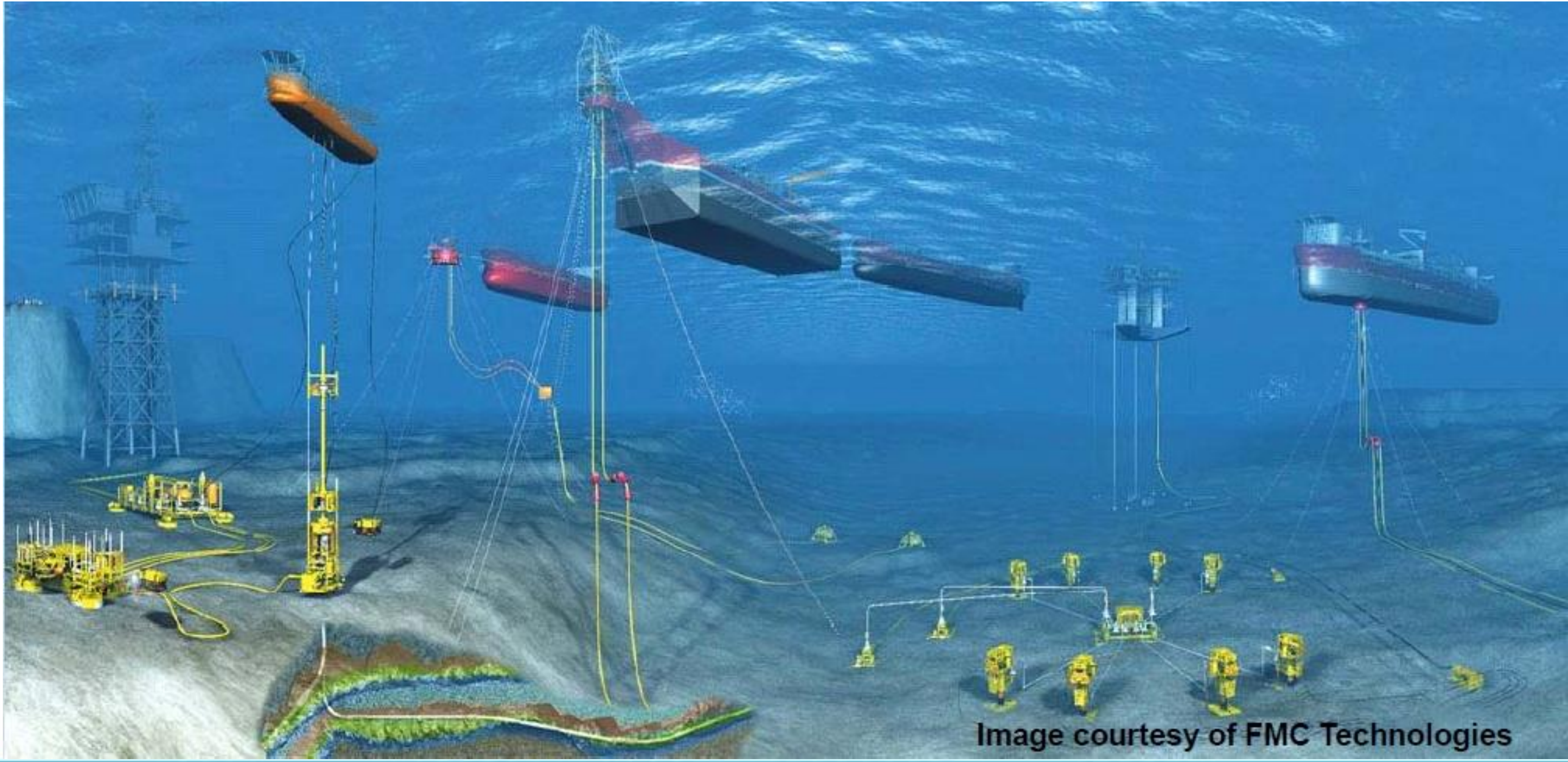
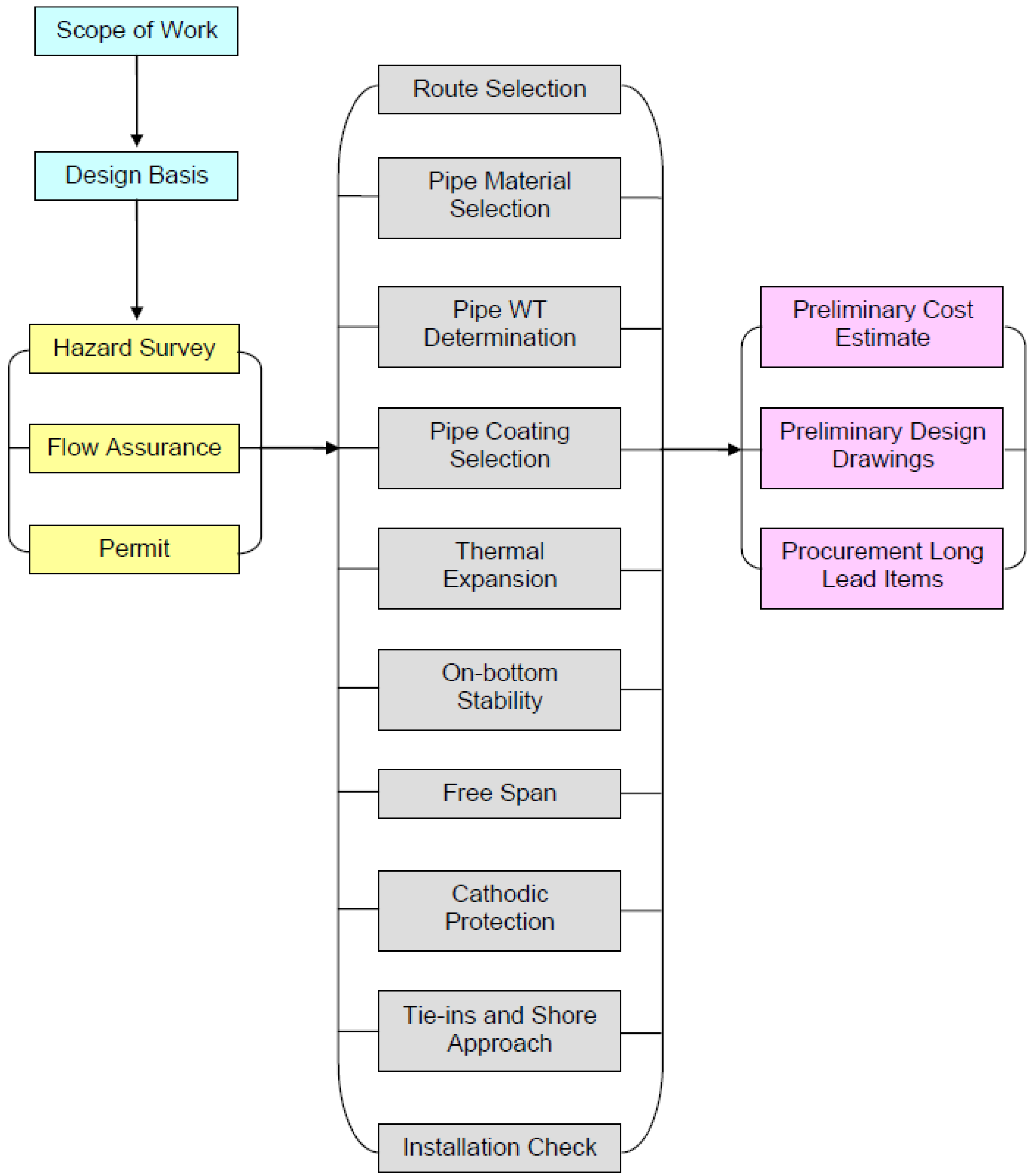


