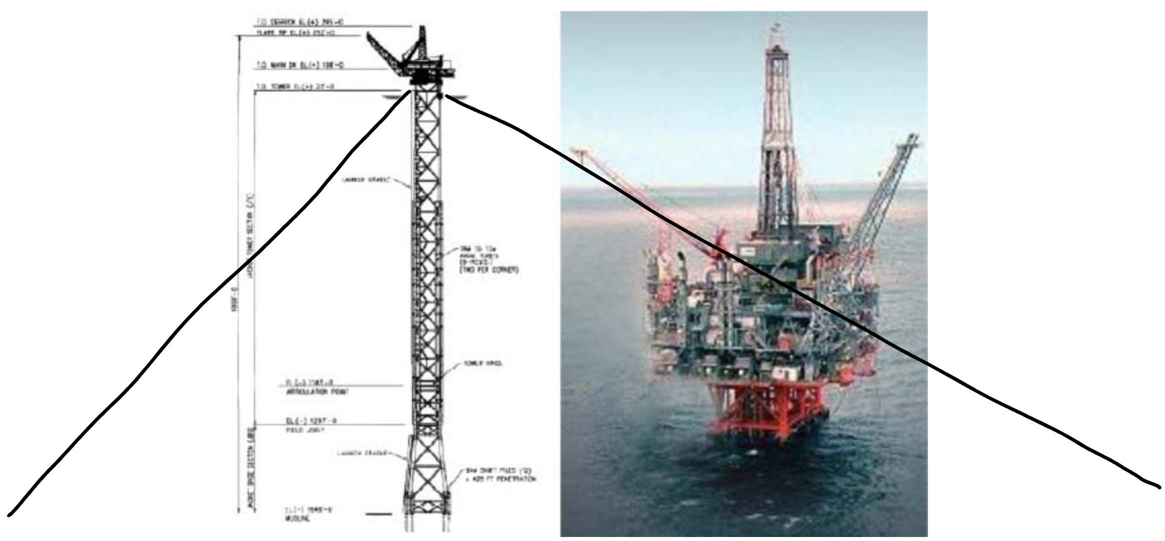
26

Comment about Tension leg platform



27

Compliant tower



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

28

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/

29

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

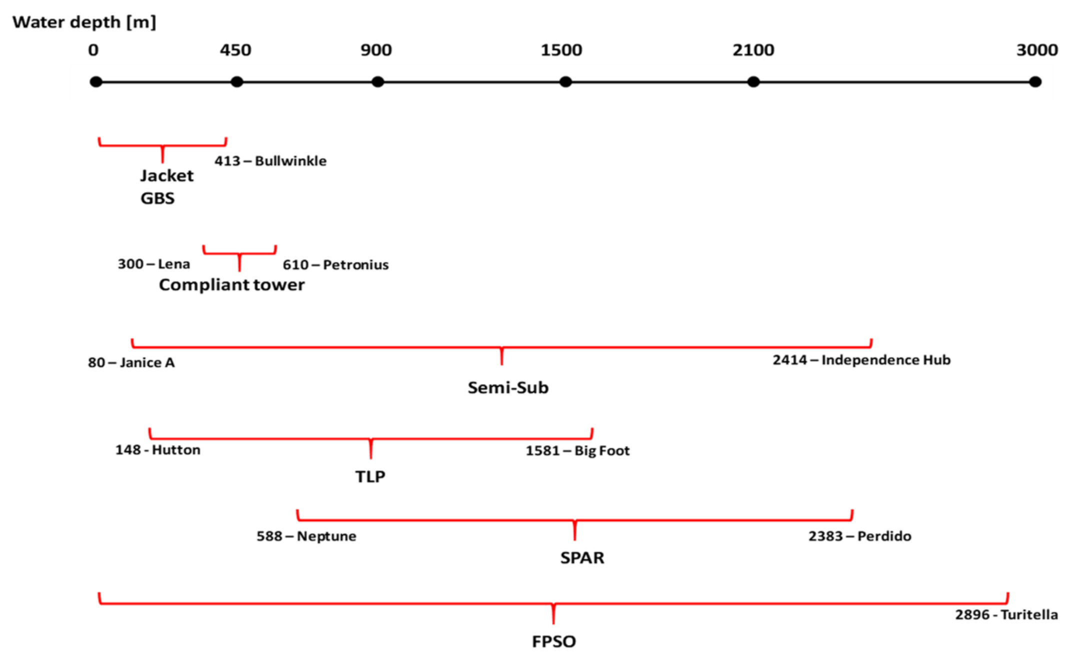
30

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

Water depth



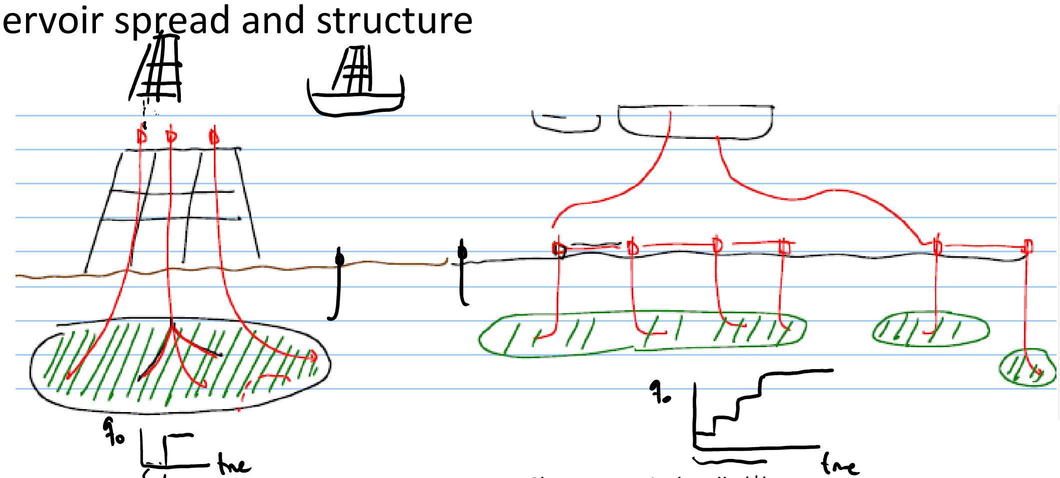
32

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

33

Reservoir spread and structure

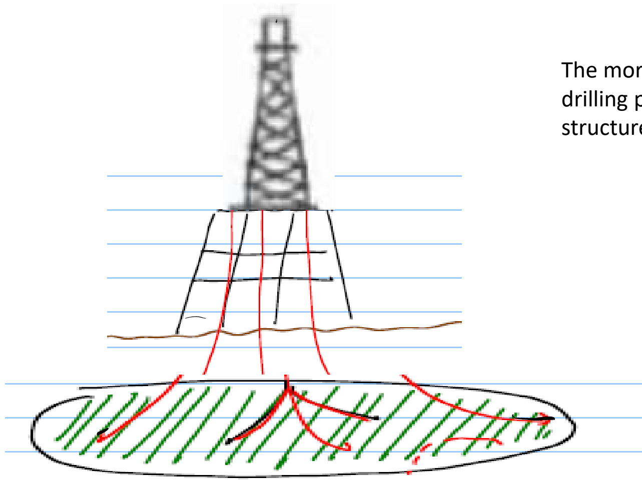


- Long deviated wells ($$$)
- Wells are drilled from one location, no need to spend mobilization time ($$)
- Production startup must be delayed until all wells are drilled

- 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)

34

Reservoir spread and structure

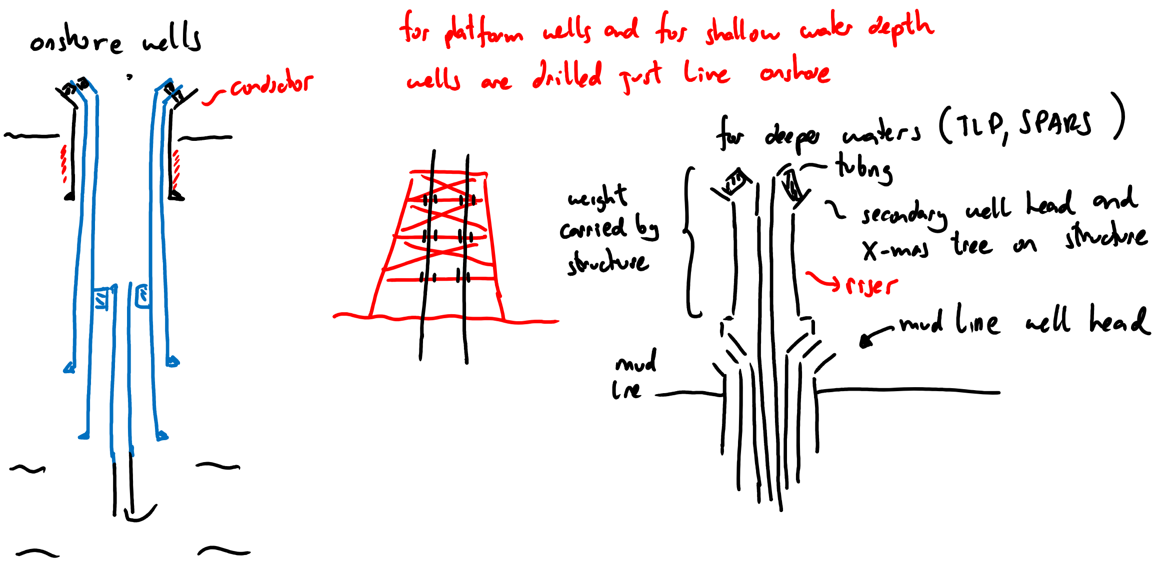


The more spread - requires a bigger and more costly drilling package – more weight on the structure, bigger structure ($$$)

35

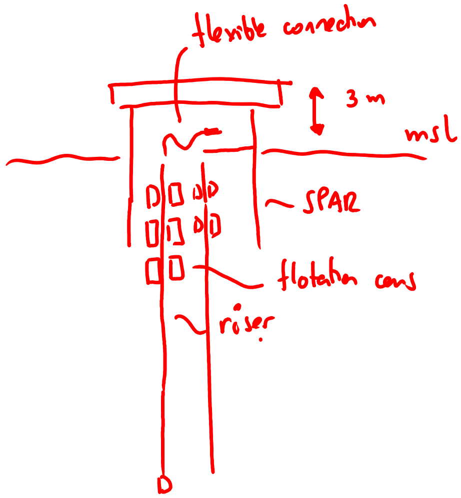
Transfer of well weight to soil and to offshore structure

for platform wells and for shallow water depth wells are drilled just like onshore



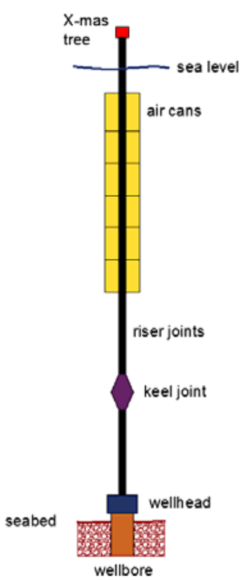
36

Transfer of well weight to soil and to offshore structure



37

Support system for dry X-mas trees – deep water



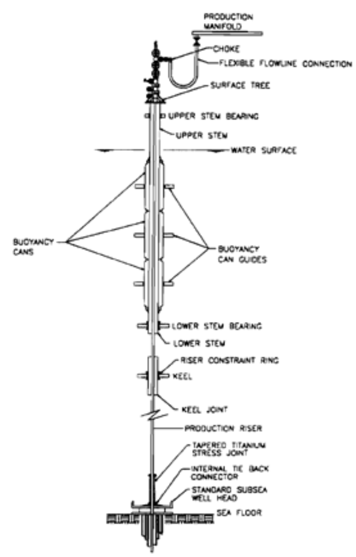


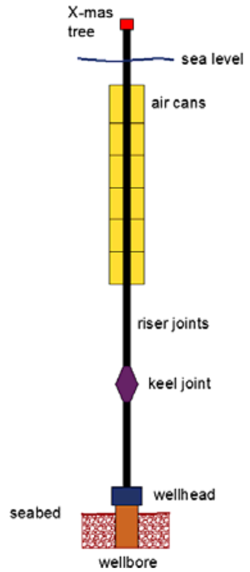
Figure 6 - Well System

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.

38

Support system for dry X-mas trees – deep water



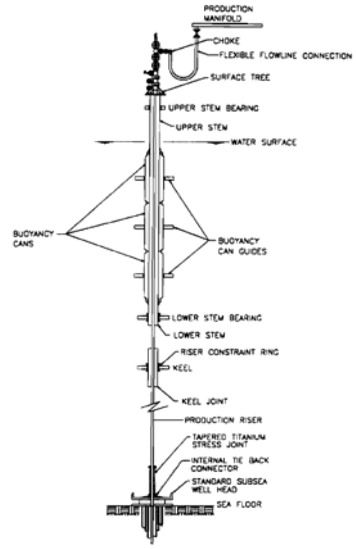


Figure 6 - Well System

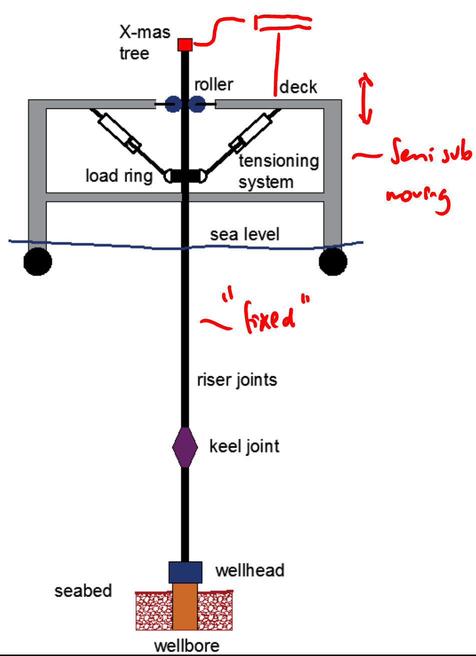
OTC 8382

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

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

39

Support system for dry X-mas trees – deep water



40

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

41

Possibility for jackets without drilling package

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

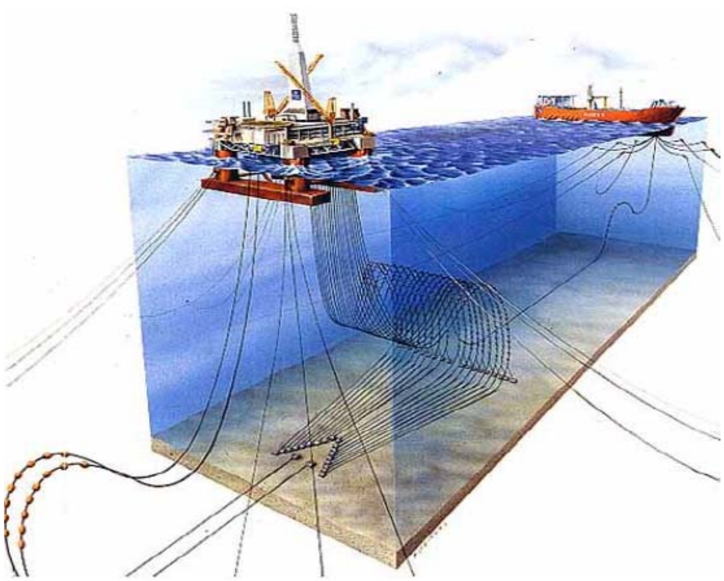
42

Possibility for jackets without drilling package

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

43

Njord: subsea wells with well intervention possibility



44

Layout of subsea systems – template wells

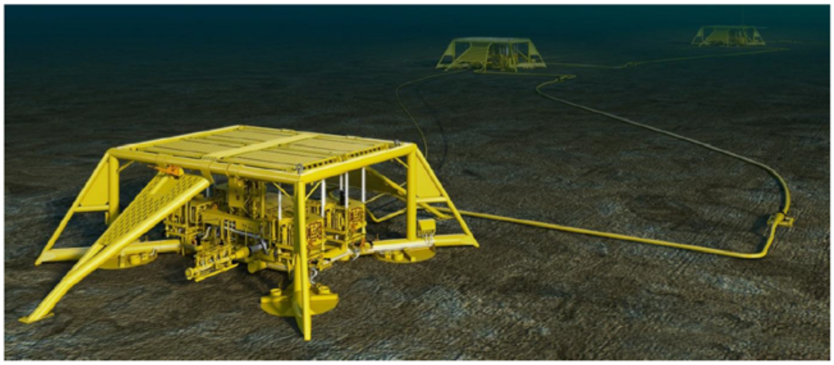
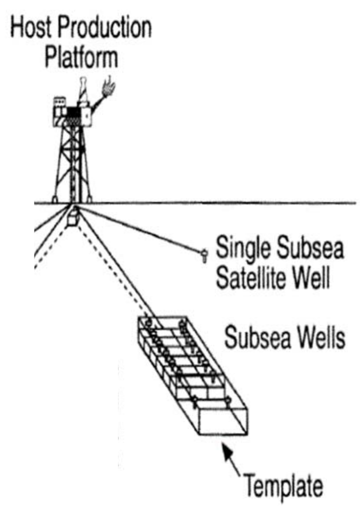


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

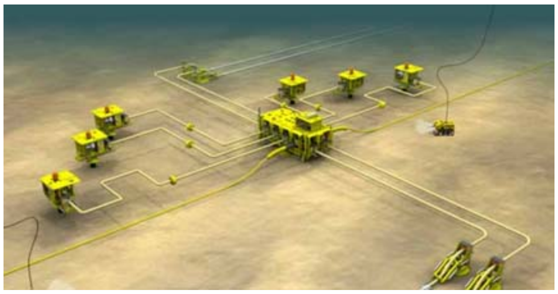
45

Layout of subsea systems – template wells



46

Satellite wells



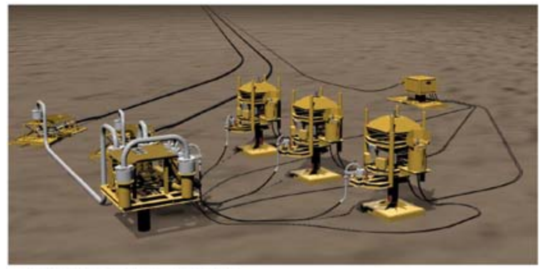
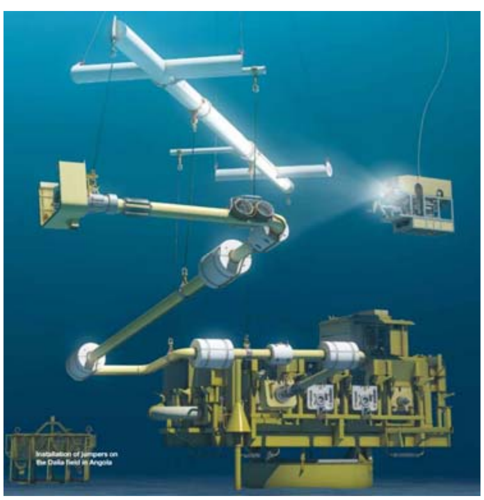


Figure 3.4 Typical GOM subsea tie-back

47

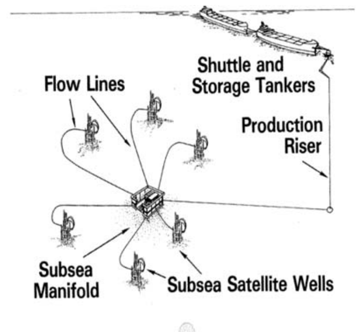
Jumpers for satellite wells (if close)



48

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

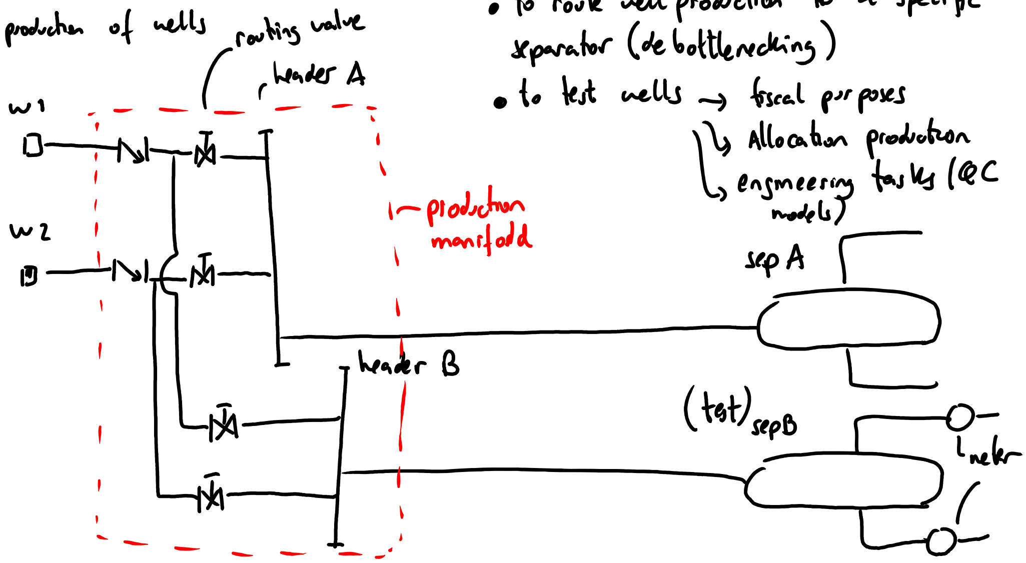
- Shorter, vertical wells
- The drilling rig must be mobilized often which costs money
- More flowlines, pipelines. Manifolds are required

49

The production manifold

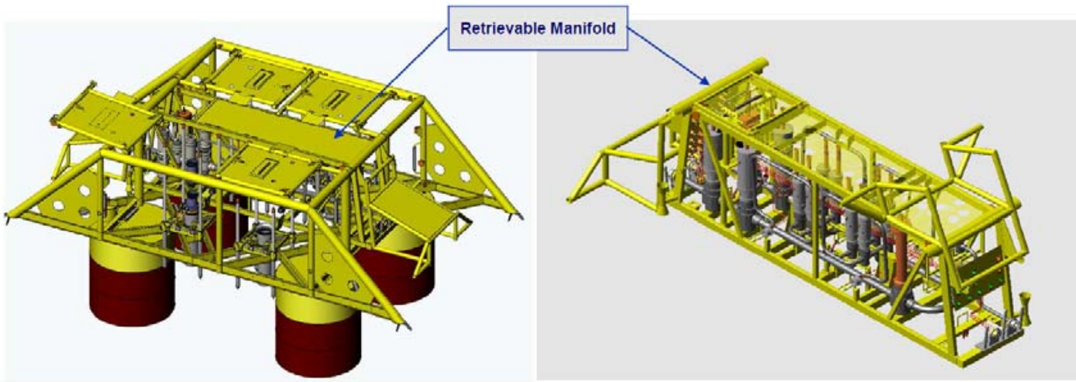
- commingle the production of wells

- to route well production to a specific separator (debottlenecking)
- to test wells → fiscal purposes
  - ↳ Allocation production
  - ↳ engineering tasks (QC models)



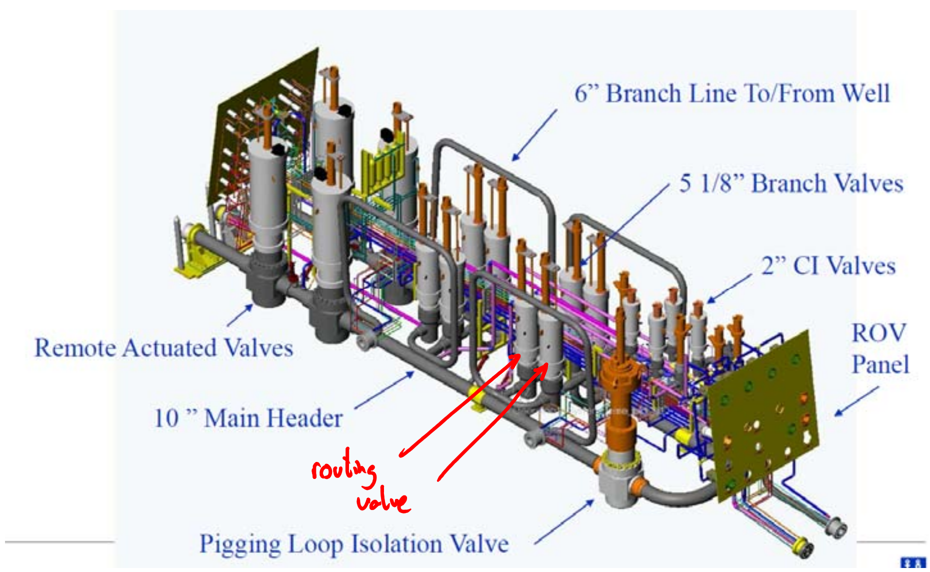
50

4 well template – the production manifold



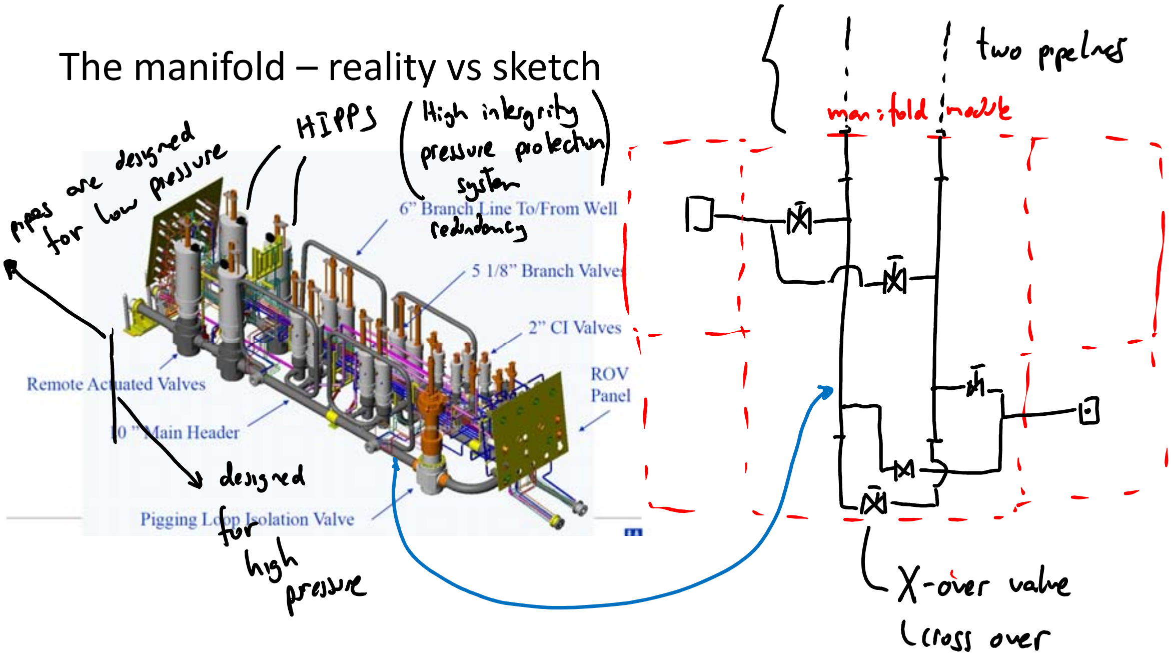
51

The manifold



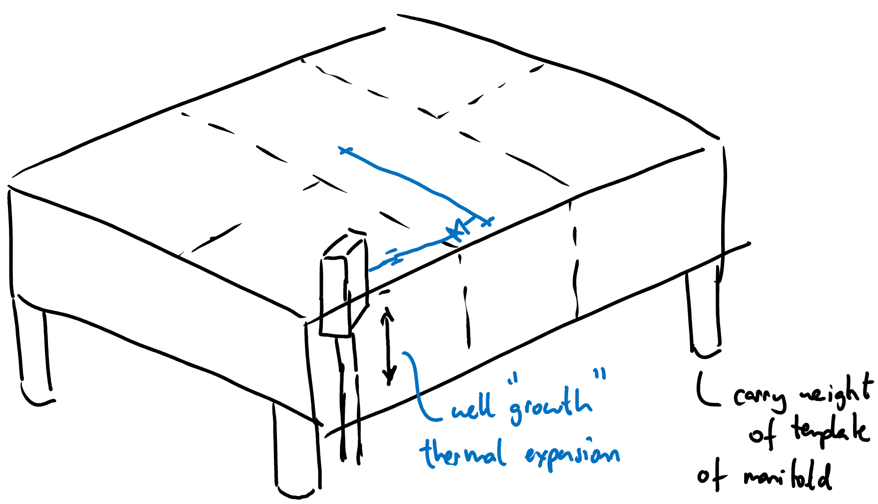
52

The manifold – reality vs sketch



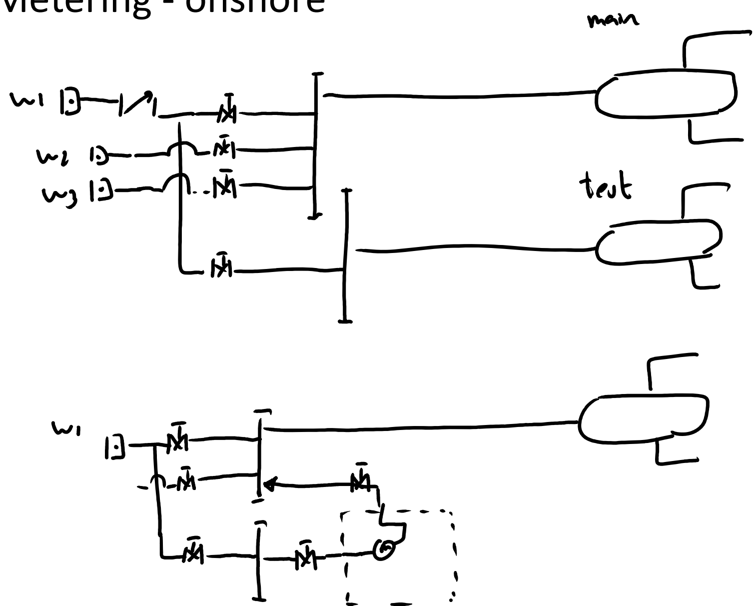
53

4 well template – weight transfer



54

Metering - onshore



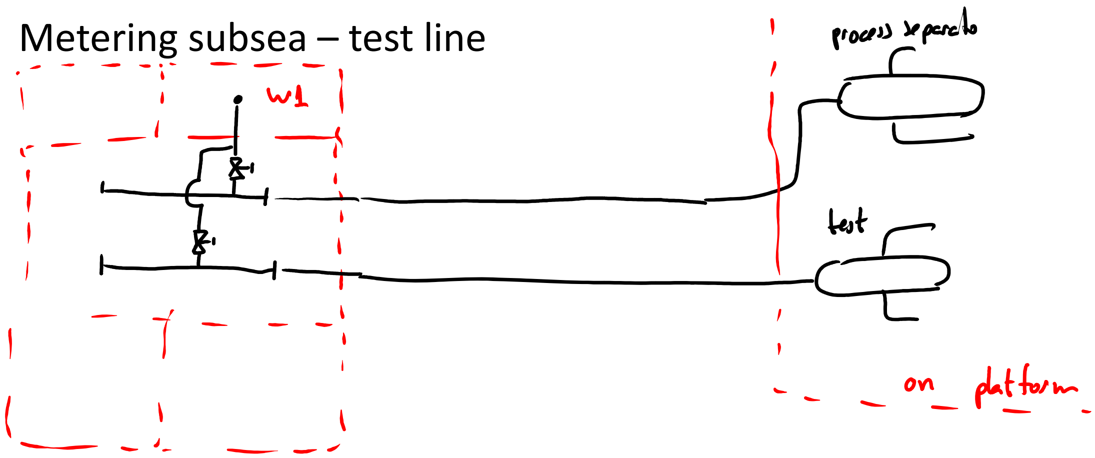
instead of separating, a multiphase meter can also be used, instead of a test separator

55

Metering onshore – test separator

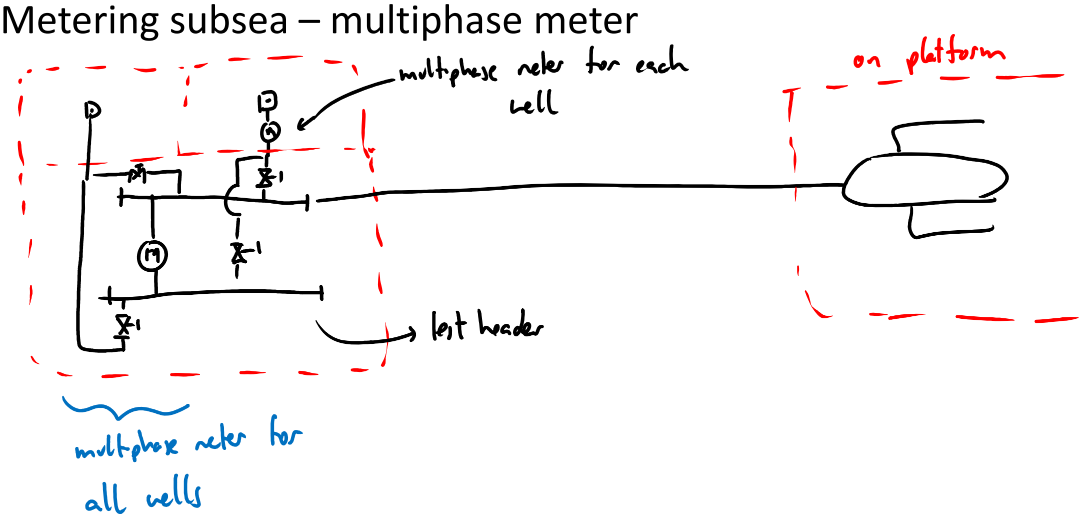
56

Metering subsea – test line



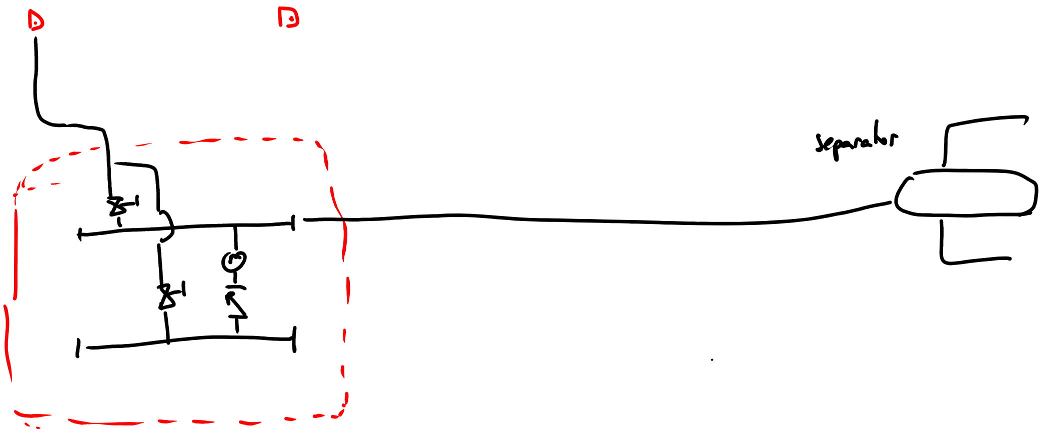
57

Metering subsea – multiphase meter



58

multiphase meter - satellite wells



59

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.

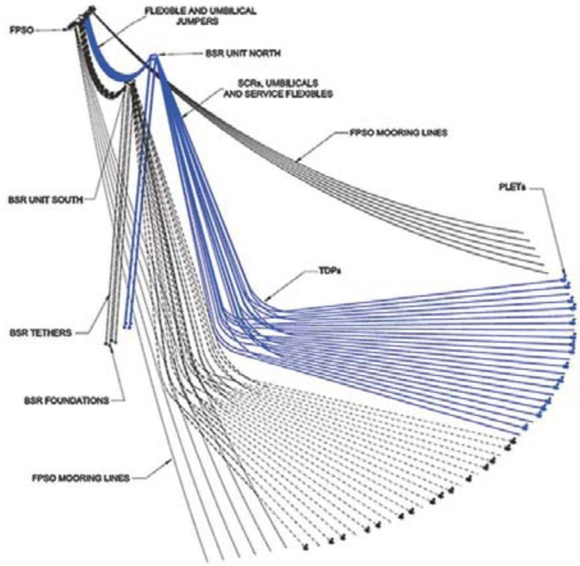
7.2.7.4. Devem ser utilizados separadores de testes ou tanques de testes nos testes de poços. Outros métodos de testes, utilizando novas tecnologias, devem ser previamente aprovados pela ANP.

