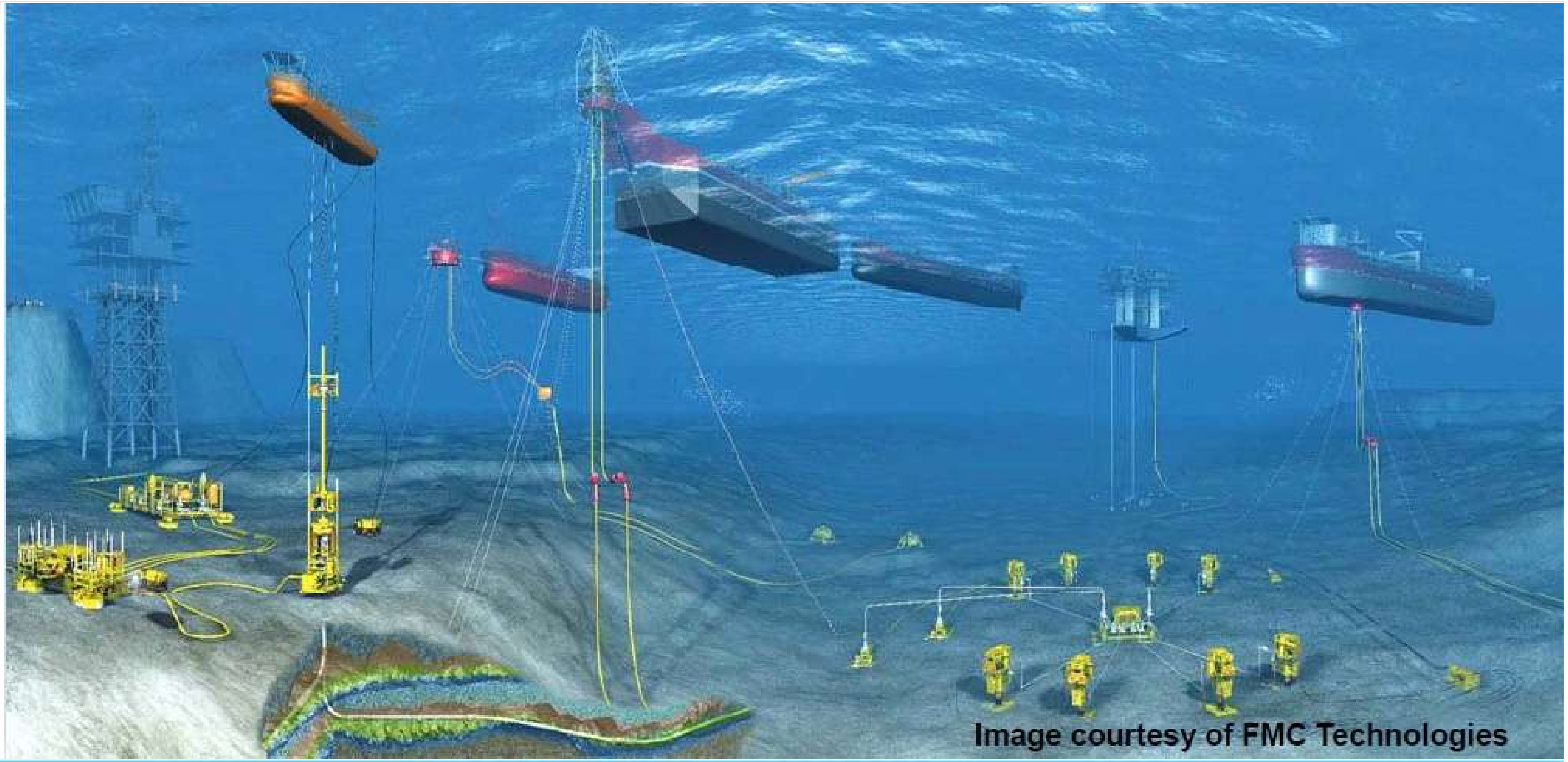
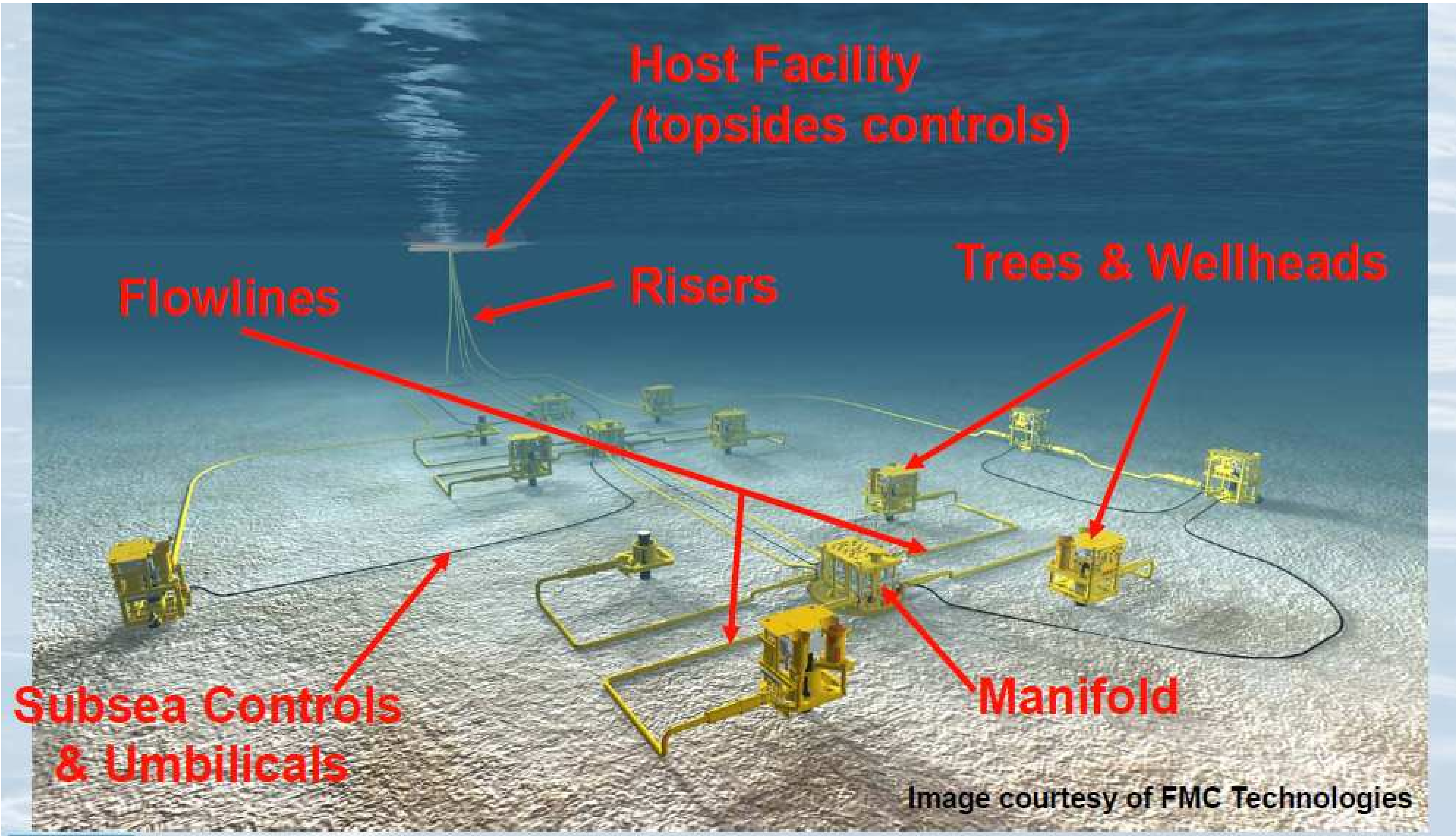


해양플랜트 공학 입문

서유택

What you must be learned?

- Production system components required for subsea fields development
- Engineering and scientific knowledge to design and operate subsea production system



Lecture Plan

1주	해양사업 구조/저류층 유체 특성
2주	해저 생산 시스템/해저배관 제작 및 설치
3주	Flow assurance: 다상 유동, 고체 침적
4주	해저 생산 시스템 설계 절차
5주	해양 플랫폼 분류와 특성: 고정식/유연식/부유식
6주	해양 플랫폼 제작, 운송, 설치 및 계류
7주	해양 플랫폼 하중과 정적/동적 구조해석, Dynamic positioning
8주	중간고사
9주	**Oil-FPSO, LNG-FPSO, LNG carrier** 구조
10주	**Topside** 공정 시스템 설계 절차**,** 삼상분리설비 **(Separator)** 역할
11주	기액 상평형 계산, 각 모듈의 구성과 역할**, Untilities: steam** 및 **electricity**
12주	**Safety:** 위험도**(Risk)** 및 신뢰도**(Reliability)**
13주	해양 유전**,** 가스전 개발 **case study**
14주	해양에너지(풍력, 조력, 조류, 파랑, 온도차, 농도차)
15주	기말고사

Subsea field development

Exploration

Quantitative analysis

Field architecture development

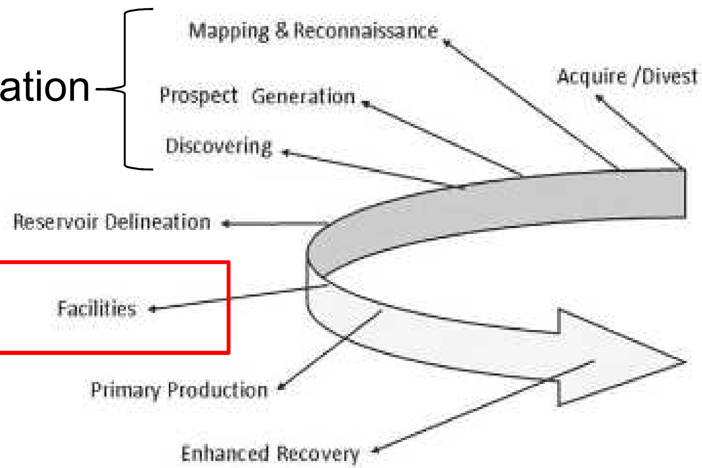
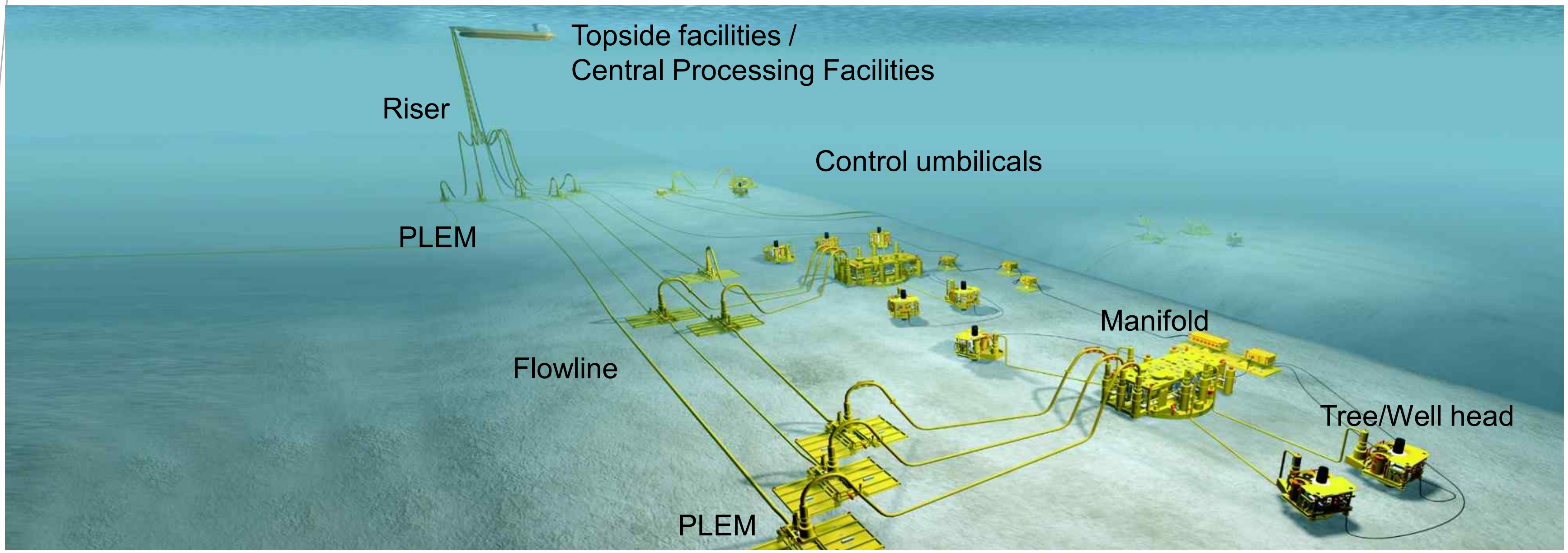
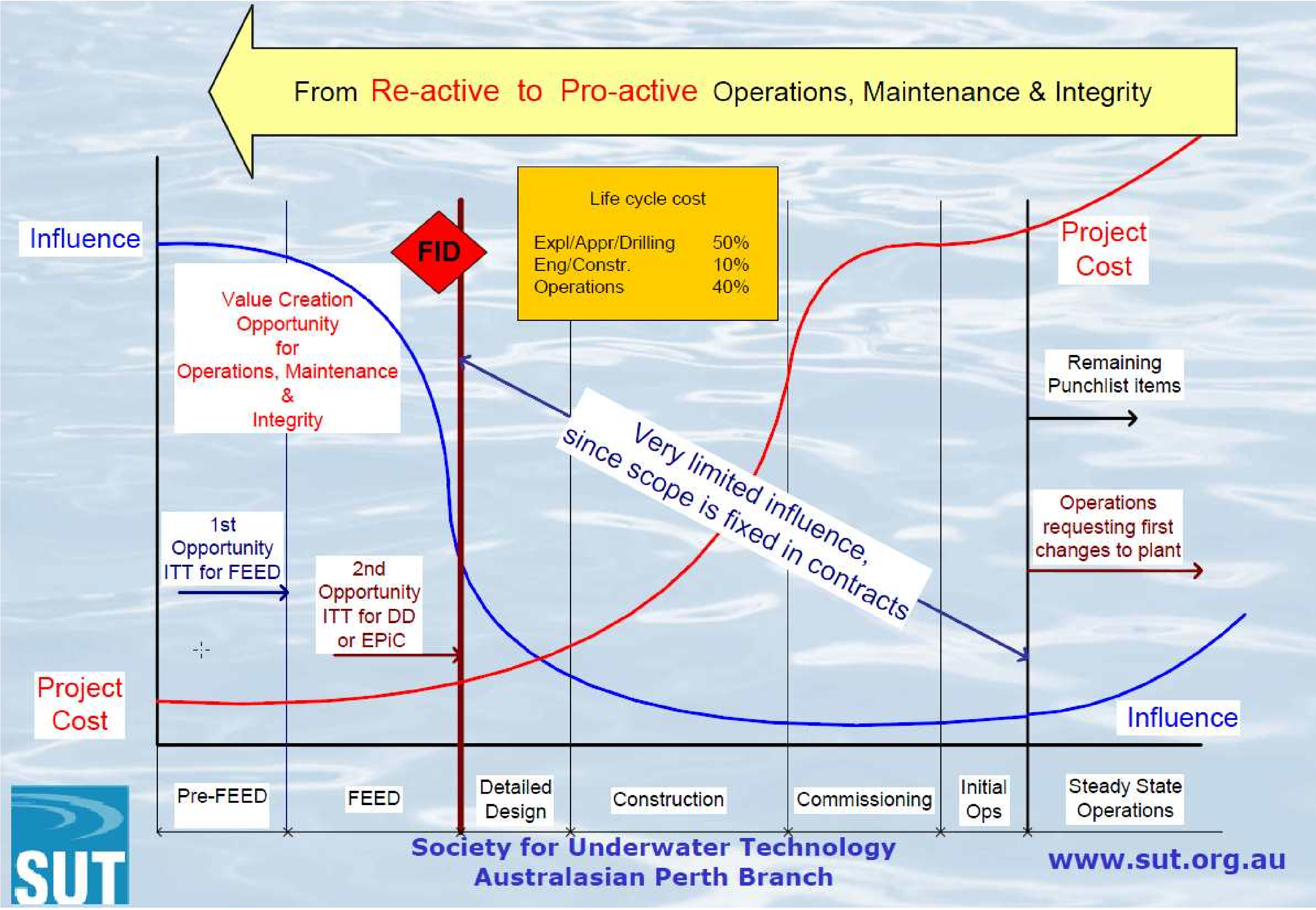


Figure 2-1 Field Development Life Cycle



Subsea system design phases



Offshore fields development

Wet tree vs. Dry tree

- For the dry tree system, trees are located on or close to the platform, whereas wet trees can be anywhere in a field in terms of cluster, template, or tie-back methods.
- Globally, more than 70% of the wells in deepwater developments that are either in service or committed are wet tree systems.

