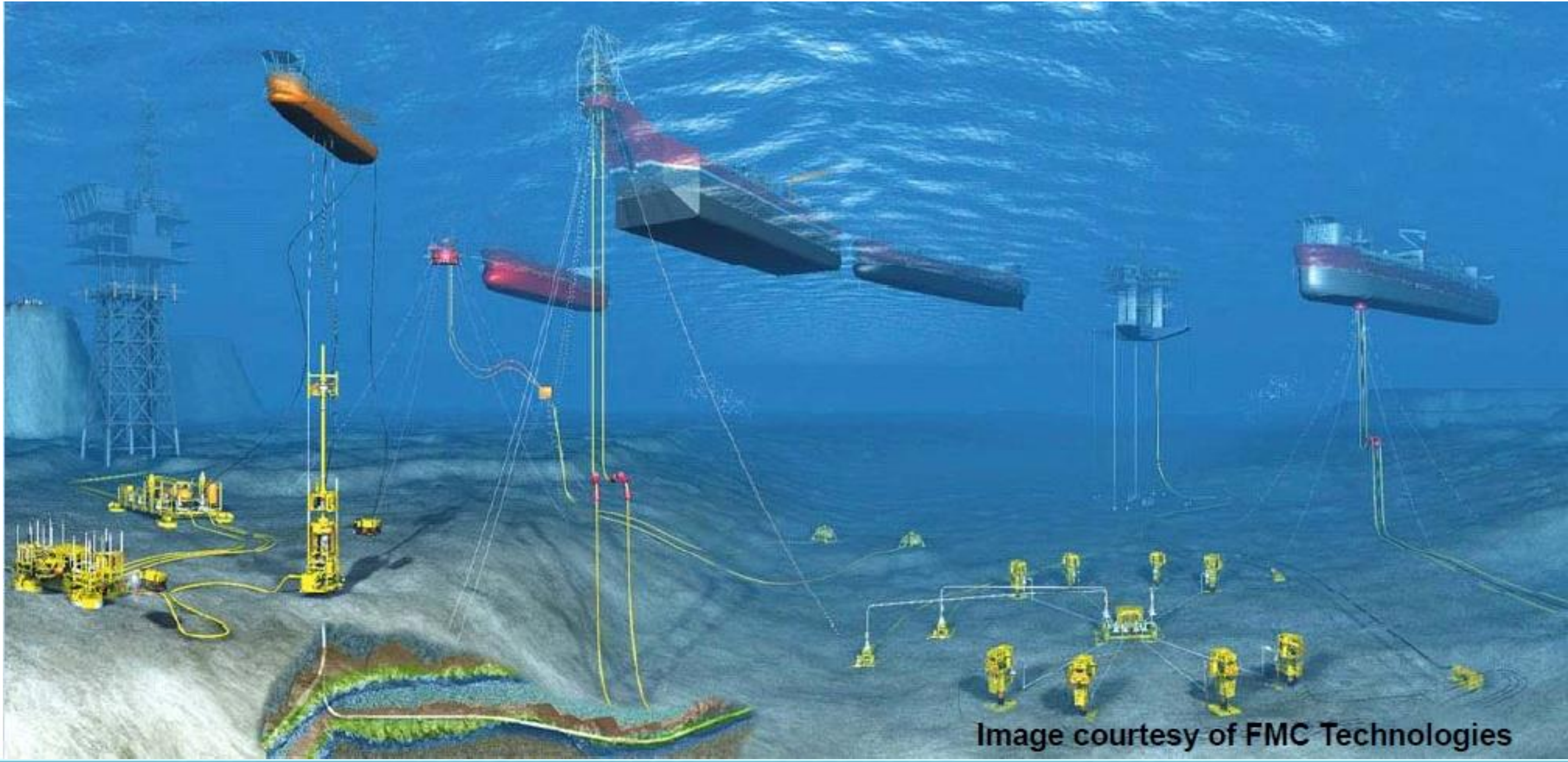
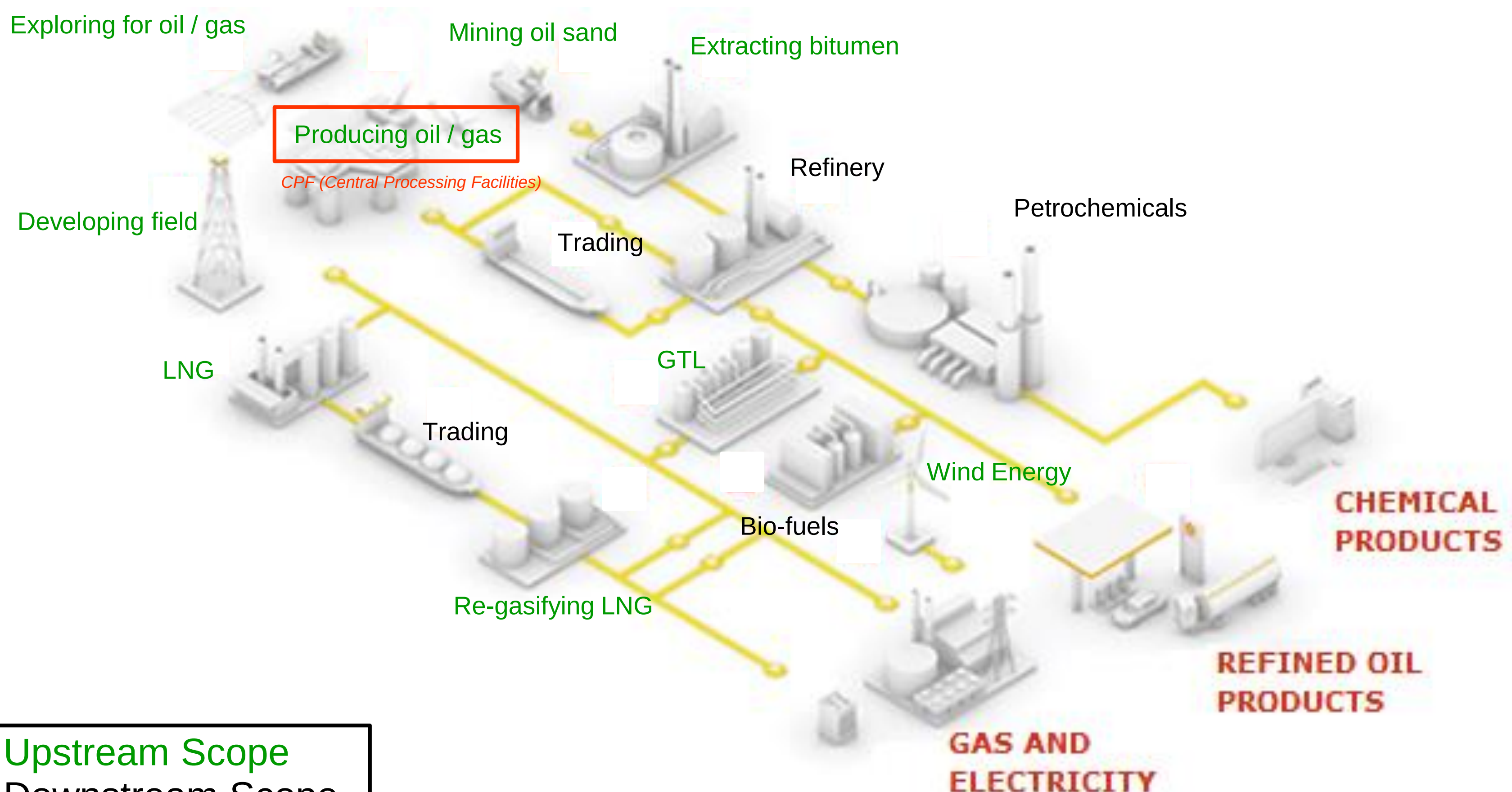


Introduction to Offshore Engineering

Yutaek Seo

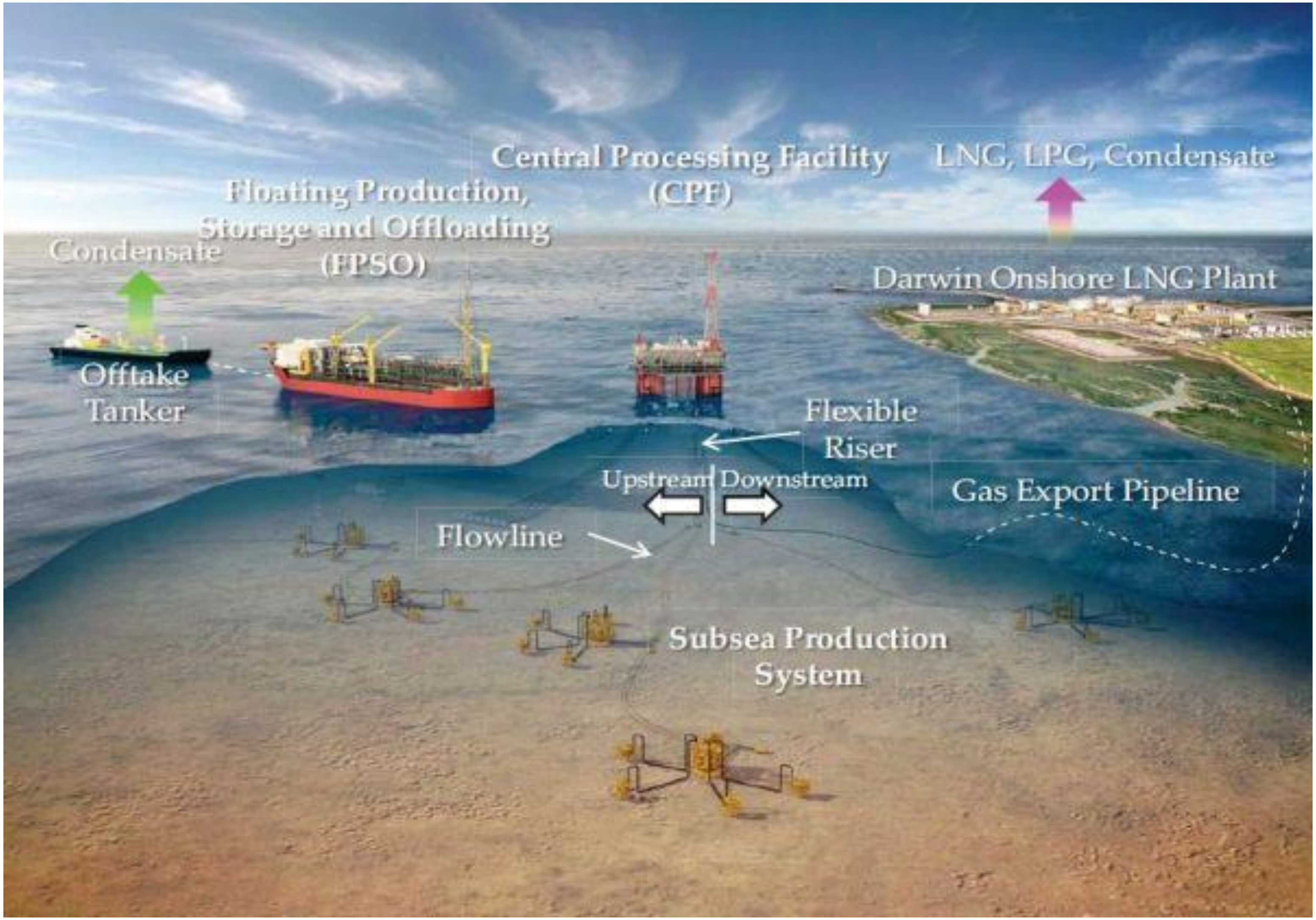
Upstream & Downstream



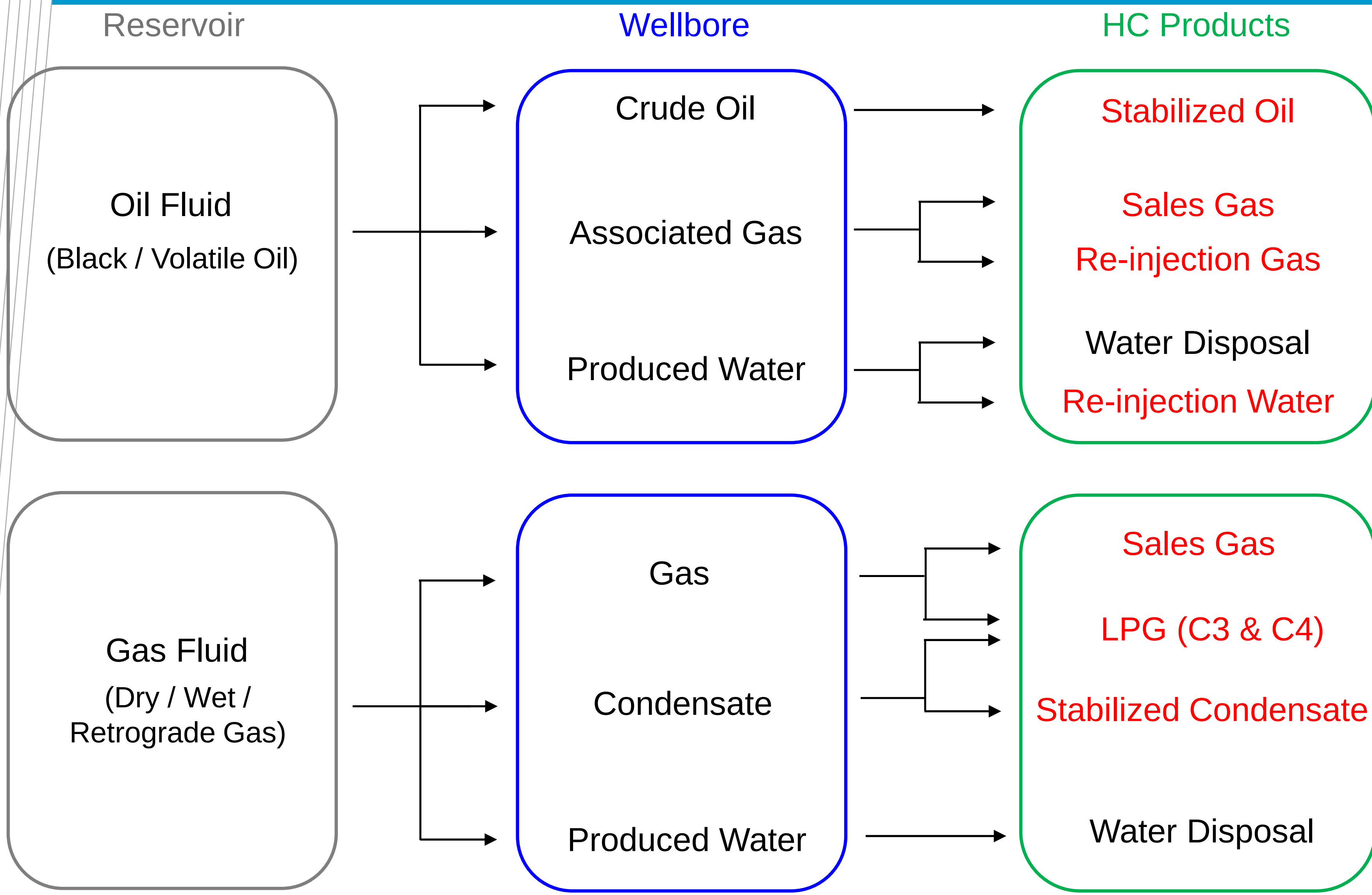
Upstream Scope
Downstream Scope

CPF (Central Processing Facilities)

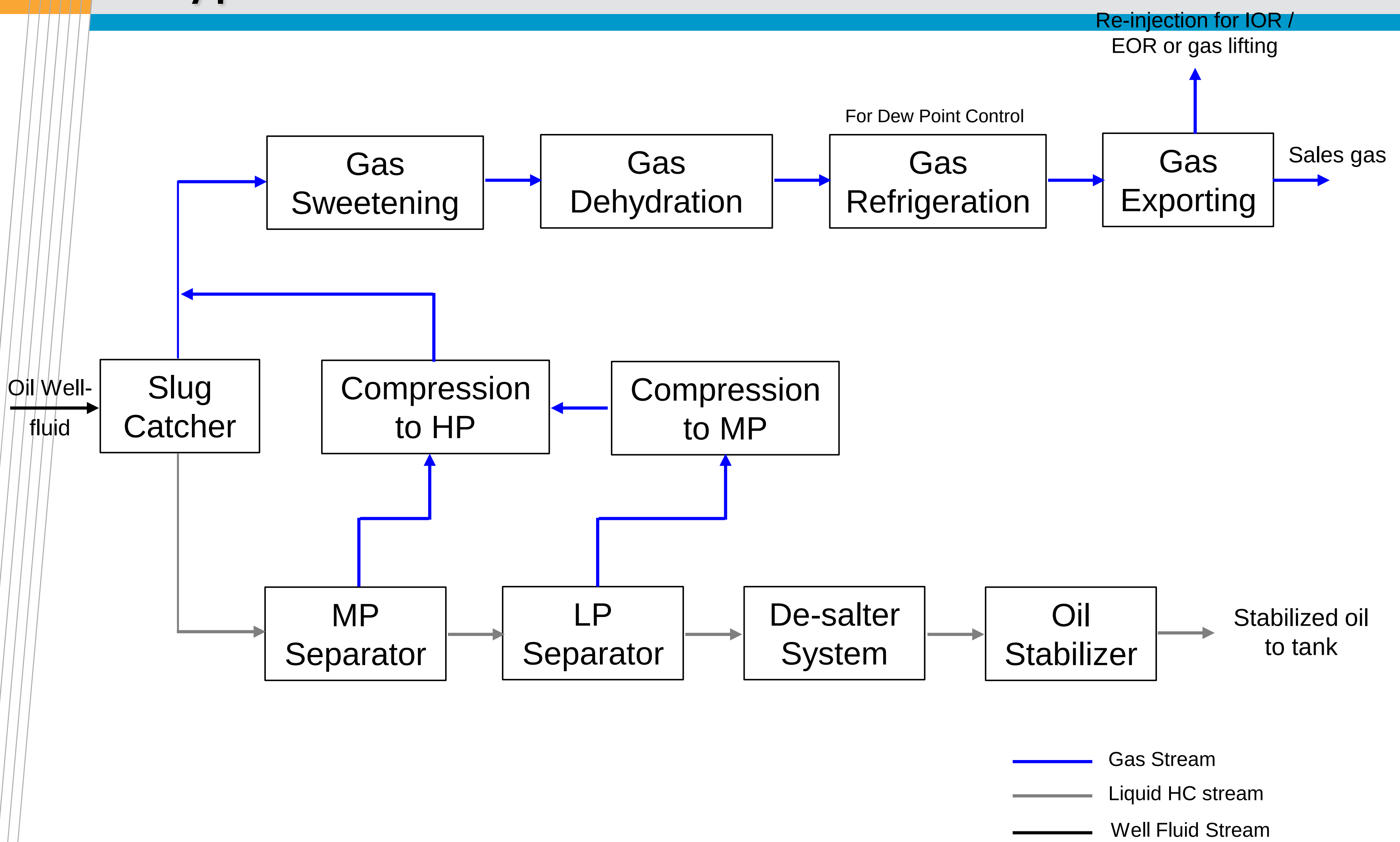
Gas / Condensate Production for Dawin LNG Project (AU)



