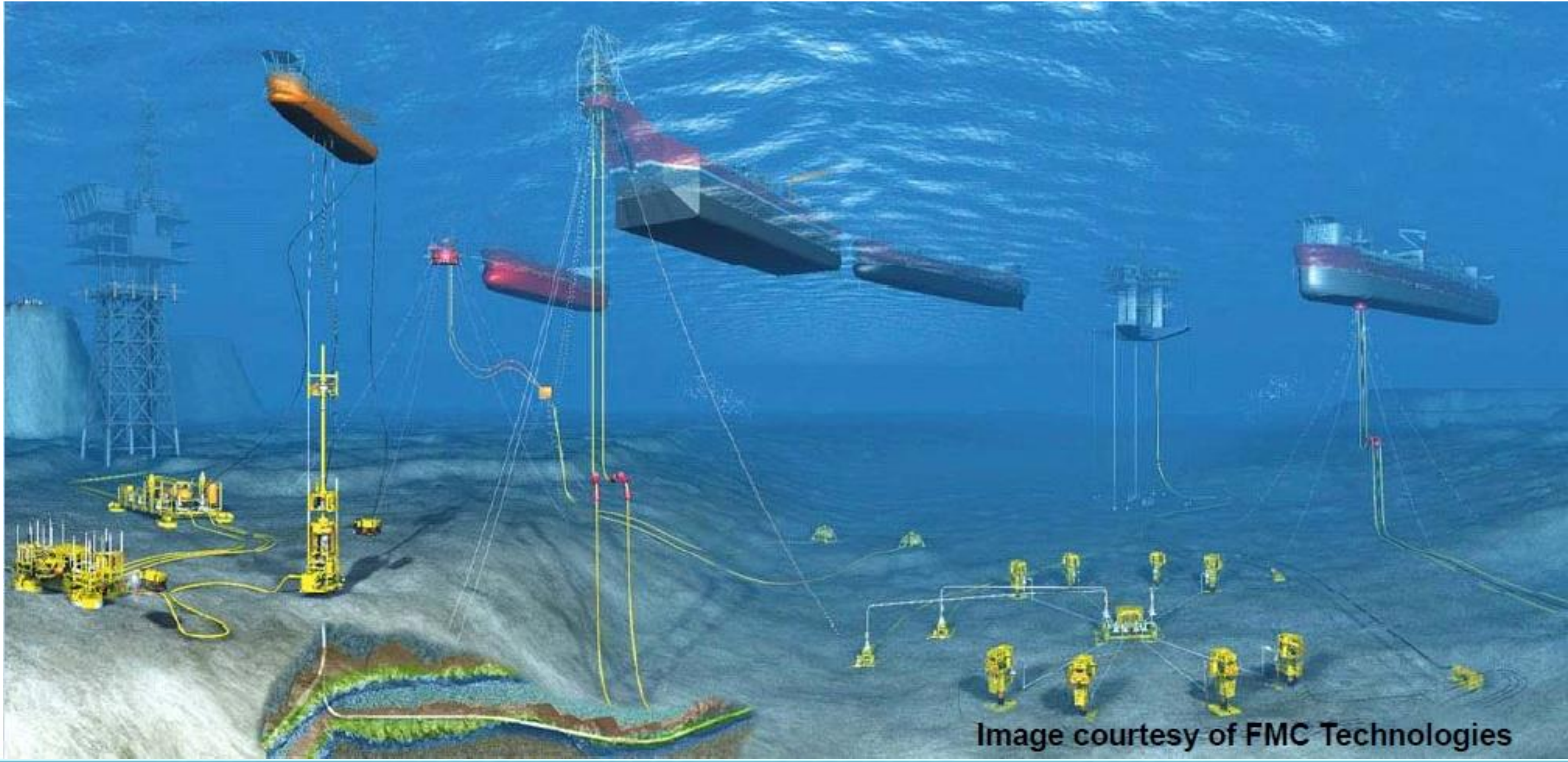


Offshore platform FEED

Yutaek Seo

Oil and Gas production

- Hydrocarbon fluids produced from a reservoir are seldom (if ever) suitable for direct sale to a buyer. These fluids must be conditioned prior to their disposition.
- Petroleum reservoirs are a mixture of crude oil, natural gas and water. These constituents are separated and processed to make marketable products.
- The gas conditioning and processing equipment is only a part of the entire system. The total system may look very much like that shown below.

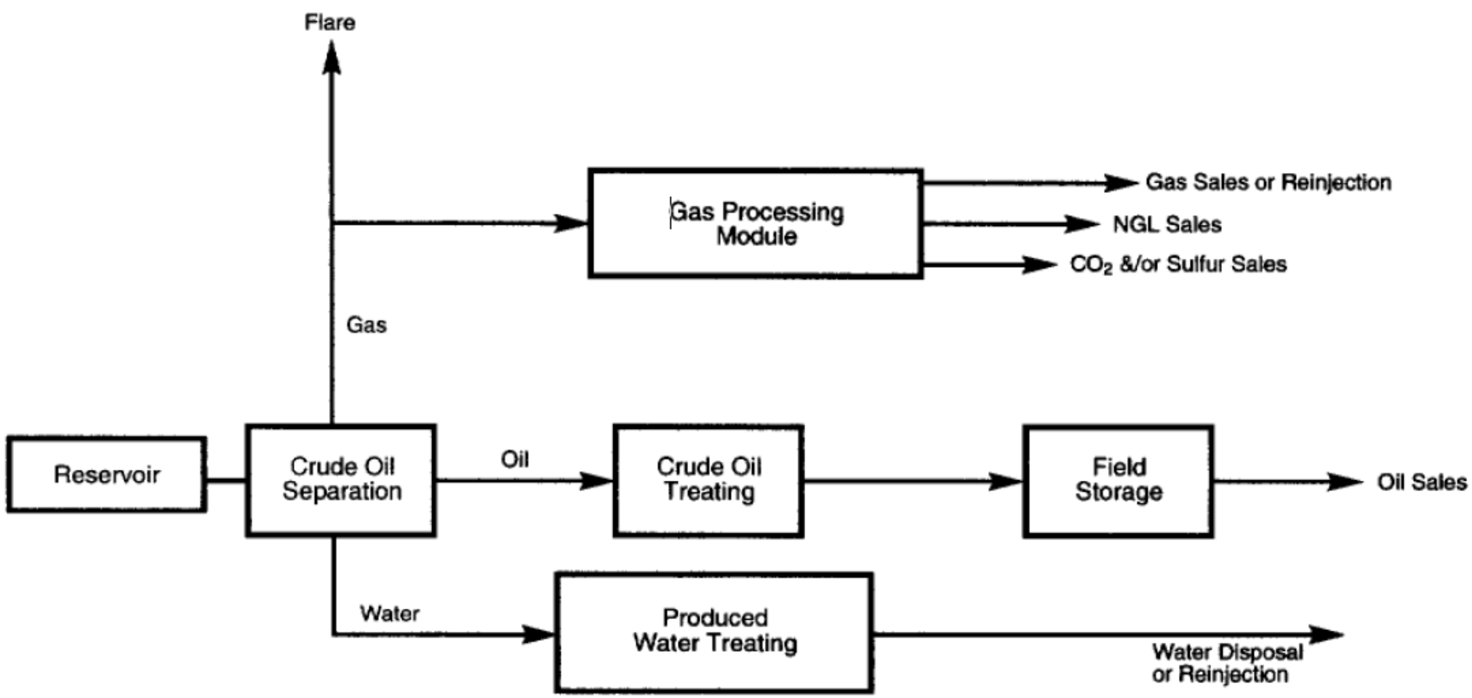


Figure 1.1 Schematic View of a Total Production Processing System

- For convenience, we divide each system into modules. A dehydration unit, for example, would be a module; as would a fractionation tower with its auxiliary equipment.
- The choice of modules is governed by convenience, both for calculation and decision purposes.
- Unfortunately, one can do a sound job of designing, specifying and operating each modular unit, but end up with a poor system.
- The reason is that each module has varying characteristics under varying loads that may result in a type of internal incompatibility. One modular unit may require a certain incoming analysis to produce the output desired.
- If a previous unit does not maintain this, then the downstream unit may not prove satisfactory. The fault might not lie so much with that unit but with **total** system design.
- Root of most problems

  : One is to concentrate on the detailed design of each module without proper consideration of the total system within which it resides.

  : Another is failure to properly recognize the degree of uncertainty in the input and output specifications of the system, random variables within practical limits.

- The process simulation is nothing more than performing (in advance) those calculations which characterize system behavior. The most routine form of simulation simply involves solving the equations which (hopefully) describe the operation of concern.
- Although we currently do much of this on a computer, it adds nothing to the value of the result unless greater true precision is obtained.
- Total simulation must recognize formally the uncertainty of the numbers used. Using an average or most probable analysis is not an answer. These are only two points on the likely distribution curve (mean and mode respectively).
- Total simulation must include these concerns so that the system may possess necessary flexibility with minimum use of arbitrary safety factors.

The basic system

- Figure 1.1 represents a fairly complete processing setup for handling produced fluids. It encompasses almost all systems used.
- Each of the squares shown represents a calculation module. Within this module there is a body of equations and practice which enables one to design it subject to the imposed constraints.
- Not shown in the modular setup are the pumps, compressors, valves and fittings, and lines necessary to move, control and contain the fluids flowing between modules. These are interconnecting modules difficult to show on diagrams. (goes to P&ID)
- Some major modules shown have a number of sub-modules representing component parts that involve some unique and/or separate engineering concern.

- For example, the NGL extraction module could be subdivided as shown in Figure 1.2. This figure is for the very simplest form of refrigeration system consisting of a well stream exchange, refrigeration source, and separation of liquid from vapor.

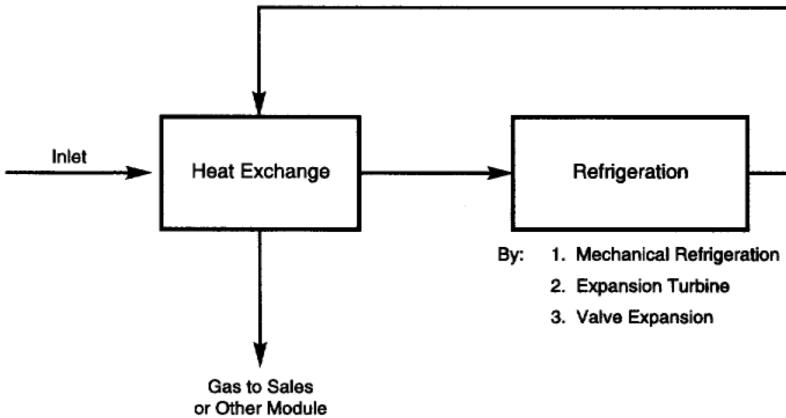


Figure 1.2 Refrigeration Type of Liquids Recovery Module

- The production operation does not change the basic system or its needs.
- On one hand, the planner does not always possess the technological expertise to impose realistic constraints on each individual element in the system.
- On the other hand, the people charged with operating each element resist change from those practices which have served them well traditionally.
- Handling the system as a system instead of a series of loosely connected individual functions can lead to a more rational basis for greater net profit.
- Constraints of the basic system
  1. The quantity and analysis of fluids entering
  2. The market demand (quantity and price) for the effluent products
  3. Legal and quasi-legal conditions imposed "no-flare" gas orders, proration, contracts and agreements, national and political concerns, and the like
  4. Environmental factors labor availability and quality, climate, local customs, population density, availability of utilities and services, and the like
  5. The risk tolerance level technological, political and economic
  6. The quantity and quality of available data

- There are an infinite number of systems that could be devised to market the hydrocarbons available for sale in the reservoir (theoretically). Actually, the choice is limited by a series of practical considerations.
- As a practical matter, the first problem is “Marketing”

  : Technological design must not only serve the present market efficiently but possess sufficient flexibility to accommodate a future market at minimum additional cost.

  : For example, many reserves now exist in areas where there is no significant market for natural gas and natural gas liquids. However, any system design that is incompatible with future gas processing in these areas is a poor one.
- Total reserves might be the paramount constraint. The maximum capital outlay that will yield a fair profit is fixed at some point by this concern.
- An uncertain political climate might offer a similar constraint limit the amount of risk capital to that which will afford both a realistic payout time (to reduce time risk) and a satisfactory rate of return.
- These overall economic constraints provide the boundaries for our system “jigsaw puzzle”. One then proceeds to the lower order, but equally important, legal and quasi-legal restrictions familiar.

  : Compressor capacity rather than the reservoir may limit oil production when a "no flare" order is in effect.

  : Fulfillment of a gas marketing contract may require a production schedule that is "inefficient" from the reservoir viewpoint alone.