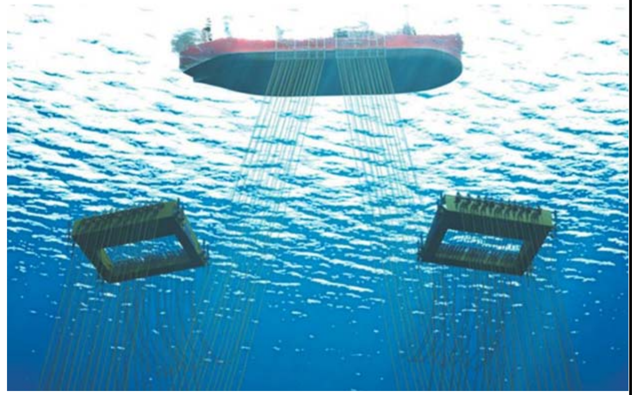
http://www.anp.gov.br/wwwanp/?dw=66648

60

Metering requirements - Brazil

$$$





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

61

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.

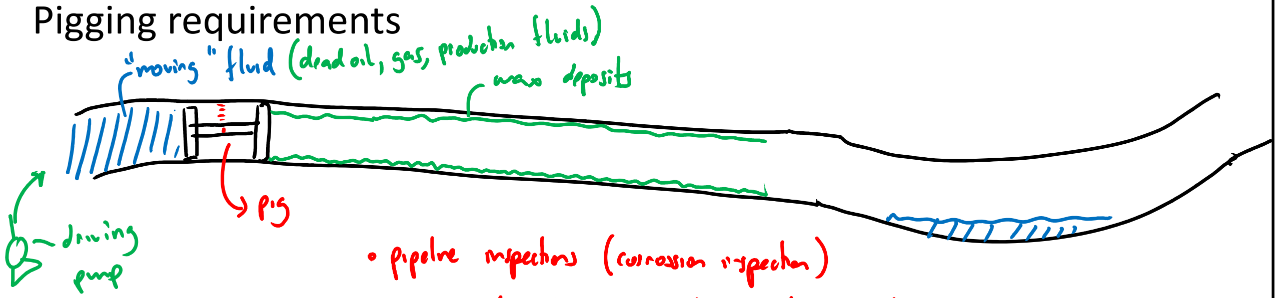
The following elements shall be satisfactorily documented to allow use of a concept based on multiphase measurement, cf. Chapter VII and Section 18:

- 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.

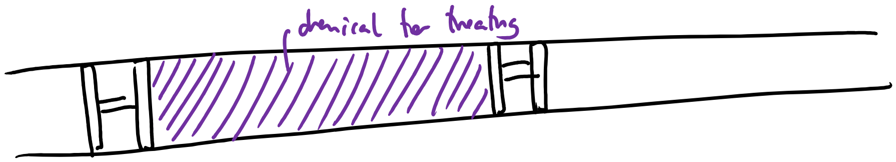
When the multiphase meters are part of the fiscal measurement system, they shall be treated as other fiscal measurement equipment and the administrative requirements which apply pursuant to these Regulations shall therefore be fulfilled.

62

Pigging requirements



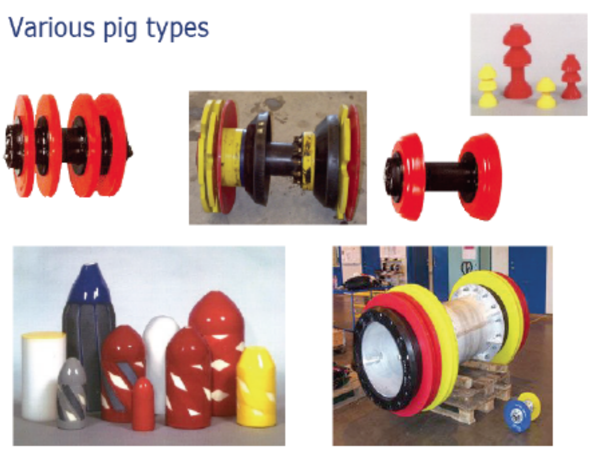
- pipeline inspections (corrosion inspection)
- remove liquid accumulated in low points
- chemical treatment
- wax scraping



63

Pigs

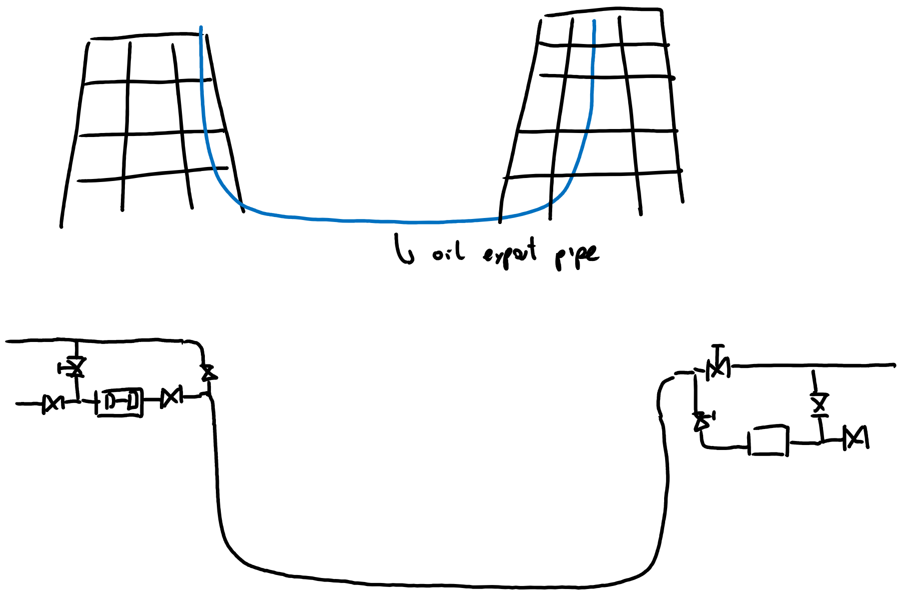
Various pig types



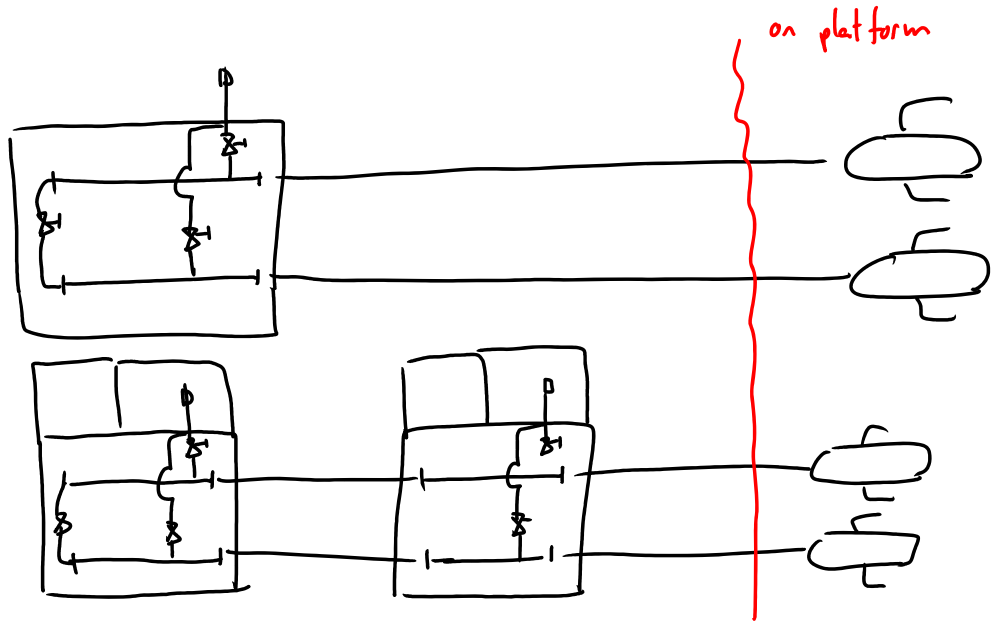
Wax plug-North Sea line pigging

64

Pigging loop and subsea pig launcher

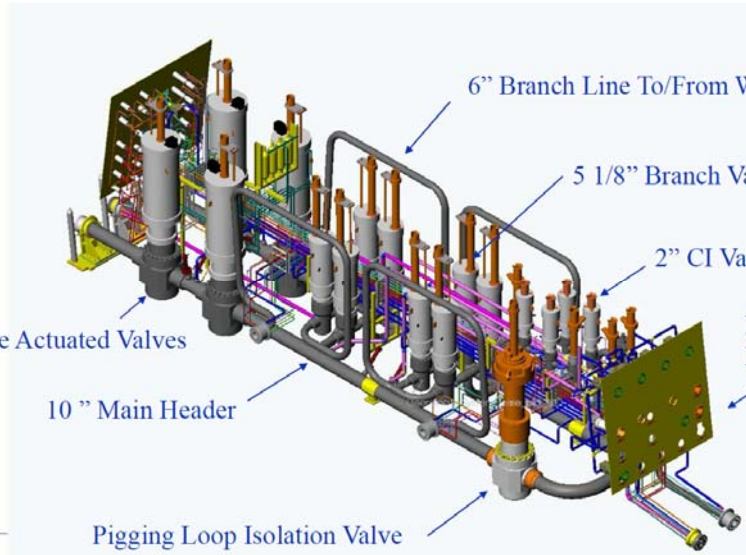


65



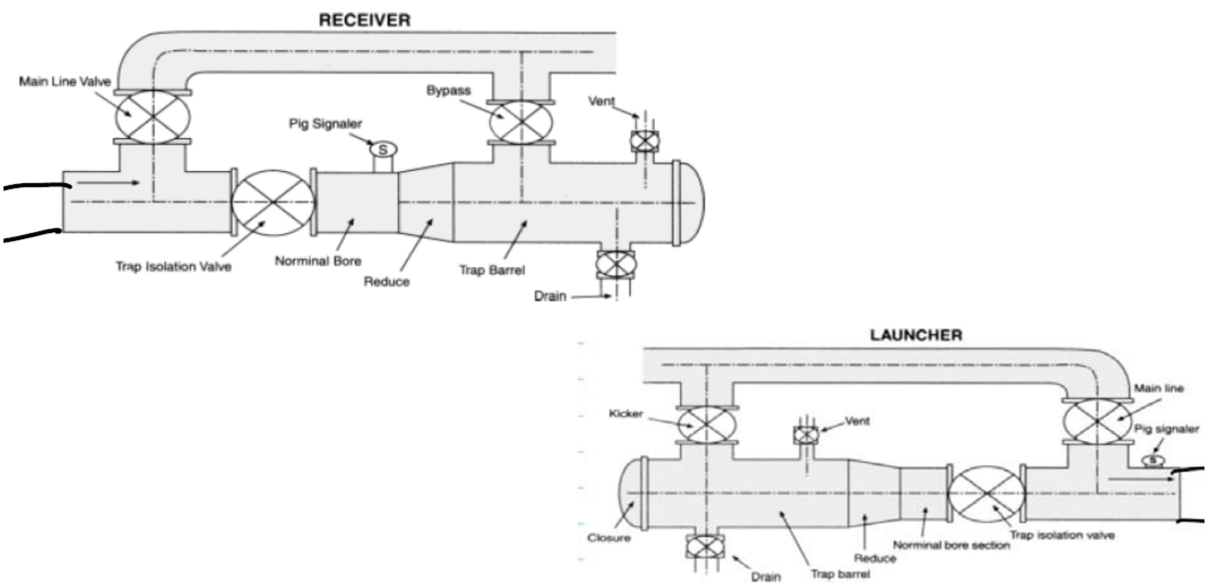
66

The pigging valve



67

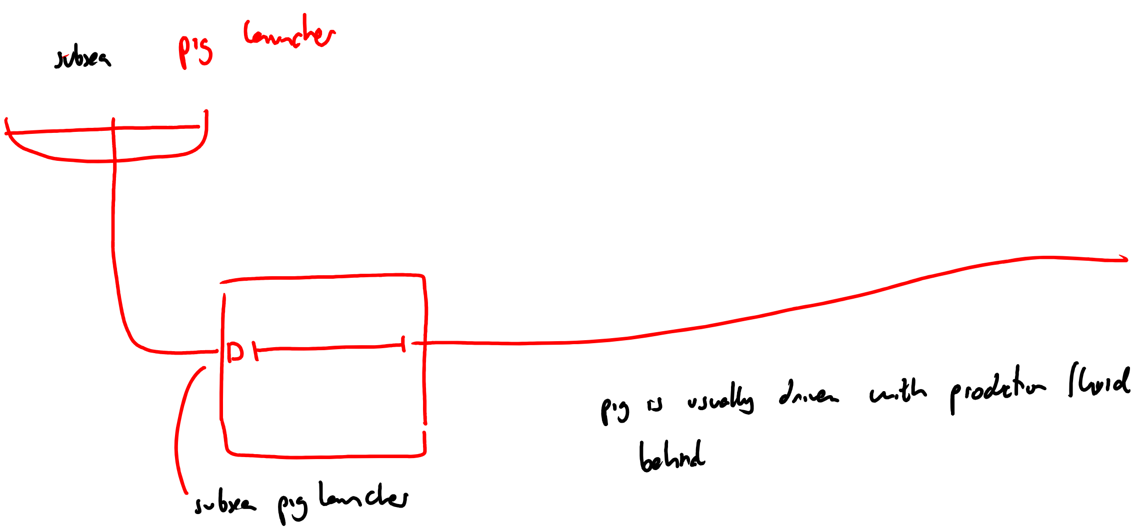
Pig launcher and receiver



68

Pigging - video

69



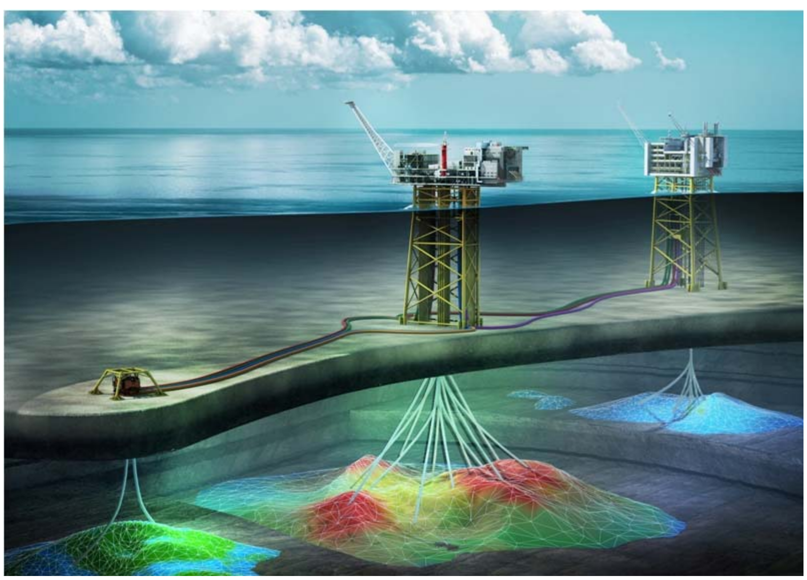
70

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

71

Combinations can be used



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

72

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

73

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

74

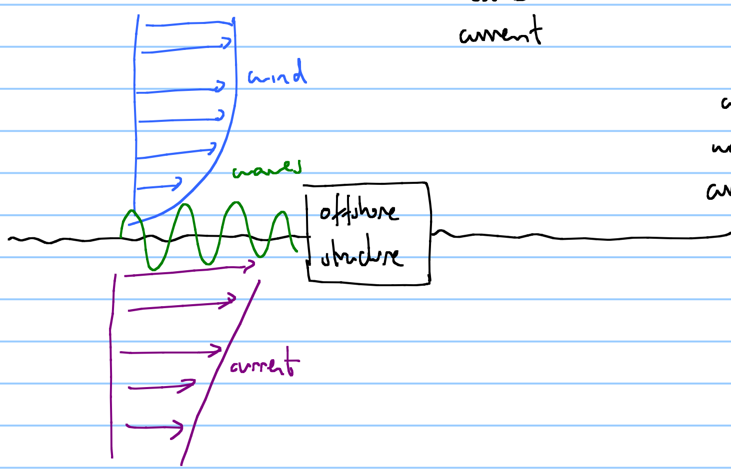
Other selection criteria for offshore structures

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

75

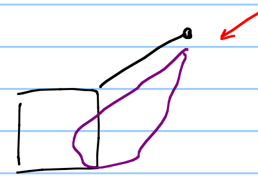
Offshore structures for oil and gas production

• effect of oceanographic environment: wind
waves
current

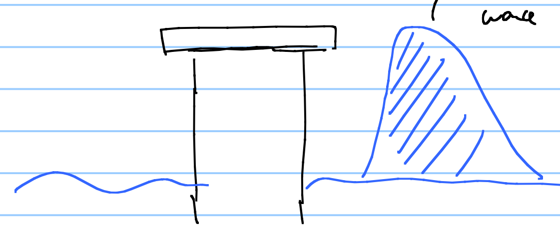


wind, waves, current must be taken into account when designing the offshore structure

• Location of flare



• deck elevation



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

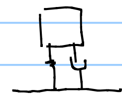
• storm (100 year storm)

• long term variations ⇝ fatigue

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

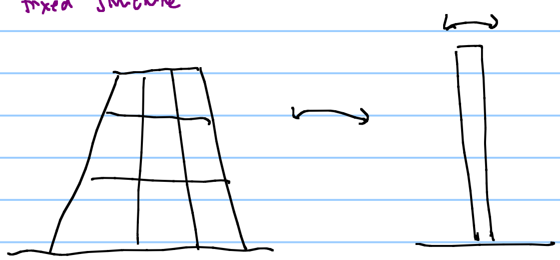
• magnitude
• frequency
• direction

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

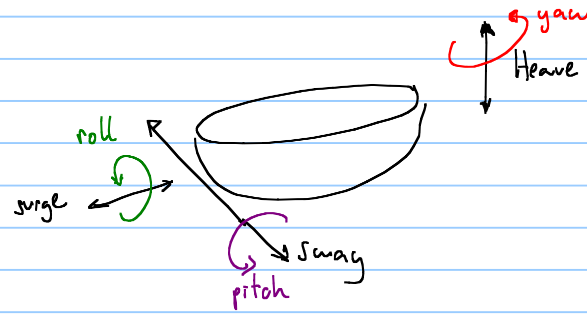


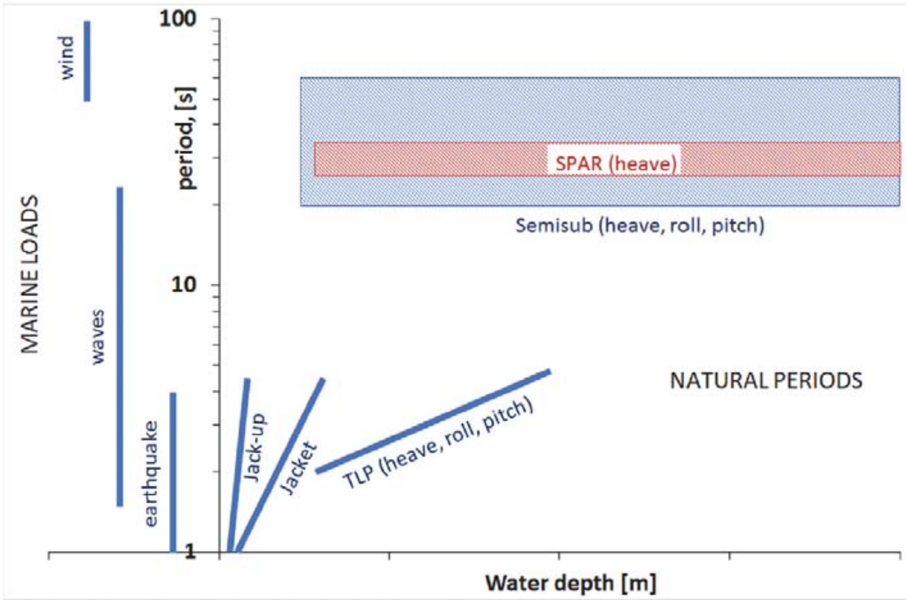
will have a natural frequency that if excited at this frequency might exhibit maximum movement and stress.

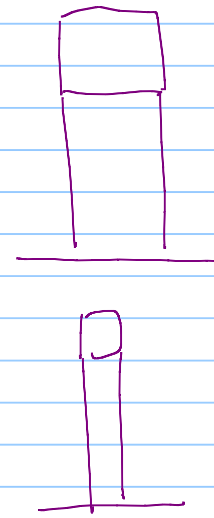
fixed structure

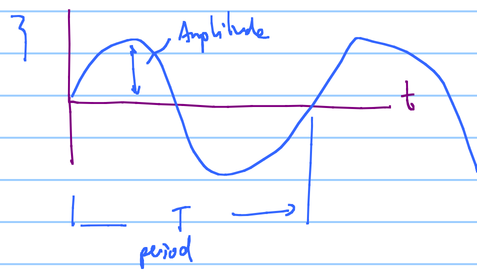


floating structure





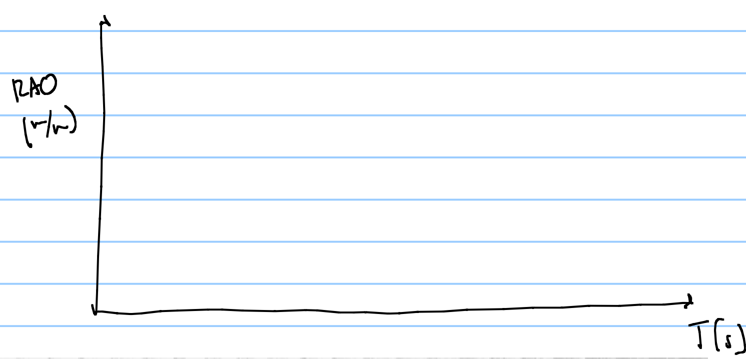




Response amplitude operator (RAO) $= \dfrac{\text{amplitude of response}}{\text{amplitude of excitation}} = \dfrac{\text{Heave [m]}}{\text{wave amplitude [m]}}$

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

RAO = 2



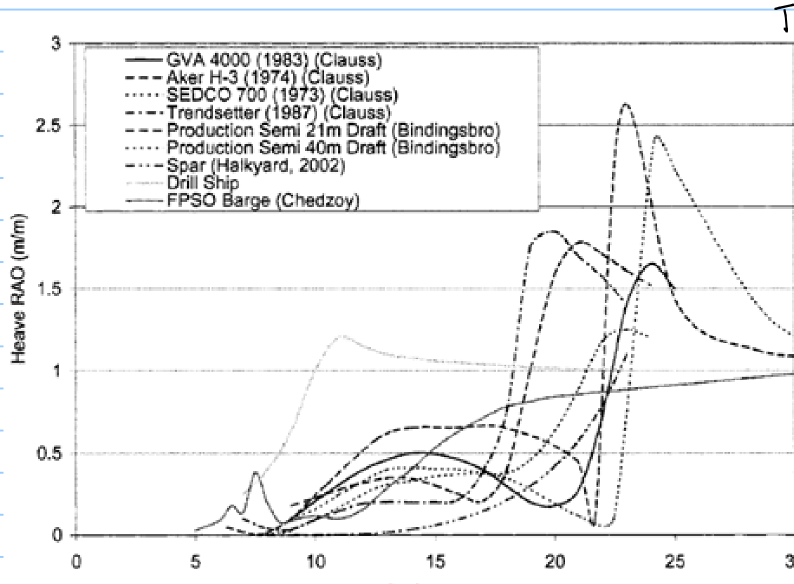
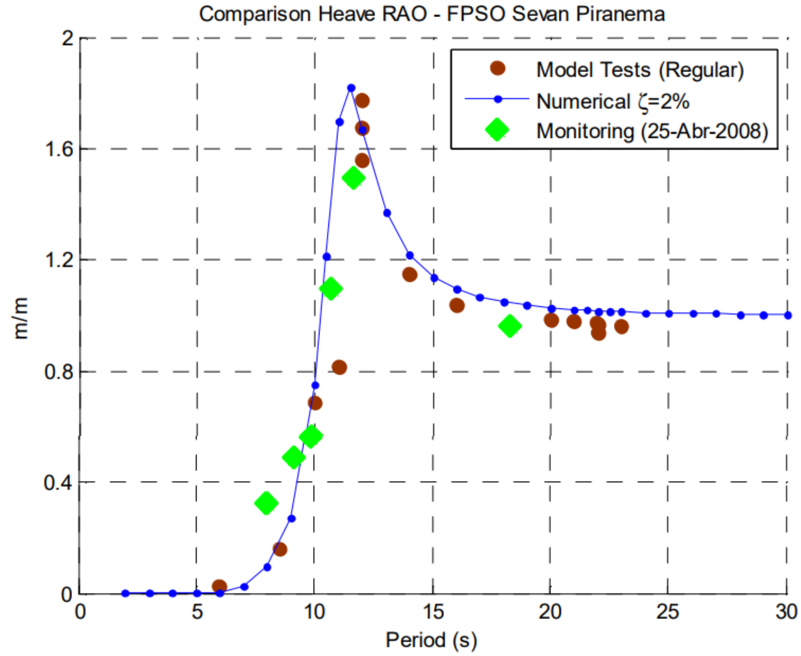


Figure 7.3 Example heave RAOs of various floaters



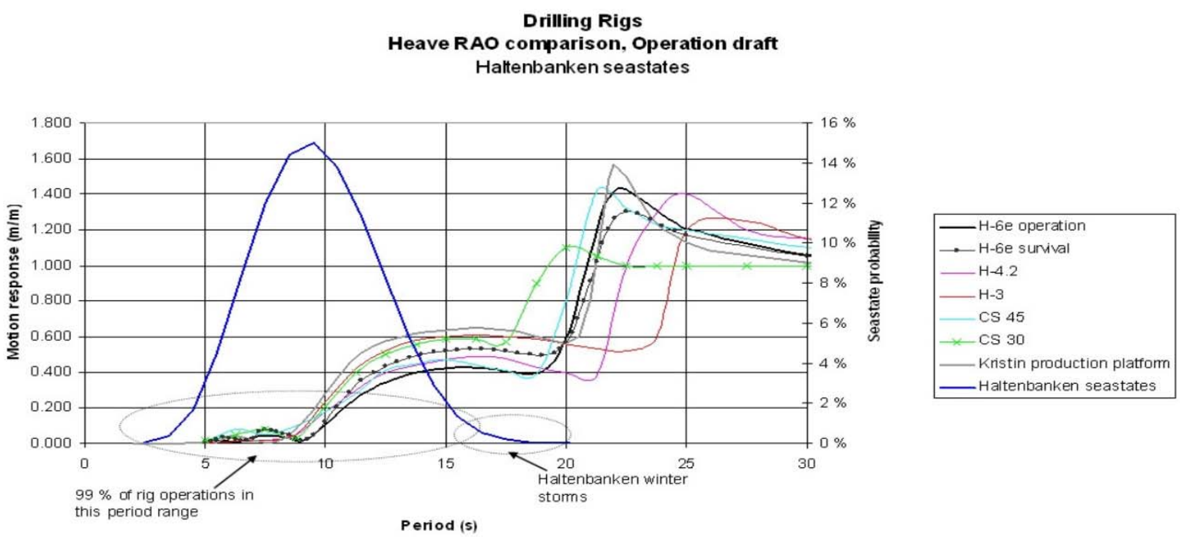


Figure 16.2: *RAO published on the AKER Drilling website.*

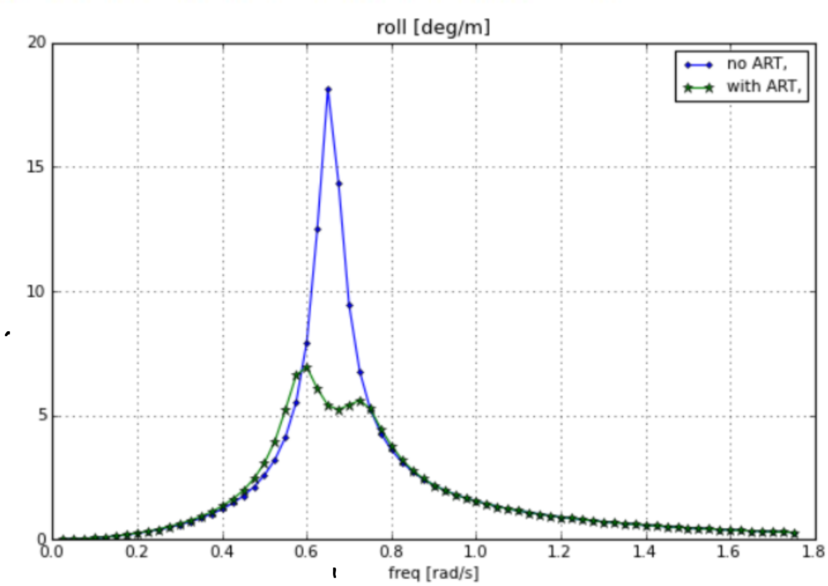
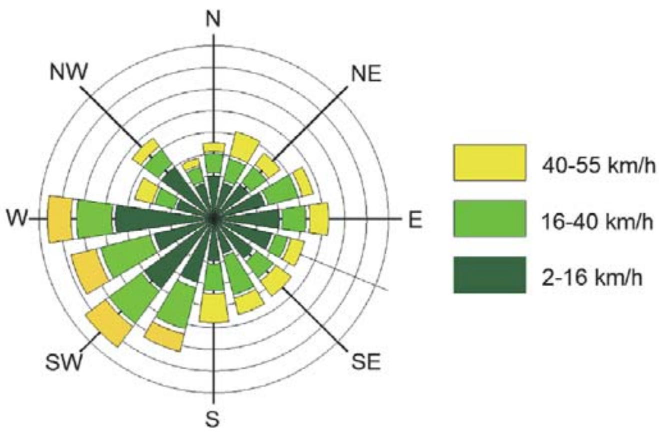


Figure 1: Typical RAO of roll of a ship with and without ART.

Wind



wind rose

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

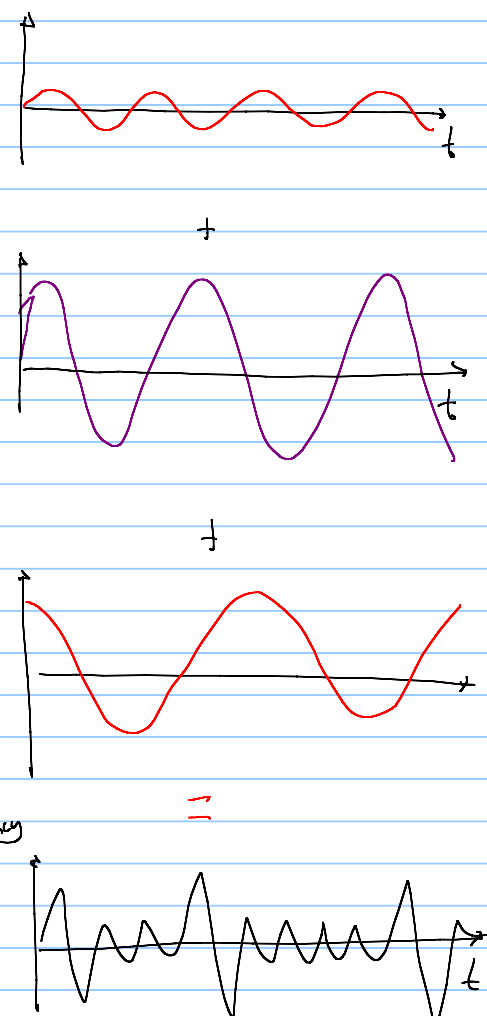
Waves

Fourier

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

angular frequency $\omega_i = 2\pi f_i$

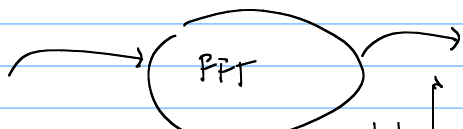
$\omega_i = \frac{rad}{s}$ $\left[\frac{\cancel{cycle}}{s}\right]\left[\frac{2\pi \ rad}{1 \ \cancel{cycle}}\right]$



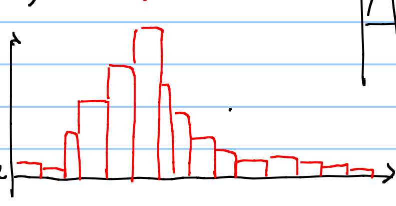
Discrete Fourier transform

FFT Fast fourier transform

t	value
D	D
D	D
D	D
D	D

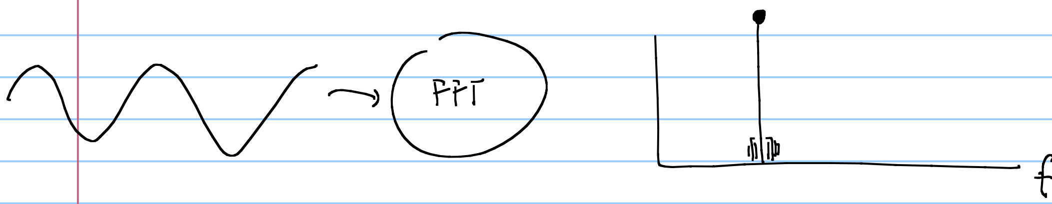


spectral peak period
dominant frequency



sometimes analytical equations are used

Pierson Moskowitz, JONSWAP



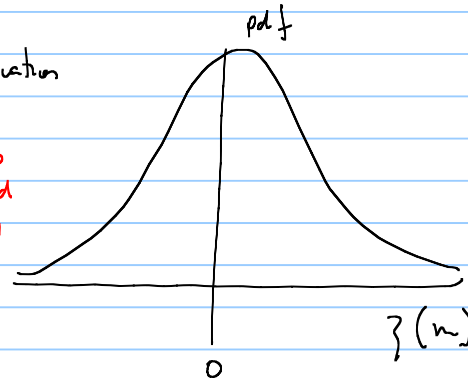
to deal with the variability of waves in time, we apply FFT on the signal and report spectral peak period

the spectral peak period does not change significantly in 3 hours

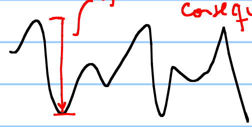
sea state

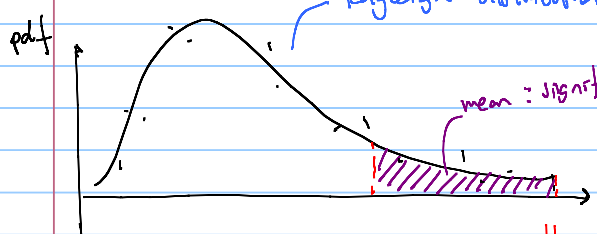
what to do with amplitudes?

statistics on wave elevation



wave height



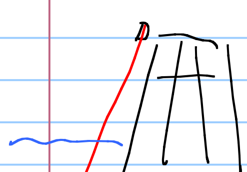


to characterize a sea state (3 hrs) Hs and Tp are used

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

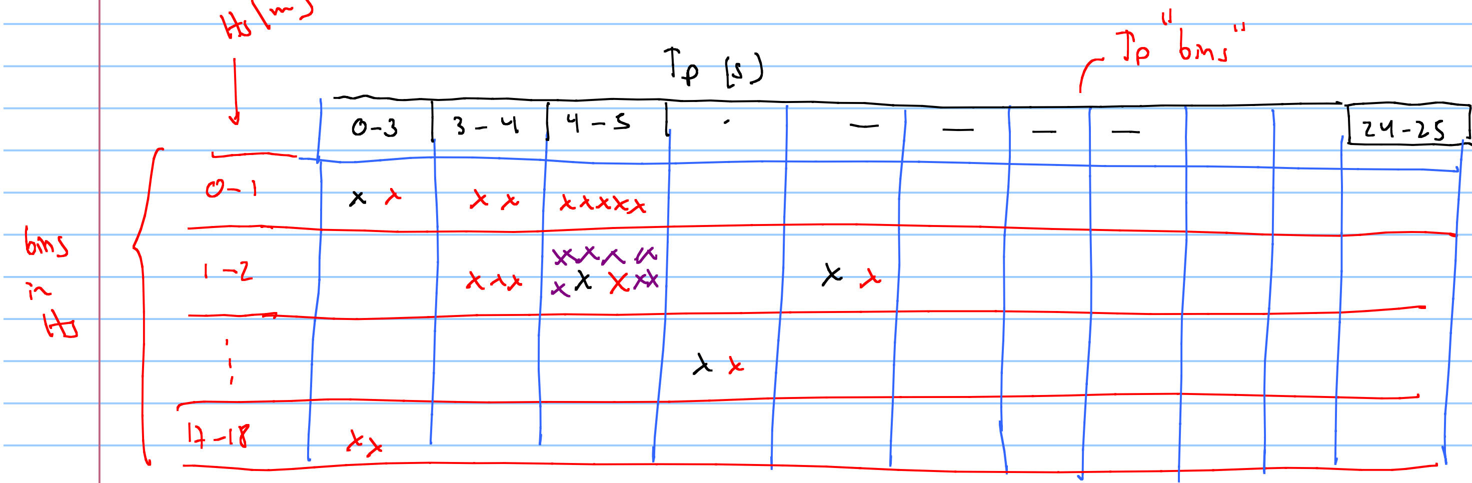
How many sea states are in 2 years

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



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

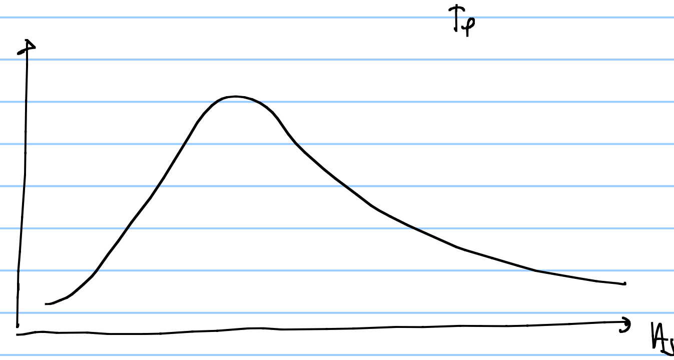
	Spectral Peak period (T_p) [s]																							
Hs [m]	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	Sum
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1	96348
2-3	0	2	94	1050	4532	10304	15020	15953	13457	9752	5991	3403	1795	894	426	197	88	39	17	7	3	1	1	83026
3-4	0	0	2	72	686	2782	6171	8847	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

$$\frac{292172}{2420\left(\frac{\text{states}}{1\text{ year}}\right)} \approx 120 \text{ years}$$

for a fixed wave Hs

for a fixed Tp



Class exercise

Wave statistics for the Aasta Hansteen area.