Offshore Equipment

Yutaek Seo

Pipeline design procedures



Subsea pipeline: Material selection

Subsea pipelines burst

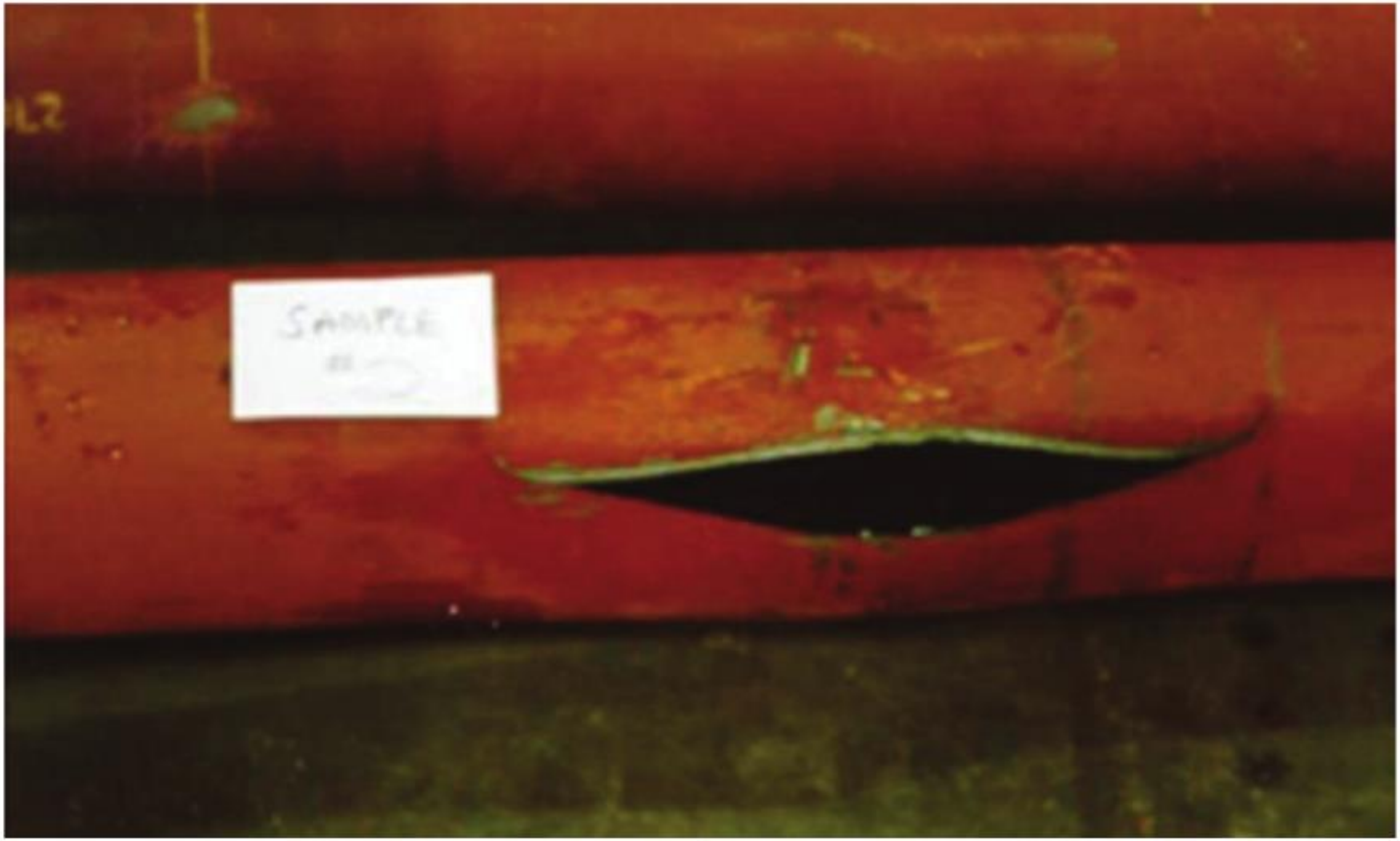


Figure A.1—Ductile Burst Sample

Figure A.2—Brittle Burst Sample

Pipe material selection

- Pipe material type, i.e. rigid, flexible, or composite, should be determined considering
  : Conveyed fluid properties (sweet or sour) and temperature
  : Pipe material cost
  : Installation cost
  : Operational cost (chemical treatment)

- There are several different pipes used in offshore oil & gas transportation as follows:
  : Low carbon steel pipe
  : Corrosion resistant alloy (CRA) pipe
  : Clad pipe
  : Composite pipe
  : Flexible pipe
  : Flexible hose
  : Coiled tubing

Low carbon steel pipe

- Low carbon (carbon content less than 0.29%) steel is mild and has a relatively low tensile strength so it is used to make pipes.

- Medium or high carbon (carbon content greater than 0.3%) steel is strong and has a good wear resistance so they are used to make forging, automotive parts, springs, wires, etc.

- Carbon equivalent (CE) refers to method of measuring the maximum hardness and weldability of the steel based on chemical composition of the steel.

- Higher C and other alloy elements such as Mn, Cr, Mo, V, Ni, Cu, etc. tend to increase the hardness (harder and stronger) but decrease the weldability (less ductile and difficult to weld).

- The CE shall not exceed 0.43% of total components, per API-5L, as expressed below. (note: IIW = International Institute of Welding)

$$CE(IIW) = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Ni + Cu}{15} < 0.43\%$$

- Pipes are graded per their tensile properties. Grade X-65 means that SMYS (specified minimum yield strength) of the pipe is 65 kpsi.

- The API-5L line pipe specification defines two different product specification levels, PSL 1 and PSL 2. PSL 2 is commonly used for weld joint connections

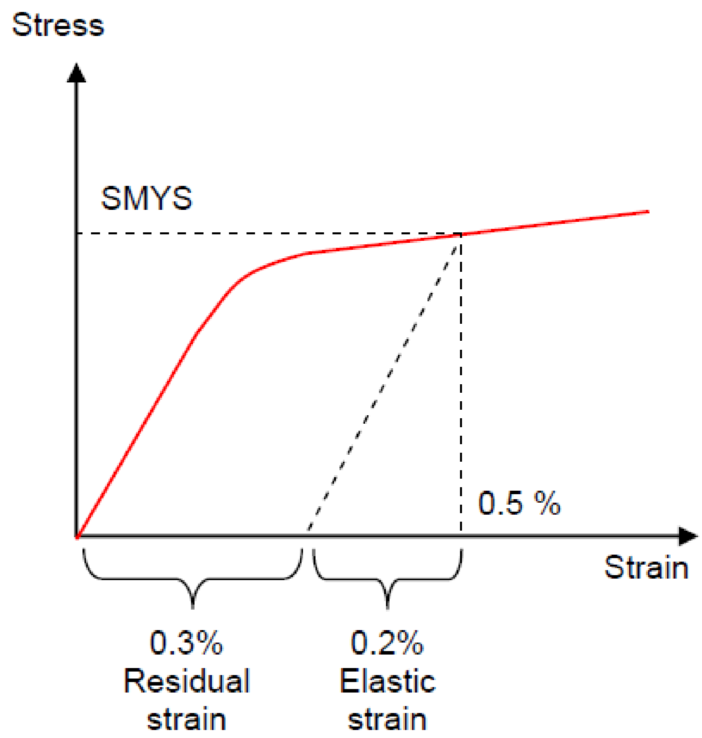
Table 1. Tensile Requirements for API-5L PSL 2 Pipe

Grade	Yield Strength, Minimum		Yield Strength, Maximum[b]		Ultimate Tensile Strength, Minimum		Ultimate Tensile Strength, Maximum[c]	
	psi	MPa	psi	MPa	psi	MPa	psi	MPa
B	35,000	(241)	65,000[d]	(448)	60,000	(414)	110,000	(758)
X42	42,000	(290)	72,000	(496)	60,000	(414)	110,000	(758)
X46	46,000	(317)	76,000	(524)	63,000	(434)	110,000	(758)
X52	52,000	(359)	77,000	(531)	66,000	(455)	110,000	(758)
X56	56,000	(386)	79,000	(544)	71,000	(490)	110,000	(758)
X60	60,000	(414)	82,000	(565)	75,000	(517)	110,000	(758)
X65	65,000	(448)	87,000	(600)	77,000	(531)	110,000	(758)
X70	70,000	(483)	90,000	(621)	82,000	(565)	110,000	(758)
X80	80,000	(552)	100,000[e]	(690)	90,000	(621)	120,000	(827)

Table 2. API-5L PSL 1 vs. PSL 2

Parameter	PSL 1	PSL 2
Grade range	A25 through X70	B through X80
Size range	0.405 through 80	$4^1/_2$ through 80
Type of pipe ends	Plain-end, threaded-end; belled-end; special coupling pipe	Plain-end
Seam welding	All methods; continuous welding limited to Grade A25	All methods except continuous and laser welding
Electric welds: welder frequency	No minimum	100 kHz minimum
Heat treatment of electric welds	Required for grades > X42	Required for all grades (B through X80)
Chemistry: max C for seamless pipe	0.28% for grades ≥ B	0.24%
Chemistry: max C for welded pipe	0.26% for grades ≥ B	0.22%
Chemistry: max P	0.030% for grades ≥ A	0.025%
Chemistry: max S	0.030%	0.015%
Carbon equivalent:	Only when purchaser specifies SR18	Maximum required for each grade
Yield strength, maximum	None	Maximum for each grade
UTS, maximum	None	Maximum for each grade
Fracture toughness	None required	Required for all grades
Nondestructive inspection of seamless	Only when purchaser specifies SR4	SR4 mandatory
Repair by welding of pipe body, plate, and skelp	Permitted	Prohibited
Repair by welding of weld seams without filler metal	Permitted by agreement	Prohibited
Certification	Certificates when specified per SR15	Certificates (SR15.1) mandatory
Traceability	Traceable only until all tests are passed, unless SR 15 is specified	Traceable after completion of tests (SR15.2) mandatory

- The yield strength is defined as the tensile stress when 0.5% elongation occurs on the pipe, per API-5L.
- The DNV code defines the yield stress as the stress at which the total strain is 0.5%, corresponding to an elastic strain of approximately 0.2% and a plastic (or residual) strain of 0.3%.



- In elastic region, when the load is removed, the pipe tends to go back to its origin. If the load exceeds the elastic limit, the pipe does not go back to its origin when the load is removed.
- Instead, the stress reduces the same rate (slope) as the elastic modulus and reaches a certain strain at zero stress, called a residual strain.