The decision modules

The Reservoir Module

- A reservoir study generally is undertaken for one of two reasons: to establish value or to forecast performance under various production strategies.
- The typical report deals in gross numbers not entirely suitable. Needed is a special report showing greater detail about the character and condition of produced oil and gas.

    : Based on current samples, compositional balances can be made to forecast changes in gas and liquid analysis with time.

    : Geological data are valuable for judgment decisions involving the extrapolation of current data number of wells, likelihood of solids production from core data, gathering system layout, etc.

    : Pressure maintenance is used to permit high initial production rates without excess pressure decline. The injection of water and/or gas usually is involved. At some point in time these will begin to "break through" into the production wells. Wellhead pressure will be different; liquid-gas ratios will change. Production/processing system needs will change accordingly.

    : Is the surface system designed to accommodate only current conditions? If so, some major modifications will be necessary eventually. In an offshore or frontier environment the cost of modification plus the hidden cost of inefficient production practices can seriously compromise future profitability and limit reservoir recovery efficiency.

The Separation Module

- With few exceptions, some liquid will be obtained even though the fluid in the reservoir is all vapor, at reservoir conditions. In this instance, a flash calculation must be made at separation conditions to obtain the quantity and composition of all effluent streams.
- If the primary effluent is crude oil or any other liquid stream, containing a reasonable percentage of heavy hydrocarbon molecules (larger than octane), this calculation is difficult.
- Gas specific gravity alone is inadequate for subsequent liquid recovery computations.
- Furthermore, even routine changes in temperature and pressure will affect the performance of subsequent modules.

Crude Oil Treating Module

- This module is required to meet crude oil sales specifications:

1. BS&W (Basic Sediment and Water)

   The BS&W specifications is essentially an entrained water specification. It limits the amount of free water carried with the crude. It often varies from **0.3%** to **3.0%** by volume with the lower number applied to light crudes and the higher number to very heavy crudes (< 20 API).

2. Vapor pressure

   The vapor pressure specification limits the volatility of the crude oil. If the crude oil is stored or transported at or near atmospheric pressure this specification will often be equal to or less than **101.3 kPa [14.7 psia]** at the system temperature. True Vapor Pressure (TVP) or Reid Vapor Pressure (RVP).

3. Salt

   Salt is removed by mixing the crude with fresh water and removing the resultant water in a crude oil dehydration module.

4. Sulfur content

   Sulfur compounds may be removed by gas stripping, or chemical conversion, or a combination of the two.

Produced Water Treating Module

- Produced water must be treated in order to meet reinjection or disposal specifications:

  1. Hydrocarbons

     The hydrocarbon specification is particularly important if the produced water is discharged to the sea. For example, in the North Sea the oil content in the discharged water from an offshore platform is limited to 40 ppm by weight (monthly average).

     This specification is typically met by gravity separation, flotation units, centrifugal separation (hydrocyclones).

  2. Free solids

     Free solids may require removal if the produced water is to be reinjected into the reservoir.

     Removal methods include gravity separation, filtration and centrifugal separation.

  3. Dissolved solids e.g., $CaCO_3$, $NaCl$, $BaSO_4$, etc.

     Dissolved solids must be analyzed to assess their compatibility with connate water in the reinjection zone or with reinjection water from other sources such as sea water. In this case, specifications can only be established by detailed sampling and testing of the streams involved.

Gas Processing Module

- Natural gas must also be processed to meet basic specifications prior to its sale. These include water content, hydrocarbon dewpoint, sulfur content and heating value.
- The gas processing techniques depends on the composition of the gas, product specifications and the markets for natural gas and natural gas liquids (NGLs).
- Gas condition and processing are terms used to describe a variety of processes which involve the removal of one or more components from a natural gas or natural gas liquids (NGL) streams.
- Gas processing is sometimes generically used for any equipment required to make the produced gas marketable.

  : includes compression, dehydration, sweetening, impurity rejection / recovery (nitrogen, helium, etc.) and NGL extraction.
- In this manual, we will divide gas processing into two categories:

  : *Gas **Conditioning*** will refer to the dehydration, impurity rejection / recovery and sweetening of produced gas.

  : *Gas **Processing*** will refer to NGL extraction.

Factors affecting gas processing schemes

1. Reservoir conditions - fluid composition, temperature, pressure
2. Field development plan - volumes, temperatures, pressures
3. Legal restrictions - no-flare orders, contracts, nominations, etc.
4. Environmental factors - field location, labor, local customs, etc.
5. Markets - natural gas, NGL, sulfur, and C02 market availability, quantity, price
6. Product specifications (gas) - water and hydrocarbon dewpoint, H_2S, heating value
7. Product specifications (NGL) - vapor pressure, water content, H_2S and C02
8. Economic - profitability of treatment process
9. Political - national interests such as resource conservation
10. Processing agreements - for NGL extraction

- While all of the above items are critical to **an** effective design, four factors which warrant more emphasis are
  1) fluid composition,
  2) gas contracts and specifications,
  3) NGL contracts and specification, and
  4) Processing agreements.

Examples of gas composition in the U.S.

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

Contract terms

<u>Gas contract quality</u>

1. Minimum, maximum, and nominal delivery pressure
2. Maximum water content (expressed as a dewpoint at a given pressure)
3. Maximum condensable hydrocarbon content expressed as a hydrocarbon dewpoint
4. Maximum delivery temperature
5. Allowable concentration of contaminants such as H2S, carbon disulfide, mercaptans, etc.
6. Minimum and maximum heating value
7. Cleanliness (allowable solids concentration)

- These quality specifications are extremely important factors in the selection of the gas treatment process.
- Quality specifications for gas handled by transmission and distribution companies vary from country to country.
- In a number of instances specifications have been set for historic reasons rather than technical reasons.

- Table 2.4 provides a comparison between the U.K., North America, and Middle East specifications.

Example of Sales Gas Specifications(2.12)

	U.K.	North America	Middle East
H_2S – max	4-5 ppm (vol)	4-16 ppm(vol) [0.25-1.0 gr/100 scf]	8 ppm (vol)
Total S – max	150 mg/std m^3	8-480 ppm (vol) [0.5-30 gr/100 scf]	—
CO_2 – max vol	no limit	1-3%	< 5%
O_2 – max vol	0.5%	0.001-1%	—
H_2O dewpoint	–10°C @ 70 Barg [15°F @ 1000 psig]	4-7 lb H_2O/MMscf Gas	-3°C [26°F]
Total Inlets (N_2, CO_2, O_2)			
Gross heating value — max min	 30 MJ/std m^3 [800 Btu/scf]	1050-1235 Btu/scf 950-1000 Btu/scf	 1020-1200 Btu/scf
Wobbe Index	41-45 MJ/std m^3 [1100-1200 Btu/scf]	Not typical, but 1200-1300 Btu/scf	—
Hydrocarbon dewpoint	–1°C [30°F] @ delivery pressure	–50°F to 40°F	10°C [50°F]

Notes: 1) std m^3 is abbreviation of standard cubic meters (at 15°C and 101.325 kPa).
2) Wobbe Index is equal to:

$$\frac{\text{Gross Heating Value}}{\sqrt{\text{Specific Gravity}}}$$

and is a way of characterizing the heat release at the burner tip for gaseous fuels.

TABLE 2.5

North American Pipeline Quality Specification Survey[2.11]

	Water Content, lb/MMcf	Sulfur Compounds		Nitrogen, Oxygen, and Carbon Dioxide				NGL Content		Total Heating Value		Allowable Temperature	
		H_2S	Total	Total Inerts,[1] vol%	CO_2, vol%	N_2, vol%	O_2, vol%	Max. Dewpoint, °F	Max. C_5+, vol%	Min.	Max.	Min.	Max.
		Grain/100 cf								Btu/scf		°F	
1. Arkla	7	0.25	5		2	3	0.2	20 @ 800 psi	0.2			40	120
2. Colorado	7	1.00	20		3		0.001	25		968	1235		120
3. Columbia Gulf	7	1.00	20	4	3		1			978		40	120
4. CNG		1.00	20	5	3					967			
5. El Paso	7	0.25	5	3	2		0.2	20		967		50	120
6. Equitrans	7	0.30	30	4	3		1		0.2	1000			
7. KN Energy	6	0.25	5		2		0.001	25		950	1050		120
8. Midwest	7	0.25	20	4	3		0.2			967	1100		120
9. NGPL	7	0.25	0.5		2	3	0.001	Norm p/l Cond.		950		40	120
10. Northern Border	4	0.30	2		2		0.4	-50 @ 800 psi		967			
11. Northwest	7	0.25	20		3	3	0.2	15		985			120
12. Nova	4	1.00	5		2		0.4	14		965		14	120
13. CNG	7	0.25	20	4	2		0.2			967	1080		120
14. Panhandle Eastern	—[3]	1.00	20							950	1100		
15. Tennessee	7	0.25	20	4	3		0.2			967	1100		120
16. Texas Eastern	7	0.50	10	4	3		0.2		0.2	967			120
17. Texas Gas	7	1.00	20	4.5	2		0.1	10		967		40	120
18. TransCanada	4	1.00	20		2			14 @ 800 psi		950		14	122
19. Transco	7	0.30	9	3			1			960	1100		120
20. Transwestern	7	0.25	0.75	4	3		0.2			970		40	120
21. Valero	7	0.25	10		3		1			950		40	120
22. Viking	7	0.25	20	4	3		0.2			967	1100		120
23. Westcoast	4	0.25	1		2		0.4	16					120
24. Williams	7	0.25	20		1		0.2	40		950			120

Notes: [1] Total Inerts = N_2 + CO_2. Must meet both toal inerts and CO_2 specification if two are shown.

[2] Dewpoint measured at maximum delivery pressure unless otherwise noted.

[3] No free water allowed.

Liquid contract quality specifications

- Products from natural gas - Natural gas liquids (NGLs) consist of all hydrocarbons heavier than methane which can be extracted from a natural gas stream.
- A list of NGL products is provided below:

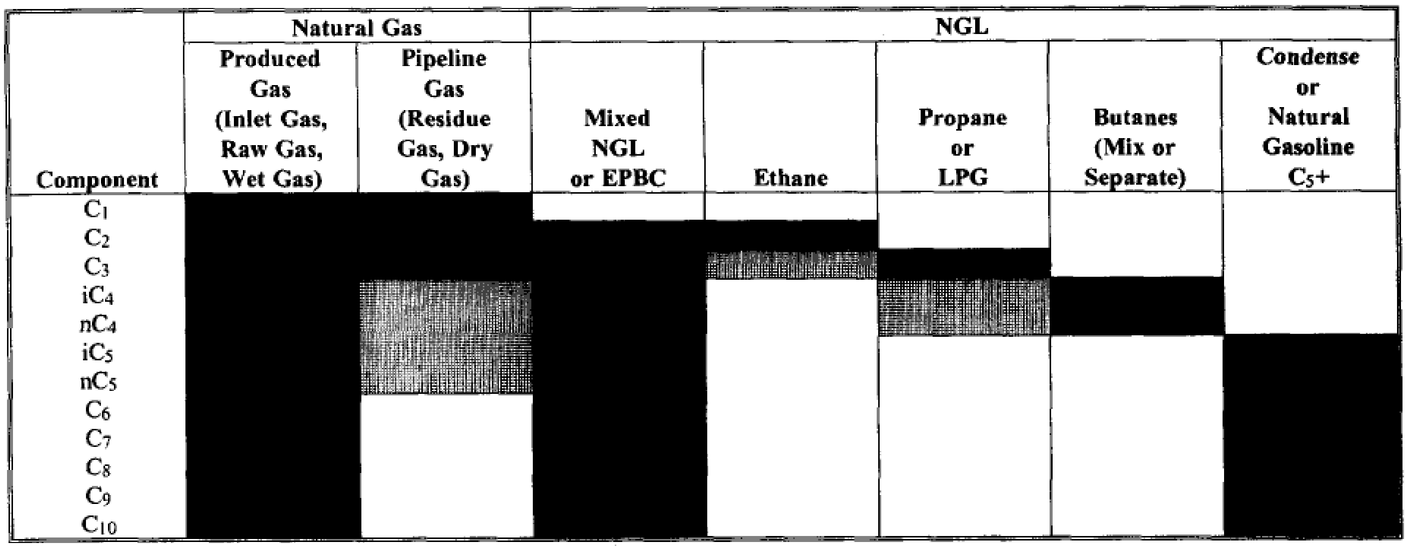
1. C2 Ethane
2. C3 Propane
3. iC4 iso-butane
4. nC4 normal-butane
5. C5+ Pentanes and heavier

- Liquid contracts usually contain the following basic considerations:

1. Quality of products expressed as vapor pressure, relative or absolute density, or by standard designation such as Commercial Propane
2. Specifications such as color, concentration of contaminants, etc., as determined by standard tests
3. Maximum water content

- NGL components normally found in natural gas and the resulting NGL products.