You have been invited onboard the R/V Gunnerus, a ship that belongs to NTNU that will carry several research activities on a trip to the Norwegian Sea. The vessel will be visiting the area where the Aasta Hansteen field will be located (67° Latitude and 7°Longitude). Equinor sponsors your stay and place on the ship. The ship is equipped with a buoy that measures wave elevation every 0.5 s.

Part 3.1. To show your gratitude to Equinor, you intend to process the wave elevation data that has been gathered for a period of 2047.5 s during the trip (See the excel data attached). The tasks are as follow:

- Perform an FFT of the data provided. Do this in Python. We will follow the instructions in the document "Frequency Domain Using Excel" written by Larry Klingenberg, from San Francisco State University. Please note that the procedure provided by Prof. Klingenberg already calculates the amplitude (wave elevation, in m), **NOT** the spectral energy.
  Plot the wave spectrum (amplitude in m vs frequency), provide the periods with the highest amplitude on a table and report the peak spectral period (the period with the highest amplitude). Is it possible to reconstruct the original wave elevation data with this plot?

How to do discrete fourier Transform https://www.youtube.com/watch?v=mkGsMWi_j4Q

all rows

time=elevation[:,0]

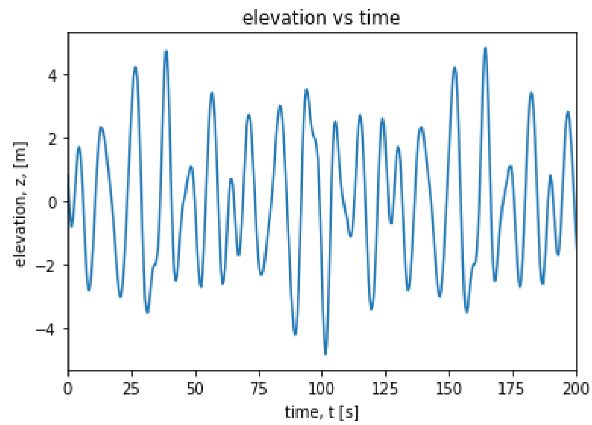
take only column 0

elevation

$$\begin{array}{cc} (0) & (1) \\ \left[\begin{array}{cc} a & b \\ c & d \\ e & f \end{array}\right] \\ \text{time} & \text{elevation} \end{array}$$

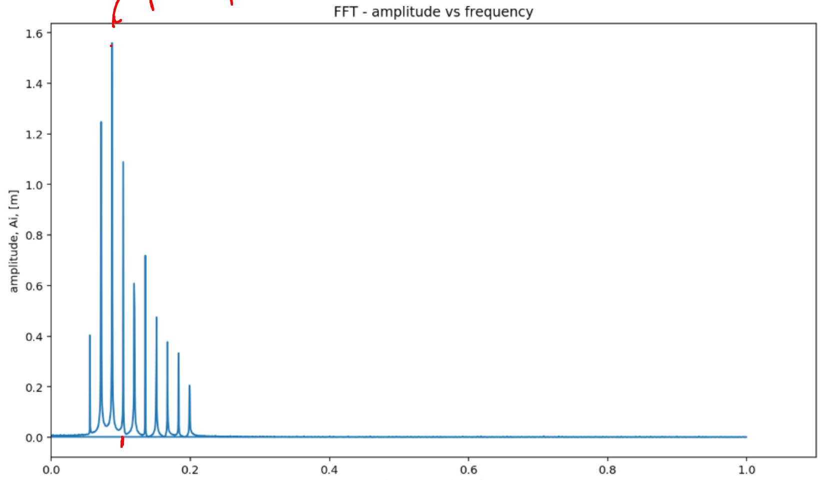
In [24]:
```python
#importing needed libraries
import numpy as np
import matplotlib.pyplot as plt
```

In [38]:
```python
#reading and plotting wave elevation measured data
elevation=np.loadtxt('elevation_vs_time.txt')
time=elevation[:,0]
elevation=elevation[:,1]
n_points=time.size
plt.plot(time,elevation)
plt.xlim(0,200)
plt.title('elevation vs time')
plt.xlabel('time, t [s]')
plt.ylabel('elevation, z, [m]')
plt.show()
```



In [39]:
```python
fft_mag=np.abs(np.fft.fft(elevation))*2/n_points
fft_freq=np.fft.fftfreq(n_points,time[1]-time[0])
plt.plot(fft_freq,fft_mag)
plt.xlim(0)
plt.title('amplitude vs frequency')
plt.xlabel('frequency, f [Hz]')
plt.ylabel('amplitude, [m]')
plt.show()
```

peak spectral period $1/0.1 \approx 1.25$ s

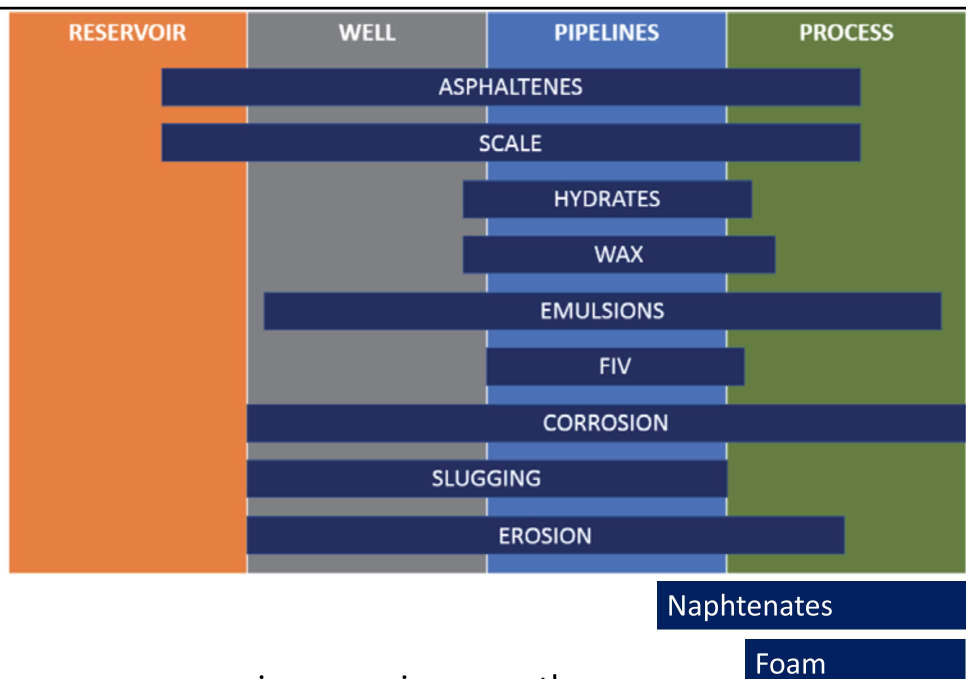


Flow assurance considerations in hydrocarbon field development and planning

Prof. Milan Stanko (NTNU)

1

Issues

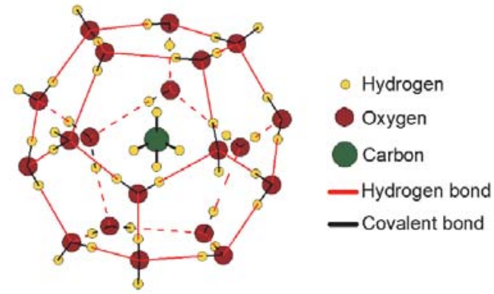


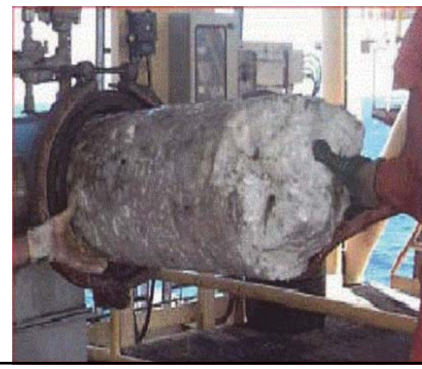
- microorganism growth

2

Hydrates

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

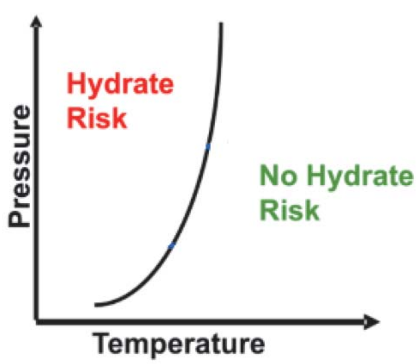




3

Hydrates - conditions

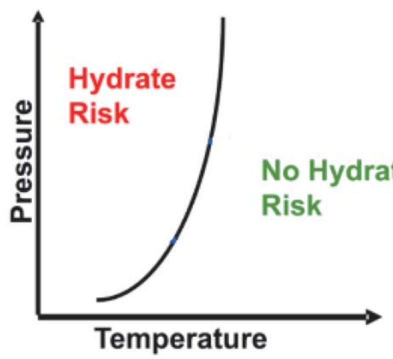
- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

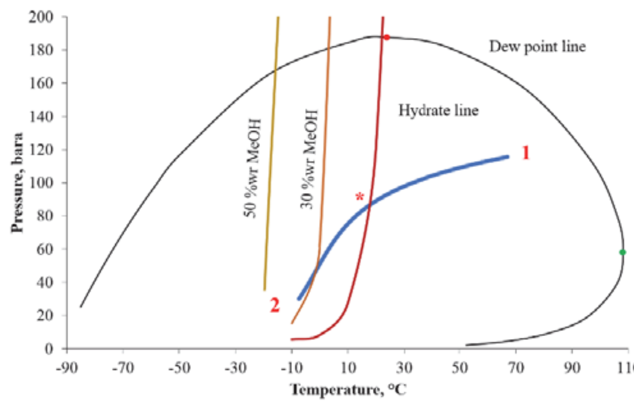


4

Hydrates - conditions

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

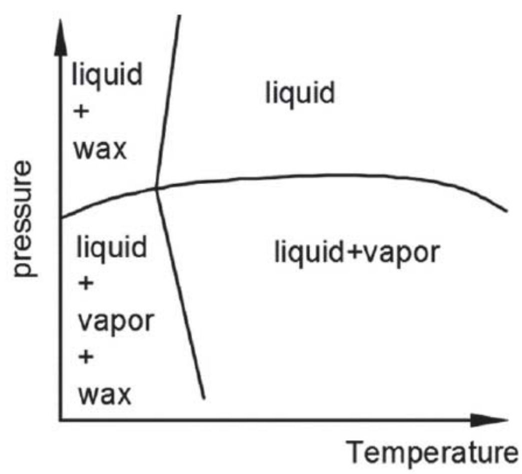




5

Wax

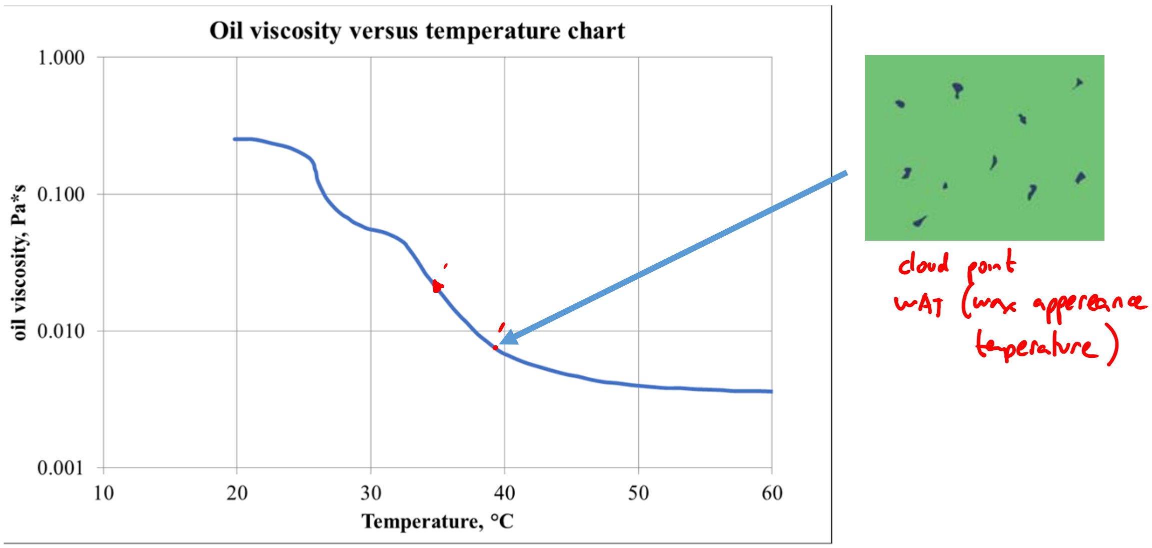
TAKEN FROM EQUINOR



Paraffins (C18 - C36)

6

Wax

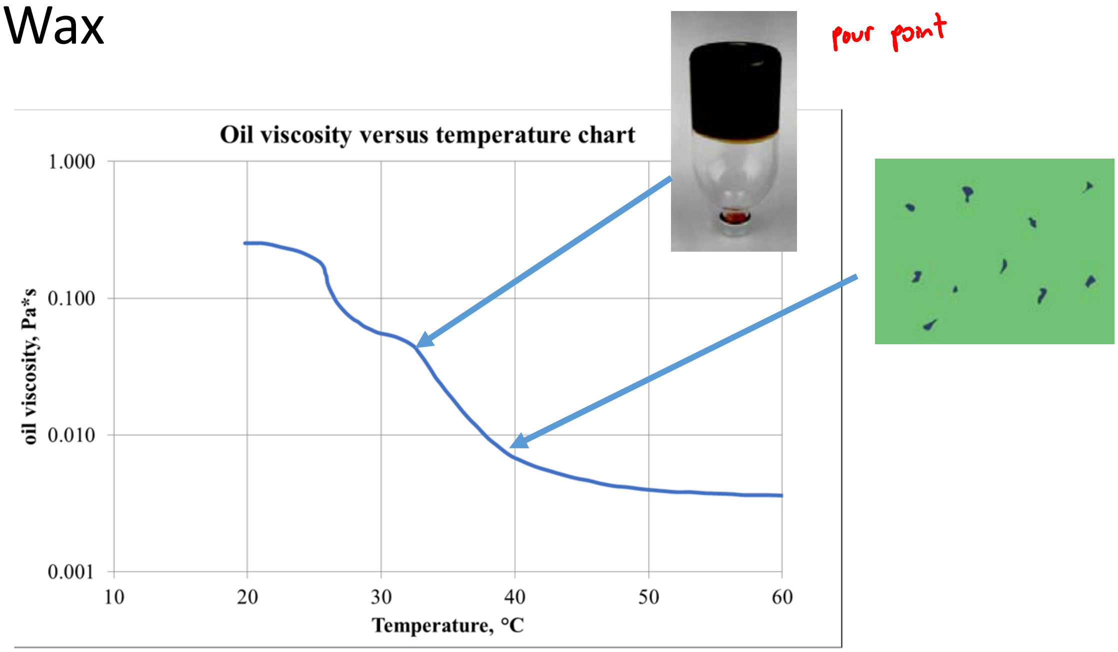


cloud point
WAT (wax appereance temperature)

7

Wax

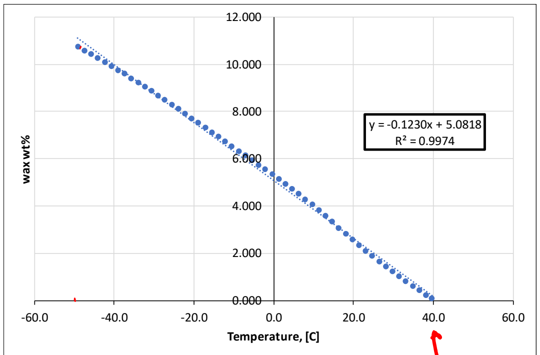
pour point



8

Wax

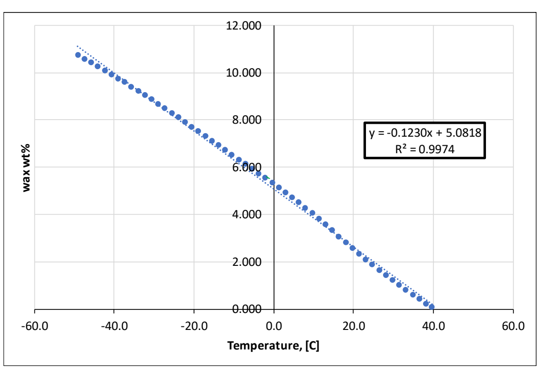
$$\frac{\text{weight of wax particles}}{\text{total weight}} \times 100$$

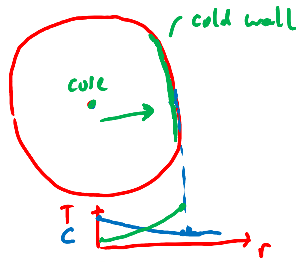


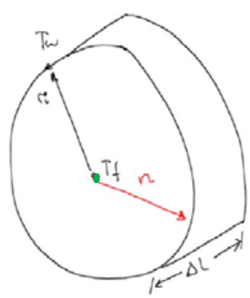
WAT

9

Wax





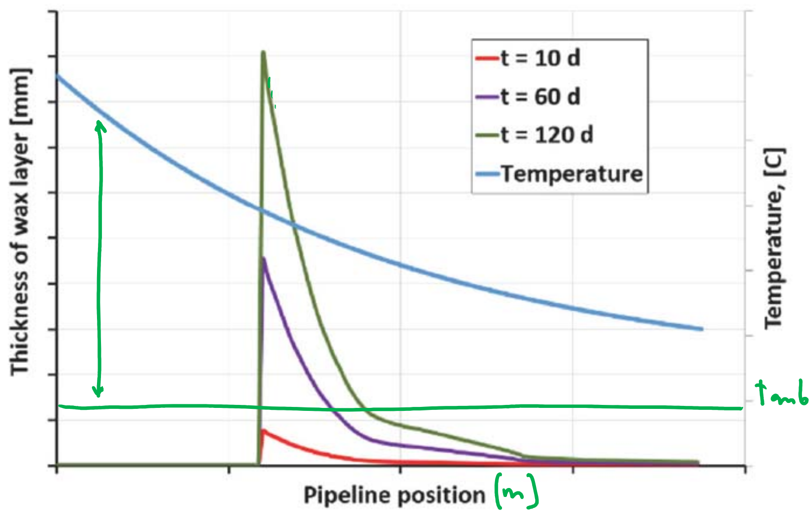


r_i : internal pipe diameter
T_f : fluid temperature
T_w : wall Temperature
n : mass flux of wax from fluid to wall [$Kg/s.m^2$]
$dA = 2\pi r_i dL$
total mass flow of wax (m_w) deposited in a section
$m_w = n.dA$

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

10

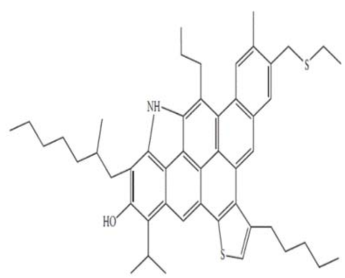
Wax

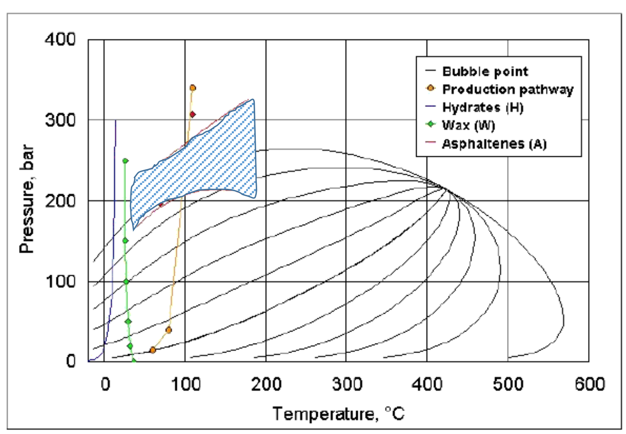


11

Asphaltenes

TAKEN FROM EQUINOR (KALLEVIK)





12

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

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

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

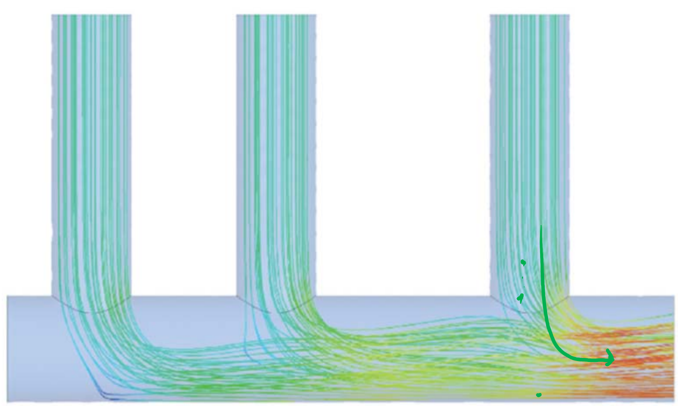
$p\downarrow$
$T\uparrow$ $\rightarrow$

$BaSO_4$ $CaCO_3$ NaCl

TAKEN FROM EQUINOR (SANDENGEN)

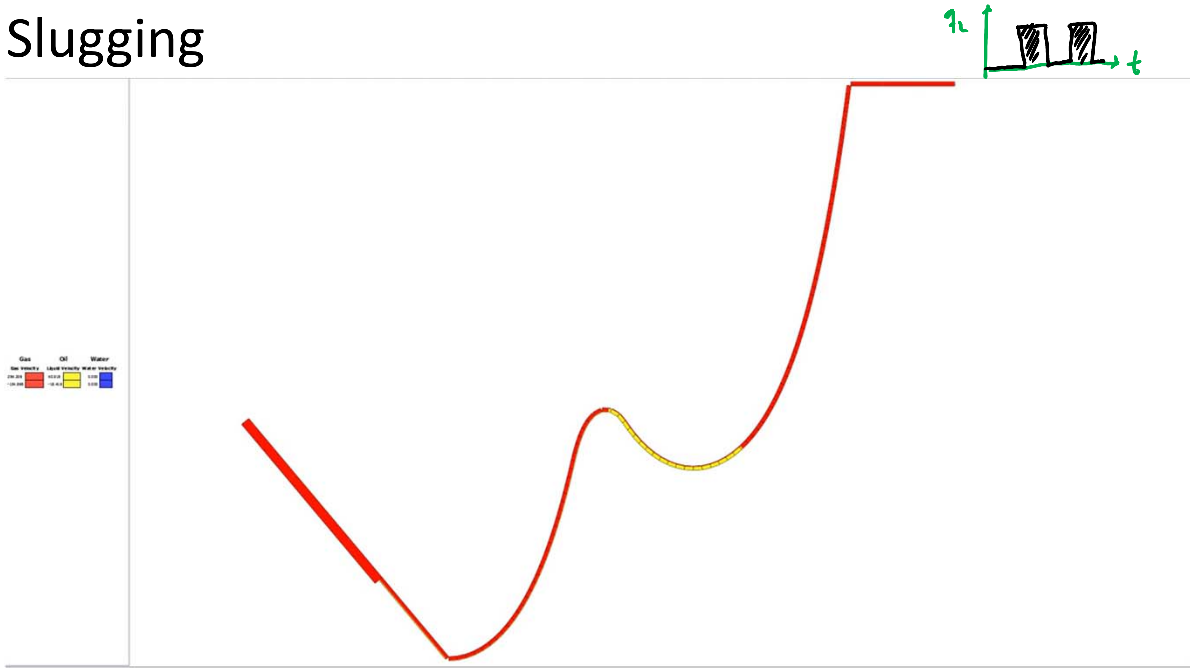
13

Erosion



14

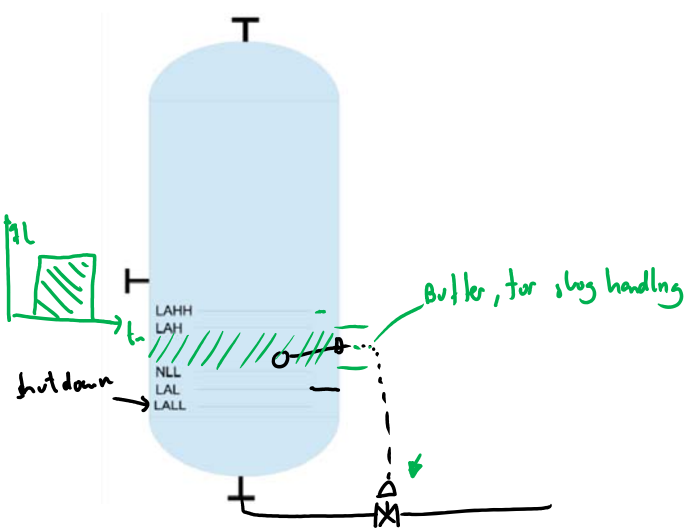
Slugging



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

15

Slugging – impact on separator operation

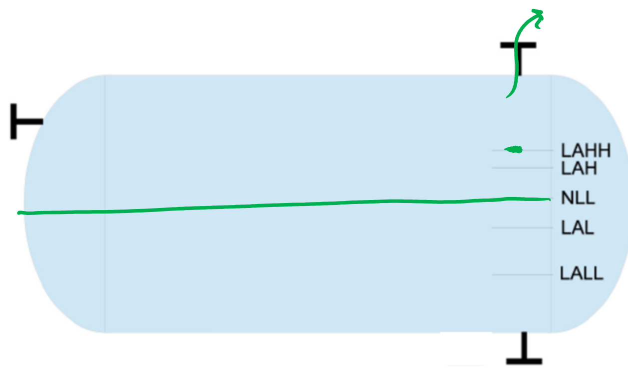


LAL: Level alarm low
LAH: Level alarm high
LALL: Level alarm low low
LAHH: Level alarm high high

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

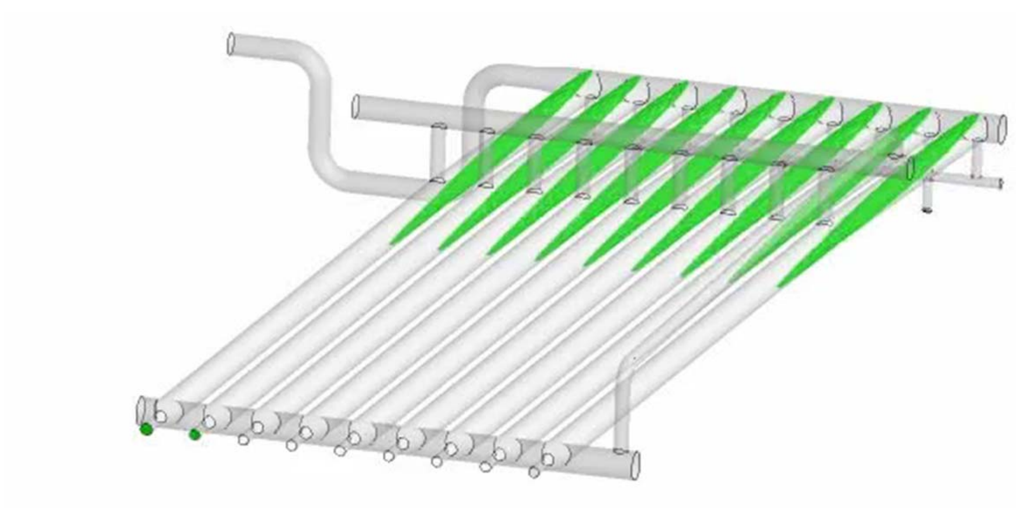
16

Slugging – impact on separator operation



17

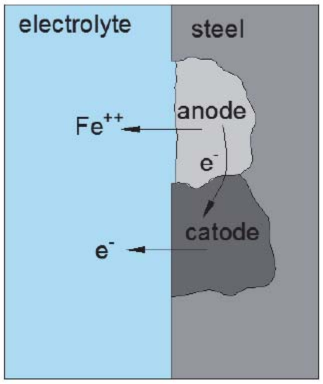
Slugging – slugcatcher handling slugs

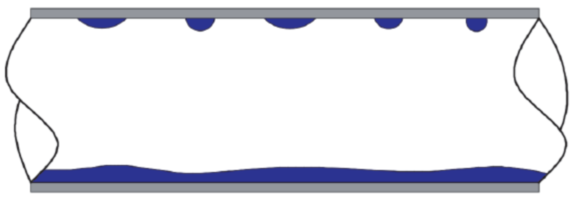


https://www.youtube.com/watch?v=LKLW5284adI

18

Corrosion





TOP of line corrosion

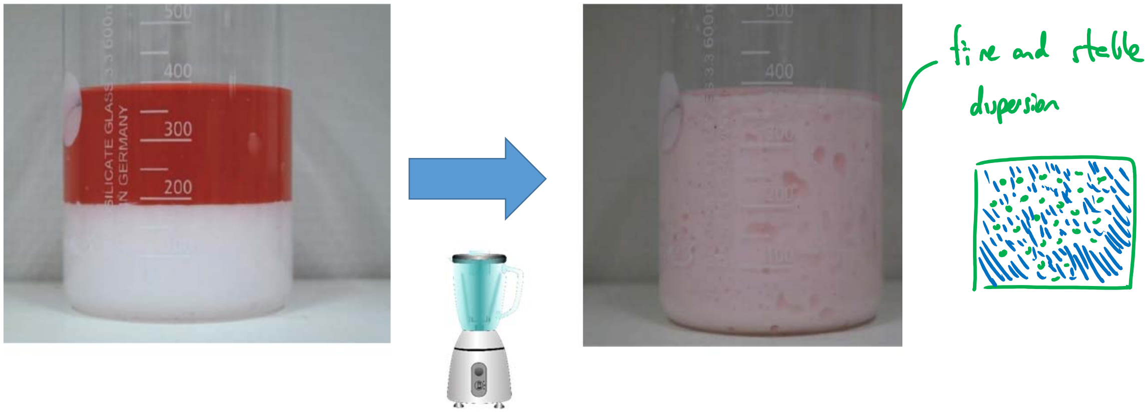
19

Oil-water emulsions

water

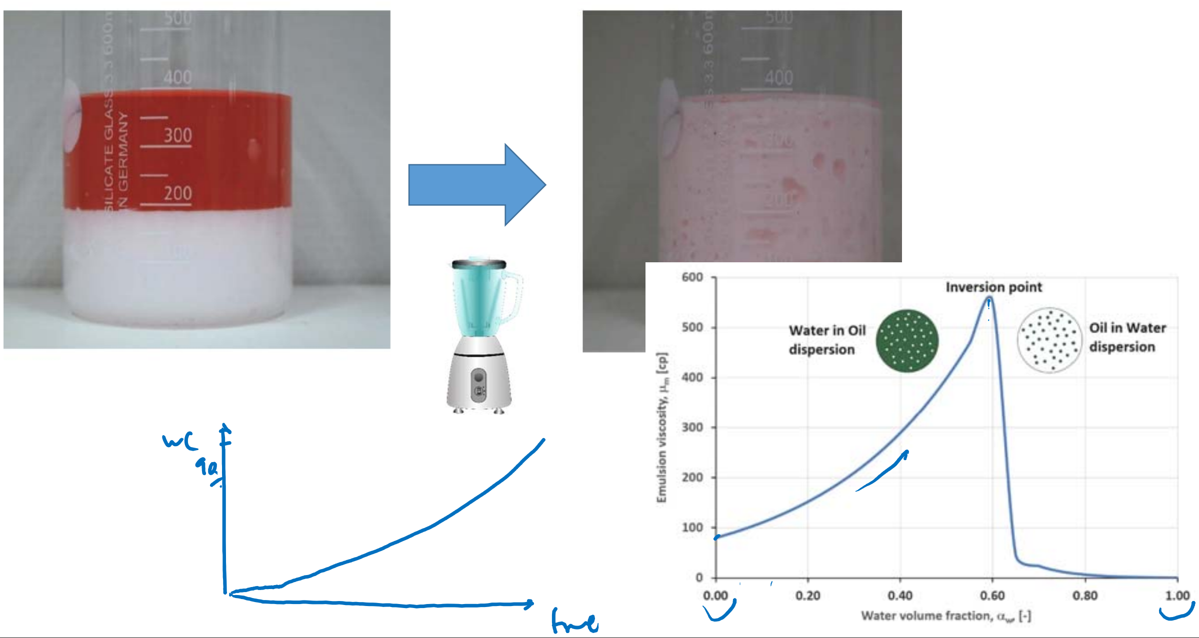
20

Oil-water emulsions



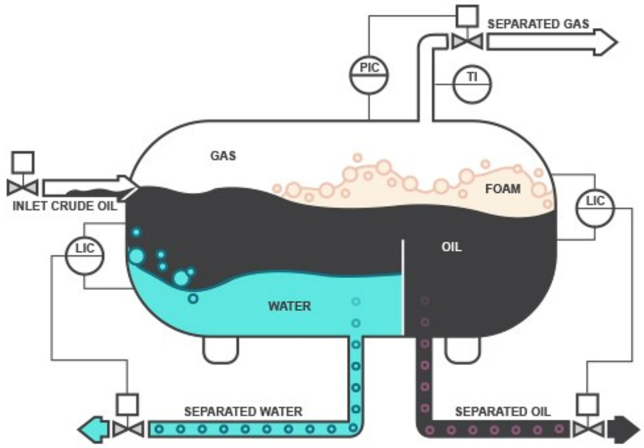
21

Oil-water emulsions

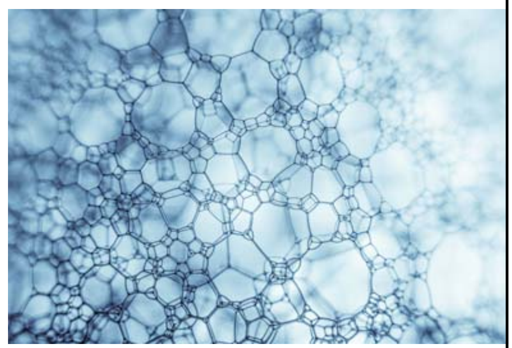


22

Foam



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



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

23

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

24

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

25

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

26

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

28

Release and disposal of chemicals

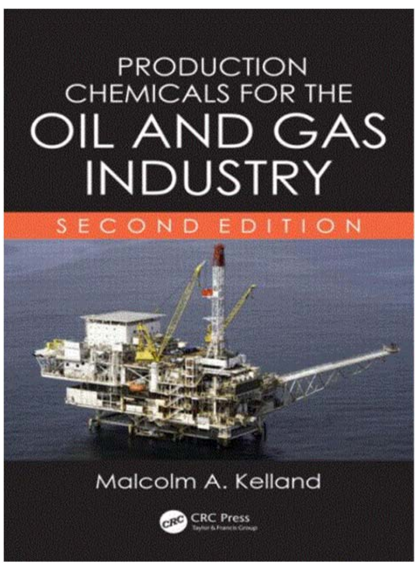
Tabell 7-4 Miljømessige egenskaper til produksjonskjemikalier som vil følge produsert vann fra Johan Castberg-feltet

