TPG4230 FIELD DEVELOPMENT AND OPERATIONS

Note Title 05.01.2015

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TODAY'S AGENDA: PRACTICAL INFO
SHORT INTRO

CLASSES P10 MONDAYS 8:15-11:00
TUESDAYS 8:15-10:00 } MIXED LECTURES + EXERCISES

ASSISTANTS: AFTAB HUSSAIN ARAIN
PRIYADHARSHINI SAPTHARISHI

EVALUATION:
- 40% EXERCISES (MANDATORY FOR TAKING THE ORAL EXAM)
  1 SET OF PROBLEMS EVERY TWO WEEKS ⤳ 5-6 SETS OF EXERCISES
- 60% ORAL EXAMINATION. 19.05.2015 9:00 (4 hrs. DURATION)

QUALITY IN EDUCATION ⤳ REFERENCE GROUP { • THOMAS BERTELSEN

COURSE INFO THROUGH ITS LEARNING. CHECK FREQUENTLY!

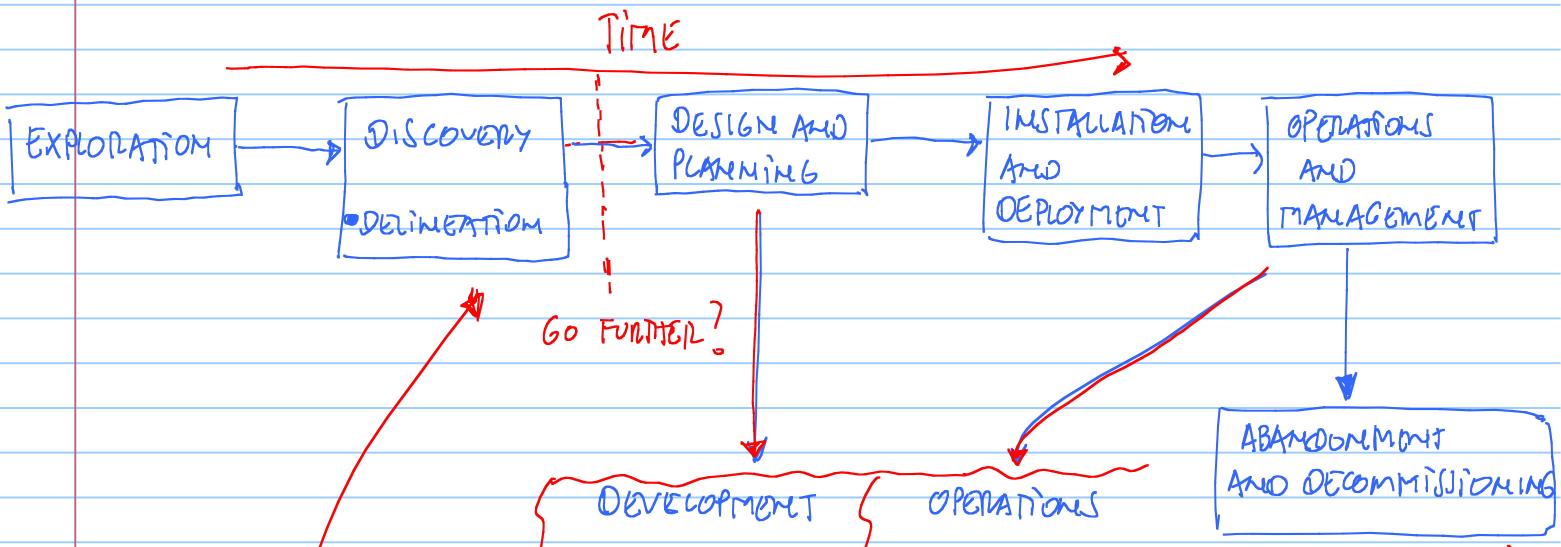
- INVITED LECTURERS
  - PROF. CURTIS WITHSON (IAM)
  - PROF. JESUS DE ANDRADE { COMPRESSORS (19.01)

- BIBLIOGRAPHY ⤳ CHECK ITS LEARNING.

//

IN THIS COURSE WE ARE FOCUSED ON → OFFSHORE FIELD

LIFE CYCLE OF A HYDROCARBON FIELD



DEVELOPMENT
- FLEXIBILITY
- UNCERTAINTY
- SENSITIVITY ANALYSIS {SCENARIOS}
- ↑ MONEY

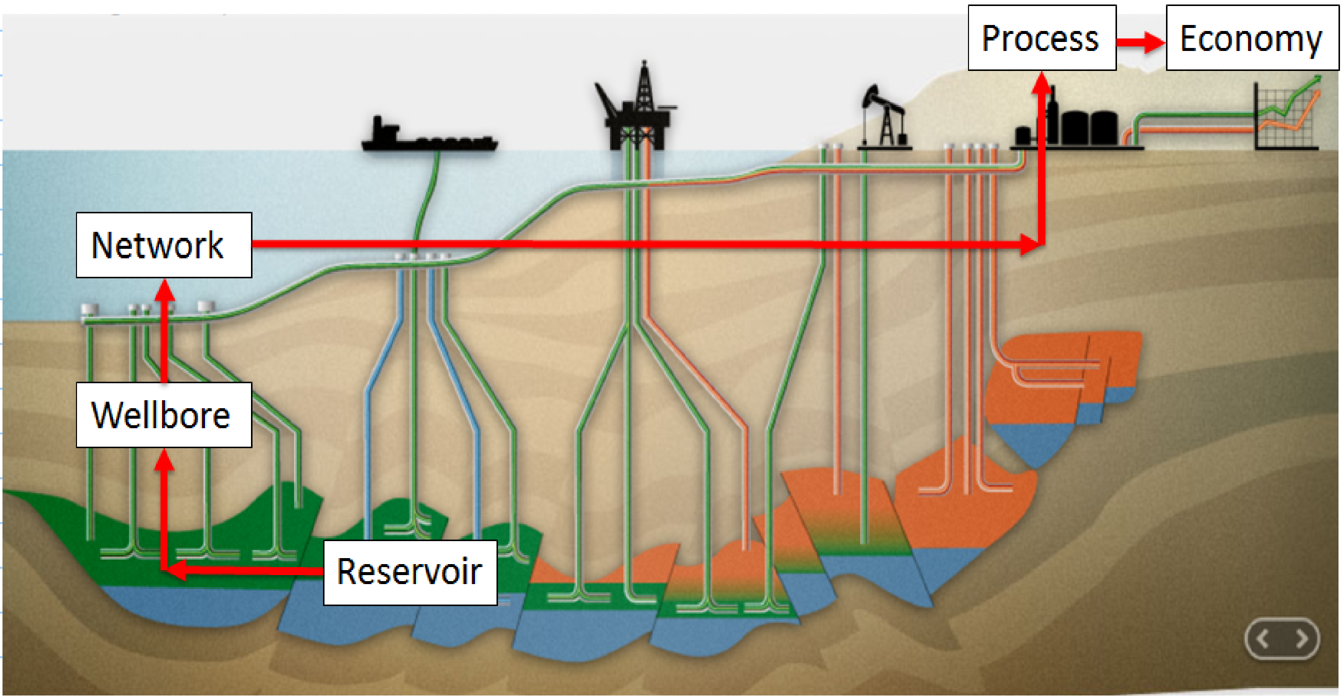
OPERATIONS
- WORKING WITH AN EXISTING SYSTEM
  - EXPLOIT ITS ADVANTAGES
  - COPE WITH ITS DEFICIENCIES
- OPTIMIZATION ↑ PROFIT ↓ COST
- TROUBLESHOOTING
- MAINTENANCE.

WHO PAYS FOR IT?

DIFFERENT APPROACHES IF YOUR MAIN PRODUCT IS GAS OR OIL

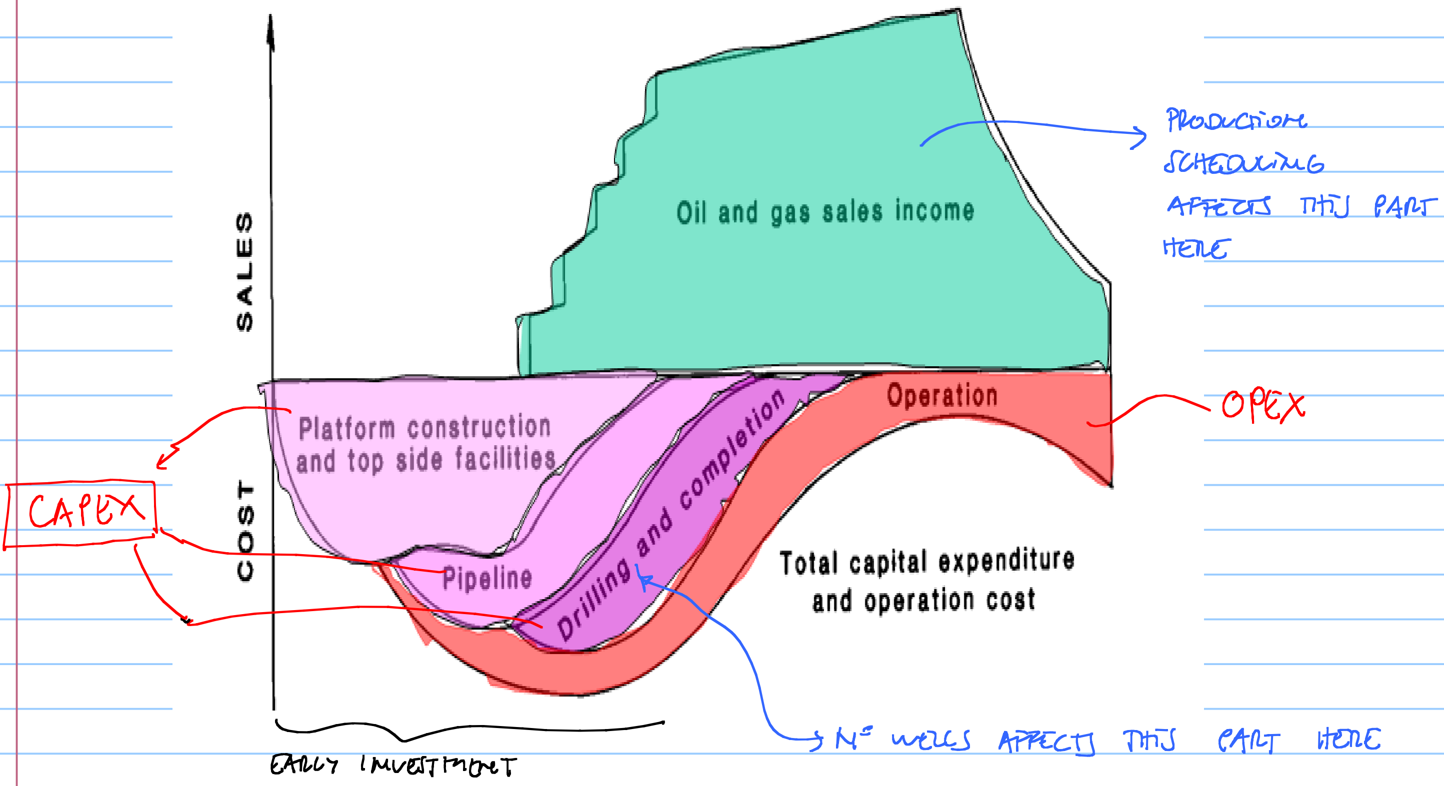
→ FOR GAS YOU NEED TO HAVE A BUYER + SALES CONTRACT + INFRASTRUCTURE / LNG
PIPELINE

OVERVIEW OF THE COMPONENTS OF A HYDROCARBON FIELD



It is very important (sometimes it is the most important factor) to look at the economy of my asset/field. This is what the cash flow looks like:

Revenue and Cost Profiles



PRODUCTION SCHEDULING AFFECTS THIS PART HERE

OPEX

CAPEX

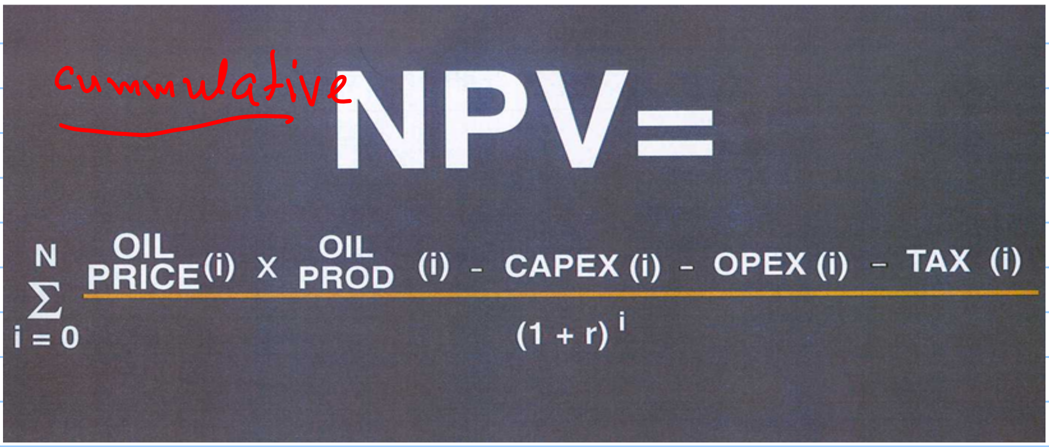
N° WELLS AFFECTS THIS PART HERE

EARLY INVESTMENT

NET PRESENT VALUE.

FOR AN OIL/GAS FIELD

The Ultimate driver in E&P operations (cummulative NPV)



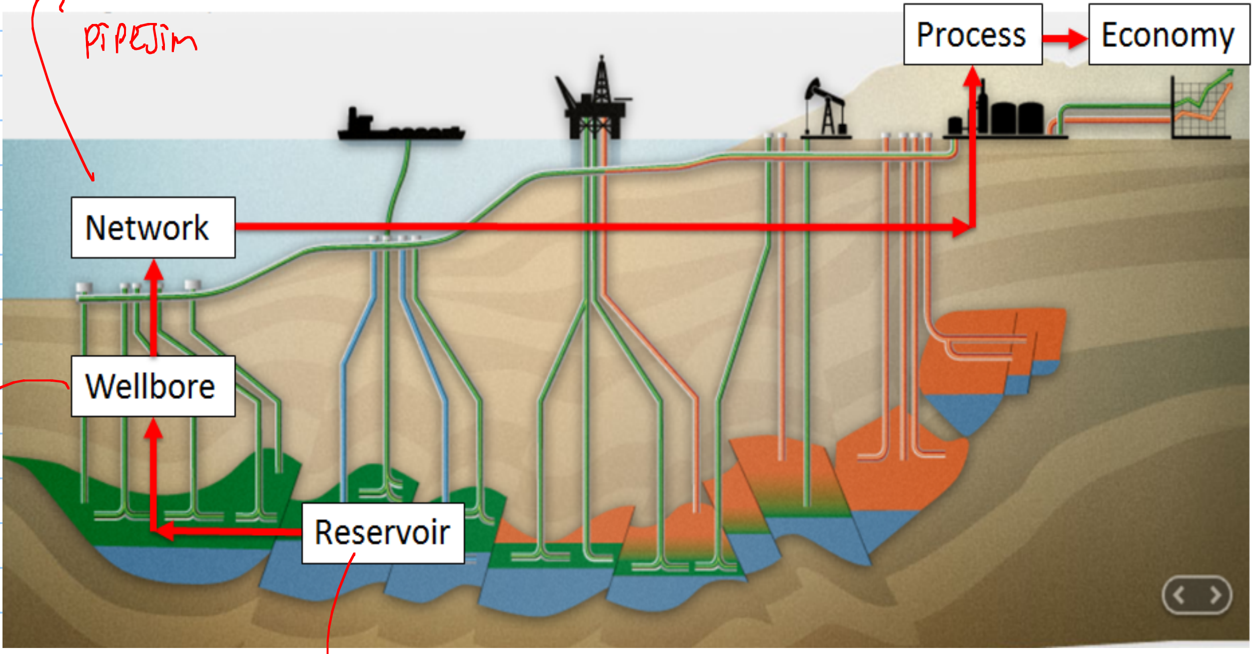
$$\text{cummulative NPV} = \sum_{i=0}^{N} \frac{\text{OIL PRICE}(i) \times \text{OIL PROD}(i) - \text{CAPEX}(i) - \text{OPEX}(i) - \text{TAX}(i)}{(1+r)^{i}}$$

MANY TIMES, THE DECISION BETWEEN DIFFERENT SCENARIOS/DEVELOPMENT STRATEGIES IS BASED ON WHICH ONE HAS THE HIGHEST NPV / RECOVERY FACTOR.

IN THE EVALUATION OF DIFFERENT SCENARIOS (DEVELOPMENT)
IN THE EVALUATION OF THE OPERATION (OPERATIONS) } COMPANIES USE SPECIALIZED PETROLEUM SOFTWARE

HYSYS

GAP
PIPESIM



PROSPER
PIPESIM

ECLIPSE
MBAL
CMG
MORE

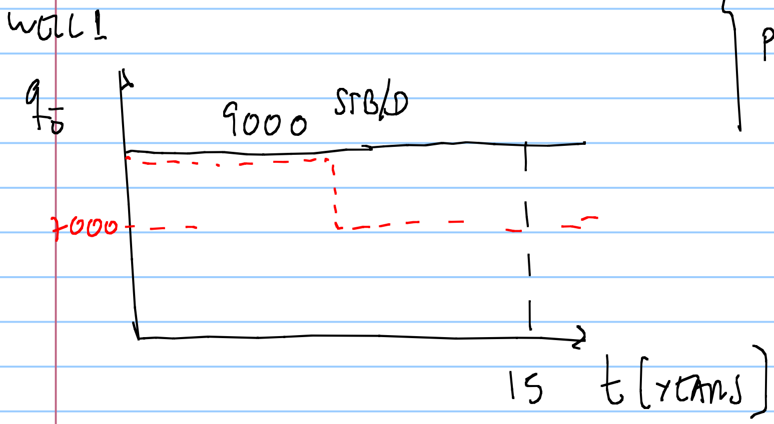
IAM : INTEGRATED ASSET MODELING

AVOCET, RESOLVE, PIPE-IT, ETC.

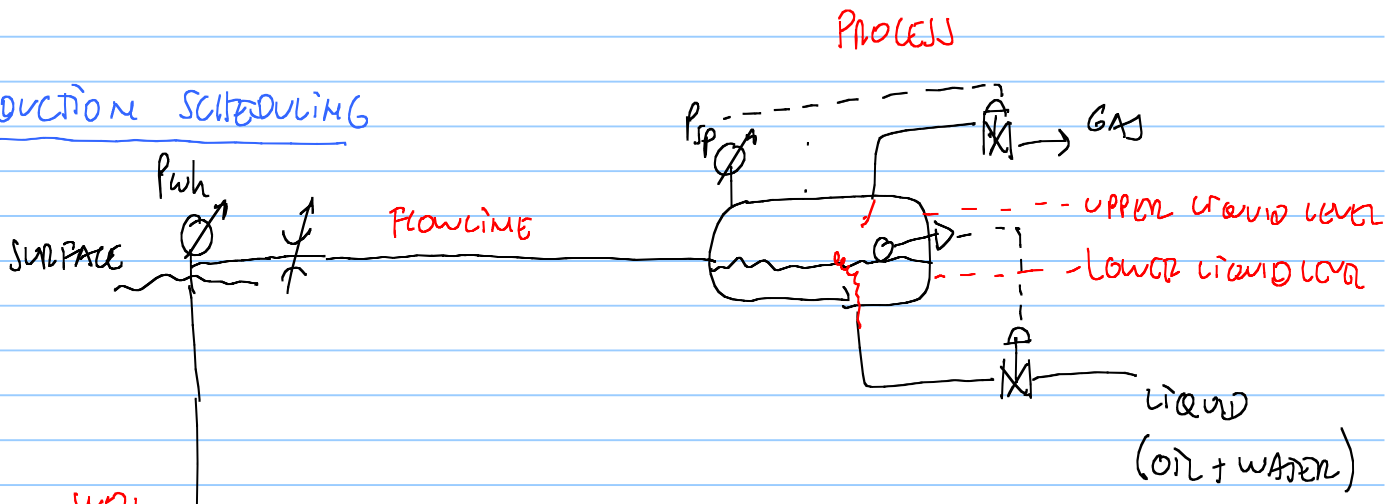
TWO FACTORS THAT HAVE AN IMPORTANT IMPACT IN THE NPV VALUE OF THE PROJECT ARE:

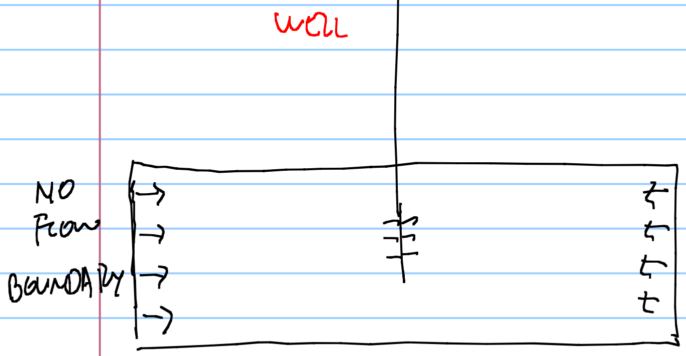
- NUMBER, LOCATION OF WELLS
- PRODUCTION SCHEDULING

HOW IS THE OFFTAKE GOING TO BE?
PRODUCTION PROFILE WITH TIME.

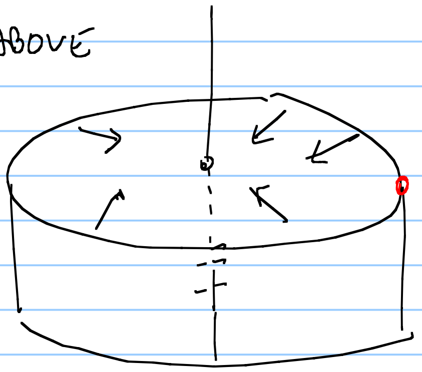


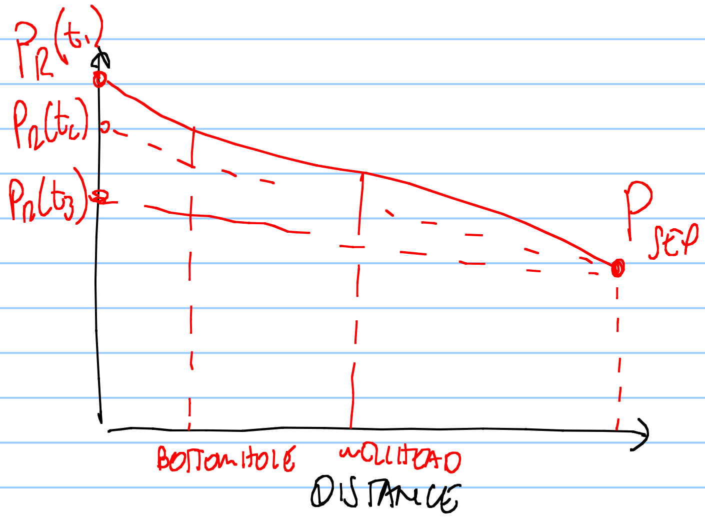
PRODUCTION SCHEDULING



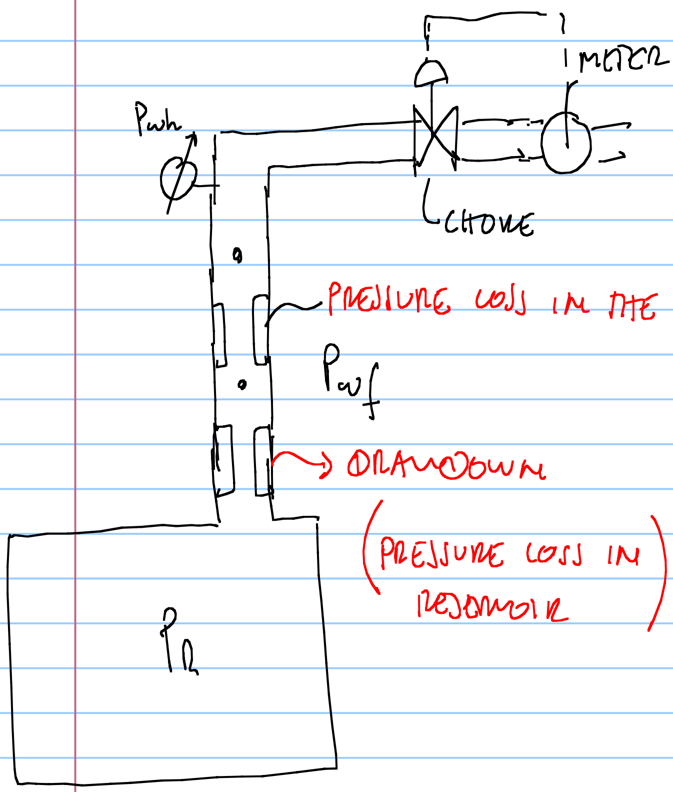


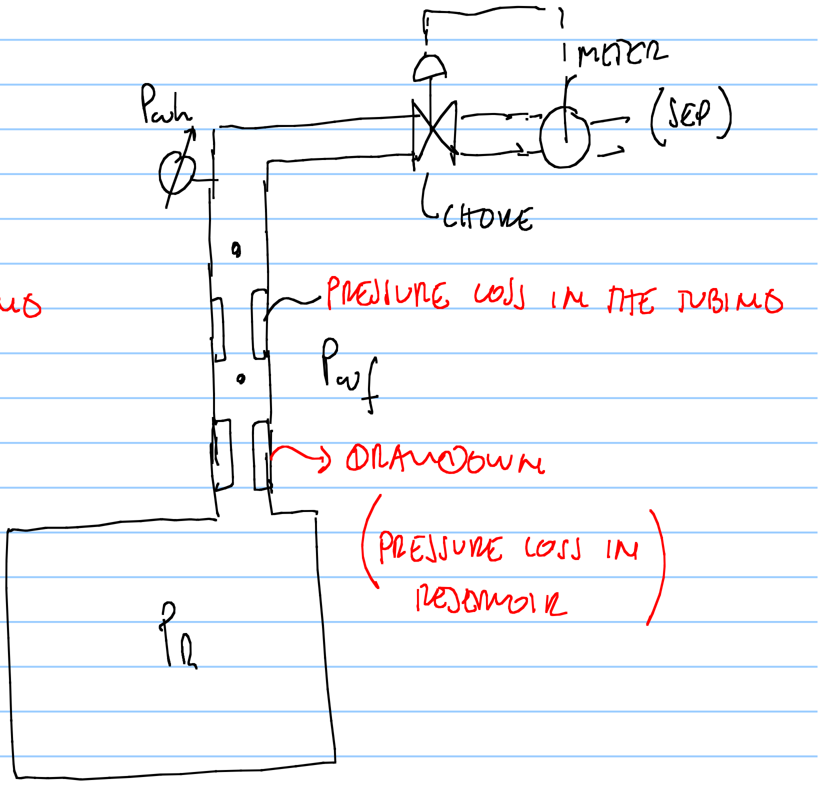
VIEW FROM ABOVE





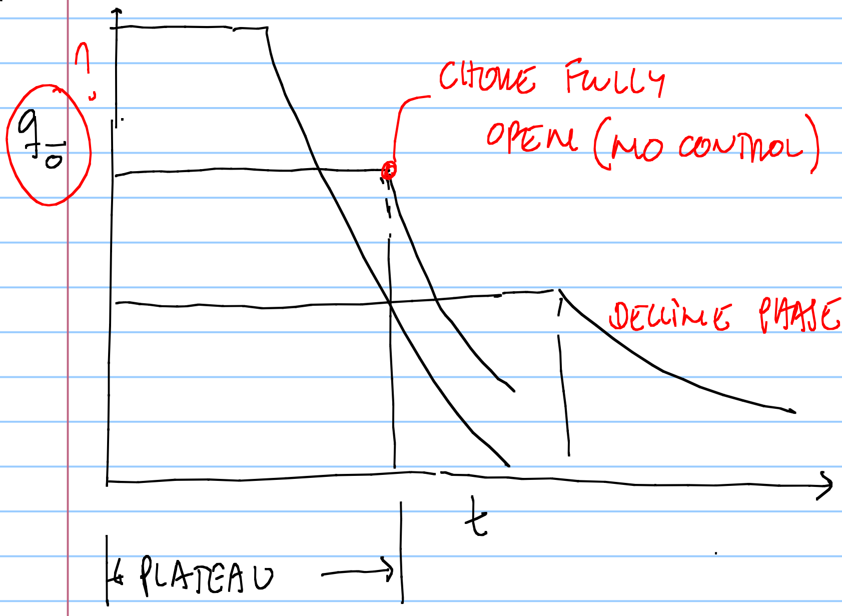
- MECHANICAL ANALOGY OF FIELD, TO INTRODUCE OPERATIONS MODE OF A FIELD:





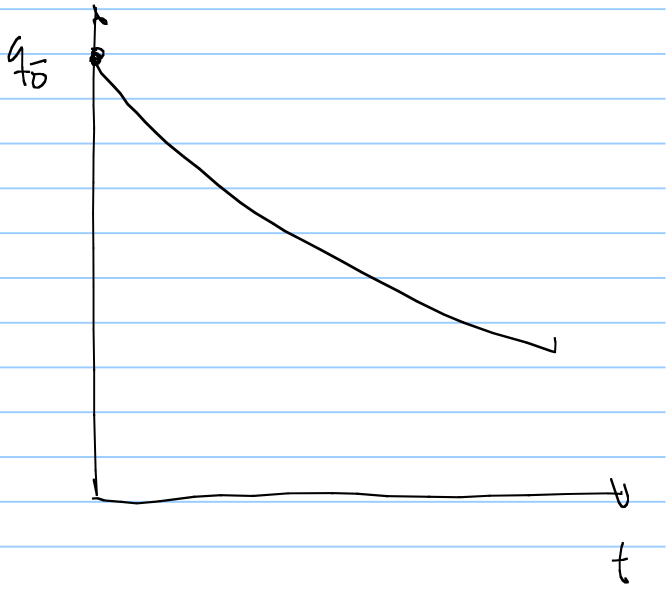
MODE A

CONSTANT RATE
PRESSURE DECLINE



MODE B

CONSTANT PRESSURE
RATE DECLINE



COMPROMISE BETWEEN PLATEAU RATE AND PLATEAU DURATION

EXAMPLE OF CONSTANT PRESSURE RATE DECLINE FIELD { Edda Field
CONOCO-PHILLIPS

SATELLITE TO EKOFISK COMPLEX

! CHECK WWW.NPD.NO FOR THE PRODUCTION PROFILE OF OTHER FIELDS

WHERE ARE THE DIFFERENT MODES EMPLOYED?

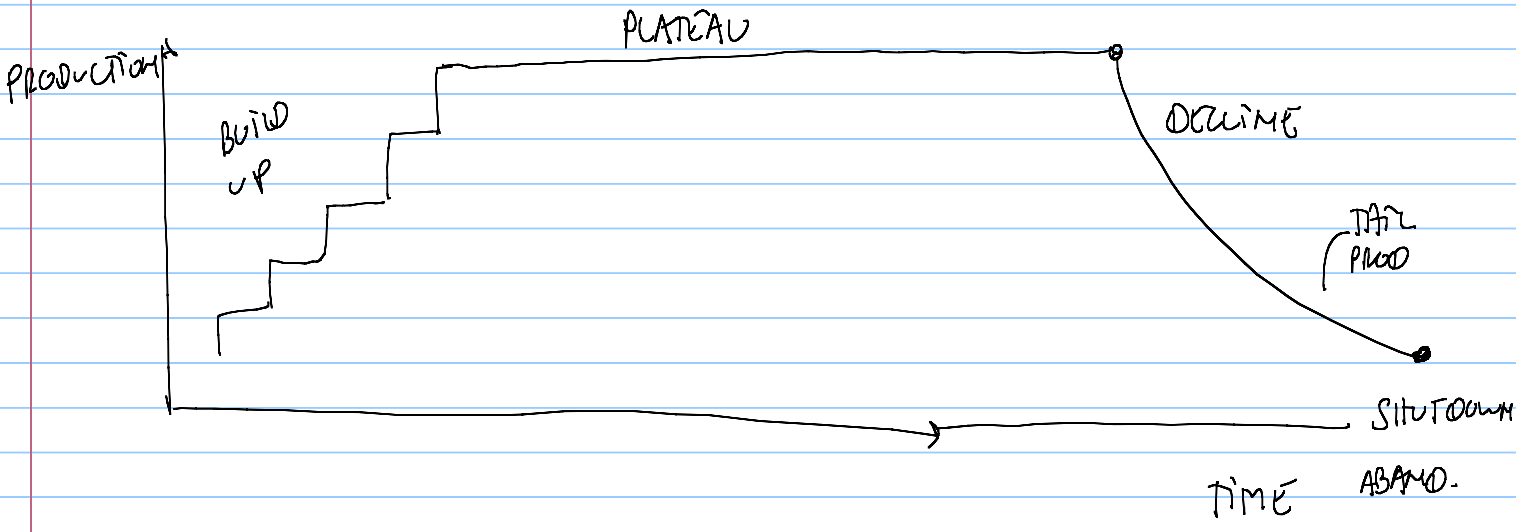
MODE B

- ITS **NOT** USED FOR A NEW INFRASTRUCTURE
- SATELLITE FIELD USING AN EXISTING INFRASTRUCTURE (EXISTING PROCESSING, PIPELINE, ETC)

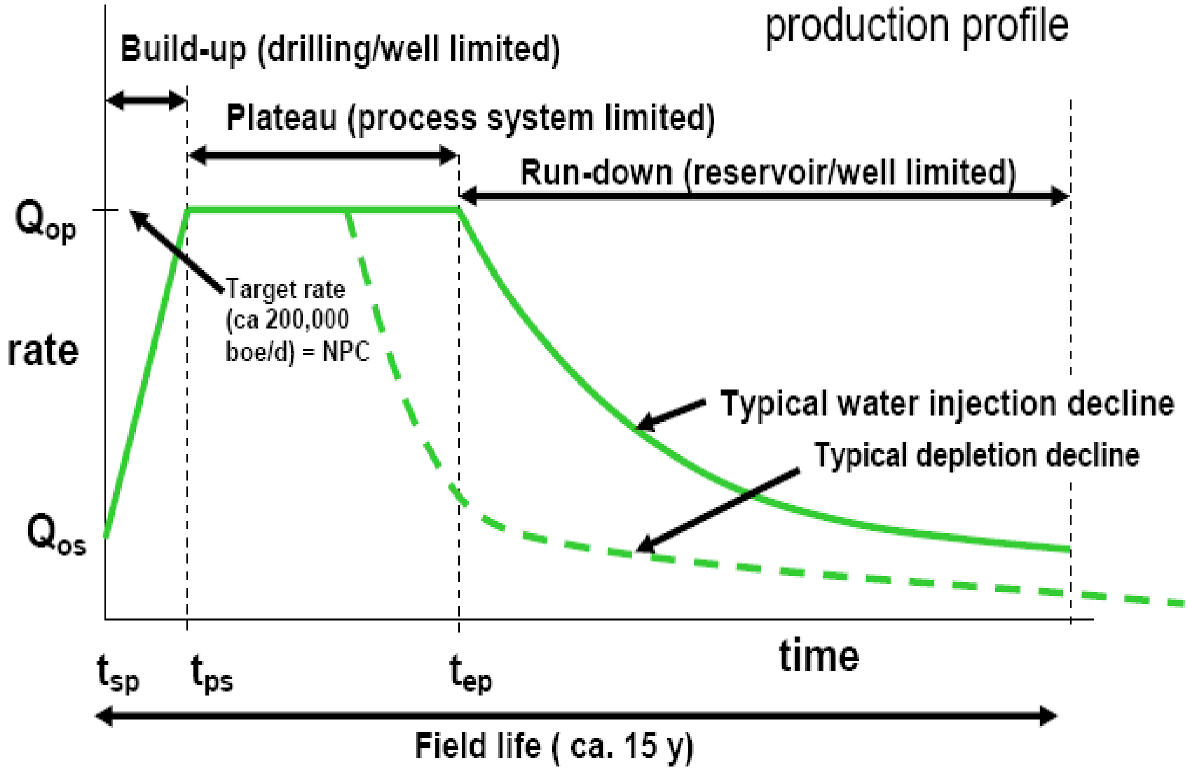
MODE A

- STAND ALONE FIELD
- BUILD THE WHOLE INFRASTRUCTURE FROM SCRATCH

DETAILED VIEW OF THE PERIODS OF THE FIELD

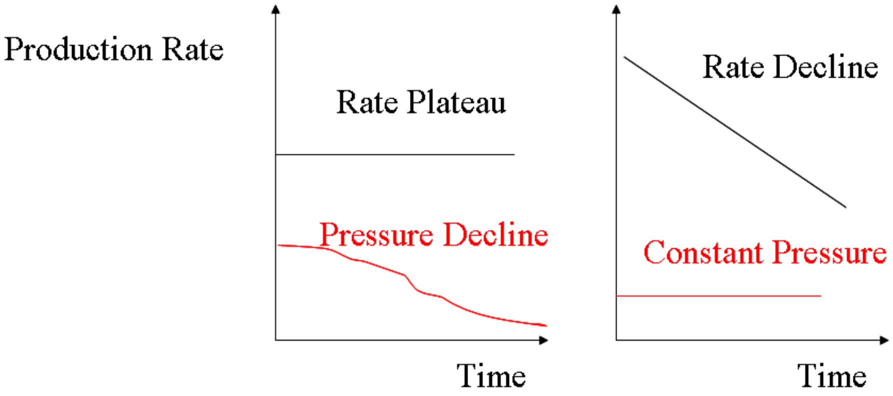


Three periods of the production profile



Modes of Reservoir offtake

Production Profile



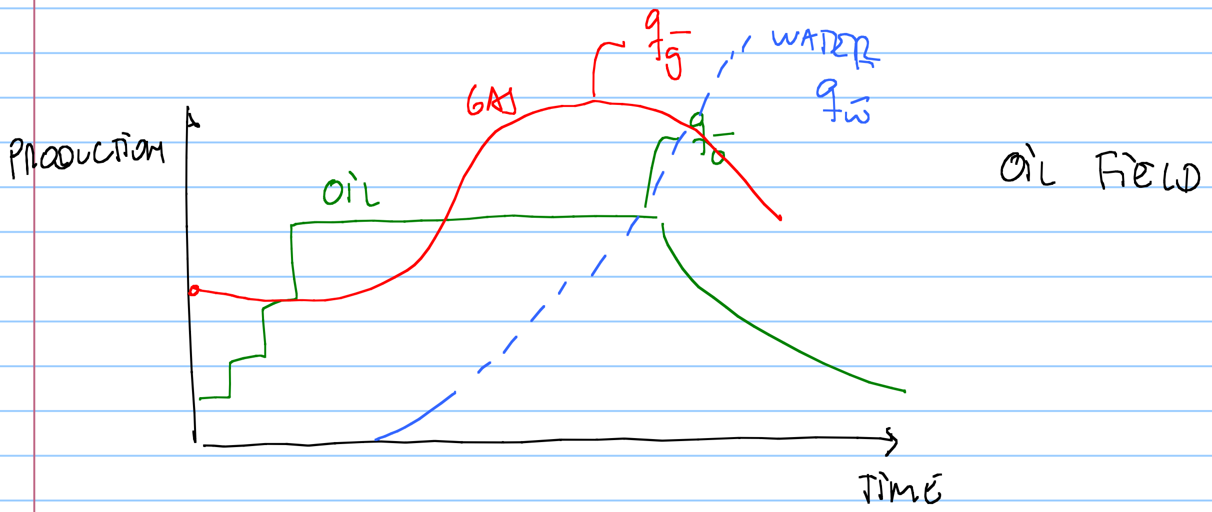
Which offtake mode to select?

- **Constant Pressure**
- Existing infrastructure

- **Plateau Rate**
- Stand-alone field
- No infra structure

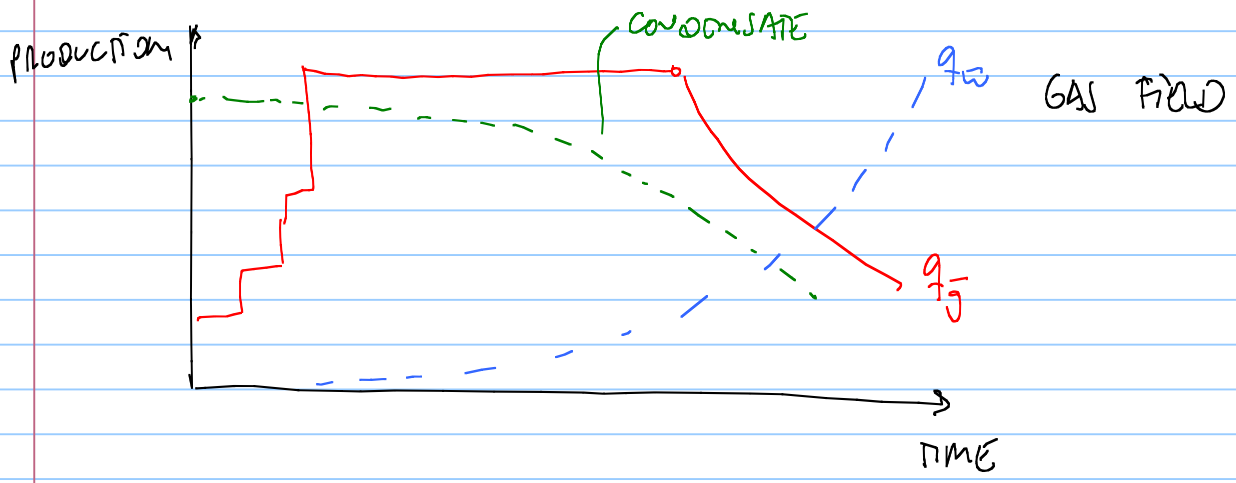
IT IS ALSO IMPORTANT TO TAKE INTO ACCOUNT THE OTHER PRODUCTS OF AN OIL/GAS FIELD:

- OIL FIELD: ACCOMPANYING PRODUCTS: GAS, WATER



IF THE WATER AND GAS PRODUCTION RISE VERY MUCH, THE PROCESSING FACILITIES MIGHT NOT HAVE ENOUGH CAPACITY TO HANDLE THESE STREAMS

- GAS FIELD: ACCOMPANYING PRODUCTS: CONDENSATE (OIL) + WATER



THE REDUCTION IN CONDENSATE PRODUCTION REDUCES THE INCOME OF THE FIELD (SOMETIMES IS VERY RELEVANT)

INCREASED WATER PRODUCTION MIGHT CREATE HIGH PRESSURE DROP IN THE TUBING AND FLOW ASSURANCE ISSUES (SLUGGING, HYDRATES, BLOCKAGE).

HOW DO WE DETERMINE THE PLATEAU RATE?

AS A FIRST APPROXIMATION (RULE OF THUMB):

What is a typical plateau level that is practiced in fields design in the North Sea? (first design iteration)

Oil fields:

Annual offtake rate=0.1(Total Recoverable Reserve)

Gas fields:

Annual offtake rate=0.05(Total Recoverable Reserve) → VOLUME

VOLUME

0.05 - 0.035

N

RECOVERY FACTOR

TOTAL RECOVERABLE RESERVE = IOIP · RF ~> 8-10 YEARS PLATEAU

PRODUCED ECONOMICALLY WITH EXISTING TECHNOLOGY

27%	35%	50%
1970	1990	2010

EVOLUTION OF ULTIMATE RECOVERY FACTOR OF THE FIELD

$RF = \frac{Np}{N}$

Np ~> COMMULATIVE OIL PRODUCTION Sm³ | STB

N ~ IOIP ~ INITIAL OIL IN PLACE

$RF = \frac{Gp}{G}$

Gp → CUMMULATIVE GAS PRODUCTION

G → IGIP ~> INITIAL GAS IN PLACE Sm³ | Scf

$$\text{FIELD RATE} = \frac{\text{ANNUAL OFFTAKE RATE}}{\text{N° DAYS IN A YEAR}} = $$

Sm³/d

STB/d

Scf/d.

TPG4230 Field development and operations

Snowhite ↝ Snøhvit ↝ Blanca Nieves (Spanish)

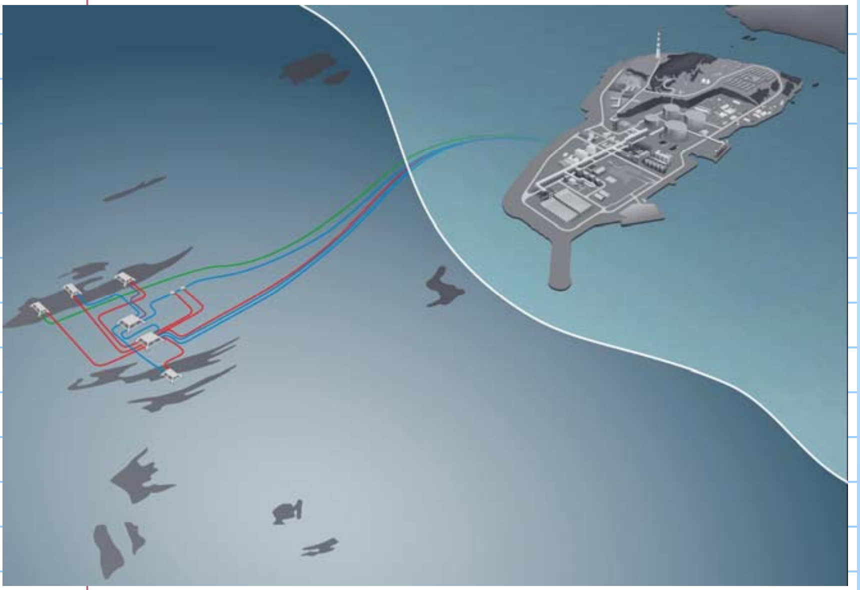
Persian: Sepid Barfi

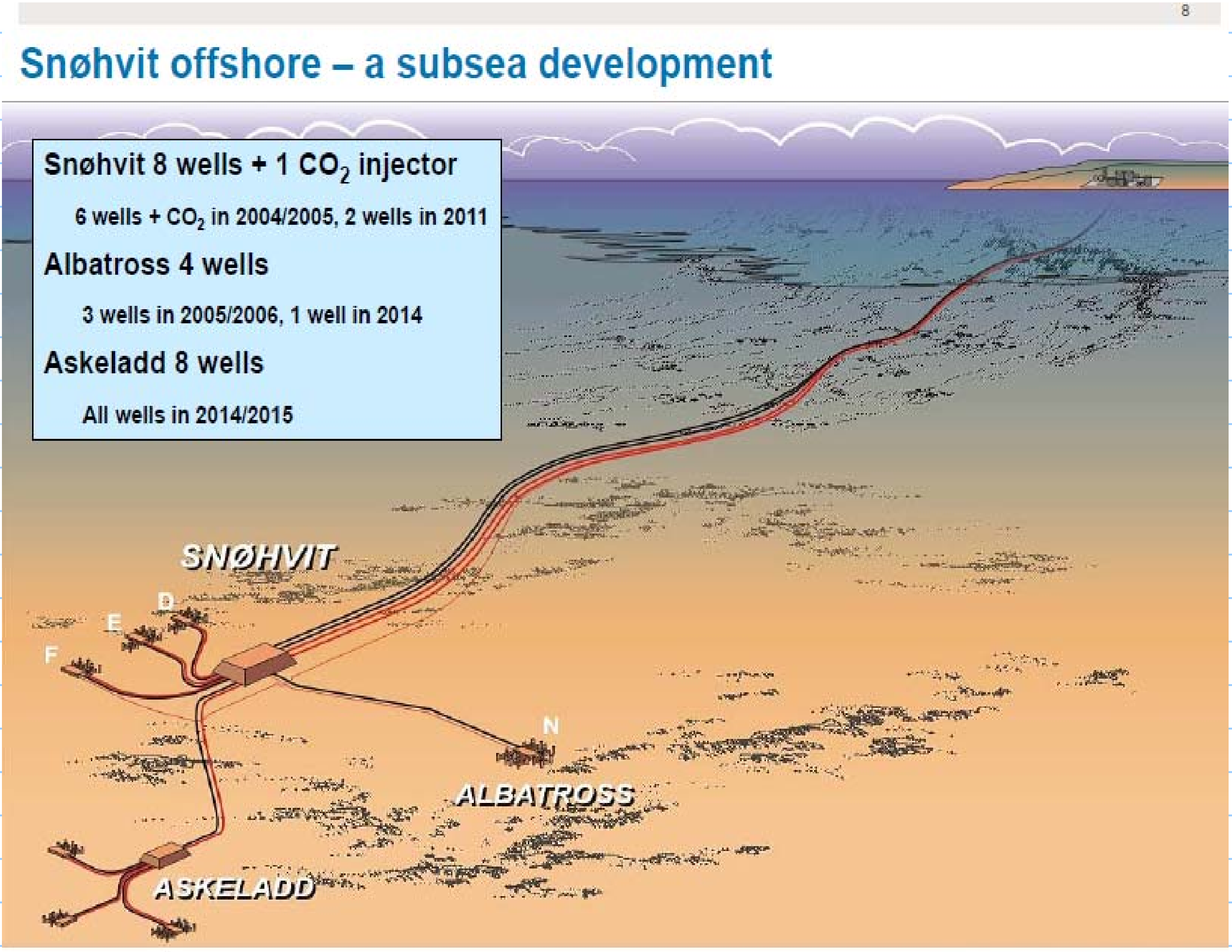
Danish: Snehvide

Russian: БЕЛОСНЕЖКА (BELOSNESHKA)

Bulgarian: Снежнобял

140 – 143 Km





Snøhvit offshore – a subsea development

Snøhvit 8 wells + 1 CO_2 injector

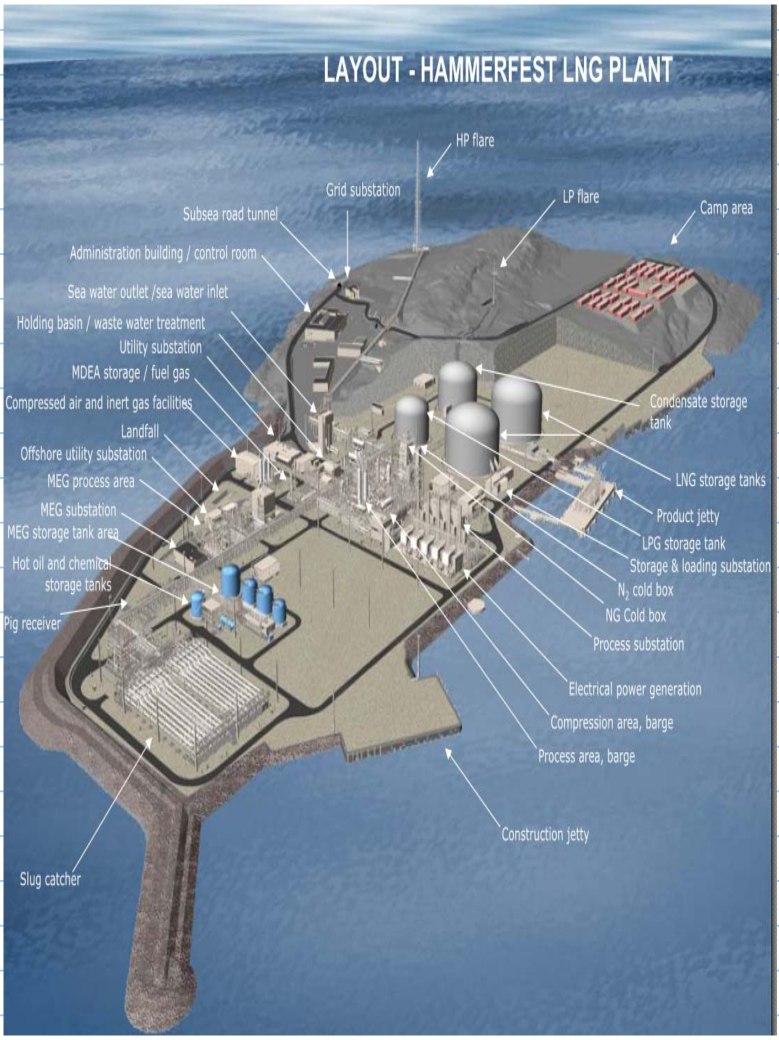
6 wells + CO_2 in 2004/2005, 2 wells in 2011

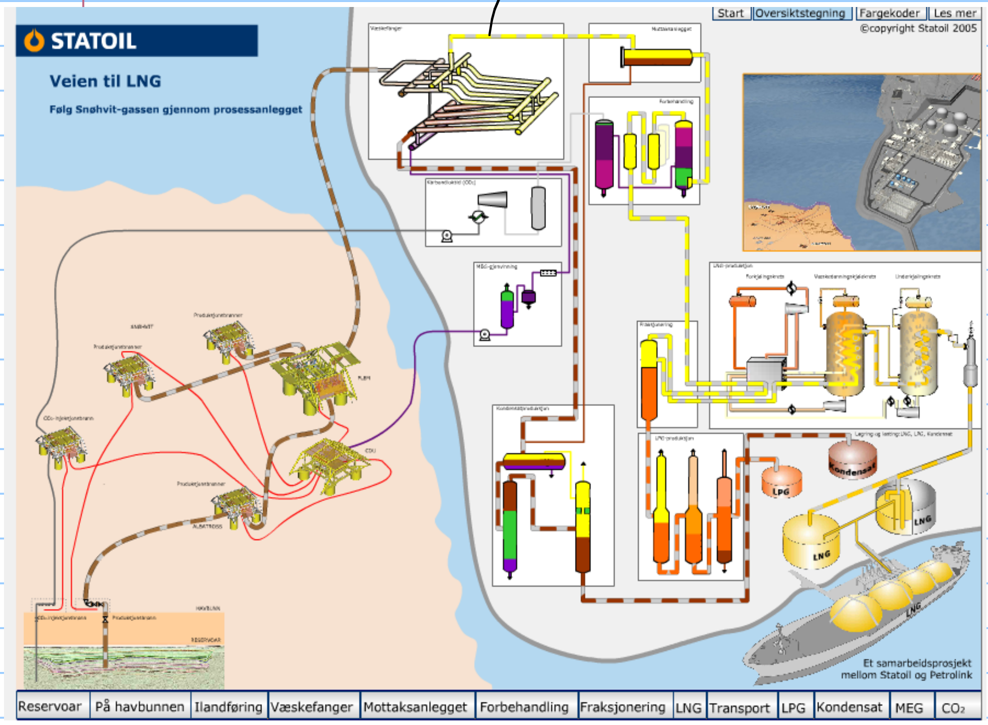
Albatross 4 wells

3 wells in 2005/2006, 1 well in 2014

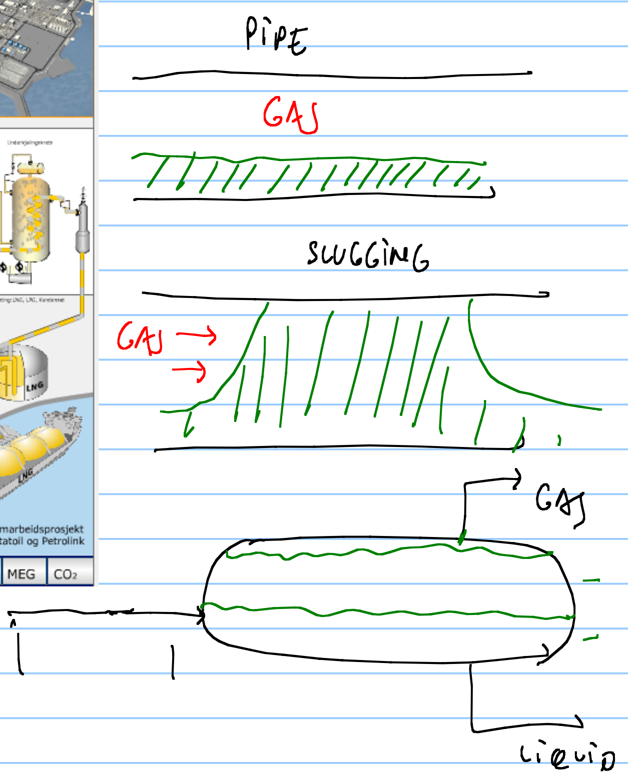
Askeladd 8 wells

All wells in 2014/2015


LAYOUT - HAMMERFEST LNG PLANT
HP flare
Grid substation
LP flare
Camp area
Subsea road tunnel
Administration building / control room
Sea water outlet /sea water inlet
Holding basin / waste water treatment
Utility substation
MDEA storage / fuel gas
Compressed air and inert gas facilities
Landfall
Offshore utility substation
MEG process area
MEG substation
MEG storage tank area
Hot oil and chemical storage tanks
Pig receiver
Condensate storage tank
LNG storage tanks
Product jetty
LPG storage tank
Storage & loading substation
N_2 cold box
NG Cold box
Process substation
Electrical power generation
Compression area, barge
Process area, barge
Construction jetty
Slug catcher

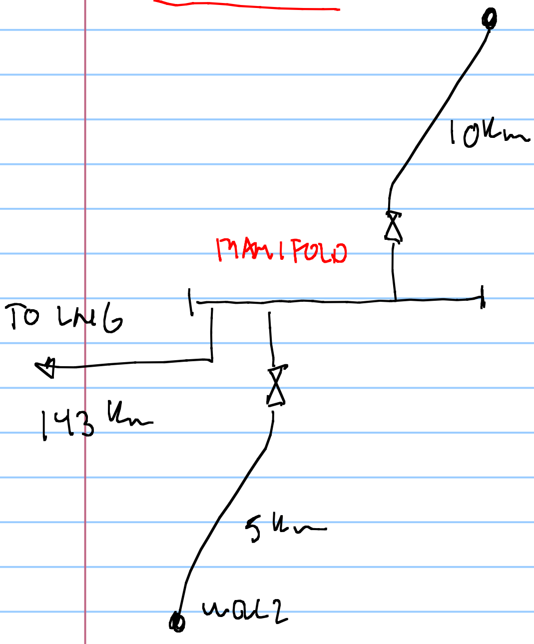


SLUG CATCHER / SEPARATOR

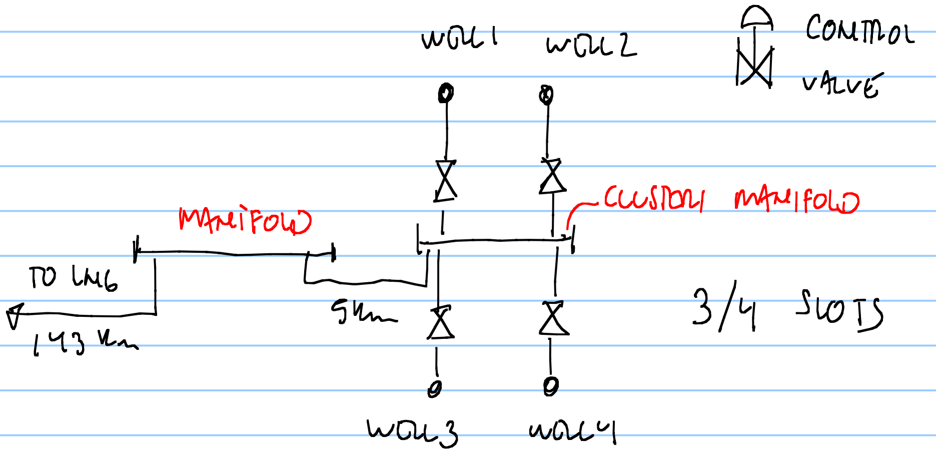


CONSTRUCTION OF SUBSEA WELLS

SATELLITE

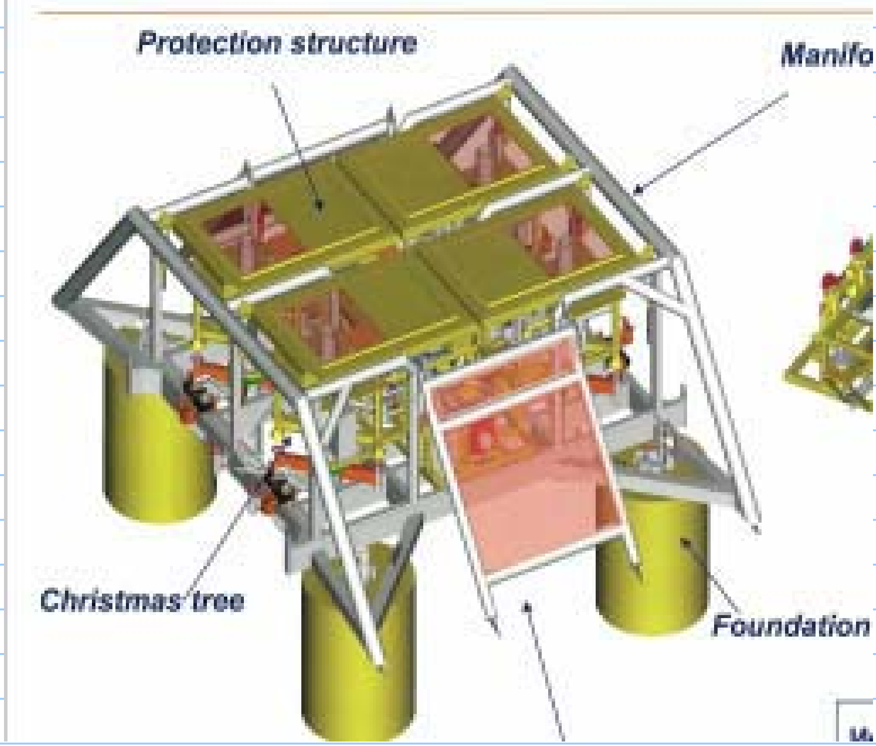


TEMPLATE, CLUSTER

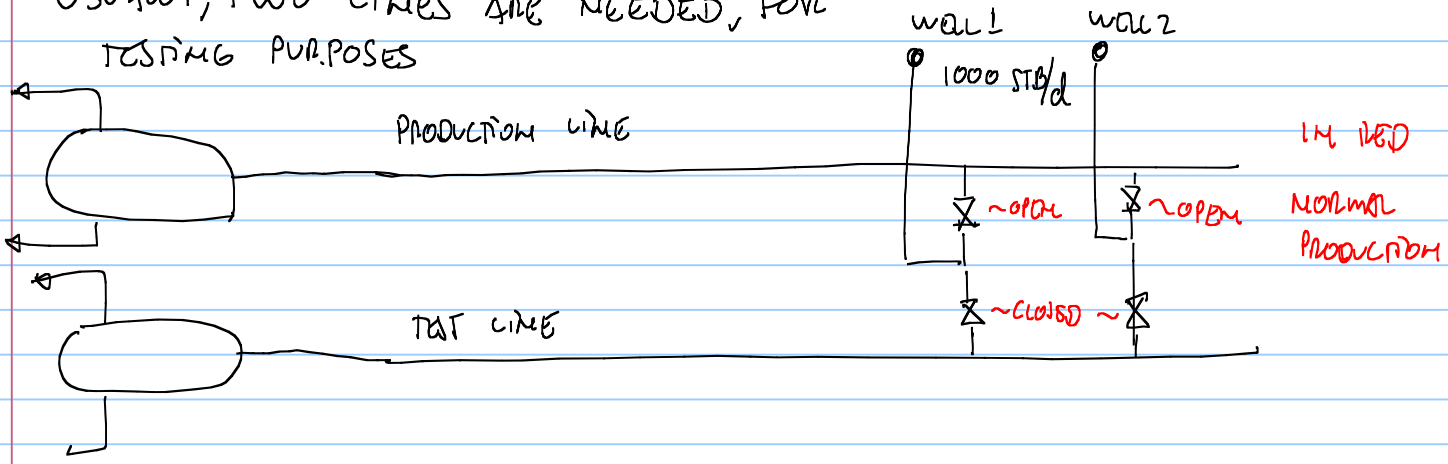


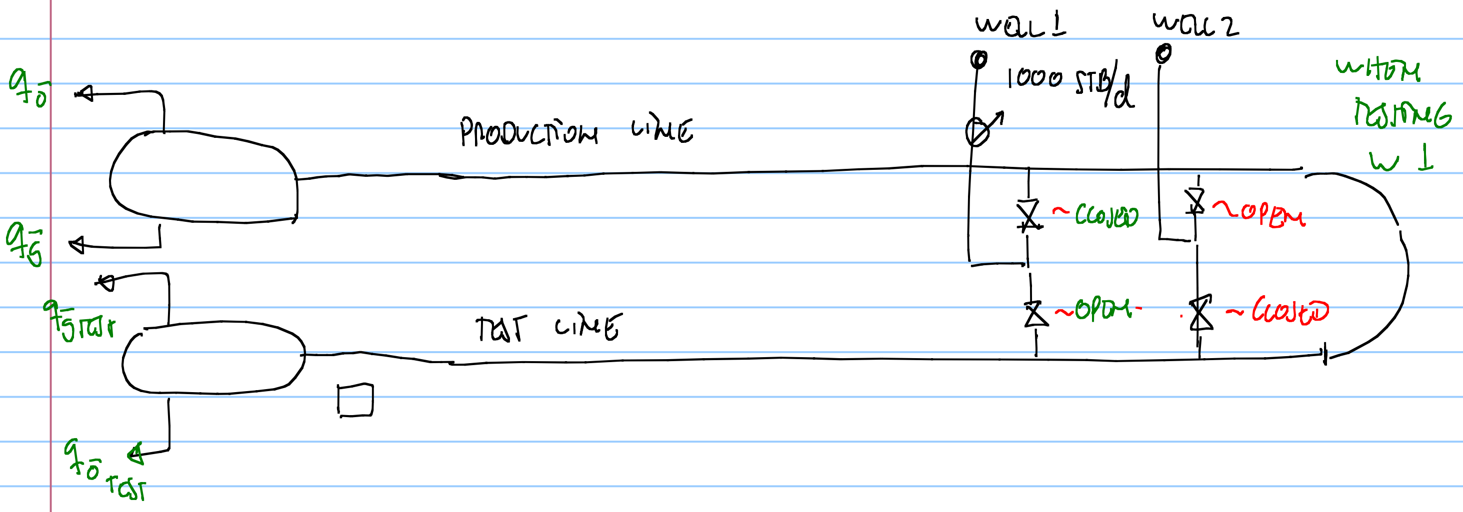
DEVIATED WELLS / INCLINED WELLS

DRILL VERTICALLY ABOVE
THE AREA OF INTEREST



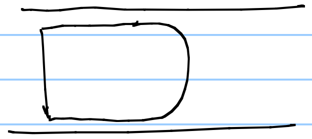
USUALLY, TWO LINES ARE NEEDED, FOR TESTING PURPOSES



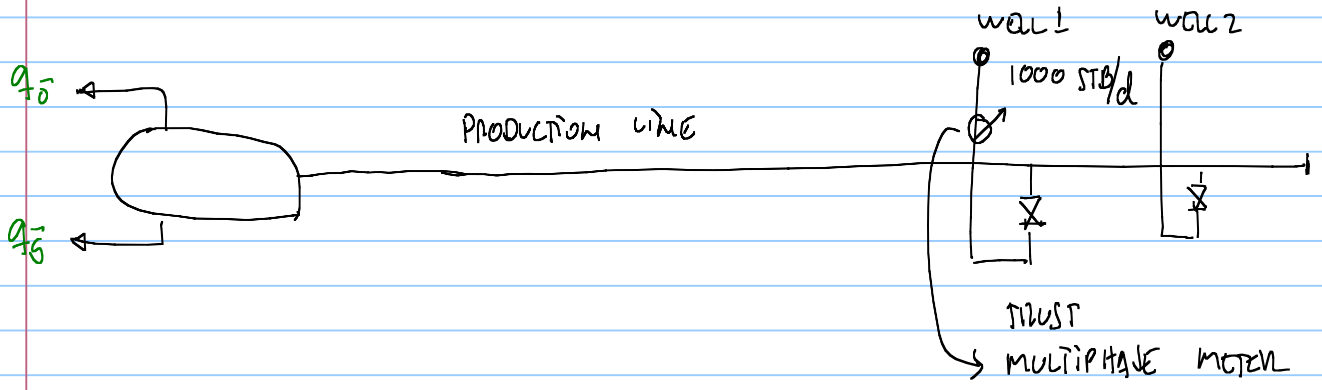


PIGGING OPERATIONS : MAINTENANCE AND REMOVAL OF UNDESIRED MATERIAL FROM PIPE (WAX DEPOSITION)

C_{30}^{+}



IN SNØHVIT THERE IS ONLY ONE PIPELINE



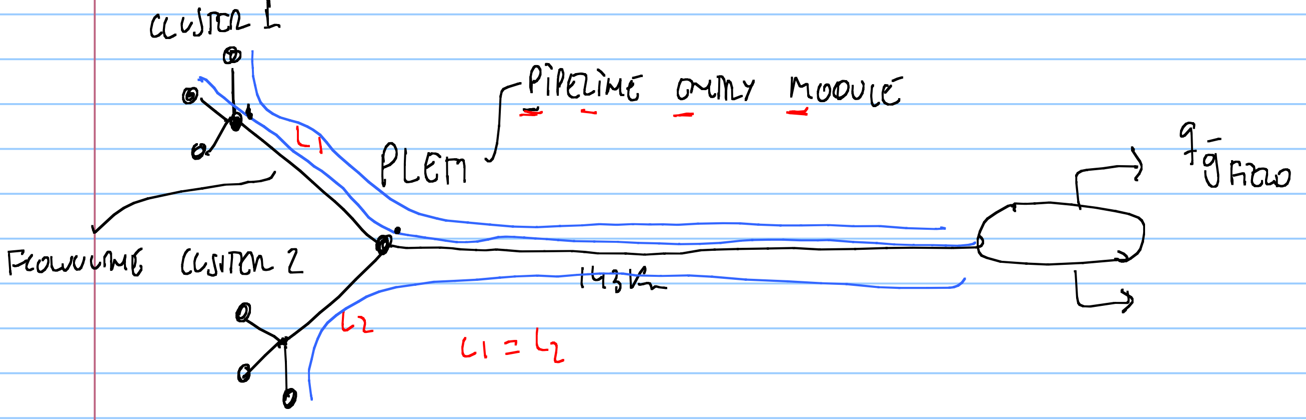
JUSTIFICATION FOR NOT HAVING A TEST LINE

WATER DETECTOR

HYDRATES

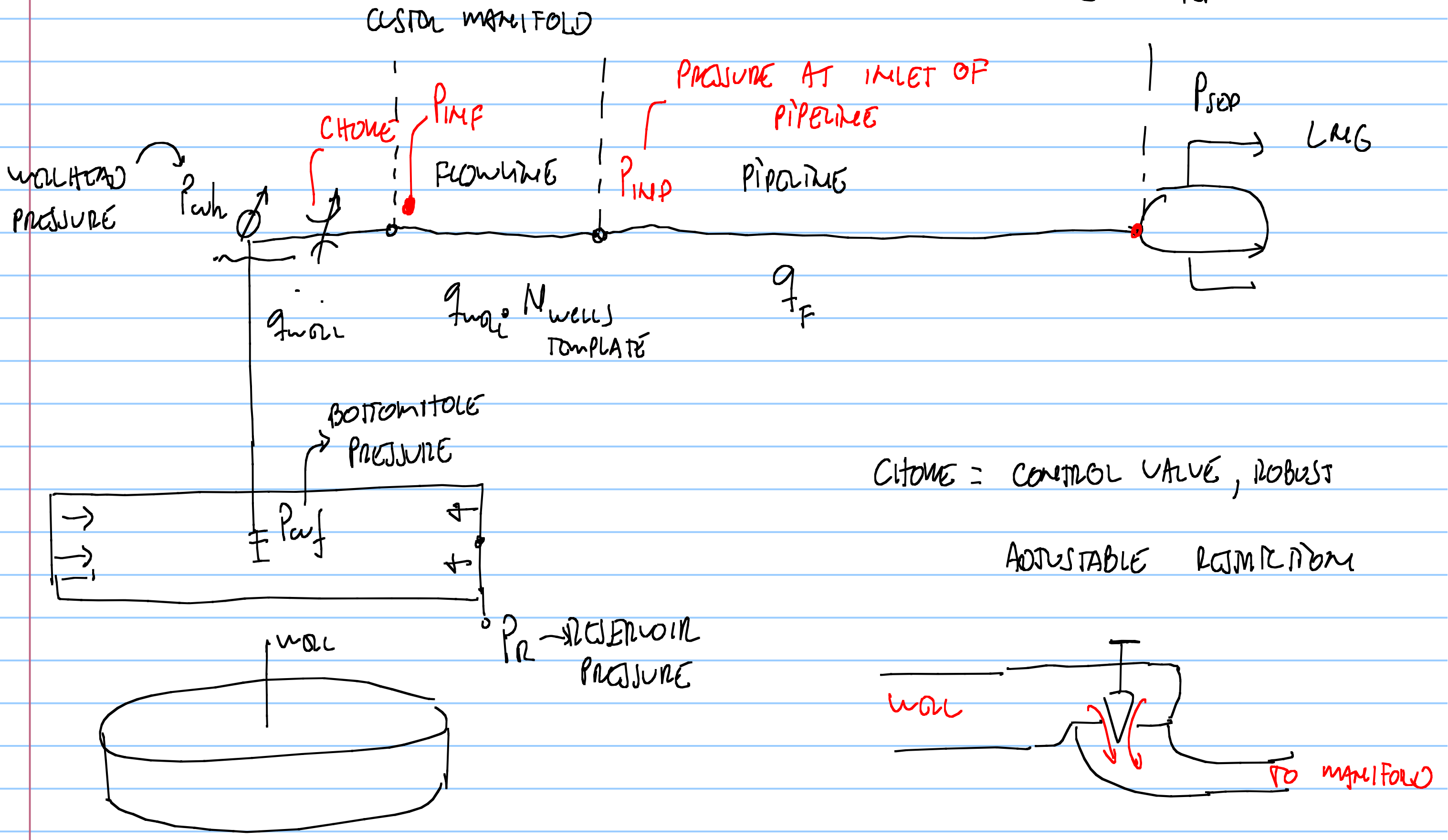
JUSTIFICATION FOR NOT HAVING PIGGING. SHUT IN THE WELL ONCE WATER IS DETECTED

SIMPLIFIED FIELD DEVELOPMENT STUDY FOR SNØHVIT



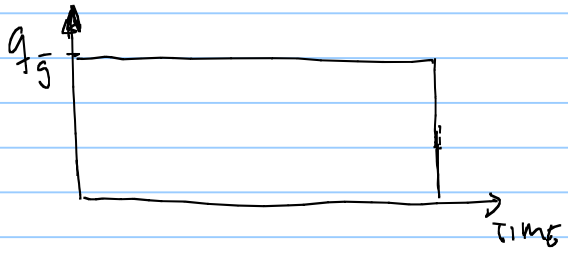
AS A FIRST APPROXIMATION
ASSUME THAT ALL WELLS ARE EQUAL

$$q_{well} = \frac{q_{g\,FIELD}}{N_{wells}} = \frac{q_F}{N} = q_{well}$$



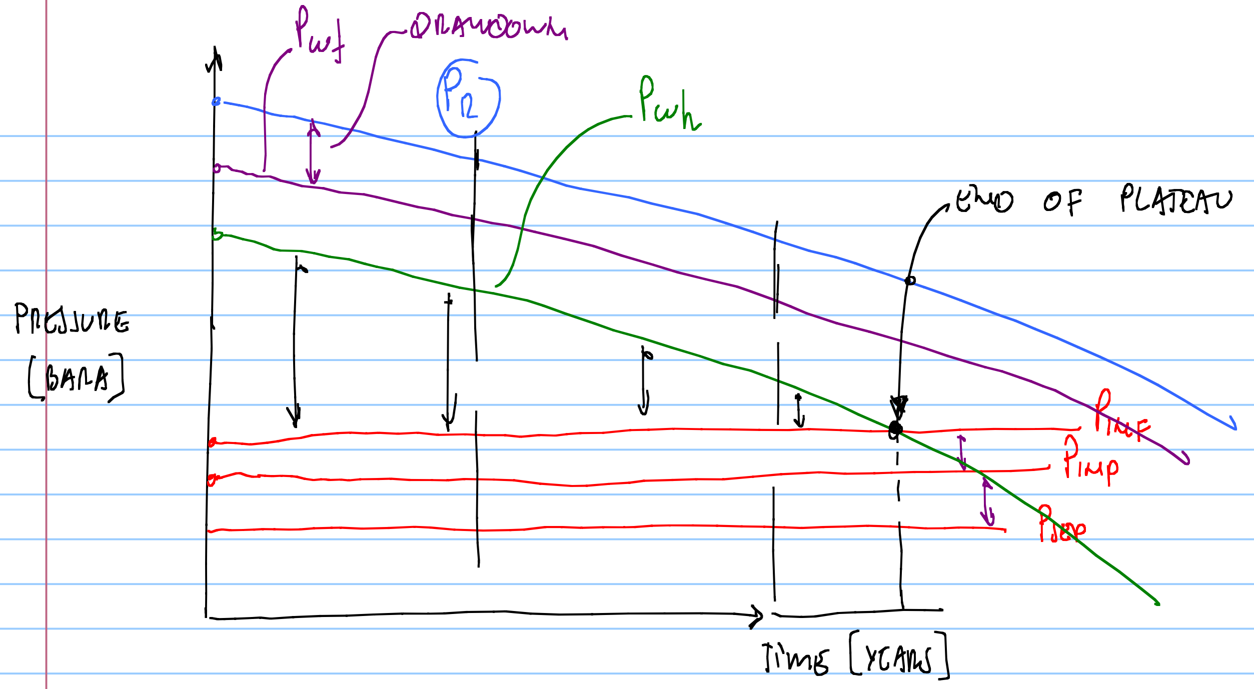
CHOKE = CONTROL VALVE, ROBUST
ADJUSTABLE RESTRICTION

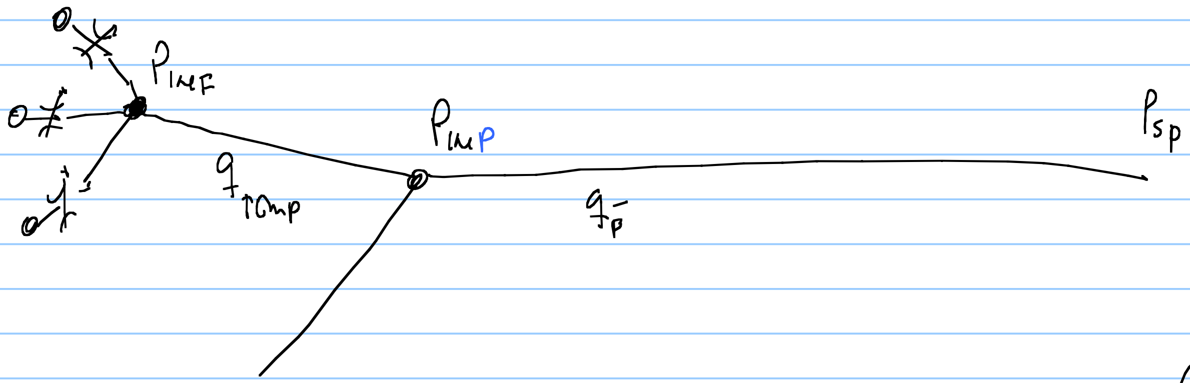
DEVELOP IT USING MODE A ~> PLATEAU RATE



TOTAL TIME ~> CONTRACT TIME

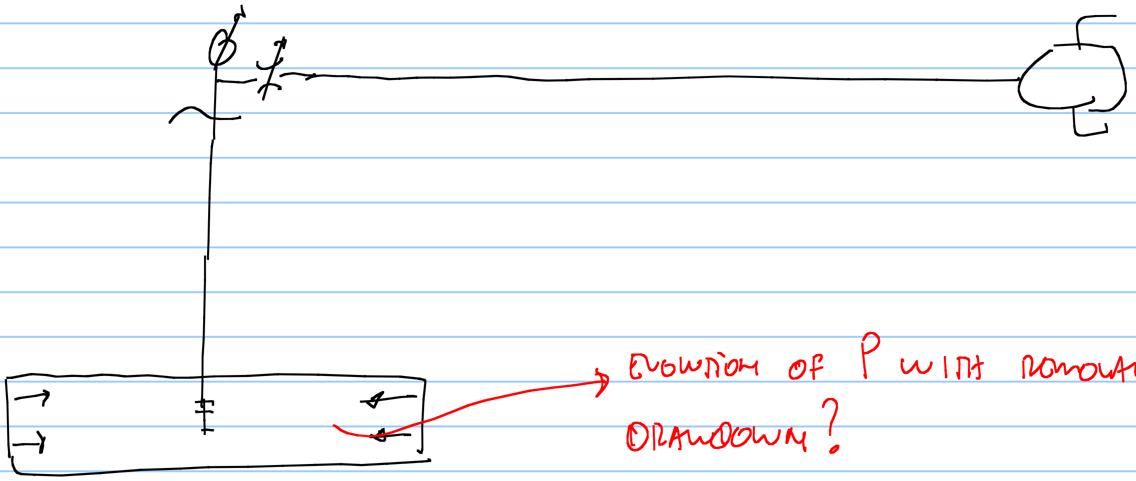
WILL STATOIL BE ABLE TO DELIVER
THE PROMISED AMOUNT OF GAS
FOR THE REQUIRED PERIOD?





PRODUCTION SYSTEM: TWO DIFFERENT MECHANISMS

- TIME DEPENDENT
  MEMORY
  TRANSIENT — RESERVOIR
- STEADY STATE
  NO MEMORY — WELLS
  → FLOWLINE
  → PIPELINE



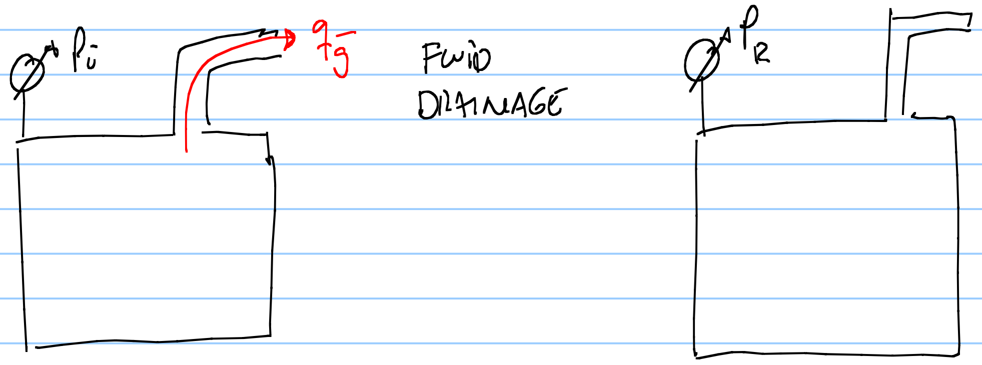
EVOLUTION OF P WITH REMOVAL OF GAS

DRAWDOWN?

How is a reservoir modeled (usually)?

Three options

- Material balance (tank model)



Relationship between mass and pressure → Equation of state

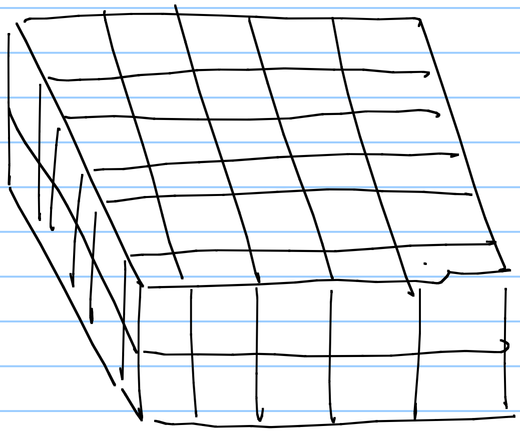
- Decline curve analysis ~ (Used in US, gas wells)

Fekete

DCA

G_p ~ Cummulative gas production
G ~ Initial gas in place

- Reservoir simulation



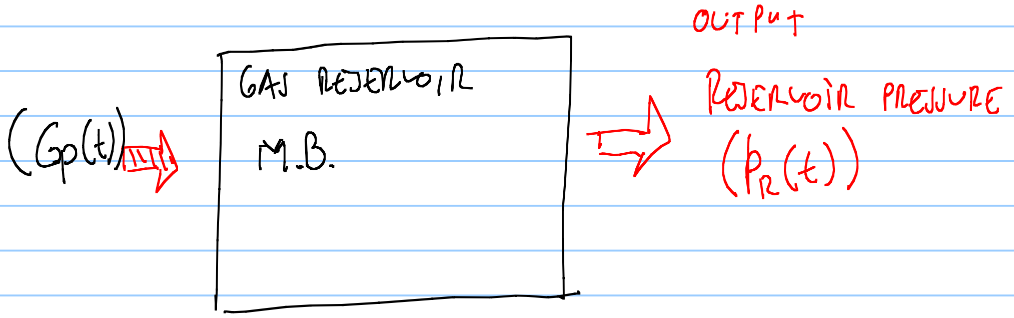
- Mass conservation between elements
- Flow equations (Darcy law)
- PVT behavior { EOS / Black oil aproach
  - Pressure volume temperature

FOR OUR FIELD, WE WILL USE MATERIAL BALANCE (MB) TO ESTIMATE THE DECLINE OF RESERVOIR PRESSURE WITH TIME

Ⓝ OIL IOIP

G GAS IGIP

→ SIMPLE DRY GAS MATERIAL BALANCE



$$G_p = q_{\bar{g}} \cdot (t - t_0)$$

$$G_p = \int_{t_0}^{t^*} q_{\bar{g}}\, dt$$

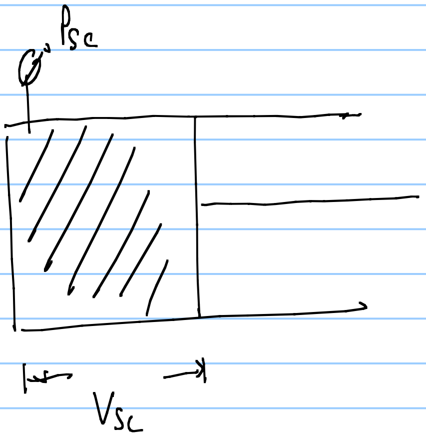
HOW MUCH GAS IS IN THE CONTAINER?

ANSWER DEPENDS ON THE DISCIPLINE:

MECH. ENGINEER	~>	kg	m
CHEM. ENGINEER	~>	mole	Ⓝ
PET. ENGINEER	~>	Sm^3	Ⓥ

T_{sc}

P_{sc}



? HOW TO RELATE V_{sc} WITH n?

REAL GAS EQUATION OF STATE

$$pV = zn\underbrace{R}T$$

p PRESSURE

T TEMPERATURE

n : NUMBER OF MOLES

R UNIVERSAL GAS CONSTANT

SPECIFIC GAS CONSTANT

$$R^* = \frac{R}{M}$$ MOLECULAR WEIGHT

$$R = 8314 \cdot \frac{J}{kg\text{-}mol\ K}$$

MOLES

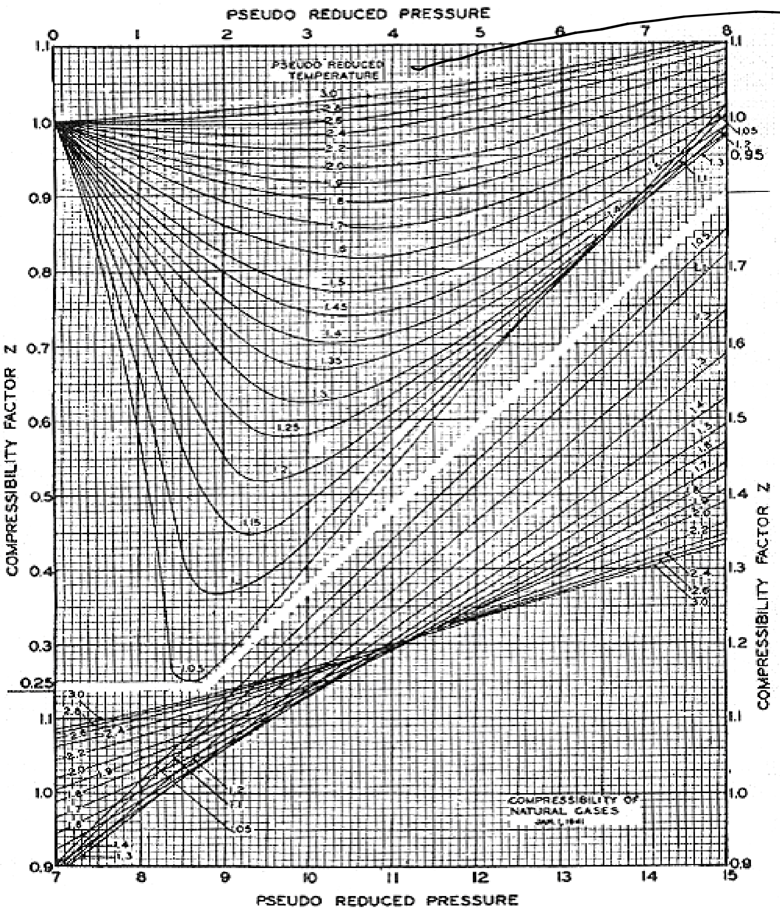
MASS [kg]

$$n = \frac{m}{MW}$$

MOLECULAR WEIGHT $\left[\frac{kg}{kg\text{-}mol}\right]$

Z COMPRESSIBILITY FACTOR (DEVIATION FACTOR) A CORRECTION IN THE IDEAL GAS EQUATION TO ACCOUNT FOR THE DEVIATION OF A REAL GAS FROM THE IDEAL BEHAVIOR

Z



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

CRITICAL TEMPERATURE OF THE GAS

$$P_r = \frac{P}{P_c}$$

CRITICAL PRESSURE OF THE GAS

STANDARD CONDITIONS:

DEPEND ON THE PLACE AND WHICH ENTITY IS USED AS A GUIDELINE

Standard reference conditions in current use

Temperature	Absolute pressure	Relative humidity	Publishing or establishing entity
°C	kPa	%	
0	100.000		IUPAC (STP)[1]
0	101.325		NIST,[7] ISO 10780,[8] formerly IUPAC[1]
15	101.325	0[2][9]	ICAO's ISA,[9] ISO 13443,[2] EEA,[10] EGIA[11]
20	101.325		EPA,[12] NIST[13]
22	101.325	20-80	American Association of Physicists in Medicine[14]
25	101.325		EPA[15]
25	100.000		SATP[16]
20	100.000	0	CAGI[17]
15	100.000		SPE[18]
20	101.3	50	ISO 5011[19]

WE ARE USING SPE's

ERROR IN WIKIPEDIA,

IT SHOULD BE:

$15.56\,°C = T_{sc}$

$1.01325\ BARA = P_{sc}$

IN BRAZIL:

$T_{sc} = 20°C$

$P_{sc} = 1.01325\ BARA$

APPLYING THE REAL GAS EQUATION FOR STANDARD CONDITIONS:

$$P_{sc} \overset{\downarrow}{V} = \overset{1}{z}\, n\, R\, T_{sc}$$

$$V = \frac{R\, T_{sc}}{P_{sc}} \cdot n$$

$$8314 \frac{J}{kgmol\,\cancel{K}} \cdot \frac{(15.56+273.15)\,\cancel{K}}{101325\ Pa} = 23.689\ \frac{Sm^3}{Kg\ mol}$$

VOLUME AT SC

$$\boxed{V_{sc} \propto n}$$

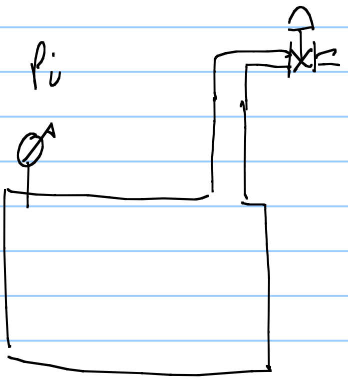
IN CONSEQUENCE $G \propto n_i$

$G_p \propto n_p$

IT IS POSSIBLE TO WRITE THE FOLLOWING EQUATION

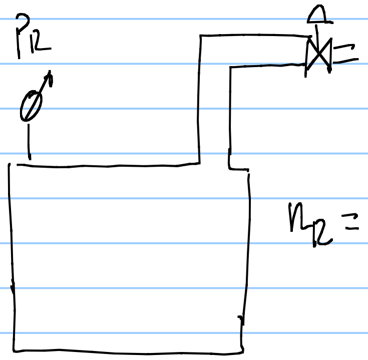
$$\frac{(G-G_p)}{G} = \frac{(n_i - n_p)}{(n_i)} = \frac{n_R}{n_i}$$

RESERVOIR TANK AT INITIAL STATE



$$n_i = \frac{P_i V_R}{z_i R T_R}$$

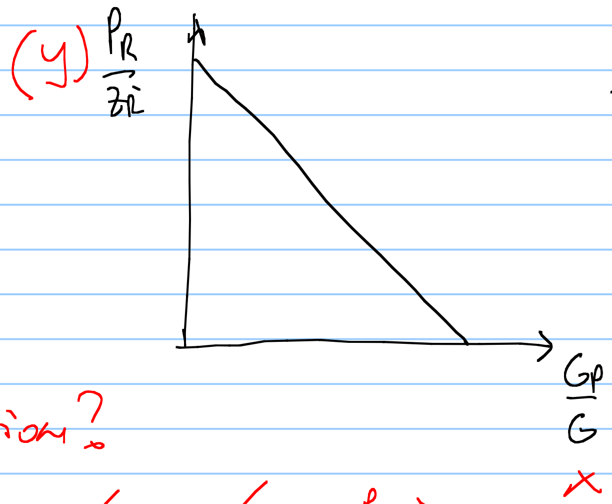
AT A LATER STAGE, WHAT IS LEFT IN THE RESERVOIR:

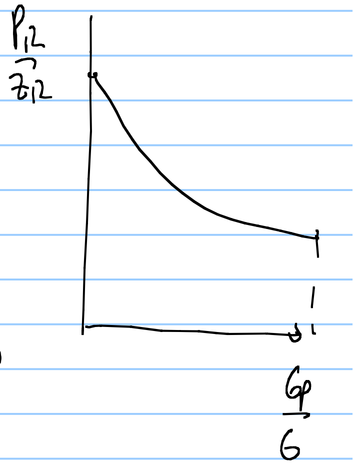


$$n_R = \frac{P_R . V_R}{z_R R T_R}$$

SUBSTITUTE n_i AND n_R IN EXPRESSION $\frac{G-G_p}{G} = \frac{n_R}{n_i}$

$$\underbrace{\frac{P_R}{Z_R}}_{y} = \underbrace{\frac{P_i}{Z_i}}_{m}\left(1-\underset{\substack{\downarrow \\ x}}{\frac{G_p}{G}}\right)$$



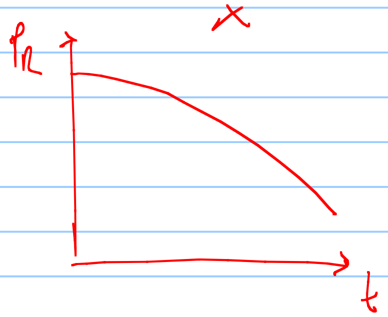


HOW TO USE THE EQUATION?

IF WE HAVE G_p,

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

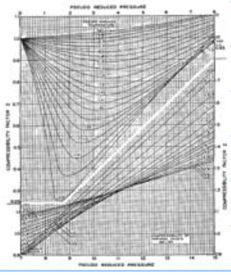
HOW DO WE CALCULATE P_R?



WE HAVE A RELATIONSHIP BETWEEN Z_R AND P_R

$Z_R = f(P_R, T_R, MW)$

- CHART
- EQUATION



SUGGESTED PROCEDURE:

INPUT G_p, ASSUME Z_R^{ASSUMED}

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

USE $P_R, T_R, MW \Rightarrow Z_R^{\text{CALCULATED}}$

IS $Z_R^{\text{ASSUMED}} = Z_R^{\text{CALCULATED}}$?

IF NOT, REPEAT

FOR CALCULATING P_{wf},

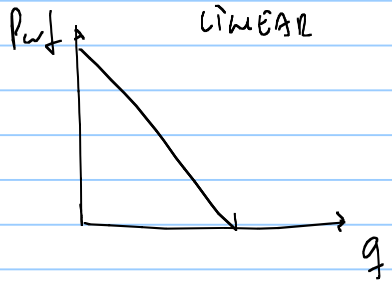
$P_R \rightsquigarrow P_{wf}$?

FLOW IN POROUS MEDIA.

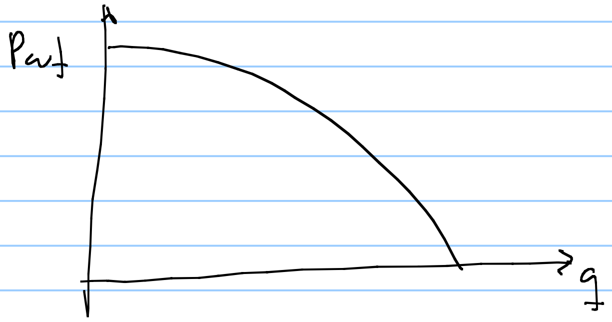
EQUATION THAT RELATES

P_R, P_{wf} AND q_g ?

INFLOW PERFORMANCE RELATIONSHIP (IPR)



UNDERSATURATED FLUIDS



BACK PRESSURE EQUATION, (FOR DRY GAS)

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

NOT NUMBER OF MOLES

$0.5 \leq n < 1$

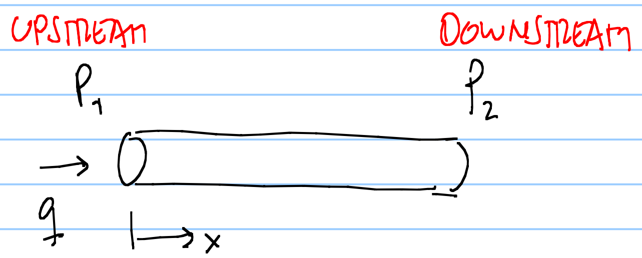
↓

ACCOUNTS FOR TURBULENCE IN THE POROUS MEDIA

	INPUT		OUTPUT
①	P_R P_{wf}	⇒	q_g
②	q_g P_R	⇒	P_{wf}

PRESSURE DROP IN CONDUITS : P_{wh}, P_{INF}, P_{INP}
(PIPES)

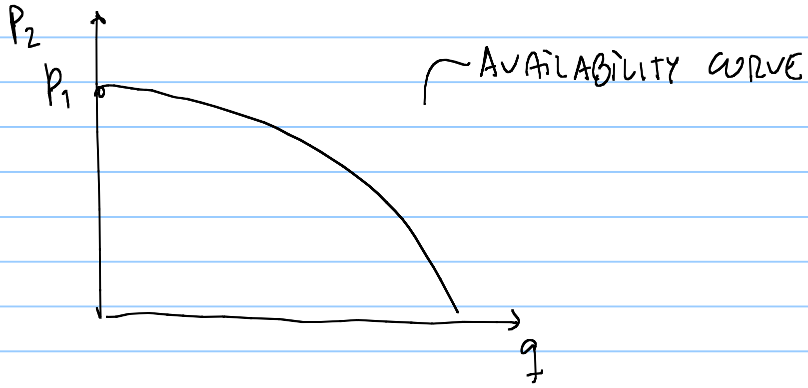
HORIZONTAL PIPE



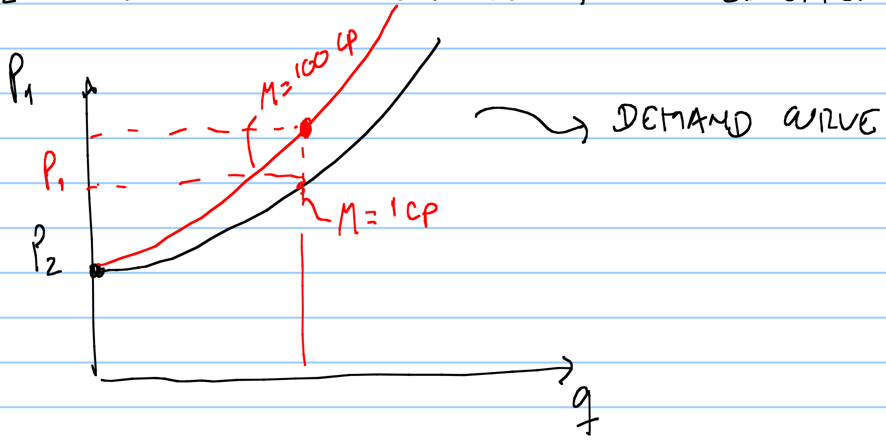
INPUT	OUTPUT	
P_1, P_2	q	
P_1, q	P_2	Ⓐ
P_2, q	P_1	Ⓑ

TWO MODES OF CALCULATION

Ⓐ P_1 IS FIXED PERFORMING THE CALCULATIONS COCURRENT



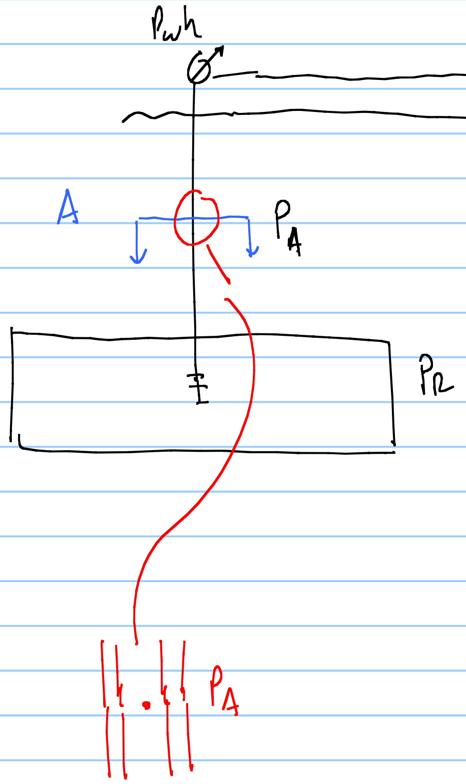
Ⓑ P_2 IS FIXED PERFORM A COUNTERCURRENT CALCULATION

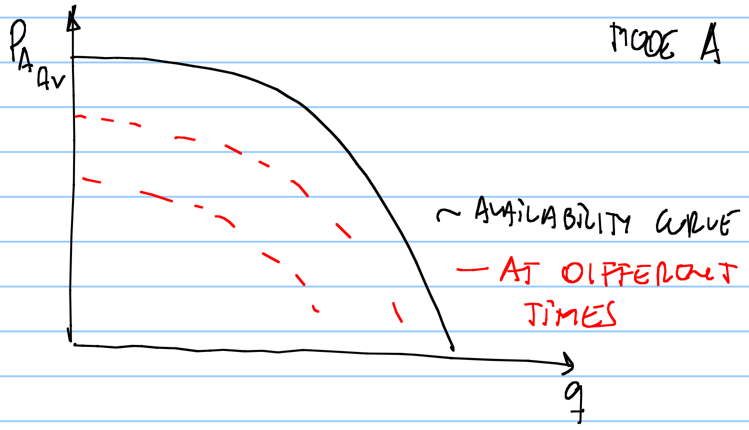


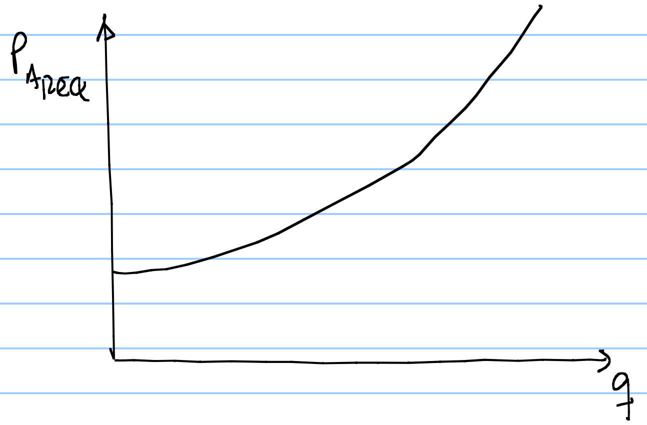
$$\underbrace{\frac{dp}{dx}}_{\text{PRESSURE GRADIENT}} = \frac{dp}{dx}\Big|_{\text{GRAVITATIONAL}} + \underbrace{\frac{dp}{dx}\Big|_{\text{FRICTION}}} + \frac{dp}{dx}\Big|_{\text{ACCELERATION}}$$

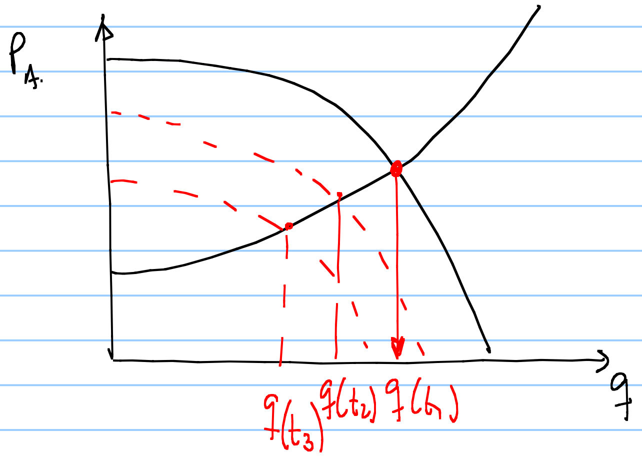
LIQUID $\rho \neq f(P,T)$
GAS ←
MULTIPHASE FLOW

FLOW EQUILIBRIUM : (NODAL ANALYSIS)

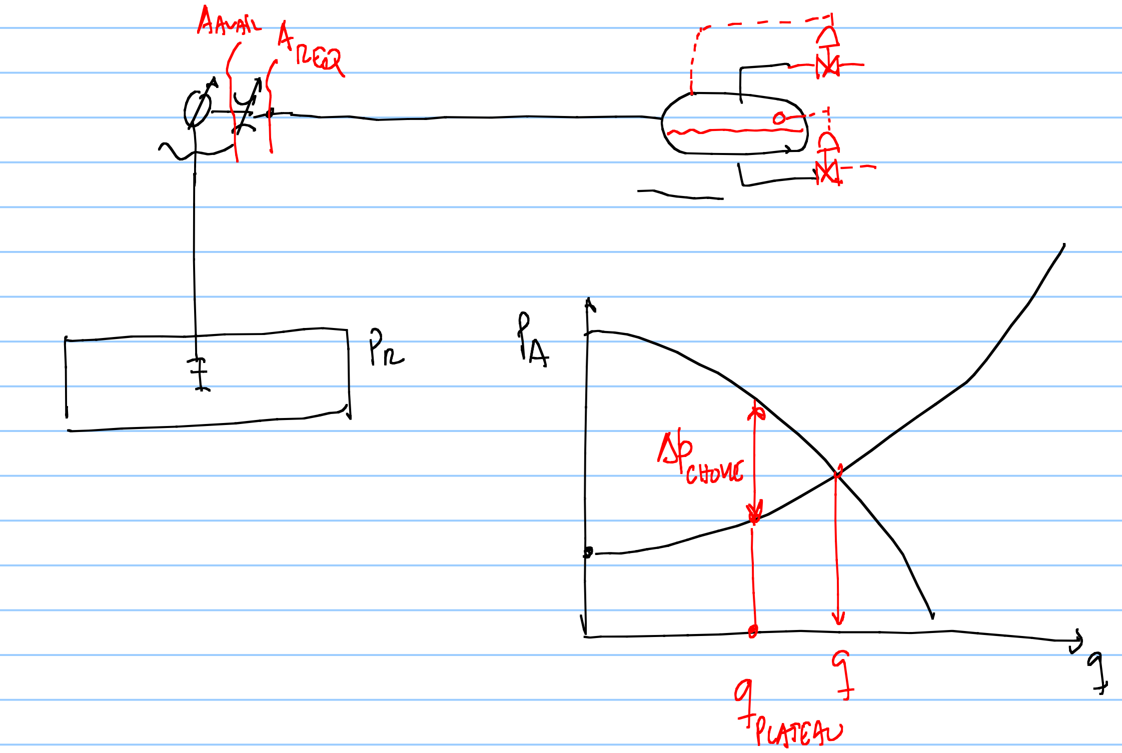








IF WE CHOOSE OUR POINT A AT THE CHOKE



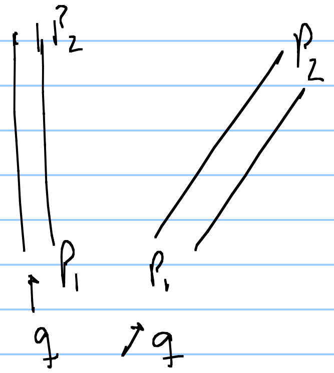
TWO PREFERRED PLACES TO PERFORM EQUILIBRIUM ANALYSIS:

- DOWNHOLE (BOTTOM HOLE) → WELL DESIGN
  - → ARTIFICIAL LIFT DESIGN
  - → CONTROL RESERVOIR SIMULATOR

- WELLHEAD → FIELD DESIGN
  - → ALLOCATION
  - → CONDITION MONITORING

PRESSURE LOSSES IN THE TUBING, FOR DRY GAS

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



S .. ELEVATION FACTOR

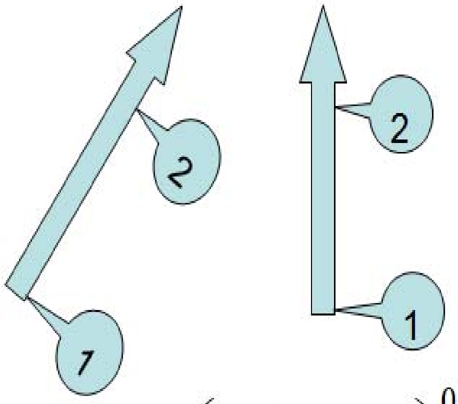
IF $q_g = 0$ $P_1 = P_2 \cdot e^{S/2}$

Tubing flow Equation-Dry gas

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

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

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



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

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

FOR HORIZONTAL LINE, EQUATION FOR FLOWLINE AND PIPELINE:

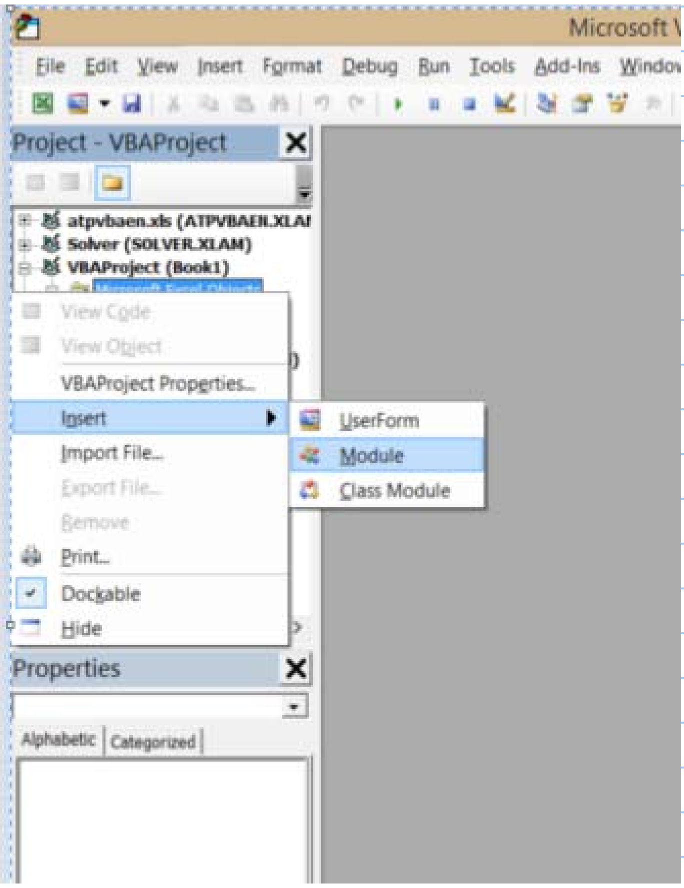
$$q_g = C_{PL}\left(P_1^2 - P_2^2\right)^{0.5}$$

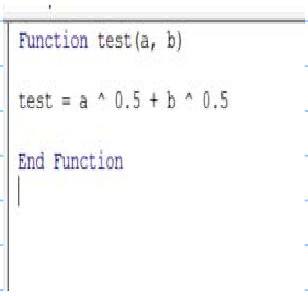
FOR SOLVING THE FIELD DEVELOPMENT STUDY, WE WILL USE EXCEL

UDF: USER DEFINED FUNCTIONS

WITH A WORKBOOK OPEN, PRESS $\boxed{\text{ALT}} + \boxed{\text{F11}} \rightsquigarrow$ VBA MODULE

VISUAL BASIC FOR APPLICATIONS



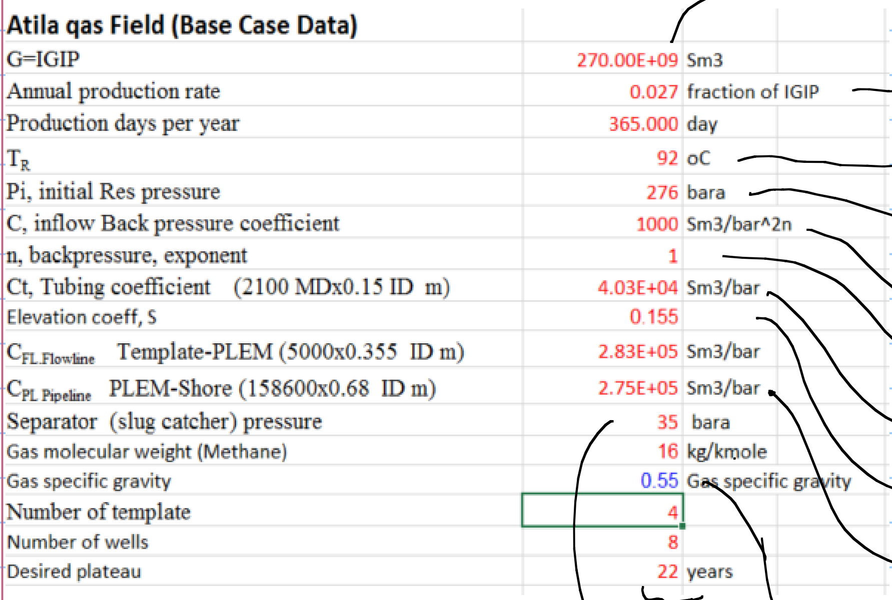


```
Function test(a, b)

test = a ^ 0.5 + b ^ 0.5

End Function
```

$\frac{G_p}{G} = RF$ RECOVERY FACTOR



Atila qas Field (Base Case Data)

G=IGIP	270.00E+09	Sm3
Annual production rate	0.027	fraction of IGIP
Production days per year	365.000	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 ID m)	4.03E+04	Sm3/bar
Elevation coeff, S	0.155	
$C_{FL,Flowline}$ Template-PLEM (5000x0.355 ID m)	2.83E+05	Sm3/bar
$C_{PL\ Pipeline}$ PLEM-Shore (158600x0.68 ID m)	2.75E+05	Sm3/bar
Separator (slug catcher) pressure	35	bara
Gas molecular weight (Methane)	16	kg/kmole
Gas specific gravity	0.55	Gas specific gravity
Number of template	4	
Number of wells	8	
Desired plateau	22	years

MB, q_g

$\rightarrow$

$\rightarrow z(p,T,\gamma_g)$

MB

IPR

IPR

Δp well

Δp pipeline, flowline

Psep

$z(p,T,\gamma_g)$

OLD NEWS CLIP:

Skipet skal bygges av Mitsubishi Heavy Industries i Japan og får en lastekapasitet på 145.000 kubikkmeter flytende naturgass (LNG). Investeringene i forbindelse med kontrakten er på om lag 1,5 milliarder kroner.

Statoil og de fem rettighetshaverne skal snart undertegne en kontrakt for ytterligere to skip med et annet rederi. De franske rettighetshaverne på Snøhvitfeltet, TotalFinaElf og Gaz de France, skal hente gass fra Snøhvitfeltet med egne skip.

Alle de tre skipene blir engasjert for frakt av gass fra

Snøhvitfeltet i en periode på 20 år fra feltet kommer i

produksjon i 2006. I alt skal rundt 70 laster med LNG skipes ut fra Melkøya årlig.

I henhold til gass-salgsavtalene skal 2,4 milliarder kubikkmeter gass i året skipes til USA og 1,6 milliarder kubikkmeter til kunder i Spania.