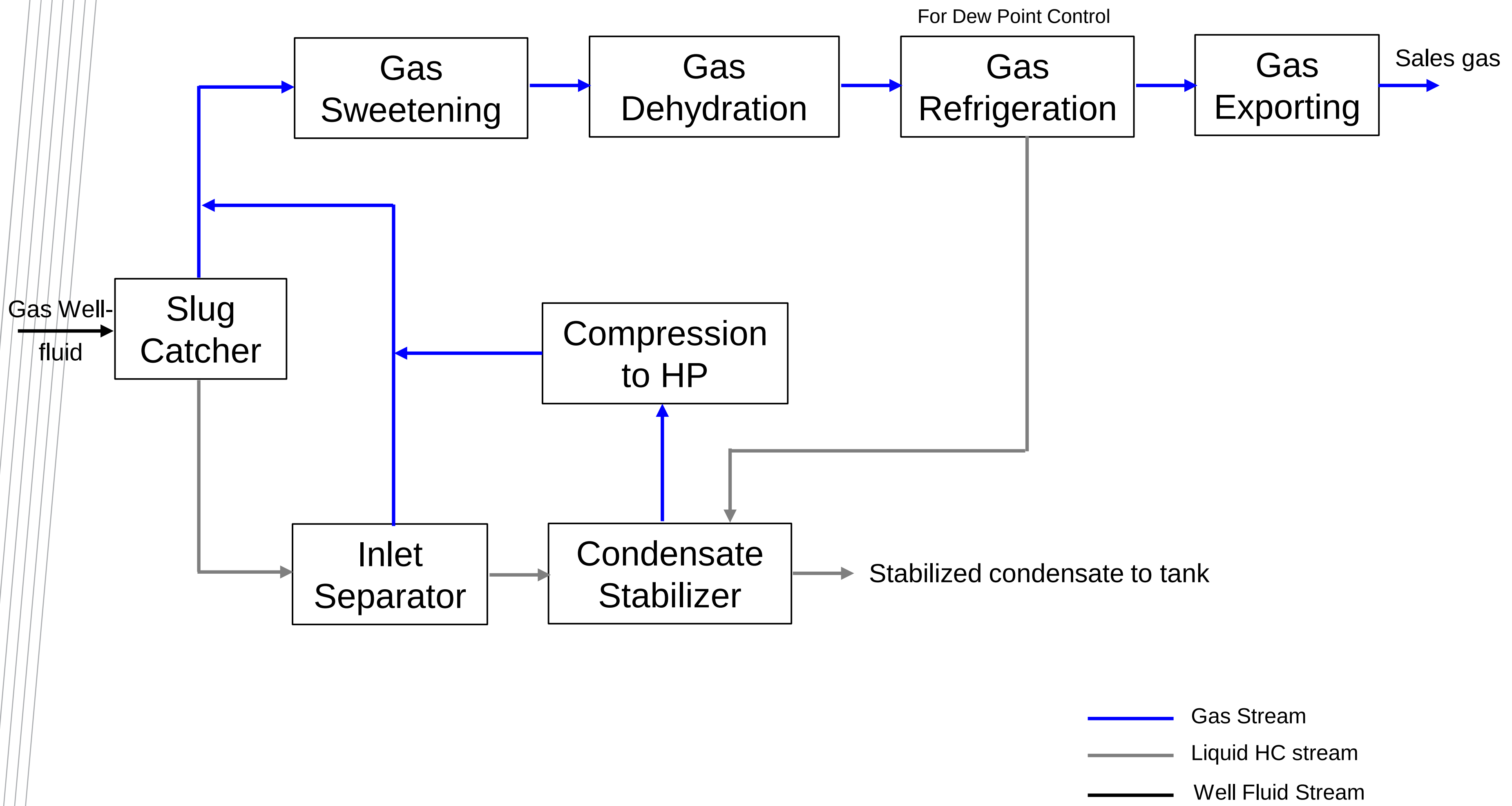
Form Reservoir To Products



Typical CPF : Oil Field

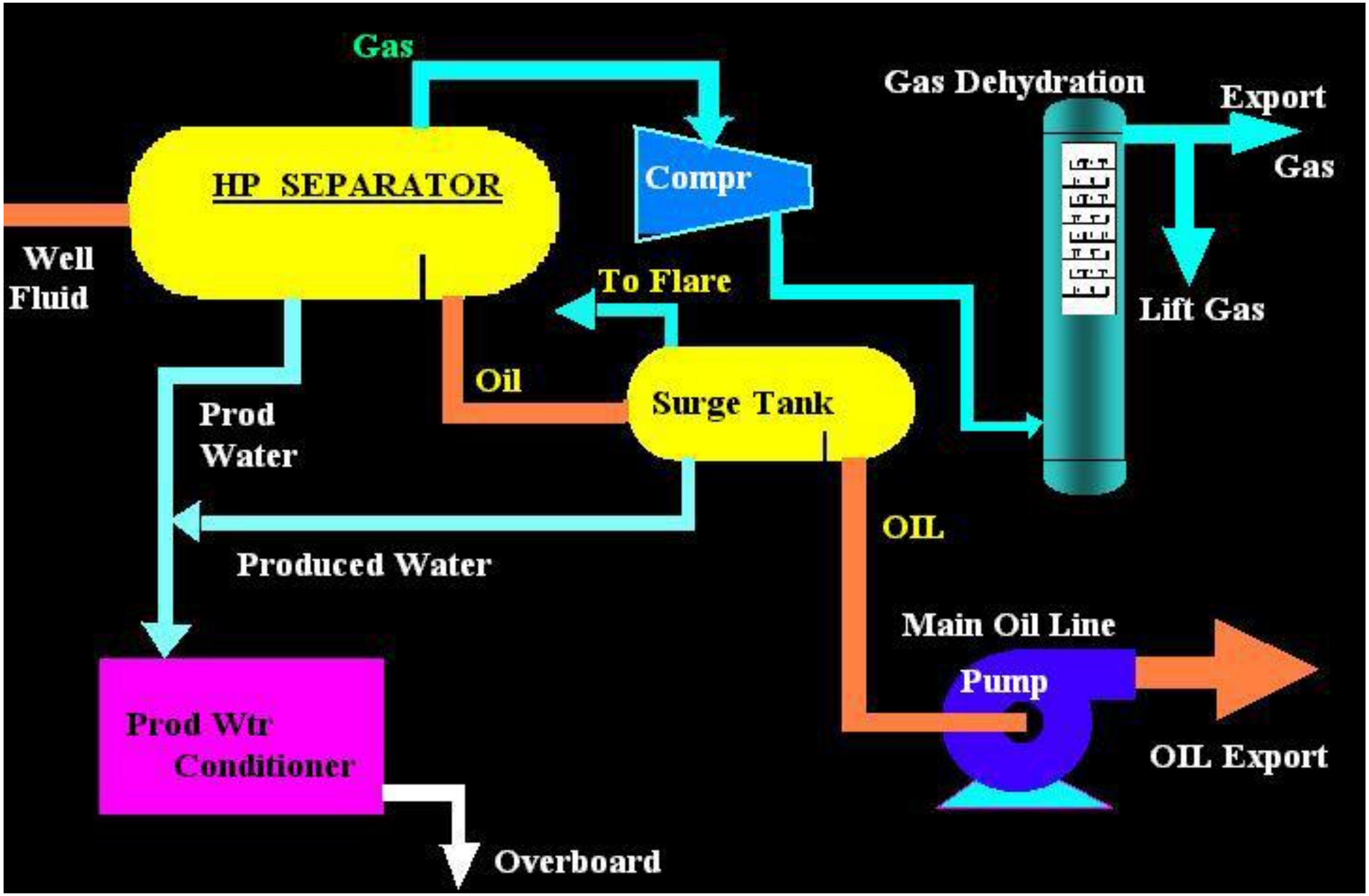


Typical CPF : Gas Field

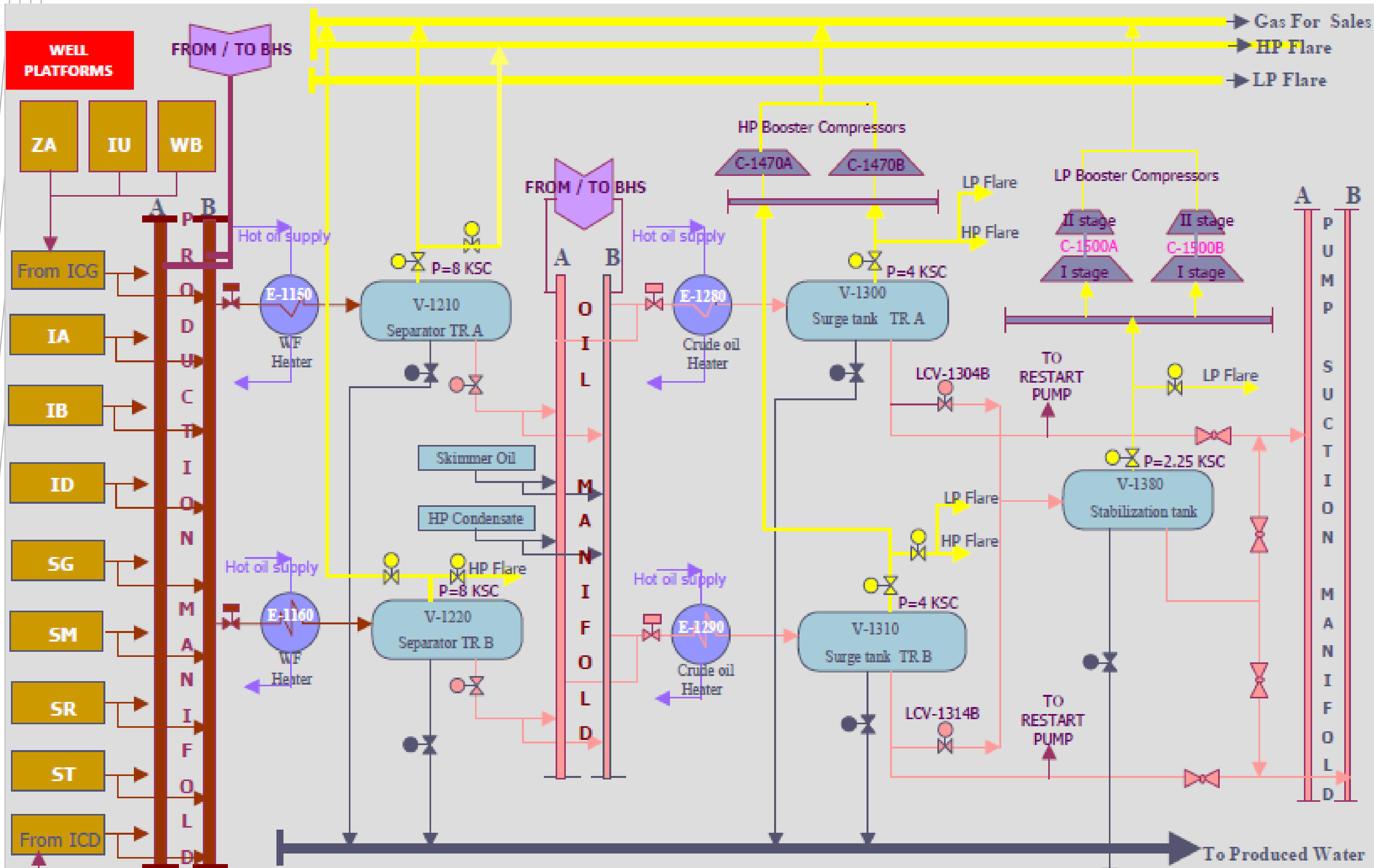


Processing in offshore platforms

Process flow for separation



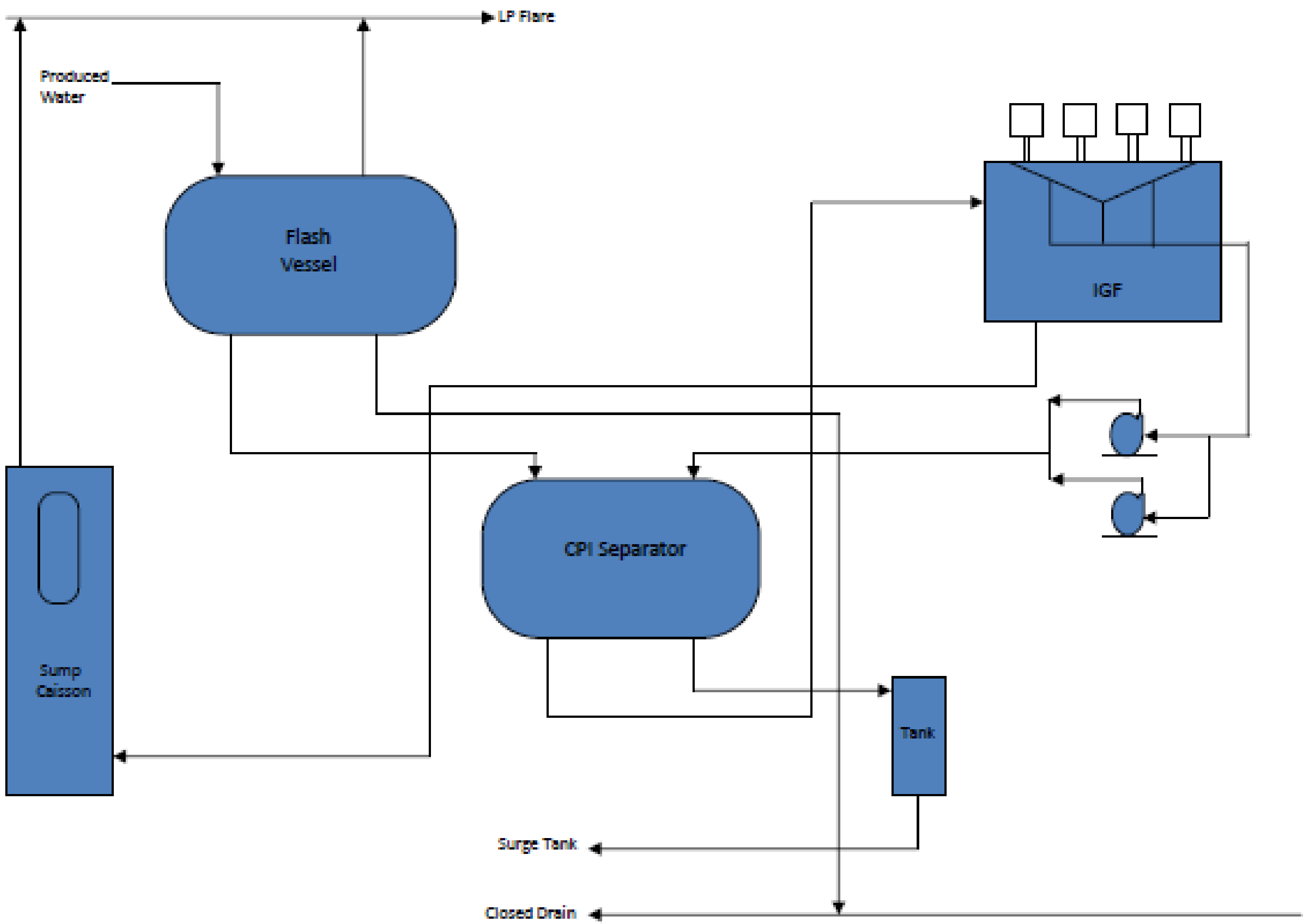
Separation trains



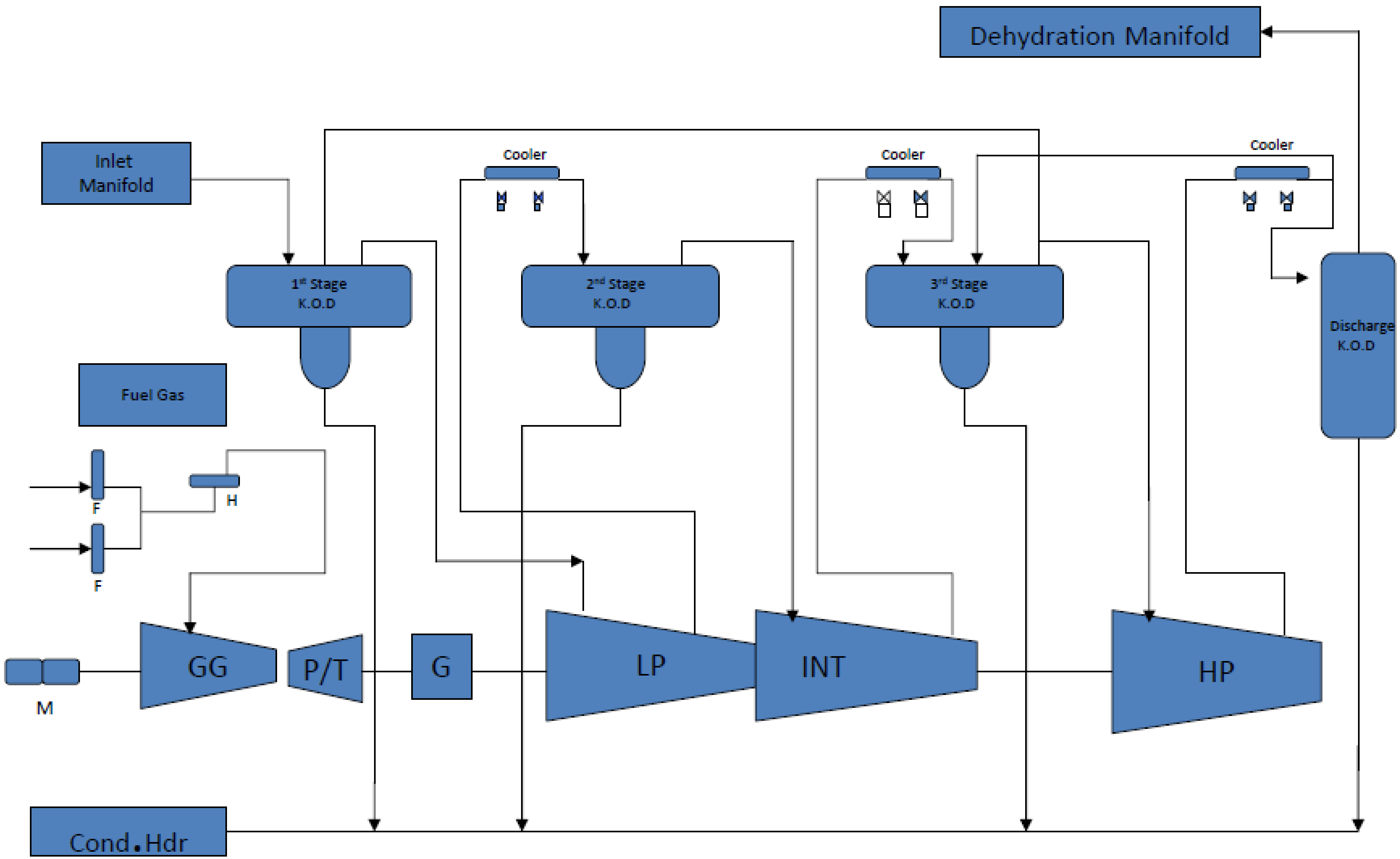
Separation of oil, gas, and water

Crude oil export via tanker

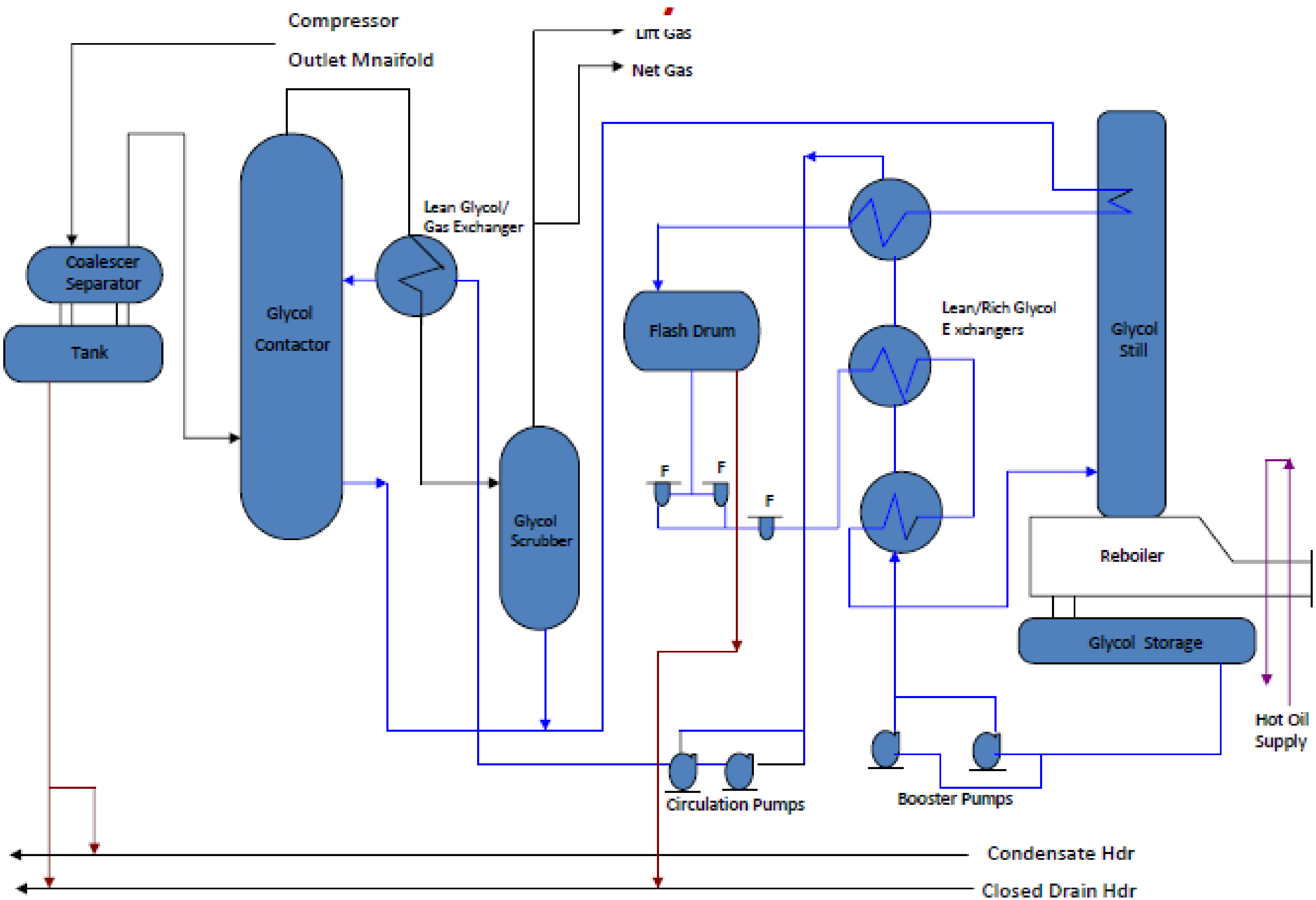
Water treatment



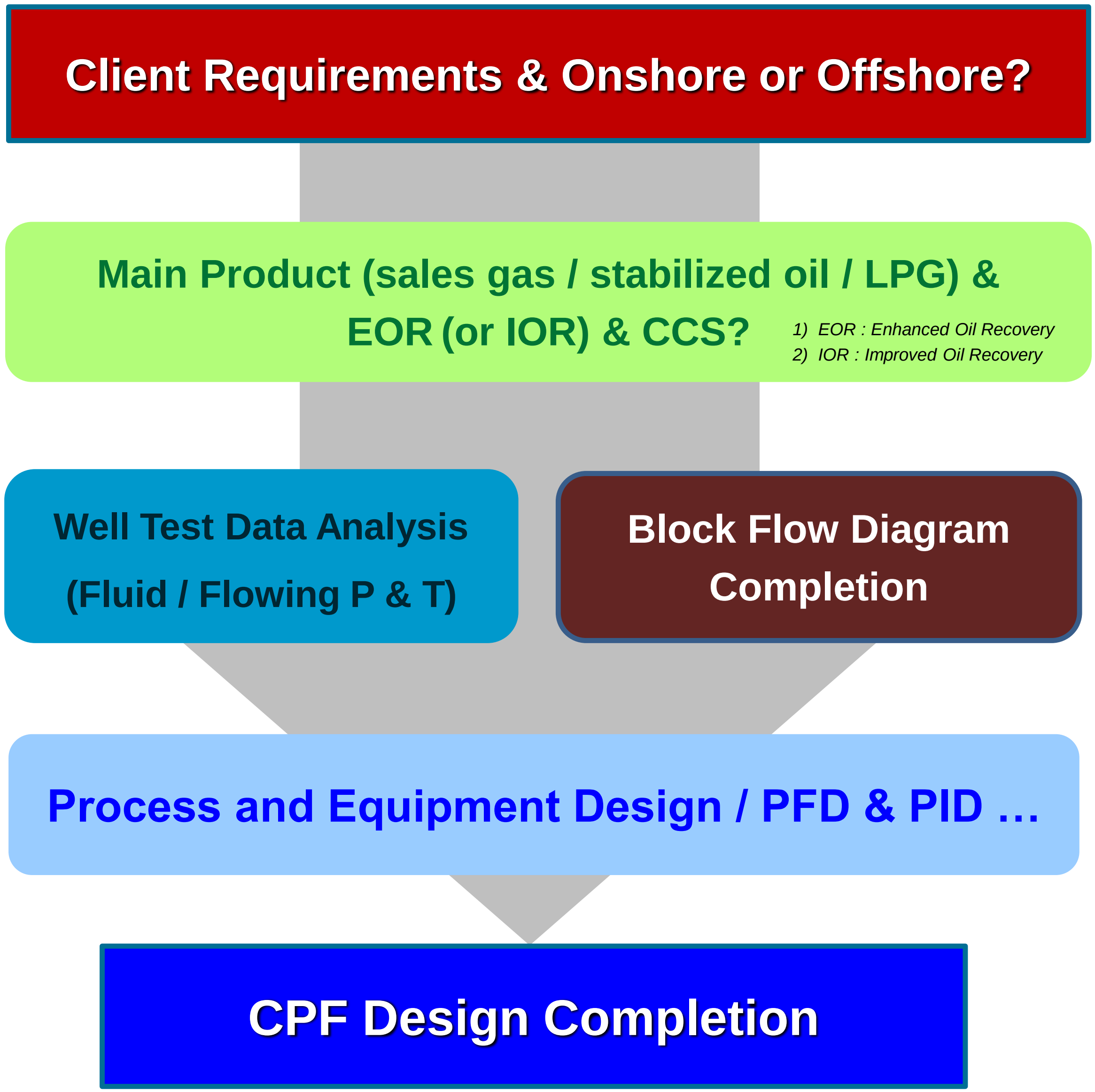
Gas collection and compression



Gas dehydration



Design Process



Oil FPSO

- FPSOs are large ships equipped with processing facilities and moored to a location for a long period.

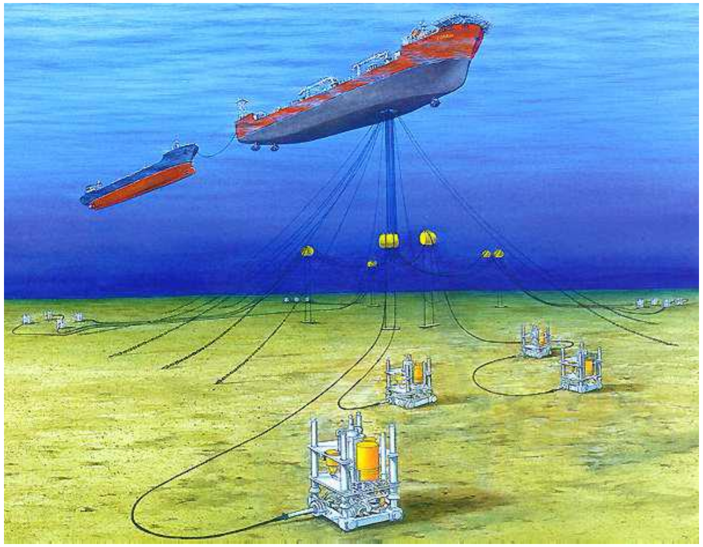
The main types of floating production systems are:

FPSO(floating production, storage, and offloading system),

FSO (floating storage and offloading system), and

FSU (floating storage unit).

- These ships do not actually drill for oil or gas.



Maintenance and supply

- A typical offshore platform is self-sufficient in energy and water needs, housing electrical generation, water desalinators and all of the equipment necessary to process oil and gas such that it can be either delivered directly onshore by pipeline or to a Floating Storage Unit and/or tanker loading facility.
- Elements in the oil/gas production process include wellhead, production manifold, Production separator, glycol process to dry gas, gas compressors, water injection pumps, oil/gas export metering and main oil line pumps.
  - All production facilities are designed to have minimal environmental impact.
  - Larger platforms are assisted by smaller ESVs (emergency support vessels) that are summoned when something has gone wrong, e.g. when a search and rescue operation is required.
  - During normal operations, PSVs (platform supply vessels) keep the platforms provisioned and supplied, and AHTS vessels can also supply them, as well as tow them to location and serve as standby rescue and fire fighting vessels.