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

29

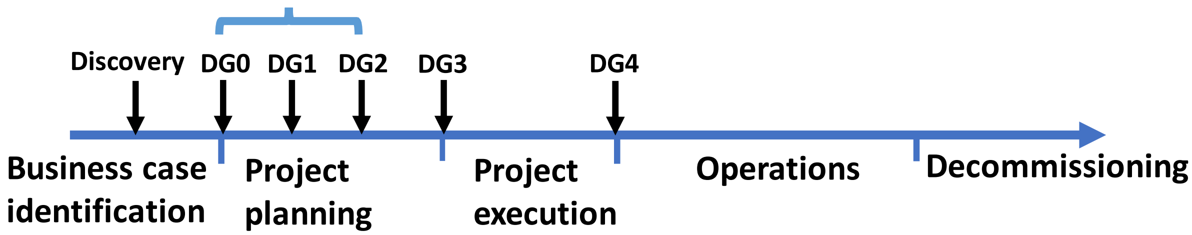
More about production chemicals



30

Flow assurance evaluation during field planning

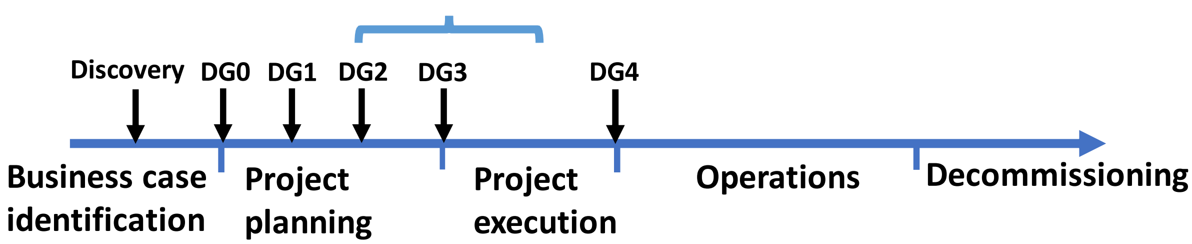
- Detect potential showstoppers and communicate technical constraints and repercussions to field planner
- Laboratory tests



31

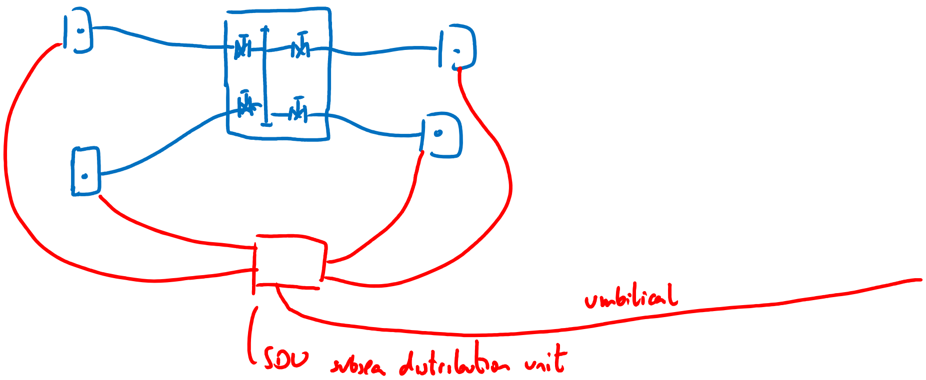
Flow assurance evaluation during field planning

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



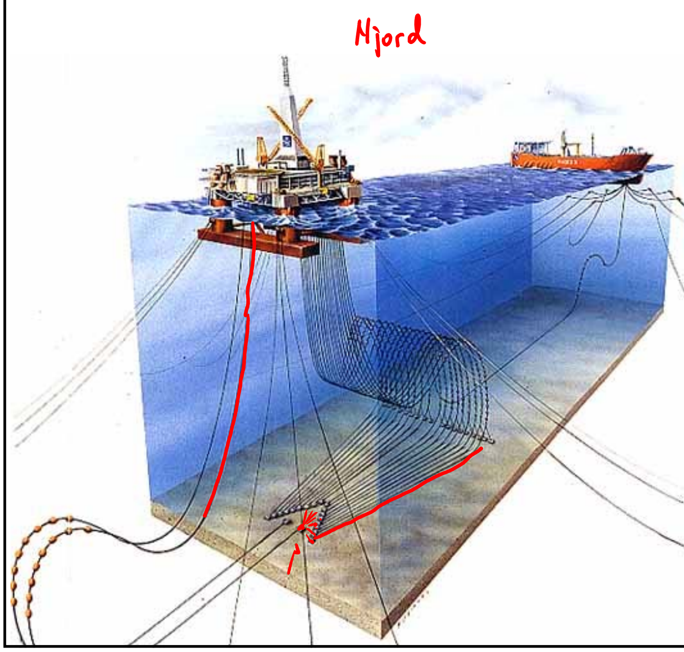
32

Injection of production chemicals subsea



33

Injection of production chemicals



34

Umbilicals, injection of production chemicals

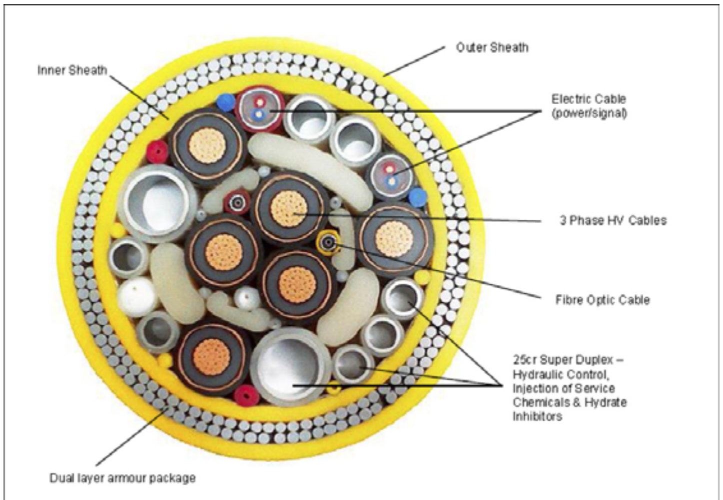
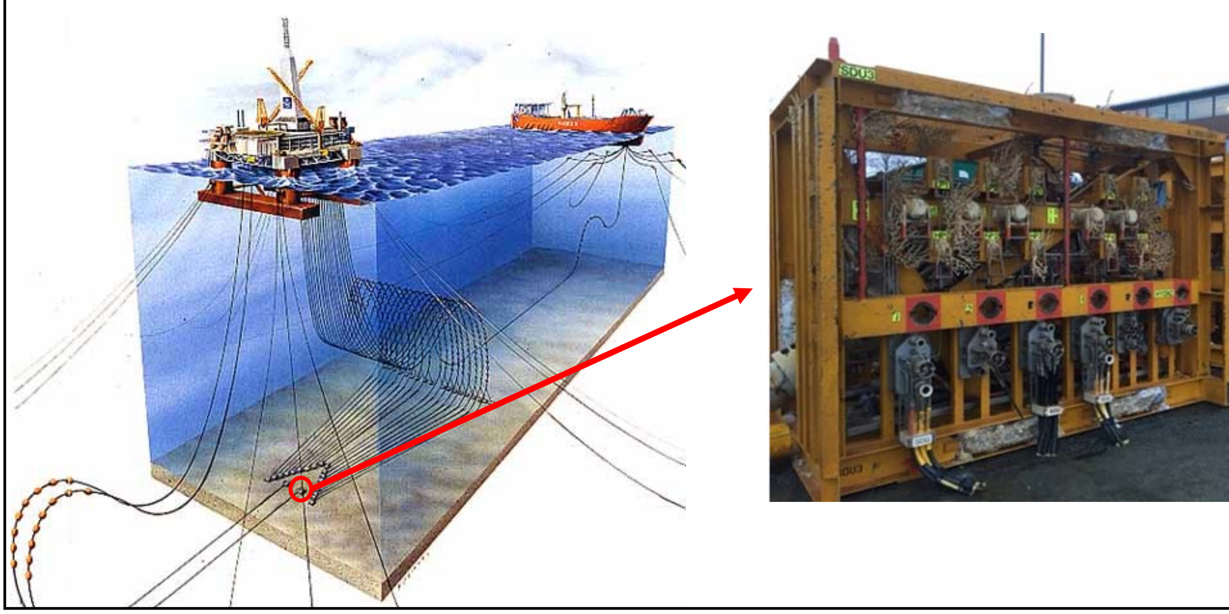


Figure 3 – Umbilical Cross Section Example

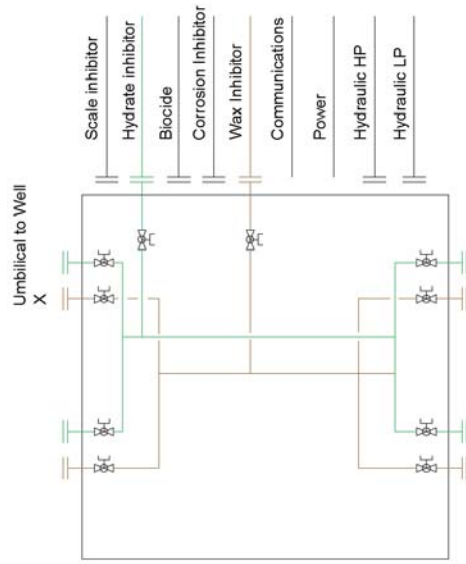
35

Umbilicals, injection of production chemicals

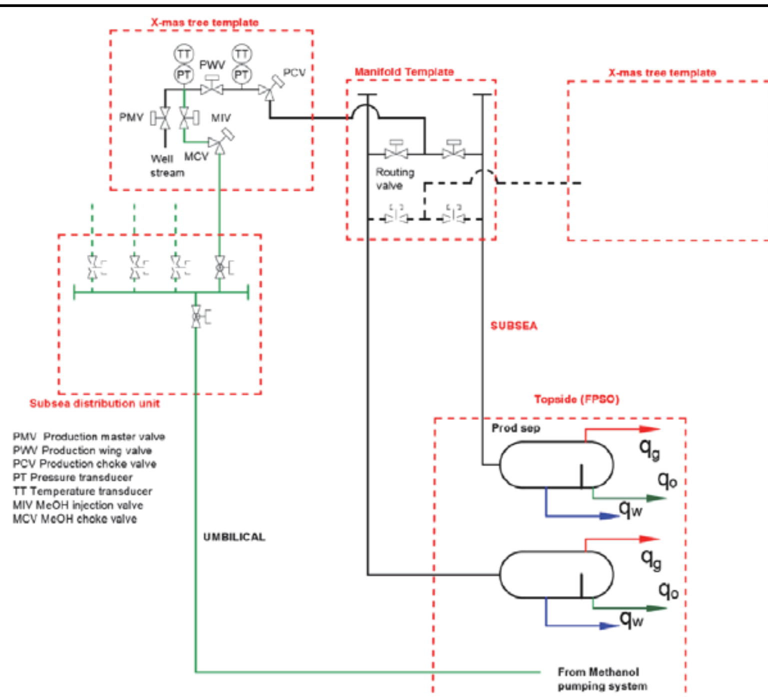


36

Release and disposal of chemicals

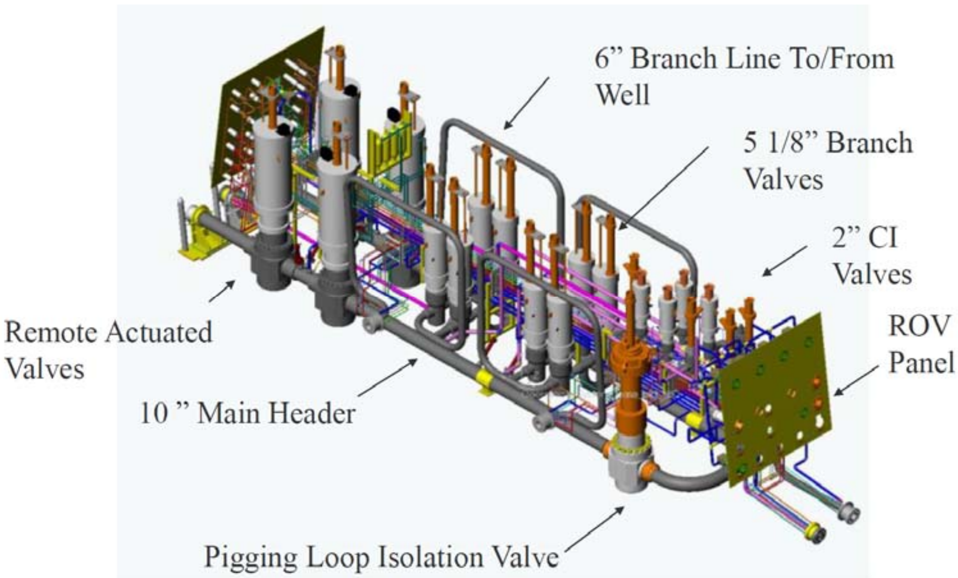


37



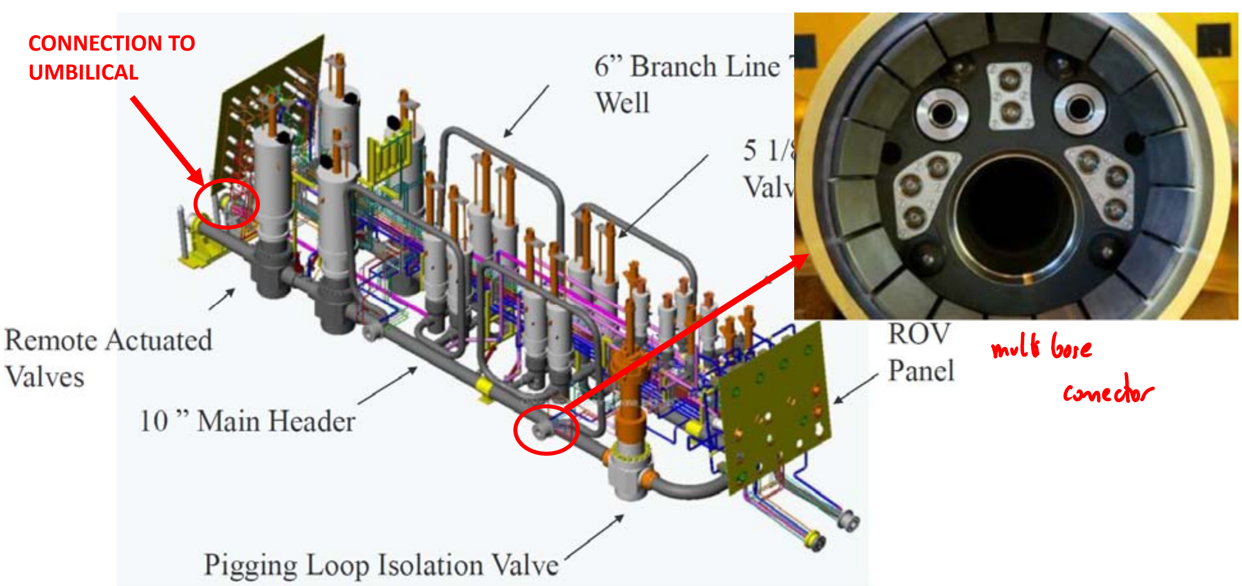
38

Injection of production chemicals – template wells

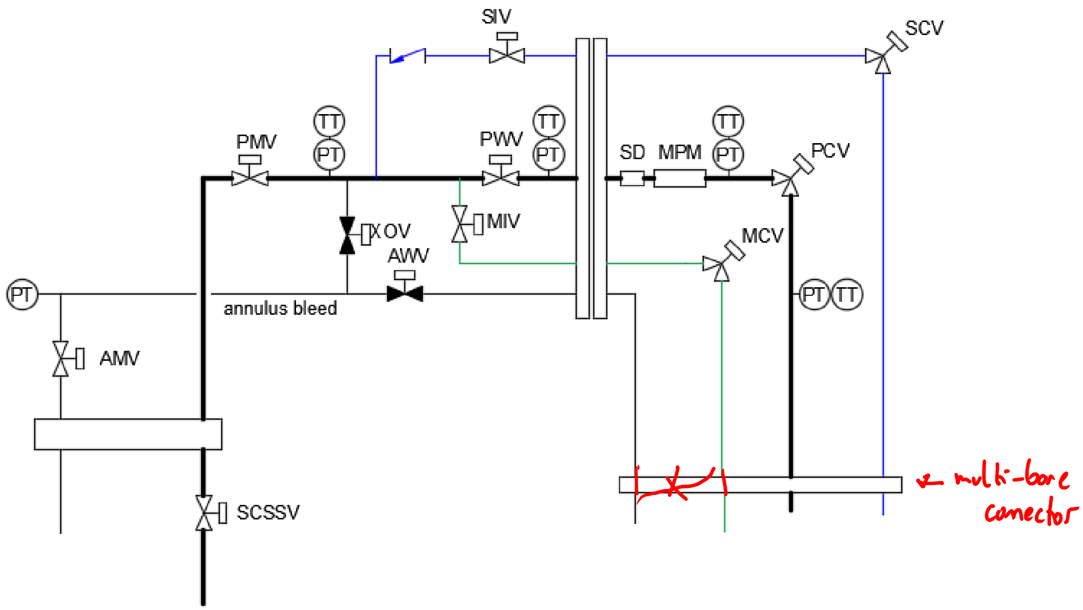


39

Injection of production chemicals – template wells

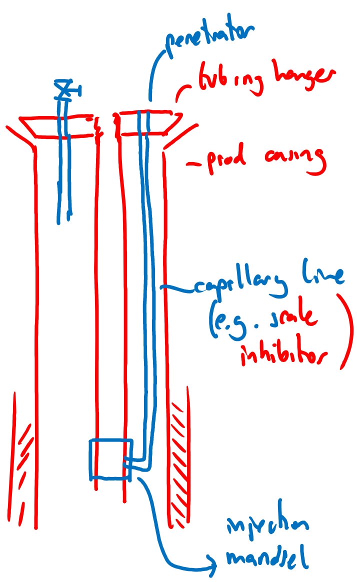


40



41

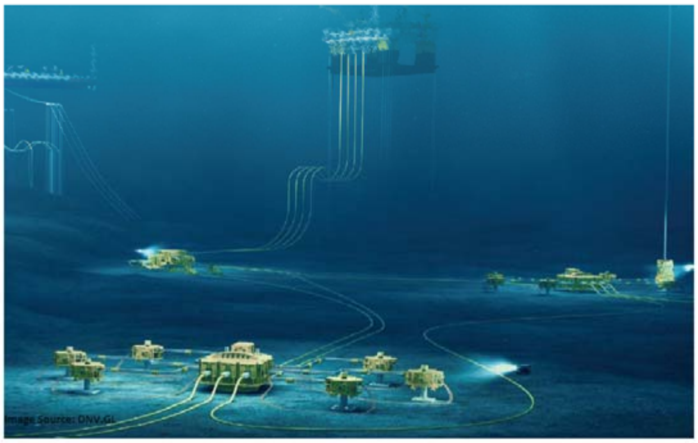
Injection of production chemicals in well

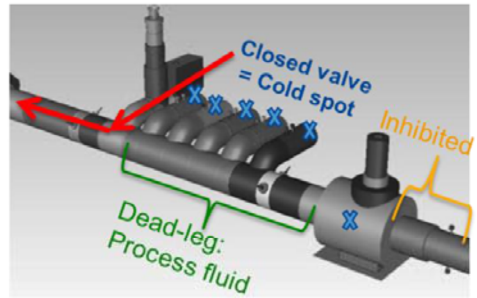


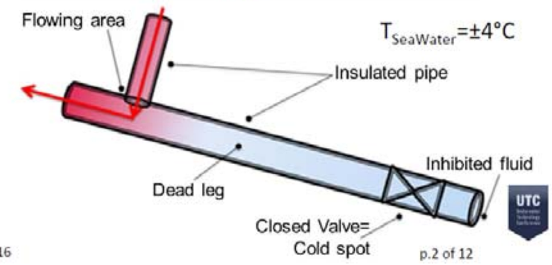
42

Subsea manifold and dead-leg geometry

- Dead-legs are inherently present

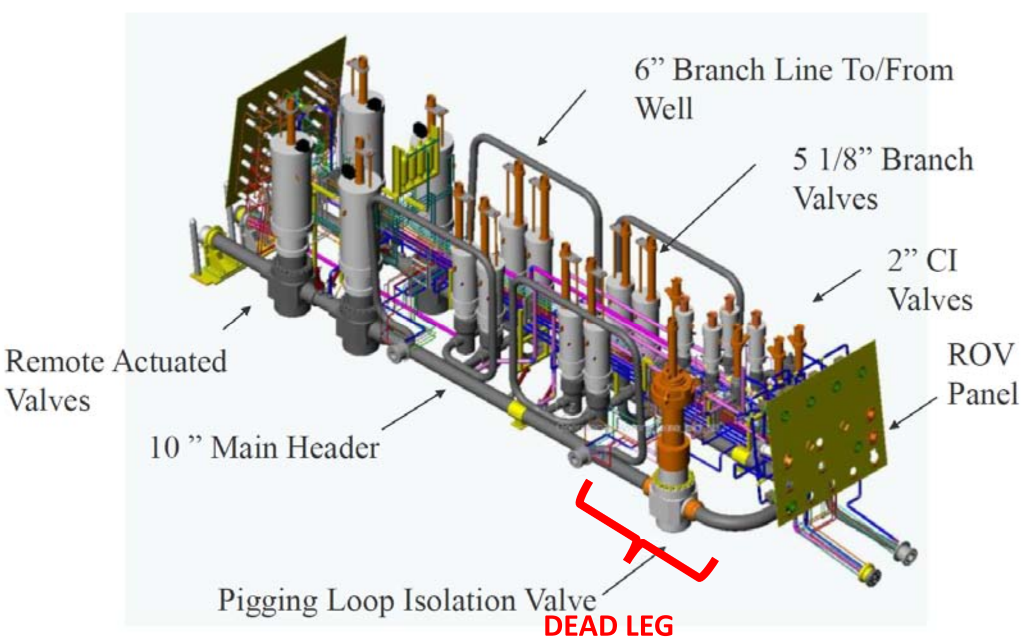






UTC Bergen - 16th June 2016

43



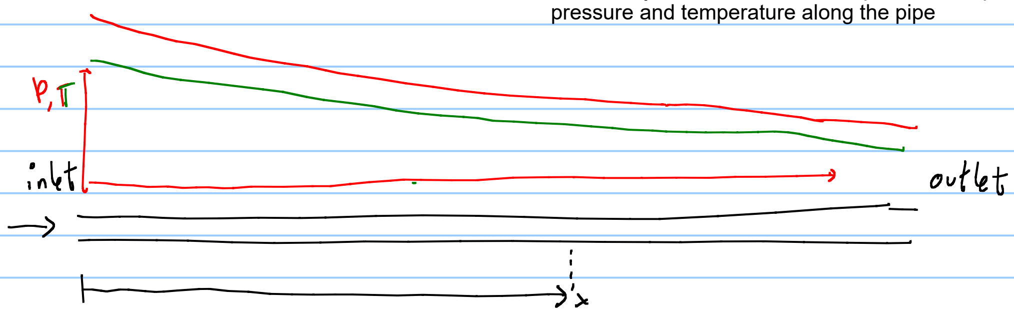
44

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)

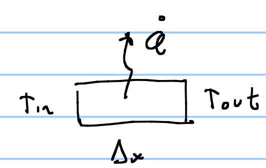
45

Most analysis on flow assurance problems require to compute distribution of pressure and temperature along the pipe



$\frac{dP}{dx}$ → momentum equation

$\underbrace{\frac{dT}{dx}}$ → energy conservation

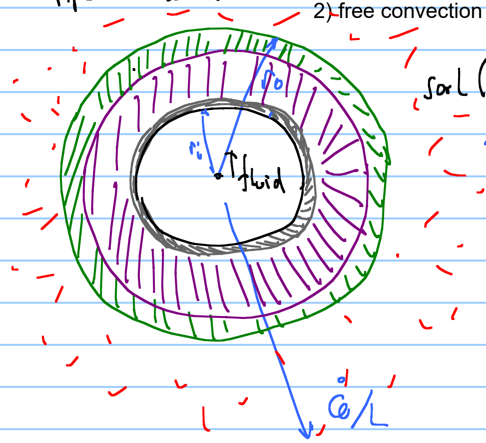


$\dot{Q} = A_i \cdot \Delta x \cdot U_i \,(T_f - T_{amb})$

Can be reffered with respect to the innermost radius or outermost radius

pipe cross section

From innermost: forced convection, conduction in pipe, conduction in insulation, and 1) conduction in soil or 2) free convection with seawater



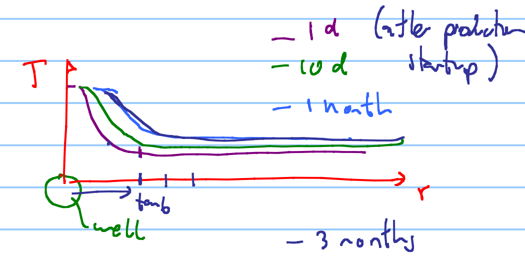
soil (buried or well) → gradual heating of soil

• Seawater

CO/L

• Tamb

Transient problem!



A clever solution proposed by Ramey

Wellbore Heat Transmission

1962

H. J. RAMEY, JR.
MEMBER AIME
MOBIL OIL CO.
SANTA FE SPRINGS, CALIF.

When the temperature of the formation is changing, U_o must be substituted by the transient overall heat transfer coefficient $U_f(t)$, defined by:

$$U_f(t) = \frac{U_o \cdot k_{soil}}{k_{soil} + r_{ins,o} \cdot U_o \cdot f(t)} \qquad \text{EQ. D-21}$$

$$f(t) = -ln\left(\frac{r_{ins,o}}{2 \cdot \sqrt{\alpha_{soil} \cdot t}}\right) - 0{,}29 \qquad \text{EQ. D-22}$$

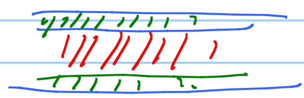
$$\alpha_{soil} = \frac{k_{soil}}{\rho_{soil} \cdot C_{p,soil}} \qquad \text{EQ. D-23}$$

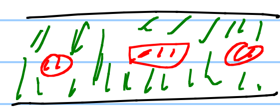
Where:

k_{soil}	Thermal conductivity, soil [W/m.K]
$C_{p,soil}$	Specific heat capacity, soil [J/K.kg]
α_{soil}	Thermal diffusivity, soil [m²/s]
t	Time [s]

It is important to make an order or magnitude analysis on the terms that make up the U and determine which one are most

$$\frac{1}{U_i} = \underbrace{\frac{1}{h_i}}_{\text{it might be low contribution}} + \underbrace{\frac{r_i \cdot \ln\left(\frac{r_i}{r_o}\right)}{k_p}}_{\text{low contribution to "U"}} + \underbrace{\frac{r_i \cdot \ln\left(\frac{r_{ins,o}}{r_o}\right)}{k_{ins}}}_{\text{significant contribution}} + \underbrace{\frac{r_i}{r_{ins,o} \cdot h_o}}_{\text{medium contribution}}$$





CHECK APPENDIX C and D of compendium!

Production optimization

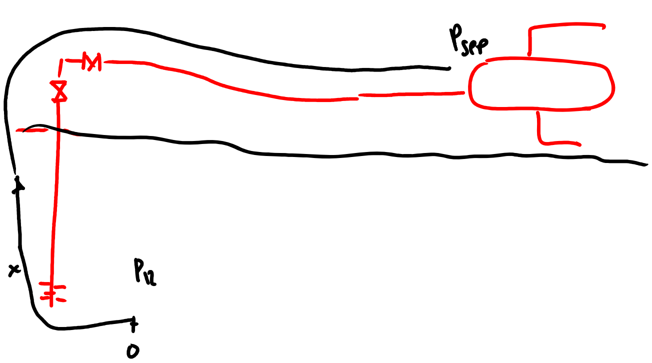
Prof. Milan Stanko (NTNU)

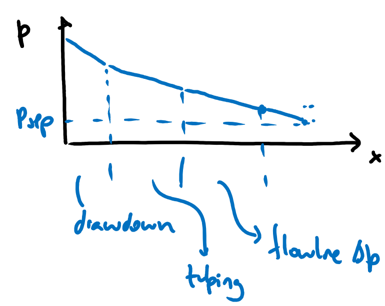
*Chapter 3 of compendium

1

Production optimization – what is it?

- Detect locations in the system with abnormally high-pressure loss and flow restrictions





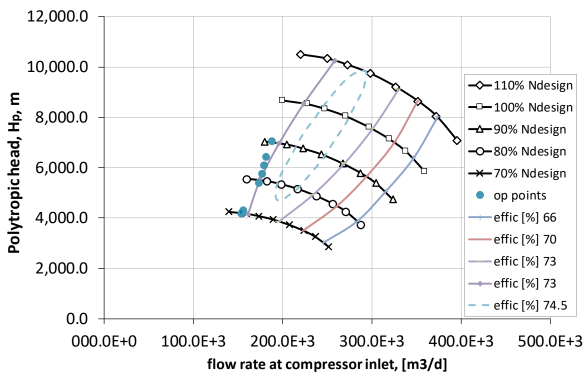
- wrongly designed (e.g. Φ of tubing, pipe)
- wax, scale, sand

Result: increase in production

2

Production optimization – what is it?

- Verification of equipment design conditions vs actual operating conditions



subsea compressor

3

Production optimization – what is it?

- Identification and addressing fluid sources that have “disadvantageous” characteristics (e.g. high water cut, high H_2S content)
- Identify and correct system malfunctions and unintended behavior
- Analyze and improve the logistics and planning of maintenance, replacement and installation of equipment or in the execution of field activities.
- Review the occurrence of failures and recognize patterns (data analytics?)

4

Production optimization – what is it?

- Calibration of instrumentation
- Identification of operational constraints (e.g. water handling capacity, power capacity)
- Observe and analyze the response of the system when changes are introduced
- Find control settings of equipment (or system characteristics) that give a production higher than current (or, preferably, that give maximum production possible)
- Find control settings of equipment (or system characteristics) that maximize an objective KPI
- Identify bottlenecks
- Identifying and monitoring Key Performance Indicators (KPIs)

5

Production optimization – what is it?