Natural Gas and NGL Product Specifications



- NGL products

Natural gasoline **:** mixed product whose basic specification is vapor pressure

Reid vapor pressure: 70-235 @a [lo-34 psia]

Percentage evaporated at 60°C [140"FI: 25-85%

Percentage evaporated at 135°C [275"F]: not less than 90%

Corrosion: not corrosive by specified test

Color: not less than plus 25 (Saybolt)

Water content: no free water

Commercial ethane **:** chemical feed stock for the manufacture of plastics

Demethanized mixes **:** containing ethane, propane, butane, and natural gasoline (true vapor pressure 600 psia at 100°F)

Commercial propane **:** at least 95% propane (true vapor pressure not exceed1.43 MPa(g) [208 psig] at 38°C [100°F])

Propane HD-5 **:** special grade of propane for motor fuel (true vapor pressure of more than 1.43 MPa(g) [208 psig] at 38°C)

Commercial butane **:** predominantly butanes (true gauge vapor pressure not greater than 483 kPa(g) [70 psig] at 38°C [100 °F])

Butane-propane mixtures **:** sold for domestic heating service or used for secondary recovery of oil (vapor pressure of the commercial product seldom exceeds 860 kPa(g) [125 psig] at 38°C [100°F])

Vapor pressure

- Vapor pressure specifications may be expressed in terms of a TVP (True Vapor Pressure) or RVP (Reid Vapor Pressure).
- The vapor pressure or volatility specification is probably the most important factor determining the ultimate amount of NGLs recovered and the type of NGL process selected.
- The vapor pressure of **an** NGL product can be estimated from the following equation:

$$P_{v_{mix}} = \sum x_i \, P_{v_i}$$

$P_{v_{mix}}$ = vapor pressure of the NGL mixture

x_i = mol fraction of each component in the mixture

P_{v_i} = vapor pressure of each component in the mixture

- This equation simply says that the vapor pressure of an NGL mixture is proportional to the vapor pressure and amount of each individual component in the mixture.
- For specification purposes, vapor pressures are almost always expressed at a temperature of 38°C [100°F].

- Physical properties of several NGL components (SI)

Physical Constants of Paraffin Hydrocarbons and Other Components of Natural Gas

(GPA Publication 2145 SI-80 International System (SI) Units [Abridged—Approval Pending]

	Component											
	Methane	**Ethane**	**Propane**	**i-Butane**	**n-Butane**	**i-Pentane**	**n-Pentane**	**n-Hexane**	**n-Heptane**	**n-Octane**	**n-Nonane**	**n-Decane**
Molecular Weight	16.043	30.070	44.097	58.124	58.124	72.151	72.151	86.178	100.205	114.232	128.259	142.286
Boiling Point @ 101.3250 kPa (abs), K	111.63	184.57	231.08	261.34	272.66	300.99	309.21	341.89	371.57	398.82	423.97	447.31
Freezing Point @ 101.3250 kPa (abs), K	90.68	90.35	85.47	113.55	134.79	113.25	143.42	177.83	182.57	216.39	219.66	243.51
Vapor Pressure @ 313.15 K, kPa (abs)	(35 000.)	(6000.)	1341.	528.	377.	151.3	115.66	37.28	12.34	4.143	1.40	0.4732
Density of Liquid @ 288.15 K & 101.3250 kPa (abs)												
Relative density (water = 1)	(0.3)	0.3581	0.5083	0.5637	0.5847	0.6250	0.6316	0.6644	0.6886	0.7073	0.7224	0.7346
Absolute density, kg/m^3 (in vacuum)	(300.)	357.8	507.8	563.2	584.2	624.4	631.0	663.8	688.0	706.7	721.7	733.9
Apparent density, kg/m^3 (in air)	(300.)	356.6	506.7	562.1	583.1	623.3	629.9	662.7	686.9	705.6	720.6	732.8
Density of Gas @ 288.15 K & 101.3250 kPa (abs)												
Relative density (air = 1), ideal gas	0.5539	1.0382	1.5225	2.0068	2.0068	2.4911	2.4911	2.9753	3.4596	3.9439	4.4282	4.9125
Kilogram per cubic metre, kg/m^3, ideal gas	0.6784	1.2718	1.8650	2.4582	2.4582	3.0516	3.0516	3.6443	4.2373	4.8309	5.4259	6.0168
Volume @ 288.15 K & 101.3250 kPa (abs)												
Liquid, cm^3/mol	(50.)	84.04	86.84	103.2	99.49	115.6	114.3	129.8	145.6	161.6	177.7	193.9
Ratio, gas/(liquid in vacuum)	(442.)	281.3	272.3	229.1	237.6	204.6	206.8	182.1	162.4	146.3	133.0	122.0
Critical Conditions												
Temperature, K	190.55	305.43	369.82	408.13	425.16	460.39	469.6	507.4	540.2	568.76	594.56	617.4
Pressure, kPa (abs)	4604.	4880.	4249.	3648.	3797.	3381.	3369.	3012	2736.	2486.	2288.	2099.
Gross Calorific Value, Combustion @ 288.15 K & Constant Pressure												
Megajoule per kilogram, MJ/kg, liquid	–	51.586	50.008	49.044	49.158	48.579	48.667	48.344	48.104	47.919	47.783	47.670
Megajoule per kilogram, MJ/kg, ideal gas	55.563	51.920	50.387	49.396	49.540	48.931	49.041	48.722	48.482	48.290	48.137	48.043
Megajoule per cubic metre, MJ/m^3, ideal gas	37.694	66.032	93.972	121.426	121.779	149.319	149.654	177.556	205.431	233.286	261.189	289.066
Megajoule per cubic metre, MJ/m^3, liquid	–	18458.	25394.	27621.	28718.	30333.	30709.	32091.	33095	33865.	34485.	34985.
Volume air to burn one volume gas, ideal gas	9.54	16.70	23.86	31.02	31.02	38.18	38.18	45.34	52.50	59.65	66.81	73.97
Flammability Limits @ 310.93 K & 101.3250 kPa (abs)												
Lower, volume % in air	5.0	2.9	2.0	1.8	1.5	1.3	1.4	1.1	1.0	0.8	0.7	0.7
Upper, volume % in air	15.0	13.0	9.5	8.5	9.0	8.0	8.3	7.7	7.0	6.5	5.6	5.4
Heat of Vaporization @ 101.3250 kPa (abs) kJ/kg @ boiling point	509.86	489.36	425.73	366.40	385.26	342.20	357.22	334.81	316.33	301.26	288.82	276.06
Specific Heat @ 288.15 K & 101.3250 kPa (abs)												
C_p gas, kJ/(kg·K), ideal gas	2.204	1.706	1.625	1.616	1.652	1.600	1.622	1.613	1.606	1.601	1.598	1.595
C_v gas, kJ/(kg·K), ideal gas	1.686	1.429	1.436	1.473	1.509	1.485	1.507	1.517	1.523	1.528	1.533	1.537
$k = C_p/C_v$, ideal gas	1.307	1.194	1.132	1.097	1.095	1.077	1.076	1.063	1.054	1.048	1.042	1.038
C_p liquid, kJ/(kg·K)	–	3.807	2.476	2.366	2.366	2.239	2.292	2.231	2.209	2.191	2.184	2.179

- Physical properties of several NGL components (FPS)

Physical Constants of Paraffin Hydrocarbons and Other Components of Natural Gas

(GPA Publication 2145 English (fps) Units [Abridged—Approval Pending]

	Component											
	Methane	**Ethane**	**Propane**	**i-Butane**	**n-Butane**	**i-Pentane**	**n-Pentane**	**n-Hexane**	**n-Heptane**	**n-Octane**	**n-Nonane**	**n-Decane**
Molecular Weight	16.043	30.070	44.097	58.124	58.124	72.151	72.151	86.178	100.205	114.232	128.259	142.286
Boiling Point @ 14.696 psia, °F	-258.73	-127.49	-43.75	10.78	31.08	82.12	96.92	155.72	209.16	258.21	303.47	345.48
Freezing Point @ 14.696 psia, °F	-296.44	-297.04	-305.73	-255.28	-217.05	-255.82	-201.51	-139.58	-131.05	-70.18	-64.28	-21.36
Vapor Pressure @ 100°F, psia	(5000.)	(800.)	188.4	72.58	51.71	20.445	15.574	4.960	1.620	0.5369	0.1795	0.0609
Density of Liquid @ 60°F & 14.696 psia												
Relative density @ 60°F/60°F	(0.3)	0.3562	0.5070	0.5629	0.5840	0.6247	0.6311	0.6638	0.6882	0.7070	0.7219	0.7342
°API	(340.)	265.6	147.3	119.8	110.7	95.1	92.7	81.60	74.08	68.64	64.51	61.23
Absolute density, lbm/gal (in vacuum)	(2.5)	2.970	4.227	4.693	4.870	5.208	5.262	5.534	5.738	5.894	6.018	6.121
Apparent density, lbm/gal (in air)	(2.5)	2.960	4.217	4.683	4.861	5.198	5.252	5.524	5.729	5.885	6.008	6.112
Density of Gas @ 60°F & 14.696 psia												
Relative density (air = 1), ideal gas	0.5539	1.0382	1.5225	2.0068	2.0068	2.4911	2.4911	2.9755	3.4598	3.9441	4.4284	4.9127
lb/M ft^3, ideal gas	42.28	79.24	116.20	153.16	153.16	190.13	190.13	227.09	264.06	301.02	337.98	374.95
Volume @ 60°F & 14.696 psia												
Liquid, gal/lb-mol	(6.4)	10.13	10.43	12.39	11.94	13.85	13.72	15.57	17.46	19.38	21.31	23.45
ft^3 gas/gal liquid, ideal gas	(59.1)	37.48	36.375	30.64	31.79	27.39	27.67	24.37	21.73	19.58	17.81	16.33
Ratio, gas/(liquid in vacuum)	(442.)	280.4	272.1	229.2	237.8	204.9	207.0	182.3	162.6	146.5	133.2	122.2
Critical Conditions												
Temperature, °F	-116.67	89.92	206.06	274.46	305.62	369.10	385.8	453.6	512.7	564.22	610.68	652.0
Pressure, psia	666.4	706.5	616.0	527.9	550.6	490.4	488.6	436.9	396.8	360.7	331.8	305.2
Gross Calorific Value, Combustion @ 60°F												
Btu/lb, liquid	–	22181.	21489.	21079.	21136.	20891.	20923.	20783.	20679.	20601.	20543.	20494.
Btu/lb, gas	23891.	22332.	21653.	21231.	21299.	21043.	21085.	20942.	20838.	20759.	20700.	20651.
Btu/ft^3, ideal gas	1016.0	1769.6	2516.1	3251.9	3262.3	4000.9	4008.9	4755.9	5502.5	6248.9	6996.5	7742.9
Btu/gal, liquid	–	65869.	90830.	98917.	102911.	108805.	110091.	115021.	118648.	121422.	123634.	125448.
Volume air to burn one volume, ideal gas	9.54	16.71	23.87	31.03	31.03	38.19	38.19	45.35	52.52	59.68	66.84	74.00
Flammability Limits @ 100°F & 14.696 psia												
Lower, volume % in air	5.0	2.9	2.0	1.8	1.5	1.3	1.4	1.1	1.0	0.8	0.7	0.7
Upper, volume % in air	15.0	13.0	9.5	8.5	9.0	8.0	8.3	7.7	7.0	6.5	5.6	5.4
Heat of Vaporization @ 14.696 psia												
Btu/lb @ boiling point	219.45	211.14	183.01	157.23	165.93	147.12	153.57	143.94	136.00	129.52	124.36	119.65
Specific Heat @ 60°F & 14.696 psia												
C_p gas, Btu/(lb-°F), ideal gas	0.5267	0.4078	0.3885	0.3867	0.3950	0.3844	0.3882	0.3863	0.3845	0.3833	0.3825	0.3818
C_v gas, Btu/(lb-°F), ideal gas	0.4029	0.3418	0.3435	0.3525	0.3608	0.3569	0.3607	0.3633	0.3647	0.3659	0.3670	0.3678
$k = C_p/C_v$, ideal gas	1.307	1.193	1.131	1.097	1.095	1.077	1.076	1.064	1.054	1.048	1.042	1.038
C_p liquid, Btu/(lb-°F)	–	0.9723	0.6200	0.5707	0.5727	0.5333	0.5436	0.5333	0.5280	0.5241	0.5224	0.5210

- Example: Estimate the true vapor pressure (TVP) of an NGL mixture with the following composition.

	mol%
C3	30
nC4	20
nC5	20
nC6	30
total	100

Component	x_i	P_{vi}	$X_i\ P_{vi}$
C3	0.30	13.41	4.02
nC4	0.20	3.77	0.75
nC5	0.20	1.16	0.23
nC6	0.30	0.373	0.11
	1.00		5.11 bar

- This is an extremely important concept in the design and operation of NGL facilities.
- We want the extraction and stabilization processes to be selective. This means we want to drive out as many of the highly volatile components as possible from the liquid product while retaining the less volatile components.
- The highly volatile components raise the vapor pressure of the product unnecessarily and reduce the “room” (in terms of vapor pressure) for the less volatile components.
- The following example indicates this concept.