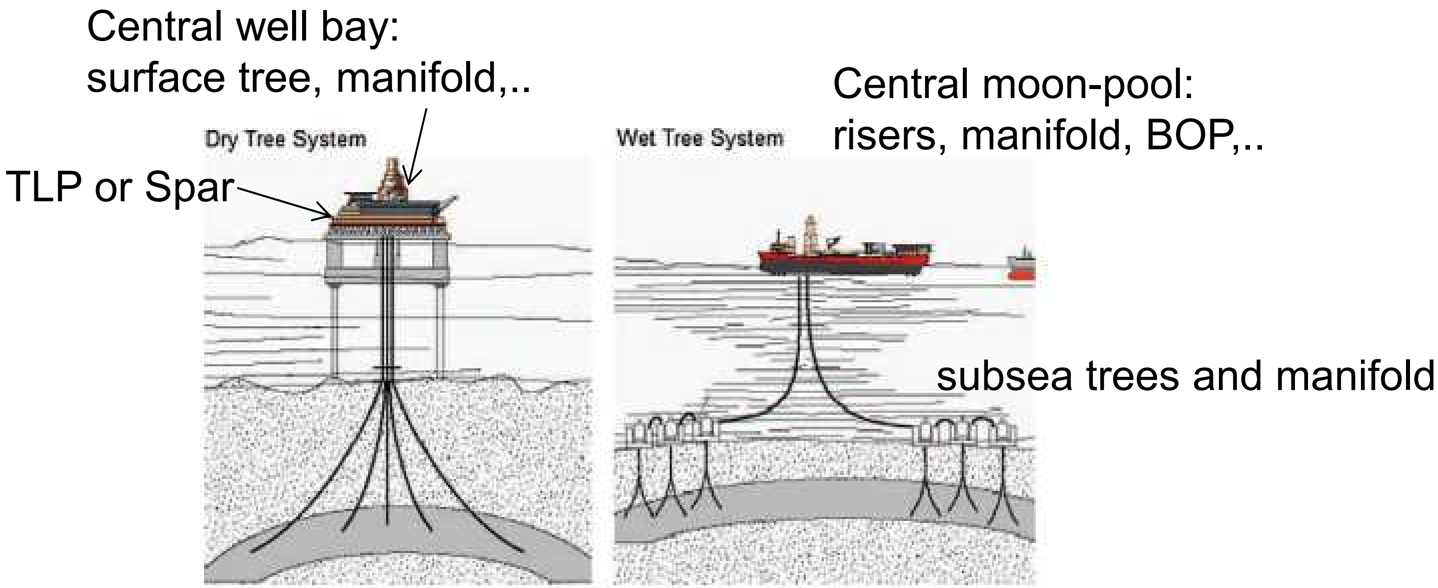


Figure 2-2 Dry Tree and Wet Tree Systems [1]

Wet tree systems

• Subsea cluster wells

: gathers the production in the most efficient and cost-effective way from nearby subsea wells, or from a remote /distant subsea tie-back to an already existing infrastructure based on either a FPSO or a FPU

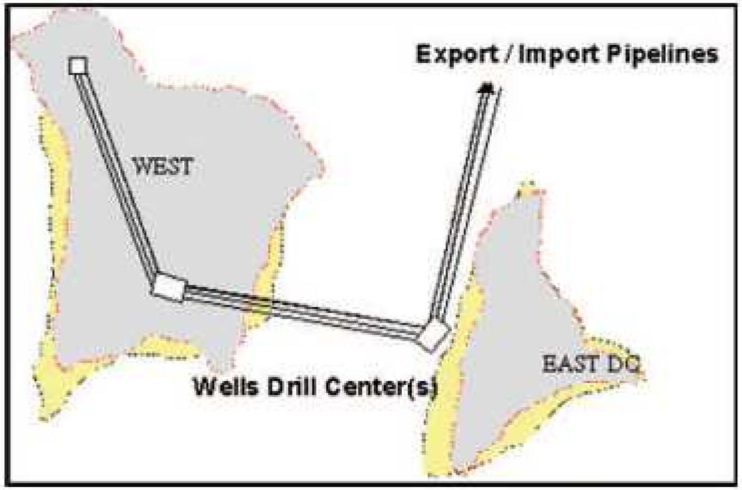


Figure 2-3 Tie-Back Field Architecture [1]

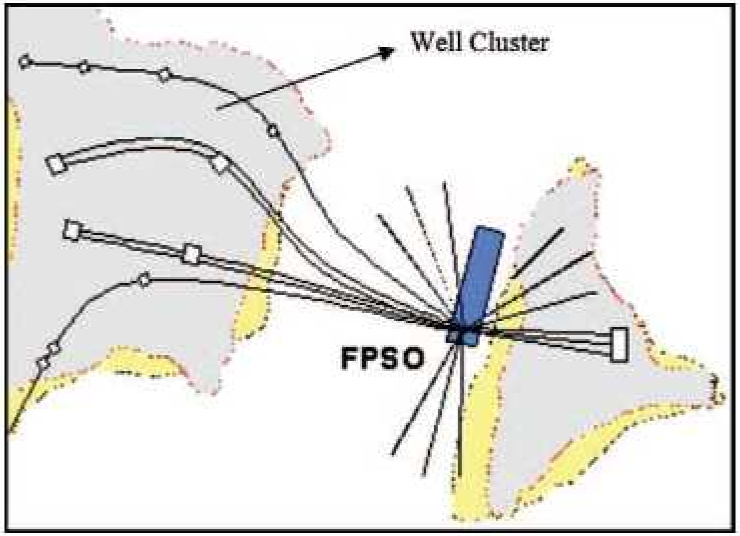
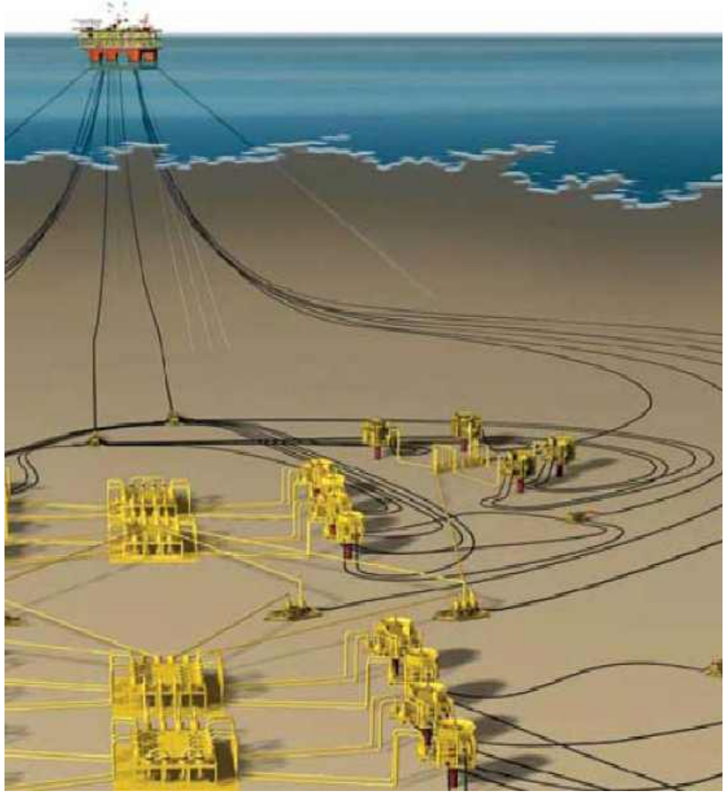


Figure 2-5 FPSO Field Architecture [1]

Wet tree system benefits

- Tree and well access at the seabed isolated from people
- Full range of hull types can be used
- Low cost hull forms are feasible
- Simplified riser/vessel interfaces



Wet tree risers challenges

- Steel risers

  : Fatigue critical requiring good quality offshore welds and fatigue testing requirement

- Flexible risers

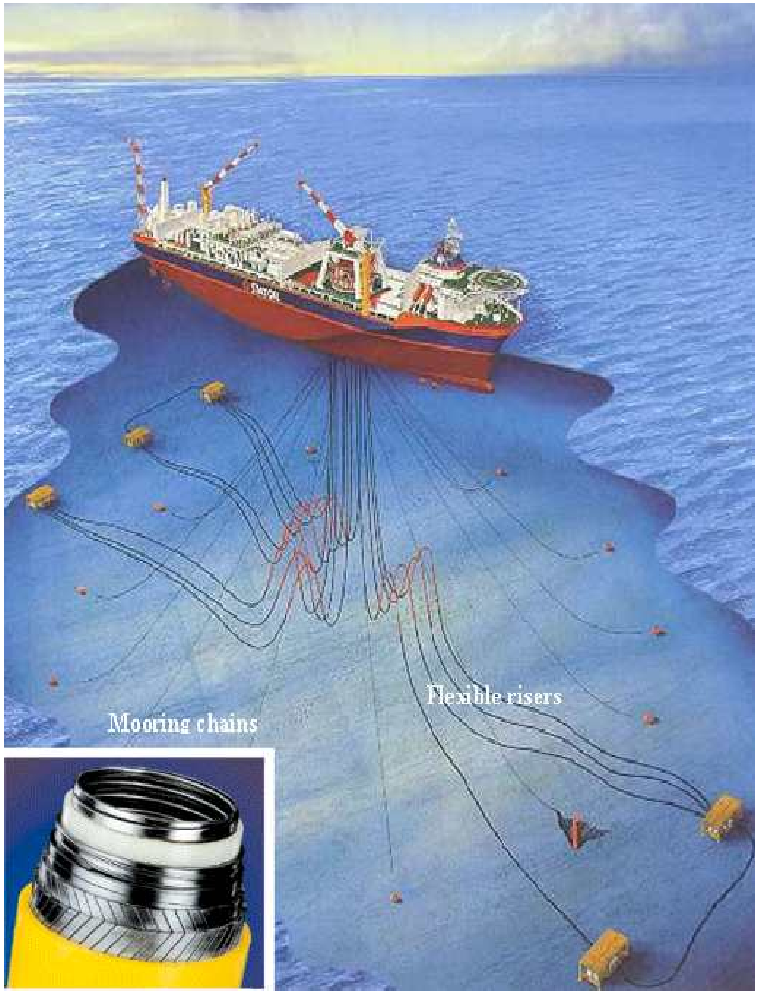
  : Water depth (collapse) limitations

  : Pipe diameter limitations for deep water and higher internal pressure

  : Prone to external sheath damage during installation

  : Potential of internal sheath (PA11) aging due to high water cut

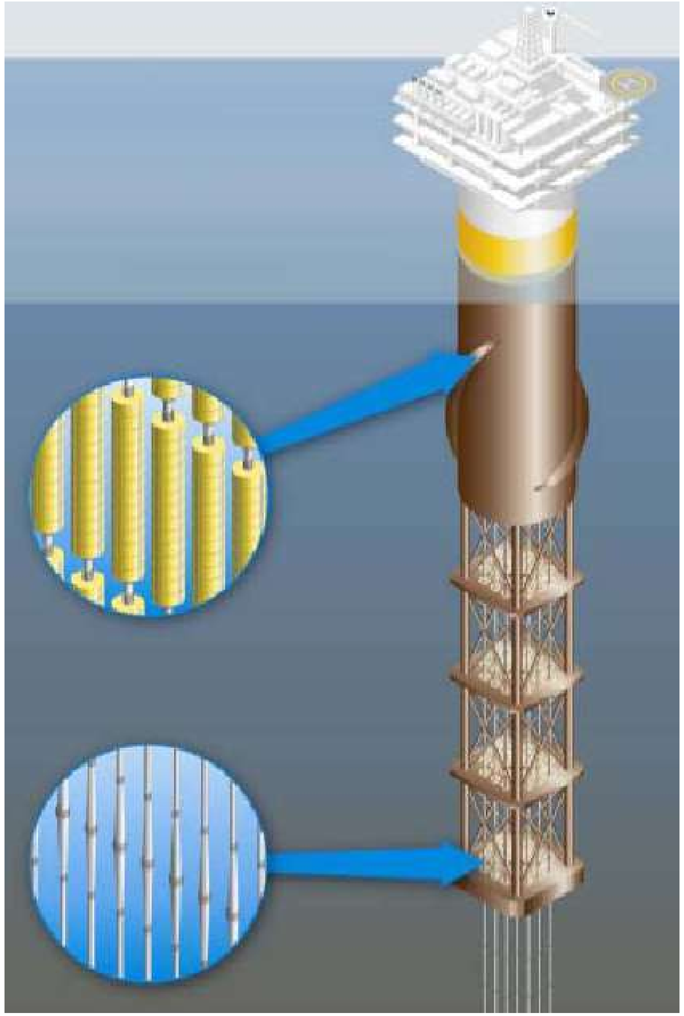
  : Potential end fitting integrity issue



Dry tree systems

- the main alternative to the subsea well cluster architecture
- surface well architectures provide direct access to the wells
- system architectures consist of an FPDU hub based either on a TLP, on a Spar, or even (in some cases) on a compliant piled tower (CPT)
- Risers for dry completion units (DCUs) could be either single casing, dual casing, combo risers (used also as drilling risers), or tubing risers and could include a split tree in some cases.
- The riser tensioning system also offers several options such as active hydropneumatic tensioners, air cans (integral or nonintegral), locked-off risers, or king-post tensioning mechanism

Dry tree system benefits



- Tree and well control at surface in close proximity of people
- Drilling conducted from the facility –reduced CAPEX
- Direct vertical access to wells for future intervention activities
- Minimal offshore construction
- Enable future drilling and expansion

Dry tree system challenges

- Safety concern due to well access at surface
- Large vessel payloads due to the need for supporting risers
- Require high cost vessels such as Spar, TLP due to design sensitivity to vessel motions
- Complex riser design issues
- Limited by existing riser tensioner capacity
- Riser interface with vessel require specialty joints, e.g. keel joint, tapered stress joint
- Heavy lift requirement for riser installation