Processes

- 3-Phase well fluid is received from Wells/Well Platforms and processed at Large Process Platforms generally consisting of the following four Major Processing Modules.
  - Separation (Oil, Gas and Produced water) & Oil dispatch
  - Gas Compression & dehydration
  - Produced Water Conditioning
  - Sea water processing & injection system

- These process complexes will also have the following:
  - Fire detection & Suppression system
  - Power Generation
  - Well services/drilling Modules
  - Water Maker/Utilities/Sewage Treatment
  - Living Quarters

Fire detection and suppression system

- Detection System
  - Gas Detection
  - Fusible Plug
  - Fire Detection
  - Smoke Detection
  - Heat Detection

- Suppression System
  - FIRE WATER PUMPS
  - Water Sprinkler
  - Dry Chemical
  - FM-200
  - CO2Extinguisher
  - AFFF SYSTEM

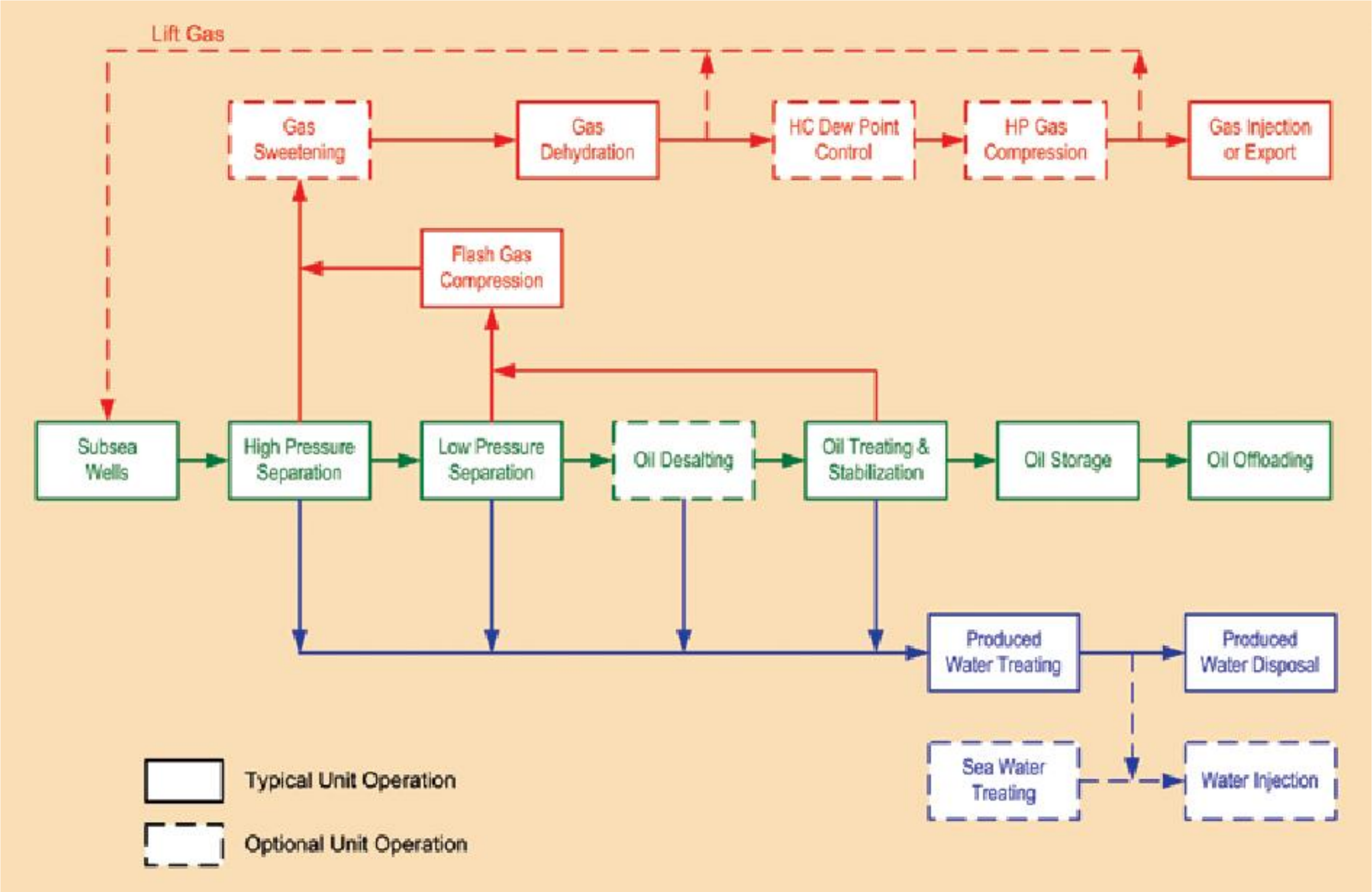
Escape / Abandon

- Escape Ladder
- Scramble Net
- Life Ring
- Life Raft
- Life Boat
- Jumping Rope

Utilities

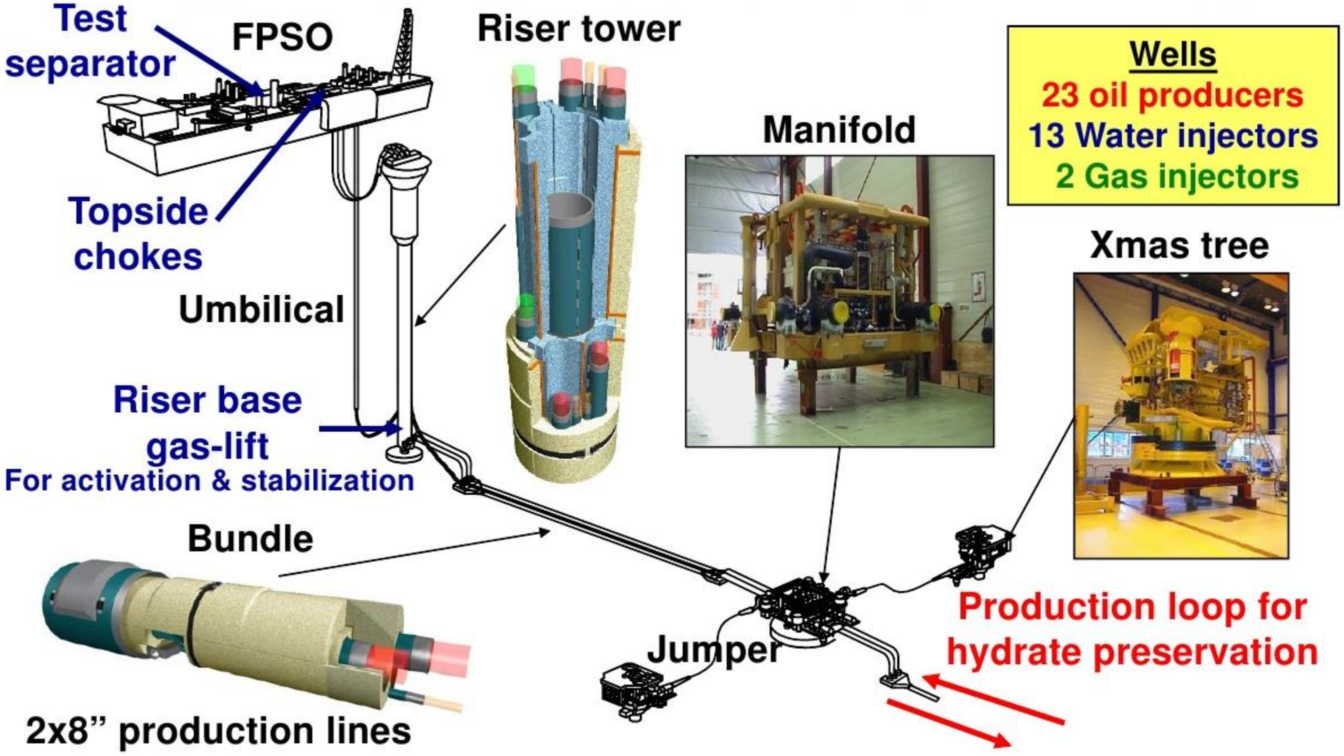
- POWER GENEARTION –GAS TURBINE DRIVEN GEBERATORS
- WATER MAKERS-RO WATER MAKERS
- LIVING QUARTERS AND ASSOCIATED REQUIREMNETS LIKE LAUNDRY, GALLEY
- EMERGENCY DIESEL GENERATORS
- COMMUNICATION SYSTEMS

Oil FPSO topside facilities



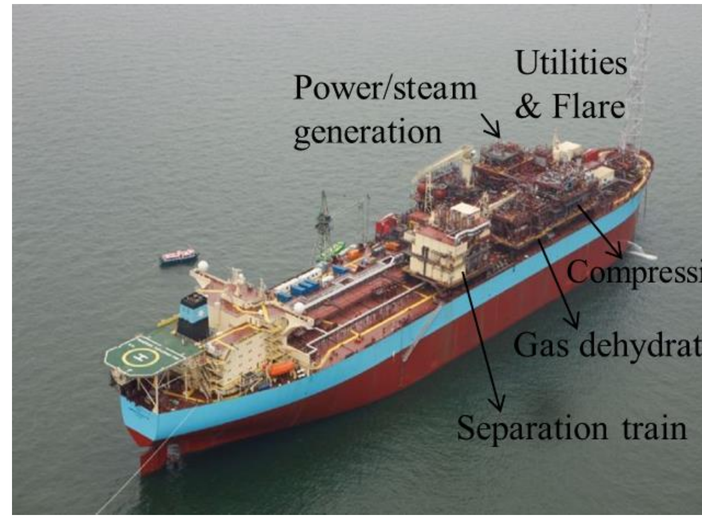
FPSO in West Africa

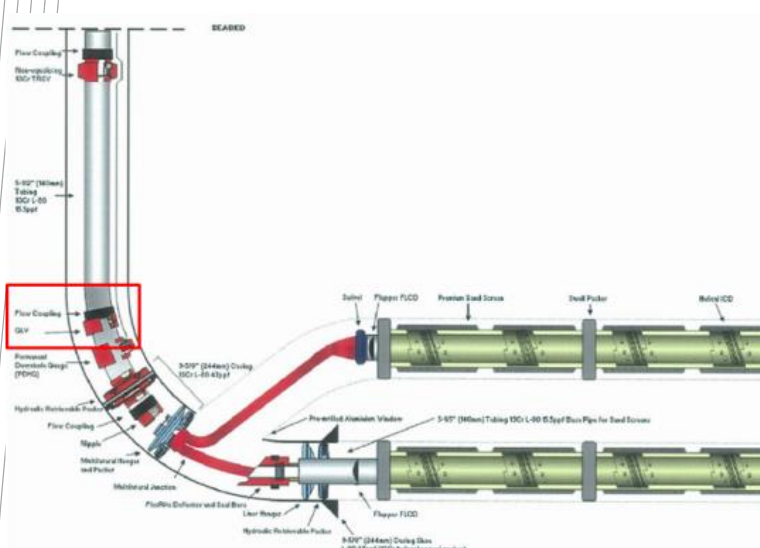
- Girassol (TotalFinaElf)
  - : Located of NNW Luanda, Angola - 1350m of water
  - : Producing 32º API crude oil from 23 wells
  - : Total storage capacity 2 million bbl of crude oil
  - : Liquid processing 180,000 bpd
  - : 3 million m^3/d gas lift with 8 million m^3/d gas compression and dehydration

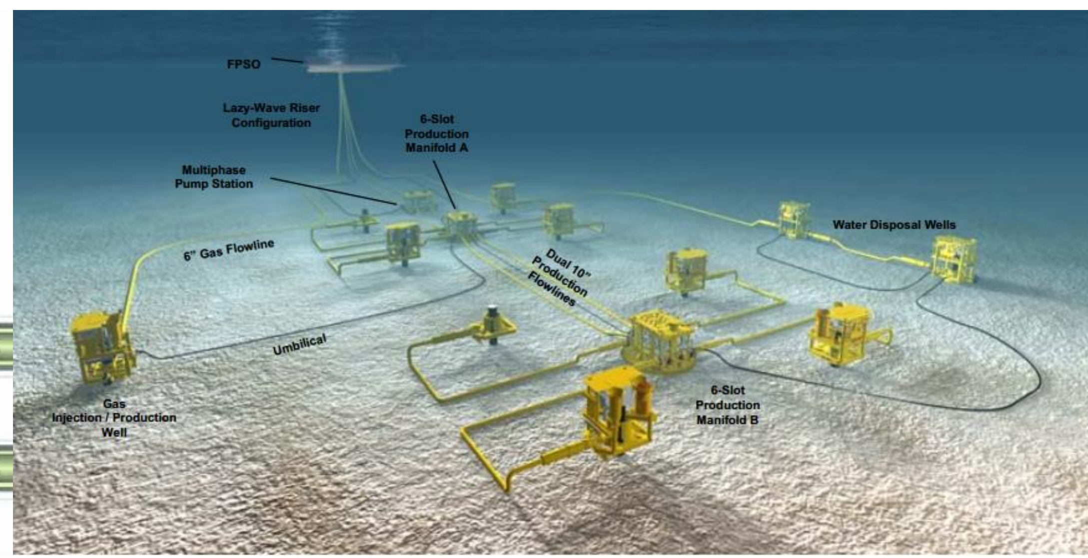


FPSO in Western Australia

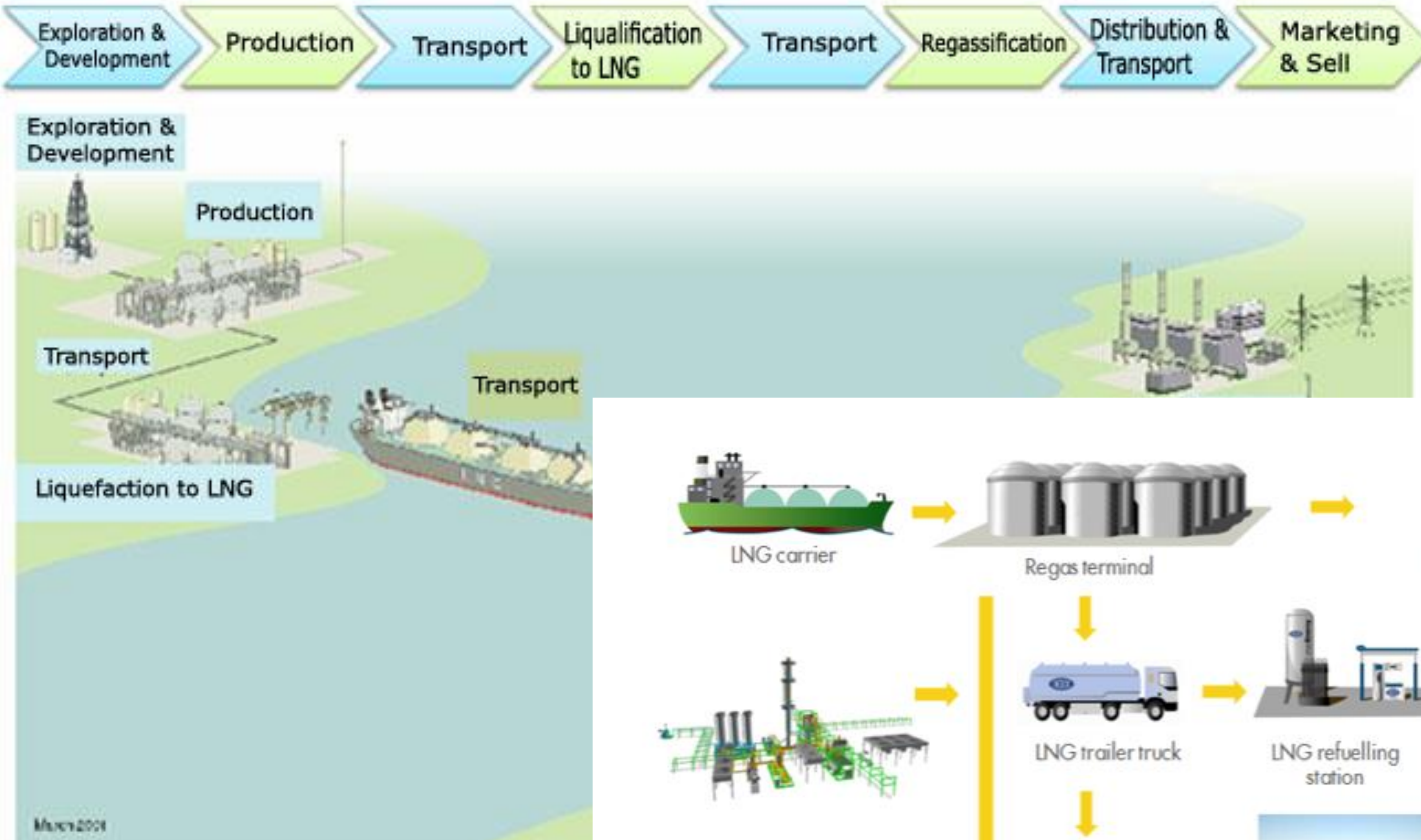
- **Vincent oil field**
  : Located offshore Exmouth in Western Australia
  : Water depth 350m, 17° API crude from 8 wells
  : Oil column thickness 8.5 ~ 19.0 m
  : Total Liquid processing capacity 120,000 b/d with total storage capacity of 1.2 million barrels of oil
  : Water (150,000 b/d) & Gas (80 MMscf/d) Injection
  : Dual sided hull and disconnectable mooring





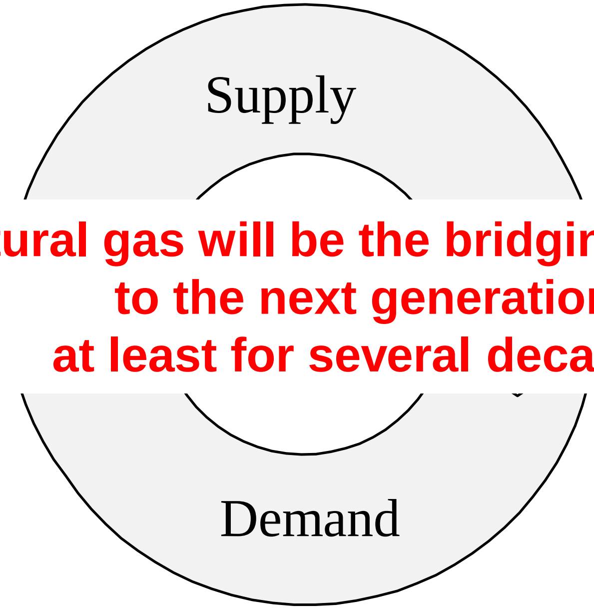


LNG value chain



Why natural gas?

- Sufficient reserves: onshore and offshore
- New solutions to non-conventional gas development (FPSO, Shale gas production)



Natural gas will be the bridging energy
to the next generation
at least for several decades

- Greener: Less CO2
- Less polluting: Negligible NOx, No SOx, No PM
- More economical: Cheaper than crude-driven fuels

Why LNG?

LNG utilization like crude

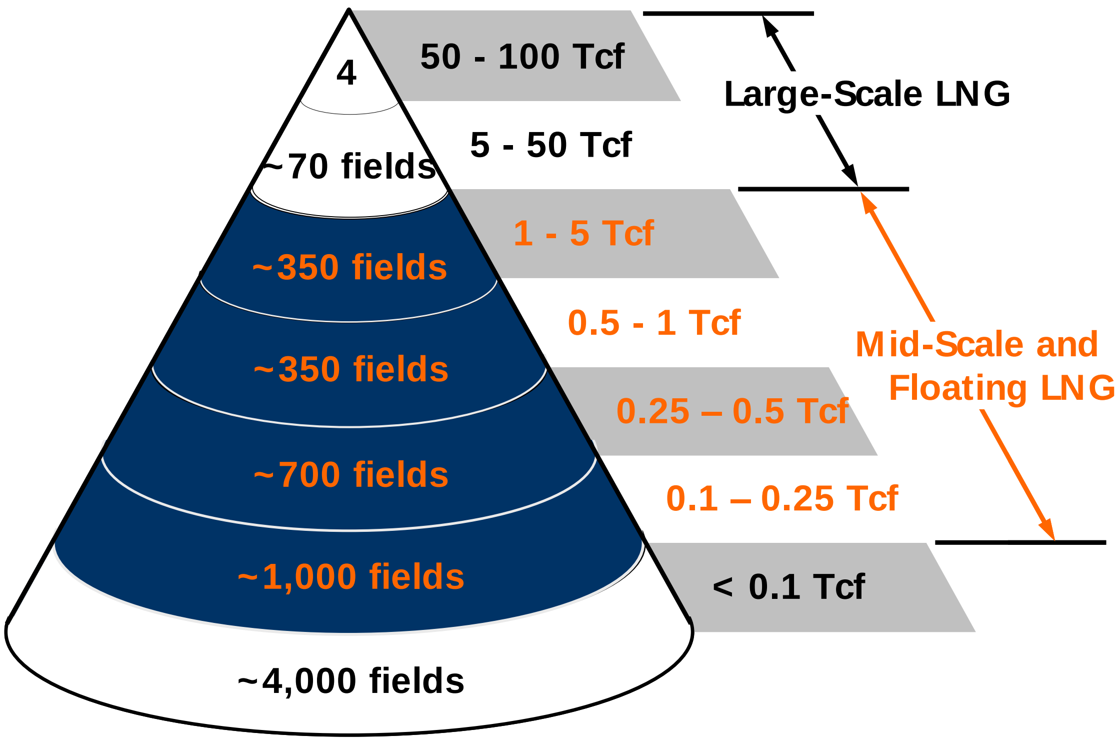
Short-lead time for LNG infrastructure

LNG-fuelled ship propulsion

LNG

FLNG opening more gas to development

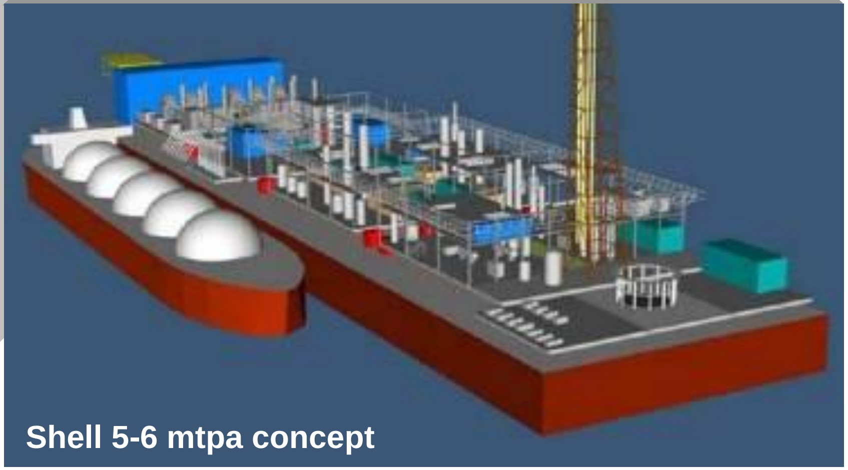
- Accesses gas unsuitable for base-load development
- Eliminates pipeline & loading infrastructure costs
- Reduces security and political risks
- Constructed in controlled shipyard environment
- Can relocate facility upon field depletion



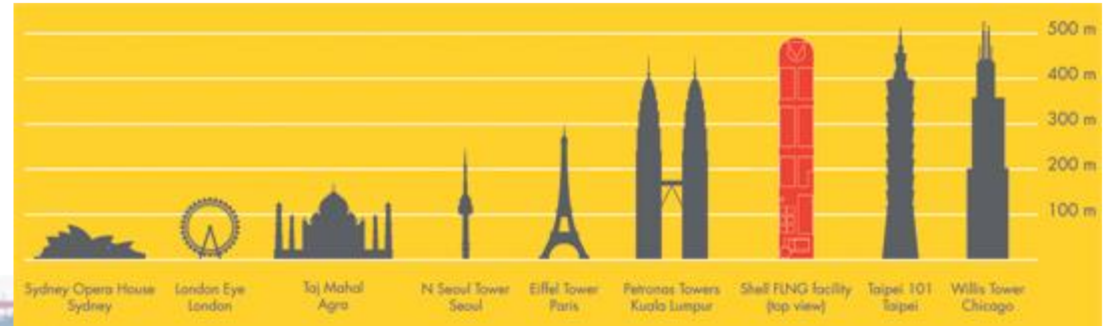
Two distinct development paths emerging

Characteristic	Small-scale Floating LNG	Large-scale Floating LNG
Liquefaction capacity:	less than 3.0 mtpa	3.5 to 6.0 mtpa
Required reserves:	0.5 to 3.0 Tcf	more than 3.0 Tcf
Hull:	Ship-like	Barge-like
Storage capacity:	up to 220,000 m^3	more than 250,000 m^3
Liquefaction processes:	Simpler processes (e.g., Single Mixed Refrigerant processes, dual expander processes)	Baseload-type processes (e.g., Dual MR, Mixed Fluid Cascade)