- Line pipe is usually specified by Nominal Pipe Size (NPS) and schedule (SCH). The most commonly used schedules are 40 (STD), 80 (XS), and 160 (XXS)

NPS	OD (inches)	Wall Thickness (inches) SCH 10s	SCH 10	SCH 20	SCH 30	SCH 40s	SCH 40	SCH 60	SCH 80s	SCH 80	SCH 100	SCH 120	SCH 140	SCH 160
10	10.75	.165	.165	.250	.307	.365	.365	.500	.500	.593	.718	.843	1.000	1.125
12	12.75	.180	.180	.250	.330	.375	.406	.500	.500	.687	.843	1.000	1.125	1.312
14	14.00	.188	.250	.312	.375	.375	.437	.593	.500	.750	.937	1.093	1.250	1.406
16	16.00	.188	.250	.312	.375	.375	.500	.656	.500	.843	1.031	1.218	1.437	1.593
18	18.00	.188	.250	.312	.437	.375	.562	.750	.500	.937	1.156	1.375	1.562	1.781
20	20.00	.218	.250	.375	.500	.375	.593	.812	.500	1.031	1.280	1.500	1.750	1.968
24	24.00	.250	.250	.375	.562	.375	.687	.968	.500	1.218	1.531	1.812	2.062	2.343

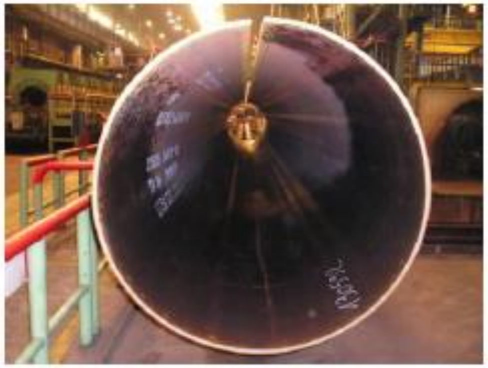
SCH 80s = 80 ksi SMYS stainless steel

NPS	OD	Table 7.1.4 API-5L Standard Pipe Wall Thickness																
(inch)	(inch)	(inch)																
4	4	0.250	0.281	0.318														
4.5	4.5	0.337	0.438	0.531	0.674													
5	5.563	0.375	0.500	0.625	0.750													
6	6.625	0.375	0.432	0.500	0.562	0.625	0.719	0.750	0.864	0.875								
8	8.625	0.375	0.438	0.438	0.500	0.562	0.625	0.719	0.750	0.812	0.875	1.000						
10	10.75	0.365	0.438	0.438	0.500	0.562	0.625	0.719	0.812	0.875	0.938	1.000	1.250					
12	12.75	0.375	0.406	0.438	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.250		
14	14	0.375	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.250	
16	16	0.375	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
18	18	0.375	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
20	20	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	1.312	1.375
22	22	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	1.312	1.375	1.438	1.500
24	24	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	1.312	1.375	1.438	1.500	1.562
26	26	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000									
28	28	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000									
30	30	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
32	32	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
34	34	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
36	36	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
38	38	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
40	40	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
42	42	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
44	44	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					
46	46	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250					

- Depending on pipe manufacturing process, there are several pipe types as
  - : Seamless pipe
  - : DSAW (double submerged arc welding) pipe or UOE pipe
  - : ERW (electric resistant welding) pipe
- Seamless pipe is made by piercing the hot steel rod, without longitudinal welds.
- It is most expensive but ideal for small diameter, deepwater, or dynamic applications.
- Currently up to 24” OD pipe can be fabricated by manufacturers.

- DSAW or UOE pipe is made by folding a steel panel with “U” press, “O” press, and expansion (to obtain its final OD dimension).
- The longitudinal seam is welded by double (inside and outside) submerged arc welding.
- DSAW pipe is produced in sizes from 18" through 80" OD and wall thicknesses from 0.25" through 1.50".

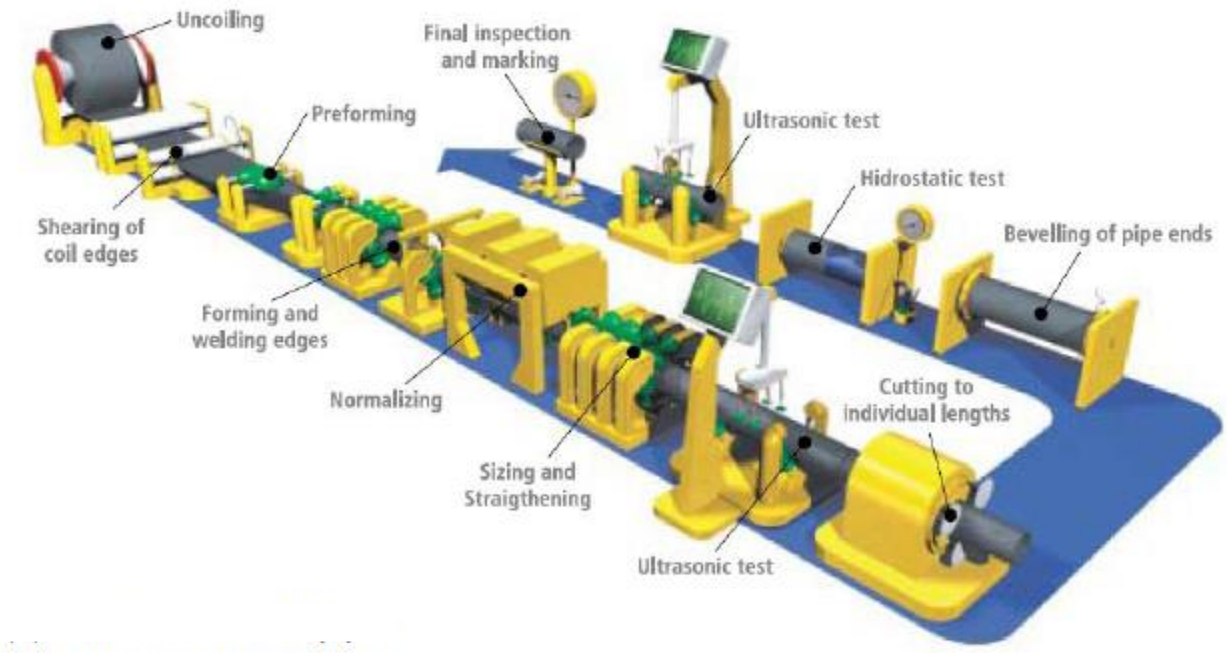
U-forming



O-forming

Expansion

- ERW pipe is cheaper than seamless or DSAW pipe but it has not been widely adopted by offshore industry, especially for sour or high pressure gas service, due to its variable electrical contact and inadequate forging upset.
- However, development of high frequency induction (HFI) welding enables to produce better quality ERW pipes.



CRA (Corrosion resistant alloy) Pipe

- Depending on alloy contents, CRA pipe can be broken into follows,

- Stainless steel: 316L, 625 (Inconel), 825, 904L, etc.
- Chrome based alloy: 13 Cr, Duplex (22 Cr), Super Duplex (25 Cr), etc.
- Nickel based alloy : 36 Ni (Invar) for cryogenic application such as LNG transportation (-160^{o}C)

- Titanium: Light weight (56% of steel), high strength (up to 200 ksi tensile), high corrosion resistance, low elastic modulus, and low thermal expansion, but high cost (~10 times of steel). Good for high fatigue areas such as riser touchdown region, stress joint, etc.

- Aluminum: Light weight (1/3 of steel), low elastic modulus (1/3 of steel), high corrosion resistance, but low strength (only up to 90 ksi tensile). Applications can include casing, air can, and risers.

- Some key properties of each material

Properties	Carbon Steel	Stainless Steel	Titanium	Aluminum
Specific Gravity (Density)	7.85 (490 lb/ft^3)	8.03 (500 lb/ft^3)	4.50 (281 lb/ft^3)	2.70 (168 lb/ft^3)
Elastic Modulus (@ 200°F)	29,000 ksi (200,000 Mpa)	28,000 ksi (193,000 Mpa)	15,000 ksi (104,000 Mpa)	10,000 ksi (69,000)
Thermal Conductivity (@ 125°C)	30 Btu/hr-ft-°F (51 W/m-°C)	10 Btu/hr-ft-°F (17 W/m-°C)	12 Btu/hr-ft-°F (20 W/m-°C)	147 Btu/hr-ft-°F (255 W/m-°C)
Thermal Expansion Coefficient	6.5 x 10^{-6} /°F (11.7 x 10^{-6} /°C)	8.9 x 10^{-6} /°F (16.0 x 10^{-6} /°C)	4.8 x 10^{-6} /°F (8.6 x 10^{-6} /°C)	12.8 x 10^{-6} /°F (23.1 x 10^{-6} /°C)

1 ksi = 6.8948 Mpa

1 Btu/(hr-ft-°F) = 1.731 W/(m-°C)

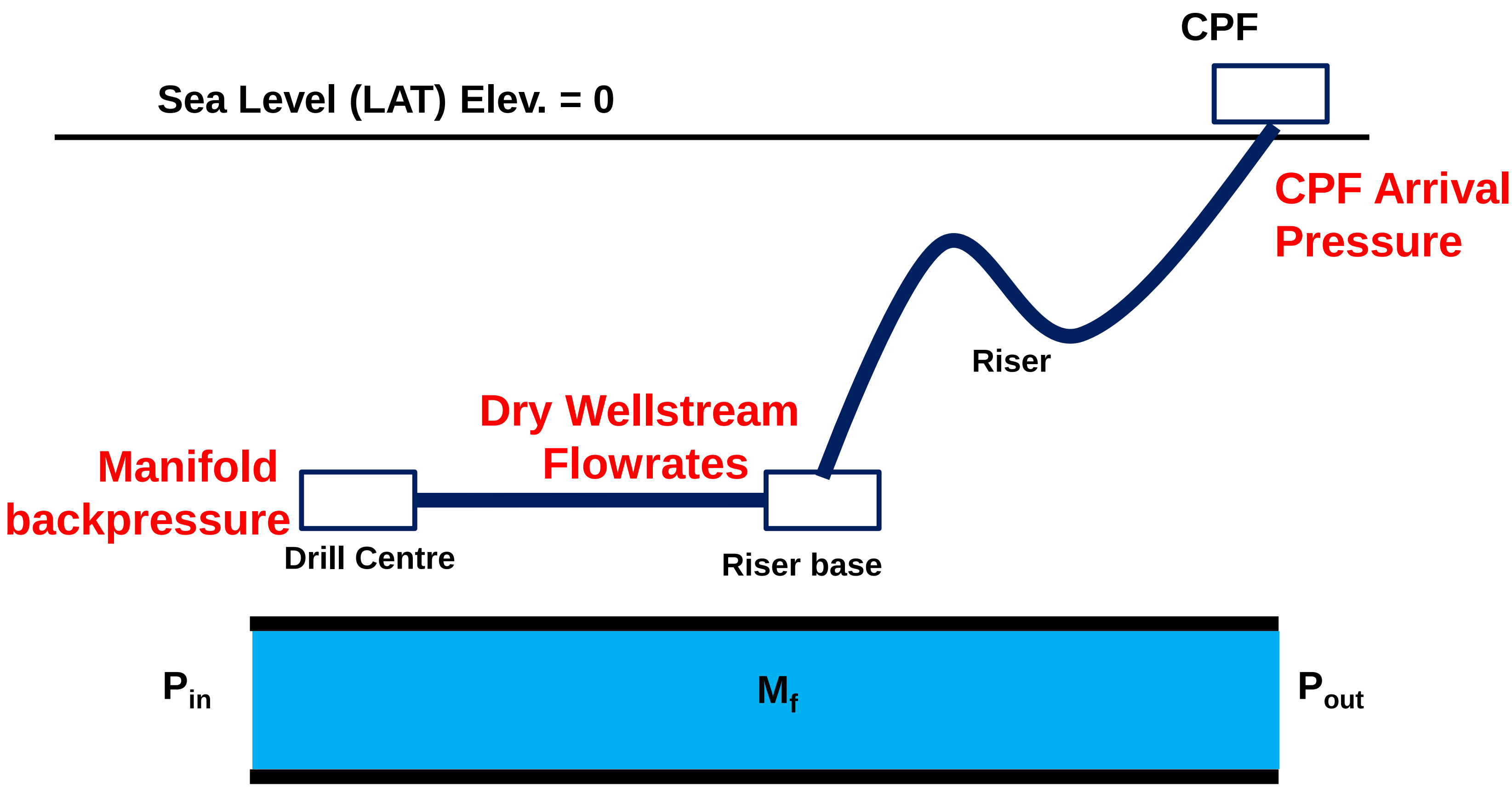
- Depending on sour contents in the fluid, different chrome based alloy pipe should be selected as follows