2.4 E9 Sm^3 TO USA

1.6 E9 Sm^3 TO SPAIN

4 E9 Sm^3

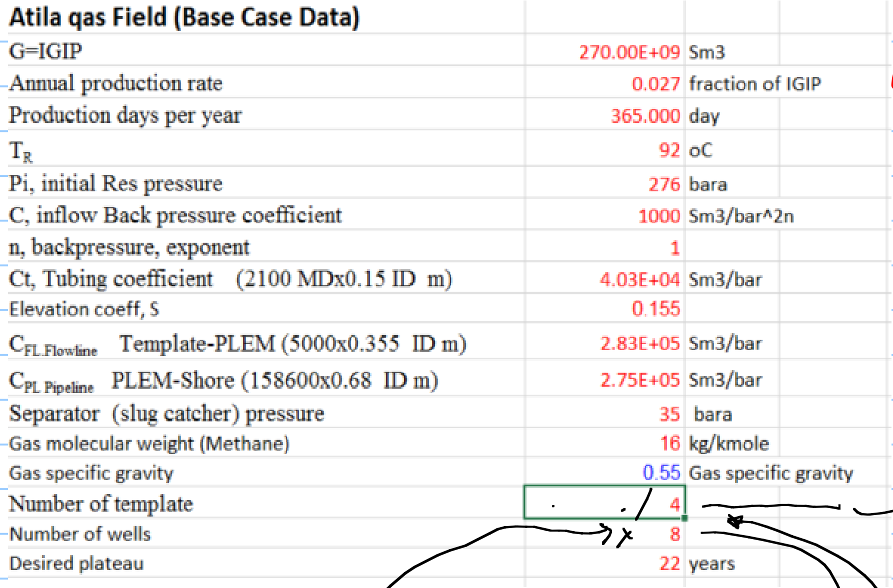
$$q_g = \frac{4E9\ Sm^3}{MDAYS\ YEAR} = \frac{4E9\ Sm^3}{365\ d} =$$

10 E6 Sm^3/d

TAKING THE DOWNTIME INTO ACCOUNT

THE ACTUAL GAS RATE IS TWICE THAT NUMBER: 20E6 Sm^3/d

PLANNING OUR EXCEL SHEET TO SOLVE THE PROBLEM:



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→ INITIAL INFO

🟥 INPUT

🟦 OUTPUT

time YEARS	P_R [BARA]	q_g^{well} [Sm³/d]	P_{wf} [BARA]	P_{wh} [BARA]	P_{SEP} [BARA]	q_{FLOW} [Sm³/d]	P_{PLEM} P_{INP} [BAR]	q_{TEMP} [Sm³/d]	P_{TEMP} P_{INF} [BAR]	Δp CHOKE (BAR)
🟥 0	🟥 P_i	🟥	🟦	🟦	🟥	$q^{well} \cdot N_{well}$	🟦	🟦	🟦	🟦

IPR

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

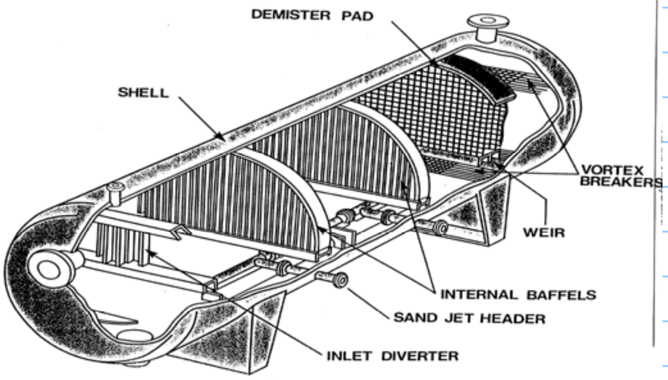
$$q_g = C_T \left(\frac{P_1^2}{e^s} - P_2^2\right)^{0.5}$$

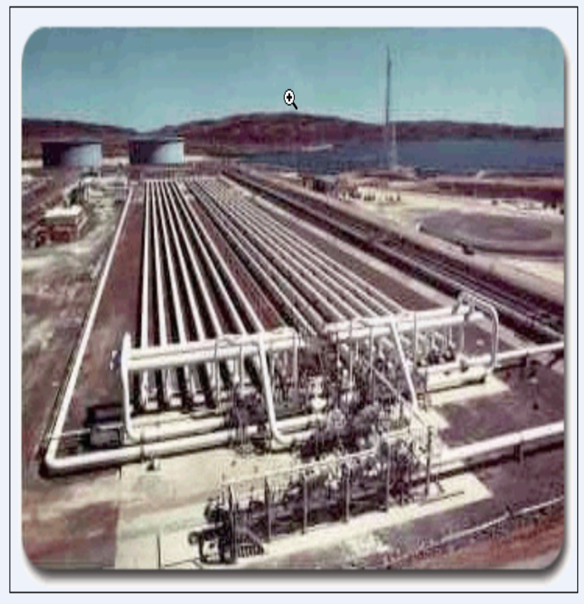
$$q_g = C_{PL} \, (P_1^2 - P_2^2)^{0.5}$$

$P_{wh} - P_{TEMP}$

COMENTS ABOUT SEPARATION:

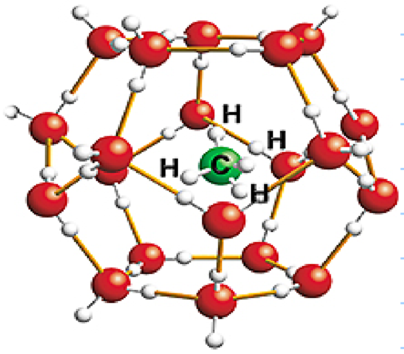
Horizontal separator

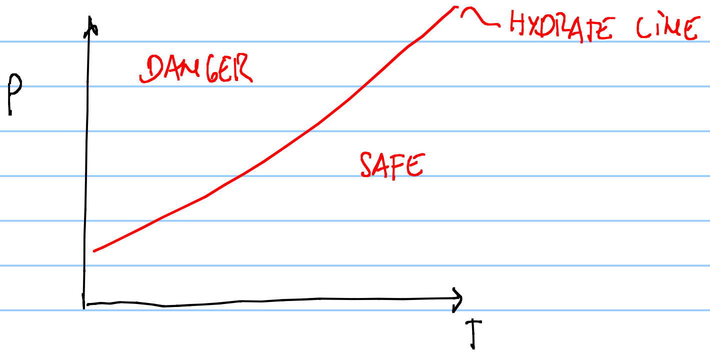




CONVENTIONAL SEPARATOR vs. SLUG CATCHER

COMENTS ON HYDRATES:



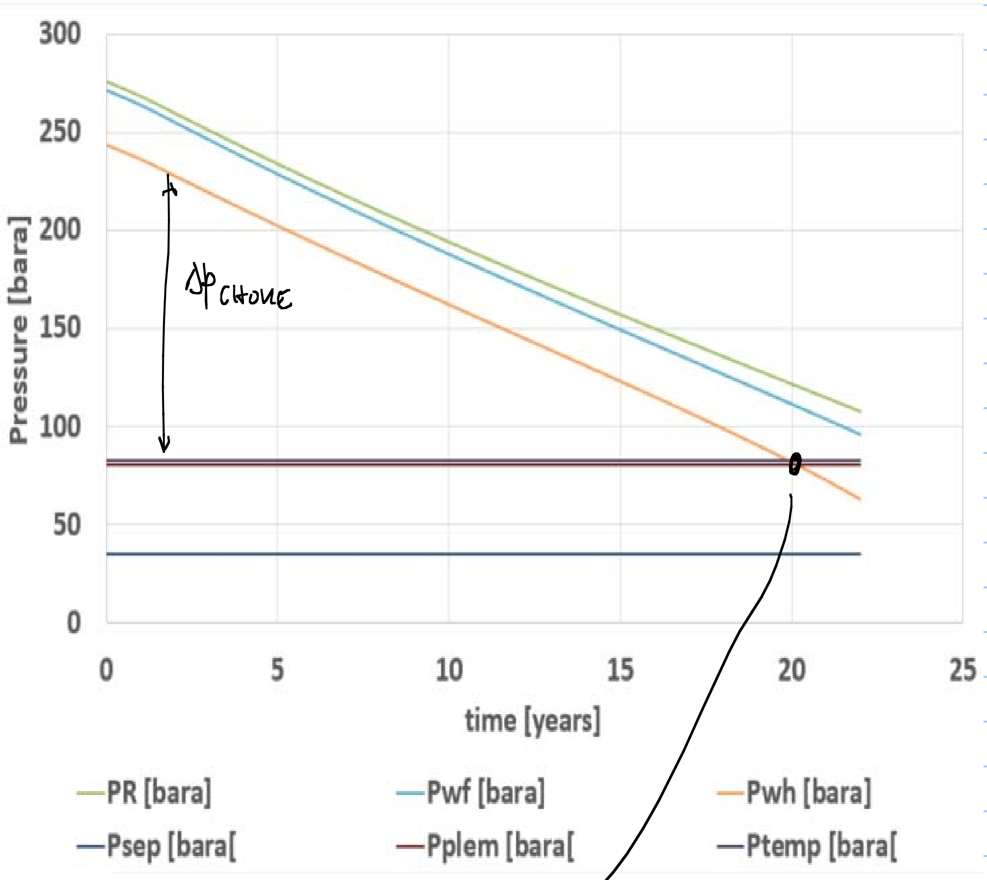


PIPELINE EQUATION

$$q_g = C_{PL}\left(P_1^2 - P_2^2\right)^{0.5}$$

LIME P_1

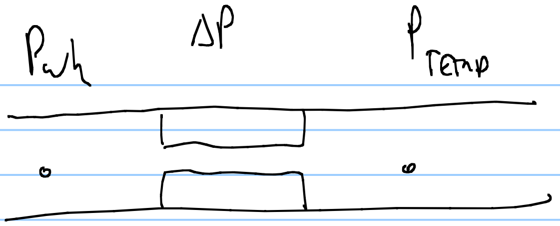
$$P_1 = \sqrt{\left(\frac{q_g}{C_{PL}}\right)^2 + P_2^2}$$

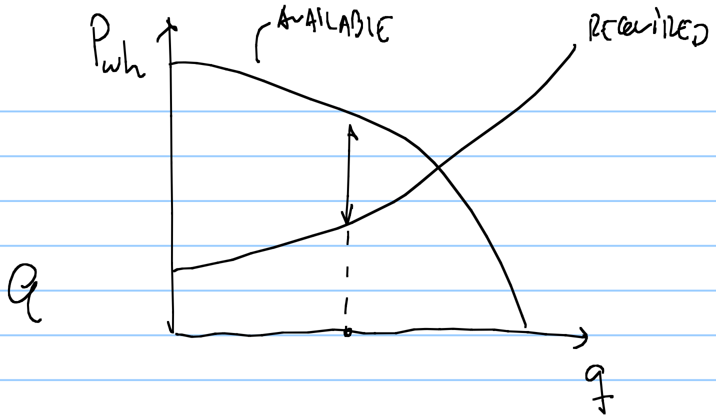


AFTER THIS POINT, WE HAVE TWO POSIBILITIES:

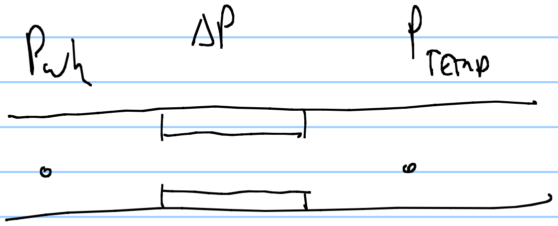
- REDUCE THE RATE. (OPEN CHOKE)
- PUT A COMPRESSOR (BRIDGE THE PRESURE)

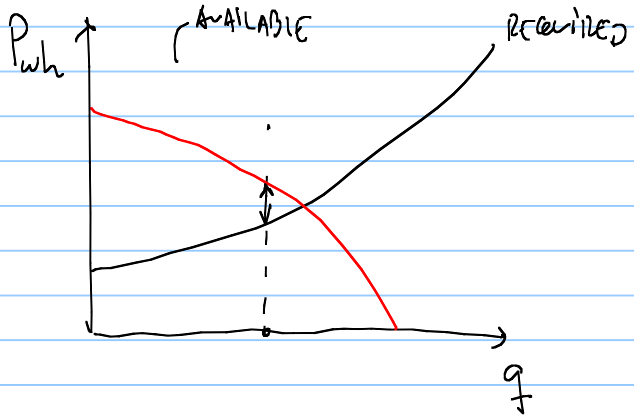
t_1



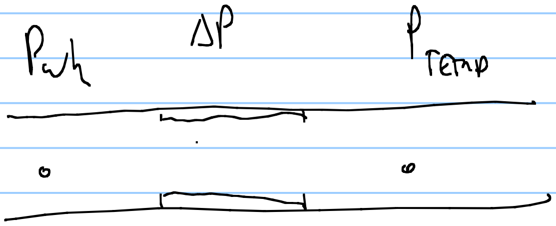


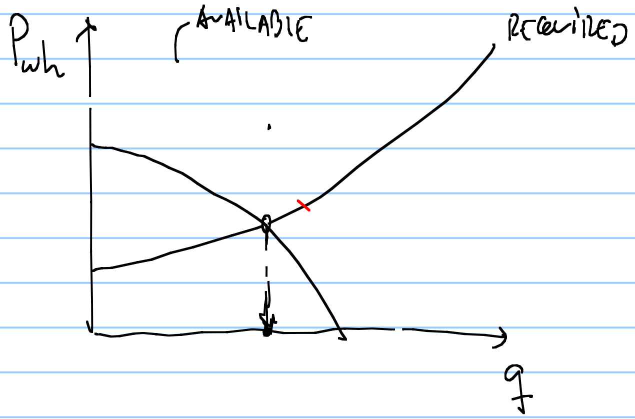
t_2



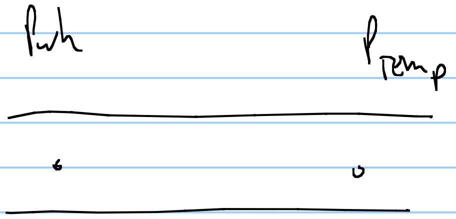


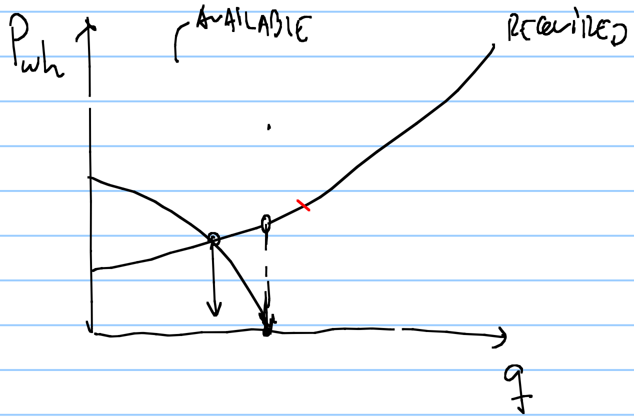
t_3





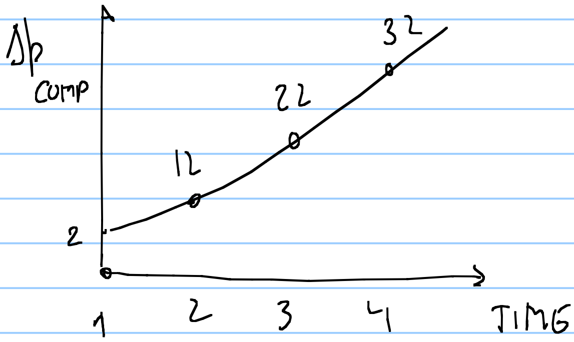
t_4

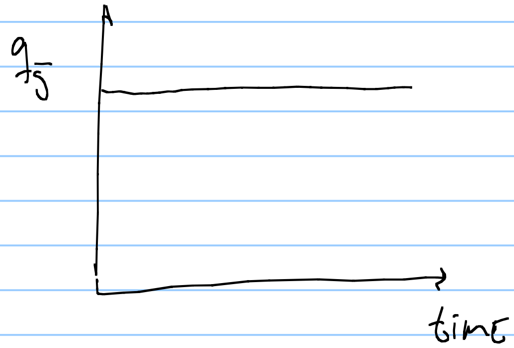




- OPERATING REQUIREMENTS FOR THE SUBSEA COMPRESSOR

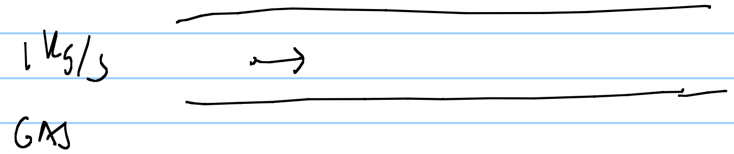
$[Sm^3/d] \sim [kg/s] \sim [kgmol/s] \qquad [m^3/d]$





$$V = \frac{\overset{\downarrow}{Q}}{A_{PIPE}} = \frac{\dot{m}/\rho}{A_{PIPE}} \sim \rho \; f(p,T)$$

Ⓥ



$q_{\bar{g}} = [Sm^3/d]$ FLOWRATE AT STANDARD CONDITIONS

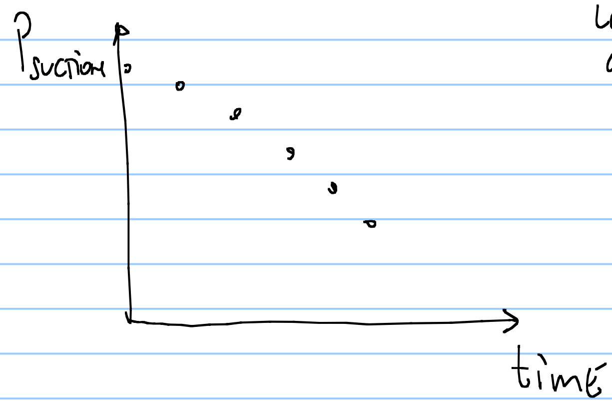
$q_g \; [m^3/d] \sim p, T$ AT THE INLET OF THE COMPRESSOR

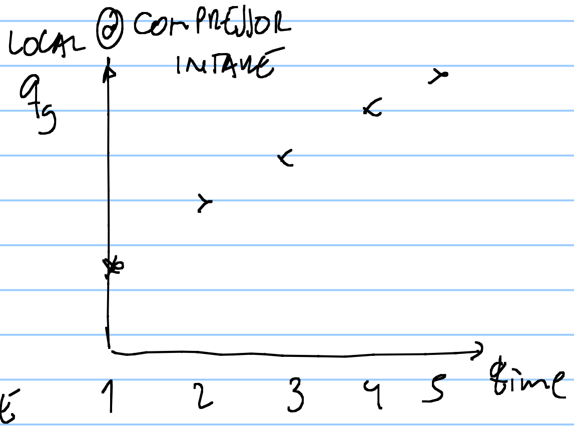
FLOWRATE AT LOCAL CONDITIONS

(UPSTREAM THE COMPRESSOR)

PRESSURE AT INLET OF COMPRESSOR VS. TIME

$$\overset{LOCAL}{q_g} = \overset{CONST}{\dot{m}_g} / \overset{\downarrow}{\rho}$$ GOING DOWN WITH PRESSURE





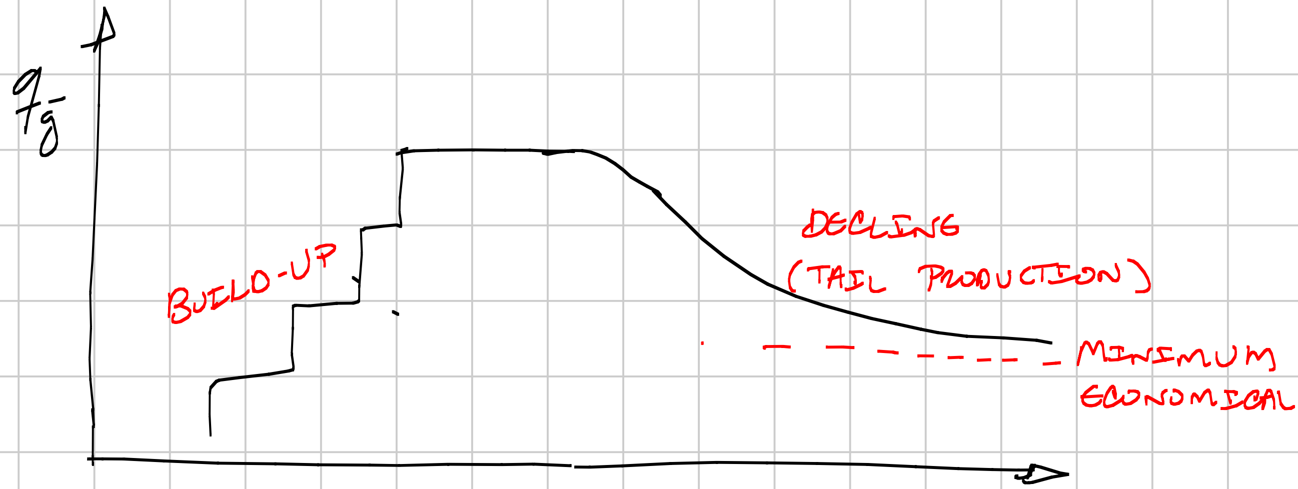
COMPRESSOR SPECIALISTS PREFER

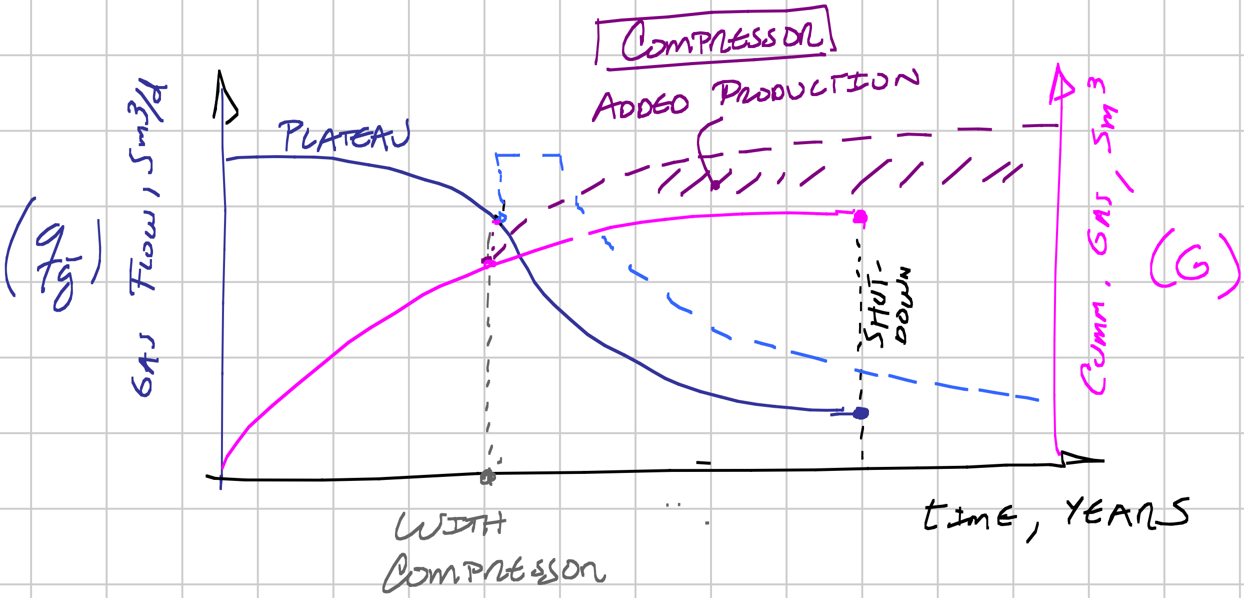
PRESSURE RATIO $r_p = \frac{P_{OUT}}{P_{SUC}}$

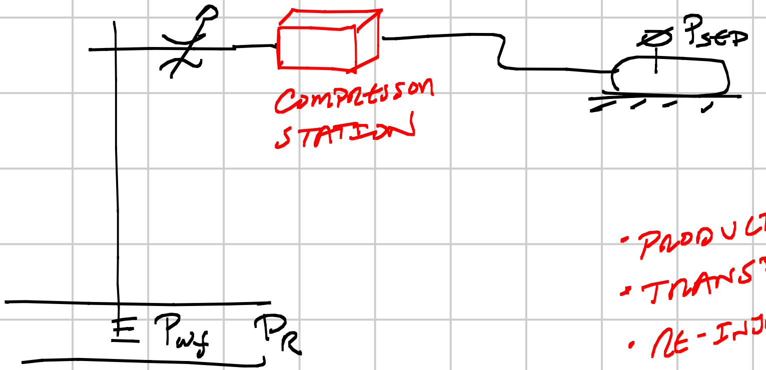
FIELD DEVELOPMENT - COMPRESSOR SYSTEMS

JESÚS DE ANDRADE   e-mail: jesus.andrade@NTNU.NO

⇒ PRODUCTION STRATEGY - WHY COMPRESSORS?





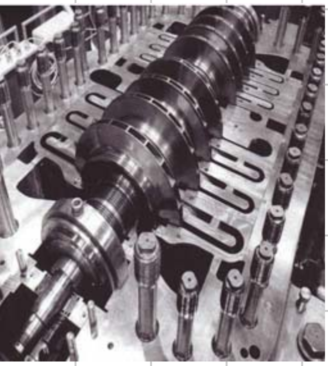


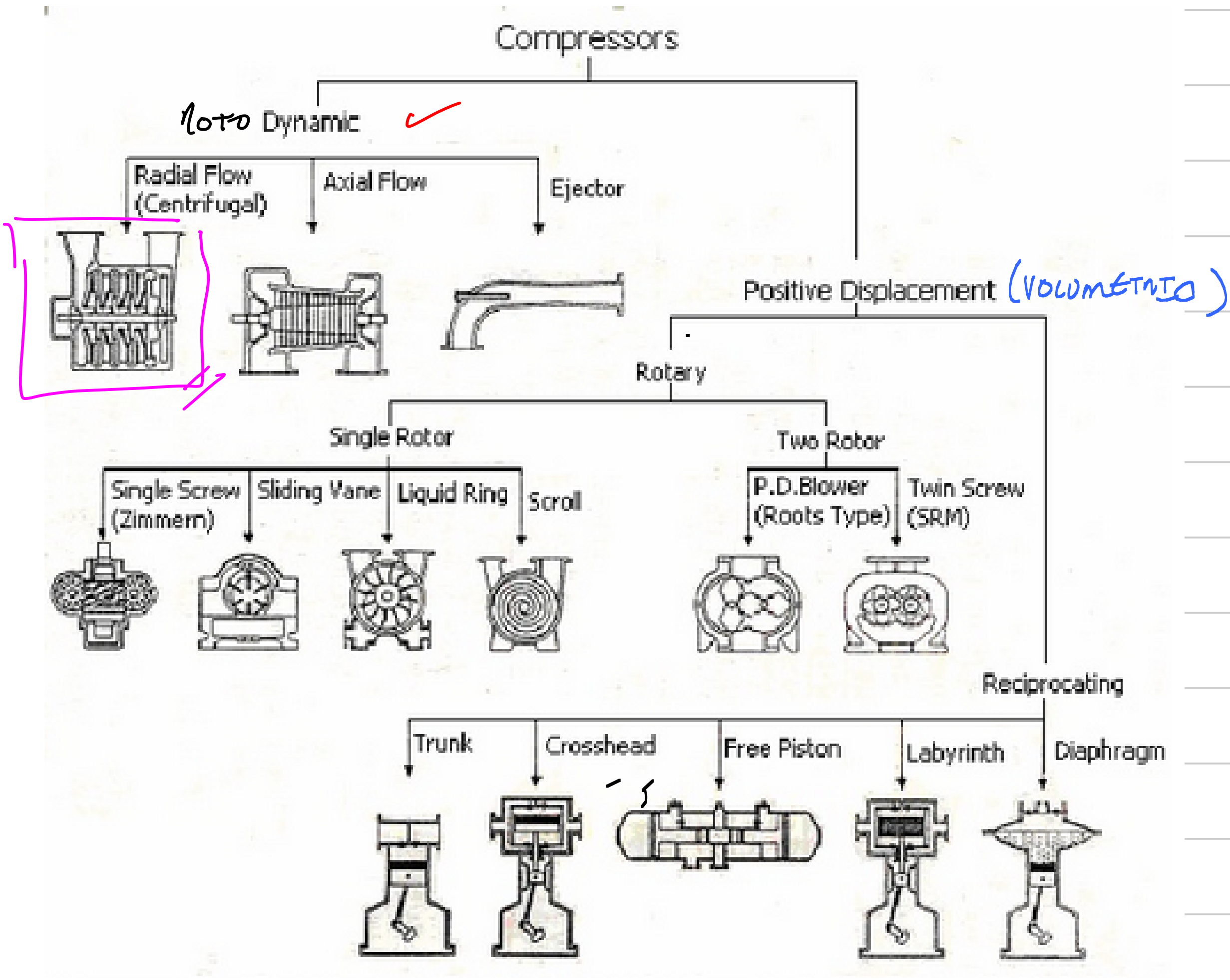
WHAT DOES THE COMPRESSOR DO?

- INCREASE PRESSURE
- " TEMP.
- REDUCE ν (SPECF. VOL.)
  ↳ (SAFE MONEY IN TRANSP.)

- PRODUCTION
- TRANSP.
- RE-INJECTION
- TREATMENT

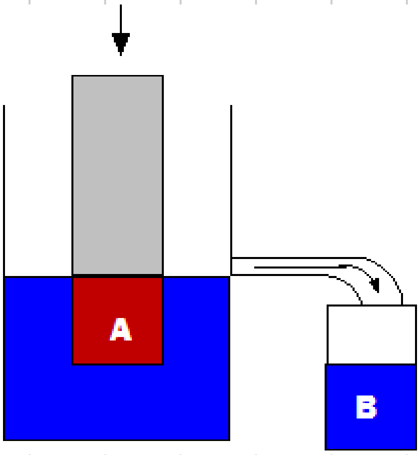
⇒ CLASIFICATION OF COMPRESSORS



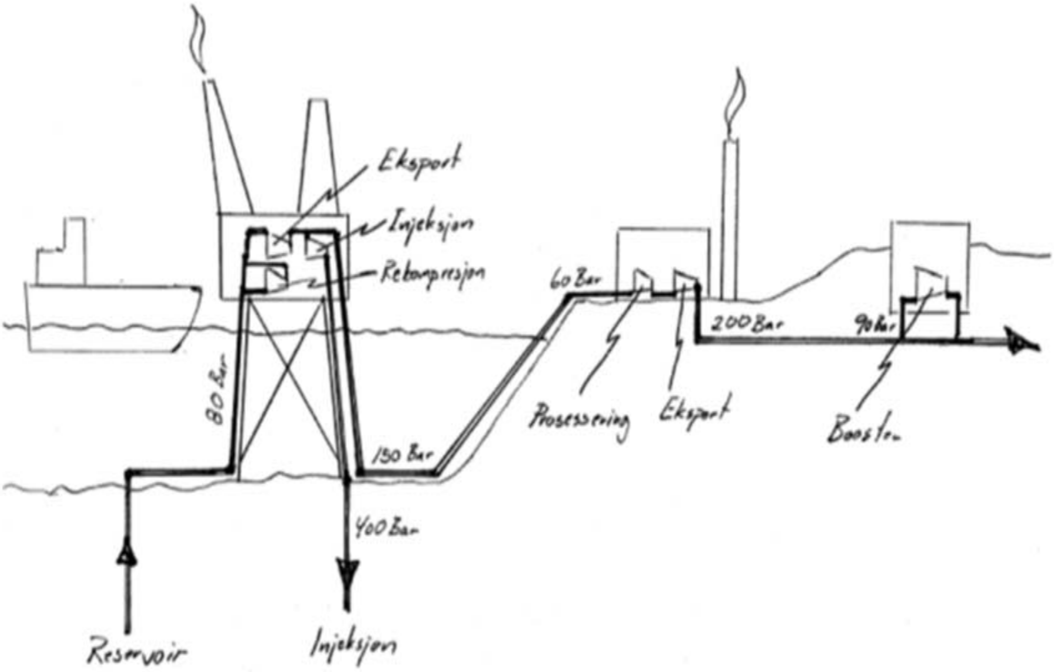


ROTO-DYNAMICS	VOLUMETRIC
• HIGH FLOW RATE	• LOW FLOW RATE
• LOW COMPRESSION RATIO (r_p) (EACH STAGE).	• HIGH r_p
↳ FOR HIGHER r_p ↳ MULTIPLE STAGES	

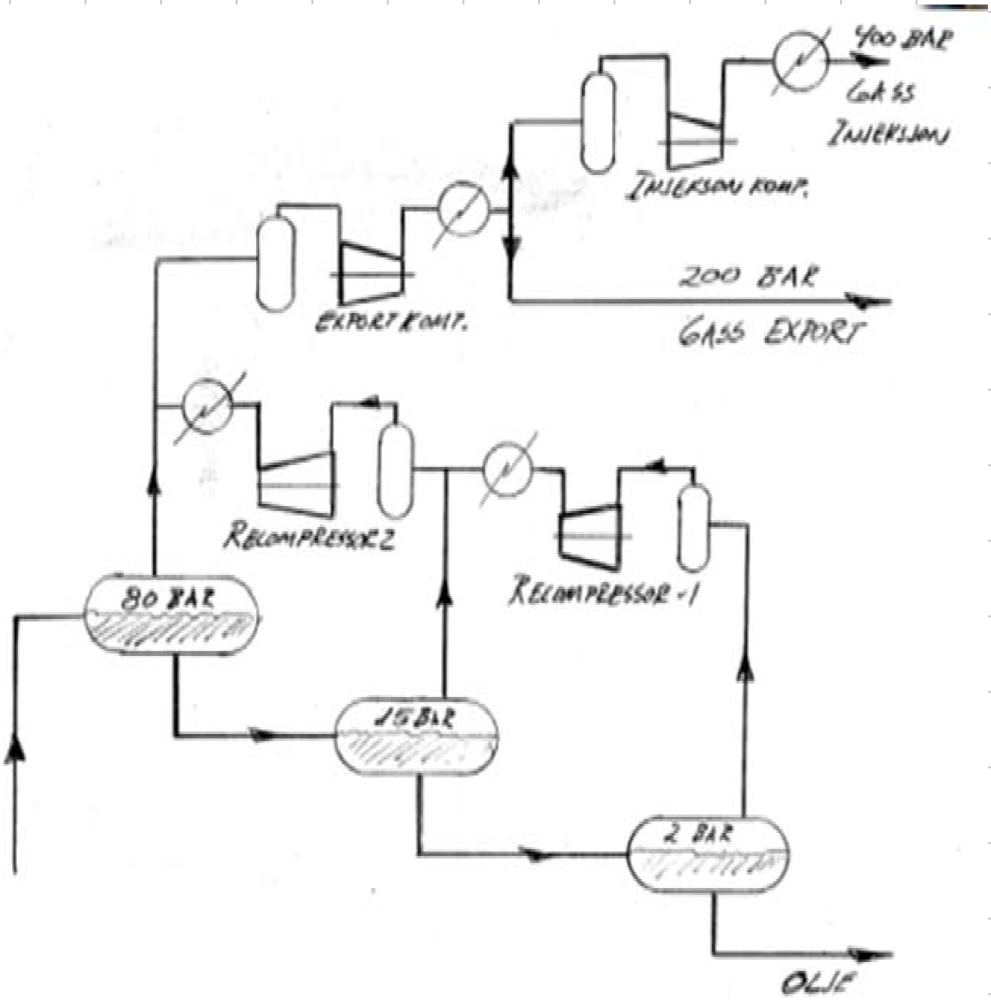
TWO DIFFERENT PRINCIPLES



⇨ Compressor APPLICATIONS



- Field Gas Compression (Gas Boosting)
- Pipeline Compression
- Flash Gas Compression
- Export Compression
- Reinjection Compression
- Gas Lift Compression
- Refrigeration Compression
- Vapor Recovery



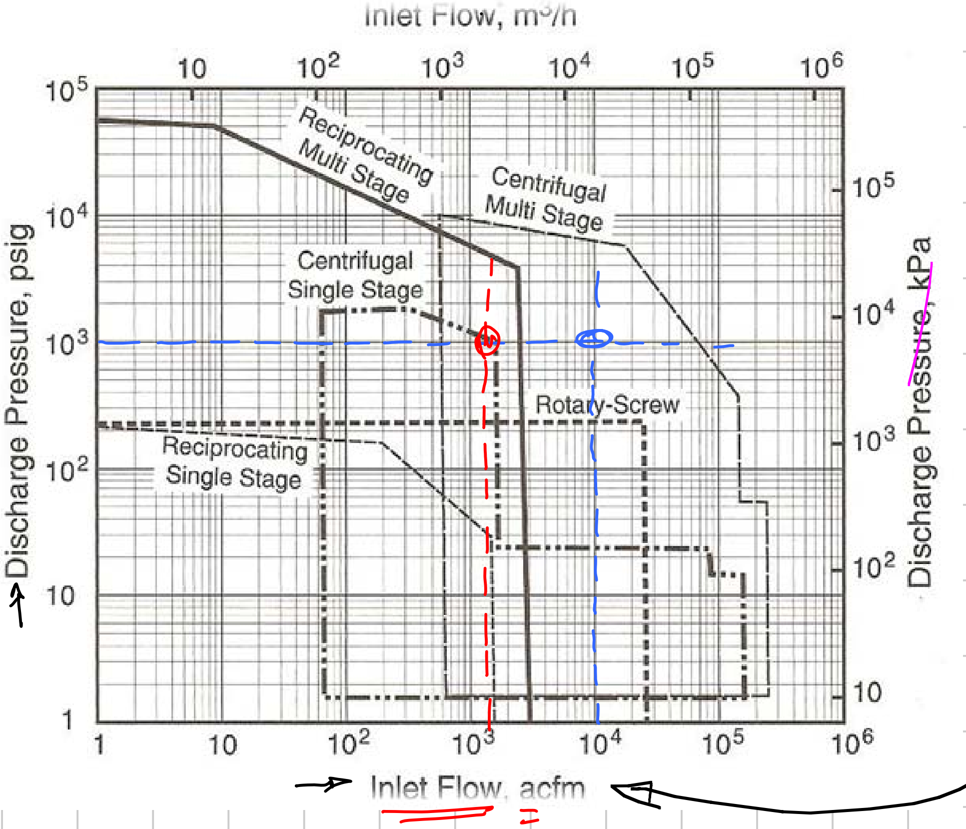
COMPRESSOR PROBLEM AREAS

⇒ • SELECTION OF COMPRESSOR TYPE:
  - Axial or centrifugal compressor
  - Horizontally- / vertically-split casing

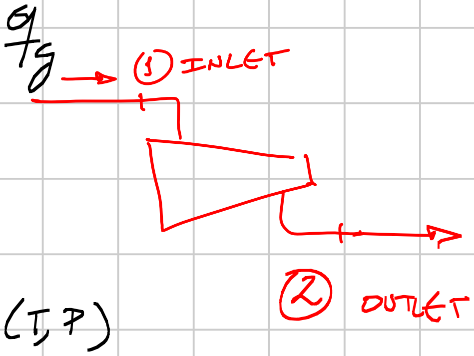
• CALCULATION OF:
  - Shaft power ⇒ POWER < 50-60 ; POWER < 15 MW SUBSEA
  - Number of stages ⇒ MAX. NUMBER OF STAGES $\overline{\overline{i \approx 8}}$ } $P > 100 bar$ $i \leq 6$
  - Discharge (exit) temperature ⇒ $T_{DISC} < 450$ K [LIMITS WITH SEALS]
  - Speed
  - Number of compressors ⇒ { SERIES / PARARELL

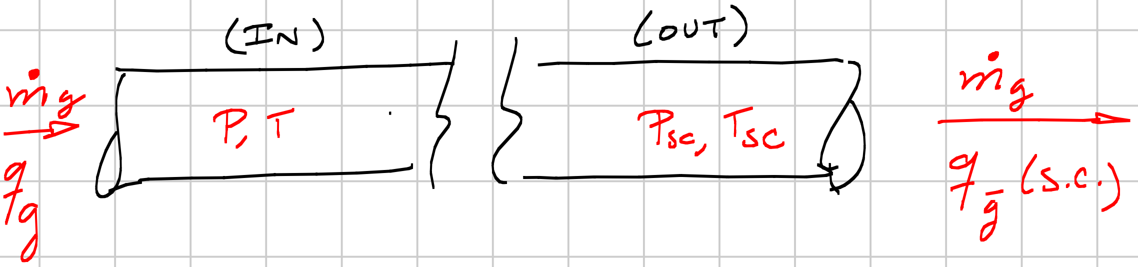
• SELECTION OF:
  - Driver → ELECTRIC DRIVER (COMMONLY)
  - Anti surge system → STABLE RANGE ⇒ CAN BE SUPPLY BY THE COMPRESSOR MANUFACTURE BUT ALSO OTHER COMPANY
  - Gearbox
  - Lay-out of package → SIZE OF THE COMPRESSOR STATION → RELEVANT FOR OFF-SHORE INSTALLATION

→ COMPRESSOR SELECTION MAP



=
↳ ACTUAL (LOCAL) FLOW RATE AT INLET CONDITIONS (T, P)





$$\dot{m} = q_{IN}\,\rho_{IN} = q_{OUT}\,\rho_{OUT} \Rightarrow q_g = \rho_{\bar{g}} \cdot \frac{1}{\rho_g} \cdot q_{\bar{g}}$$

COMPRESSOR:

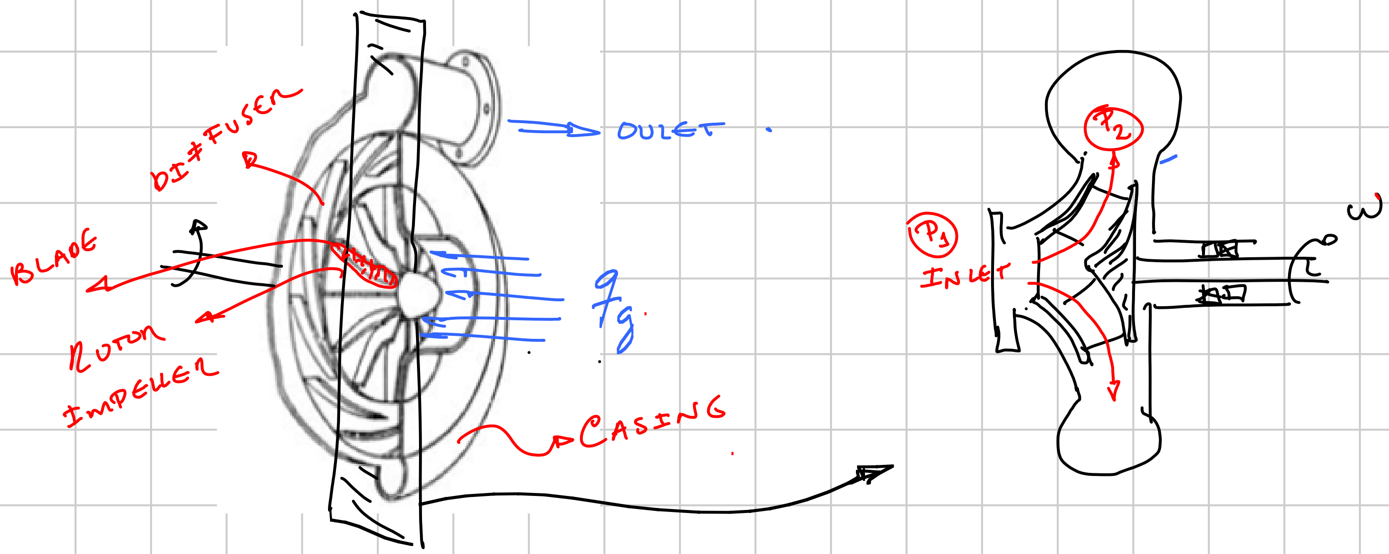
$$q_{INLET} = \frac{P_{sc}}{\cancel{R}\,T_{sc}\,\underbrace{z_{sc}}_{\approx 1}} \times \frac{\cancel{R}\,T_{IN}\,z_{IN}}{P_{IN}}\; q_{\bar{g}}$$

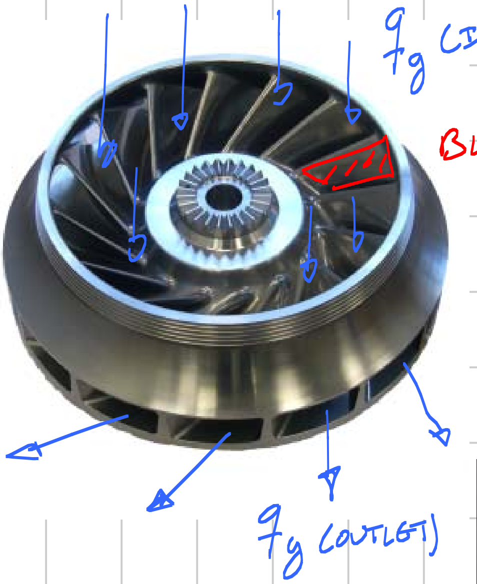
(LOCAL / ACTUAL)

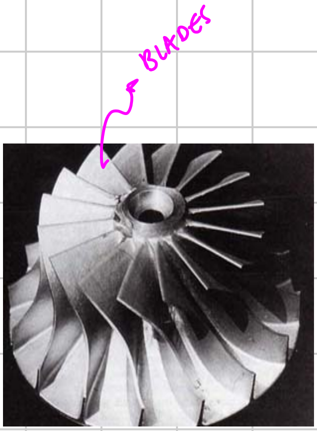
$$R = \frac{\bar{R}}{M_g}$$

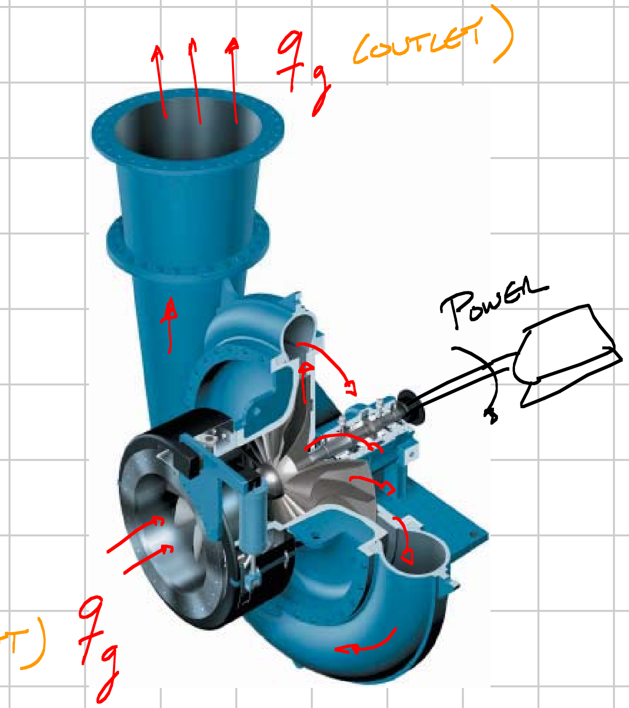
$P_{sc} = 101325$ Pa , $T_{sc} = 60°F = (15.56 + 273.15)$ K

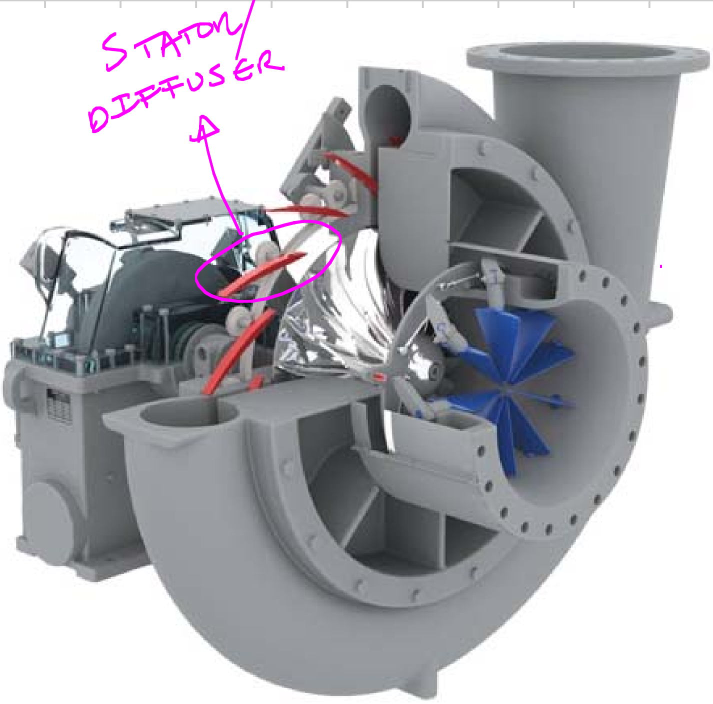
⇒ SIMPLE CENTRIFUGAL COMPRESSOR



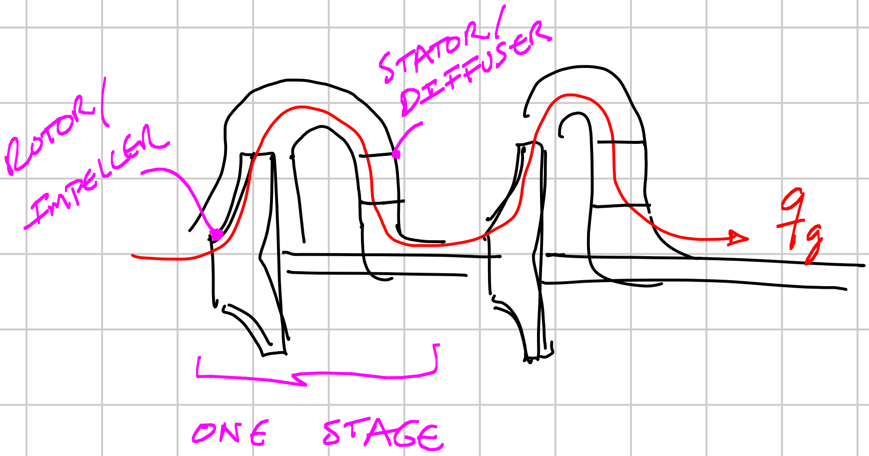








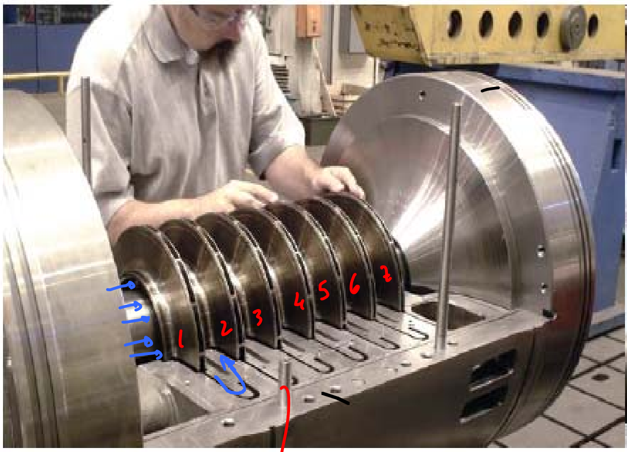
⇒ MULTI-STAGE CENTRIFUGAL COMPRESSOR

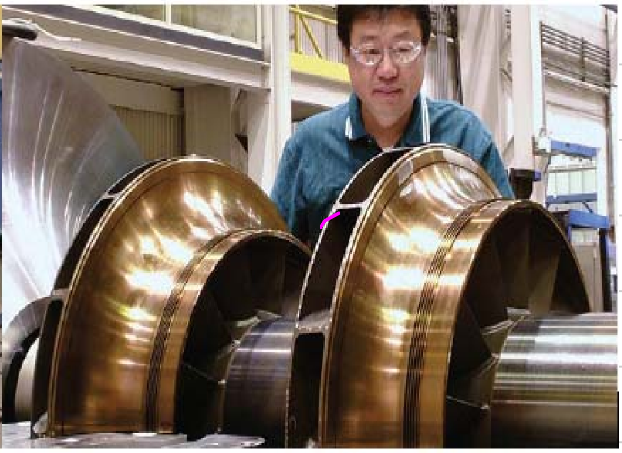


ONE STAGE:

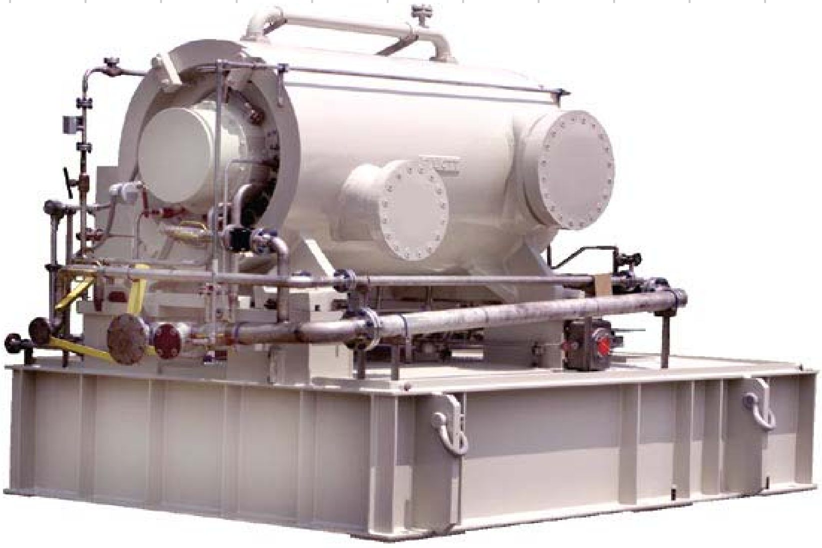
$r_p = 2$ TO 5

(EVEN MORE)





7 STAGES !

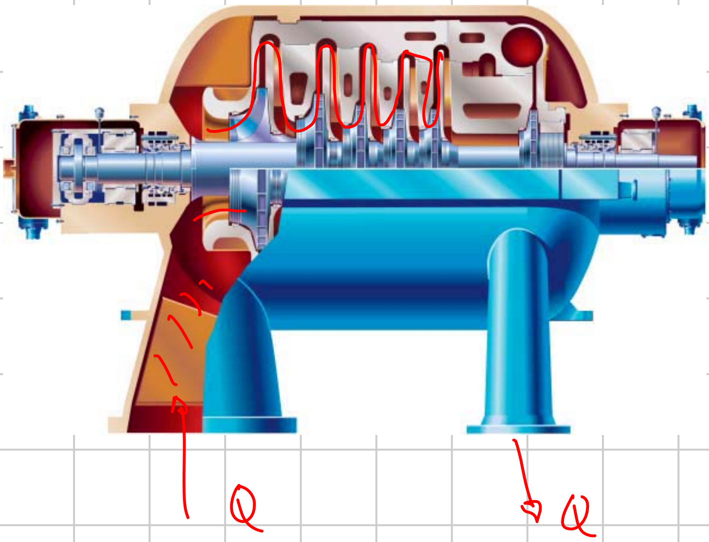


MECHANICAL CONSTRAIN:

COMPRESSOR CAN HAVE ΔP RESTRICTIONS

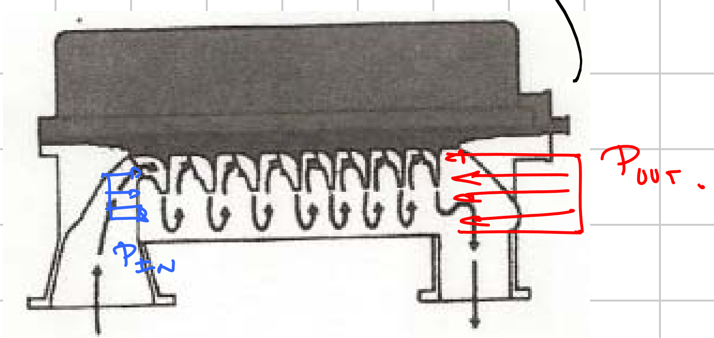
↳ FRAMO WGC 4000

↳ $\Delta P_{max} = 30\,bar$



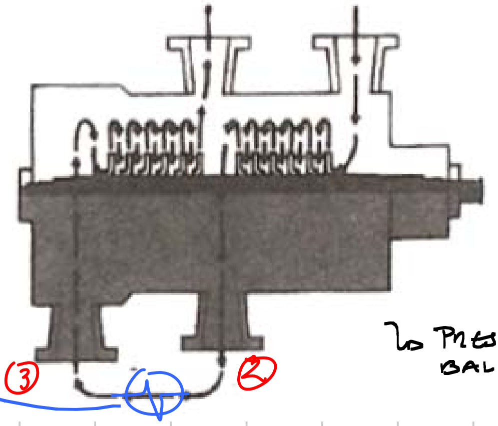
UNBALANCED PRESSURE

↳ AXIAL FORCES



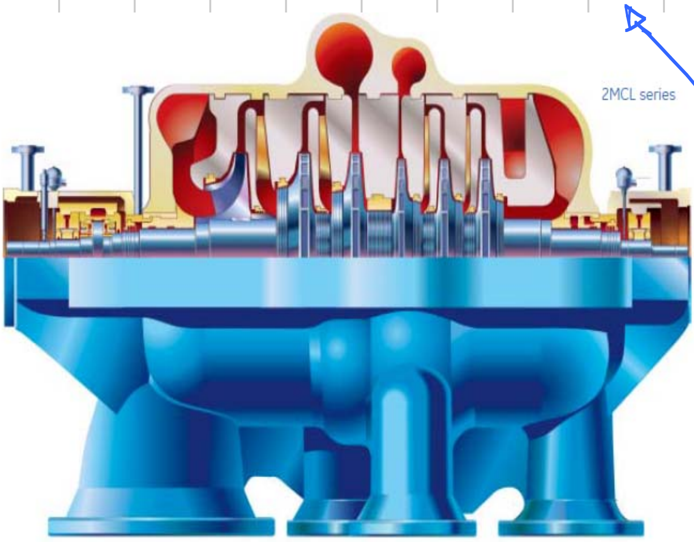
$T_{DISC} > 450K$

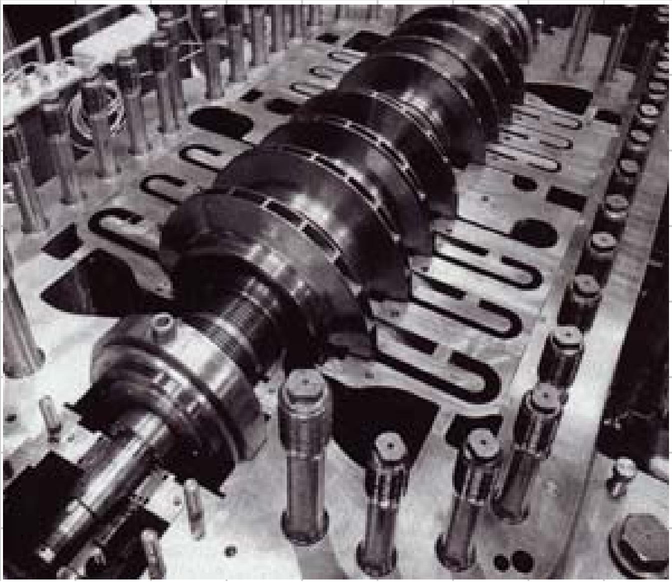
Schematic of a back-to-back centrifugal compressor. The thrust from two rotor halves oppose each other



IT IS POSSIBLE INTER-STAGE COOLING

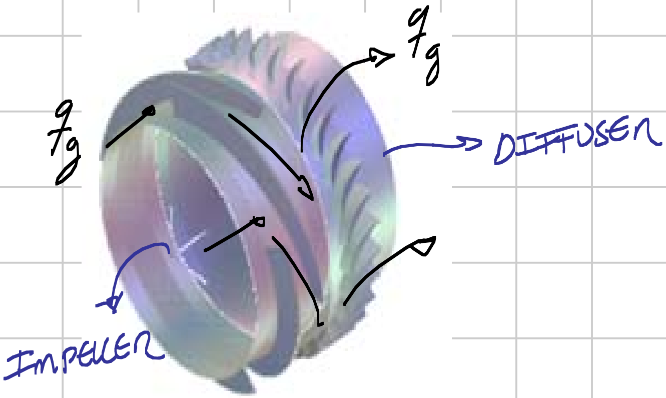
↳ PRESSURE BALANCED





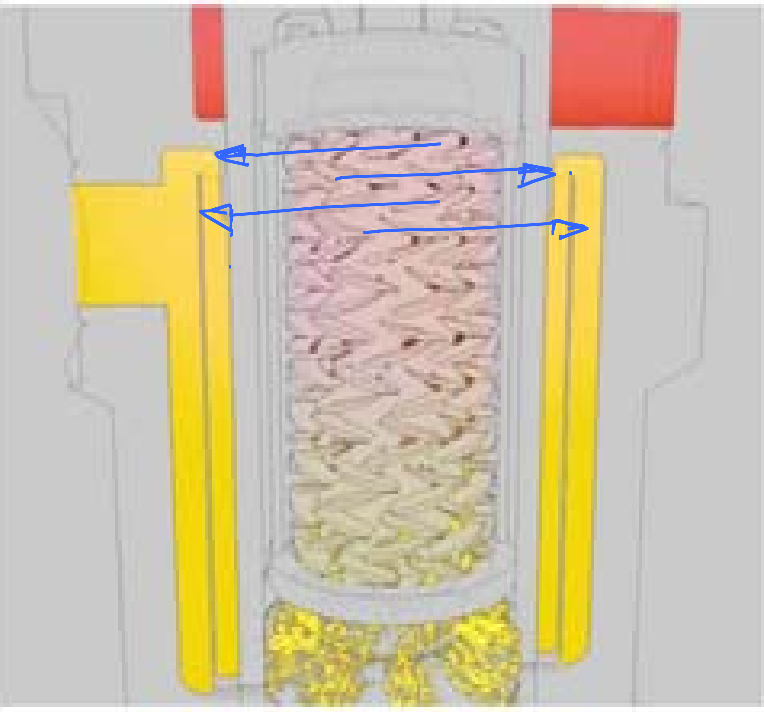
⇒ HELICO-AXIAL COMPRESSOR (MULTIPHASE PUMP)

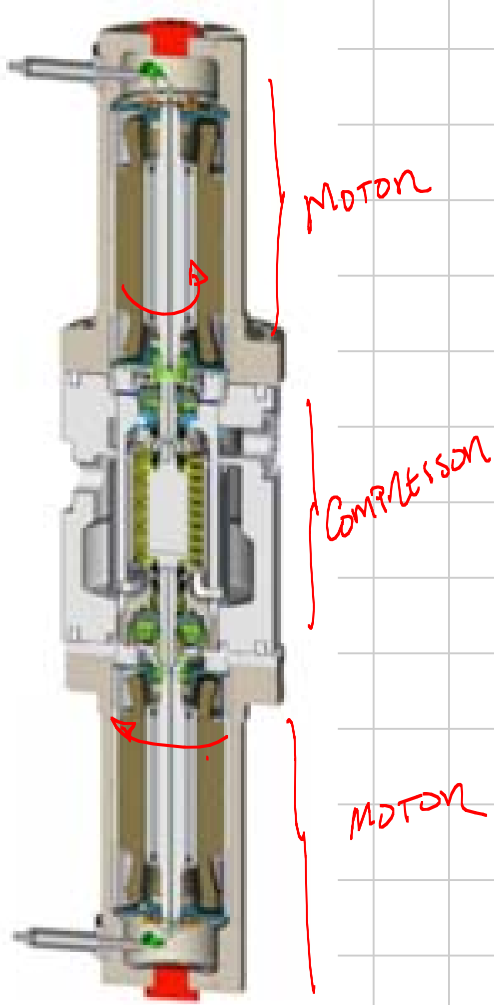
- HIGH FLOW RATE, q
- LOW r_p PER STAGE ($r_{p_{STAGE}} = 1.2$ TO 1.5)



FRAMO WGW 4000

↳ COUNTER ROTATING IMPELLERS
(STATOR NOT USED)



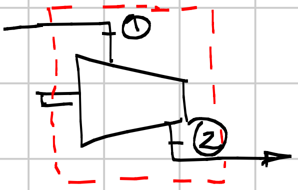


⇒ COMPRESSORS PERFORMANE

IN ORDER TO UNDERSTAND IT, WE FIRST NEED TO DISSCUSS THE THERMODYNAMIC COMPRESSION PROCESS...

1ST LAW – COMPRESSOR

h ... SPECIFIC ENTHALPY



FOR THE CONTRO VOLUME:

$$\underset{\frac{\text{HEAT}}{\text{TIME}}}{\dot{Q}} - \underset{\frac{\text{WORK}}{\text{TIME}}}{\dot{W}} = \underset{\frac{\text{ENERGY}}{\text{TIME}}}{\frac{dE}{dt}} = \overset{\frac{\text{MASS}}{\text{TIME}}}{\dot{m}} \left[\overbrace{\left(\underset{\frac{\text{ENTALPY}}{\text{MASS}}}{h_2} + \frac{1}{2} \underset{\text{FLOW VELOCITY}}{V_2^2} + \underset{\text{ELEVATION}}{z_2} g \right)}^{\text{ENERGY OUTLET}} - \overbrace{\left(h_1 + \frac{1}{2} V_1^2 + z_1 g \right)}^{\text{ENERGY INLET}} \right]$$

IT'S POSSIBLE TO ASSUME: $V_2 \approx V_1$ AND $Z_1 \approx Z_1$ (SAME ELEVATION)

AND $\dot{Q} \approx 0$ (ADIATIC PROCESS)

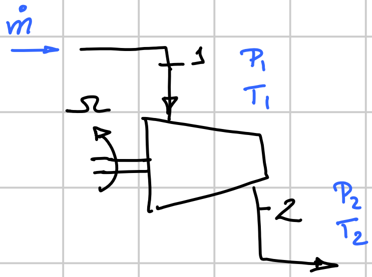
THEN,

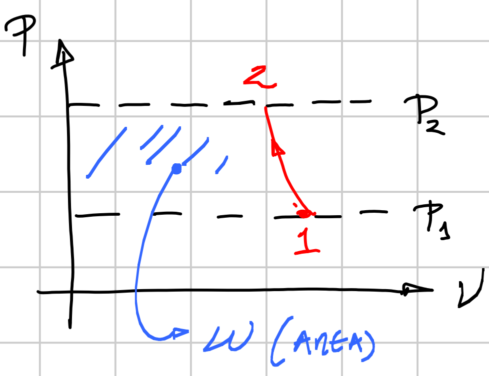
$$\boxed{\underset{\substack{\text{POWER} \\ [\text{WATTS}] \\ \frac{\text{JOULE}}{\text{SEC.}}}}{\dot{W}} = \overset{\substack{\text{MASS FLOW} \\ \text{RATE } [\text{kg/s}]}}{\dot{m}} \underset{\substack{\text{SPECIFIC} \\ \text{ENTHALPY} \\ \left[\frac{\text{JOULE}}{\text{kg}}\right]}}{\Delta h}} \Longrightarrow \overset{\text{SPECIFIC POWER}}{\boxed{w = \Delta h}} \quad \left[\text{JOULE}/\text{kg}\right]$$

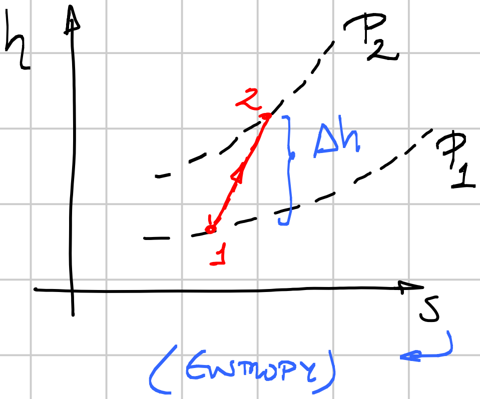
IT IS ALSO

$$w = \int_{P_1}^{P_2} v \, dP$$

THE COMPRESSION PROCESS IN P-v AND h-s DIAGRAMS:

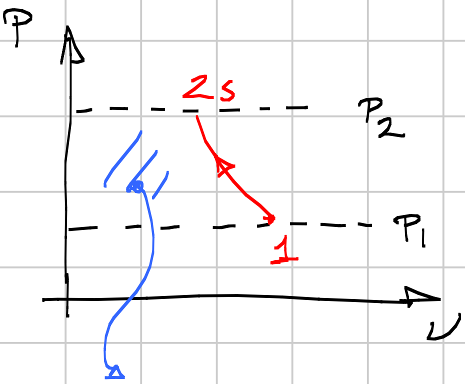


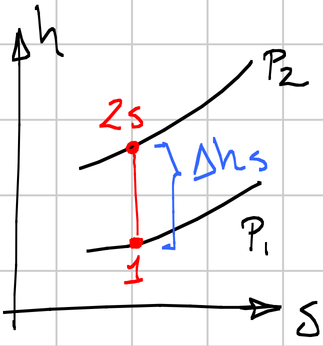




SPECIFIC WORK (FOR ISENTROPIC, IDEAL GAS)

THE IDEAL COMPRESSION PROCESS (NO ENERGY LOSES) IS RELATED TO A REVERSIBLE AND ADIABATIC PROCESS, CALLED "ISENTROPIC"





FOR IDEAL GAS:
(I.D.)

$$C_p = \left(\frac{\partial h}{\partial T}\right)_p = C_p(T)$$

$$C_v = \left(\frac{\partial u}{\partial T}\right)_v = C_v(T)$$

$$k = \frac{C_p(T)}{C_v(T)} = k(T)$$

AREA → WORK PERFORMED

$$w_s = \int_1^{2s} v\,dP = h_2 - h_1 = \Delta h_s$$

ALONG THE PROCESS, PRESSURE AND TEMPERATURE ARE RELATED BY:

$$P v^{k} = cTTe$$

CONSIDERED CONSTANT ALONG THE COMPRESSION

WHERE k IS THE ADIABATIC EXPONENT

$$\left[k = 1.3 - 0.31(\gamma_g - 0.55)\right]$$

GASES

FOR IDEAL GAS IT CAN BE PROVED THAT: $\frac{T_{2s}}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}}$

THE SPECIFIC WORK:

$$w_s = h_{2s} - h_1 = C_p(T_{2s} - T_1) = C_p\, T_1 \left[\frac{T_{2s}}{T_1} - 1\right]$$

$$\left\{\begin{array}{l} C_p - C_v = R \\ k = \frac{C_p}{C_v} \end{array}\right\} \quad C_p = \frac{kR}{k-1}$$

THEN WE CAN GET :

$$\rightarrow \boxed{w_s = \frac{kR}{k-1}\cdot\left[\underbrace{\left(\frac{P_2}{P_1}\right)}_{r_p}^{\frac{k-1}{k}} - 1\right]}$$

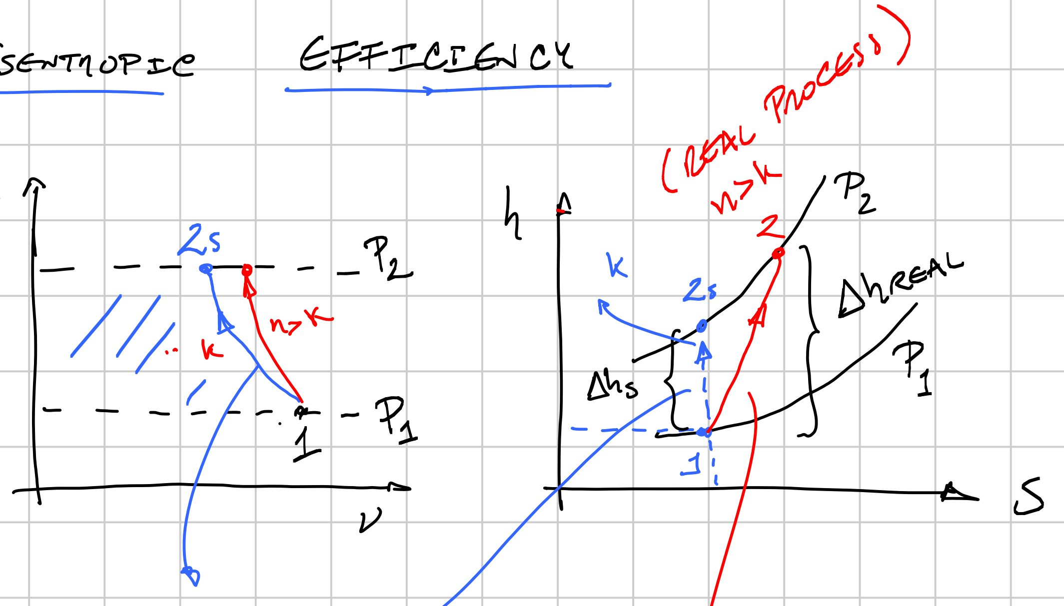
FOR AN IDEAL (ISENTROPIC COMPRESSOR

→ r_p ... RELEVANT FOR COMPRESSOR !

FOR A REAL GAS : $$\Delta h_s = Z_{AV}\,\frac{kR}{k-1}\,T_1\left[(r_p)^{\frac{k-1}{k}} - 1\right]$$

(AVERAGE) $$Z_{AV} = \frac{Z_1+Z_2}{2}$$

⇨ ISENTROPIC EFFICIENCY



ISENTROPIC
(IDEAL PROCESS)

pv^k = CONSTANT

(REAL PROCESS)

→ POLYTROPIC

pv^n = CONSTANT

⇓

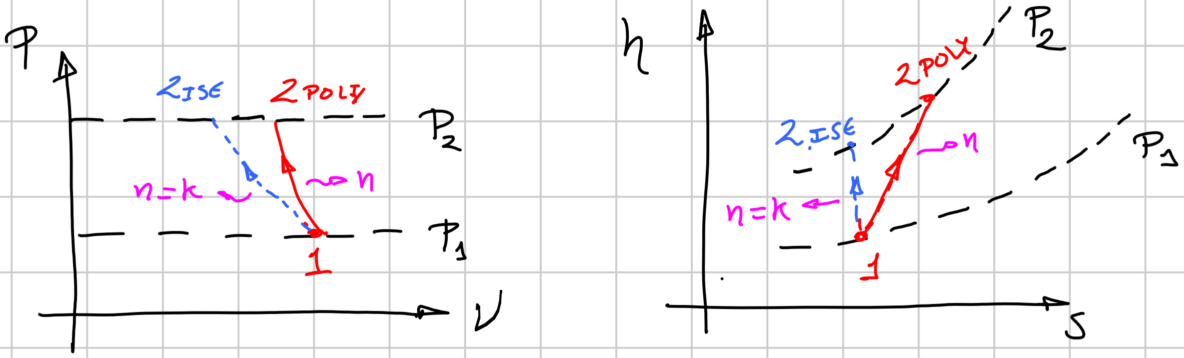
IS A COMPRESSION PROCESS DEFINED AS REVERSIBLE AND NOT ADIABATIC

ISENTROPIC (ADIABATIC) EFFICIENCY : $$\eta_c = \frac{\overset{IDEAL}{\Delta h_s}}{\underset{REAL}{\Delta h}} = \frac{h_{2s}-h_1}{h_2-h_1} = \frac{\cancel{c_p}(T_{2s}-T_1)}{\cancel{c_p}(T_2-T_1)}$$

⇒ POLYTROPIC PROCESS

AND OBEYS THE RELATION: $pv^n = \text{CONSTANT}$

IN P-V AND h-s DIAGRAMS:



THE POLYTROPIC PROCESS IS THE ONE THAT BETTER DEFINES THE REAL COMPRESSION PROCESS

THE SPECIFIC WORK CAN BE WRITTEN AS FOR EQ. ⑥, THEN:

$$\boxed{W_p = R T_1 \frac{n}{n-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right]}$$

⇒ CLOSEST TO THE REAL COMPRESSION PROCESS

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}}$$

DEFINE THE PROCESS

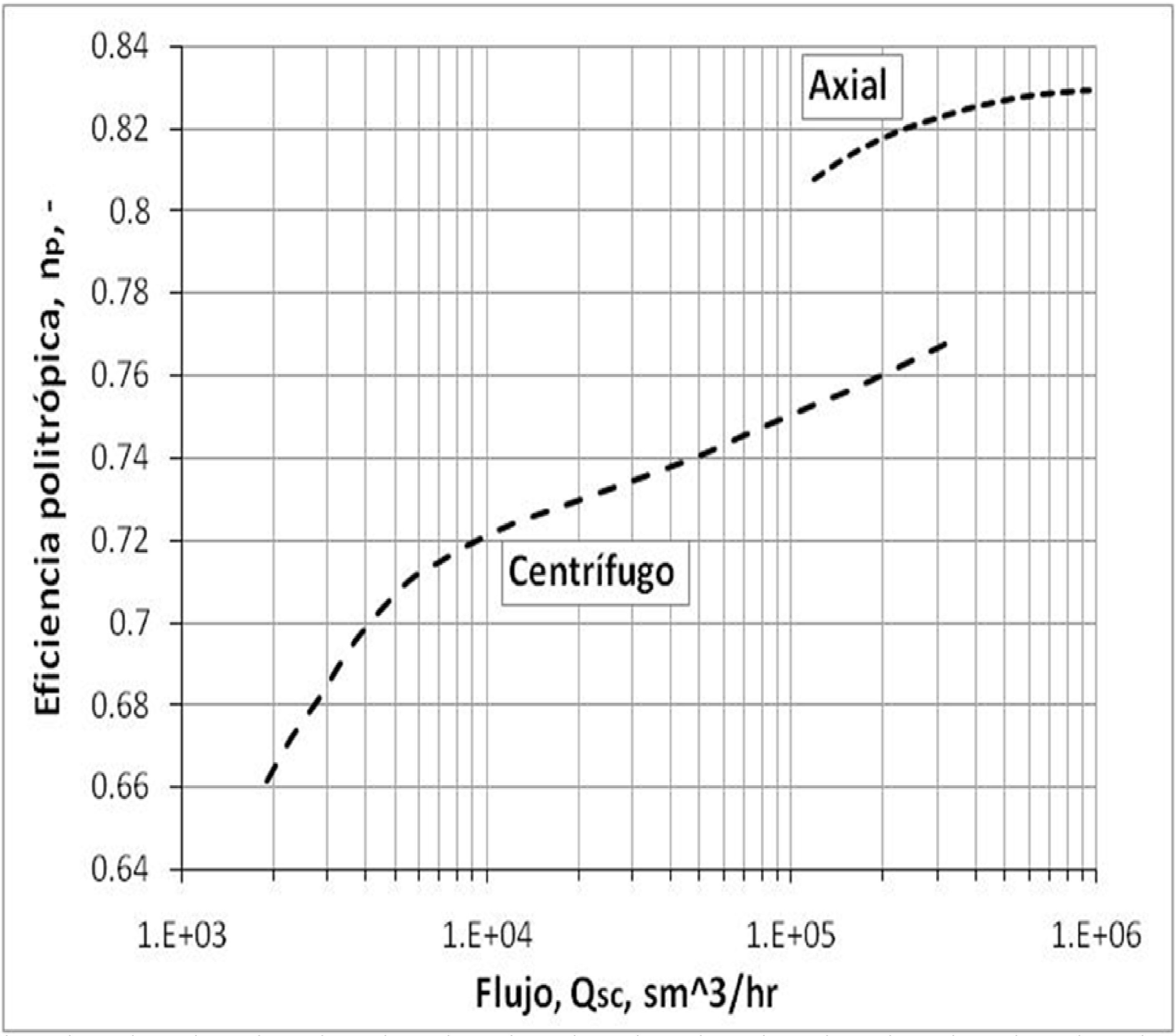
$P v^{n} = \text{CONSTANT}$

n ... POLYTROPIC COEFFICIENT

POLYTROPIC EFFICIENCY "η_P" $\frac{n-1}{n} = \frac{k-1}{k\,\eta_P}$

IT IS THE ONE TYPICALLY REPORTED FOR COMPRESSORS

REFERENTIAL...



⇒ **POLYTROPIC ENTHALPY HEAD :**

$$\boxed{\Delta h_p = T_1 Z_{AV} R \frac{n}{n-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right]}$$

⇒ **POLYTROPIC HEAD :**

$$\boxed{H_p = \frac{\Delta h_p}{\underbrace{g}_{\text{gravity}}}} \qquad \frac{[J/kg]}{[m/s^2]} = [m]$$

↳ MAIN PARAMETER USED FOR COMPRESSOR PERFORMANCE

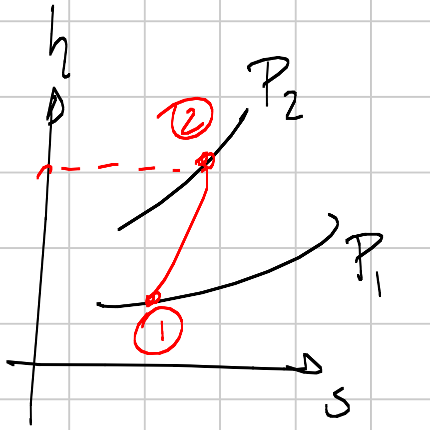
⇒ **POWER REQUIRED :**

$$\text{POWER} = \dot m\, w_{REAL} = \frac{\dot m\, \Delta h_s}{\eta_c \times \underbrace{\eta_m}_{\text{mechanical EFFICIENCY}}} = \boxed{\frac{\dot m\, \Delta h_p}{\eta_p \times \eta_m}}$$

$\eta_m \approx 98\%$

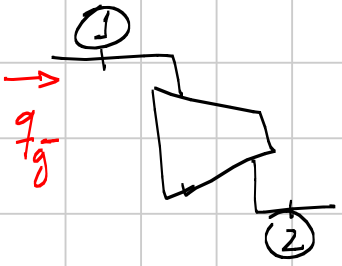
⇒ **DISCHARGE TEMPERATURE**

$$T_2 = T_1 \left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} = T_1 \left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k\eta_p}}$$



EXERCISE . WITH MOLLIER DIAGRAM:

COMPRESSOR FOR: $q_g = 1\times 10^6$ Sm³/day , $P_1 = 1\times 10^6$ Pa TO $P_2 = 3\times 10^6$ Pa



T_1 (INLET) = 303.15 K , $\gamma_g = 0.7$, $Z_{av} = 0.98$

$\eta_c = 78\%$ (ISO) $\eta_o = 75\% = \eta_c \cdot \underbrace{\eta_m}_{}$ (OVERALL)   MECHANICAL

Q: REQUIRED POWER ?   TEMP. OUTLET ?

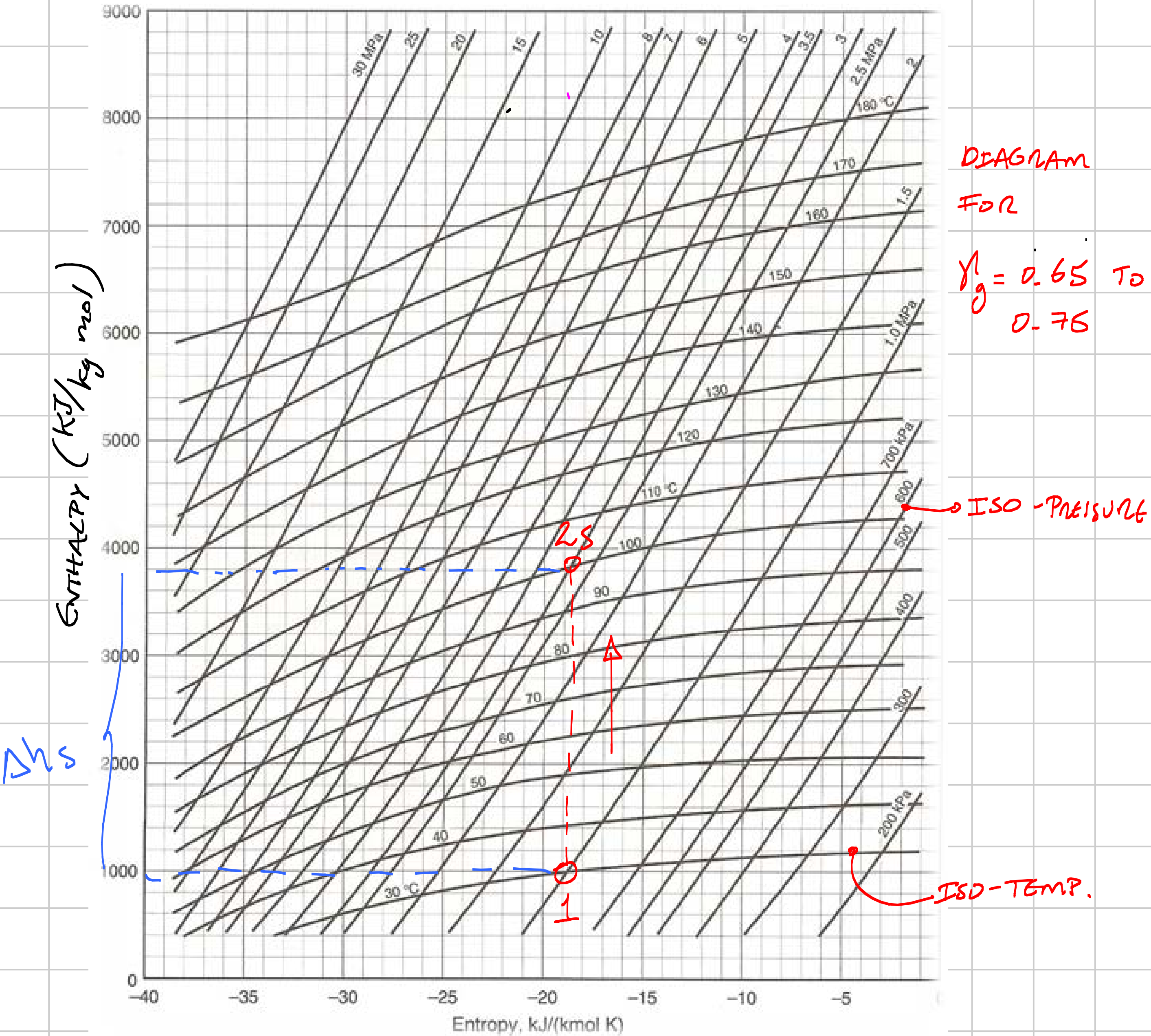


DIAGRAM FOR $\gamma_g = 0.65$ TO 0.76

$\Delta h_s = 3800 \frac{kJ}{kg\,mol} - 1000 \frac{kJ}{kg\,mol} = 2800 \left[\frac{kJ}{kg\,mol}\right]$ → LATER WE NEED IT IN [kJ/kg]

- THE MASS FLOW RATE :

$$\dot{m} = \underbrace{q_g \rho_g}_{\text{LOCAL INLET}} = \underbrace{q_{\bar{g}} \rho_{\bar{g}}}_{\text{STANDARD CONDITIONS}} = q_{\bar{g}} \frac{P_{sc}}{Z_{sc} R T_{sc}}$$

- R OF THE GAS :

$$R = \frac{\bar{R}}{M_g} = 8314 \frac{J}{kgmol.k} \frac{1}{0.7 \times \underbrace{28.97}_{\text{AIR}} \frac{kg}{kgmol}} = 409 \frac{J}{kg.K}$$

THEN

$$\dot{m} = q_{sc} \frac{P_{sc}}{Z_{AV} \cdot R T_{sc}} = \frac{1 \times 10^6 \ Sm^3/d}{86400 \ sec/day} \times \frac{101325 \ Pa}{1 \times 409 \frac{J}{kg K} \times 288.61 K}$$

$$\dot{m} = 9.95 \ kg/sec.$$

- THE POWER REQUIRED: $P_{ow} = \frac{\dot{m} \Delta h_s}{\eta_{GLOBAL}} = \frac{9.95 \ \cancel{kg}/sec \times 138.07 \ kJ/\cancel{kg}}{0.75}$

$$\Delta h_s = 2800 \frac{kJ}{kgmol} \times \frac{1}{\underbrace{M_g}_{0.7 \times 28.95}} = 138.07 \frac{kJ}{kg}$$

$$\text{Power} = 1.832 \ Mw = 1.832 \times 10^6 \ \text{Watts}$$

$$- \ \Delta h_{REAL} = \frac{\Delta h_s}{\eta_c} = \frac{2800 \ kJ/kgmol}{0.78} = 3590 \frac{kJ}{kgmol} \rightarrow \overset{(REAL)}{h_2 = 4590 \frac{kJ}{kgmol}}$$

- FIND THE OUTLET TEMPERATURE WITH THE DIAGRAM

$$T_D \approx 115°C$$

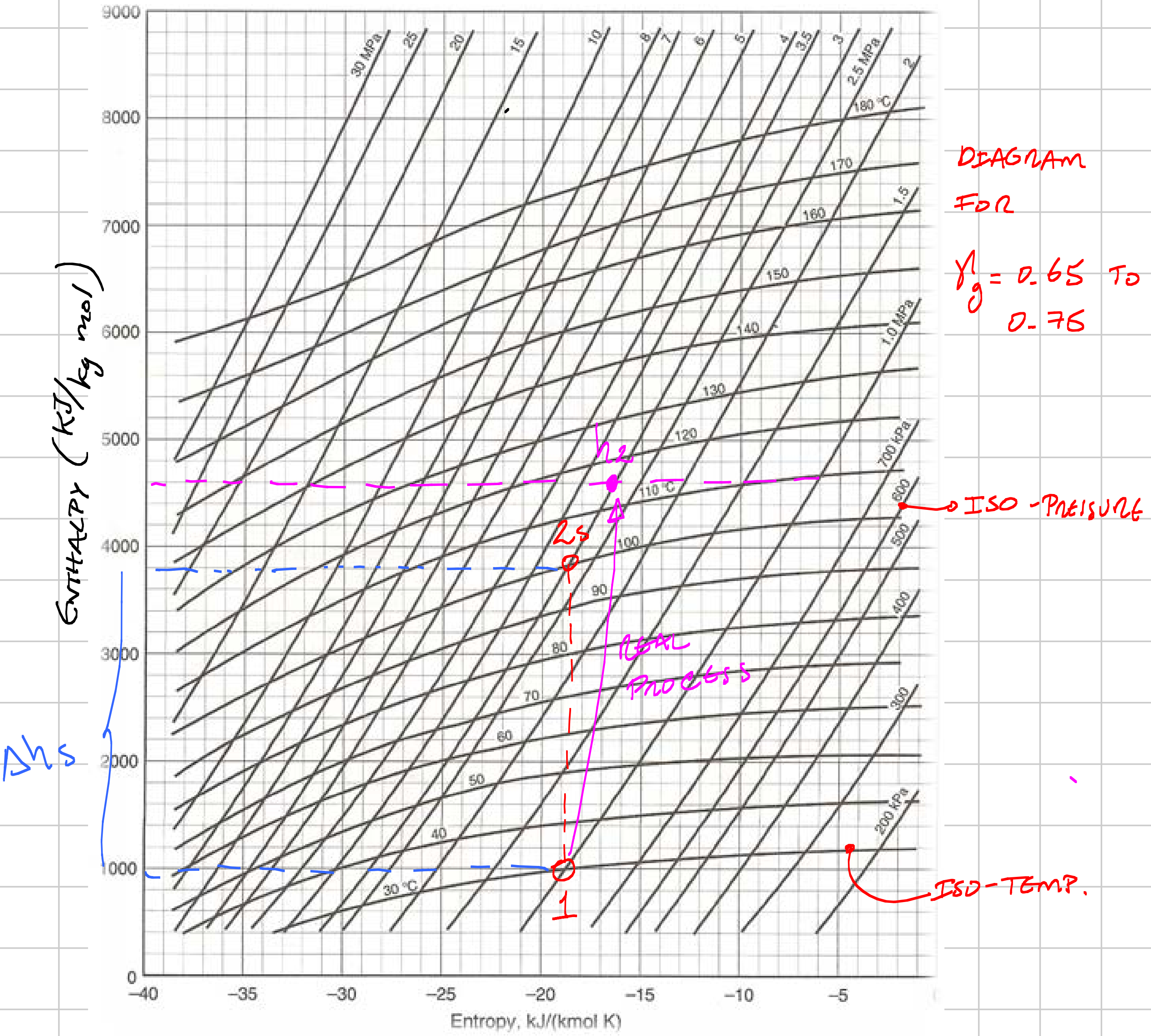
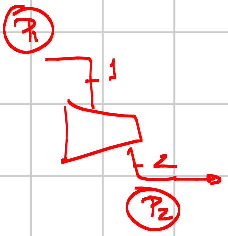


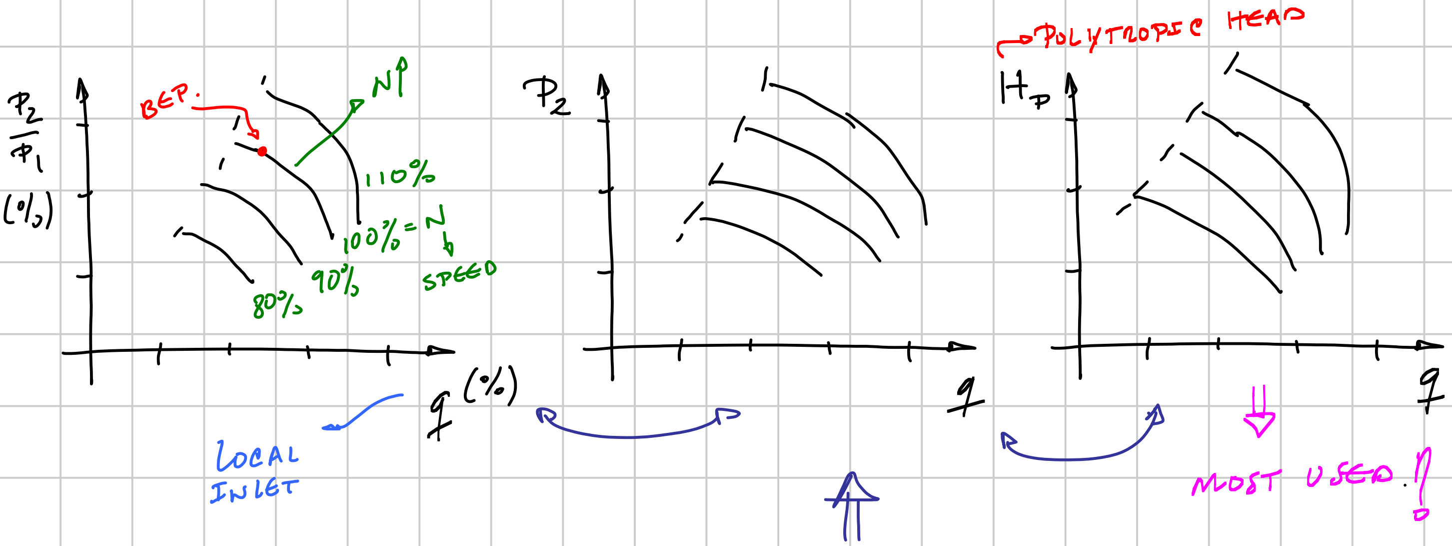
DIAGRAM FOR $\gamma_g = 0.65$ TO 0.75
ENTHALPY (KJ/kg mol)
Entropy, kJ/(kmol K)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
−40
−35
−30
−25
−20
−15
−10
−5
30 MPa
25
20
15
10
8
7
6
5
4
3.5
3
2.5 MPa
2
1.5
1.0 MPa
700 kPa
600
500
400
300
200 kPa
180 °C
170
160
150
140
130
120
110 °C
100
90
80
70
60
50
40
30 °C
h_2
2s
1
REAL PROCESS
Δh_s
ISO-PRESURE
ISO-TEMP.

⇒ COMPRESSOR MAPS



$r_p = \frac{P_2}{P_1}$ (PRESSURE RATIO)

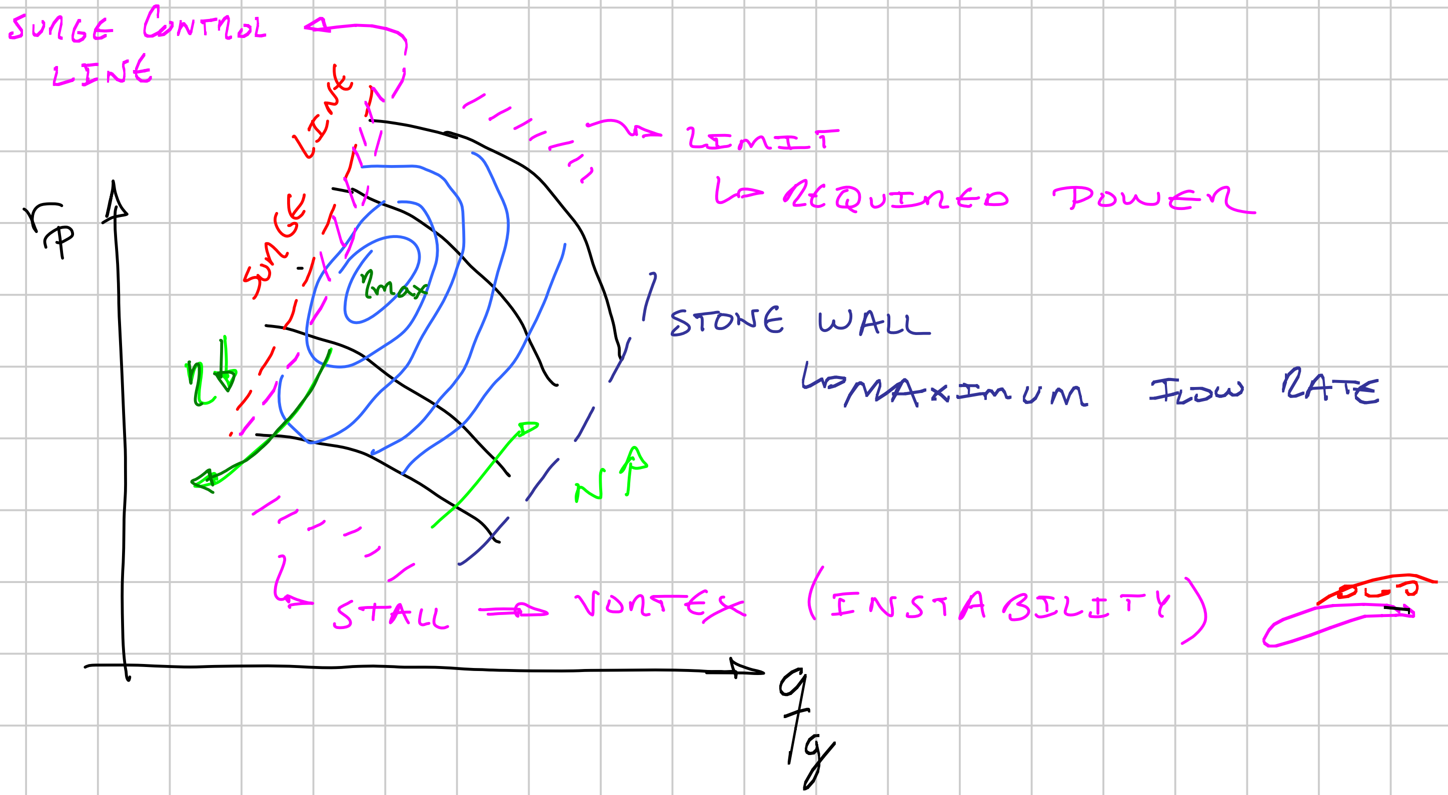
MANFACTURES OFFER DIFFERENT TYPES OF MAPS



IT'S IS ALSO NEEDED THE CONDITIONS OF THE TEST

↳ T_1, P_1, M_g, K

IN DETAIL..

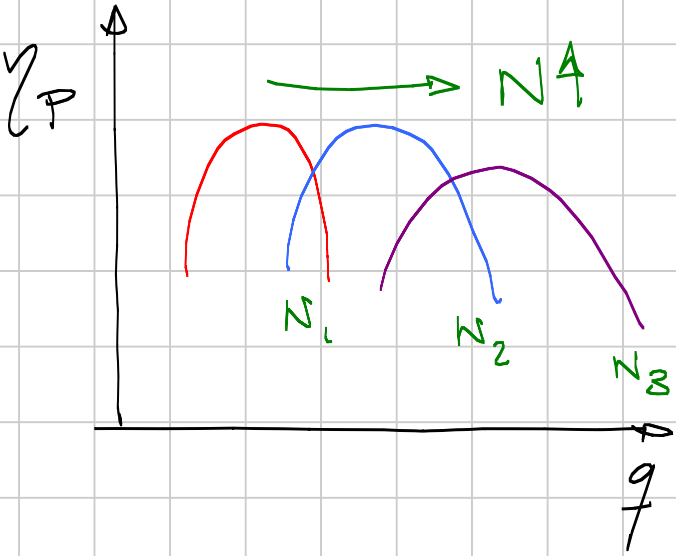


- STONE WALL ⇒ MAXIMUM FLOW RATE THAT CA BE HANDLED BY THE COMPRESSOR FOR AT CERTAIN SPEED
  - ↳ DO NOT AFFECT THE LIFE OF THE LIFE OF THE COMPRESSOR
  - ↳ LIMITS ITS OPERATION

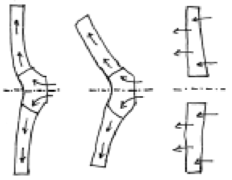
→ BORDER FOR STABLE OPERATION

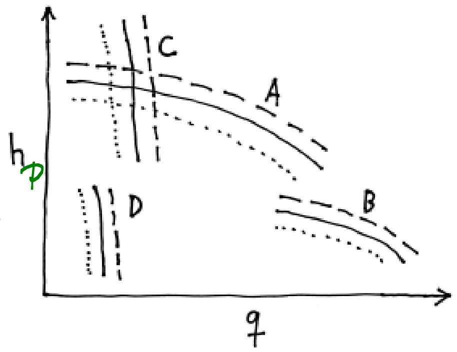
- SURGE ⇒ OCCURS AT LOW FLOW RATES
  - ↳ BIG FLUCTUATIONS OF FLOW AN PRESSURE
  - ↳ FLOW FORDWARD AND BACKWARD IN CYCLES OF 0.3 TO 3 sec.
  - ↳ VIBRATION AND NOISE
  - ↳ $T_{DISCHARD}$ ↑

POLYTROPIC EFFICIENCY:



Characteristic Curves





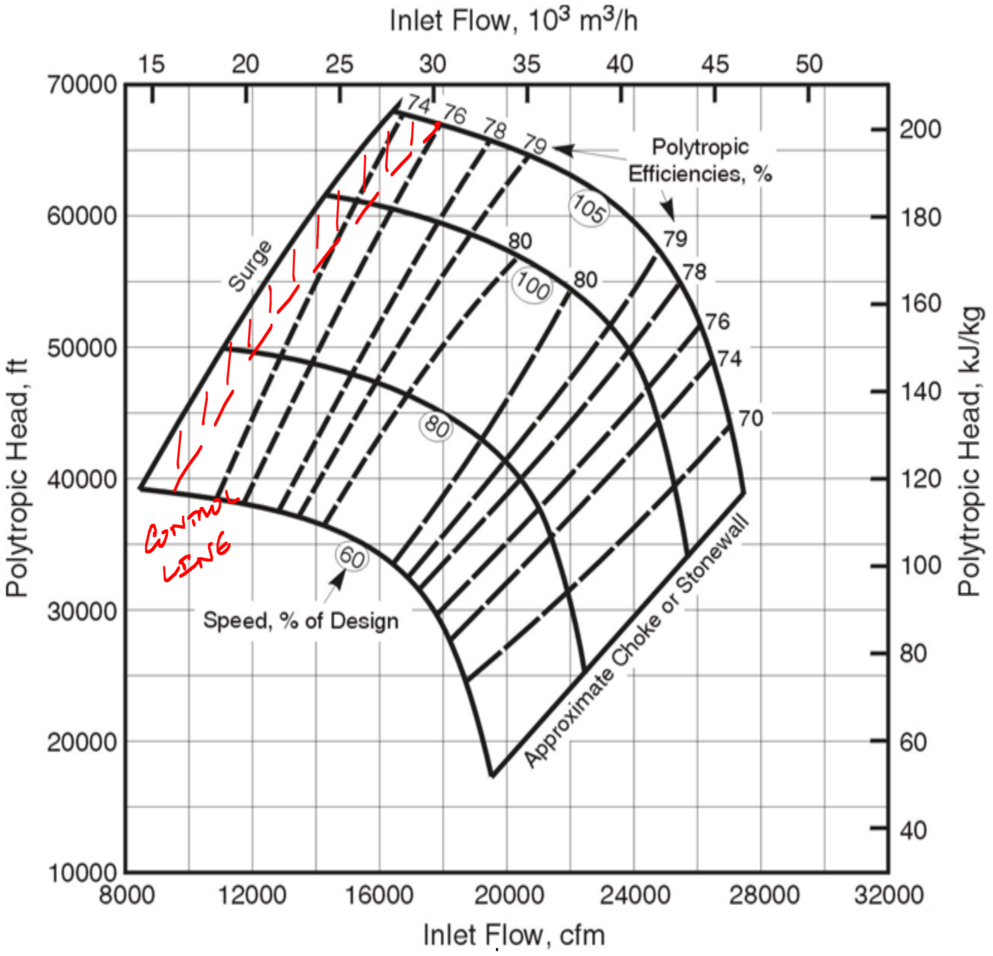
Left: Radial,

Middel: xxx,

Right:Axia

A: Centrifugal, B: Axial,
C: Piston, D: Screw

Centrifugal Compressor Performance Curves



P_1
T_1
M_g
k

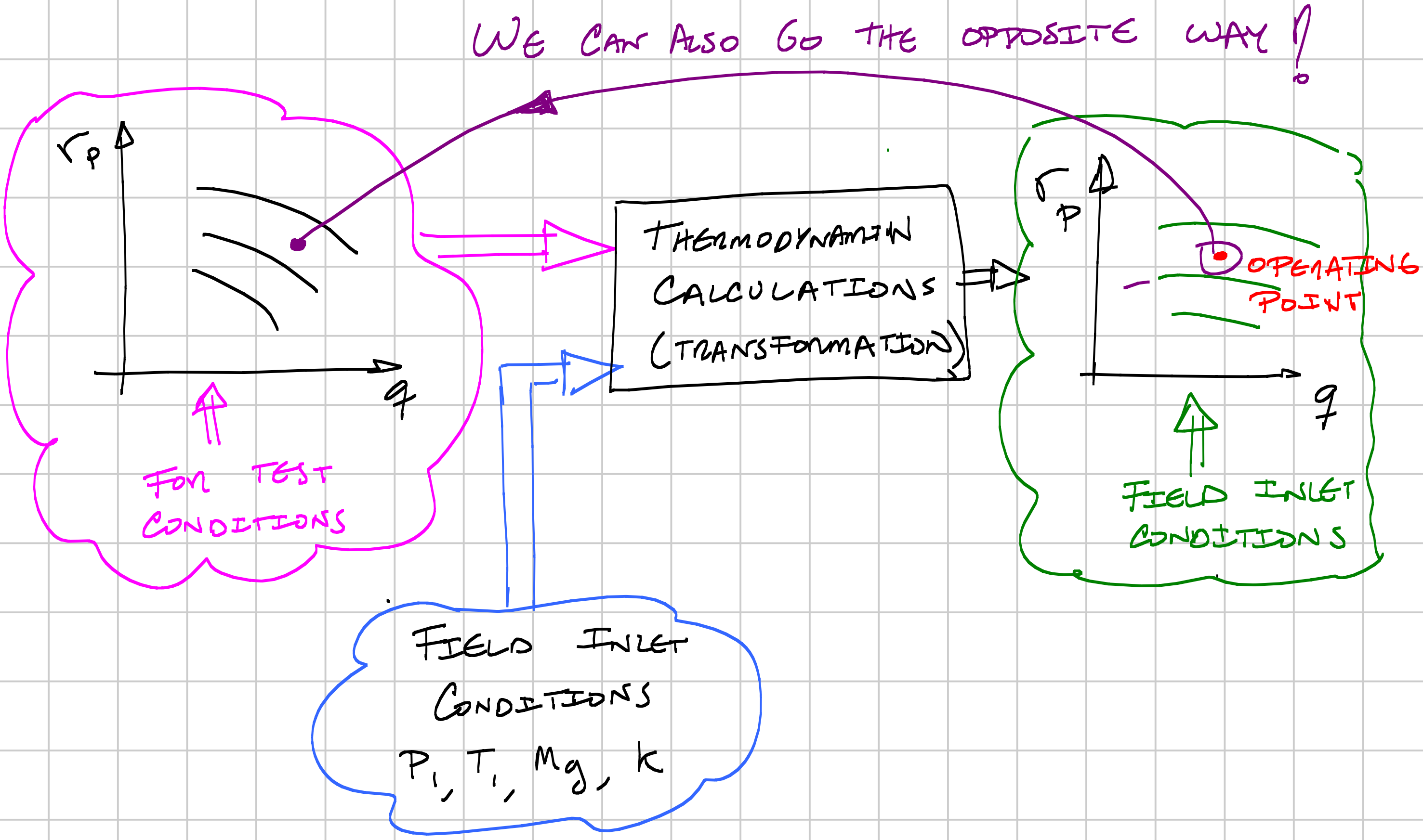
GAS

STANDARD
ISO 5389

THE COMPRESSOR CURVES WILL CHANGE FOR DIFFERENT CONDITIONS (P_1, T_1, M_g, k) FROM THE COMPRESSOR INLET TEST CONDITIONS

THE BASIC THERMODYNAMIC PROCEDURE TO ESTIMATE COMPRESSOR CURVES EXPECTED FOR NEW INLET CONDITIONS

- ASSUMED, THE η_p IS KEPT FOR THE NEW OPERATING CONDITIONS



- CORRECTION OF FLOW RATE :

$$\phi = \frac{\dot{m}}{\rho_{01} a_{01} D^2} \Rightarrow \underset{(TEST)}{\phi_T} = \underset{(ACTUAL)}{\phi_a} \Rightarrow \frac{\dot{m}_T}{\rho_T a_T \cancel{D^2}} = \frac{\dot{m}_a}{\rho_a a_a \cancel{D^2}}$$

$$\Rightarrow \frac{q_T \cdot \cancel{\rho_T}}{\cancel{\rho_T} \; a_T} = \frac{q_a \cancel{\rho_a}}{\cancel{\rho_a} \; a_a} \Rightarrow q_a = q_{TEST} \times \frac{\sqrt{k_a R_a T_a}}{\sqrt{k_{TEST} R_{TEST} T_{TEST}}}$$

$$\Rightarrow \boxed{q_{ACTUAL} = q_{TEST} \sqrt{\frac{k_a}{k_{TEST}}} \times \sqrt{\frac{M_{TEST}}{M_a}} \times \sqrt{\frac{T_a}{T_{TEST}}}}$$

- CORRECTION OF PRESSURE RATIO :

THE POLYTROPIC HEAD REMAINS THE SAME . _

$$\boxed{H_{p_{TEST}} = H_{p_A}}$$

THEN, ...

$$\left[\frac{R T_1 Z_1 n}{n-1}\left[r_p^{\frac{n-1}{n}} - 1\right]\right]_{TEST} = \left[\frac{R T_1 Z_1 n}{n-1}\left[r_p^{\frac{n-1}{n}} - 1\right]\right]_{ACTUAL}$$

$$\frac{n-1}{n} = \frac{k-1}{k \cdot \eta_p}$$

THEN . . .

$$\boxed{r_{p_a} = \left[\frac{M_a}{M_T}\,\frac{T_T}{T_a}\,\frac{Z_a}{Z_T}\,\frac{\frac{n_T}{n_T-1}}{\frac{n_a}{n_a-1}}\left[r_{p_T}^{\frac{n_T-1}{n_T}} - 1\right] + 1\right]^{\frac{n_a}{n_a-1}}}$$

- THE POWER . . .

THE DIMENSIONLESS POWER $\hat{P} = \frac{\text{POWER}}{\rho_{01} N^3 D^5}$

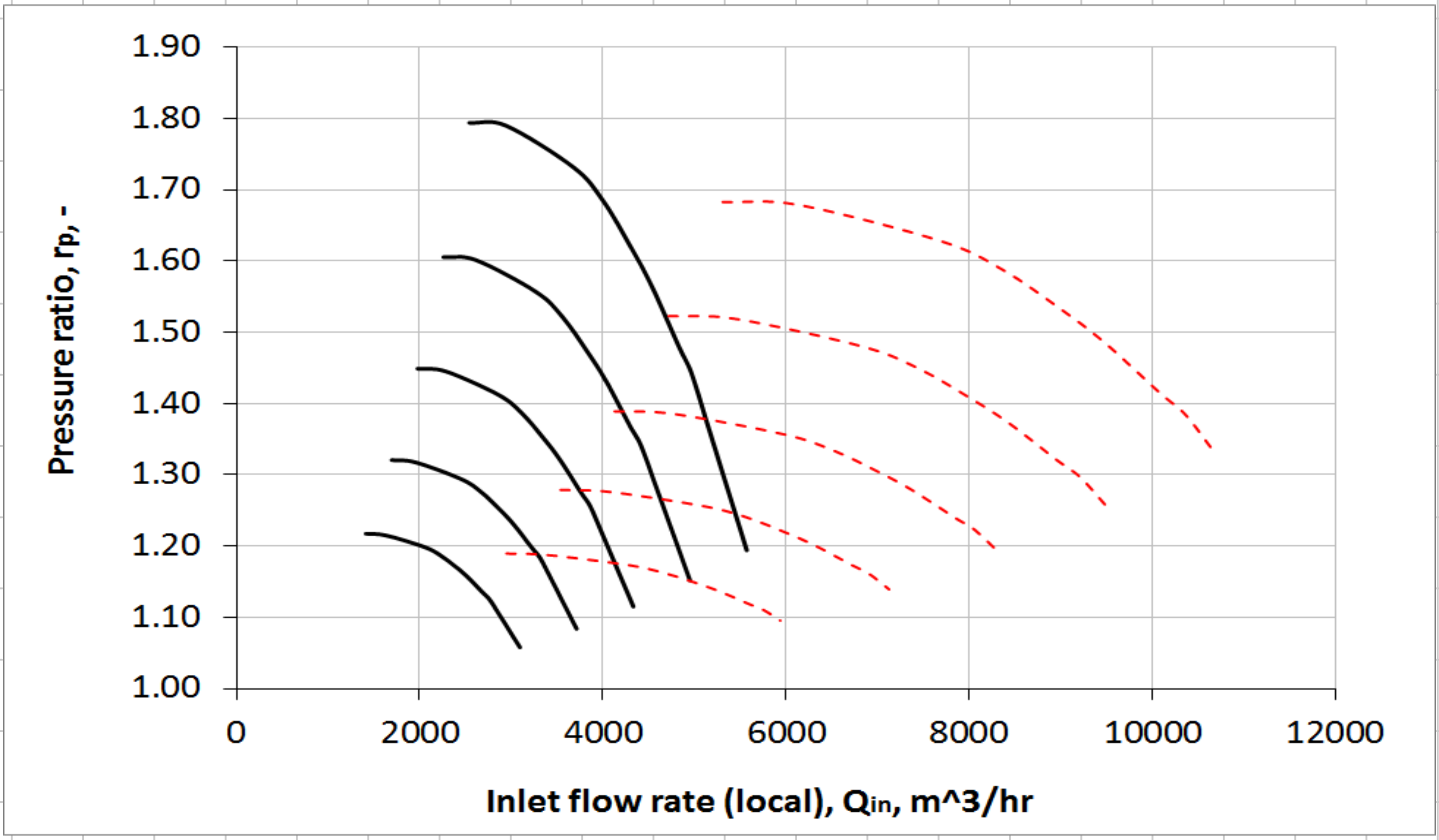
$$\left.\frac{\text{POWER}}{\rho_1 \cancel{N^3} \cancel{D^5}}\right|_{TEST} = \left.\frac{\text{POWER}}{\rho_1 \cancel{N^3} \cancel{D^5}}\right|_{ACTUAL}$$

$$\rho = \frac{P}{ZRT}$$

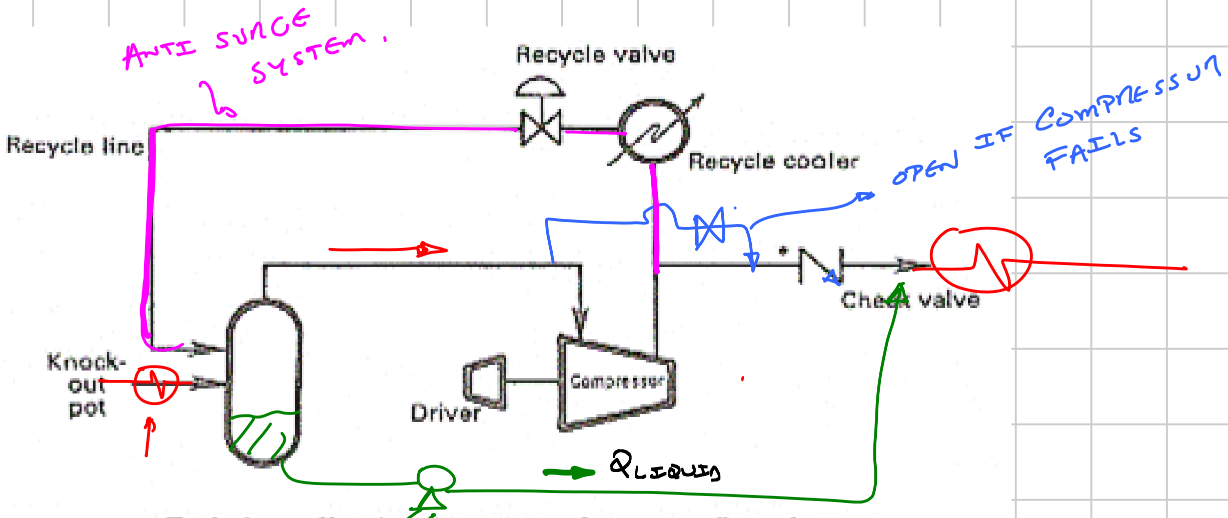
$$\text{POWER}_{ACTUAL} = \text{POWER}_{TEST} \frac{\rho_{ACTUAL}}{\rho_{TEST}} = \text{POWER}_{TEST} \times \frac{\frac{P_a}{R_a T_a}}{\frac{P_T}{R_T T_T}}$$

$$\boxed{\text{POWER}_{ACTUAL} = \text{POWER}_{TEST} \times \frac{P_A}{P_T} \times \frac{M_A}{M_T} \times \frac{T_T}{T_a}}$$

SHIFT OF CURVES



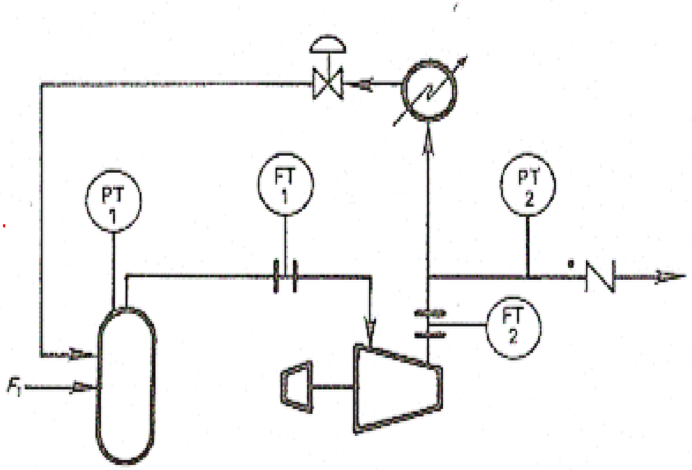
⇒ TYPICAL COMPRESSION STATION DIAGRAM



Typical centrifugal compressor equipment configuration.

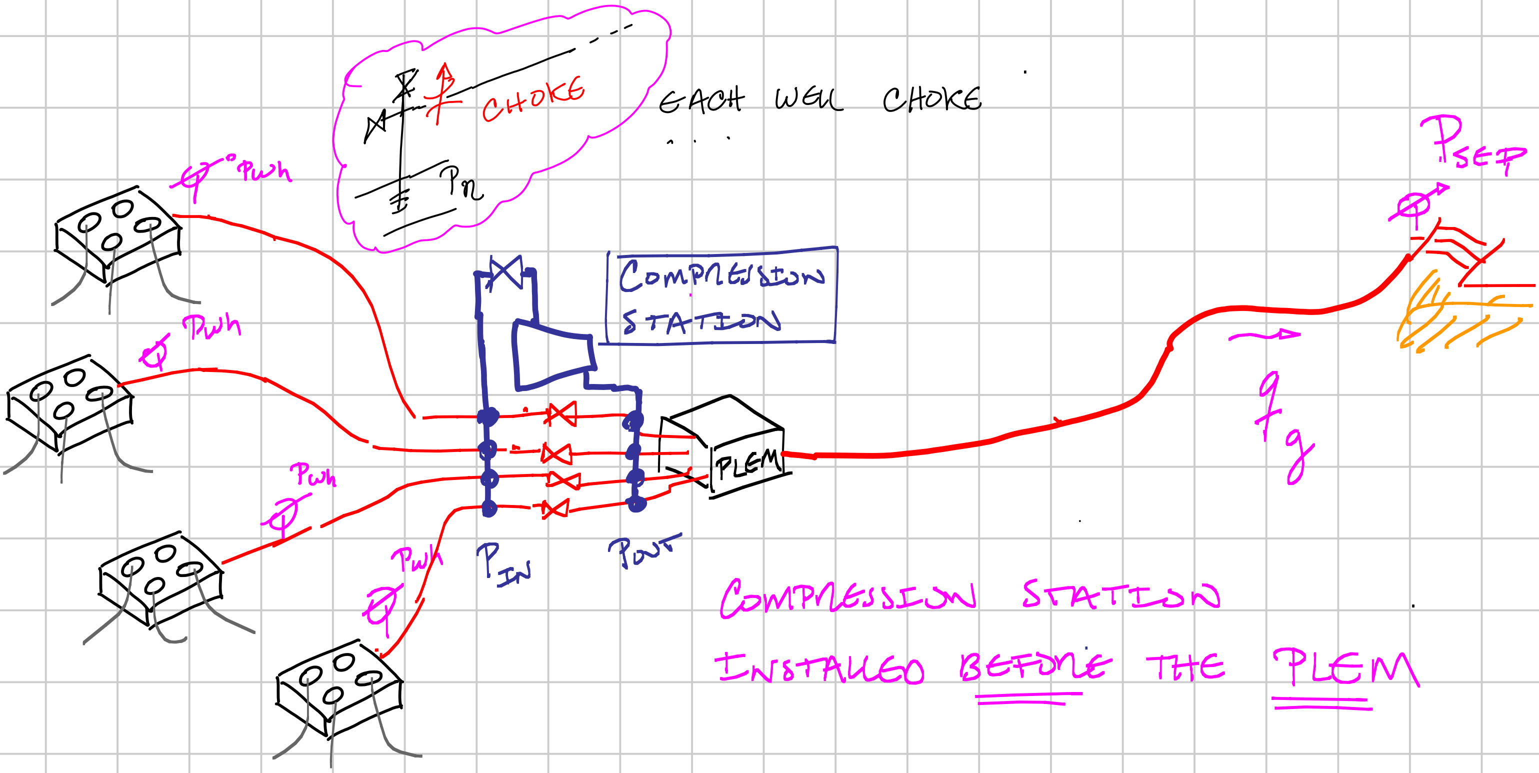
COMPRESSOR STATION FACILITIES:

- GAS SCRUBBER
  - ↳ LIQUIDS REMOVAL
- COMPRESSOR AND DRIVER UNIT
- PIPES, VALVES
- COOLERS
  - INLET/INTER-STAGE/OUTLET
- CONTROLS
  - VELOCITY
  - ANTISURGE
- INSTRUMENTATION AND MONITORING EQUIPMENT



Flow and pressure measurements commonly found on centrifugal compressors.