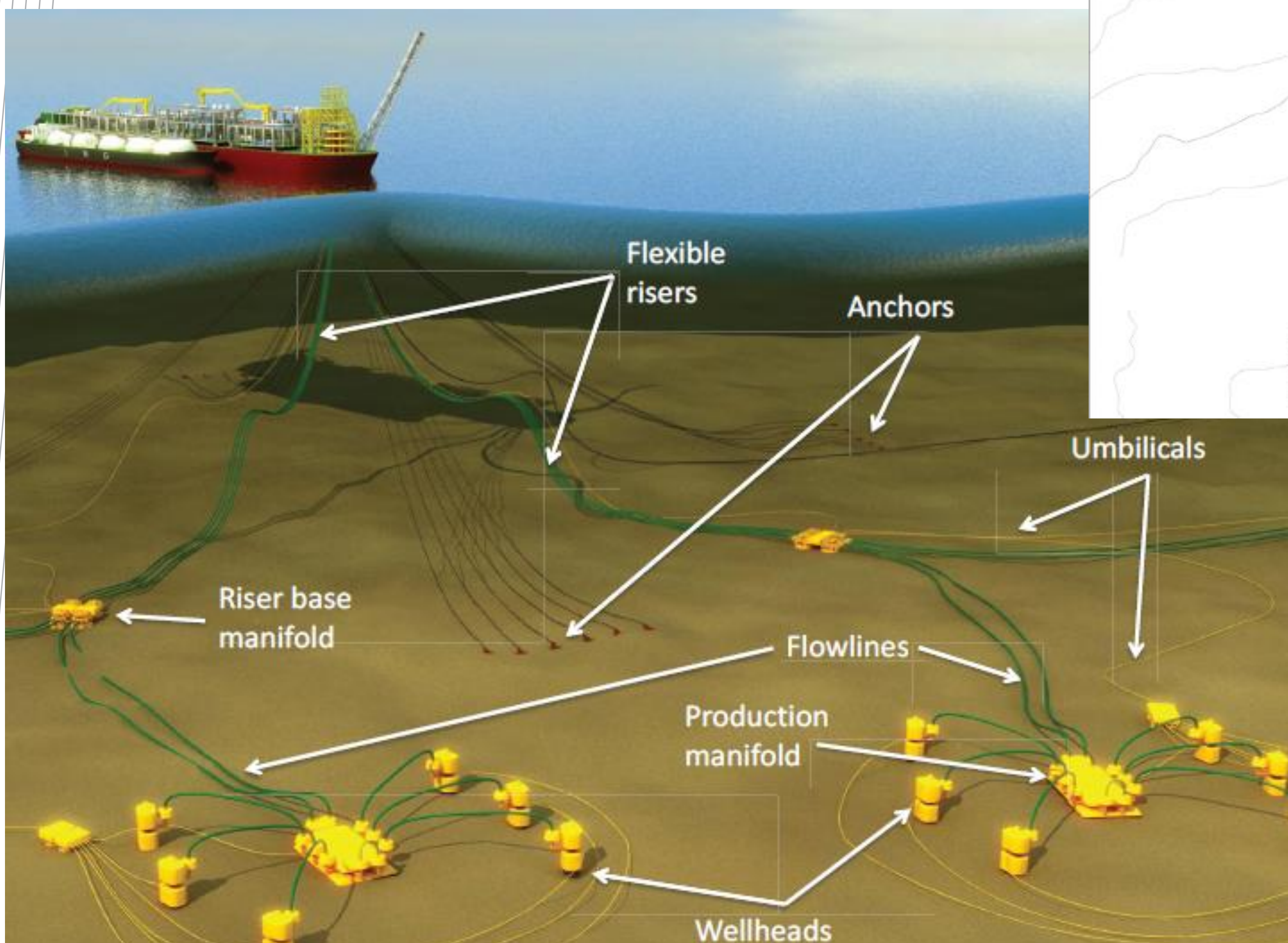
SBM Offshore 2.5 mtpa

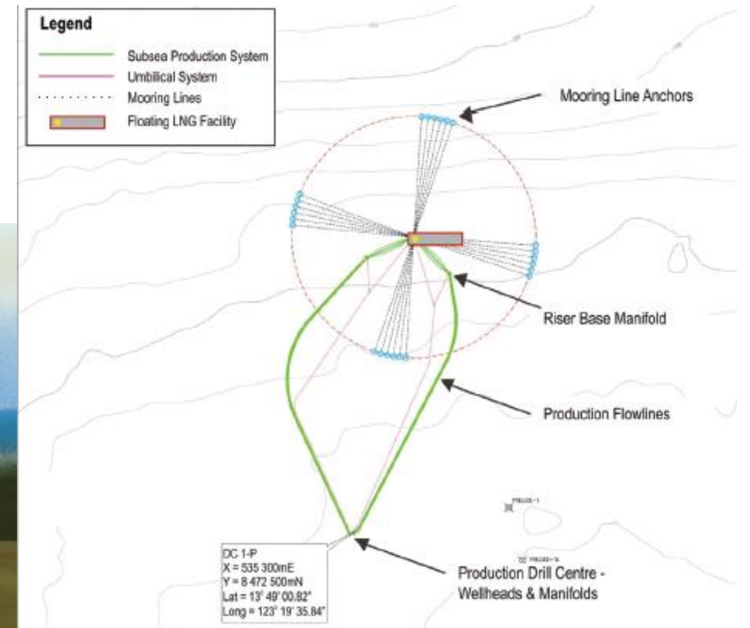

Shell 5-6 mtpa concept

Prelude FLNG

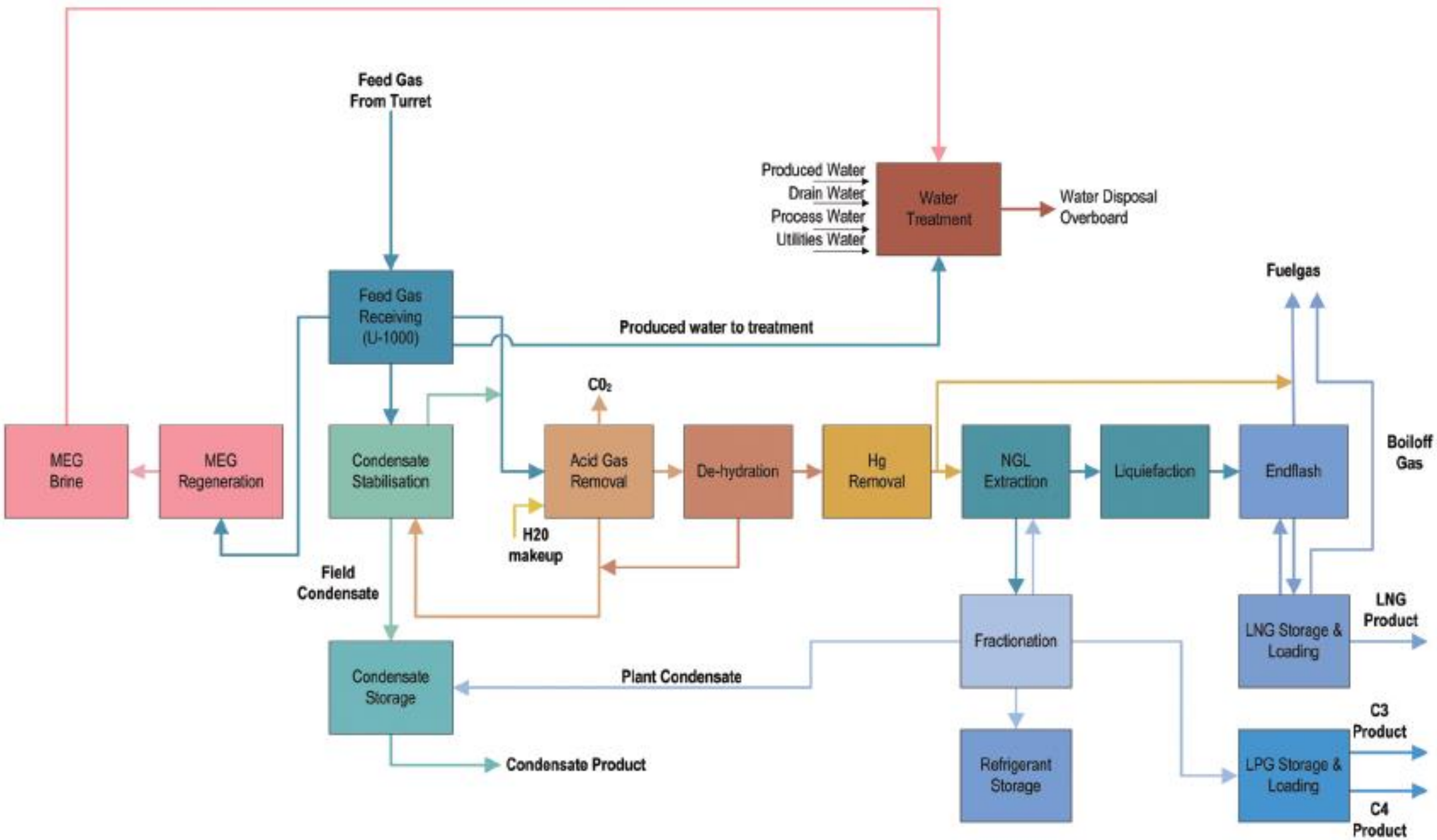


Prelude FLNG in operation

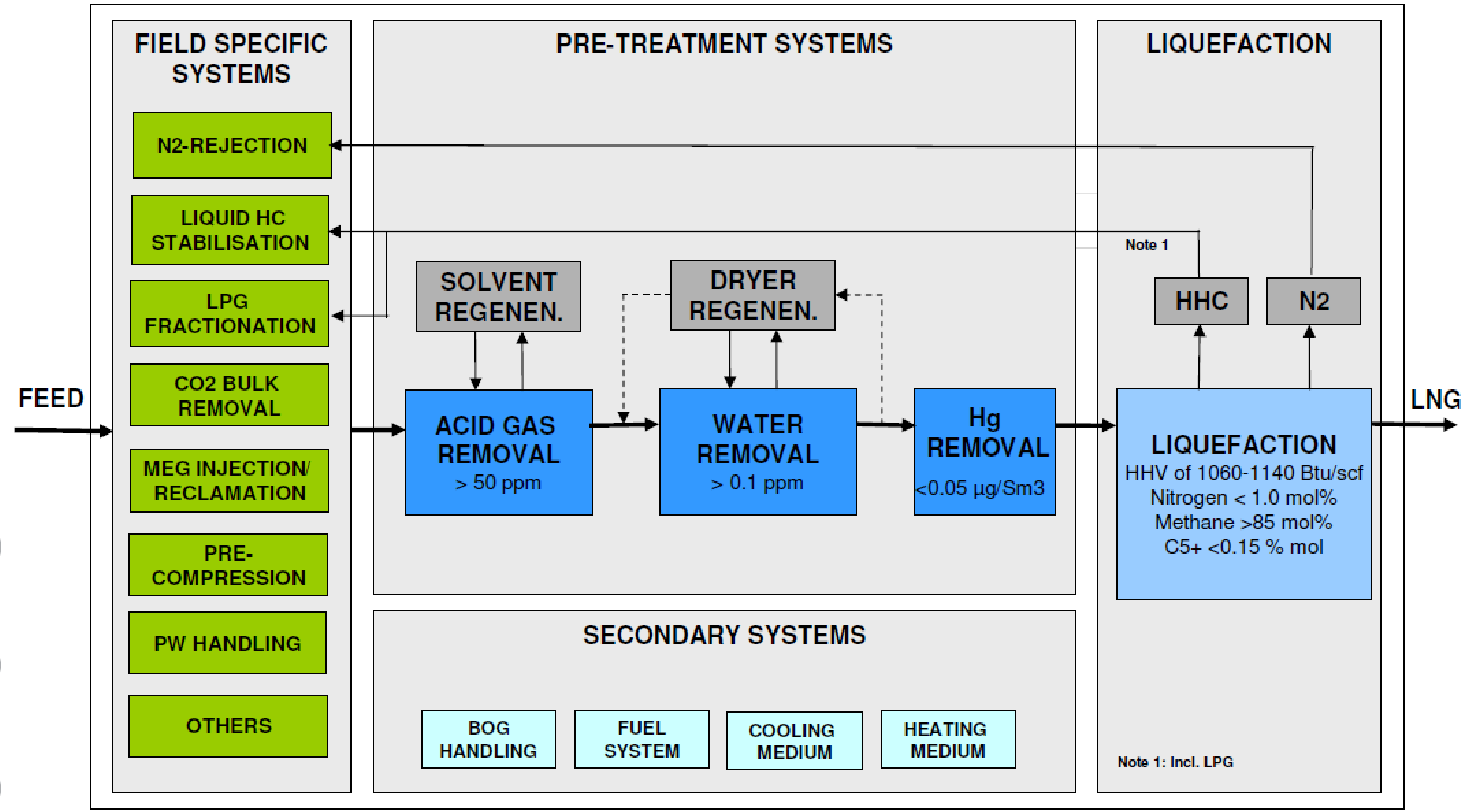




FLNG process overview



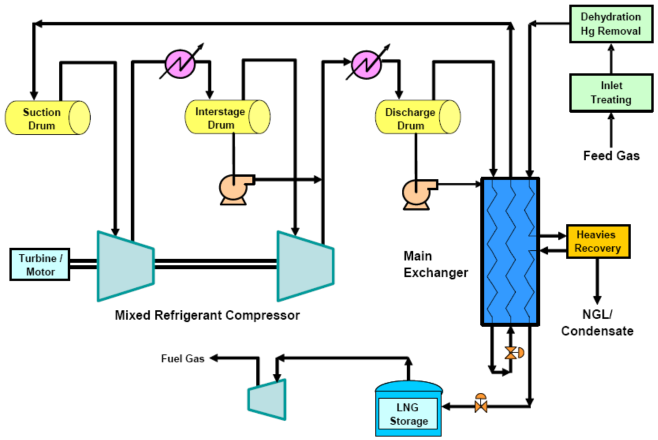
Field specific and pre-treatment systems



Liquefaction choices e

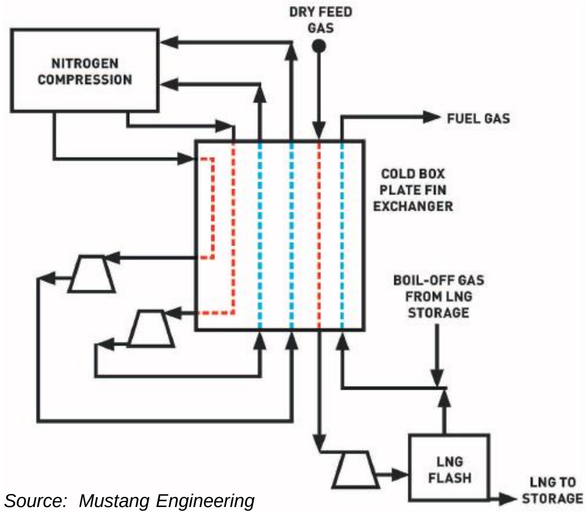
- Need simple, robust and compact liquefaction solutions
  - Single mixed refrigerant cycles
  - Gas expander-based cycles
- Concerns
  - Process efficiencies
  - Scale-up performance
  - LPG refrigerant storage
  - Marine performance and reliability

Black & Veatch PRICO SMR Process



Source: Black & Veatch

Mustang NDX-1 Process (patent pending)



Source: Mustang Engineering

LNG Properties

- LNG is liquefied natural gas for easy transportation and storage.
- Volume ratio between LNG and natural gas is 1/600 at - 162^{o}C, 1 atm.
- Due to its low temperature, it must be treated as “Cryogenic liquid” requiring special equipment and procedures.
- Contacting cryogenic LNG induces fast cooling and loss of both mechanical strength and functions. Special containment system has to be used for storage of LNG.
- LNG is colorless, odorless, no corrosion, non flammable, and non toxic.
- Specific LNG properties are as follows,
  - Composition
  - Boiling point
  - Density and specific gravity
  - Flammability
  - Flash point

LNG composition

- Natural gas composition may vary depending on the gas fields location and types of processing process.
- LNG production can be made from the natural gas composed of methane, ethane, propane, butane, and small amount of heavy hydrocarbons.
- Impurities include Nitrogen, Carbon dioxide, Hydrogen sulfide, and water. These impurities must be removed through the pretreatment process, increasing methane content more than 85 vol%.

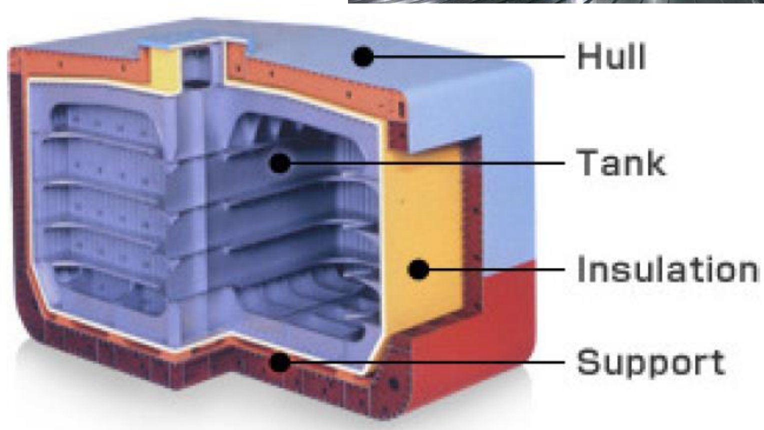
Chemical	Chemical Formula	Low	High
Methane	CH_4	87%	99%
Ethane	C_2H_6	<1%	10%
Propane	C_2H_8	>1%	5%
Butane	C_4H_{10}	>1%	>1%
Nitrogen	N_2	0.1%	1%
Other Hydro-carbons	Various	Trace	Trace

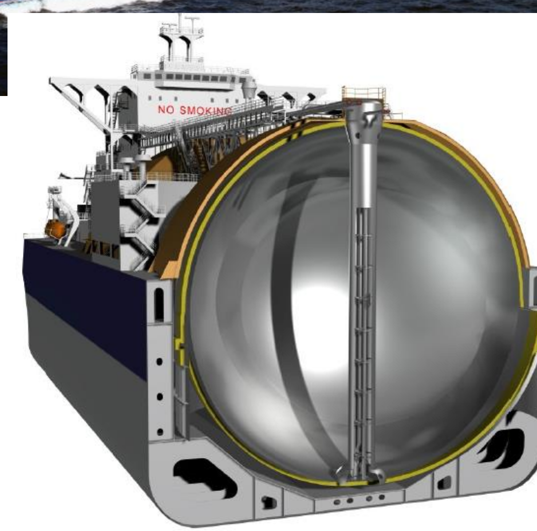
LNG boiling point, density & specific gravity

- LNG boiling point may change with natural gas composition, but normally is -162ºC (-259ºF).
- When cryogenic LNG is exposed to warm air or water, LNG start to boil on the surface.

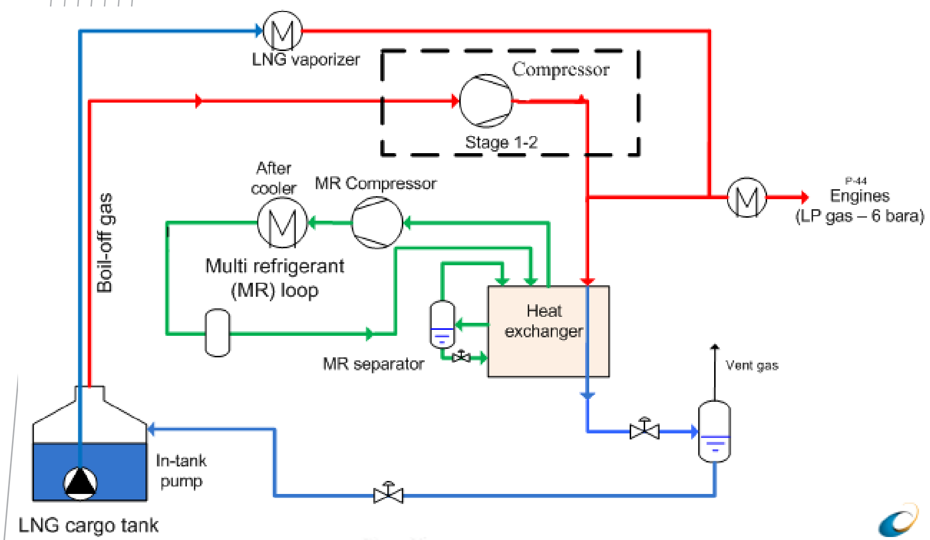
LNG Carrier

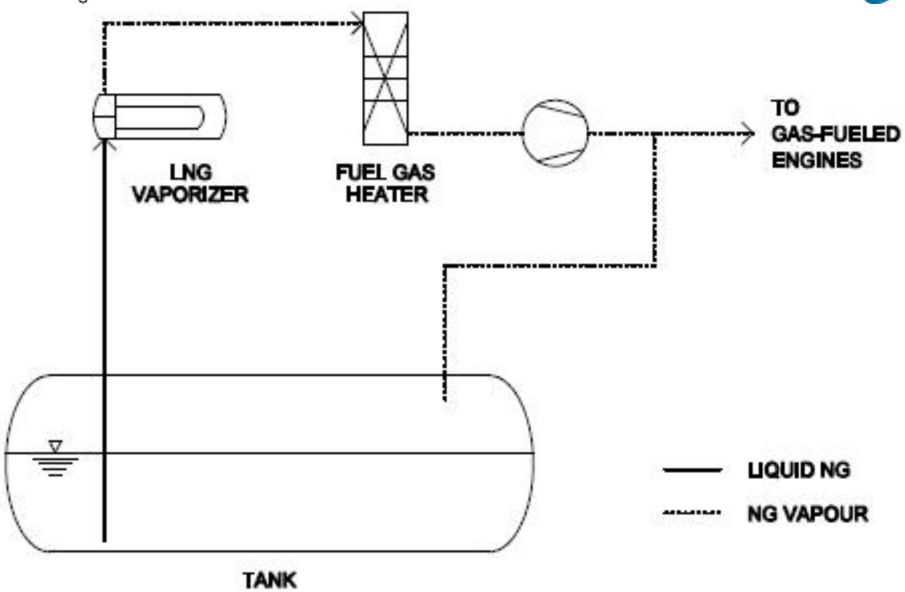
- Which type of tanks in it?