Conveyed Fluid	13% Cr	22% Cr	25% Cr
CO_2	> 1%	> 1%	> 1%
H_2S	< 0.04 bar	< 0.2 bar	< 0.4 bar
Cl	No	< 3%	< 5%

Subsea pipeline: Diameter selection

Multiphase simulation for pipeline design

- Among two of P_{in} (Inlet pressure), M_F (Flowrate) , P_{out} (Outlet pressure) were given, other unknown can be calculated.
- For offshore fields, P_{in} = Manifold backpressure, M_F = Dry Wellstream Flowrate, P_{out} = CPF Arrival pressure.



Steady state multiphase flow modeling

- Most offshore pipelines are sized by use of three design criteria: available pressure drop, allowable velocities, and slugging.

- Line sizing is usually performed by use of steady state simulators, which assume that the temperatures, pressures, flowrates, and liquid holdup in the pipeline are constant with time. This assumption is rarely true in practice, but line sizes calculated from the steady state models are usually adequate.

Flowline pressure drop

- The maximum allowable pressure drop in a pipeline is constrained by its required outlet pressure and available inlet pressure. In addition, the pressure in a pipeline must always be less than the maximum allowable operating pressure.
- Allowable pressure drop is a function of the parameters of the flow system. No fixed criteria exist for determining the maximum pressure drop for a pipeline design.

Steady state production flowline pressure drops

- Rules of Thumb for Frictional Pressure Drops
  - Gas or Gas Condensate Production Flowline: 10-20 psi per mile
  - Oil Production Flowline: 50-250 psi per mile
  - Note: Hydrostatic head needs to be accounted to determine the total pressure drop
  - Conservative estimate for production flowlines (with only reservoir energy to promote flow): the pressure drop at maximum flowrate should be about 1/3 of the difference between the initial FWHP and the required arrival pressure at the host.
- Flowline capacity can be limited by ΔP or by EVR (erosion velocity ratio)

Pressure drop in an offshore gathering system

- For a gathering system, the ideal way to check for allowable pressure drop is to simulate the whole system, from the reservoir to the separator, over the design life of the field.
- This approach will account for the changes in reservoir pressure, flowrate and compositions in the gathering system over the-field life.
- If rigorous simulations cannot be conducted on a gathering system, a conservative rule of thumb is to take 1/3 of the difference between the initial wellhead pressure and the separator pressure as the allowable pressure drop in the pipeline/riser system.

Pressure drop and liquid holdup

- In a multiphase pipeline pressure drop is not always the maximum at the highest flowrate.
- If a pipeline contains significant "hills and valleys", it is possible that the highest pressure drop occurs at a lower flowrate. This is due to increased liquid holdup at lower flowrates.

Flow velocity

- The velocity in multiphase flow pipelines should be kept within certain limits to ensure proper operation.
- Operating problems can occur if the velocity is either too high or too low. There are guidelines to determining these limits, but they are not absolute values.

Maximum flow velocity and erosion

- Solids Free Erosion Velocity limits can be determined using API RP14E, given in the equation below. V_e is the maximum velocity allowed to avoid excessive corrosion/erosion.

$$V_e = \frac{C}{\sqrt{\rho_{mix}}}$$

Where,

V_e = erosional velocity (ft/s)

C = empirical coefficient

ρ_{mix} = gas/liquid mixture density (lb/ft^3), which is defined as

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

Where,

ρ_{mix} = liquid density,

ρ_{gas} = gas density,

C_L = flowling liquid volume fraction ($C_L = Q_L / (Q_L + Q_G)$)

- This equation attempts to indicate the velocity at which erosion-corrosion begins to increase rapidly. This equation is an over-simplification of a highly complex subject, and as a result, there has been considerable controversy over its use.
- For wells with no sand present, values of C have been reported to be as high as 300 without significant erosion/corrosion in carbon steel pipes.

Table 13-9 Empirical Constant in the Equation

Service Type	Operational Frequency	
	Continuous	Intermittent
Two-phase flow without sand	100	125

If possible, the minimum velocity in two-phase lines should be greater than 3 m/s (10 ft/s) to minimize slugging.

Material	C Factor $lb^{0.5} / ft^{0.5}.sec$
Carbon steel	135
CRA	300
Flexible risers	200

- For flowlines with significant amounts of sand present, there has been considerable erosion-corrosion for lines operating below C = 100.
- Assuming on erosion rate of 10 mils per year, the following maximum allowable velocity is recommended by Salama and Venkatesh, when sand appears in an oil/gas mixture flow:

$$V_M = \frac{4d}{\sqrt{W_s}}$$

Where,

V_M = maximum allowable mixture velocity (ft/s)

d = pipeline inside diameter, in.

W_s = rate of sand production (bbl/month)

Minimum flow velocity

- The concept of a minimum velocity for a flowline is also important.
- Velocities that are too low are frequently a greater problem than excessive velocities.
- The following items may effectively impose minimum velocity constraints:

  Slugging: Slugging severity typically increases with decreasing flow rate. The minimum allowable velocity constraint should be imposed to control the slugging in multiphase flow for assuring the production deliverability of the system.

  Liquid handling: In gas/condensate systems, the ramp-up rates may be limited by the liquid handling facilities and constrained by the maximum line size.

  Pressure drop: For viscous oils, a minimum flow rate is necessary to maintain fluid temperature such that the viscosities are acceptable. Below this minimum, production may eventually shut itself in.

Liquid loading: A minimum velocity is required to lift the liquids and prevent wells and risers from loading up with liquid and shutting in. The minimum stable rate is determined by transient simulation at successively lower flow rates. The minimum rate for the system is also a function of GLR.

Sand bedding: The minimum velocity is required to avoid sand bedding.

Problem with flow velocities which are too low

- Liquid holdup may increase rapidly at low mixture velocities.
- Water may accumulate at low spots in the line. This may cause enhanced localized corrosion.
- Low velocities may cause terrain induced slugging in hilly terrain pipelines and pipeline-riser systems.
- The minimum velocity depends on many variables, including: topography; pipeline diameter; gas-liquid ratio; and operating conditions of the line. Roughly a value for the minimum velocity would be a mixture velocity of 5-8 *ft/s*

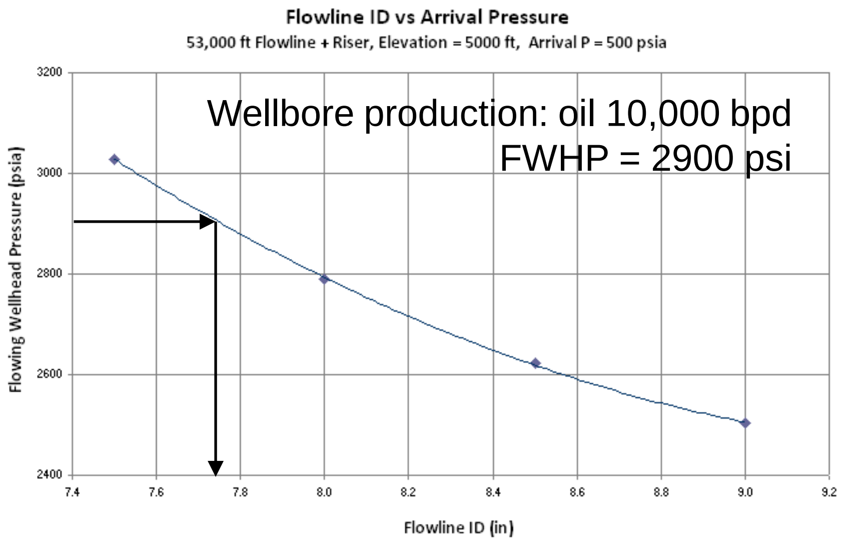
(note: API recommends 10 ft/s to minimize slugging)