⇨ PRE-DESIGN OF COMPRESSION STATION FOR ATILA FIELD - DRY GAS



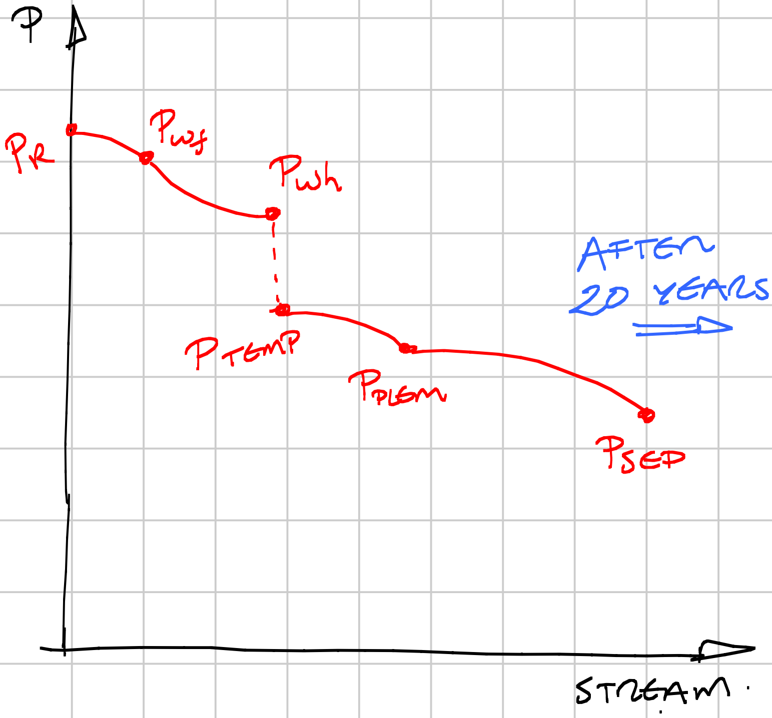
EACH WELL CHOKE ...

COMPRESSION STATION INSTALLED BEFORE THE PLEM

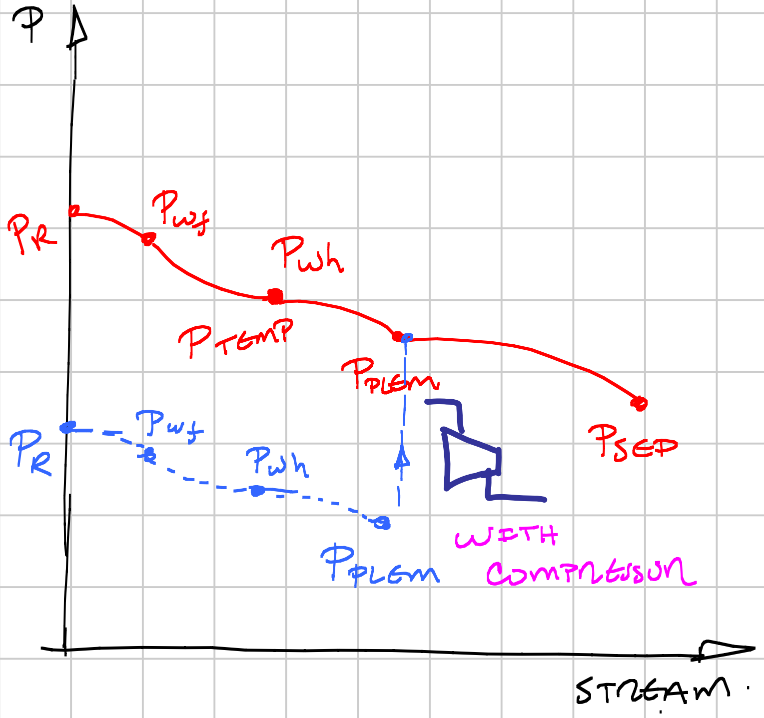
① RESERVOIR MATERIAL BALANCE

② CO-CURRENT FLOW CALCULATION FROM P_R TO P_{IN} (PLEM AVAILABLE)

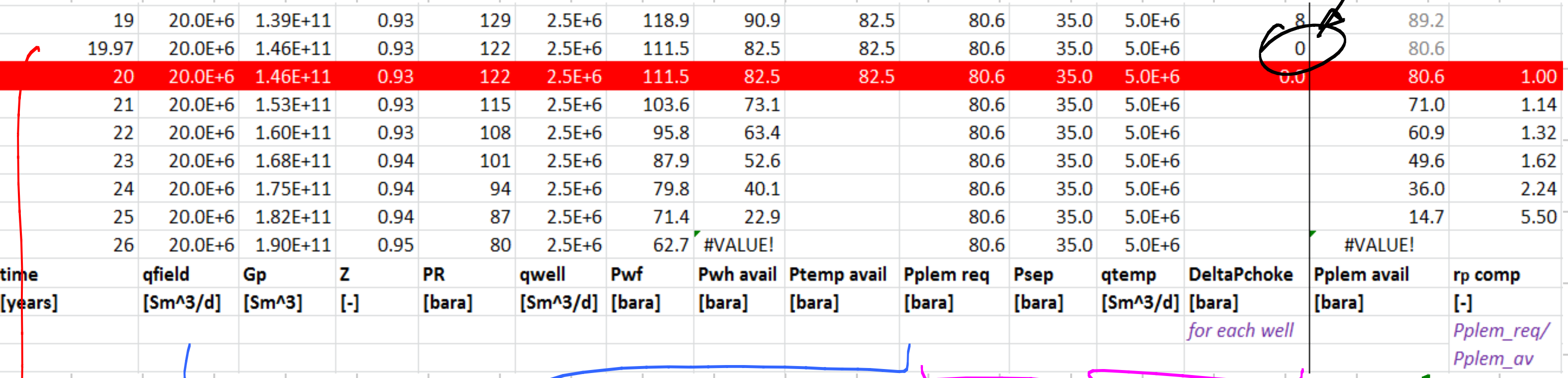
③ COUNTER-CURRENT FLOW CALCULATION FROM P_{SEP} TO P_{OUT} (PLEM REQUIRED)



AFTER 20 YEARS ⟹



CALCULATIONS DEPART FROM NATURAL FLOW PLATEAU END!



19	20.0E+6	1.39E+11	0.93	129	2.5E+6	118.9	90.9	82.5	80.6	35.0	5.0E+6	8	89.2	
19.97	20.0E+6	1.46E+11	0.93	122	2.5E+6	111.5	82.5	82.5	80.6	35.0	5.0E+6	0	80.6	
20	20.0E+6	1.46E+11	0.93	122	2.5E+6	111.5	82.5	82.5	80.6	35.0	5.0E+6	0.0	80.6	1.00
21	20.0E+6	1.53E+11	0.93	115	2.5E+6	103.6	73.1		80.6	35.0	5.0E+6		71.0	1.14
22	20.0E+6	1.60E+11	0.93	108	2.5E+6	95.8	63.4		80.6	35.0	5.0E+6		60.9	1.32
23	20.0E+6	1.68E+11	0.94	101	2.5E+6	87.9	52.6		80.6	35.0	5.0E+6		49.6	1.62
24	20.0E+6	1.75E+11	0.94	94	2.5E+6	79.8	40.1		80.6	35.0	5.0E+6		36.0	2.24
25	20.0E+6	1.82E+11	0.94	87	2.5E+6	71.4	22.9		80.6	35.0	5.0E+6		14.7	5.50
26	20.0E+6	1.90E+11	0.95	80	2.5E+6	62.7	#VALUE!		80.6	35.0	5.0E+6		#VALUE!	
time	qfield	Gp	Z	PR	qwell	Pwf	Pwh avail	Ptemp avail	Pplem req	Psep	qtemp	DeltaPchoke	Pplem avail	rp comp
[years]	[Sm^3/d]	[Sm^3]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bara]	[bara]	[-]
												for each well		Pplem_req/
														Pplem_av

CO-CURRENT FLOW CALCULATION

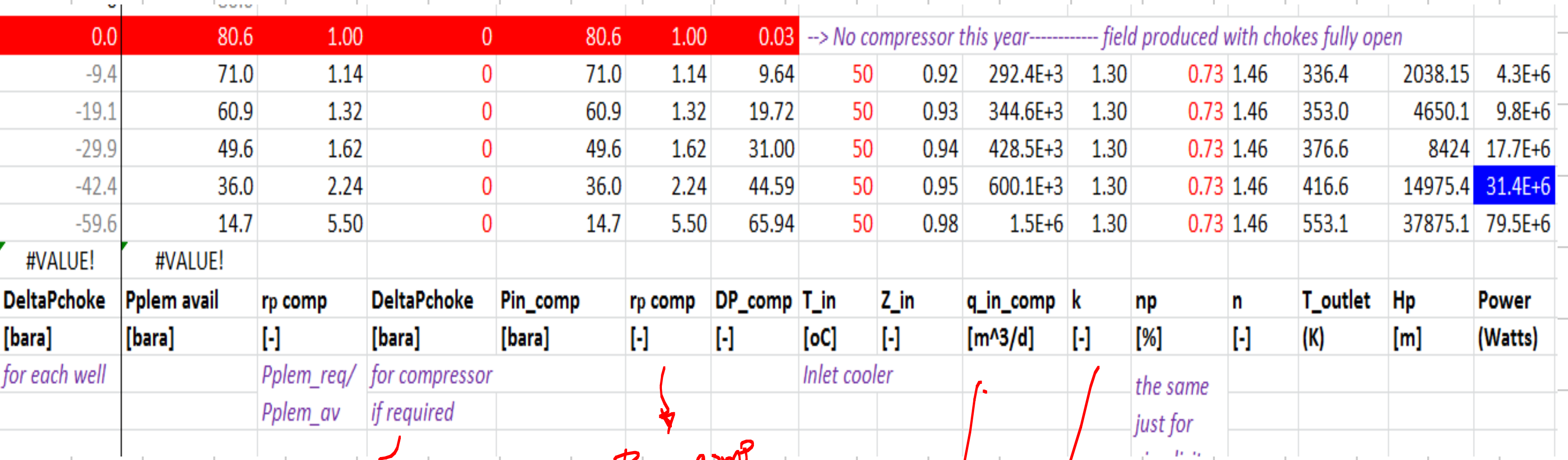
COUNTER-CURRENT FLOW CALCULATION

NEW EQUILIBRIUM IN PLEM

END OF YEAR 20

BEGINNING OF COMPRESSION

NEW COMPRESSOR CALCULATIONS



0.0	80.6	1.00	0	80.6	1.00	0.03	--> No compressor this year----------- field produced with chokes fully open								
-9.4	71.0	1.14	0	71.0	1.14	9.64	50	0.92	292.4E+3	1.30	0.73	1.46	336.4	2038.15	4.3E+6
-19.1	60.9	1.32	0	60.9	1.32	19.72	50	0.93	344.6E+3	1.30	0.73	1.46	353.0	4650.1	9.8E+6
-29.9	49.6	1.62	0	49.6	1.62	31.00	50	0.94	428.5E+3	1.30	0.73	1.46	376.6	8424	17.7E+6
-42.4	36.0	2.24	0	36.0	2.24	44.59	50	0.95	600.1E+3	1.30	0.73	1.46	416.6	14975.4	31.4E+6
-59.6	14.7	5.50	0	14.7	5.50	65.94	50	0.98	1.5E+6	1.30	0.73	1.46	553.1	37875.1	79.5E+6
#VALUE!	#VALUE!														
DeltaPchoke	Pplem avail	rp comp	DeltaPchoke	Pin_comp	rp comp	DP_comp	T_in	Z_in	q_in_comp	k	np	n	T_outlet	Hp	Power
[bara]	[bara]	[-]	[bara]	[bara]	[-]	[-]	[oC]	[-]	[m^3/d]	[-]	[%]	[-]	(K)	[m]	(Watts)
for each well		Pplem_req/	for compressor				Inlet cooler				the same				
		Pplem_av	if required								just for				

IF REQUIRED TO SECURE COMPRESSOR RANGE

$$\frac{P_{IN-COMP}}{P_{PLEM-AVAIL}}$$

$$k = 1.3 - 0.31(\gamma_g - 0.55)$$

$$\underset{(ACTUAL)}{q_{IN}} = q_g \frac{P_{SC}}{T_{SC}} \cdot \frac{T_{IN} Z_{IN}}{P_{IN}}$$

$$\rightarrow POWER = \frac{\rho_{IN} q_{IN} H_p g}{\eta_p}$$

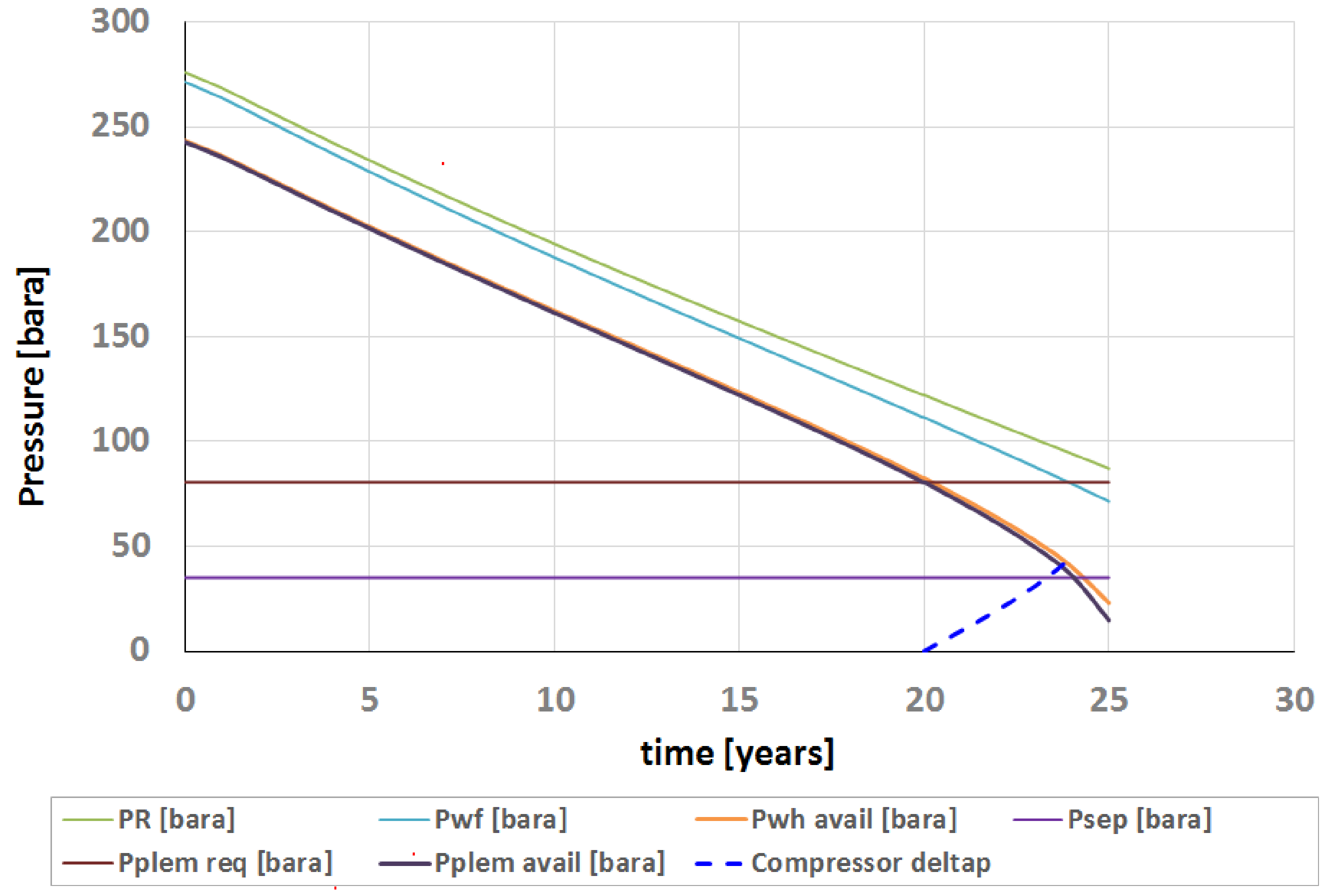
$$\rightarrow n = \frac{k \cdot \eta_p}{k \cdot \eta_p - k + 1}$$

$$\rightarrow H_p = \frac{n}{n-1} R T_1 \left[r_p^{\frac{n-1}{n}} - 1 \right]$$

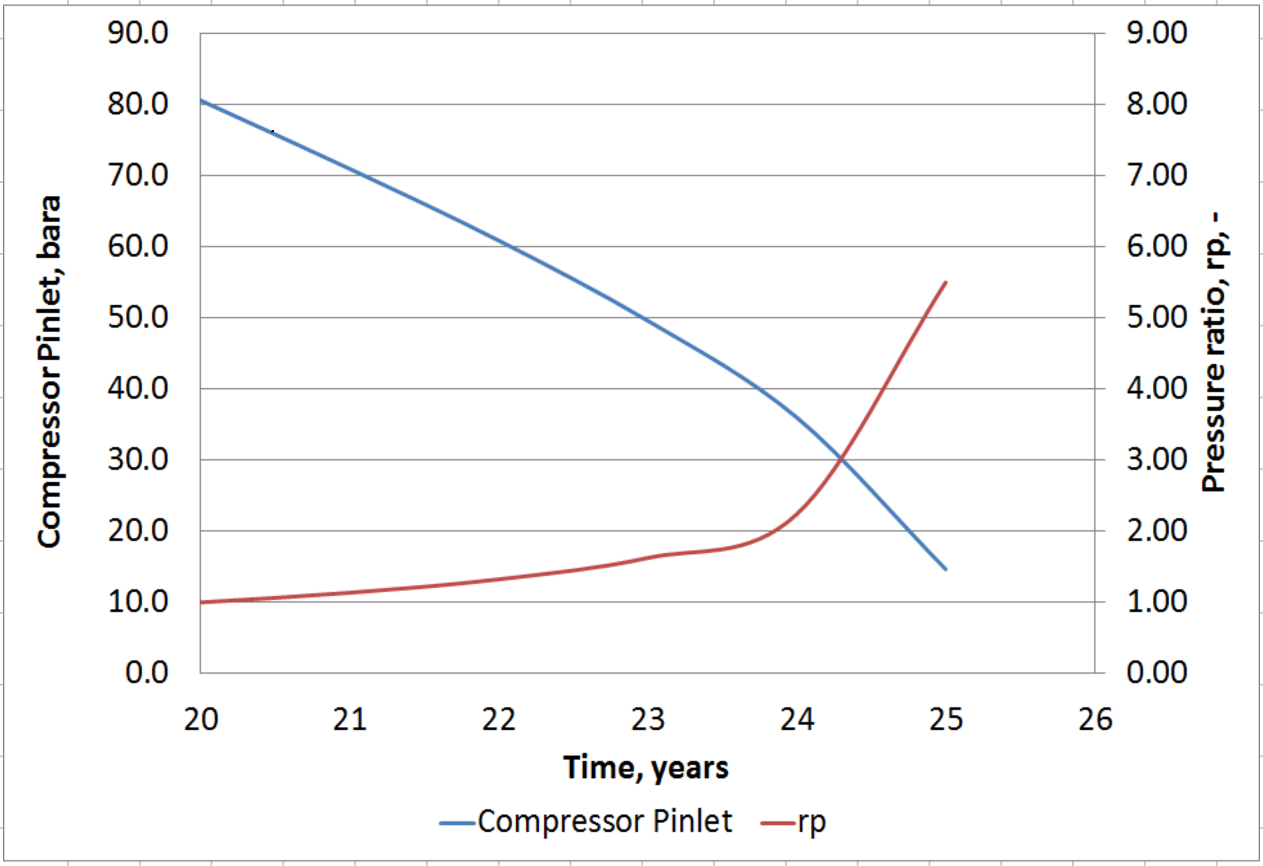
$$\frac{n-1}{n} = \frac{k-1}{k} \frac{1}{\eta_p}$$

$$R = \frac{8314}{M_g} \left[J/kg\text{-}K \right]$$

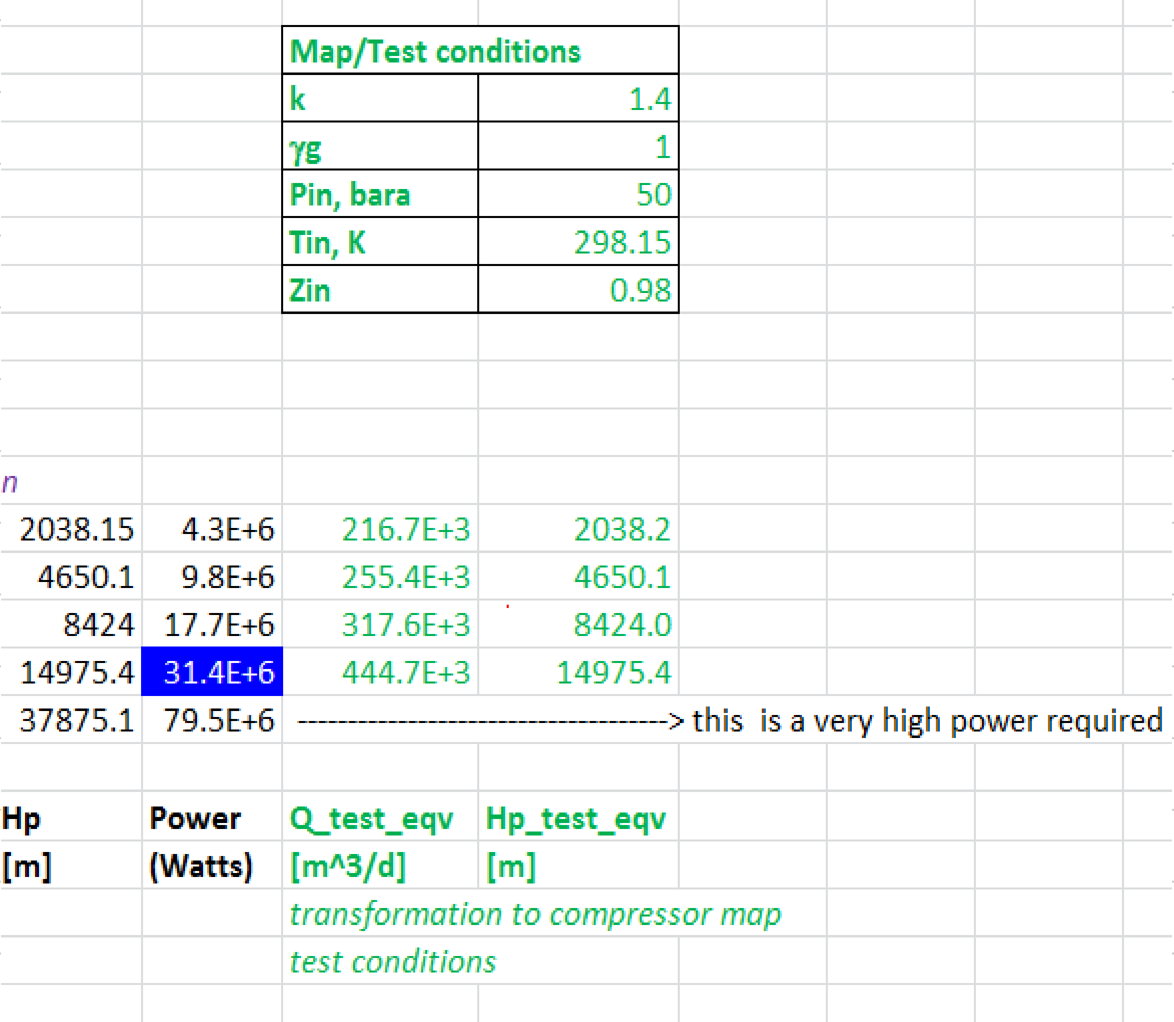
$$\rightarrow \frac{T_{OUT}}{T_{IN}} = \left(\frac{P_{OUT}}{P_{IN}} \right)^{\frac{n-1}{n}}$$



300
250
200
150
100
50
0
Pressure [bara]
0
5
10
15
20
25
30
time [years]
PR [bara]
Pwf [bara]
Pwh avail [bara]
Psep [bara]
Pplem req [bara]
Pplem avail [bara]
Compressor deltap



90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Compressor Pinlet, bara
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Pressure ratio, rp, -
20
21
22
23
24
25
26
Time, years
Compressor Pinlet
rp



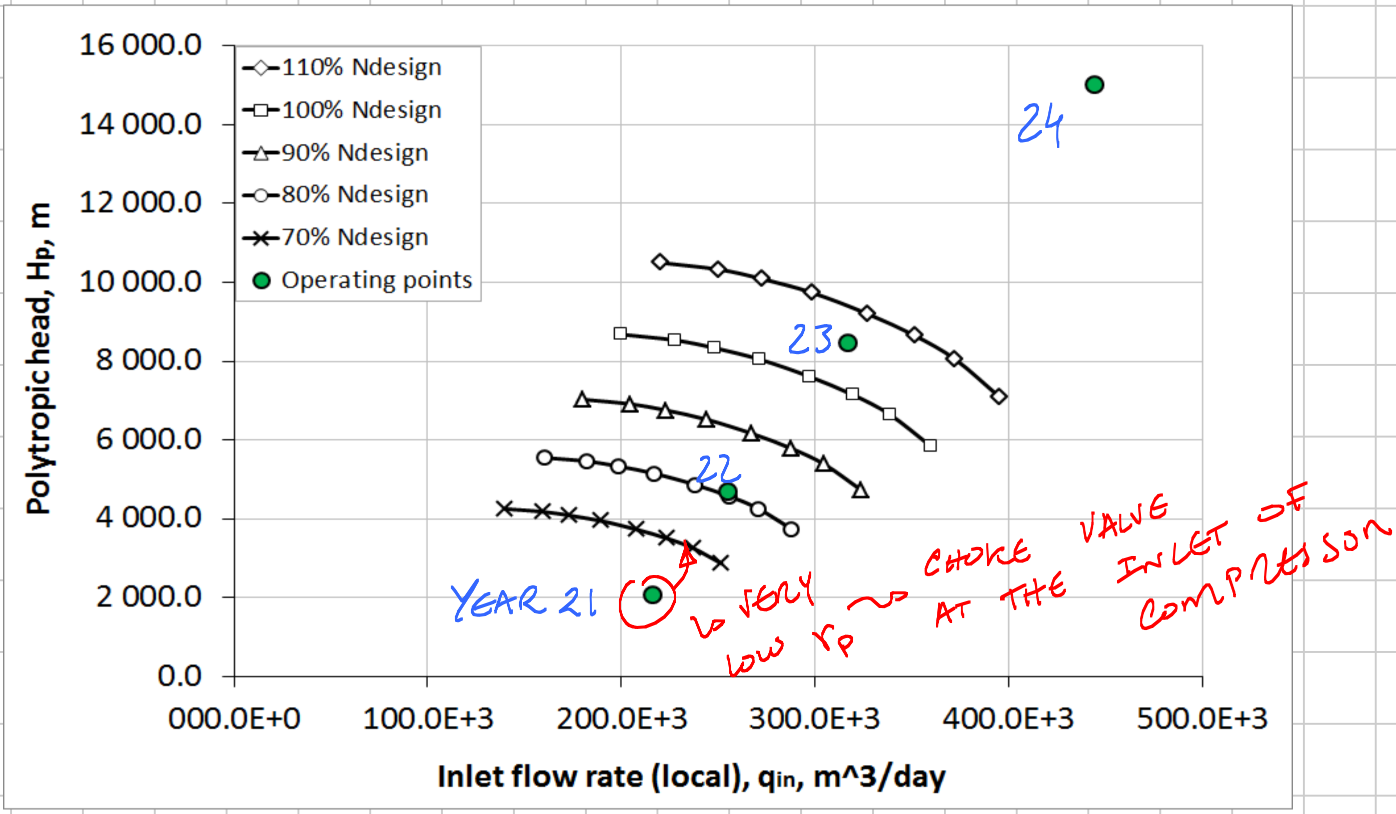
Map/Test conditions	
k	1.4
γg	1
Pin, bara	50
Tin, K	298.15
Zin	0.98

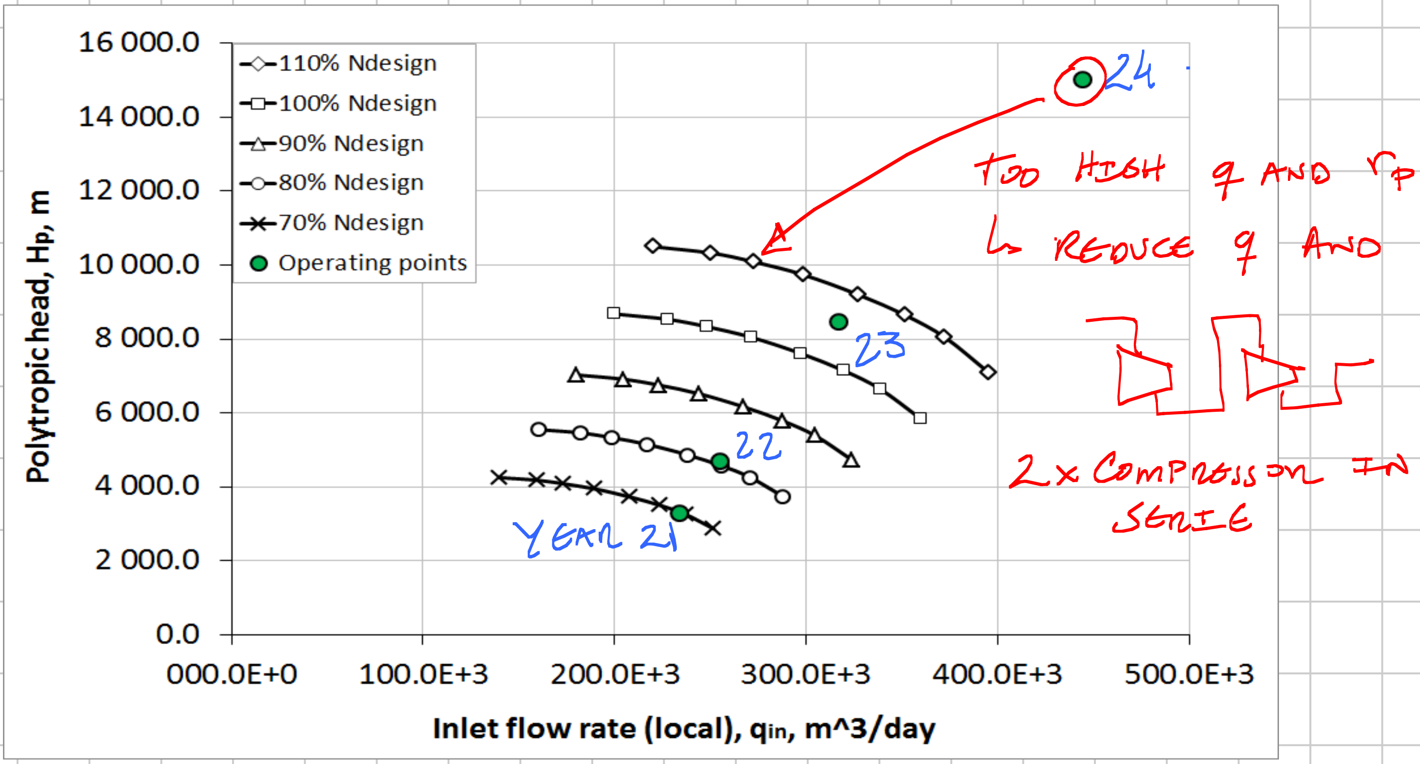
n

2038.15	4.3E+6	216.7E+3	2038.2
4650.1	9.8E+6	255.4E+3	4650.1
8424	17.7E+6	317.6E+3	8424.0
14975.4	31.4E+6	444.7E+3	14975.4
37875.1	79.5E+6	------------------------------------> this is a very high power required	
Hp	**Power**	**Q_test_eqv**	**Hp_test_eqv**
[m]	**(Watts)**	**[m^3/d]**	**[m]**

transformation to compressor map
test conditions

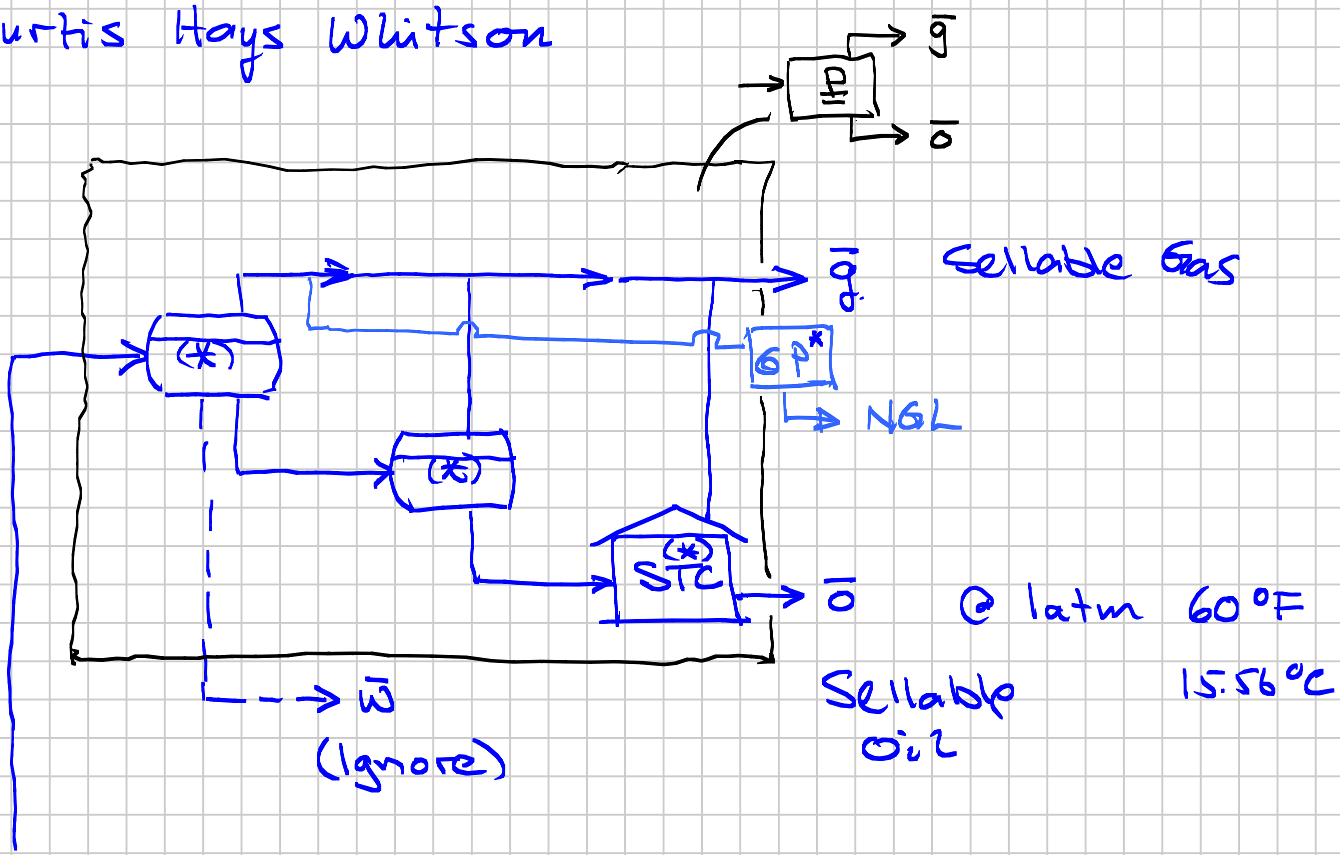
OPERATING POINTS ON THE TEST COMPRESSOR MAP





SURFACE PROCESS CALCULATIONS

Curtis Hays Whitson



FEED SOURCES:

Well	z_{wi}	$\dot{n}_w$
Group	z_{Gi}	$\dot{n}_G$
Field	z_{Fi}	$\dot{n}_F$

z_i: Mole Fraction

(1) Molar Component Rates
z_i & n

⇒(2) Volumetric Rates
q_g q_o q_w

- Field Well Tests (Periodic)
  q_{gsp1} q_{osp} ($\rightarrow q_{\bar{o}}$)

⇓

SOURCE CONVERSION

Black Oil
($q_{\bar{g}}$ $q_{\bar{o}}$)
to
Compositional

(1) WTC

(2) BOZ

⋮

- Allocated rates (Daily)
  - well Tests + Metering
- Reservoir Simulation
  - using same $\underline{P}$ $(q_{\bar{g}}\ q_{\bar{o}})$

* Unit Flash Calculation

p-T Flash

- $z_i \rightarrow$ Entering the Unit
- p, T specified
- $\underbrace{K_i(p, T, z_i)} \equiv \frac{y_i}{x_i}$
  - Correlations (modified Wilson)
  - Trial-and-Error w/ EOS
- Thermodynamic Consistency

$$\left.\begin{aligned} \mu_{vi} &= \mu_{Li} \\ \mu_{gi} &= \mu_{oi} \end{aligned}\right\}$$

EOS: Equal Chemical Energy

EQUATION OF STATE (EOS) – Gases & oils

(1) Name : SRK (Soave Redlich Kwong)
PR (Peng Robinson)

(2) Table 1 – Component Properties

$$\underline{\text{Name}}\ \{p_c\quad T_c\quad \omega\}\ \overbrace{M\quad \underbrace{s\ (c)}_{\text{Volume Shift}}}$$

Name	p_c	T_c	ω	M	s (c)
N_2					
CO_2					
H_2S					

Volume Shift

Rackett

(instead of COSTALD)

C_1
⋮

(3) Table 2 – Binary Interaction Parameters (BIPs) k_{ij} ~ −0.1-ish to +0.2-ish

N_2 CO_2 H_2S C_1 . . .

N_2

CO_2 $k_{ii} = 0$ Diagonal

H_2S $k_{ij} = k_{ji}$ Symetric

C_1

⋮

CO_2–HC
N_2–HC
H_2S–HC
} Defaults: ~ 0.05–0.15 – Bit different SRK & PR

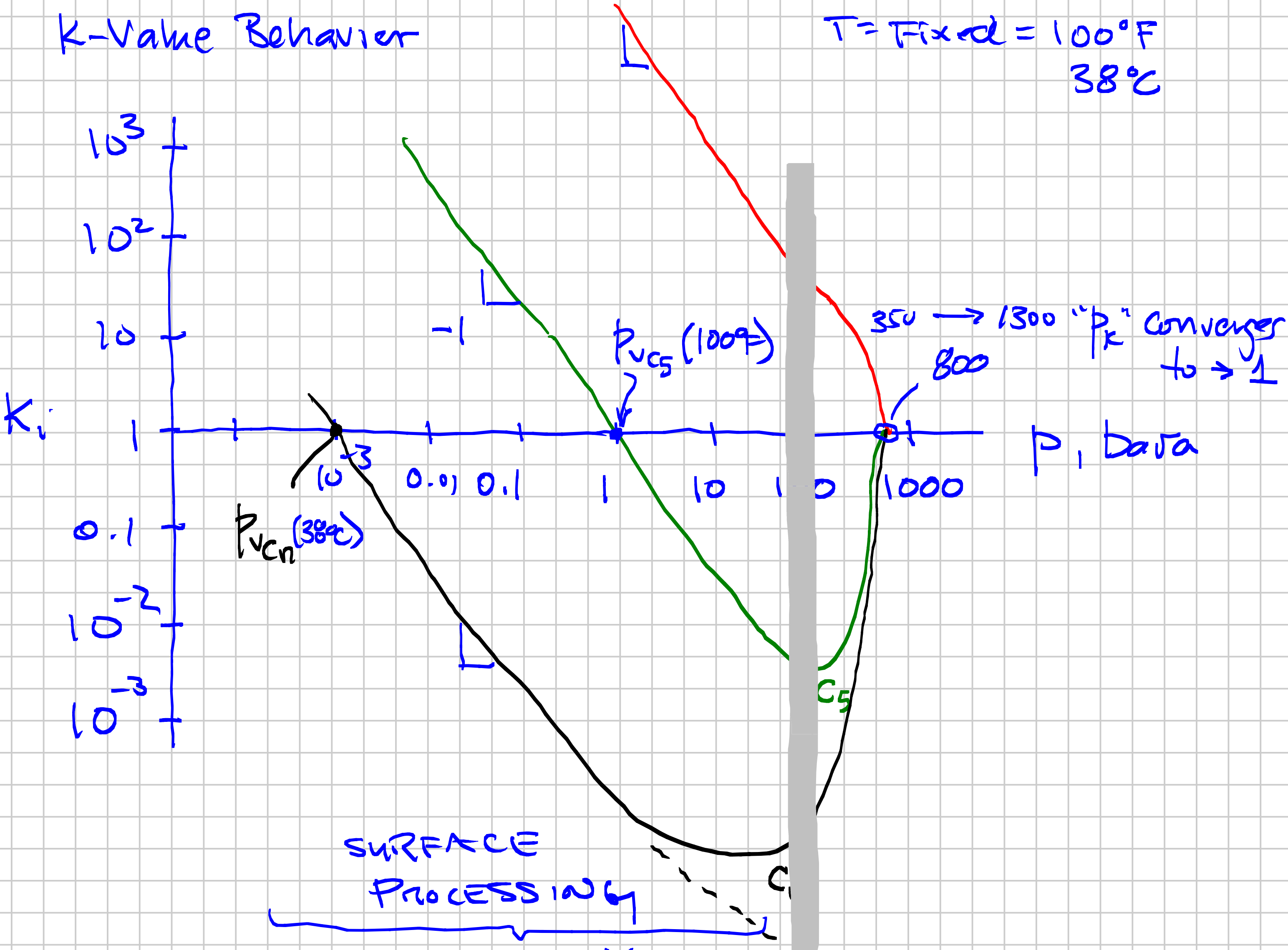
SRK HC–HC ~ 0 default

PR HC–HC ~ 0 default EXCEPT $k_{C_1-C_{7+}}$ ~ 0.02–0.1 (≳ 50–100 bara)

k_{ij} PRIMARILY Affect K_i & K_j at higher pressures & Near Critical Points

K-Value Behavior

T = Fixed = 100°F
38°C



$$K_i \cong \frac{p_{vi}(T)}{p}$$

~ Wilson Eq.

→| |← 50-100 bar ⟶

$K_i \sim f(p,T)$

NOT $\underline{z_i}$

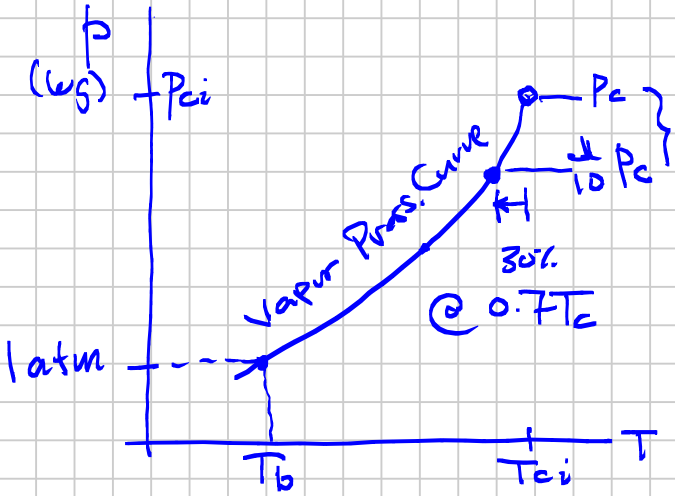
$K_i(p,T,\underline{z_i})$

$K_i^{EOS}(p,T,z_i\,;\,\underline{\underline{BIPs}})$

EOS (Table 1): Tc_i Pc_i ω_i

Component $\underline{\underline{i}}$

Normal Pressure ⇒



Pitzer : $\omega \equiv -1 - \log_{10} \underbrace{\frac{p_v(0.7T_c)}{p_c}}_{0.1}$

He $\quad -1 - (-1)$

$C_1 \quad = 0$

$C_{40} \quad \frac{p_v(0.7T_c)}{p_c} \sim \frac{1}{100} \Rightarrow \omega \sim 1$

ω_i (with T_{c_i} P_{c_i}) $\Rightarrow$ guarantees EOS (PR or SRK)

gives ACCURATE $p_{v_i}(T)$

$\Rightarrow$ ACCURATE $K_i(T, p \lesssim \overset{\text{so}-}{100}$ bara)

M $\quad$ SRK $\quad$ Given x_i

EOS: $p = \underbrace{\frac{RT}{v-b}} - \underbrace{\frac{a_i \cdot \alpha_{SRK}(T,\omega)}{v(v+b)}}$ $\Big\}$ $\omega_i \; \underbrace{a_i \; b_i \; p, T}$ $\Downarrow$ $\boxed{v}$

$v \equiv \frac{V}{n}$

$\rho = \frac{\overset{\downarrow}{M}}{\underbrace{v}} = \frac{m}{\overset{V/n}{V}}$

$a = \Omega_a \frac{R^2 T_c^2}{p_c}$ $\quad \Omega_a = \sim 0.4$

$b = \Omega_b \frac{R T_c}{p_c}$ $\quad \Omega_b = \sim 0.1$

$$\alpha_i = [1 + m_i(1 - \sqrt{T_r})]^2$$

$$m_i = \overbrace{\overbrace{m_0 + m_1\omega_i}^{\text{Soave}} + m_2\omega_i^2}^{\text{3 constants}}$$

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

Mixture x_i e.g.

$$\bar{a} = \sum_i \sum_j x_i x_j (a_i a_j)^{0.5} \cdot (1 - k_{ij})$$

$$\bar{b} = \sum_{i=1}^{N} x_i b_i$$

Liquid mixtures: $v_L^{EOS2(SRK|PR)}$ ~ $\underline{\text{10−35\% high wrong!}}$

1981: Peneloux, et al.

$$v = \underbrace{v^{EOS2}} - c$$

$$c = s \cdot b$$

↑ dimensionless "shift" factor (−0.2 → +0.3)

$$\bar{c} = \sum x_i c_i$$

ρ_L ~1−3%

(ρ_V ✓ 1−3%)

HYSYS: Allowed s_i to be input (~2005)
(Beware!)

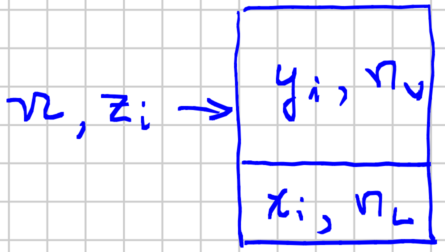
$$v = v^{EOS2} + c$$

Input "−s"

ECL300
EAP } EOS w/ S_i

Given $x_i \Rightarrow \mu_{Li}$
$\neq$
$y_i \Rightarrow \mu_{vi}$ } wrong K_i

P-T FLASH CALCULATION
(In Each Separator Unit) } Rachford-Rice
Muskat-McDowell



(P,T) = Fixed

$$n = n_v + n_L$$

$$n_i = n_{vi} + n_{Li}$$

$$n z_i = n_v y_i + n_L x_i$$

Define $\beta \equiv n_v / n \quad (= F_v)$ Ch. 3&4

$$\boxed{z_i = \beta y_i + (1-\beta) x_i} \Leftarrow$$

$$z_i \equiv \frac{n_i}{n}$$

$$y_i \equiv \frac{n_{vi}}{n_v}$$

$$x_i \equiv \frac{n_{Li}}{n_L}$$

$$\Sigma z_i = 1$$

$$\left.\begin{aligned} \Sigma y_i &= 1 \\ \Sigma x_i &= 1 \end{aligned}\right\} (\Sigma y_i - \Sigma x_i) = 0$$

Given: z_i, Guess set of $K_i(P,T; z_i)$

Solve: β, y_i & x_i

$$K_i = \frac{y_i}{x_i}$$

$$\Rightarrow \boxed{z_i = \beta y_i + (1-\beta) x_i} \Leftarrow$$

$$\sum y_i - x_i = 0$$

$$z_i = \beta \underset{\downarrow}{y_i} + x_i - \beta x_i$$

$$z_i = \beta K_i x_i + x_i - \beta x_i$$

$$= x_i \left(\beta K_i - \beta + 1 \right)$$

$$= x_i \left[\beta (K_i - 1) + 1 \right]$$

$$y_i = K_i x_i$$

$$\boxed{x_i = \frac{z_i}{\beta (K_i - 1) + 1}}$$

$$\uparrow$$

$$?$$

$$0 = \sum y_i - x_i$$

$$\sum (K_i - 1) x_i = 0$$

$$\left[\sum \frac{z_i (K_i - 1)}{\beta (K_i - 1) + 1} = 0 \right] = h(\beta)$$

One unknown β

One Eq. (RR)

Muskat-McDowell

$$c_i = \frac{1}{K_i - 1} \quad ; \quad c_i = 0 \quad \text{for} \quad K_i = 1$$

$$h(\beta) = \sum_i \frac{z_i}{\beta + c_i} = 0$$

Once β solved:

$$x_i = \frac{z_i}{\beta (K_i - 1) + 1}$$

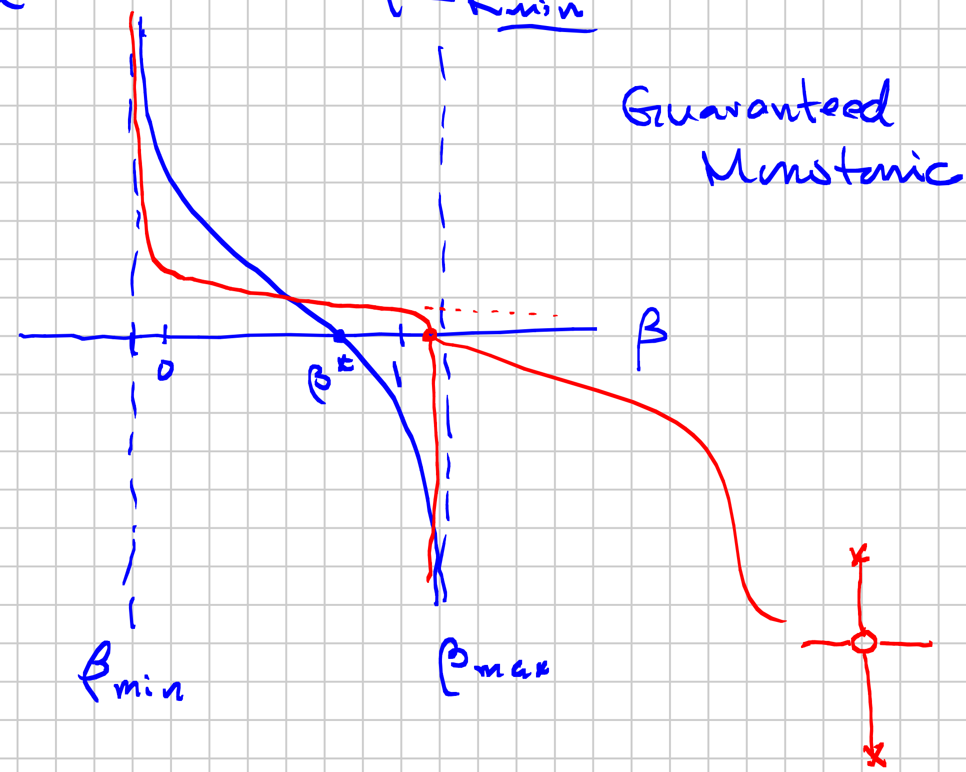
$$y_i = K_i x_i$$

* Multiple β solutions satisfying the Eq.

* Only one solution β^* where

$$\left.\begin{array}{l} \text{ALL } y_i > 0 \\ x_i > 0 \end{array}\right\} \text{needed to be physical}$$

$$\underbrace{\overset{\checkmark}{\beta_{min}}}_{=\frac{1}{1-\underline{K_{max}}}} < \beta^* < \underbrace{\overset{\checkmark}{\beta_{max}}}_{=\frac{1}{1-\underline{K_{min}}}}$$



Guaranteed Monotonic

$$\left.\begin{array}{ll} (g) & \beta^* < 0 \\ (o) & \beta^* > 1 \end{array}\right\} z_i \text{ is a single phase}$$

$z_i = x_i$

$\beta^* = 0$ ε : z_i is a oil at its bubblepoint

$\beta^* = 1$ z_i is a gas at it dewpoint

$z_i = y_i$

Got y_i => EOS $\left[\begin{matrix}\mu_{vi} \\ \overset{?}{=} \\ \mu_{Li}\end{matrix}\right]$

x_i => EOS

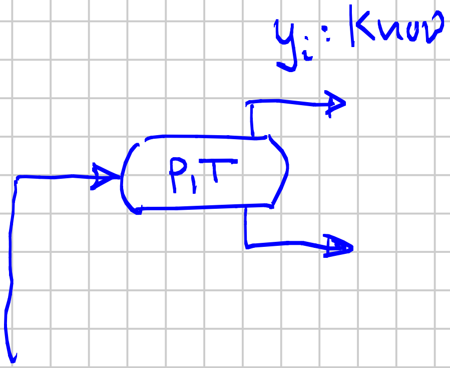
Fugacity f_i

$\mu_i \equiv RT \cdot \ln f_i + \overset{\lambda_i(T)}{\text{const}}$

- Not equal, guess new set $K_i^{new} = K_i^{old} \cdot \underbrace{\left(\frac{f_{Li,old}}{f_{vi}}\right)}_{\text{Ch. 4}}$

- Equal, you've done with this unit calculation

App. B Phase Behavior monograph Example



Know : y_i, K_i

Want : z_i, x_i, β

comments on exercise 1.

Ex-1 → Production schedulling

Related concepts

1. production plateau

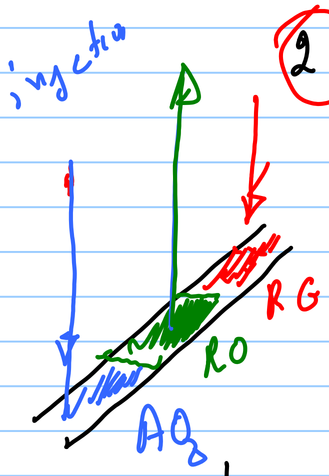
$1\ Sm^3 \approx 35\ scf$

2. Length of the plateau

$20\ \frac{Sm^3}{D} \approx 700 \times 10^6\ scf/D$

important issue:

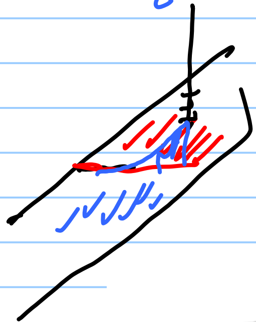
prolonging plateau:



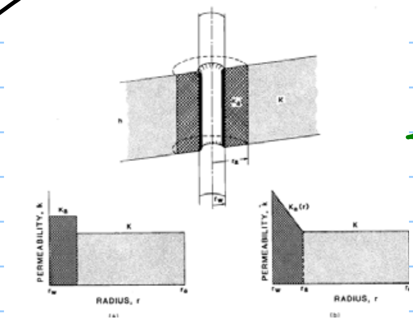
- Pressure maintenance in oil field
  - inject water
  - inject gas
- productive/Efficient well completion

Horizontal completion

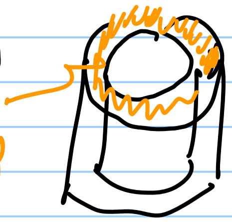
Lager tubing



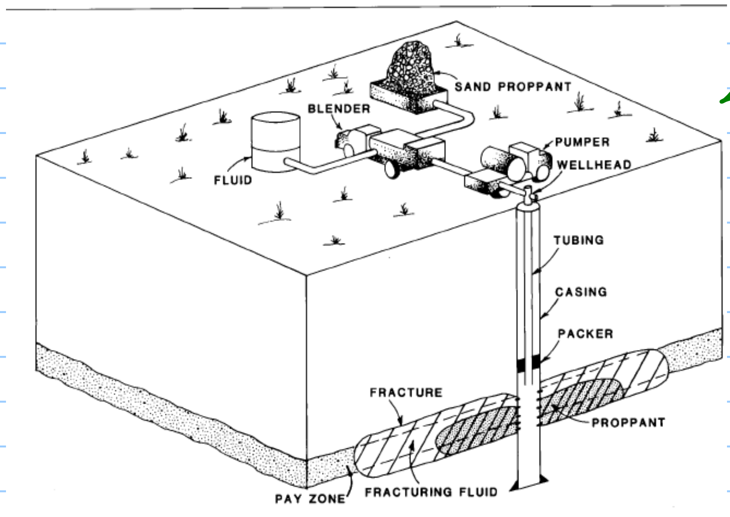
- stimulation
  - acidizing
  - fracturing



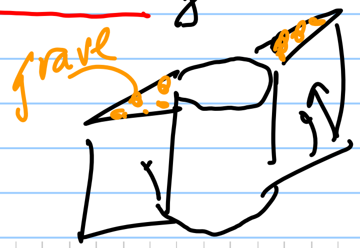
acidizing

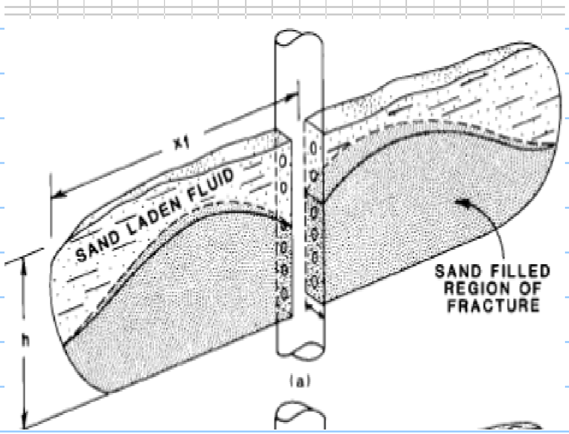


acid affected region



fracturing





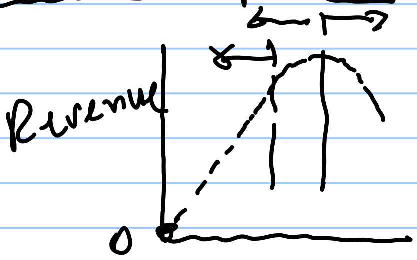
increasing number of wells

1 well → 100 Sm³/D

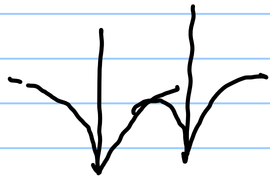
2 wells → 50 Sm³/D

wells in parallel

$Q_T = Q_1 + Q_2$



$\Delta P_T = \underline{\Delta P_1} = \Delta P_2$



Sources in parallel (wells)

$Q_{Total} = Q_1 + Q_2 = \sum Q_i$

$\Delta P_{Total} = P_1 = P_2 = \cdots P_i$

more wells with less rate per well provide higher available pressure at the wellhead (Less pressure loss the reservoir and in the tubing per well)

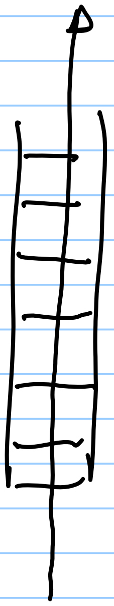
Sources in series

ESP

stages in series

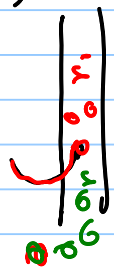
$Q_T = Q_1 = Q_2 = \cdots Q_i$

$\Delta P_T = \sum \Delta P_i$



⑤ Boosting the flow - Boosters

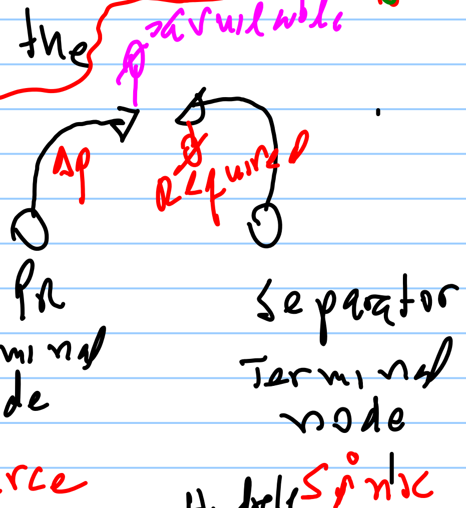
- wellhead compessors (for gas)
- for oil - Downhole pump
  - gas lift

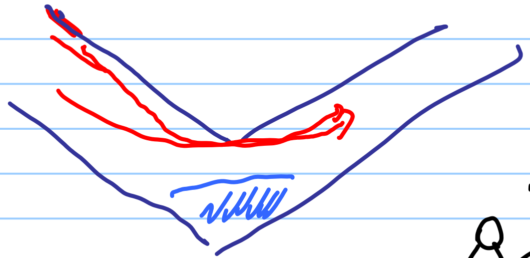


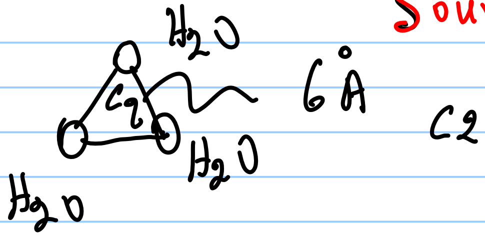
important

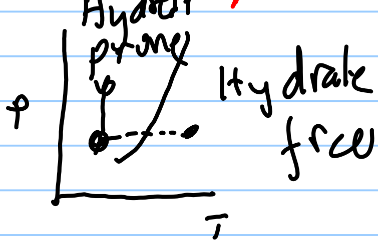
! !

All the 5 measures above increase the available pressure in the equilibrium analysis









Another measure to increase the plateau length: Reducing required pressure

① Reduce separator pressure

② increasing size of the flowline

pipeline Equation

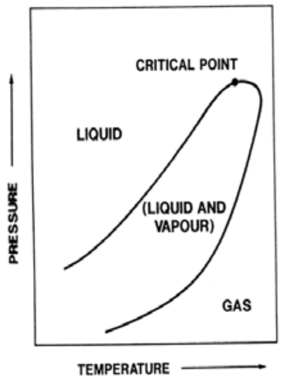
$$q_g = \underset{\sim}{C_{fl}}\left(p_{in}^2 - p_{out}^2\right)^{0.5}$$

in Exercise 1

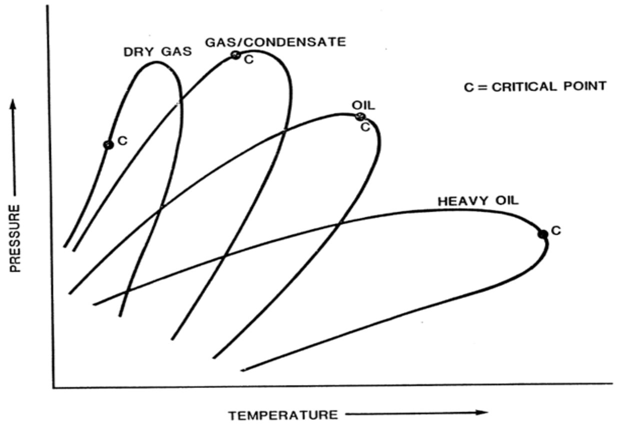
- stimulation changes C in $q_g = \underset{\sim}{C}\left(p_R^2 - p_{wf}^2\right)^n$
- increasing tubing size changes C_T in $q_g = \underset{\sim}{C_T}\left(\frac{p_{in}^2}{e^s} - p_{out}^2\right)^{0.5}$

comments on phase envelope

Phase diagram of reservoir oil (Mulitі-component system)



Phase diagram of variety of reservoir fluids systems



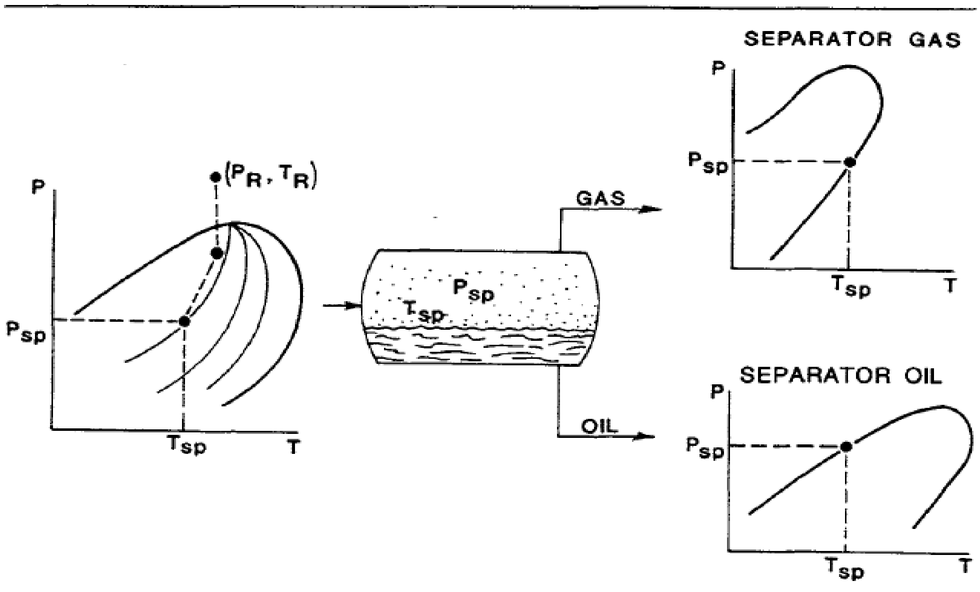
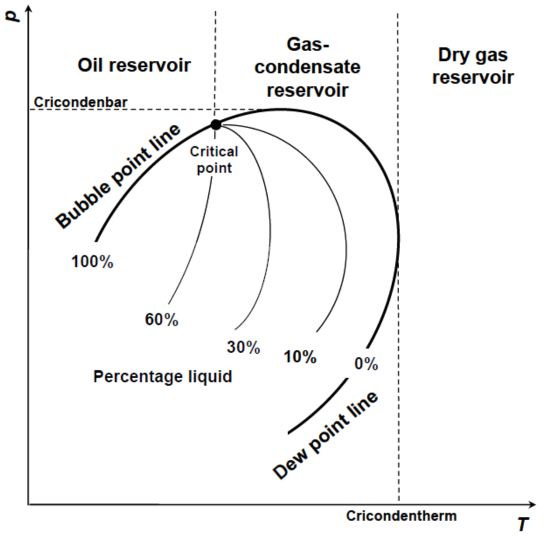
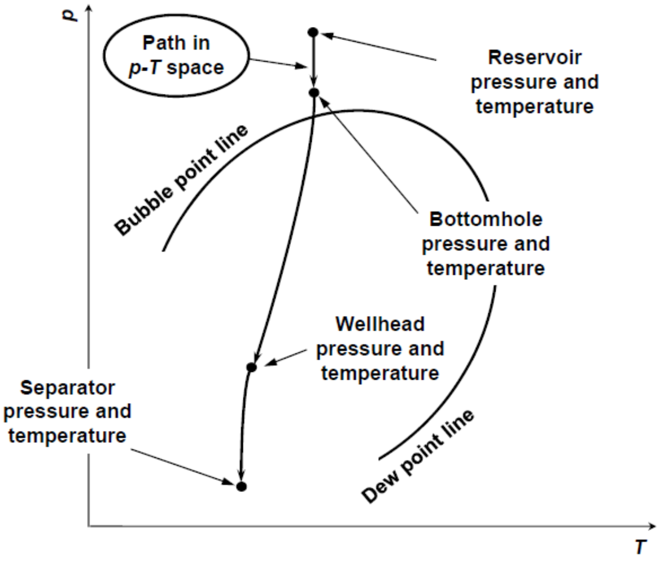


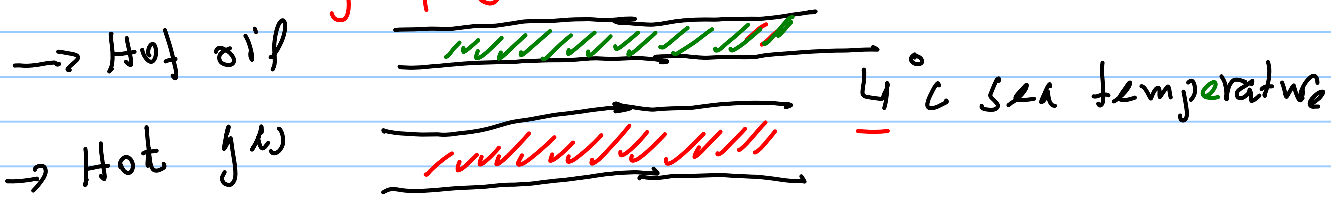
Figure 1.8 Pressure–temperature phase diagram used to describe surface separation.

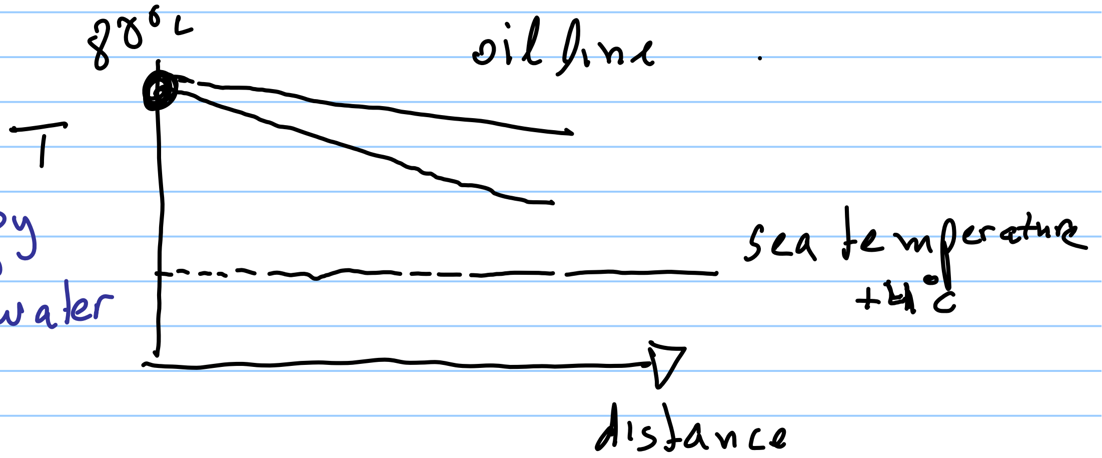
(Well Performance: Golan Whitson



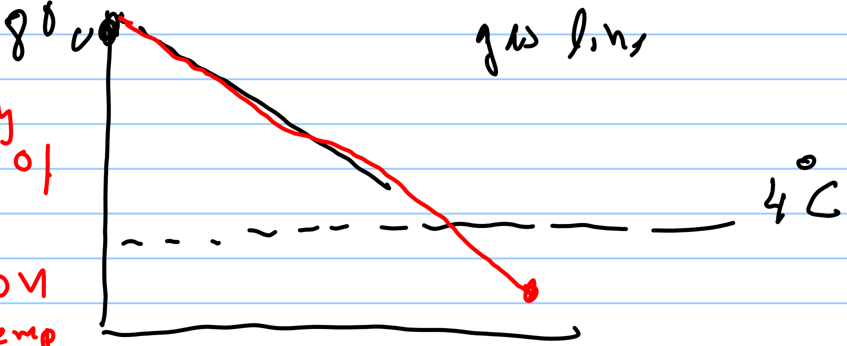


The difference between cooling of oil lines and cooling of gas lines in cold sea water



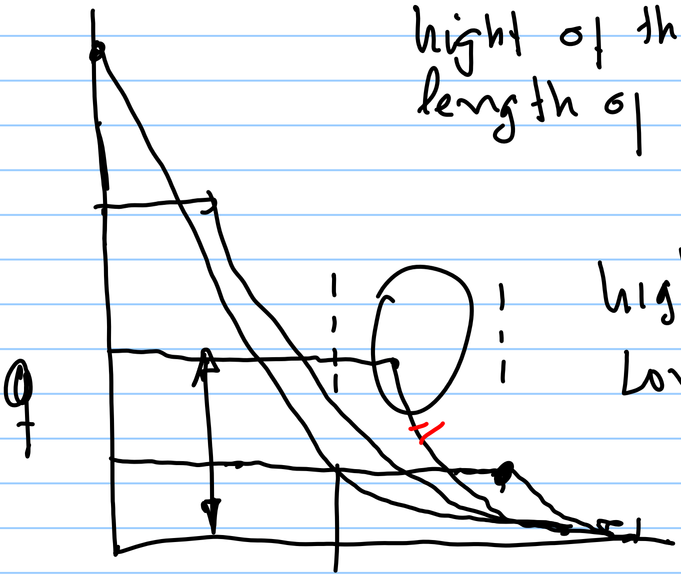


Oil lines cool by heat losses to the cold sea water



gas lines cool by a combination of heat losses and by gas expansion (can cool to a temp below sea temp.)

Additional issue: The relationship between the hight of the plateau and the length of the plateau



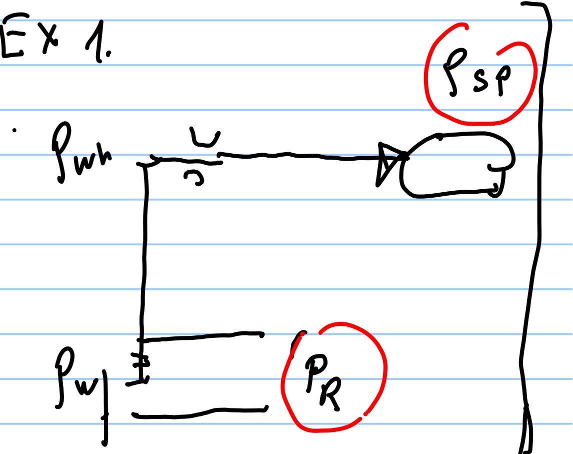
higher plateau yields Longer plateau

→ Gp = cummulative production gas S_m^3

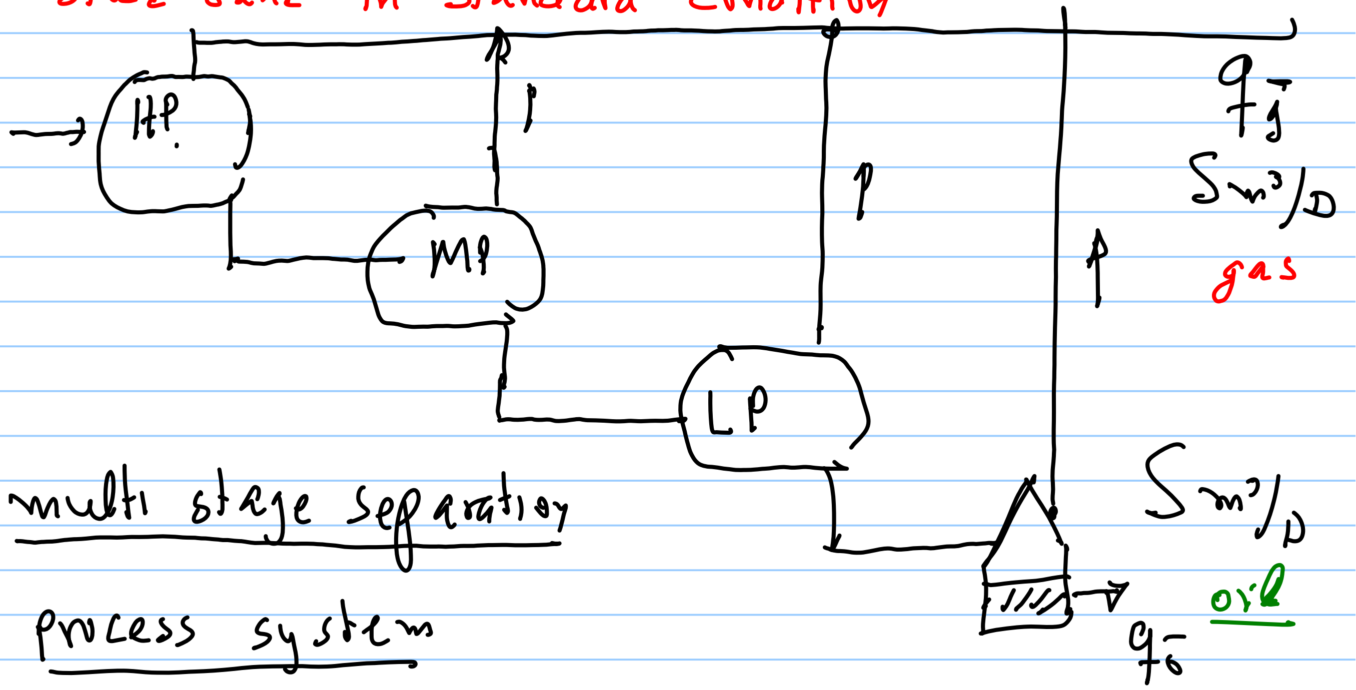
Np = cummulative production oil

The production system in Ex 1.

The production system in Exercise 1 starts from a soure, p_R, and terminales at a sink, p_{sp}. It address pressure vesus rate conditions in the reservor, wells, gathering system, and production line, and ends at the inlet separator



The system addressed by Arnard in his Hysys example addresses flow conditions and phase equilibrium in the prosses: from the inlet separator (High pressure) to stock tank in standard condition

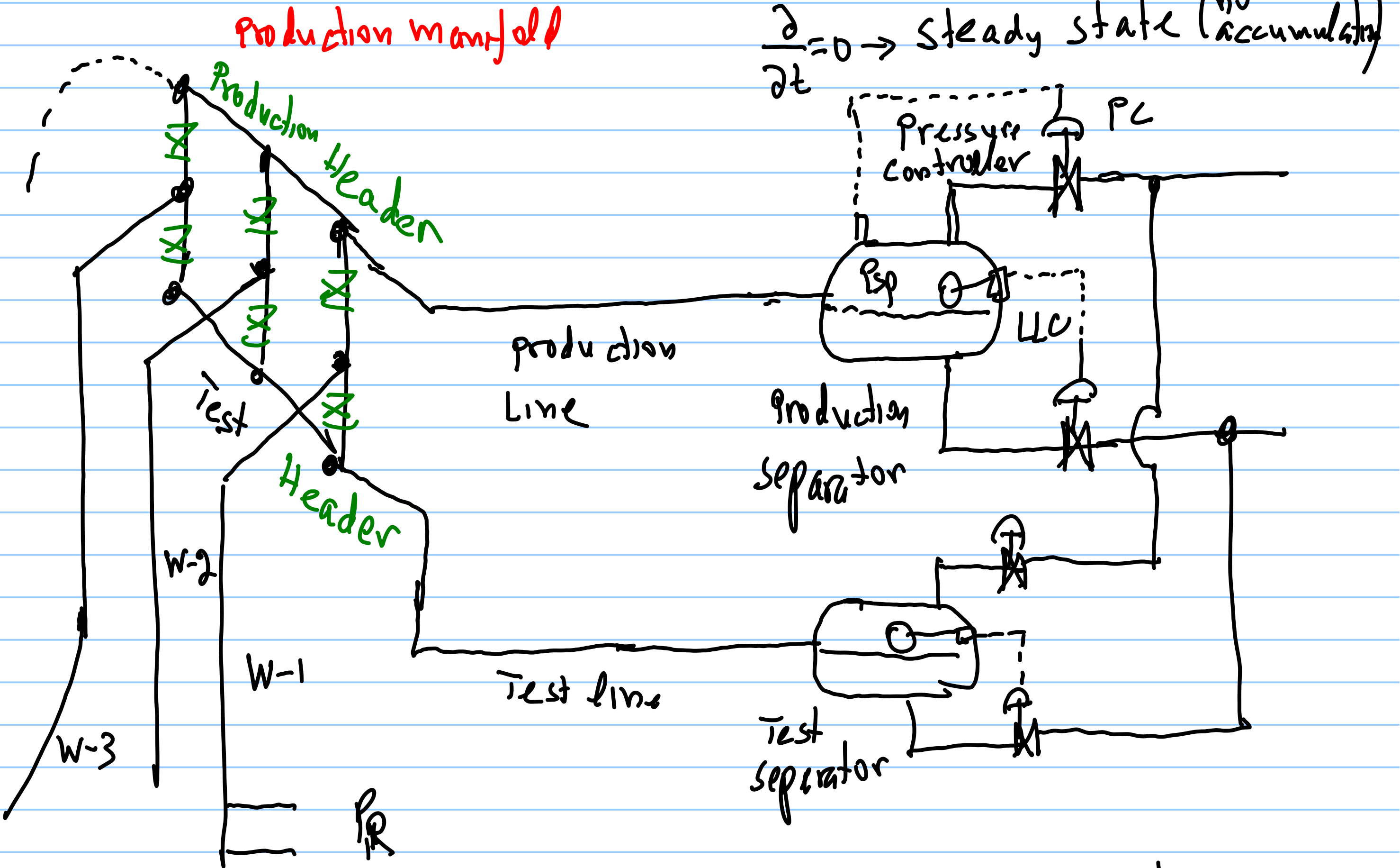


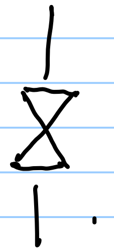
in summary: we have seen that the field production system consists of two main parts: ① production (where we normally use production simulator

② process (where we normally use process simulator yesterday main focus → how to prolong the plateau?

simple production system - 3 wells cluster, no-water

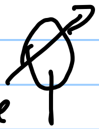
$\frac{\partial}{\partial t}=0$ → steady state (no accumulation)




valve
on-off

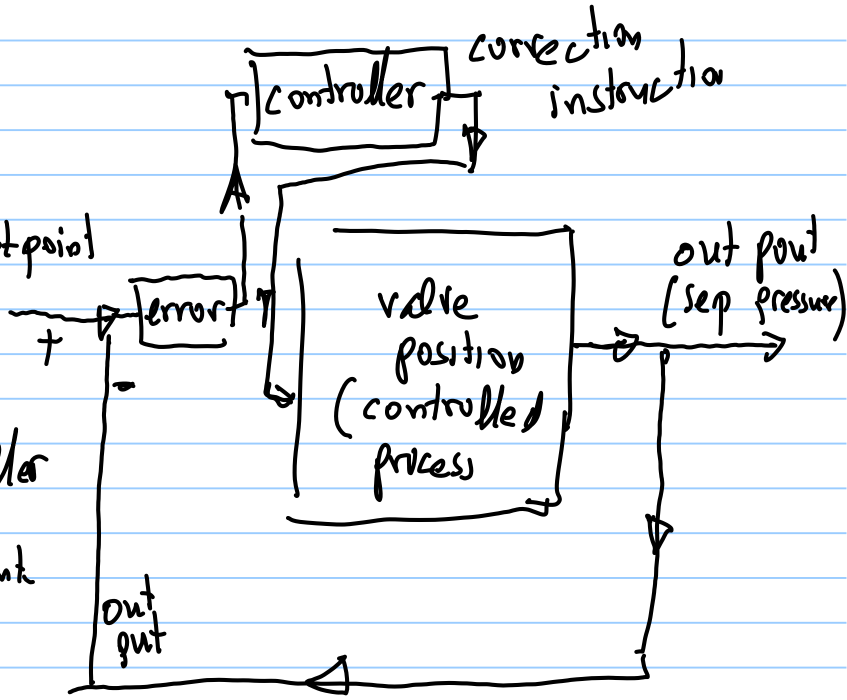

automatic
control
valve

PC - pressure controller
LLC - Liquid level cont

Pressure gauge

PG

Pressure transducer PT

------- Logi

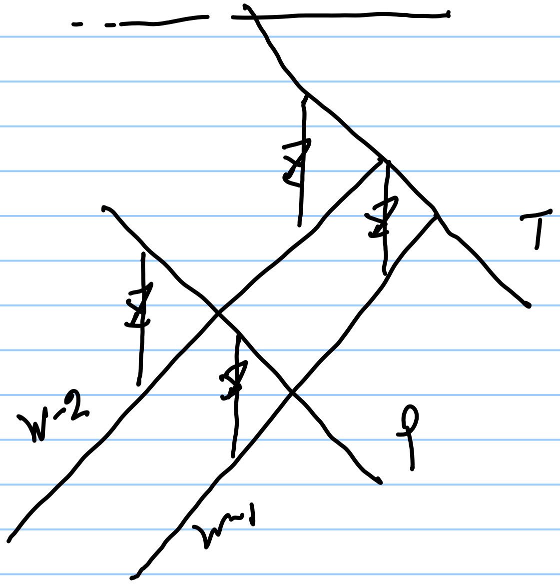


Feedback Loop

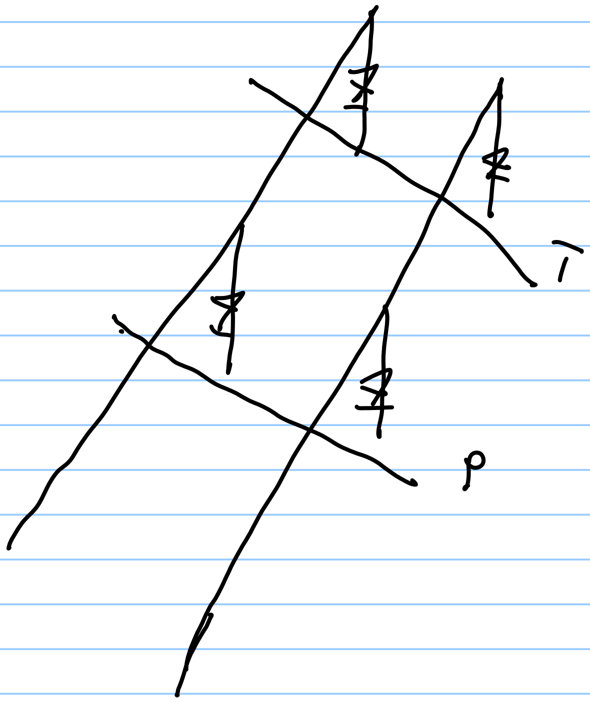
Wintershall's oil manifold, oil field As Sarah, Libya.

manifold valves → select if well will produce to the production header or test header

Header above wells



Header below wells



Function of manifold

1. commingle the production of all the wells
2. Isolate individual well and divert it to test separator (for the purpose of production testing

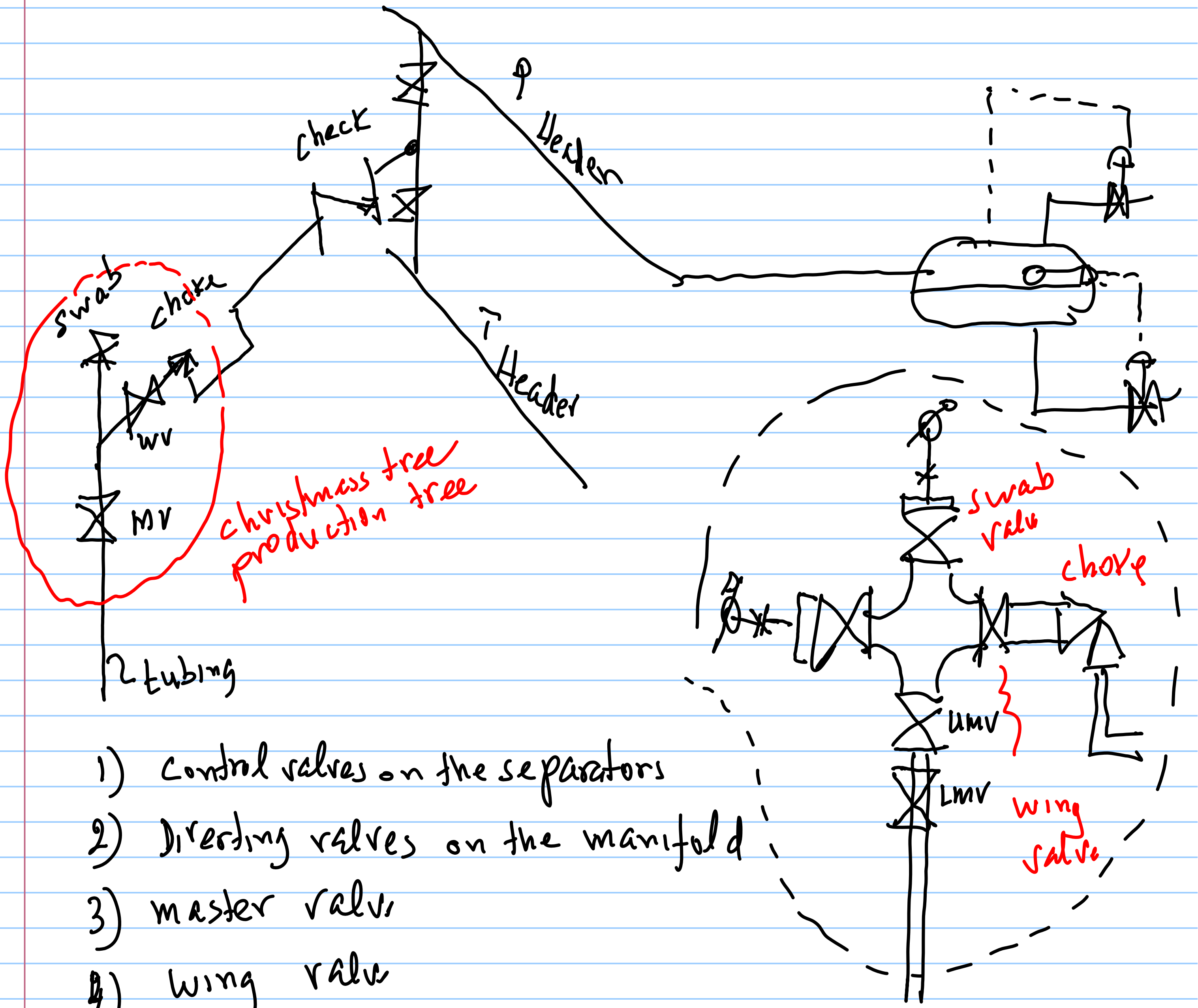
p_{sp}, q_o q_g q_w q_o, $GOR = \frac{q_g}{q_o}$ $f_w = \frac{q_w}{q_o + q_w}$

$$\left.\begin{array}{ll} GOR=\dfrac{q_{\bar g}}{q_{\bar o}} & \begin{matrix}\gamma_g\\ \gamma_o\end{matrix}\end{array}\right\}$$

gives in most cases good information on the phase behaviour. (Black oil approach)

$$\gamma_o=\left.\frac{\rho_o}{\rho_w}\right|_{sc} \qquad \gamma_g=\left.\frac{\rho_g}{\rho_{air}}\right|_{sc}\approx\frac{M_g}{M_{air}}=\frac{M_g}{28.97}$$

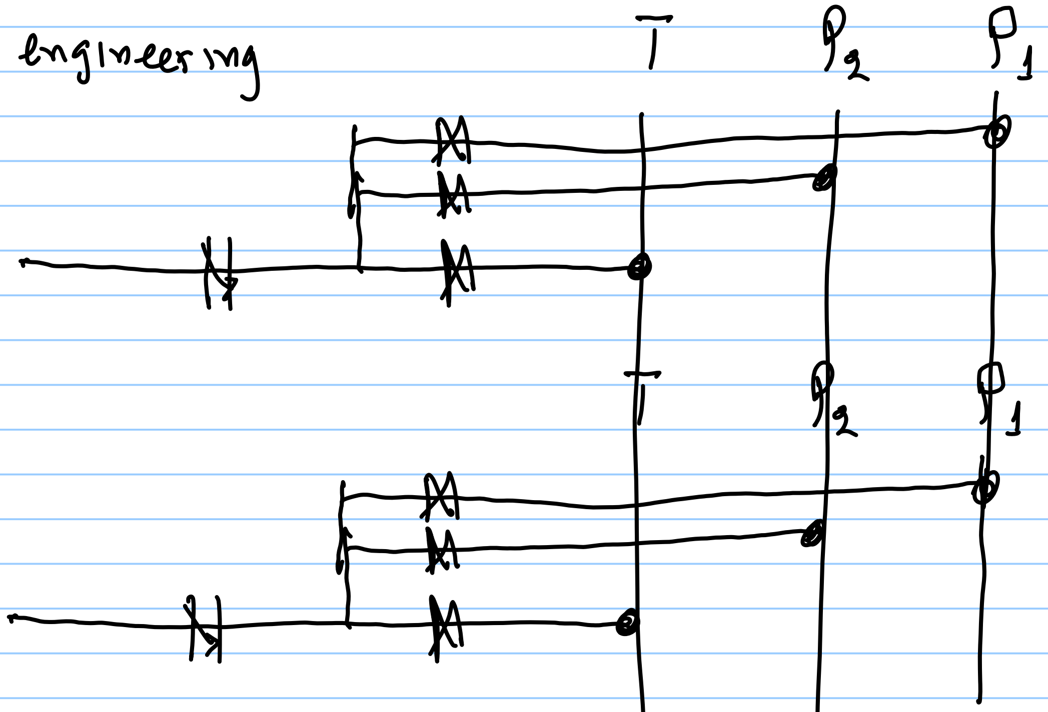
3. Divert each well to each separation train

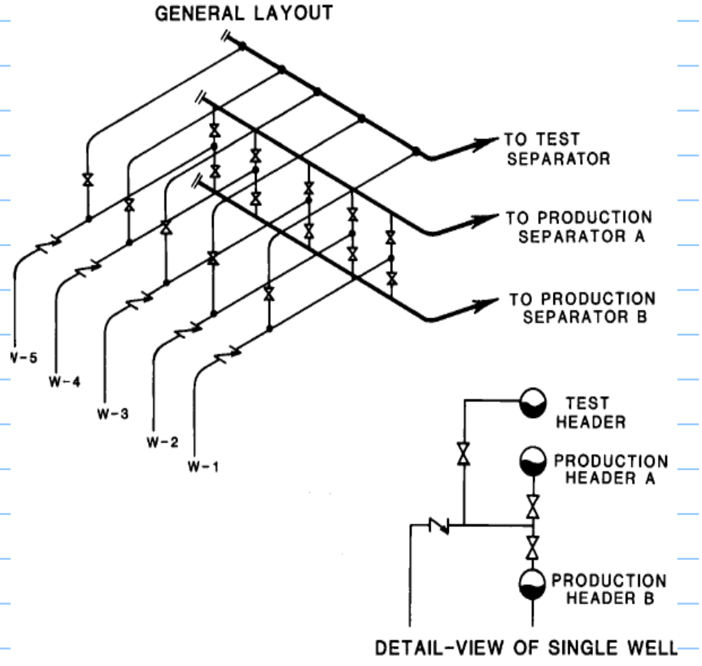


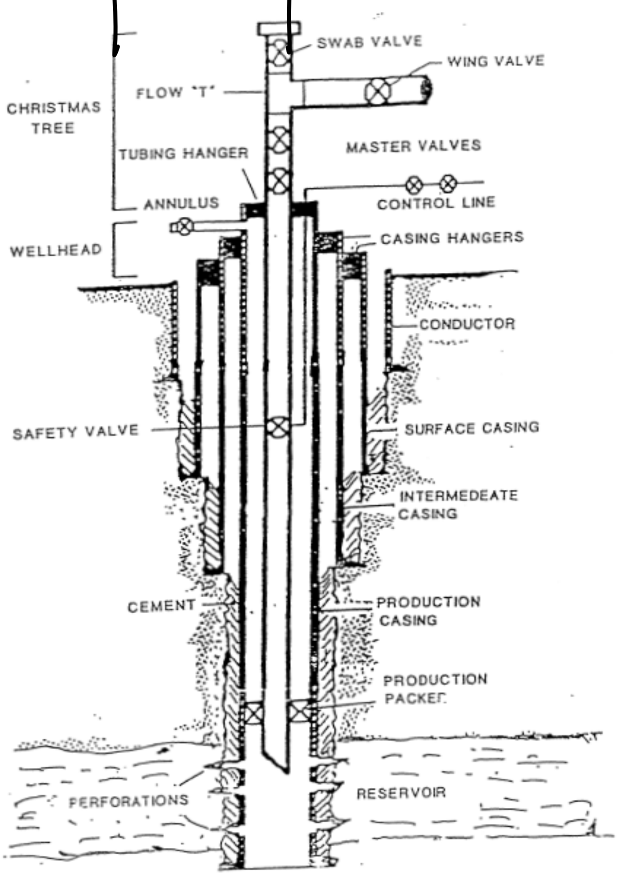
1) Control valves on the separators
2) Diverting valves on the manifold
3) master valve
4) wing valve
5) Swab valve
6) check valve
7) choke
8) Downhole Safety valves

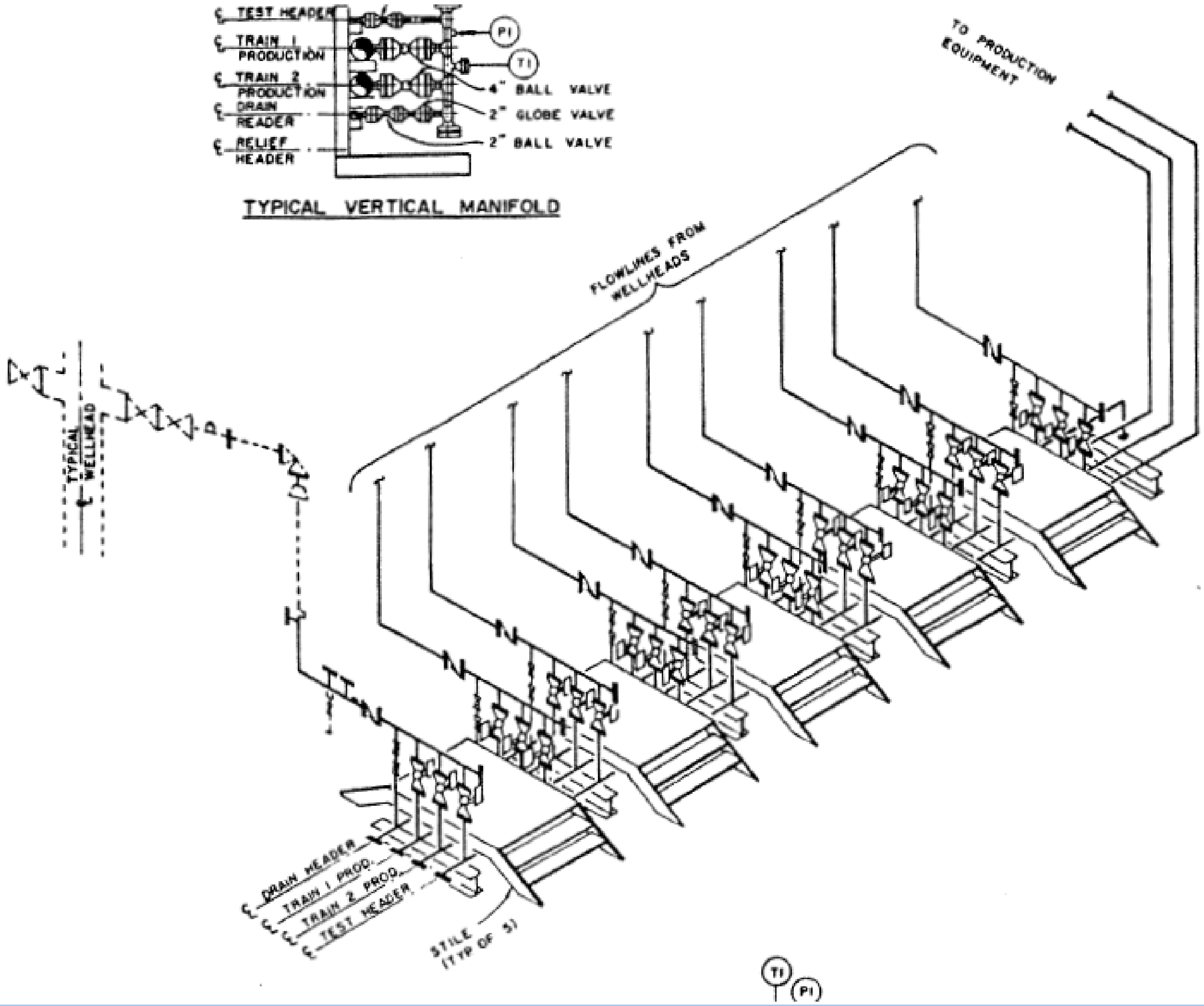
P&I diagram (piping and instrumentation diagram)

Mechanical engineering



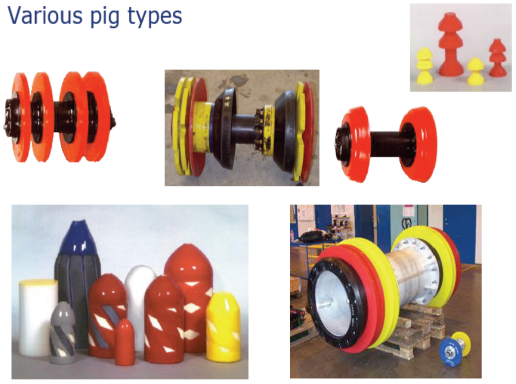






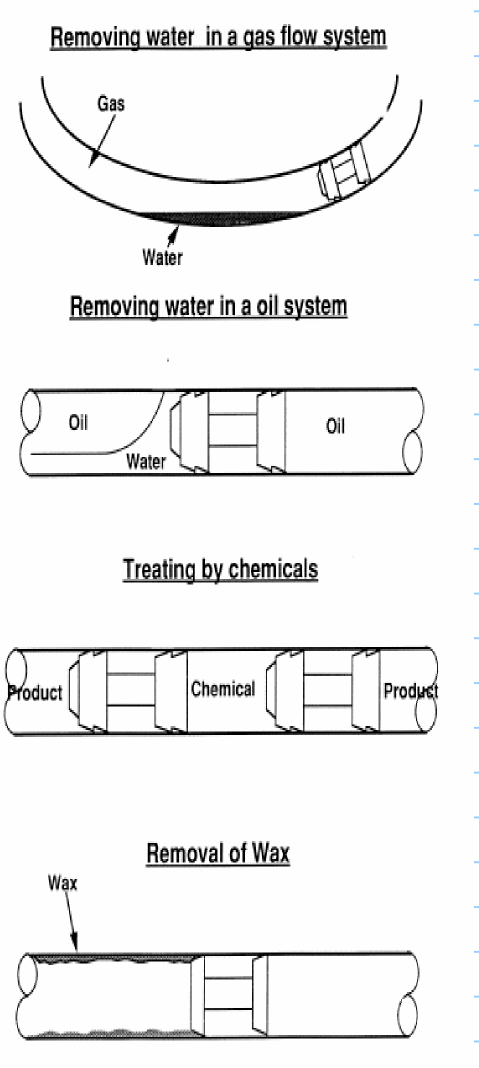
Pigging

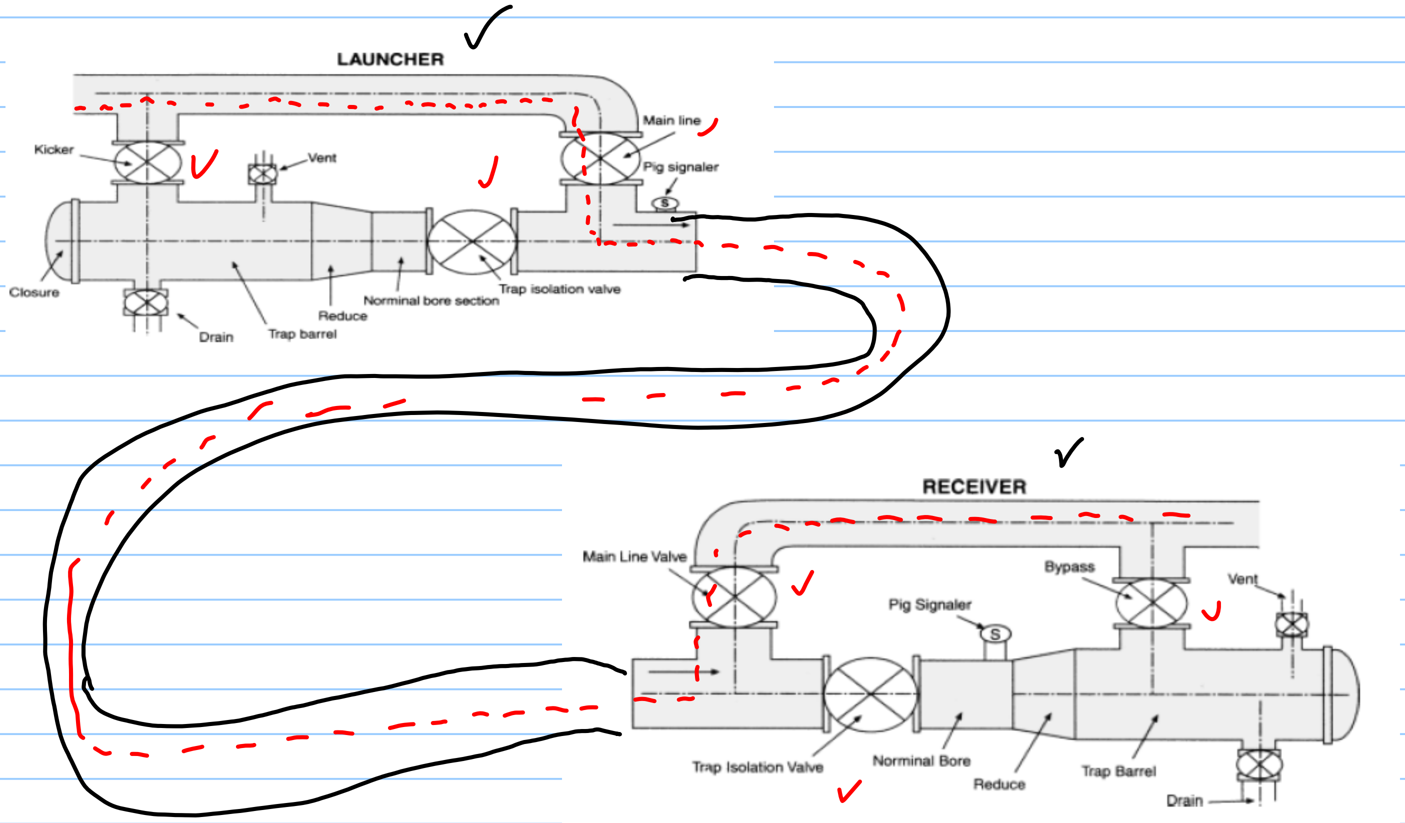
Various pig types



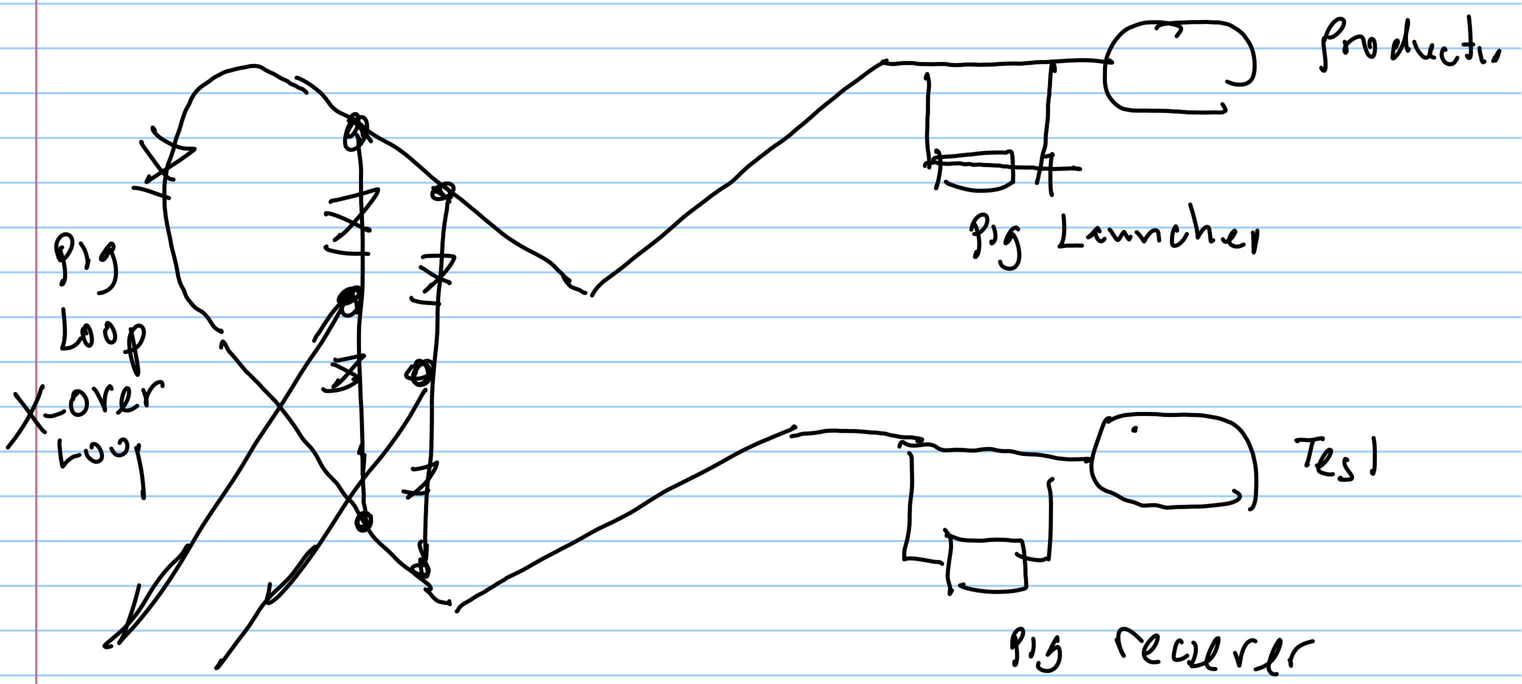
Wax plug-North Sea line pigging

Pig function

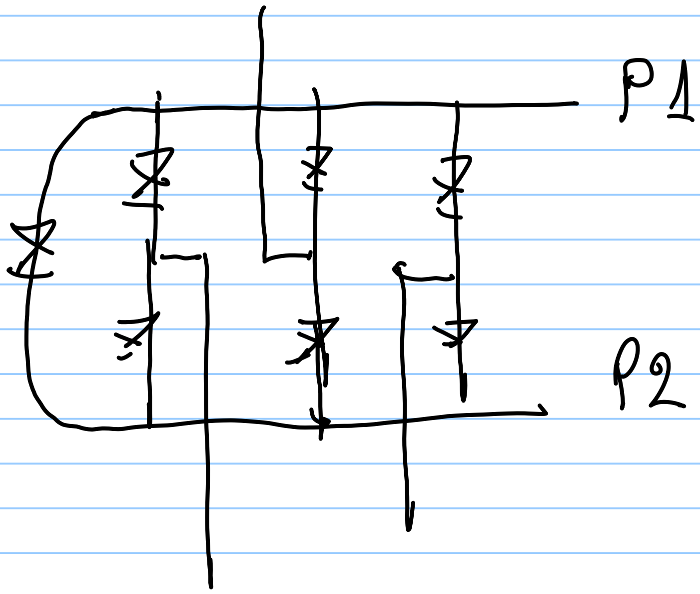


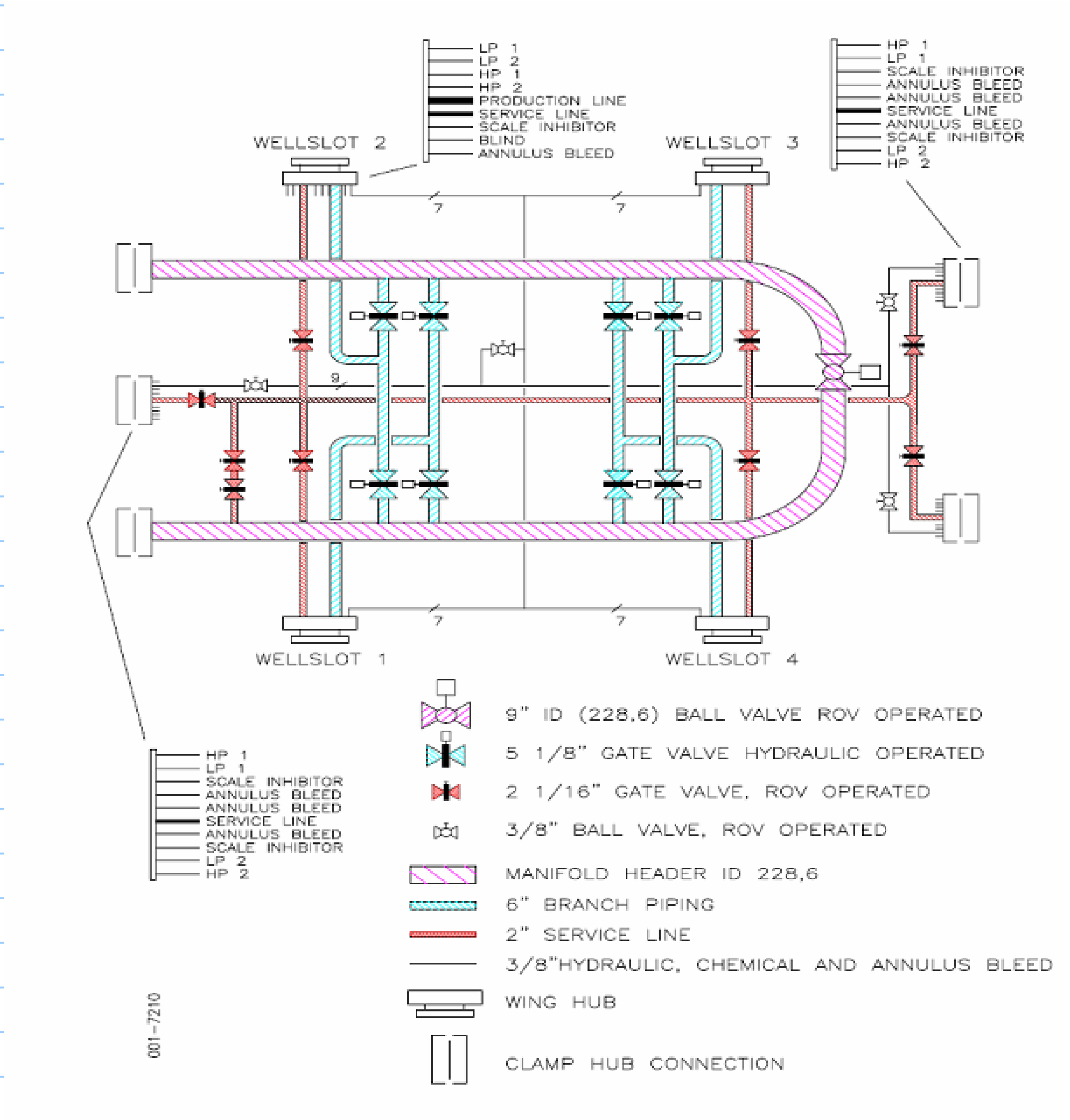


subsea manifold

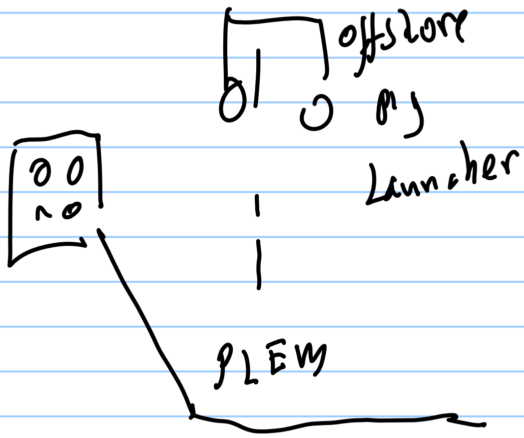


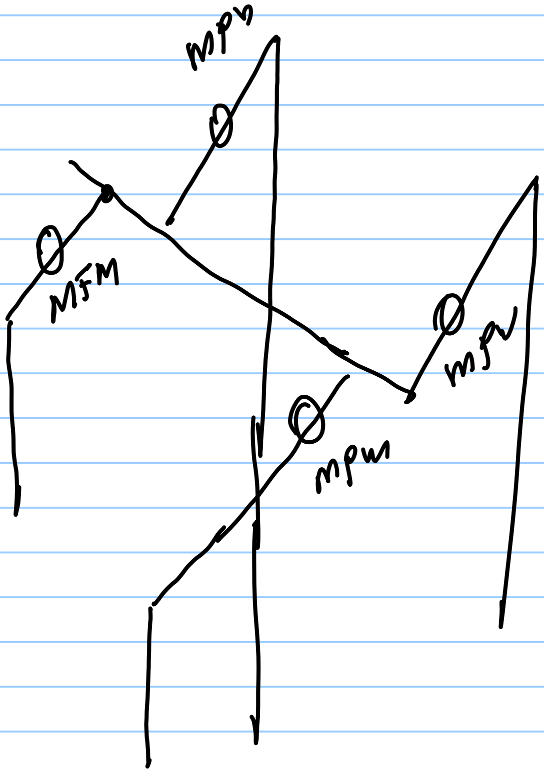
subsea manifold with pigging Loops




LP 1
LP 2
HP 1
HP 2
PRODUCTION LINE
SERVICE LINE
SCALE INHIBITOR
BLIND
ANNULUS BLEED
WELLSLOT 2
WELLSLOT 3
HP 1
LP 1
SCALE INHIBITOR
ANNULUS BLEED
ANNULUS BLEED
SERVICE LINE
ANNULUS BLEED
SCALE INHIBITOR
LP 2
HP 2
7
7
9
7
7
WELLSLOT 1
WELLSLOT 4
HP 1
LP 1
SCALE INHIBITOR
ANNULUS BLEED
ANNULUS BLEED
SERVICE LINE
ANNULUS BLEED
SCALE INHIBITOR
LP 2
HP 2
9" ID (228,6) BALL VALVE ROV OPERATED
5 1/8" GATE VALVE HYDRAULIC OPERATED
2 1/16" GATE VALVE, ROV OPERATED
3/8" BALL VALVE, ROV OPERATED
MANIFOLD HEADER ID 228,6
6" BRANCH PIPING
2" SERVICE LINE
3/8"HYDRAULIC, CHEMICAL AND ANNULUS BLEED
WING HUB
CLAMP HUB CONNECTION
001-7210

snow white


offshore
Pig
Launcher
PLEM

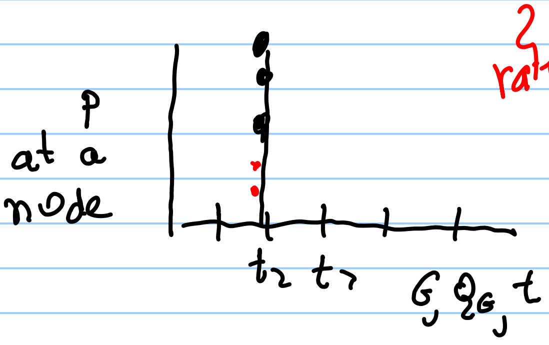

mpv
MFM
mpv
mpw

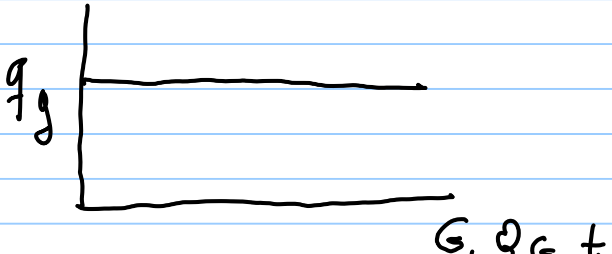
Last week issures

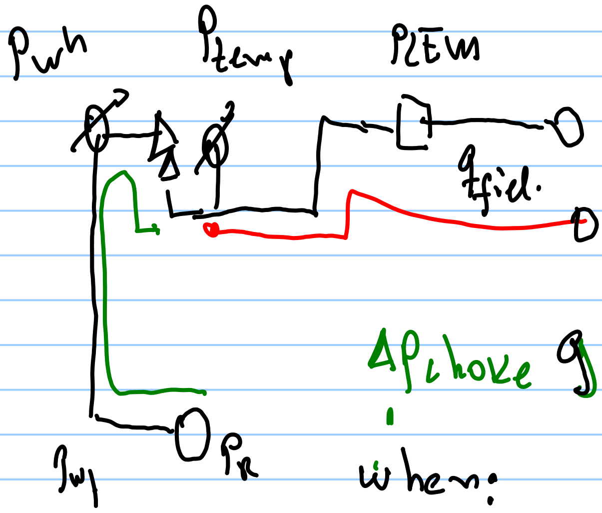
1. Flow equlibrium

$q \times p \times X, t$

rate pressure point in the system (Node) time







EX 1.