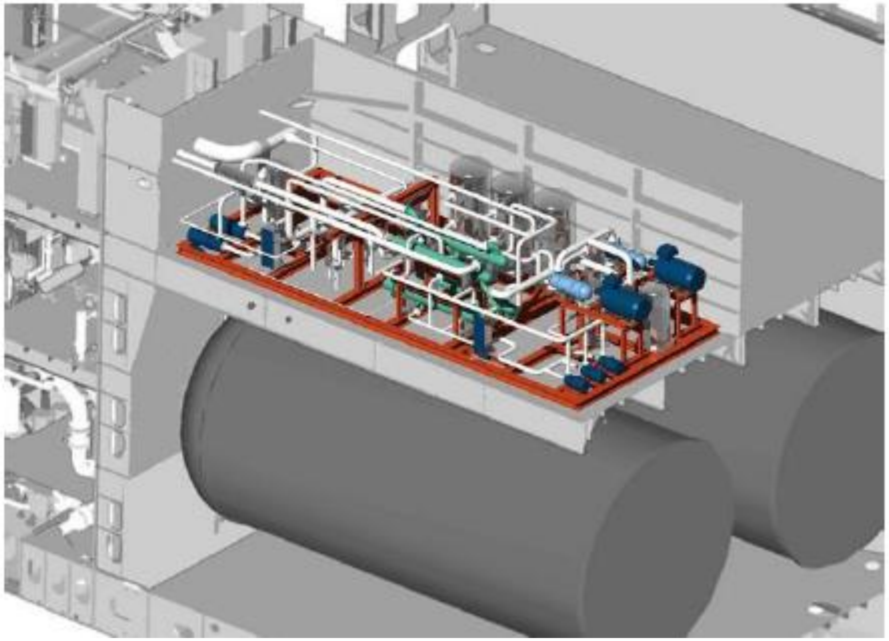




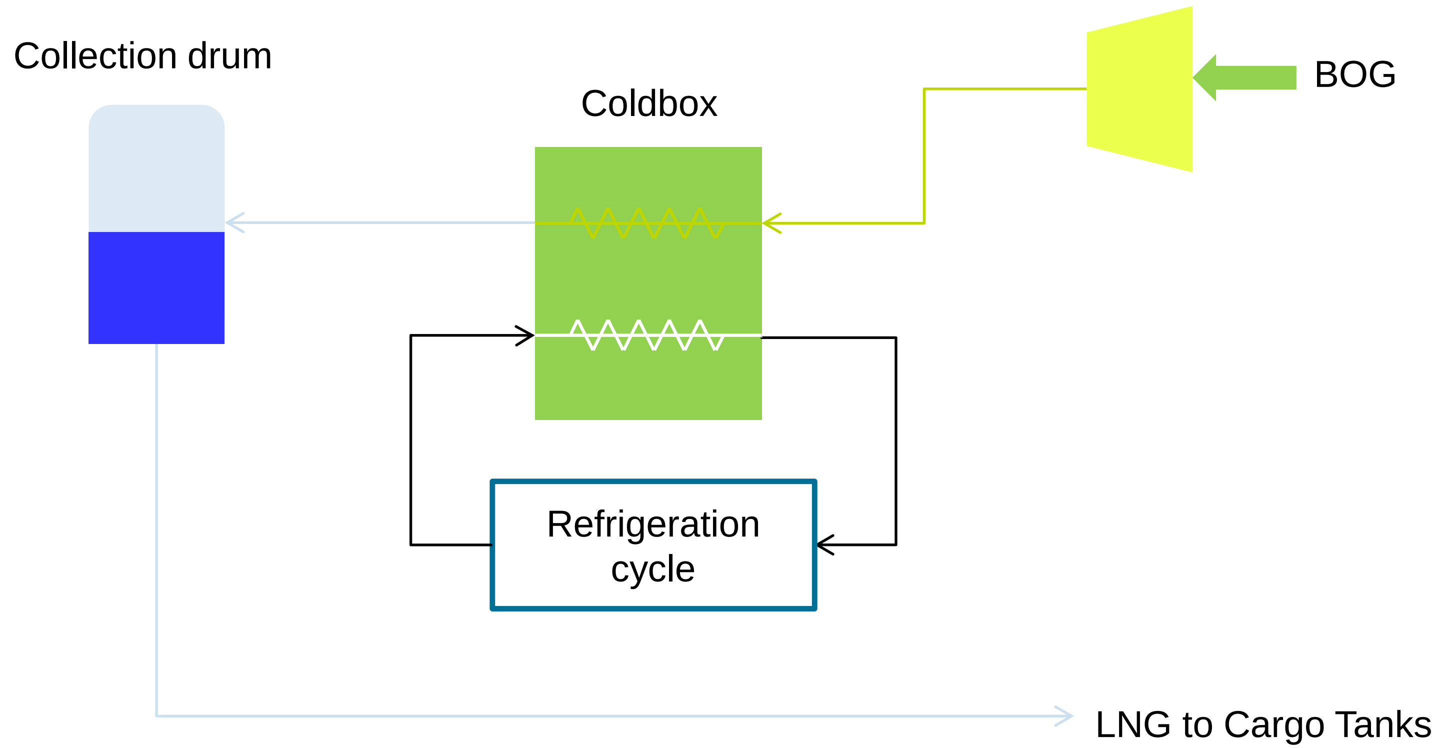
Cargo handling and fuel gas system







BOG liquefaction technology

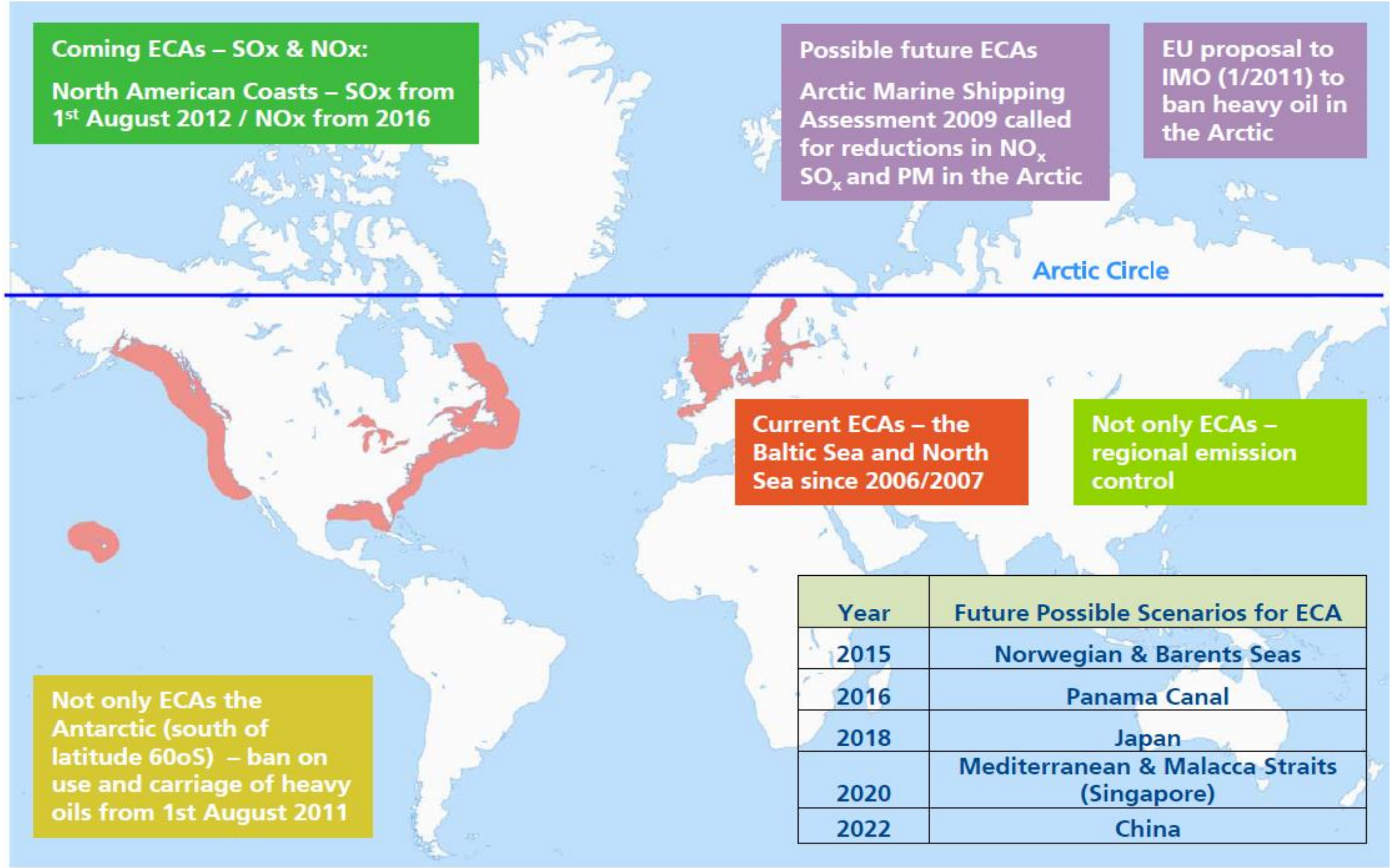


- Effective to treat continuous BOG
- To treat the BOG during LNG bunkering
  - Considerable capacity: 40 ton/hr to treat 40 ton BOG for 1 hr
  - Intermittent operation: 1 hr operation + 9 hr stop

LNG-fuelled ship propulsion

Regulation on fuel quality within emission control area (ECA)

- Currently, the seas around Europe and the North America are ECAs.
- ECAs are expanding, ultimately all over the world.

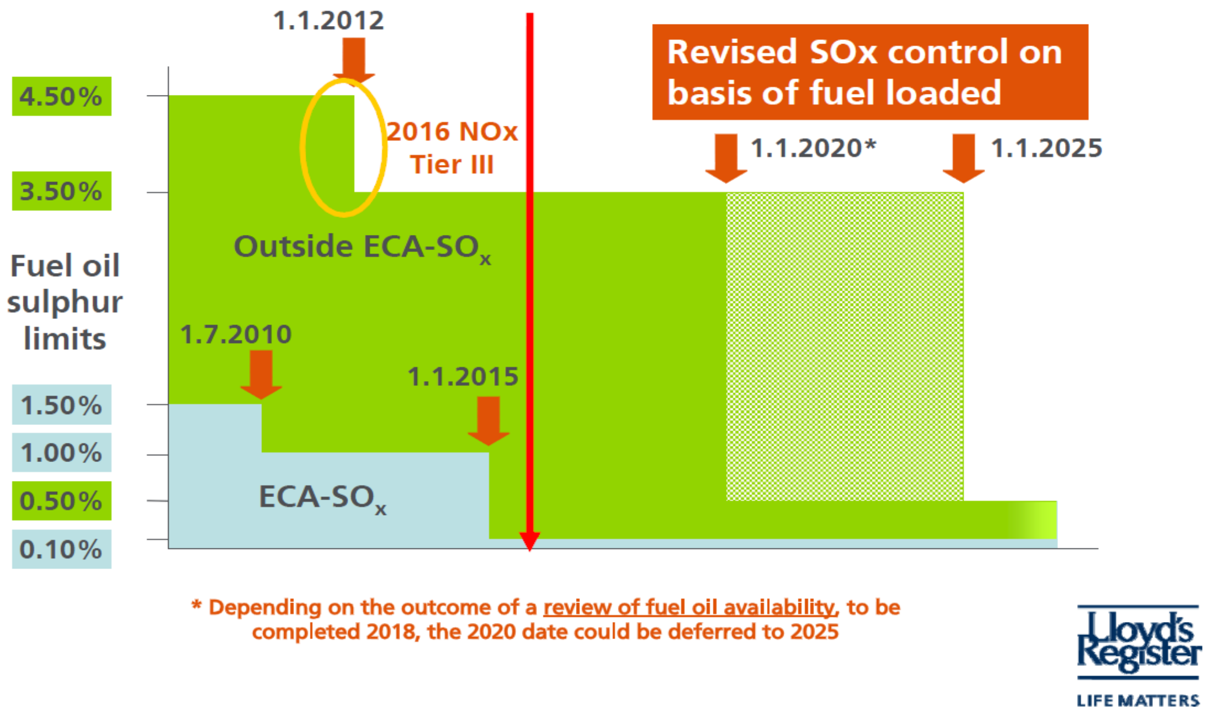


Year	Future Possible Scenarios for ECA
2015	Norwegian & Barents Seas
2016	Panama Canal
2018	Japan
2020	Mediterranean & Malacca Straits (Singapore)
2022	China

Regulation on fuel quality within emission control area (ECA)

- Regulations on emissions from ships, especially for SOx
  - Stringent regulation on fuel quality
  - Effective from 2015 for ECAs (emission control areas)

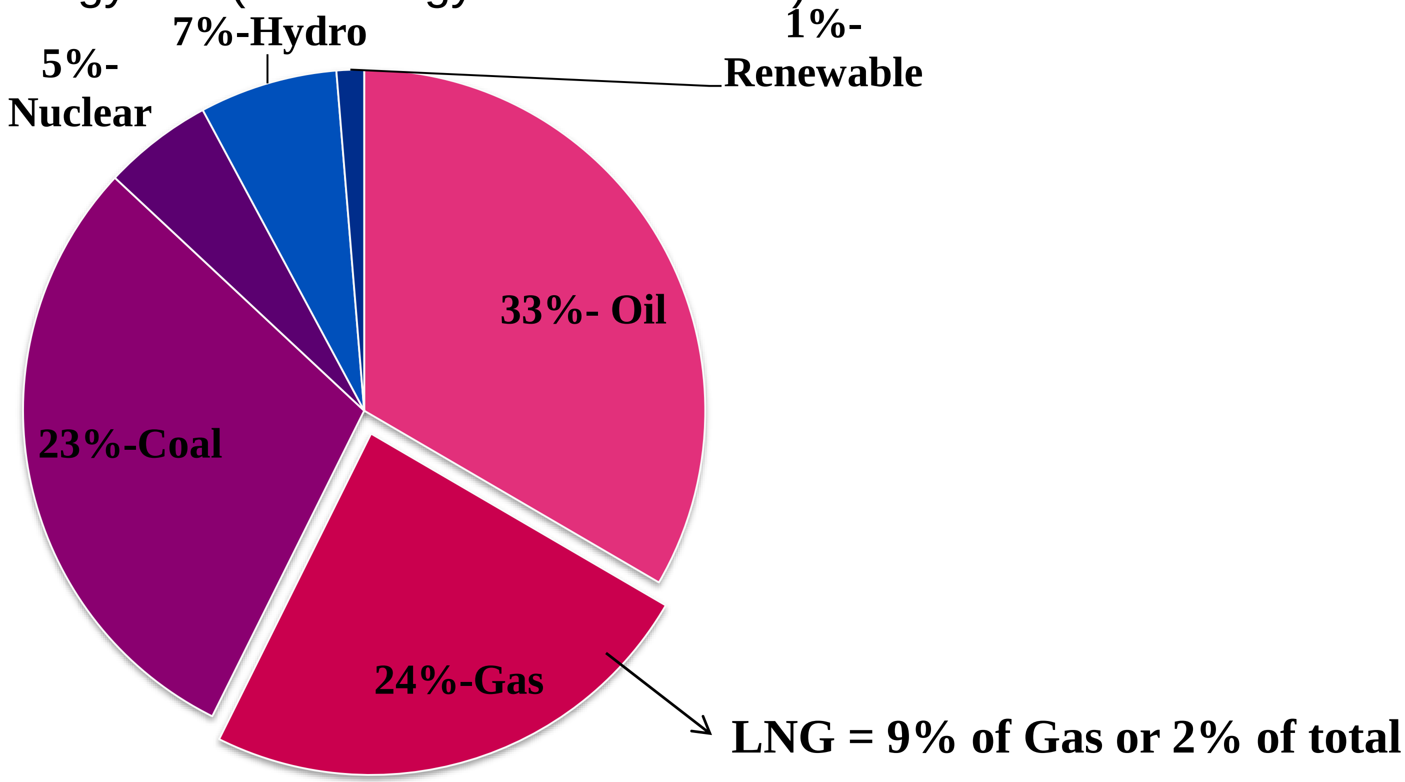
    from 2020 or 2025 globally



MARPOL Annex VI Requirements - SOx

Impact of LNG fuelled propulsion

- World Energy Mix (BP Energy statistics 2011)



Shipping is consuming 3% of total world energy.
➔ 300-375 million tonnes, 250 billion US$/yr
➔ LNG-fuelled shipping will consume 1.5 times the current world LNG trade.
➔ The world LNG consumption will increases to 250%.

LNG fuelled propulsion growing

- LNG fuelled propulsion: in service




Year	Ship Name	Ship Type	Ship Owner	Location	Tank	Engine	Fuel Type	Ships	Note
2000	Glutra	Car/pass. Ferry	Fjord1	Norway	**2 x 32 m3**	Mitsubish	**LNG**	1	In use
2003	Viking Energy	Offshore Supply	Eidesvik	Norway sea	**1 x 234 m3**	Wartsila	**LNG (DF)**	1	
2003	Stril Pioneer	Offshore Supply	Simon Mokster	Norway sea	**1 x 234 m3**	Wartsila	**LNG (DF)**	1	
2006	Bergens fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Fana fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Raune fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Stavanger fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Mastra fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2008	Viking Queen	Offshore Supply	Eidesvik	Norway sea	**2 x 234 m3**	Wartsila	**LNG (DF)**	1	
2008	Viking Lady	Offshore Supply	Eidesvik	Norway sea	**2 x 234 m3**	Wartsila	**LNG (DF)**	1	
2009	Tidekongen	Pass. Ferry	Tide	France	**1 x 29 m3**	Mitsubish	**LNG**	2	
2009	Barentshav	Military Vessel	Norwegian Coast Guard	Norway	**1 x 234 m3**	Mitsubish	**LNG**	2	Under Building
2009	-	RO-RO	Sea Cargo AS	Norway	**2 x 216 m3**	Rolls-Royce	**LNG**	2	
2010	Molde fjord	Car/pass. Ferry	Fjord1	Poland	**1 x 125 m3**	Mitsubish	**LNG**	4	
-	-	Offshore Supply	-	Norway	**1 x 210 m3**	Mitsubish	**LNG**	1	

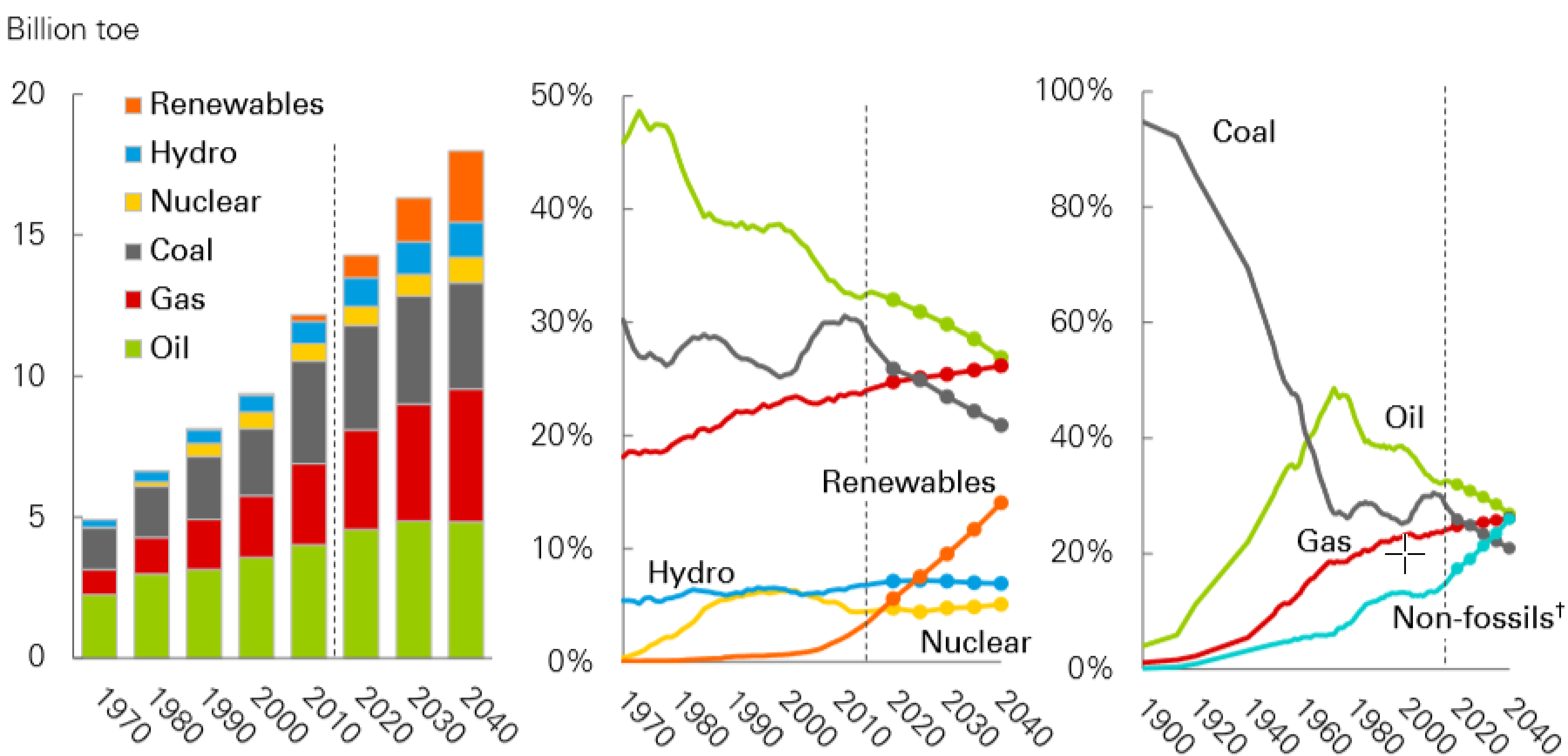
Why LNG or Natural Gas??

Energy mix

- The transition to a lower carbon fuel mix continues.

Primary energy consumption by fuel

Shares of primary energy



Golden Age of Gas?

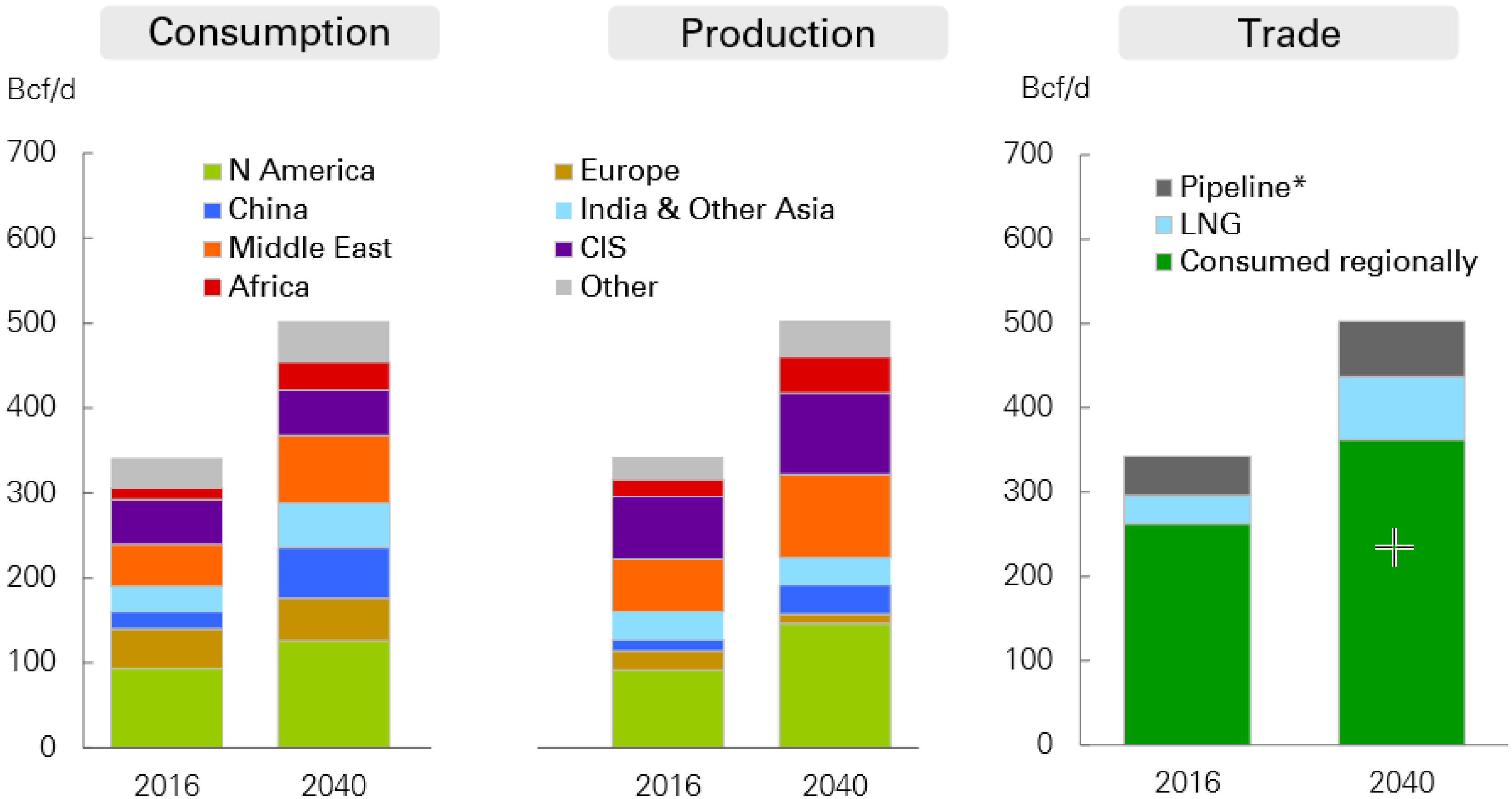
- In 2011, the World Energy Outlook took the question “Are we entering a Golden Age of Gas?”, in which the role of gas in the energy system expanded more rapidly than in our main scenario, reaching 25% of the global mix by 2035.
- This was based on a number of positive assumptions about the availability of gas (much of it unconventional) and its price, as well as the addition of policies on the demand side that would promote its use in certain countries, notably China, and in certain sectors, such as transport.
- A few years on, where do we stand relative to the putative Golden Age?