- Calibration of instrumentation
- Identification of operational constraints (e.g. water handling capacity, power capacity)
- Observe and analyze the response of the system when changes are introduced
- **Find control settings of equipment (or system characteristics) that give a production higher than current (or, preferably, that give maximum production possible)**
- **Find control settings of equipment (or system characteristics) that maximize an objective KPI**
- Identify bottlenecks
- Identifying and monitoring Key Performance Indicators (KPIs)

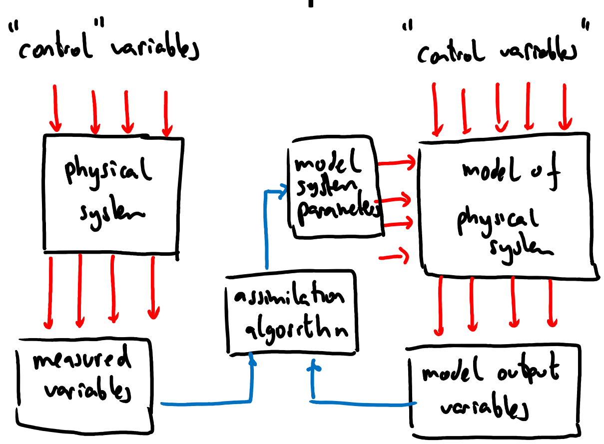
6

Time scales of production optimization

Long term	Short term	Shorter term
• Years, months	• Daily, weekly	• Seconds, minutes, hours

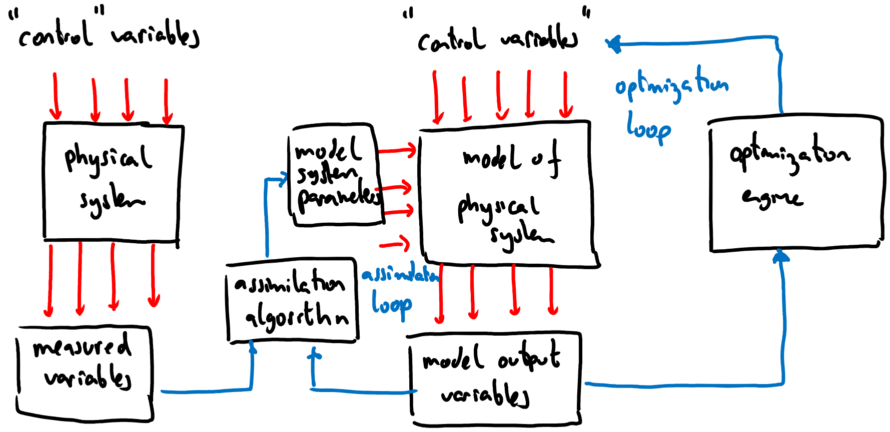
7

Model-based production optimization: fidelity



8

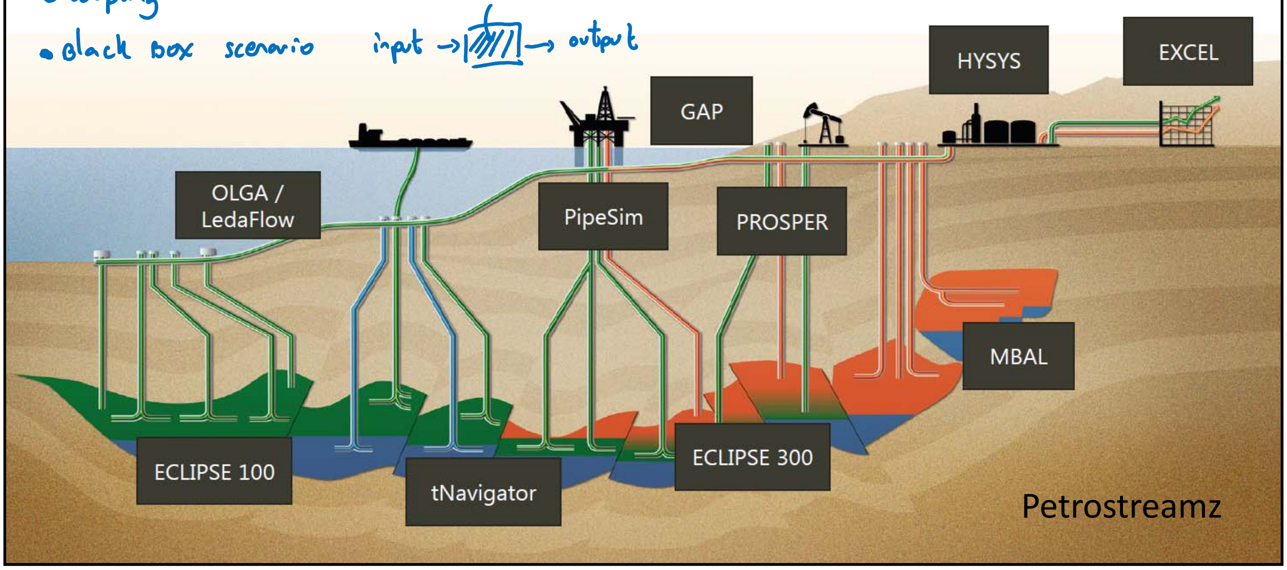
Model-based production optimization: optimization



9

Integrated asset modeling (IAM)

- consistency !!
- coupling
- black box scenario input → [ ] → output



10

Time scales of production optimization and models

Long term	Short term	Shorter term
• Years, months Models are highly uncertain (limited data) Models are typically transient (reservoir model) but in IAM also steady-state models are included	• Daily, weekly There is data to tune models Models are typically steady state (network, well, processing plant)	• Seconds, minutes, hours • Can we use steady state models? Or do we need transient models? • Why to use models? We can develop optimization strategies on the actual system

11

Time scales of production optimization and examples

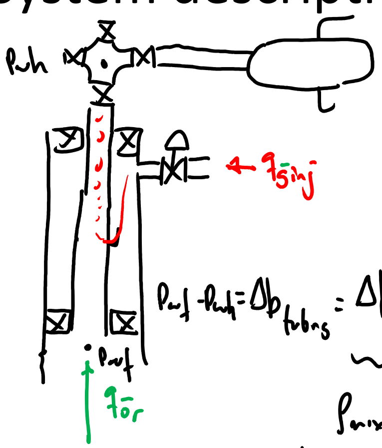
Long term	Short term	Shorter term
• Maximize recovery factor and NPV, reduce water cut and GOR • Control variables: well placement, well rates, well "status", well routing, "presence" of equipment (processing, ICD)	• Maximize oil production, condensate production, gas production, revenue • How to allocate a scarce resource (gas injection, power) • Variables: choke opening, gas lift rates, pump frequency, well routing	• Maximize production, revenue • Reduce and mitigate fluctuations • Variables: ~~choke~~ control valve opening, gas lift rates, pump frequency,

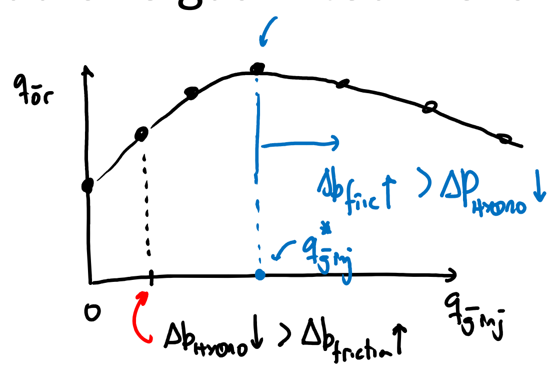
12

Examples

13

1. (Short term) Two standalone gas-lifted wells
System description





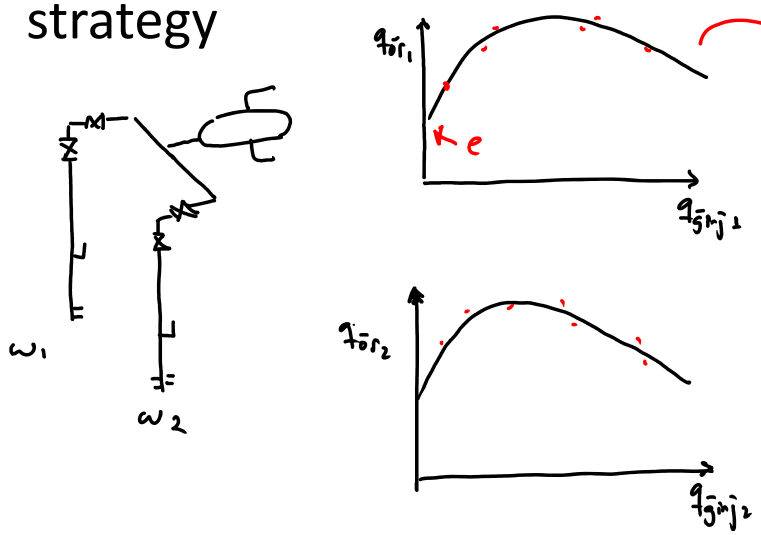
$$P_{wf} - P_{wh} = \Delta p_{tubing} = \underbrace{\Delta p_{HYDRO}}_{\rho_{mix} \cdot g} + \Delta p_{fric}$$

$$\Delta p_{fric} \downarrow \quad v^2 \quad \left(\frac{q_o + q_g}{A_p}\right)^2 \rightsquigarrow \Delta p_{fric} \uparrow$$

when $q_{g\,inj}$ increases $\rightsquigarrow \rho_{mix} \to \rho_{gas} \rightsquigarrow \Delta p_{HYDRO} \downarrow$

14

1. Two standalone gas-lifted wells: modeling strategy



$q_{or} = a\, q_{\bar{g}inj}^4 + b\, q_{\bar{g}inj}^3 + c\, q_{\bar{g}inj}^2 + d\, q_{\bar{g}inj} + e$

when is $q_{\bar{o}total} = q_{\bar{o}r_1} + q_{\bar{o}r_2}$ maximum?

at which $q_{\bar{g}inj_1}$? $q_{\bar{g}inj_2}$?

what if there is a gas constraint on gas available? $q_{\bar{g}inj\,tot} \geq q_{\bar{g}inj_1} + q_{\bar{g}inj_2}$

15

1. Two standalone gas-lifted wells: objective function behavior – brute force color map

$q_{\bar{o}TOTAL} = q_{\bar{o}r_1}(q_{\bar{g}inj_1}) + q_{\bar{o}r_2}(q_{\bar{g}inj_2})$

$q_{\bar{o}TOTAL} = f(q_{\bar{g}inj_1}, q_{\bar{g}inj_2})$

$\underset{max}{z} = f(x, y)$

x^*, y^*

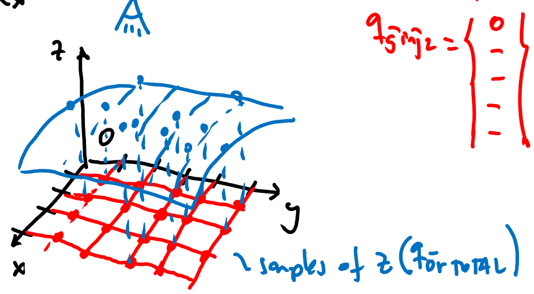
$q_{\bar{g}inj_1} = \{ - \; - \; - \; - \; - \}$

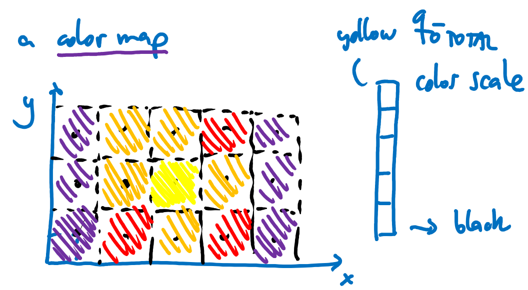
$q_{\bar{g}inj_2} = \{ 0 \; - \; - \; - \; - \}$

1) element-wise combination of all

2) evaluate z ($q_{\bar{o}TOTAL}$) for all

3) make a color map





16

1. Two standalone gas-lifted wells: objective function behavior – brute force color map

```python
#CASE: SYSTEM OF TWO STANDALONE GAS-LIFTED WELLS
#AUTHOR: MILAN STANKO, NTNU, COURSE: TPG4230
#IMPORTING NEEDED LIBRARIES
import numpy as np
from scipy.optimize import fsolve
import matplotlib.pyplot as plt
```

```python
def GLPerf_qo(a, b, c, d,e, qgi):
    res =a*np.power(qgi,4)+ b*np.power(qgi,3)+c*np.power(qgi,2)+d*qgi+e  #performance curve fitted to 4th degree polynomial
    return res
```

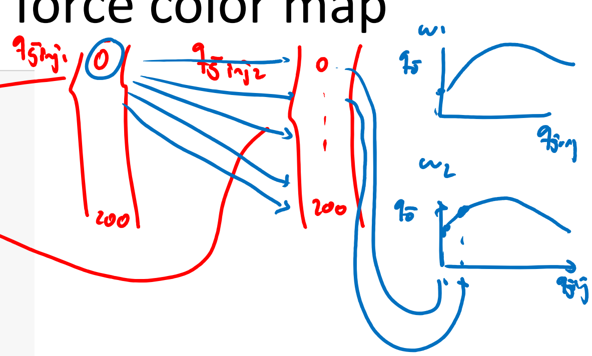
```python
#gas lift performance curve data for two wells
a1=-3.9e-7  #(1/1e03 Sm3/d)^3
b1=2.1e-4   #(1/1e03 Sm3/d)^2
c1=-0.043   #(1/1e03 Sm3/d)
d1=3.7      #
e1=12       #(1e03 Sm3/d)
a2=-1.3e-7  #(1/1e03 Sm3/d)^3
b2=1e-4     #(1/1e03 Sm3/d)^2
c2=-0.028   #(1/1e03 Sm3/d)
d2=3.1
e2=-17       #(1e03 Sm3/d)
Po=6.29*80   #oil price USD/Sm3
Pg=2/8     #gas price, USD/Sm3
```

17

1. Two standalone gas-lifted wells: objective function behavior – brute force color map

```python
#BRUTE-FORCE COMPUTING ALL COMBINATIONS
npoints=100
qgi_max=200  #[1e03 Sm3/d]
qgi_w1=np.linspace(0,qgi_max,npoints)
qgi_w2=np.linspace(0,qgi_max,npoints)
qotot=[]
qgitot=[]
revenue=[]
#computing objective (total oil production or revenue) and
#constraint, total gas injected
for qgi1 in qgi_w1:
    for qgi2 in qgi_w2:
        qo1=GLPerf_qo(a1,b1,c1,d1,e1,qgi1)
        qo2=GLPerf_qo(a2,b2,c2,d2,e2,qgi2)
        qotot=np.append(qotot,qo1+qo2)
        qgitot=np.append(qgitot,qgi1+qgi2)
        revenue=np.append(revenue,(qo1+qo2)*Po-(qgi1+qgi2)*Pg)
revenue=revenue/1e3
```

[1E03 USD]



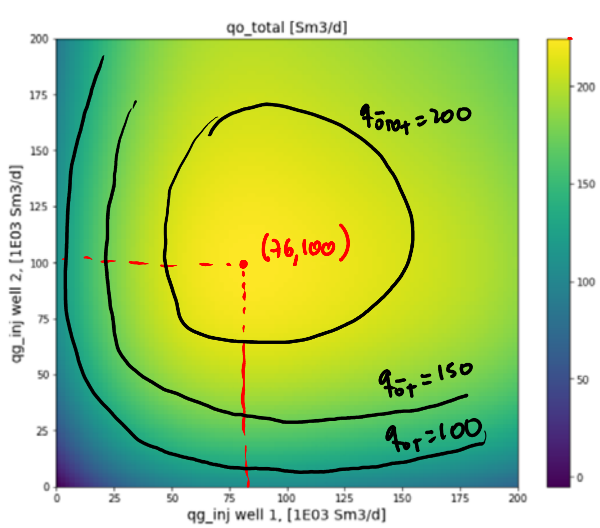
18

1. Two standalone gas-lifted wells: objective function behavior – brute force color map

```
#CREATING COLORMAPS AND CONTOUR PLOTS OF OBJECTIVE VARIABLE (total oil production)
#AND CONSTRAINED VARIABLE (total gas injection rate)
obj_opt=2  #1 if oil rate, 2 if revenue
if obj_opt==2:
    obj=revenue
    tag='revenue [1e3 USD]'
    levels_obj=np.linspace(50,110,5)
elif obj_opt==1:
    obj=qotot
    tag='qo_total [Sm3/d]'
    levels_obj=np.linspace(50,210,5)
constr=qgitot
#specifying desired number and range of contour lines
levels_qgi=np.linspace(100,200,4)
plt.figure(figsize=(10,8))
#creating mesh of qgin1,qgin2 to plot
xi,yi=np.mgrid[qgi_w1.min():qgi_w1.max():npoints*1j,qgi_w2.min():qgi_w2.max():npoints*1j]#ar
#Contour plot of objective function, total oil production
contour_obj=plt.contour(xi,yi,obj.reshape(xi.shape),levels=levels_obj,colors='black')
plt.clabel(contour_obj, inline=True, fmt='%1.0f',fontsize=12)
#Plot contour of constraint variable, total gas injection
contour_qgi=plt.contour(xi,yi,constr.reshape(xi.shape),levels=levels_qgi,colors='maroon')
plt.clabel(contour_qgi, inline=True,fmt='%1.0f', fontsize=12)
#plot color map of objective function, total oil production
plt.pcolormesh(xi,yi,obj.reshape(xi.shape))
#axis labels and plot title
plt.xlabel('qg_inj well 1, [1E03 Sm3/d]',fontsize=14)
plt.ylabel('qg_inj well 2, [1E03 Sm3/d]',fontsize=14)
plt.title(tag,fontsize=14)
plt.colorbar()
plt.show()
```

19

1. Two standalone gas-lifted wells: objective function behavior – brute force color map



where is $q_{o\,total}$ maximum? i believe:

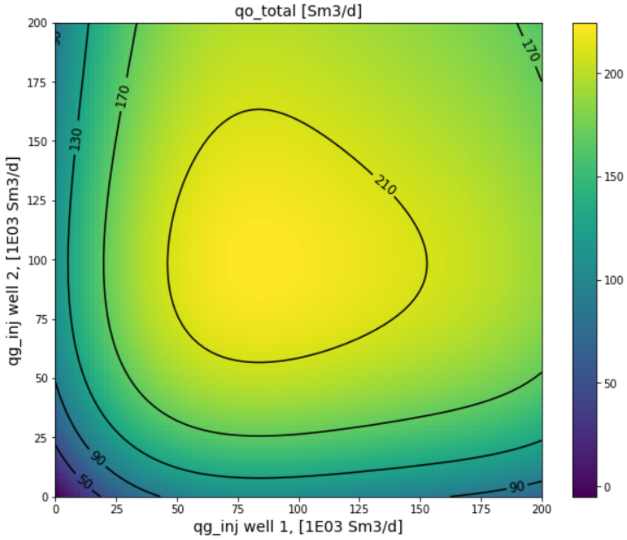
$q_{o\,total} = 225$ Sm³/d $q_{g\,inj\,1} \simeq 76E3$ Sm³/d

$q_{g\,inj\,2} \simeq 100E3$ Sm³/d

contour plot → join all points with a line that have the same $q_{o\,total}$

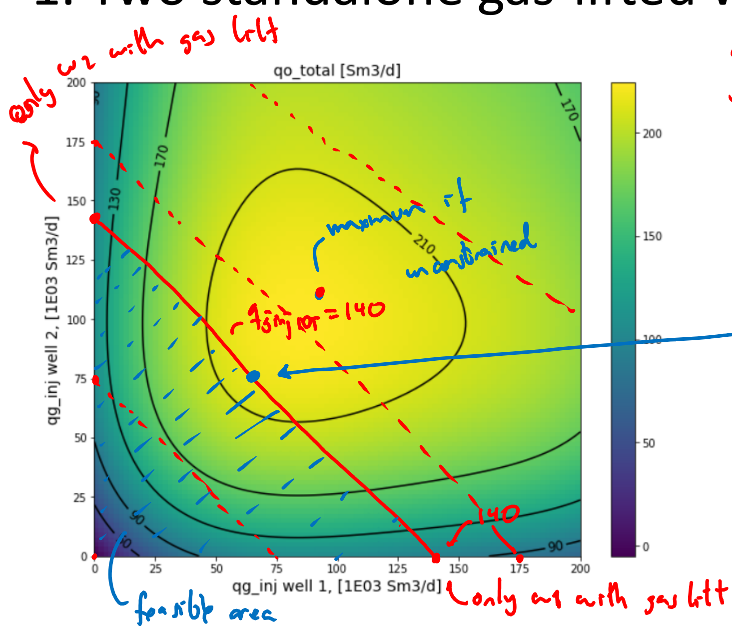
20

1. Two standalone gas-lifted wells: objective function behavior – contour lines



21

1. Two standalone gas-lifted wells: constraint



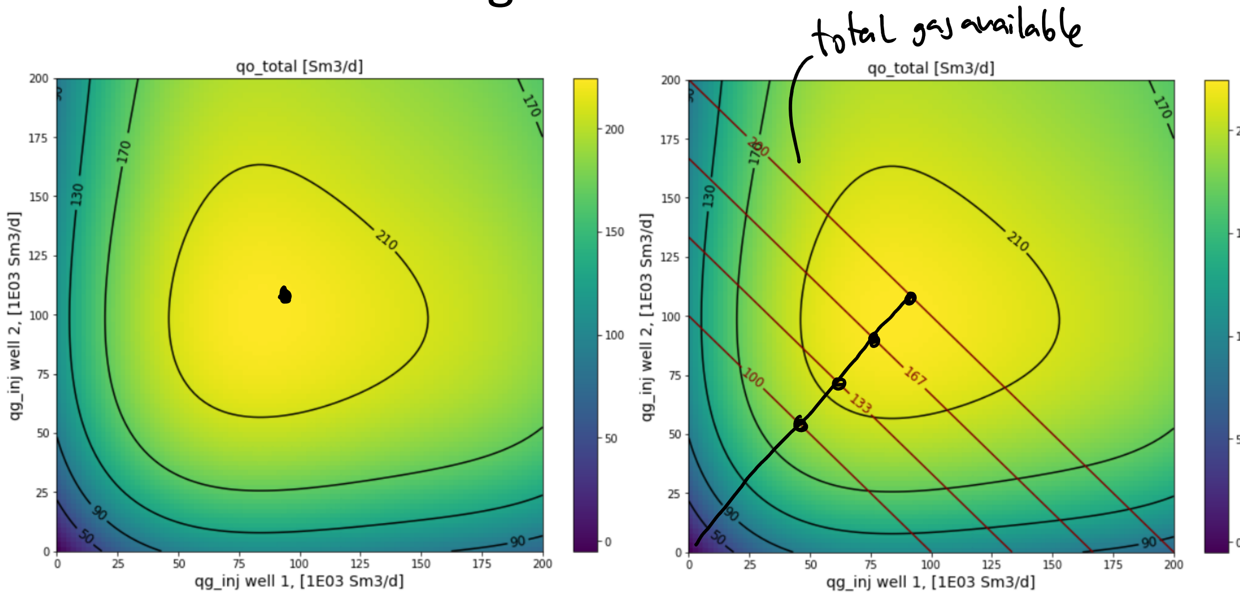
$$\underbrace{q_{g\,inj\,total}}_{140\text{ E03 Sm}^3/d} \geq \underbrace{q_{g\,inj\,1} + q_{g\,inj\,2}}$$

$x + y = \text{constant}$

$y = \text{const} - x$

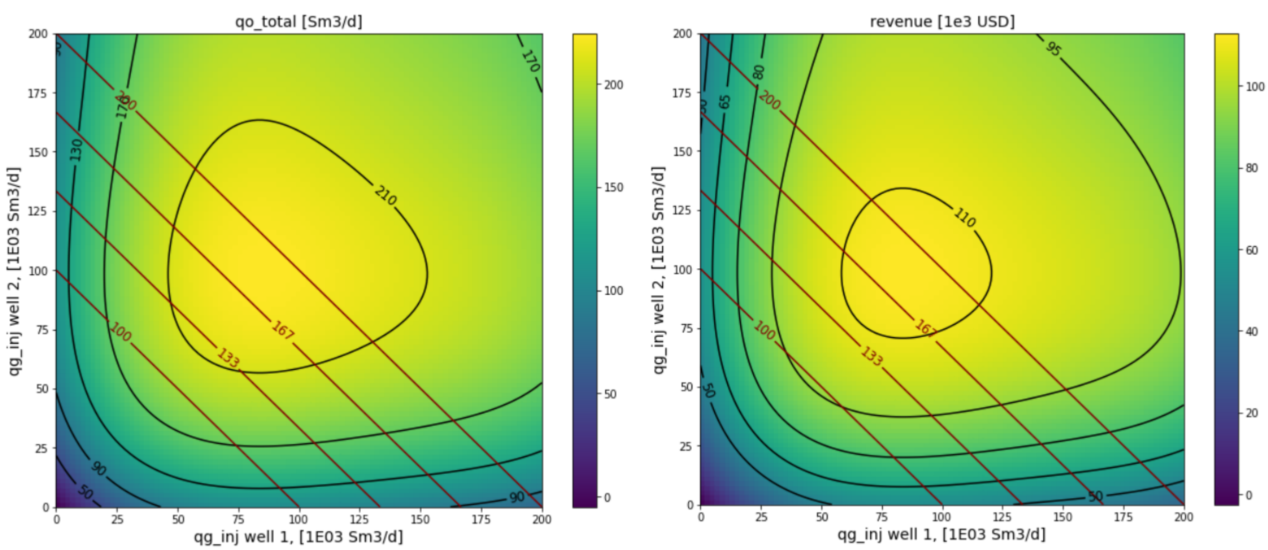
22

1. Two standalone gas-lifted wells: constraint



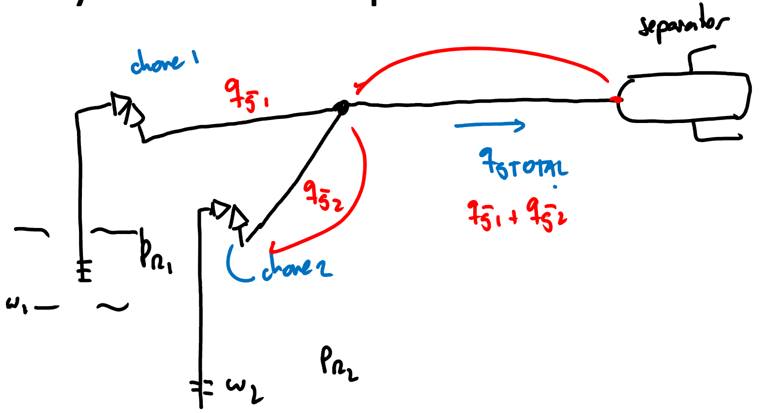
23

1. Two standalone gas-lifted wells: change of objective function



24

2. (Short term)Two gas wells in a network System description



each well produces some condensate

$CGR_1 = 0$

$CGR_2 =$ non zero

maximize $q_{\bar{g}TOTAL}$, revenue, condensate

constraints in $q_{\bar{g}1} \leq q_{\bar{g}max}$

to avoid sand production

25

2. Two gas wells in a network – modeling approach

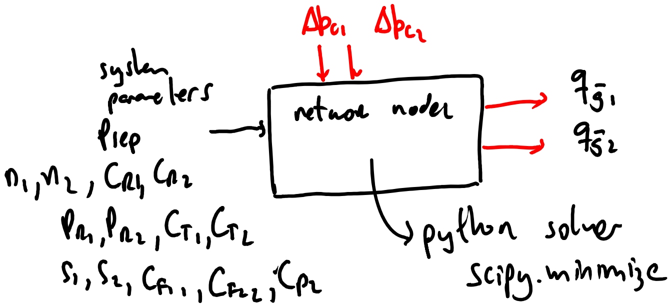
Dry gas equations :

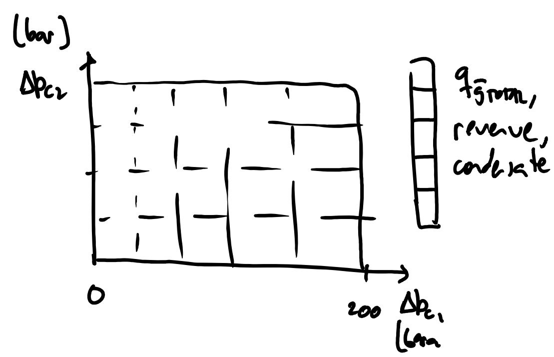
$$q_{\bar{g}} = C_R \left(p_R^2 - p_{wf}^2\right)^n$$

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

$$q_{\bar{g}} = \left(p_{in}^2 - p_{out}^2\right)^{0.5} C_{FL}$$

$$q_{\bar{g}} = f\left(\Delta p_{choke1}, \Delta p_{choke2}\right)$$



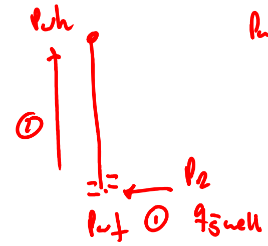


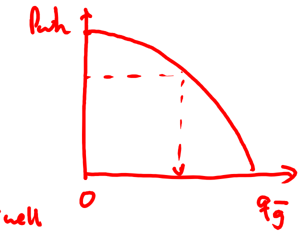
26

2. Two gas wells in a network – modeling approach

```python
#AUTHOR: MILAN STANKO, NTNU, COURSE: TPG4230
#IMPORTING NEEDED LIBRARIES
import numpy as np
from scipy.optimize import minimize
import matplotlib.pyplot as plt
```

```python
#FUNCTIONS
def IPRqg(CR, n, pR, pwf):
    a = CR * np.power((np.power(pR, 2) - np.power(pwf,2)),n)
    return a

def IPRpwf(CR, n, pR, qg):
    a = np.power(((np.power(pR, 2) - np.power((qg / CR), (1 / n)))) , 0.5)
    return a

def Tubingqg(CT, s, p1, p2):
    a = CT * np.power((np.power(p1, 2) / np.exp(s) - np.power(p2, 2)), 0.5)
    return a

def Tubingp1(CT, s, p2, qg):
    a = math.exp(s / 2) * np.power((np.power(p2, 2) + np.power((qg / CT),2)), 0.5)
    return a

def Tubingp2(CT, s, p1, qg):
    a = np.power((np.power(p1, 2) / np.exp(s) - np.power((qg / CT), 2)),0.5)
    return a
#WELLHEAD PERFORMANCE RELATIONSHIP
def WPR_pwh(pR,CR,n,CT,S,qg):
    pwf=IPRpwf(CR, n, pR, qg)
    pwh=Tubingp2(CT,S,pwf,qg)
    return pwh

v_WPR_pwh=np.vectorize(WPR_pwh)
```



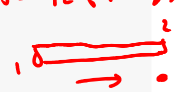


WPR_pwh({pR1, pR2}, {CR1, CR2}, {n1, n2}, {CT1, CT2}, {S1, S2}, {qg1, qg2}) = {pwh1, pwh2}

27

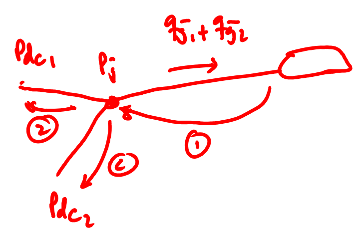
2. Two gas wells in a network – modeling approach

$q_g = C_{pL}(p_1^2 - p_2^2)^{0.5}$



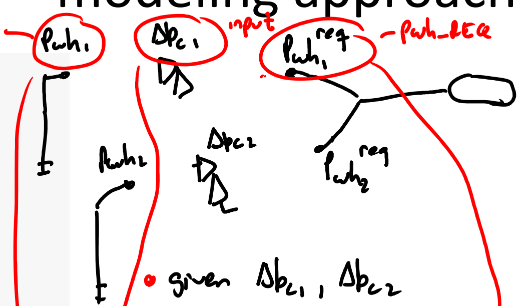

```python
def Lineqg(Cfl, p1, p2):
    a = Cfl * np.power(np.power(p1, 2) - np.power(p2, 2), 0.5)
    return a

def Linep1(Cfl, p2, qg):
    a = np.power((np.power(p2, 2) + np.power((qg / Cfl), 2)),0.5)
    return a

def Linep2(Cfl, p1, qg):
    a = np.power((np.power(p1, 2) - np.power((qg / Cfl), 2)), 0.5)
    return a

v_Linep1=np.vectorize(Linep1)
#REQUIRED PRESSURE AT CHOKE DISCHARGE CALCULATED FROM SEPARATOR FOR ALL WELLS
def pwh_REQ(Cpl,Cfl,psep,qg):
    pj=Linep1(Cpl,psep,np.sum(qg))
    pwh=v_Linep1(Cfl,pj,qg)
    return pwh

def error(qg,pR,CR,n,CT,S,Cpl,Cfl,psep,DP):
    pavail=v_WPR_pwh(pR,CR,n,CT,S,qg)
    preq=pwh_REQ(Cpl,Cfl,psep,qg)
    a=pavail-DP-preq
    a=np.power(a,2)
    return np.sum(a)
```

Line p1({CfL1, CfL2}, {pj, pj}, {qg1, qg2}) → {pin1, pin2}



28

2. Two gas wells in a network – modeling approach




```
def Lineqg(Cfl, p1, p2):
    a = Cfl * np.power(np.power(p1, 2) - np.power(p2, 2), 0.5)
    return a

def Linep1(Cfl, p2, qg):
    a = np.power((np.power(p2, 2) + np.power((qg / Cfl), 2)),0.5)
    return a

def Linep2(Cfl, p1, qg):
    a = np.power((np.power(p1, 2) - np.power((qg / Cfl), 2)), 0.5)
    return a

v_Linep1=np.vectorize(Linep1)
#REQUIRED PRESSURE AT CHOKE DISCHARGE CALCULATED FROM SEPARATOR FOR ALL WELLS
def pwh_REQ(Cpl,Cfl,psep,qg):
    pj=Linep1(Cpl,psep,np.sum(qg))
    pwh=v_Linep1(Cfl,pj,qg)
    return pwh

def error(qg,pR,CR,n,CT,S,Cpl,Cfl,psep,DP):
    pavail=v_WPR_pwh(pR,CR,n,CT,S,qg)
    preq=pwh_REQ(Cpl,Cfl,psep,qg)
    a=pavail-DP-preq
    a=np.power(a,2)
    return np.sum(a)
```

calculate P_{wh_1}, P_{wh_2}

calculate $P_{wh_1}^{req}, P_{wh_2}^{req}$

- given Δp_{c_1}, Δp_{c_2}
- find q_{g_1}, q_{g_2} such that

$$P_{wh_1} - \Delta p_{c_1} = P_{wh_1}^{req}$$

$$P_{wh_2} - \Delta p_{c_2} = P_{wh_2}^{req}$$

$$error = \left(P_{wh_1} - \Delta p_{c_1} - P_{wh_1}^{req}\right)^2 + \left(P_{wh_2} - \Delta p_{c_2} - P_{wh_1}^{req}\right)^2$$

29

2. Two gas wells in a network – modeling approach

solver changing q_{g_1}, q_{g_2}, such that

$$\min \left(P_{wh_1} - \Delta p_{c_1} - P_{wh_1}^{req}\right)^2 + \left(P_{wh_2} - \Delta p_{c_2} - P_{wh_2}^{req}\right)^2$$

30

2. Two gas wells in a network – modeling approach

```
#INPUT DATA
pR1=240  #bara
pR2=210  #bara
pR=[pR1,pR2]
CR1=1000 #Sm3/bar2n
CR2=700 #Sm3/bar2n
CR=[CR1,CR2]
n1=0.8
n2=0.75
n=[n1,n2]
S1=0.43
S2=0.34
S=[S1,S2]
CT1=38152 #Sm3/bar2
CT2=41163 #Sm3/bar2
CT=[CT1,CT2]
qg=[10,10]  #initial seed for well rate Sm3/d
Cpl=49406 #Sm3/bar2
Cfl1=70152.7 #Sm3/bar2
Cfl2=69883.2 #Sm3/bar2
Cfl=[Cfl1,Cfl2]
psep=60  #bara
CGR1=0  #Sm3/Sm3
CGR2=1/3000  #Sm3/Sm3
CGR=[CGR1,CGR2]
Po=6.29*80  #oil price USD/Sm3
Pg=1.5/8    #gas price, USD/Sm3
```

31

2. Two gas wells in a network – modeling approach

```
#BRUTE FORCE SOLVING ALL COMBINATIONS
npoints=20
DP1max=150  #bara
DP1=np.linspace(0,DP1max,npoints)
DP2max=150  #bara
DP2=np.linspace(0,DP2max,npoints)
qgtotal=[]
qctotal=[]
qg1=[]
qg2=[]
for dp1 in DP1:
    for dp2 in DP2:
        x=minimize(error,qg,args=(pR,CR,n,CT,S,Cpl,Cfl,psep,[dp1,dp2]),method='Nelder-Mead')
        qg1=np.append(qg1,x.x[0])
        qg2=np.append(qg2,x.x[1])
        qctotal=np.append(qctotal,np.dot(CGR,x.x))
        qgtotal=np.append(qgtotal,np.sum(x.x))
revenue=qctotal*Po+qgtotal*Pg
#converting output to millions
revenue=revenue/1e06
qg1=qg1/1e06
qg2=qg2/1e06
qgtotal=qgtotal/1e06
```

Δp_{c1} [0, -, -, -, -, -, 150]

Δp_{c2} [0, -, -, -, -, 150]

~ like excel solver

by changing $\{q_{g1}, q_{g2}\}$

collection of results $\{q_{g1}, q_{g2}\} \cdot \{CGR_1, CGR_2\}$ +

32

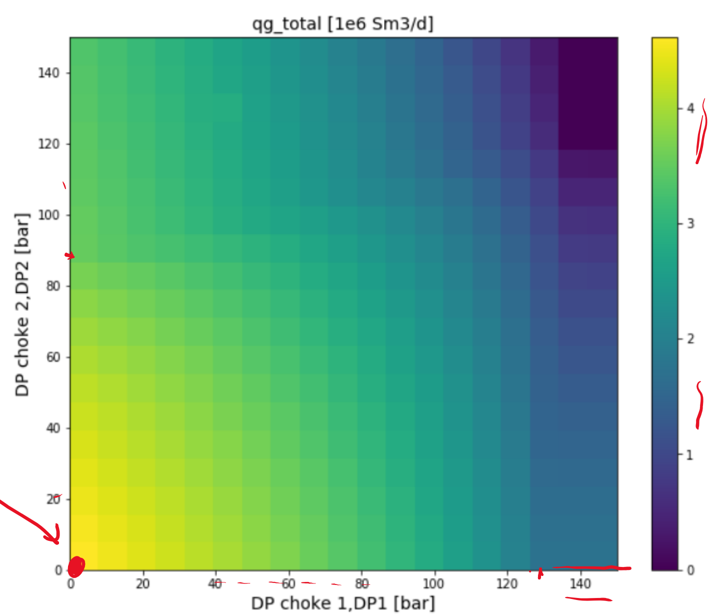
2. Two gas wells in a network – plotting

```
#CREATING COLORMAPS AND CONTOUR PLOTS OF OBJECTIVE VARIABLE
#AND CONSTRAINED VARIABLE
obj_opt=3  #1 if revenue, 2 if gas, 3 if condensate
if obj_opt==1:
    obj=revenue
    tag='revenue [1e6 USD]'
elif obj_opt==2:
    obj=qgtotal
    tag='qg_total [1e6 Sm3/d]'
elif obj_opt==3:
    obj=qctotal
    tag='qc_total[Sm3/d]'
const_opt=1 #1 if well 1 gas rate, 2 if gas rate of well 2, 3 if total gas rate
if const_opt==1:
    constr=qg1
elif const_opt==2:
    constr=qg2
elif const_opt==3:
    constr=qgtotal
plt.figure(figsize=(10,8))
#creating mesh of DP1,DP2 to plot
xi,yi=np.mgrid[DP1.min():DP1.max():npoints*1j,DP2.min():DP2.max():npoints*1j]#another option to this is to use X,Y=np.meshgr
#Contour plot of objective function
contour_obj=plt.contour(xi,yi,obj.reshape(xi.shape),4,colors='black')
plt.clabel(contour_obj, inline=True, fmt='%1.1f',fontsize=12)
#Contour plot of constraint
contour_constr=plt.contour(xi,yi,constr.reshape(xi.shape),4,colors='maroon')
plt.clabel(contour_constr, inline=True, fmt='%1.1f',fontsize=12)
#plot color map of objective function,
plt.pcolormesh(xi,yi,obj.reshape(xi.shape))
#axis labels and plot title
plt.xlabel('DP choke 1,DP1 [bar]',fontsize=14)
plt.ylabel('DP choke 2,DP2 [bar]',fontsize=14)
plt.title(tag,fontsize=14)
plt.colorbar()
plt.show()
```