- Example: An NGL product must be stabilized to meet a TVP specification of 3.5 bar abs [50 psia] at 38°C [10O0F].

The unstabilized product has the following composition:

	mol%
C2	10
C3	25
nC4	20
nC5	10
nC6	35

What percent of the unstabilized feed can be recovered as liquid product if

a) no C2 remains in the liquid product?

b) 2% C2 remains in the liquid product?

- No ethane in product

(1)	(2)	(3)	(4)	(5)	(6)
Component	Mol fraction	Pv, pisa	Product, mols	Product, Mol %	(3) * (5)
Ethane	0.10	800			
Propane	0.25	188	13.70	17.41%	32.73
n-butane	0.20	51.74	20.00	25.41%	13.10
n-pentane	0.10	15.575	10.00	12.71%	1.98
n-hexane	0.35	4.96	35.00	44.47%	2.21
	1.00		78.70	100.00%	50.02 psia

- 2% ethane in product

(1)	(2)	(3)	(4)	(5)	(6)
Component	Mol fraction	Pv, pisa	Product, mols	Product, Mol %	(3) * (5)
Ethane	0.10	800	1.45	2.00%	16.00
Propane	0.25	188	5.84	8.08%	15.19
n-butane	0.20	51.74	20.00	27.67%	14.26
n-pentane	0.10	15.575	10.00	13.83%	2.15
n-hexane	0.35	4.96	35.00	48.42%	2.40
	1.00		72.29	100.00%	50.00 psia

- effect of the selectivity of the stabilization system upon product recovery.

  : If the stabilization system allows a mere 2% ethane in the liquid product, the product rate decreased by almost 10%. (78.70 → 72.29 mols)

  : The small amount of ethane in the product contributes over 30% of vapor pressure. (16.00/50.00 psia)

- Two basic types of stabilization systems are employed in oil production and NGL recovery facilities.

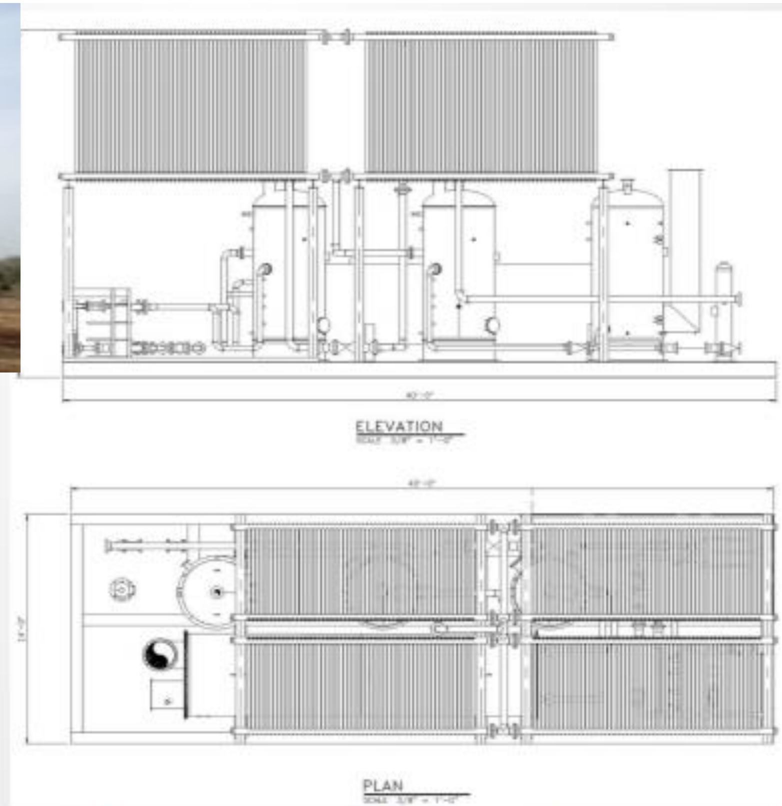
- These are:

  1. Flash stabilization - NGL product is flashed to progressively lower pressures. Flash vapors are recompressed and may be recycled back into the inlet. Heat exchangers may be used to control the product temperature. The oil-gas separation system on the North Slope uses this type of stabilization process to meet the TVP specification of the export crude.

  2. Distillation - NGL product is stabilized at constant pressure in a packed or trayed tower. Temperature is varied from the top to bottom. Stabilizer tower may be refluxed or non-refluxed (top tray feed). A non-refluxed stabilizer is often used in gas processing plants to control the vapor pressure of the NGL product mixture.

- The flash stabilization method (1) is the traditional method used in field processing facilities, especially offshore. It has the advantages of simplicity, ease of control, and it simplifies topside design.
- Method (2), distillation, is more common in gas processing facilities. It has the advantages of more selective separation, so product rates are higher. It also minimizes recompression costs.

Flash stabilization



MQC Condensate Flash Stabilizer Package Consists of:

- Inlet Filter Separator
- Plate Frame Cross Exchanger
- Blowcase System for NGL Recovery
- 2 MMBtu/h Line Heater
- Hot Flash Separator
- Ambient Condenser

What We Need To Know To Quote:

- Inlet Temperature
- Inlet Pressure
- Inlet Flow Rate
- Liquid Analysis
  - Typically FESCO C31+ Hydrocarbon Liquid Analysis
  - Can also use ASTM Boil Away Curve Data
- Condensate Specification
  - Typically a Reid Vapor Pressure (RVP) Specification (9-12 psi)
- NGL Product Specification (optional)
  - Typically a component ratio (i.e. C2/C3 ratio)
  - Could also be a volume percent limit (i.e. < 7% ethane)
- Compressor Suction Pressure that the Flash Gas will be recycled to
- Ambient Temperature and elevation (or Location)
- Customer will need a bullet tank for the NGLs (we can provide if necessary)
- Customer will need to pipe up to our skid edge connections and provide product tanks
- Flat level service to set the equipment must also be provided by the customer

NGL distillation

- The equipment used in the DPC stabilizer process simply provides a way to "cook" the volatile hydrocarbons liquid mix, at the optimum pressure (50 to 350 psig) and the required temperature levels (100°F to 400°F).
- This is done in a distillation tower, controlled in such a way as to drive off the light gaseous hydrocarbons and other gaseous contaminants to be used as a fuel stream or recycled through the conditioning equipment, eventually to be sold as part of the pipeline quality natural gas.
- The resulting "stabilized" liquid thereby has a much-reduced volatility.

NGL market factors

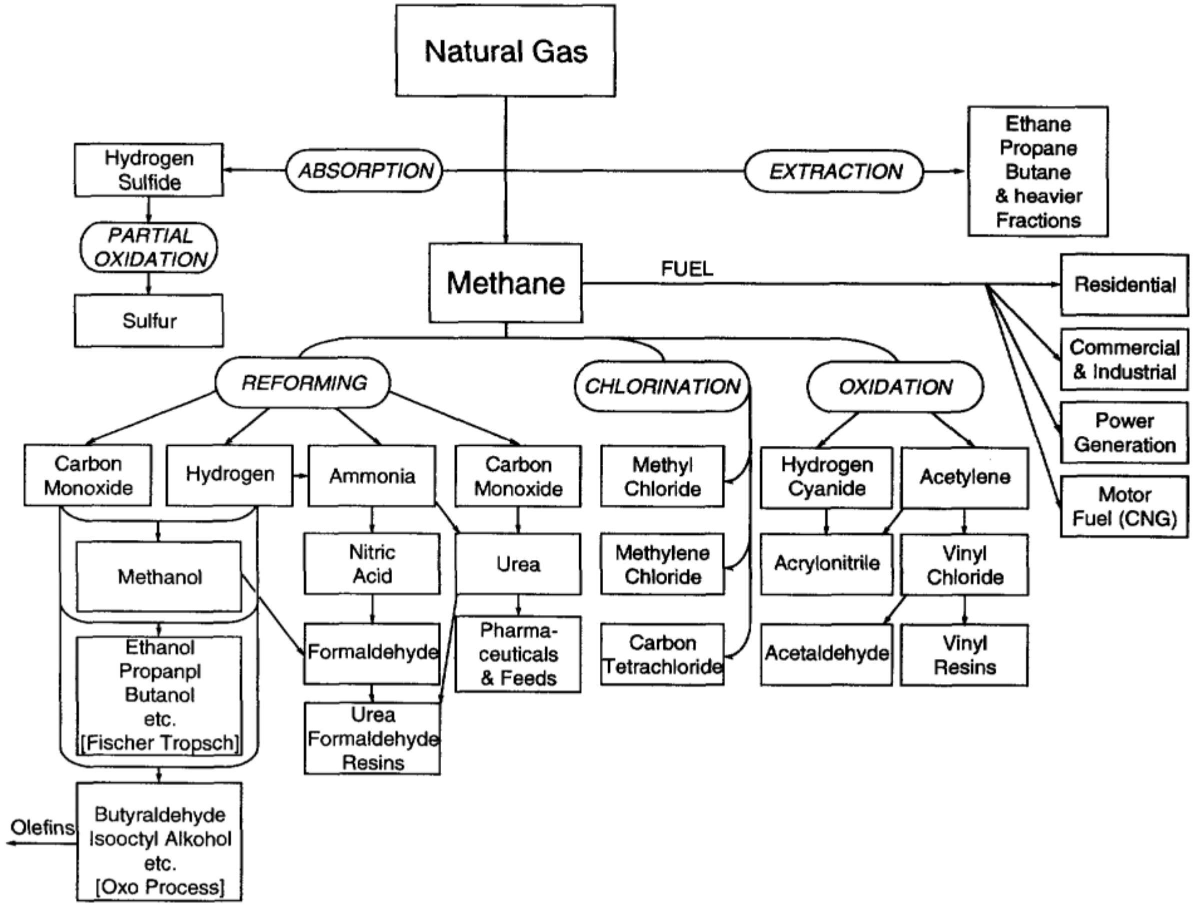
- The natural gas liquids market provides feedstock to the petrochemical and refining industries and supplies fuel for residential, agriculture, commercial, power and transportation sectors.

- Understanding the market factors are important in the proper selection of the NGL extraction technology.

- The disposition of liquids is a primary consideration in determining whether a dew point control facility is installed (recovering the minimum liquids to meet pipeline specifications) or if a high liquid recovery facility is constructed.