  : Natural gas prices in 2016 are very much in line with those anticipated in the “Golden Age” scenario, so in that sense the story has been realized. North American shale gas has been hugely successful; however, contrary to what was assumed in the “Golden Age” scenario, replication of the North American shale gas success story in other shale-rich countries has been very limited

  : In terms of demand, there are substantial variations. Some countries, notably the United States and elsewhere in North America, are already well ahead of the projections in the “Golden Age” scenario; the Middle East and Latin America are also using at least as much gas as anticipated. But Europe is at the opposite end of the spectrum, with gas demand having fallen. Demand in developing Asia, notably India, as well as Africa, is also well below the projections in the Golden Age scenario.

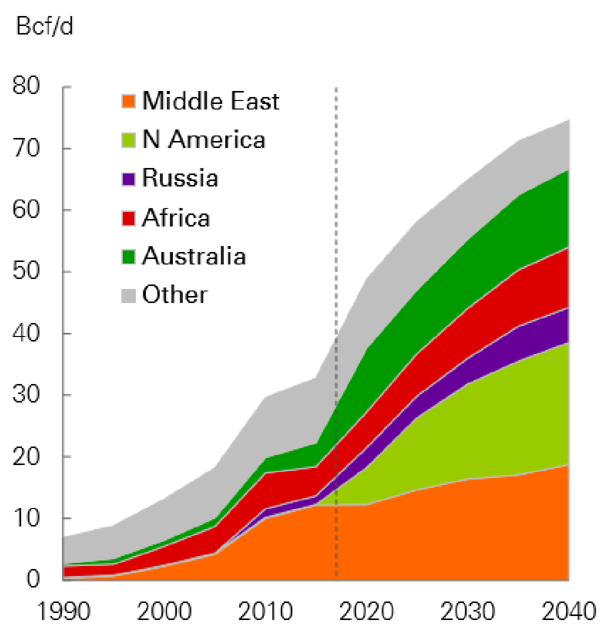
Natural gas outlook

- Natural gas growth is supported by a number of factors: increasing levels of industrialization and power demand (particularly in emerging Asia and Africa); continued coal-to-gas switching (especially in China); and the increasing availability of low-cost supplies (in North America and the Middle East).

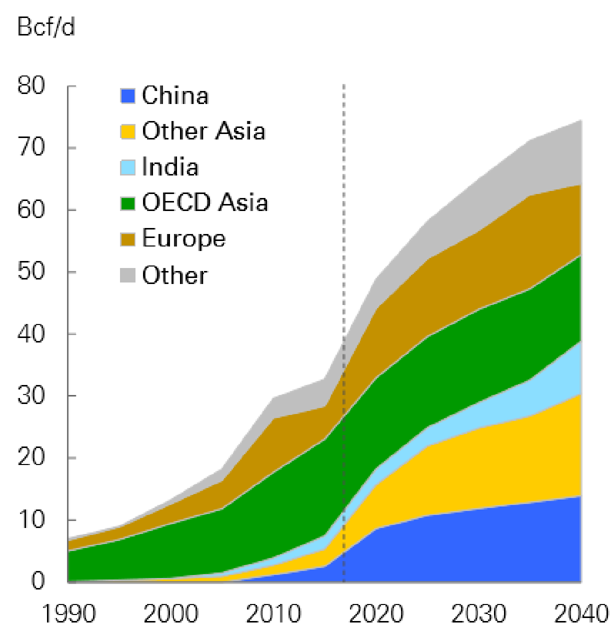


- The US and the Middle East (Qatar and Iran) contribute over half of the incremental production. By 2040, the US accounts for almost one quarter of global gas production, ahead of both the Middle East and CIS (each accounting for around 20%).
- Global LNG supplies more than double over the Outlook, with around 40% of that expansion occurring over the next five years. The sustained growth in global LNG supplies greatly increases the availability of gas around the world, with LNG volumes overtaking inter-regional pipeline shipments in the early 2020s.

LNG exports



LNG imports



Natural gas reserves

- Remaining technically recoverable natural gas resources by type and region, end-2016 (tcm).

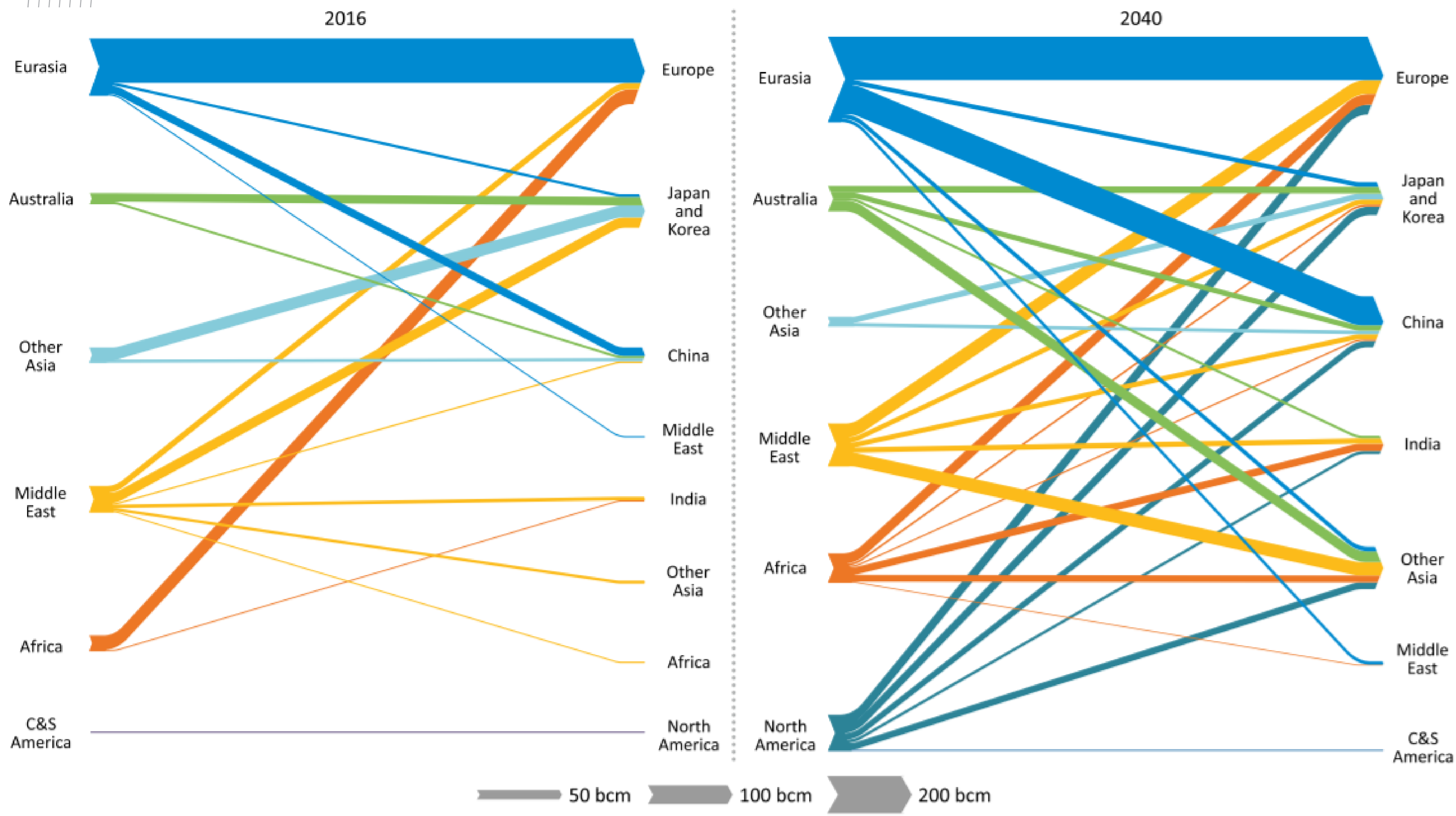
	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
North America	51	11	61	7	79	130	12
Central & South America	28	15	41	-	56	84	8
Europe	19	5	18	5	28	47	5
Africa	51	10	40	0	50	101	17
Middle East	103	9	11	-	20	123	80
Eurasia	134	10	10	17	38	172	74
Asia Pacific	45	21	53	21	94	139	20
World	432	82	233	50	365	796	216

Sources: BGR (2016); BP (2017); Cedigaz (2017); OGJ (2016); US DOE/EIA/ARI (2013); US DOE/EIA (2017); USGS (2012a, 2012b); IEA databases and analysis.

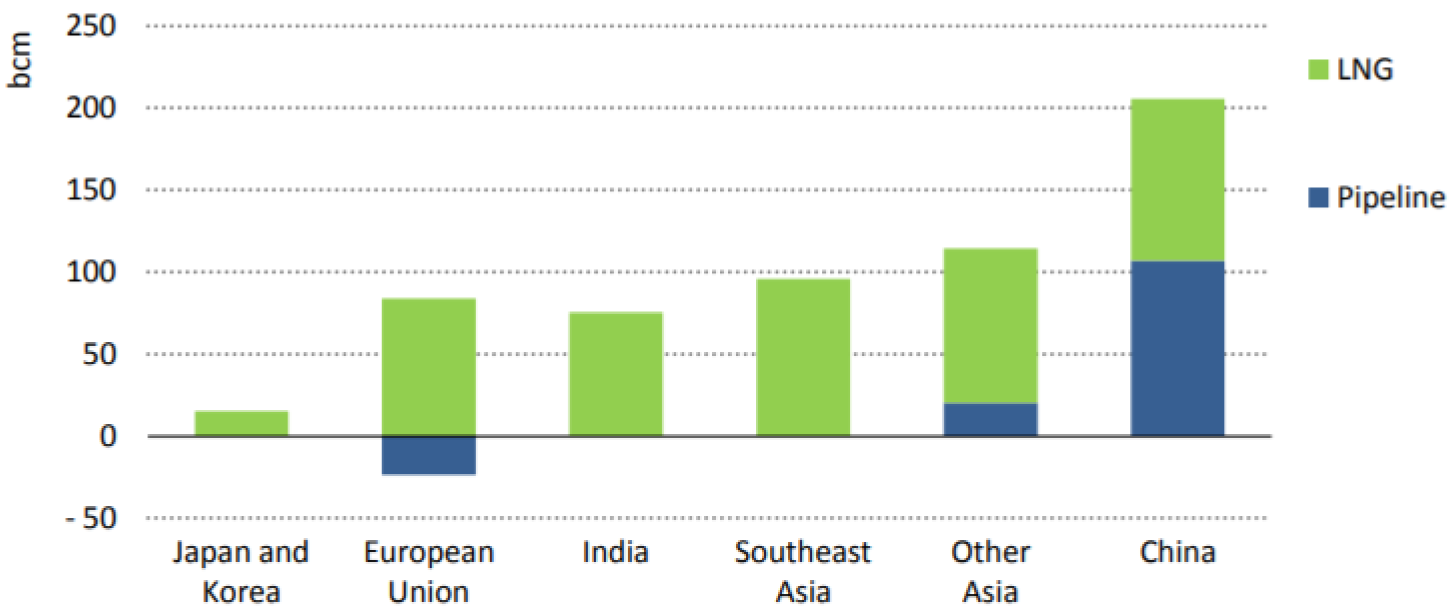
- Production of natural gas expands globally by 1,685 bcm over the next 25 years, reaching over 5,300 bcm in 2040. The United States, Russia and Iran are the three largest gas producers today.

Global gas trade flows

- A fundamental shift of trade away from the Atlantic basin to the Asia Pacific.

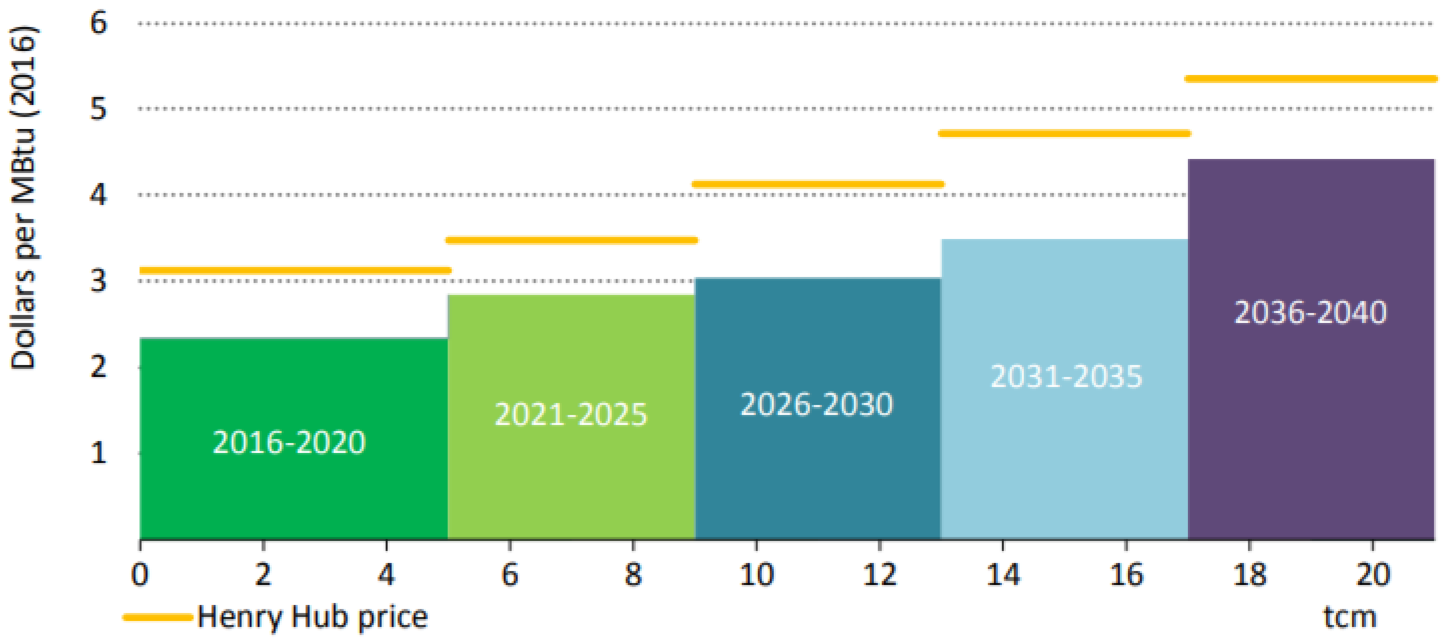


- The countries that have good domestic gas production prospects will rely on the existing and newly-built pipeline infrastructure.
- Asian countries lead the growth in global gas trade; outside china, new pipeline trade routes find it hard to advance in a market with LNG readily and flexibility available, such countries as Malaysia, Thailand, Pakistan, and Bangladesh.
- There will be gas-on-gas competition between LNG and pipeline gas.



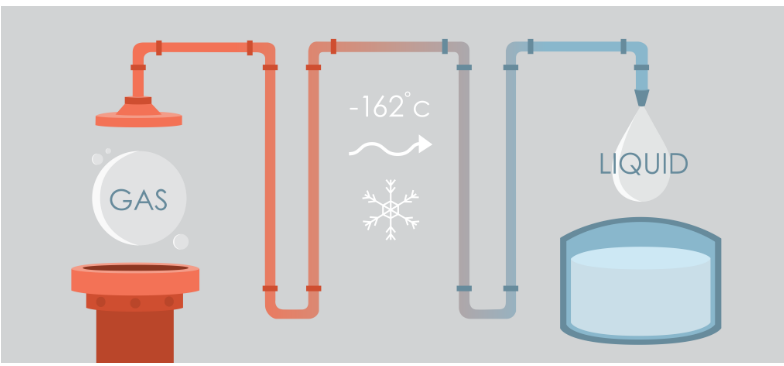
Rising costs of gas resources

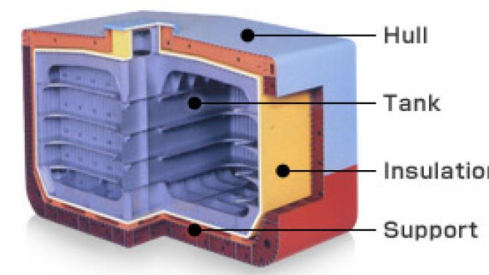
- The availability of relatively low cost gas and the resource estimate has led to a more optimistic assessment of the size and number of sweet spots, i.e. the economically most attractive portions of a gas deposit.
- Nonetheless, producers are forced gradually to move away from the sweet spots to less productive zones. Continued technology learning and innovation mitigate the effect of this move on the economics of gas development.
- Overall, however, the cost of new resources developed gradually increases and puts upward pressure on gas prices.



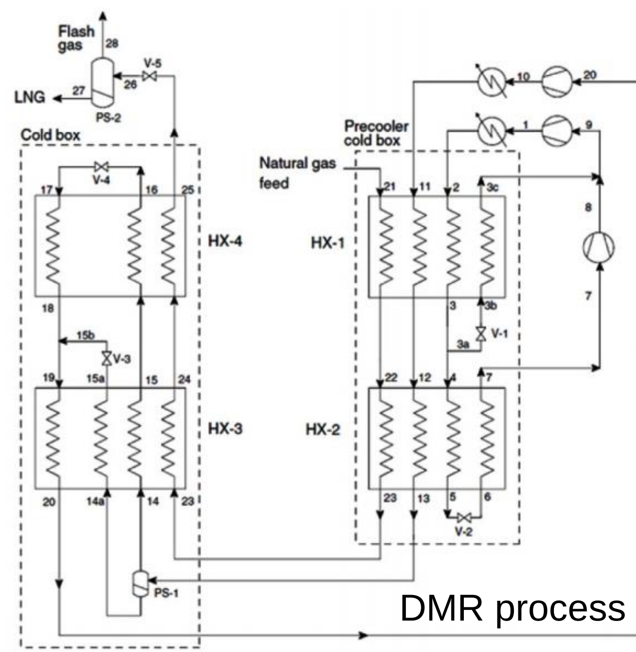
LNG (Liquefied Natural Gas)

- LNG is liquefied natural gas for easy transportation and storage.
- Volume ratio between LNG and natural gas is 1/600 at - 162^{o}C, 1 atm.



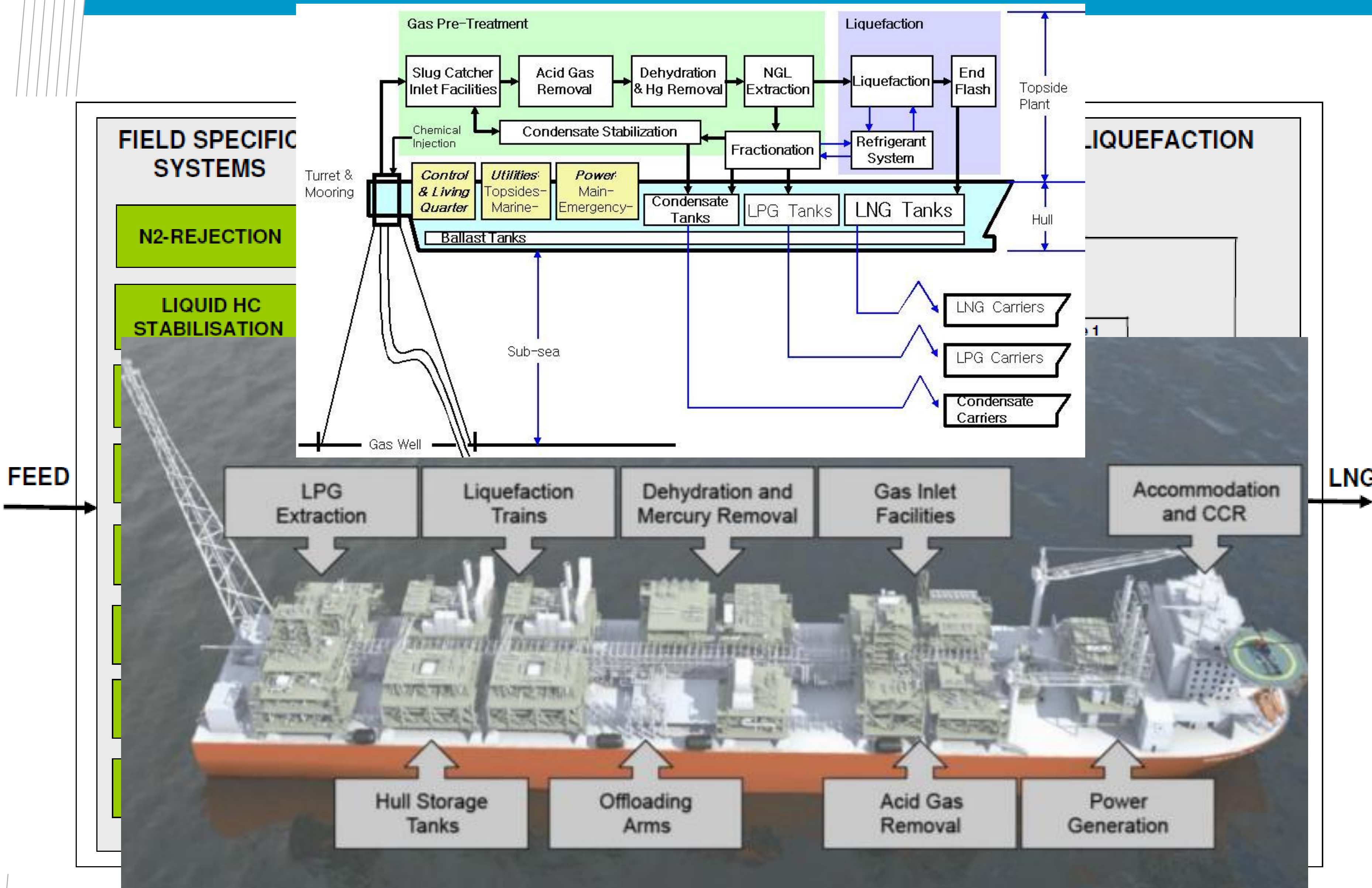


Chemical	Chemical Formula	Low	High
Methane	CH_4	87%	99%
Ethane	C_2H_6	<1%	10%
Propane	C_3H_8	>1%	5%
Butane	C_4H_{10}	>1%	>1%
Nitrogen	N_2	0.1%	1%
Other Hydro-carbons	Various	Trace	Trace



DMR process

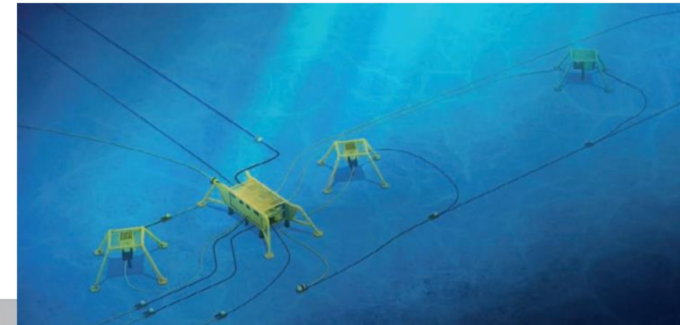
Gas processing for liquefaction process



PNG (Pipeline Natural Gas)