33

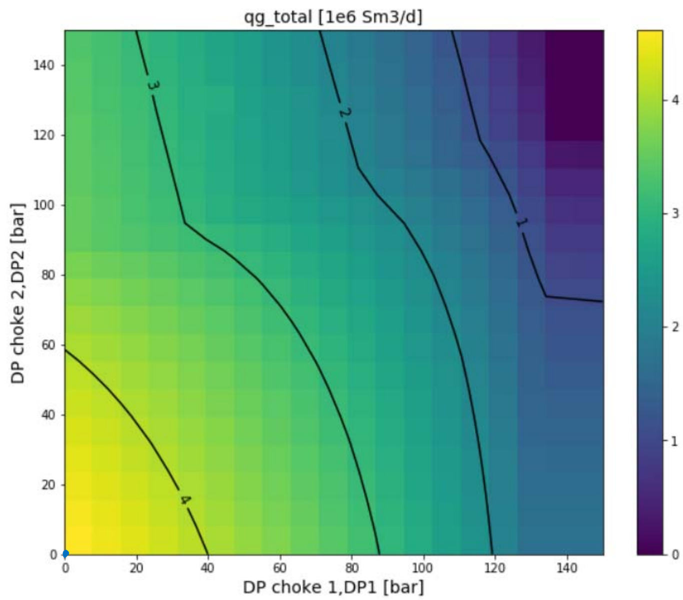
2. Two gas wells in a network – objective function: gas rate

maximum total gas production



34

2. Two gas wells in a network – objective function: gas rate

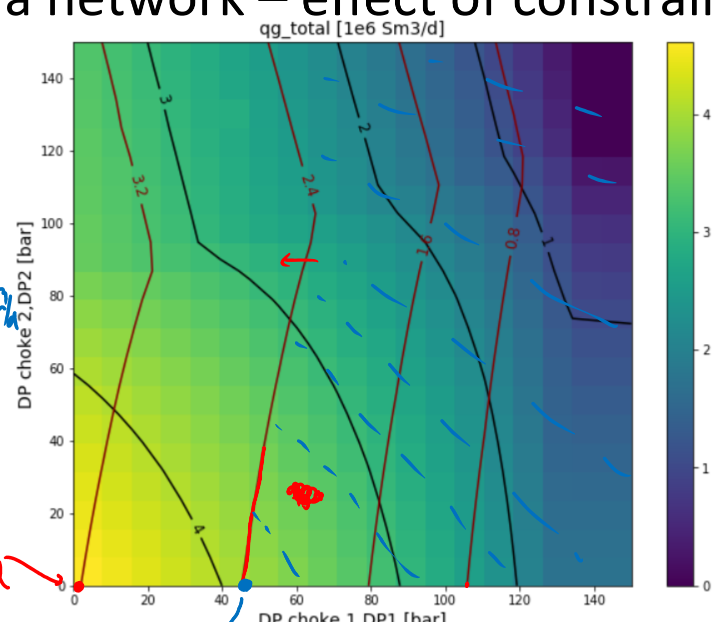


35

2. Two gas wells in a network – effect of constraint: gas rate or well 1

2.4E06
$q_{g1} \leq$ ~~[illegible]~~ Sm^3/d
due to sand production

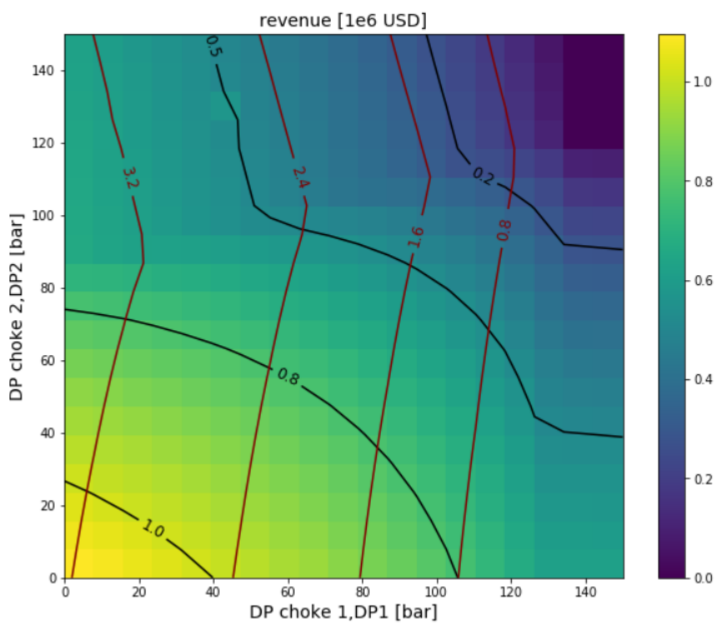
max q_g if constrained by $q_{g1} \leq 2.4E6$ Sm^3/d



max q_g if unconstrained

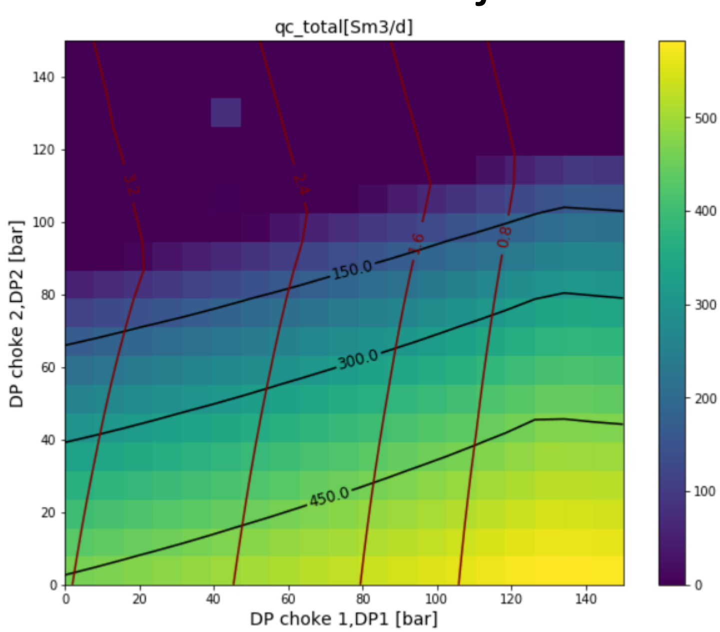
36

2. Two gas wells in a network – objective function: revenue



37

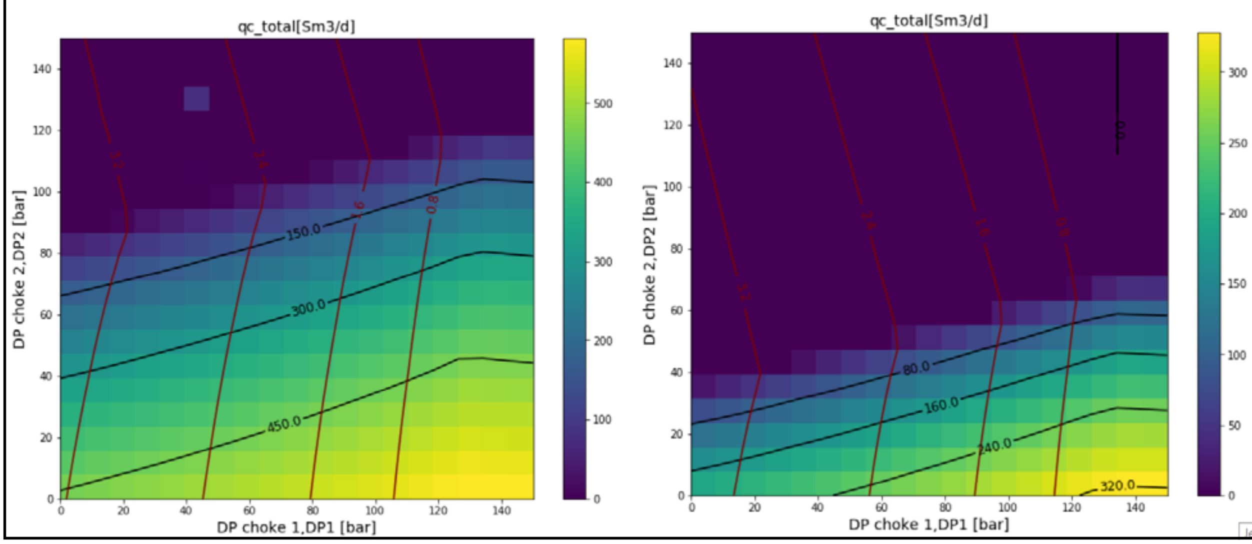
2. Two gas wells in a network – objective function: condensate



38

2. Two gas wells in a network – effect of depletion

$P_{R_2} = 210$ bara $P_{R_2} = 150$ bara



39

3. (Long term) Field planning: effect of plateau rate and well number on NPV

3. Field planning: effect of plateau rate and well number on NPV

The NPV function:

$$f_{NPV} = \sum_{k=1}^{N} \frac{Rt_k}{(1+i)^k}$$

Where, for year «k»:

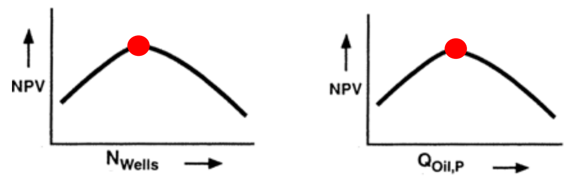
$$Rt_k = Revenue_k - OPEX_k - DRILLEX_k - CAPEX_k$$

Known issue: There is an optimal production scheduling and drilling schedule that maximize NPV

Action	Advantages	Disadvantages
Higher HC rates during early times	Gives higher revenue	Gives higher cost (CAPEX, OPEX)
Drill more wells	Allows for higher rates, extends field life	Gives higher cost (DRILLEX, CAPEX, OPEX)

3. Field planning: effect of plateau rate and well number on NPV

Variation of NPV with plateau rate and number of wells:



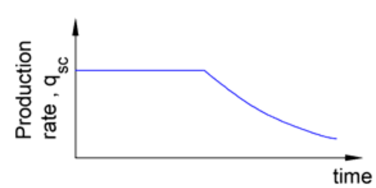
Choosing between rocks, hard places and a lot more: the economic interface

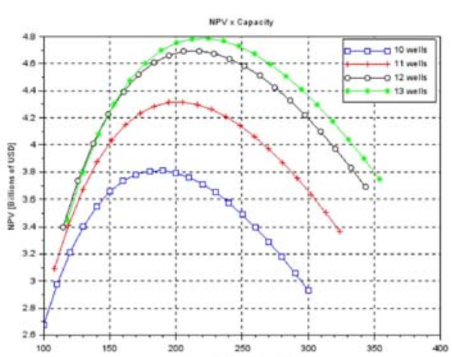
Helge Hove Haldorsen

42

3. Field planning: effect of plateau rate and well number on NPV

- The field will produce initially in plateau mode, with constant rate and then decline
- Constant hydrocarbon price
- All wells are pre-drilled and available from start
- Decision variables: plateau rate and number of wells





OTC-28898-MS

A Cost Reduction Methodology for Offshore Projects

G. C. Nunes, Rio Petroleo Consulting Group; A. H. da Silva and L. G. Esch, Universidade do Estado do Rio de Janeiro

43

3. Field planning: effect of plateau rate and well number on NPV

$$NPV_{rev} = q_{p,f} \cdot P_o \cdot \left[\frac{m + i - m \cdot e^{-\left(\frac{q_{ppo}}{q_{p,f}} - 1\right)\frac{i}{m}} - i \cdot e^{-(m+i)\cdot t + \left(\frac{q_{ppo}}{q_{p,f}} - 1\right)}}{i \cdot (m + i)} \right]$$

$$t_p = \left(\frac{q_{ppo}}{q_{p,f}} - 1\right) \cdot \frac{1}{m}$$

$$m = A \cdot N_w \cdot J$$

$$q_{ppo} = N_{wells} \cdot J \cdot (p_i - p_{wf,min})$$

$$A = \frac{B_o}{\left[N \cdot B_{o,i} \cdot \left(c_o + \frac{c_w \cdot S_w + c_f}{S_o}\right) + V_a \cdot \phi_a \cdot B_w \cdot (c_w + c_f)\right]}$$

$$CAPEX_{TOPSIDES} = 33056 \cdot WEIGHT_{TOPSIDES} + 5 \cdot 10^8$$

$$WEIGHT_{TOPSIDES} = 16500 + n \cdot q_p \left(0.01 + \frac{GOR}{10^4} + (0.01 + \frac{GOR}{2 \cdot 10^4}) y_{CO2} + (0.005 + \frac{GOR}{4 \cdot 10^4})(y_{SRU} + y_{H2S})\right)$$

$$CAPEX_{HULL} = 200 n \cdot q_p + 20 \cdot 10^6$$

$$CAPEX_{PO+GL} = n 2442000 + 8580 nh + 5217 \sum_{k=1}^{n} \ell_k$$

$$CAPEX_{WI} = n_{WI} 1576833 + 3432 n_{WI} h + \sum_{k=1}^{n_{WI}} 2128 \ell_k$$

$$CAPEX_{XT} = 22 \cdot 10^6 \; US\$ / XTree$$

$$CAPEX_{MF} = 32 \cdot 10^6 \; US\$ / manifold$$

$$CAPEX_{INST} = \left(\sum_{k=1}^{n+n_{WI}} \ell_k + (n + n_{WI}) 300 + 1{,}625 \sum_{k=1}^{n+n_{WI}} h_k \right) \cdot C_{INST}$$

$$CAPEX_{MOORING} = 130 \cdot 10^6$$

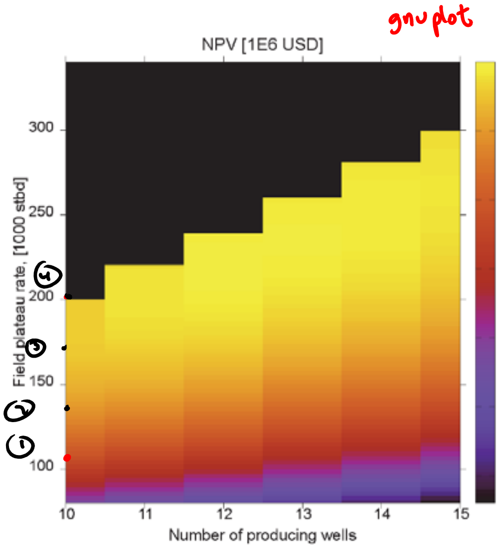
$$CAPEX_{WELLS} = n 150 \cdot 10^6 + n_{WI} 150 \cdot 10^6$$

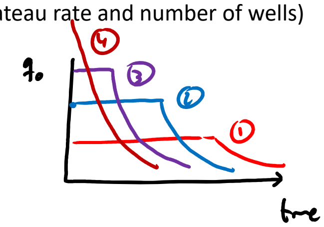
Page 116 of compendium

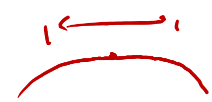
44

The NPV function as a colour plot (function of both plateau rate and number of wells)

gnu plot

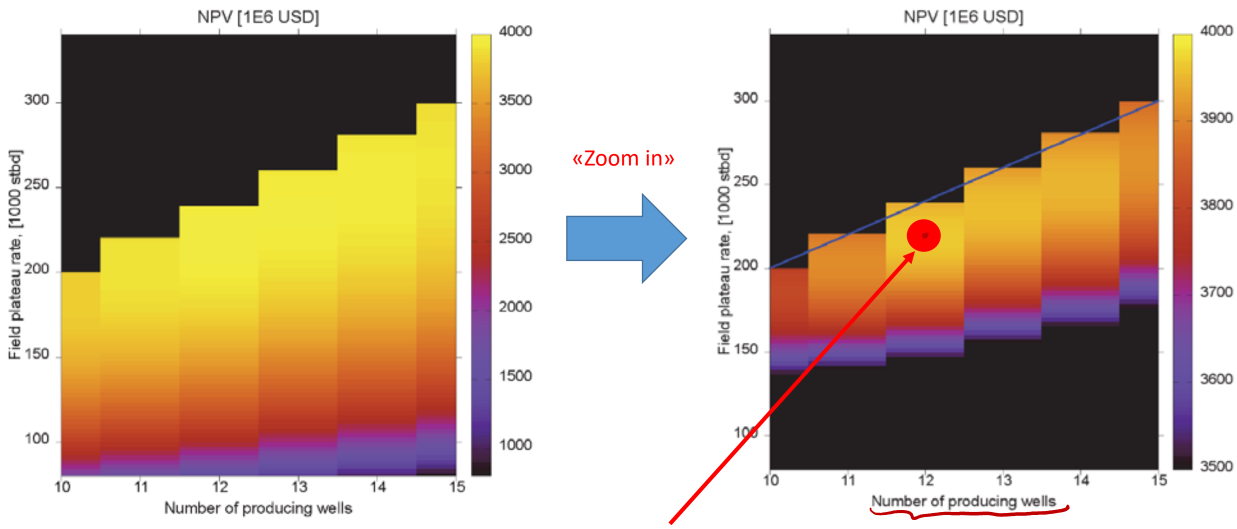






45

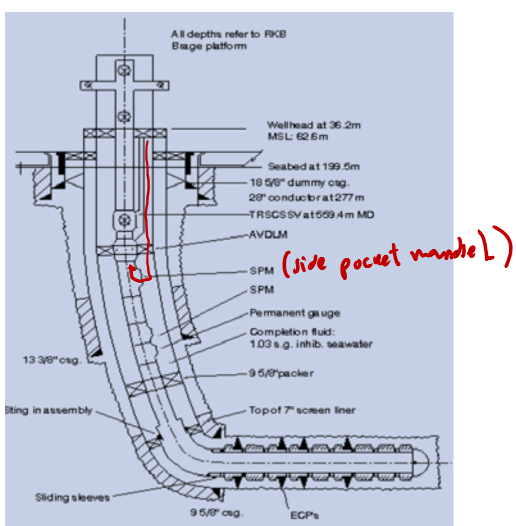
The NPV function as a colour plot (function of both plateau rate and number of wells)



Sweet spot: 12 wells and 212 000 stb/d

46

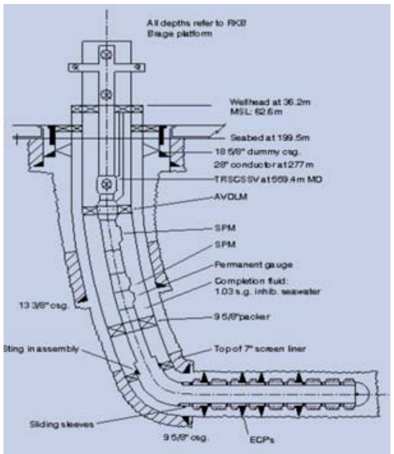
4. (Shorter term) Active choking to prevent well slugging



SPE77650 – Active feedback control of unstable wells at the Brage Field. Dalsmo et al.

47

4. Active choking to prevent well slugging



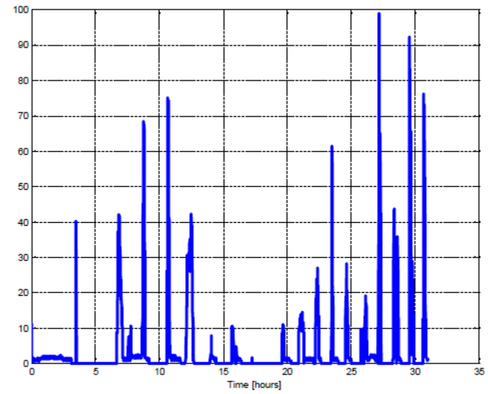


Figure 12: A-21 well test May 11- 12, 2001: *Test separator oil rate* [Sm³/h]

SPE77650 – Active feedback control of unstable wells at the Brage Field. Dalsmo et al.

48

4. Active choking to prevent well slugging

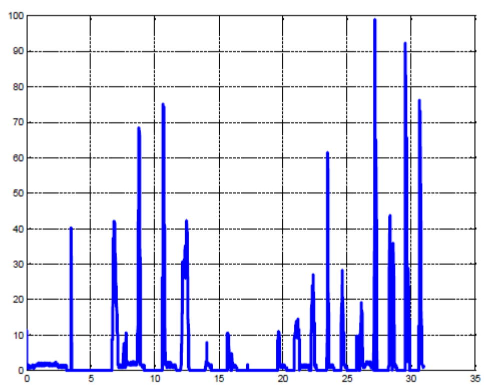


Figure 12: A-21 well test May 11- 12, 2001: *Test separator oil rate* [Sm³/h]

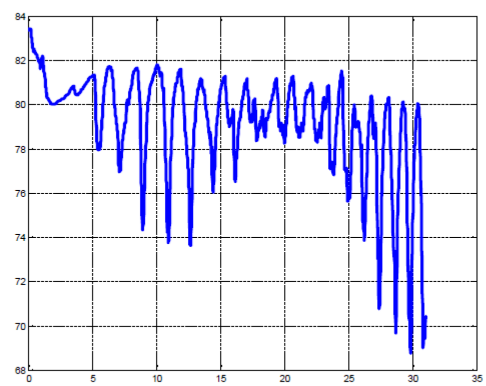
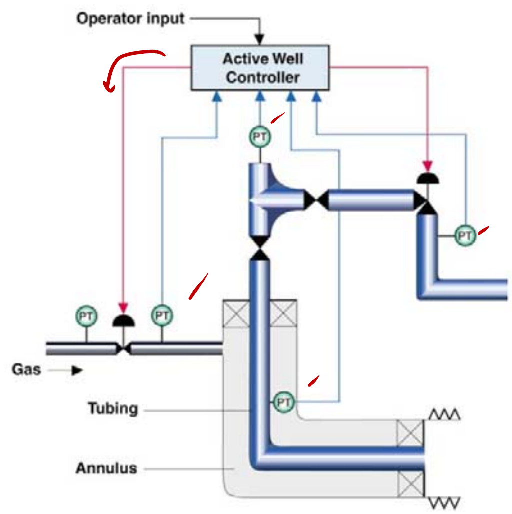


Figure 10: A-21 well test May 2001: *Down hole pressure* [bar]

SPE77650 – Active feedback control of unstable wells at the Brage Field. Dalsmo et al.

49

4. Active choking to prevent well slugging



SPE77650 – Active feedback control of unstable wells at the Brage Field. Dalsmo et al.

50

4. Active choking to prevent well slugging

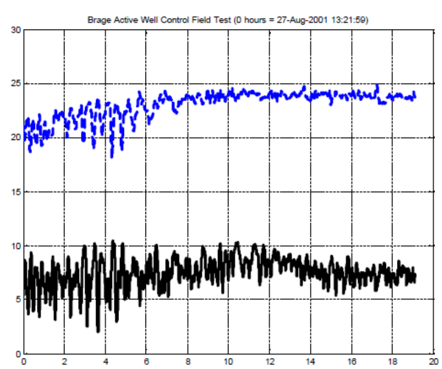


Figure 20: *Test separator oil rate* [Sm3/h] and *test separator water rate* [Sm3/h] (four hours moving average) corresponding to the downhole pressure and the choke opening in Figure 18 and Figure **19** respectively.

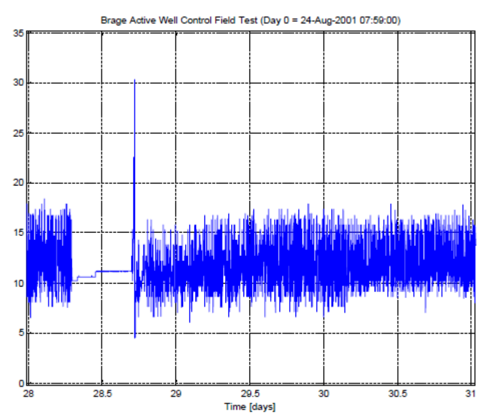


Figure 21: *Choke opening* [%]. As a test, the well is operated manually for a period of time, resulting in constant choke opening.

SPE77650 – Active feedback control of unstable wells at the Brage Field. Dalsmo et al.

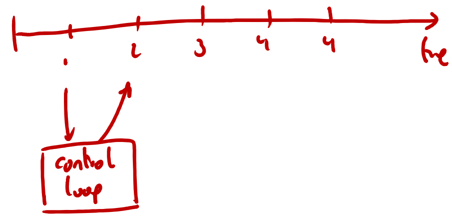
51

Optimization types

$z = \underbrace{f(x,y)}_{\text{model}}$ find x^*, y^* z is maximum

fixed model

- Parametric (static) – using a model
- Dynamic (control) – using a model, physical system, or a combination of both



Optimization problems

- Linear
- Non-linear
- Integer (e.g nr. wells)
- Continuous
- Constrained

https://en.wikipedia.org/wiki/Simulation-based_optimization

Optimization methods

- Simplex
- Derivative-based (gradients, hessians)
- Line search/ Trust region
- Heuristic

Examples

54

Linear problems

Variable non-negativity: $x_1 \geq 0, \quad x_2 \geq 0$

Objective Function:

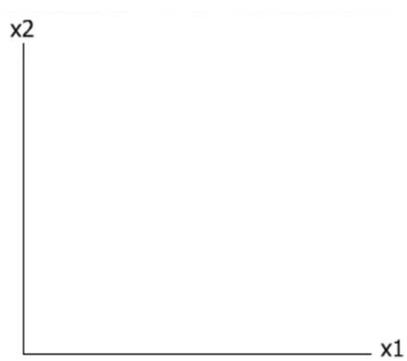
Maximize daily profit: $\text{MAX } z = 15x_1 + 10x_2$

Constraints:

Mountain bike production limit: $x_1 \leq 2$

Racer production limit: $x_2 \leq 3$

Metal finishing machine production limit: $x_1 + x_2 \leq 4$



First let's look at the constraints.

Press the Start button to begin.

<< | < | Start | Stop | > | >>

http://optlab-server.sce.carleton.ca/POAnimations2007/Graph.html

55

Simplex

Variable non-negativity: $x_1 \geq 0, \quad x_2 \geq 0$

Objective Function:

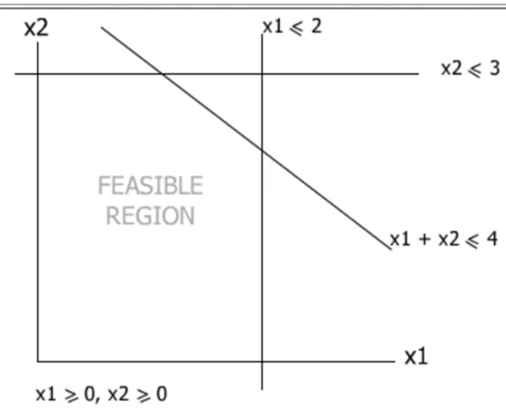
Maximize daily profit: $\text{MAX } z = 15x_1 + 10x_2$

Constraints:

Mountain bike production limit: $x_1 \leq 2$

Racer production limit: $x_2 \leq 3$

Metal finishing machine production limit: $x_1 + x_2 \leq 4$



Recall the graph of the feasible region from the Acme Bicycle Company problem. Press the Start button to begin.

<< | < | Start | Stop | > | >>

http://optlab-server.sce.carleton.ca/POAnimations2007/TwoPhaseGraph.html

56

Branch and bound

Maximize $Z = 8x_1 + 5x_2$

Subject to:

$x_1 + x_2 \leq 6$

$9x_1 + 5x_2 \leq 45$

x_1, x_2 are integer and non-negative.

Let's look at a graph of the above problem.

Press the Start button to begin.

<< | < | Start | Stop | > | >>

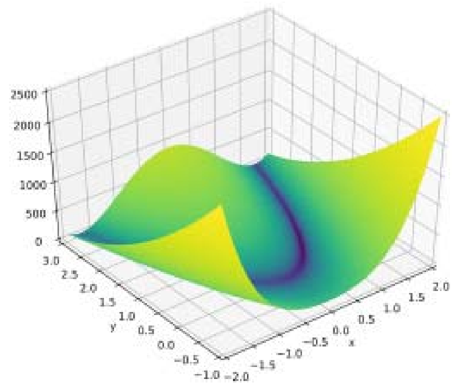
http://optlab-server.sce.carleton.ca/POAnimations2007/MILP.html

57

Newton

$x_k + \Delta x$ **is a local extremum if:**

$$\nabla f(x_k + \Delta x) = 0$$



https://jamesmccaffrey.wordpress.com/page/2/

Taken from Arnaud Hoffmann

58

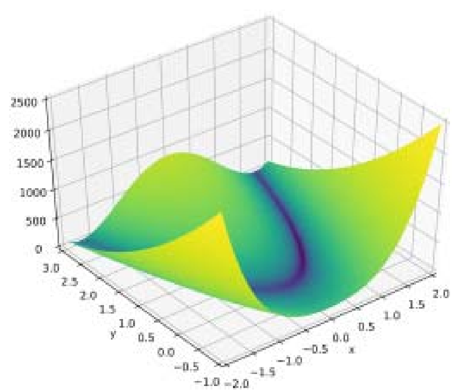
Newton

$x_k + \Delta x$ **is a local extremum if:**

$$\nabla f(x_k + \Delta x) = 0$$

$$\nabla f(x_k) + H\,.\,\Delta x = 0$$ **(Taylor expansion)**

$$H(f) = \begin{bmatrix} \frac{\partial^2 f}{\partial x_1^2} & \frac{\partial^2 f}{\partial x_1 \partial x_2} & \cdots & \frac{\partial^2 f}{\partial x_1 \partial x_n} \\ \frac{\partial^2 f}{\partial x_2 \partial x_1} & \frac{\partial^2 f}{\partial x_2^2} & \cdots & \frac{\partial^2 f}{\partial x_2 \partial x_n} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial^2 f}{\partial x_n \partial x_1} & \frac{\partial^2 f}{\partial x_n \partial x_2} & \cdots & \frac{\partial^2 f}{\partial x_n^2} \end{bmatrix}$$

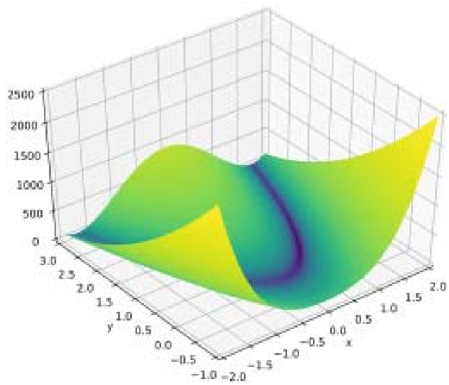


https://jamesmccaffrey.wordpress.com/page/2/

Taken from Arnaud Hoffmann

59

Newton



https://jamesmccaffrey.wordpress.com/page/2/

$x_k + \Delta x$ **is a local extremum if:**

$$\nabla f(x_k + \Delta x) = 0$$

$$\nabla f(x_k) + H \,.\, \Delta x = 0$$ **(Taylor expansion)**

$$H(f) = \begin{bmatrix} \frac{\partial^2 f}{\partial x_1^2} & \frac{\partial^2 f}{\partial x_1 \partial x_2} & \cdots & \frac{\partial^2 f}{\partial x_1 \partial x_n} \\ \frac{\partial^2 f}{\partial x_2 \partial x_1} & \frac{\partial^2 f}{\partial x_2^2} & \cdots & \frac{\partial^2 f}{\partial x_2 \partial x_n} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial^2 f}{\partial x_n \partial x_1} & \frac{\partial^2 f}{\partial x_n \partial x_2} & \cdots & \frac{\partial^2 f}{\partial x_n^2} \end{bmatrix}$$

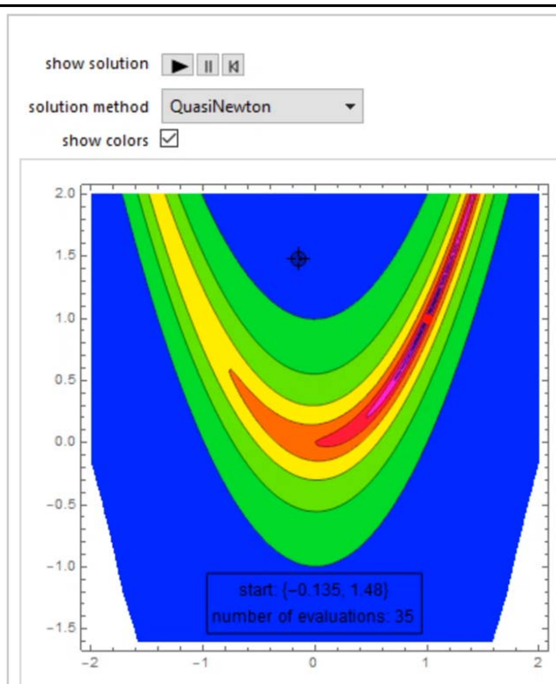
$$\Delta x = -H^{-1} . \nabla f(x_k)$$

$$x_{k+1} = x_k + \Delta x$$

Taken from Arnaud Hoffmann

60

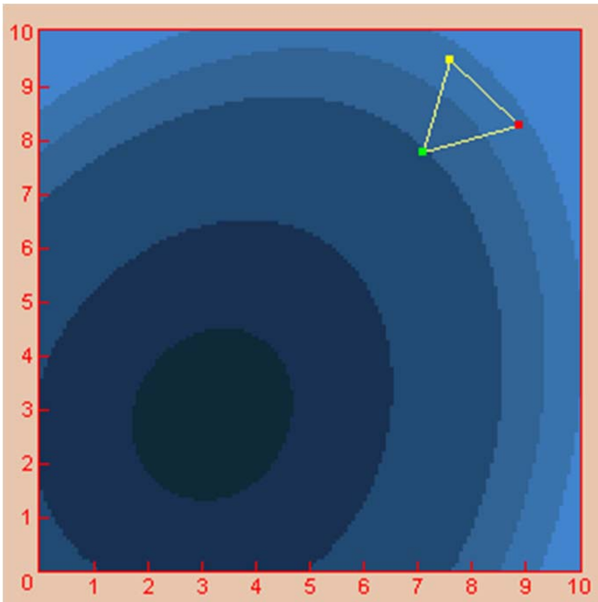
Newton

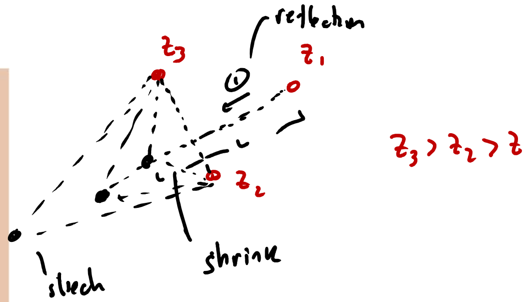


https://demonstrations.wolfram.com/MinimizingTheRosenbrockFunction/

61

Nelder-Mead

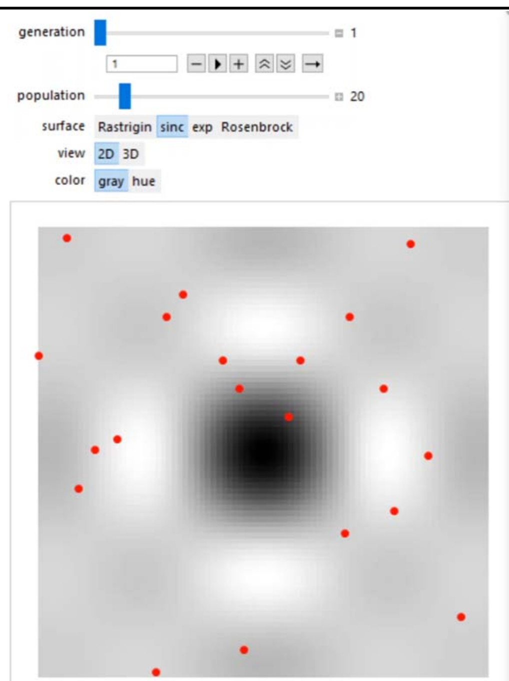




http://195.134.76.37/applets/AppletSimplex/Appl_Simplex2.html

62

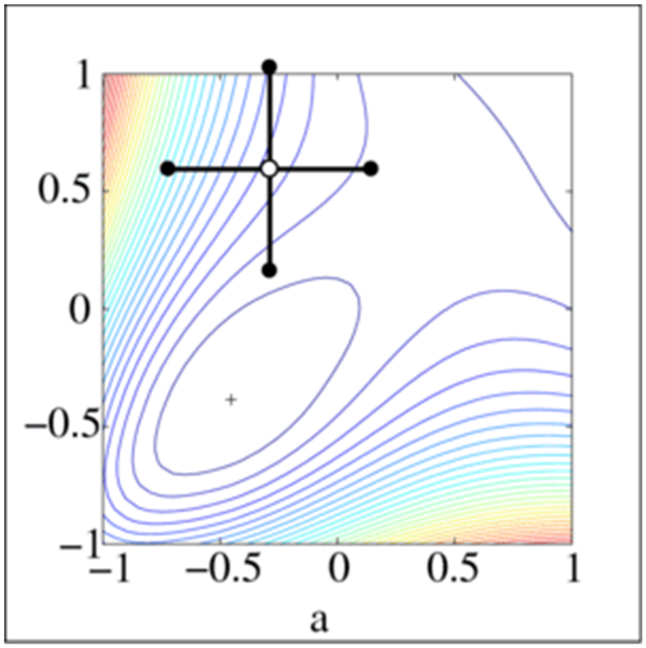
Genetic algorithm



https://demonstrations.wolfram.com/GlobalMinimumOfASurface/

63

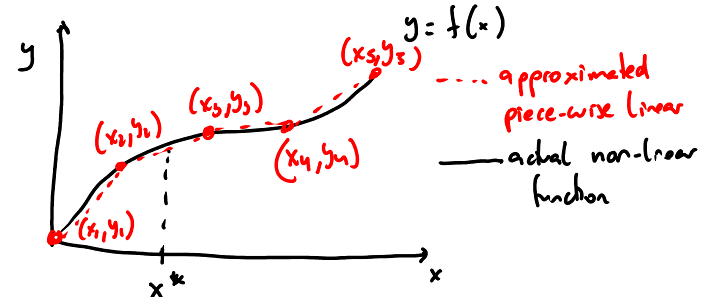
Pattern search



https://en.wikipedia.org/wiki/Pattern_search_(optimization)