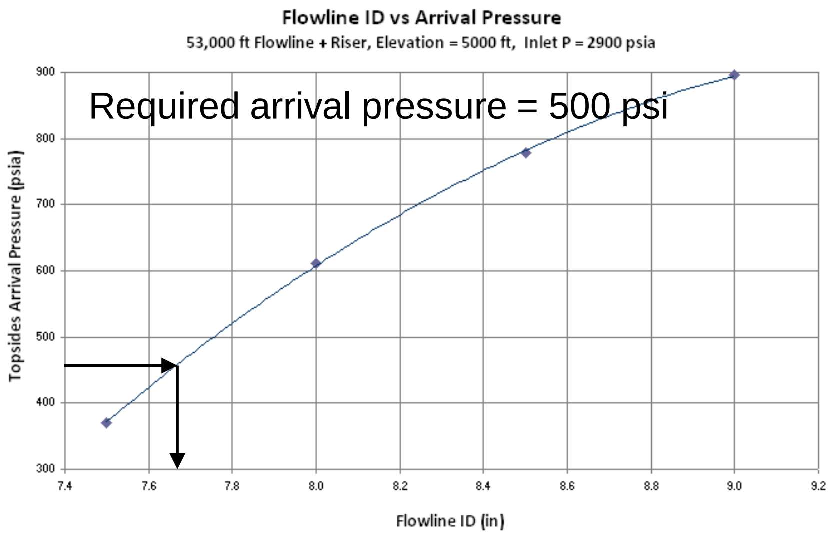
Flow in networks

- A basic approach for networks outlined by Gregory & Aziz (1978) relies on an initial knowledge of the flow from each feed of a gas gathering system, the details of each flowline section (construction, topography etc.) and the pressure and temperature at the outlet (final gathering point).
- Calculations are performed backwards through the system to ascertain the pressure and temperature at each node.
- This approach may require many iterations to study constraints and limitations at supply wells and/or the arrival point.

Determine Line Size

- Most offshore pipelines are sized by three major design criteria : Available pressure drop, allowable velocities, and slugging
- Line sizes calculated by use of the steady state simulators
- The maximum allowable pressure drop is constrained by its required outlet pressure and available inlet pressure





- Unlike single-phase pipelines, multiphase pipelines are sized taking into account the limitations imposed by production rates, erosion, slugging, and ramp-up speed. Artificial lift is also considered during line sizing to improve the operational range of the system.
- The line sizing of the pipeline is governed by the following technical criteria:

  Allowable pressure drop;

  Maximum velocity (allowable erosional velocity) and minimum velocity;

  System deliverability;

  Slug consideration if applicable.

- Other criteria considered in the selection of the optimum line size include:
  - Standard versus custom line sizes;
  - Ability of installation;
  - Future production;
  - Number of flowlines and risers;
  - Low-temperature limits;
  - High-temperature limits;
  - Roughness.

Multiphase flow simulation in subsea systems

9 Conservation equations

Mass (5)
Momentum (3)
Energy (1)

Mass transfer
Momentum transfer
Energy transfer

Input

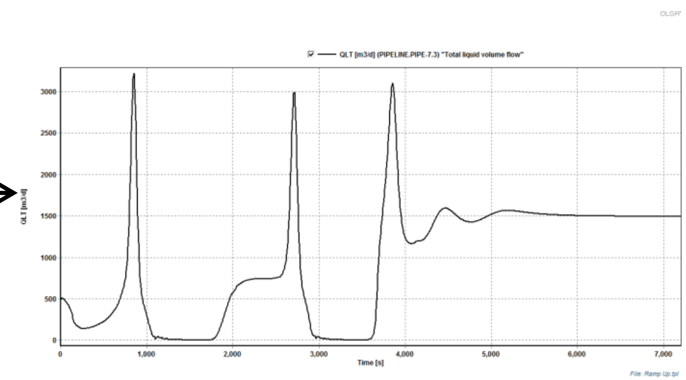
Boundary and initial conditions

Pipe and process data

Fluid properties

OLGA

Output



- Handles general networks of pipes and process equipment
- Complete models with transitions between flow regimes
- One-dimensional (calculates along pipe axis)

Output parameters

- Primary variables

  : 5 mass fractions (gas, oil, water, oil droplets, water droplets)

  : 3 velocities (gas+droplets, oil, water)

  : 1 pressure

  : 1 temperature

- Secondary variables

  : Volume fractions

  : Flow rates

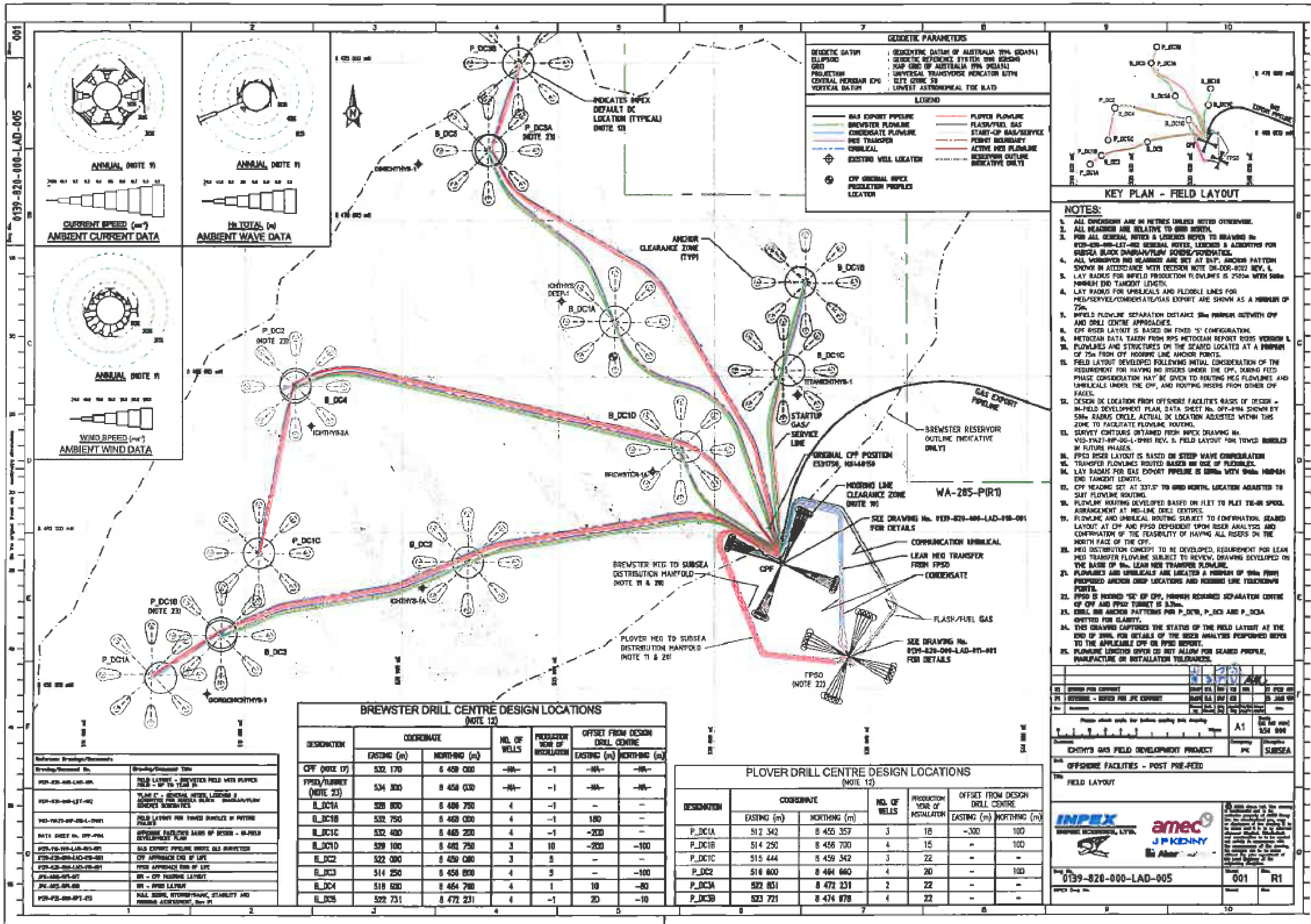
  : Fluid properties

  And hundreds more

Most common variables	
PT	Local pressure in fluid
TM	Local fluid temperature
HOL	Local total liquid volume fraction
QG	Gas flow rate
QLT	Total liquid flow rate
ID	Flow pattern identifier
UG	Gas velocity
UL	Total liquid velocity
EVR	Erosional velocity ratio (When EVR>1, the API 14 max velocity is violated.)