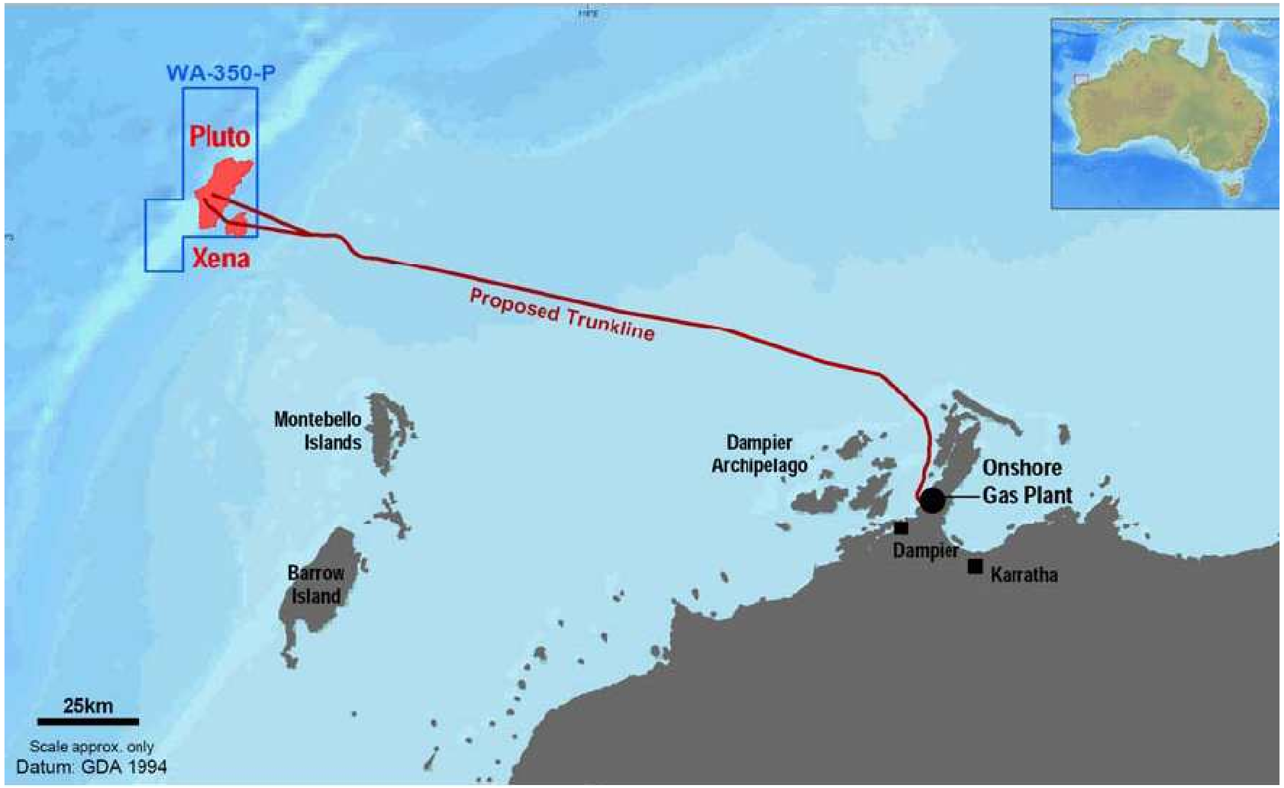
System selection

- Economic factors: Estimated NPV, internal rate of return (IRR), project cash flow, project schedule, and possibly enhanced proliferation control initiative (EPCI) proposals (if any available at the time of the selection) will most certainly be the key drivers of this choice.
- Technical factors: These factors are driven primarily by reservoir depletion plans and means, field worldwide location, operating philosophy, concept maturity and reliability, feasibility, and industry readiness.
- External factors: These factors are in the form of project risks, project management, innovative thinking, operator preferences, and people (the evaluation method may vary between each individual).

Woodside – Pluto project

100% Woodside-owned gas field

- Discovered in early 2005 at North West Shelf (NWS) area
- 190km from the Burrup Peninsula
- Water depth ranging from 400 to 1000m
- Potential resource 4.1 trillion ft^3 gas and small amount of condensate (42mmbl)
- Potential revenue boost by AUD 5.5 billion and Job creation of more than 4500



Woodside – Pluto project (cont'd)

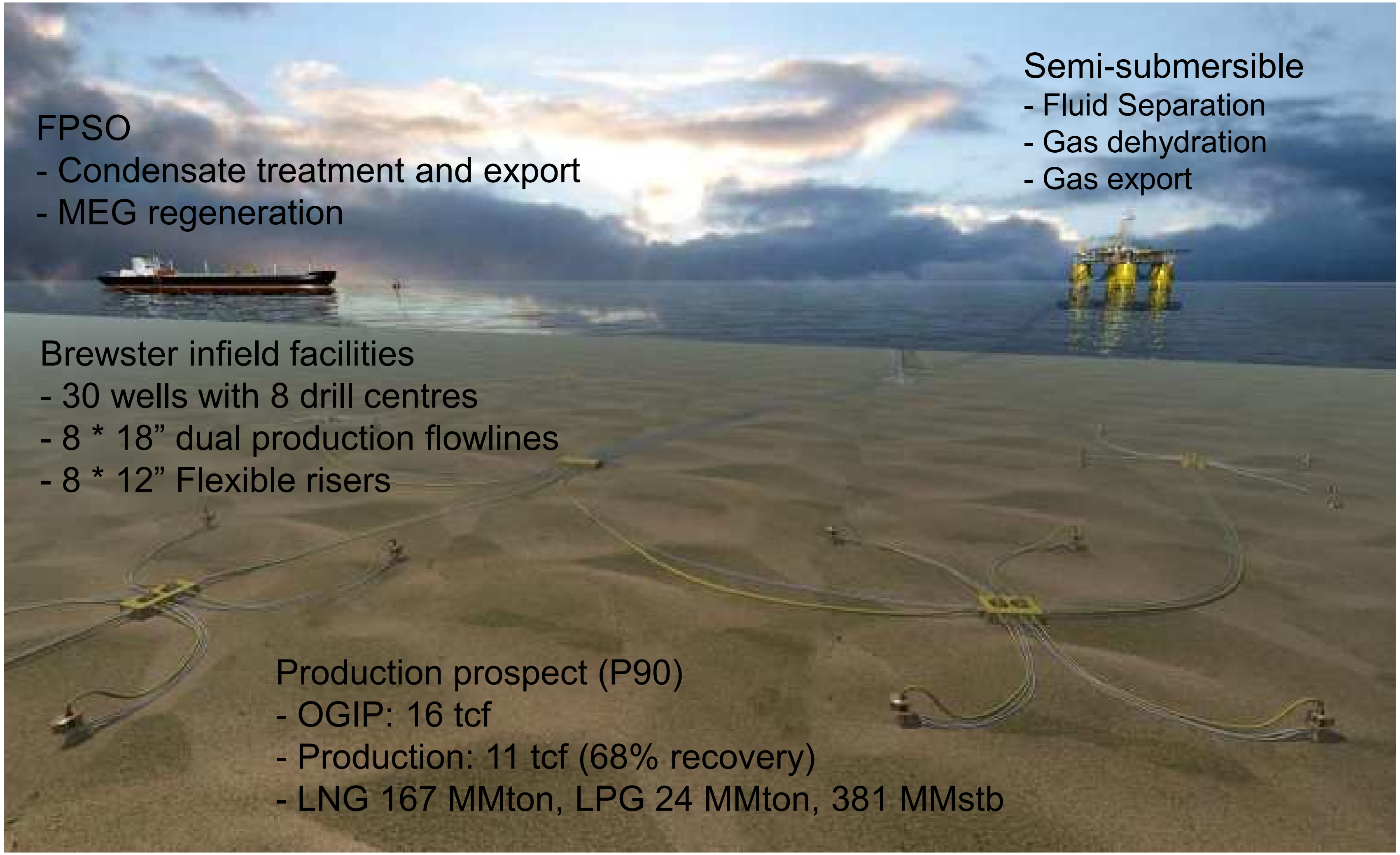
Criteria	Key characteristics
Hydrocarbon resource size	Approximately 116 000 Mm^3 (4.1tcf) – recoverable dry gas Approximately 6.7Mm^3 (42mmbbl) – recoverable condensate
Proposed number of wells	Up to 7 wells in 2008 Up to 12 wells in total
Subsea infrastructure	Two manifolds with dual flowlines, 32km
Offshore platform	Unmanned riser platform located in 80~85m water depth
Offshore gas trunkline	A 762~1068 mm (30~42") carbon steel trunkline A 188km length offshore trunkline from platform through Mermaid Sound.
Onshore gas trunkline	Trunkline from landfall to processing plant at Burrurp Peninsula
Onshore gas processing plant	Up to 12 Mtpa
Gas storage and export facilities	2 * 160 000m^3 LNG cryogenic tanks 2-3 condensate tanks with a combined capacity of up to 130000m^3
First gas	End 2010
Design life	Up to 30 years

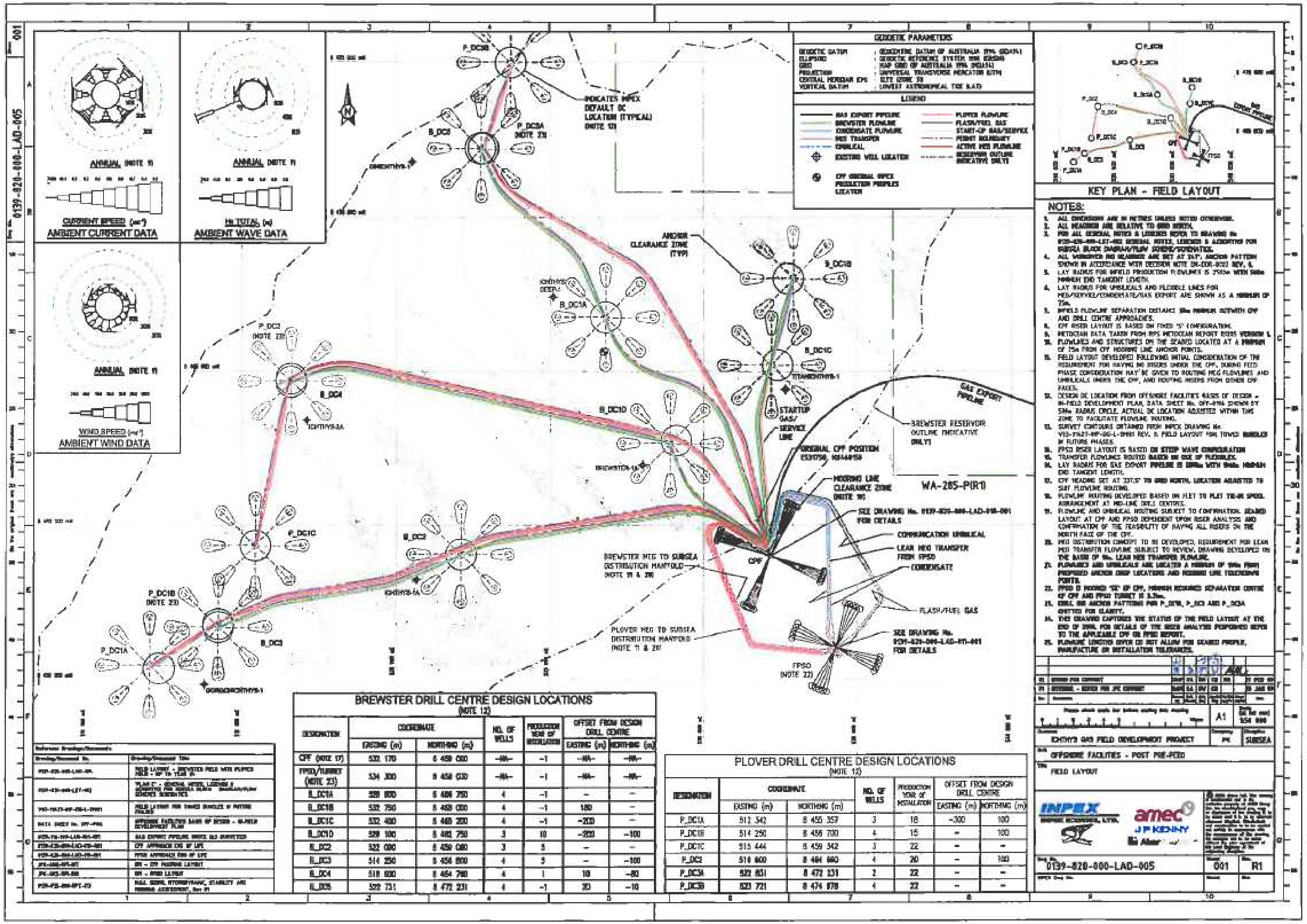
Woodside – Pluto project (cont'd)

Development concept

- Subsea wells tied back, Gas and condensate export pipeline
- Onshore LNG gas treatment plant, LNG, LPG and condensate storage tanks
- Turning basin and shipping channel, Export jetty
- Operational for 20-30 years