64

Piecewise linearization



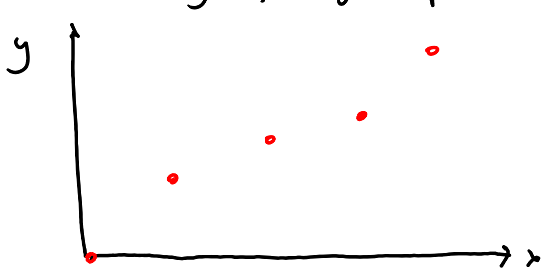
x	y
x_1	y_1
x_2	y_2
x_3	y_3
x_4	y_4
x_5	y_5

for j in (0,4):

→ if $x_j \leq x^* \leq x_{j+1}$

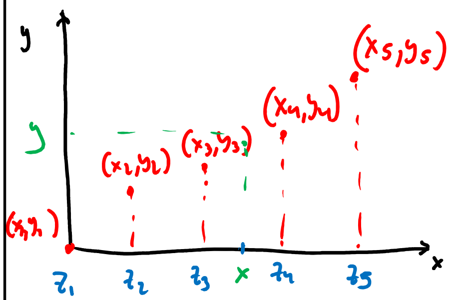
$$y^* = y_j + \left(\frac{y_j - y_{j+1}}{x_j - x_{j+1}}\right)(x^* - x_j)$$

to avoid using "if" (logical operator) we can use, for example



65

Piecewise linearization



$$X = z_1 x_1 + z_2 x_2 + z_3 x_3 + z_4 x_4 + z_5 x_5$$

$$y = z_1 y_1 + z_2 y_2 + z_3 y_3 + z_4 y_4 + z_5 y_5$$

z_i is a SOS2 set

$\sum z_i = 1$

$0 \leq z_i \leq 1$

adjacency condition

if $i \neq 0$ then only $i+1$ OR $i-1$ can be $\neq 0$

66

Handling constraints

- Lagrange multipliers
- Barrier functions

67

Handling constraints

- **Lagrange multipliers**
- Barrier functions

68

Lagrange multipliers example: Constrained gas-lift optimization (single well)

$q_o = f(q_{ginj})$

$q_{ginj} \leq q_{gTOTAL}$

create Lagrange function

$L(q_{ginj}) = f(q_{ginj}) - \lambda (q_{ginj} - q_{gTOTAL})$

$\frac{df(q_{ginj})}{dq_{ginj}} - \lambda = 0 \Rightarrow \frac{df(q_{ginj})}{dq_{ginj}} = \lambda$

subjected to : $\lambda \geq 0$

$\lambda \cdot (q_{gTOTAL} - q_{ginj}) = 0$

$q_{ginj} \leq q_{gTOTAL}$ -

at maximum:

$\frac{dL}{dq_{ginj}} = 0$

two solutions:

$\lambda = 0$ then 1

$\frac{df(q_{ginj})}{dq_{ginj}} = 0$

$q_{ginj} < q_{gTOTAL}$

69

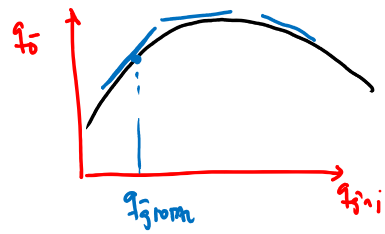
Lagrange multipliers example: Constrained gas-lift optimization (single well)

② $\lambda > 0$

$$\lambda \left(q_{g\,total} - q_{g\,inj} \right) = 0$$

$$q_{g\,total} = q_{g\,inj}$$

$$\frac{d f(q_{g\,inj})}{d q_{g\,inj}} = \lambda$$



70

Lagrange multipliers example: Constrained gas-lift optimization (multiple wells)

$q_o = \sum_{i=1}^{N} f_i(q^i_{g\,inj})$ "N" wells

$\sum_{i=1}^{N} q^i_{g\,inj} \leq q_{g\,total}$

$$\Rightarrow \quad L(q^i_{g\,inj}) = \sum_{i=1}^{N} f_i(q^i_{g\,inj}) - \lambda \left(\sum_{i=1}^{N} q^i_{g\,inj} - q_{g\,total} \right)$$

maximum is achieved when $\nabla L = 0 \Rightarrow \frac{\partial L}{\partial q^i_{g\,inj}} = 0$

deriving with respect to "i"

$$\frac{\partial f_i(q^i_{g\,inj})}{\partial q^i_{g\,inj}} - \lambda = 0 \quad \Rightarrow \quad \frac{\partial f_i(q^i_{g\,inj})}{\partial q^i_{g\,inj}} = \lambda$$

$\lambda \geq 0 \qquad \lambda \left(q_{g\,total} - \sum_{i=1}^{N} q^i_{g\,inj} \right) = 0 \qquad q_{g\,total} \geq \sum_{i=1}^{N} q^i_{g\,inj}$

71

Lagrange multipliers example: Constrained gas-lift optimization (multiple wells)

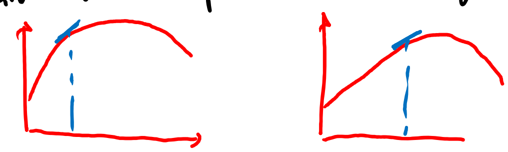
2 possible solutions: ① $\lambda = 0$ $\sum_{i=1}^{N} q^{i}_{ginj} < q_{g\,total}$, there is enough gas for all wells to be at their maximum

$$\frac{\partial f_i(q^{i}_{ginj})}{\partial q^{i}_{ginj}} = 0$$

① $\lambda > 0$ all gas is used $\sum_{i=1}^{N} q^{i}_{ginj} = q_{g\,total}$

$$\frac{\partial f_i(q^{i}_{ginj})}{\partial q^{i}_{ginj}} = \lambda$$

all wells must operate at the same gradient!



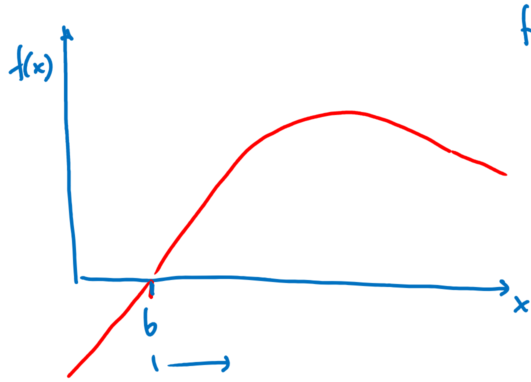
72

Handling constraints

- Lagrange multipliers
- **Barrier functions**

73

Handling constraints: barrier functions



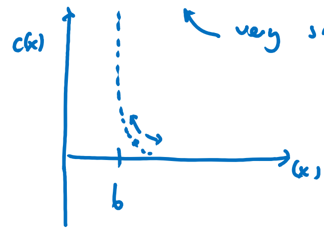
fin minimum of $f(x)$
$x > b$

$f(x) + c(x)$

$c(x) \begin{cases} \text{high!} & x \leq b \\ 0 & x > b \end{cases}$

a possible $c(x) = \mu \log(x-b)$

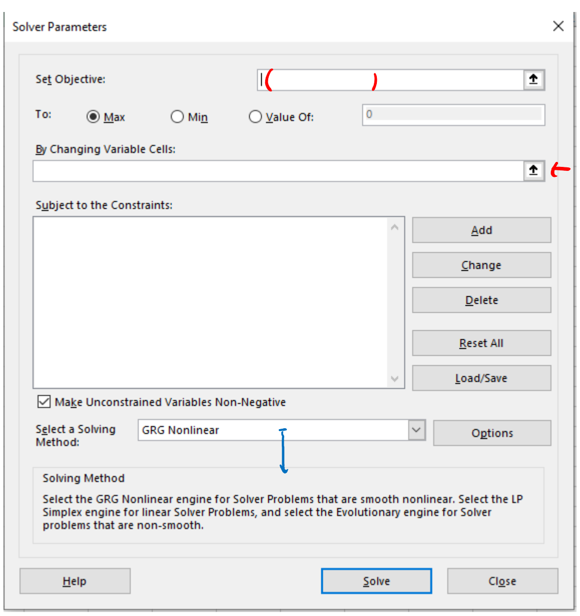
very small number



74

Examples of static optimization

75



optimization formulation

maximize (or minimize) → f objective

by changing x variables

subjected to: constraints

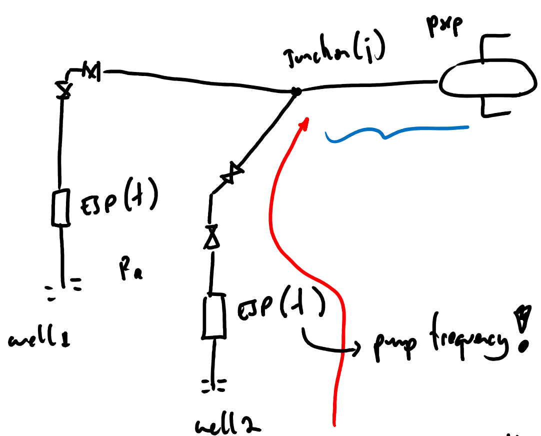
method

76

Setting up the optimization: optimizer «outside» the model

2 well ESP lifted in a network

no choke

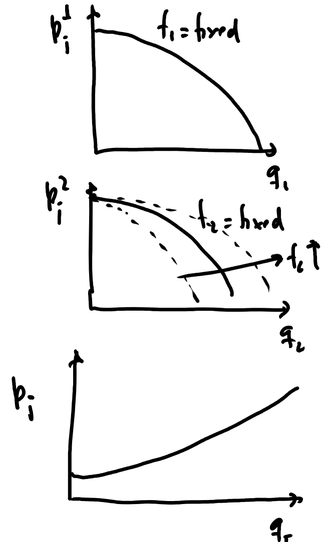


$p_j^1 = F_1(q_1, f_1)$

F: IPR, TPR, ESP, FPR

$p_j^2 = F_2(q_2, f_2)$

$p_j = F_3(q_1 + q_2)$



How to solve this system given f_1, f_2

77

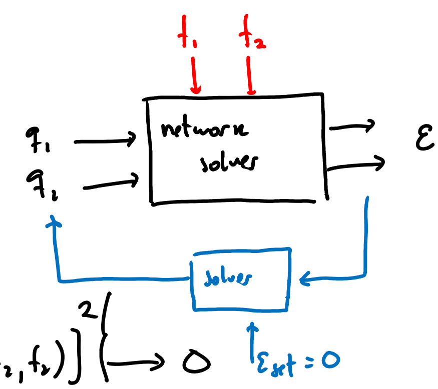
Setting up the optimization: optimizer «outside» the model

all p_j must be equal!

given f_1, f_2

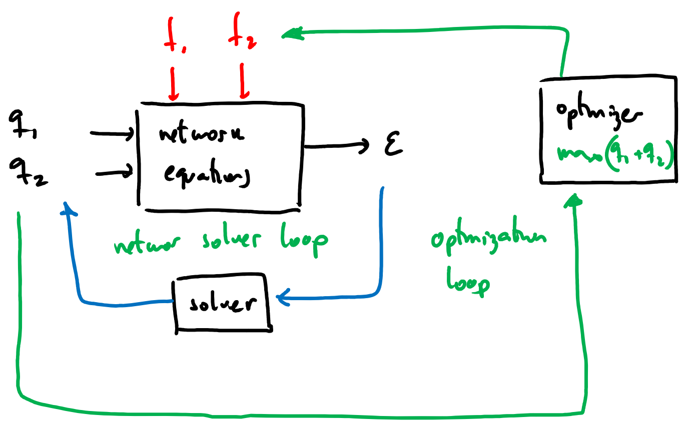
change q_1, q_2 to drive

$$\underbrace{\left\{ \underbrace{\left[F_1(q_1, f_1) - F_2(q_2, f_2) \right]^2}_{p_j^1 = p_j^2} + \underbrace{\left[F_3(q_1, q_2) - F_2(q_2, f_2) \right]^2}_{p_j = p_j^2} \right\}}_{\varepsilon \text{ (error)}} \longrightarrow 0$$



78

Setting up the optimization: optimizer «outside» the model



the two loops are solved sequentially

for each iteration of optimizer, the network solver must be converged

if the optimizer employs for a Newton method

$$\nabla(q_1, q_2) \qquad \underbrace{\begin{matrix} \dfrac{\partial q_1}{\partial f_1} & \dfrac{\partial q_1}{\partial f_2} \\ \dfrac{\partial q_2}{\partial f_1} & \dfrac{\partial q_2}{\partial f_2} \end{matrix}}_{\text{not typically output by network solver}}$$

79

Details on optimization setup

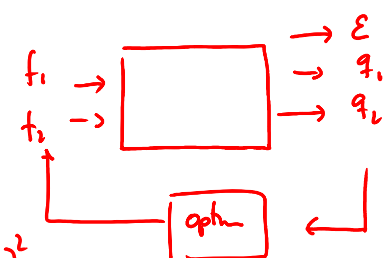
- Model + optimizer together

max $q_T = q_1 + q_2$

by changing f_1, f_2, q_1, q_2

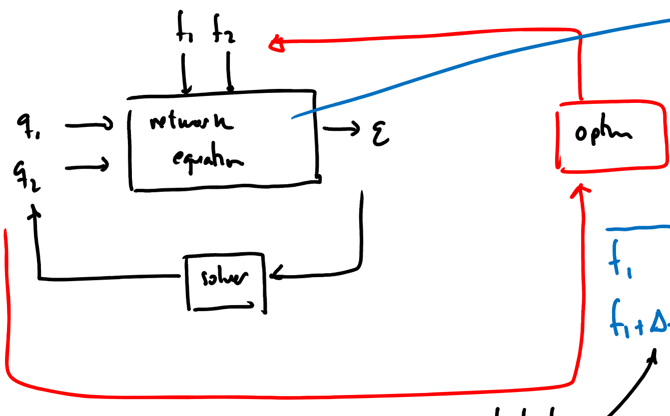
subject to constraint: $\varepsilon = 0$

$$\left[P_1(q_1, f_1) - P_2(q_1, f_2)\right]^2 + \left[P_3(q_1, q_2) - P_2(q_2, f_1)\right]^2 = 0$$



80

«Black-box» optimization (optimizer outside)



if black box, I don't have access to $\frac{\partial}{\partial f}$ (analytical eq)

one option is to estimate numerically the gradient (can be expensive for large number of variables)

f_1	q^1_{TOTAL}
$f_1 + \Delta f$	q^2_{TOTAL}

perturbation

$$\frac{\partial q_T}{\partial f_1} = \frac{q^2_{TOTAL} - q^1_{TOTAL}}{\Delta f}$$

derivative free: if Nelder-mead f_1^1 f_1^2 f_1^3

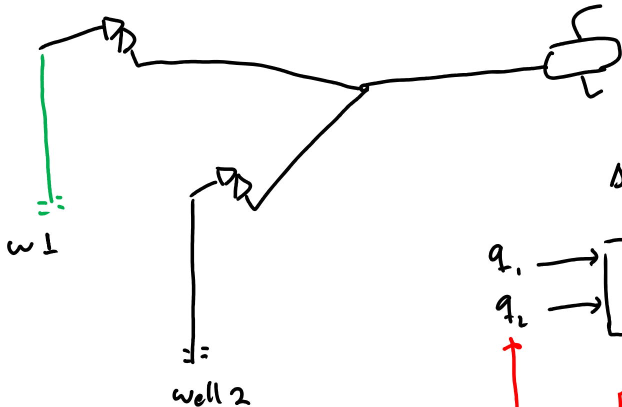
three function evaluations

81

Effect of optimization formulation

82

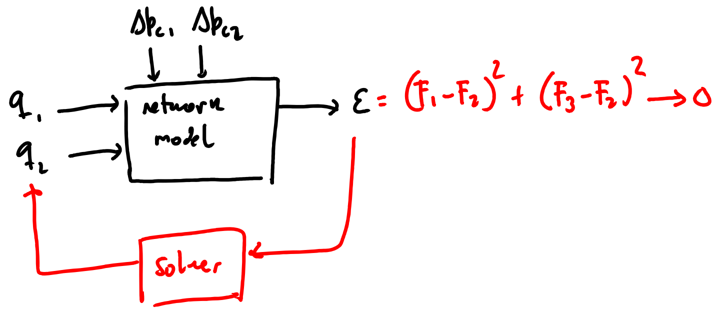
2. Two gas wells in a network – Optimization with DP choke



$$p_j^1 = F_1(q_1, \Delta p_{c1})$$

$$p_j^2 = F_2(q_2, \Delta p_{c2})$$

$$p_j = F_3(q_1, q_2)$$



83

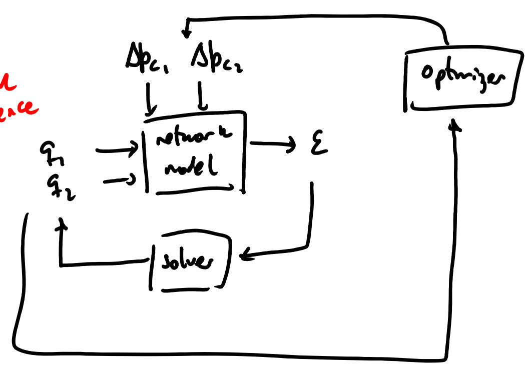
2. Two gas wells in a network – Optimization with gas rates

max $q_{tot} = q_1 + q_2$

by changing $\Delta p_{c1}, \Delta p_{c2}, q_1, q_2$

subject to $\varepsilon = 0$ $\quad \underbrace{(F_1-F_3)^2 + (F_3-F_2)^2}_{\text{non-linear function}}$ network convergence

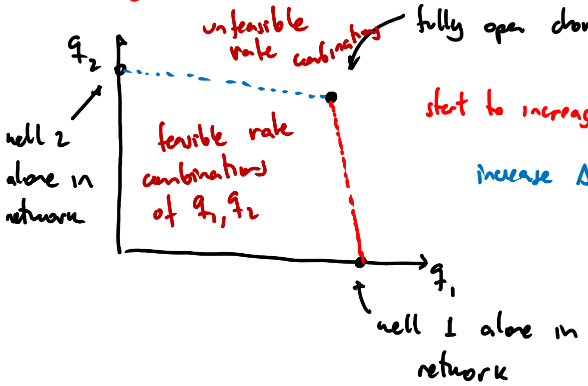
$q_1 \le q_{g1max}$



84

2. Two gas wells in a network - Differences when formulating the problem

Let's try to reformulate the problem as a linear problem



fully open choke $\Delta p_{c1} = 0$

$\Delta p_{c2} = 0$

start to increase Δp_{c2}, $\Delta p_{c1} = 0$

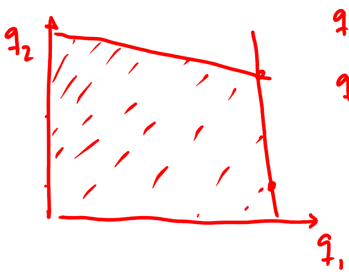
increase Δp_{c1}, keep $\Delta p_{c2} = 0$

if I knew this area before hand, then the optimization can be re-formulated as a linear problem

2. Two gas wells in a network - Differences when formulating the problem

max $q_1 + q_2 = q_T$ linear problem!

subject to $q_i \leq q_{max}$



$q_2 \leq q_2^0 - a \cdot q_1$

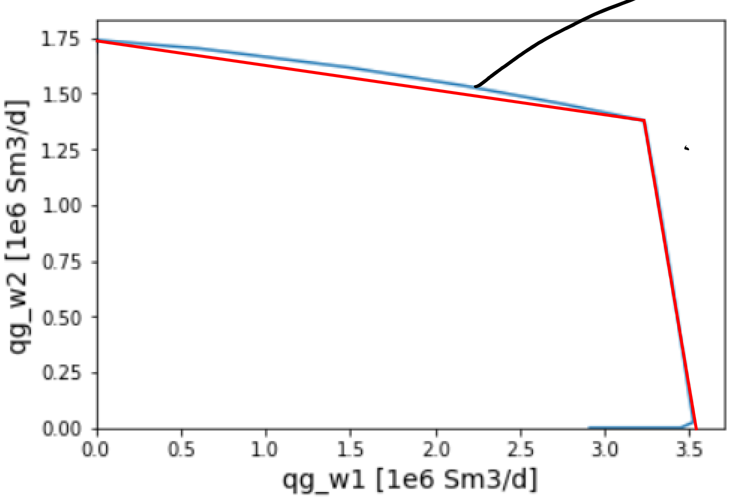
$q_1 \leq q_1^0 - b\, q_2$

2. Two gas wells in a network - Differences when formulating the problem

```python
#ESTIMATING FEASIBLE OPERATING REGION, qg1, qg2
qg1=[]
qg2=[]
dp2=0
DP=np.linspace(250,0,10)
for dp1 in DP:
    x=minimize(error,qg,args=(pR,CR,n,CT,S,Cpl,Cfl,psep,[dp1,dp2]),method='Nelder-Mead')
    qg1=np.append(qg1,x.x[0])
    qg2=np.append(qg2,x.x[1])
DP=np.linspace(0,250,10)
dp1=0
for dp2 in DP:
    x=minimize(error,qg,args=(pR,CR,n,CT,S,Cpl,Cfl,psep,[dp1,dp2]),method='Nelder-Mead')
    qg1=np.append(qg1,x.x[0])
    qg2=np.append(qg2,x.x[1])
plt.plot(qg1/1e06,qg2/1e06)
plt.xlabel('qg_w1 [1e6 Sm3/d]',fontsize=14)
plt.ylabel('qg_w2 [1e6 Sm3/d]',fontsize=14)
plt.xlim(0)
plt.ylim(0)
plt.show()
```

87

2. Two gas wells in a network - Differences when formulating the problem

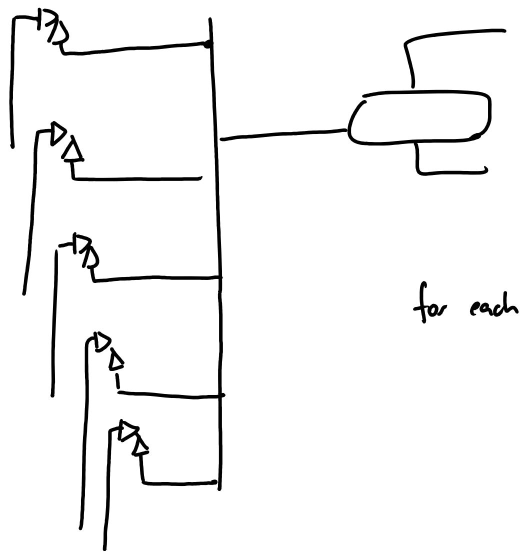


deviation between linear approximation and real behavior :

$$\underbrace{q_2 \le q_2^0 - a q_1 - b q_1^2}_{\text{this is non-linear !}}$$

88

3. Well routing – class exercise



wells have different GOR, WC

find how much to produce from each well, to maximize total oil production and be below constraints

$q_{\bar{w}\,max}$

$q_{\bar{g}\,max}$

for each well $\underbrace{q_o^i = f(\Delta p_c^i)}_{\text{IPR, TPR, choke eq.}}$ → non linear function!

89

3. Well routing – class exercise

one option

max $q_{to}^T = \sum_{i=1}^{5} q_{to}^i$ —— $q_o^i = f(\Delta p_c^i)$ is non-linear!

by changing Δp_c^i for $i = 1 .. N$

subject to $\sum_{i=1}^{N} q_{\bar{g}}^i \le q_{\bar{g}\,max}$

$\sum_{i=1}^{N} q_{\bar{w}}^i \le q_{\bar{w}\,max}$

A different approach ... to make it linear

90

3. Well routing – class exercise

max $q_o = q_{\bar{o}_1} + q_{\bar{o}_2} + q_{\bar{o}_3} + q_{\bar{o}_4} + q_{\bar{o}_5}$

by changing $q_{\bar{o}_1}, q_{\bar{o}_2}, q_{\bar{o}_3}, q_{\bar{o}_4}, q_{\bar{o}_5}$

subject to

$$\sum_{i=1}^{N} q_{\bar{g}}^{i} \leq q_{\bar{g}\,max} \qquad q_{\bar{g}}^{i} = q_{\bar{o}}^{i} \cdot GOR^{i}$$

$$\sum_{i=1}^{N} q_{\bar{w}}^{i} \leq q_{\bar{w}\,max} \qquad q_{\bar{w}}^{i} = q_{\bar{o}}^{i} \cdot \frac{wc^{i}}{(1-wc^{i})}$$

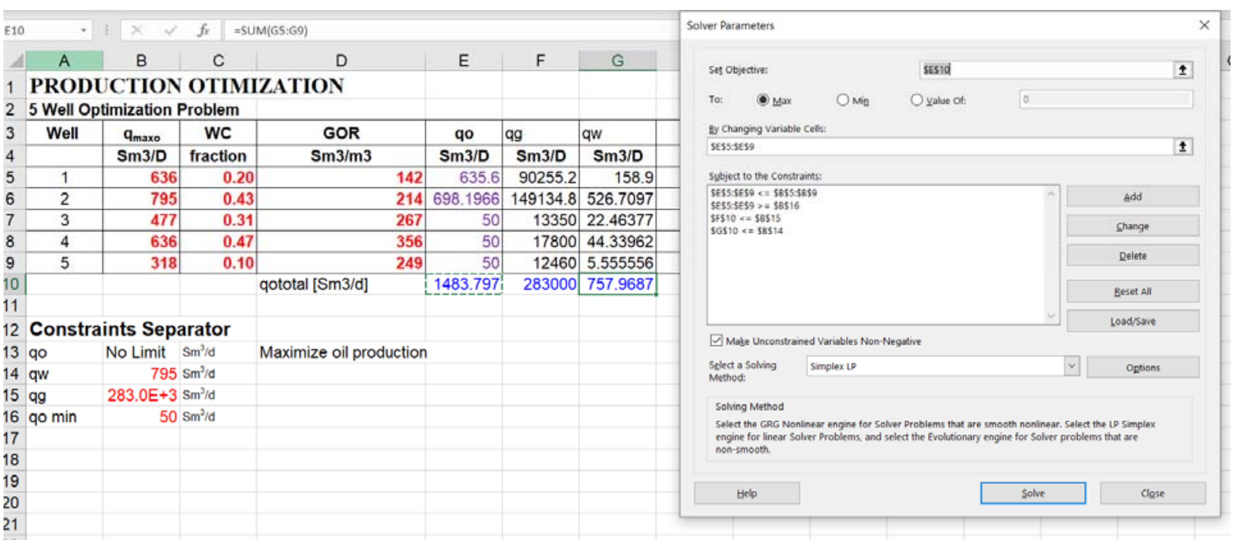
$q_{\bar{o}_1} \leq q_{\bar{o}_1 max}$ ← fully open choke { either from model or from field test

$q_{\bar{o}_2} \leq q_{\bar{o}_2 max}$ $\qquad q_{\bar{o}_4} \leq q_{\bar{o}_4 max}$

$q_{\bar{o}_3} \leq q_{\bar{o}_3 max}$ $\qquad q_{\bar{o}_5} \leq q_{\bar{o}_5 max}$

91

3. Well routing – class exercise



PRODUCTION OTIMIZATION

5 Well Optimization Problem

Well	q_{maxo} Sm3/D	WC fraction	GOR Sm3/m3	qo Sm3/D	qg Sm3/D	qw Sm3/D
1	636	0.20	142	635.6	90255.2	158.9
2	795	0.43	214	698.1966	149134.8	526.7097
3	477	0.31	267	50	13350	22.46377
4	636	0.47	356	50	17800	44.33962
5	318	0.10	249	50	12460	5.555556
			qototal [Sm3/d]	1483.797	283000	757.9687

Constraints Separator

qo	No Limit	Sm³/d	Maximize oil production
qw	795	Sm³/d	
qg	283.0E+3	Sm³/d	
qo min	50	Sm³/d	

92

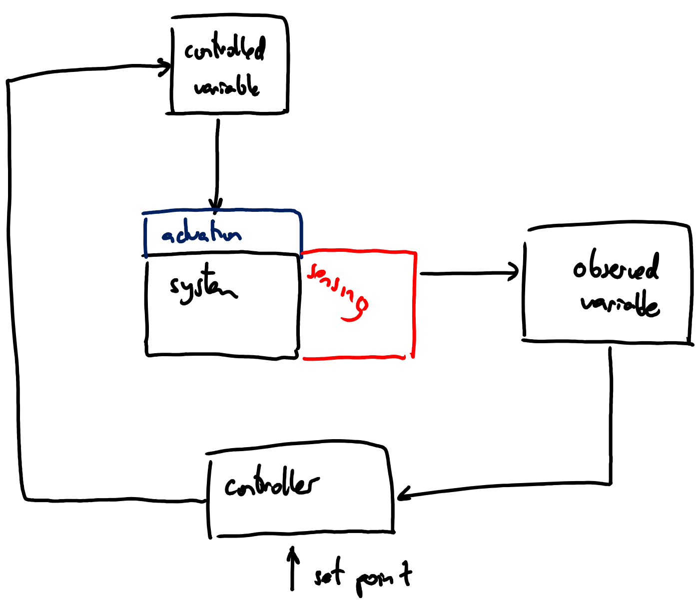
Optimization types

- Parametric (static) – using a model
- **Dynamic (control)** – using a model, physical system, or a combination of both

https://en.wikipedia.org/wiki/Simulation-based_optimization

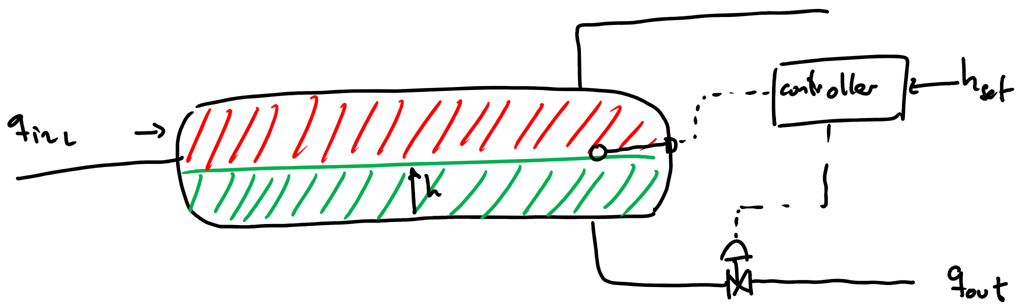
93

Dynamic optimization (control)

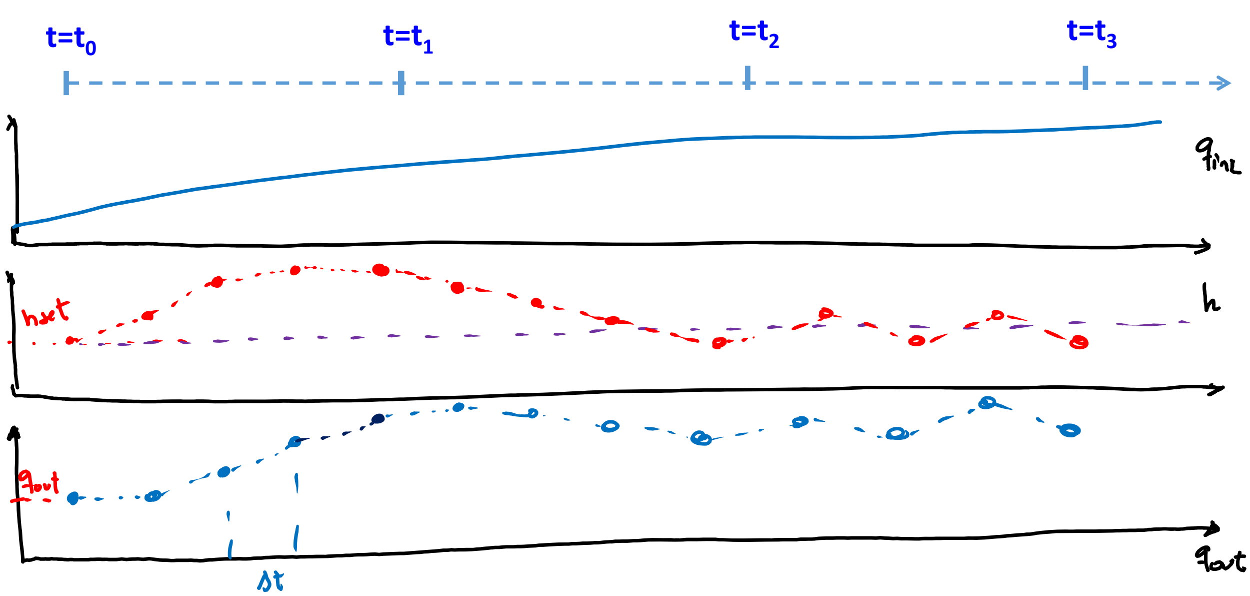


94

Dynamic optimization (control): gas-liquid separator



95



96

Dynamic optimization (control)

to calculate $h(t)$ we need → model (transient mode)
→ measurement on physical system

but we can also apply control using a steady state model. for example in the gas lift case $q_o = f(q^1_{ginj}, q^2_{ginj})$

we evaluate the function in each time, depending on the value of q^1_{ginj} and q^2_{ginj}

97

Dynamic optimization (control)

t_1 t_2 t_3 t_4

↑ check $q_o^{*} \rightarrow \boxed{\text{controller}} \rightarrow q^1_{ginj}, q^2_{ginj}$

then on t_3, evaluate $q_o = f(\; , \;)$, then

$q_o^{**} \rightarrow \boxed{\text{controller}} \rightarrow q^1_{ginj}, q^2_{ginj}$