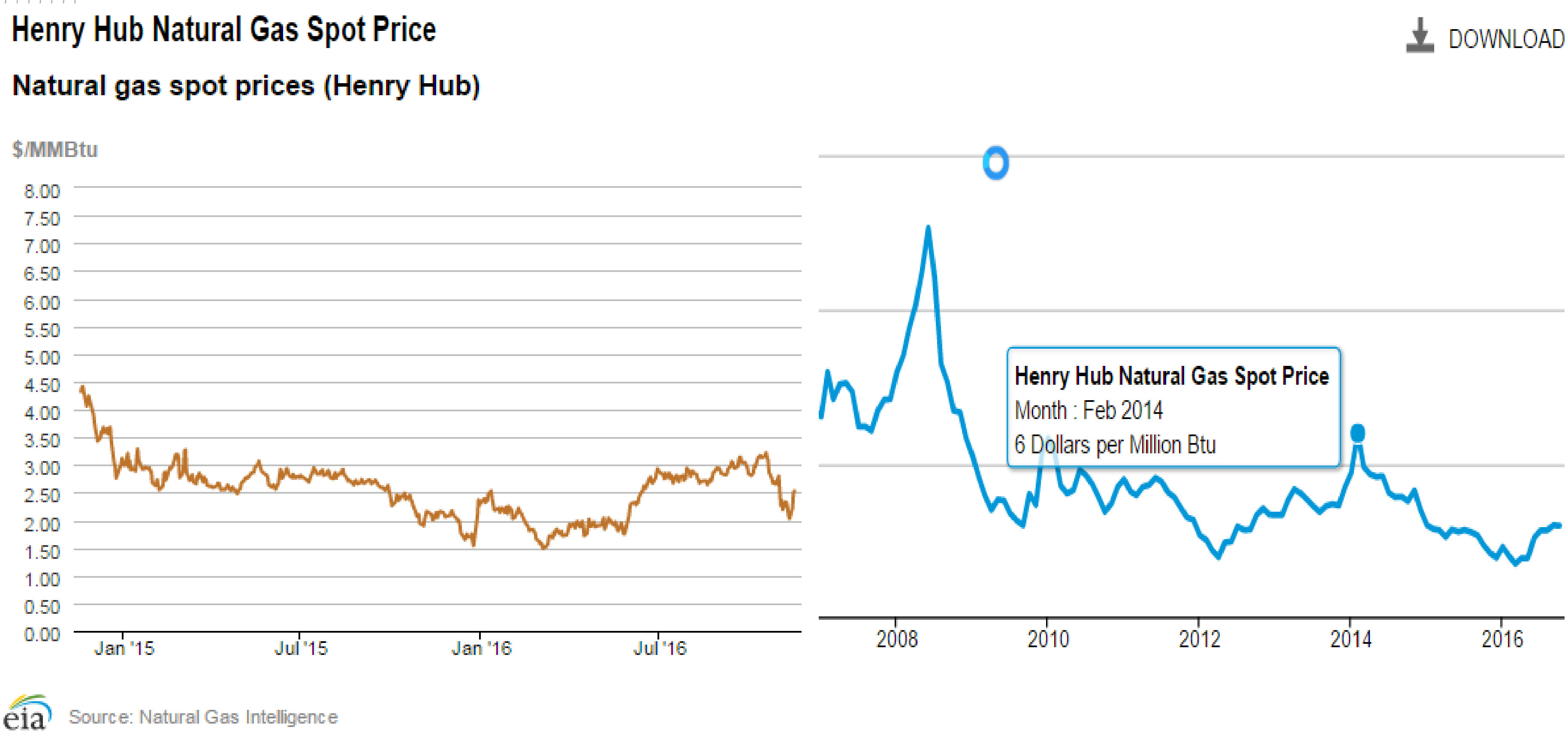
Natural gas

- The two main uses for natural gas are fuel (residential, commercial, industrial, power generation, and transportation) and chemical manufacturing feedstock.
- Worldwide, the primary chemicals manufactured from natural gas are methanol and urea (fertilizer).



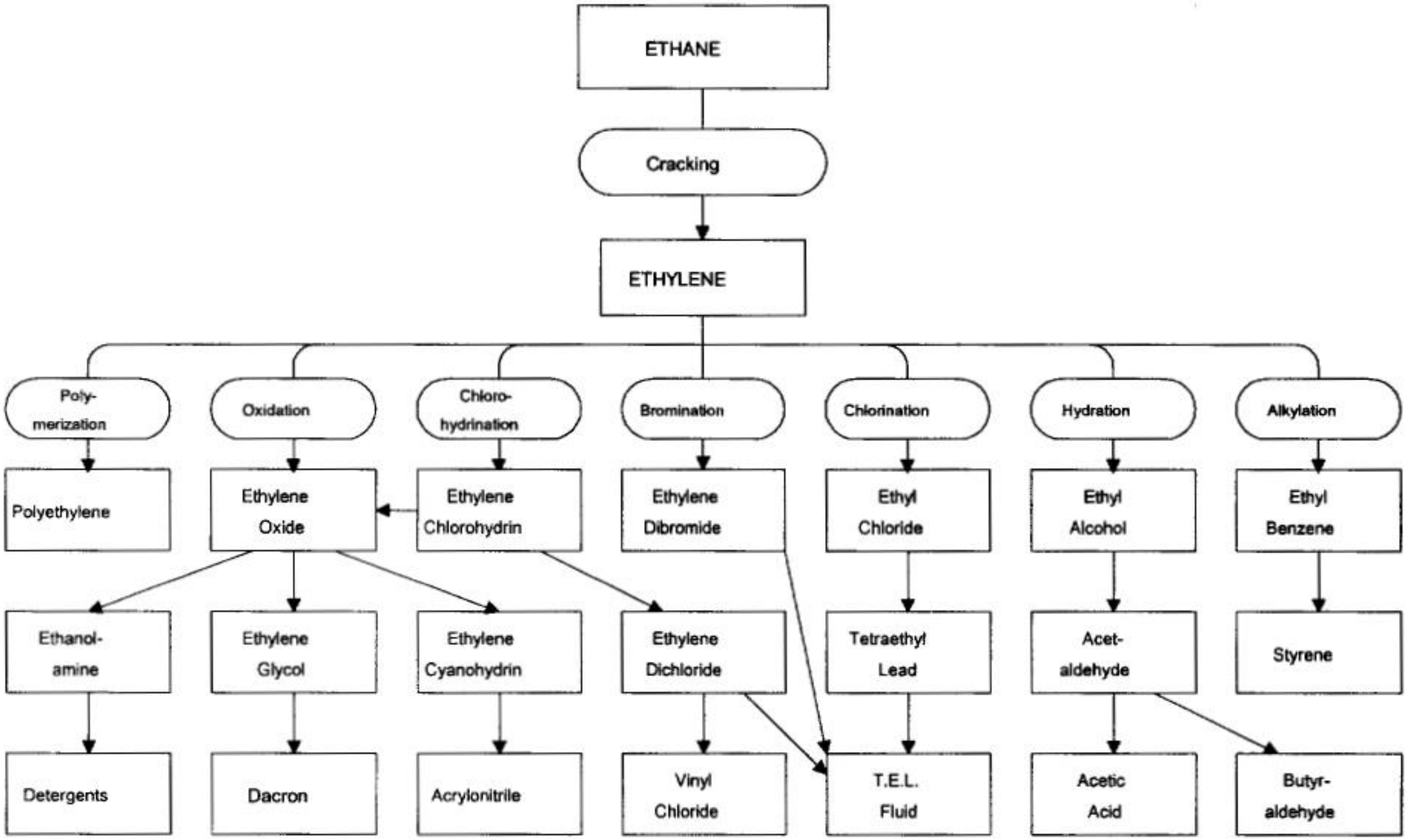
Natural gas prices

- The Henry Hub is a distribution hub on the natural gas pipeline system in Erath, Louisiana. Due to its importance, it lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX)



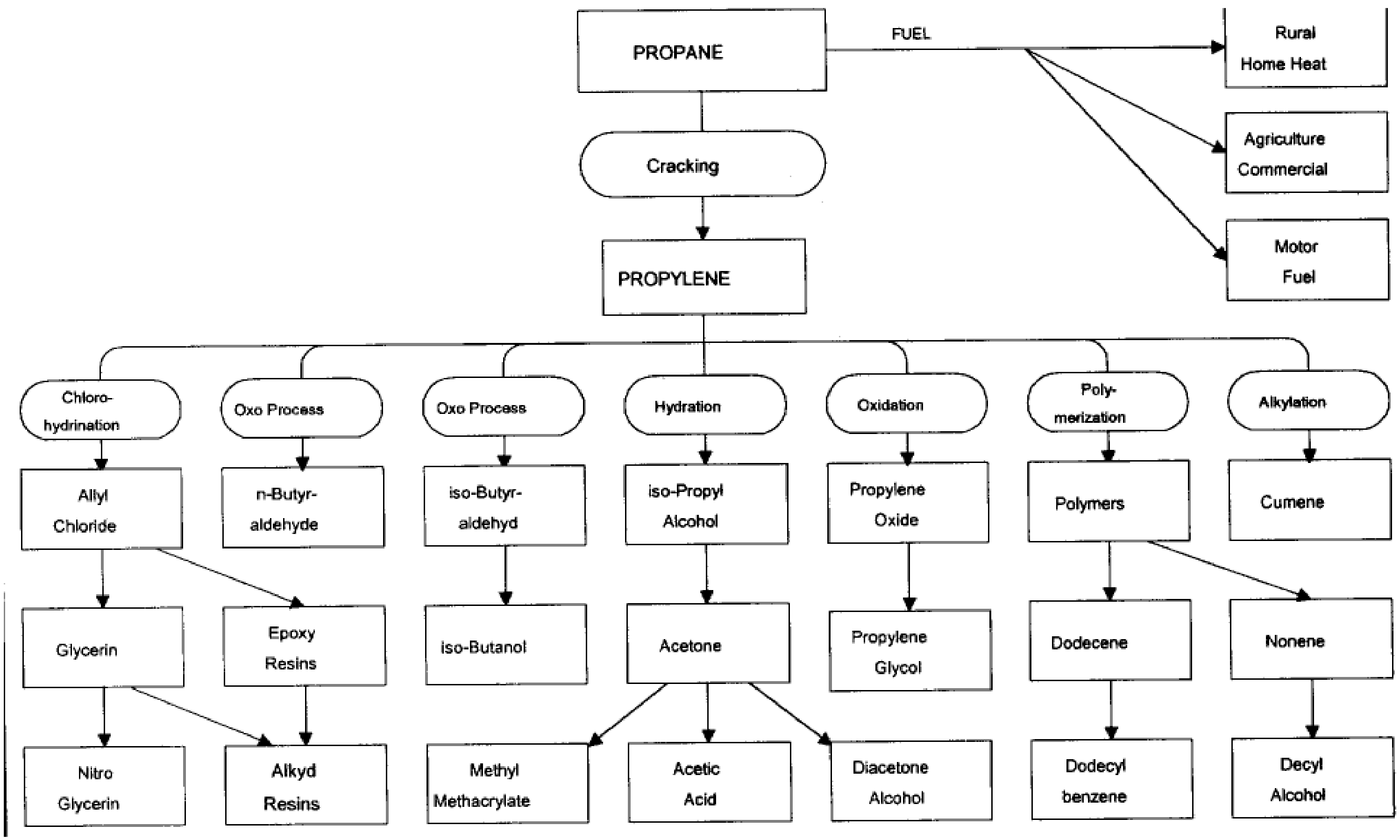
Ethane

- Ethane is the lightest NGL component. It has one end use – petrochemical feedstock for the manufacture of ethylene.
- The demand for ethane is a function of the demand and price for petrochemicals and the price of competing feedstocks (heavier hydrocarbons).

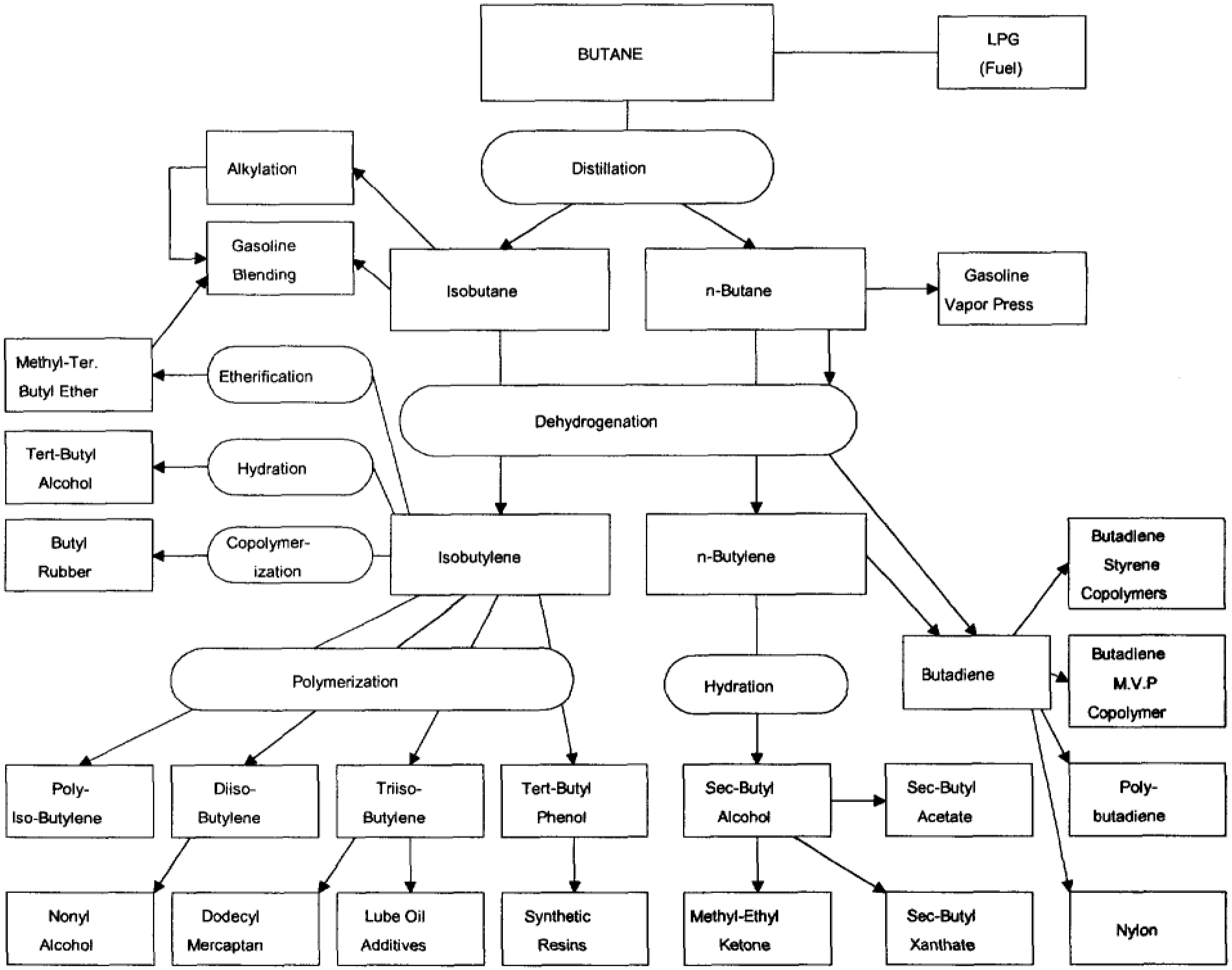


Propane

- The market for propane liquid is divided between petrochemical feedstock and fuel (residential, agriculture, commercial, and transportation).
- Propane is often called LPG (Liquefied Petroleum Gas) but the term LPG may also refer to propane-butane mixtures or a predominately butane stream.