1: Stratified flow
2: Annular flow
3: Slug flow
4: Bubbly flow

Flowline analysis in Ichthys field



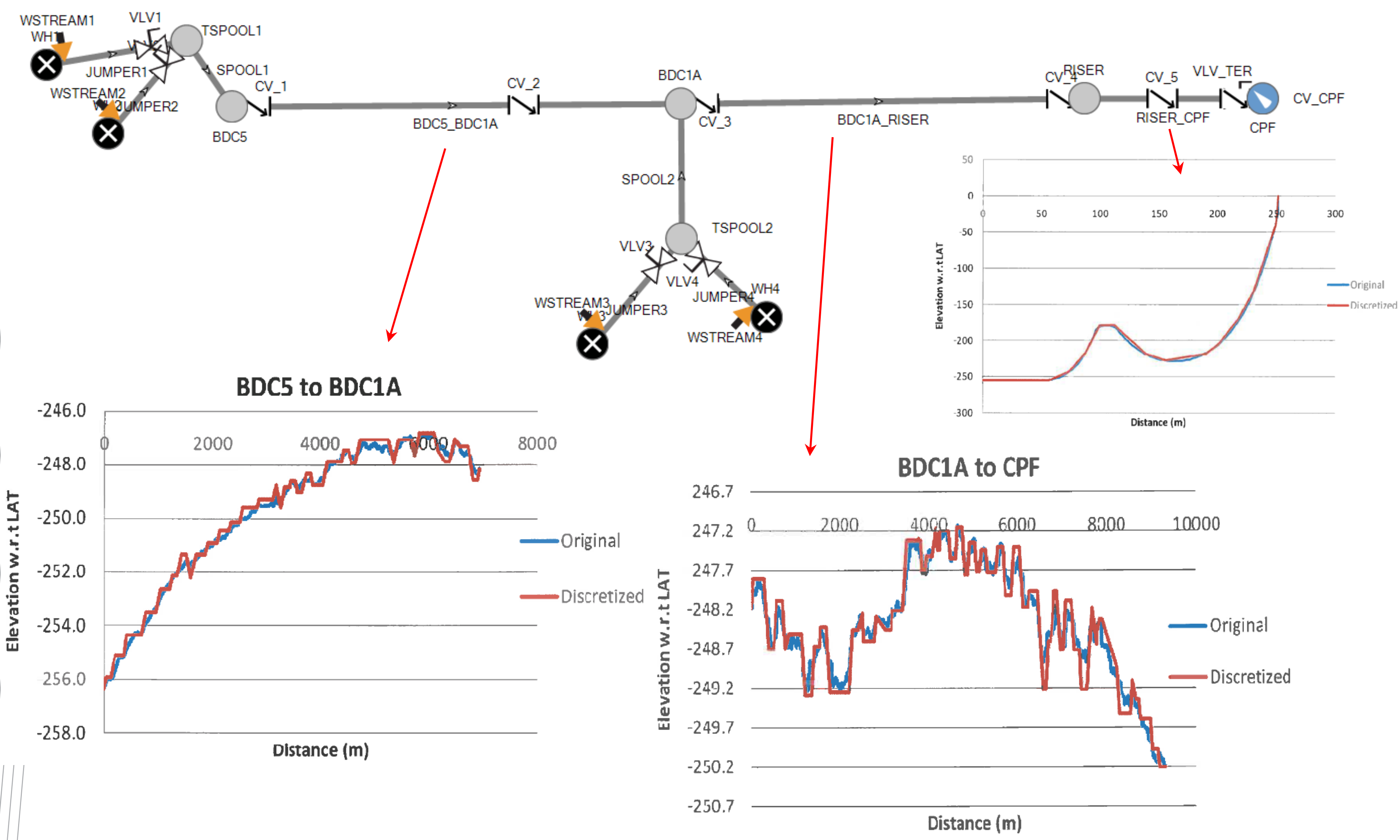
BREWSTER DRILL CENTRE DESIGN LOCATIONS
(NOTE 12)

DESIGNATION	COORDINATE EASTING (m)	COORDINATE NORTHING (m)	NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE EASTING (m)	OFFSET FROM DESIGN DRILL CENTRE NORTHING (m)
CPF (NOTE 17)	532 170	8 459 000	-NA-	-1	-NA-	-NA-
FPSO/TURRET (NOTE 23)	534 300	8 454 030	-NA-	-1	-NA-	-NA-
B_DC1A	528 800	8 486 750	4	-1	-	-
B_DC1B	532 750	8 469 000	4	-1	100	-
B_DC1C	532 400	8 465 200	4	-1	-200	-
B_DC1D	529 100	8 462 750	3	10	-200	-100
B_DC2	522 090	8 459 080	3	5	-	-
B_DC3	514 250	8 456 800	4	5	-	-100
B_DC4	518 600	8 464 780	4	1	10	-80
B_DC5	522 731	8 472 231	4	-1	20	-10

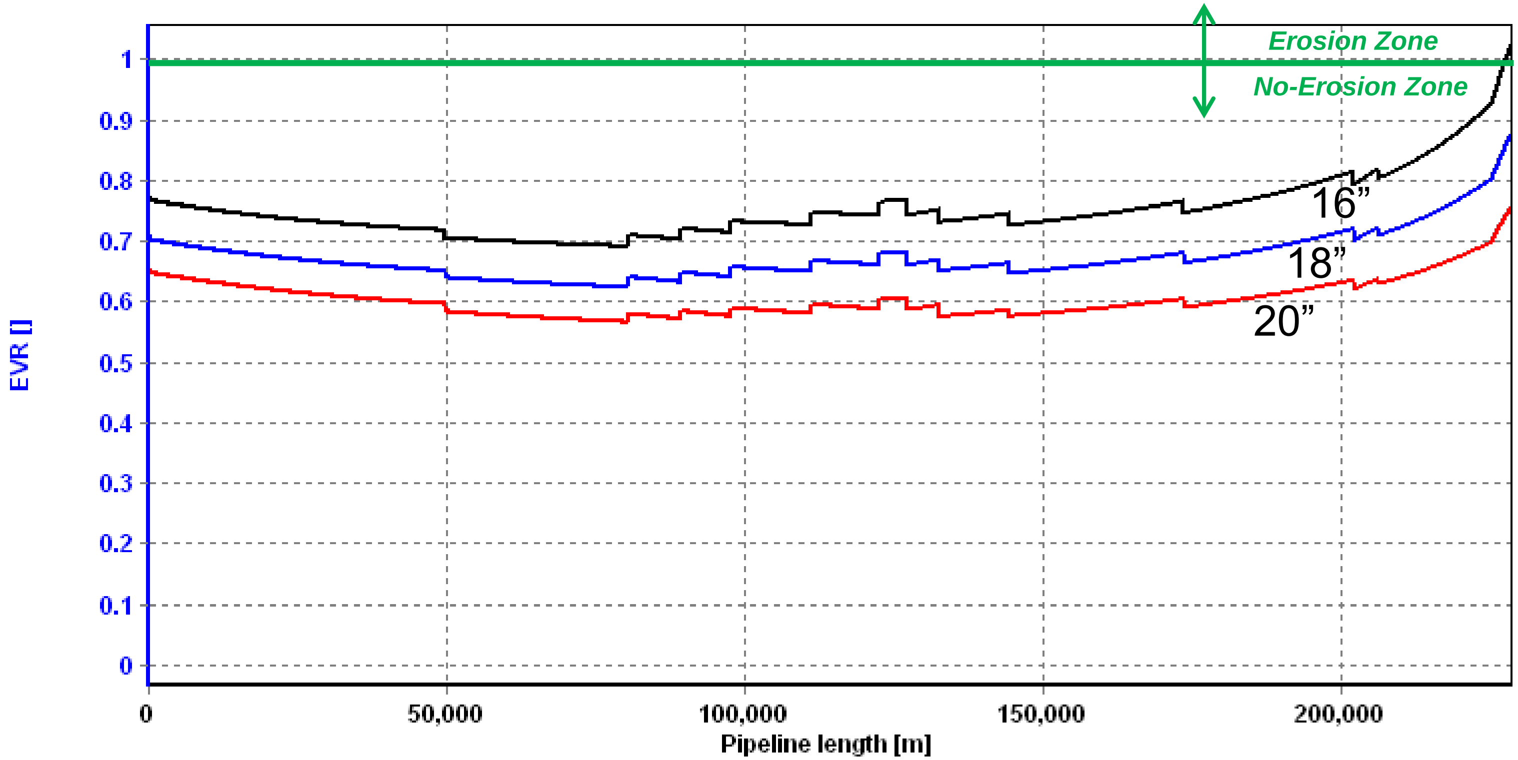
PLOVER DRILL CENTRE DESIGN LOCATIONS
(NOTE 12)

DESIGNATION	COORDINATE EASTING (m)	COORDINATE NORTHING (m)	NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE EASTING (m)	OFFSET FROM DESIGN DRILL CENTRE NORTHING (m)
P_DC1A	512 342	8 455 357	3	18	-300	100
P_DC1B	514 250	8 456 700	4	15	-	100
P_DC1C	515 444	8 459 342	3	22	-	-
P_DC2	516 600	8 464 660	4	20	-	100
P_DC3A	522 831	8 472 231	2	22	-	-
P_DC3B	523 721	8 474 878	4	22	-	-