Ichthys: Western Australia

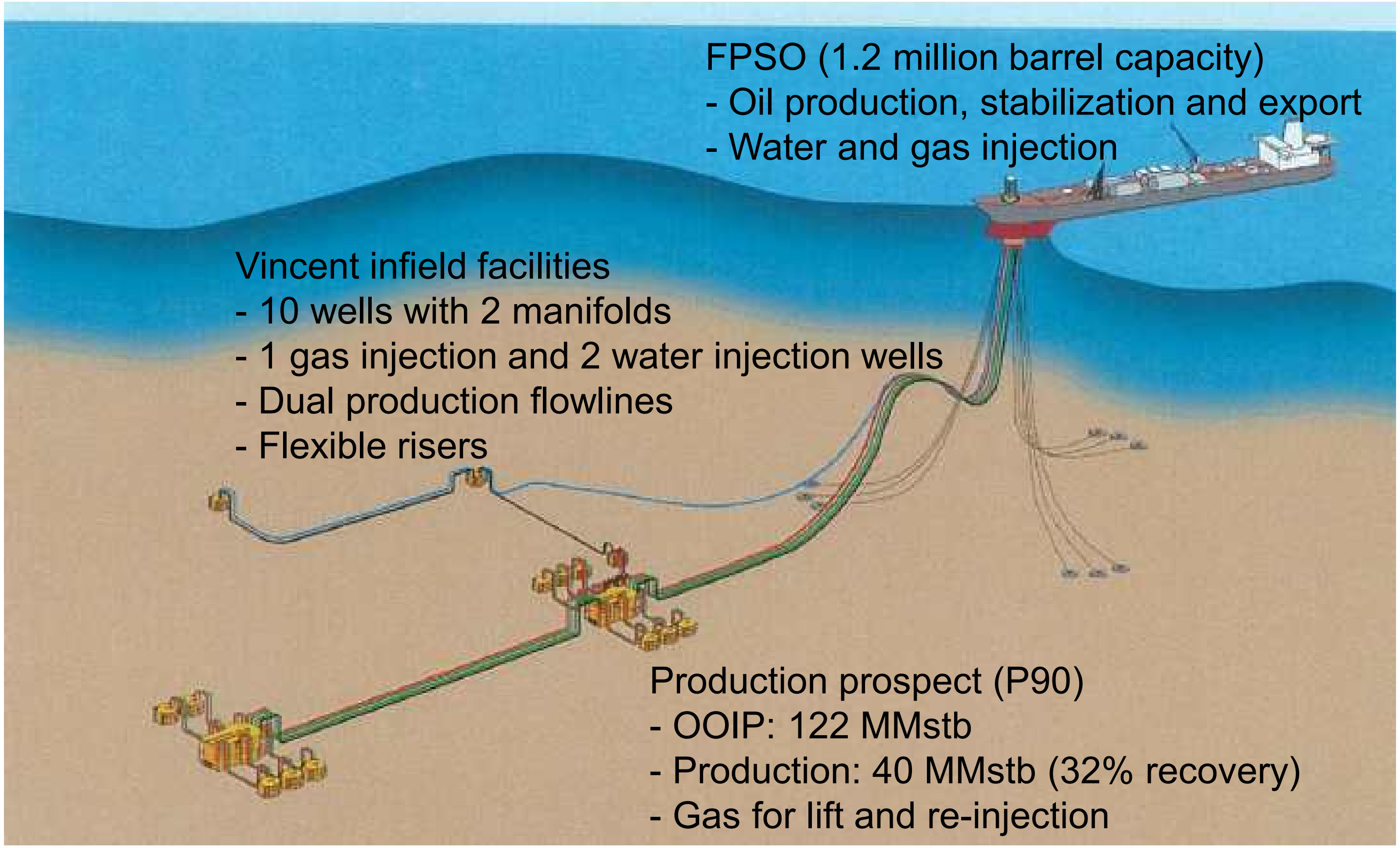




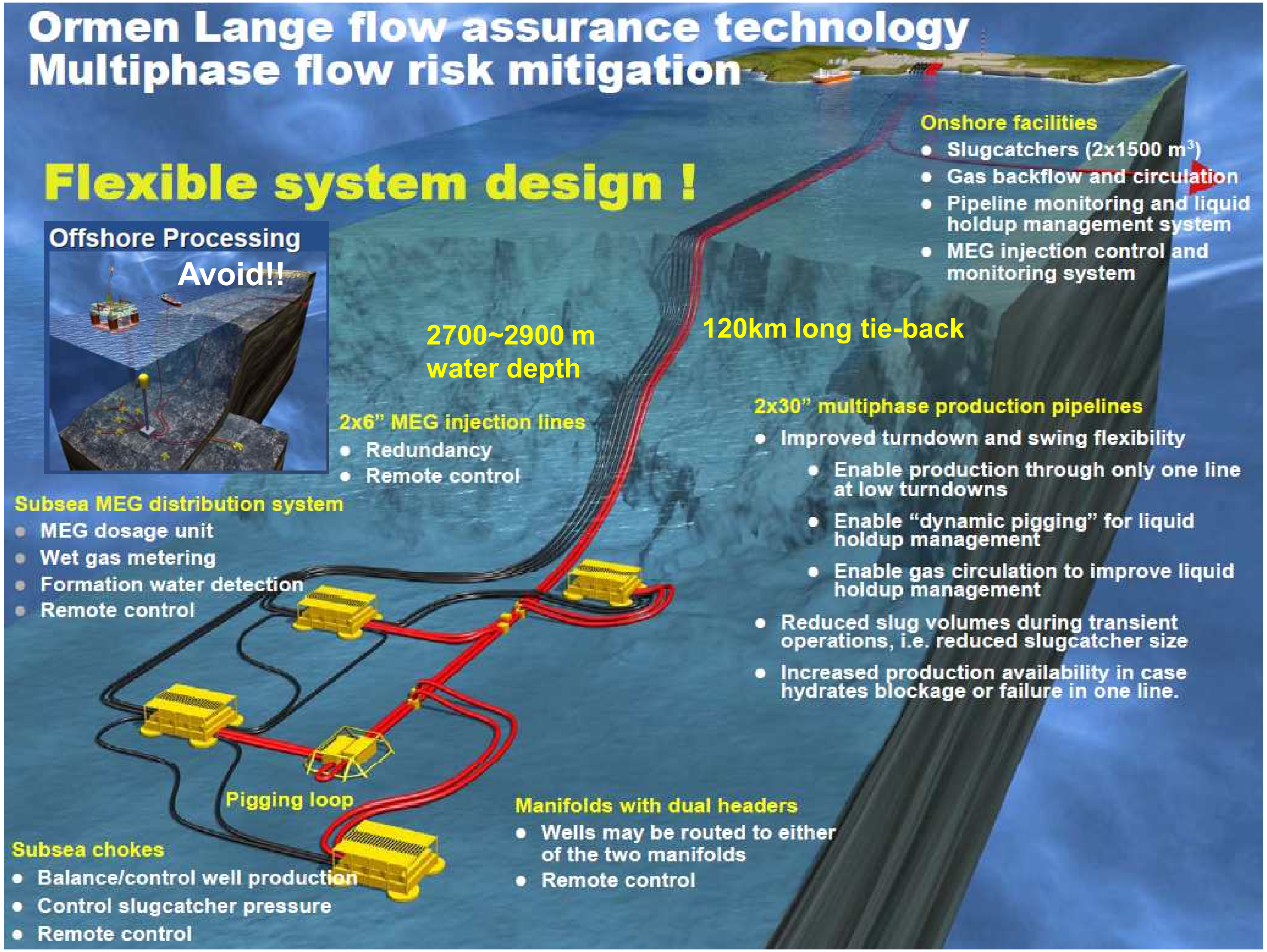
BREWSTER DRILL CENTRE DESIGN LOCATIONS (NOTE 12)						
DESIGNATION	COORDINATE		NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE	
	EASTING (m)	NORTHING (m)			EASTING (m)	NORTHING (m)
CPF (NOTE 17)	532 170	8 459 000	-NA-	-1	-NA-	-NA-
FPSO/TURRET (NOTE 23)	534 300	8 458 000	-NA-	-1	-NA-	-NA-
B_DC1A	528 800	8 486 750	4	-1	–	–
B_DC1B	532 750	8 460 000	4	-1	180	–
B_DC1C	532 400	8 463 200	4	-1	-200	–
B_DC1D	529 100	8 462 750	3	10	-200	-100
B_DC2	522 080	8 459 080	3	5	–	–
B_DC3	514 250	8 456 800	4	5	–	-100
B_DC4	518 600	8 464 790	4	1	10	-80
B_DC5	522 731	8 472 231	4	-1	20	-10

PLOVER DRILL CENTRE DESIGN LOCATIONS (NOTE 12)						
DESIGNATION	COORDINATE		NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE	
	EASTING (m)	NORTHING (m)			EASTING (m)	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	510 600	8 464 660	4	20	–	100
P_DC3A	522 851	8 472 231	2	22	–	–
P_DC3B	523 721	8 474 878	4	22	–	–

Vincent: Western Australia



Remote Production System



Subsea tie-back development

- the overall capital expenditure can be decreased by utilizing the processing capacity on existing platform infrastructures, rather than by continuing to build new structures for every field.
- The economics of having a long tie-back are governed by a number of factors specific to that field

  : Distance from existing installation;

  : Water depth;

  : Recoverable volumes, reservoir size, and complexity;

  : Tariffs for processing the produced fluids on an existing installation;

  : The potential recovery rates from subsea tie-backs, usually low due to limitations in the receiving facility's processing systems;

  : The potential recovery rates in case of building new platform wells, usually high due to easier access to well intervention and workovers.

Limitations of long distance tie-back

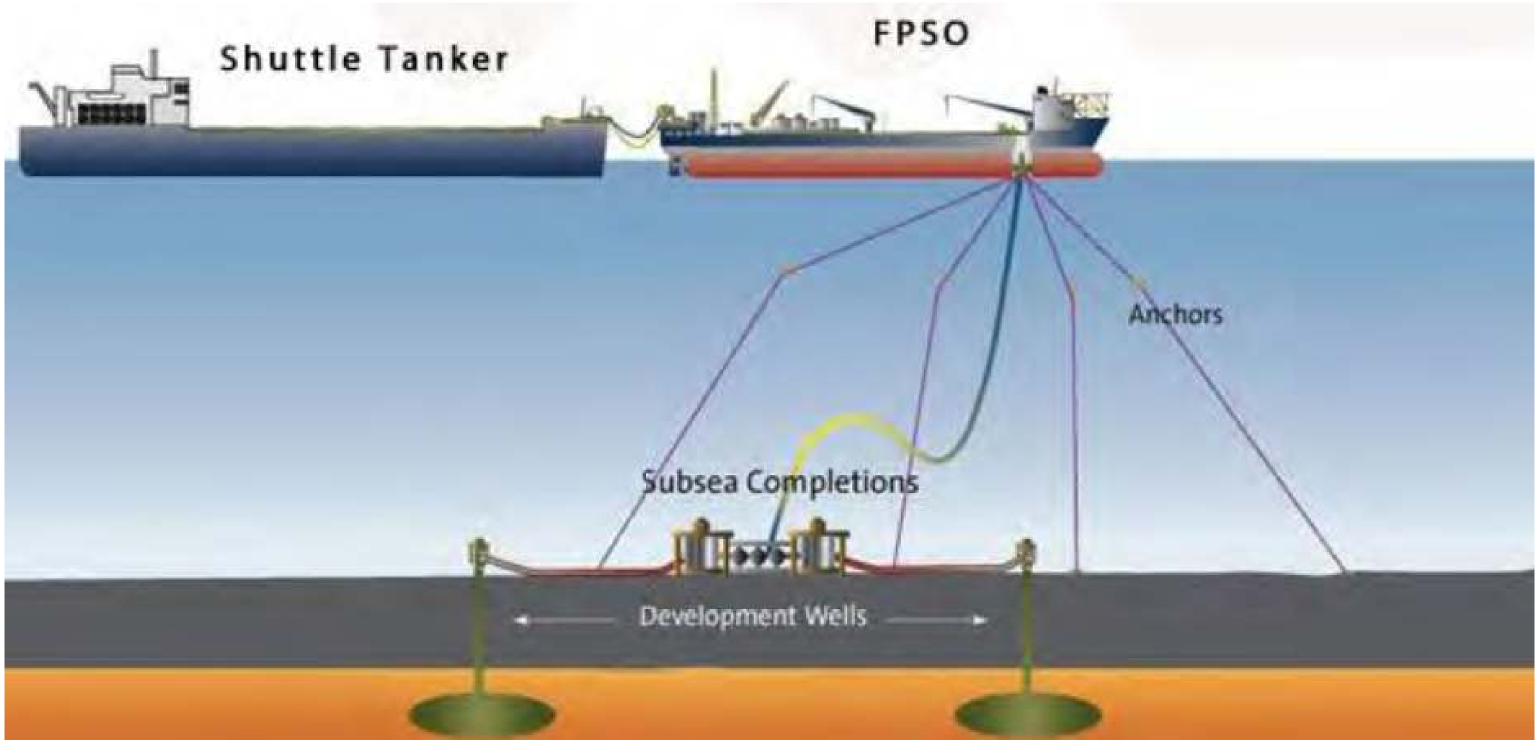
- Reservoir pressure must be sufficient to provide a high enough production rate over a long enough period to make the development commercially viable. Gas wells offer more opportunity for long tie-backs than oil wells. Hydraulic studies must be conducted to find the optimum line size.
- It may be difficult to conserve the heat of the production fluids and they may be expected to approach ambient seabed temperatures. Flow assurance issues of hydrate, asphaltene, paraffin, and high viscosity must be addressed. Insulating the flowline and tree might not be enough. Other solutions can involve chemical treatment and heating.
- The gel strength of the cold production fluids might be too great to be overcome by the natural pressure of the well after a prolonged shutdown. It may be necessary to make provisions to circulate out the well fluids in the pipeline upon shutdown, or to push them back down the well with a high-pressure pump on the production platform, using water or diesel fuel to displace the production fluids.

Host Facilities Geographic Trends

	Gulf of Mexico	Brazil	North Atlantic	West Africa
TLP/Spar	High	Med	Med	Med
Subsea to Platform	High	Low	Med	Low
Subsea to FPSO	Med	High	High	High

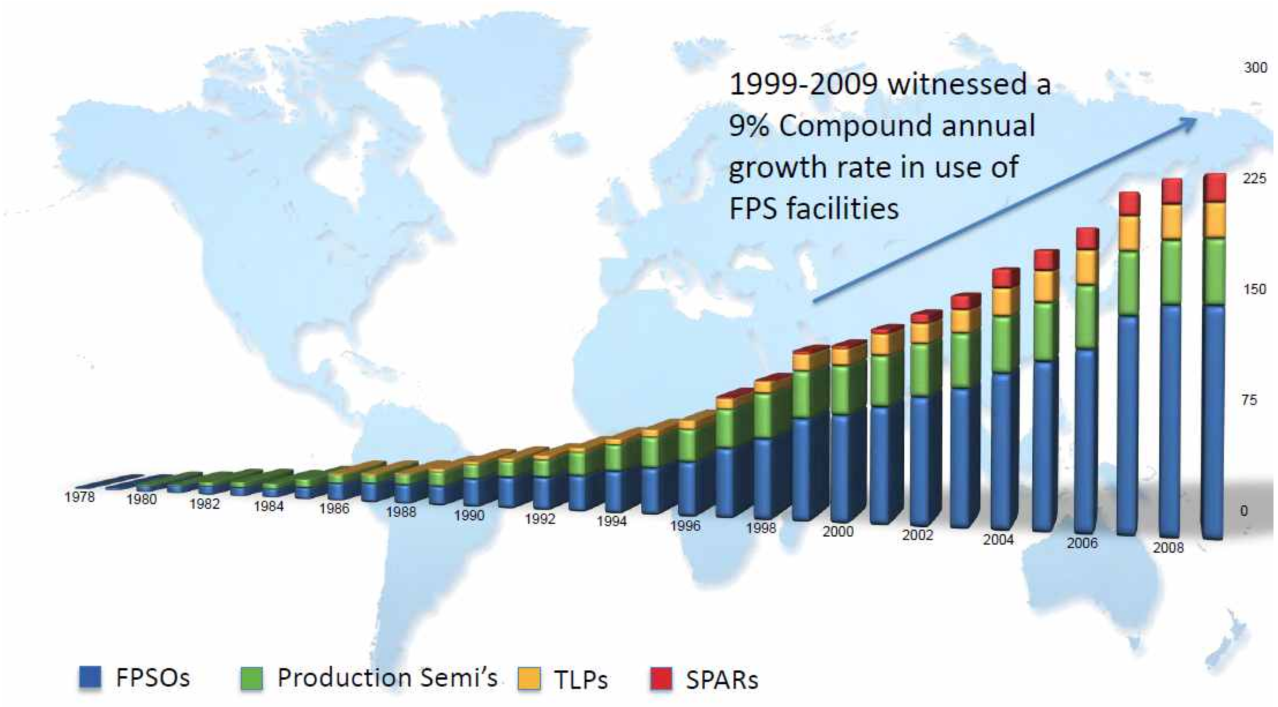
Oil FPSO

- Processes hydrocarbons received from local production wells i.e. from a platform or subsea template
- Well stream is processed & stored on the vessel, offloaded to a shuttle tanker or exported via a pipeline



Advantages

- They eliminate the need for costly long-distance pipelines to an onshore terminal
- Particularly effective in remote or deep water locations where seabed pipeline are not cost effective
- In bad weather situations (cyclones, icebergs etc.) FPSOs release mooring/risers and steam to safety.
- On field depletion FPSOs can be relocated to a new field



FPSO for Deepest Water

- FPSO Pioneer

  : BW Offshore operated on behalf of Petrobras Americas Inc.