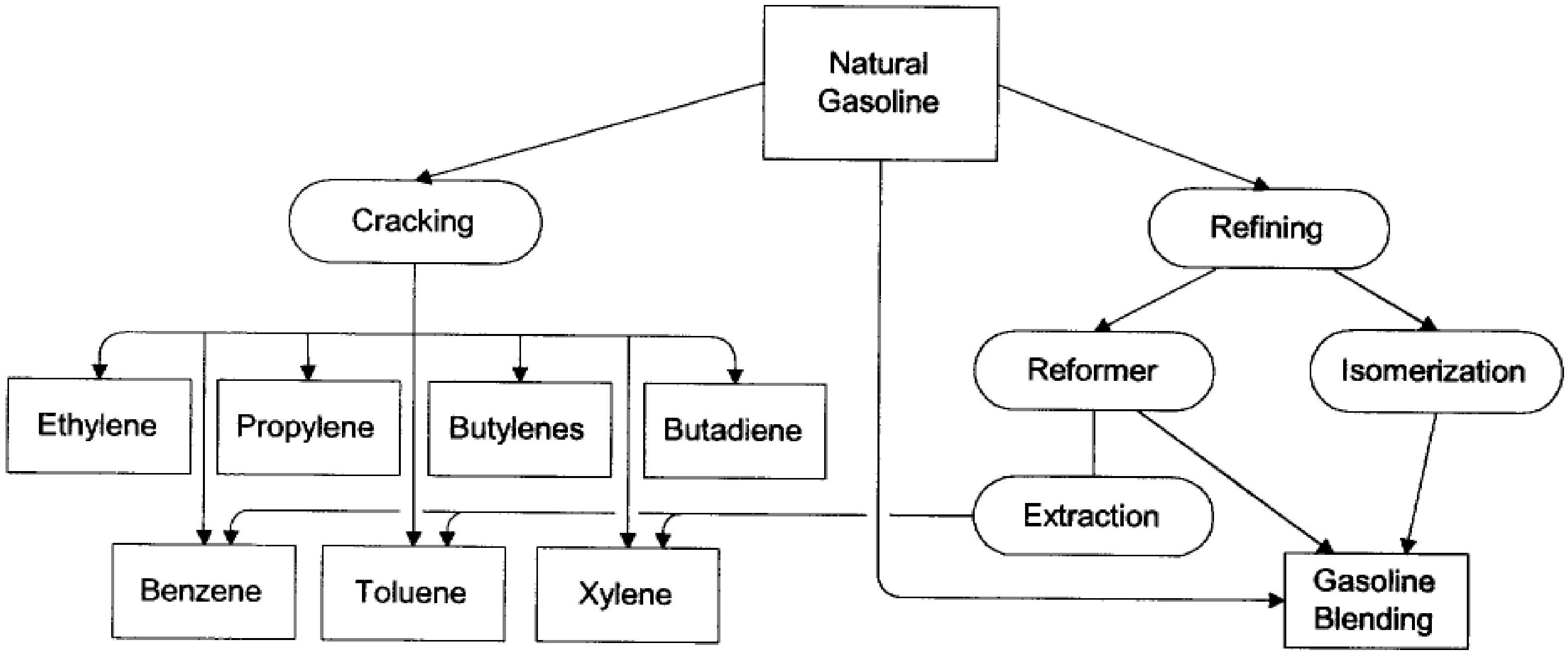
Butane



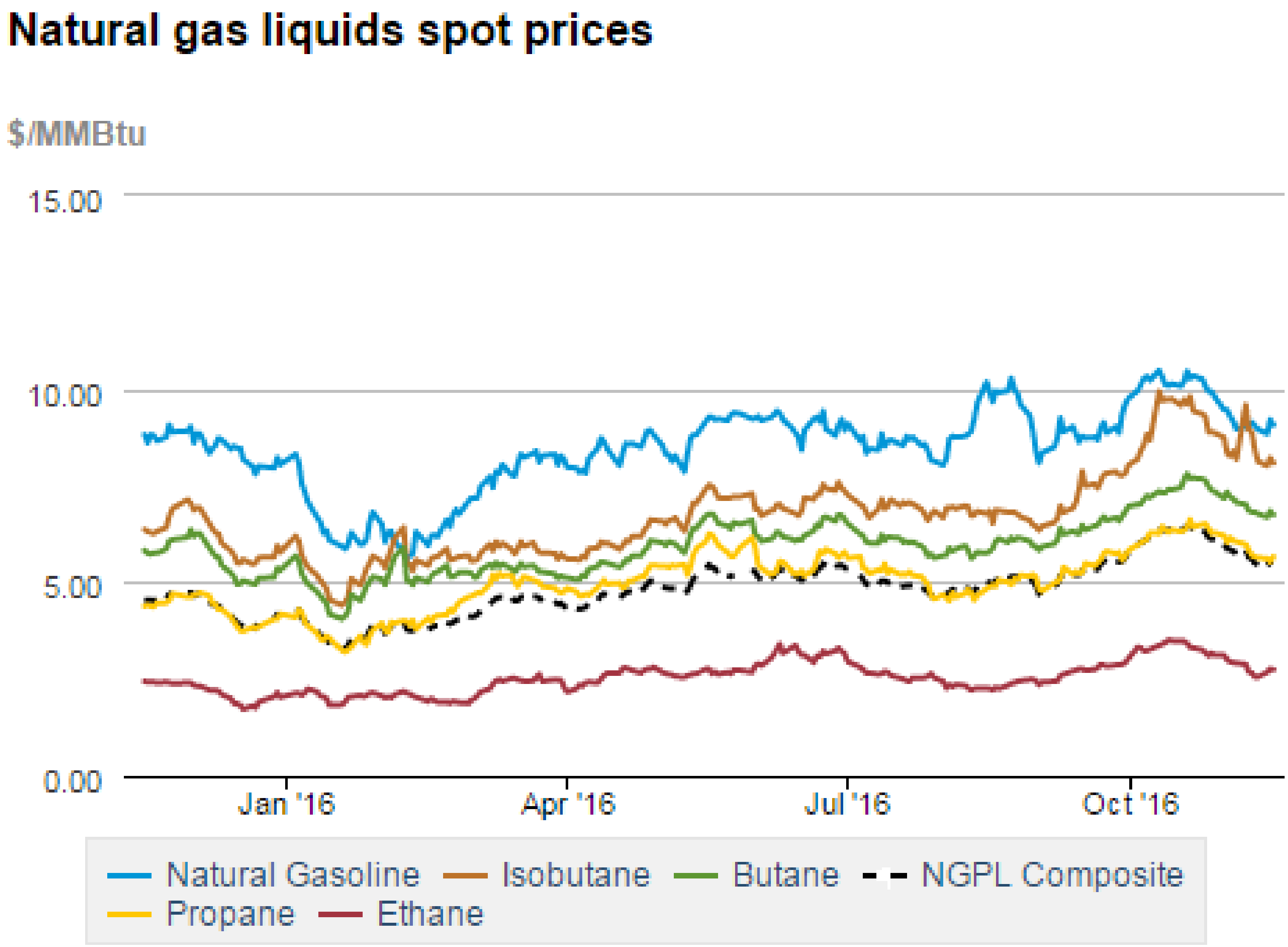
BUTANE
LPG (Fuel)
Distillation
Alkylation
Gasoline Blending
Isobutane
n-Butane
Gasoline Vapor Press
Methyl-Ter. Butyl Ether
Etherification
Dehydrogenation
Tert-Butyl Alcohol
Hydration
Butyl Rubber
Copolymer-ization
Isobutylene
n-Butylene
Butadiene Styrene Copolymers
Polymerization
Hydration
Butadiene
Butadiene M.V.P Copolymer
Poly-Iso-Butylene
Diiso-Butylene
Triiso-Butylene
Tert-Butyl Phenol
Sec-Butyl Alcohol
Sec-Butyl Acetate
Poly-butadiene
Nonyl Alcohol
Dodecyl Mercaptan
Lube Oil Additives
Synthetic Resins
Methyl-Ethyl Ketone
Sec-Butyl Xanthate
Nylon

Natural Gasoline

- Natural gasoline is a mixture of pentanes and heavier hydrocarbons. It may also contain small amounts of butanes.
- This product is sometimes call condensate. Natural gasoline is almost always shipped to a refinery either as a separate stream or mixed in a crude oil stream.
- Vapor pressure control is important when it is blended with crude. Recently it has become economical to feed natural gasoline to olefin crackers for petrochemical manufacturing.

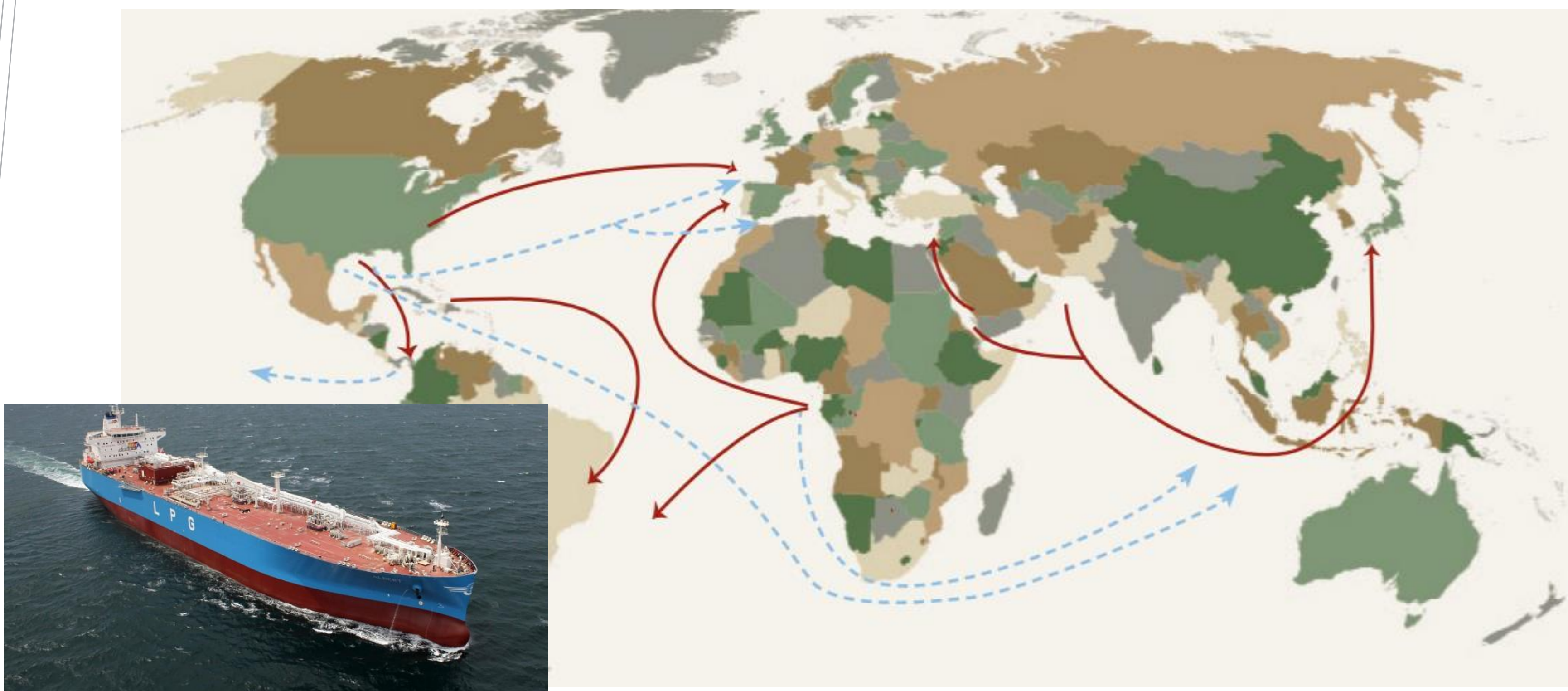


NGL prices


Natural gas liquids spot prices
$/MMBtu
15.00
10.00
5.00
0.00
Jan '16
Apr '16
Jul '16
Oct '16
Natural Gasoline
Isobutane
Butane
NGPL Composite
Propane
Ethane

NGL transportation

- In the mid 1940's Warren Petroleum began hauling propane from Houston to Newark, NJ. This ocean going ship could carry 35 000 barrels of product.
- Today waterborn LPG shipments are critical to the international gas processing industry. A typical long haul LPG carrier has four or five tanks and carries 350,000 to 550,000 barrels of product.
- The product is refrigerated to reduce the vessel design pressure.