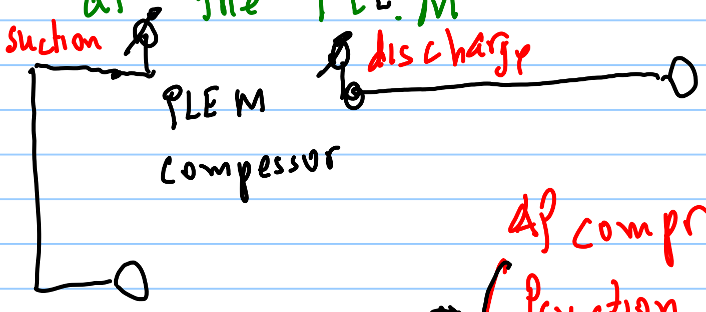
terminal node (sink), separator

ΔP_{choke} goes down with depletion

when:

$\Delta P_{choke} = 0 \rightarrow$ end of plateau

Ex 2. part 1 subsea boosting compressure at the PLEM



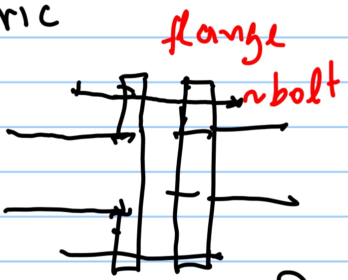
moving the equilibrium point analysis from the chock to the compressor

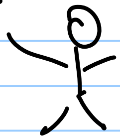
$$\Delta P_{compressure} = -\left(P_{suction\ available} - P_{discharge\ required}\right)$$

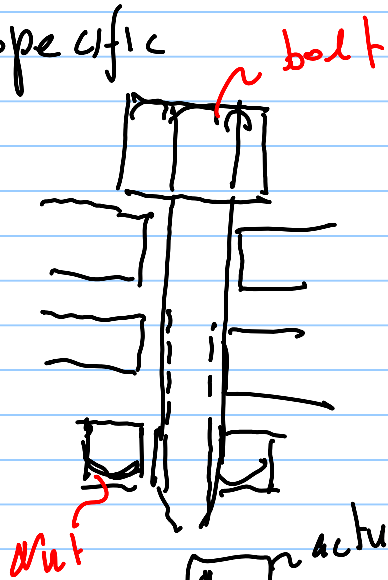
The elements of the course

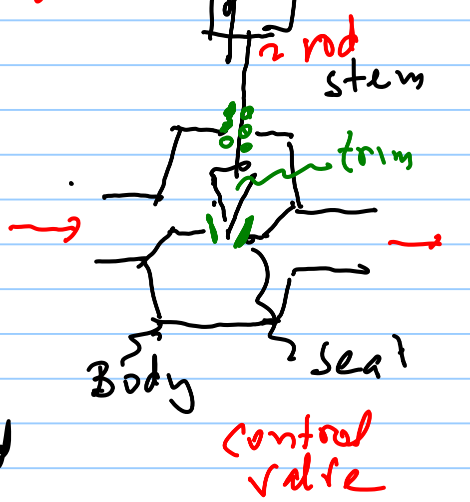
1. Technology < oil and gas field specific / generic

2. Specific technologies
   - ⊙ ↳ Architecture of oil field
   - ⊙ Well technology (mechanics)
   - ⊙ Process and flow technology
   - ⊙ control and instrumentation
   - ⊙ Offshore technology





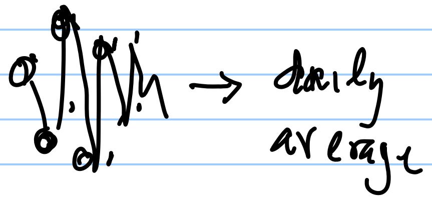




3. working process
   - Life cycle of an oil field
   - Land marks
     1. statement of commerciality (SOC)
     - plan for development and opration (PDO)

     Norsk = (PUD)

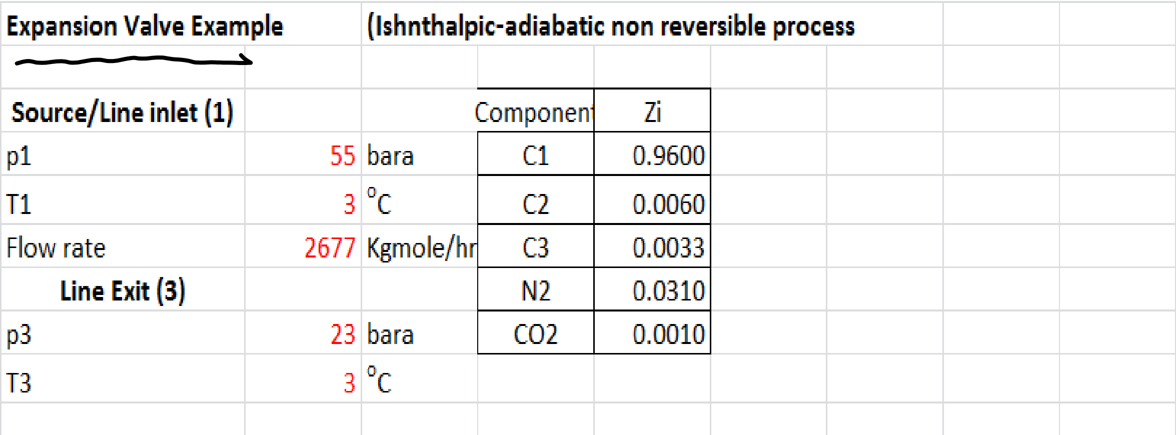
4. Basic engineering skills
   - o Engineering mechanics
   - o Math and Data
   - o economical analysis



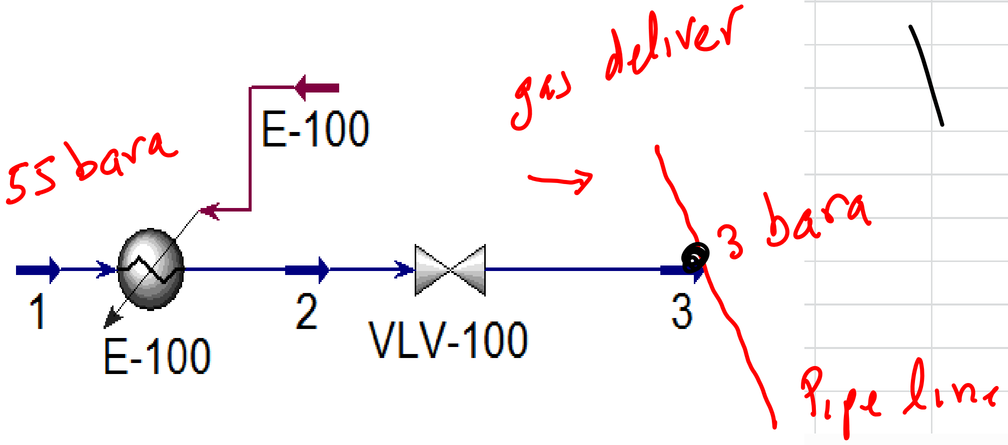
our course will focus on the content of PDO & SOC

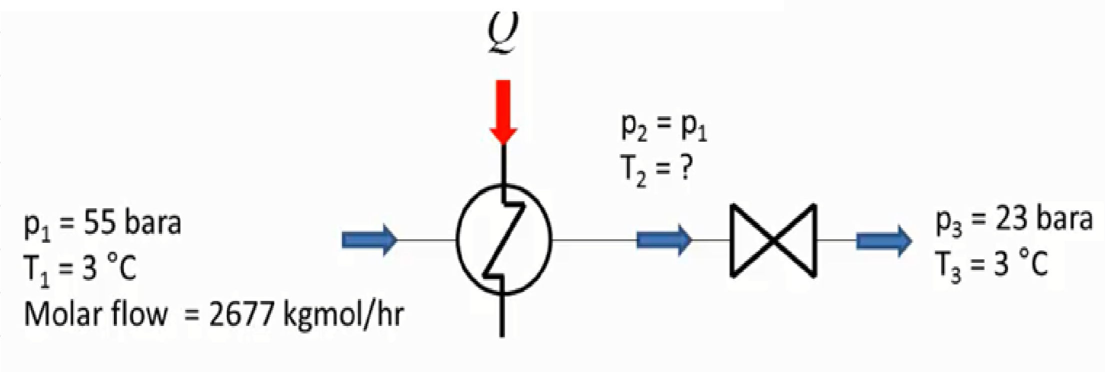
Use of Hysys (NTNU v 8.3)

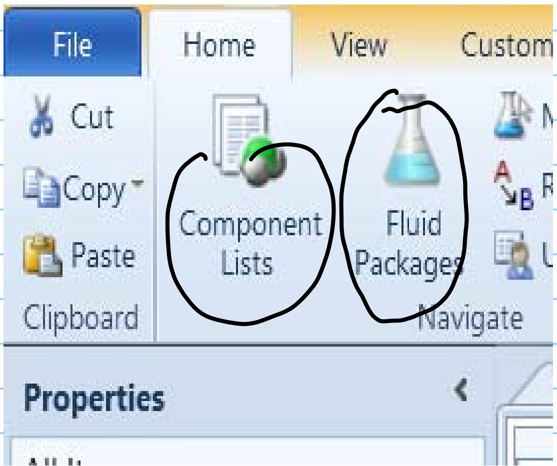
simple Hysys example to illustrate the backwards capability of the solver of Hysys



Expansion Valve Example		**(Ishnthalpic-adiabatic non reversible process**		
Source/Line inlet (1)			Componen	Zi
p1	55	bara	C1	0.9600
T1	3	°C	C2	0.0060
Flow rate	2677	Kgmole/hr	C3	0.0033
Line Exit (3)			N2	0.0310
p3	23	bara	CO2	0.0010
T3	3	°C		







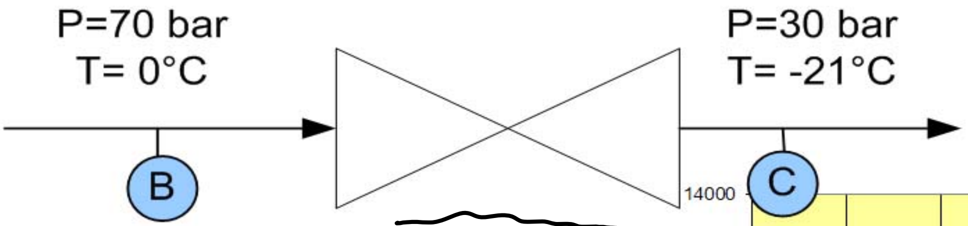
Hysys → compositional analysis

steps:

1) component list
2) Fluid packge
3) Simulation – Process Flow sheet (PFS)

what process take place in the valve ?

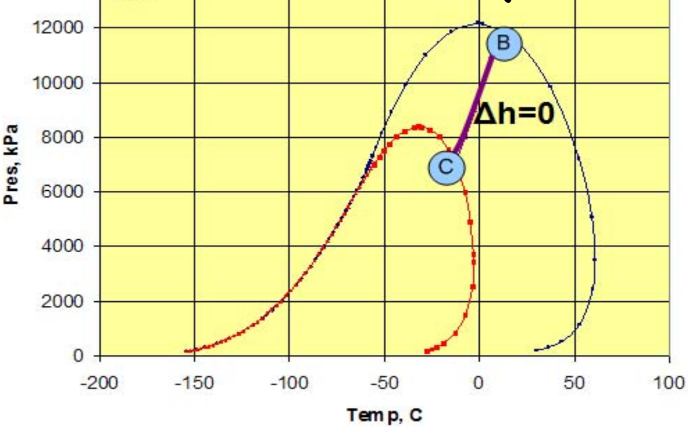
Refrigerating while expanding across a valve



first Law of thermodynamic for open system

$$\boxed{\Delta h=0}$$

Used when a pressure drop is available (high inlet pressures, low export pressures)



Definition of enthalpy

$$h = u + \frac{P}{\rho} = \text{enthalpy} \ \frac{kJ}{kg}$$

enthalpy { internal energy

flow energy in open system

valve

$\Delta Z = 0$

$W = 0$

$q = 0$ adiabatic

$$\Delta H = Q - W$$

$$dH = TdS + VdP$$

-***Expansion valve***: Temperature drop while expanding. No heat exchanged with the environment, no work performed.

valve ✓

Q=W=0=ΔH

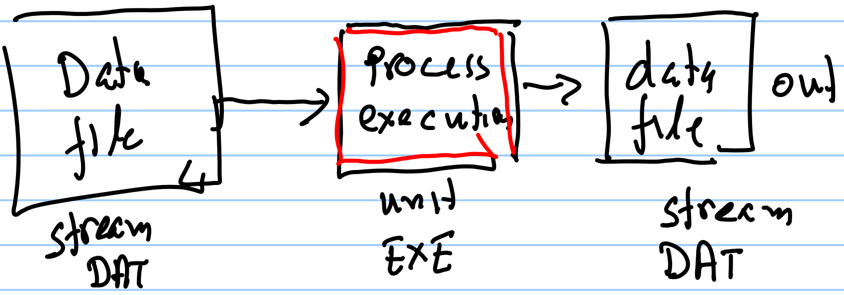
~~-***Compressor, Expander***: Assume isentropic, which means adiabatic (Q=0) and reversible (the reversibility assumption is corrected introducing the efficiency concept) →~~

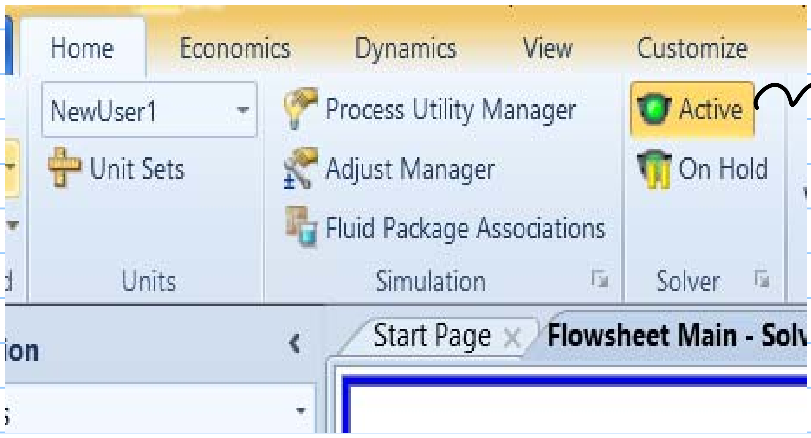
W=ΔH

turbo expender

(not addressed in this course)

simple case Hysys → both forward and backward calculations along a single stream

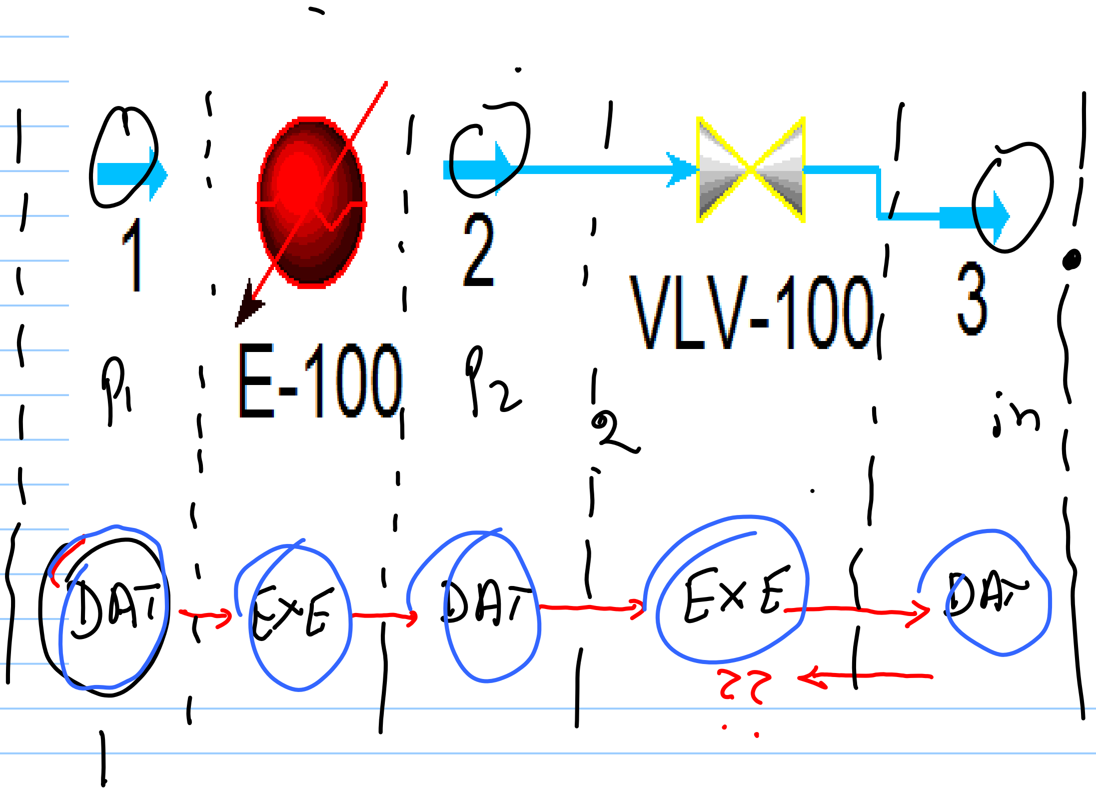




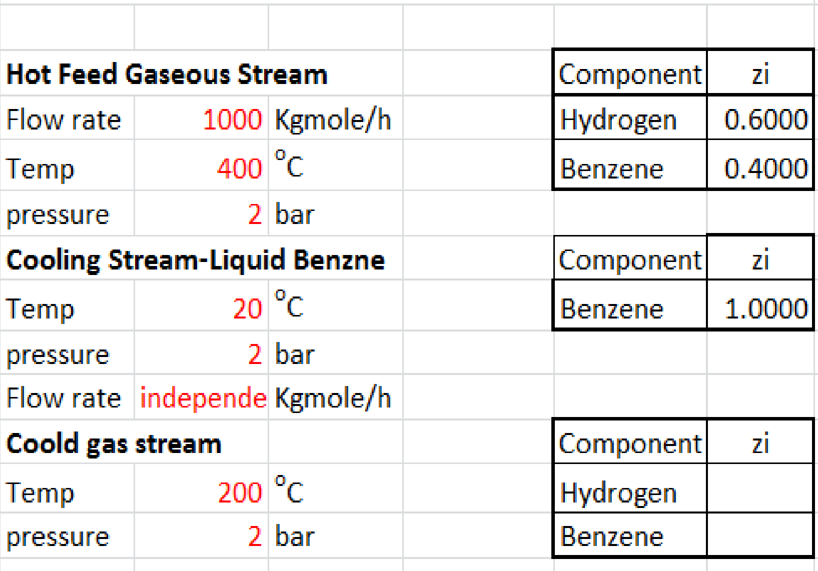
solver

make sure that in simulation the solver is active!!!

Remmember: you cannot connect Directly DAT-to-DAT and EXE to EXE.



more involved example requires the use of Adjust



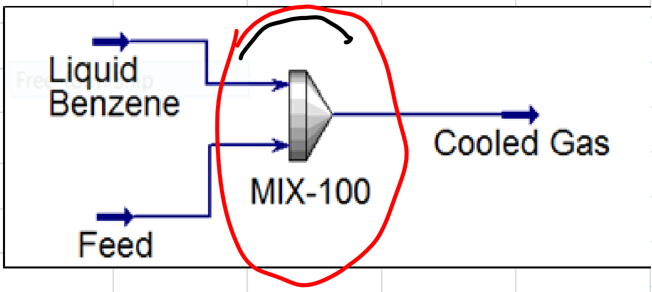
Cooling Gas stream by adiabatic mixing with Cold Liquid stream

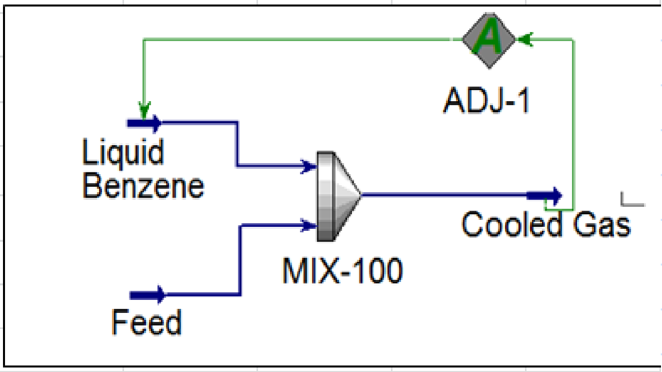
Hot Feed Gaseous Stream		
Flow rate	1000	Kgmole/h
Temp	400	°C
pressure	2	bar
Cooling Stream-Liquid Benzne		
Temp	20	°C
pressure	2	bar
Flow rate	independe	Kgmole/h
Coold gas stream		
Temp	200	°C
pressure	2	bar

Component	zi
Hydrogen	0.6000
Benzene	0.4000

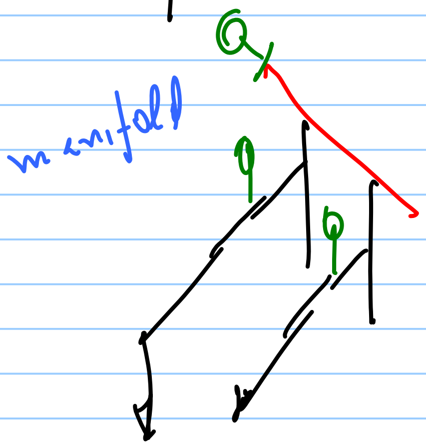
Component	zi
Benzene	1.0000

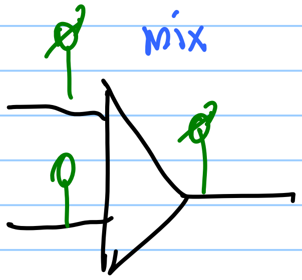
Component	zi
Hydrogen	
Benzene	

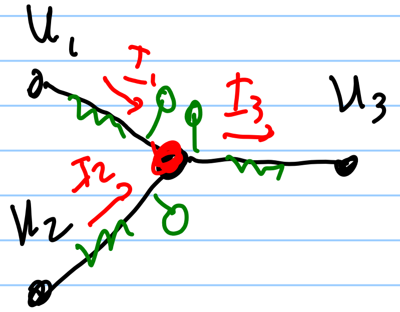




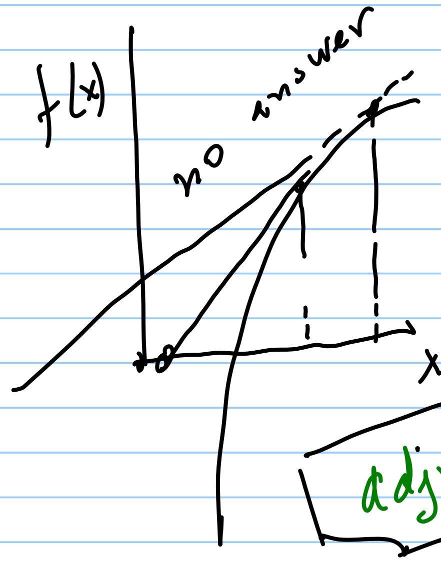
mixture is basically a manifold with single header

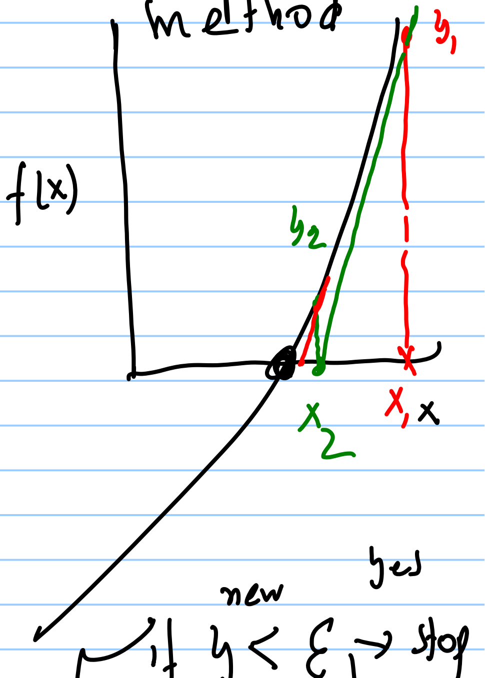




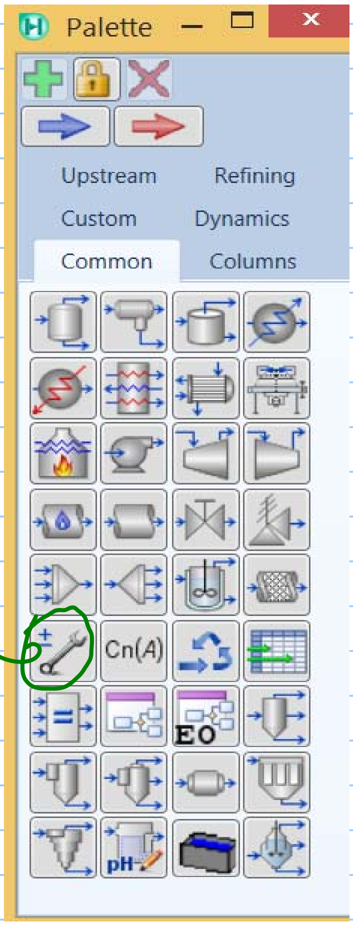


Newton Raphson method





adjust

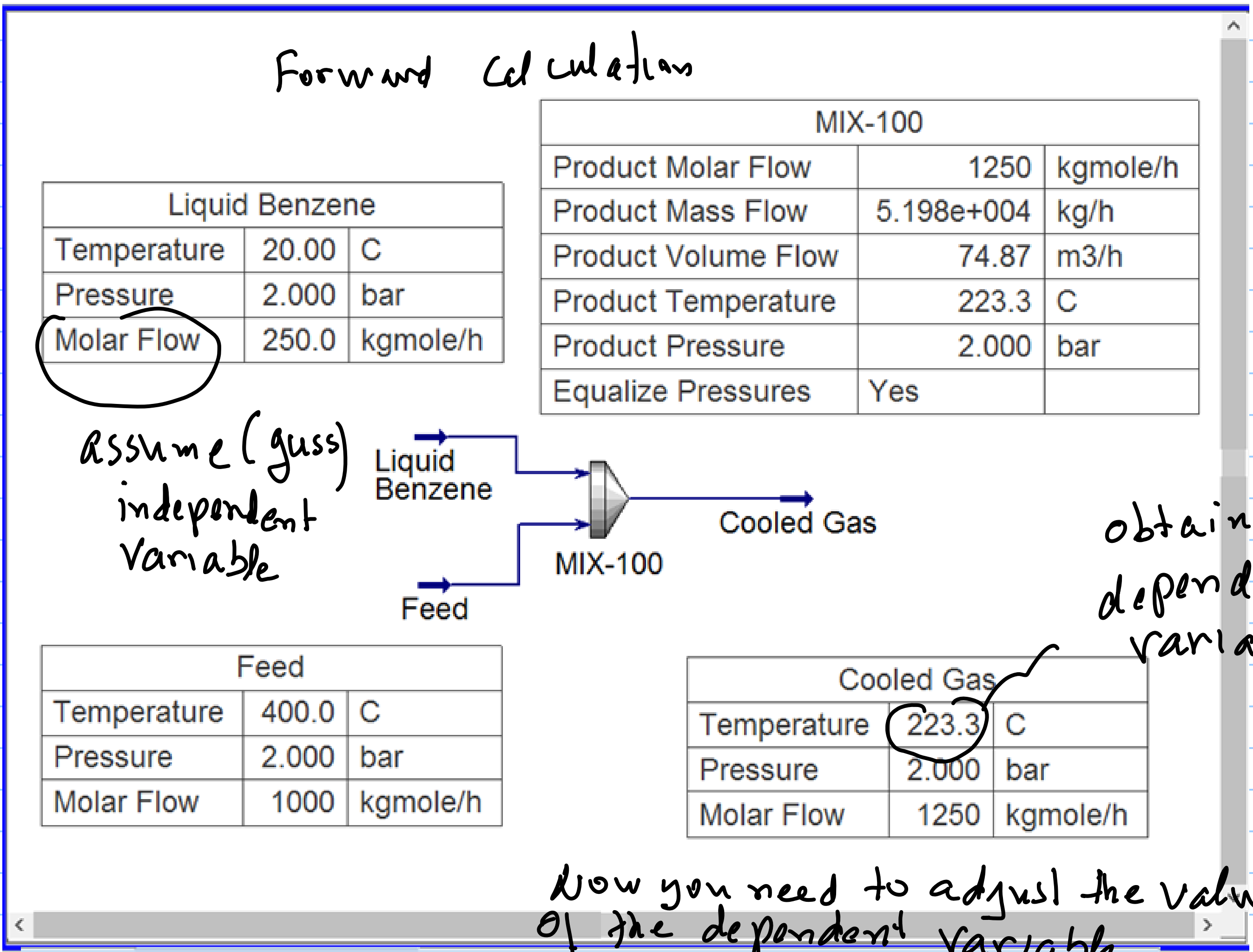


A successfull numerical solution depends on the initial guess value

new yes

if $y < \varepsilon \rightarrow$ stop

Forward calculation



MIX-100		
Product Molar Flow	1250	kgmole/h
Product Mass Flow	5.198e+004	kg/h
Product Volume Flow	74.87	m3/h
Product Temperature	223.3	C
Product Pressure	2.000	bar
Equalize Pressures	Yes	

Liquid Benzene		
Temperature	20.00	C
Pressure	2.000	bar
Molar Flow	250.0	kgmole/h

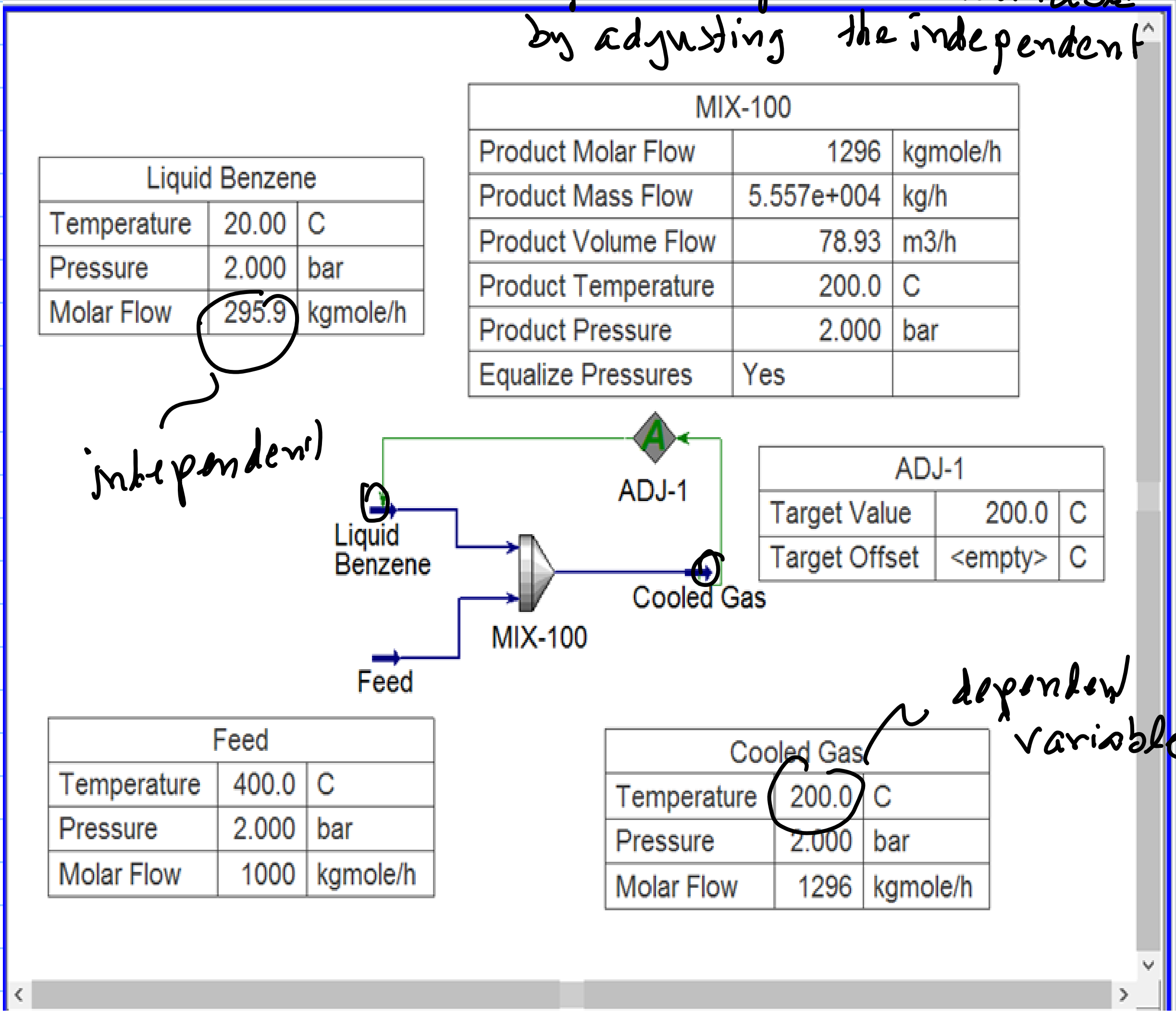
assume (guess) independent variable

obtain dependent variable

Feed		
Temperature	400.0	C
Pressure	2.000	bar
Molar Flow	1000	kgmole/h

Cooled Gas		
Temperature	223.3	C
Pressure	2.000	bar
Molar Flow	1250	kgmole/h

Now you need to adjust the value of the dependent variable by adjusting the independent variable



MIX-100		
Product Molar Flow	1296	kgmole/h
Product Mass Flow	5.557e+004	kg/h
Product Volume Flow	78.93	m3/h
Product Temperature	200.0	C
Product Pressure	2.000	bar
Equalize Pressures	Yes	

Liquid Benzene		
Temperature	20.00	C
Pressure	2.000	bar
Molar Flow	295.9	kgmole/h

independent

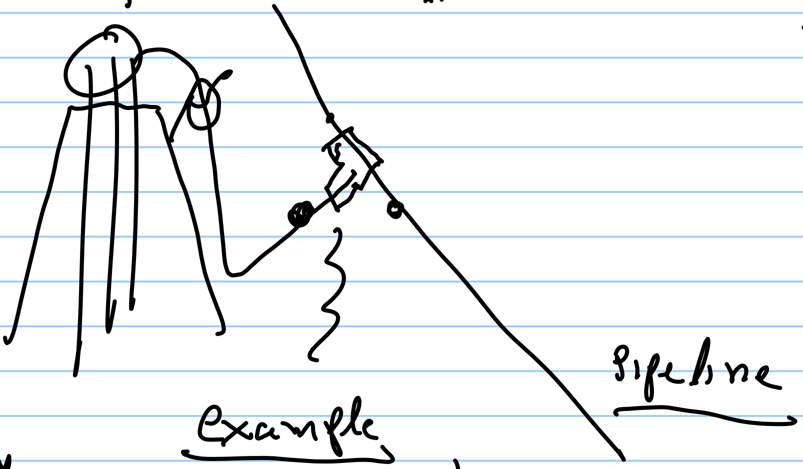
ADJ-1		
Target Value	200.0	C
Target Offset	<empty>	C

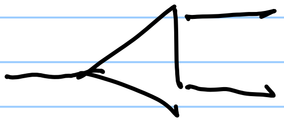
dependent variable

Feed		
Temperature	400.0	C
Pressure	2.000	bar
Molar Flow	1000	kgmole/h

Cooled Gas		
Temperature	200.0	C
Pressure	2.000	bar
Molar Flow	1296	kgmole/h

question: where and why we need to control of the temp at the output?





ρ

T

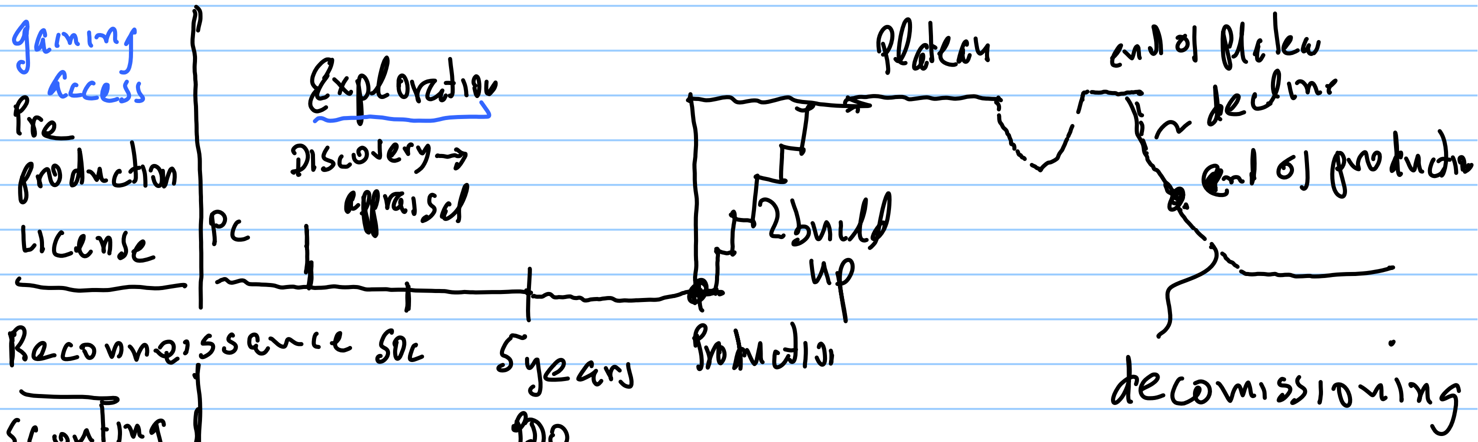
production platfor

Example

at the export point from a platform to a pipeline

New topic

Life cycle of offshore field



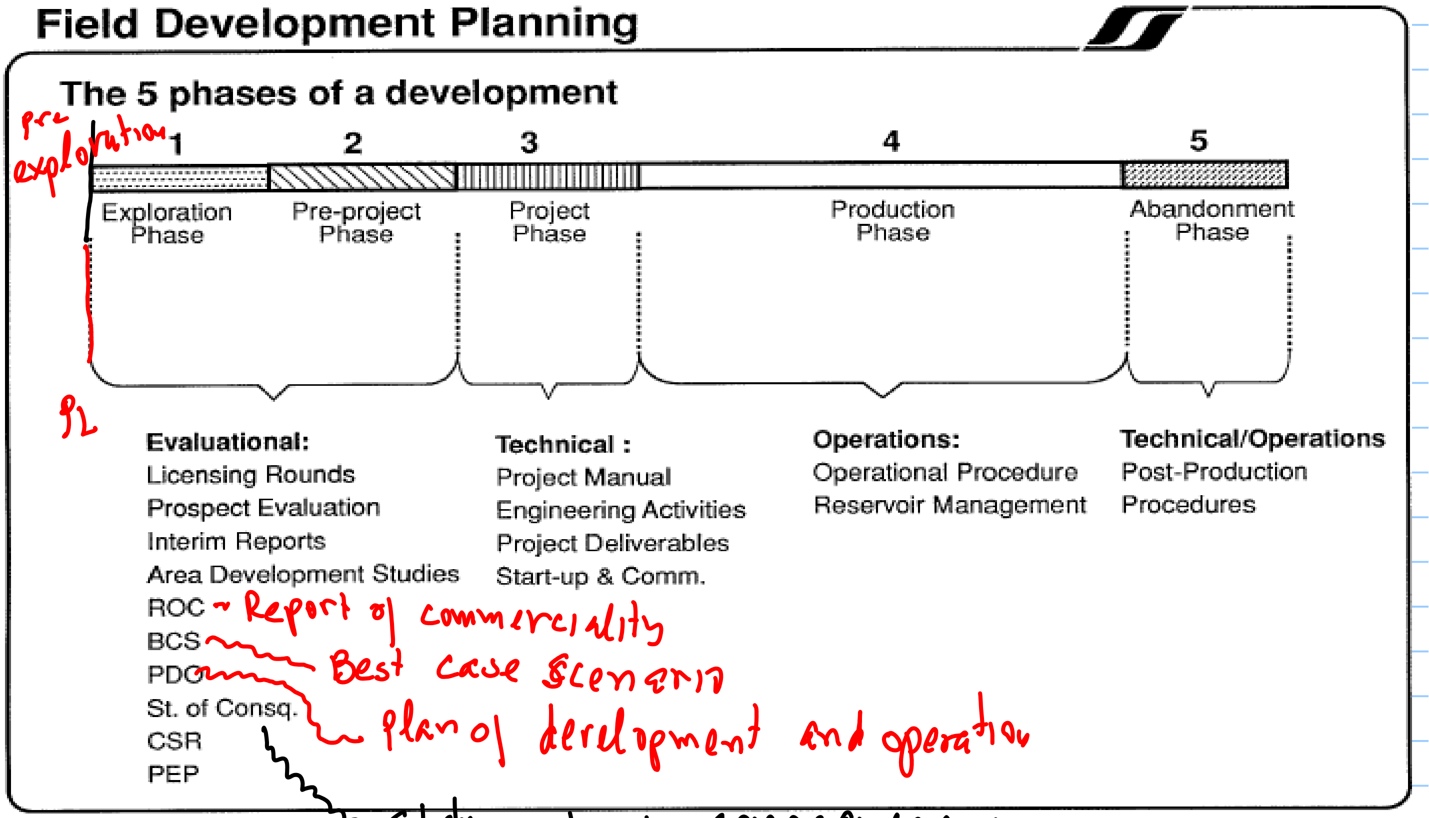
Scouting

no-exclusive right to do some exploration activities

PDO Development project Design

Production License P.C

invited to apply for PL



Field Development Planning

The 5 phases of a development

Evaluational:
- Licensing Rounds
- Prospect Evaluation
- Interim Reports
- Area Development Studies
- ROC ~ Report of commerciality
- BCS ~ Best case scenario
- PDO ~ plan of development and operation
- St. of Consq. ~ statement of consequences
- CSR
- PEP

Technical :
- Project Manual
- Engineering Activities
- Project Deliverables
- Start-up & Comm.

Operations:
- Operational Procedure
- Reservoir Management

Technical/Operations
- Post-Production Procedures

Landmarks along the Life Cycle of a field (offshore)

Pre Production License

- Scouting / Reconnaissance
- gaining acess / Being invited to apply for PL
- prepare PL Applicatio

PL

- Exploration < Surveys / Exploration drilling
- Discovery
- Appraisal
- SOC / PDO
- Approval for Development

Development

- Engineering
- Construction
- Installation
- Development Drilling
- Commissioning / start up

Operations

- Production
- maintenance and modification
- plateau and decline management
- Tail production

Production shut Down (or selling the field)

- Decommissioning of the field
- Remove the facilities and restore the environment to the original conditions
- Relinquish the field to the goverment or mineral owner

Life cycle of offshore oil and gas fields

1) Pre explortion - Scouting
collecting information to evaluate the interest in a certain area
Political, geological, geographical
sociale, environmental

2) getting acess
↳ pre exploration access - no exclusive
G & G studies (Geological & geophysical)
Reservoir studies

3) Identify prospect - focus the interest
(Data room access / work)

4) obtain an exclusive PL (Production License)
- Prequalification - technical
  - financial
- joint venture - operation
  - no operating partners

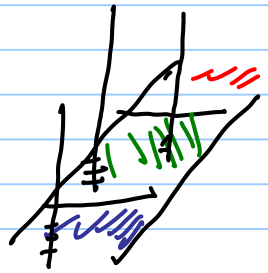
$\boxed{\text{operator + Partners}}$ (JV) = Joint venture

(5) Exploration phase → 5 + 25

Regional geological studies
seismic survey 2D
Focused survey 3D
exploration drilling
, Discovery - SOC → statement of commerciality
- Relinquish back to mineral owner

6) **Appraisal** → generate more reliable information

↘ Decisions



- more appraisal
- sell the discovery
- Do nothing (pay fee)
- Decide to Develop (gambling)

End of Appraisal
↳ SOC
↳ relinquish

Project phase

Front End Engineering (FEE) → · identify development scenarios
· Rank scenaries
· Best case scenario

Ranking scenarios

- Economy ✓
- complexity
- Risk
- Technological gap (need development and qualification)
- BCS → Best case scenario
- PDO → plan for development and operation

(PUD) norsk

Detailed Engineering

until 1980

- Engineering contractors - Detailed Engineering and spe.
- Bid on
  - manufacturing
  - supply
  - installation
  - commissioning
- construction
  - supply
  - integration
  - Commissioning
  - Training

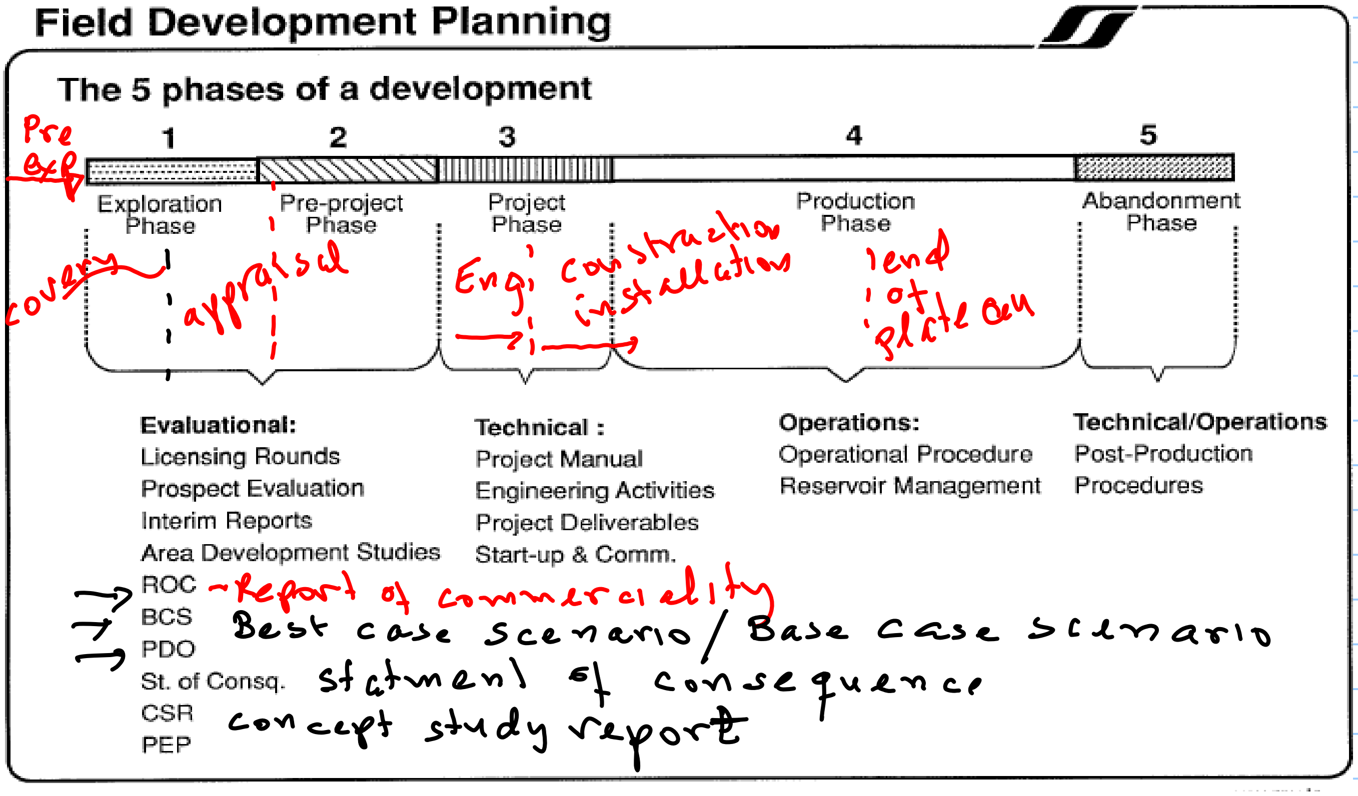
project management

1990 → EPCM contracts

work packges

- Engineering
- Procrument
- construction
- Installation
- Commissioning
- management

Life cycle of an oil and gas fields



Field Development Planning

The 5 phases of a development

Evaluational:
Licensing Rounds
Prospect Evaluation
Interim Reports
Area Development Studies
ROC -Report of commerciality
BCS Best case scenario / Base case scenario
PDO
St. of Consq. statment of consequence
CSR concept study report
PEP

Technical :
Project Manual
Engineering Activities
Project Deliverables
Start-up & Comm.

Operations:
Operational Procedure
Reservoir Management

Technical/Operations
Post-Production
Procedures

relinquish → return to the goverment

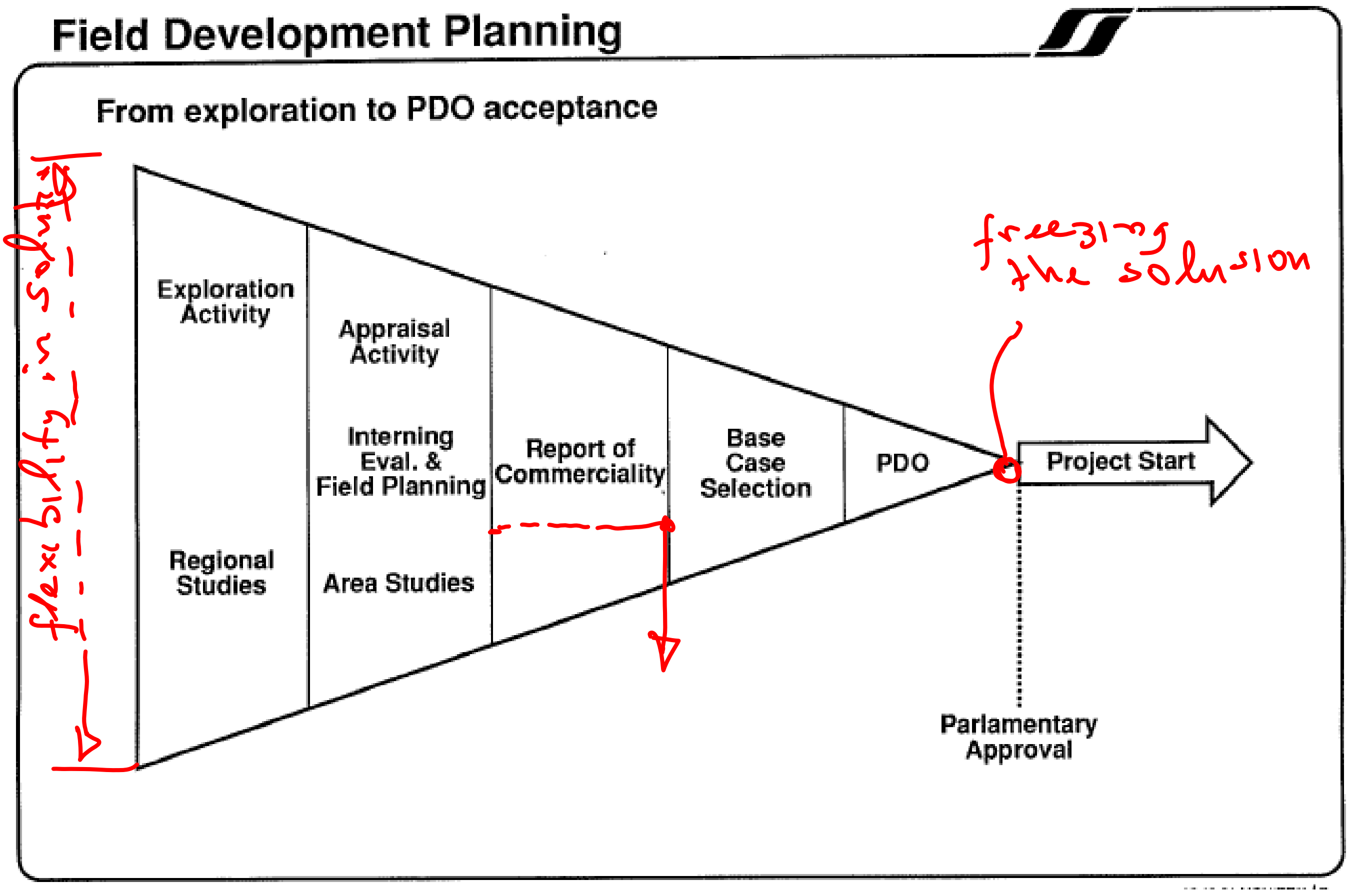
1) ROC/SOC → report / statement of commerciality

At least one economically worth development scenary

2) PDO → plan for development and operation

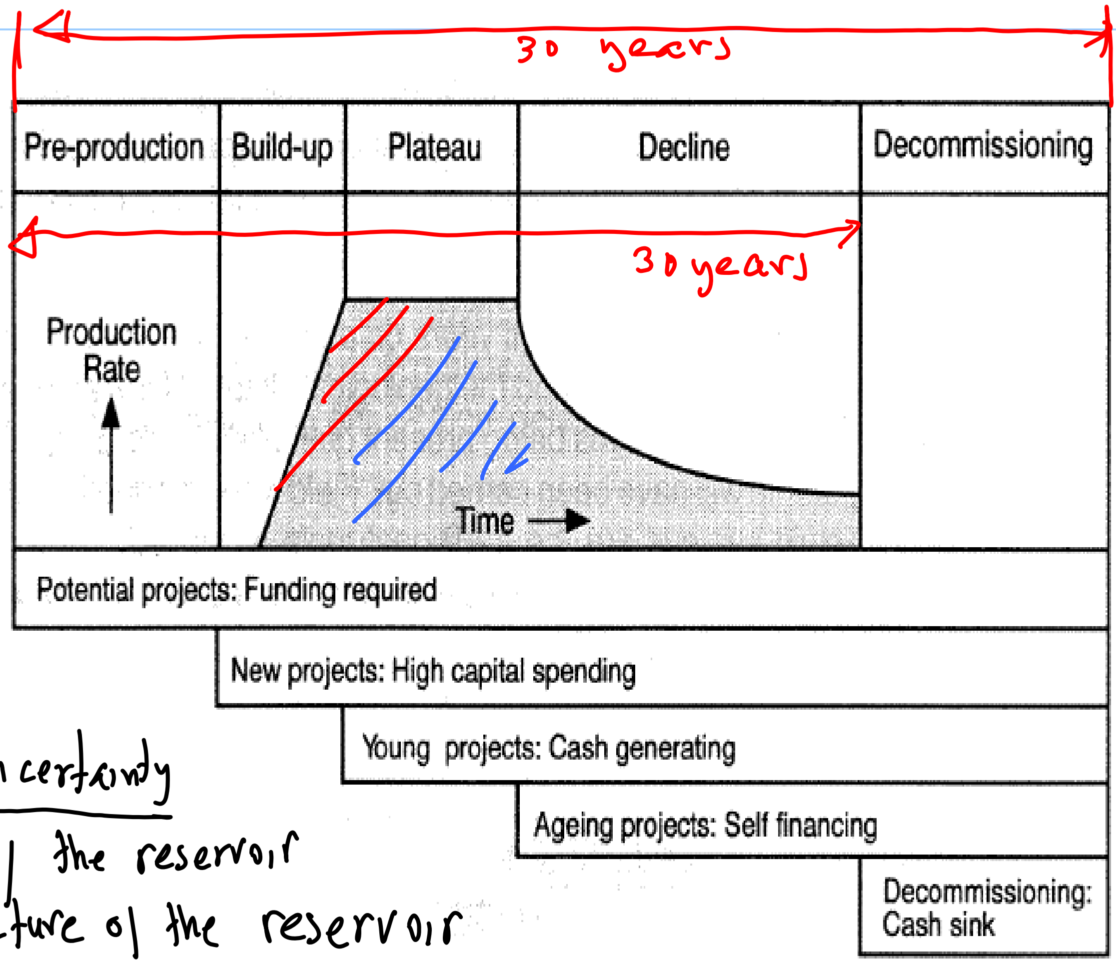
- Lists and analyze development and operation options
- Rank the options

PDO	PUD	FDP
	Norsk	Field development plan



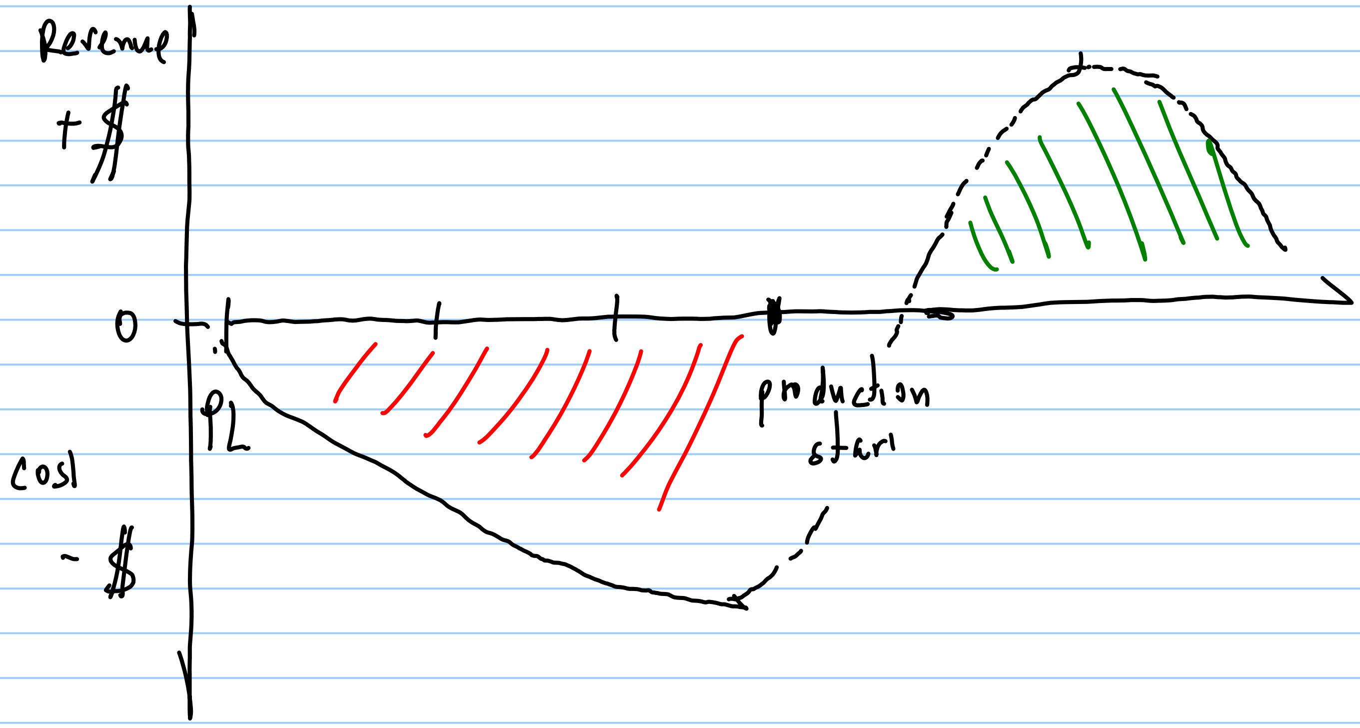
Field Development Planning

From exploration to PDO acceptance

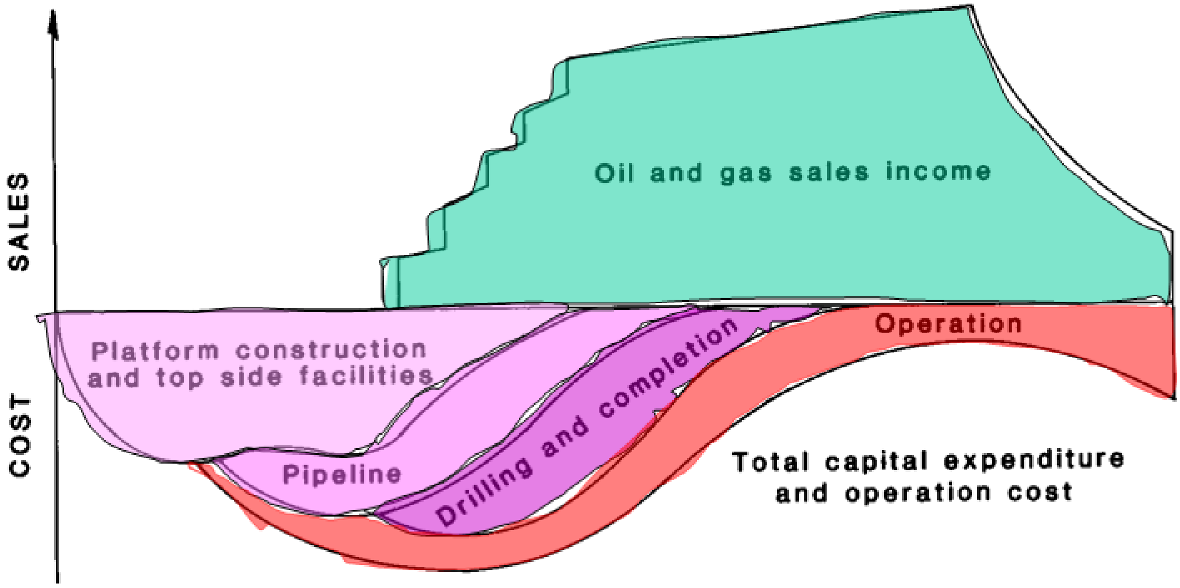


initial uncertainty

1. size of the reservoir
2. structure of the reservoir
3. Dynamic behaviour - Drive mechanisms



Revenue and Cost Profiles



Time value of mony

Net cash Recovery = (Revenue - cost)

year	cost	Revenue	NCR= (R-C)
0			
1			
2			
3			

Revenues from a field

selling products

oil (crude)

gas

Condensate

NGL → Natural gas Liquid

LNG (Liquified natural gas mainly C_1) Liquid in very Low Temp and standard pressure ($\approx -167°C$)

LPG = Liquified Petroleum gas (C_2, C_3, C_4)

Costs

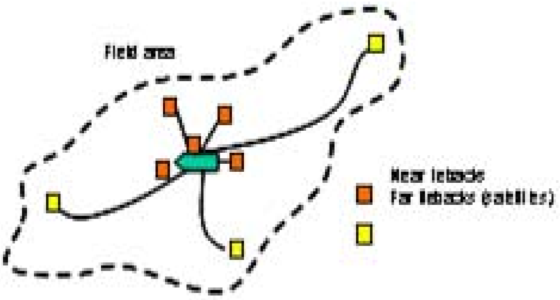
OPEX → operating costs

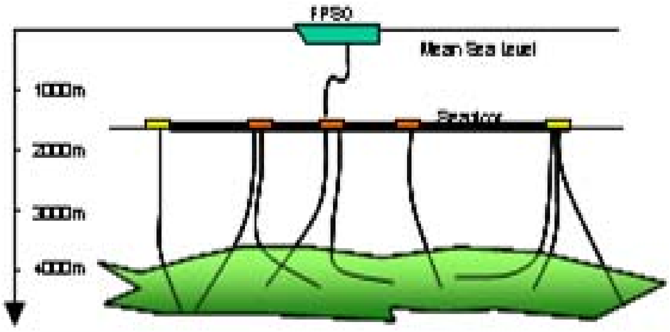
CAPEX → capital expenditure

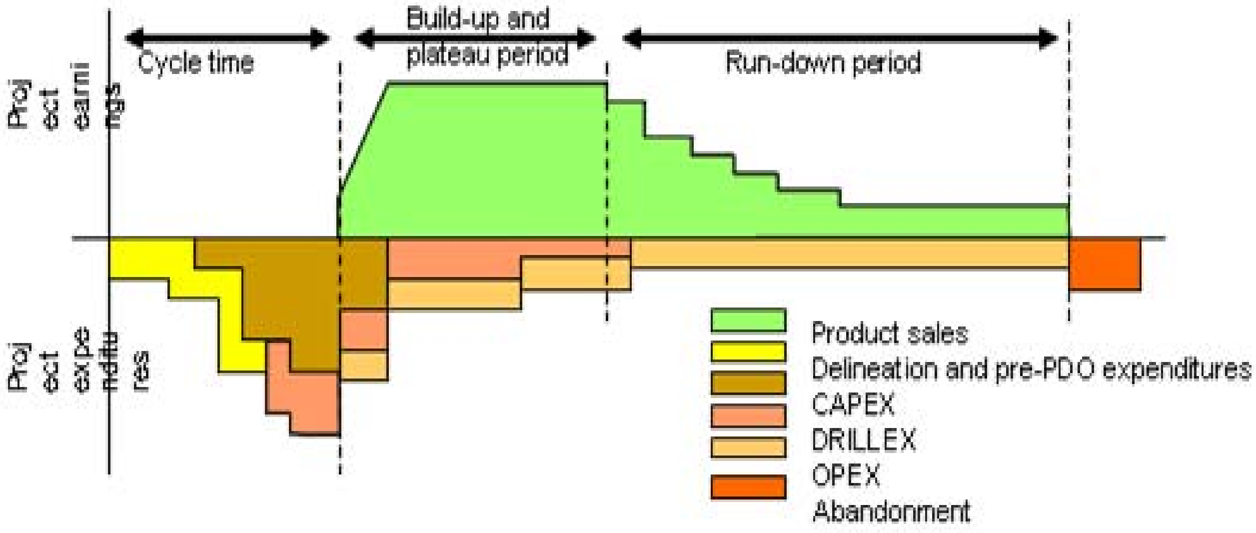
Drillex → Well construction costs

TAX → (on net revenue)

Royalties → on gross production







Time value of money

i = interest rate (fraction) = 0.09 → 9%

n = number of years (start of first year is the end of year 0)

$(1+i)$ = compound factor (CF)

$$\frac{1}{(CF)^n} = \frac{1}{(1+i)^n} = \text{Discount factor}$$

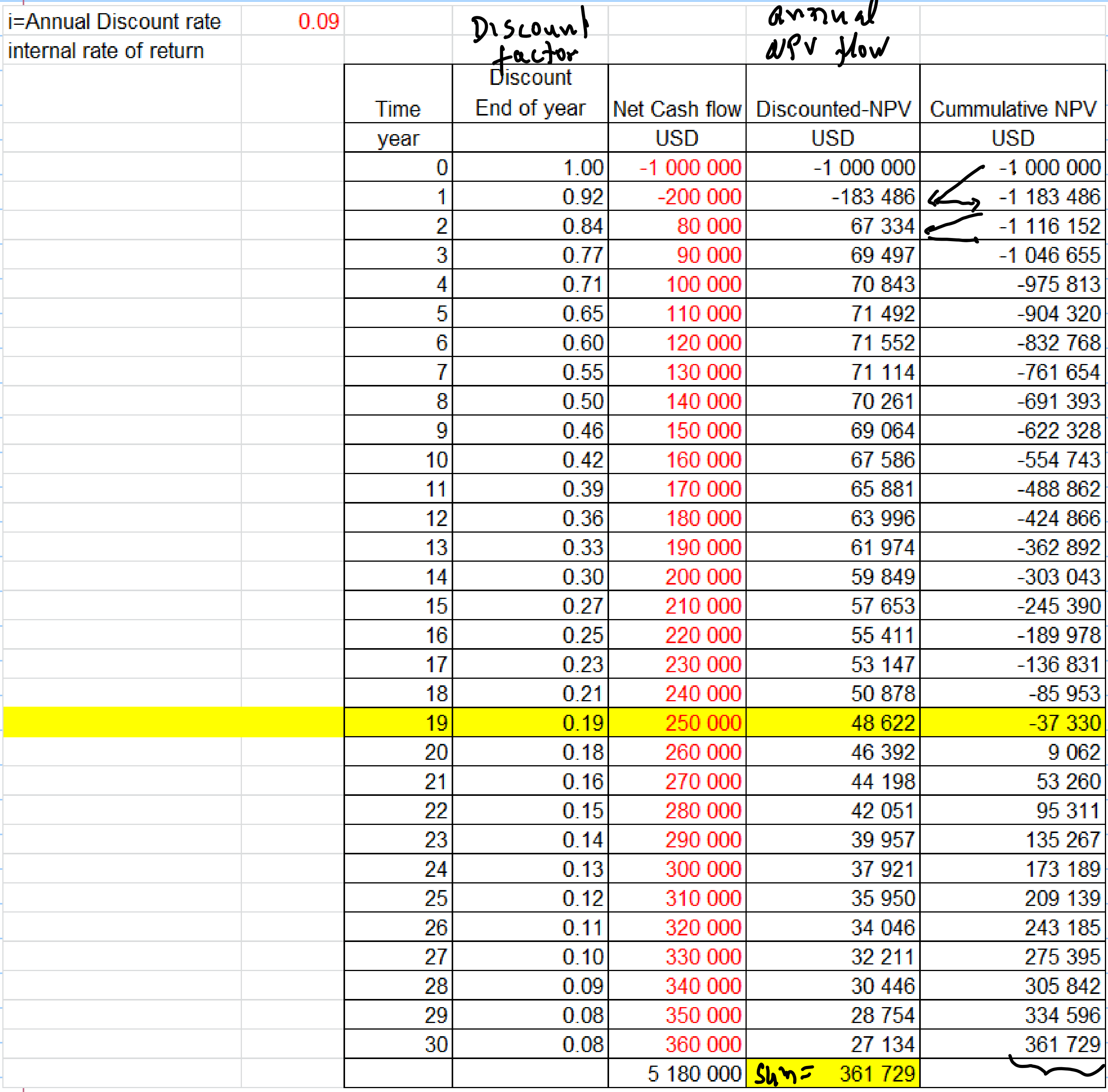
present Value of money in the future $\Bigg\}$ $V_p = V_f \left[\frac{1}{(1+i)^n} \right]$ ✓

$$V_F = \frac{V_p}{\left[\frac{1}{(1+i)^n} \right]}$$

future

year	Cost	Revenue	Net cash recovery	NPV
0				
1				
2				
3				
4				

Σ cummulative net present value of the project



Discount factor

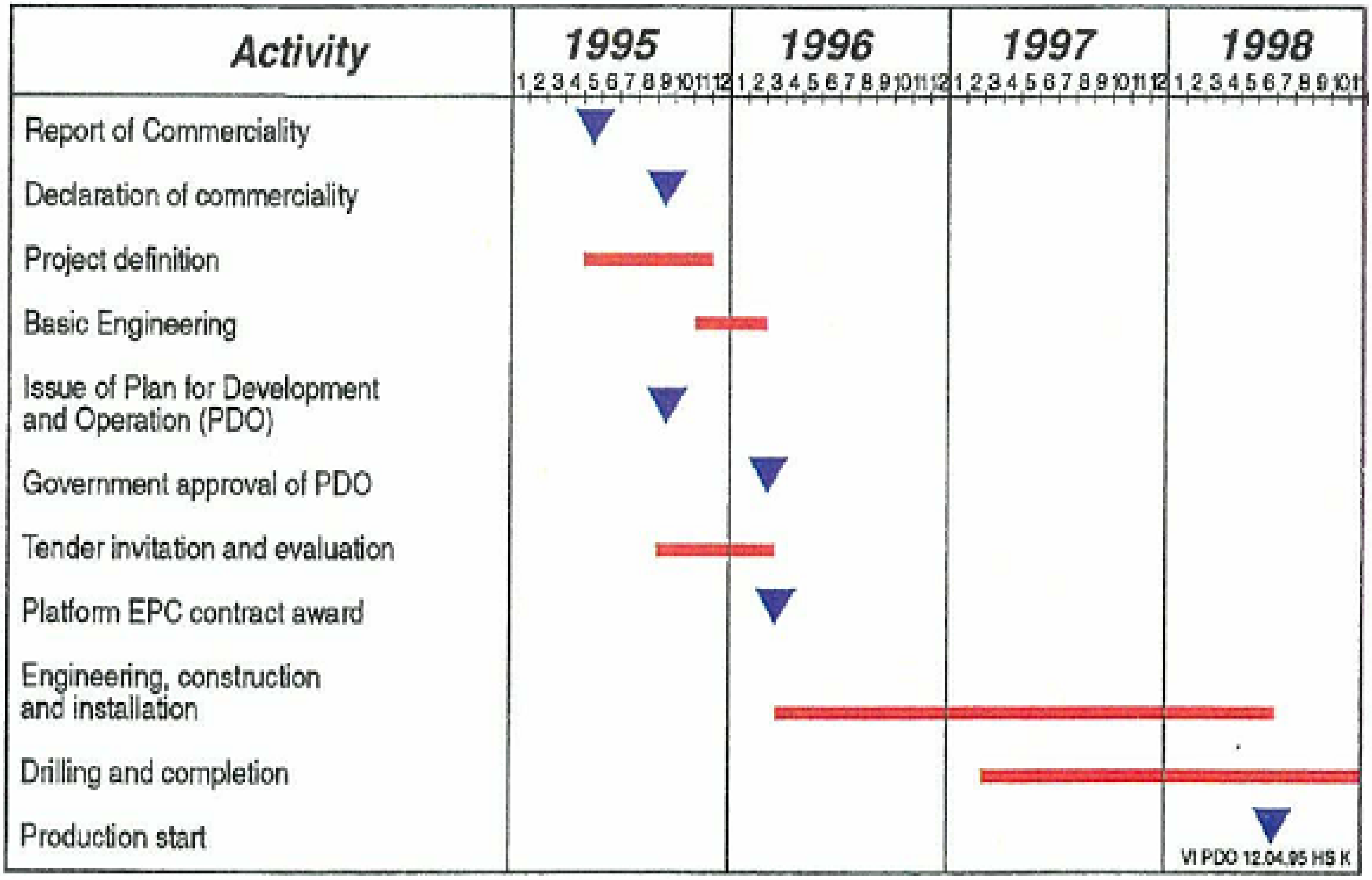
annual NPV flow

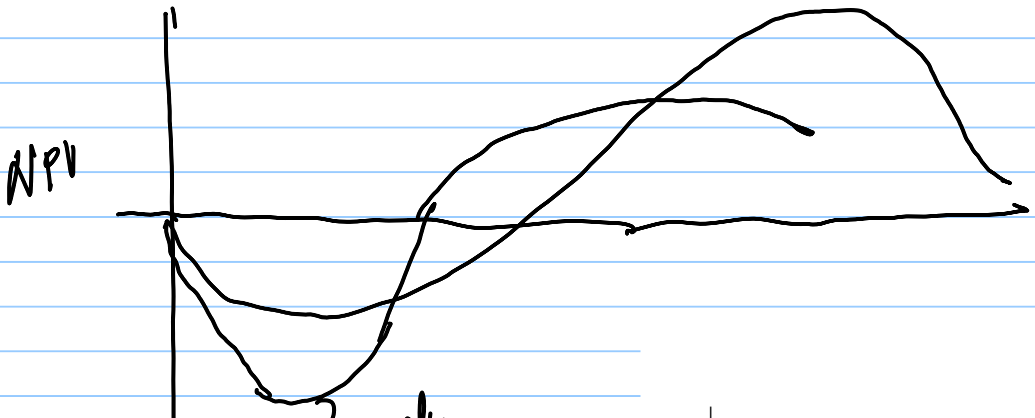
		Time	Discount End of year	Net Cash flow	Discounted-NPV	Cummulative NPV
i=Annual Discount rate	0.09					
internal rate of return						
		year		USD	USD	USD
		0	1.00	-1 000 000	-1 000 000	-1 000 000
		1	0.92	-200 000	-183 486	-1 183 486
		2	0.84	80 000	67 334	-1 116 152
		3	0.77	90 000	69 497	-1 046 655
		4	0.71	100 000	70 843	-975 813
		5	0.65	110 000	71 492	-904 320
		6	0.60	120 000	71 552	-832 768
		7	0.55	130 000	71 114	-761 654
		8	0.50	140 000	70 261	-691 393
		9	0.46	150 000	69 064	-622 328
		10	0.42	160 000	67 586	-554 743
		11	0.39	170 000	65 881	-488 862
		12	0.36	180 000	63 996	-424 866
		13	0.33	190 000	61 974	-362 892
		14	0.30	200 000	59 849	-303 043
		15	0.27	210 000	57 653	-245 390
		16	0.25	220 000	55 411	-189 978
		17	0.23	230 000	53 147	-136 831
		18	0.21	240 000	50 878	-85 953
		19	0.19	250 000	48 622	-37 330
		20	0.18	260 000	46 392	9 062
		21	0.16	270 000	44 198	53 260
		22	0.15	280 000	42 051	95 311
		23	0.14	290 000	39 957	135 267
		24	0.13	300 000	37 921	173 189
		25	0.12	310 000	35 950	209 139
		26	0.11	320 000	34 046	243 185
		27	0.10	330 000	32 211	275 395
		28	0.09	340 000	30 446	305 842
		29	0.08	350 000	28 754	334 596
		30	0.08	360 000	27 134	361 729
				5 180 000	Sum= 361 729	

Net Cash Recovery

NPV (Total)

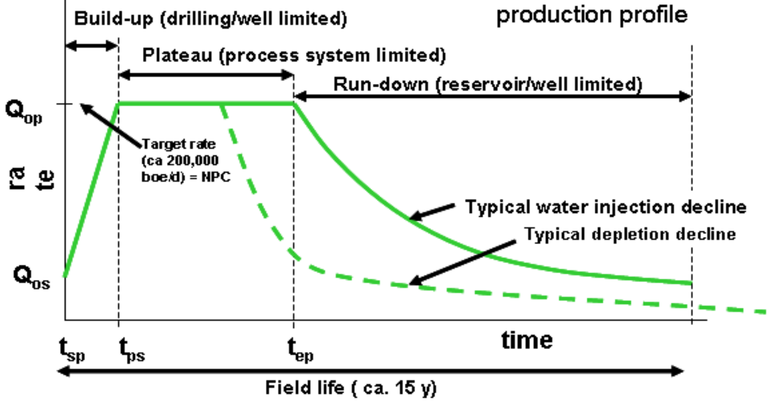
Cummulatif NPV





Early production system

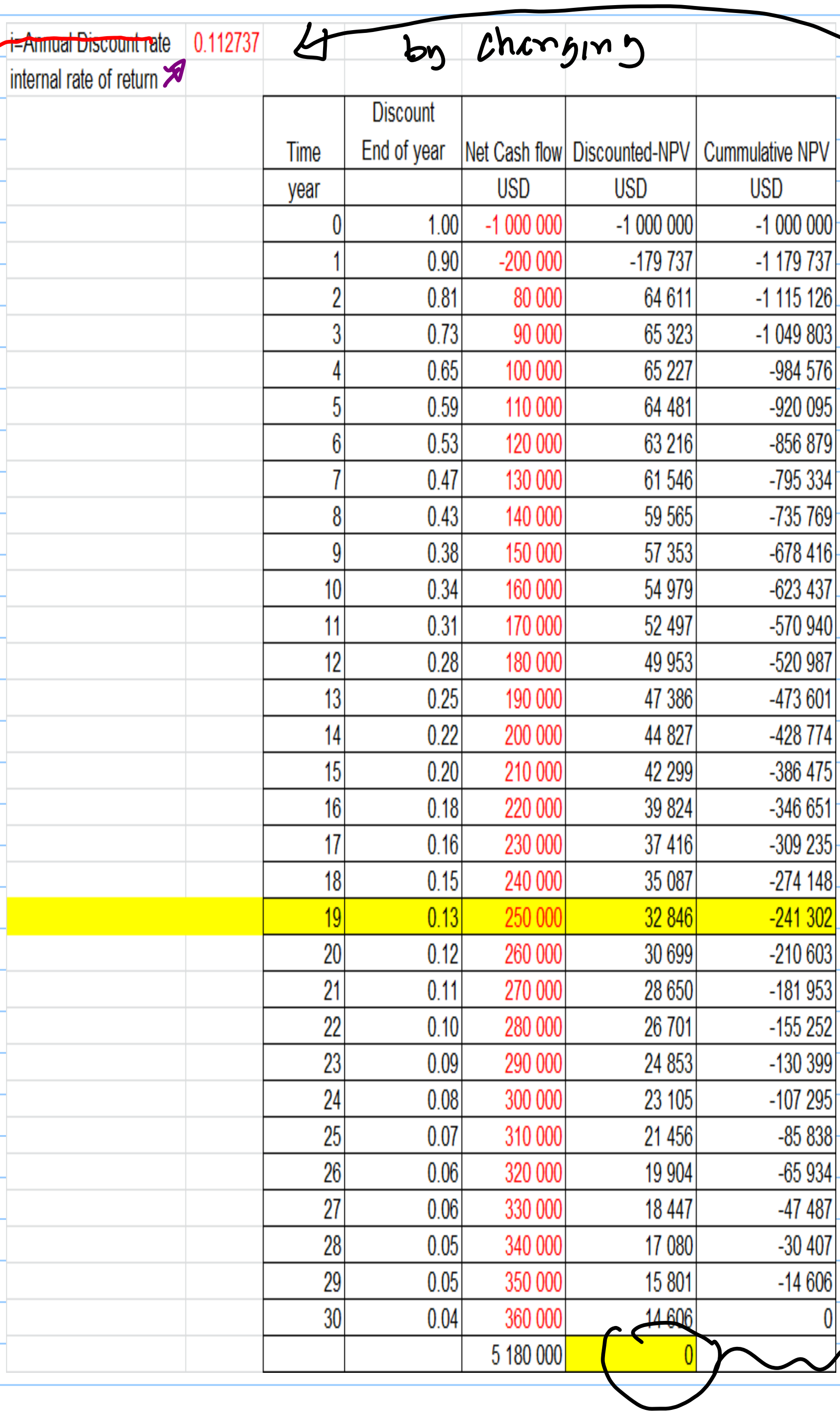
Three periods of the production profile



Two alternative concepts to rank the value of the project

1. Total NPV of the project
2. Internal rate of return (IRR)

IRR = the interest rate that give "0" Total NPV



~~i=Annual Discount rate~~ 0.112737 by changing
internal rate of return

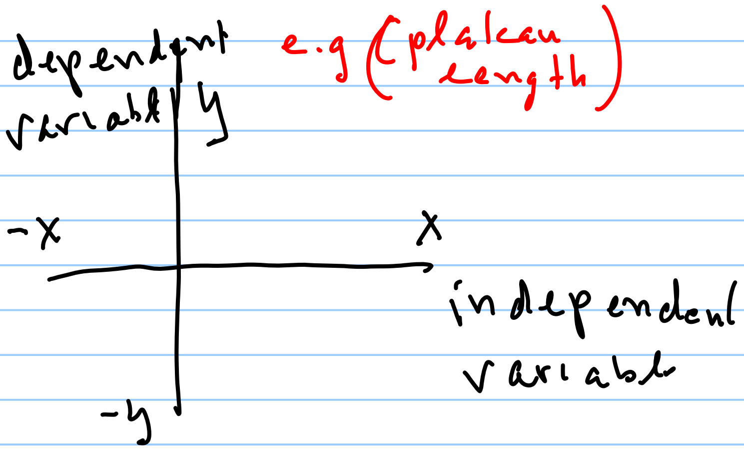
Time	Discount End of year	Net Cash flow	Discounted-NPV	Cummulative NPV
year		USD	USD	USD
0	1.00	-1 000 000	-1 000 000	-1 000 000
1	0.90	-200 000	-179 737	-1 179 737
2	0.81	80 000	64 611	-1 115 126
3	0.73	90 000	65 323	-1 049 803
4	0.65	100 000	65 227	-984 576
5	0.59	110 000	64 481	-920 095
6	0.53	120 000	63 216	-856 879
7	0.47	130 000	61 546	-795 334
8	0.43	140 000	59 565	-735 769
9	0.38	150 000	57 353	-678 416
10	0.34	160 000	54 979	-623 437
11	0.31	170 000	52 497	-570 940
12	0.28	180 000	49 953	-520 987
13	0.25	190 000	47 386	-473 601
14	0.22	200 000	44 827	-428 774
15	0.20	210 000	42 299	-386 475
16	0.18	220 000	39 824	-346 651
17	0.16	230 000	37 416	-309 235
18	0.15	240 000	35 087	-274 148
19	0.13	250 000	32 846	-241 302
20	0.12	260 000	30 699	-210 603
21	0.11	270 000	28 650	-181 953
22	0.10	280 000	26 701	-155 252
23	0.09	290 000	24 853	-130 399
24	0.08	300 000	23 105	-107 295
25	0.07	310 000	21 456	-85 838
26	0.06	320 000	19 904	-65 934
27	0.06	330 000	18 447	-47 487
28	0.05	340 000	17 080	-30 407
29	0.05	350 000	15 801	-14 606
30	0.04	360 000	14 606	0
		5 180 000	0	

Solver objective

sensitivity analysis

one parameter at a time [ceteris Paribus]

e.g (plateau length)

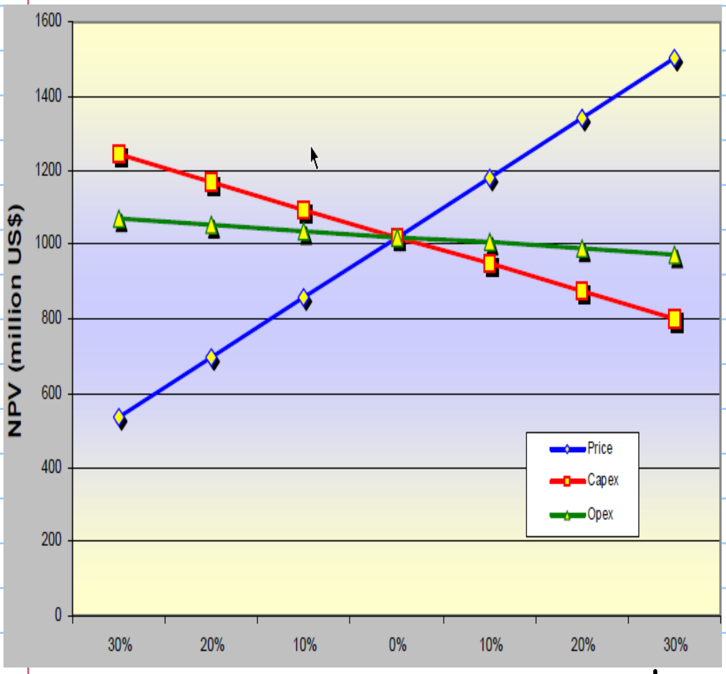


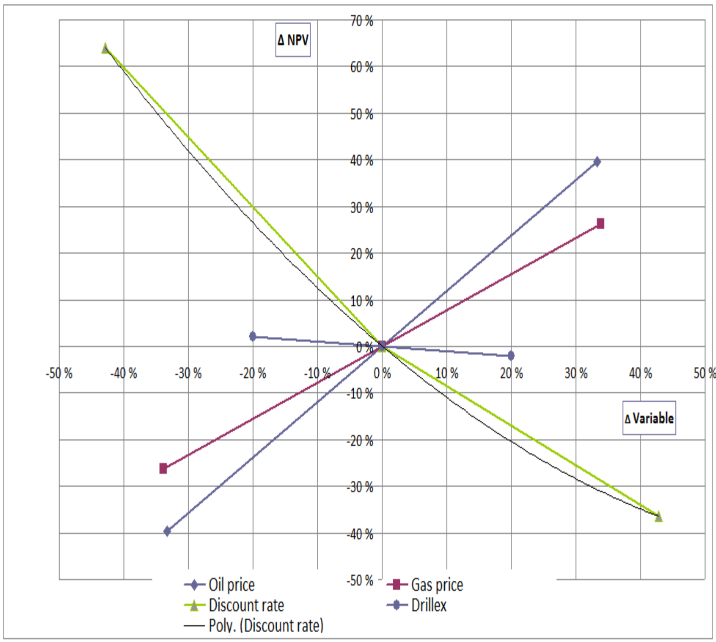
spider diagram

Parameter normalization
(e.g number of wells)

$$\text{normalized indepent variable} = \frac{X - X_{\text{base case}}}{X_{\text{base case}}} \%$$

$$\text{normalized dependent variables} \simeq \frac{y - y_{\text{base case}}}{y_{\text{base case}}} \%$$





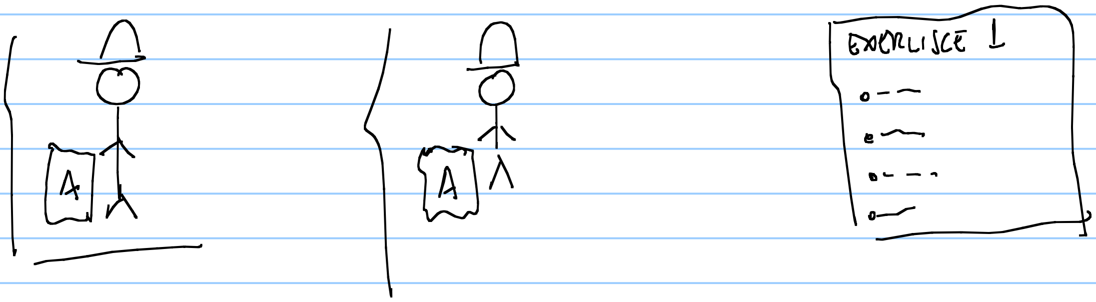
To investigate the uncertainty of multiple independent variables we will use the Monte-Carlo Analysis

Looking back: what have we covered so far?

- Introduction. Production scheduling. Field production modes
- Simplified field development analysis: Snøhvit field. field infrastructure
- Tools required to perform the field development study: Material balance, IPR, pressure losses in tubing, flow in pipes, flow equilibrium. performed the study using Excel
- Compressors: types, applications, selection criteria. Thermodynamics of the compression process. Characteristic curves of the compressor. Application to the Snowhite field
- EOS calculations for process. Fundamentals and challenges. Flash calculations.
- Hysys.
- How to prolong the plateau?
- Manifold configuration in production systems.
- Pigging
- Examples of Hysys usage
- Life cycle of an offshore field.
- Revenue and cost profiles. ← Hydrocarbon price.

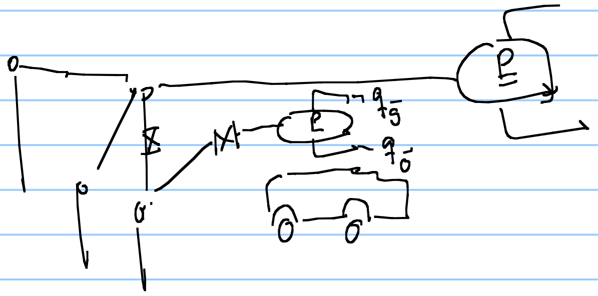
//

Difference between good engineer and average engineer:



Two approaches to handle the fluid behavior:

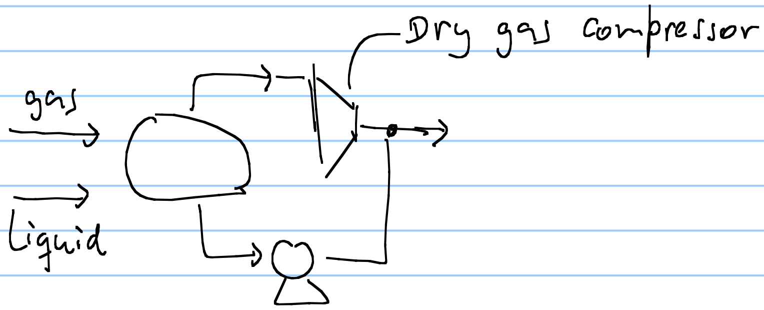
Black Oil	Compositional
$q_{\bar{o}} = 1000$ Sm^3/d [STB/d]	• EOS
• Correlation	$q_{\bar{o}} = 10000$ kgmol/d CI
• BO table	
• linked to a surface process	



Test rate conversion

//

Snøhvit not really an application case for wet gas compression.



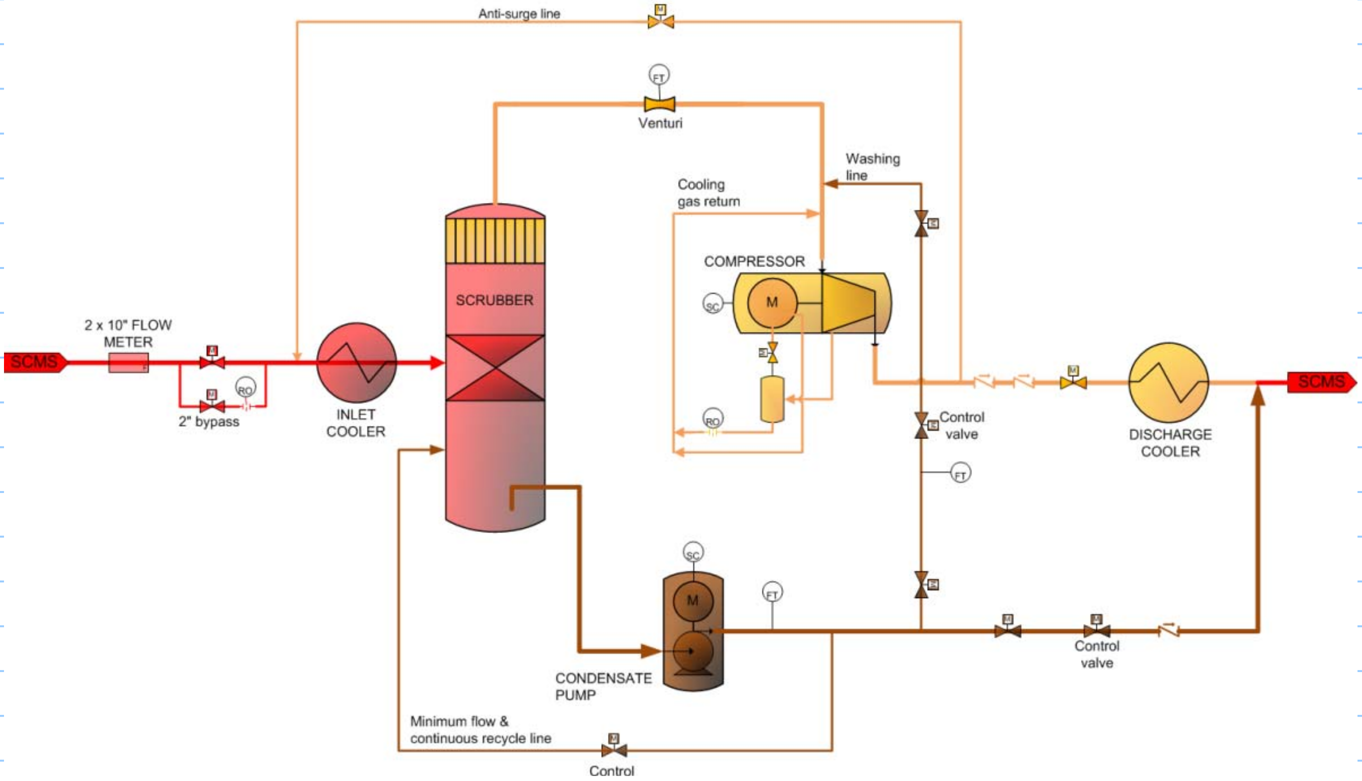
Dry gas compression

- Ormen Lange
- Åsgard

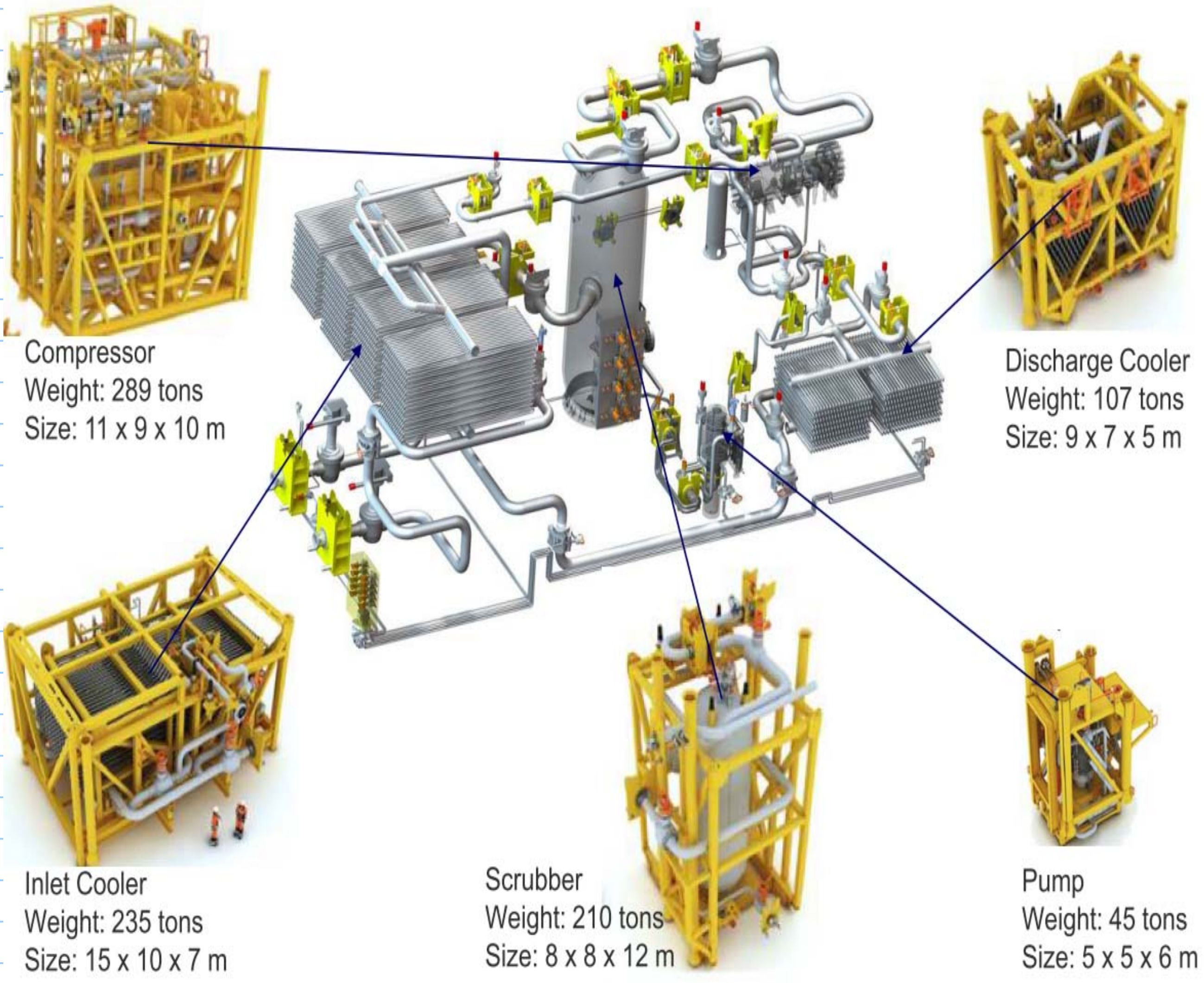
Wet gas compression

- Gullfaks South

Process Flow Diagram



Process Modules- Sizes and Dry Weights



Compressor
Weight: 289 tons
Size: 11 x 9 x 10 m

Discharge Cooler
Weight: 107 tons
Size: 9 x 7 x 5 m

Inlet Cooler
Weight: 235 tons
Size: 15 x 10 x 7 m

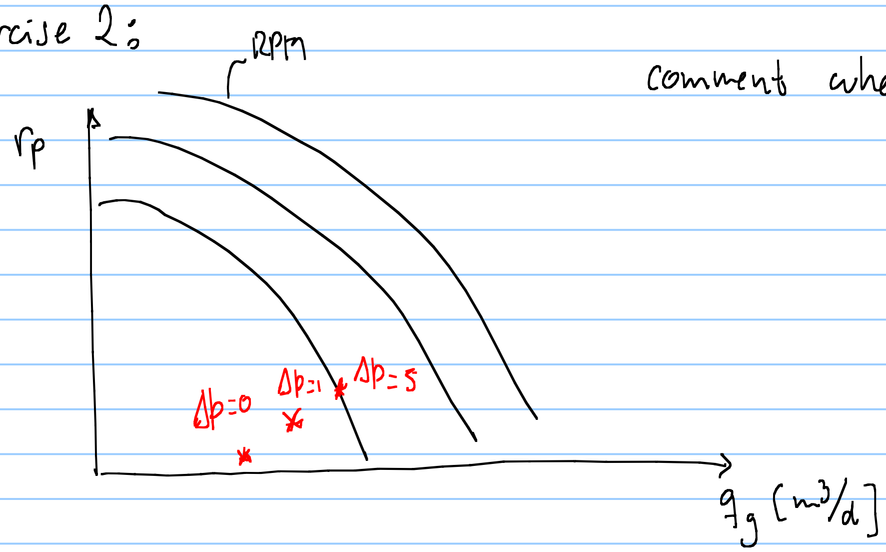
Scrubber
Weight: 210 tons
Size: 8 x 8 x 12 m

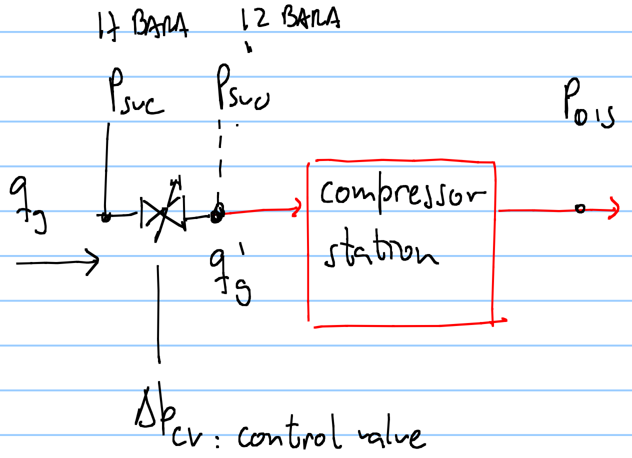
Pump
Weight: 45 tons
Size: 5 x 5 x 6 m

Exercise 3. Cost calculations in a field (NPV).

Exercise 2:

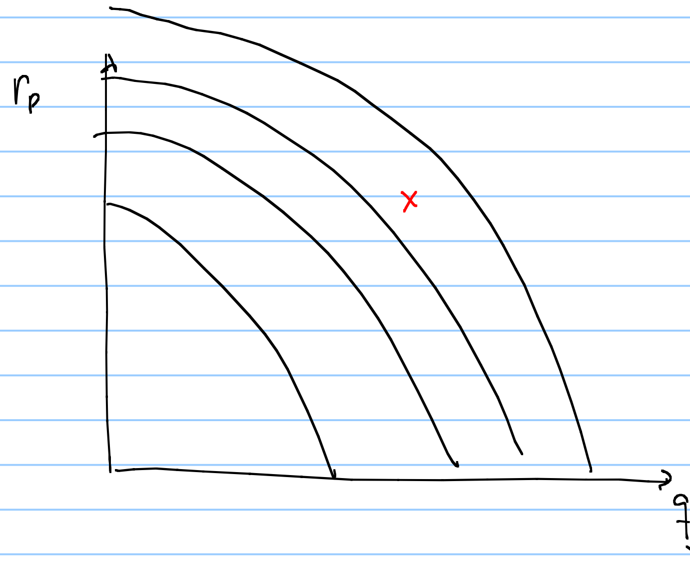
comment when the r_p is too small

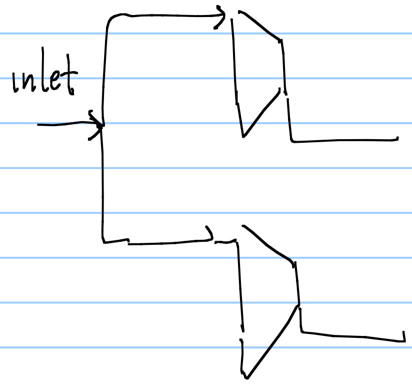




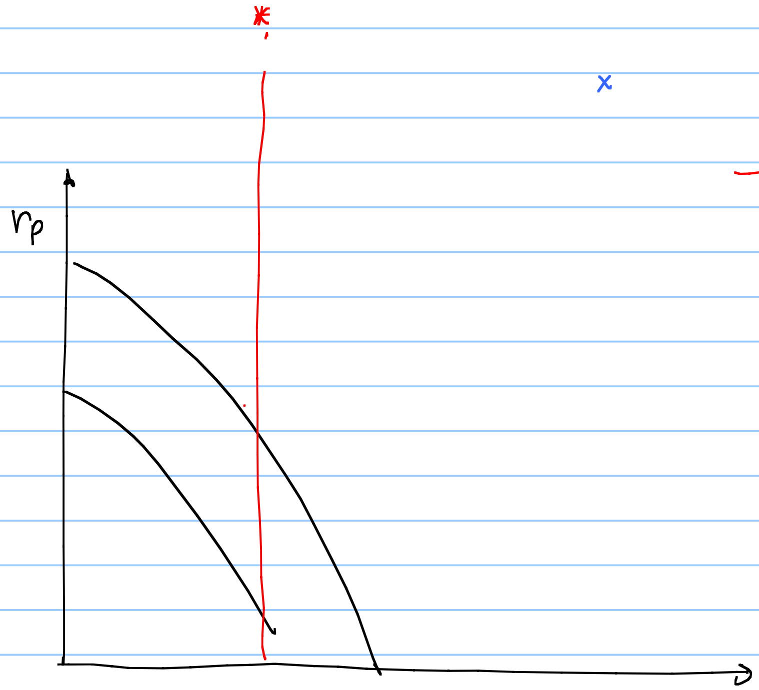
$$r_p' = \frac{P_{o1s}}{P_{suo}'} \qquad q_g'$$

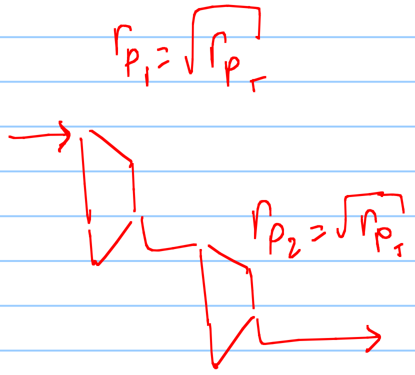
what happens when q_g is too high





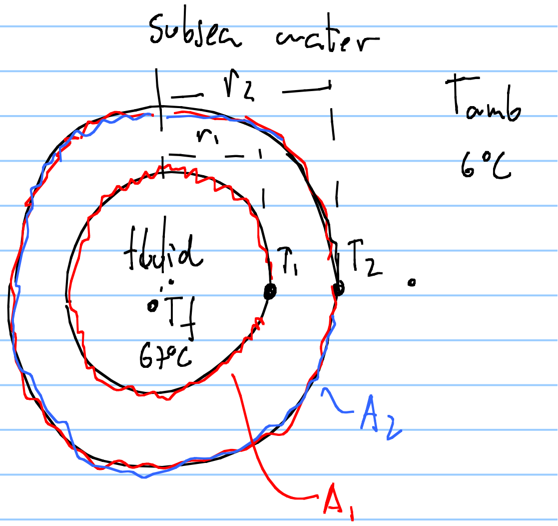
what happens if rp is too high





- U .. overall heat transfer coefficient

Snowhite pipe.



$$\dot{Q} = h_i A_1 (T_f - T_1)$$

↓

convection coefficient

conduction (solid material)

$$\dot{Q} = 2\pi K L \cdot (T_1 - T_2) \, 1/\ln(r_2/r_1)$$

↳conductivity coefficient

$$\dot{Q} = \underbrace{h_{out}} \cdot A_2 \, (T_2 - T_{amb})$$

$$W = \left[\frac{W}{m^2 K}\right] m^2 \, (K)$$

$\underline{T_f - T_1} = \frac{\dot{Q}}{h_i A_1}$ $\qquad$ $(T_1 - T_2) = \frac{\dot{Q}}{2\pi K L} \ln\left(\frac{r_2}{r_1}\right)$ $\qquad$ $(T_2 - T_{amb}) = \frac{\dot{Q}}{h_o A_2}$

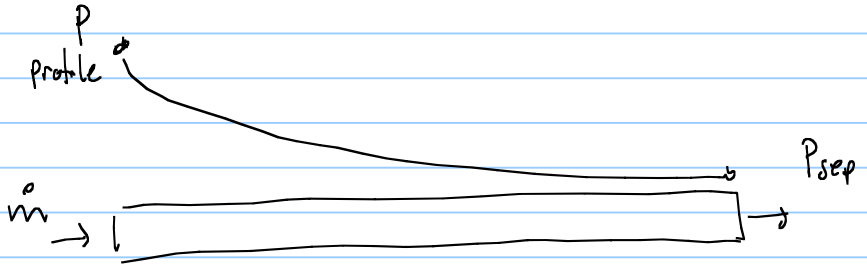
sum all of them

$$(T_f - T_{amb}) = \dot{Q}\left[\frac{1}{h_i A_1} + \frac{1}{h_o A_2} + \frac{\ln(r_2/r_1)}{2\pi K L}\right]$$

$$\dot{Q} = U \cdot A_2 \cdot (T_f - T_{amb})$$

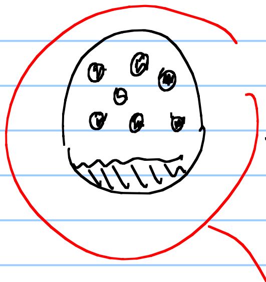
$$\frac{1}{U A_2} = \left[\frac{1}{h_i A_1} + \frac{1}{h_o A_2} + \frac{\ln(r_2/r_1)}{2\pi K L}\right]$$

$$U = \left[A_2 \left[\frac{1}{h_i A_1} + \frac{1}{h_o A_2} + \frac{\ln(r_2/r_1)}{2\pi K L}\right]\right]^{-1}$$



$$\dot{m} = Q \cdot \rho = A_p \cdot V \cdot \rho$$

Multiphase flow



homogeneous flow approach { all phases travel at the same speed

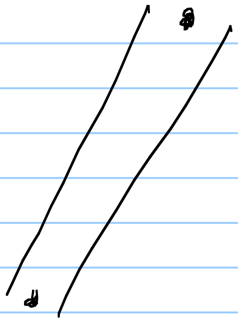
$$\rho_{mix} = \lambda_g \cdot \rho_g + (1-\lambda_g)\cdot\rho_L$$

q_g q_L

$$\lambda_g = \frac{q_g}{q_L+q_g} = \frac{A_g}{A_L+A_g} = \frac{A_g}{A_p}$$

NON SLIP CONDITIONS

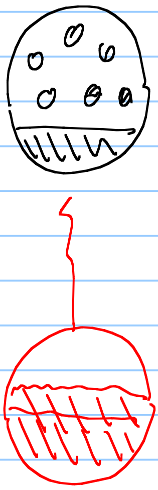
gas volume fraction



μ_{eff}

$v_g = v_L = v$

$$\frac{\cancel{v_g}\cdot A_g}{\cancel{v_L}\cdot A_L + \cancel{v_g}\cdot A_g}$$



slip between the phases v_L v_g

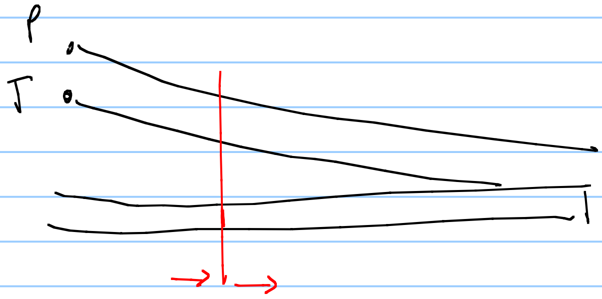
$$\lambda_g = \frac{q_g}{q_o+q_g}$$

$v_g > v_L$

$q_g = v_g \uparrow \cdot A_g$

$= \frac{A_g}{A_L+A_g}$

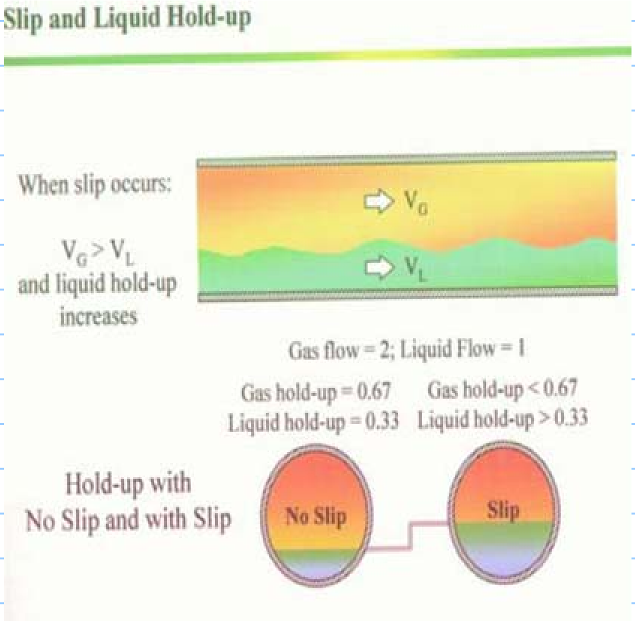
$q_L = v_L \downarrow \cdot A_L$



$\dot{m}_g = q_g \cdot \rho_g$

$\dot{m}_L = q_L \cdot \rho_L$

$\frac{d\dot{m}}{dt} = 0$



Slip and Liquid Hold-up

When slip occurs:

$V_G > V_L$
and liquid hold-up
increases

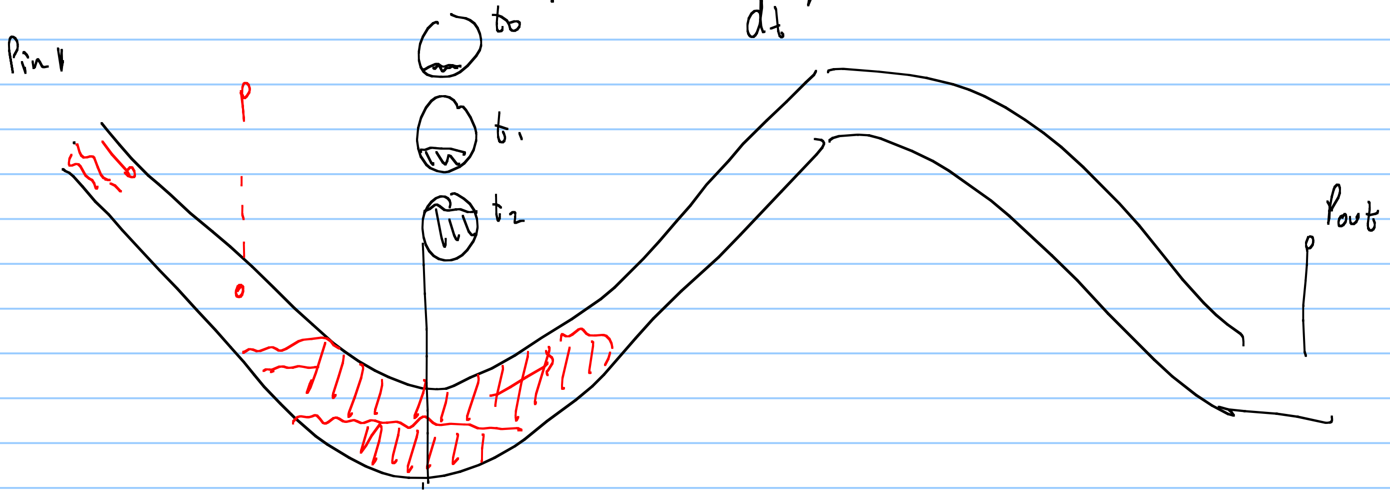
Gas flow = 2; Liquid Flow = 1

Gas hold-up = 0.67
Liquid hold-up = 0.33

Gas hold-up < 0.67
Liquid hold-up > 0.33

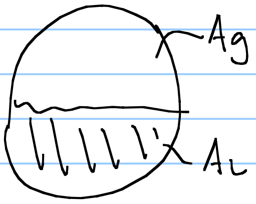
Hold-up with
No Slip and with Slip

Accumulation or transient effects $\frac{d}{dt} \neq 0$



IF Fluid is Homogeneous

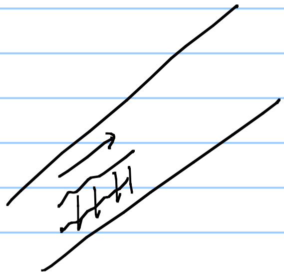
Holdup $H_L = \frac{A_L}{A_L + A_g}$

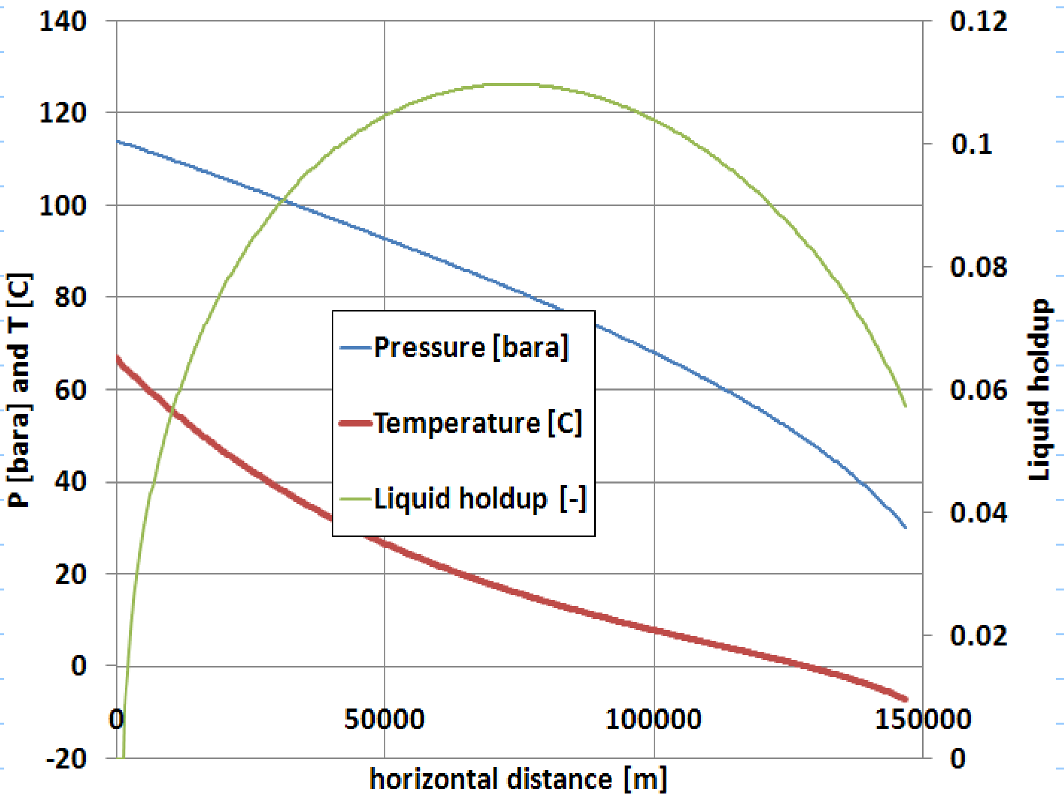


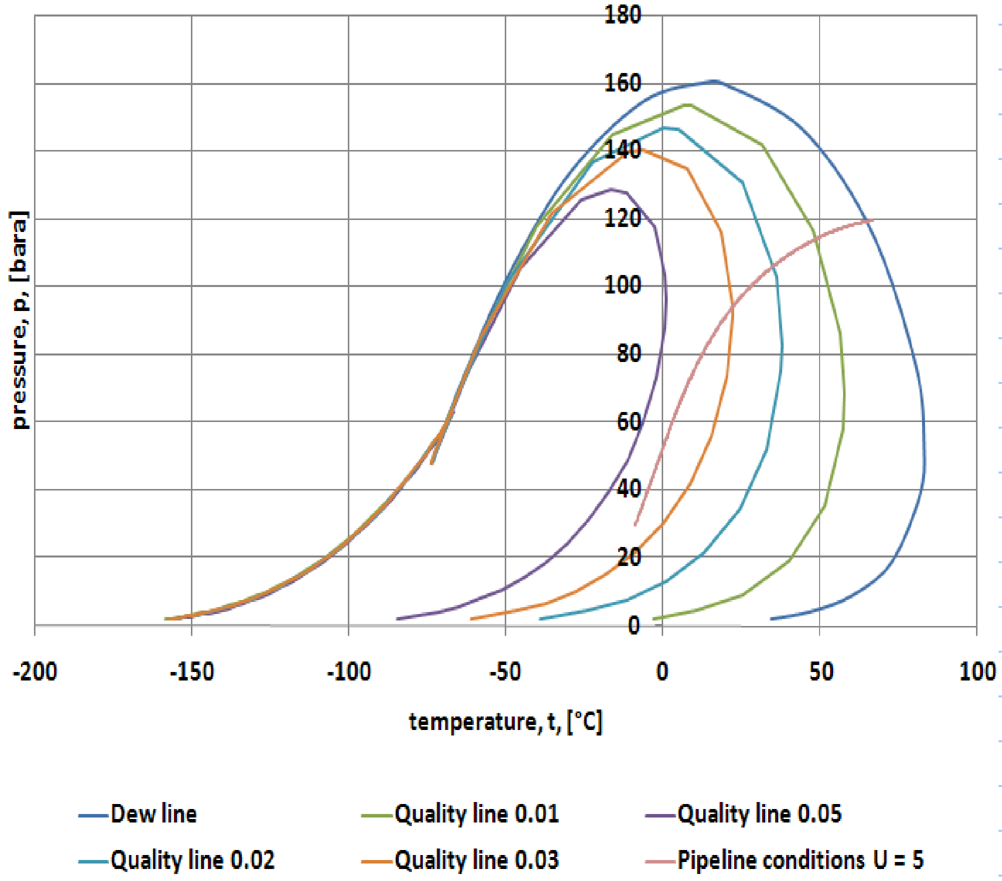
$H_L = \lambda_L = \frac{q_L}{q_g + q_L}$

is the fuid is not homogeneous

$H_L \neq \lambda_L$

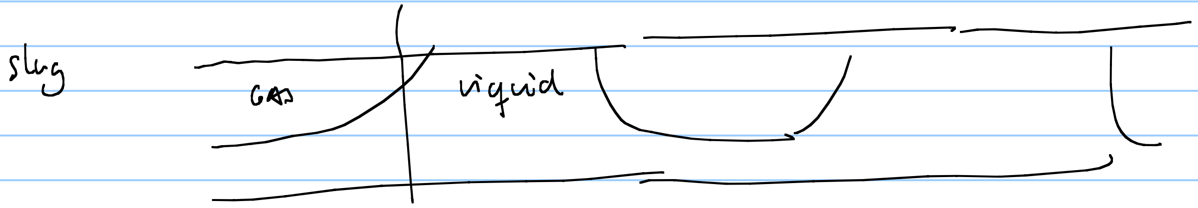






quality (X_g) $= \frac{m_g}{m_T} = \frac{m_g}{m_L + m_g}$

$X_L = \left(\frac{m_L}{m_g + m_L} \right)$



Reservoir

- Eclipse (Schlumberger)
- CMG (CMG)
- MORE (ROXAR)
- Sensor (Coats engineering)
- REVEAL (Petroleum Experts)
- MBAL (" ")
  (PETEX)

Production

- Prosper (PETEX)
- GAP (PETEX)
- PIPESIM (Schlumberger)
- WELLFLO (WEATHERFORD)
- OLGA (Schlumberger)

Process

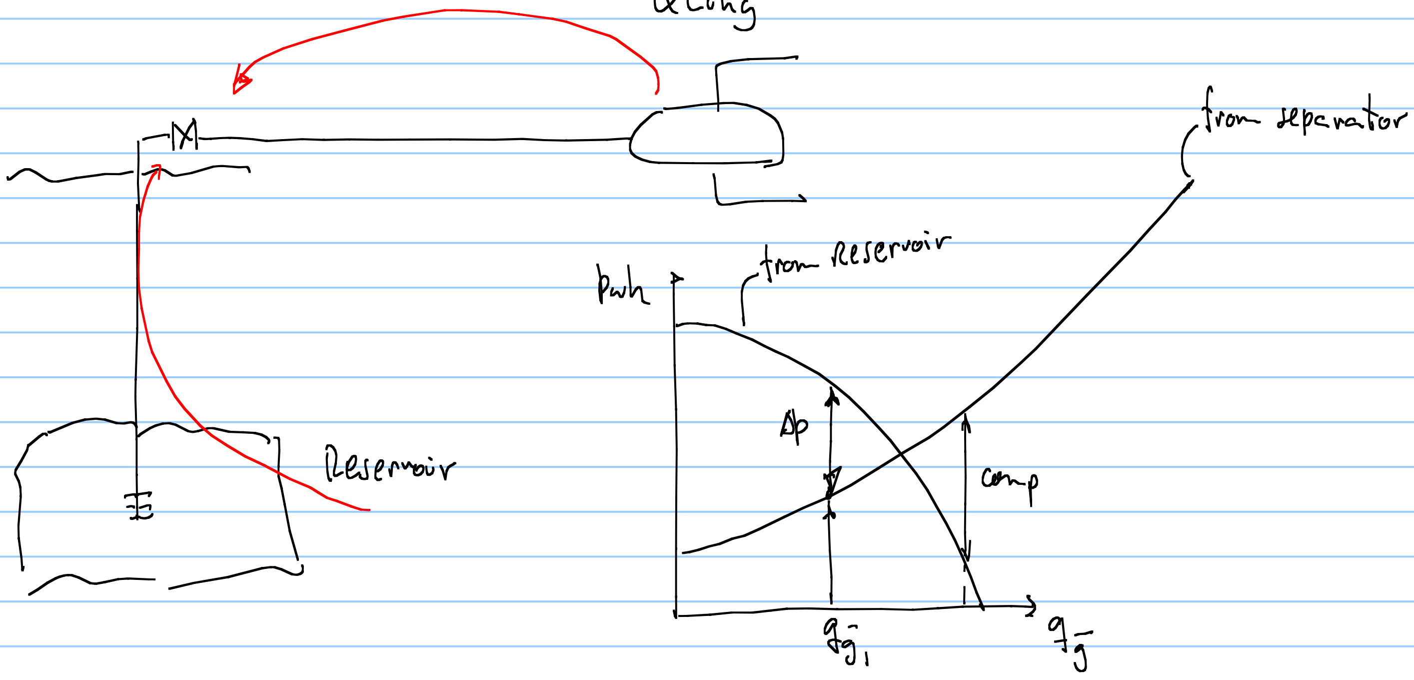
- HYSYS (Aspentech)
- Unisim (Honeywell)
- Pro/II (Invensys)

Integration

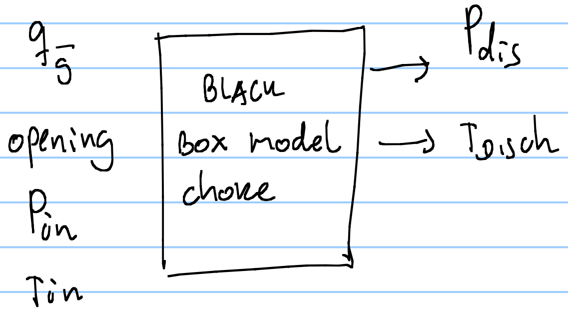
- AVOCET IAM (Schlumberger)
- Resolve (PETEX)
- Pipe-it (Petrostreamz)

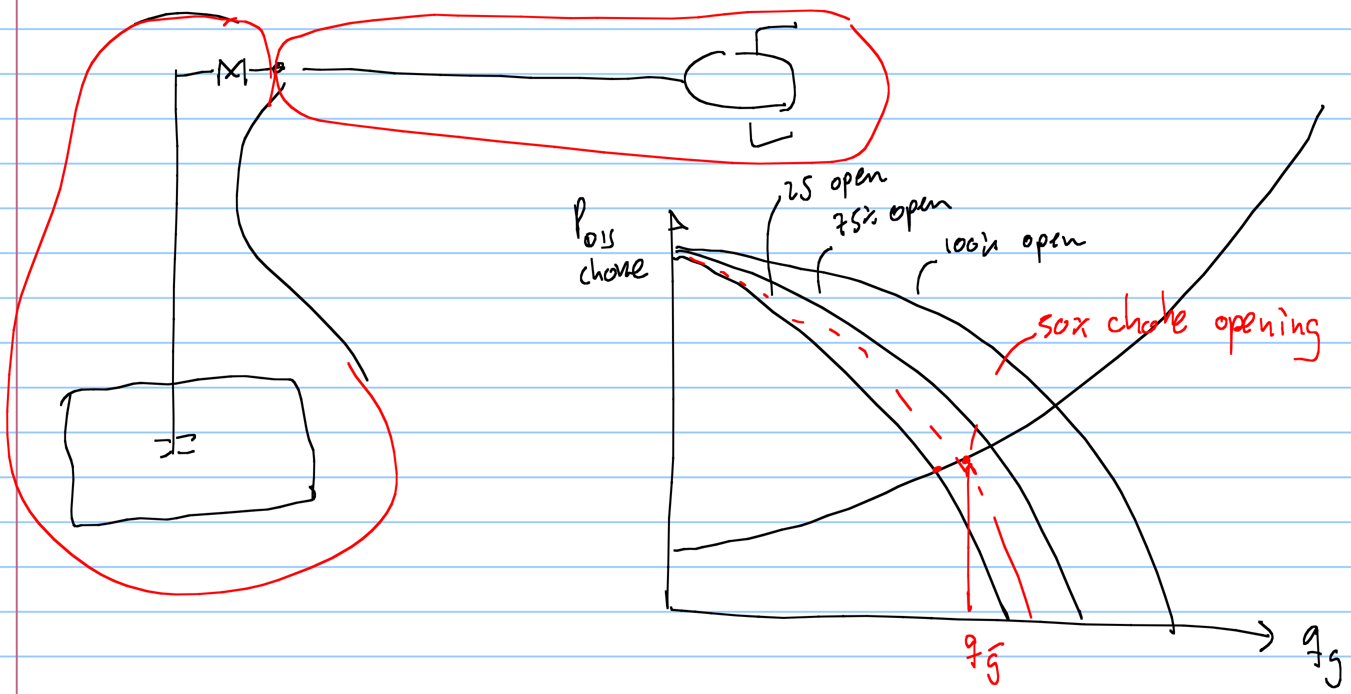
A lot of software!   GARBAGE in → Garbage out

QCing



lets assume that we have a choke model





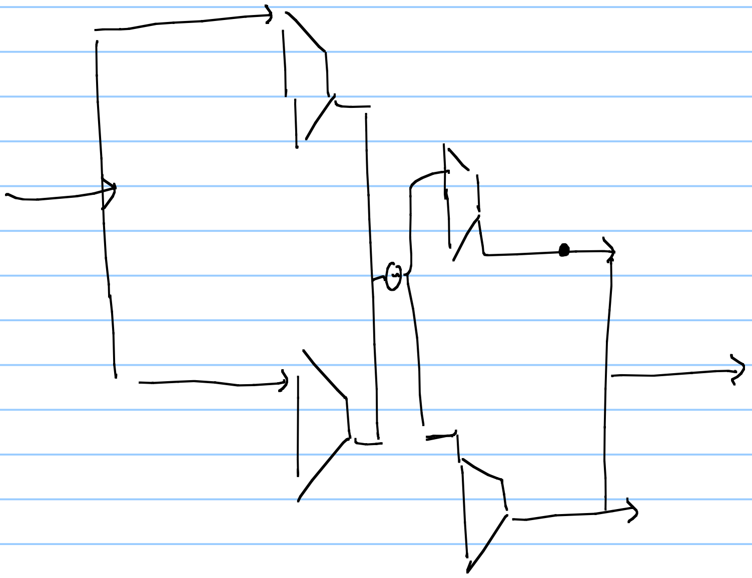
17.02.2015

One comment on exercise 2. HW.