  : 8,530 feet (2,600m) depth of water (DOW) in Gulf of Mexico

  : 100,000bbl/d (16,000 m3/d)

  : First oil Q3 2011

  : FPSO conversion at Keppel Shipyard in Singapore

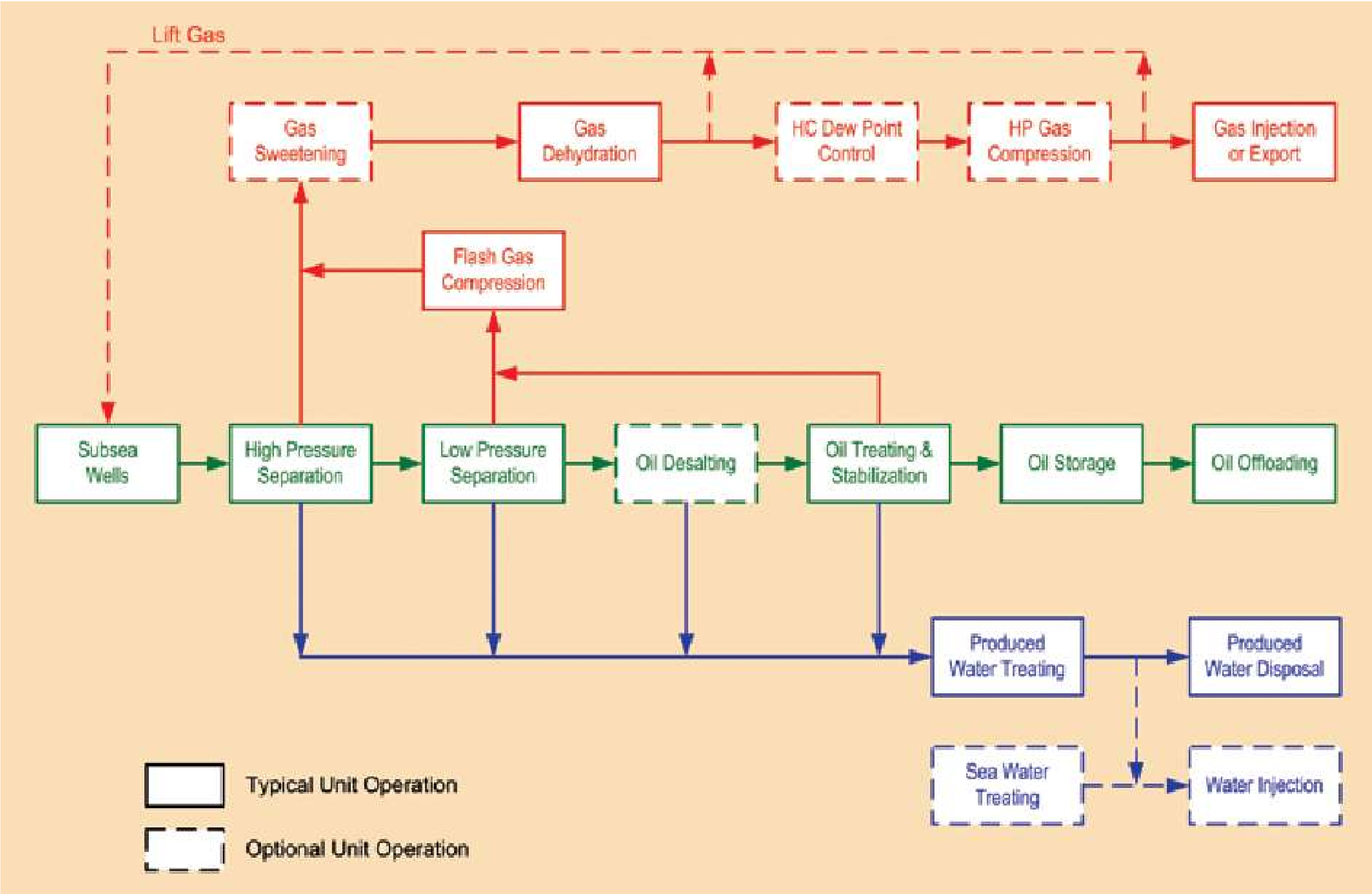
  : Vessel has disconnectable turret so it can disconnect for hurricanes and reconnect with minimal downtime

Longest FPSO

- FPSO Girassol
  : Operated by TotalFinaElf
  : Located of NNW Luanda, Angola - 1350m of water
  : 300m Long x 59.6m Wide, 30.5m High
  : Average draught 23m
  : Displacement 396,288 tons

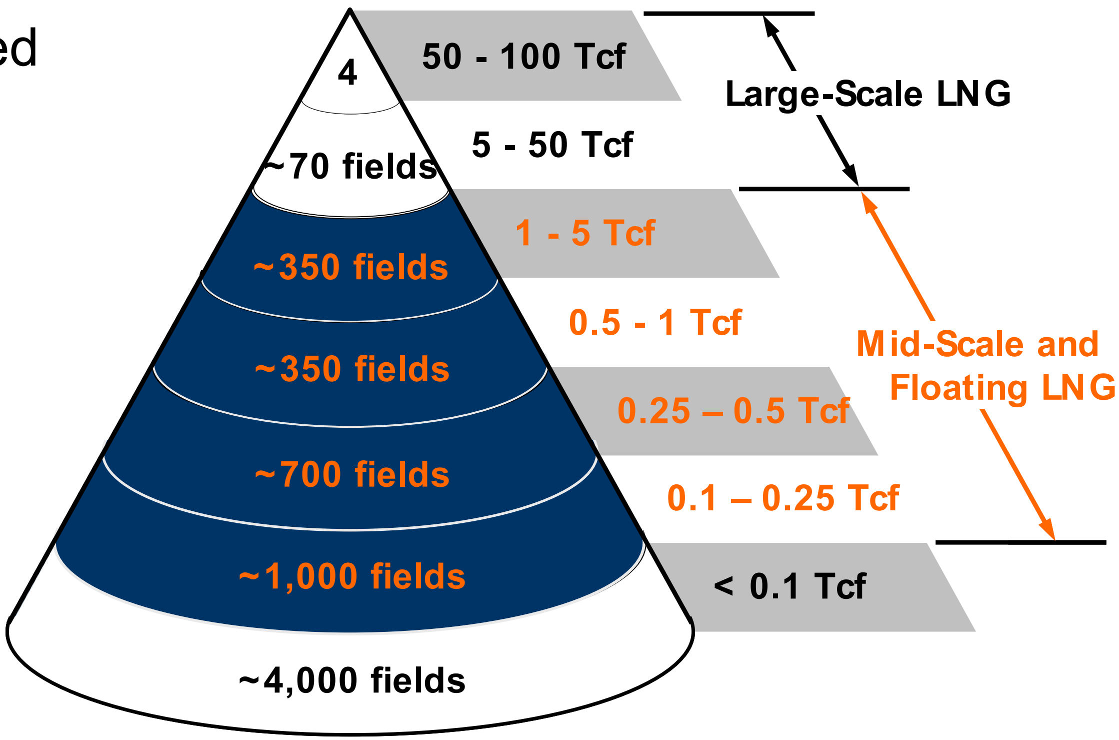
FPSO topside configuration (~25,000 Te Belanak)

Oil FPSO topside facilities



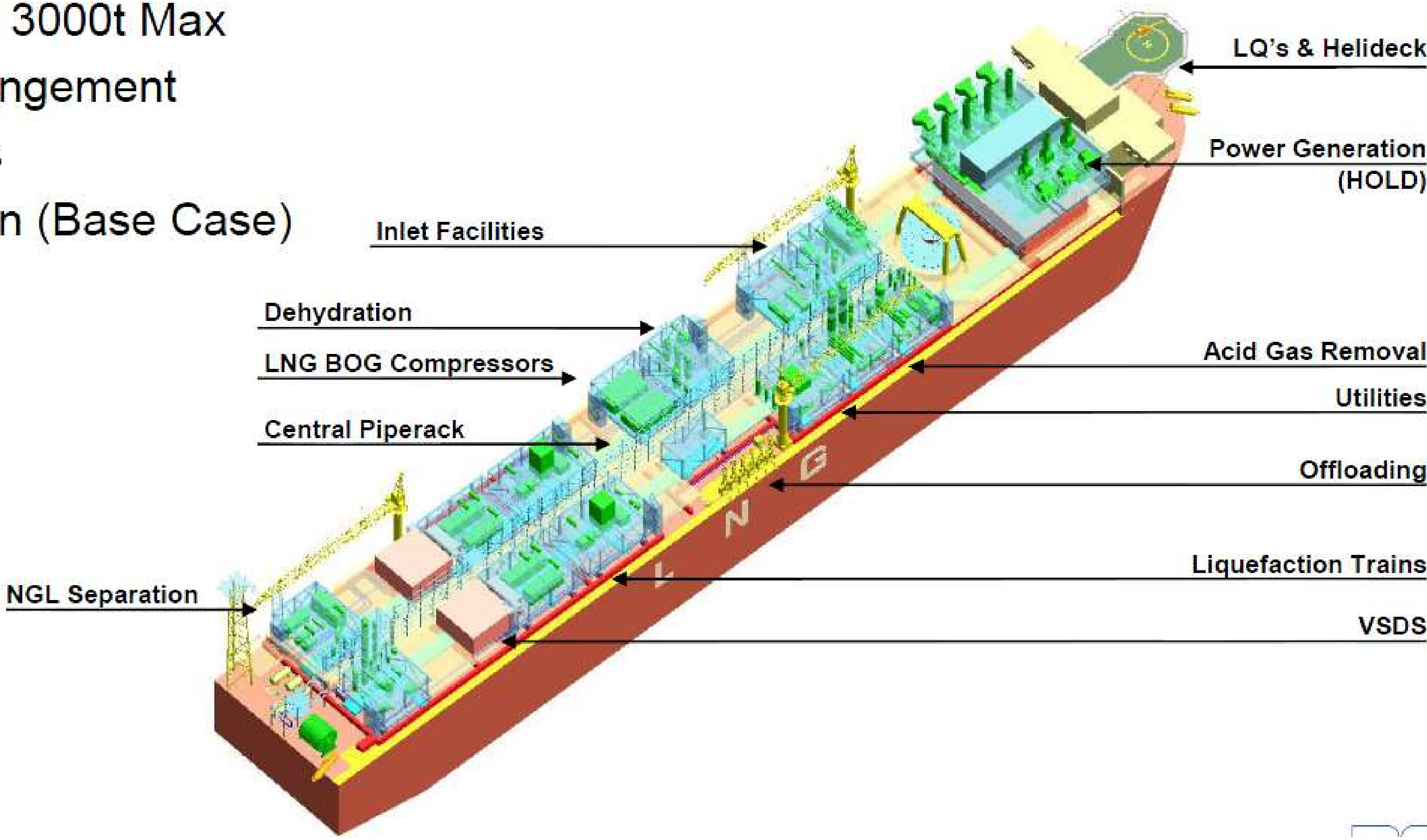
FLNG opening more gas to development

- Accesses gas unsuitable for baseload development
- Eliminates pipeline & loading infrastructure costs
- Reduces security and political risks
- Constructed in controlled shipyard environment
- Can relocate facility upon field depletion

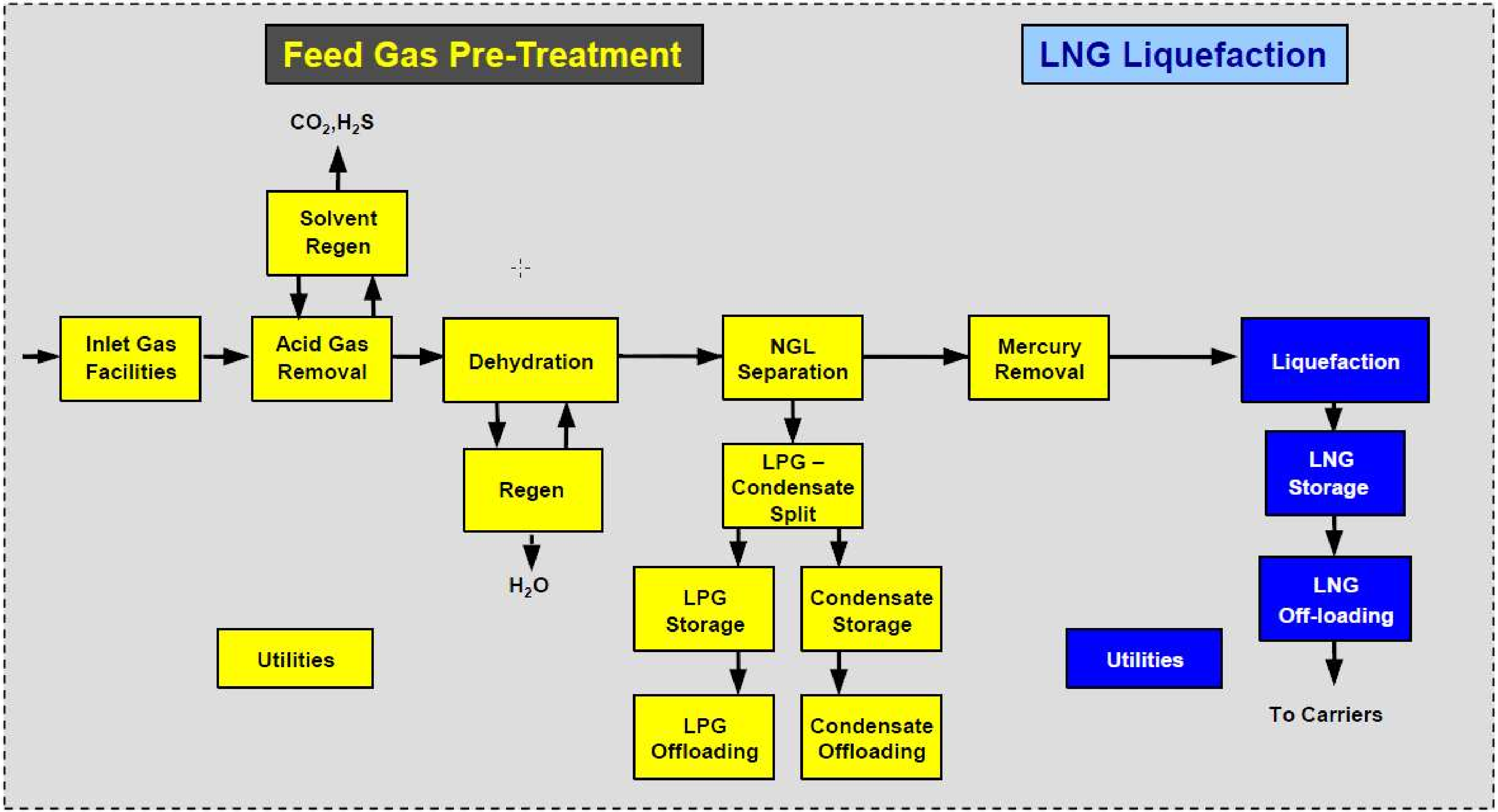


HÖEGH FLNG, 2008

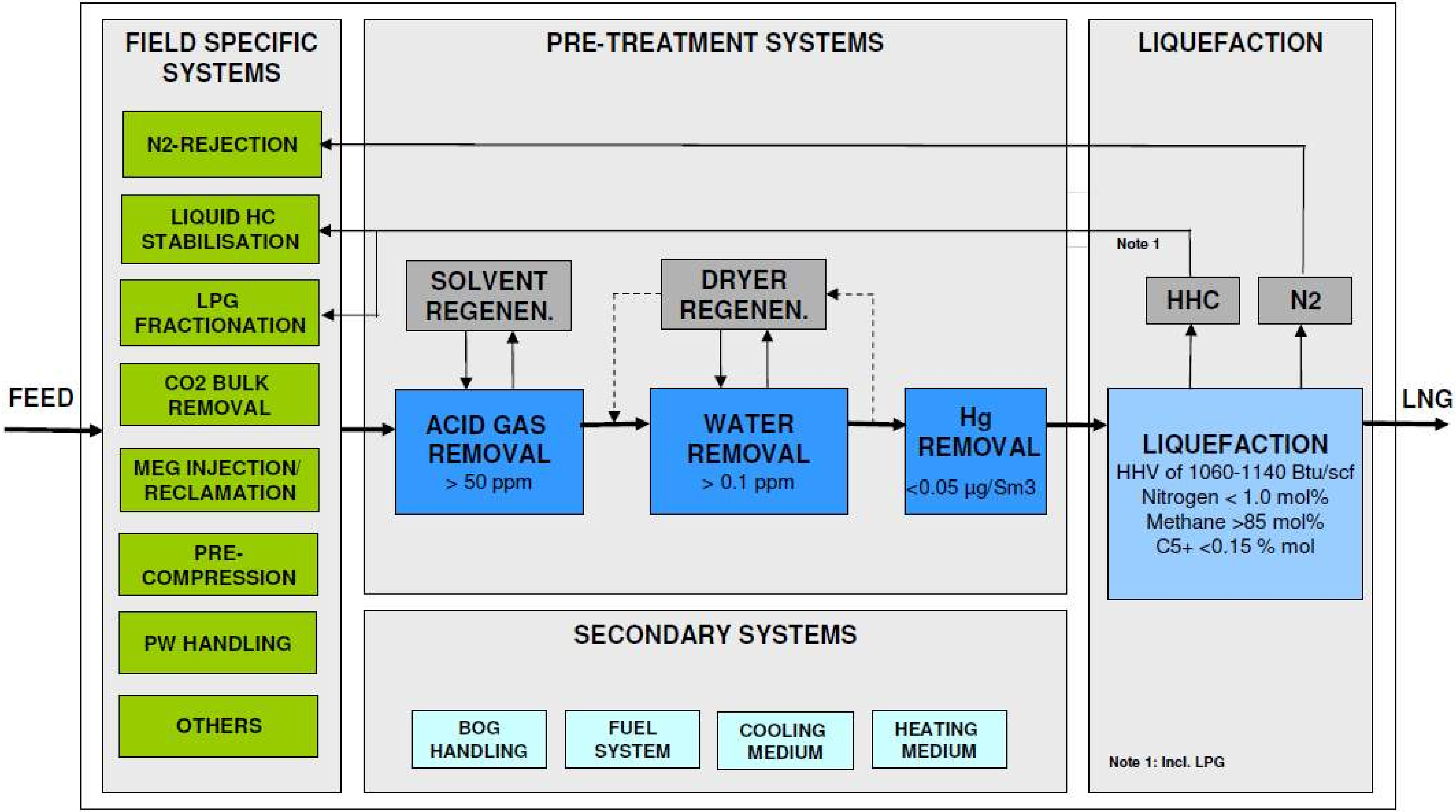
- 14 Modules
- Installation - 3000t Max
- Module Arrangement
- Safety Gaps
- Electrification (Base Case)
- Offloading