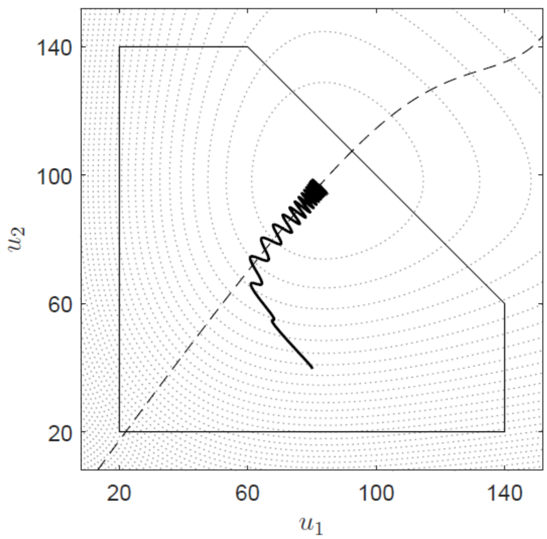
one approach to make the controller optimize is to drive $\frac{\partial q_o}{\partial q^1_{ginj}} = 0$

$\frac{\partial q_o}{\partial q^2_{ginj}} \rightarrow 0$

$\frac{\partial q_o}{\partial q^1_{ginj}} = \frac{\partial q_o}{\partial q^2_{ginj}}$

98

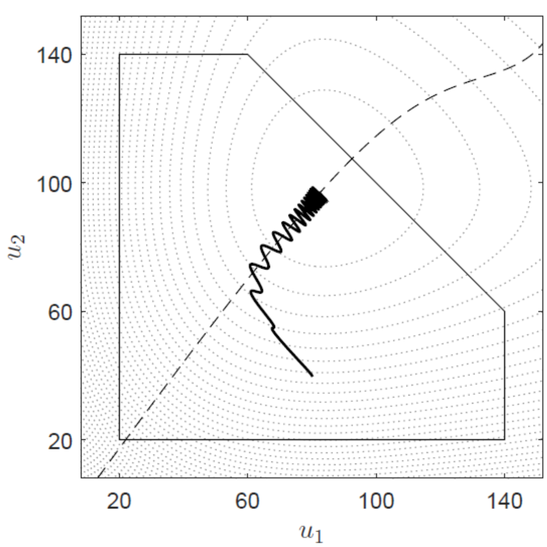
Dynamic optimization (control)

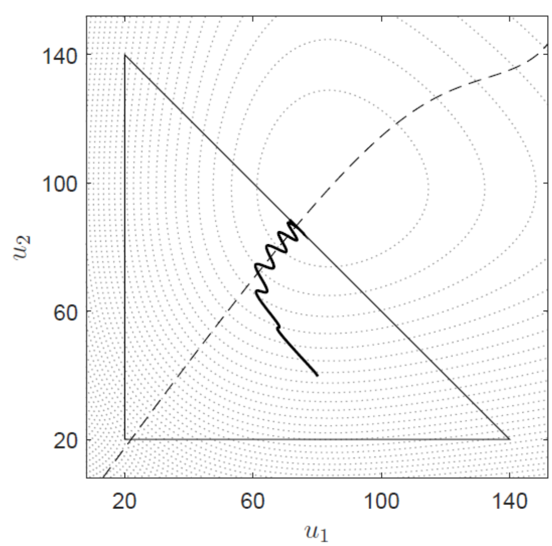


Practical extremum-seeking control for gas lifted oil production – Pavlov et al

99

Dynamic optimization (control)





Practical extremum-seeking control for gas lifted oil production – Pavlov et al

100

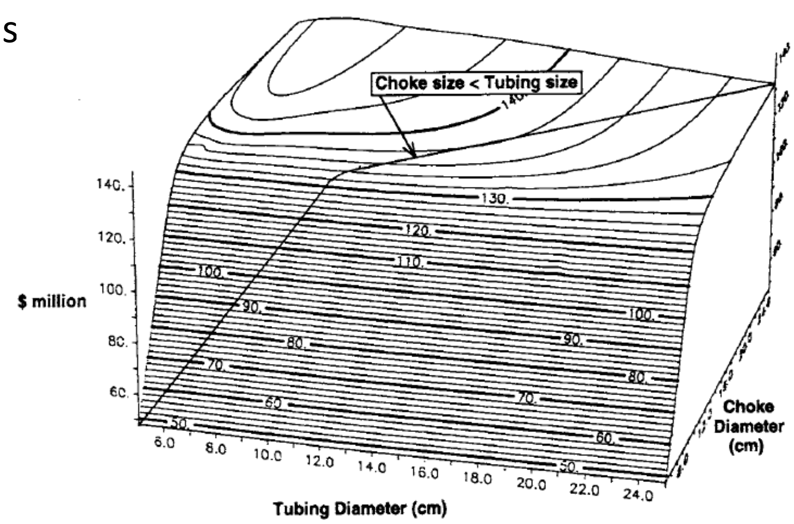
Limitations and pitfalls

- Model fidelity
- Is it actually possible to change the decision settings?:
  - Is the equipment/actuator functional and available?
  - Am I allowed to operate the control element?
  - Actuator response time

101

Limitations and pitfalls

- Flat peak of optimum- more efforts give less res

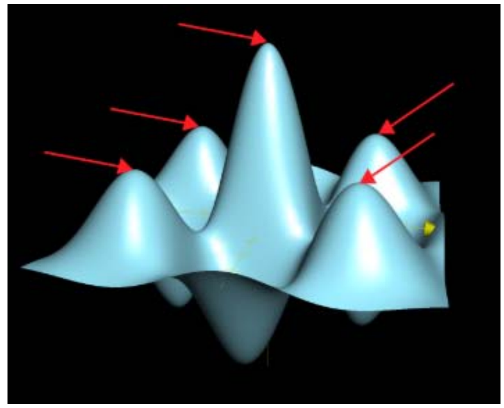


SPE-166027-MS Multivariate optimization of production systems optimization Carroll and Horne

102

Limitations and pitfalls

- Local optima
- Starting point
- Running time
- Short term versus long term optimization



(Khan academy)

103

Limitations and pitfalls

- Short term versus long term optimization

Maximize NPV
By changing $q_o(t)$

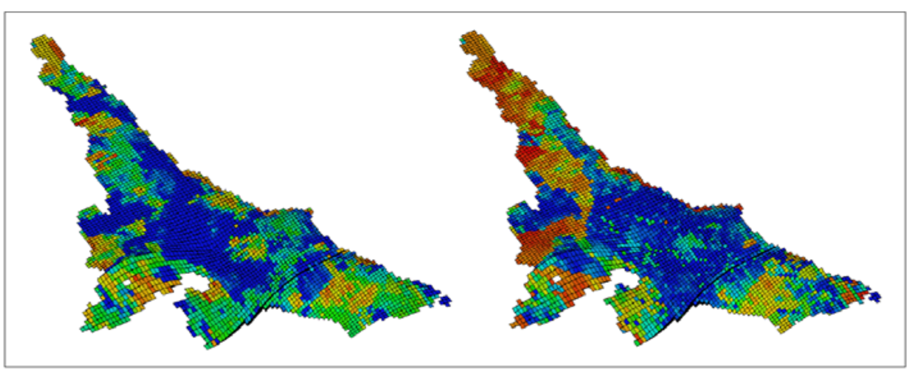


Figure 3: Permeability (left) and porosity (right) distributions of the south wing.

SPE-166027-MS Decision analysis for long term and short-term production optimization Applied to the Voador field, Agus Hasan

104

• Short term versus long term optimization

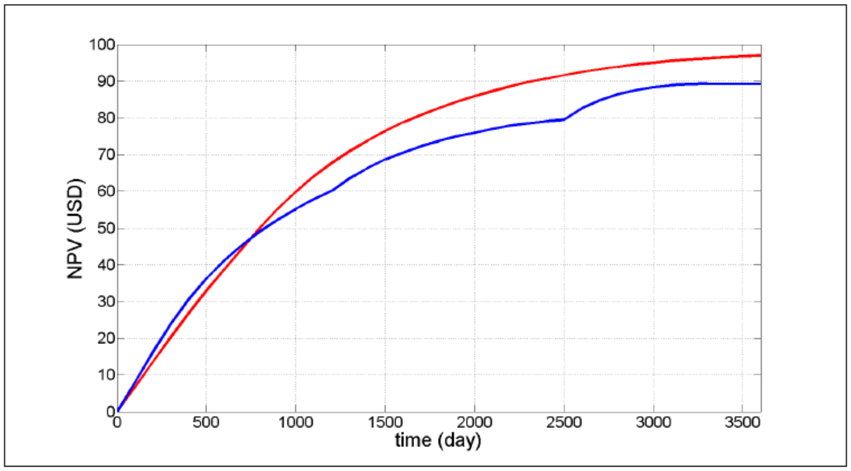


Figure 4: Normalized NPV of the long-term optimization (red) using adjoint-based optimization and short-term optimization (blue) using reactive control.

SPE-166027-MS Decision analysis for long term and short-term production optimization Applied to the Voador field, Agus Hasan

105

• Short term versus long term optimization

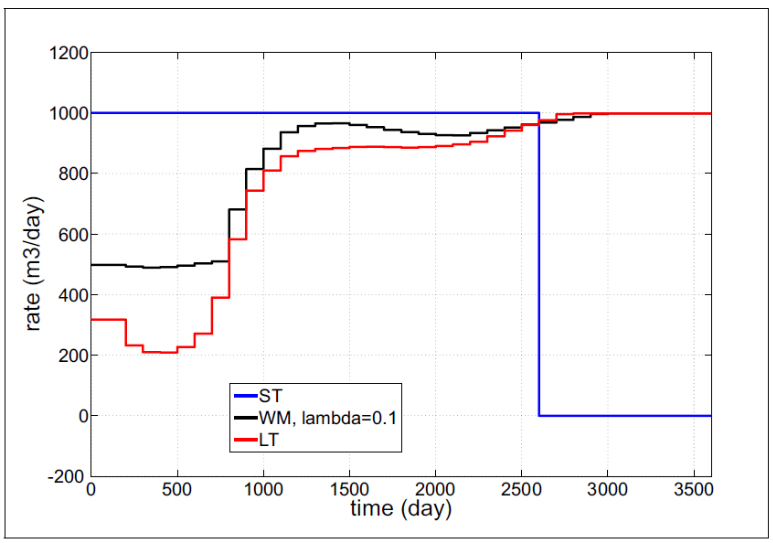


Figure 9: Oil rate from production well PROD3 using different strategies; reactive control (blue), adjoint-based optimization (red), and the weighted-sum method (black).

106

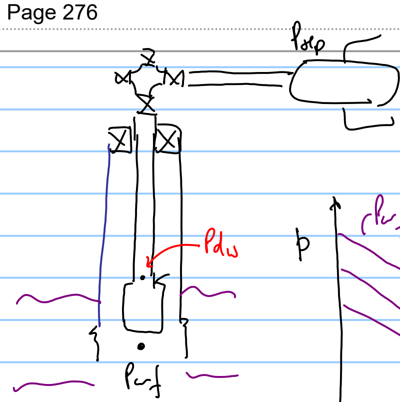
Final advice:

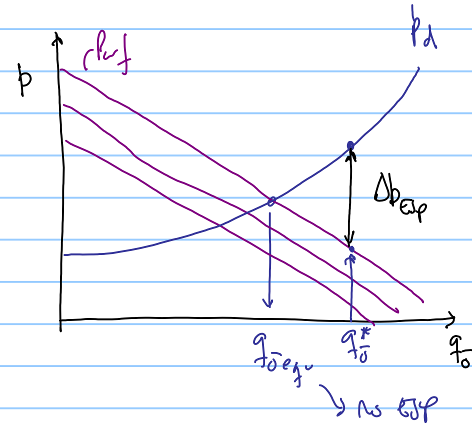
- Look at the rest of the list first!
- Do we REALLY need to do optimization?
- Think carefully what is the main, most important, first order of magnitude problem
- Define objective, constraints and variables
- Determine relevance of constraints
- Is it realistic to modify optimization variables?
- Formulate your optimization in a smart way (choose the right variable)
- Study how your input affects your results

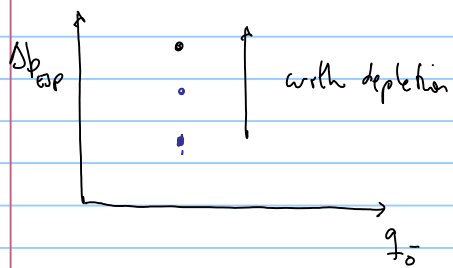
SLIDE 2

- Detect locations in the system with abnormally high-pressure loss and flow restrictions
- Verification of equipment design conditions vs actual operating conditions
- Identification and addressing fluid sources that have disadvantageous characteristics (e.g. high water cut, high H_2S content)
- Identify and correct system malfunctions and non-intended behavior
- Analyze and improve the logistics and planning of maintenance, replacement and installation of equipment or in the execution of field activities.
- Review the occurrence of failures and recognize patterns
- Calibration of instrumentation
- Identification of operational constraints (e.g. water handling capacity, power capacity)
- Observe and analyze the response of the system when changes are introduced
- Find control settings of equipment that give a production higher than current (or, preferably, that give maximum production possible)
- Identify Bottlenecks
- Identifying and monitoring Key Performance Indicators (KPIs)

ESP electric submersible pump





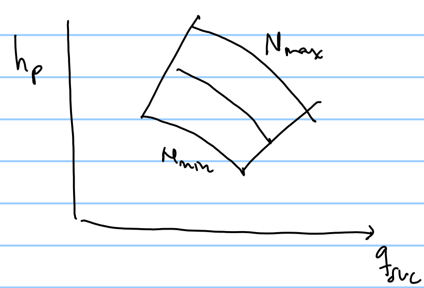


with depletion Δp_{ESP} is increasing

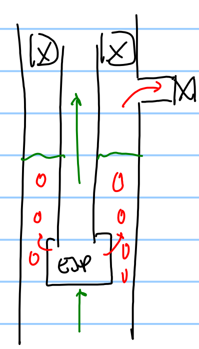
the pump also has operational constraints

- limited available (maximum power) capacity
- operational map (envelope)
- $P_{suc} \geq P_b(T_R)$
  ↳ bubble point pressure (no gas is allowed in the pump)

for compressor:



onshore



offshore

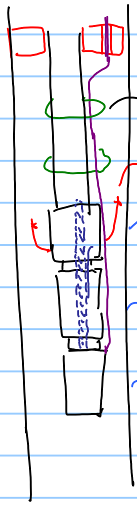
typical gas tolerance in ESP is GVF = 10%

gas volume fraction

$$GVF = \frac{q_g}{q_L + q_g} \times 100\%$$

$q_L = q_o + q_w$

Armais Arutunoff



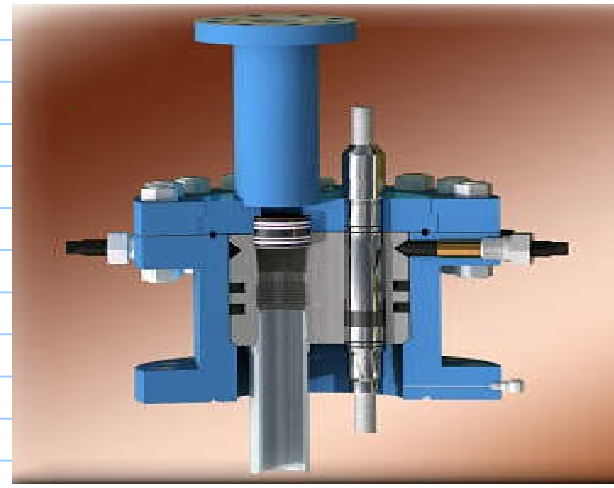
clamps

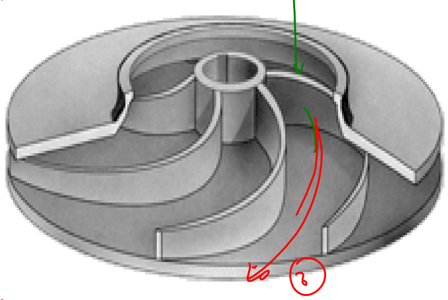
gas

pump might have a gas separator

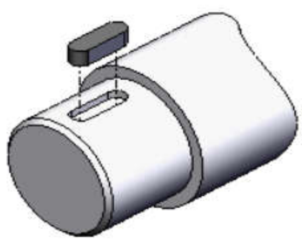
protector / seal

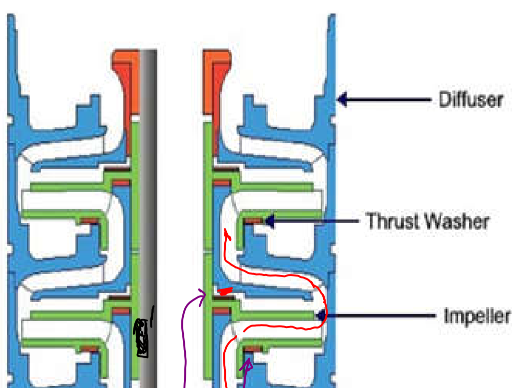
motor





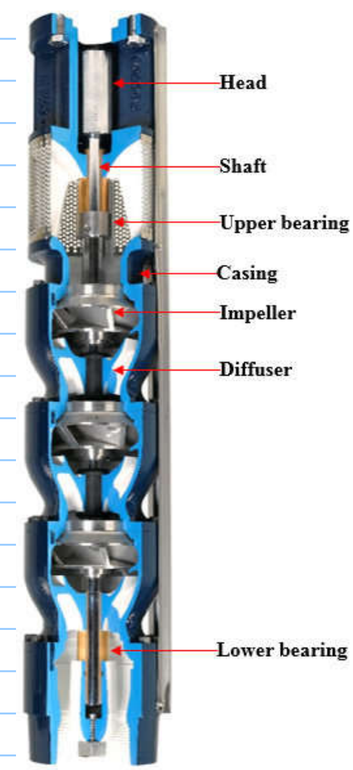
stage : impeller (rotor) + diffuser

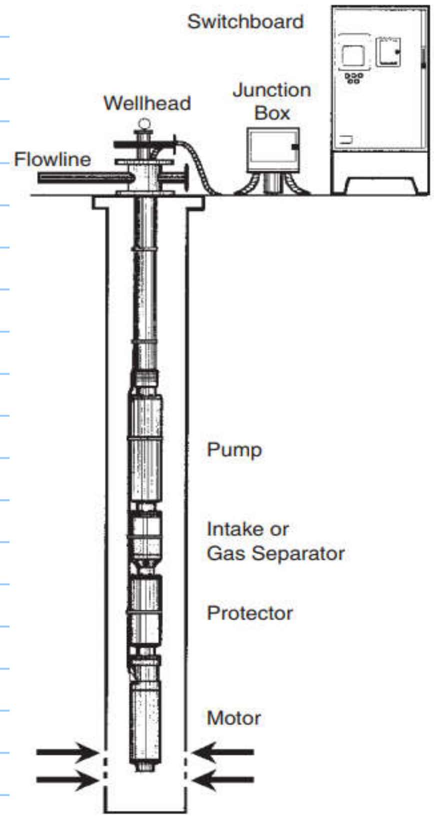


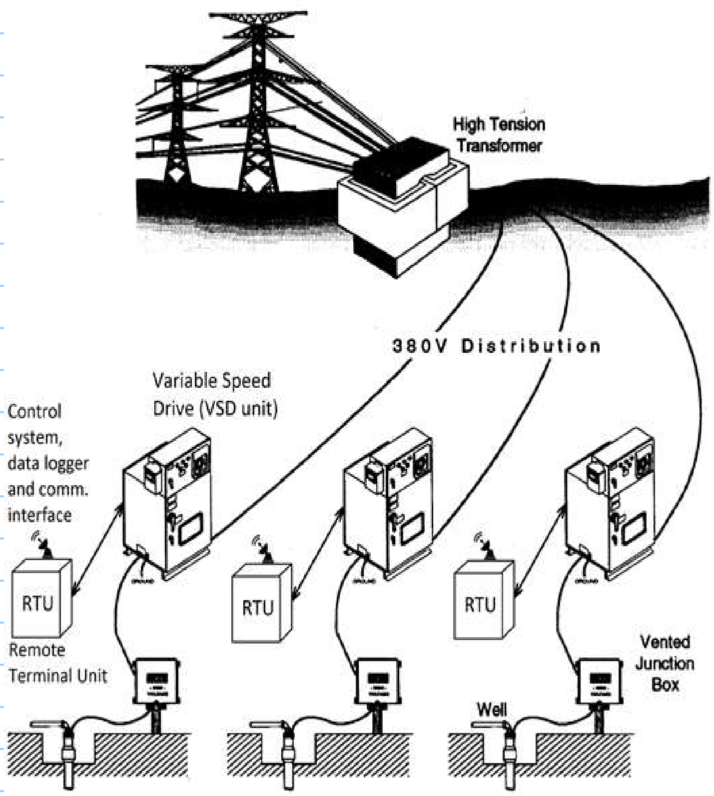


upthrust

down thrust



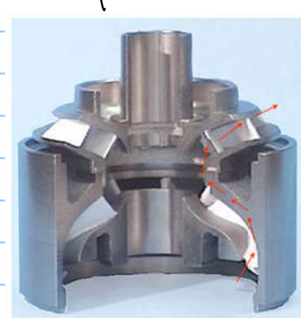




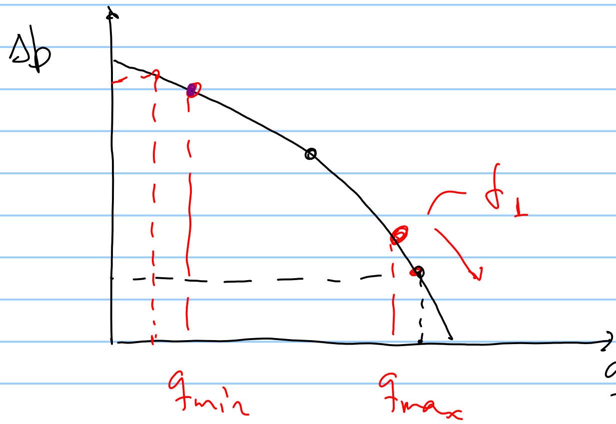
pump frequency

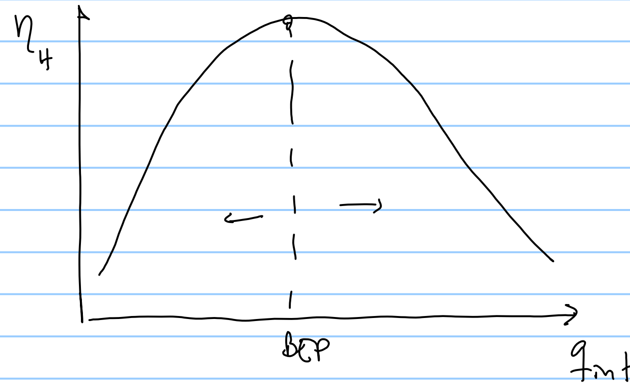
$f = 30 - 70$ hz

gas impeller and diffuser more tolerant to gas



operational map of ESP

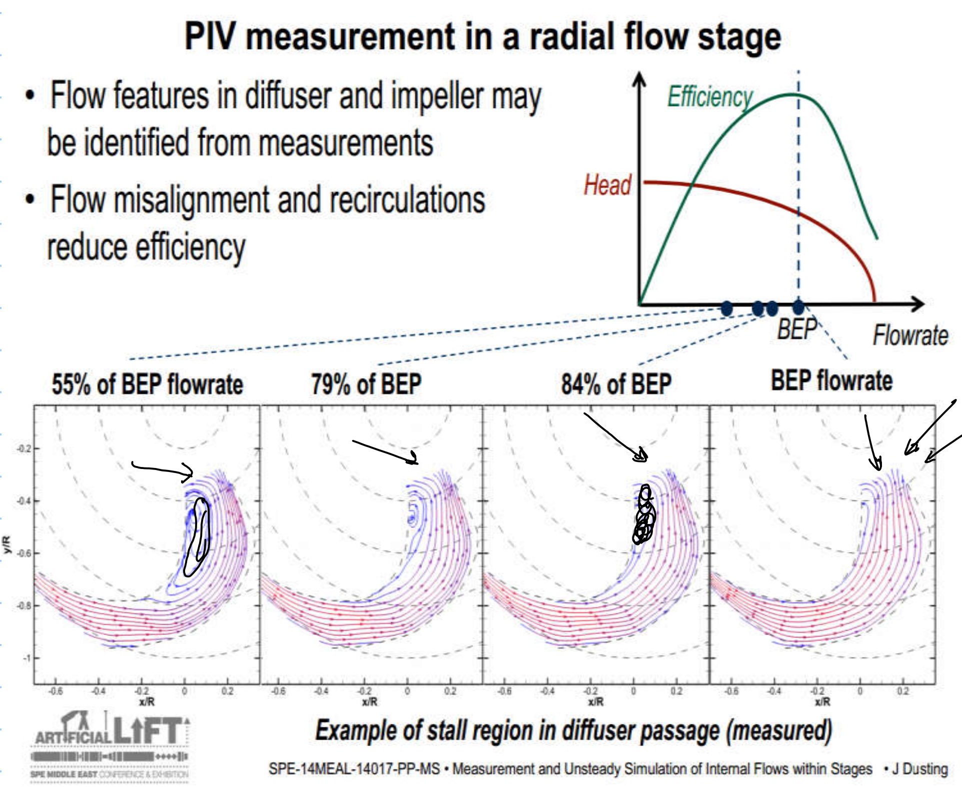


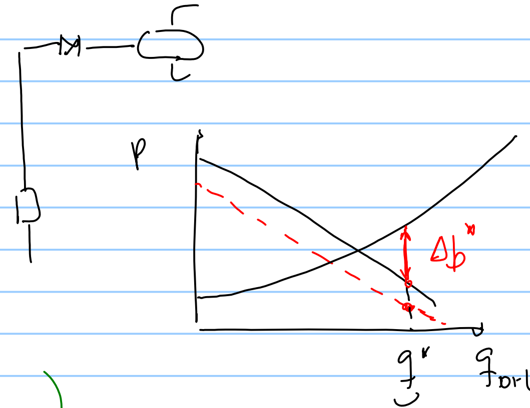


downthrust

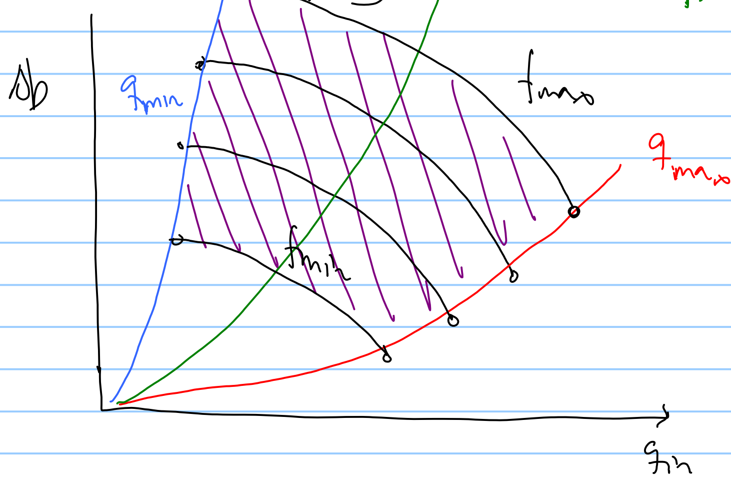
if $q > q_{max}$ then upthrusts but also low efficiency

pump hydraulic power $P_H = \dfrac{\Delta p \cdot q_{inlet}}{\eta_H}$

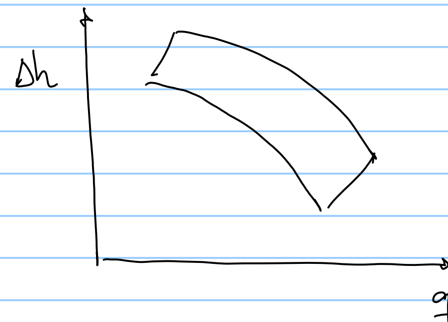


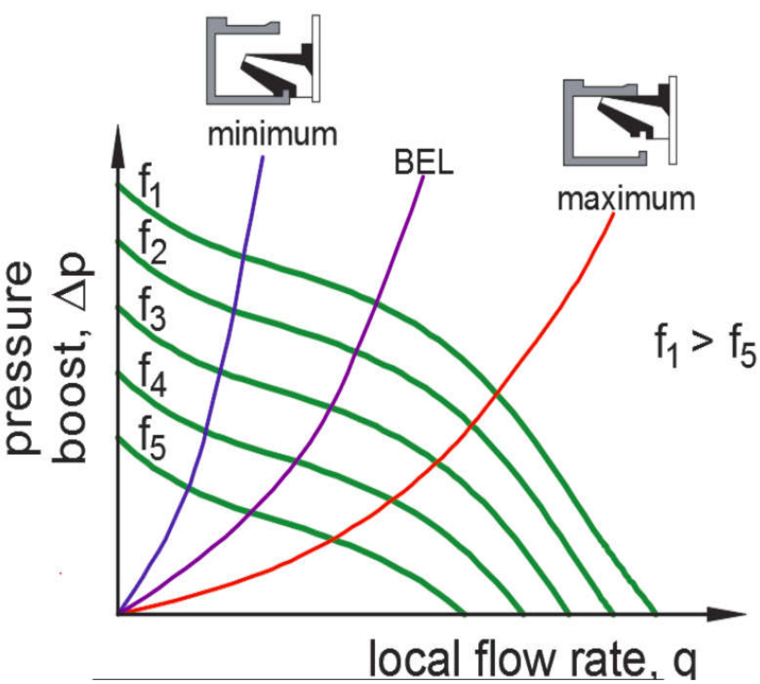


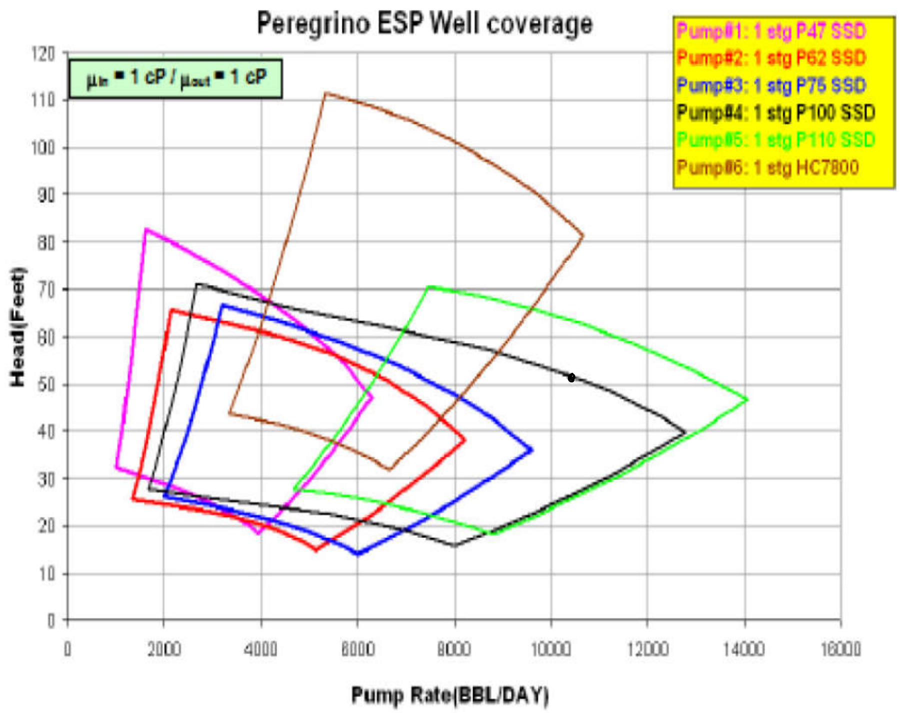
changes in pump frequency BEL (best efficiency line)



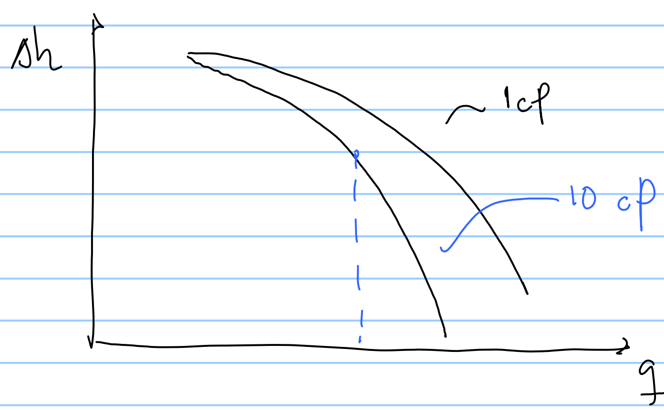
$$\Delta h = \text{head} = \frac{\Delta p}{\rho_{mix}}$$

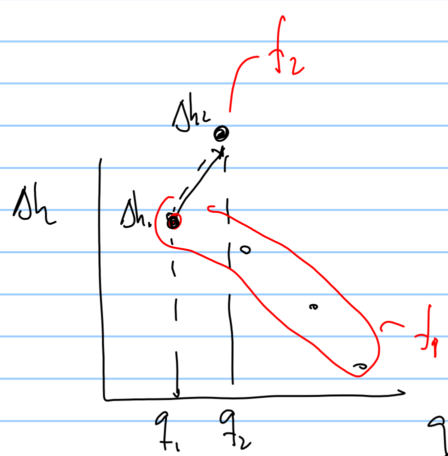






the viscosity of fluid also affects the performance of pump





for a given frequency

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

$$\frac{\Delta h_{@f_1}}{\Delta h_{@f_2}} = \left(\frac{f_1}{f_2}\right)^2 \qquad \frac{q_1}{q_2} = \frac{f_1}{f_2} \qquad \text{similarity law}$$

$$\frac{q_{ref}}{q} = \frac{f_{ref}}{f}$$

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

PENSUM:

- Field development workflow.
    - Overview – The field development process (ppt)
    - Production modes
    - Discounting
    - Relationship between plateau height and length
    - Rule of thumb between plateau height and TRR
    - Bottlenecking
    - Onshore vs offshore
    - Oil vs gas
- Field production performance
    - Dry gas production system: material balance, IPR, TPR, FPR. Flow equilibrium, production scheduling (Class exercise, Home exercise)
    - Production potential dry gas system (Class exercise)
    - Home exercise: Multi-field production scheduling using the production potential
    - Home exercise: production scheduling in a saturated oil field.
    - Dry gas networks (class exercise)
    - Tubing tables (home exercise)
    - Gap, Prosper and MBAL (ppt, class exercise)
    - Coupling reservoir and well and network models
- Value chain model, cost estimation and NPV calculations (Class exercise, Home exercise)
- Subsea compression (Class exercise)
- Probabilistic reserve estimation
    - Monte Carlo (Class exercise in Excel and Jupyter notebook)
    - Latin Hypercube Sampling – LHS (Class exercise in Jupyter notebook)
- Decision and probability tree analysis (Class exercise in Jupyter notebook)
- Home exercise: quantification of uncertainty in NPV - early field development
- Offshore structures
    - Overview (ppt)
    - Layout of production systems (ppt) (Home exercise, problem 4)
    - Marine loads on offshore structures (Class exercise in Jupyter notebook)
- Flow assurance considerations (ppt)
    - General overview
    - Inhibitor subsea system. Disposal.
    - Home exercise: Hydrate and p and T calculations on wet gas pipeline.
- Production optimization (ppt)
    - Introduction
    - Time scales
    - Cases (examples)
    - Algorithms for production optimization
    - Examples
    - Limitations and pitfalls
    - Class exercise
- Electric submersible pumps (class exercise)

Tools:

-Excel with VBA, Excel solver, Jupyter Notebook (python), gap, prosper and MBAL (Petex)

Generic Skills and topics

-Sampling with Monte Carlo, Latin Hypercube
-Probability trees
-Optimization
-Marine loads on offshore structures
-FFT

INDUSTRY PRESENTATIONS:
-Subsea transport and processing
-Flow assurance in Aasgard
-Hydrates
-Flow assurance in field development
-Compact separation

Exercise grades:
-To be uploaded in the following weeks

Exam
-Guest lectures are not to be included in the exam
Type of exercises:
-Theory, writing
-Hand calculations and fill results and procedure in Inspera
-Use of Excel and upload Excel file to Inspera. Excel can be run from the local machine or from examfarm.ntnu.no