Δh h .. specific enthalpy $\left[\frac{kJ}{kg}\right]$

For an ideal gas $\int_1^{1} dh = \int_1^{1} C_p(T)\,dT$

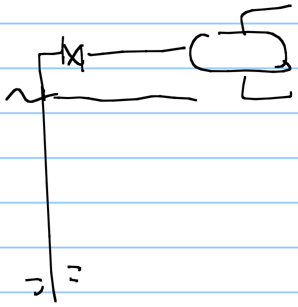
$$h_2 - h_1 = \int_{T_1}^{T_2} C_p\,dT$$

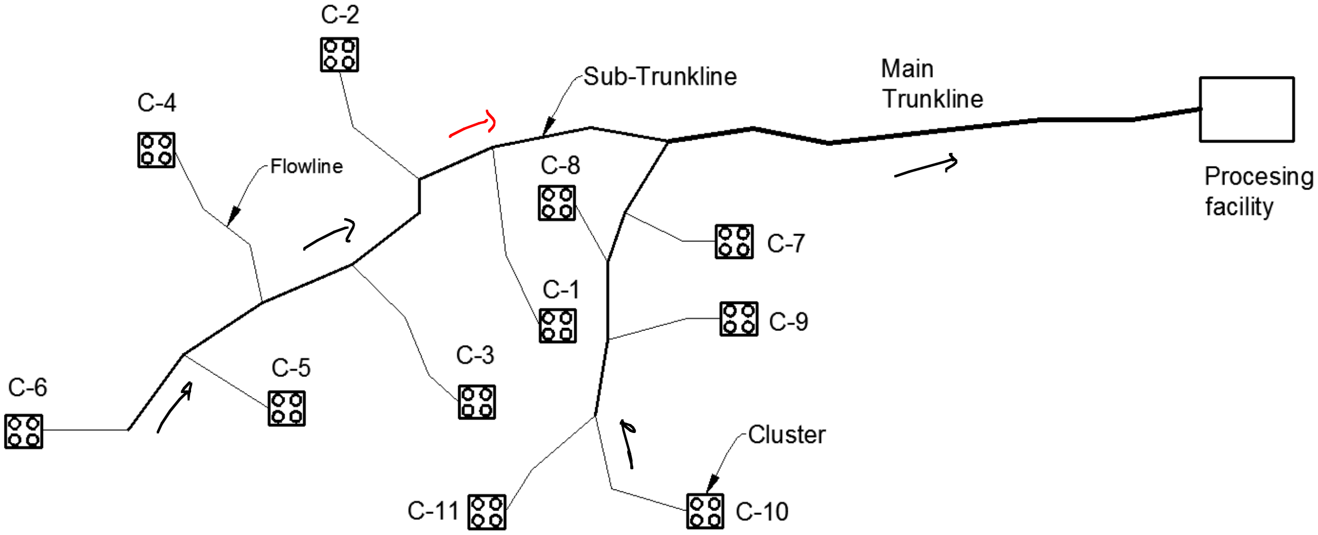


- Network solving

Service Network, production network, production system

Network: piping system to take well production to the processing facilities.



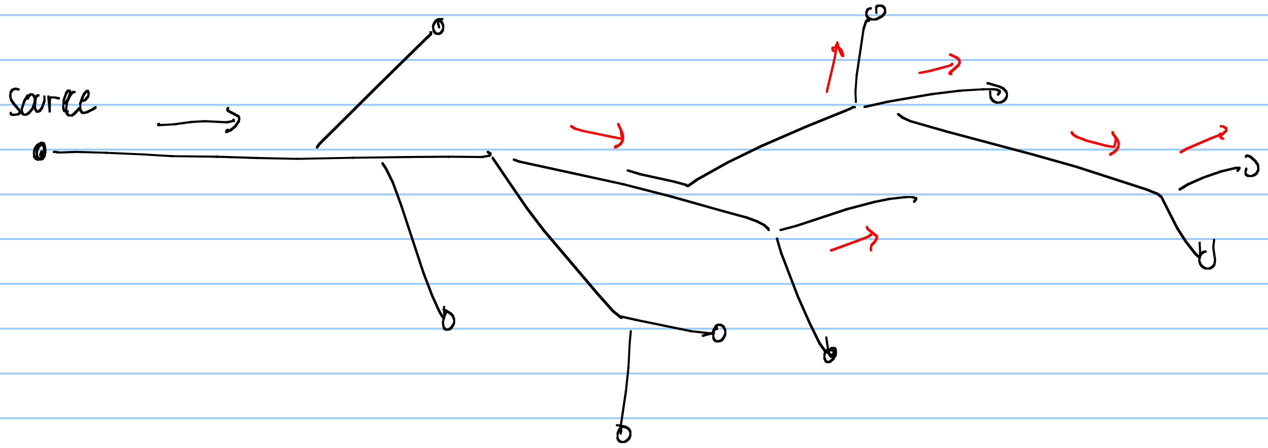


Commingling network, gathering network.

We also have distribution network

Injection network

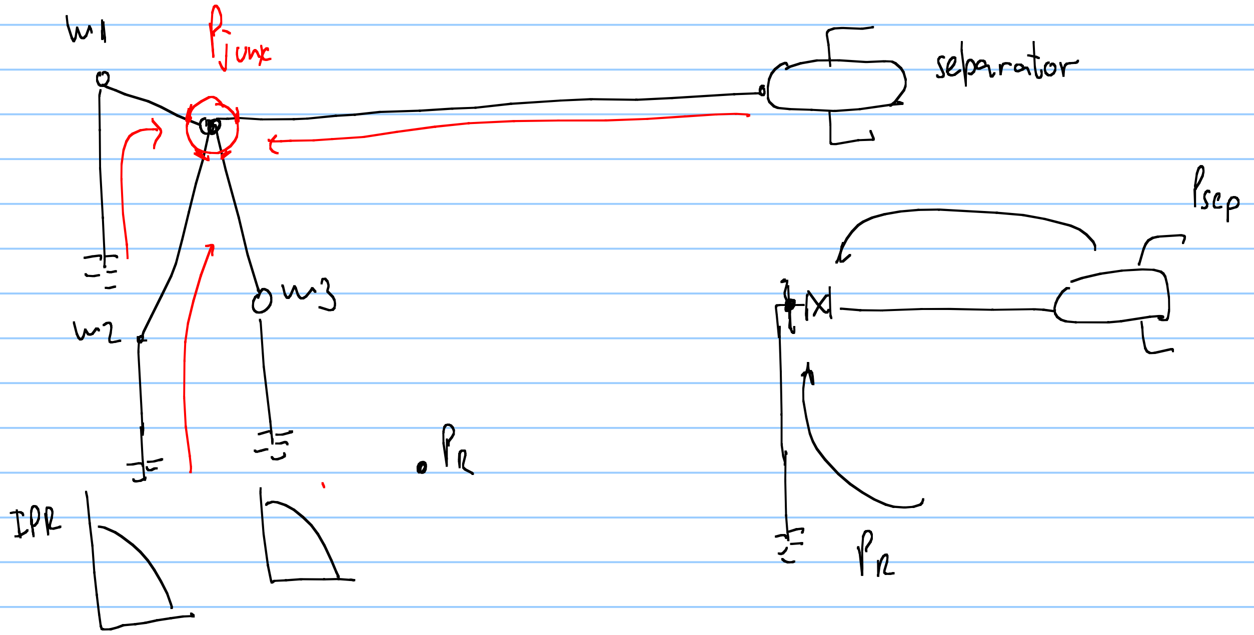
Gas lift distribution network



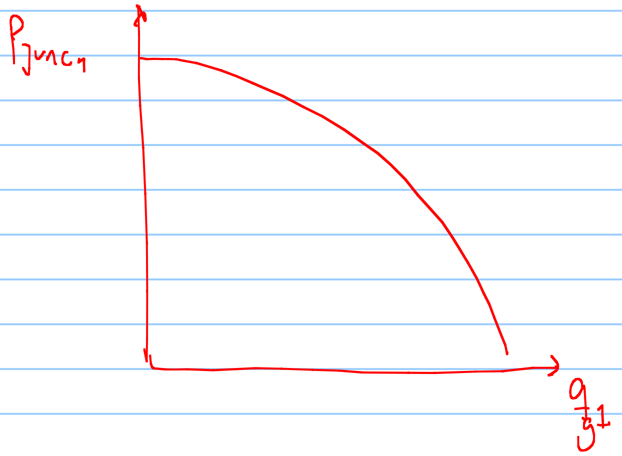
Solving: calculating the operating conditions of the network.

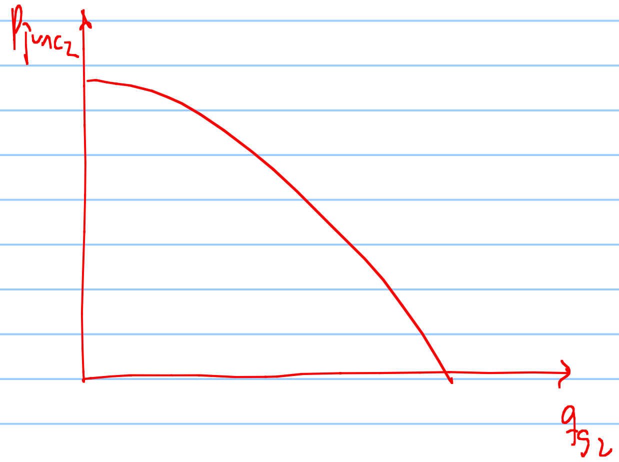
- well rates
- p, T
- Flow rate in trunklines

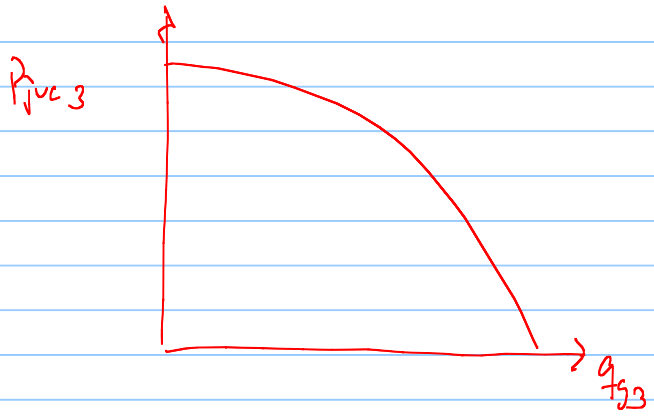
No adjustable elements in our network (chokes, pumps (ESP), compressors)



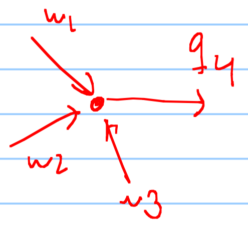
Solving the problem graphically:



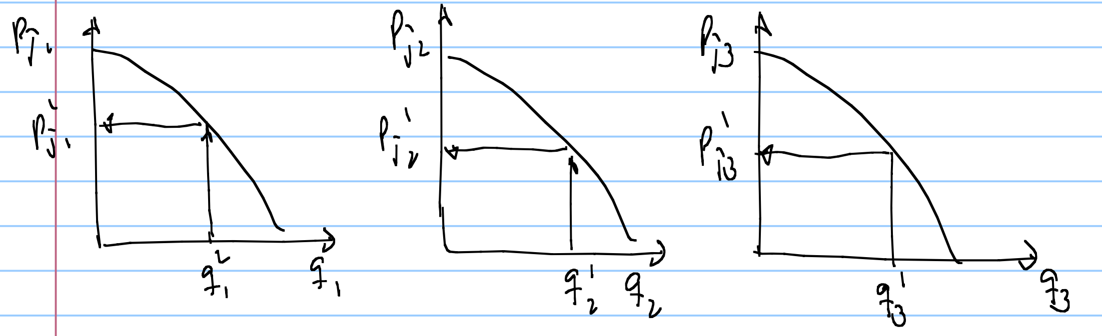


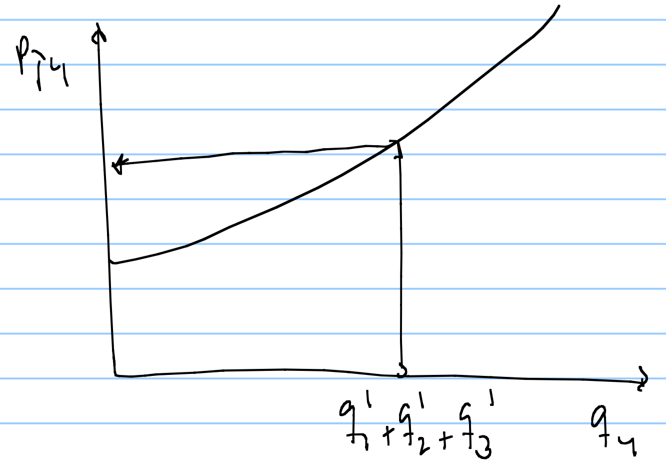


$q_4 = q_1 + q_2 + q_3$



Graphical procedure. Assume q_1', q_2', q_3' ~



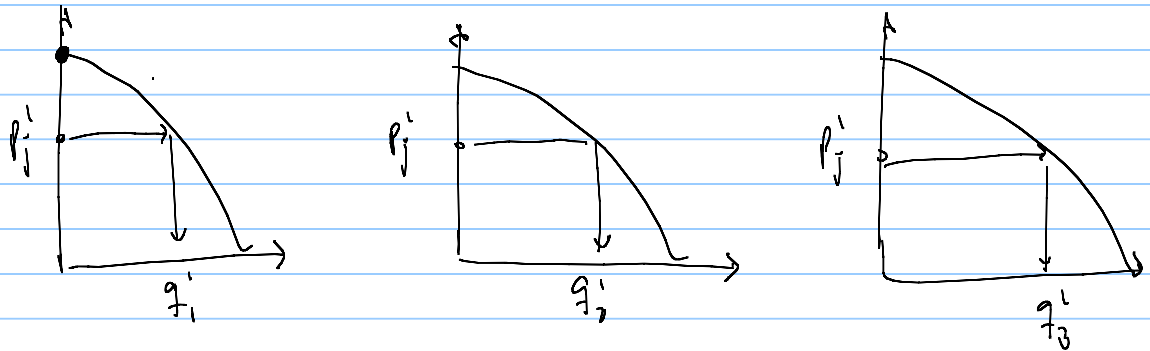


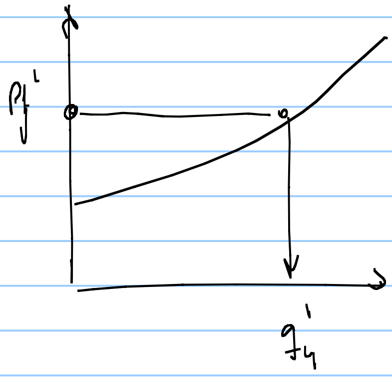
$p_{j1} = p_{j2} = p_{j3} = p_{j4}$?

repeat until they are the same

$p_{j1}(q_1) =$

Choose to assume p_j





is $q_1' + q_2' + q_3' = q_4'$?

assume another p_j

when solving the problem using equations, mathematics :

For each well $P_{j1}(q_1) = f_1(q_1)$ ✓

$P_{j2}(q_2) = f_2(q_2)$ ✓

$P_{j3}(q_3) = f_3(q_3)$ ✓

$\overset{\checkmark}{P}_{j4}(q_4) = f_4(q_4)$ ✓

5 unknowns, 4 equations

$q_4 = q_1 + q_2 + q_3$ 1 extra equation

$$\underbrace{\left\{\begin{array}{l} P_{j1}(q_1) \\ P_{j2}(q_2) \\ P_{j3}(q_3) \\ P_{j4}(q_1, q_2, q_3 \end{array}\right|}$$

(4 unknowns, 4 equations)

Use a numerical method for solving a system of non-linear equations (Newton method)

Need derivatives

$$P_{jav} = \frac{P_{j1} + P_{j2} + P_{j3} + P_{j4}}{4}$$

$$\varepsilon = (P_{j1} - P_{jav})^2 + (P_{j2} - P_{jav})^2 + (P_{j3} - P_{jav})^2 + (P_{j4} - P_{jav})^2$$

with excel solver drive $\varepsilon \to 0$, TOL By changing q_1, q_2, q_3

Doing the excel exercise

Network solving

Nonlinear system of equations

given a set of non-Liner equations (NLE)°

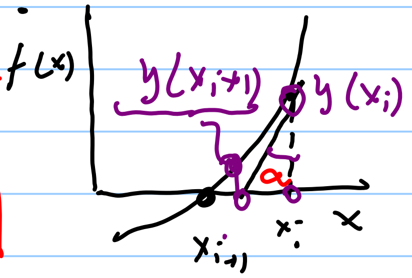
$$f_1(x_1, x_2, \cdots\cdots x_n) = 0$$
$$f_2(x_1, x_2 \cdots\cdots x_n) = 0$$
$$\vdots$$
$$f_n(x_1, x_2 \cdots\cdots x_n) = 0$$

find a set of values $x_1 x_2 \cdots\cdots x_n$ that simultaneously results in all equation equaling zero

x x x x x x x x x x x x x x x x x x

Recall Newton-Raphson root finding procedure of $f(x)=0$.

$$\boxed{tg\,\alpha = f'(x_i) = \frac{f(x_i) - 0}{x_i - x_{i+1}}}$$



Rearranging

$$\boxed{x_{i+1} = x_i - \frac{f(x_i)}{f'(x_i)}} \text{ or } \boxed{f' = \frac{f}{-dx}} \text{ or } \boxed{f'(x) \cdot dx = -f(x)}$$

This is Newton Raphson formula

solution procedure (for one NLE)

1. guss x
2. find $f(x)$ and $f'(x)$
3. calculate $dx = (x_{i+1} - x_i) = -\dfrac{f(x)}{f'(x)}$
4. update $x^{new} = x^{old} + dx$
5. calculate $f(x)^{new}$
6. If $f(x)^{new} \leq \varepsilon \rightarrow$ yes → Exit; no → go to 2

The graphical procedure is based on first-order Taylor series expansion

$$f(x_{i+1}) = f(x_i) + (x_{i+1} - x_i) f'(x_i)$$

One approach for solving a set of NLE is to use multi-dimensional version of Newton Raphson method for one equation above:
This is based on multi-dimension Taylor series expansion:

for example,

$f_1(x_1, x_2) =$

$f_2(x_1, x_2)$

$$f_1^{i+1} = f_1^i + \underbrace{(x_1^{i+1} - x_1^i)}_{dx_1} \frac{\partial f_1^i}{\partial x_1} + \underbrace{(x_2^{i+1} - x_2^i)}_{dx_2} \frac{\partial f_1^i}{\partial x_2}$$

$$f_2^{i+1} = f_2^i + \underbrace{(x_1^{i+1} - x_1^i)}_{dx_1} \frac{\partial f_2^i}{\partial x_1} + \underbrace{(x_2^{i+1} - x_2^i)}_{dx_2} \frac{\partial f_2^i}{\partial x_2}$$

Recal for single equation

$$f'(x) \cdot dx = - f(x)$$

we can prove (soon) that this equation is valid for set of equations and can be written as an Array Formula As matrix

$$\begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} \\ \frac{d f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} \end{bmatrix} \begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = - \begin{bmatrix} f_1(x_1, x_2) \\ f_2(x_1, x_2) \end{bmatrix}$$

$$\boxed{\frac{\partial \bar{f}}{\partial x} \cdot d\bar{x} = - \bar{f}}$$

- The partial derivative metrix is called the Jacobian of the system. Thus

$$J \begin{bmatrix} dx_1 \\ dy_1 \end{bmatrix} = -\begin{bmatrix} f_1 \\ f_2 \end{bmatrix}$$

$$\begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = -J^{-1}\begin{bmatrix} f_1 \\ f_2 \end{bmatrix}$$

$$\begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = -\frac{\begin{bmatrix} f_1 \\ f_2 \end{bmatrix}}{J} =$$

In algebraic form:

$$dx_1 = \underbrace{x_1^{i+1} - x_1^{i}}_{dx_1} = -\frac{f_1 \frac{\partial f_2}{\partial x_2} - f_2 \frac{\partial f_1}{\partial x_2}}{\underbrace{\frac{\partial f_1}{\partial x_1} \cdot \frac{\partial f_2}{\partial x_2} - \frac{\partial f_1}{\partial x_2} \cdot \frac{\partial f_2}{\partial x_1}}_{\text{Determinant of the Jacobian}}}$$

$$dx_2 = x_2^{i+1} - x_2^{i} = -\frac{f_2 \cdot \frac{\partial f_1}{\partial x_1} - f_1 \frac{\partial f_2}{\partial x_1}}{\underbrace{\frac{\partial f_1}{\partial x_1} \frac{\partial f_2}{\partial x_2} - \frac{\partial f_1}{\partial x_2} \cdot \frac{\partial f_2}{\partial x_1}}_{\text{determinant of } J}}$$

in more general form (Jacobian form)

$$J = \begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \frac{\partial f_2}{dx_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_n} \\ \vdots & & & \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_2} \end{bmatrix}$$

The array equation is then

$$\begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \frac{\partial f_2}{dx_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_n} \\ \vdots & & & \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_2} \end{bmatrix} \begin{bmatrix} \Delta x_1 \\ \Delta x_2 \\ \vdots \\ \Delta x_n \end{bmatrix} = - \begin{bmatrix} f_1 \\ f_2 \\ \vdots \\ f_n \end{bmatrix}$$

$$\{\bar{x}_i\}^T = \lfloor x_1^i, x_2^i, \cdots x_n^i \rfloor$$

$$\{\bar{x}_{i+1}\}^T = \lfloor x_1^{i+1}, x_2^{i+1}, \cdots x_n^{i+1} \rfloor$$

$$\{\bar{f}_i\}^T = \lfloor f_1^i, f_2^i, \cdots f_n^i \rfloor$$

$$[J]\{\bar{x}_{i+1}] = -\{\bar{f}_i\} + [J]\{\bar{x}_i\}$$

This equation can be solved using technique such as Gaus Eliminatio

$$J_{ij}\, \bar{\Delta x_j} = -\bar{f}_i$$

$$\Delta x_j = - J_{ij}^{-1} \cdot f_i$$

$$x^{n+1} = x^n + \Delta x$$

1. guss x_j
2. find $f(x)$ and $f'(x)$
3. calculate $dx = -\frac{f(x)}{f'(x)}$
4. update $x^{new} = x^{old} + dx$
5. got to 2 if necessary

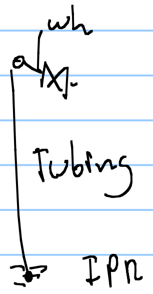
Anothe apprach to solution of
a set of NLE

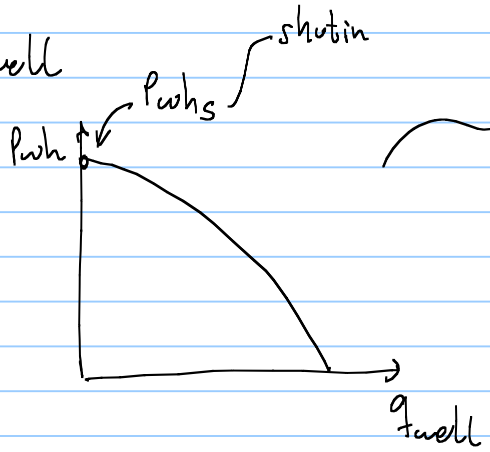
1. Formulate the non-Linear system
as a single function

$$F(x) = \sum_{i=1}^{n} [w_i f_i (x_1, x_2 \cdots x_n]^2$$

The value of $\bar{X}$ that minimize the
function represent the solution
of the non-Linear system.
This formulation is a class of
Problem call <u>non-Linear regression</u>

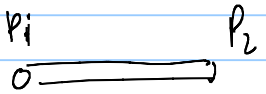
Extract one well





$$\underbrace{q_g = (P_{whs}^2 - P_{wh}^2)\, C_{wh}}_{\text{representing IPR and tubing}}$$

horizontal flowline



$$q = C_{fL} \cdot (P_1^2 - P_2^2)$$

Determining max rate values for excel problem:

$$q_g = (P_{whs}^2 - P_{whf}^2) . C_{wh}$$

$$P_{whf} = \sqrt{\underbrace{P_{whs}^2 - \frac{\boxed{q_g}}{C_{wh}}}_{\text{becomes negative}}} \text{ — too high}$$

$$P_{whs}^2 - \frac{q_{glimit}}{C_{wh}} = 0$$

$$q_{glimit} = P_{whs}^2 . C_{wh}$$

there is one problem with this approach, we are neglecting the flowline between wellhead and juction. A better way is

$$q_g = C_{wh}\,(P_{whs}^2 - P_{wh}^2) \qquad q_g = C_{fL}\,(P_{wh}^2 - P_j^2)$$

$$\frac{q_g}{C_{wh}} = P_{whs}^2 - P_{wh}^2 \qquad \frac{q_g}{C_{fL}} = P_{wh}^2 - P_j^2$$

adding the two equations

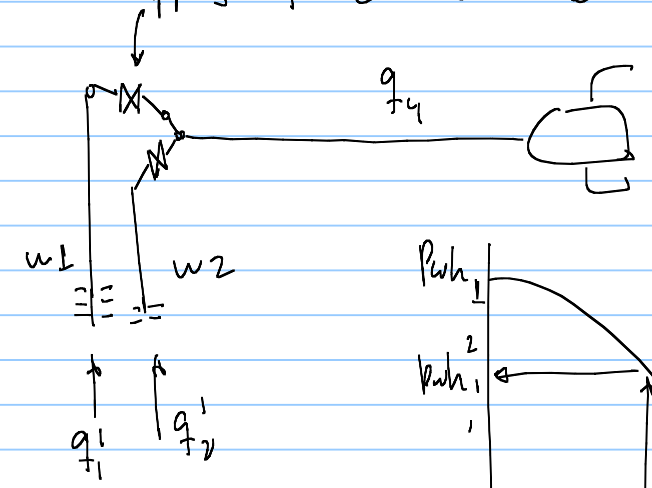
$$\underline{q_g}\left(\frac{1}{C_{wh}}+\frac{1}{C_{fl}}\right)=P_{whs}^2-P_j^2$$

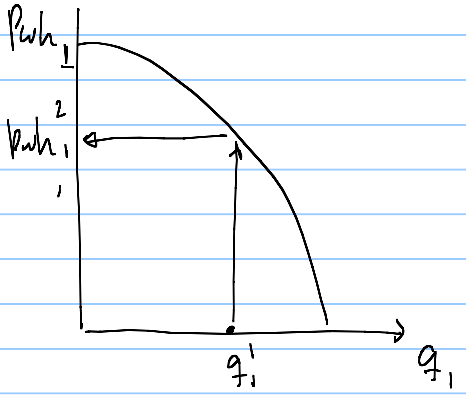
$$P_j=\sqrt{\underbrace{P_{whs}^2-q_g\left(\frac{1}{C_{wh}}+\frac{1}{C_{fl}}\right)}_{\geq 0}}$$

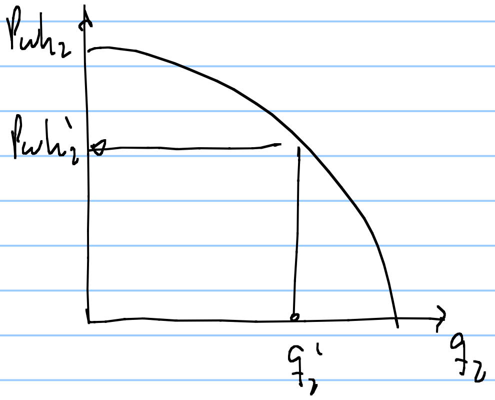
$$P_{whs}^2\geq q_g\left(\frac{1}{C_{wh}}+\frac{1}{C_{fl}}\right)$$

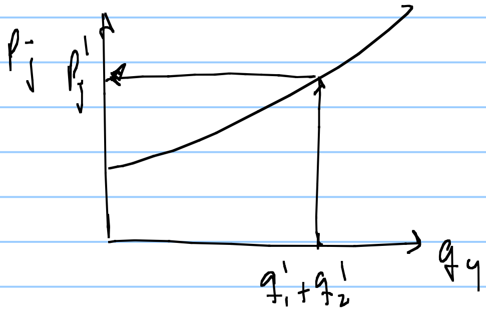
$$\left(\frac{1}{C_{wh}}+\frac{1}{C_{fl}}\right)^{-1}P_{whs}^2\geq q_g$$

What happens if we have a network wih chokes?







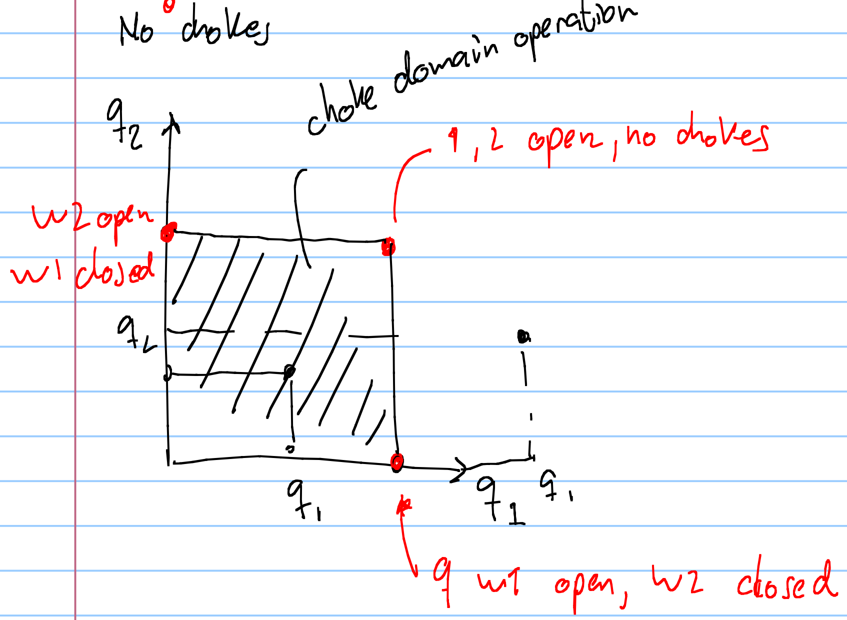


choke in well 1: $P_{wh_1}' - P_j'$

choke in well 2 $P_{wh_2}' - P_j'$

It has to be > 0, if not, there is not enough energy in the well to flow that rate. change the rate and repeat.

No chokes



repeat excel exercise with chokes

Fix rate for each well

$q_1 = 300E3\ Sm^3/d$

$q_2 = 350E3\ Sm^3/d$

$q_3 = 300E3\ Sm^3/d$

Neglect the flowline between the well and the junction

23.02.2015

Agenda for today:

Network solving

- Procedure of calculating choked wells in commercial software
- Both choked wells and Natural flowing wells in a network. Example in Excel

Discussion about part 2 of Exercise 2

- Physical interpretation of holdup distribution in pipeline and P and T evolution in the phase envelope
- Liquid accumulation in low points in the pipe

Notification: Sets of exercise 3 published.

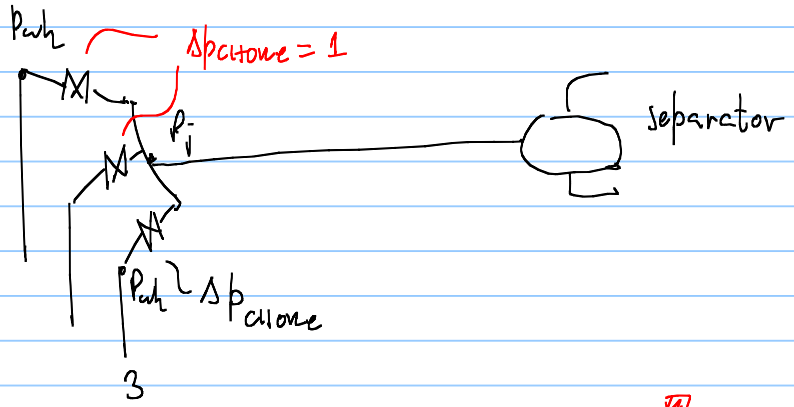
Inflow performance relationship

- Introduction and general discussion. Physical meaning

Absolute open flow potential- applications

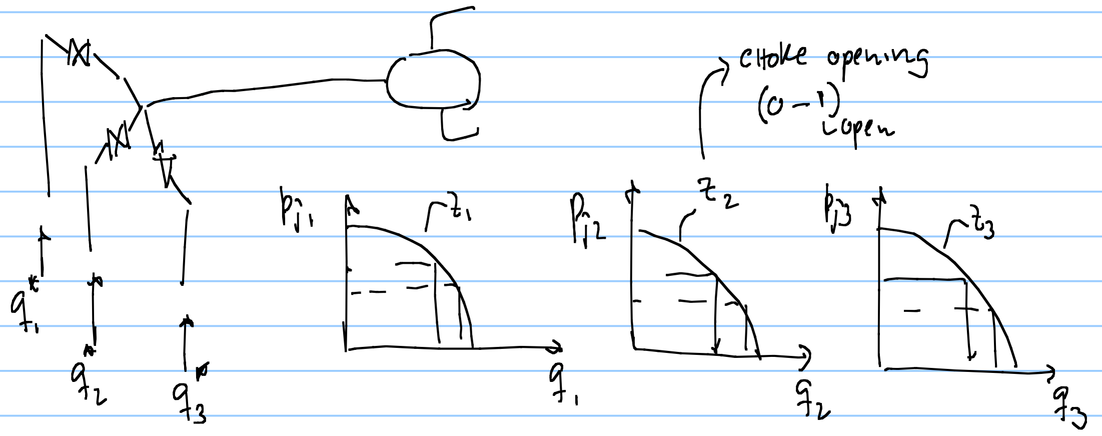
- Decline curve analysis – reservoir engineering - Example

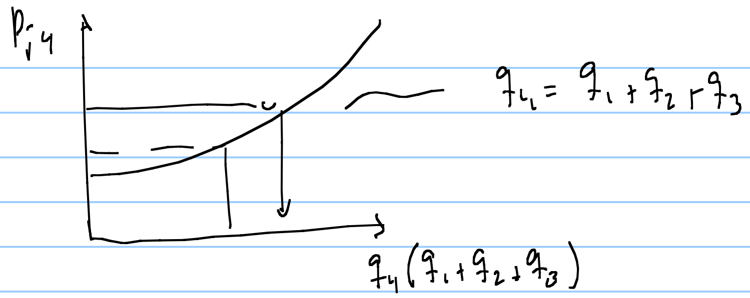
Excel example : Surface network with 1 well choked, 2 flowing naturally



See excel sheet ! do it yourself !

Commercial sofware with choked wells   the choke model is included in the calculations



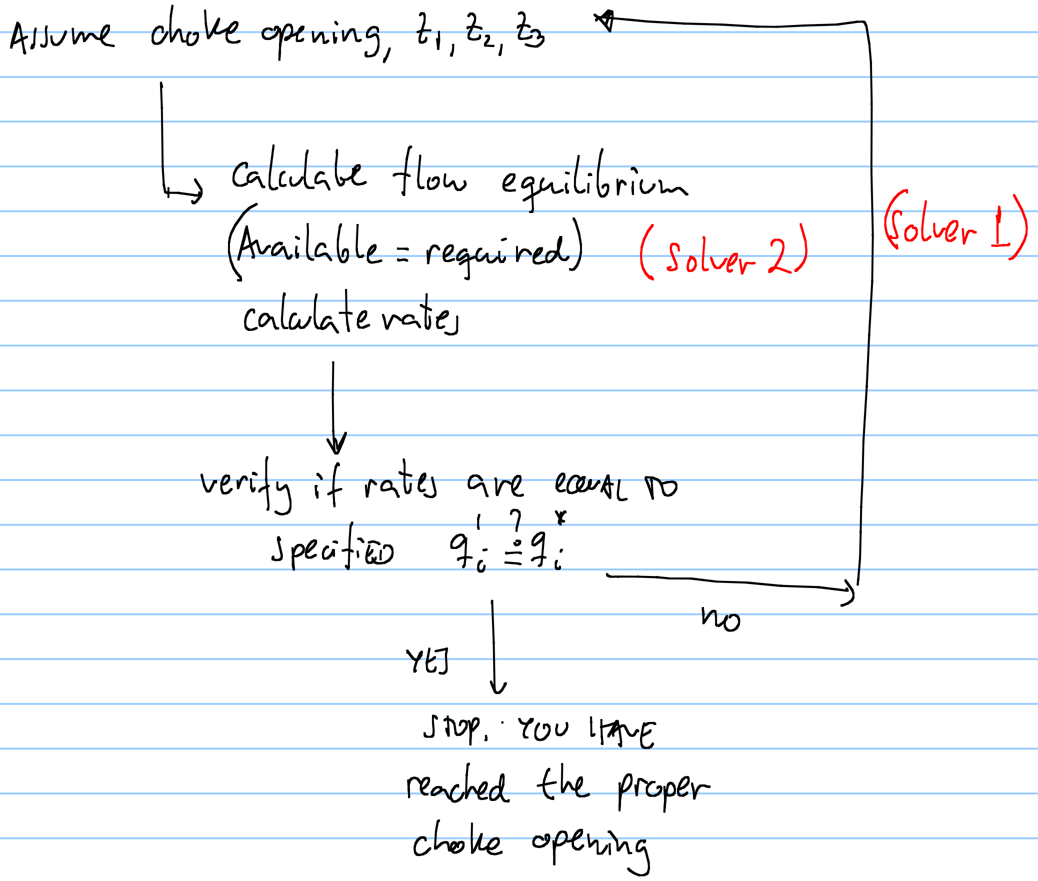


Calculate natural flow equilibrium

and a set of rates is obtained $\underbrace{q_1', q_2', q_3'}$

$$\varepsilon = (q_1^* - q_1')^2 + (q_2^* - q_2')^2 + (q_3^* - q_3')^2$$

You need two solvers:


Assume choke opening, z_1, z_2, z_3

calculate flow equilibrium (Available = required) (Solver 2)

calculate rates

verify if rates are equal to specified $q_i' \overset{?}{=} q_i^*$

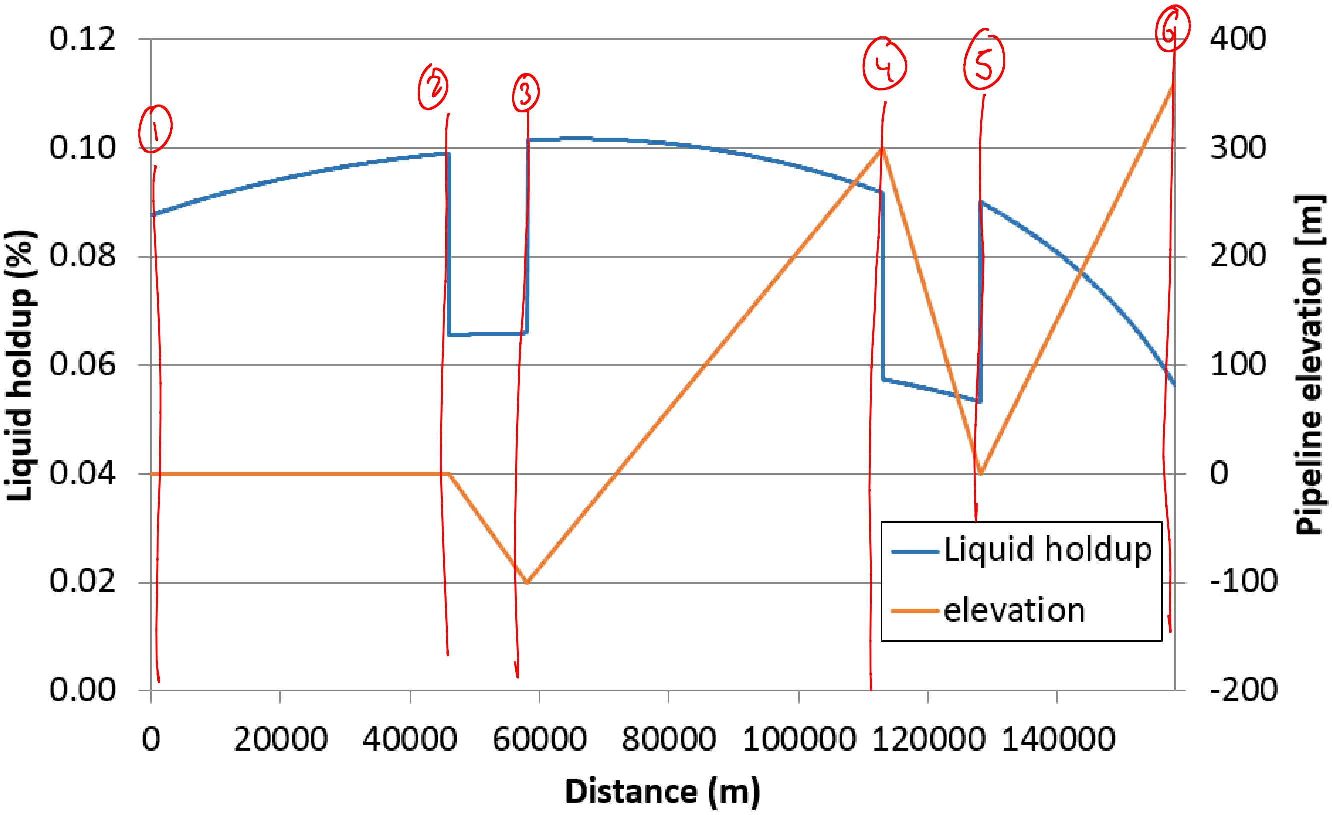
no

(Solver 1)

yes

stop. You have reached the proper choke opening

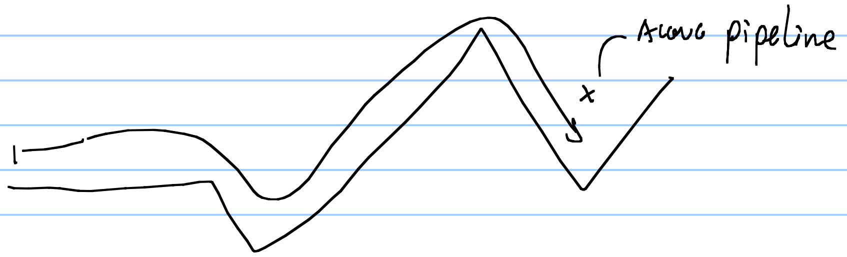
Discussion about part 2 of exercise 2



$H_L = \frac{A_L}{A_p}$

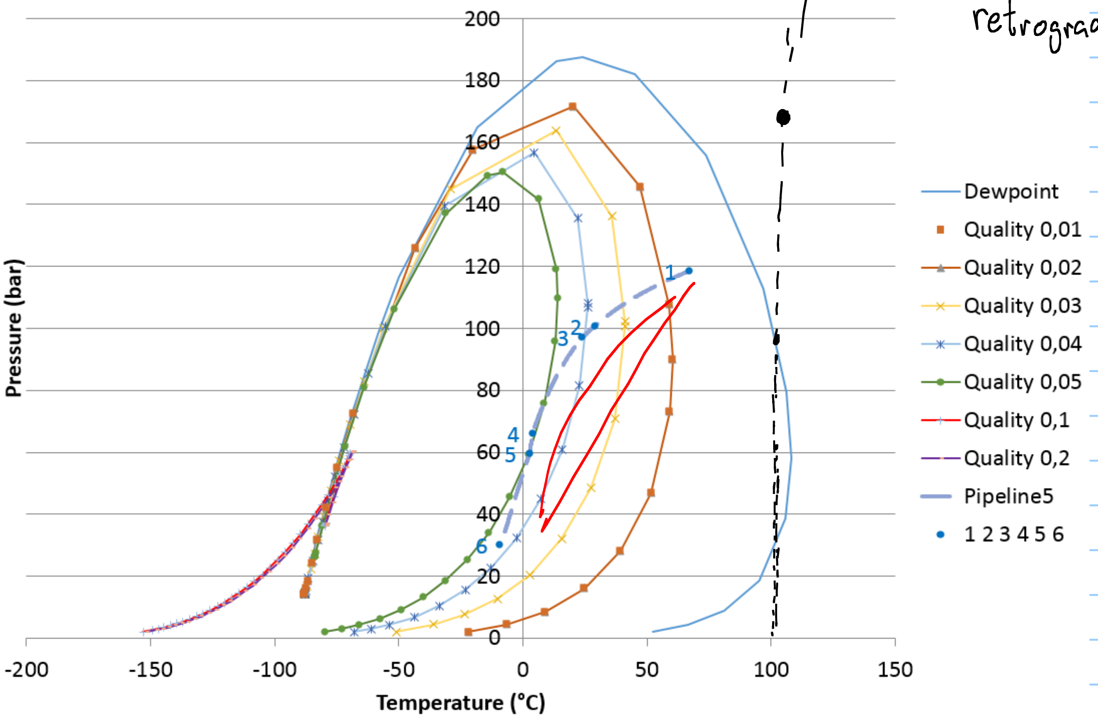
→ condensation
evaporation
$\partial \dot{m}_L$ $\partial \dot{m}_g$

→ dynamics of multiphase flow (slip)

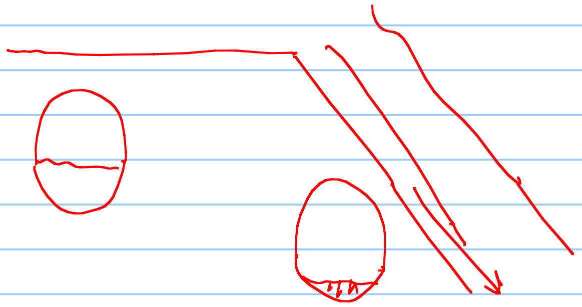


P,T evolution in reservoir

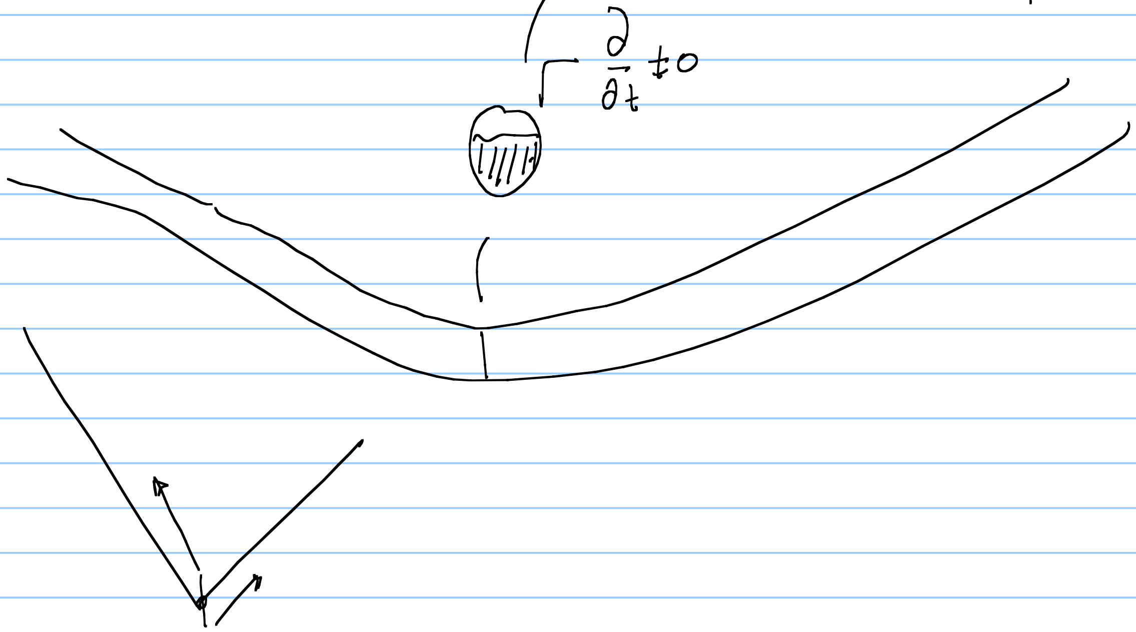
retrograde condensation

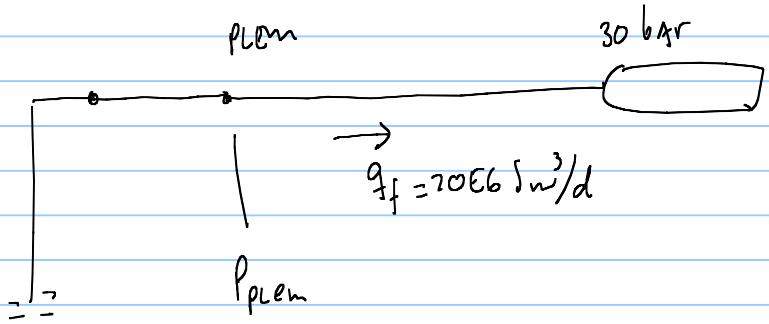


$X = \frac{m_L}{m_T}$



transient phenomenon { need a transient simulator





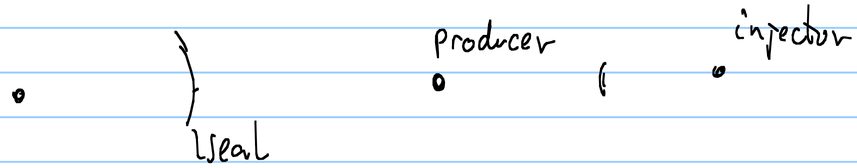
- IPR Inflow performance relationship ≠ PI (productivity index)

is a model/equation to describe the behavior of the reservoir

└ availability of the reservoir

IPR contains

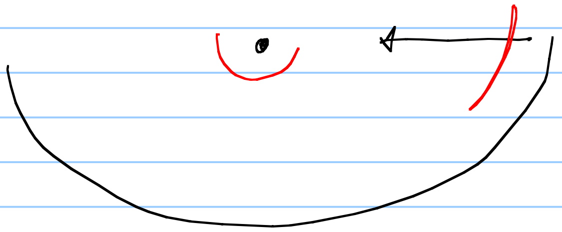
- Information about conditions far from the well (boundary)



- flow restrictions into the wellbore :
  (perforation, skin, formation damage)

- flow of gas, oil, water in the porous media

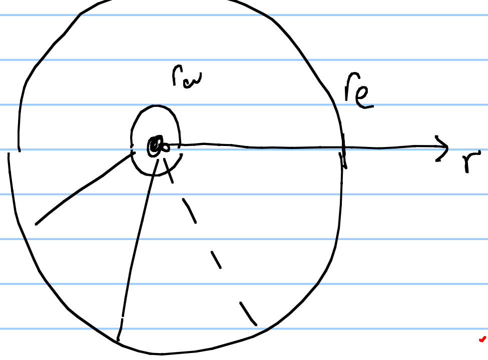
- Convergence effect



- Steady state or pseudo steady state description (no depletion)

assume vertical well

top view

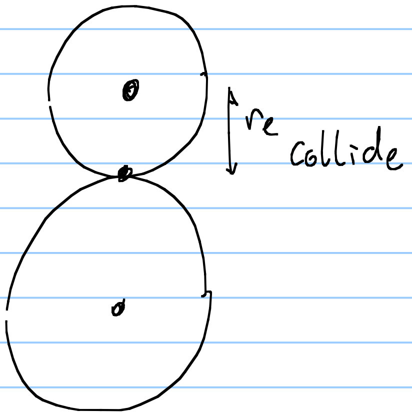


plot the pressure distribution around the well
from r_w to outer boundary r_e

how to define r_e

- Interaction with other wells

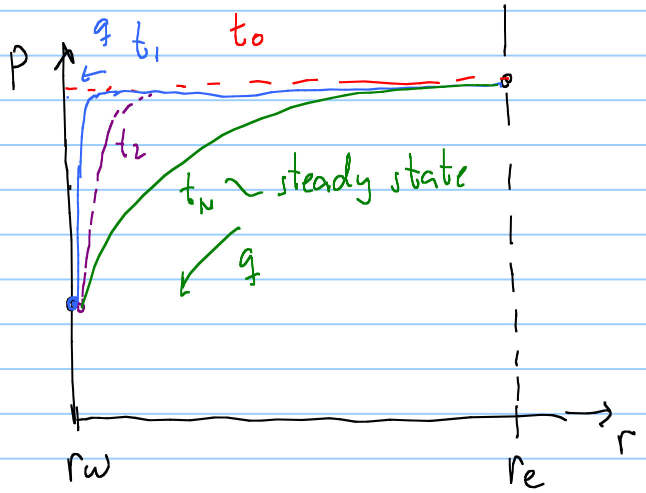
- sealing, fault



radial well, single phase, slightly compressible

$$\frac{K}{\mu} 2\pi h \frac{\partial}{\partial r}\left(r \frac{\partial p}{\partial r}\right) = 2\pi h \phi c \, r \left(\frac{\partial p}{\partial t}\right)$$ PDE { Partial differential equation }

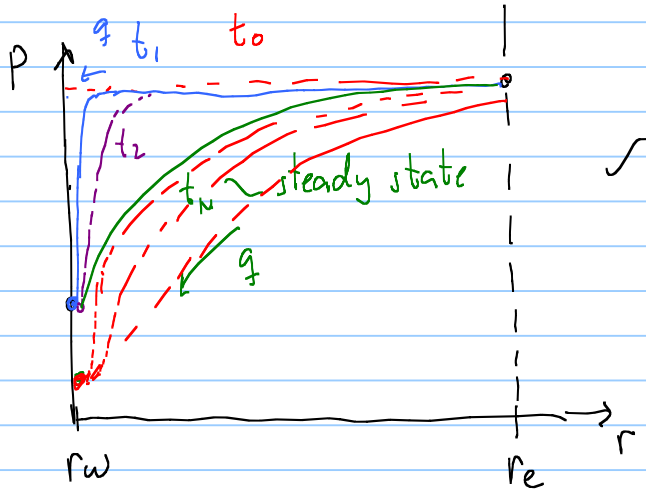
+ Boundary conditions



2 types of outer (re) Boundary conditions

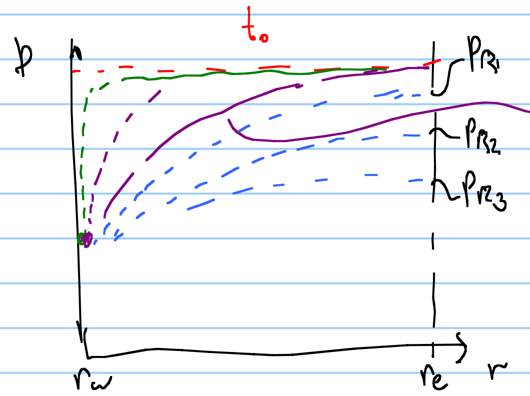
- FIXED PRESSURE (water injection
  gas injection
- pressure maintenance measure

$t_1 \rightarrow t_n$ ~ transient period



→ IPR describes steady state only !

- no flow boundary
  - sealing structure
  - → interaction with another well



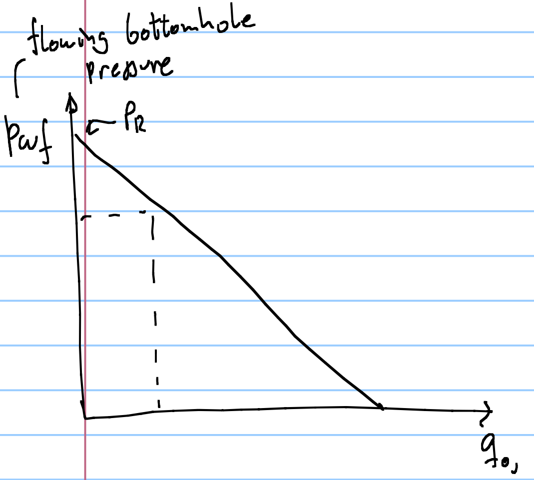
steady state

pseudo steady state

for reservoir with long transients, the concept of IPR is not really applicable

IPR model for $\left\{ q_o, q_g, q_w, P_{wf}, \underset{\sim}{P_R} \right.$

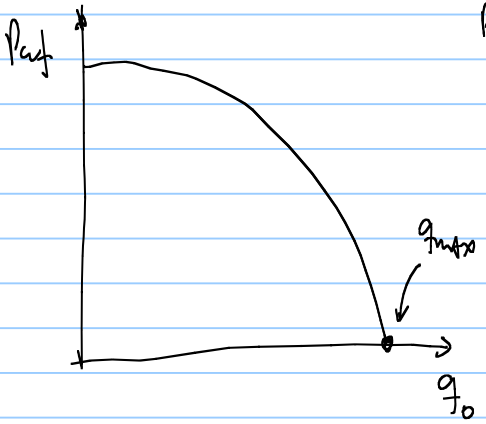
- volumetric average pressure around the well
- → I can measure
- P_R changes with time



undersaturated oil

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

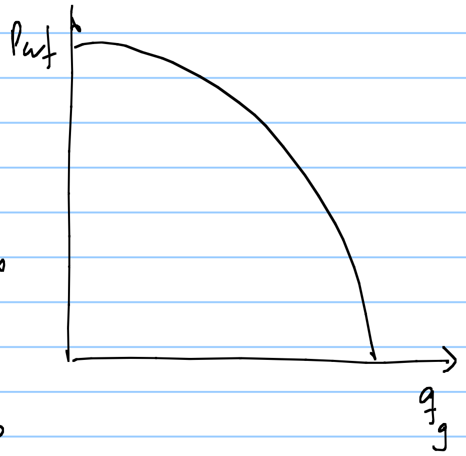
productivity index



saturated oil

VOGEL EQUATION

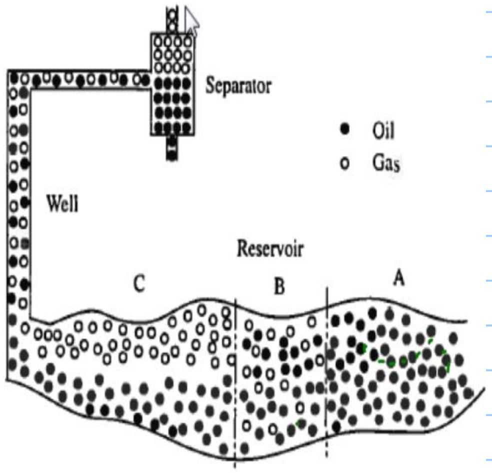
$$\frac{q}{q_{max}} = 1 - 0.2\frac{P_{wf}}{P_R} - 0.8\left(\frac{P_{wf}}{P_R}\right)^2$$



GAS

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

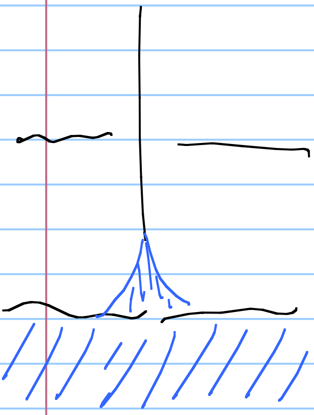
$$1 \geq n \geq 0.5$$



Phase transition in an under saturated oil reservoir.

IPR one equation for the preferred phase (main) and the rest are calculated using a ratio

$$\begin{cases} \dfrac{q_o}{q_{o\,max}} = 1 - 0.2\dfrac{P_{wf}}{P_R} - 0.8\left(\dfrac{P_{wf}}{P_R}\right)^2 \\ GOR \\ WC \end{cases}$$

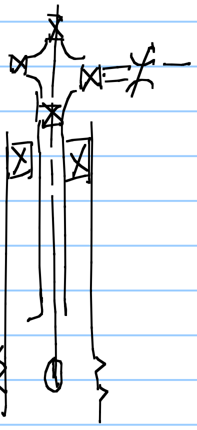


gas $\begin{cases} q_g = C\left(P_R^2 - P_{wf}^2\right)^n \\ CGR \quad \text{(condensate-gas ratio)} \\ WC \end{cases}$

IPR could change with time

How do we get IPR

- multirate test



choke opening

q_o	P_{wf}	Z
☐	☐	☐
☐	☐	☐
☐	☐	☐

tune to an equation

- expensive
- transient { Give enough time between points

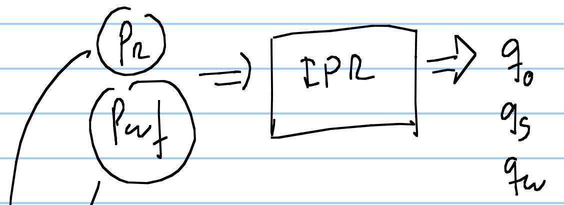
- Well test ~> reservoir properties + analytical equation = IPR

$$q_o = \frac{kh(p_R - p_{wf})}{141.2\mu_o B_o[\ln(r_e/r_w) - 0.5]}.$$

- Reservoir simulation:

- Open Flow Potential (OFP)

IPR tells you how much your well can produce



P_R is affected by { material entering the reservoir (injection) / " leaving the reservoir (producer) } material balance / reservoir simulator

P_{wf} is affected by production system } hydraulic equilibrium

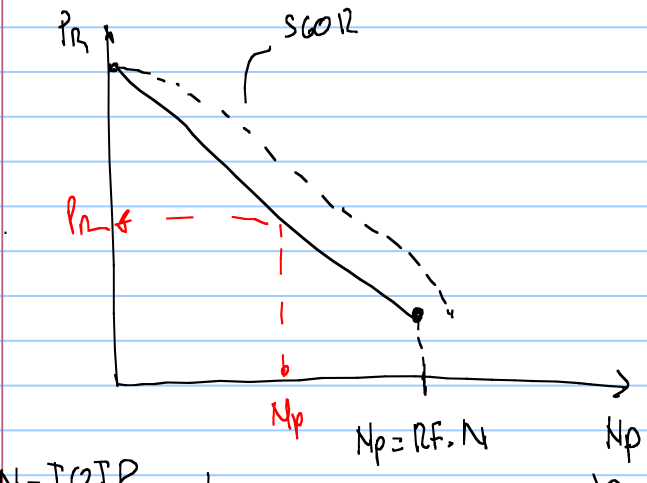
Approach by reservoir engineers $P_{wf} = P_{wf}^*$ { 100 Bara / 170 Bara } a constant value

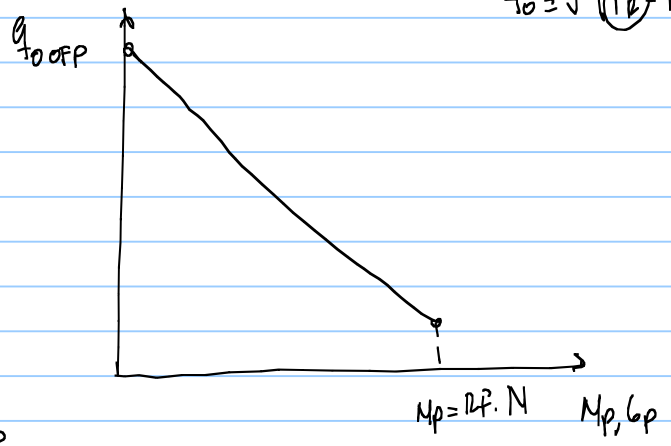
OFP ~> Produce the well with no chokes ~ record the rate $q_{fw\,OFP}$

↳ produce the well with a constant P_{wf}^* ~ $q_{fw\,OFP}$

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

no injection





N = IOIP
represents ↓ MB

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

$$N_p = \int_0^t q_o(t)\,dt \qquad G_p = \int_0^t q_g(t)\,dt$$

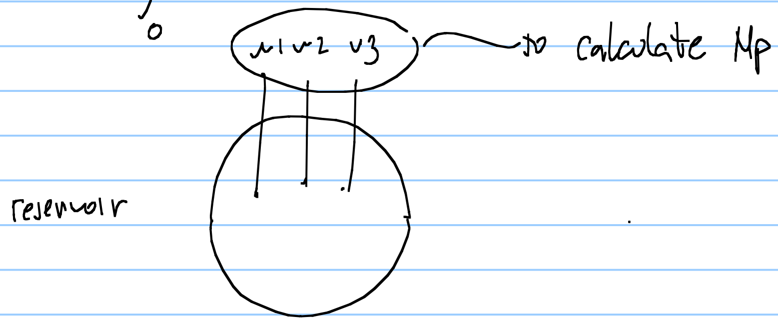
single well

$$q_{o\,OFP} = f(N_p)$$

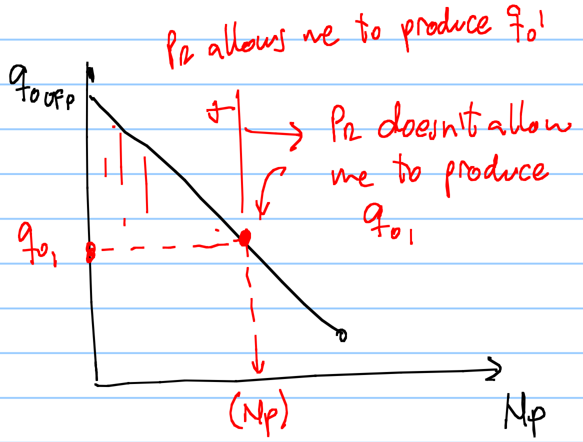
$$q_{g\,OFP} = f(G_p)$$

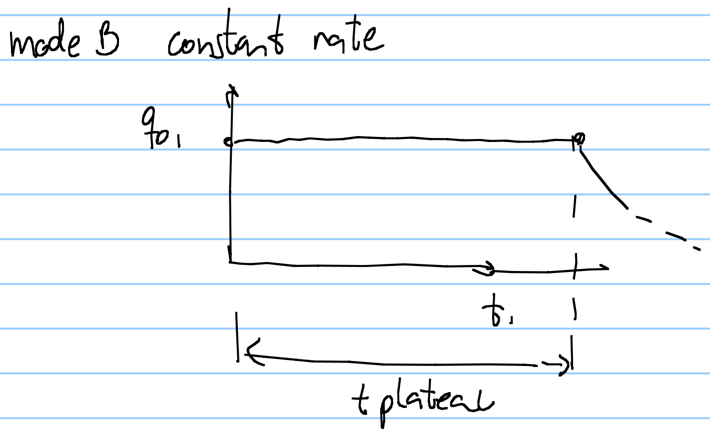
when there are multiple wells:

$$N_p = \int_0^t \left(q_{o_1}(t) + q_{o_2}(t) + q_{o_3}(t) + \cdots \right) dt$$



estimating the platea duration of your well



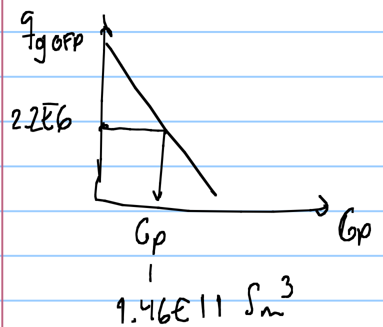


$$t_{plateau} = \frac{(N_p)}{q_{o_1} \cdot N_{wells}} =$$

from Excel, calculate plateau duration

for $q_{field} = 20E6 \ Sm^3/d$ $N_{wells} = 9$

$q_{well} = 2.2E6 \ Sm^3/d$



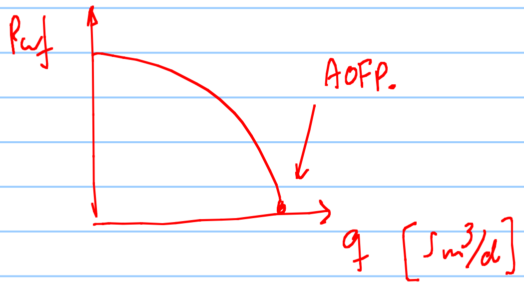
$$t_{plateau} = \frac{G_p}{q_{well} \cdot N_{wells}} = \frac{1.46E11 \ Sm^3}{2.2E6 \ Sm^3/d \cdot 9} = 20 \text{ years}$$

Last class

Some introductory concepts on Decline Curve Analysis DCA. these concepts are simplified approaches to deal {
- field development ←
- well scheduling ←
- production forecast ←
- etc

Correction: AOFP {
- Absolute open flow potential AOFP
- Atmosferic open flow potential
- Absolute flow potential AFP

} the production of a well when the pressure P_{wf} in front of the perforations = 1 atm



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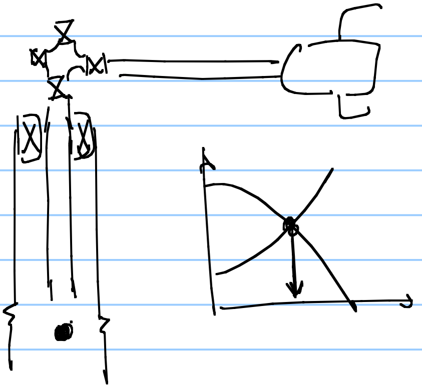
what we were discussing last class and will discuss this class is OFP open flow potential

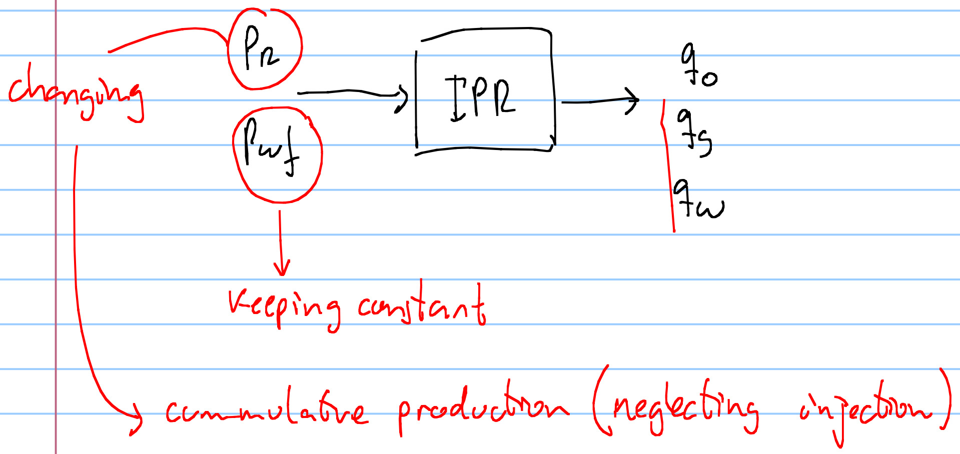
Definition: {
- reservoir engineer: well rate that i would get if P_{wf} = const
  usually P_{wf}^* = minimum operating bottomhole pressure
- According to the production engineer: well rate that I would get if remove all controls from the system (open chokes)

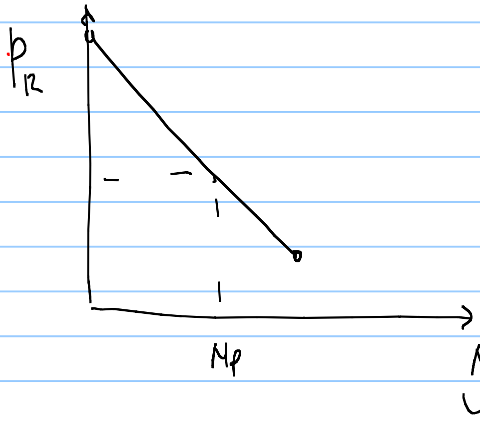


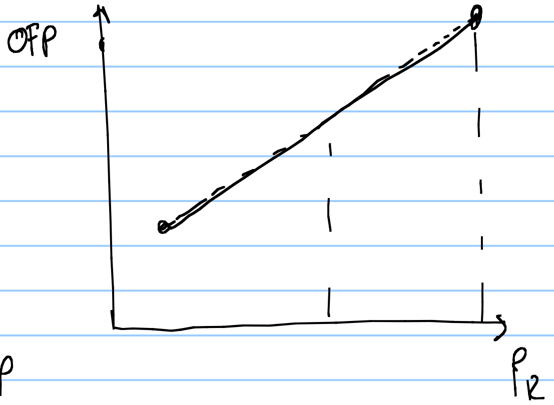
Going with the reservoir engineer approach:

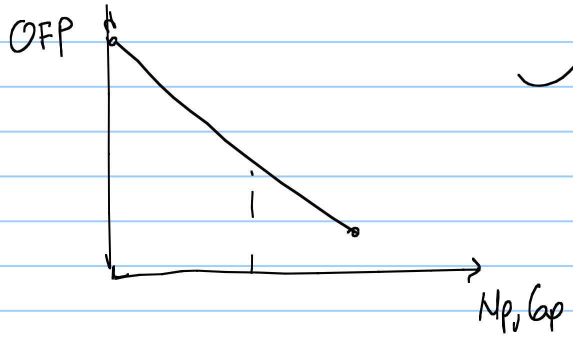
P_{wf} = const = p_{wf}^* = $p_{wf_{min}}$ {
- to remove the complexity of the downstream system
- Early planing (system not defined yet.)

Open Flow potential

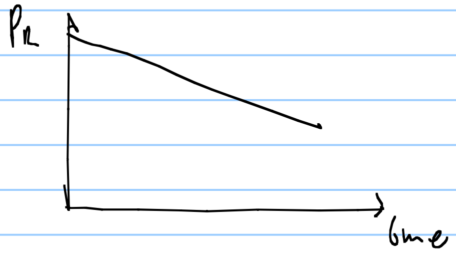


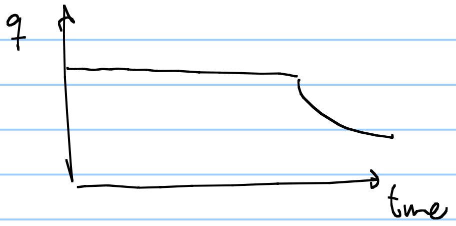


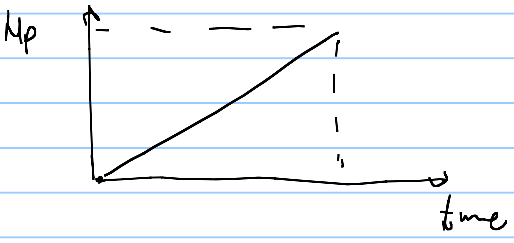




take away the time variable

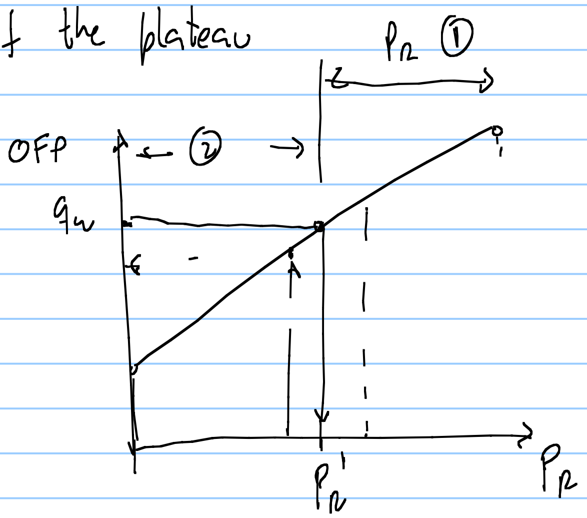


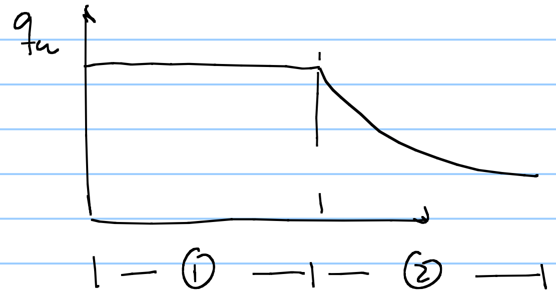


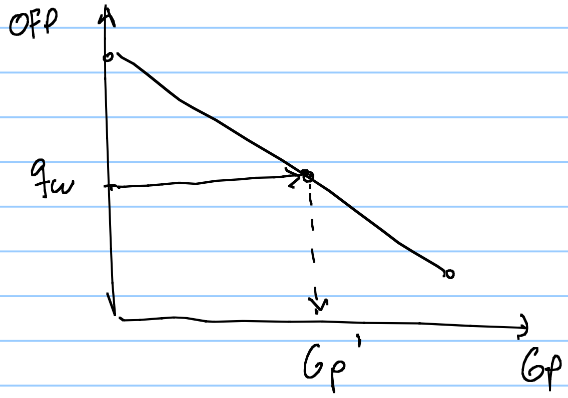


- Example single well producing from a reservoir

if I am draining q_w with my well, what would be the duration of the plateau



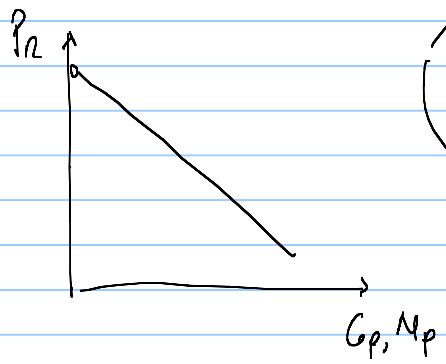


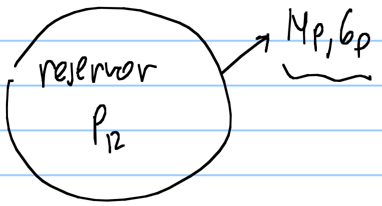


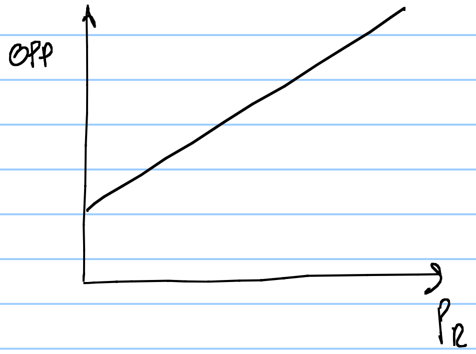
$t_{plateau} = \frac{G_p'}{q_w} = N\,DAYS \qquad N_{years} = \frac{N\,DAYS}{365}$

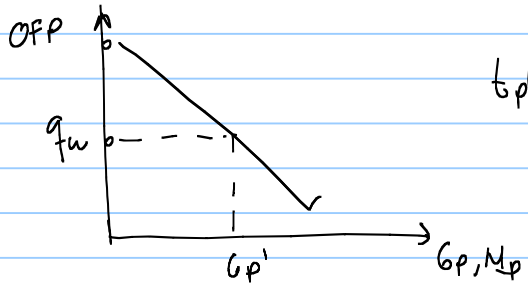
- Group of wells, all of them are identical, same IPR ~ P_{wf}

same reservoir ~ P_R









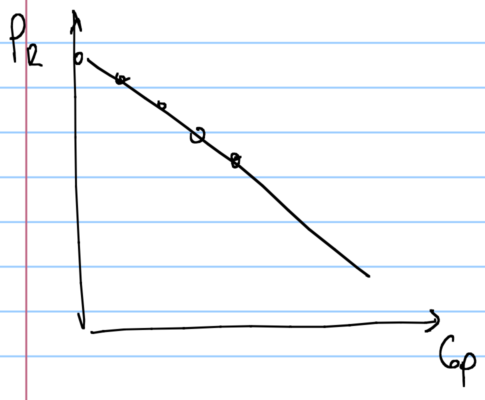
$t_{plateau} = \frac{G_p'}{q_w . N_w}$

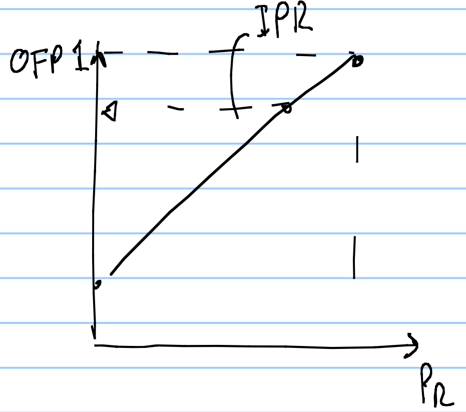
- If we have wells that are different ~> IPR different

Example: 3 wells, 1, 2, 3

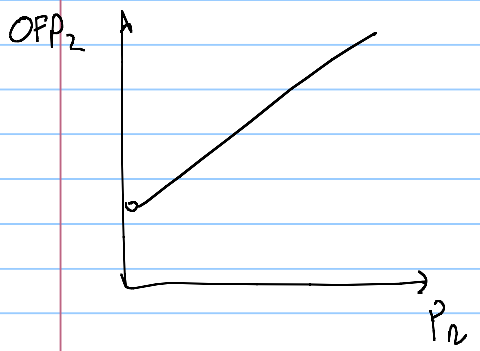
↳ same reservoir (same P_R)

↳ P_{wf} might be the same
might be different

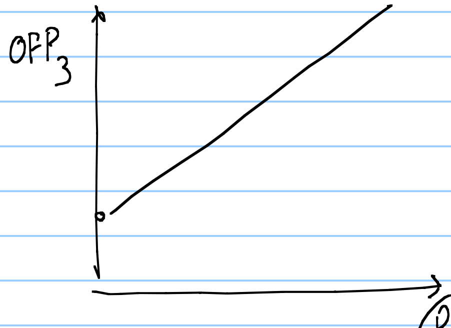




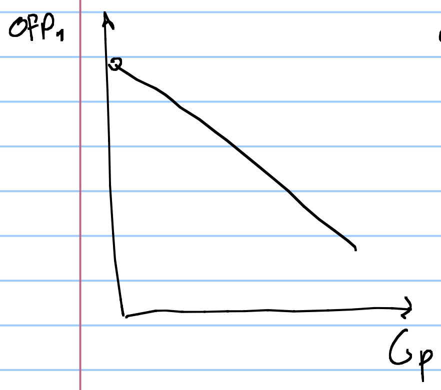
$$q_{g_1} = C_1 \left(\underbrace{P_R^2}_{} - \underbrace{P_{wf_1}^2}_{\text{fixed}}\right)^{n_1}$$

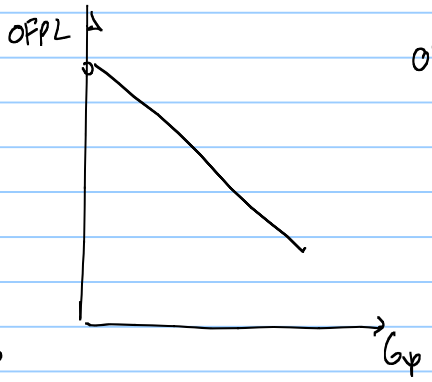


$$q_{g_2} = C_2 \left(P_R^2 - \underbrace{P_{wf_2}^2}_{}\right)^{n_2}$$



$\boxed{P_R}$ ~ depends on the total

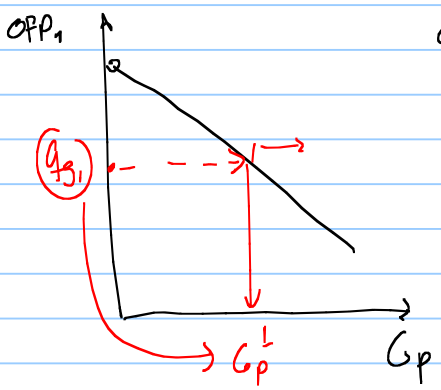


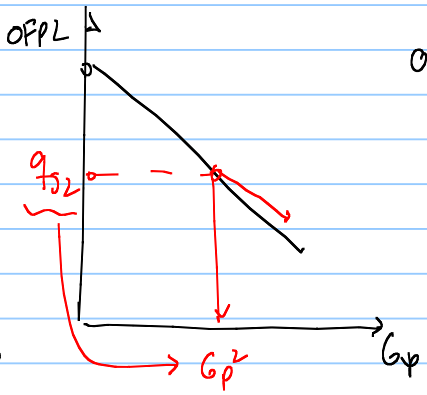


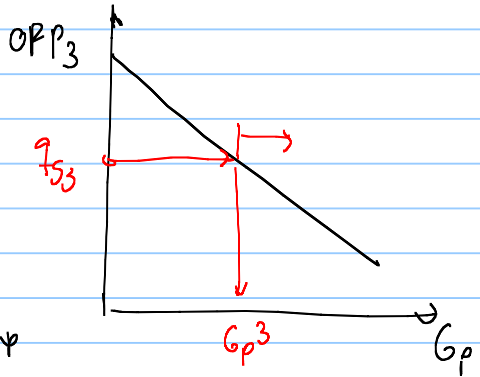
Case 1: someone defined the rates for us. q_{g_1}, q_{g_2}, q_{g_3}

$q_{g_1} + q_{g_2} + q_{g_3}$ = constant

P_R





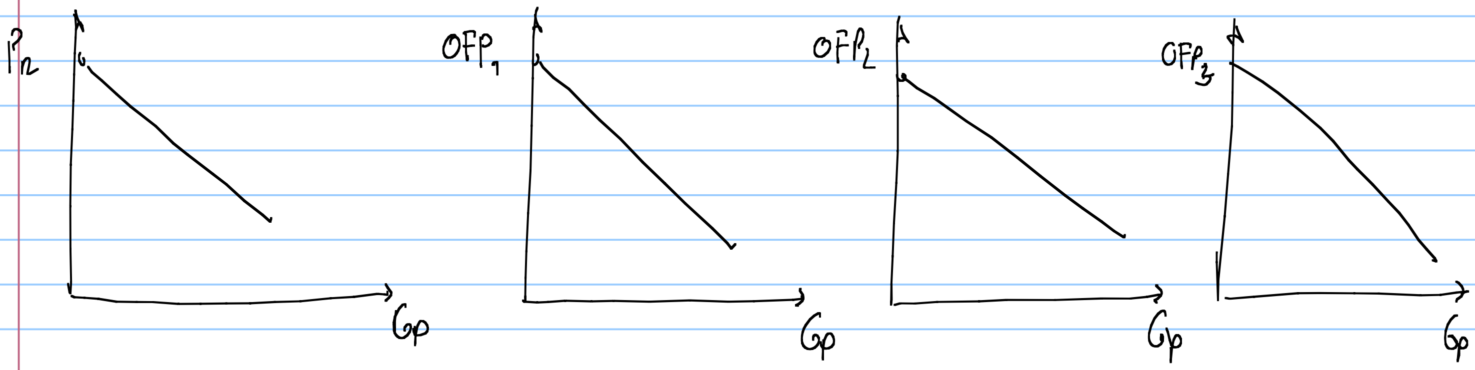


Look for the minimum Gp between $\tilde{G}_p^1$, G_p^2, G_p^3 because that is the first well that will have problems

assume that is well 1

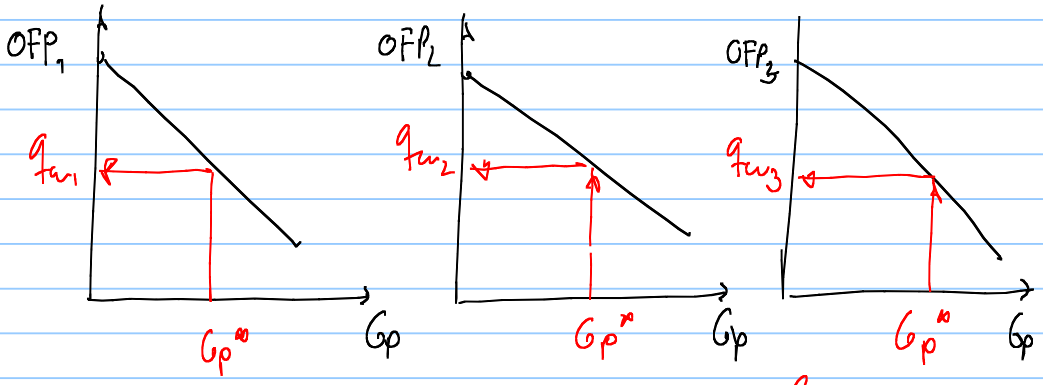
plateau period $t_{plateau} = \dfrac{G_p^1}{(q_{fg_1}+q_{fg_2}+q_{fg})_3}$

what if I can specify the rates to make $t_{plateau}$ the same for all well? q_{TOTAL}, q_{FIELD}



Assume one $G_p^* = G_p$ at end of plateau

And you enter in the OFP curve for each well and read OFP_1, OFP_2 OFP_3 For G_p^*



Check: if $q_{fw_1}+q_{fw_2}+q_{fw_3} \overset{?}{=} q_{FIELD}$ IF NOT, Assume ANOTHER G_p^*

G_p^{*} $\quad q_{w_1} + q_{w_2} + q_{w_3} > q_{FIELD}$

G_p^{**} $\quad q_{w_1} + q_{w_2} + q_{w_3} < q_{FIELD}$

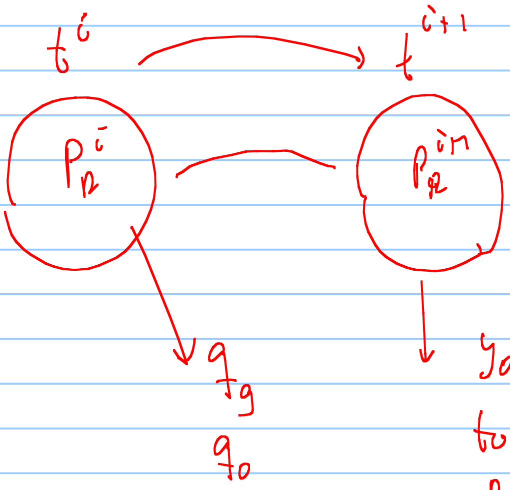
//

Practical question: where do I get P_R vs N_p, G_p?
- material balance ✓
- reservoir simulation ✓

where do I get OFP?
- IPR ~>
  - initial well test data
  - extrapolate from other wells in the area
- Reservoir simulator

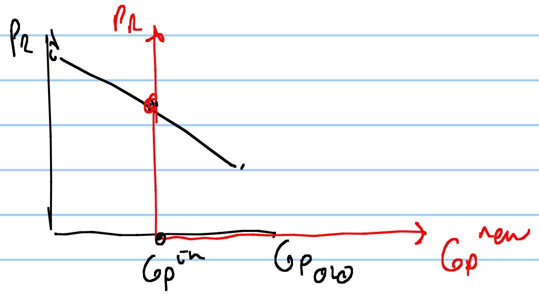
comment

time simulation



You can tell res simulator to give you q_g, q_o for $P_{wf\,min} = P_{wf\,const}$

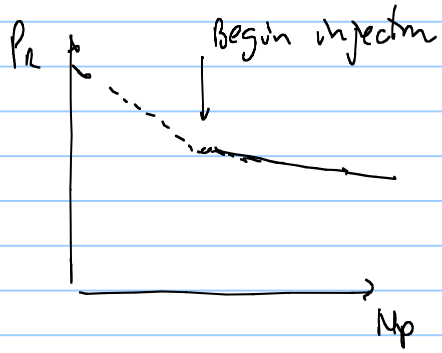
- If is an existing asset, re evaluation you can perform a re initialization



shifting your curves

$$G_p^{new} = G_p^{old} - G_p^{i}$$

these discussion is valid if there is only one (1) reservoir unit, No injection



Other applications of OFP: to set individual well rates

If q_{FIELD} = GIVEN

at a certain P_R, $G_p(N_p) \rightarrow OFP_1, OFP_2, OFP_3$

$q_{w_1}, q_{w_2}, q_{w_3}$ $\qquad \underset{\sim}{q_{TOFP}} = \sum_{i=1}^{N_w} q_{wOPP_i}$

$q_{w_1} + q_{w_2} + q_{w_3} > q_{FIELD}$ $\qquad \underset{\sim}{q_{TOFP} \neq q_{FIELD}}$

calculate well flow ratio $\quad F_i = \dfrac{q_{wOPP_i}}{q_{TOFP}} \swarrow$

to obtain the actual rate of the well

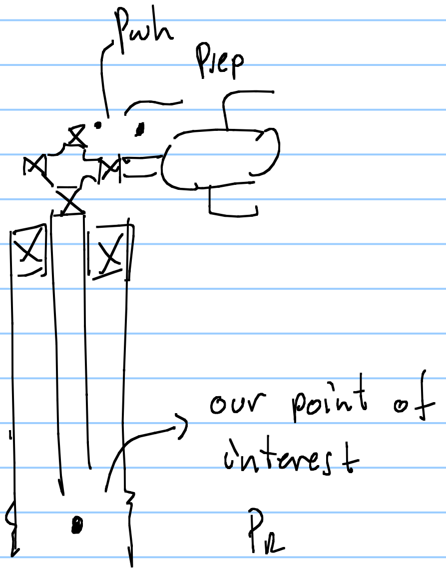
$$q_{wi} = F_i \cdot q_{FIELD}$$

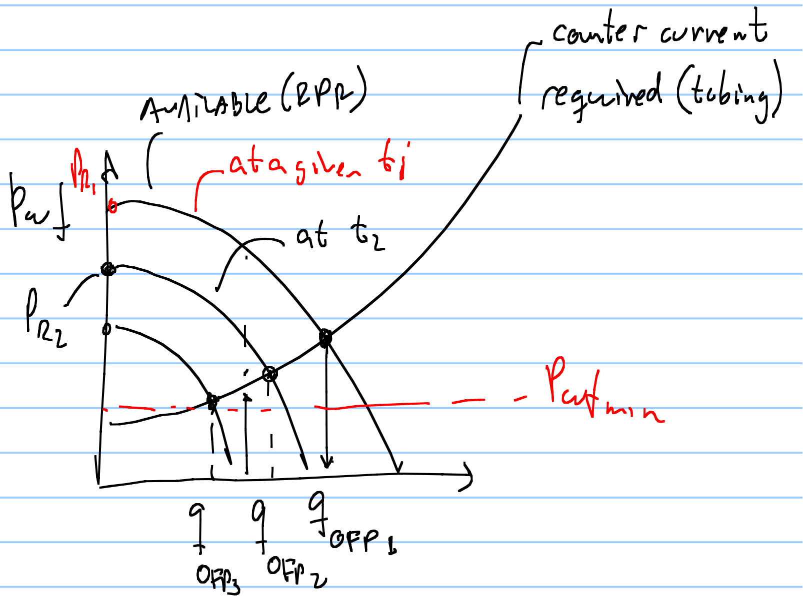
—————— // ——————

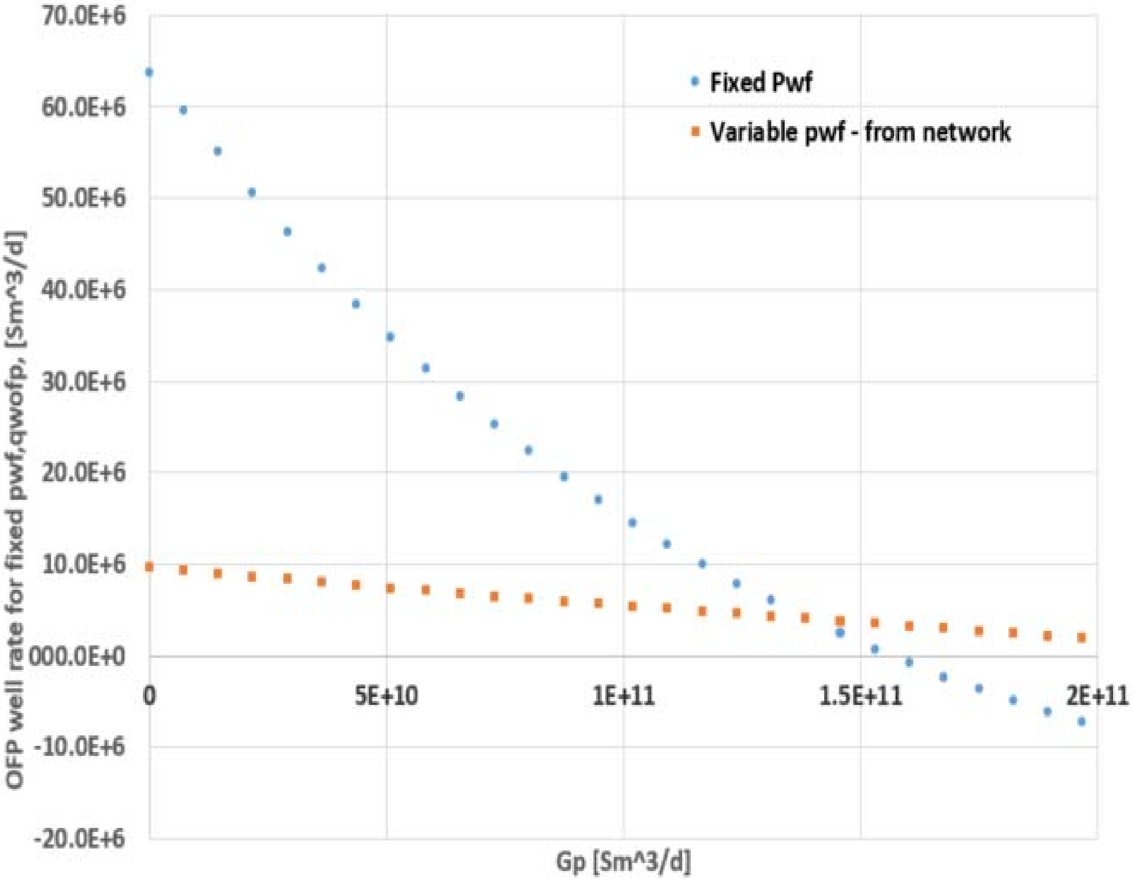
how to calculate OFP from the production engineer point of view

there is a system downstream the sand face : {
well
network
separator

- single well, no network, well is producing straight to a separator of constant pressure



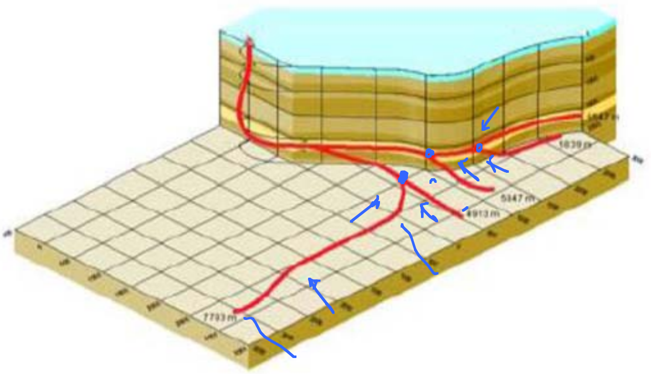




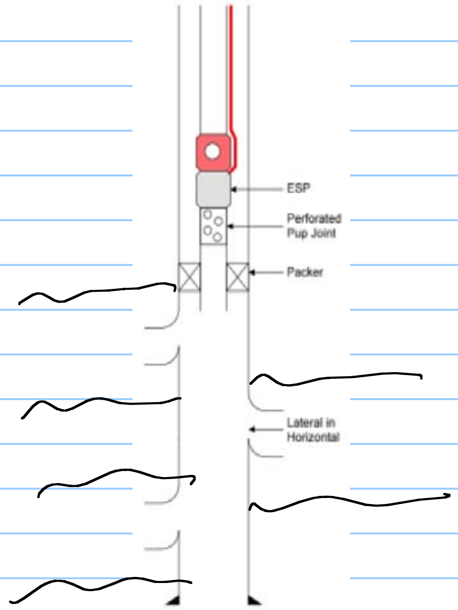
Agenda

- Downhole networks
- IAM
- Data management
- Allocation

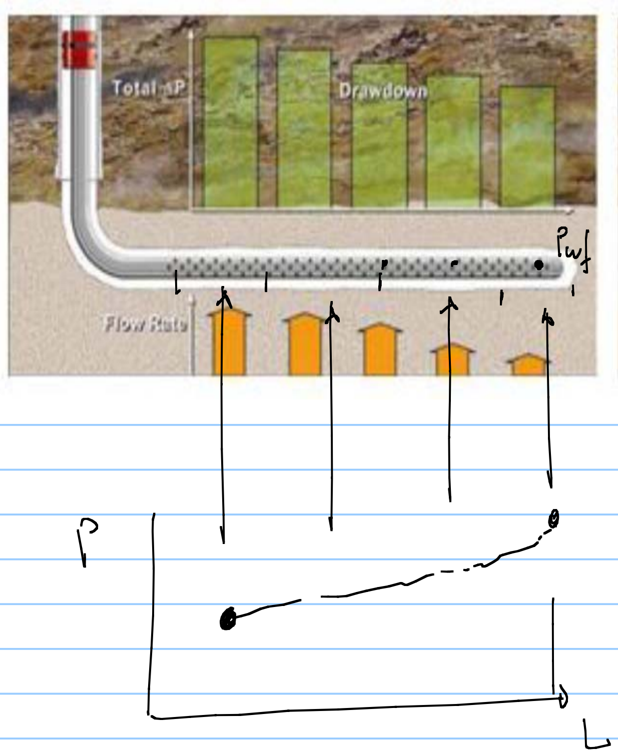
Downhole network

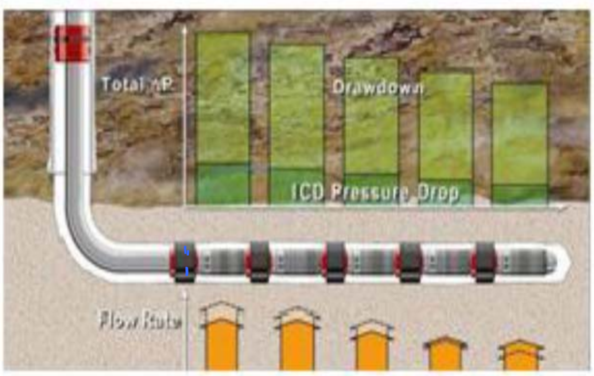


multi-lateral well

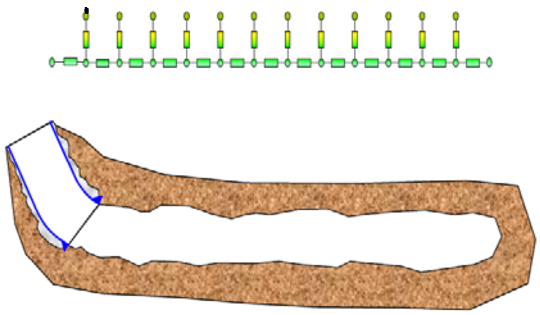


multi-layer





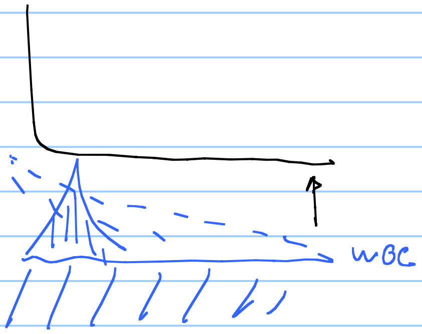
- **Horizontal well with Open Hole completion**
  – **Including damage zone**



Netool → completion analyzer Landmark

passive
ICD .. inflow control device → fixed restriction

ICV ... inflow control valve ~> variable restriction
active



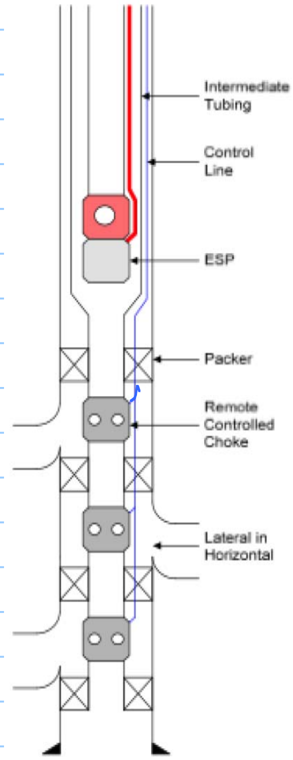
100%

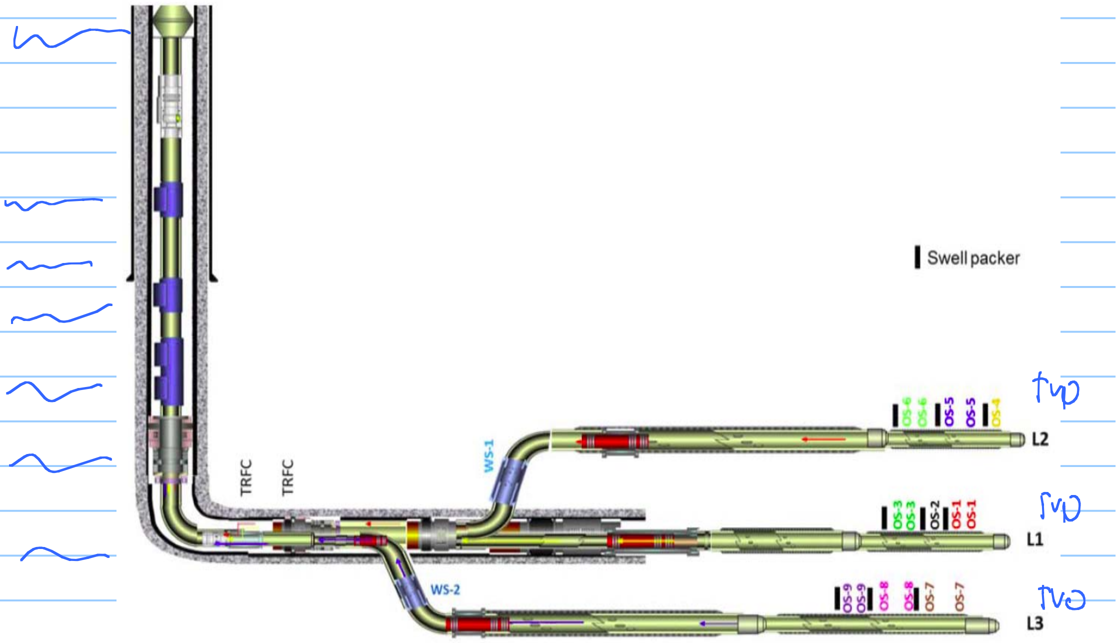
75%

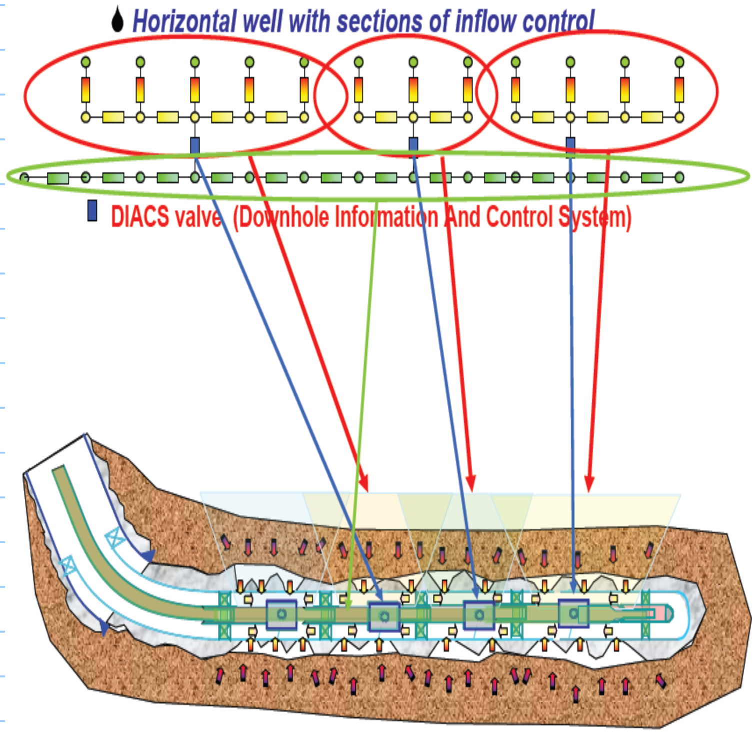
50%

25%

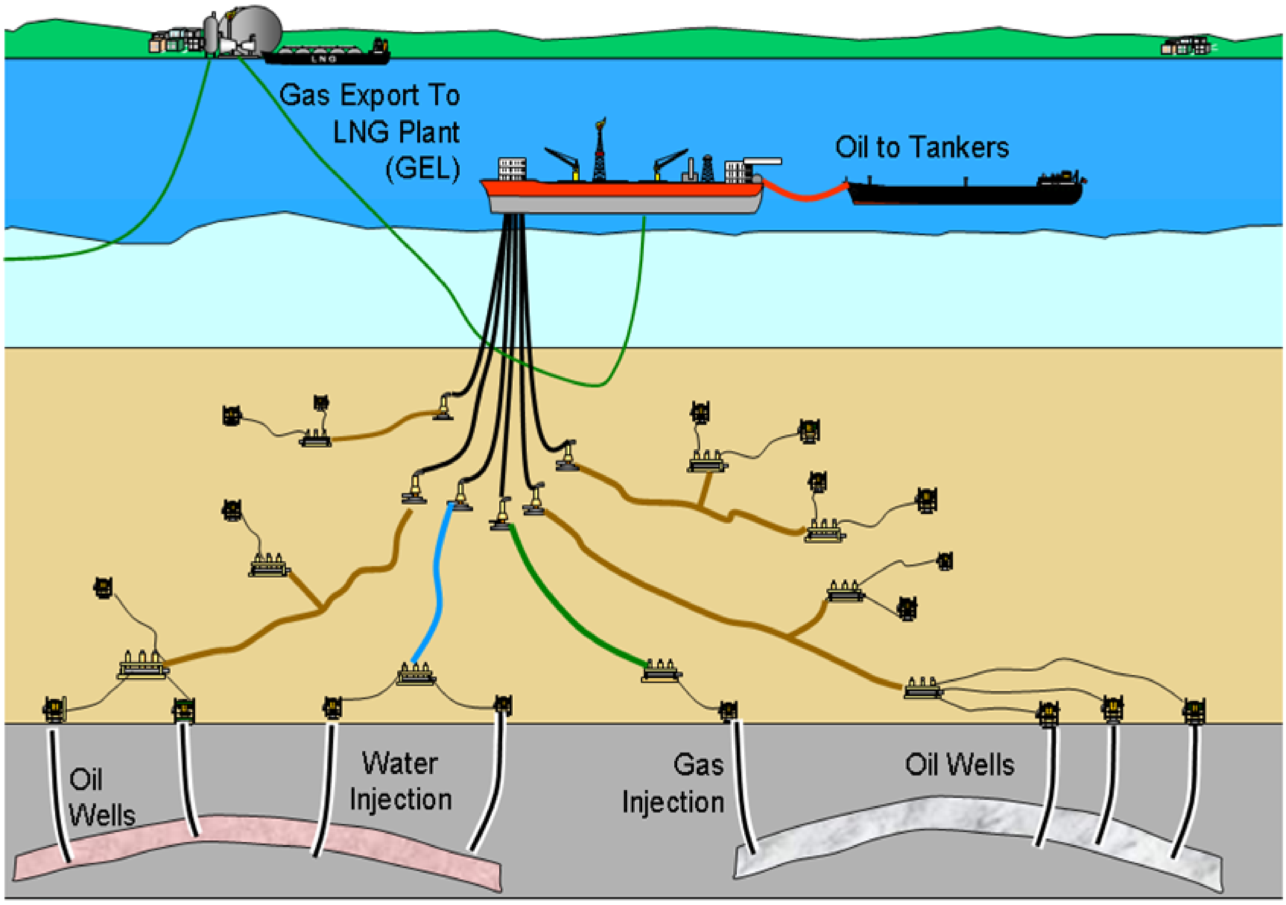
0%

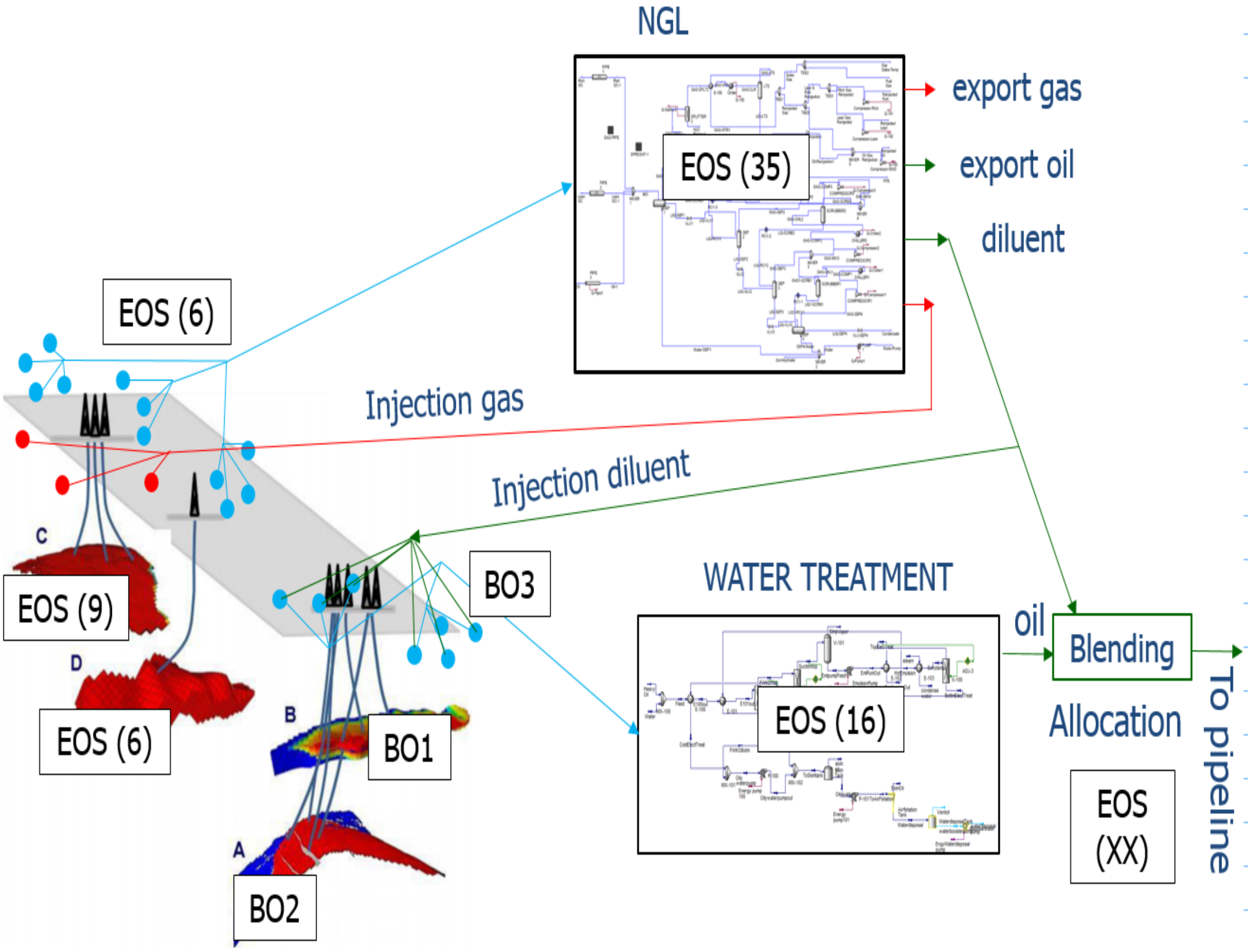


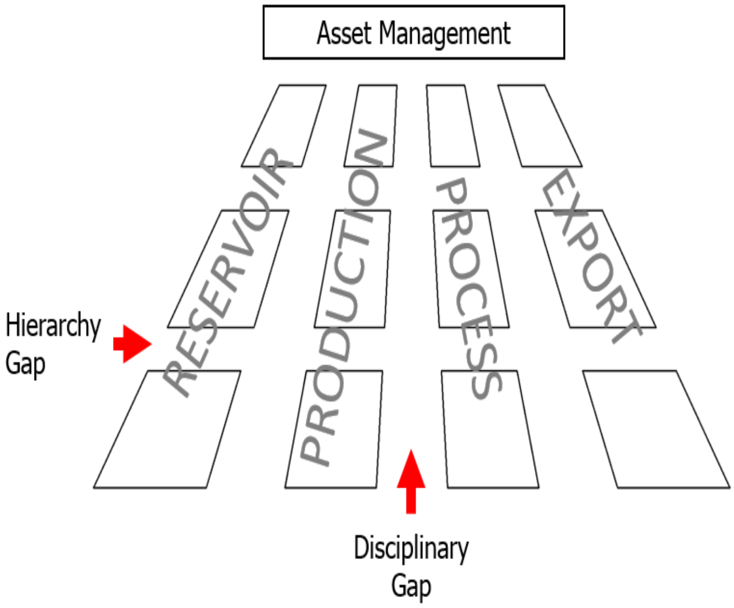




- IAM , Integrated Asset modeling







Silo management

Usually work with models → commercial software

IAM bring together all models involved

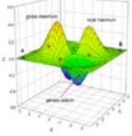
The purpose of models integration

- Compute the total asset outcome and it dependency on all important design and operational decision variables

- **Assess and rank** initial field development schemes, **appraise** the outcome of optional recovery strategies and **weigh** considered modification decisions, all in term of system outcome

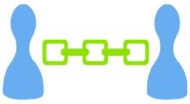
The purpose of models integration

- **Optimize** the short term and long term yield (economical and physical) subject to all imposed constraints

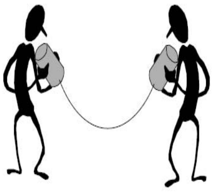


- **Allocate** the total asset produced yield; quantity, quality and monetary to individual production source (Well or Payzone)

Capture the interdependency between all the physical elements of the system through models linking and consistent variable representation in the various models



Automate the transfer of information between the models



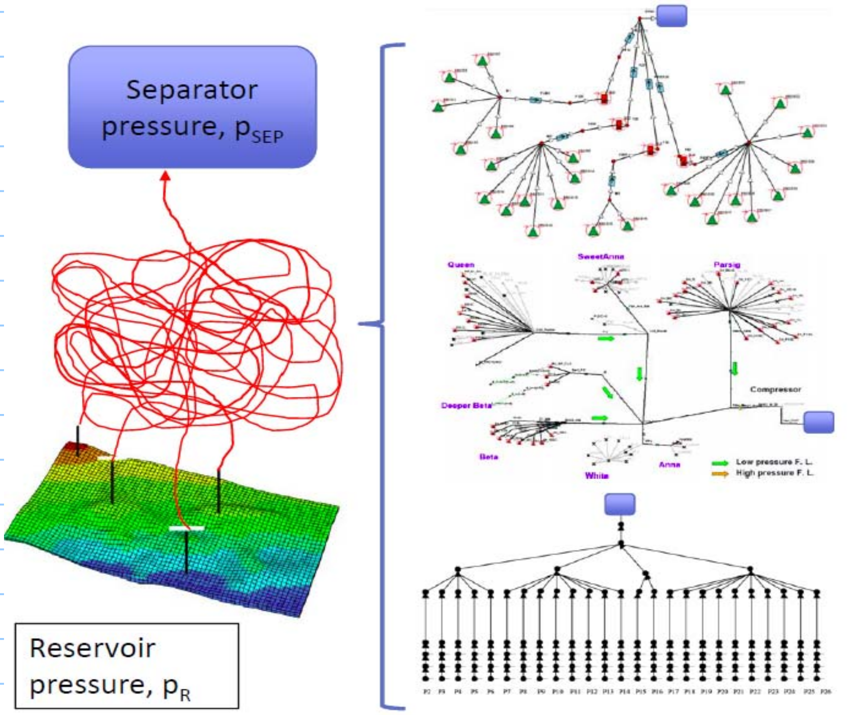
The purpose of models integration

- **Facilitate** effective **tuning** and updating of individual system models to match and predict the changing total system outcome

- Automate the running or voluminous sensitivity and parametric studies

there is a part of the asset that is critical

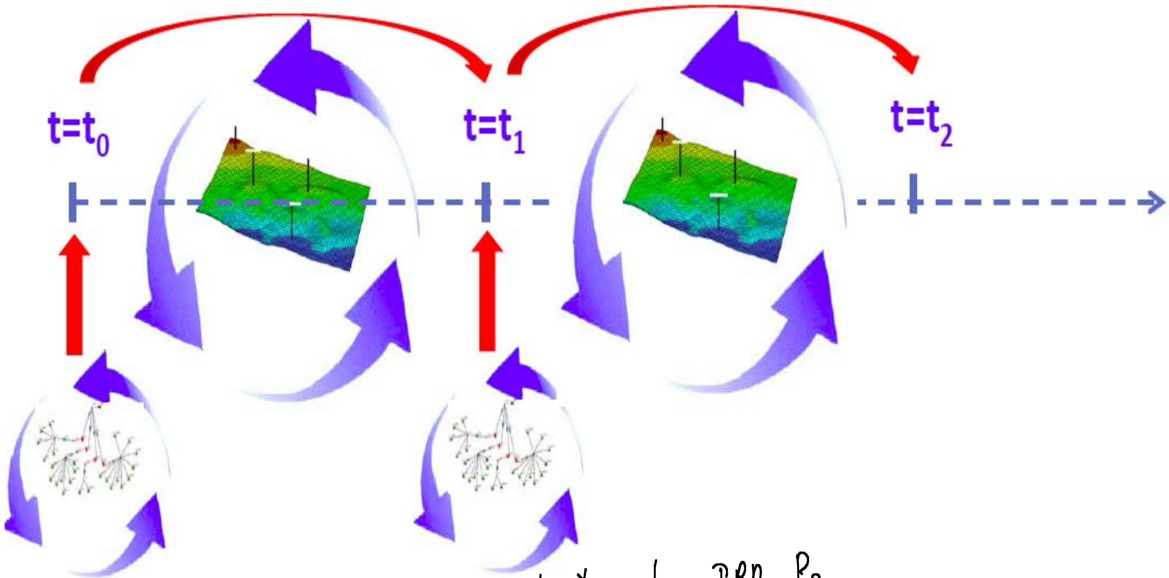
- Reservoir model and network (production system) model



What is the dependance between these two models?