LNG FPSO topside facilities



Field specific and pre-treatment systems



Primary elements

- Trees and Wellheads
- Manifolds
- Flowlines and Risers
- Control systems
- Umbilicals
- Topside facilities
  - Master control station with operator interface
  - Electrical power unit for power conditioning & monitoring
  - Hydraulic power unit for pressure generation, fluid storage
  - Topside umbilical junction boxes
  - Chemical injection skid
- Construction vessels
- Divers and ROVs
- Intervention systems

Onshore vs Offshore trees

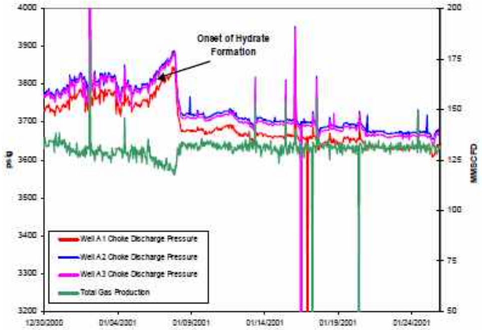
Onshore Trees..

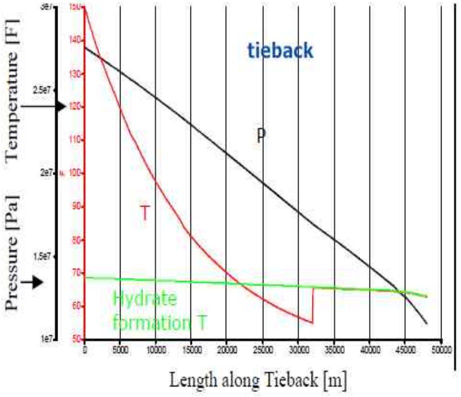
Offshore Trees.. can you see??

Operating production system

- It’s a lot easier to picture what is happening in onshore system
- But, understanding what is happening in offshore system requires experience and inferences

- Challenges
  : Hydrates
  : Corrosion
  : Wax
  : Asphaltenes
  : Scale
  : Sand (erosion, deposition etc.)
  : Other issues e.g. emulsion, heavy oil..





Typical subsea developments

Crude oil subsea tieback

- Crude oil field
- Wells tied back to existing platform 10km away
- Water depth – 150m
- 20,000 bbl/d
- 2 * 6” flowlines
- Water injection required into reservoir
- Fluid composition

  : Gas Oil Ratio 1000scf/bbl

  : water cut 20%

  : Temperature 35~70 ^{o}C

  : Pressure 30~80 bar

  : Rates 7000~20000 bbl/d

Gas tieback to LNG plant

- Gas condensate field
- Wells tied back to an LNG plant 150km away
- Water depth – 1200m
- 1000 MMscfd
- 10~30” flowline
- Continuous MEG or MeOH injection required at subsea chokes
- Fluid composition

  : Condensate gas ratio 5bbl/MMscf

  : Water gas ratio 1bbl/MMscf

  : Temperature 3~130 ^{o}C

  : Pressure 75~300 bar

  : Rates 500~1000 MMscfd

Operation challenges

Crude oil subsea tieback

- Steady-state operation
  : System operated at capacity
  : Wellhead chokes fully open
- Shutdown
  : Followed by flowline depressurization
  : Keep fluid hot to avoid wax & hydrate
- Restart
  : Hot oil circulation is required to warm enough flowline to prevent hydrates
- Pigging
  : may require routine pigging if wax deposition is an issue

Gas tieback to LNG plant

- Steady-state operation
  : Gas offtake at required rate
  : Subsea choking to maintain pressure
- Shutdown
  : Followed by MEG injection, but maintain pressure and flowline content
- Restart
  : May be accompanied by very low temperature downstream of choke
- Pigging
  : Hopefully is not a routine procedure
  : Rigorous modelling to control speed

Chemical injection

Crude oil subsea tieback

- Scale, wax, & corrosion inhibitors may require continuous injection
- Monitoring of chemical injection system performance is important both for effectiveness of chemical treatment and cost management
- Introduction of new chemical products should only follow lab testing to verify compatibility

Gas tieback to LNG plant

- Continuous MEG injection can result in a large complex processing system that may induce operation troubles
- MEG needs to be regenerated and reclaimed to remove salts

Types of reservoir fluids

Main Petroleum Components

Note:
Paraffin wax= 20<n<40

Paraffin
= Alkane
(C_nH_{2n+2})

Naphthene
= Cycloalkane

Sweet corrosion

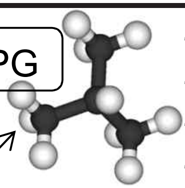
Sour corrosion

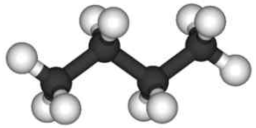
LNG

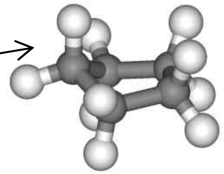
LPG

Table 13-1 Physical Properties of Main Petroleum Components [1]

Component	Formula	Boiling Temperature at 1 atm (°C)	Density at 1 atm and 15°C (g/cm^3)
Paraffins			
Methane	CH_4	−161.5	–
Ethane	C_2H_6	−88.3	–
Propane	C_3H_6	−42.2	–
i-Butone	C_4H_{10}	−10.2	–
n-Butane	C_4H_{10}	−0.6	—
n-Pentane	C_5H_{12}	36.2	0.626
n-Hexane	C_6H_{14}	69.0	0.659
i-Octane	C_8H_{18}	99.3	0.692
n-Decane	$C_{10}H_{22}$	174.0	0.730
Naphthenes			
Cyclopentane	C_5H_{10}	49.5	0.745
Methyl cyclo-pentane	$CH_3C_5H_{10}$	71.8	0.754
Cyclohexane	C_6H_{12}	81.4	0.779
Aromatics			
Benzene	C_6H_6	80.1	0.885
Toluene	C_7H_8	110.6	0.867
o-Xylene	C_8H_{10}	144.4	0.880
Naphthalene	$C_{10}H_8$	217.9	0.971
Others			
Nitrogen	N_2	−195.8	—
Carbon dioxide	CO_2	−78.4	—
Hydrogen sulfide	H_2S	−60.3	—







Natural Gas Compositions

Component	Pluto (mol %)	NWS (mol %)	Gorgon (vol. %)	Jansz (vol. %)	Browse (mol %)	Ichthys (mol %)
N_2	8.1	0.8	2.0	2.3	0.5	0.4
CO_2	1.9	3.0	14.0	0.3	9.8	8.5
CH_4	83.0	85.3	76.7	91.5	79.3	70.0
C_2H_6	3.9	5.8	3.2	3.8	5.6	10.3
C_3H_8	1.4	2.2	0.9	1.1	2.1	4.2
C_4H_{10}	0.7	1.0	0.3	0.4	0.9	1.9
C_5+	1.4	1.9	0.1	0.6	1.8	4.4

Reservoir considerations

- Oil and gas reservoirs formed in porous sedimentary rock many millions of years ago.
- Some reservoirs are close to the earth's surface whilst others are deep in the formation.
- Some have very high pressure and temperatures whilst other do not.
- The range of hydrocarbons varies, as does their concentration.

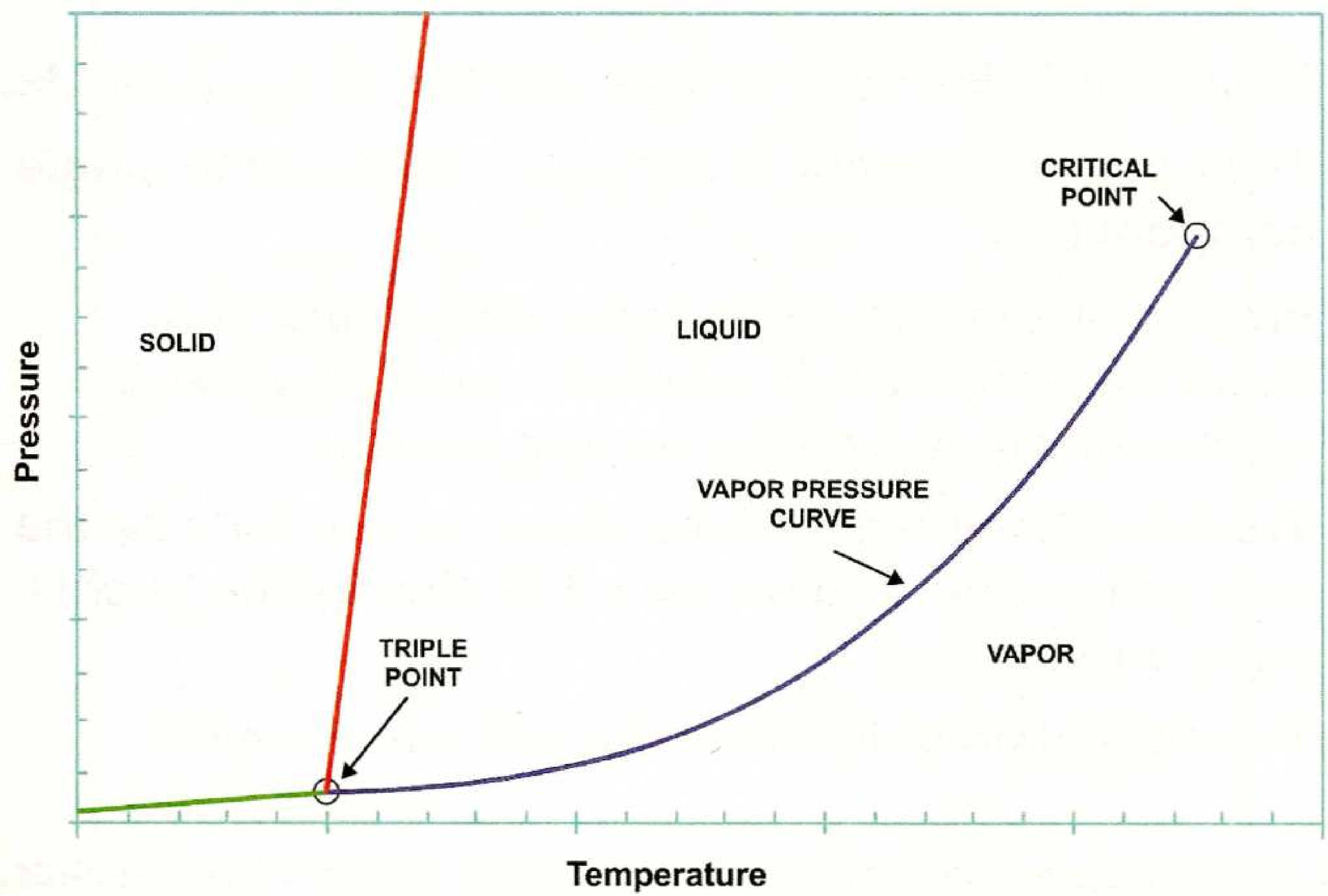
- Need to classify !!

  - Phase behavior: compositions

  - Fluid characteristics: API gravity

  - Reservoir flow characteristics: phase diagram

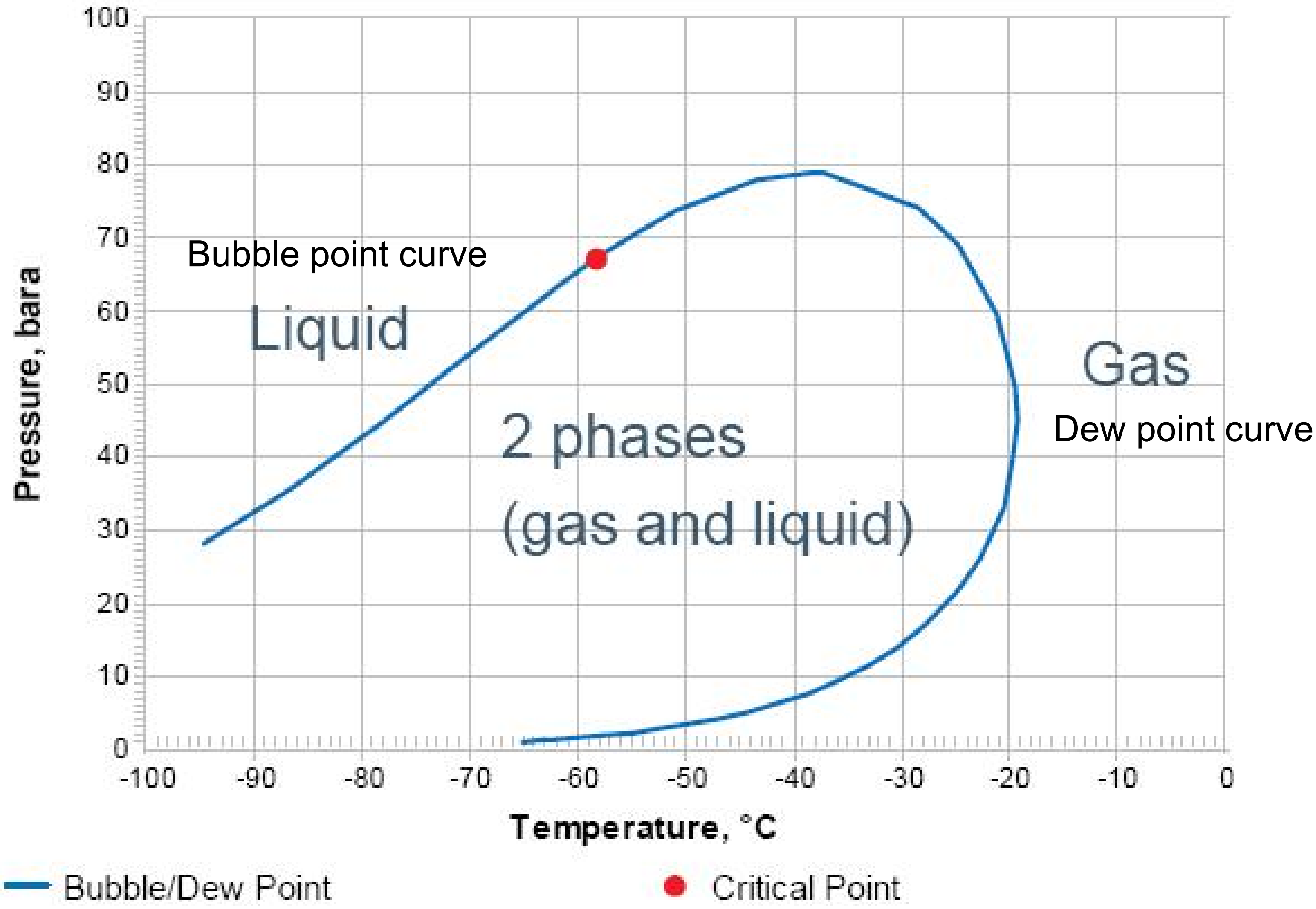
Phase behavior – Pure component



Phase behavior - Multicomponents

- Reservoir fluids have a huge number of components.
- Their phase behavior is complex compared to single components.
- Instead of a single curve separating liquid from vapor phases, there is a broad region where both vapor and liquid exist .
- The two-phase region is bounded on one side by the dew point curve and on the other side by the bubble point curve.
- The critical point is where the two curves meet