NGL recovery economics

Liquid hydrocarbons are recovered from natural gas for three reasons:

1. NGL Product Recovery
   - NGL recovery may be desirable if the market value of the various NGL components in liquid product is greater than the sum of:
     a. their equivalent heating value in the natural gas stream,
     b. the cost to fractionate and transport the NGLs to market, and the cost to build and operate a NGL extraction plant.
   - NGL recovery under these circumstances is considered ***discretionary*** (i.e., a recovery plant would not be built if it could not generate an adequate rate of return on invested capital).
2. Maximize Liquid Production
   - In many cases, no immediate market for the natural gas exists. Examples include solution gas from remote crude oil reservoirs such as Prudhoe Bay, or retrograde gas condensate reservoirs where the gas is re-injected for pressure maintenance, i.e. cycling projects.
   - In these cases, NGLs are frequently recovered and spiked into the crude or condensate stream in order to maximize liquid production. NGL recovery levels are set by the liquid product vapor pressure specification.
   - For a TVP vapor pressure specification of 8-15 psia, NGL recovery is typically confined to the C4+ components. This is strongly dependent upon the relative volume of NGL to crude or condensate. NGL recovery under these circumstances is also considered *discretionary.*

3. Hydrocarbon Dewpoint Control

- Virtually all gas sales contracts include a clause which limits the hydrocarbon dewpoint of the gas. Typical values range from 14 to 41°F [-10 to 5 °C]**.** In order to meet this provision of the contract, some type of NGL extraction is generally required.
- In many cases, the NGLs will be recovered for *discretionary* reasons, but in some cases the only justification for the NGL plant is to meet the gas sales specifications. In these instances, NGL recovery is *mandatory* since the gas could not be sold without removal of the heavier NGL components.
- Recovery levels in these facilities are usually minimal with only a portion of the C5+ components being extracted.

The construction of a plant to recover NGL products is economically justified if the cash flow generated by NGL recovery is incrementally more attractive than the cash flow resulting from the current or future sale of those recoverable components as part of the natural gas stream.

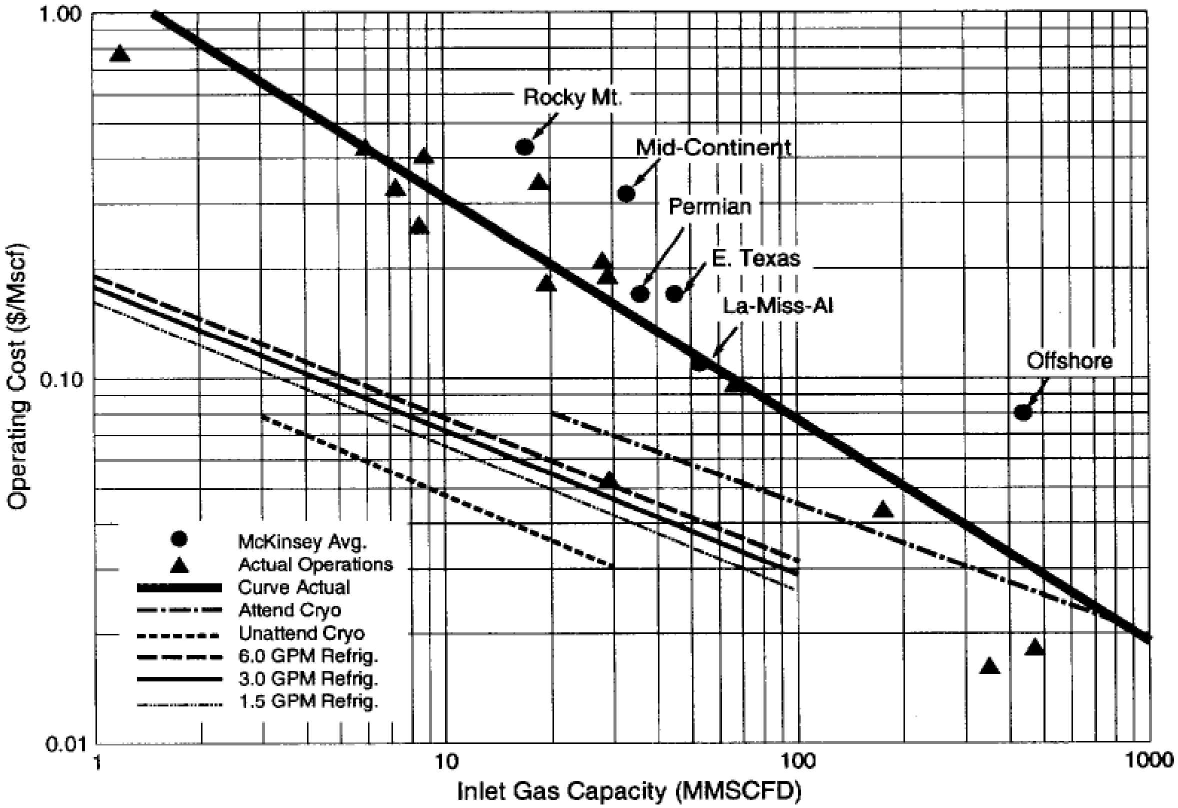
The economics of gas processing entails the margins, operating costs, and capital costs. These items will be discussed below.

Margins

- Margins describe the revenue side of the plant economics. Depending on the type of contracts, there may be gas, liquid, and/or processing fee margins (or revenue).
- The gas margins and processing fees are straight forward. The calculation of these revenue streams are describe in contracts and will not be discussed in here.
- The liquid margins can be more difficult.
- If the processing contract is a percent of proceeds type, then the liquid margin is calculated by splitting the liquid revenue received from the product sales (at the plant) as established in the contract.
- The plant product sales price is sometimes called the netback price. This price is the product price based at a market center less the transportation and fractionation fees to move the NGLs to the market and separate the liquids into final products. This netback price is the products value at the plant tailgate. In addition, processors may charge producers a marketing fee for the disposition of their NGLs.
- In keep-whole or flat rate contracts, the margins are based on the liquid revenue less producer settlements calculated for the plant shrink. To calculate the liquid shrink, the gallons of each product is converted to a gross heating value.

Operating consts

- Factors such as company philosophies, plant configurations, plant utilization, related services (gathering, compression, treating, etc.), contract terms, electrical costs, etc. impact the operating costs. Therefore the best method for determining the operating cost is from actual operations or from a budget "build-up."



The major costs for operating a gas plant are listed below:

1. Fuel and Electricity.

- The fuel and power costs are usually the most significant cost to operate recovery processes. This cost is typically associated with compression (inlet, refrigeration, residue, recycle, etc.).
- Compressor power calculations can be performed through a number different methods as discussed in Gas Conditioning and Processing - Vol. 2. An approximation of power requirements is the "Rule of 22."

$$hp = 22 \times F \times n \times CR \times Q_{sc}$$

hp = the compressor power

F = correction factor (1.00 single stage, 1.08 two stage, 1.10 three stage)

n = number of stages

CR = compression ratio per stage

Qsc = std volumetric flow (MMscfd)

The compression ratio per stage is

$$CR = \sqrt[n]{\frac{P_d}{P_s}}$$

2. Labor

- The major consideration for labor cost is the operator coverage. This is primarily a company operating philosophy, but guidelines can be provided. There are four main types of shifts: 1) three 8 hour shifts, 2) two 12 hour shifts, 3) 8 hour attend (16 hour unattend), and 4) unattend. The first two shifts require four personnel per shift-operator. The fourth person is required to rotate for weekends, holidays, and vacation. The unattended operations, personnel usually spend less than 4 hr/day at the plant.
- Unattended or 8 hour attend facilities are generally used for small gas plants that are not critical to a companies operation. These plants typically do not handle associated gas and sour gases. These types of plants are not usually located near population centers.
- The product disposition can be by truck, rail, or pipeline provided the truck loading is key-stop (automated) or the liquid production is low. The increased use of SCADA for gathering makes this type of operation more attractive.
- For large plants, most facilities are attended 24 hours per day. Multiple operators may be required if a significant amount of time is spent loading or unloading trucks and tankers. Also multiple units (gas treating, compression, utilities, etc.) may require multiple operators.

3. Maintenance.

- The maintenance budget is another major cost area. It is generally divided into major maintenance and repair maintenance. Costs can be determined from actual plant operations or vendors recommendations.
- Compressors are a significant factor in this budget. For electric motor driven compressors, some people use $40-50/bhp-yr for budgeting purposes and $60-70/bhp-yr for other compressors.

4. Chemicals and Operating Supplies.

- Chemicals may include lube oils, coolants, methanol, plant water, heat transfer fluids, desiccant, glycols, filter elements, etc. These costs may be estimated from typical usage and current pricing.

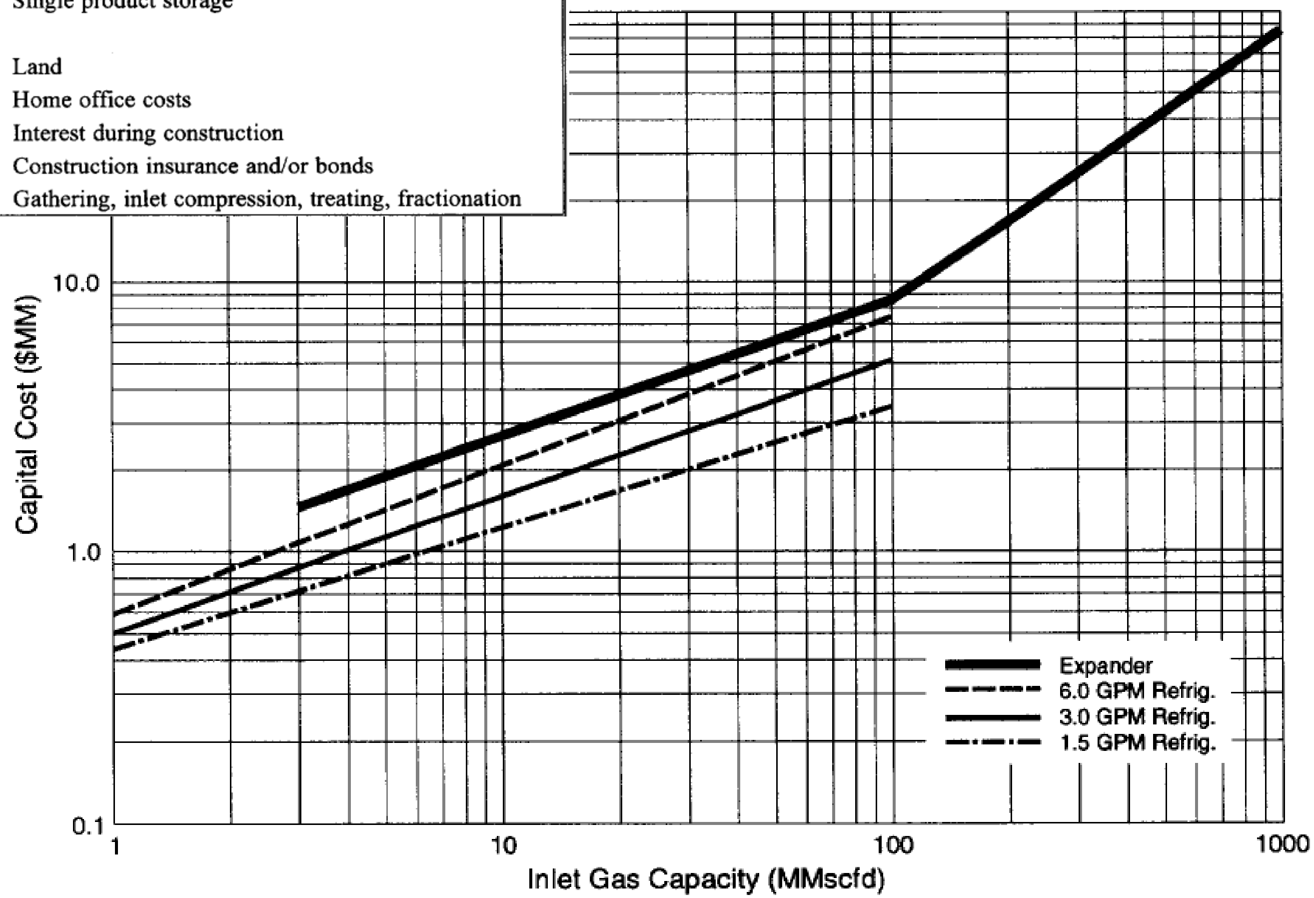
5. Other.