↳ coupling ⇝ Reservoir -- changes with time

production system --- steady state



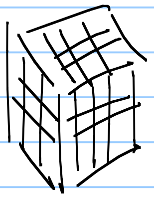
↳ transfer IPR, P_R

↓ flow equilibrium, obtain rates $q_{\bar{o}}, q_{\bar{g}}, q_{\bar{w}}$, P_{wf}

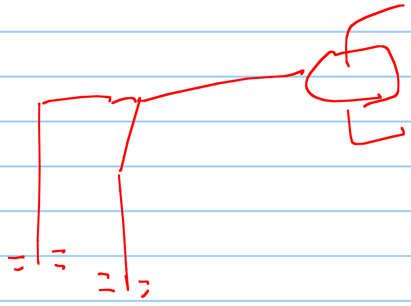
Explicit Coupling Reservoir-Production system

reservoir model (ECLIPSE)

Initial time t_0 -



stops



extract values necessary to run production system model

P_{Ri}, IPR, et

input to

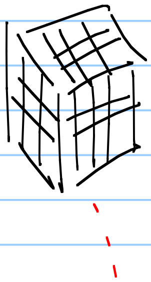
Production system model (GAP, PIPESIM)

RUN

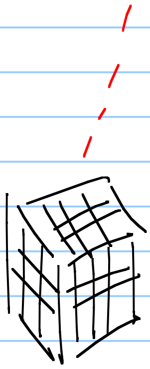
$q_{\bar{o}}, q_{\bar{g}}, q_{\bar{w}}$ for all wells

input to Reservoir model

t_0 -

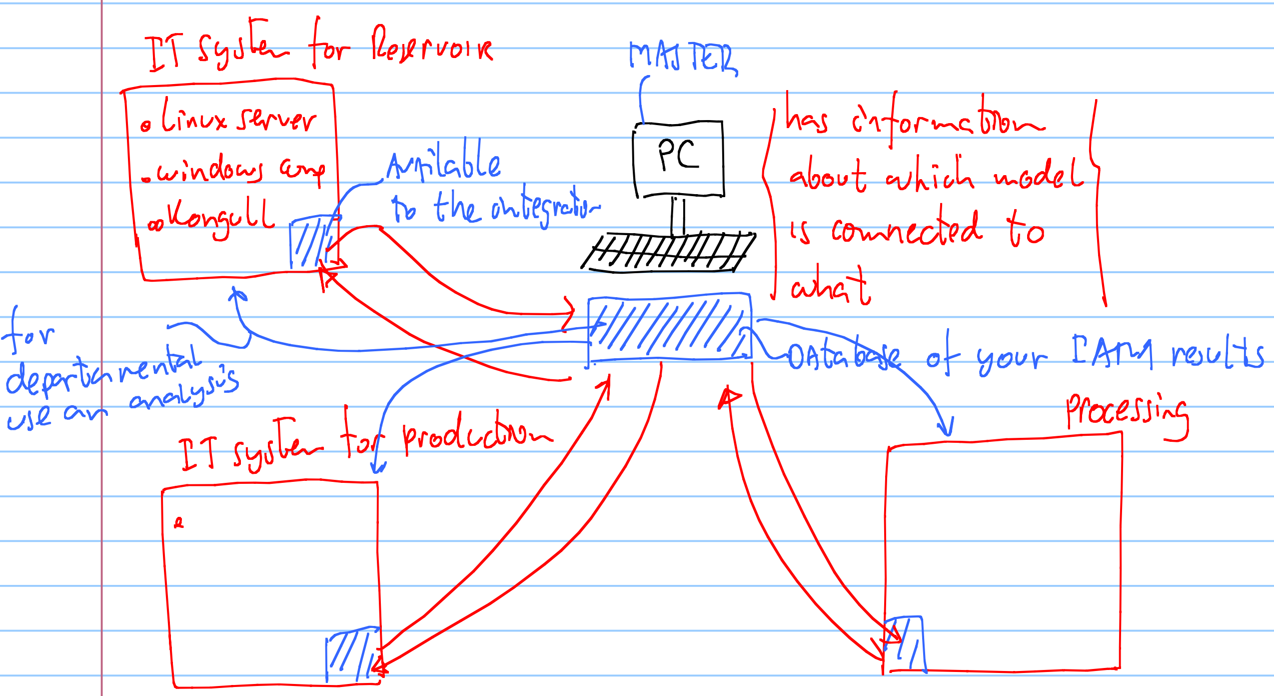


t_1



REPEAT

IT Infrastructure required for IAM

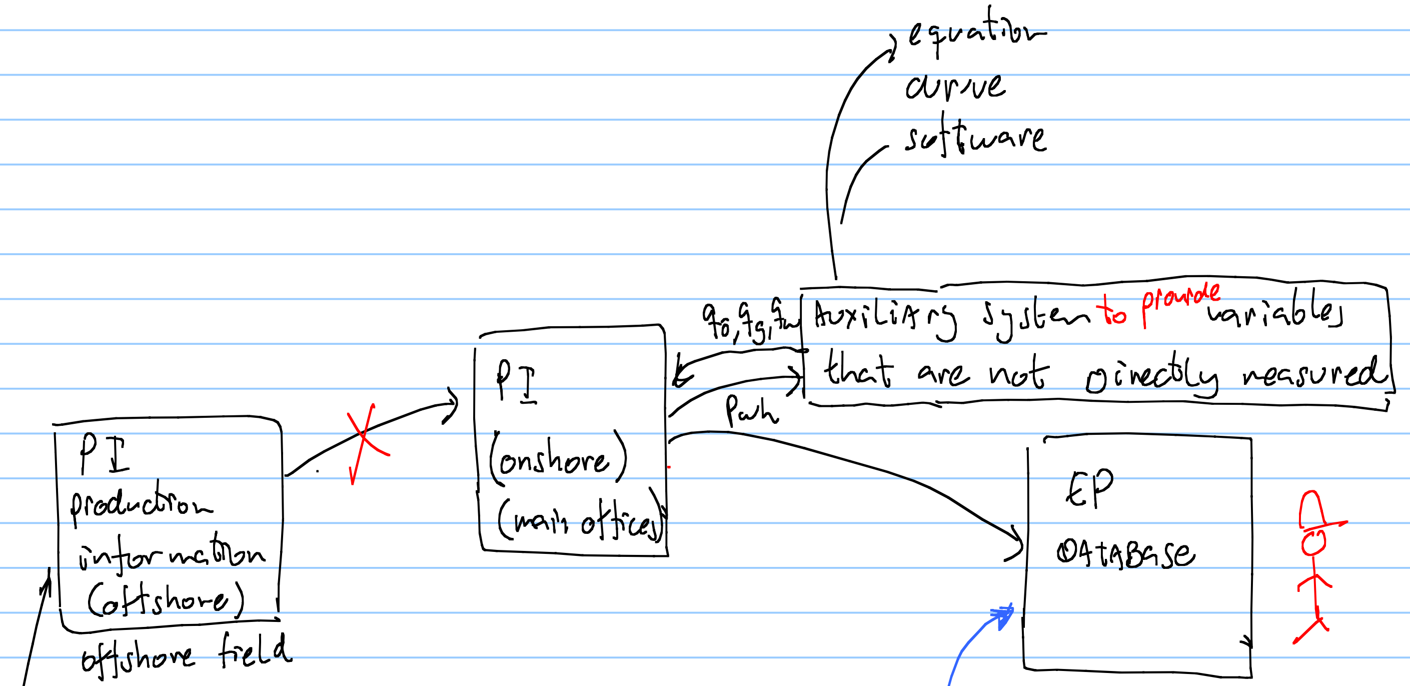


for Integration, it is necessary:
-A PC that serves as the integrator (the master)
-Shared directories
~~-Automatic transfer of information~~
-Support from other teams to troubleshoot their models and modify them in case it is necessary.
-Automation
-Free access of results and info to all participants

Commercial tools for IAM → AVOCET (Schlumberger)
RESOLVE (PETEX)
Pipe-IT (PETROSTREAMZ)

- reader of results from common software
- Interface to specify connectivity and information transfer between models
- Specify the run details
- OPTIMIZER
- SENSITIVITY cases

- Data processing and management in E and P operations

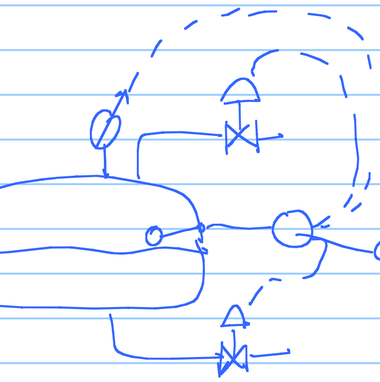


DCS
Distributed
control
system

receive information

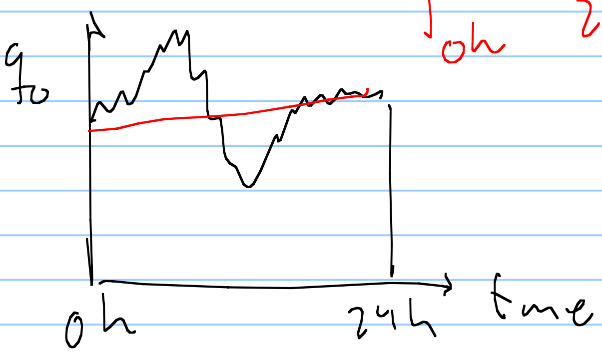
1000 sensors

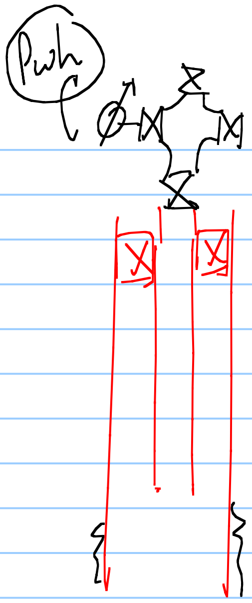
transfer
of
information

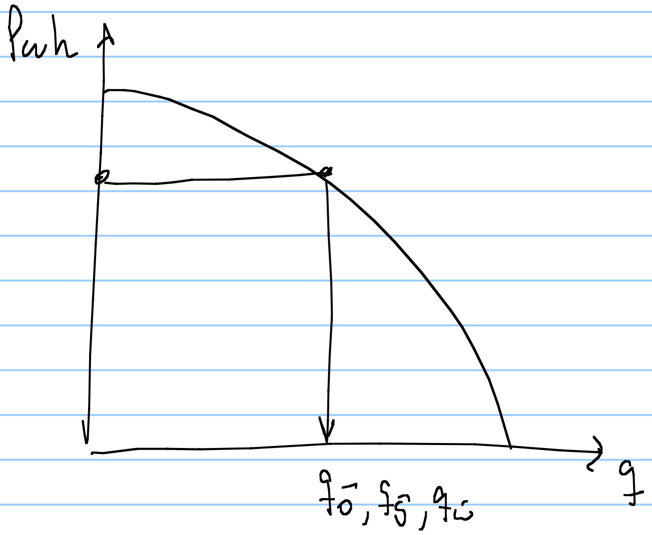


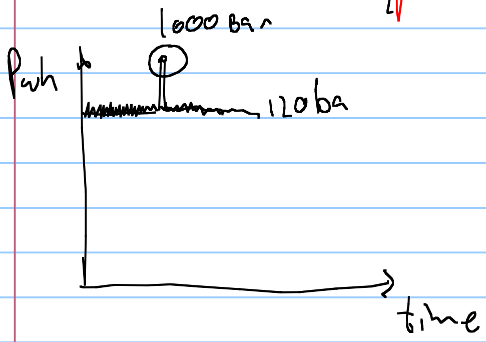
control element

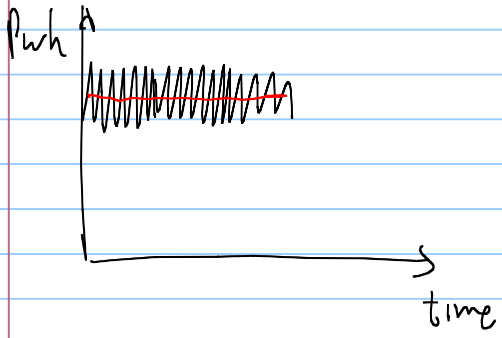
$$q_T = \frac{\int_{0h}^{24h} q_o \, dt}{24h}$$





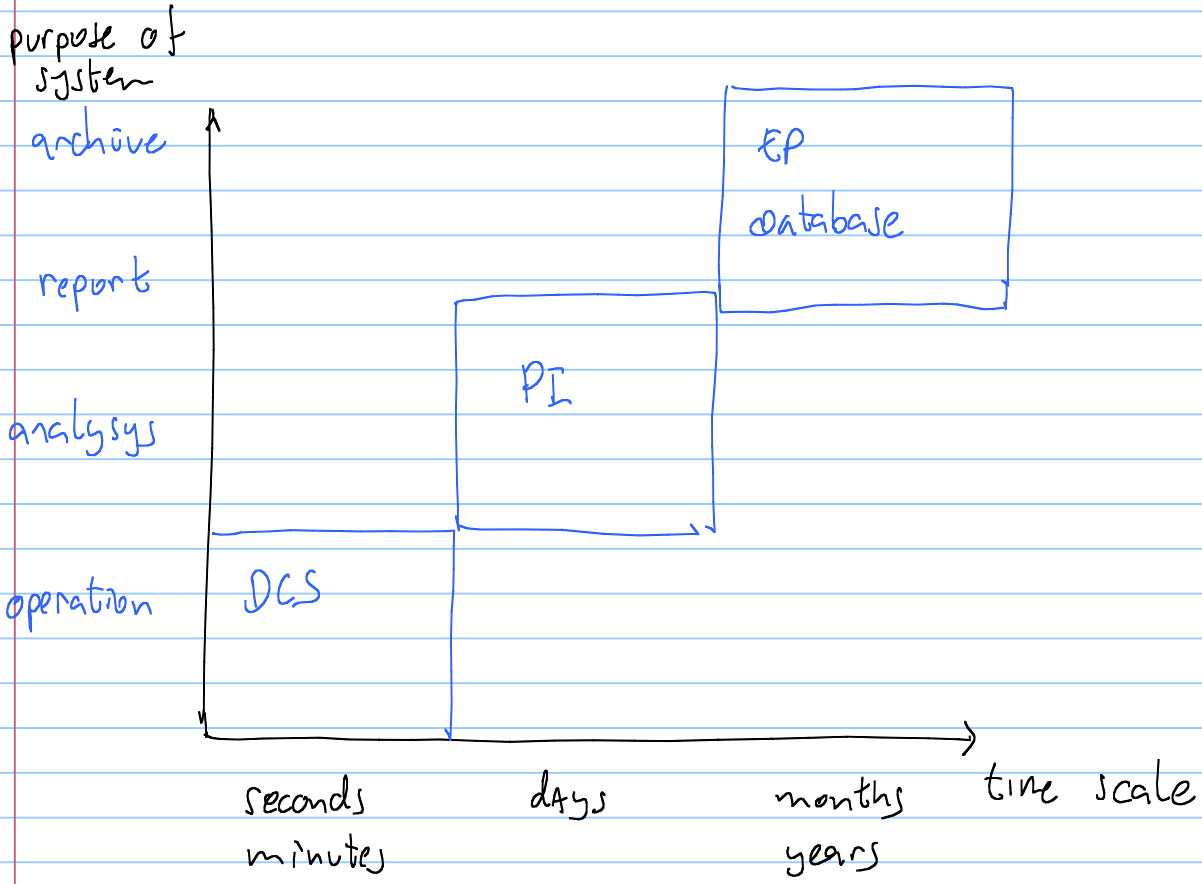


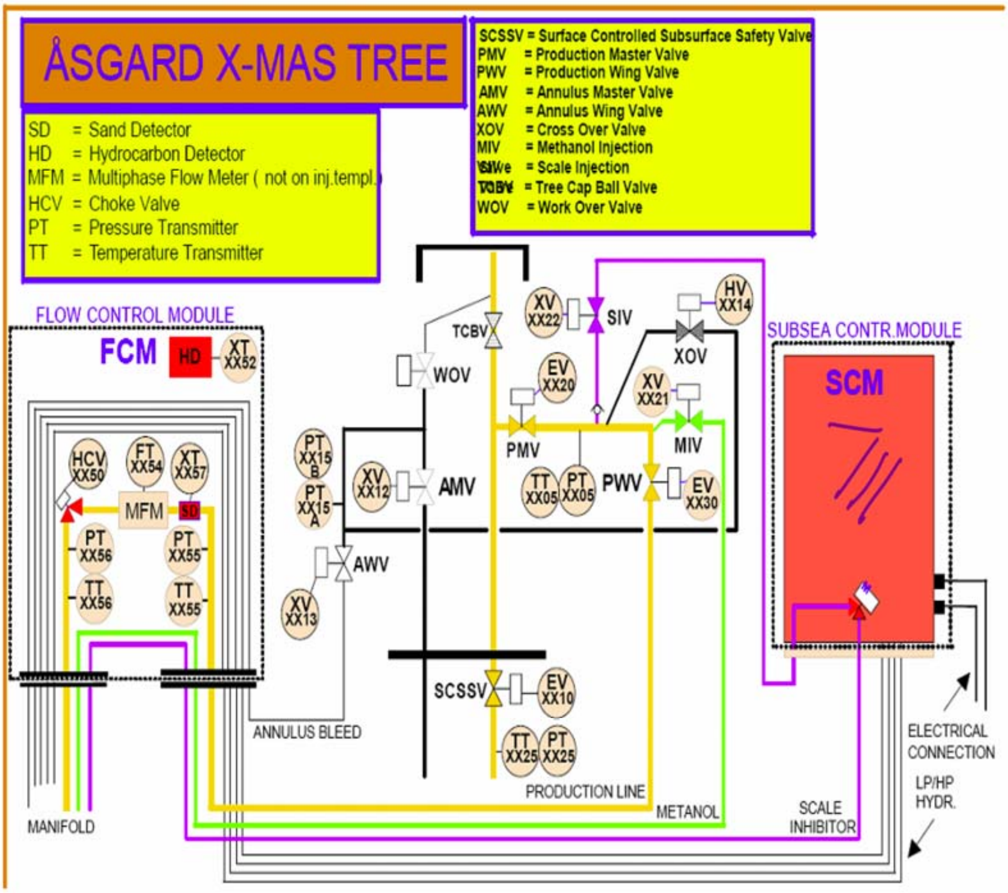




Data processing:

- aggregation
- filtering, smoothing
- cleaning, quality controt
- averaging
- visualization



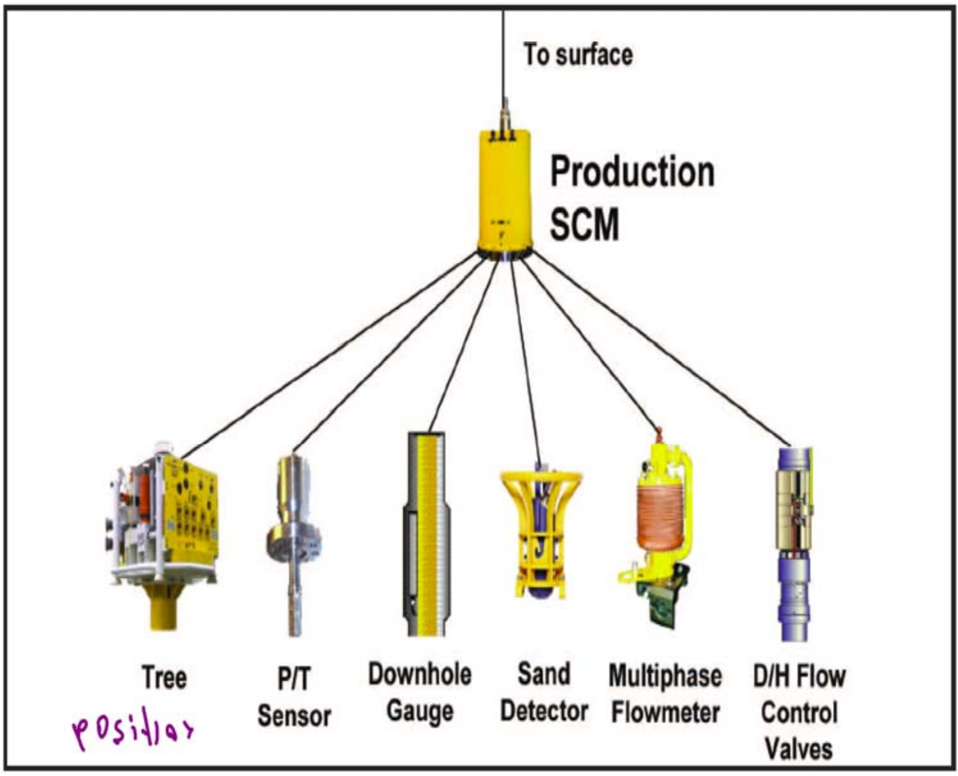


ÅSGARD X-MAS TREE

SD = Sand Detector
HD = Hydrocarbon Detector
MFM = Multiphase Flow Meter (not on inj.templ.)
HCV = Choke Valve
PT = Pressure Transmitter
TT = Temperature Transmitter

SCSSV = Surface Controlled Subsurface Safety Valve
PMV = Production Master Valve
PWV = Production Wing Valve
AMV = Annulus Master Valve
AWV = Annulus Wing Valve
XOV = Cross Over Valve
MIV = Methanol Injection
SIV = Scale Injection
TCBV = Tree Cap Ball Valve
WOV = Work Over Valve

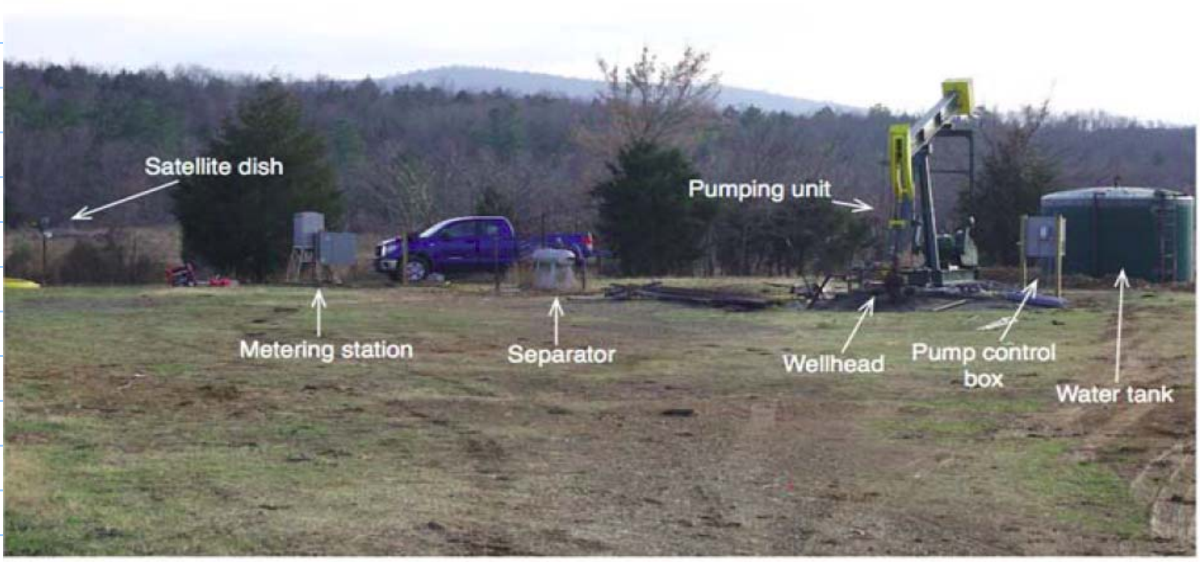
PID { Piping / process and instrumentation diagram

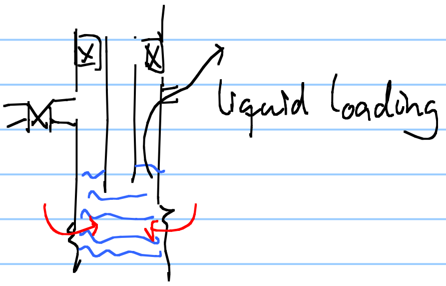


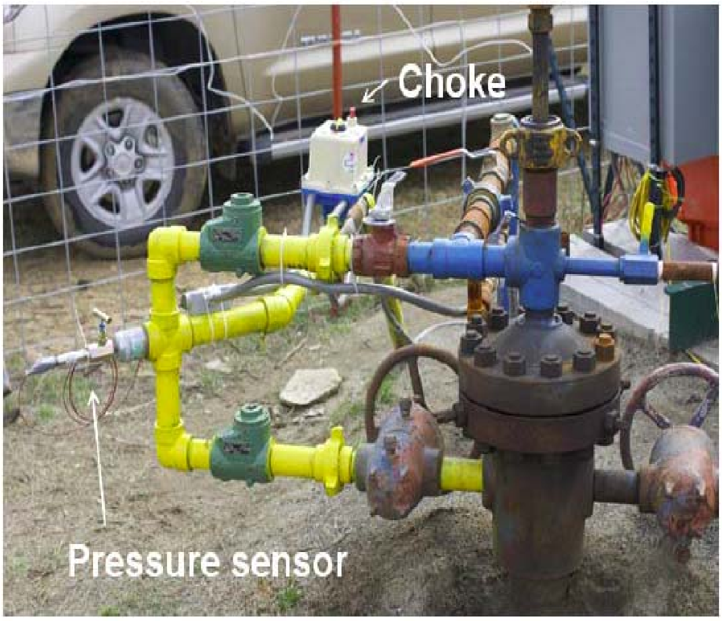
position

An example of data management : ROOKIE { Curtis Withson }

Noblin Overview







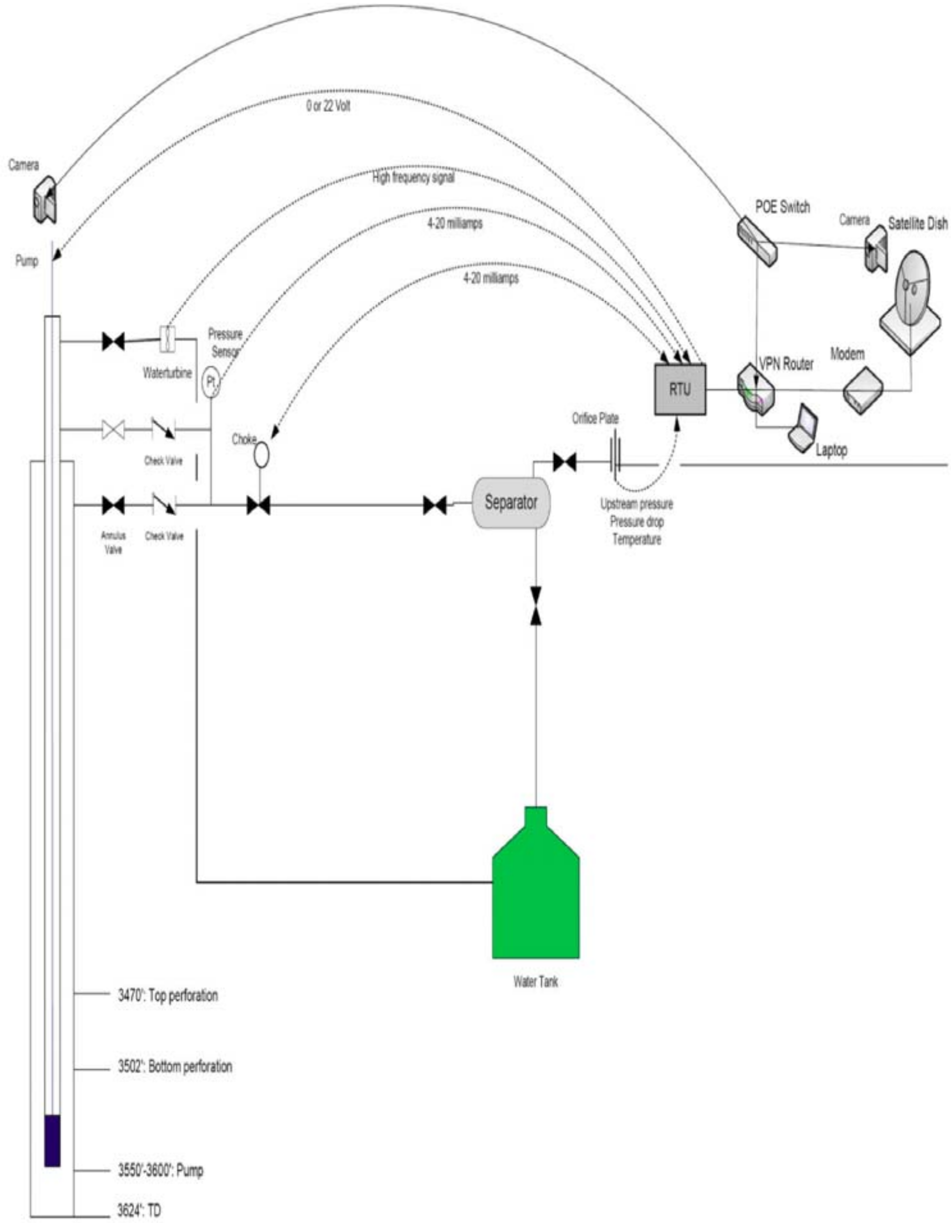
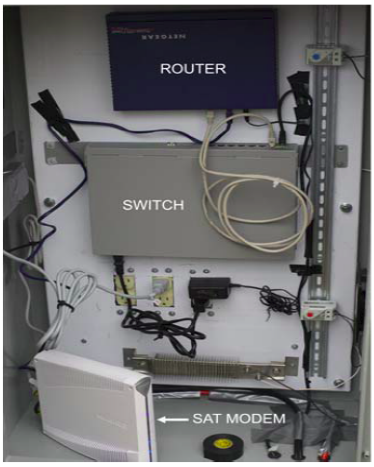
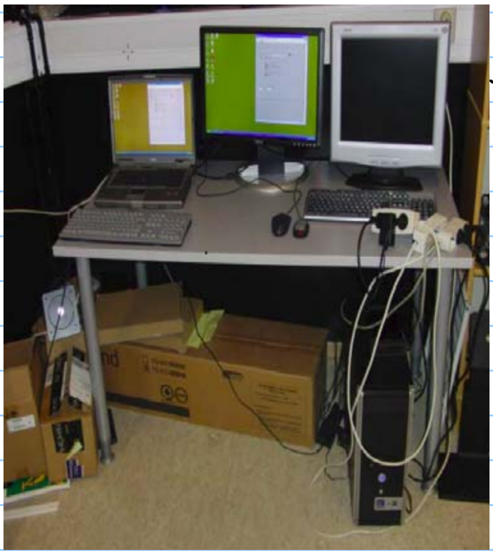


Figure 6 – Noblin gas well, instruments and signals.

RTU / Communications





in Trondheim
data server

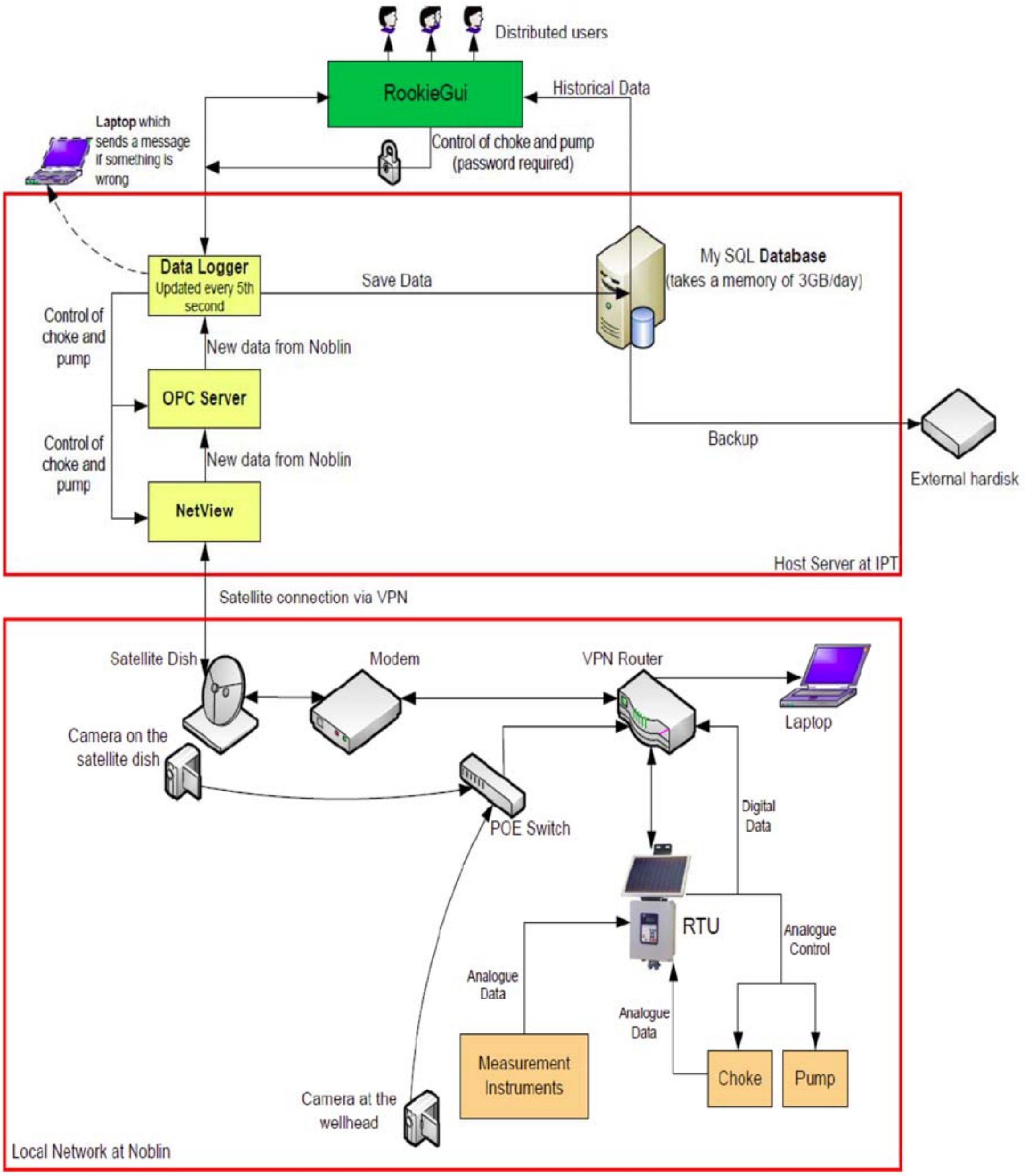
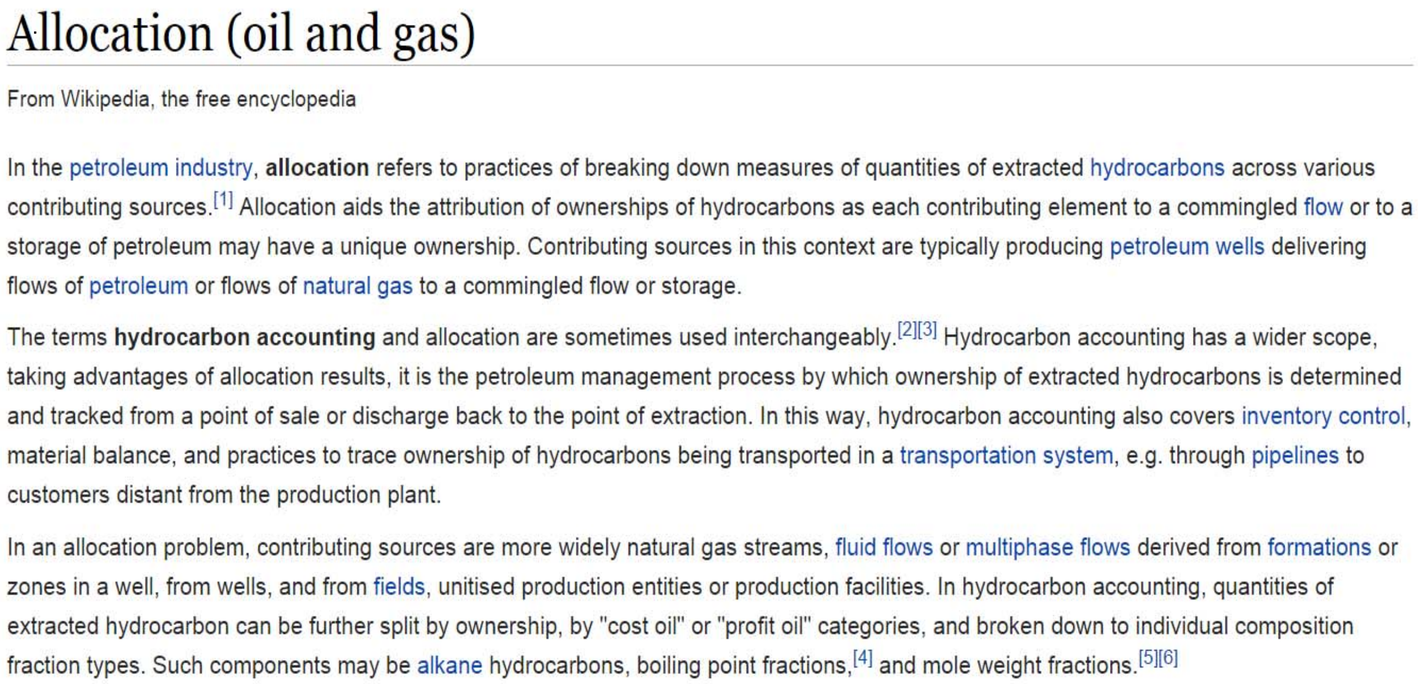


Figure 2 – The data flow from the RTU in Oklahoma to the Petroleum Institute in Norway.

MPFM : multiphase flow meter

Allocation: Determine, from the total HC production, how much is coming from a well, layer, reservoir, etc



Allocation (oil and gas)

From Wikipedia, the free encyclopedia

In the petroleum industry, **allocation** refers to practices of breaking down measures of quantities of extracted hydrocarbons across various contributing sources.[1] Allocation aids the attribution of ownerships of hydrocarbons as each contributing element to a commingled flow or to a storage of petroleum may have a unique ownership. Contributing sources in this context are typically producing petroleum wells delivering flows of petroleum or flows of natural gas to a commingled flow or storage.

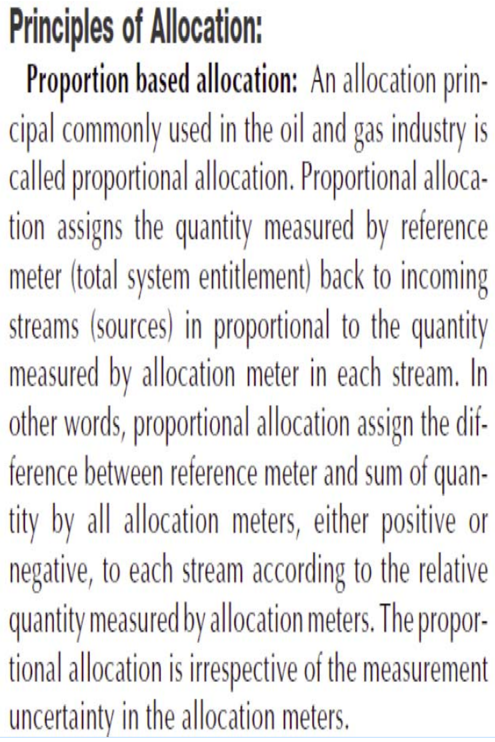
The terms **hydrocarbon accounting** and allocation are sometimes used interchangeably.[2][3] Hydrocarbon accounting has a wider scope, taking advantages of allocation results, it is the petroleum management process by which ownership of extracted hydrocarbons is determined and tracked from a point of sale or discharge back to the point of extraction. In this way, hydrocarbon accounting also covers inventory control, material balance, and practices to trace ownership of hydrocarbons being transported in a transportation system, e.g. through pipelines to customers distant from the production plant.

In an allocation problem, contributing sources are more widely natural gas streams, fluid flows or multiphase flows derived from formations or zones in a well, from wells, and from fields, unitised production entities or production facilities. In hydrocarbon accounting, quantities of extracted hydrocarbon can be further split by ownership, by "cost oil" or "profit oil" categories, and broken down to individual composition fraction types. Such components may be alkane hydrocarbons, boiling point fractions,[4] and mole weight fractions.[5][6]

hydrocarbon accounting ~ reconciliation

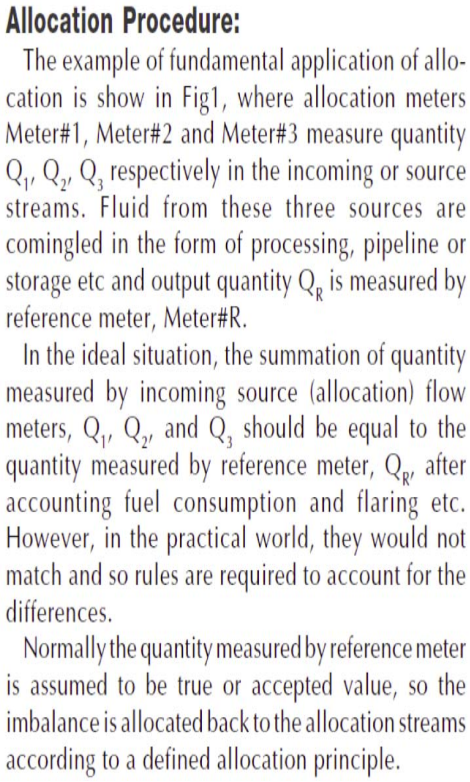
Individual well production measurement vs Production at Separator

!



Principles of Allocation:

Proportion based allocation: An allocation principal commonly used in the oil and gas industry is called proportional allocation. Proportional allocation assigns the quantity measured by reference meter (total system entitlement) back to incoming streams (sources) in proportional to the quantity measured by allocation meter in each stream. In other words, proportional allocation assign the difference between reference meter and sum of quantity by all allocation meters, either positive or negative, to each stream according to the relative quantity measured by allocation meters. The proportional allocation is irrespective of the measurement uncertainty in the allocation meters.



Allocation Procedure:

The example of fundamental application of allocation is show in Fig1, where allocation meters Meter#1, Meter#2 and Meter#3 measure quantity Q_1, Q_2, Q_3 respectively in the incoming or source streams. Fluid from these three sources are comingled in the form of processing, pipeline or storage etc and output quantity Q_R is measured by reference meter, Meter#R.

In the ideal situation, the summation of quantity measured by incoming source (allocation) flow meters, Q_1, Q_2, and Q_3 should be equal to the quantity measured by reference meter, Q_R, after accounting fuel consumption and flaring etc. However, in the practical world, they would not match and so rules are required to account for the differences.

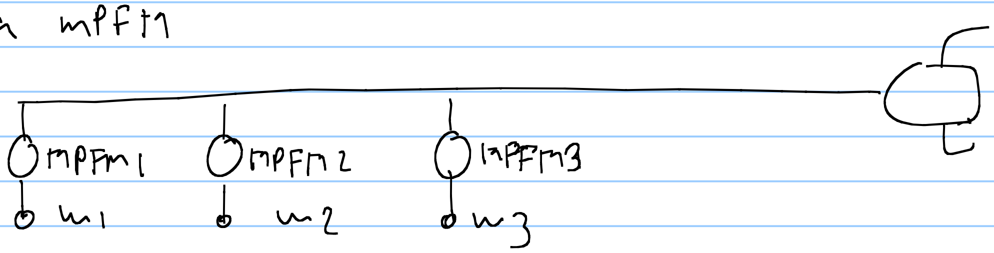
Normally the quantity measured by reference meter is assumed to be true or accepted value, so the imbalance is allocated back to the allocation streams according to a defined allocation principle.

How to measure individual well rate?

every two weeks

Use a portable test separator: (onshore fields)

- Using a MPFM



very expensive

↳ some people don't trust the results, not accepted for allocation

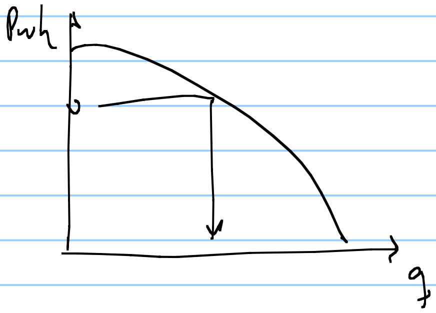
→

- Using a model

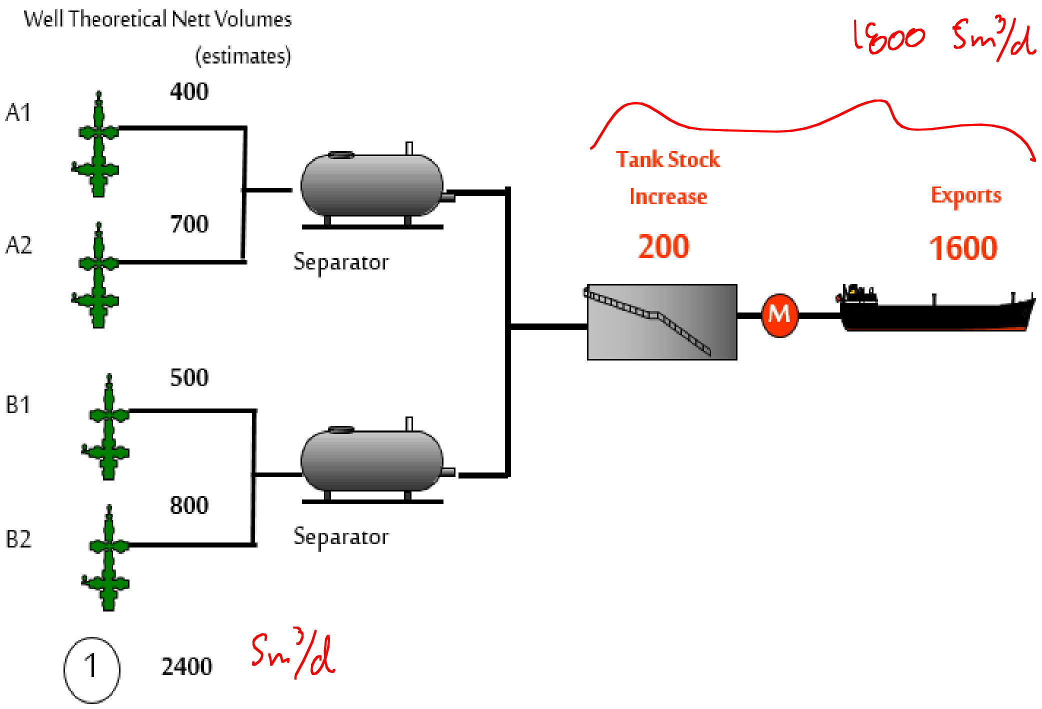
PipeSim

GAP

Prosper



Reconciliation problem

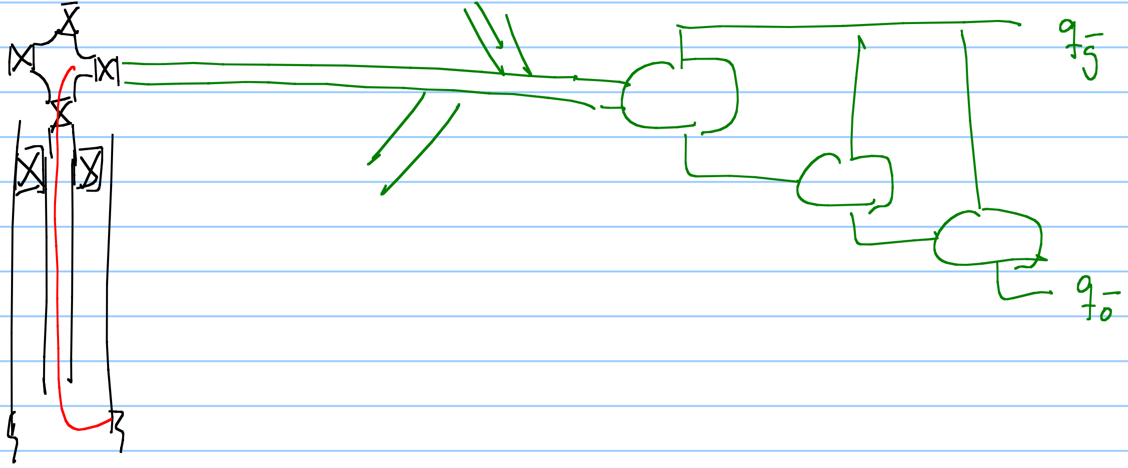


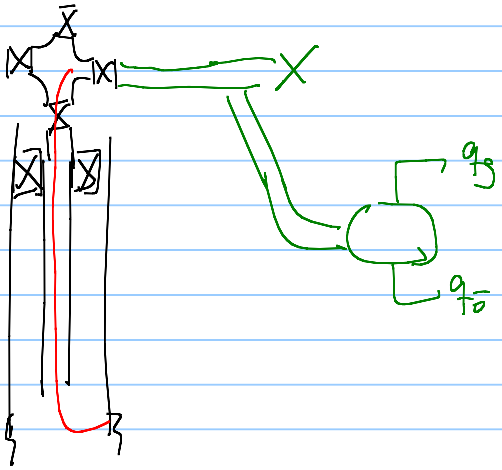
Calculate a factor $F = \frac{1800}{2400} = \frac{3}{4} = 0.75$

multiply the production of each well by that value

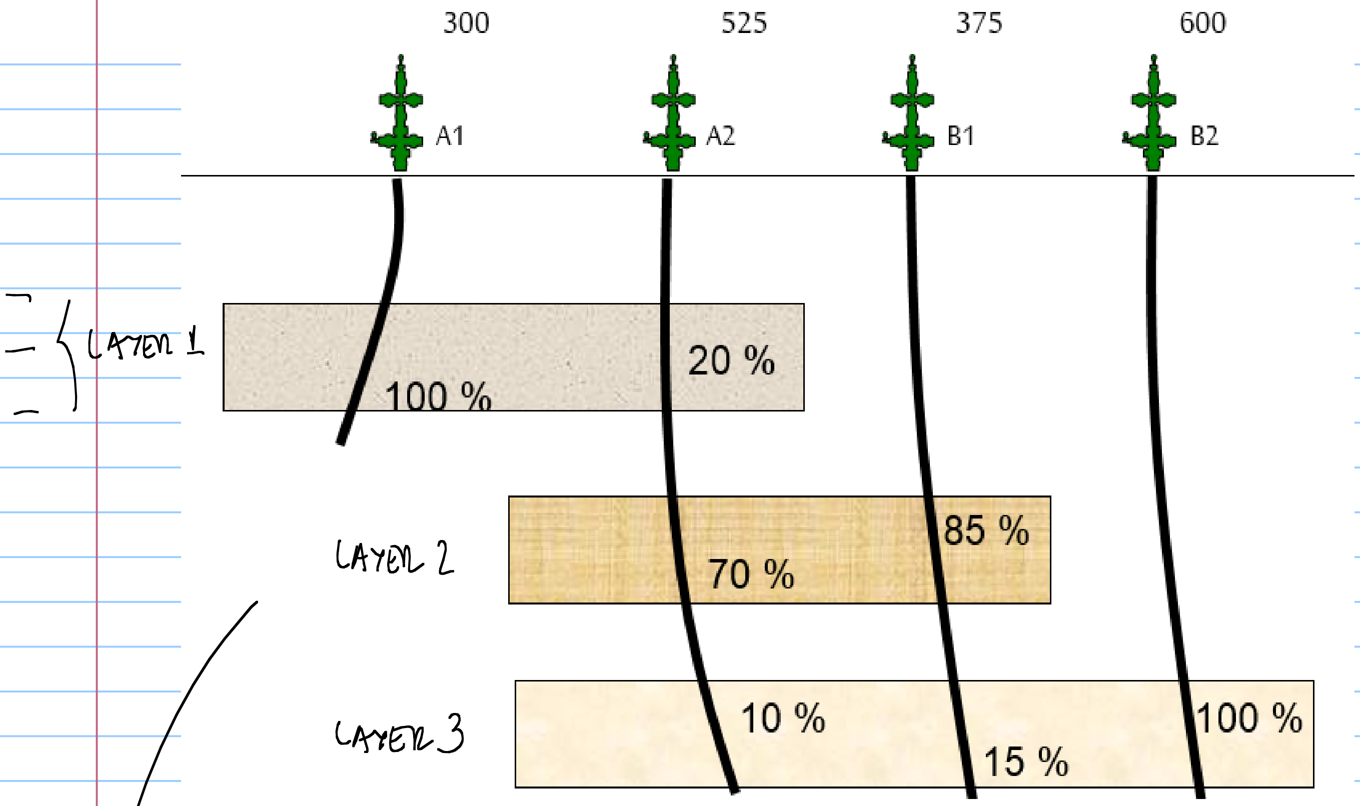
$q_{f_1} = 400 \text{ Sm}^3/d \rightsquigarrow q_{f_1}^{new} = 0.75 \cdot 400 = 300 \text{ Sm}^3/d$

$q_{f_2}^{new} = 700 \text{ Sm}^3/d \cdot 0.75 = 525 \text{ Sm}^3/d$





Allocation for reservoir or layer



From layer 1 $q_1 + 20\% \, q_2$

$300 \, Sm^3/d + 0.2 \cdot 525 \, Sm^3/d = 262.5 + 300 = 562.5 \, Sm^3/d$

to set these % : ◦ Dowhole network (Metool)

- Dowhole meter

Mathematical Optimization of Production Systems {

Don't confuse with

Effectivization : to make things more effective, to improve from a previous states

Optimization involves a mathematical procedure to:

1: Search for a maximum or minimum of an objective function, oil production
Revenue, Recovery factor, Np (cummulative production), plateau length, condensate recovery {maximize}
minimize {cost}

2: By changing some adjustable variables in the system: choke position, ESP pump frequency, gas lift injection rate, well position (at an early stage of the asset)

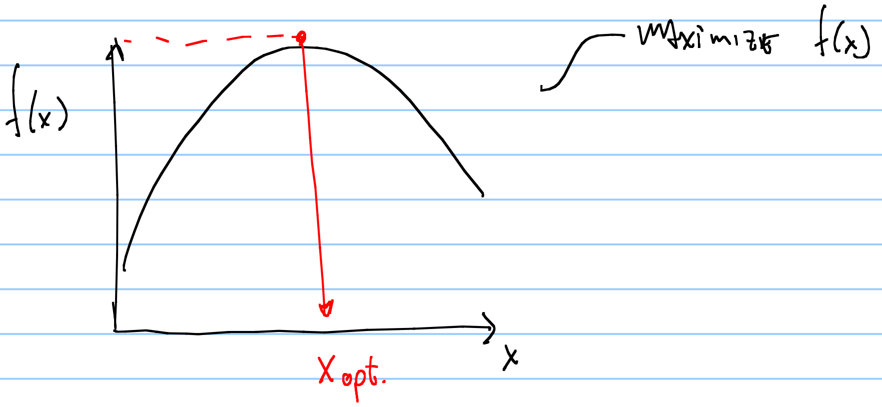
3: Honoring some constraints {water handling capacity, gas processing capacity, Energy capacity, etc

We want to operate at the best conditions. We need an advisor to tell me where is the "best" located.

this is done by using models { simulation, commercial sofware, etc.

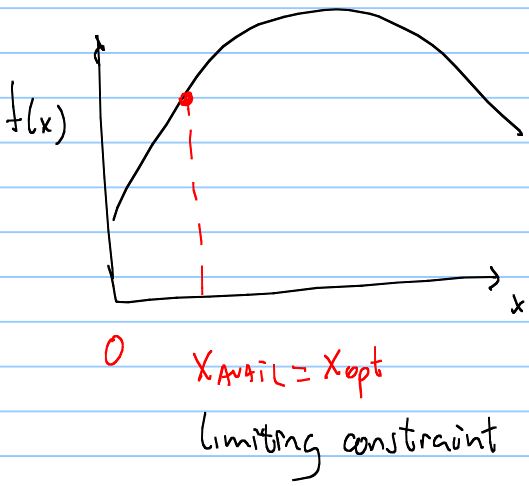
a way to manage production by using model-based optimization

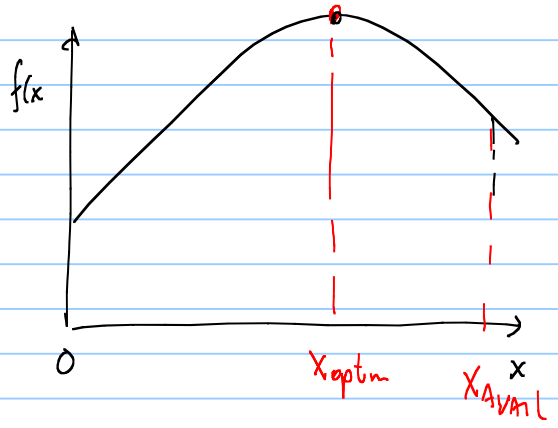
①



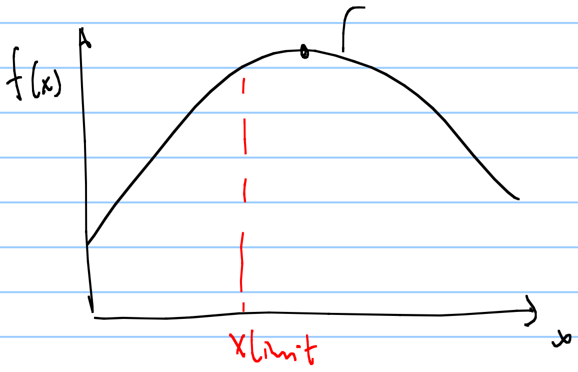
max $f(x)$, $x \leq X_{avail}$

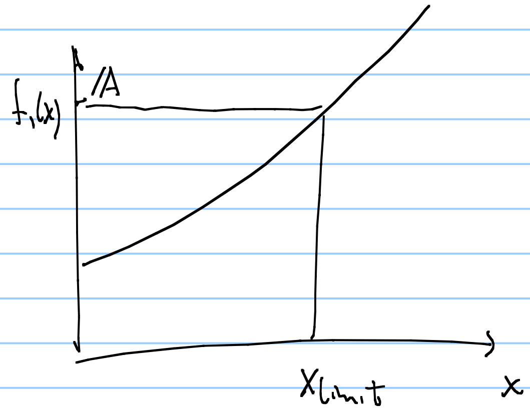
②





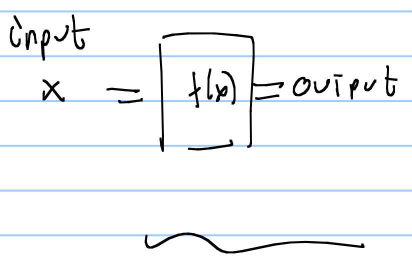
③

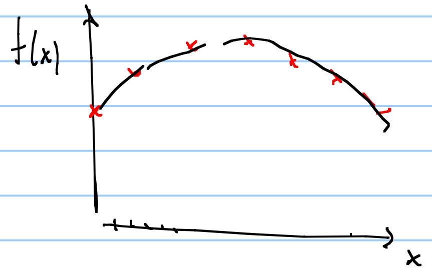


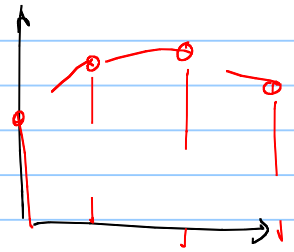


max $f(x)$ by changin x , and subjected to $f_1(x) \leq A$

In optimization in petroleum operations, the functions (objective function, constraint functions) are outputs of our models (reservoir model, processing facility model, production network model, etc).







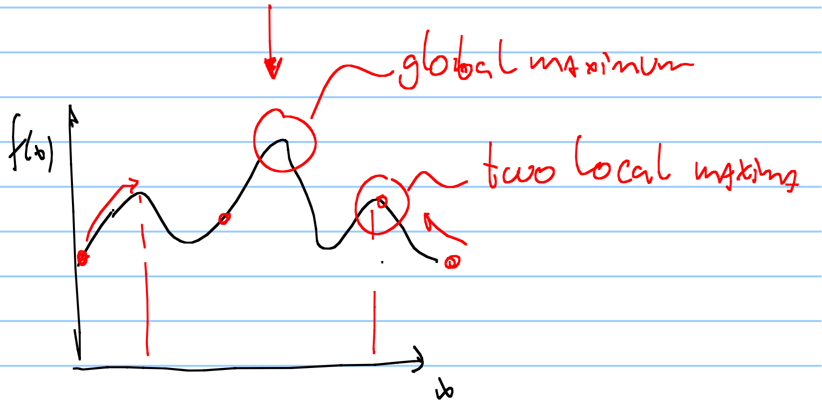
function reconstruction, very expensive, requires a lot of evaluations

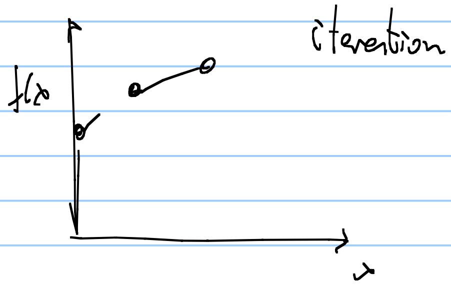
Optimization types

- Constrained optimization, unconstrained optimization
- Continuous optimization or discrete/integer optimization → nature of the adjustable variable
- Local search or global search

  multistart: start your optimization from different positions

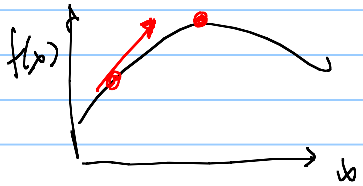
  is very difficult to be sure (in a problem with multiple maxima) that you have found the global maximum



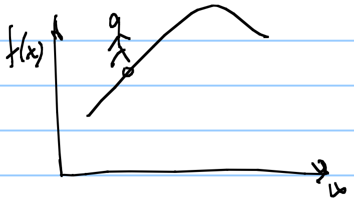


- Optimization techniques (methods)
  - Specific algorithms for certain type of problems
  - Calculate search direction using Gradients (derivatives)

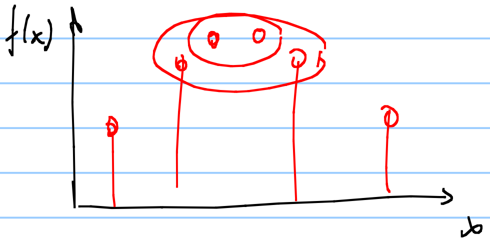
    continuous problem



- Heuristic : start with an arbitrary value and progress using penalization logic



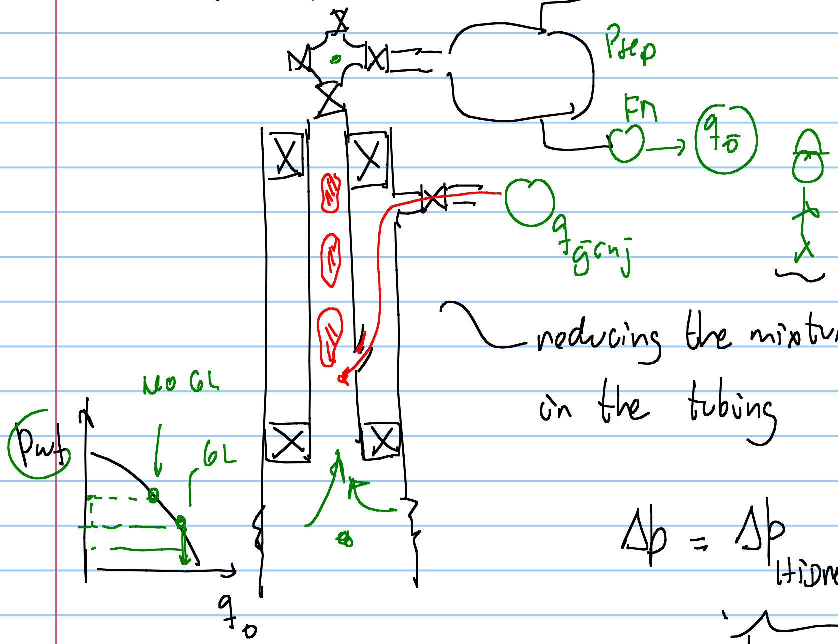
- Stochastic method: Generate random variables, random search ..
  Evolutionary algorithm, genetic algorithms,



- combinatorial techniques ~> integer

//

Gas lift optimization



reducing the mixture density of the fluid circulating in the tubing

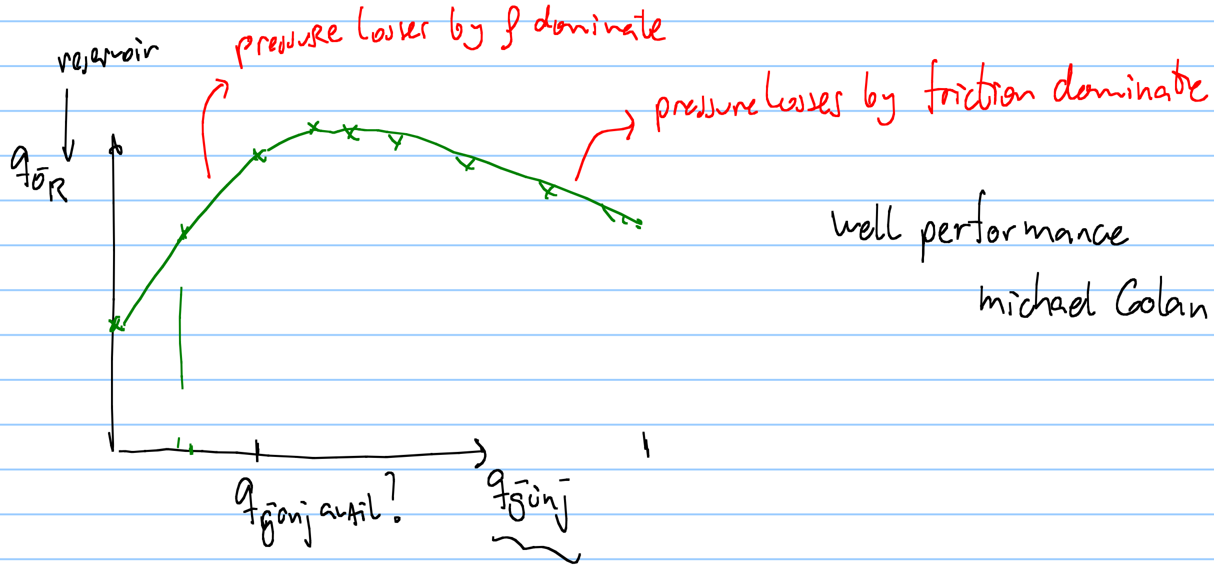
reducing this term

increasing this term

$$\Delta p = \underbrace{\Delta p_{Hidrostatic}}_{\rho h . g} + \underbrace{\Delta p_{friction}}_{f \frac{L}{D} \frac{v^2}{2g}}$$

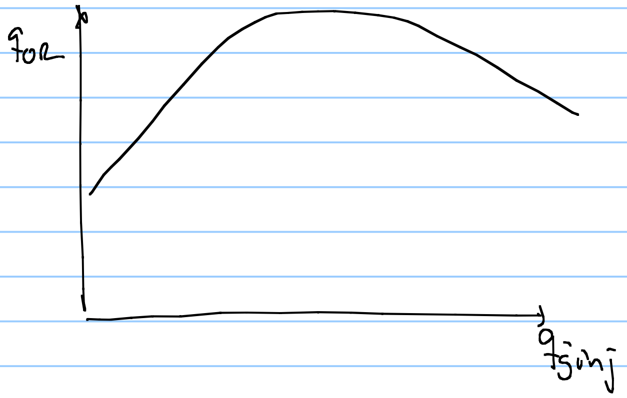
h → height

~Gas lift performance curve



well performance
michael Golan

single well

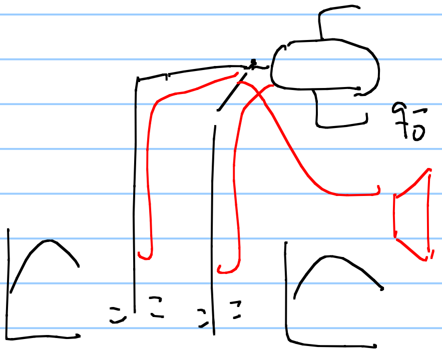


Collection of points we want to have a f(x) $q_{oR}(q_{ginj}) =$

$$q_p = \tilde{\alpha}_1(2 - e^{-\hat{\beta}_1 q_i}) - \tilde{\alpha}_2 e^{\beta_2 q_i}$$

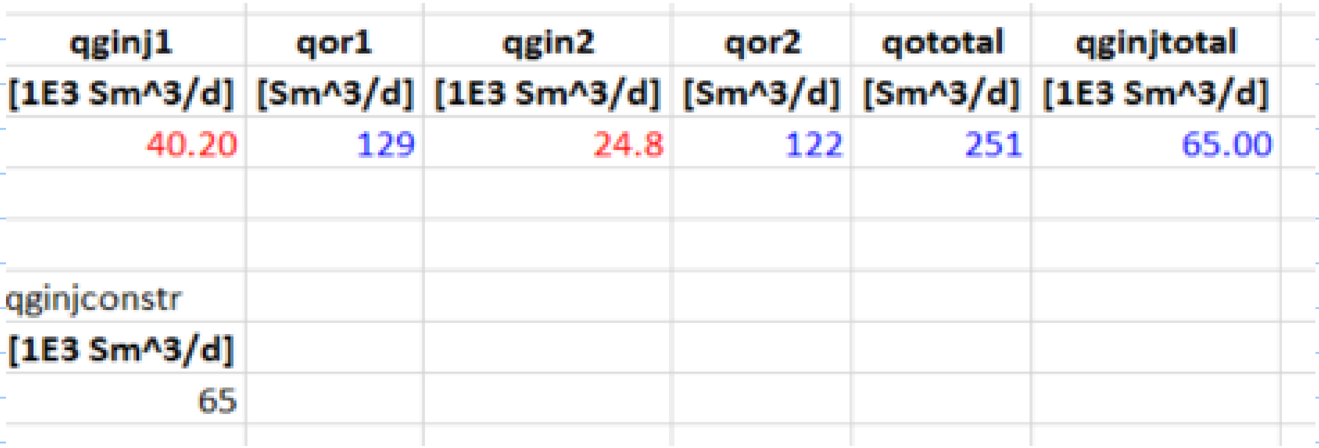
constants tuned with field data

$$\left.\frac{\partial q_{oR}}{\partial q_{ginj}}\right|$$



$q_{\bar{o}} = q_{\bar{o}R_1} + q_{\bar{o}R_2}$ ~objective function by changing q_{ginj_1}, q_{ginj_2}

With no constraints, the joint optimization ($q_{oR1} + q_{oR2}$) is equal to optimize separately

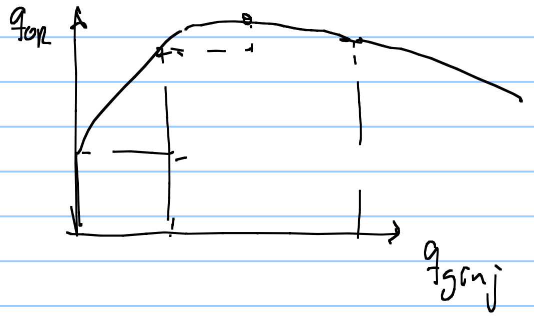


qginj1 [1E3 Sm^3/d]	qor1 [Sm^3/d]	qgin2 [1E3 Sm^3/d]	qor2 [Sm^3/d]	qototal [Sm^3/d]	qginjtotal [1E3 Sm^3/d]
40.20	129	24.8	122	251	65.00
qginjconstr					
[1E3 Sm^3/d]					
65					

Solve the problem using Lagrange multipliers.

$$\frac{\partial q_{oRi}}{\partial q_{ginj\,i}} = \text{same}$$

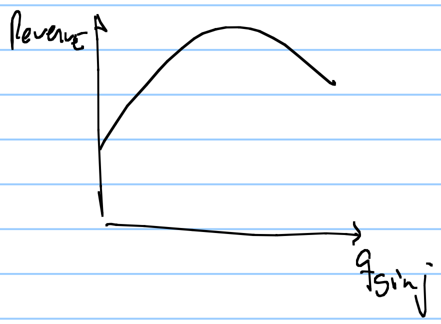
Change your objective function from oil production to Revenue



$$\text{Revenue} = q_{oR} \cdot P_o - q_{ginj} \cdot P_g \}$$

price of oil

- gas price
- Compressor power requirements
- etc



You are a production engineer

~ sabana

reservoir with low GOR

& high water cut

wc-30% → 95%

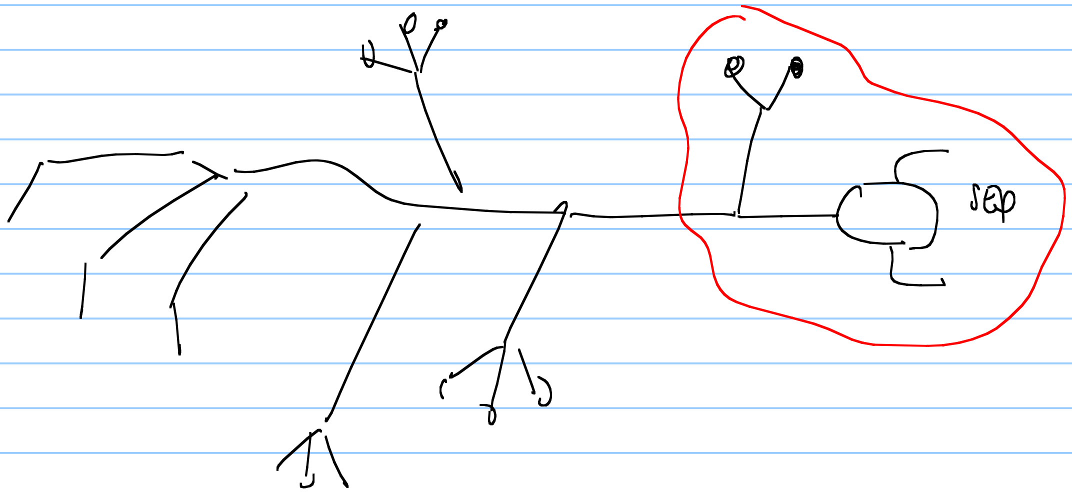
well operating with ESP.

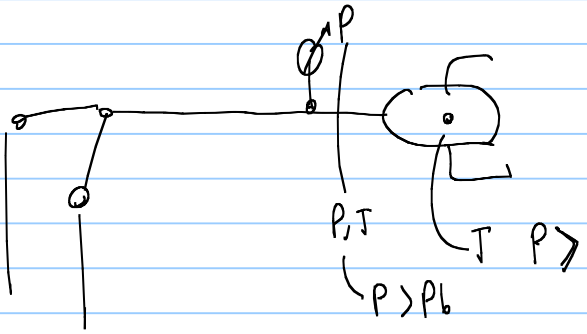
constraints

Optimize oil production by changing pump frequency ~> water handling capacity

→ $P_{suc} \geq 13.6$ bara

500 wells with ESP

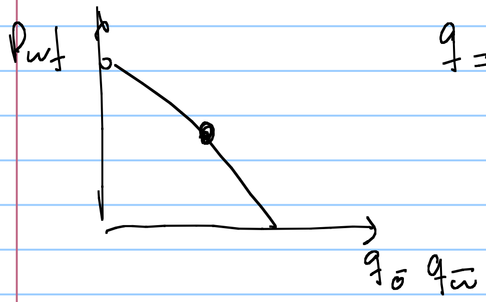




~ running optimization on a model.

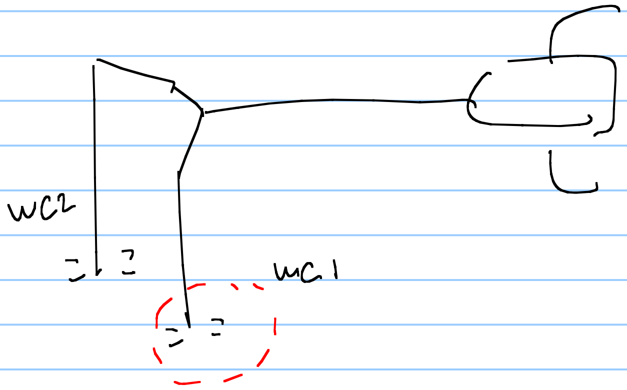
• only flow of water and oil in the system

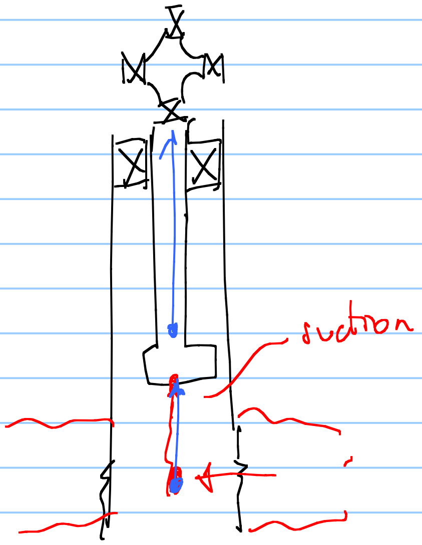
PVT report of the oil   Pb(T)



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

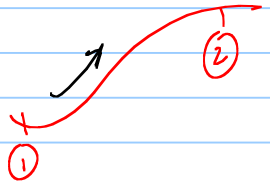
single phase fluid incompressible in the reservoir





flow from perforations to pump suction
flow in pipes oil and water?

Bernoulli equation



$$H_{①} = H_2$$

$$\overbrace{\frac{v_1^2}{2g} + z_1 + \frac{P_1}{\boxed{\rho_1} g} = \frac{v_2^2}{2g} + z_2 + \frac{P_2}{\rho_2 g} + \Delta H_{losses}}$$

velocity

elevation

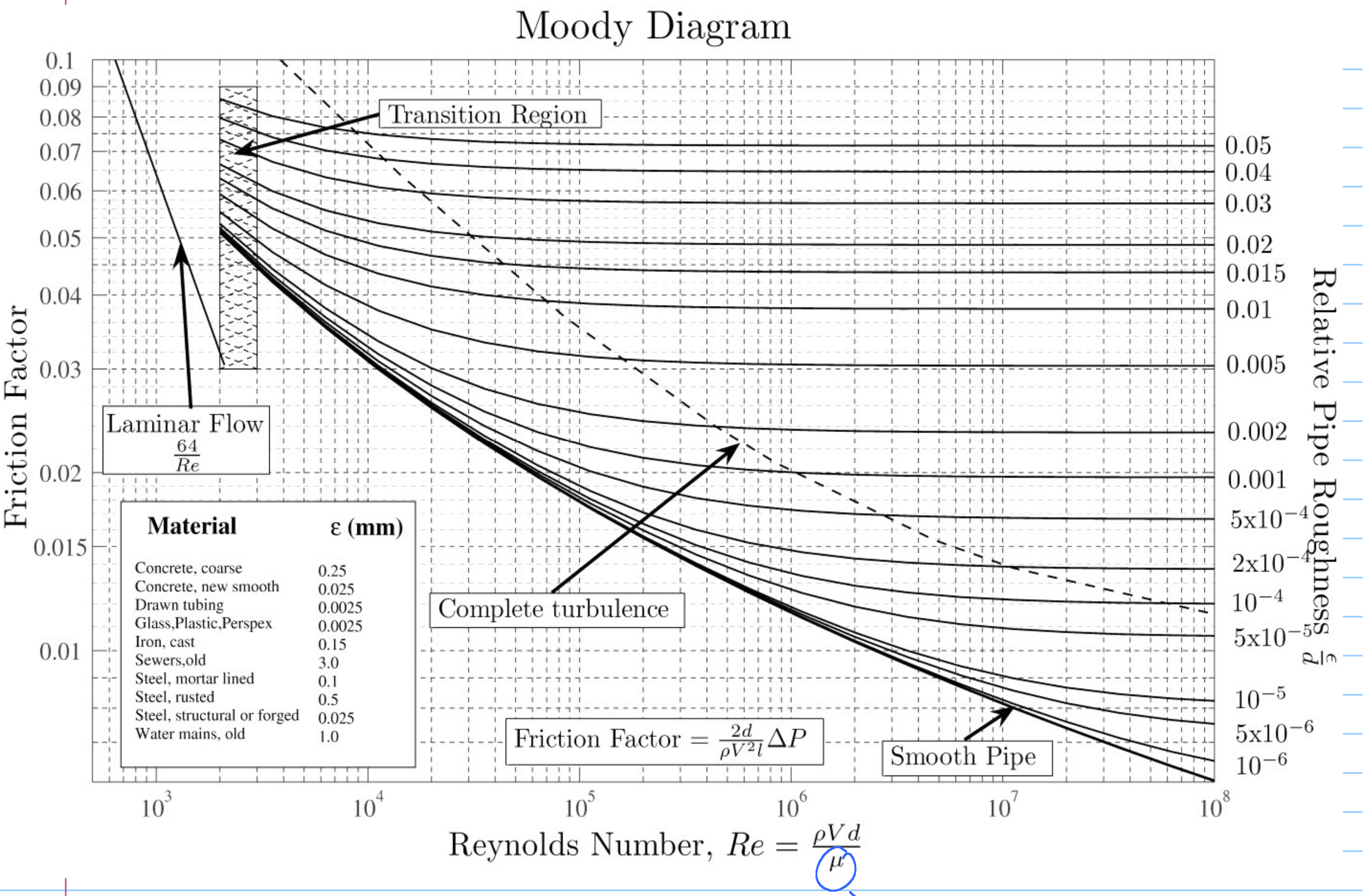
$$\Delta H_{losses} = f \frac{L}{D} \cdot \frac{v^2}{2g}$$

pipe length

pipe ID

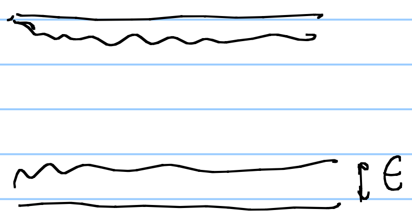
friction factor

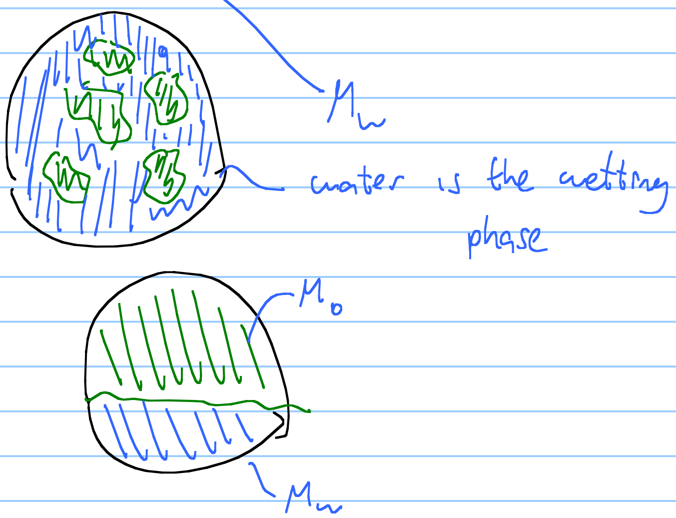
for density $= \rho_{mix} = \rho_o \cdot (1 - wc) + \rho_w (wc)$



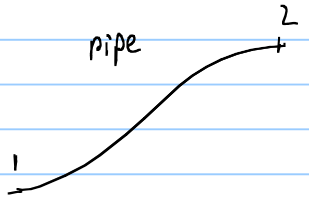
Friction Factor $= \frac{2d}{\rho V^2 l}\Delta P$

Material	**ε (mm)**
Concrete, coarse	0.25
Concrete, new smooth	0.025
Drawn tubing	0.0025
Glass,Plastic,Perspex	0.0025
Iron, cast	0.15
Sewers,old	3.0
Steel, mortar lined	0.1
Steel, rusted	0.5
Steel, structural or forged	0.025
Water mains, old	1.0



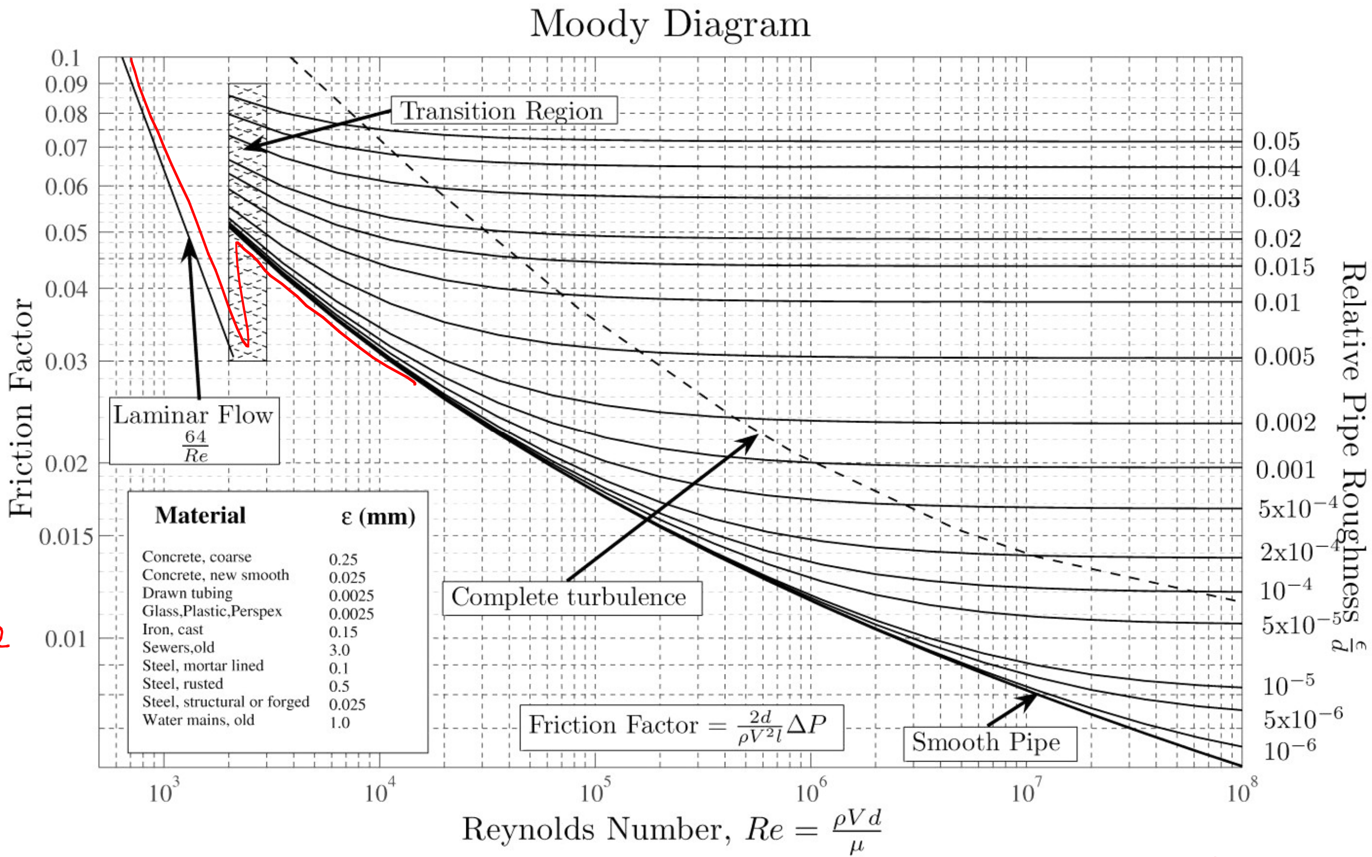


Final objective: perform optimization using our excel model



$$H_1 = H_2 + \Delta H_f$$

$$\frac{P_1}{\rho \cdot g} + \cancel{\frac{v_1^2}{2g}} + z_1 = \frac{P_2}{\rho \cdot g} + \cancel{\frac{v_2^2}{2g}} + z_2 + f \cdot \frac{L}{D} \frac{v^2}{2g}$$



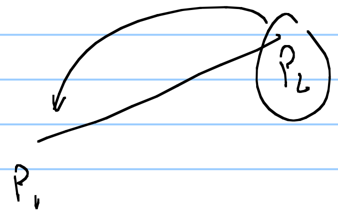
Adim. pressure loss

↳ adimensional velocity

- Haaland Correlation for Darcy friction factor

$$\frac{1}{\sqrt{f}} = -1.8 \log_{10}\left[\left(\frac{\varepsilon/D}{3.7}\right)^{1.11} + \frac{6.9}{\mathrm{Re}}\right]$$ [7]

$$\underbrace{\frac{P_1}{\rho g} + z_1 = \frac{P_2}{\rho g} + z_2 + f\frac{L}{D}\frac{V^2}{2g}}$$



↳ Two ways to use it:

- I have P_1 and q find P_2 ← Available
- I have P_2 an q find P_1 ← required

In excel VBA $$P_1 = \left[\frac{P_2}{\underset{\sim}{\rho} g} + (z_2 - z_1) + f\frac{L}{D}\frac{V^2}{2g}\right]\rho g$$

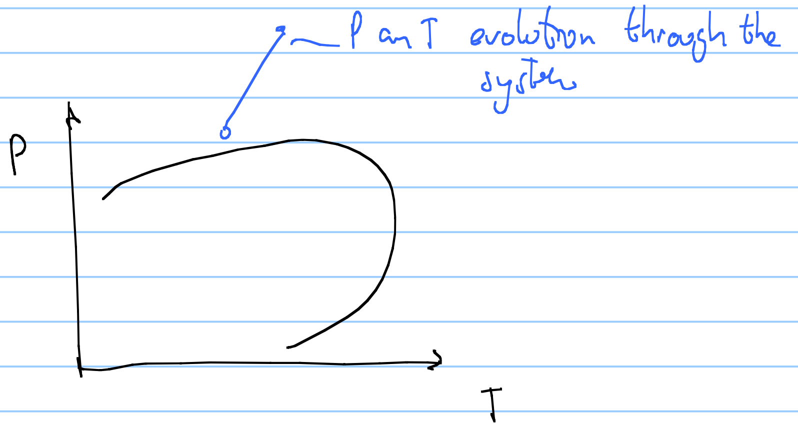
$$\rho_{mix} = wc.\rho_w + (1-wc)\rho_o$$

$$f \quad \rightarrow \quad Re = \frac{\rho . V . D}{\underset{\sim}{\mu}}$$

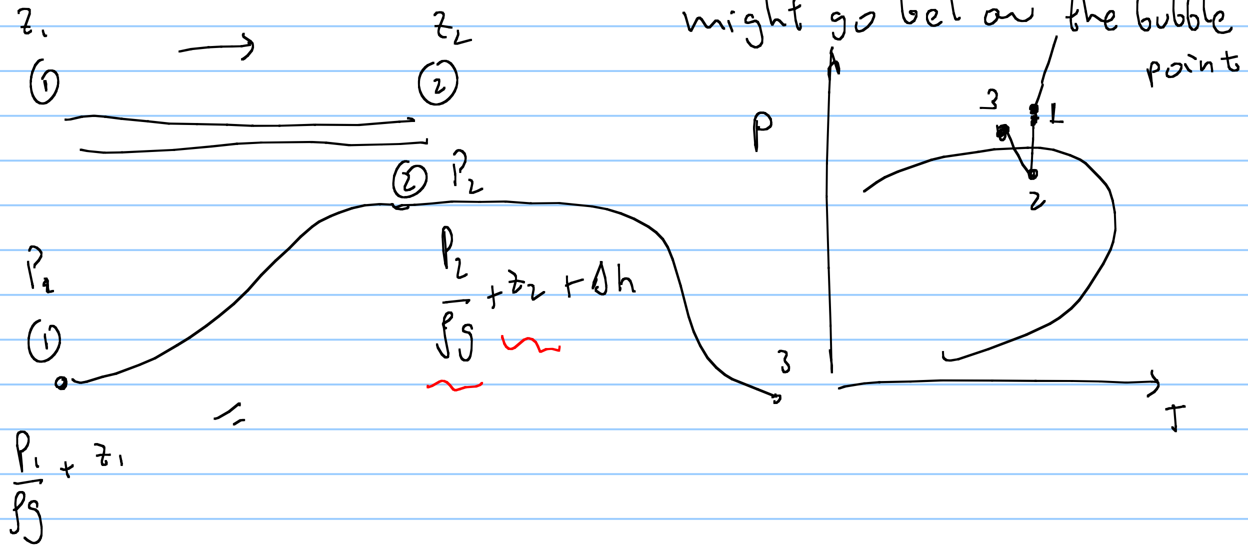
- Assumptions taken so far to build our model:

-no gas in the system

z_i of oil



be careful with pipe elevation and liquid, the pressure might go below the bubble point



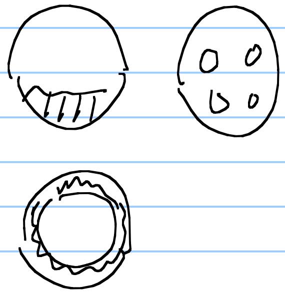
- wall wetting phase is water, $\rho_{mix} = wc\,\rho_w + (1-wc)\,\rho_o$ ⤳ multiphase expert

  no slip

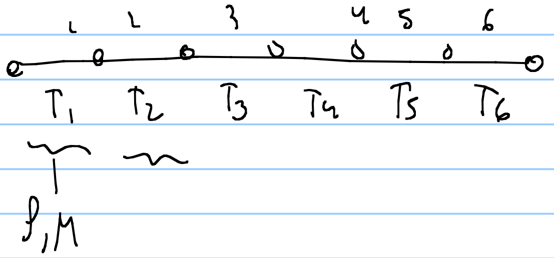
  $\rho_o, \rho_w, v_o, v_w,$ inclination angle, ID

or use commercial software
OLGA

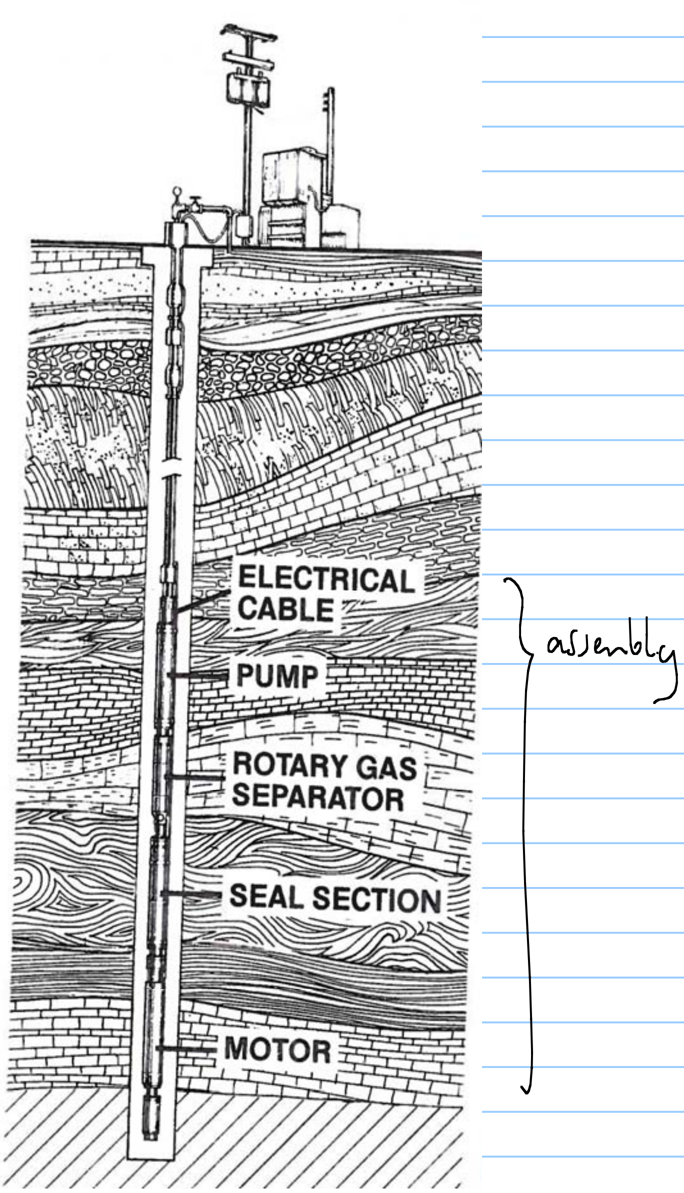
is there slip?
what is the flow pattern?
Can the homogeneous flow approach be used?