Phase behavior – Natural Gas



Multicomponent Phase Diagram

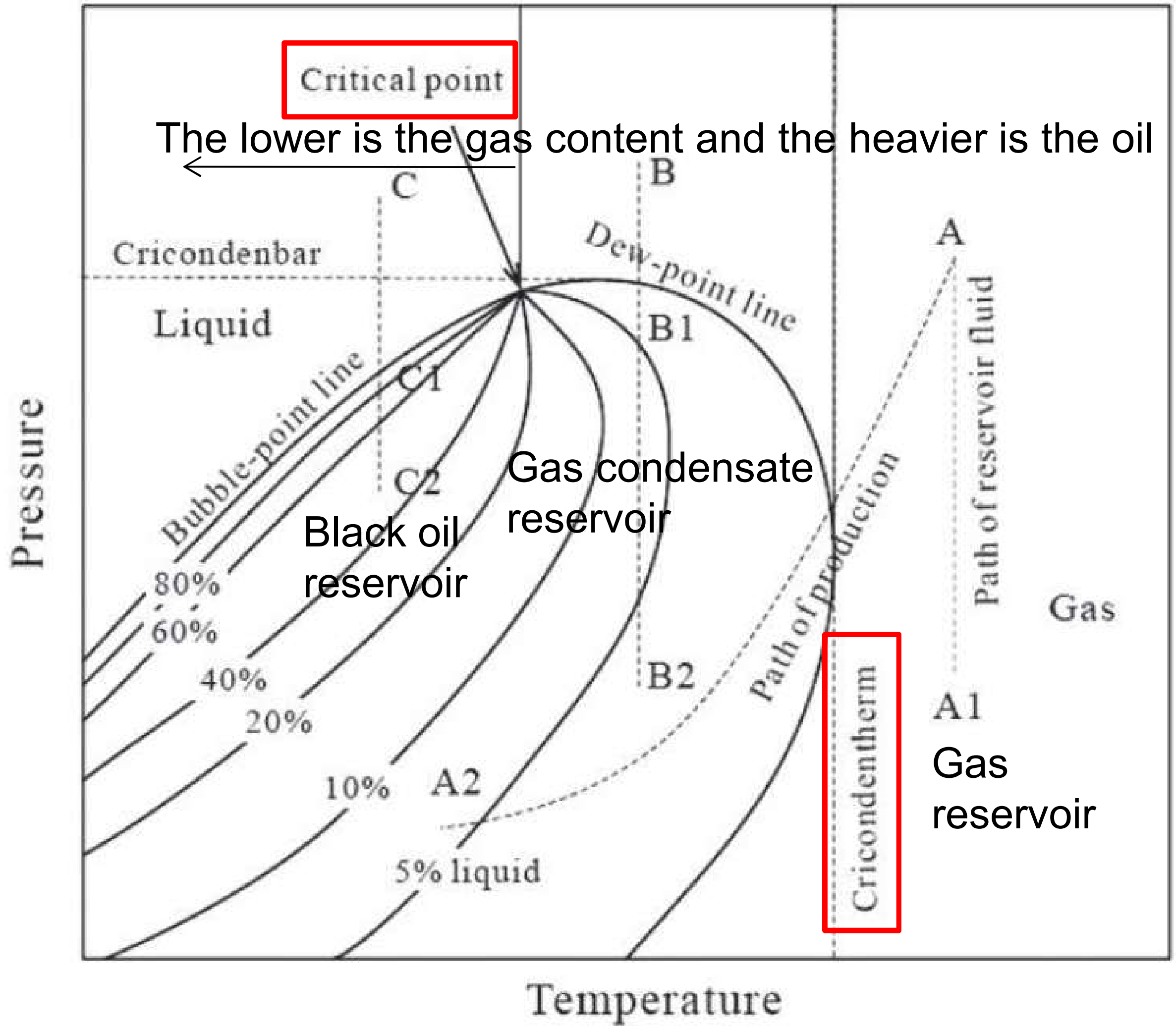


Figure 13-2 Typical Phase Diagram of Hydrocarbons

Physical properties - Density

- Dead oil is defined as oil without gas in solution.
- Specific gravity

  : the ratio of oil density and water density at the same T and P

$$\gamma_o = \frac{\rho_o}{\rho_w}$$

- API gravity

  : the standard method of defining the density of a reservoir fluid

  : API gravity of water is 10

  : was designed so that most values would fall between 10 and 70 API gravity degrees

$$^{o}API = \frac{141.5}{\gamma_o} - 131.5$$

where γ_o is the specific gravity of oil at 60^{o}F

- Gas gravity is defined as

$$\rho_g = \frac{PM}{zRT}$$

$$M : molecular\ weight\ of\ the\ gas$$

$$R : gas\ constant$$

$$P : pressure$$

$$T : temperature$$

$$z : compressibility\ factor$$

- The gas specific gravity is defined as the ratio of the gas density and the air density at the same T and P

$$\gamma_g = \frac{\rho_g}{\rho_a} = \frac{M}{29}$$

Physical properties - Viscosity

- Dynamic viscosity
  : the resistance to flow exerted by a fluid
  : for a Newtonian fluid (typical units Pa·s, Poise, P)

$$\mu = \frac{\tau}{d\nu / dn}$$

$\tau : shear\ stress$

$\nu : velocity\ of\ the\ fluid\ in\ the\ shear\ stress\ direction$

$d\nu / dn : gradient\ of\ \nu\ in\ the\ direction\ perpendicular\ to\ flow\ direction$

- Kinematic viscosity
  : the dynamic viscosity divided by the density
  (typical units cm^2/s, Stokes, St).

$$\nu = \mu / \rho$$

$\rho : density$

Fluid characteristics

Fluid type	API gravity	GOR (scf/STB)	C1 mol%	Character
Black oil	< 30	< 2000	< 60	Liquid oil composed of various chemical species
Volatile oil	< 40	2000 ~ 3000	60 ~ 70	Fewer heavy molecules but more C2~C6; release of large amount of gas
Condensate	40 ~ 60	3300 ~ 50,000*	70 ~ 80	Gas at reservoir; Retrograde behavior yield light oil
Wet gas	40 ~ 60	> 50,000	80 ~ 90	Gas at reservoir; Two phase mixture in a flowline
Dry gas	NA	No liquid at STP	90 ~ 100	Primarily methane; solely gas under all conditions

* Retrograde gas can go as high as 150,000 scf/STB

Hydrocarbon Composition

	Composition (mol %)				
Component	Black Oil	Volatile Oil	Condensate	Wet Gas	Dry Gas
CO_2	0.02	0.93	2.37	1.41	0.10
N_2	0.34	0.21	0.31	0.25	2.07
C_1	34.62	58.77	73.19	92.46	86.12
C_2	4.11	7.57	7.80	3.18	5.91
C_3	1.01	4.09	3.55	1.01	3.58
i-C_4	0.76	0.91	0.71	0.28	1.72
n-C_4	0.49	2.09	1.45	0.24	0.0
i-C_5	0.43	0.77	0.64	0.13	0.50
n-C_5	0.21	1.15	0.68	0.08	0.0
C_6	1.61	1.75	1.09	0.14	0.0
C_7^+	56.40	21.76	8.21	0.82	0.0
Total	100.0	100.0	100.0	100.0	100.0

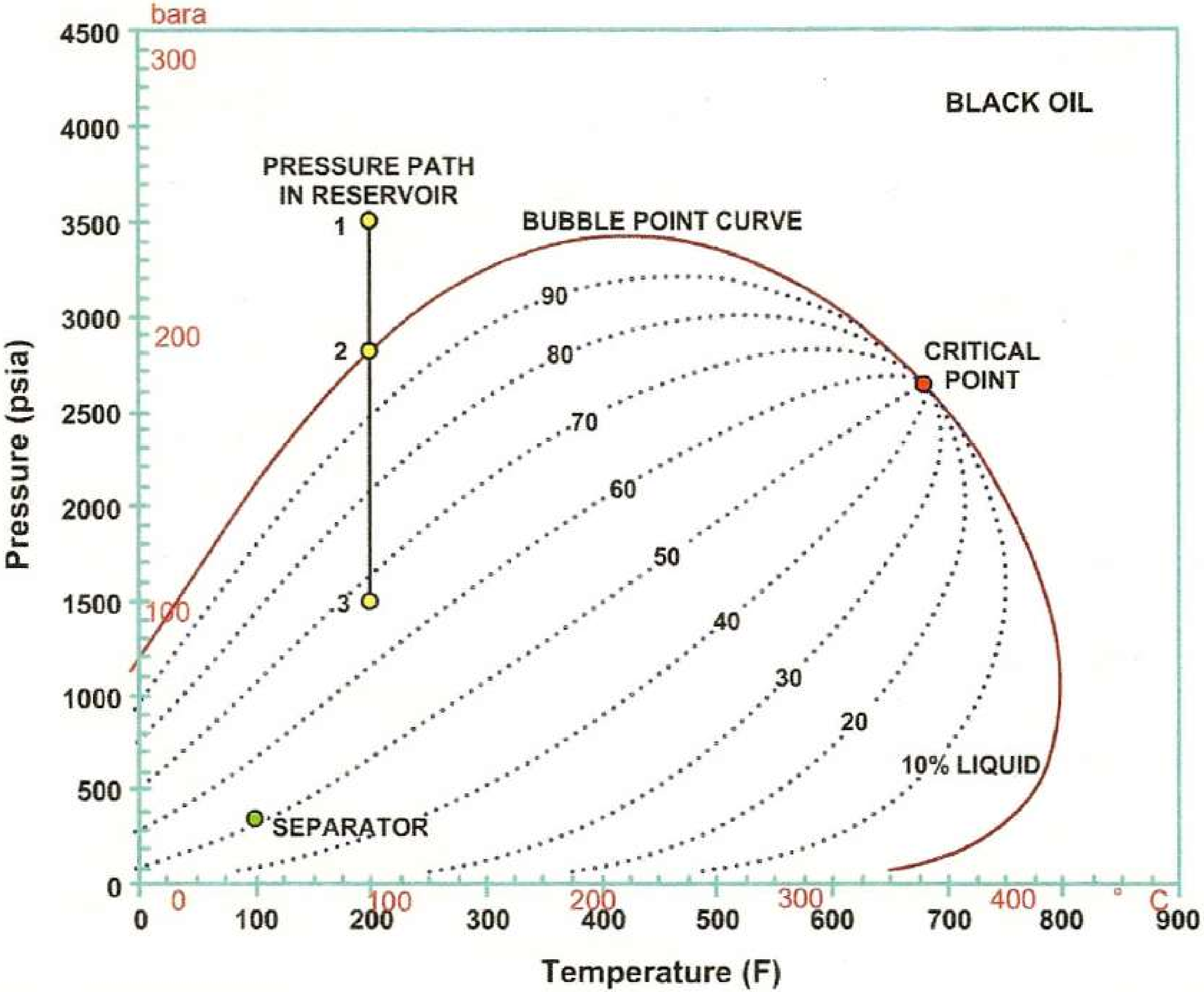
Flow characteristics

- Pressure is the main driving force for a reservoir and this will decay with time.
- The initial pressure and subsequent pressure profile of the reservoir will determine how a reservoir flows and how it will produce.
- Above the bubble point pressure, all the gas is in solution and will remain in solution until the bubble point pressure is reached.

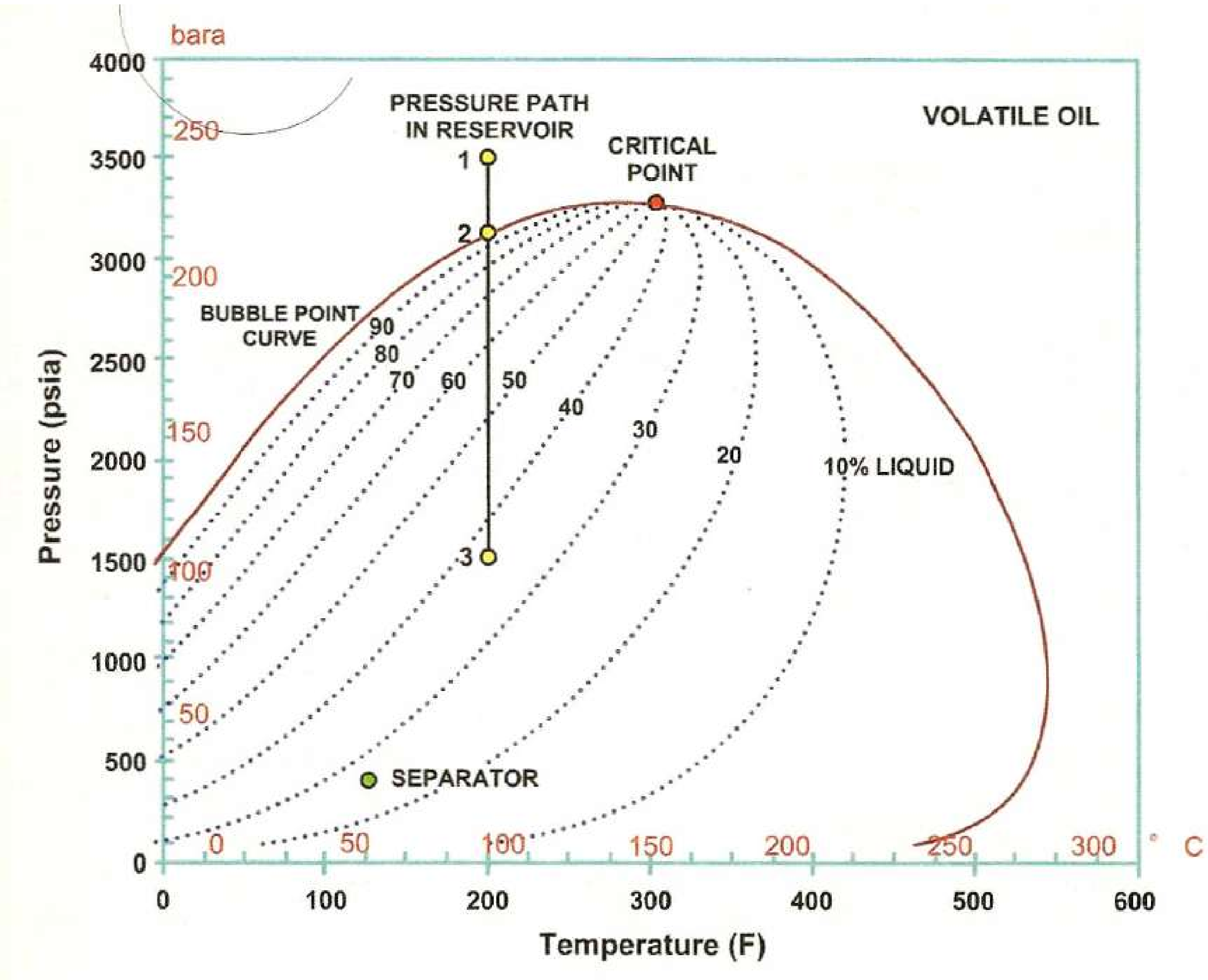
  : The reservoir produces under “solution” drive. (only 5~25% recovery of available reserves)
- At or below the bubble point pressure, the gas comes out of solution and forms a gas cap above the oil. The fluid is in the two-phase region and at equilibrium.