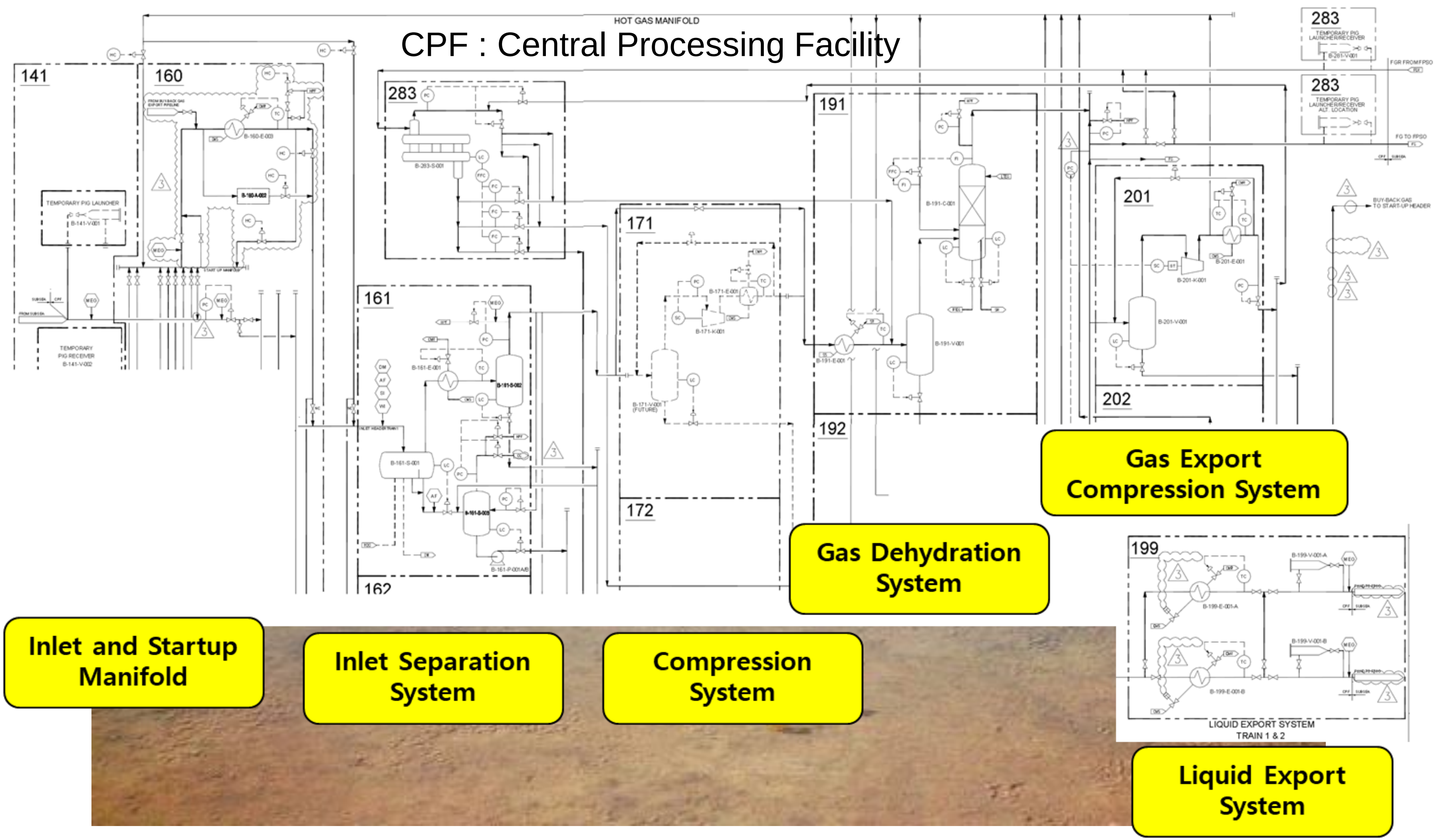
Component	Rocky Mt	Okla-KS	Permian Basin	E. TX./ TX Gulf	Gulf of Mexico
Nitrogen	0.12	2.16	2.89	0.83	0.22
Hydrogen Sulfide	0.00	0.00	0.02	0.00	1.33
Carbon Dioxide	1.58	0.34	0.05	0.18	4.00
Methane	86.75	81.54	70.45	88.88	88.15
Ethane	7.75	8.48	12.77	5.74	4.51
Propane	2.38	4.63	7.93	2.49	1.18
i-Butane	0.45	0.50	1.06	0.73	0.26
n-Butane	0.43	1.42	2.66	0.62	0.20
i-Pentane	0.18	0.27	0.66	0.14	0.05
n-Pentane	0.14	0.37	0.70	0.09	0.02
n-Hexane	0.12	0.32	0.51	0.12	0.01
n-Heptane	0.08	0.00	0.20	0.11	0.02
n-Octane	0.04	0.00	0.10	0.11	0.05
Total	100.00	100.00	100.00	100.00	100.00
C_2+ gpm	3.23	4.51	7.60	2.89	1.74

Sakhalin gas pipeline



Ichthys gas fields

Gas / Condensate Production for Darwin LNG Project

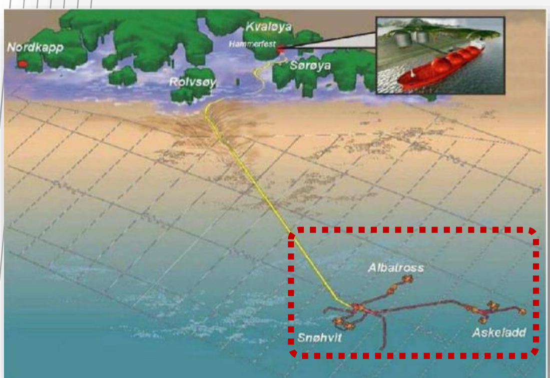


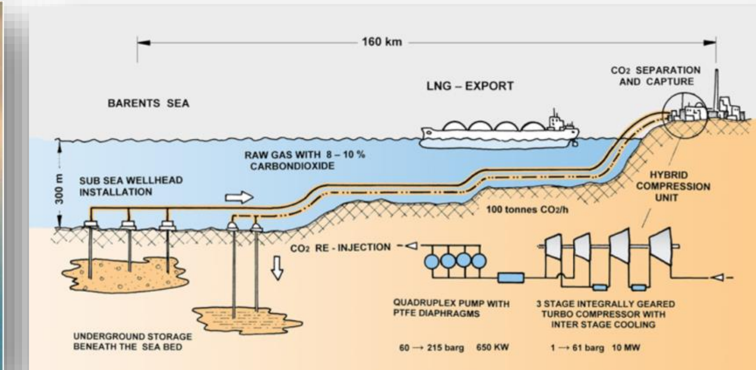
Snøhvit gas fields

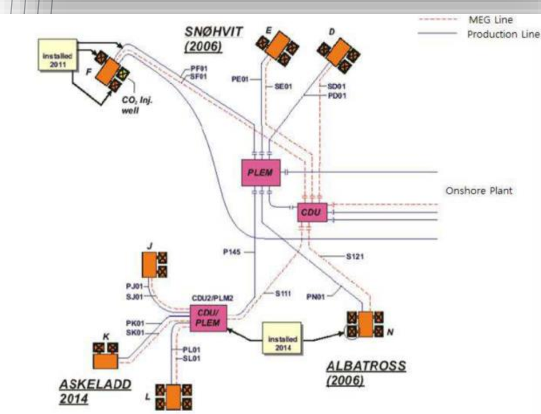
Gas / Condensate Production for LNG plant

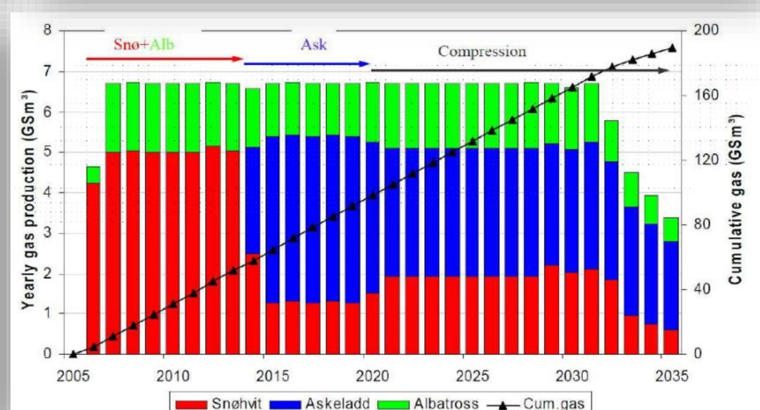
- Located in Barents sea (11.2 tcf)
- Gas processing located in onshore 160km from the offshore fields
- Snøhvit Field and Albatross Field supply the natural gas for processing ('05~'13)
- Askeladd Field produces additional gas ('14~)
- Extends field life through additional facilities and compression ('20~'35)

Component	g/liter
Na+	8,165
K+	121
Ca2+	1,050
Mg2+	68
Ba2+	41
Sr2+	n/a
Fe2+	n/a
Cl-	14,286
Br-	n/a
$SO_4$2-	29
HCO3-	360
TDS	24,120
pH	6.18









Component (mol%)	Snøhvit	Ichthys	Albatross
N2	2.5	0.4	3.45
CO2	5.3	8.5	0.47
C1	81	70	86.53
C2	5	10.3	4.91
C3	2.5	4.2	2.15
C4	1.2	1.9	0.46
C5+	2.2	4.4	0.76

Gas processing process

Gas processing to meet the products specification

Inlet fluids

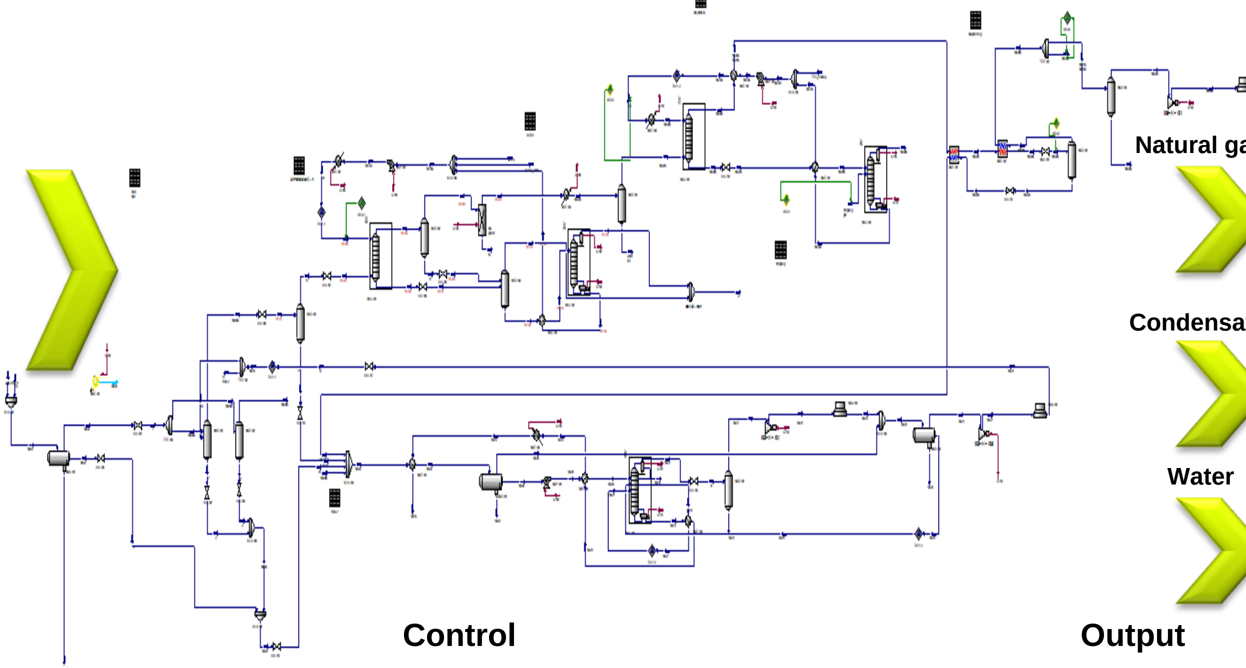
Natural gas
N2, CO2, H2S
C1, C2,
C3, C4,

Liquid Hydrocarbon
C5+,
Asphaltene.

Condensed
Water

Formation Water

Salts



Natural gas

Natural gas
For
LNG or PNG

Condensate

Stabilized
condensate

Water

Removed
Water

Removed salts

Input

FEED	Value
Hydrocarbon fluids	1020 MMscfd
: Gas rate	979 MMscfd
: Condensate rate	16100 bbl/d
Produced water	18,000 kg/hr
MEG injection for 80 wt%	5900 kg/hr

Control

Process unit	Pressure [barg]	Temperature [℃]
Separation	75 barg	25℃
Acid Gas Removal	72.5 barg	30~50℃
Dehydration	70 barg	25℃
NGL recovery	50 barg	RT
Condensate stabilizer	10 barg	50~200℃

Output

Products	Value
Natural gas	850 MMscfd
Condensate	16200 bbl/d
Regenerated MEG	5900 kg/hr

Gas Processing & Key Specifications for PNG

Feed gas

Refinery

PNG
to export pipeline

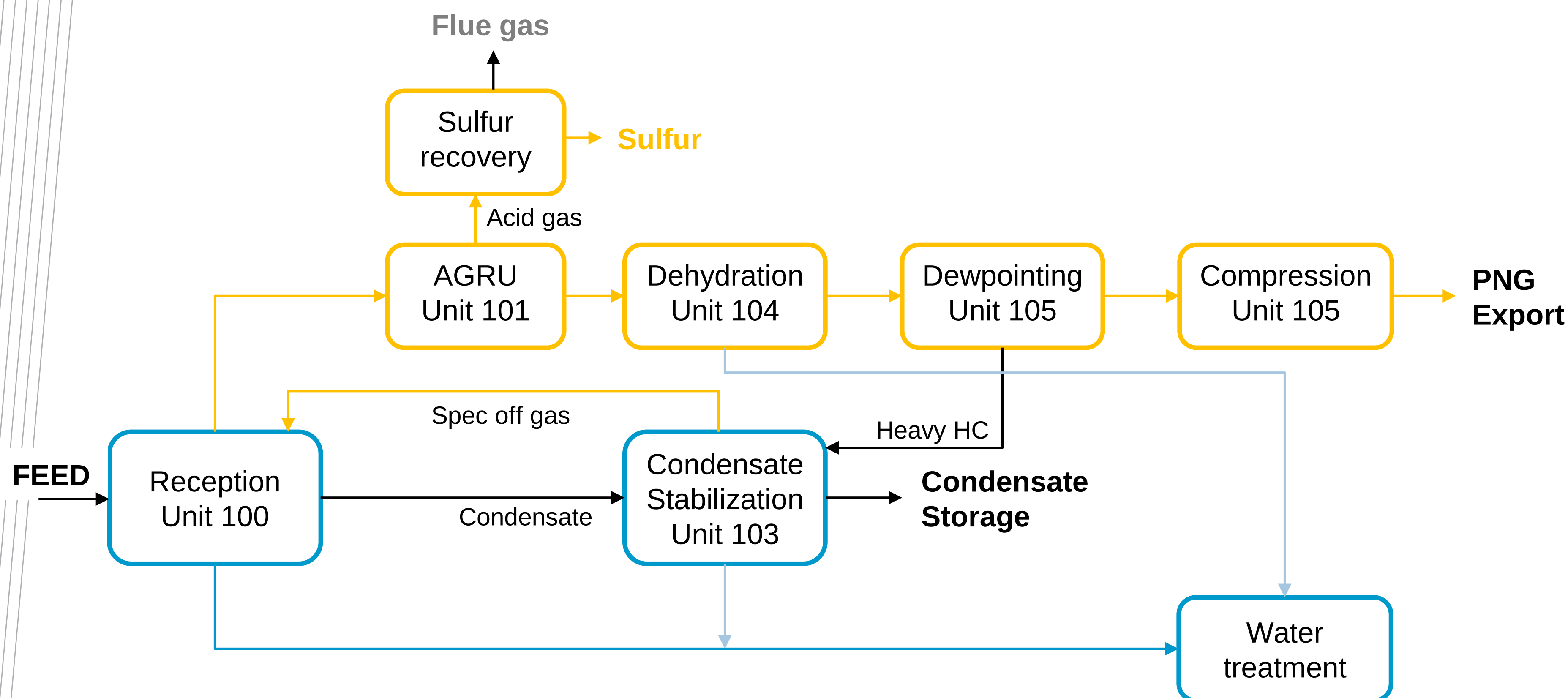
Condensate
(to storage tank)

Flue gas
(to atmosphere)

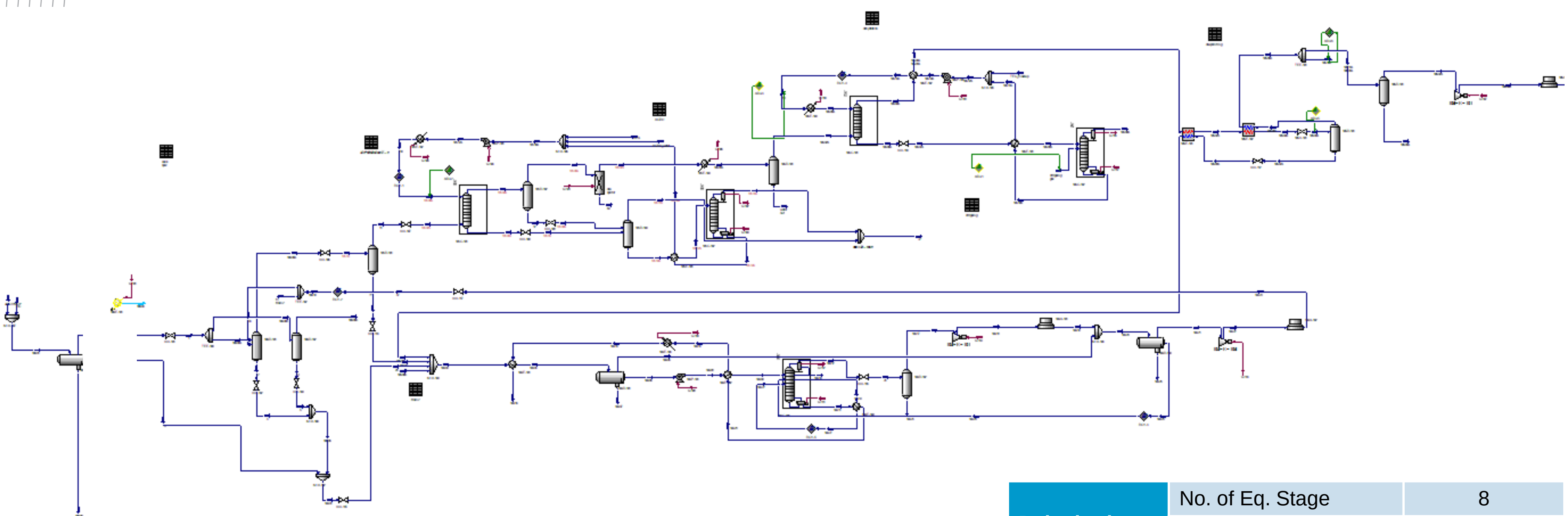
Composition	Mole fraction (%)
H2O	2.58
N2	2.61
CO2	3.46
C1	86.26
C2	2.68
C3	0.68
iC4	0.19
nC4	0.21
iC5	0.13
nC5	0.10
C6	0.25
C7	0.20
C8	0.17
C9	0.08
C10	0.06
C11	0.04
C12+	0.15
C17+	0.09
C23+	0.05

		Specifications	Reference
Sales Gas (PNG)	Hydrogen Sulfide(H2S)	< 5 mg/Sm3	Specification of Natural Gas quality
	Mercaptan sulfur(R-SH)	< 15 mg/Sm3	
	Total Sulfur	< 30 mg/Sm3	
	Carbon Dioxide(CO2)	< 2 mol%	
	Total Inert gas (CO2+N2)	< 7 mol%	
	Water Dew point	< -10°C	
	Hydrocarbon Dew point	<-7°C	
	Higher Heating Value	35.59-43.96 MJ/Sm3	
	Wobbe Index	46.05-52.34 MJ/Sm3	
Gas Export Cond.	Export Pressure	92.8 barg	Design Basis
	Export Temperature	60°C	
Conde-nsates	RVP @ 37.8℃	<10 psia (summer) <12 psia (winter)	Specification of Condensate quality
	Free water content	< 500 ppm vol	
Enviro-nmental	Carbon monoxide	<150 ppm	Design Basis
	Hydrogen sulfide	< 10 mg/m3	
	Sulfur oxides	< 800 ppm	

Overall gas processing process



Simulation and Key Operating Conditions



*Aspen HYSYS v8.8
is used for the simulation

Slug catcher	Pressure	77.5 barg
	Temperature	40 °C
Separator	Pressure	75 barg
	Temperature	25 °C
AGRU -Absorber	No. of Eq. Stage	30
	Pressure	72.5 barg
	Temperature	27-56 °C
AGRU -Stripper	No. of Eq. Stage	24
	Pressure	1.4-1.6
	Temperature	93-131 °C

Dehydration -Absorber	No. of Eq. Stage	8
	Pressure	70 barg
	Temperature	25°C
Dehydration -Stripper	No. of Eq. Stage	5
	Pressure	0-0.1 barg
	Temperature	100-131°C
Dew pointing	Expansion Pres.	50 barg
Export comp.	Pressure	92.8 barg
	Temperature	60°C
Condensate stabilizer	No. of Eq. Stage	30
	Pressure	9.4-9.7 barg
	Temperature	62-200°C

Simulation Results

Specifications Check

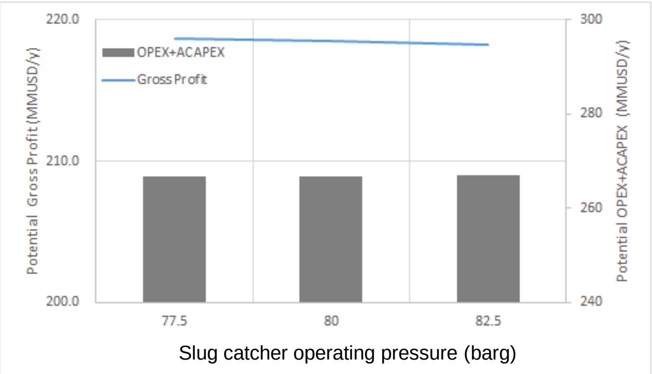
	Required Spec.	Simulation Result	Spec Check
Hydrogen Sulfide(H2S)	< 5 mg/Sm3	4.92-4.99	Satisfied
Total Sulfur	< 30 mg/Sm3	12.3-12.5	Satisfied
Carbon Dioxide(CO2)	< 2 mol%	0.49-0.50	Satisfied
Total Inert gas (CO2+N2)	< 7 mol%	3.3%	Satisfied
Water Dew point	< -10°C	-10.1	Satisfied
Hydrocarbon Dew point	<-7°C	-19.7 to -22.8	Satisfied
Higher Heating Value	35.59-43.96 MJ/Sm3	38.25	Satisfied
Wobbe Index	46.05-52.34 MJ/Sm3	39.35	Satisfied
Export Pressure	92.8 barg	92.8	Satisfied
Export Temperature	60°C	60	Satisfied
Condensate RVP @ 37.8℃	<10/12 psia	8.4-8.6 psia	Satisfied
H2S in flue gas	10 mg/m3	trivial	Satisfied
Sulfur oxide in flue gas	<800 ppm	727 ppm	Satisfied

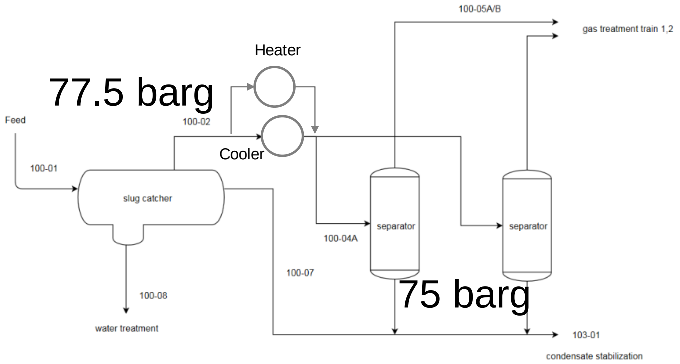
Operating Conditions – Separation Pressure

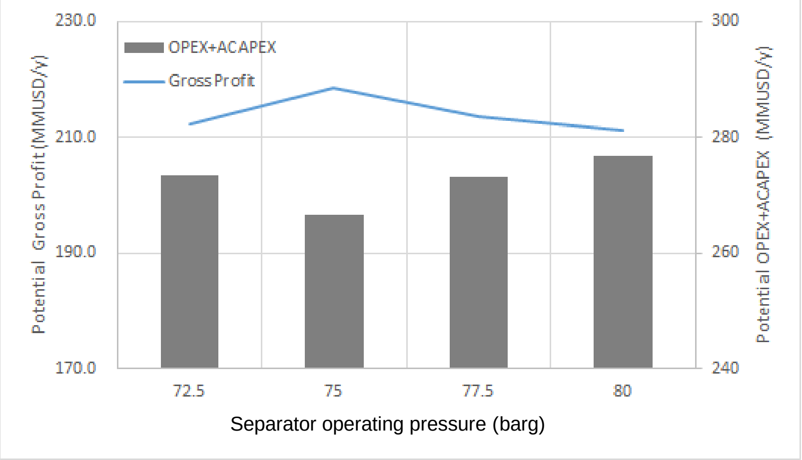
- To decide operating conditions, sensitivity analysis was performed, based on potential gross profit.
  - Potential gross profit is estimated as follows:

    Potential gross profit = Revenue – OPEX** – Annualized CAPEX****

    **Revenue was estimated by using gas (2.67USD/MMBtu)[1] and condensate (67.47 USD/bbl) price[2].*
- 77.5 and 75 barg is recommended as the operating pressure of slug catcher and separation
  - Higher P in separator makes higher CAPEX and results in decreased potential gross profit, although it has higher potential revenue due to more recovered condensates.
  - However, when the separation pressure is lower than 75, the increased heavy HC contents in gas stream requires lower operating P in dewpointing to satisfy the HC dew point specs. It causes increased CAPEX/OPEX for export compression, which decreases the potential gross profit.