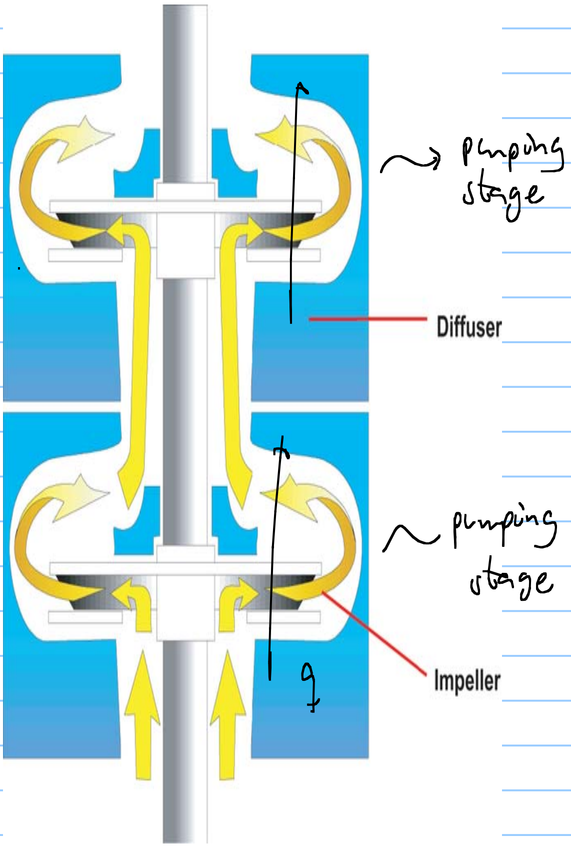


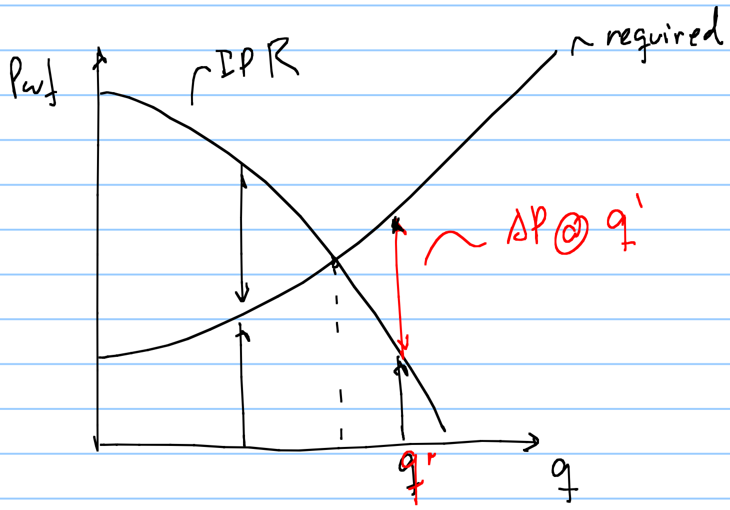
- what to do with temperature
  - Assume isothermal flow Temperature doesn't change or doesn't change such as produces a relevant variation in fluid properties
  - Discretize in segments and assume constant T and fluid properties in each segment

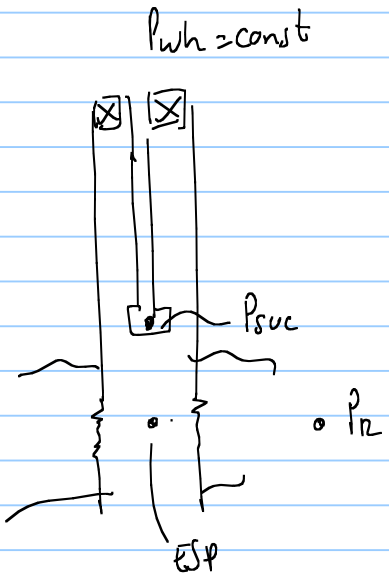


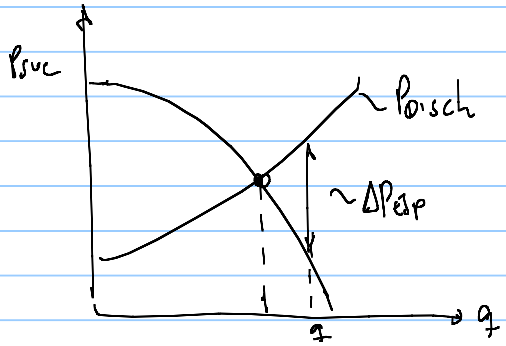
ESP.. Electric submersible pump





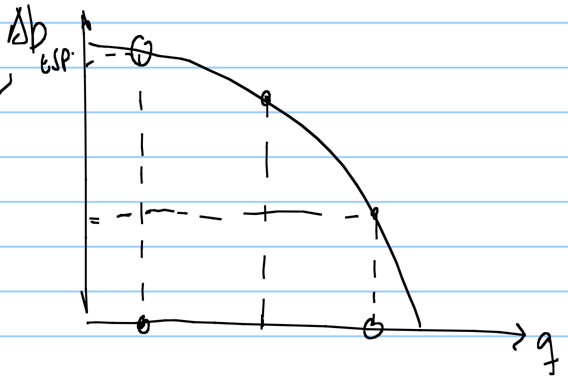


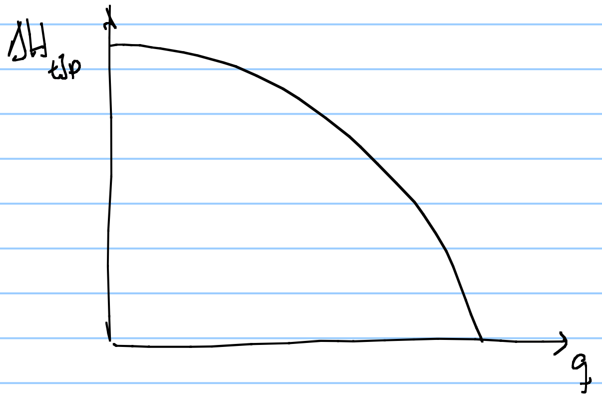




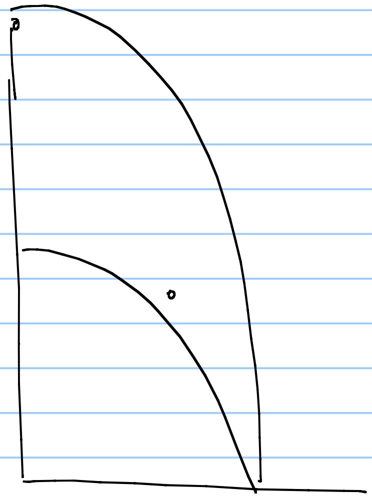
Single stage ESP performance,

$$\text{head} = \frac{\Delta p}{\rho . g}$$



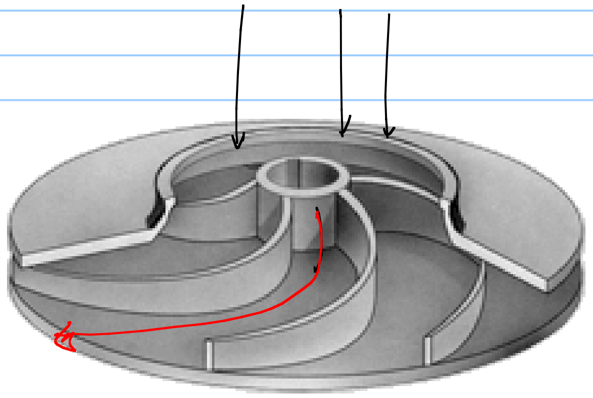


multiple stage

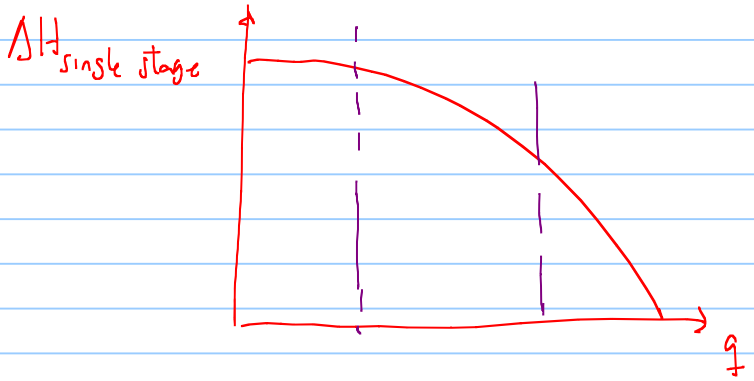


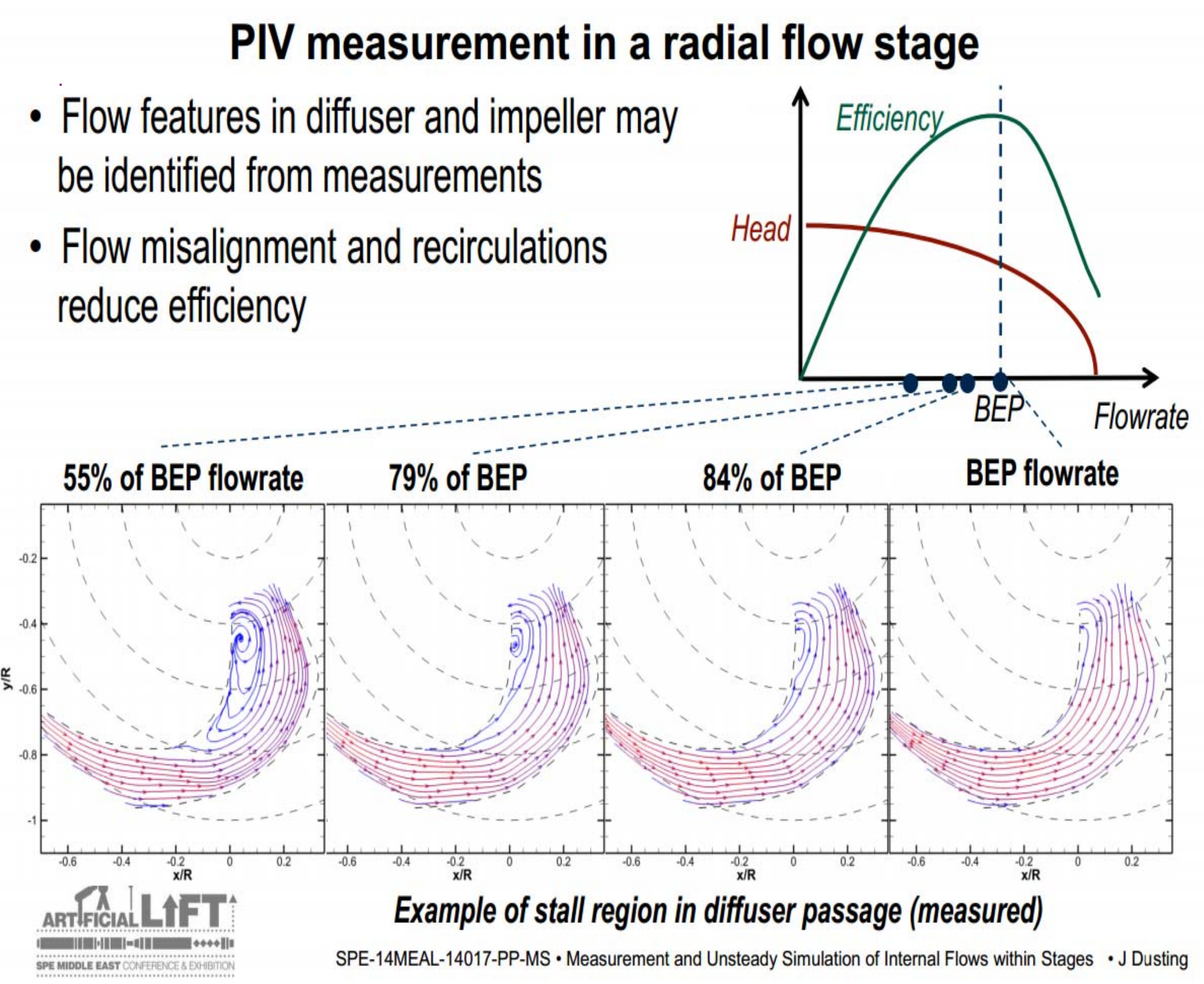
$$\Delta H_{TOTAL} = \Delta H_{single\ stage} \cdot N_{stages}$$

$$q_{TOTAL} = q_{single\ stage}$$



50 stages





PIV measurement in a radial flow stage

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

55% of BEP flowrate

79% of BEP

84% of BEP

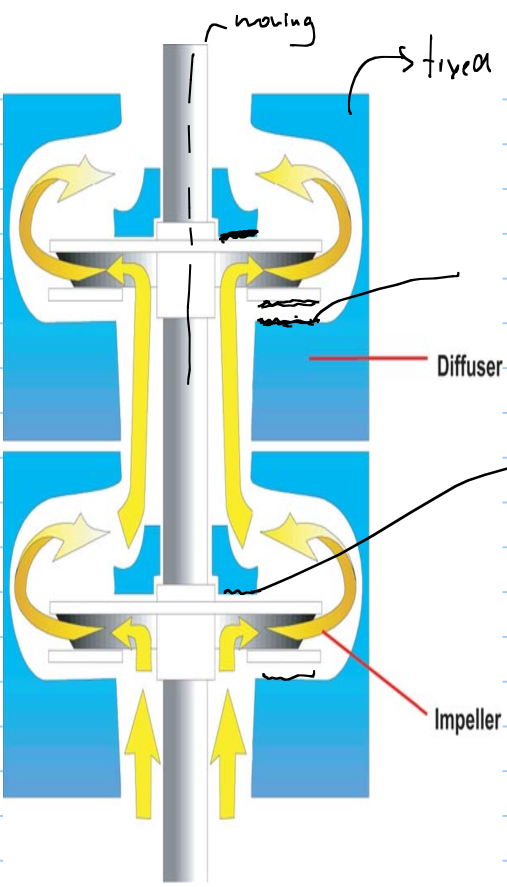
BEP flowrate

Example of stall region in diffuser passage (measured)

ARTIFICIAL LIFT SPE MIDDLE EAST CONFERENCE & EXHIBITION

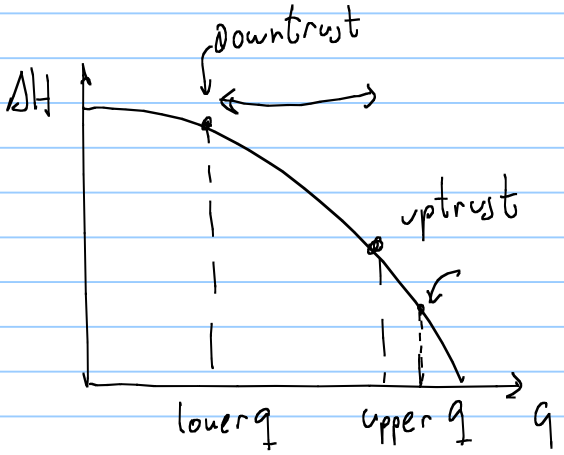
SPE-14MEAL-14017-PP-MS • Measurement and Unsteady Simulation of Internal Flows within Stages • J Dusting

upstrust and downtrust

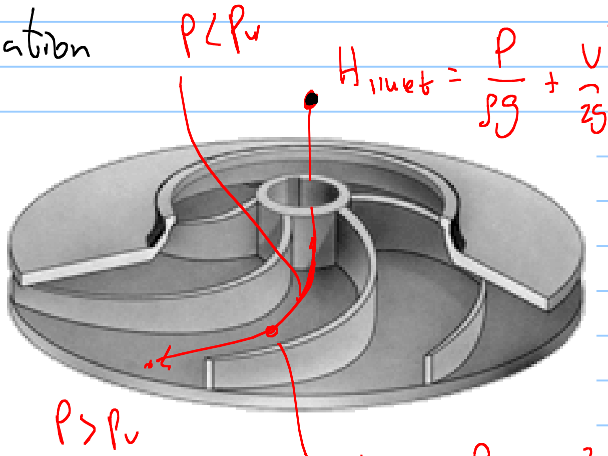


if the flow is too low, the rotor makes contact with the lower support and there is excessive wear (downtrust)

if the flow is too high, the rotor makes contact with the upper support an there is excesive wear (uptrust)

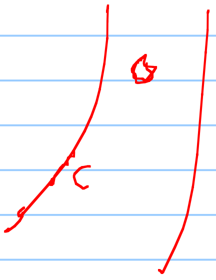


- Cavitation



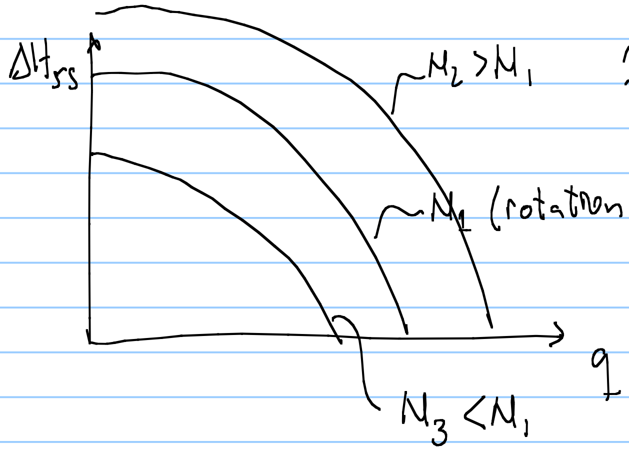
$H_{inlet} = \frac{P}{\rho g} + \frac{v^2}{2g} + z$ single liquid

$H = \frac{P}{\rho g} + \frac{v^2}{2g} + z$



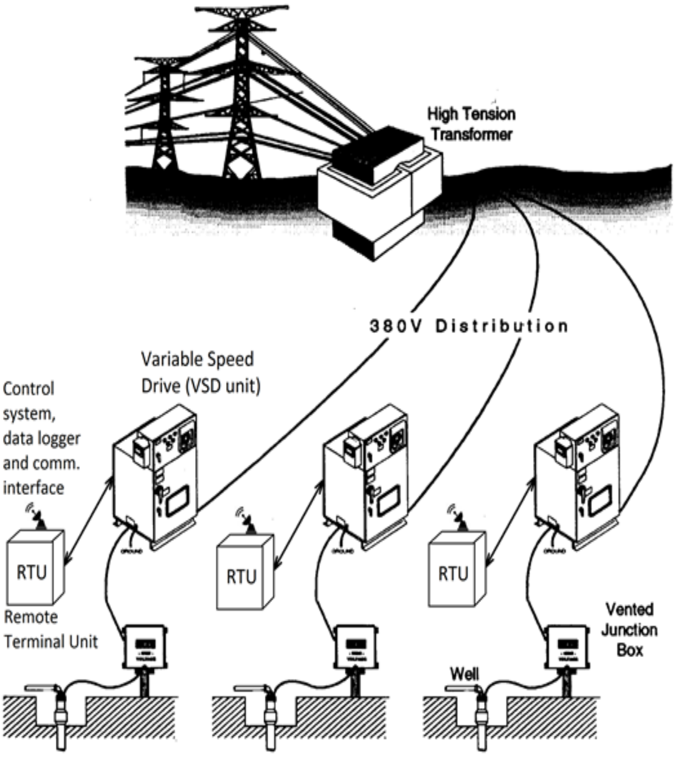
suction pressure must be high enough to avoid cavitation in the impeller (NPSH) (positive net suction head)

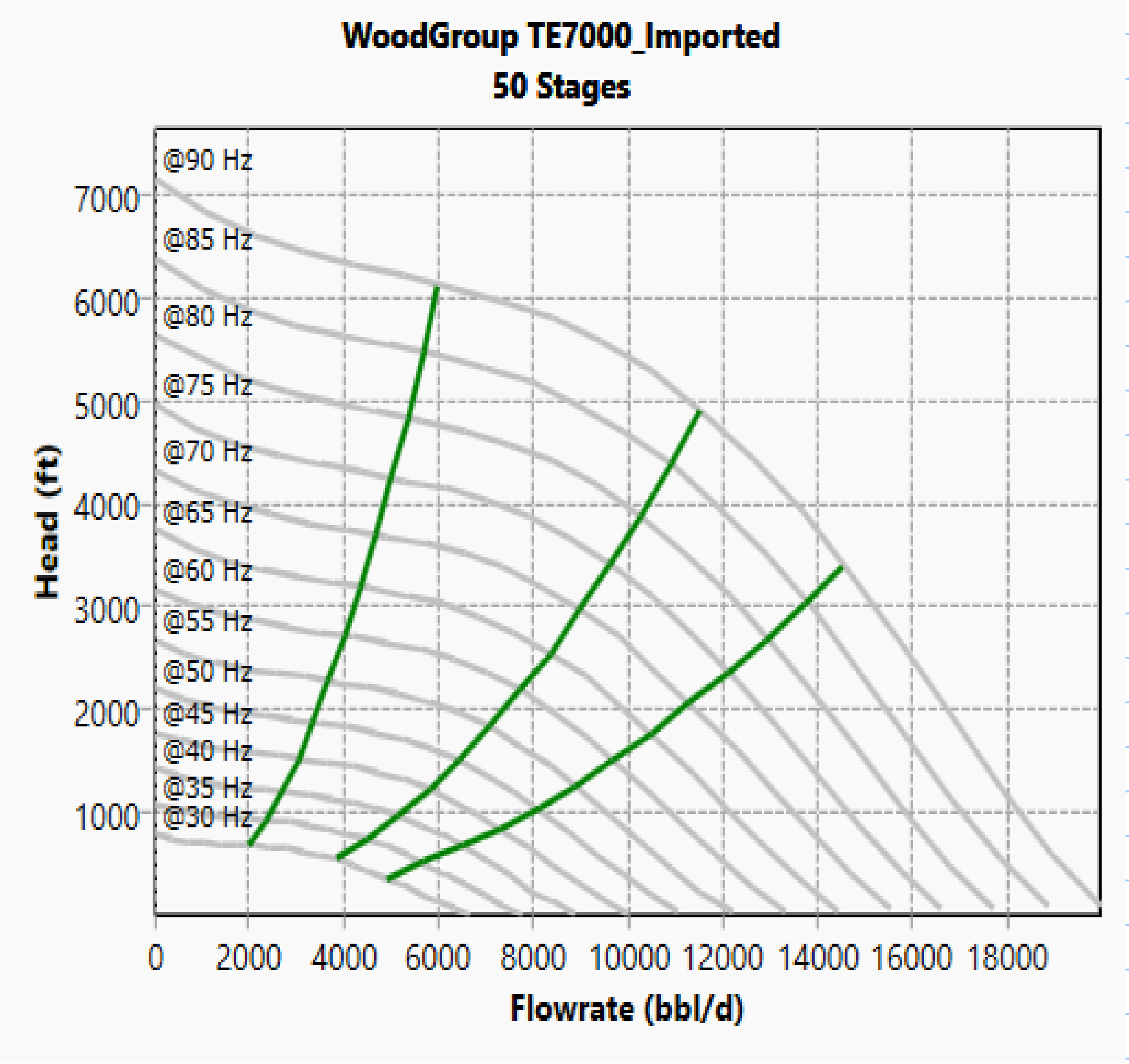
the pressure at suction of the pump > P^*_{sur}



~ rpm (N)
~ Hz · (f) ~ (30 - 60 Hz)

How to predict stage performance at a different rotational speed?

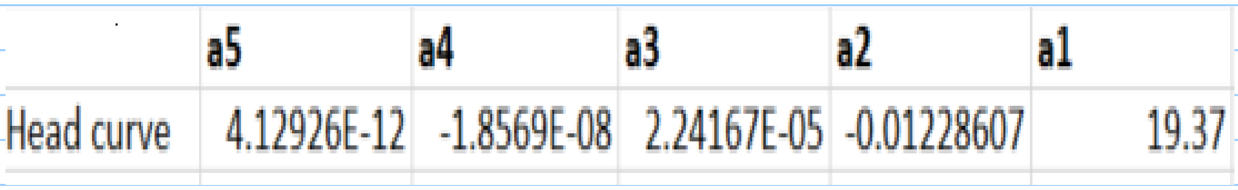

High Tension
Transformer
380V Distribution
Variable Speed
Drive (VSD unit)
Control
system,
data logger
and comm.
interface
RTU
Remote
Terminal Unit
RTU
RTU
Vented
Junction
Box
Well


WoodGroup TE7000_Imported
50 Stages
Head (ft)
Flowrate (bbl/d)
7000
6000
5000
4000
3000
2000
1000
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
@90 Hz
@85 Hz
@80 Hz
@75 Hz
@70 Hz
@65 Hz
@60 Hz
@55 Hz
@50 Hz
@45 Hz
@40 Hz
@35 Hz
@30 Hz

single stage pump equation

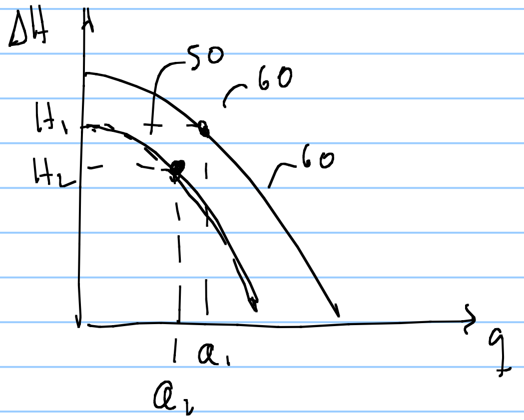
$$\Delta H = a_4 \cdot q^4 + a_3 \cdot q^3 + a_2 \cdot q^2 + a_1 \cdot q + a_0$$

Coefficients for our pump, 60 hz, single stage



	a5	a4	a3	a2	a1
Head curve	4.12926E-12	-1.8569E-08	2.24167E-05	-0.01228607	19.37

$$\Delta H_{ESP} = N_{stages} \cdot \Delta H_{single\ stage}$$



$$Q_2 = Q_1 \left(\frac{N_2}{N_1} \right)$$

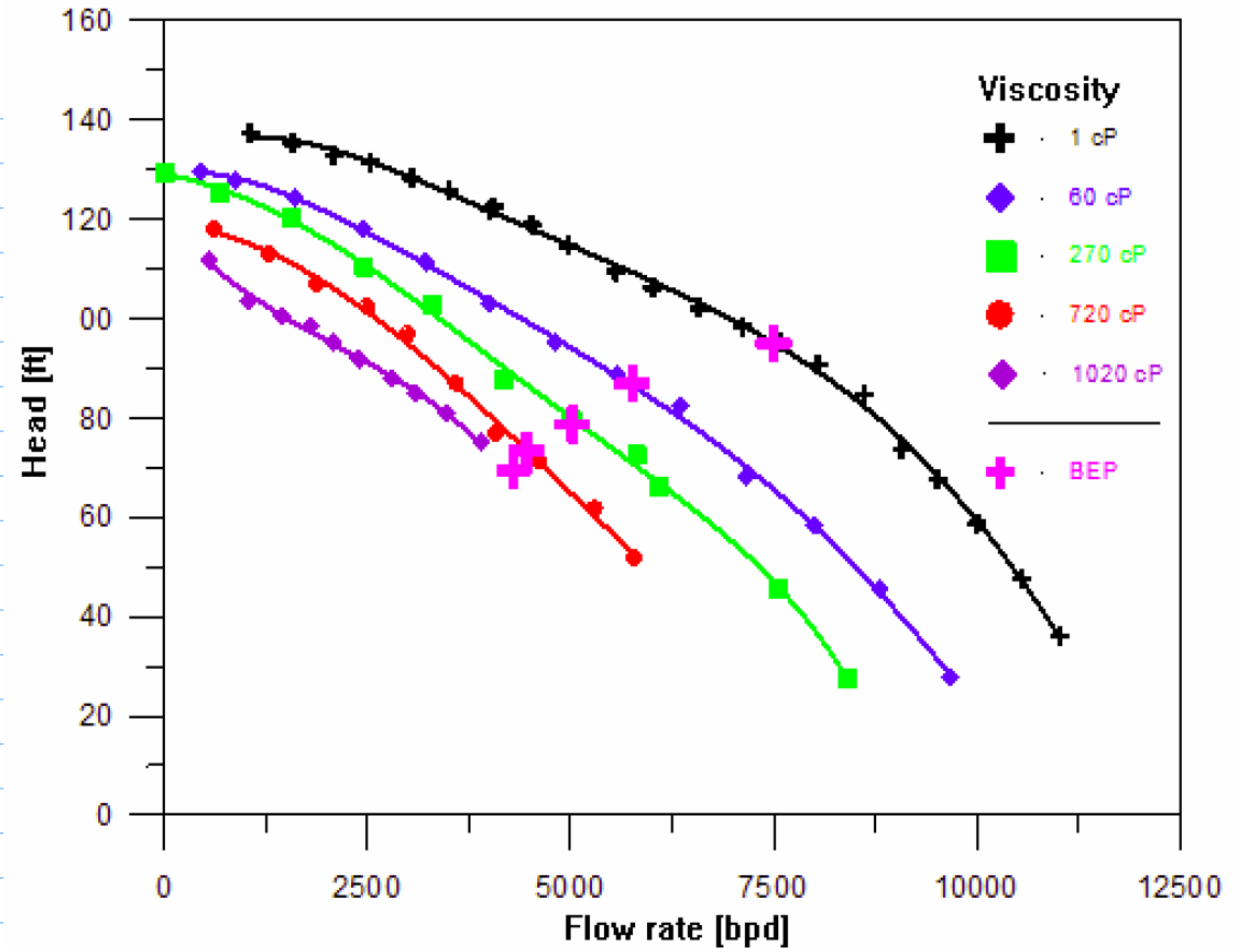
$$H_2 = H_1 \left(\frac{N_2}{N_1} \right)^2$$

→ to scale points at a given frequency to another frequency

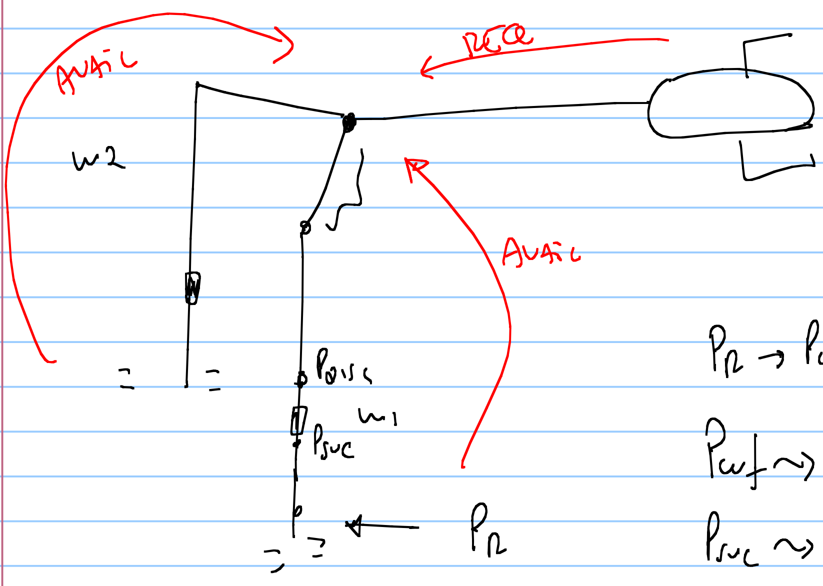
$$\Delta H = \left(a_4 \cdot \left(\frac{60\ hz}{f} \right)^4 \cdot q^4 + a_3 \cdot \left(\frac{60\ hz}{f} \right)^3 \cdot q^3 + a_2 \cdot \left(\frac{60\ hz}{f} \right)^2 \cdot q^2 + a_1 \cdot \left(\frac{60\ hz}{f} \right) \cdot q + a_0 \right) \cdot \left(\frac{f}{60\ hz} \right)^2$$

- Operation of pumps with viscous fluids

↳ usually we have to correct the pump curves for high viscosity → See Hidraulic Institute standard HI 9.6.7-2010



Now, we can finally go to Excel



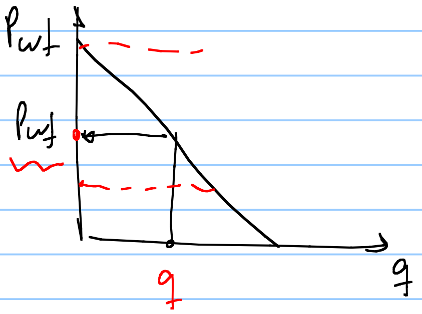
$P_R \rightarrow P_{wf}$ $\rightsquigarrow$ IPR

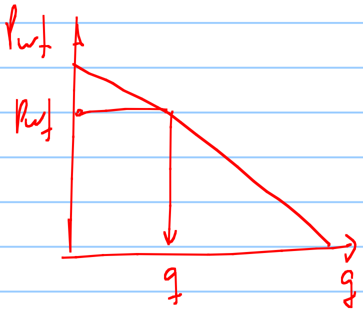
$P_{wf} \rightsquigarrow P_{suc}$ $\rightsquigarrow$ Δp for incompressible

$P_{suc} \rightsquigarrow P_{disc}$ $\rightsquigarrow$ with the equation of the pump

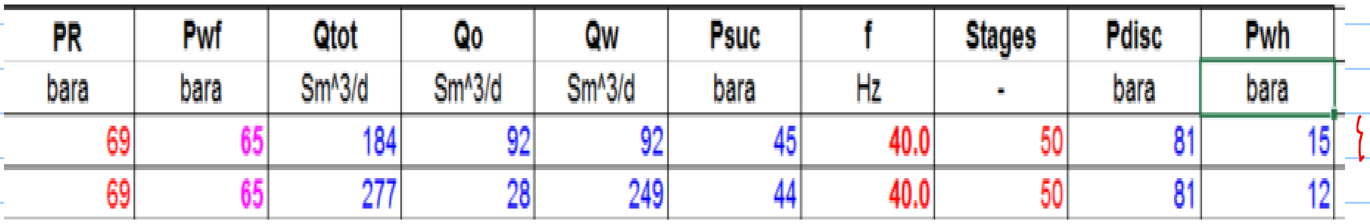
$P_{disc} \rightsquigarrow P_{wh}$ $\rightsquigarrow$ Δp for incompressible

$P_{sep} \rightsquigarrow P_{junc}$ $\rightsquigarrow$ Δp for incompressible guessing with rate





Your model has to provide a good, good enough prediction of the conditions in the field



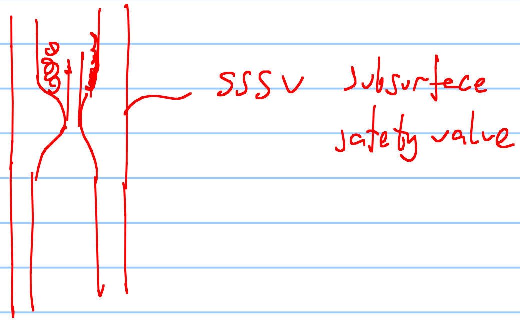
PR	Pwf	Qtot	Qo	Qw	Psuc	f	Stages	Pdisc	Pwh
bara	bara	Sm^3/d	Sm^3/d	Sm^3/d	bara	Hz	-	bara	bara
69	65	184	92	92	45	40.0	50	81	15
69	65	277	28	249	44	40.0	50	81	12

$q_1 = 184\ Sm^3/d$

$P_{wh} = 10$ bara }

$f = 40\ Hz$

$N = \underline{50}$



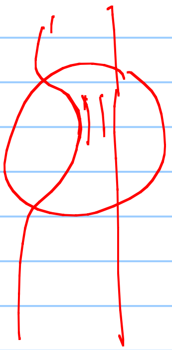
as a tuning factor

$$\Delta H_f = K \underbrace{f \frac{L}{D} \frac{v^2}{2g}}_{20}$$

$0.8 \leftarrow \boxed{K} \rightarrow 1.2$

Δp calculation procedure

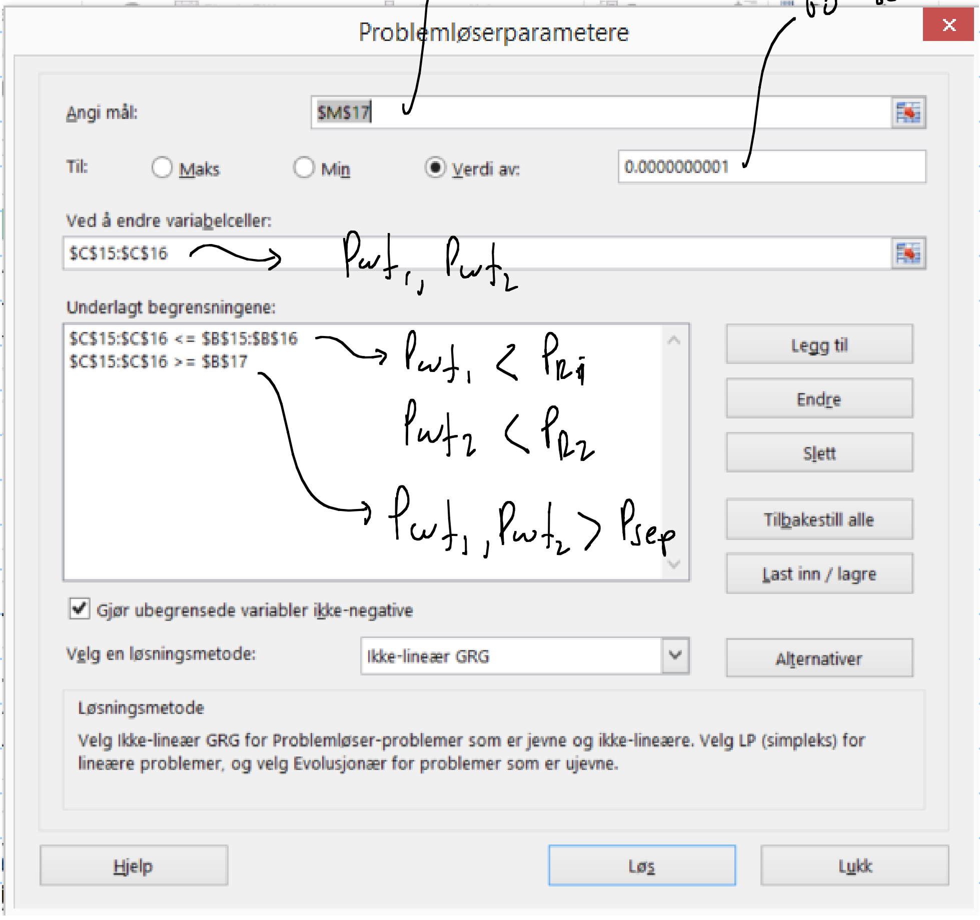
↳ correlation ~ use another correlation



Allways compare the results of your model with any field data available !!

Error cell

to zero



Angi mål: $M$17

Til: ○ Maks ○ Min ● Verdi av: 0.0000000001

Ved å endre variabelceller: $C$15:$C$16 → P_{wf_1}, P_{wf_2}

Underlagt begrensningene:
$C$15:$C$16 <= $B$15:$B$16 → $P_{wf_1} < P_{R_1}$, $P_{wf_2} < P_{R_2}$
$C$15:$C$16 >= $B$17 → $P_{wf_1}, P_{wf_2} > P_{sep}$

☑ Gjør ubegrensede variabler ikke-negative

Velg en løsningsmetode: Ikke-lineær GRG

Løsningsmetode

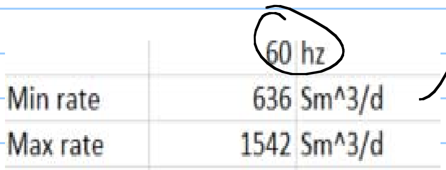
Velg Ikke-lineær GRG for Problemløser-problemer som er jevne og ikke-lineære. Velg LP (simpleks) for lineære problemer, og velg Evolusjonær for problemer som er ujevne.

what do you want to optimize?

q_{total} maximize

f_1, f_2 can be changed from 30hz to 60hz

- $P_{suc_1} > P_{cav}$ 13.8 Bara constraint
  P_{suc_2}



	60 hz
Min rate	636 Sm^3/d
Max rate	1542 Sm^3/d

Min rate → downtrust limit

Max rate → uptrust limit

$$Q_2 = Q_1\left(\frac{N_2}{N_1}\right)$$

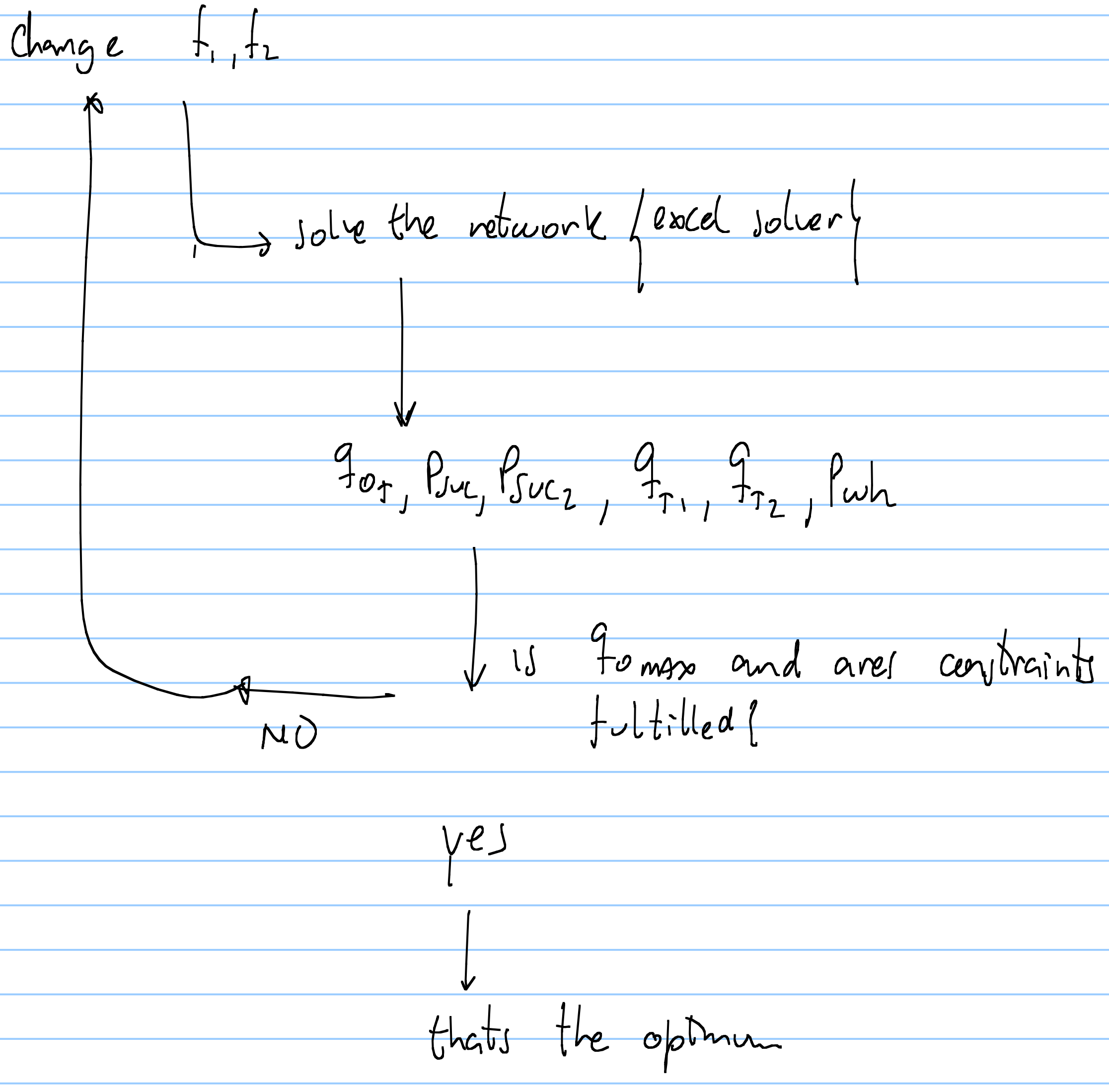
$$H_2 = H_1\left(\frac{N_2}{N_1}\right)^2$$

$$q_{downtrust\,@\,f} = q_{0.60}\cdot\left(\frac{f}{60}\right)$$

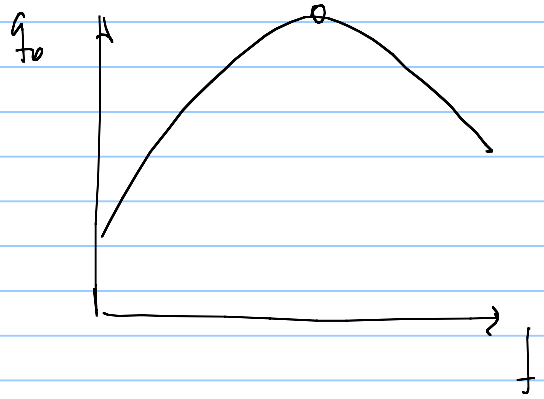
- $q_{upst\,max}$ limitation?

$P_{pipeline} < 400$ psia 27.6 bara ~ for pipe resistance

What does the optimizer has to do?

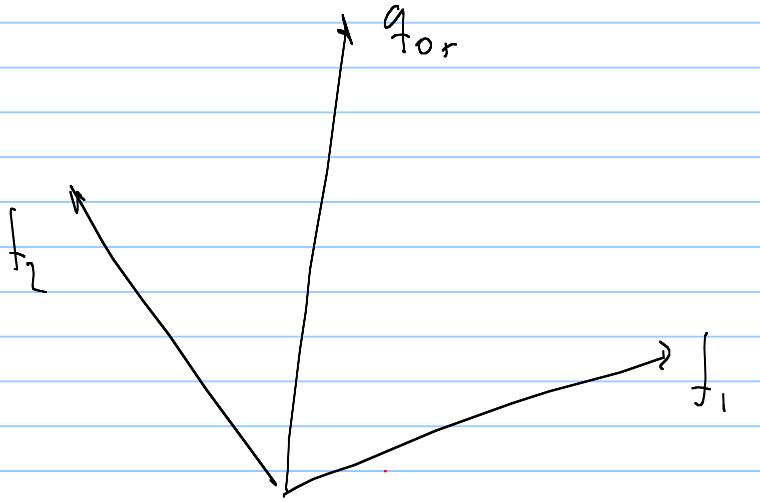


for a 1-D function

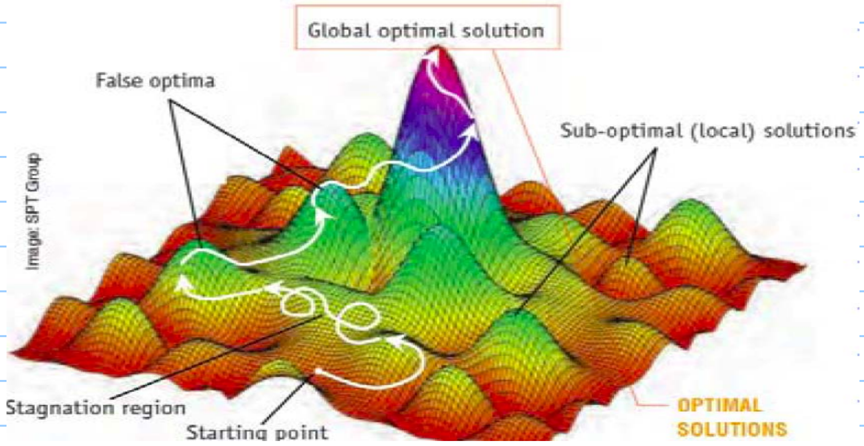


for a 2D function:

3D plot

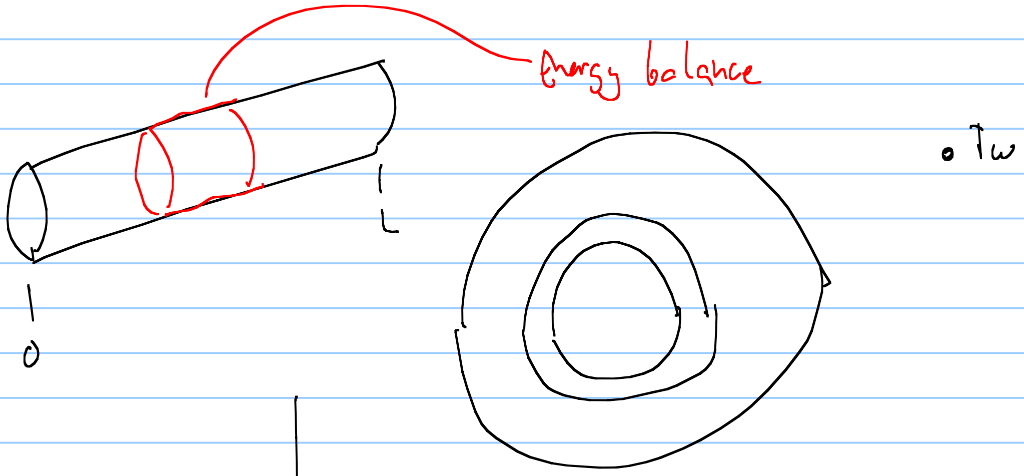


Might look something like this:



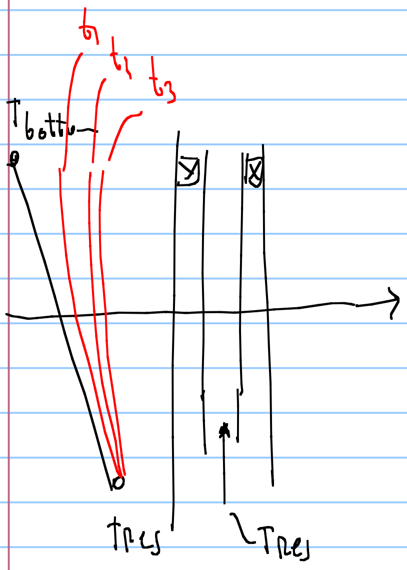
Comment about Exercise 5:

The temperature equations come from Energy balance on a small section in the pipe and integration along the pipe



unburied pipe ~> Temperature steady state distribution (t)

buried pipe
wellbore

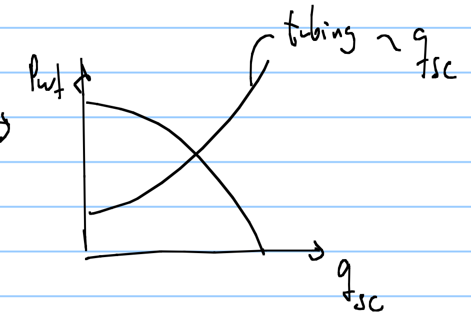


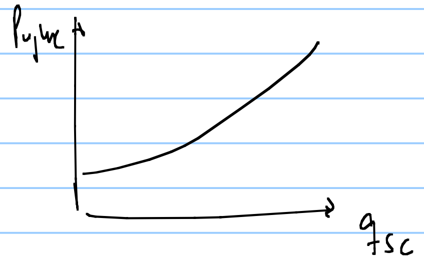
Exercise 5 focuses on transient period (soil heating)

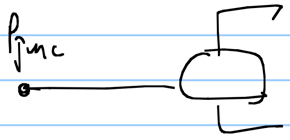
↑ Heat transfer ~> ↓ Temperature ~> ↑ viscosity

- $\underbrace{q_{sc}}$ vs. q_{local}

almost like
a mass flow
molar flow



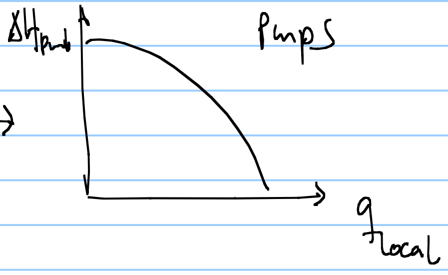




local rate, flow

Compressor

Pumps



ΔP for incompressible fluids $\quad Re = \frac{\boxed{V} \rho D}{\mu}$

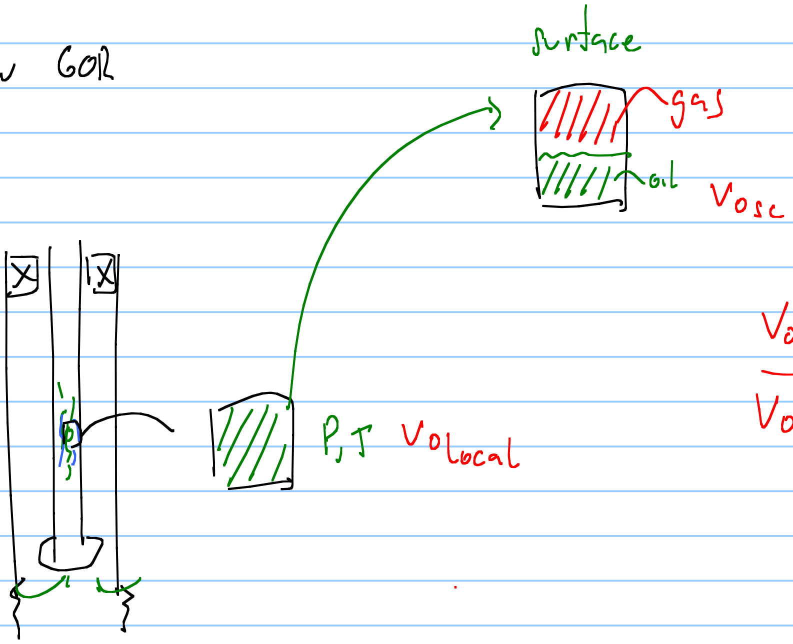
to calculate this velocity
we need to use local flow rate

ΔP in multiphase flow

for the previous exercise we were assuming that $\underbrace{q_{sc} = q_{local}}$

$B_o(P,T) = \frac{q_o(P,T)}{q_{osc}}$

Low GOR



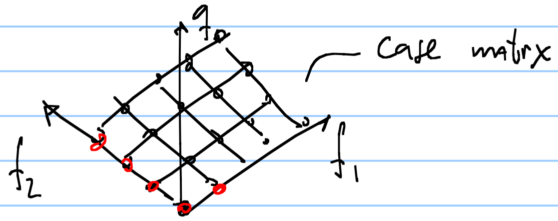
$$\frac{V_{o\,local}}{V_{osc}} = B_o(P,T)$$

we are making the assumption that B_o (every P and T) = 1

B_w (every P, and T) = 1

Optimization on our two well system → using Pipe-it

→ using excel ~ Domain visual inspection



f_1	f_2
(hz)	(Hz)
30	30
	35
	40
	45
	50
	55
	60
35	30
	35
	40

~ 7 . 7 = 49 evaluations

TPG4230 16.03.2015

Our case from last class:

- Optimization: maximization of oil production by changing ESP frequencies

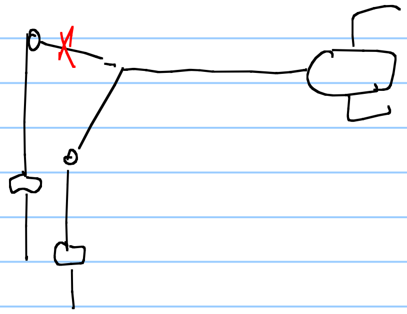
with constraints:

$f \geq 30$ Hz $f \leq 60$ Hz

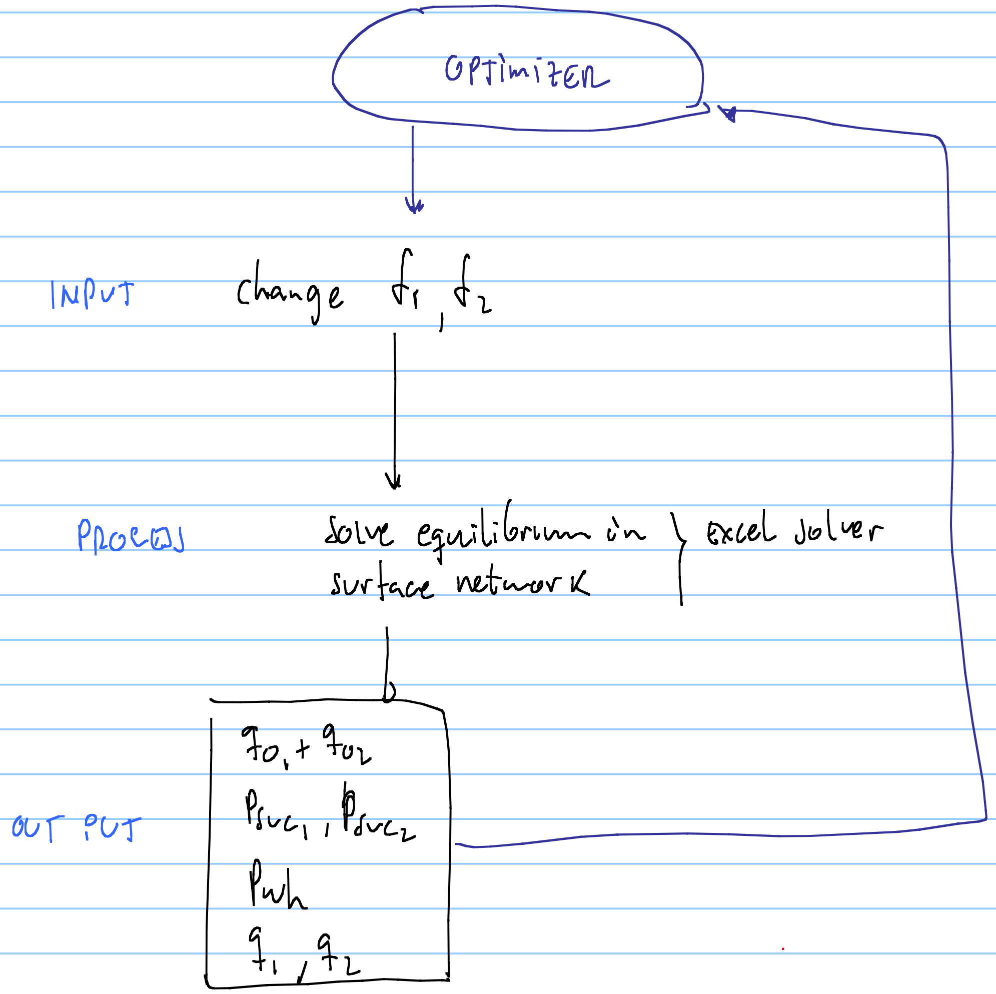
$P_{suci} \geq 20.7$ bara

$q_{fmin\,ESP}(f) \leq q_F \leq q_{fmax\,ESP}(f)$

$P_{wh} \leq 27$ bara



Option 1:



option 2: We were using a case matrix approach (test multiple combinations of f_1 and f_2, select the optimum

In Excel, we were using macros (VBA) to run "model" multiple times

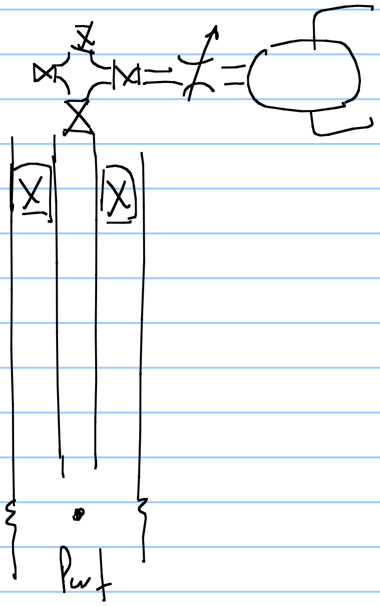
$WF = \frac{q_w}{q_t}$ ↖ 0

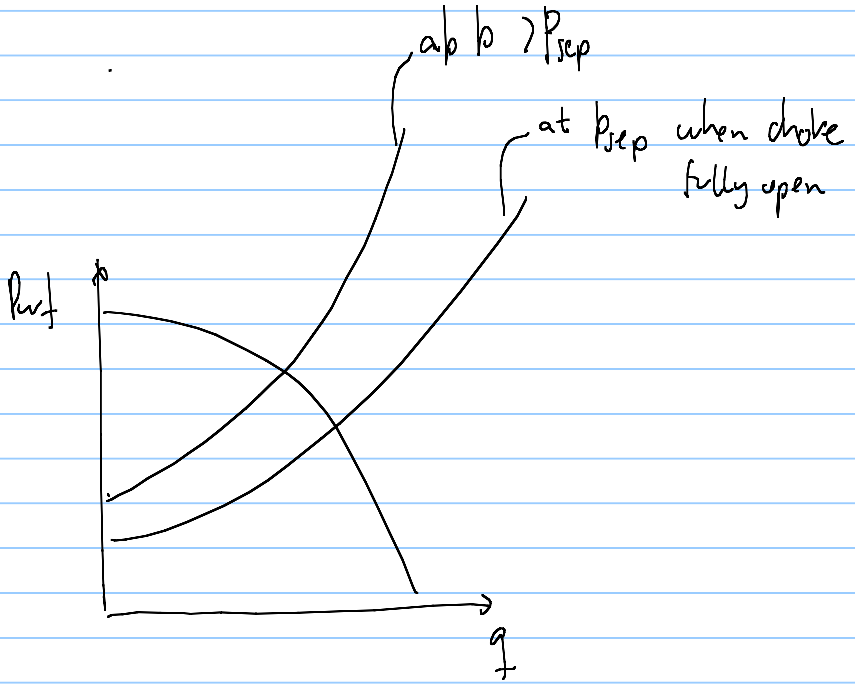
Do not include P_{wh} in the residual
if $q_{well} = 0$. the well is closed
and is not producing. !

Conditions, modifications to our model to make it bulletproof and able to run automatically with no problems.

Quiz.

kahoot.it





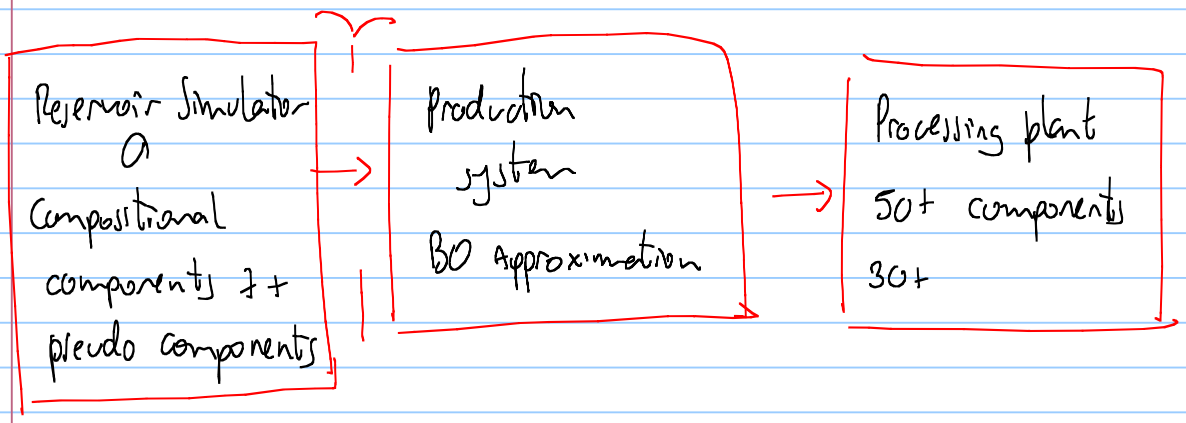
Optimization using Pipe-IT

Pipe-IT } IAM (Integrated Asset Modeling) from Petrostreamz.

based in Trondheim

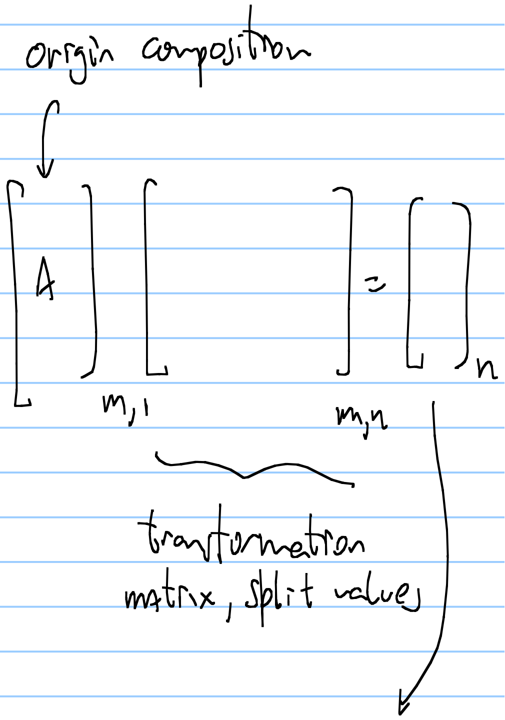
- Allows to build workflows (running automatically a sequence of programs)

- Very robust conversion methodology between fluid characterizations



C1-4 { Pseudo component that behaves like C_1, C_2, C_3, C_4

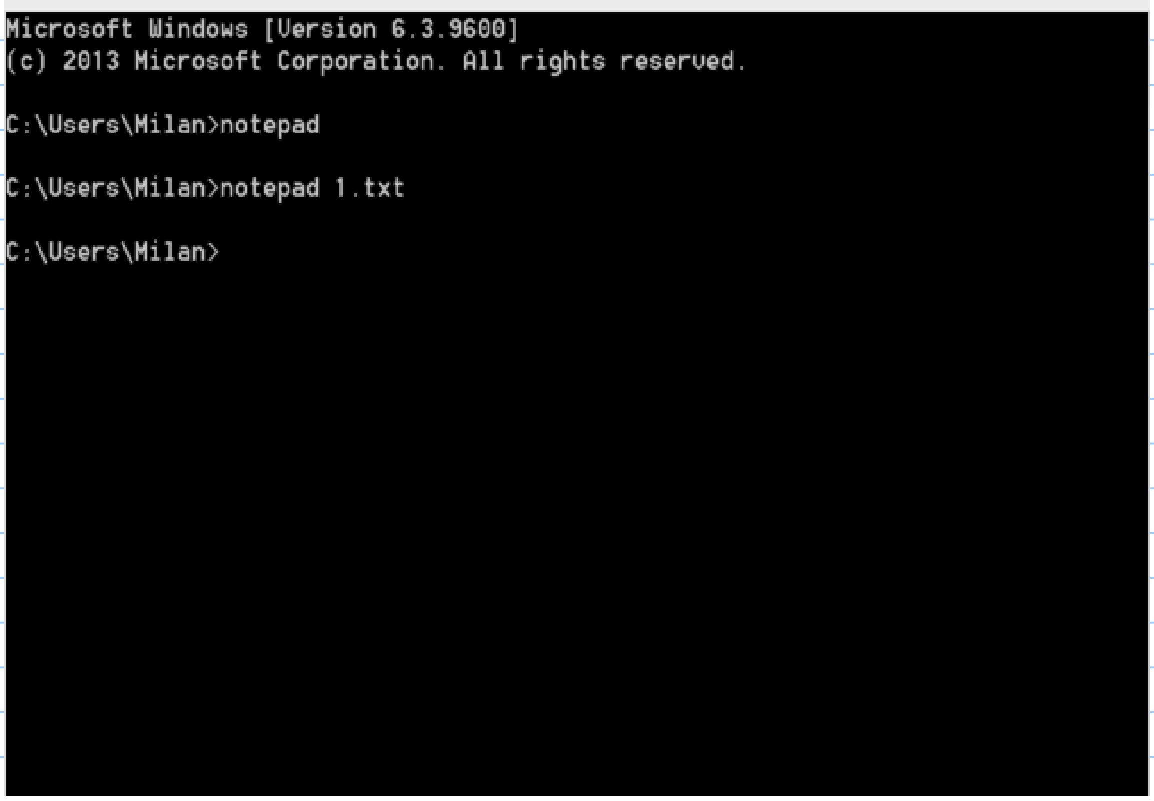
Streams technology ⇝ Matrix transformation



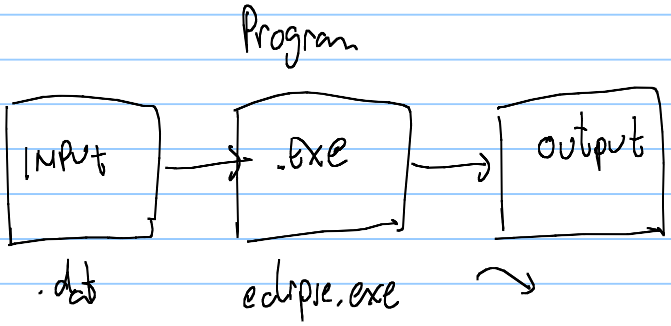
- Optimizer

- Pointer for text files / excel files. { links

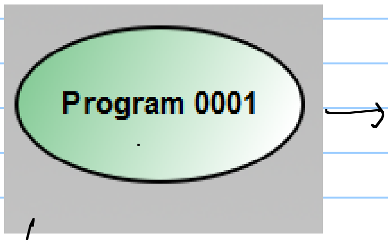
- Specially conceived to run programs that run from the command line



```
Microsoft Windows [Version 6.3.9600]
(c) 2013 Microsoft Corporation. All rights reserved.

C:\Users\Milan>notepad

C:\Users\Milan>notepad 1.txt

C:\Users\Milan>
```



Pipe-IT elements

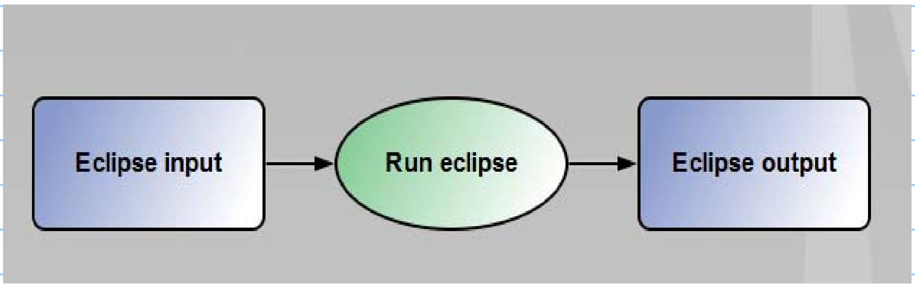


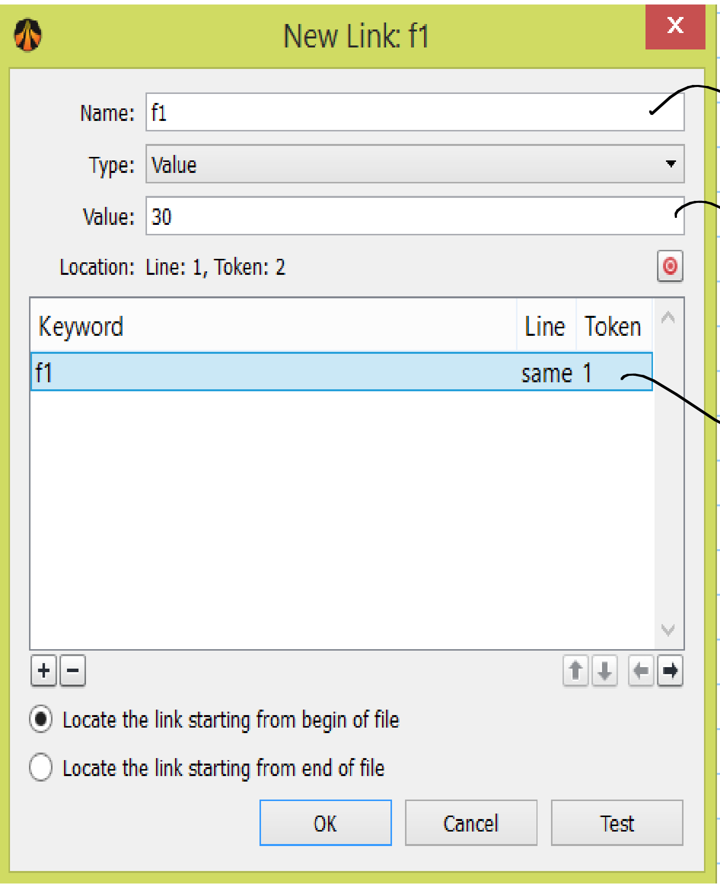
Resource

.dat

excel file
storing information

executing
a program





Name: f1

Type: Value

Value: 30

Location: Line: 1, Token: 2

Keyword	Line	Token
f1	same	1

● Locate the link starting from begin of file

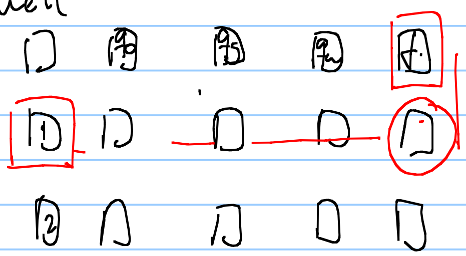
○ Locate the link starting from end of file

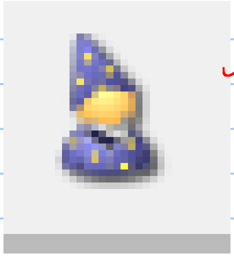
name link

value link

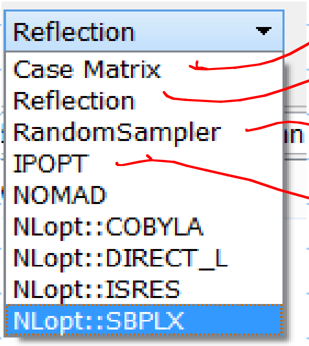
how to locate the link in the file

well





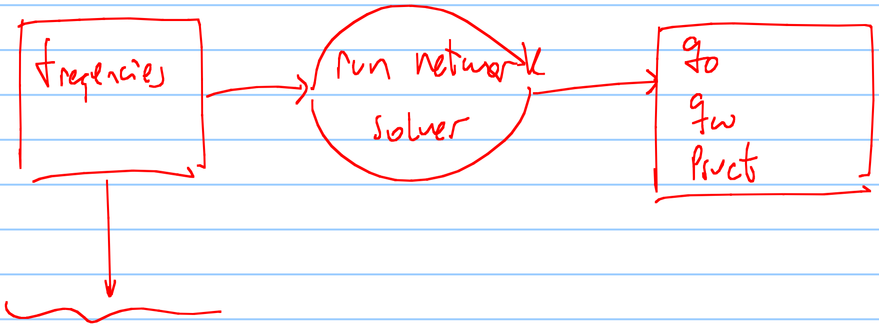
the optimizer



grid-type evaluation

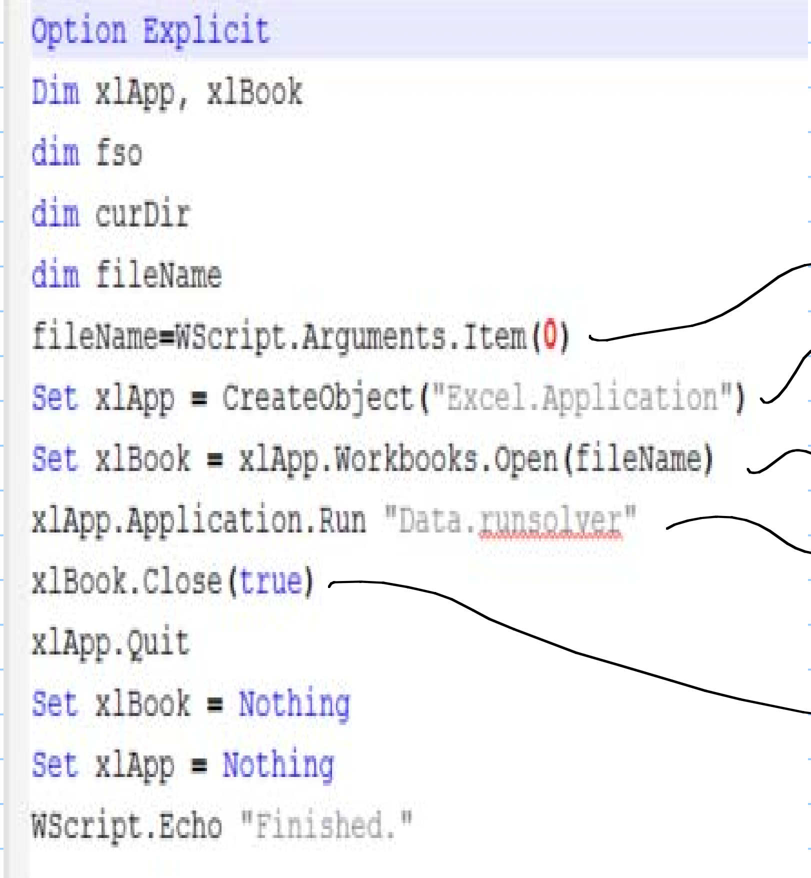
Nelder-Mead

derivative-based optimizer



In any windows-based computer there is something called .VBS visual basic script. (more flexibility than Cmd instructions).

small set of instructions that a windows computer can understand.



```
Option Explicit
Dim xlApp, xlBook
dim fso
dim curDir
dim fileName
fileName=WScript.Arguments.Item(0)
Set xlApp = CreateObject("Excel.Application")
Set xlBook = xlApp.Workbooks.Open(fileName)
xlApp.Application.Run "Data.runsolver"
xlBook.Close(true)
xlApp.Quit
Set xlBook = Nothing
Set xlApp = Nothing
WScript.Echo "Finished."
```

getting excel filename

calling excel application

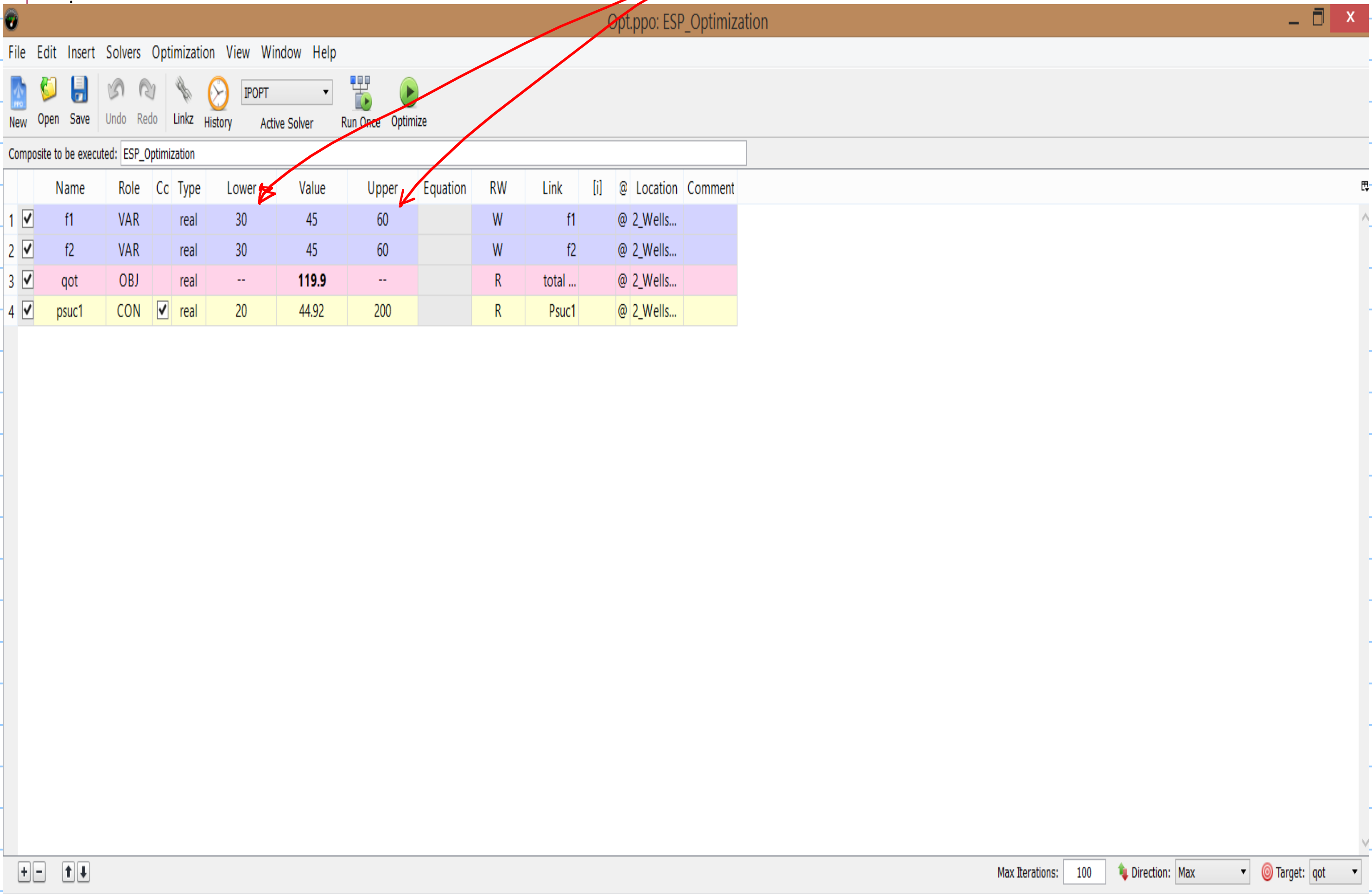
open file in excel

run macro "runsolver" located in sheet "Data"

closing excel

Optimization setup in Pipe-IT.

these bounds were missing in class!



Active Solver: IPOPT

Composite to be executed: ESP_Optimization

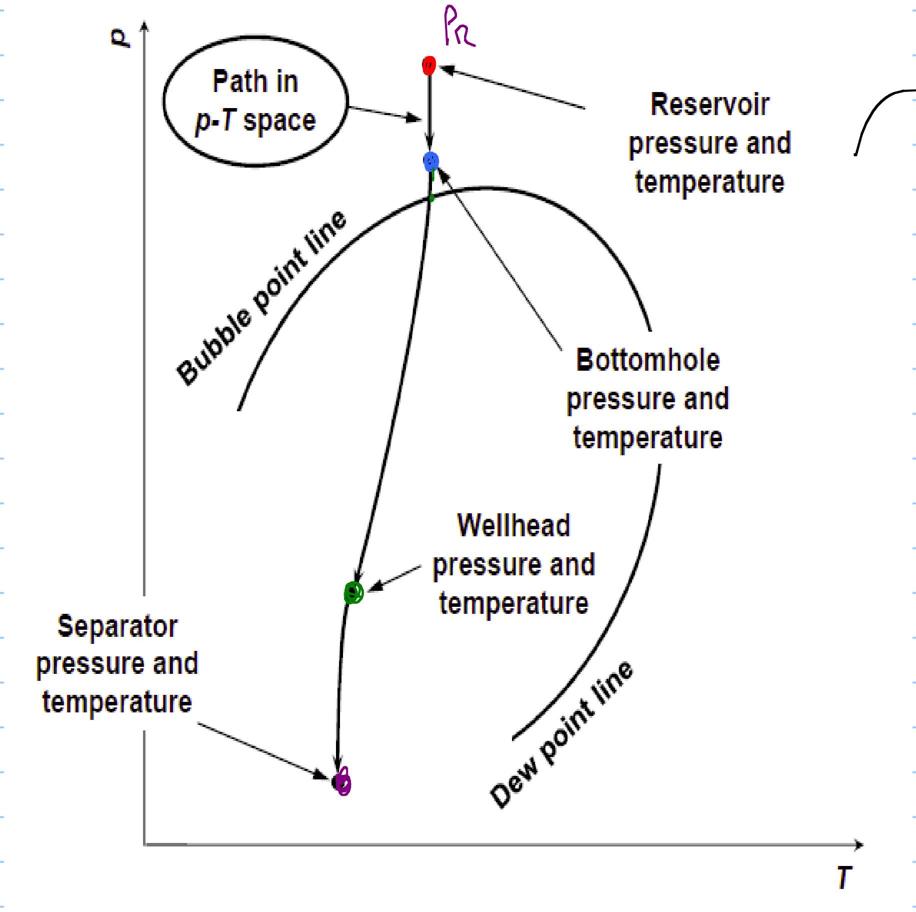
		Name	Role	Cc	Type	Lower	Value	Upper	Equation	RW	Link	[i]	@	Location	Comment
1	☑	f1	VAR		real	30	45	60		W	f1		@	2_Wells...	
2	☑	f2	VAR		real	30	45	60		W	f2		@	2_Wells...	
3	☑	qot	OBJ		real	--	**119.9**	--		R	total ...		@	2_Wells...	
4	☑	psuc1	CON	☑	real	20	44.92	200		R	Psuc1		@	2_Wells...	

Max Iterations: 100 Direction: Max Target: qot

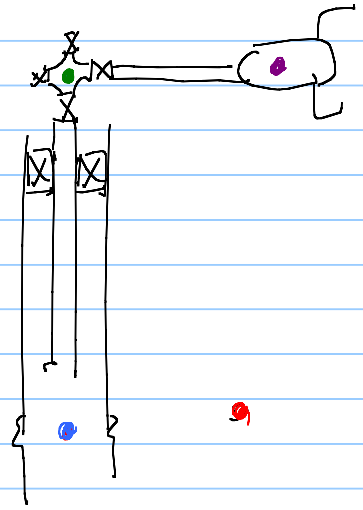
Pressure drop calculations for steady state multiphase flow in Production systems

It is common to have 3 phases
- GAS
- LIQUID - OIL
- LIQUID - WATER

} might be considered as only one phase

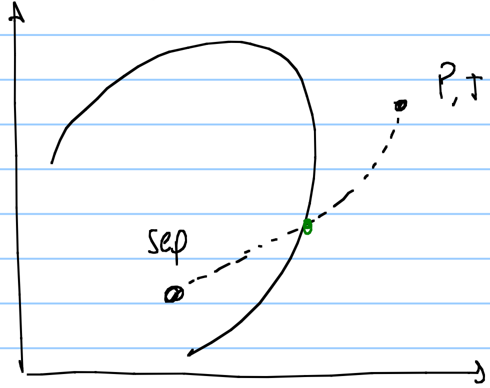


phase diagram of the fluid composition entering into the wellbore

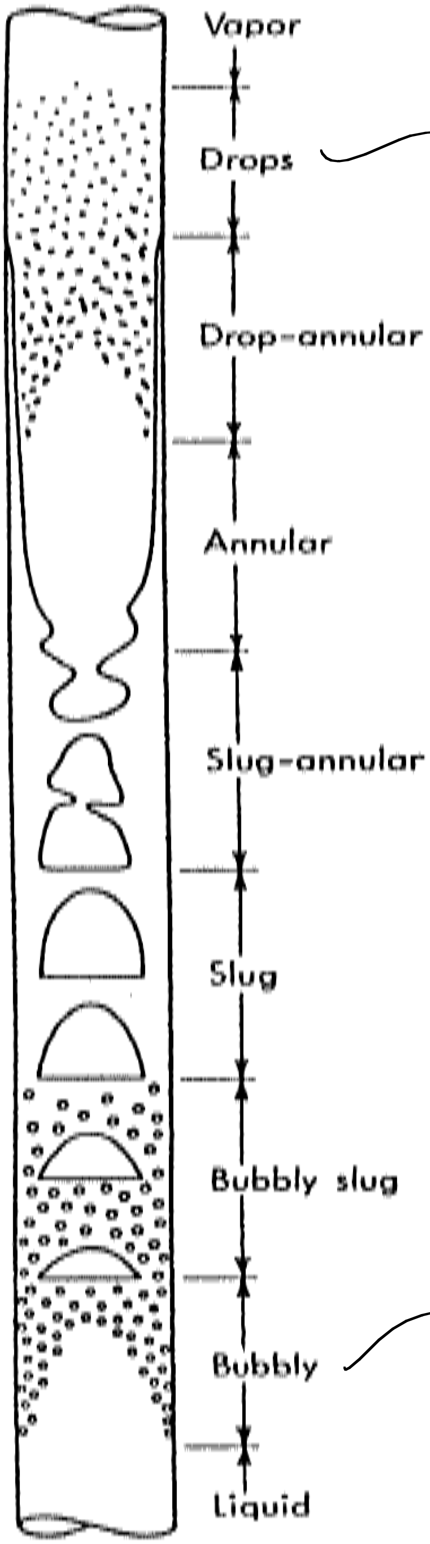


Drawing of multiphase flow along the tubing

for a gas well



flow patterns is how the phases (liquid-gas) are arranged in the pipe



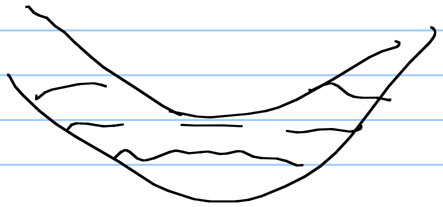
mist flow

flow pattern characterization is often not absolute (black-white)

EPT → multiphase flow Prof. Ole Jørgen Nydal
TEP4250

steady state $\frac{\partial}{\partial t} = 0$

transient $\frac{\partial}{\partial t} \neq 0$



- basic definitions about multiphase flow:

$$f = \frac{\Delta p}{\frac{v^2}{2g}}\left(\frac{\overset{ID}{\phi}}{L}\right) \qquad Re = \frac{v \cdot \rho \cdot \overset{ID}{\phi}}{\mu}$$

why not to use the same approach (adimensional numbrers) for multiphase flow:

a large group of adimensional numbers (to cover all possible configuration, system properties, fluid properties, flow conditions) and it is difficult to find a relationship between them.

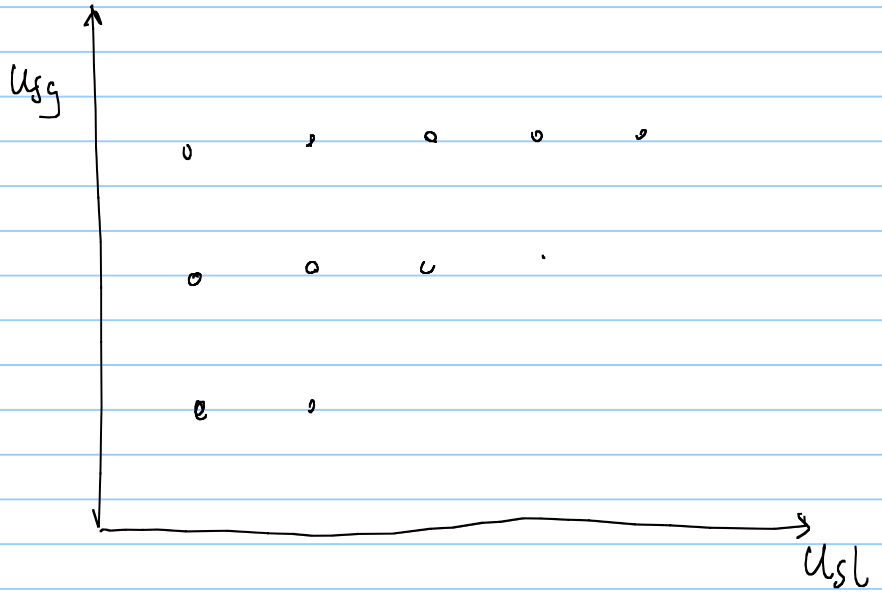
GAS-liquid flows.

- Superficial velocities

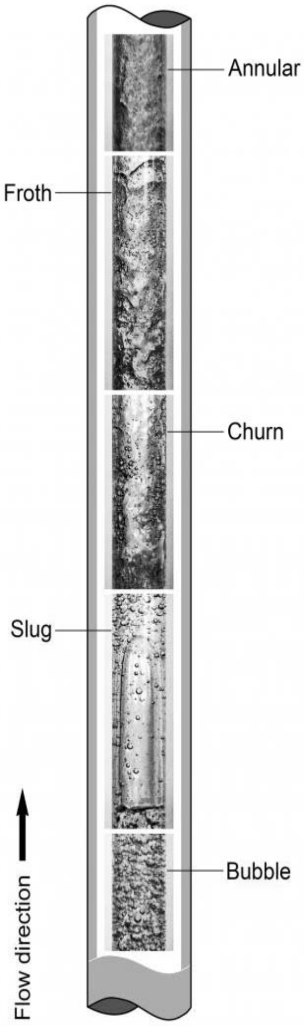
local volumetric flow rate (cannot use Sm^3/d)

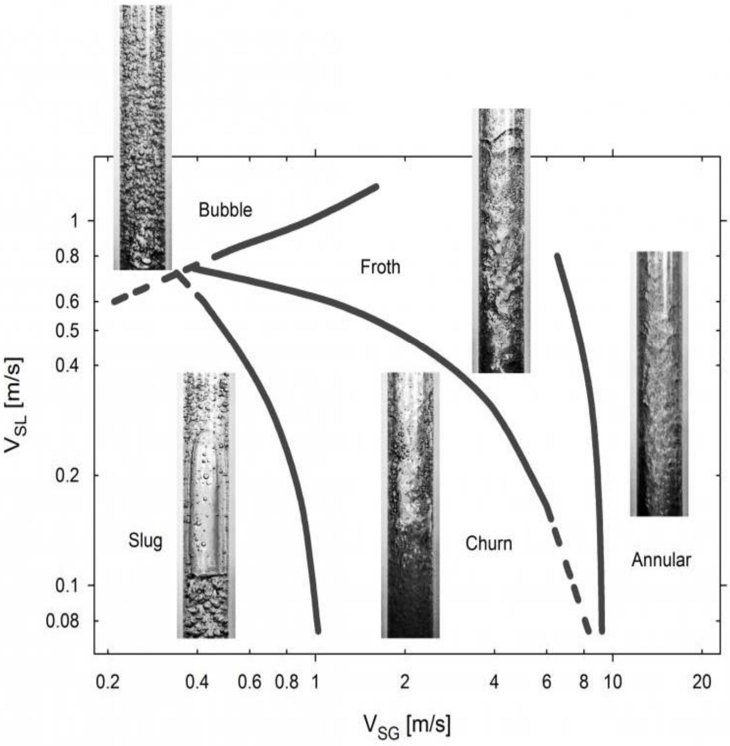
$$U_{SL} = \frac{q_L}{\underset{\uparrow\ \frac{\pi \phi^2}{4}}{A}}$$

$$U_{Sg} = \frac{q_g}{A}$$



→ for certain fluid properties
for a system with specific characteristics

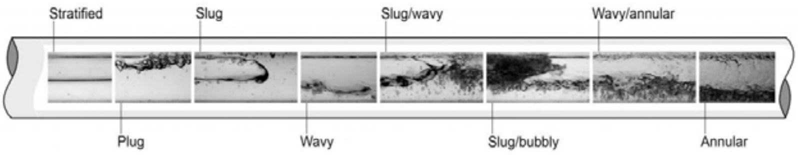


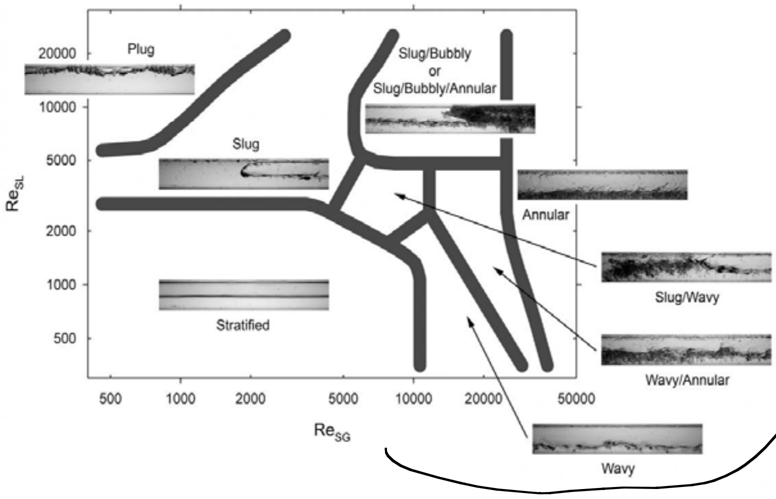


flow pattern map

$\frac{q}{A}$

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





$Re_{sg} = \frac{u_{sg} \cdot \rho_g \Phi}{\mu_g}$

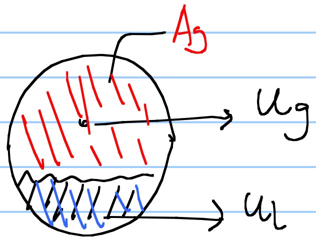
flow pattern and phase distribution is dictated by a balance between : mixing forces
segregation forces

- turbulence
- viscosity
- gravitational acceleration
- surface tension

- No slip volume fraction

$$\lambda_L = \frac{q_L}{q_g + q_L}$$

$$\lambda_g = \frac{q_g}{q_g + q_L}$$



$u_g = u_L$

$u_g \cdot A_g = q_g$ but $u_g = u_L$

$u_L \cdot A_L = q_L$

$u_m A_g = q_g$

$u_m \cdot A_L = q_L$

$$\lambda_L = \frac{\cancel{u_m} A_L}{\cancel{u_m} A_L + \cancel{u_m} A_g} = \frac{A_L}{A_L + A_g}$$

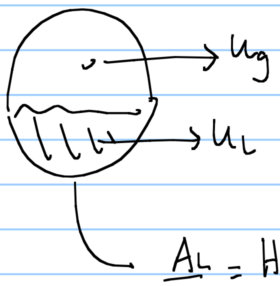
$$\lambda_g = \frac{A_g}{A_L + A_g}$$

homogeneous flow, the fluids are moving at a certain "mixture velocity"

$$u_m = \frac{q_L + q_g}{A} = \frac{q_L}{A} + \frac{q_g}{A} = u_{sL} + u_{sg}$$

this is very seldom the case

when the phases have different velocities



$\frac{A_L}{A} = H_L$ ~ liquid holdup

$\frac{A_g}{A} = H_g$ ~ void fraction, gas holdup

$$1 - H_L = H_g$$

$$H_L + H_g = 1$$

real velocities $u_g = \frac{q_g}{\underbrace{A(1-H_L)}_{\text{circulating area of the phase}}}$ ~ volume circulating through the area

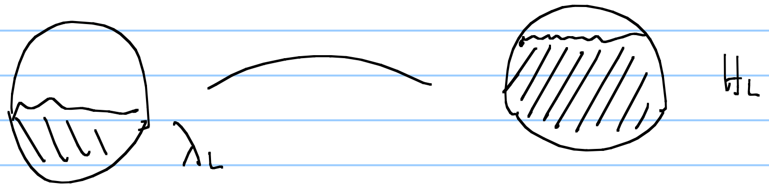
$u_L = \frac{q_L}{A(H_L)}$

$u_g = \frac{u_{sg}}{(1-H_L)}$

$u_L = \frac{u_{sL}}{H_L}$

no slip

slip condition $u_g > u_L$



$H_L > \lambda_L$

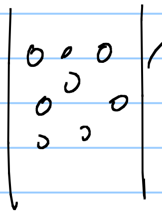
Define slip velocity $v_s = u_g - u_L$

Approaches to model multiphase flow (Δp)

- Correlation-based, equation based on tuning with exp data (old way)
- phenomenological or mechanistic approach
  - mass balance conservation
  - momentum conservation
  - energy conservation

  } solve the system of equations

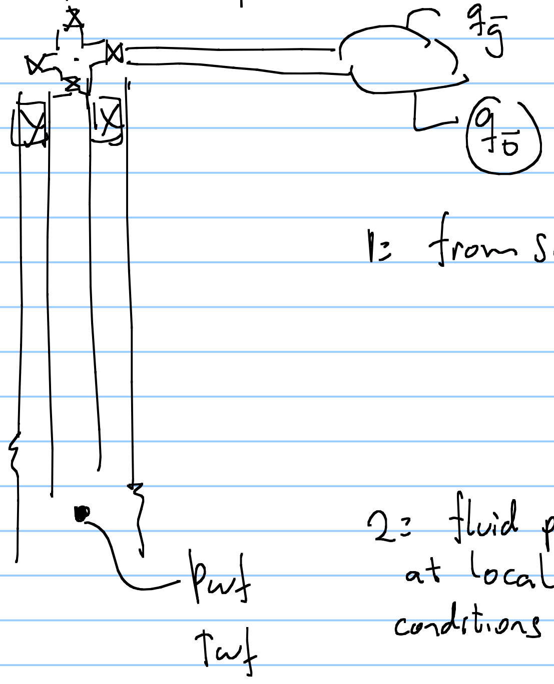
(this usually requires additional information (correlation, relationship, lab results)) the calculations in the second approach are based on flow pattern identification.



1 momentum eq is necessary
2 mass balance eq

2 momentum balance equation
2 mass balance

How pressure drop calculations are performed in production systems

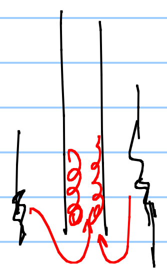


1: from s.c. to local conditions

$$q_{\bar{o}} \rightarrow q_o \quad @(p, T)$$
$$q_{\bar{g}} \rightarrow q_g$$

2: fluid properties at local conditions
- $\rho_o, \rho_g, \mu_o, \mu_g, \sigma_{og}$
- h_o, h_g

System properties in the place of interest
- inclination angle (θ)
- ID
- roughness
- entry effects (often neglected)
- wettability of walls



3 go to our multiphase flow
- model
- software
- expert

obtain $\frac{dp}{dL} = \text{const}$

differential equation. initial conditions $\left\{ \begin{array}{l} p = p_{wf} \\ T = T_{wf} \end{array} \right.$

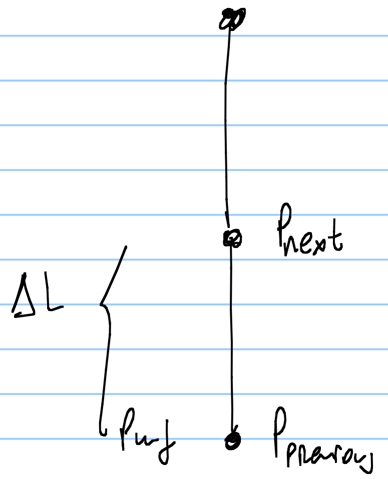
Equation $\left.\frac{dp}{dx}\right|_{\substack{x=bottomhole \\ p=p_{wf}}} = value$

numerical integration
- Euler's method
- Runge Kutta
- o

simplified approach (do not use it just for class purposes)

distance between p_0

$$p_{next} = p_{previous} + (\Delta L) \cdot \left.\frac{dp}{dx}\right|_{p_{previous}}$$

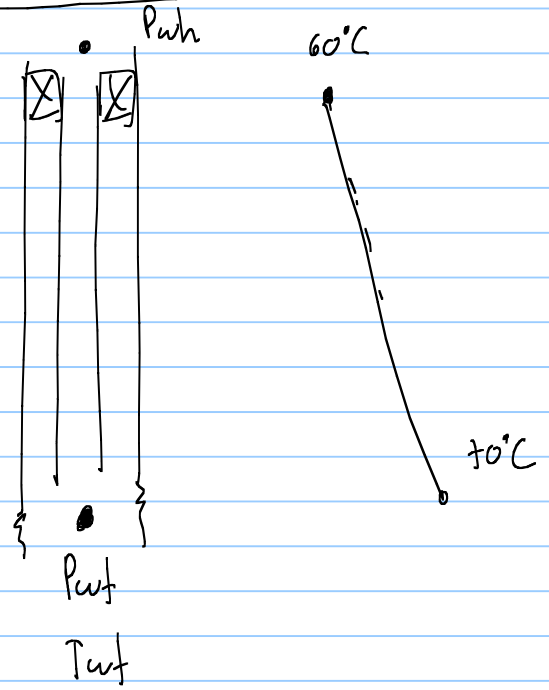


what happens if we include temperature gradient $\frac{dT}{dx}$

Numerical integration using two functions, p, T

$\frac{dT}{dx}, \frac{dp}{dx}$

Class excercise



Assume that the temperature of the fluid can be calalated using a linear interpolation between 60°C and 70°C

Using compositional approach.

assume the composition is known

	Mole %	Mole frac
Nitrogen	0.4	0.004
CO2	0.1	0.001
Methane	43.2	0.432
Ethane	4.7	0.047
Propane	3.0	0.03
i-butane	1.5	0.015
n-butane	0.9	0.009
neo-pentane	0.0	0
i-pentane	0.8	0.008
n-pentane	0.5	0.005
Hexanes	1.8	0.018
Heptanes	4.1	0.041
Octanes	5.0	0.05
Nonanes	3.8	0.038
Decanes	30.1	0.301

System info. Calculate P_{wh}

qo [Sm^3/d]	1000
qg [E03 Sm^3/d]	200
pwf [bara]	147
TR [C]	70
ID [m]	0.12
Well TVD Depth [m]	2500
Twh [C]	60
Sc oil density [Kg/m^3]	850
Sc gas density [Kg/m^3]	0.91

How to convert $q_o = 1000\ Sm^3/d$ and $q_g = 200.000\ Sm^3/d$ to local conditions?

one method: Calculate total mass flow rate

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

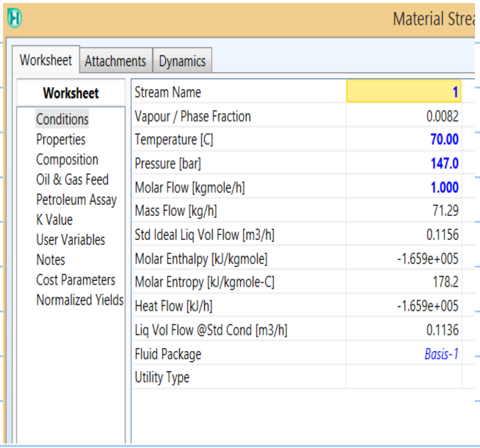
$\underset{\sim}{\dot{m}} = 11.9\ kg/s$ → total mass flow rate circulating on the tubing

$$q_o @ P_{wf}, T_{wf} = \dot{m}_o @ P_{wf}, T_{wf} / \rho_o @ P_{wf}, T_{wf}$$

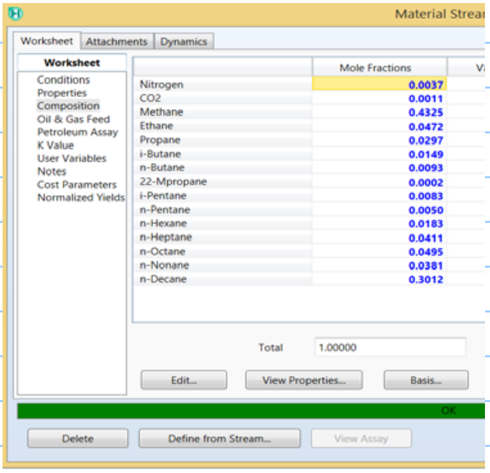
$$q_g @ P_{wf}, T_{wf} = \dot{m}_g @ P_{wf}, T_{wf} / \rho_g @ P_{wf}, T_{wf}$$

it is necessary to estimate $\dot{m}_o$ and $\dot{m}_g$ @ P_{wf}, T_{wf}.

we are going to use HYSYS as a fluid properties generator



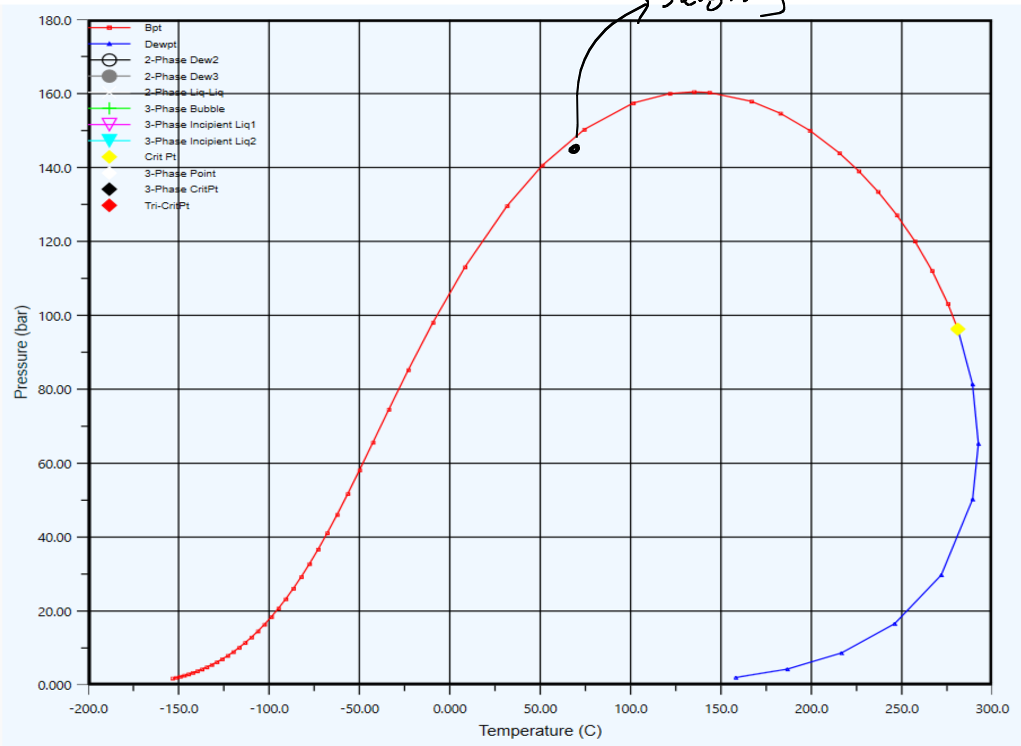
Stream Name	1
Vapour / Phase Fraction	0.0082
Temperature [C]	70.00
Pressure [bar]	147.0
Molar Flow [kgmole/h]	1.000
Mass Flow [kg/h]	71.29
Std Ideal Liq Vol Flow [m3/h]	0.1156
Molar Enthalpy [kJ/kgmole]	-1.659e+005
Molar Entropy [kJ/kgmole-C]	178.2
Heat Flow [kJ/h]	-1.659e+005
Liq Vol Flow @Std Cond [m3/h]	0.1136
Fluid Package	Basis-1
Utility Type	



	Mole Fractions
Nitrogen	0.0037
CO2	0.0011
Methane	0.4325
Ethane	0.0472
Propane	0.0297
i-Butane	0.0149
n-Butane	0.0093
22-Mpropane	0.0002
i-Pentane	0.0083
n-Pentane	0.0050
n-Hexane	0.0183
n-Heptane	0.0411
n-Octane	0.0495
n-Nonane	0.0381
n-Decane	0.3012

Total 1.00000

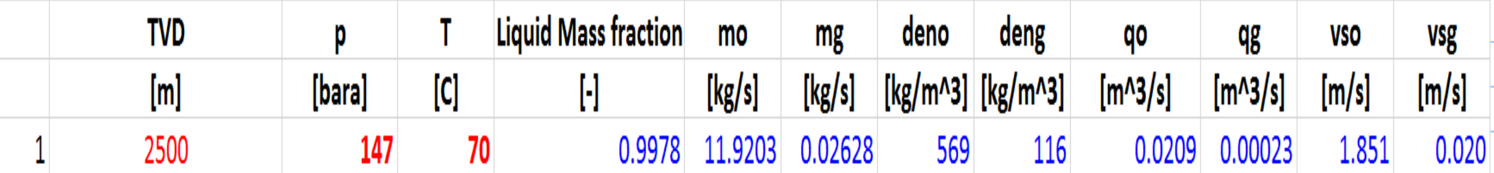
slightly saturated



· oil mass fraction @ Pwf, Twf

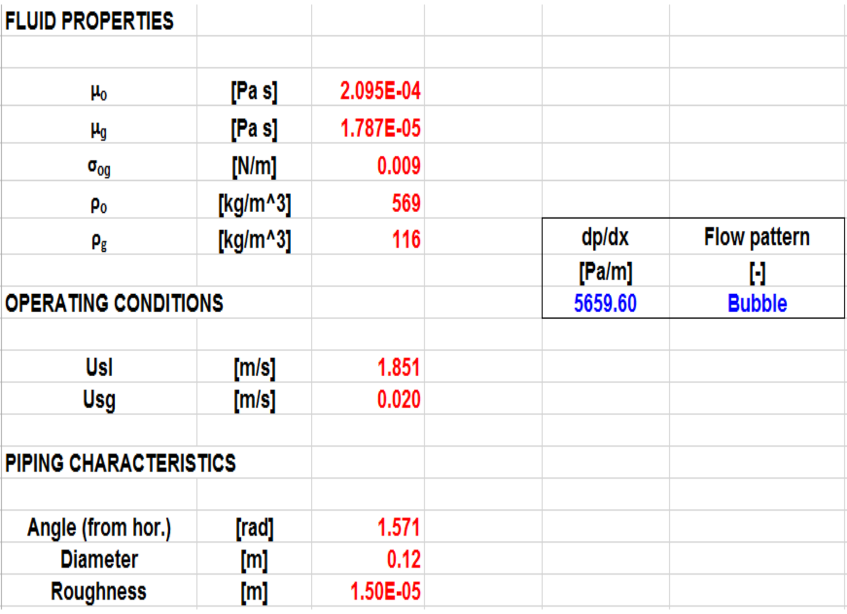
$$\frac{m_L}{m_T} = 0.9978 = \frac{\dot{m}_o}{\dot{m}_T}$$

$$\dot{m}_o = 11.9 \, kg/s \cdot 0.9978$$



	TVD	p	T	Liquid Mass fraction	mo	mg	deno	deng	qo	qg	vso	vsg
	[m]	[bara]	[C]	[-]	[kg/s]	[kg/s]	[kg/m^3]	[kg/m^3]	[m^3/s]	[m^3/s]	[m/s]	[m/s]
1	2500	147	70	0.9978	11.9203	0.02628	569	116	0.0209	0.00023	1.851	0.020

go to your multiphase expert (multiphase calculator public_xslm)



FLUID PROPERTIES		
μ_o	[Pa s]	2.095E-04
μ_g	[Pa s]	1.787E-05
σ_{og}	[N/m]	0.009
ρ_o	[kg/m^3]	569
ρ_g	[kg/m^3]	116
OPERATING CONDITIONS		
Usl	[m/s]	1.851
Usg	[m/s]	0.020
PIPING CHARACTERISTICS		
Angle (from hor.)	[rad]	1.571
Diameter	[m]	0.12
Roughness	[m]	1.50E-05

dp/dx	Flow pattern
[Pa/m]	[-]
5659.60	Bubble

calculate the next point TVD = 1000

$$P_{next_{@1000m}} = 147 \text{ bara} + 0.056596 \frac{\text{Bar}}{m} \cdot (1500 \, m)$$

$$P_{@1000m} = 62 \text{ bara.}$$

find $T_{@1000m}$ by interpolating between 60°C → 70°C

repeat

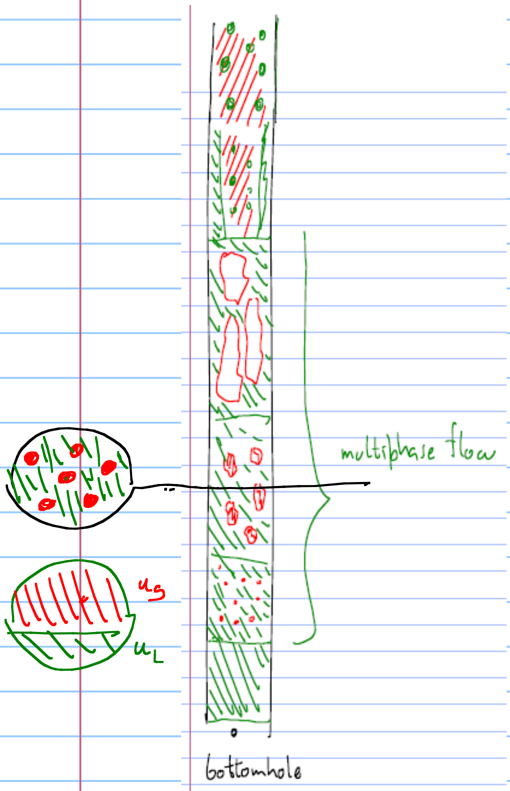
23-03-2015

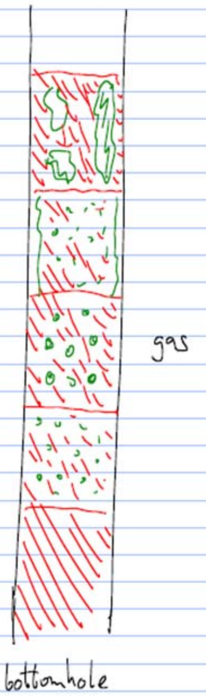
Pressure and Temperature calculations on multiphase flow for HC production systems

Usually there are three phases in the system: oil, gas, water. the mass flow of oil ($\dot{m}_o$) and mass flow of gas change along the system but the total mass flow is constant $\dot{m}_T = \dot{m}_o + \dot{m}_g + \dot{m}_w$

along the system $\dot{m}_o \downarrow$ $\dot{m}_g \uparrow$ for oil systems evaporation
$\dot{m}_g \downarrow$ $\dot{m}_o \uparrow$ for gas systems condensation

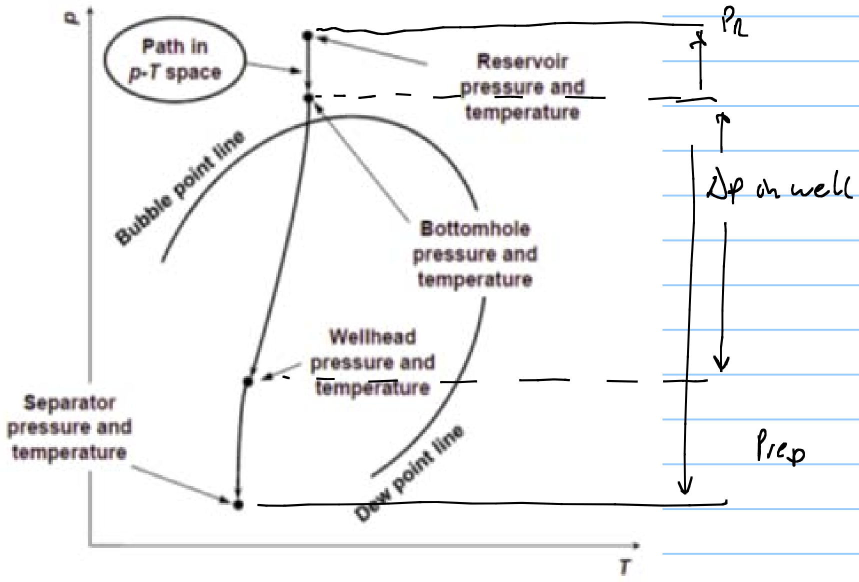
the simultaneous flow of gas-oil-water in the pipe cause a flow configuration Known as flow patterns





$p_R \rightarrow p_{sep}$

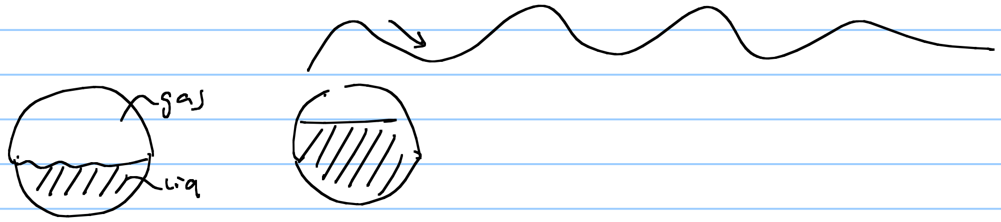
A very important part of the total pressure drop occurs in the wellbore.



- there is significant phase change in the wellbore
- the will be significant gas expansion in the wellbore
- there are multiple flow patterns in the wellbore

In multiphase flow there is usually slip (phases travel at different velocities)

oil and gas usually $v_g > u_L$ (usually for horizontal and inclined upwards pipe)



to calculate pressure drop in multiphase flow → find out flow pattern (maps)

↘ use equations for each flow pattern
- mass conservation equation
- momentum conservation equation

this also happens with water-oil systems

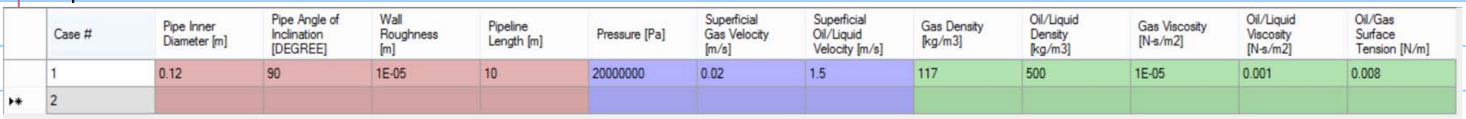
what do we need to compute multiphase pressure drop

- local flow rates → superficial velocities

$$u_{sL} = \frac{q_L}{A}$$
$$u_{sg} = \frac{q_g}{A}$$

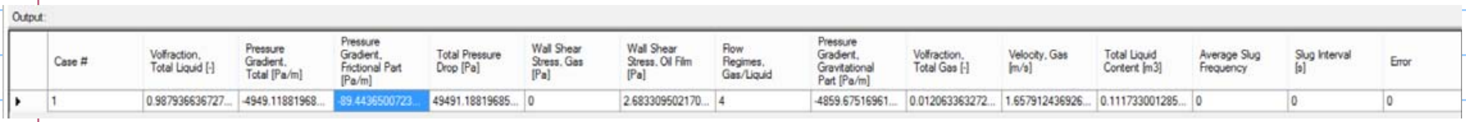
- fluid properties : $\rho_o, \rho_g, \rho_w, \mu_o, \mu_g, \sigma_{og}$
- system properties ID, $\overset{\text{roughness}}{\varepsilon}$, $\underset{\text{inclination angle}}{\theta}$, wettability of the pipe
- multiphase flow expert / multiphase toolkit

☑ Multiphase Toolkit.exe 03.10.2013 18:16 Application 420 KB input:



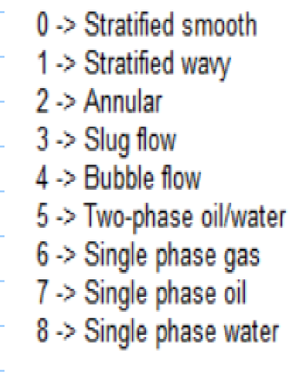
	Case #	Pipe Inner Diameter [m]	Pipe Angle of Inclination [DEGREE]	Wall Roughness [m]	Pipeline Length [m]	Pressure [Pa]	Superficial Gas Velocity [m/s]	Superficial Oil/Liquid Velocity [m/s]	Gas Density [kg/m3]	Oil/Liquid Density [kg/m3]	Gas Viscosity [N-s/m2]	Oil/Liquid Viscosity [N-s/m2]	Oil/Gas Surface Tension [N/m]
	1	0.12	90	1E-05	10	20000000	0.02	1.5	117	500	1E-05	0.001	0.008
▸*	2												

output



Output:

	Case #	Volfraction, Total Liquid [-]	Pressure Gradient, Total [Pa/m]	Pressure Gradient, Frictional Part [Pa/m]	Total Pressure Drop [Pa]	Wall Shear Stress, Gas [Pa]	Wall Shear Stress, Oil Film [Pa]	Flow Regimes, Gas/Liquid	Pressure Gradient, Gravitational Part [Pa/m]	Volfraction, Total Gas [-]	Velocity, Gas [m/s]	Total Liquid Content [m3]	Average Slug Frequency	Slug Interval [s]	Error
▸	1	0.987936636727...	-4949.11881968...	-89.4436500723...	49491.18819685...	0	2.683309502170...	4	-4859.67516961...	0.012063363272...	1.657912436926...	0.111733001285...	0	0	0



0 -> Stratified smooth
1 -> Stratified wavy
2 -> Annular
3 -> Slug flow
4 -> Bubble flow
5 -> Two-phase oil/water
6 -> Single phase gas
7 -> Single phase oil
8 -> Single phase water

due to the changes in
- flow pattern
- fluid properties
- μ_o μ_g
- q_o q_g

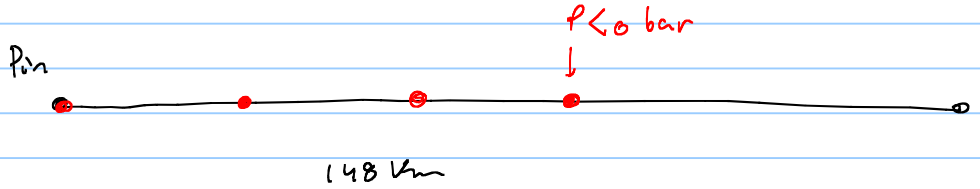
along the tubing, it is necessary to perform our calculations in segments

procedure to perform calculations in the wellbore / pipeline / flowline (if T is given)

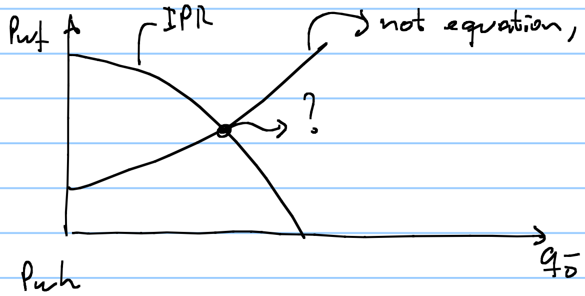
- Discretize in segments (choose a number where the results doesn't depend on the number of segments)
- Assume a pressure at starting point (last class was at the bottomhole)
- calculated total mass flow rate from surface rates
- go to PVT model and compute mass fraction of oil and gas and properties
- calculated local volume rates (q_o, q_g, q_w)
- computed superficial velocities
- go to multiphase expert/software/package ⇝ to get $\frac{dp}{dL}$
- perform numerical integration to next segment.
  - Euler
  - Runge Kutta
  - implicit euler
- calculate p and T for next point

repeat

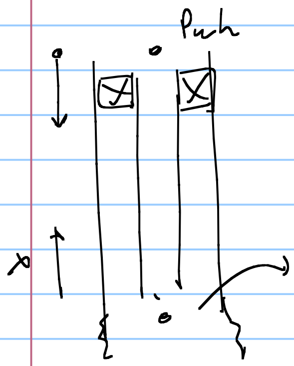
Remember error in HYSYS: "negative pressure computed in increment"



Calculating the flow equilibrium in a well



not equation, numerical integration



assume Pwf ~ IPR gives you rate q_o (cocurrent calc)

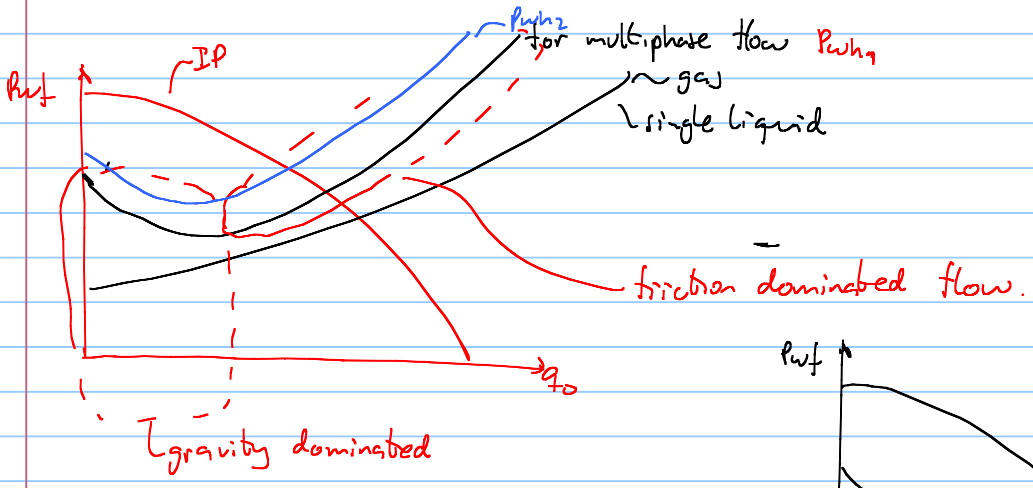
perform multiphase flow calculations from Pwf → wh

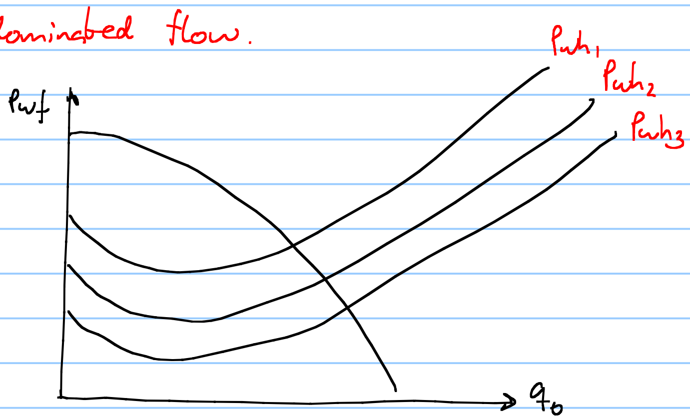
$P_{whcal} \neq P_{whgiven}$

iterative process with convergence. change Pwf until $P_{whcalc} = P_{whgiven}$

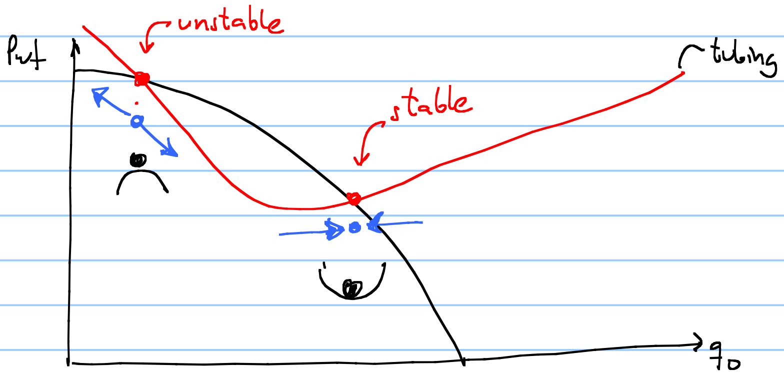
Another alternative is to begin our computations at the wellhead and integrate backwards to pwf (counter current calc)

how the tubing curve looks like for multiphase flow





two intersections between IPR and TPR (tubing performance relationship)



Tubing tables, VLP (vertical lift performance), tpd (tubing performance)

VFP vertical flow performance

- In practice the multiphase calculations are not run "live" for every case

Calculations are performed for possible operating conditions in advance.

for example, for different P_{wh}s

P_{wh} = 10 bara

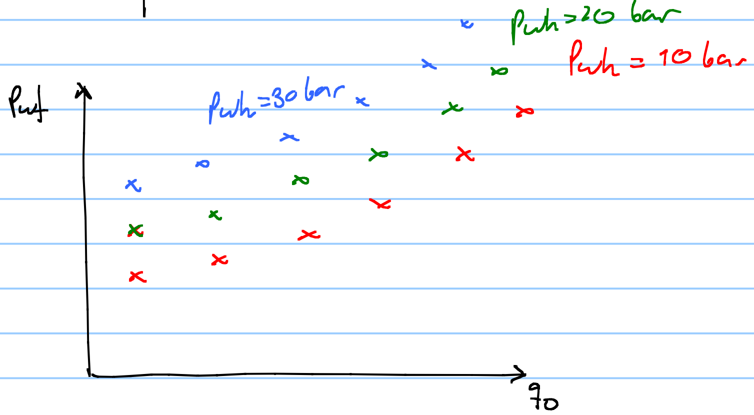
q_o	q_g	q_w	P_{wf}	T_{wh}
0	o	o	o	o
50	o	o	o	o
100	o	o	o	o
200	o	o	o	o
500	o	o	o	o

P_{wh} = 20 bara

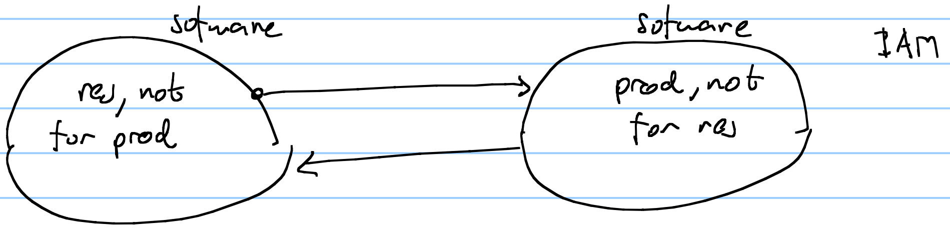
q_o	q_g	q_w	P_{wf}	T_{wh}
0	o	o	o	o
50	o	o	o	o
100	o	o	o	o
200	o	o	o	o
500	o	o	o	o

P_{wh} = 30 bara

q_o	q_g	q_w	P_{wf}	T_{wh}
0	o	o	o	o
50	o	o	o	o
100	o	o	o	o
200	o	o	o	o
500	o	o	o	o



if, in real operations, P_{wh}=25 bar, perform interpolations on the tables.



tubing tables can take into account possible changes in the future.