  : The reservoir produces under “gas” drive. (20~40% recover)
- Once the well bottom pressure is equal to the reservoir pressure, the reservoir pressure can no longer support production.

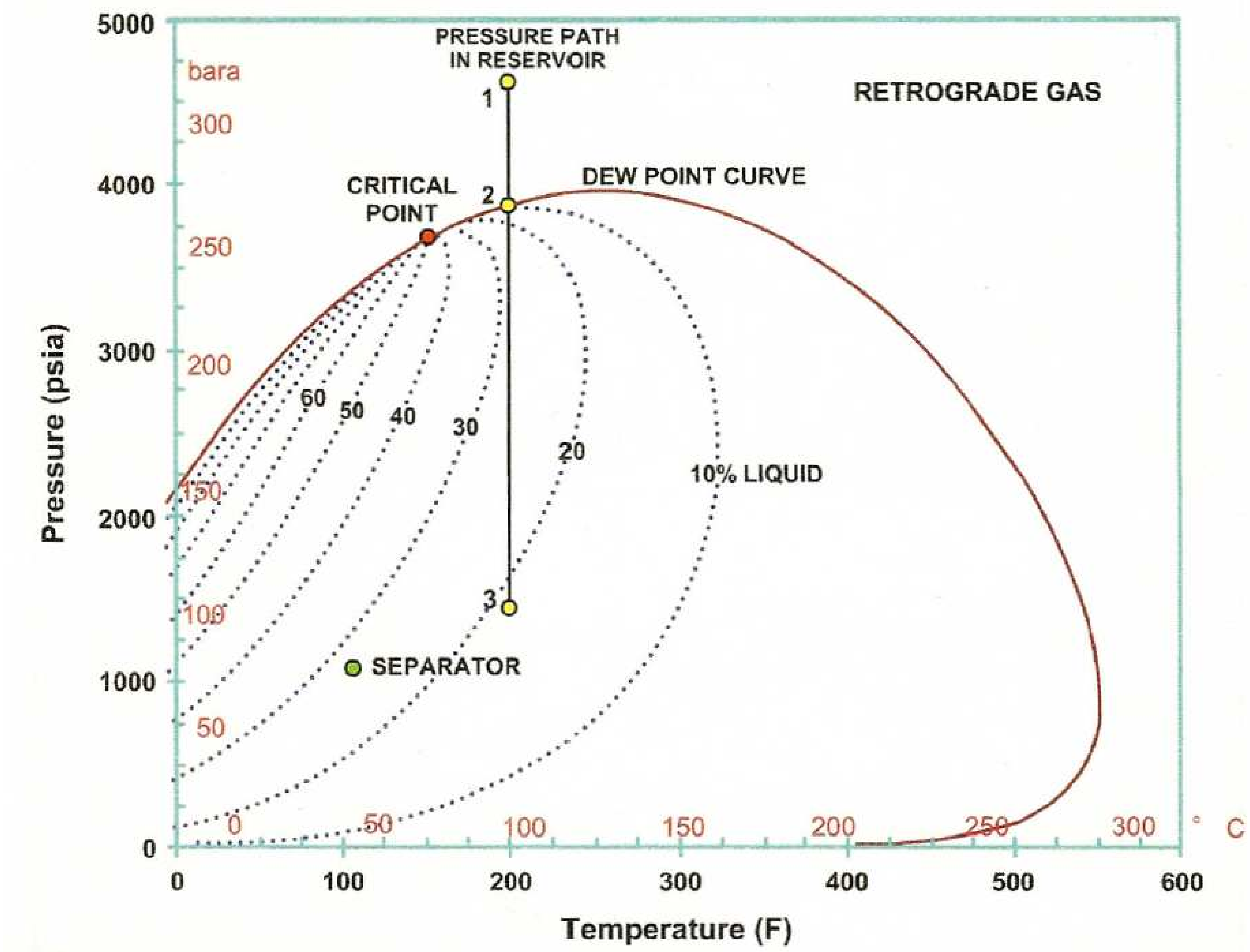
Black oil phase diagram



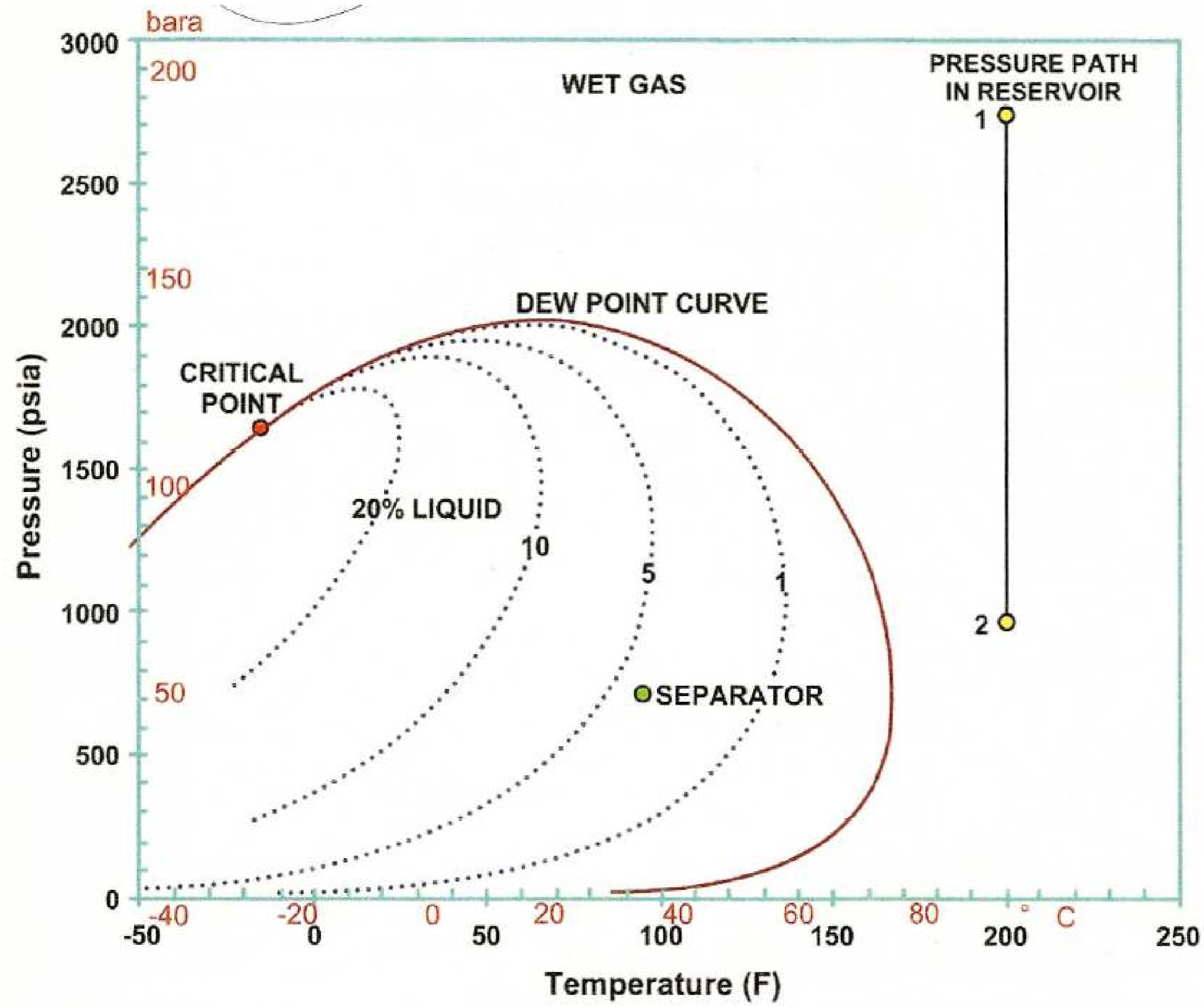
Volatile oil phase diagram



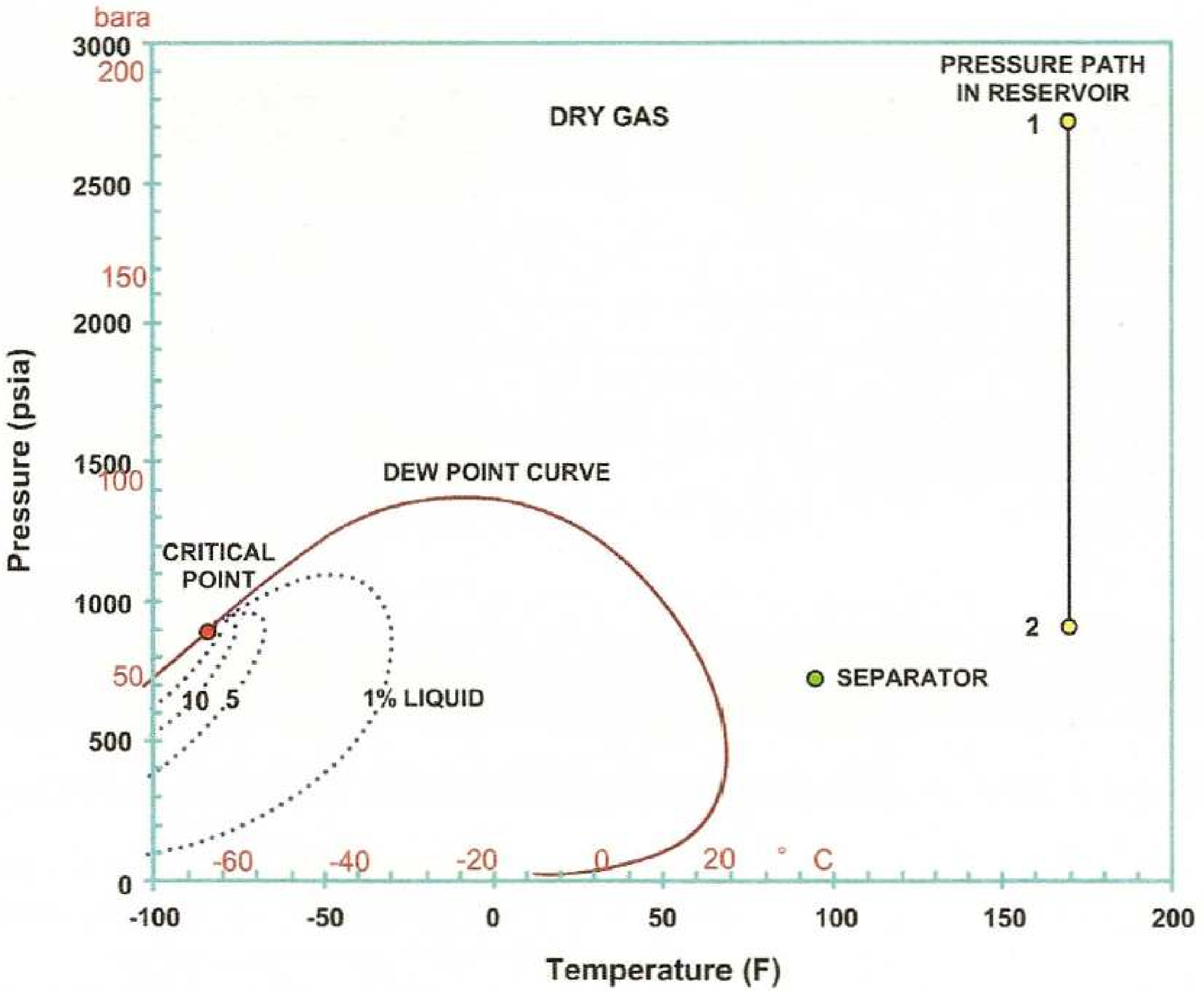
Condensate phase diagram



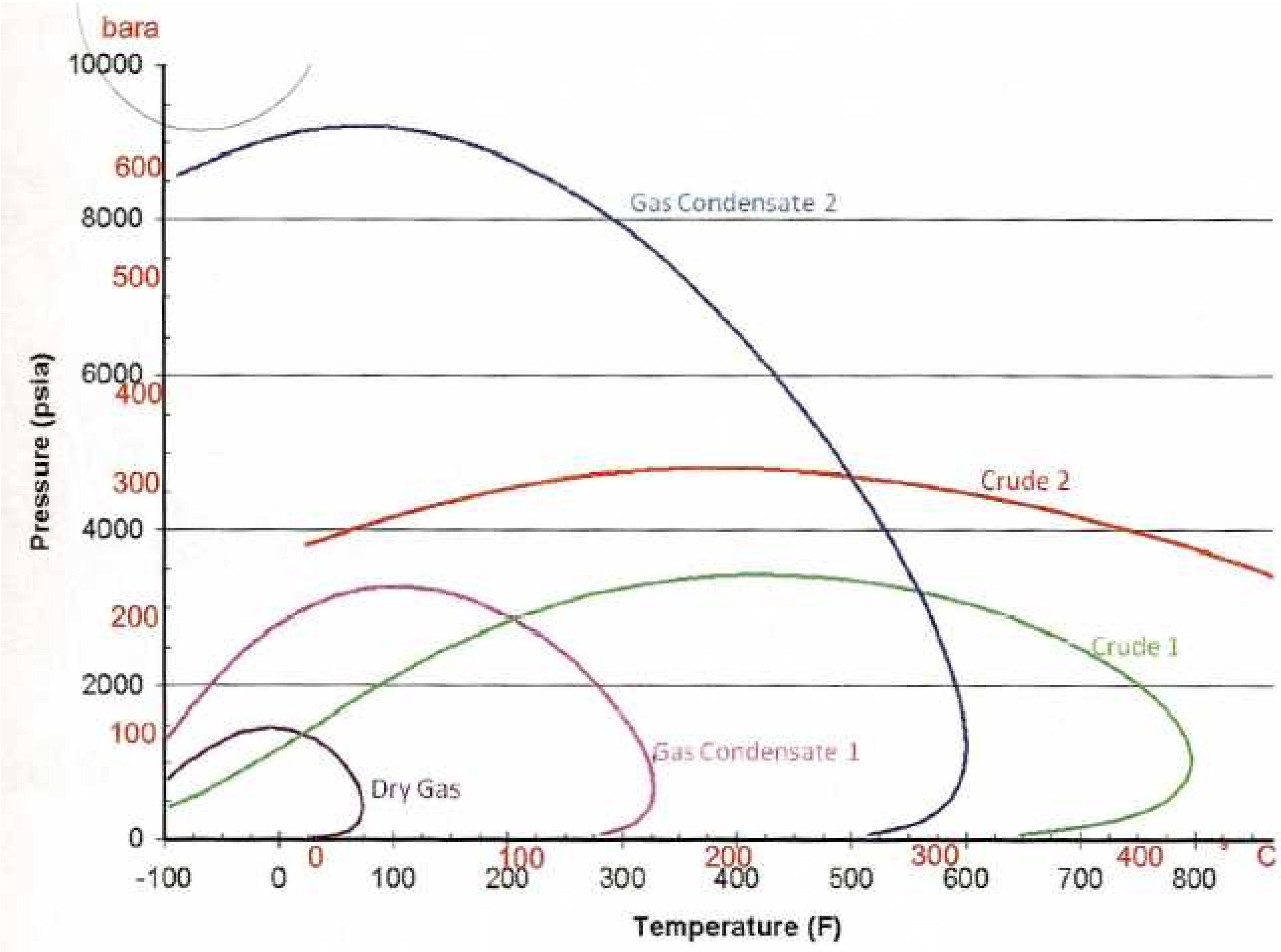
Wet gas phase diagram



Dry gas phase diagram



Two phase envelops for various fluids



Summary

- Subsea field development
- Wet tree vs. Dry tree
- Fixed / Floating – FPSO
- Subsea production system and its operation
- Multicomponent phase diagram
- Black oil / Volatile oil / Gas condensate / Wet gas / Dry gas

Thank you!