Simulation with OLGA – BDC5 to CPF

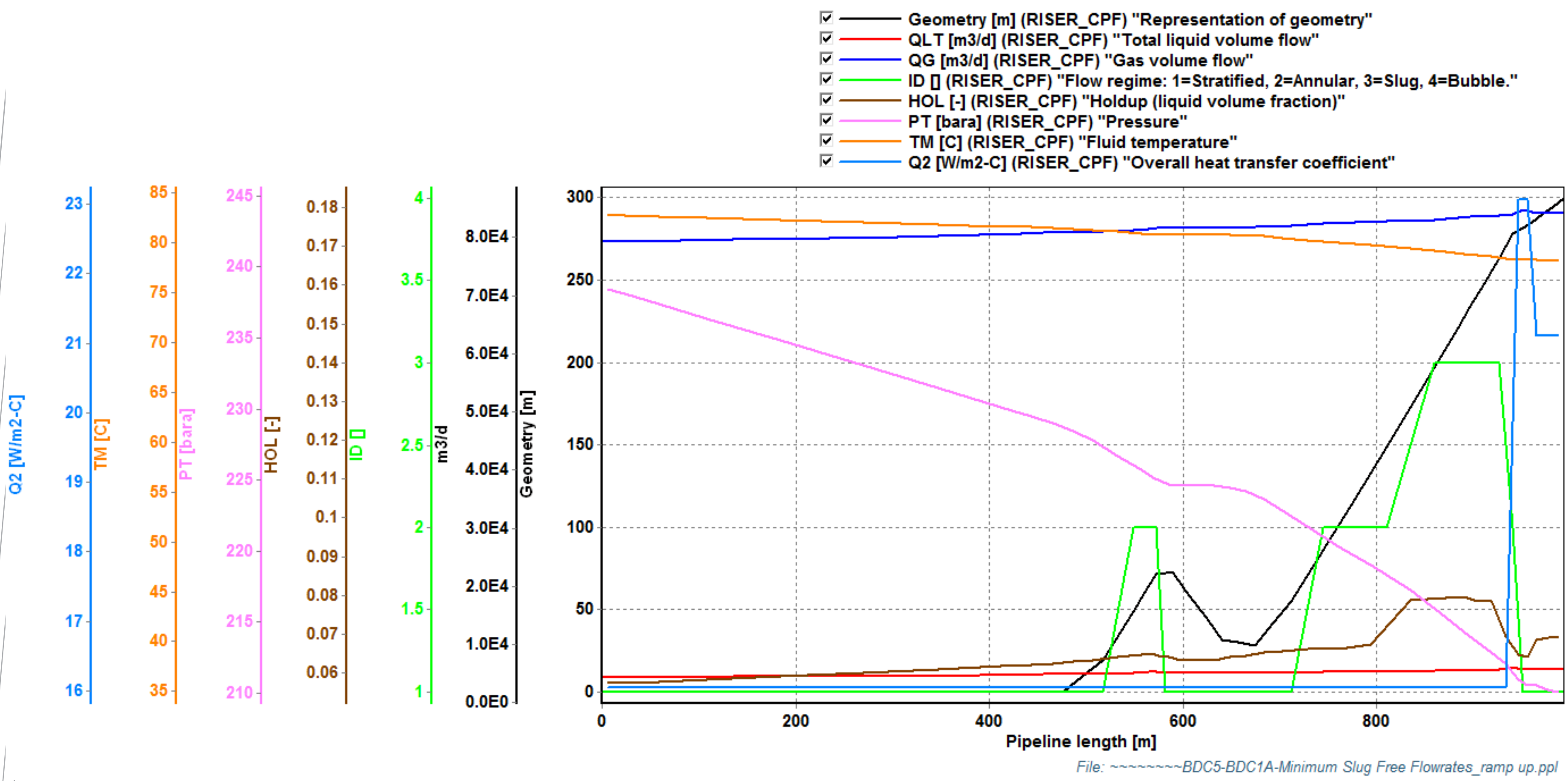


Erosion prevention



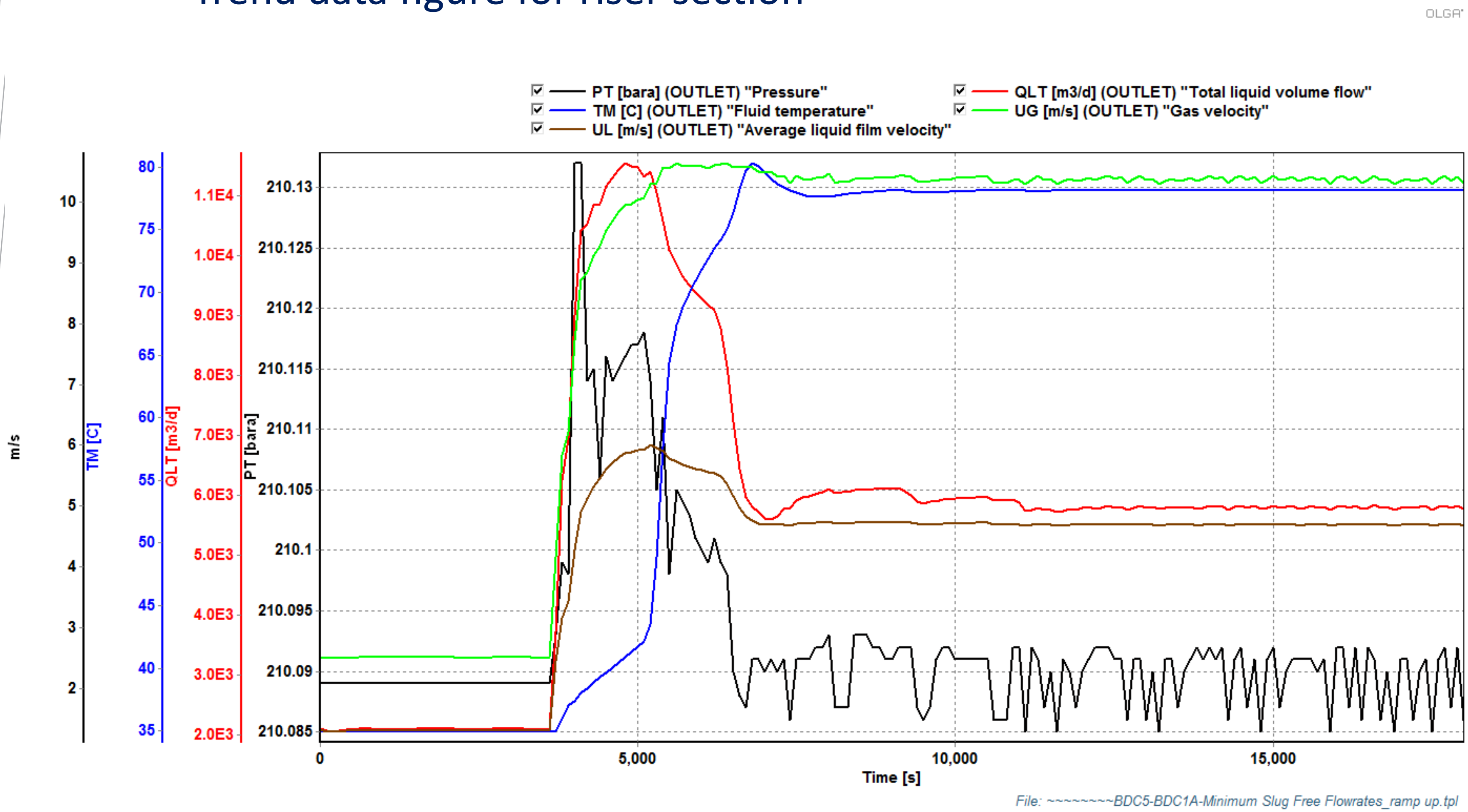
** EVR (Erosion Velocity Ratio) = Fluid Velocity / Erosional Velocity*

- **Output**
  - Profile data figure for riser section (final stage, after ramp-up)