$P_{wh} = 10$ bara GOR_1 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 20$ bara GOR_1 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 30$ bara GOR_1 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0

$P_{wh} = 10$ bara GOR_2 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 20$ bara GOR_2 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 30$ bara GOR_2 WC_1

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0

$P_{wh} = 10$ bara GOR_1 WC_2

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 20$ bara GOR_1 WC_2

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

$P_{wh} = 30$ bara GOR_1 WC_2

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
00	0	0	0	0

$P_{wh} = 10$ bara GOR_2 WC_2

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

P_{wh} = 20 bara GOR_2 WC_2

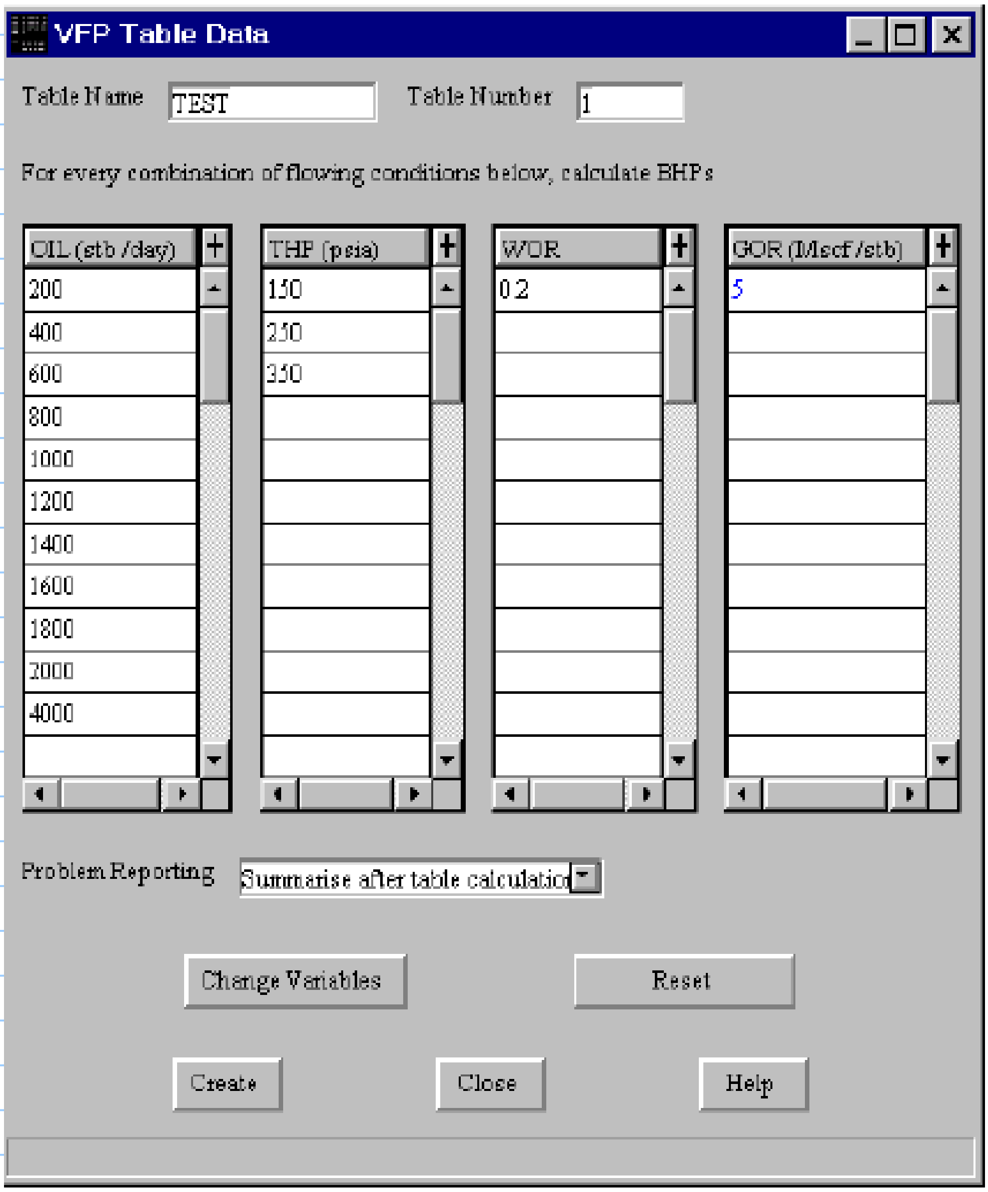
q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0
500	0	0	0	0

P_{wh} = 30 bara GOR_2 WC_2

q_o	q_g	q_w	P_{wf}	T_{wh}
0	0	0	0	0
50	0	0	0	0
100	0	0	0	0
200	0	0	0	0

GOR_1 GOR c GOR_2

100 200 200 10000



VFP Table Data

Table Name: TEST Table Number: 1

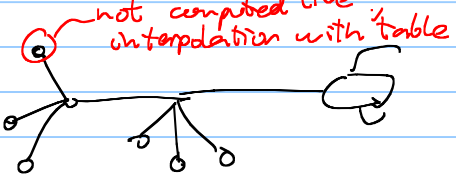
For every combination of flowing conditions below, calculate BHPs

OIL (stb/day)	THP (psia)	WOR	GOR (Mscf/stb)
200	150	0.2	5
400	250		
600	350		
800			
1000			
1200			
1400			
1600			
1800			
2000			
4000			

Problem Reporting: Summarise after table calculatio

tubing tables are used for c reservoir simulator
: production networks

./



commercial sofware for production calculations → PROSPER → well model
→ generate tubing tables

→ GAP → network model
usually is using tubing tables

- interpolation is less expensive computationally than pressure drop calculation
- interpolation is less precise than pressure drop calculation (enough points in the table to have an accurate interpolation)

- tubing tables also take into account if there is any artificial lift (e.g. pump frequency)

P_{wh_1} f_1

q_o	q_g	q_w	P_{wf}	T_{wh}

P_{wh_2} f_1

q_o	q_g	q_w	P_{wf}	T_{wh}

P_{wh_3} f_1

q_o	q_g	q_w	P_{wf}	T_{wh}

P_{wh_1} f_2

q_o	q_g	q_w	P_{wf}	T_{wh}

P_{wh_2} f_2

q_o	q_g	q_w	P_{wf}	T_{wh}

P_{wh_3} f_2

q_o	q_g	q_w	P_{wf}	T_{wh}

input to generate tubing table

q_o	P_{wh}	f_{well}	GOR

these tables are constant if:
- fluid properties don't change
- well layout / completion doesn't change

Fluid behavior for pressure and temperature drop calculations in HC. production systems

what do we need fluid behavior for? → conversion of s.c to local conditions (i.e. local flow rates of each phase)
→ to compute fluid properties $(\rho, \mu, \sigma, h, s, \{$

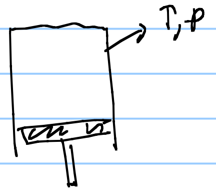
there are usually two ways to handle the fluid: → BO ~ black oil (most popular)
→ Comp ~ compositional

Simplified workflow to characterize fluid behavior in a petroleum asset

- Sampling: to take a representative sample of the fluid in the system (producing fluid). this is usually done in three locations:
  - bottomhole (RDT reservoir description tool) → all fluids simultaneously
  - test separator (sampling oil and gas separatedly, they have to be recombined using the producing rates)
  - well head → not very often used, not reliable.

Composition is determined (gas chromatography)

- testing. Laboratory tests
  - CCE Constant composition expansion
  - DLE Differential liberation expansion
  - CVD constant volume depletion
  - MSF multiphase separator experiment.

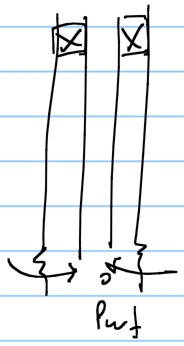


- model development → tuning
  - to develop a consistent PVT model (EOS) to represent all laboratory tests considering the uncertainties associated to each test. there is uncertainty on the heavy components.

Compositional approach:

We have used this approach last class. the well composition and an EOS are required to perform calculations.
↑

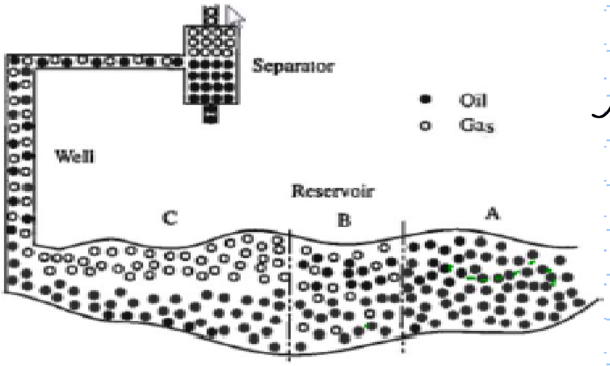
with time the well composition changes



if $P_{wf} > P_b(T_R)$ then single phase oil flowing to the well

the composition remains the same

if $P_{wf} < P_b(T_R)$ the two phase flow towards the well



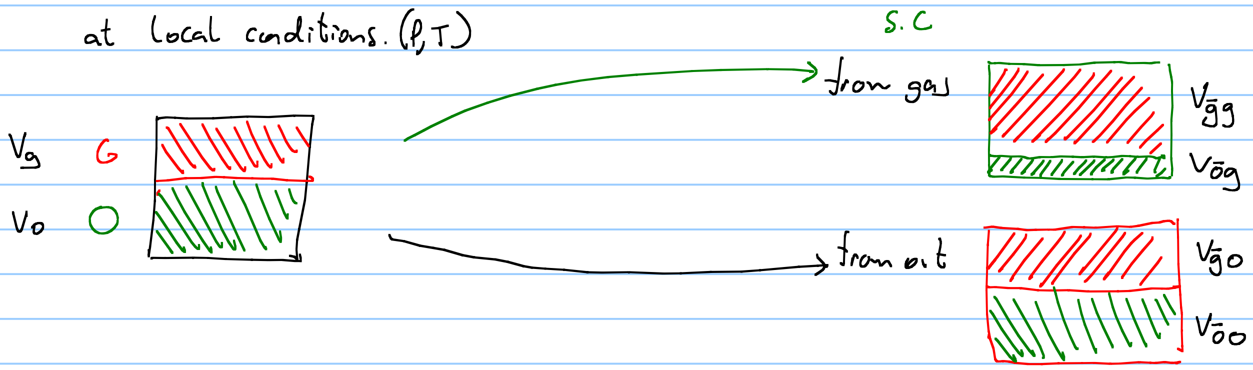
the amount of gas and oil coming into the well depends on the mobility of each phase arond the wellbore. → saturation.

- Usually if there is a change in producing GOR ⤳ change in composition
- Gas lift, you are also modifying the composition
- Gas injection in the reservoir ?

How to capture the change in composition?

- Use input from Reservoir simulator (compositional model)
- take a new well sample.

- BO approach. Relate local volumes with volumes at s.c.



Definitions

$$B_o(P,T) = \frac{V_o}{V_{\bar{o}o}} = \frac{q_o}{q_{\bar{o}o}}$$

$$R_s(P,T) = \frac{V_{\bar{g}o}}{V_{\bar{o}o}} = \frac{q_{\bar{g}o}}{q_{\bar{o}o}}$$

$$B_g(P,T) = \frac{V_g}{V_{\bar{g}g}} = \frac{q_g}{q_{\bar{g}g}}$$

$$r_s(P,T) = \frac{V_{\bar{o}g}}{V_{\bar{g}g}} = \frac{q_{\bar{o}g}}{q_{\bar{g}g}}$$

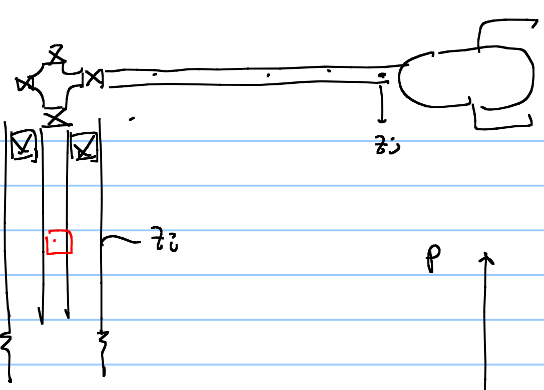
But it is possible to extrapolate to rates

$$\begin{Bmatrix} q_{\bar{g}} \\ q_{\bar{o}} \\ q_{\bar{w}} \end{Bmatrix} = \begin{bmatrix} \frac{1}{B_g} & \frac{R_s}{B_o} & 0 \\ \frac{r_s}{B_g} & \frac{1}{B_o} & 0 \\ 0 & 0 & 1 \end{bmatrix}_{(P,T)} \begin{Bmatrix} q_g \\ q_o \\ q_w \end{Bmatrix}$$

inverting the transformation matrix:

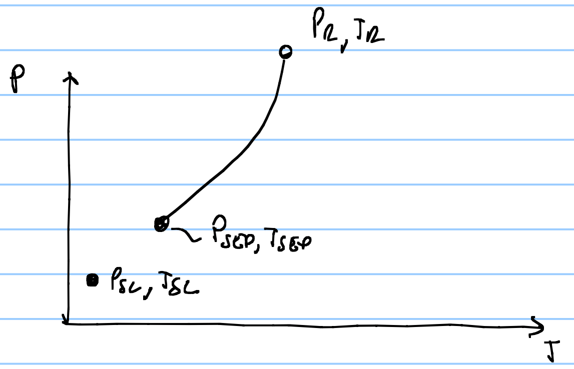
$$\begin{Bmatrix} q_g \\ q_o \\ q_w \end{Bmatrix}_{@P,T} = \begin{bmatrix} \frac{B_g}{1-R_s r_s} & \frac{-B_g R_s}{1-R_s r_s} & 0 \\ \frac{-B_o r_s}{1-R_s r_s} & \frac{B_o}{1-R_s \cdot r_s} & 0 \\ 0 & 0 & 1 \end{bmatrix}_{P,T.} \begin{Bmatrix} q_{\bar{g}} \\ q_{\bar{o}} \\ q_{\bar{w}} \end{Bmatrix}$$

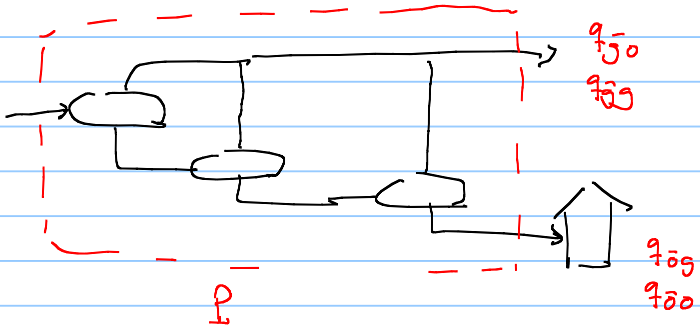
how do we obtain BO properties?



$q_{\bar{g}} = q_{\bar{g}g} + q_{\bar{g}o}$

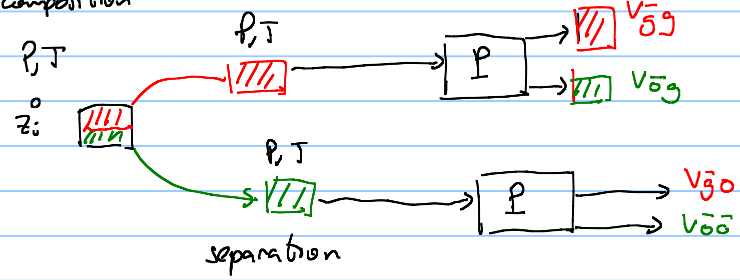
$q_{\bar{o}} = q_{\bar{o}g} + q_{\bar{o}o}$

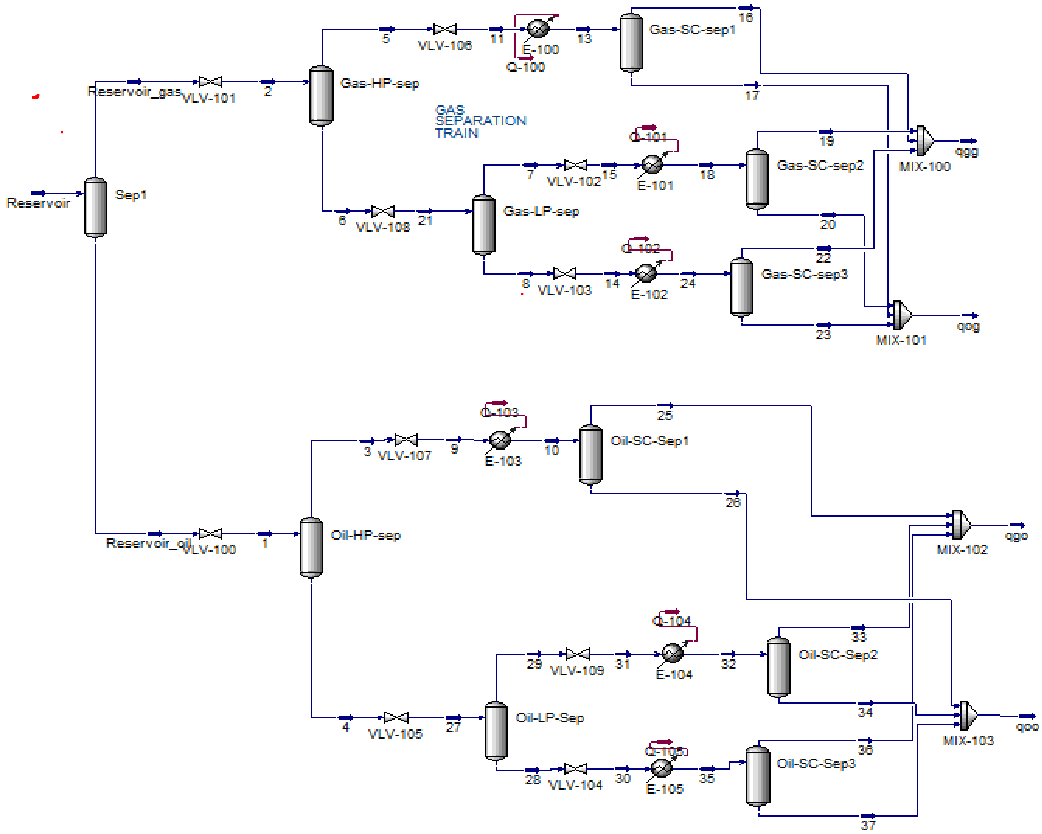


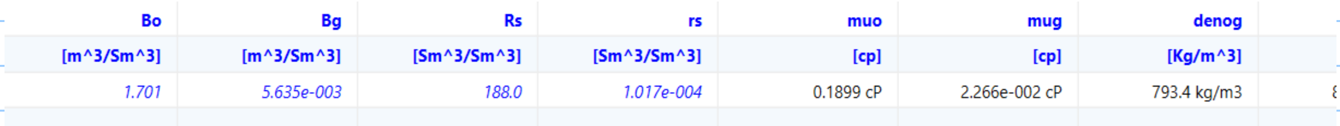


to generate BO properties
- an EOS
- a seed composition (z_i°)
- the surface process

take seed composition to local conditions







Bo	Bg	Rs	rs	muo	mug	denog
[m^3/Sm^3]	[m^3/Sm^3]	[Sm^3/Sm^3]	[Sm^3/Sm^3]	[cp]	[cp]	[Kg/m^3]
1.701	5.635e-003	188.0	1.017e-004	0.1899 cP	2.266e-002 cP	793.4 kg/m3

BO properties are stored in tables:

T_1

	Rs	rs	Bo	Bg
P_1				
P_2				
P_3				
P_4				

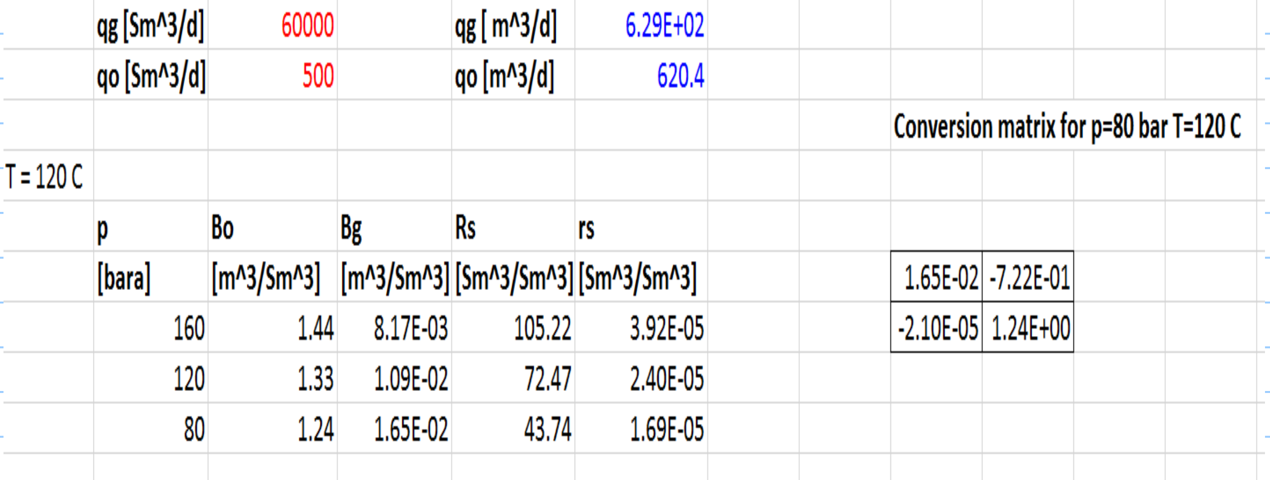
T_2

	Rs	rs	Bo	Bg
P_1				
P_2				
P_3				
P_4				

Example in excel

Multiplying matrices in Excel function MMULT(,)

to use it it is necessary to use [ctrl] + [⇧] + [ENTER]



qg [Sm^3/d]	60000	qg [m^3/d]	6.29E+02	
qo [Sm^3/d]	500	qo [m^3/d]	620.4	

T = 120 C

p	Bo	Bg	Rs	rs
[bara]	[m^3/Sm^3]	[m^3/Sm^3]	[Sm^3/Sm^3]	[Sm^3/Sm^3]
160	1.44	8.17E-03	105.22	3.92E-05
120	1.33	1.09E-02	72.47	2.40E-05
80	1.24	1.65E-02	43.74	1.69E-05

Conversion matrix for p=80 bar T=120 C

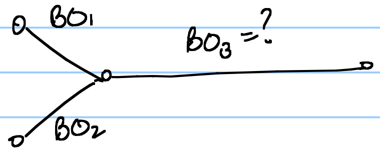
1.65E-02	-7.22E-01
-2.10E-05	1.24E+00

Advantages of BO calculations

- Quicker than compositional, there is no need to perform flash calculations. Just interpolation and matrix algebra
- Accurate enough to estimate local volume
- No change in time unless
  - → gas injection occurring in the reservoir
  - → gas recycling
  - → gas lift composition is different from reservoir gas.

Disadvantages

for networks, the wells have to have the same BO behavior.



BO correlations: (preferred method in the past)

Bubble Point Pressure

the input is usually γ_g, γ_o, GOR.

$$P_b = 18.2\left[\left(R_s/S_g\right)^{0.83}(10)^a - 1.4\right]$$

where

a = 0.00091T - 0.0125(API)
P_b = bubble point pressure, psia
R_s = solution gas to oil ratio SCF/STB
T = Temperature, °F

tune correlation to BO table.

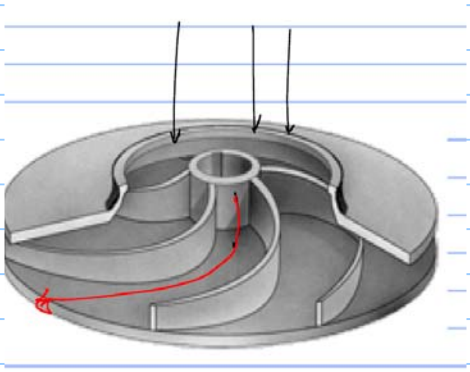
$$B_o = \overset{C_1}{0.9759} + 0.000120\left[R_s\left(S_g/S_o\right)^{0.5} + 1.25T\right]^{1.2} \cdot C_2$$

specific gravity of gas and oil

Topics for today : • brief on multiphase pumping / boosting
• marine structures in petroleum operations

Boosting
Pumping
Compressing } in petroleum operations

Application types of pumping	Drilling	production (artificial lift)	processing / topside treatment
• rotordynamic	• low return risers (single phase)	• ESPs (single phase) • multiphase pumps • subsea pumps and compressors (single phase)	• separators pumps and compressors • transportation equipment
• positive displacement	mud pump (single phase)	• rod pumps (sucker rods) (single phase) • Progressive cavity pumps (single phase) • twin screw pumps (single - multiphase)	• Transportation of small quantities



rotordynamic

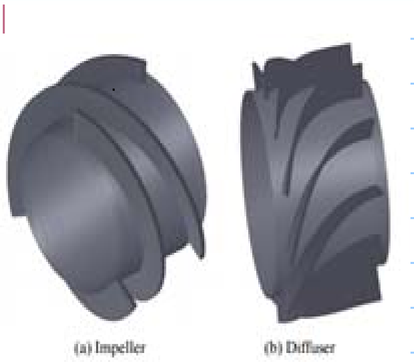
centrifugal impeller (radial)

Axial impeller

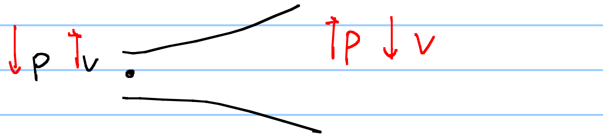
• high rates
• continuous flow
• ↑μ deterioration of efficiency

Sequence : 1 • accelerate fluid in the impeller ⇝ increase kynetic energy

2 • transform from kynetic energy to pressure energy (potential energy) diffuser

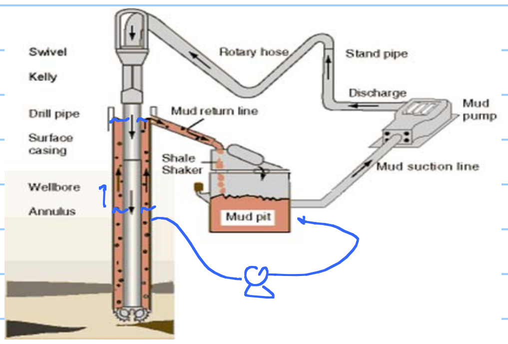


(a) Impeller (b) Diffuser



Positive displacement pump

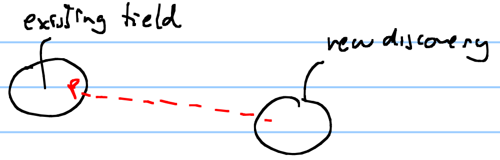
• relatively low rates
• time-varying flow rate
• possible to pump ↑μ fluids
• suitable for higher Δps



multiphase pumping for subsea developments:

Advantages:

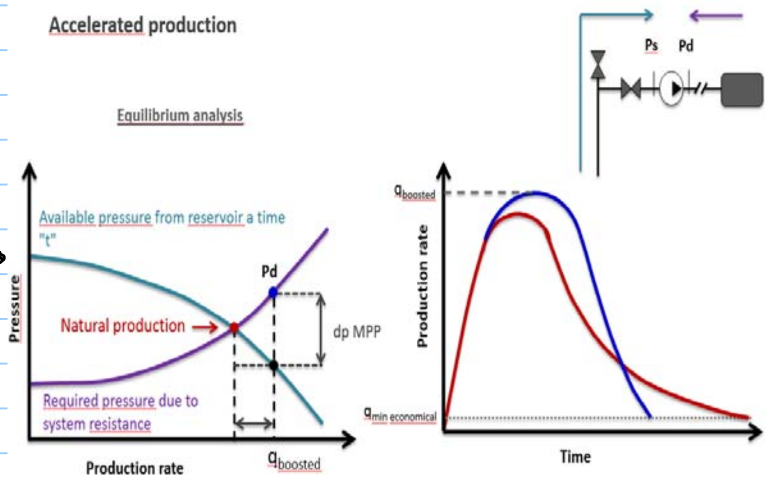
- reduce cost
- real state subsea is cheaper than real state topside.
- Increase tie-back distances

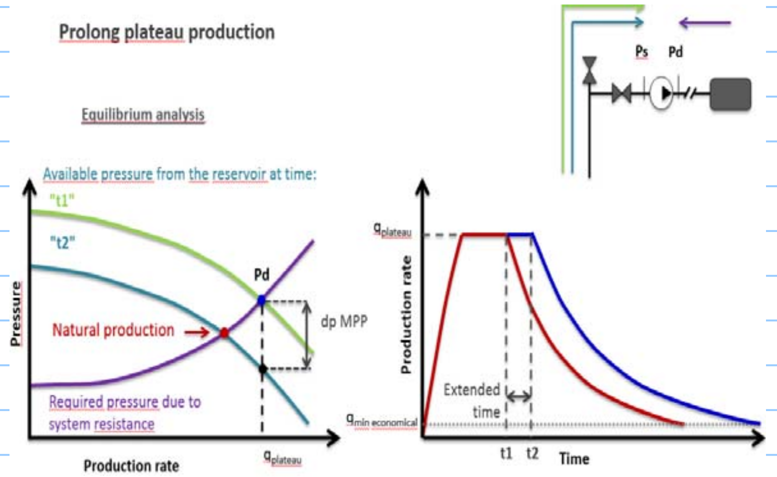


- No need for pre-separation of fluids.
- Maintain or increase production rates

Disadvantages:

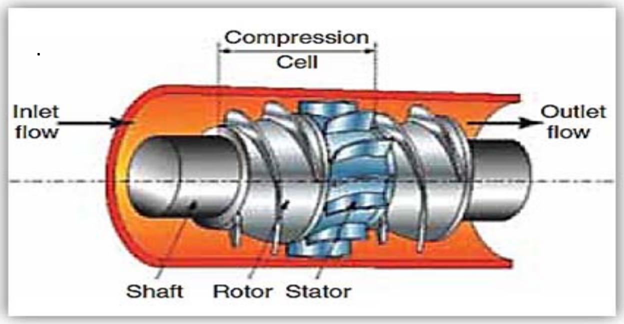
- cost of the unit (equipment)
- maintenance (accessibility, expensive)
- predictability


Accelerated production

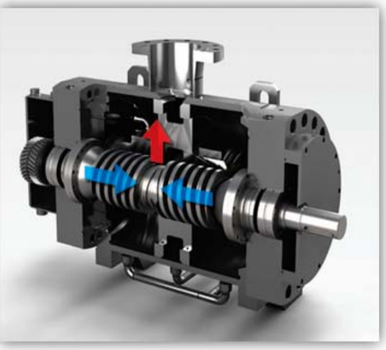

Prolong plateau production

Currently, there are two main types of multiphase subsea boosters in use:

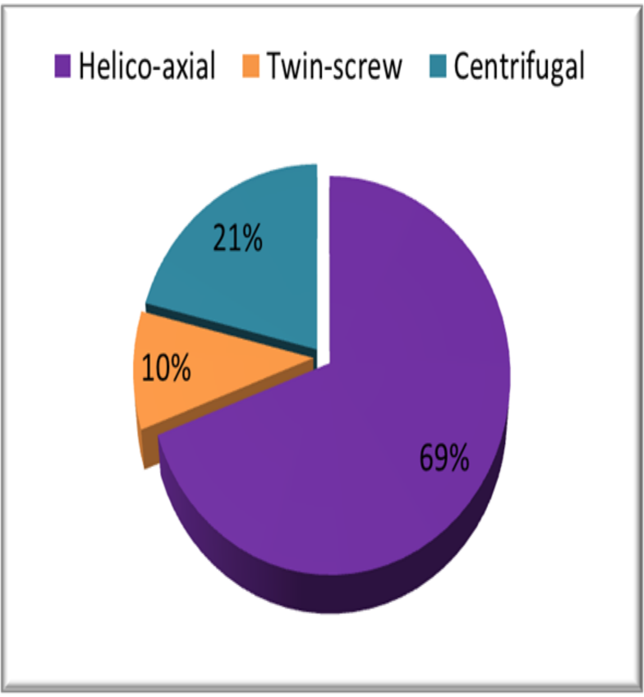
- helico-axial pump

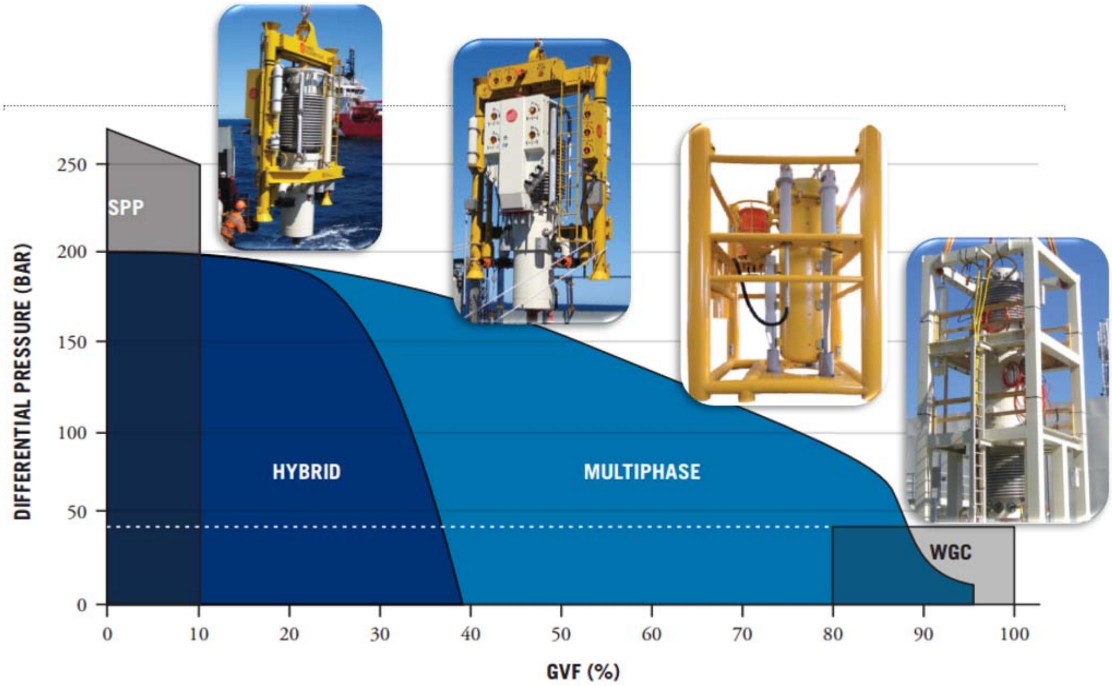


- twin screw pump



Multiphase pumps currently installed :

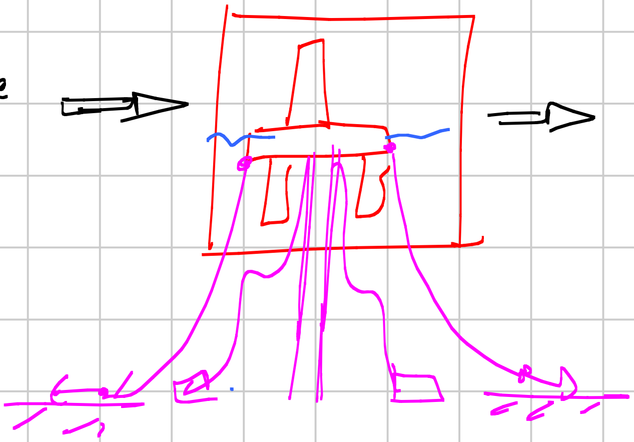




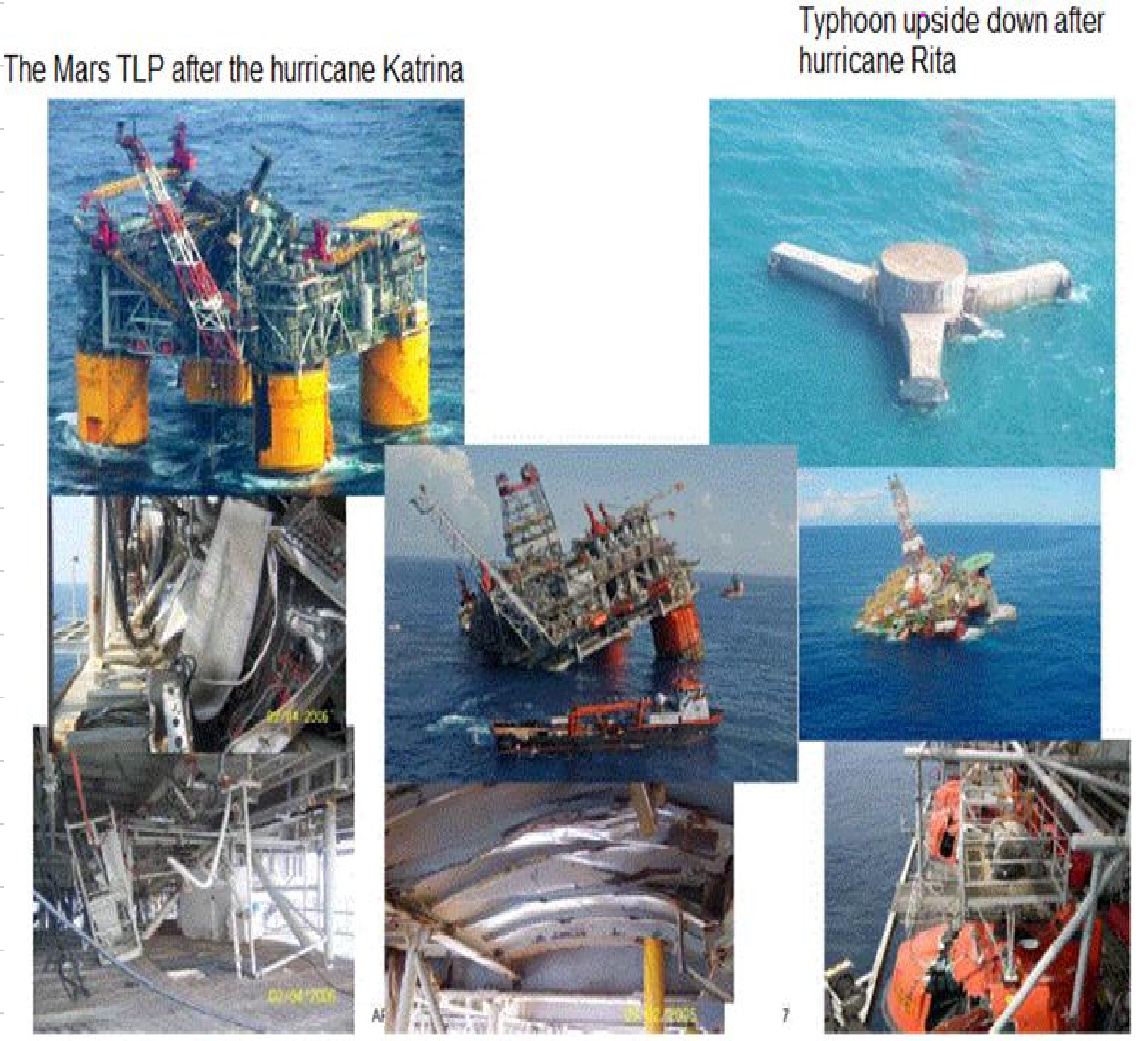
INTRODUCTION TO MARINE DYNAMICS - FLOATING STRUCTURES

JESUS DE ANDRADE, jesus.andrade@ntnu.no

HYDRODYNAMIC LOADS ⇒
- ↳ WAVES
- ↳ WIND
- ↳ CURRENT



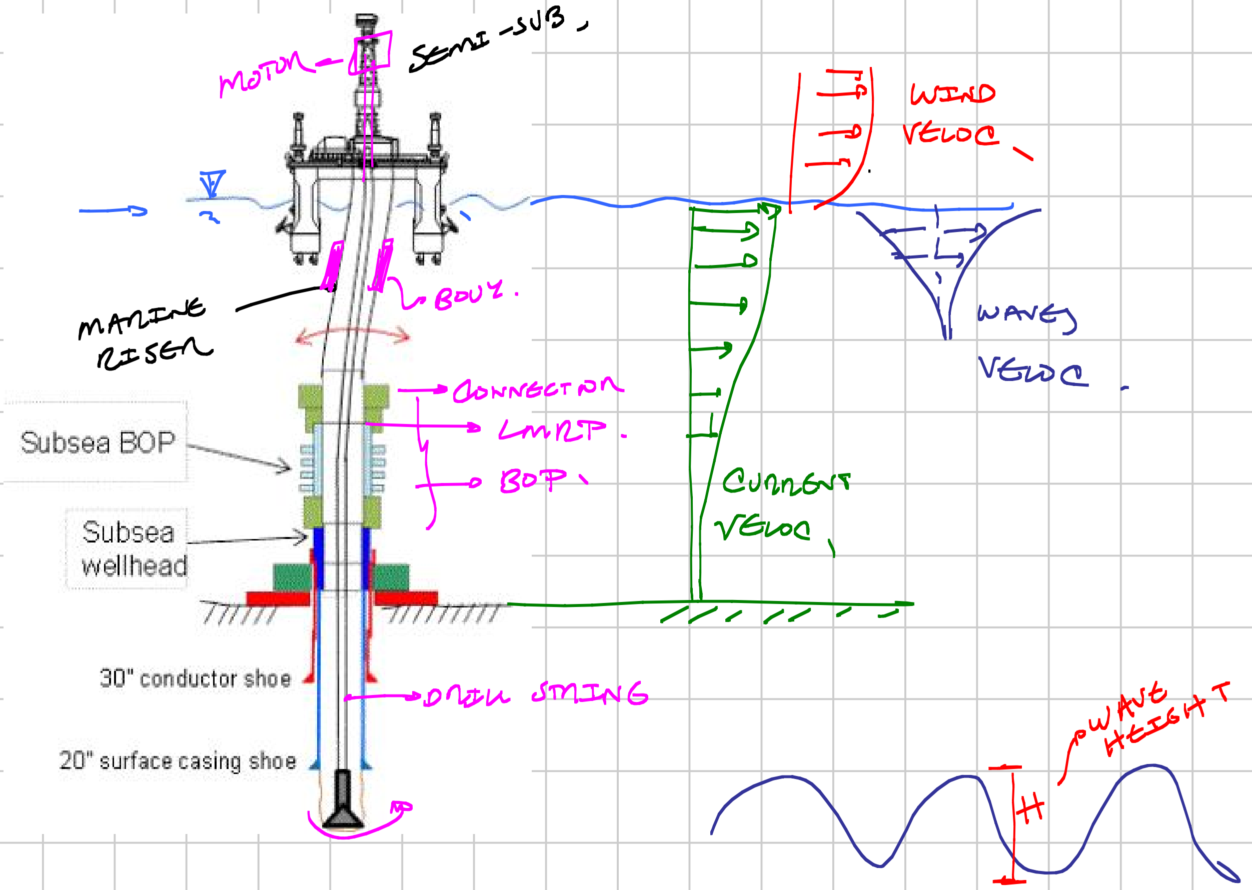
⇒ DYNAMIC RESPONSE
- ↳ MARINE STRUCTURE
- ↳ CONNECTION TO THE SEA BED
  - ↳ RISERS
  - ↳ MOORING SYSTEM



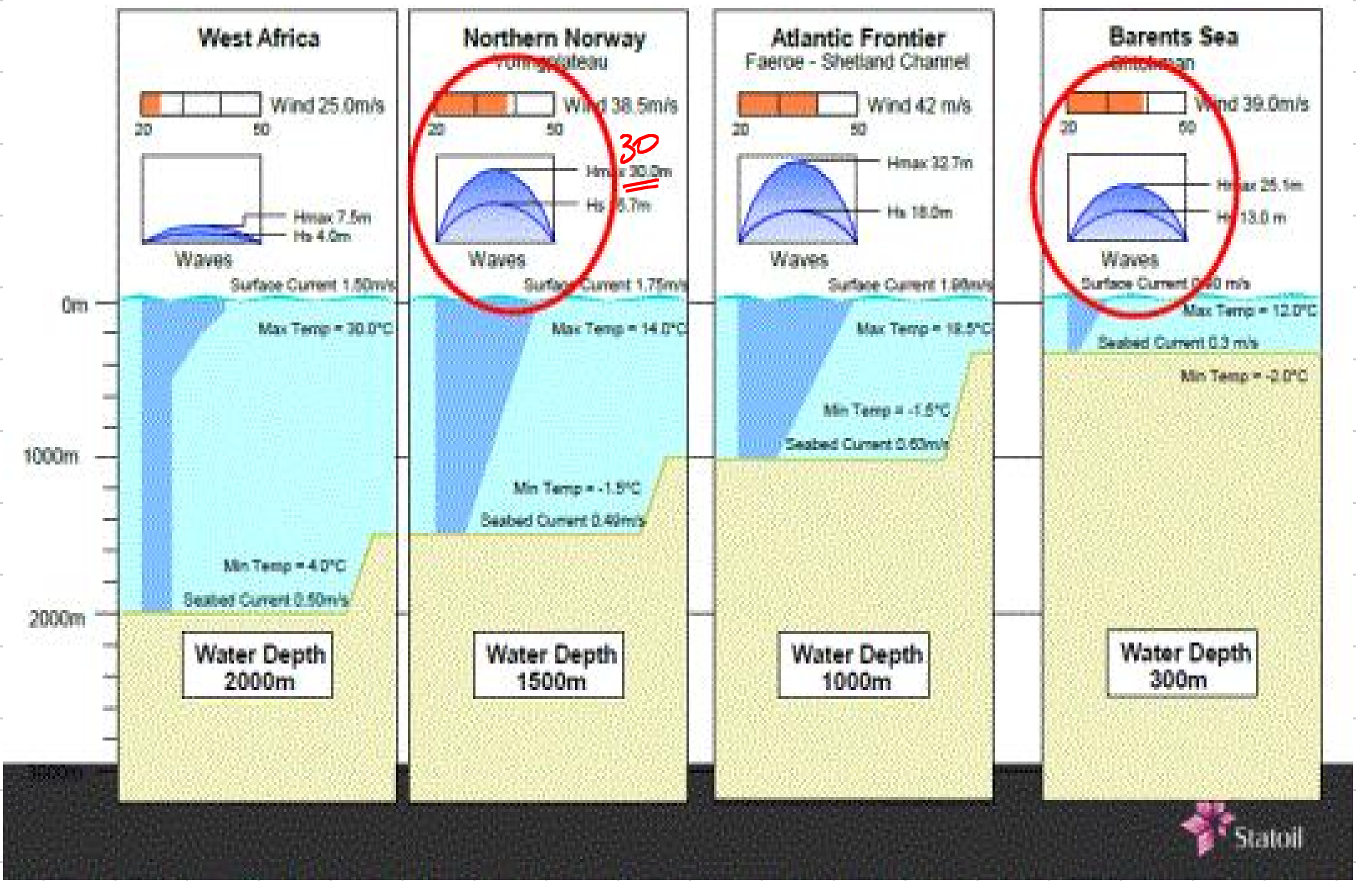
The Mars TLP after the hurricane Katrina

Typhoon upside down after hurricane Rita

ENVIRONMENTAL LOADS



Waves, wind and current comparable with Norway



CURRENT ≈ 1 m/s ⇒ IN NCS.

↳ 2 m/s IN NCS. LIKELY TO BE HIT BY STORMS.

WAVES:

$H_{max} \approx 30m$

$H_s \approx 18\ m$ ⇒ DESIGN

↳ SIGNIFICANT WAVE HEIGHT.

↳ MEAN VALUE OF THE HIGHES 1/3 WAVES

TWO SCALES

- AVERAGE CHARACT. (1 - 4 hr)
- RAPID FLUCT. (4 - 24 s)

WIND

TWO SCALES

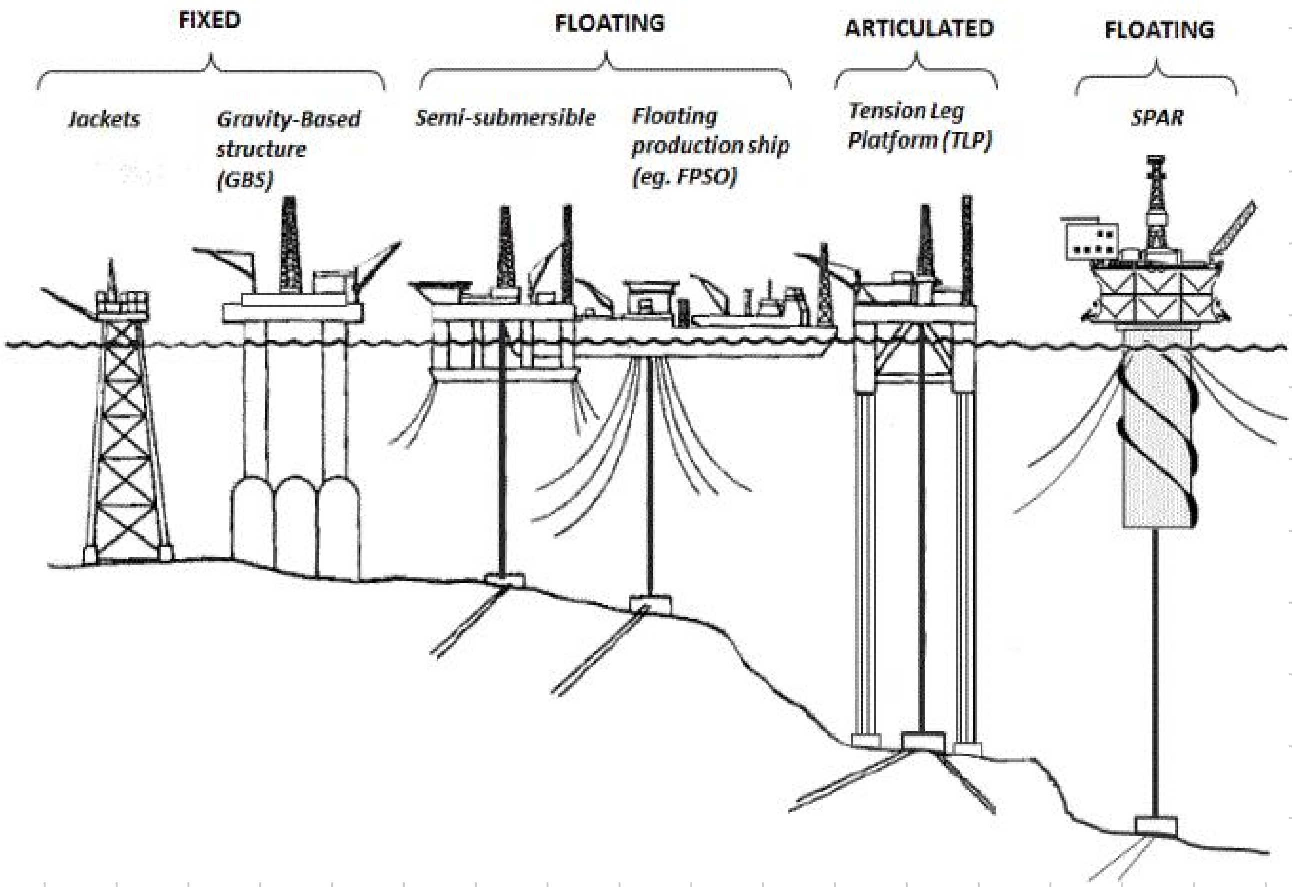
- SLOW VARYING MEAN CHARAC. (1 min) 3min
- RAPID FLUCTUATIONS.

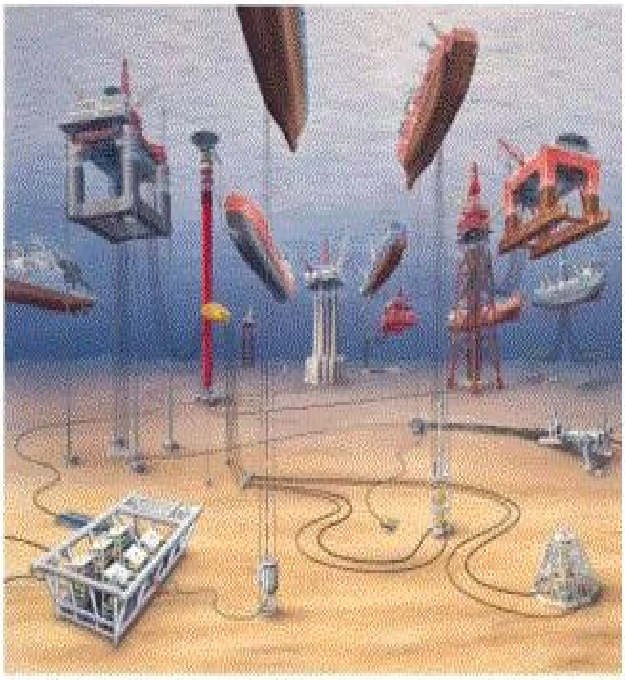
↳ 150 km/hr IN NCS.

CONVENTIONALLY DIFFERENT PLATFORM ← WATER DEPTHS

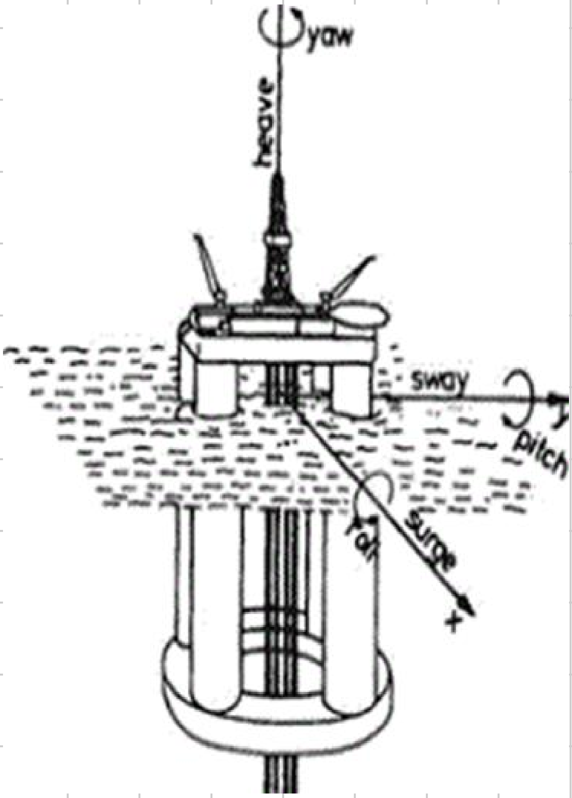
↳ MORE VERY DIFFERENT

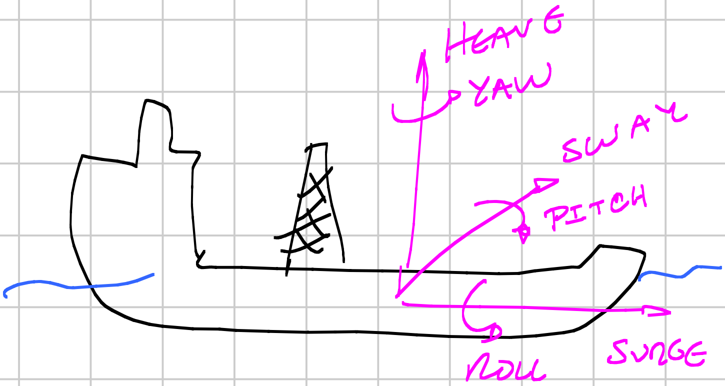
↳ HORIZ. AND VERT. MOTION

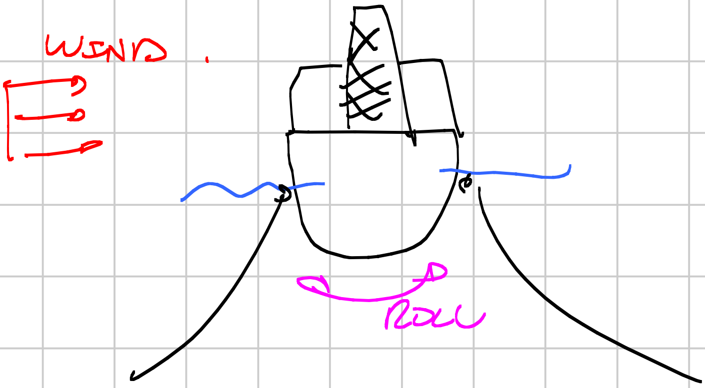




HOW FLOATING STRUCTURES MOVE UNDER OCEAN WAVES ACTION →







MARINE STRUCTURE SELECTION:

- WATER DEPTH
- HYDRODYNAMIC LOADS (STORMS, ICE)
- FOUNDATION SUPPORT (SEA BED)
- DYNAMIC RESPONSE OF THE STRUCTURE
- RESERVOIR

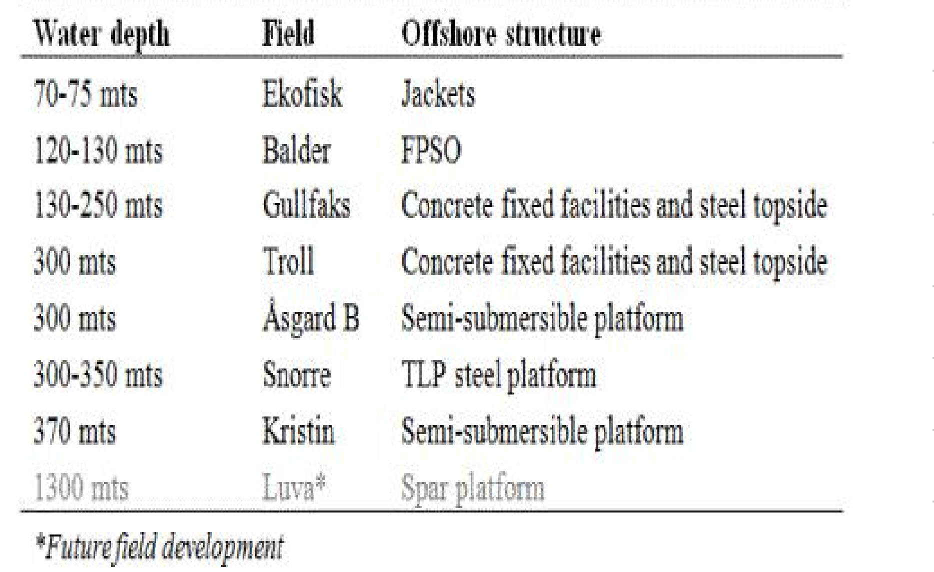


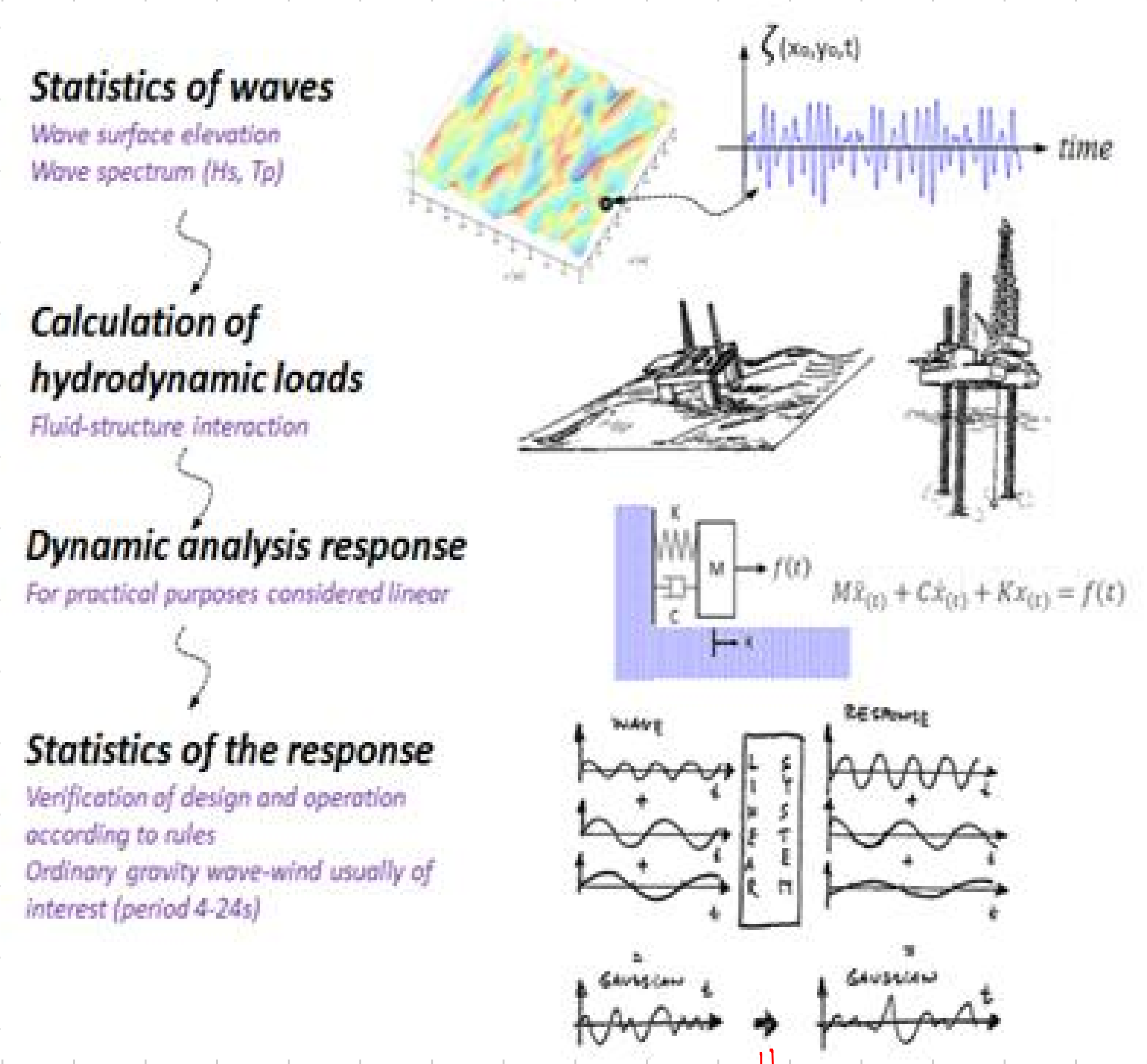
Table 1. Examples of offshore structures in the NCS for different water depths.

Water depth	Field	Offshore structure
70-75 mts	Ekofisk	Jackets
120-130 mts	Balder	FPSO
130-250 mts	Gullfaks	Concrete fixed facilities and steel topside
300 mts	Troll	Concrete fixed facilities and steel topside
300 mts	Åsgard B	Semi-submersible platform
300-350 mts	Snorre	TLP steel platform
370 mts	Kristin	Semi-submersible platform
1300 mts	Luva*	Spar platform

*Future field development

STOCHASTIC DESIG

WAVES ARE VERY RANDOM → (STATISTICA APPROACH)



Statistics of waves

Wave surface elevation

Wave spectrum (Hs, Tp)

Calculation of hydrodynamic loads

Fluid-structure interaction

Dynamic analysis response

For practical purposes considered linear

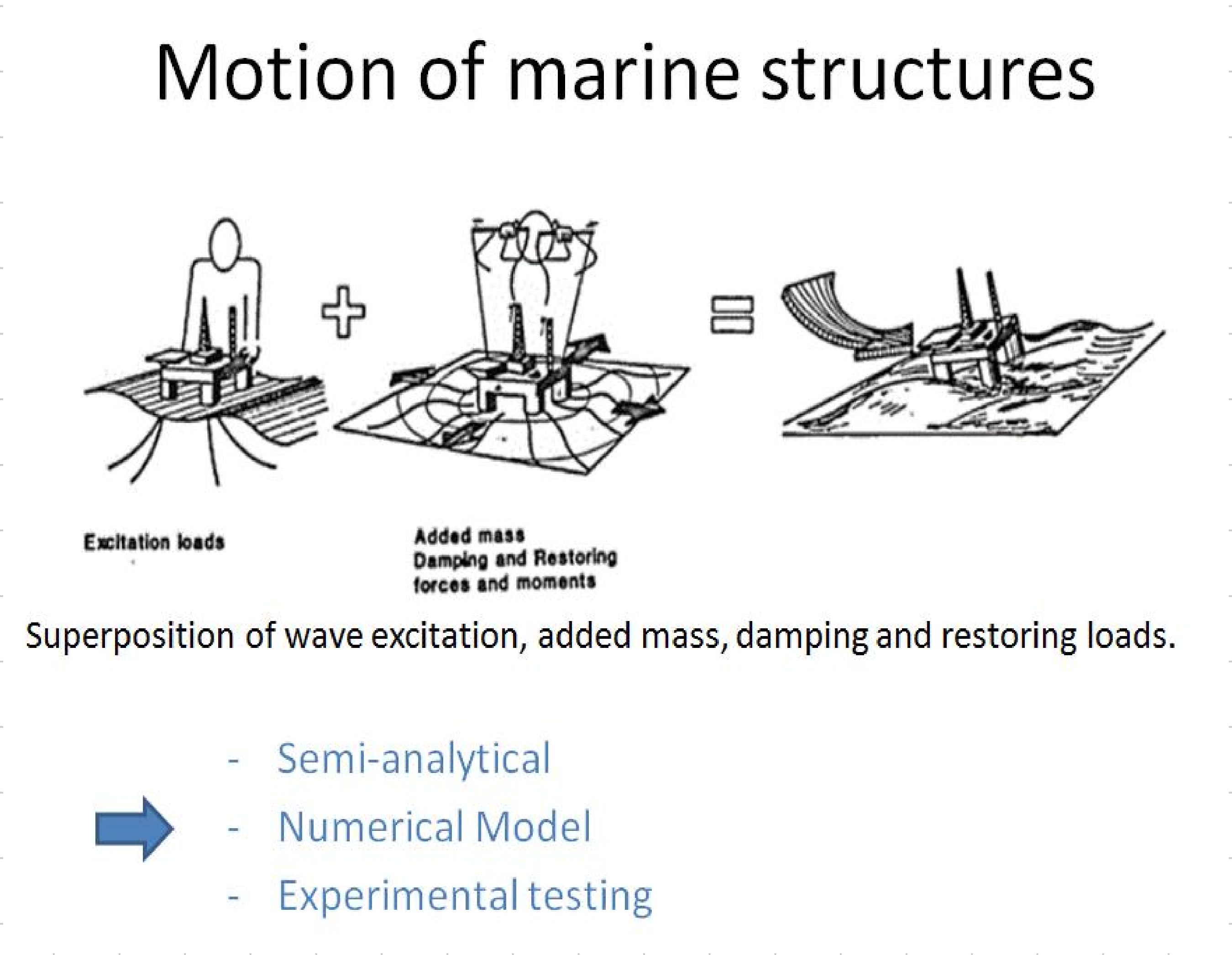
Statistics of the response

Verification of design and operation according to rules

Ordinary gravity wave-wind usually of interest (period 4-24s)

$$M\ddot{x}_{(t)} + C\dot{x}_{(t)} + Kx_{(t)} = f(t)$$

WHATS GOING TO HAPPEN THE NEXT 100 YEARS ?



Motion of marine structures

Superposition of wave excitation, added mass, damping and restoring loads.

- Semi-analytical
- Numerical Model
- Experimental testing

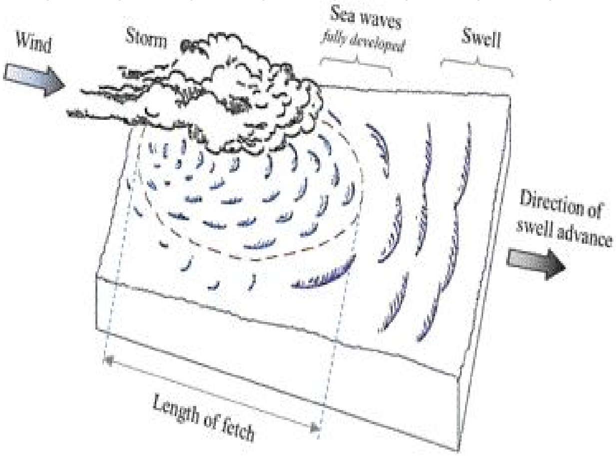
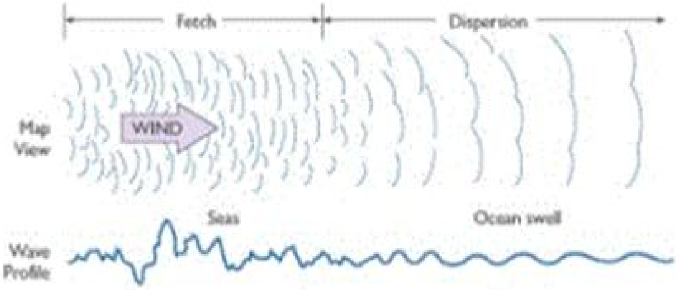
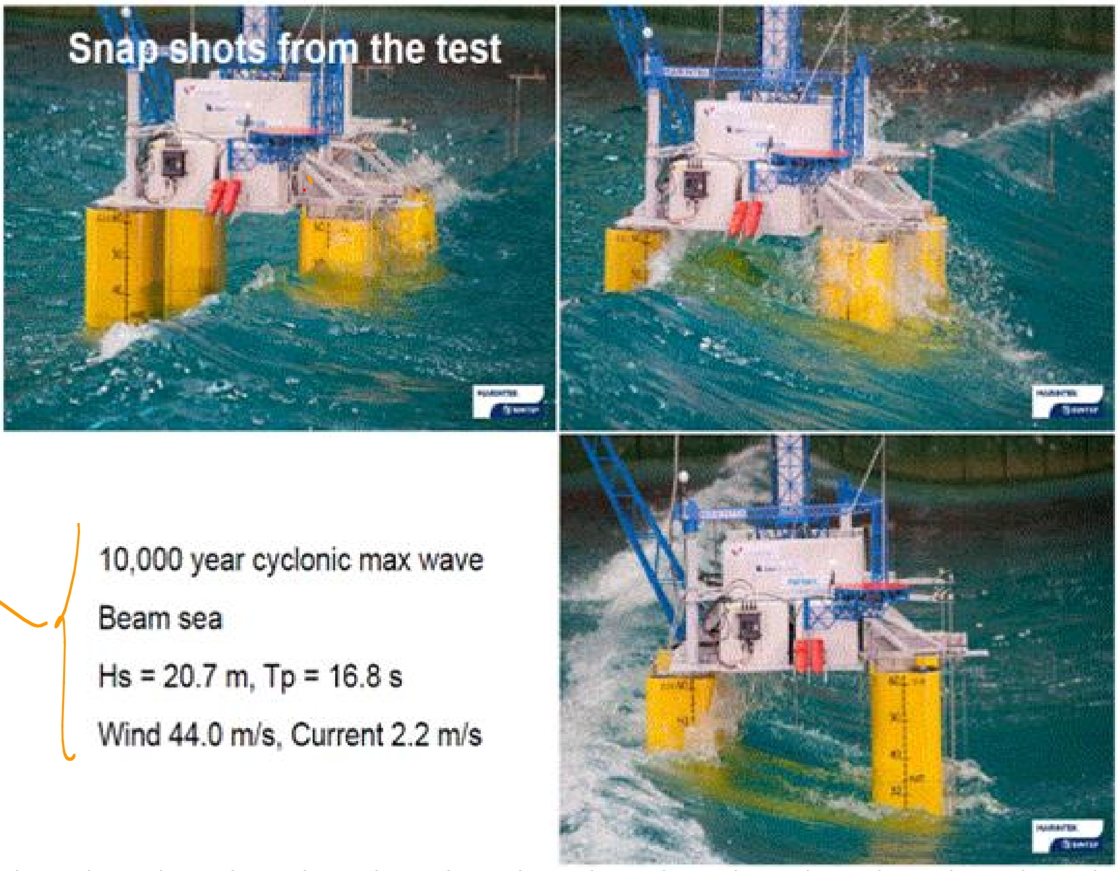


Fig. 4. Illustration of sea waves and swell generation.



SCALE DOWN EXPERIMENTS

GEOM. AND LOADS SCALED



Snap shots from the test

10,000 year cyclonic max wave

Beam sea

Hs = 20.7 m, Tp = 16.8 s

Wind 44.0 m/s, Current 2.2 m/s

Motion of marine structures

FROM EXPERIMENTS:

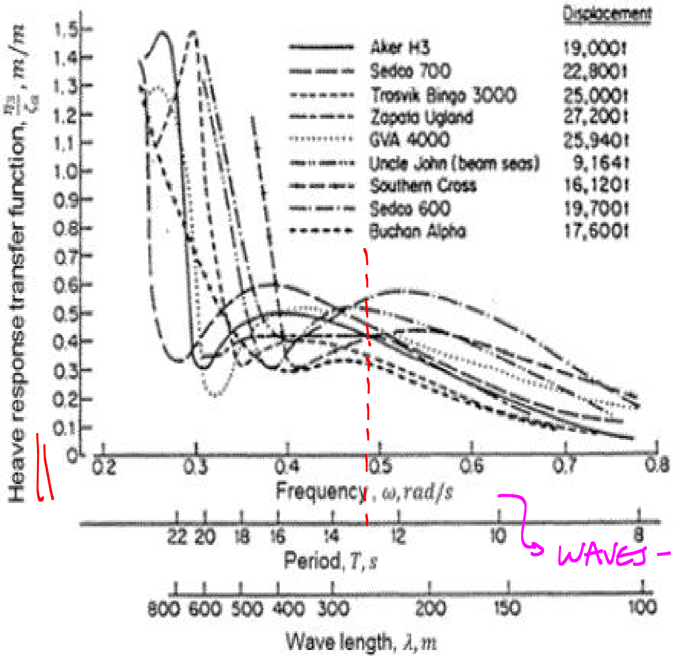
Response amplitude operator, RAO

it establishes a relation between the motion and wave amplitude in the frequency domain

heave motion of semi-submersible platforms

TYPICAL PERIOD

~ 13 sec

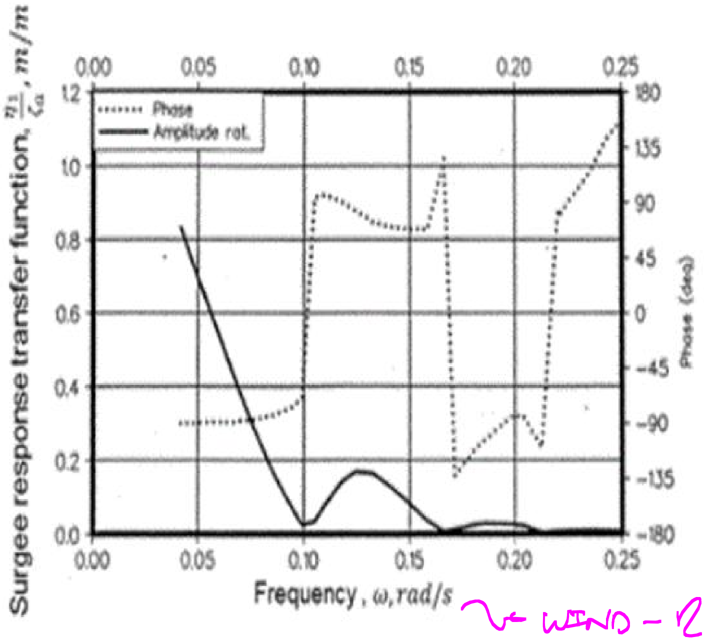


WAVES-RELATED

Fig. 24. Representative heave response transfer functions for different semi-submersibles.

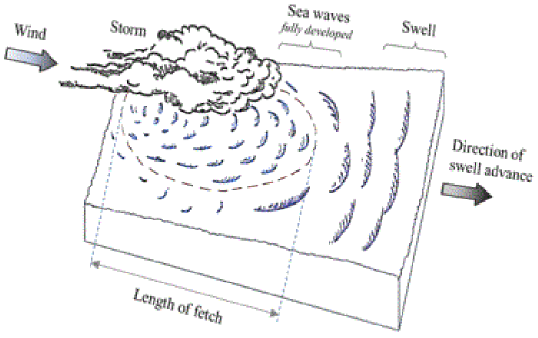
Surge (horizontal) motion of TLP platforms

≈ SEMI-SUP



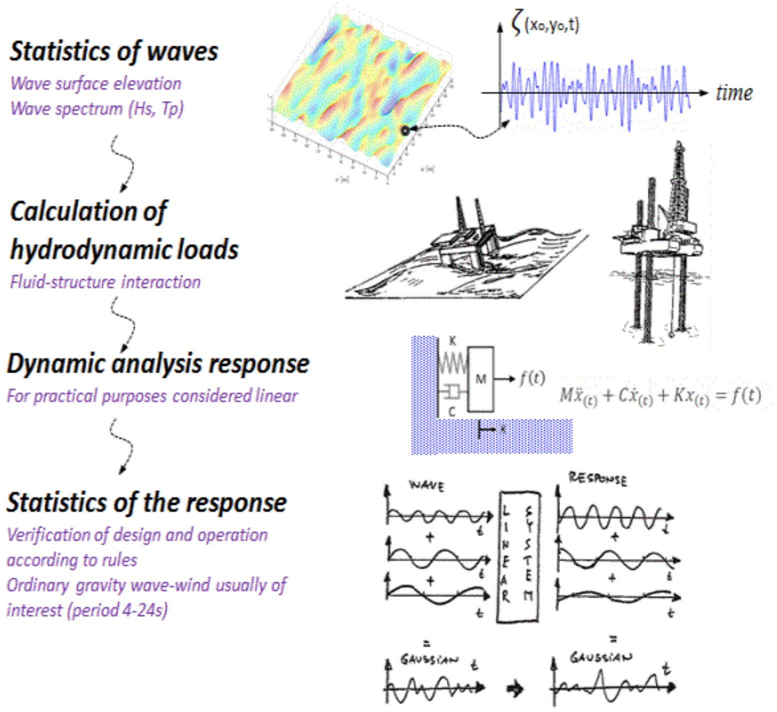
~ WIND-RELATED

Fig. 25. Surge response transfer function of TLP.



Introduction to Marine Dynamics

Jesus De Andrade
March, 2015



Statistics of waves

Wave surface elevation
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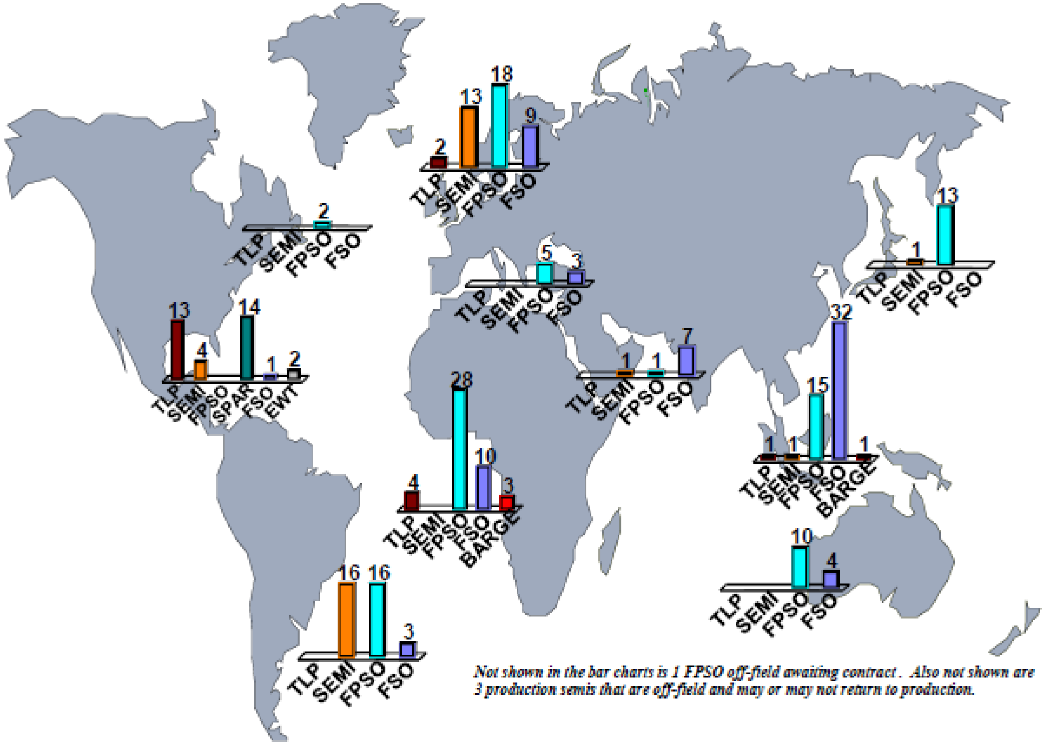
Statistics of the response

Verification of design and operation according to rules
Ordinary gravity wave-wind usually of interest (period 4-24s)

Current world fleet of floating systems



Not shown in the bar charts is 1 FPSO off-field awaiting contract . Also not shown are 3 production semis that are off-field and may or may not return to production.

256 Floating Production Units worldwide (Aug 2011, ref. Petroleum Insights)

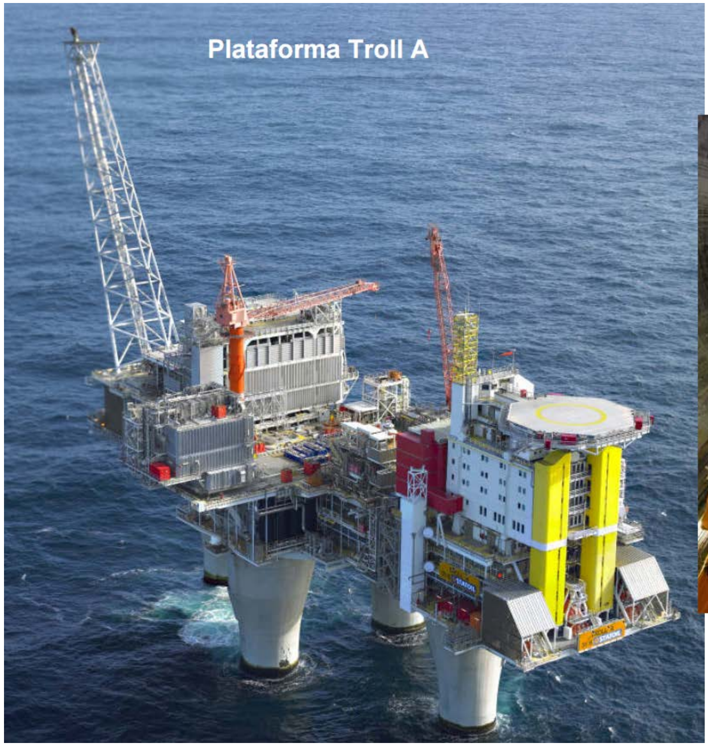
62% are floating production, storage, offloading (FPSO) vessels;

17% are production semisubmersibles (Semi);

9% are tension leg platforms (TLP);

7% are production spars;

and the remaining 5% are production barges and floating storage and regasification units (FSRUs).



Plataforma Troll A

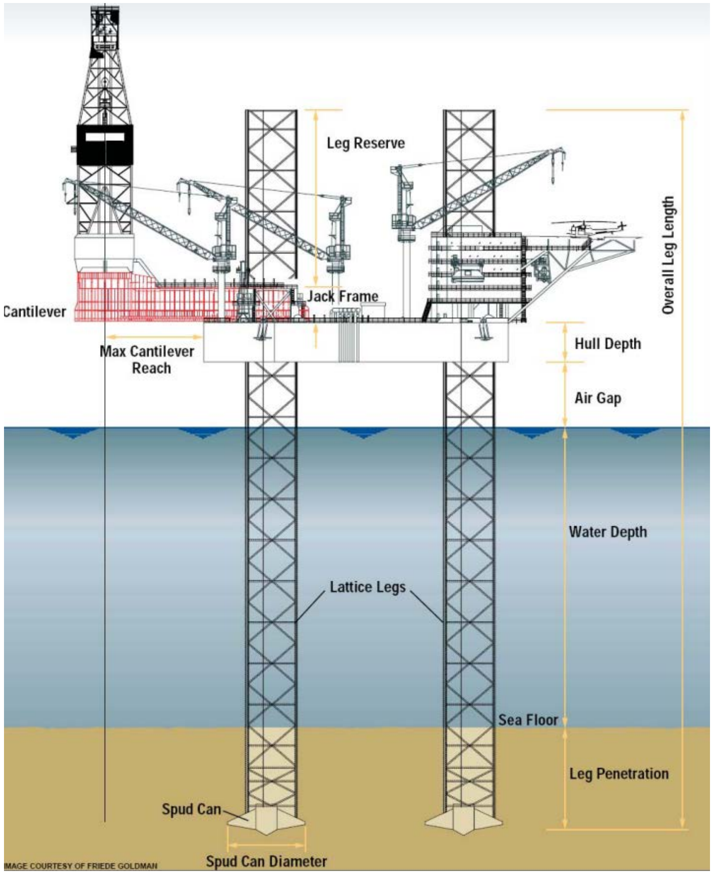
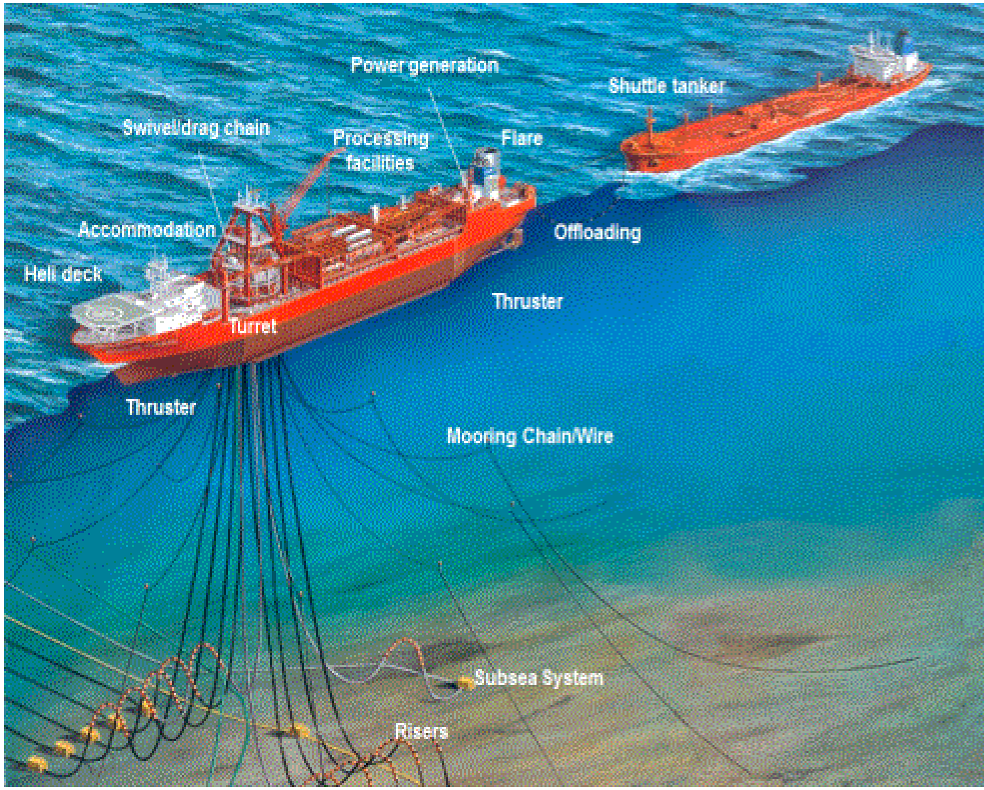


IMAGE COURTESY OF FRIEDE GOLDMAN

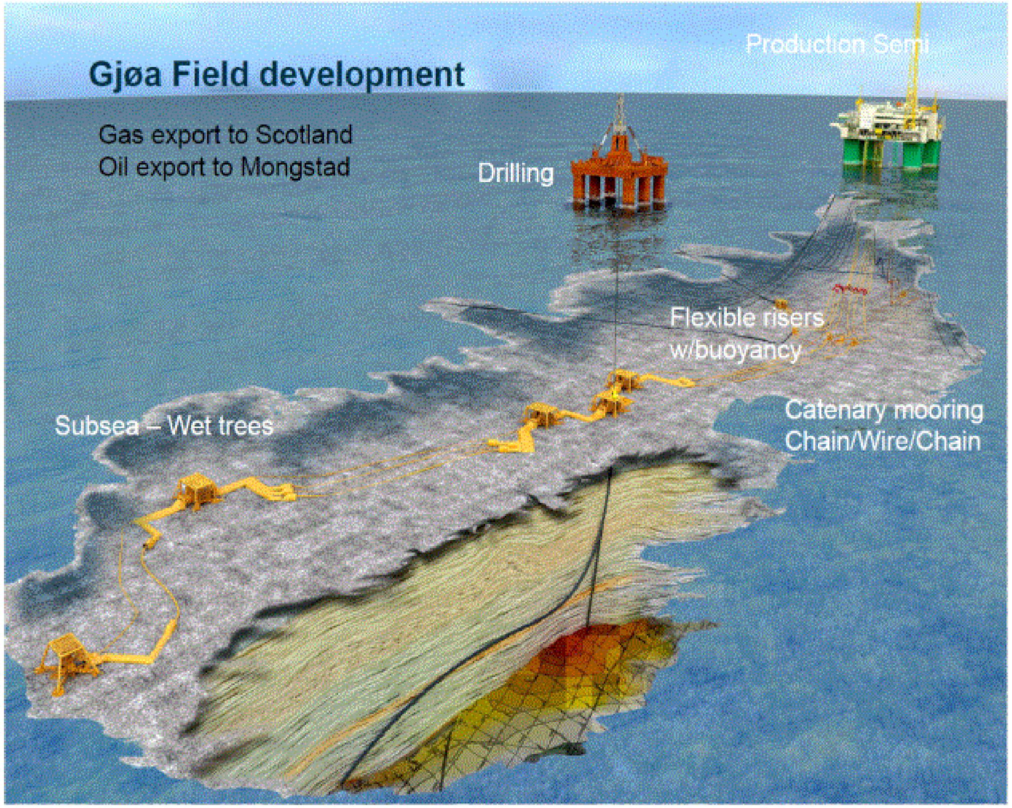
FPSO (Floating Production Storage and Offloading)

- Ship shaped or circular
- **Large storage capacity**
- Large topside capacity
- Good separation between hazardous and non-hazardous areas
- Fair motions
- Flexible risers and turret
- Integration and commissioning inshore



Semi-Submersible (Semi)

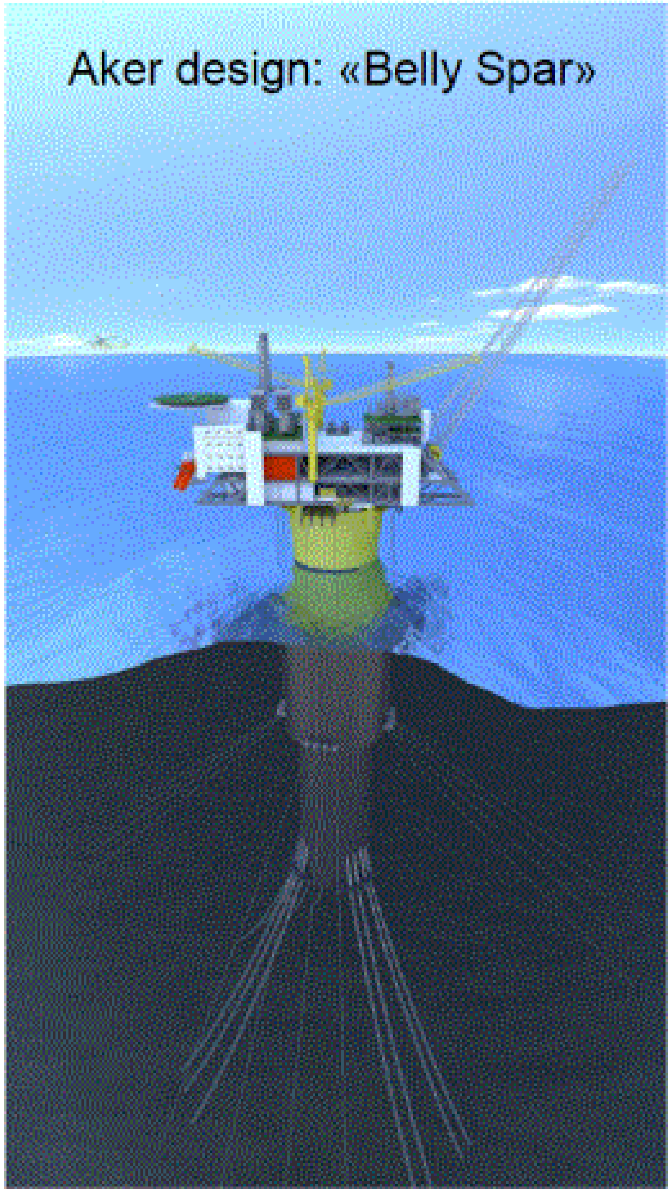
- Flexible concept with large (unlimited) capacity, topside weight and area
- Column stabilized
- **No water depth limit**
- Good motions
- Feasible with Steel Catenary Risers (SCRs) in deep water
- No (limited) storage
- Integration and commissioning inshore



Ultra-Deepwater
Semi-submersible

Spar Platforms

- Weight stable (by counter weight)
- Limited capacity, limited footprint
- **Excellent motions**
    - **Top Tensioned Risers possible**
- Storage (limited)
- Integration and commissioning offshore or inshore in deep fjord (> 200 m WD)

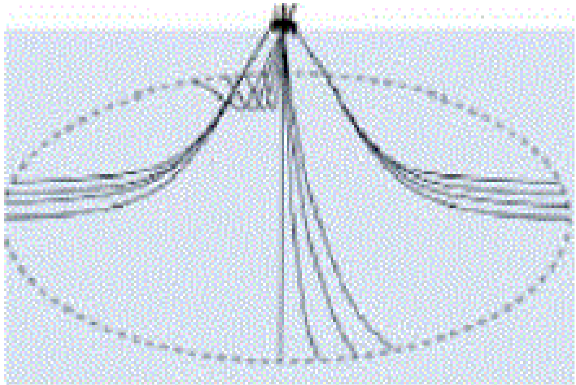


Aker design: «Belly Spar»

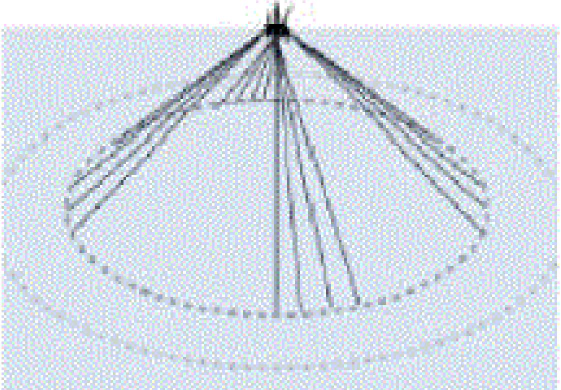
Mooring Systems

- Purpose of mooring is to keep platform on location

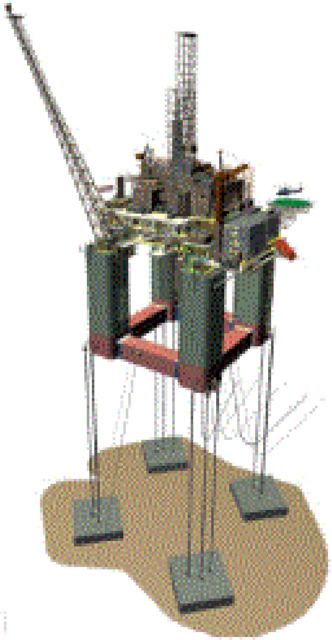
Catenary mooring (traditional)



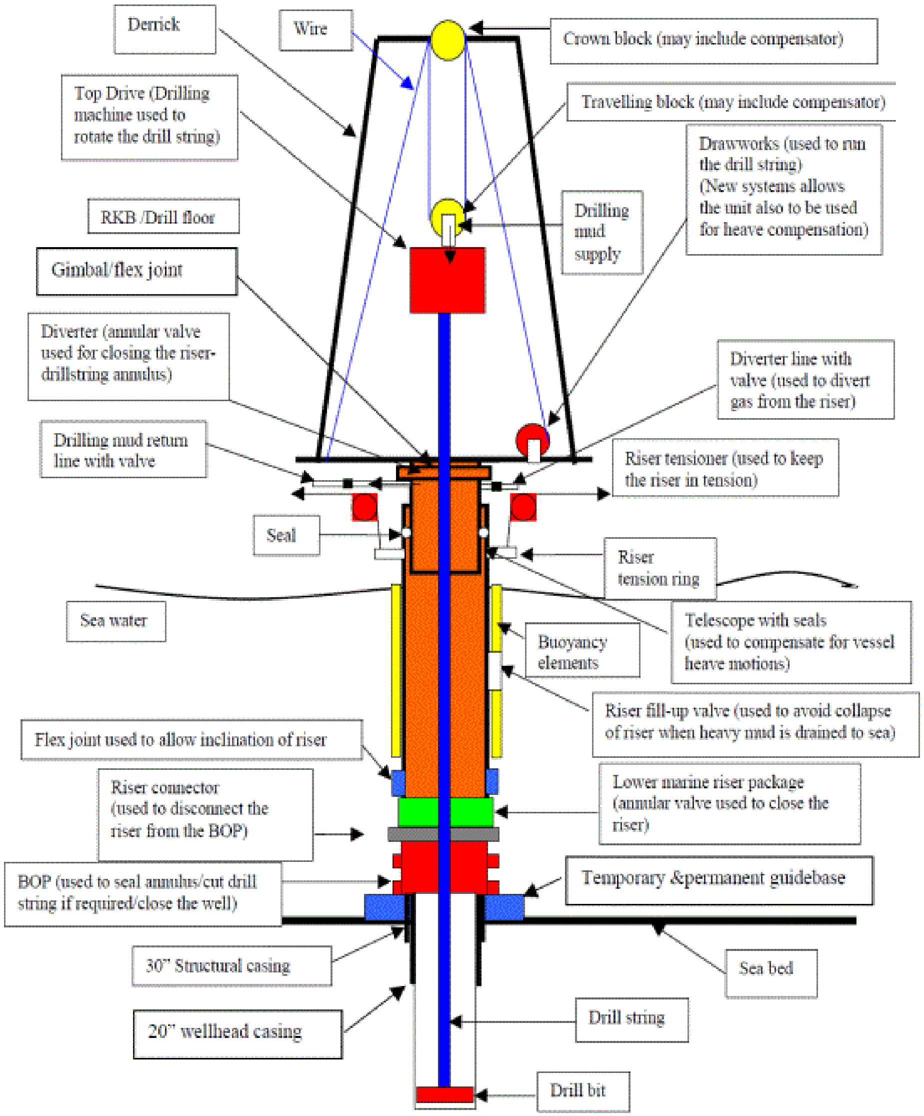
Taut mooring



Tethers (steel pipe)



Riser tensioner



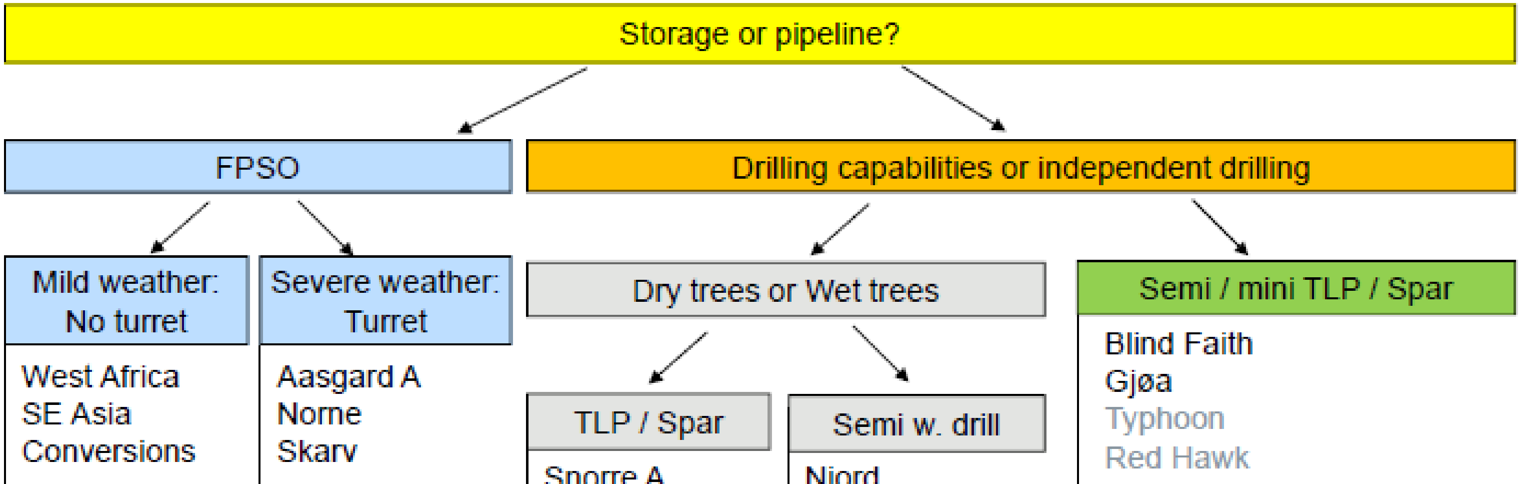

(a) Wire-line.

(b) N-line.

The different riser tensioner systems (National Oilwell Varco, 2007*b*).


Figure 5.3: Production riser tensioner system at the TLP Jolliet (National Oilwell Varco, 2007*b*).

Principal Selection Criteria



Storage or pipeline?

FPSO

Drilling capabilities or independent drilling

Mild weather:
No turret

West Africa
SE Asia
Conversions

Severe weather:
Turret

Aasgard A
Norne
Skarv

Dry trees or Wet trees

TLP / Spar

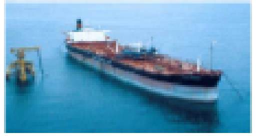
Snorre A
Diana
Shenzi
Tahiti

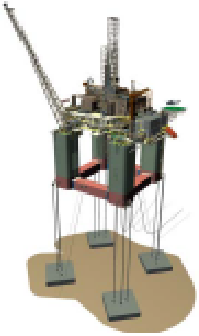
Semi w. drill

Njord
Snorre B
Thunder Horse

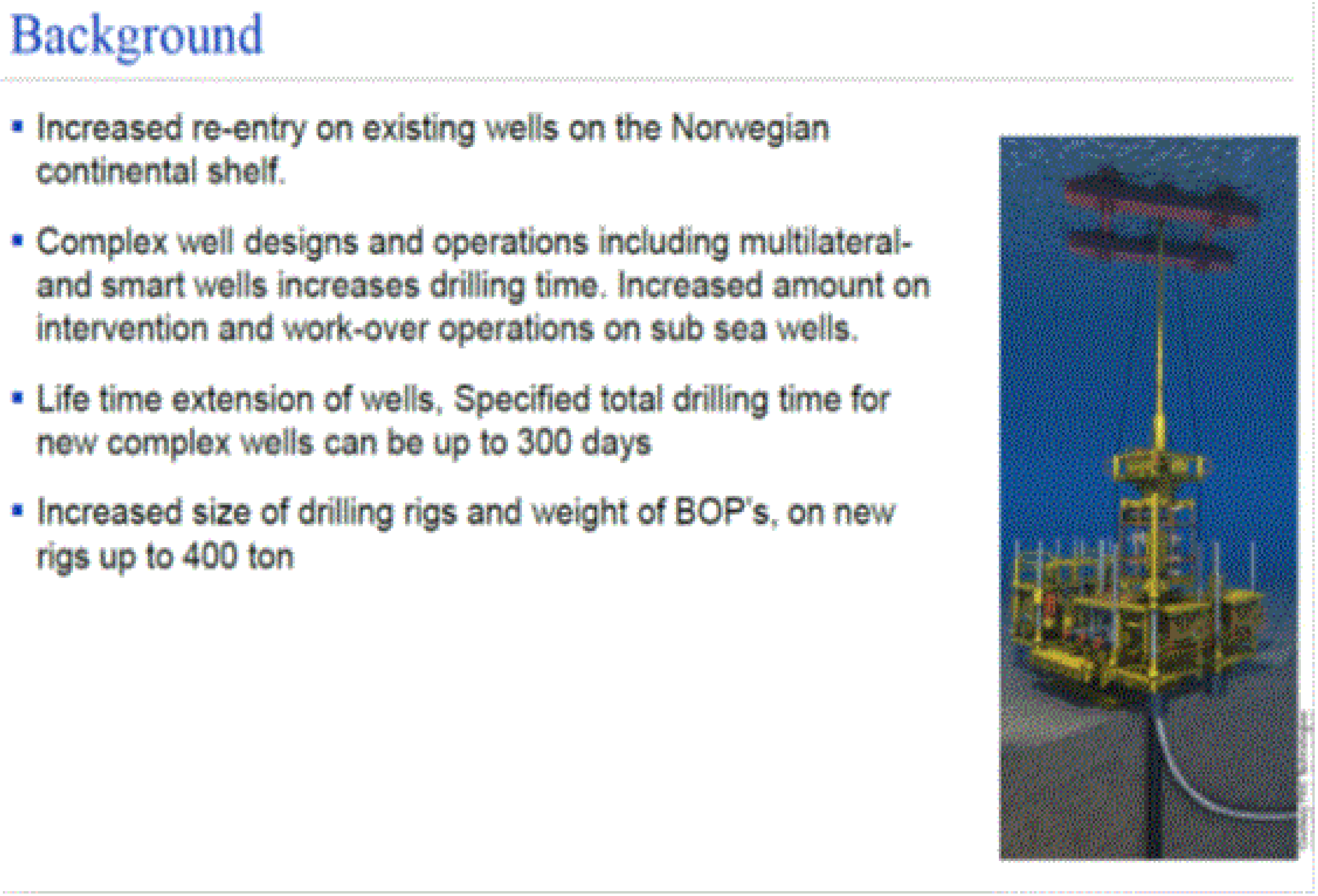
Semi / mini TLP / Spar

Blind Faith
Gjøa
Typhoon
Red Hawk



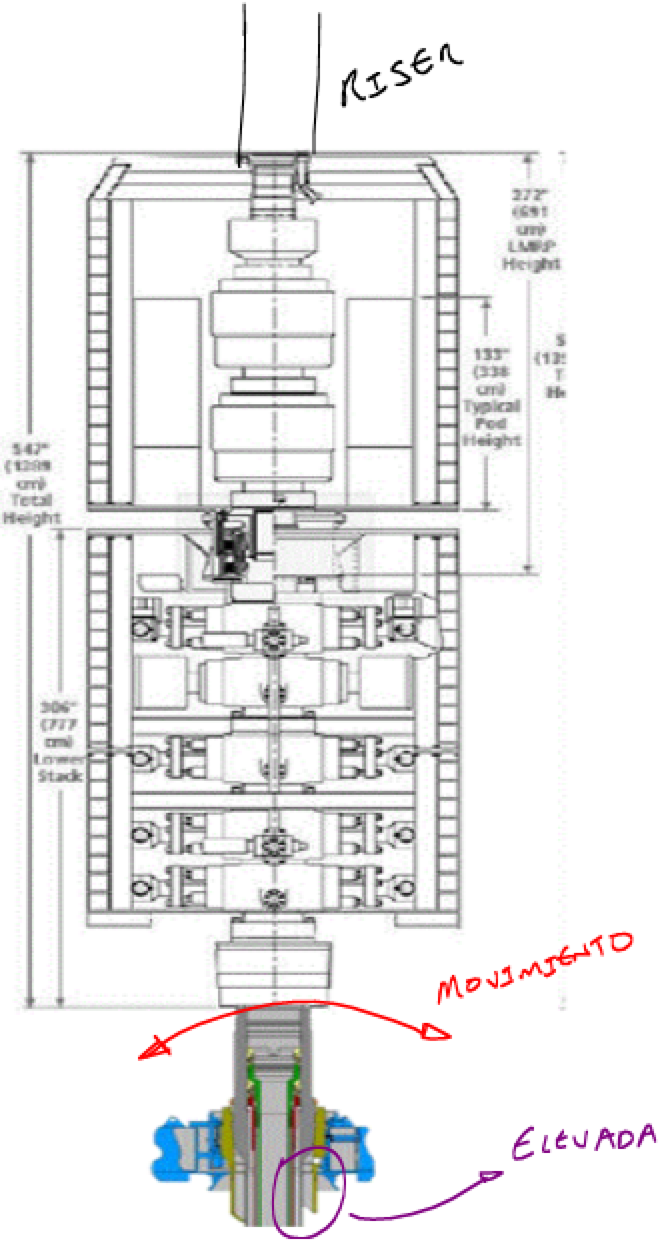


WH Fatigue

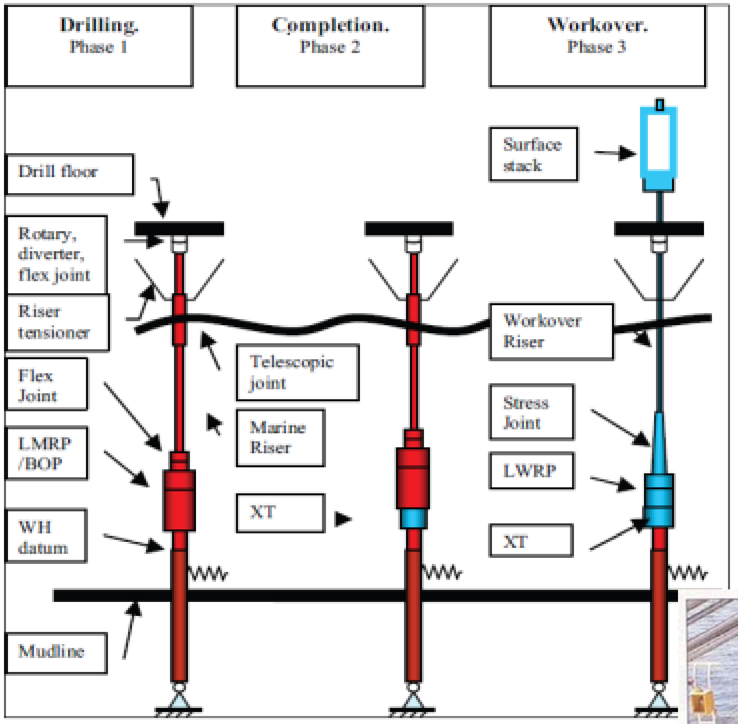


Background

- Increased re-entry on existing wells on the Norwegian continental shelf.
- Complex well designs and operations including multilateral- and smart wells increases drilling time. Increased amount on intervention and work-over operations on sub sea wells.
- Life time extension of wells, Specified total drilling time for new complex wells can be up to 300 days
- Increased size of drilling rigs and weight of BOP's, on new rigs up to 400 ton



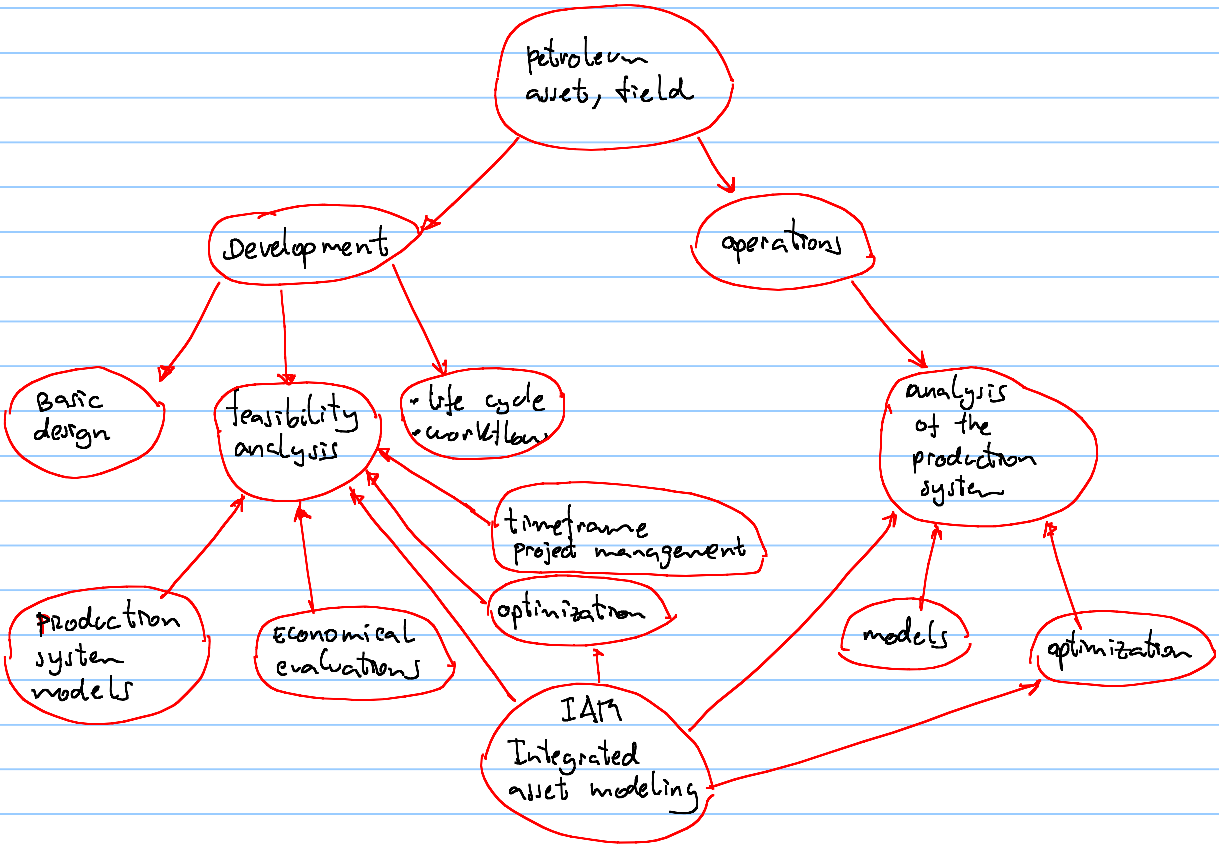
ELEVADAS CARGAS : ∘AXIAL
∘FLEXION } → FATIGA

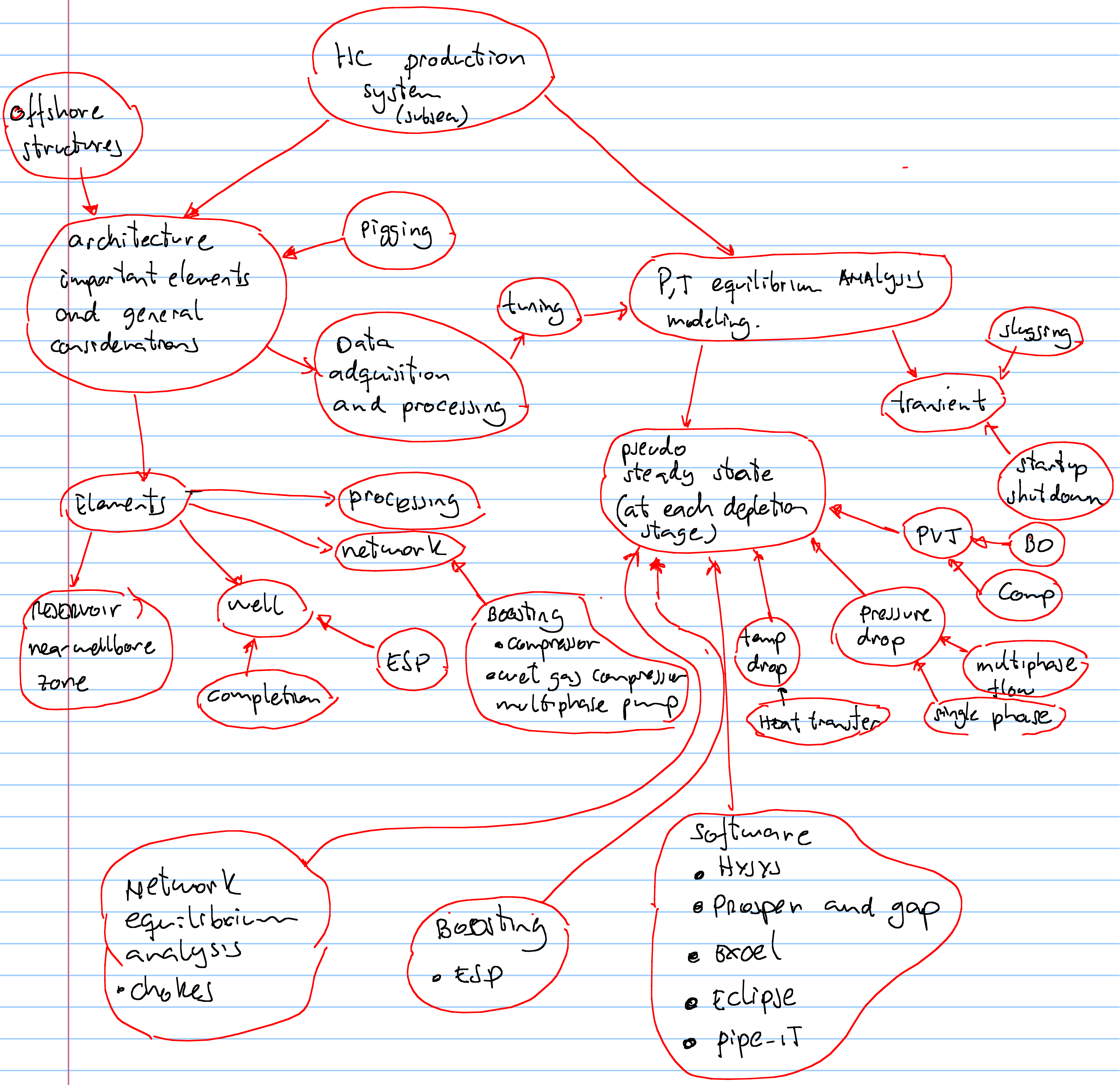


Weight : 250 T in ai

Hydril will supply two BOP control stacks and a multiplex pressure control system similar to this for the Ocean Endeavor (Fig. 3; image from Hydril Co.

- Summary of the course
- Orientation for the exam




HC production system (subsea)
Offshore structures
architecture important elements and general considerations
Pigging
P,T equilibrium Analysis modeling.
tuning
Data adquisition and processing
slugging
transient
pseudo steady state (at each depletion stage)
startup shutdown
Elements
processing
network
PVT
BO
Comp
Reservoir near-wellbore zone
well
ESP
completion
Boosting
• compressor
wet gas compressor
multiphase pump
temp drop
Heat transfer
pressure drop
multiphase flow
single phase
Network equilibrium analysis
• chokes
Boosting
• ESP
Software
• HYSYS
• Prosper and gap
• excel
• Eclipse
• pipe-IT

Exam date 19.05.2015 . from : 09:00 to 13:00. Rooms to be defined later through innsida (probably P10, P11, P12)

Material to review for the exam :
- Course notes (videos)
- Exercises
- Reference material

Info for the exam:

-Calculators without memory allowed.

-No phones (smartphones, tablets, ipods, etc) on the table (or toilet), leave everything in your backpack.

-No books or any other support material.

-No need to memorize equations, the relevant equations will be given in a handout.

- Be prepared to sketch. Also to design an excel sheet !