* *Minimum pressure drop between SL/separator was assumed as 2.5 bar.*

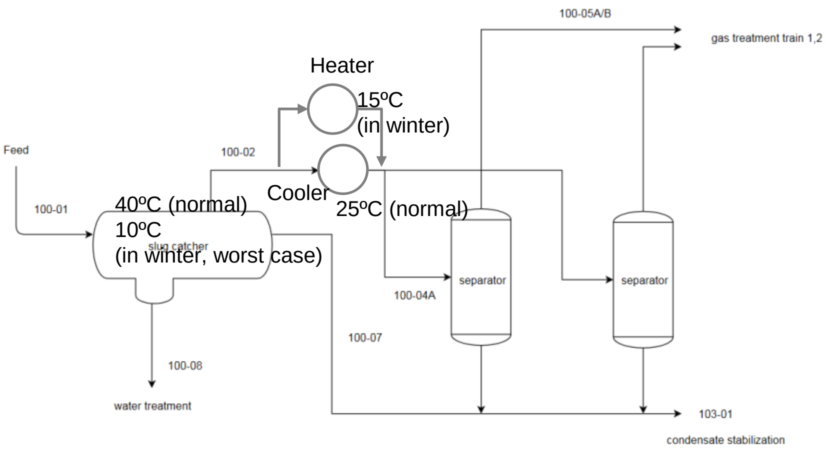
1) Gas price reference: Index mundi, Nature gas monthly price, Iran Feb, 2018. https://www.indexmundi.com/commodities/?commodity=natural-gas

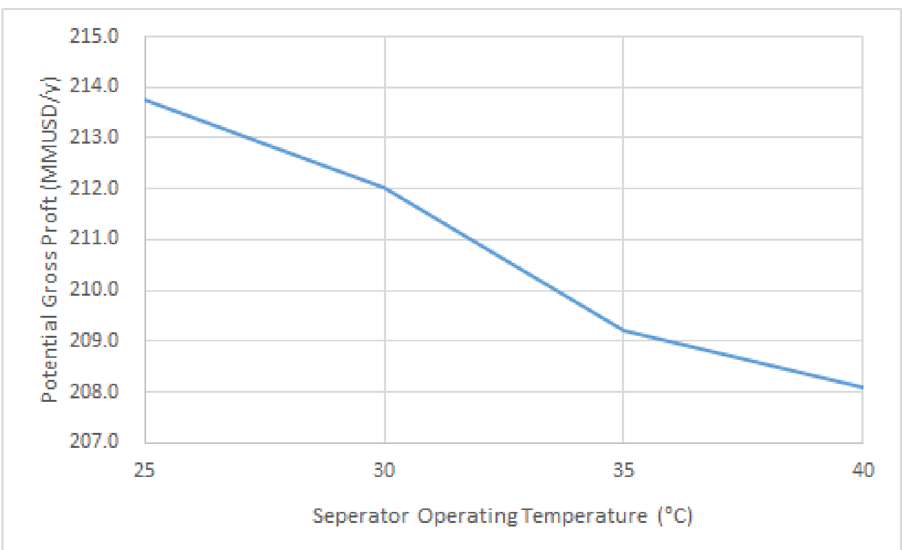
2) Condensate price reference: Iran Light, Deliveries to Northwest Europe. https://oilprice.com/oil-price-charts#prices

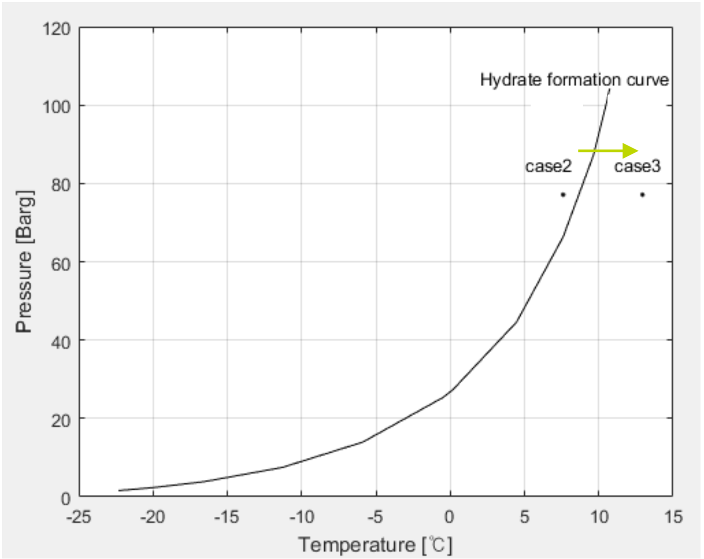
Operating Conditions – Separation Temperature

- Low operating temperature in Separator is recommended.
  - Lower temperature help to recover more condensate, increasing potential gross profit.
  - When the inlet temperature is too high, cooling before separation may help increase gross profit. CAPEX increase is relatively small.
  - However, too low temperature may cause hydrate formation problem. In winter season, therefore, heating may be required to prevent hydrate formation.

  : At least 15ºC is recommended considering safety margin.

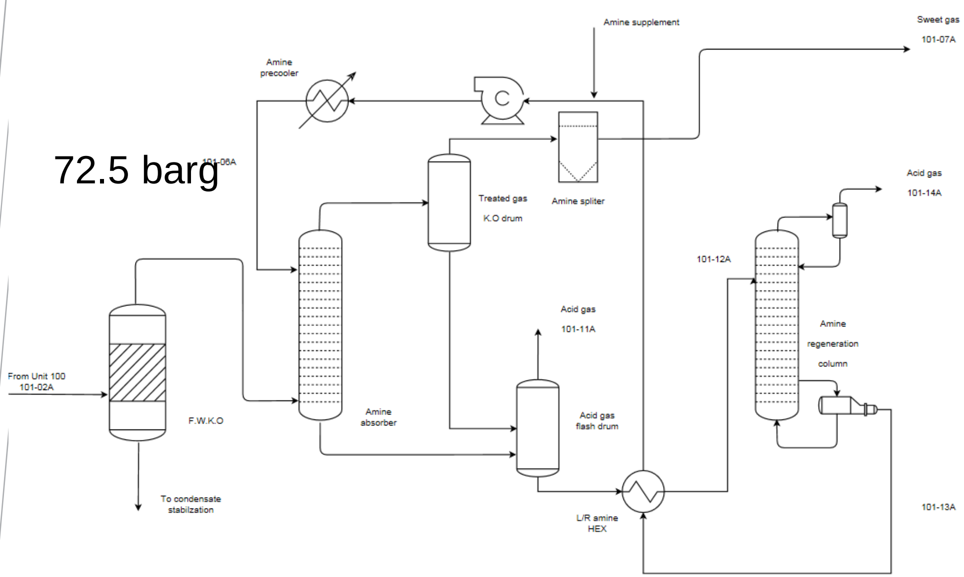


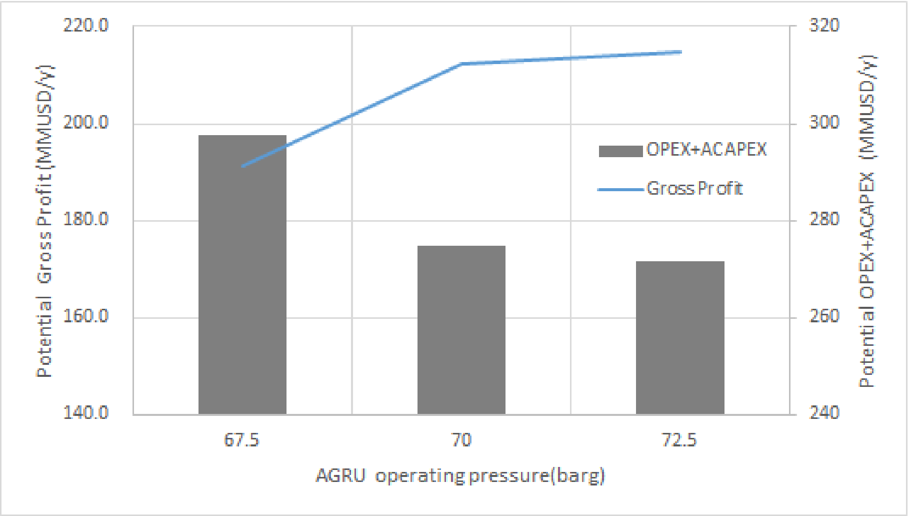




Operating Conditions – AGRU Pressure

- DEA amine absorption process is used.
  - DEA is well-known and one of most commonly used amine for AGRU in gas industries. Although it has slightly higher energy consumption than MDEA, it is still preferable option as a reference process conservatively, due to its long trustable history and wide track records.
- 72.5 barg is recommended for AGRU operating pressure*.
  - When the AGRU operating pressure becomes lower, the operating pressure in dewpointing also becomes lower to satisfy the HC dewpoint spec. It causes increased CAPEX and OPEX in export compression, decreasing gross profit.

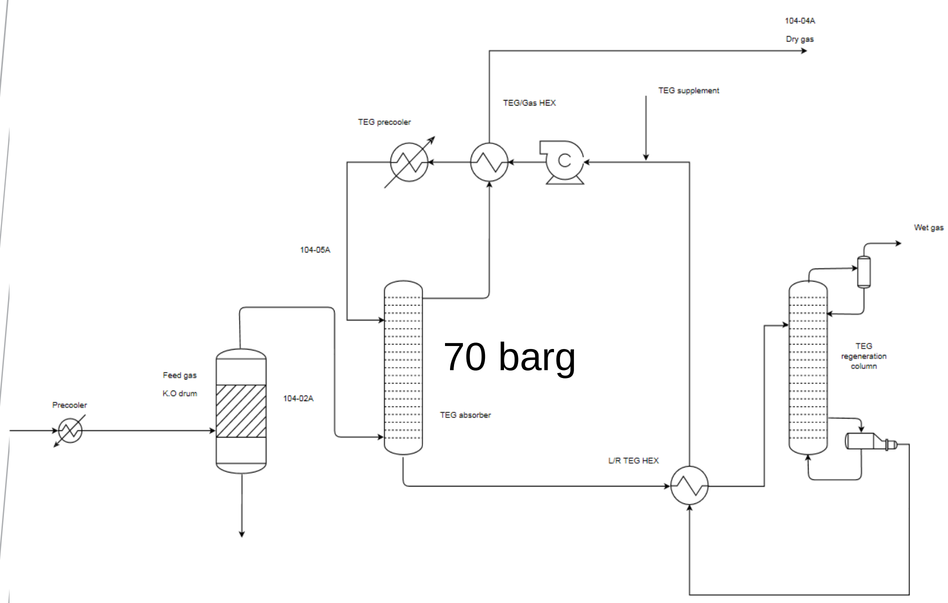


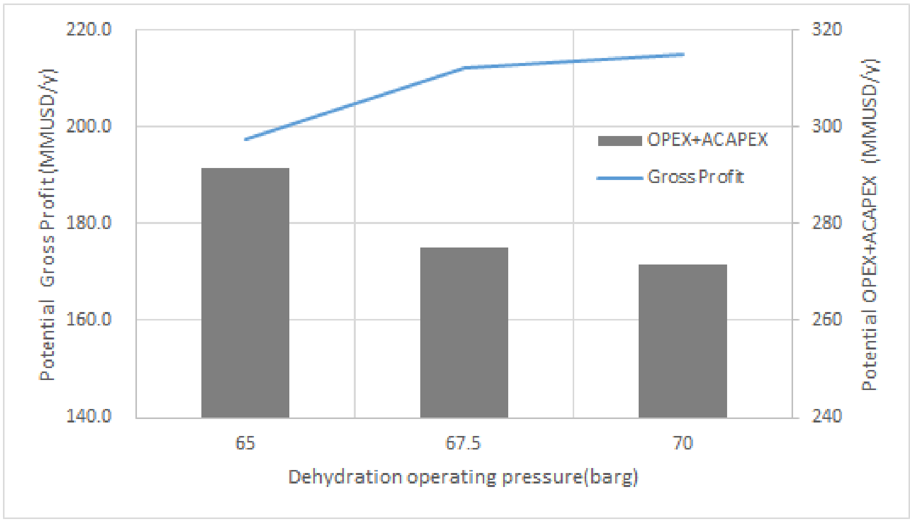


** Minimum pressure drop between modules was assumed as 2.5 bar.*

Operating Conditions –Dehydration Pressure

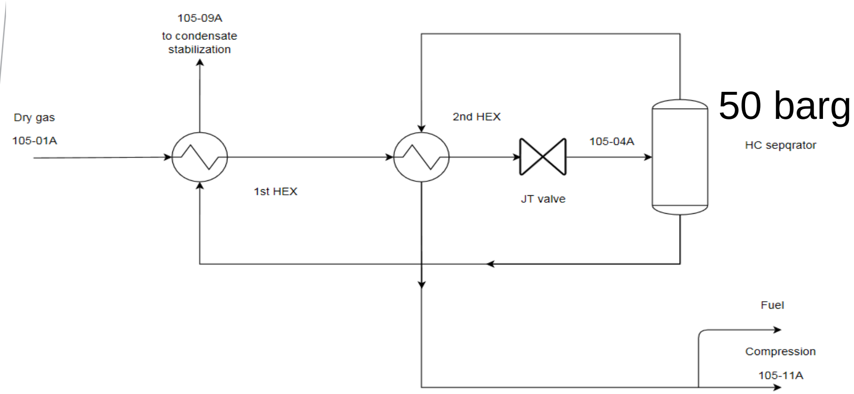
- TEG dehydration process is used.
  - TEG dehydration is a widely used dehydration process for PNG because it has a appreciably lower cost of installation and operation than adsorption (molecular sieve), although generally it will not reduce the water content as low as the adsorption*.
- 70 barg is recommended for dehydration operating pressure**.
  - When the dehydration operating pressure becomes lower, the operating pressure in dewpointing also becomes lower to satisfy the HC dewpoint spec. It causes increased CAPEX and OPEX in export compression, decreasing gross profit.

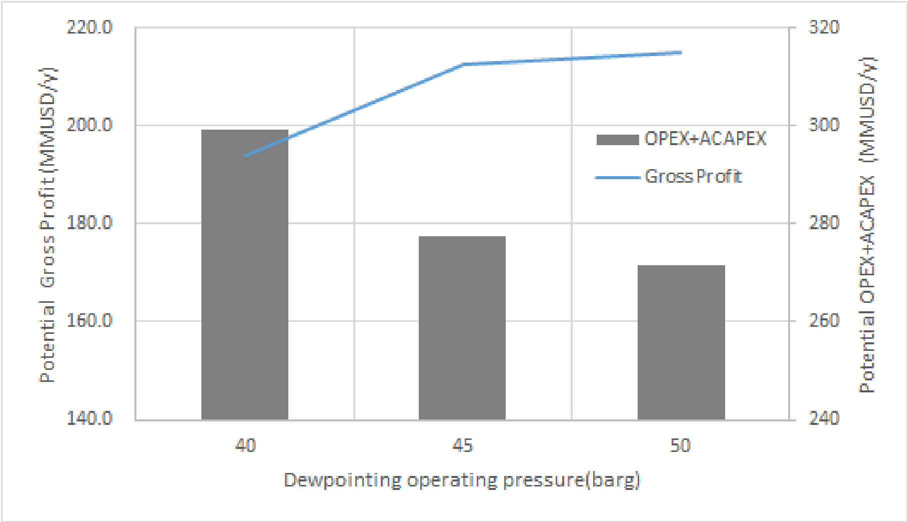




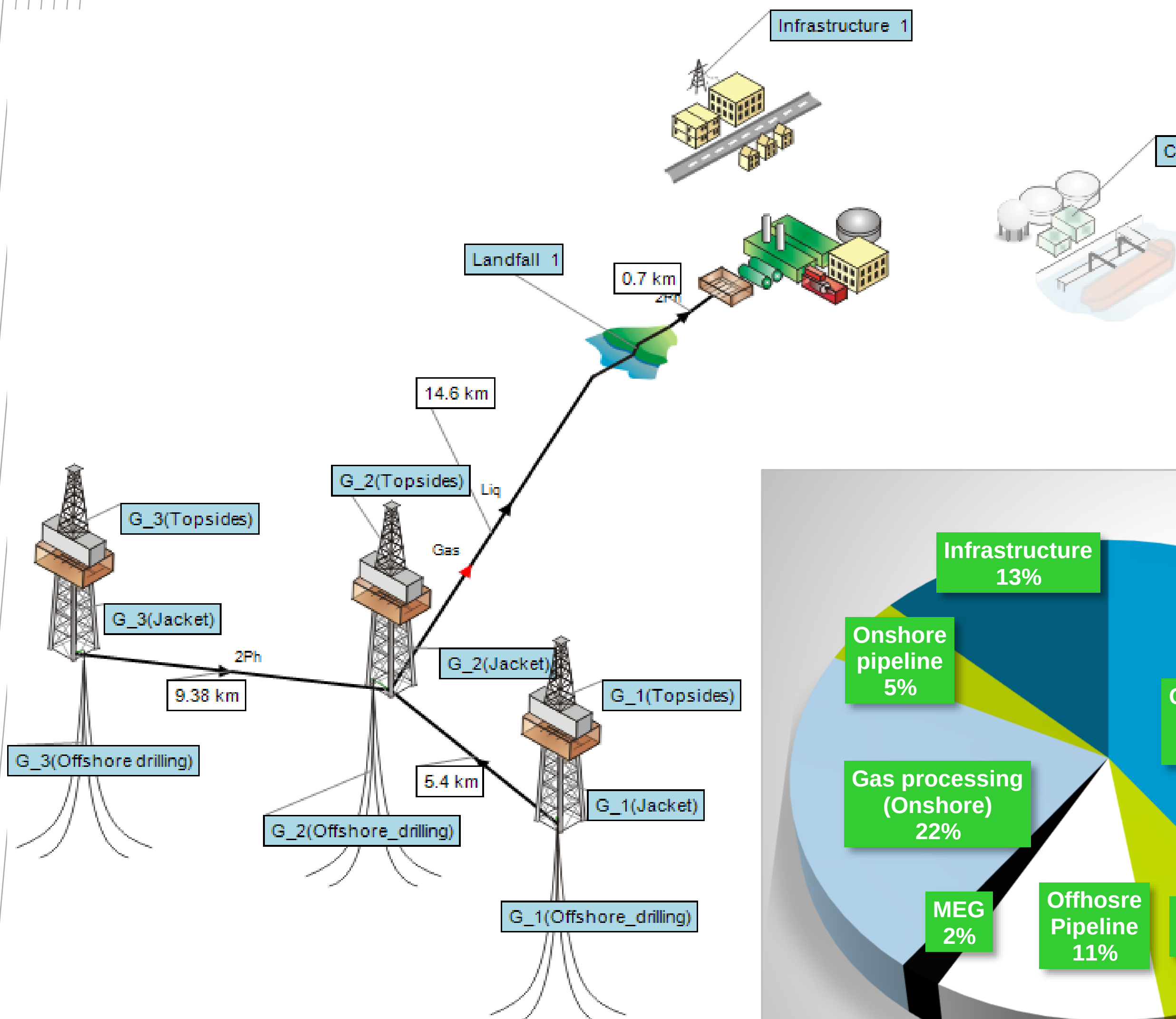
Operating Conditions – Dewpointing

- JT expansion process is used.
  - JT expansion uses the Joule-Thompson effect (temperature drop through a orifice). It does not require additional refrigerant, so is cheap and effective.
- Expansion to 50 barg is recommended for dewpointing operating pressure.
  - When dewpointing pressure decreases, CAPEX and OPEX in export compression increases, resulting reduced potential gross profit.
  - To satisfy the dewpoint specification, at least 20 bar of pressure drop is required. If the dewpointing pressure is higher than 50 barg, the produced gas cannot satisfy the dewpoint spec.

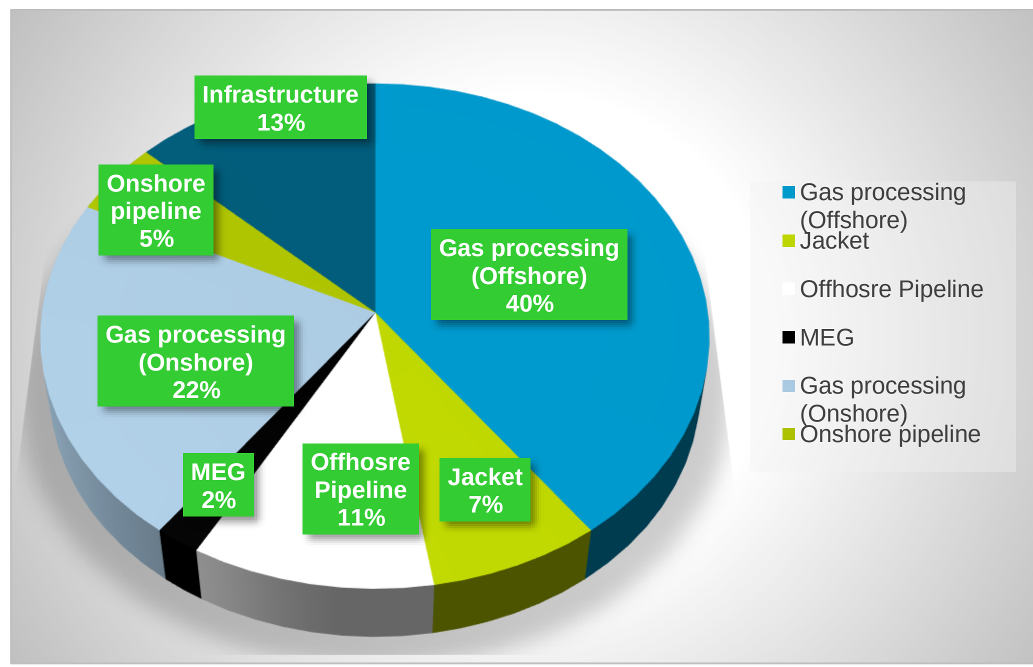




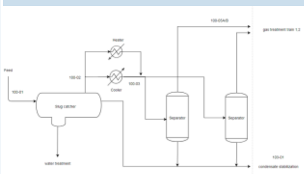
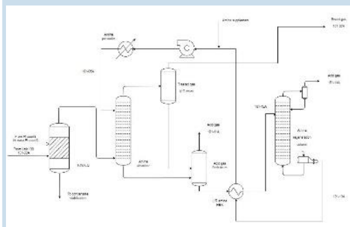
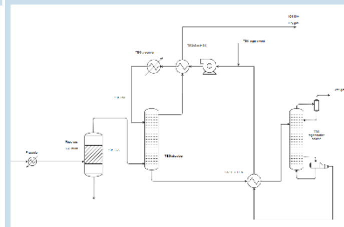
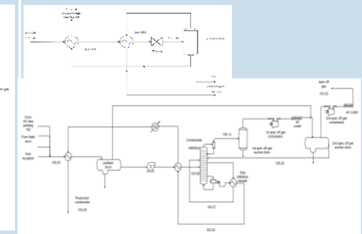
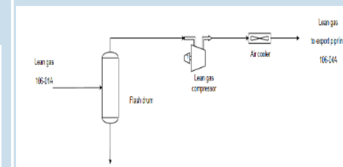
Gas field developments economics



CAPEX	USD
Gas processing (Offshore)	426,320,000
Jacket	81,752,000
Offshore Pipeline	114,980,000
MEG	21,419,000
Gas processing (Onshore)	235,741,000
Onshore pipeline	50,506,000
Infrastructure	140,076,000
Total	1,070,794,000



Gas processing cost breakdown

	Separation	Acid gas removal	Dehydration	Dewpoint control & Stabilization	Gas compression
PFD					
Units	  Slug catcher: 77.5 bar Separator: 75 bar Flow: 310000 kg/hr	 Pressure: 72.5 bar Amine regen. 131ºC Flow: 440000 kg/hr	 Pressure: 69.5 bar TEG regen. 131 ºC Flow: 400000 kg/hr	 Pressure: 50 bar Stabilization. 200 ºC Flow: 400000 kg/hr	  Pressure: 50 → 100 bar Temp. 50 → 93 ºC Flow 360000 kg/hr
CAPEX (USD)	513,000	259,000	1,148,000	2,216,000	60,344,000

Thank you!