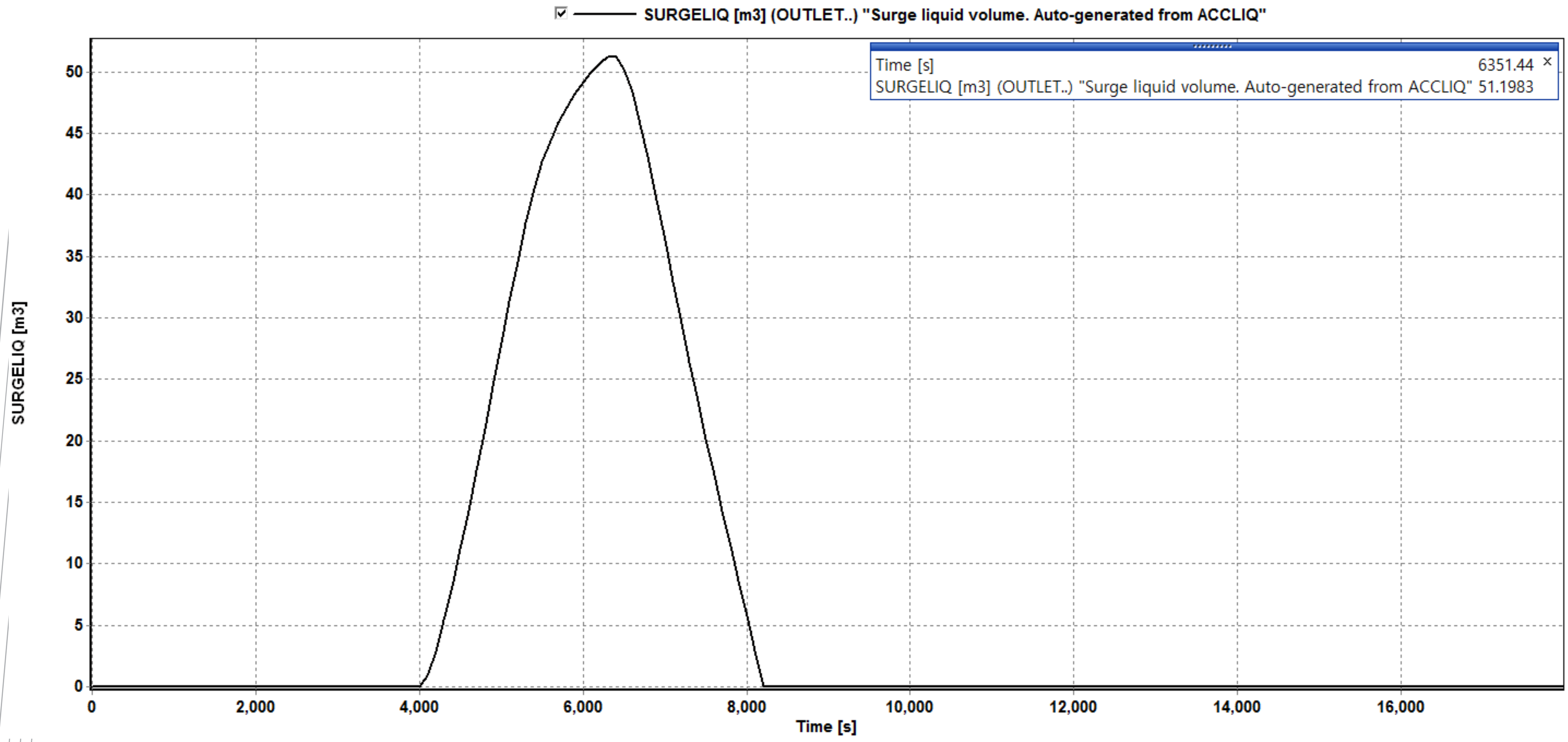
Output

- Trend data figure for riser section



Surge Volume Analysis

- Monitoring surge volume at topside outlet
- Drain rate = 354 m3/day



Simulation study for shut-down and restart

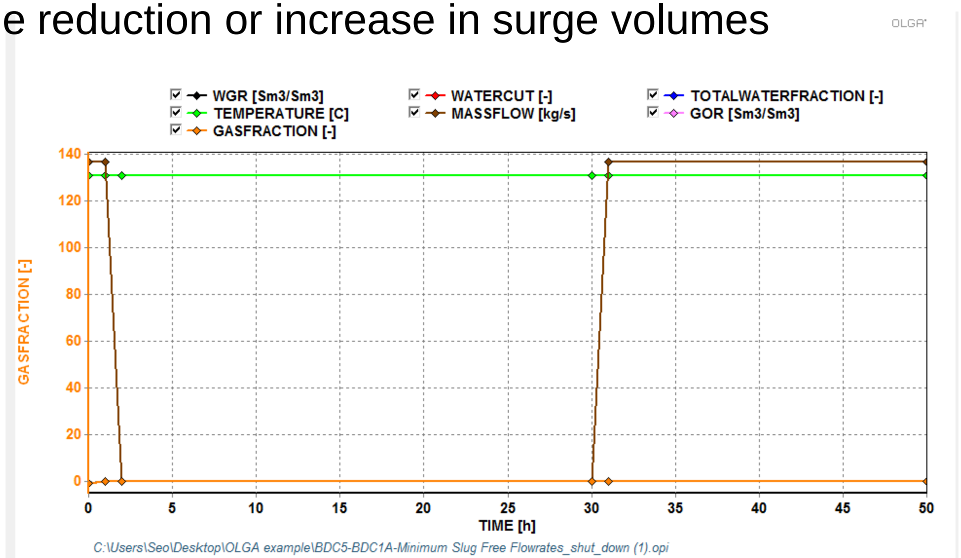
<u>i) Shut down </u>analysis

: Determine cool down time

<u>ii) Surge volume</u> estimation

: The worst surge volume case can be identified from the simulation at corresponding cases with different flowline ID.

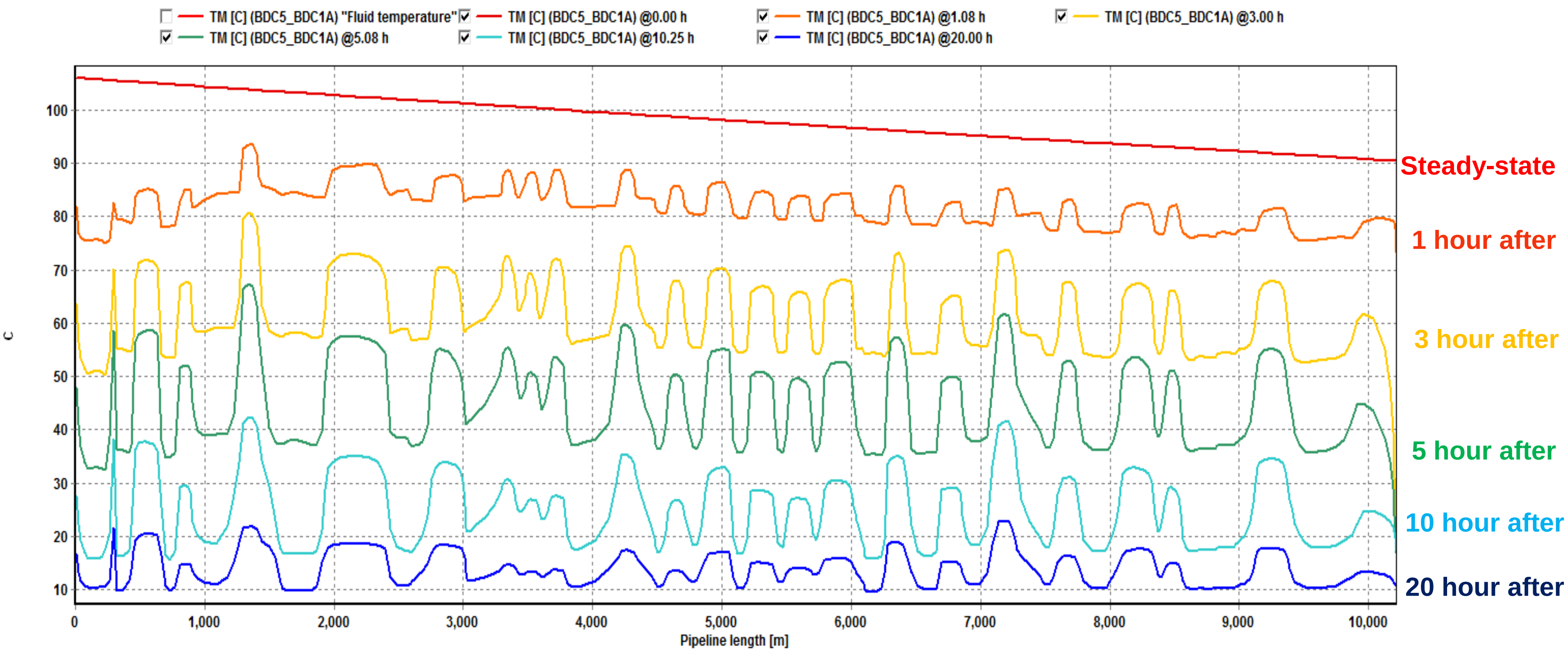
: Find out the maximum possible reduction or increase in surge volumes arriving at topside



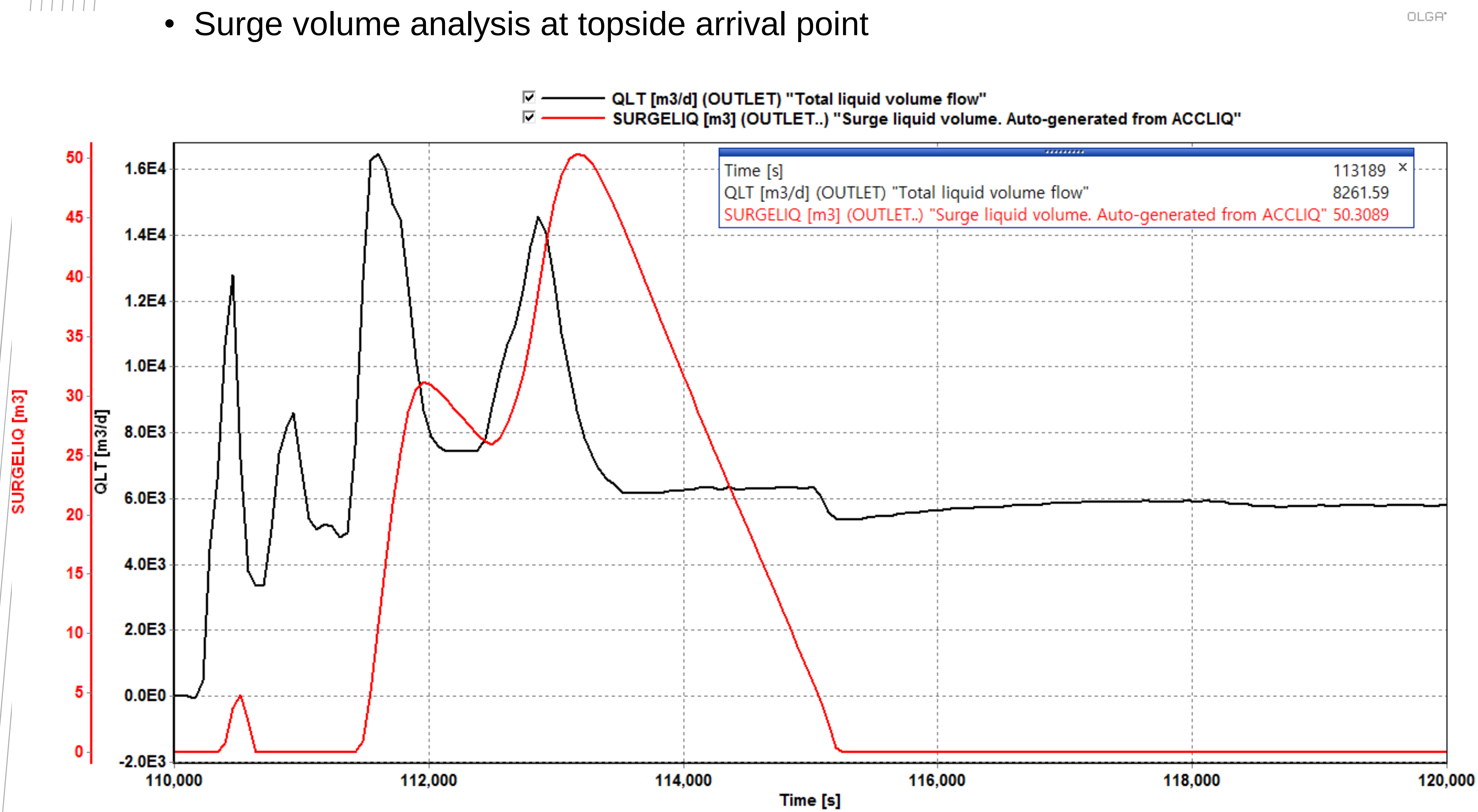
TEMPERATURE	C	130.7	130.7	130.7	130.7	130.7	130.7
PRESSURE	Pa						
MOLWEIGHT	kg/kmol						
MASSFLOW	kg/s	136.55	136.55	0	0	136.55	136.55
GOR	Sm3/Sm3	-1.0					

Shut down – Cool down time analysis

- Temperature changes at flowline (BDC5_BDC1A)



- Surge volume analysis at topside arrival point



Thank you, Question?