- There are other cost associated with gas plant operations. These include royalties, taxes, insurance, general overhead and administration, etc.

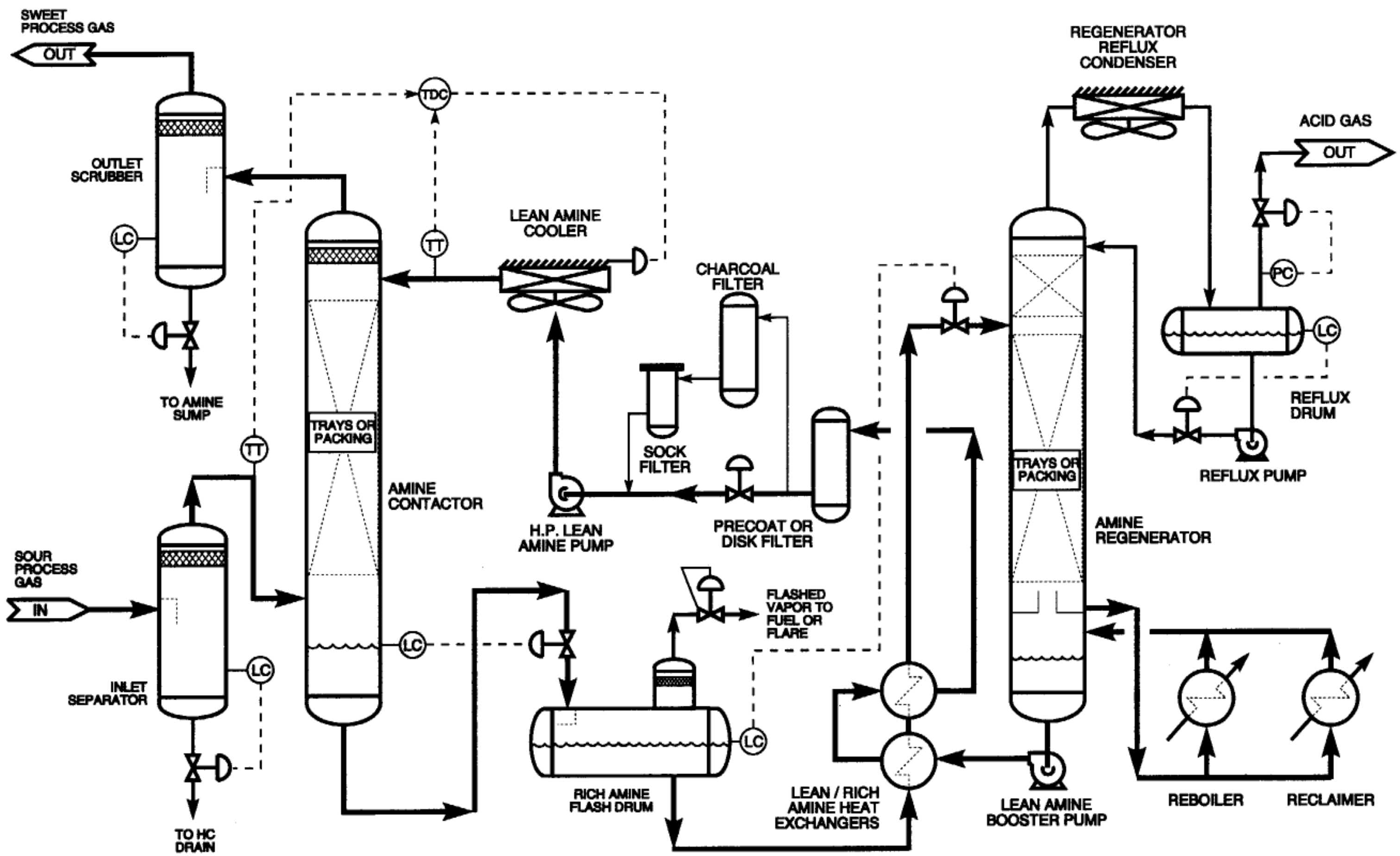
Capital costs

Included:
- 10% Contingency
- Start-up Costs at 2 months of operating expenses
- Initial start-up supplies and minimal spare parts
- Sales taxes
- Direct costs
- Single product storage

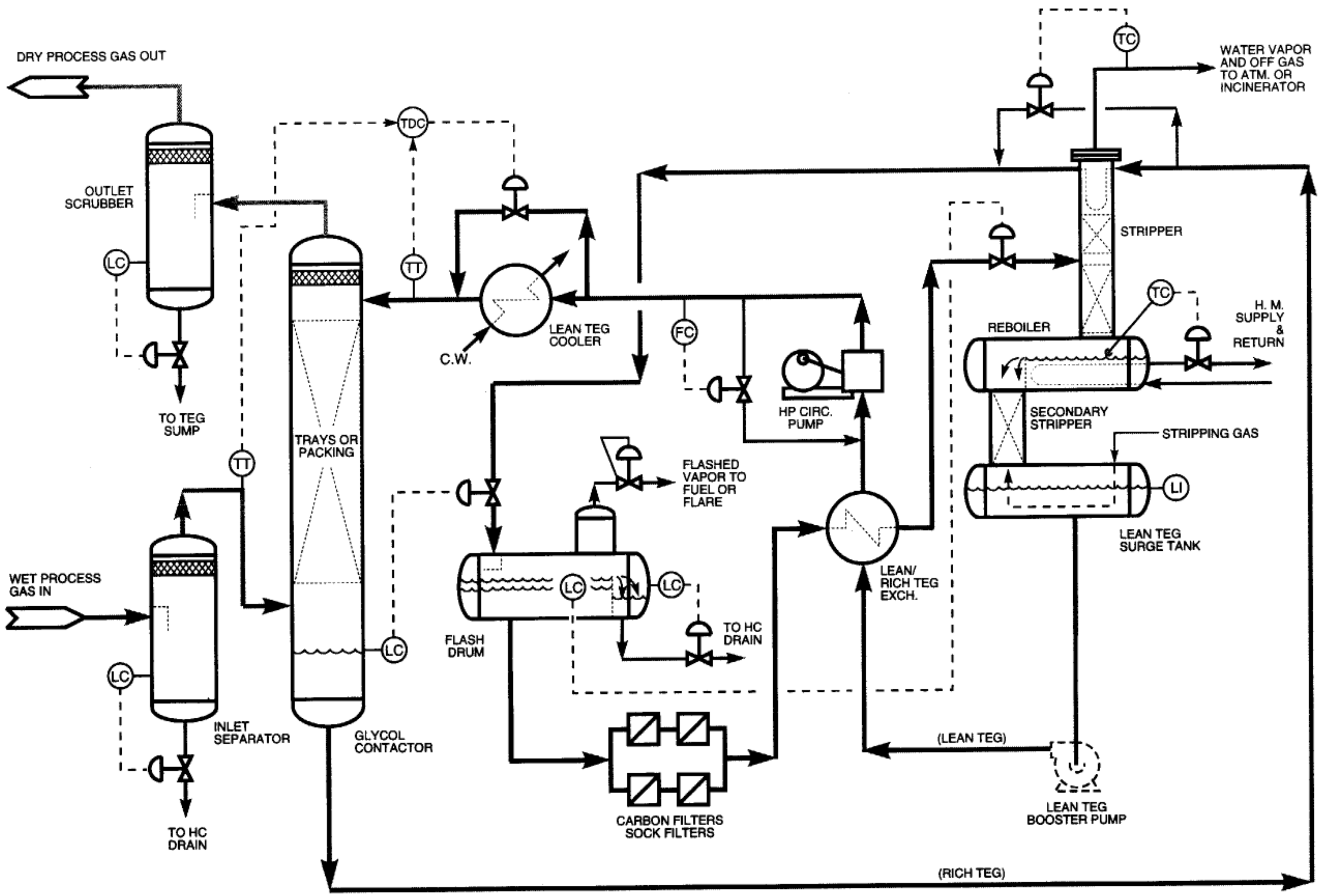
Excluded:
- Land
- Home office costs
- Interest during construction
- Construction insurance and/or bonds
- Gathering, inlet compression, treating, fractionation



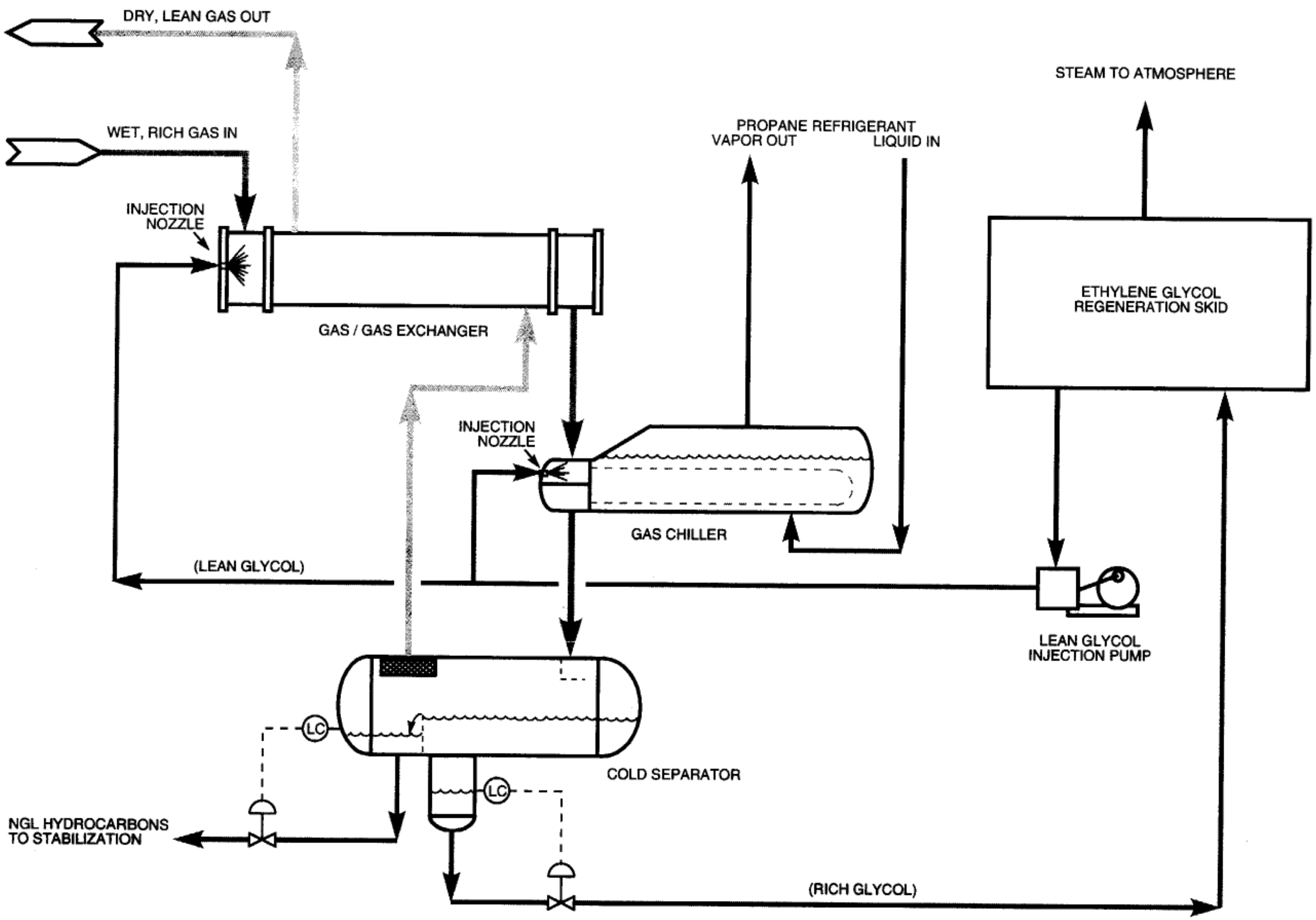
- Gas sweetening process - absorption



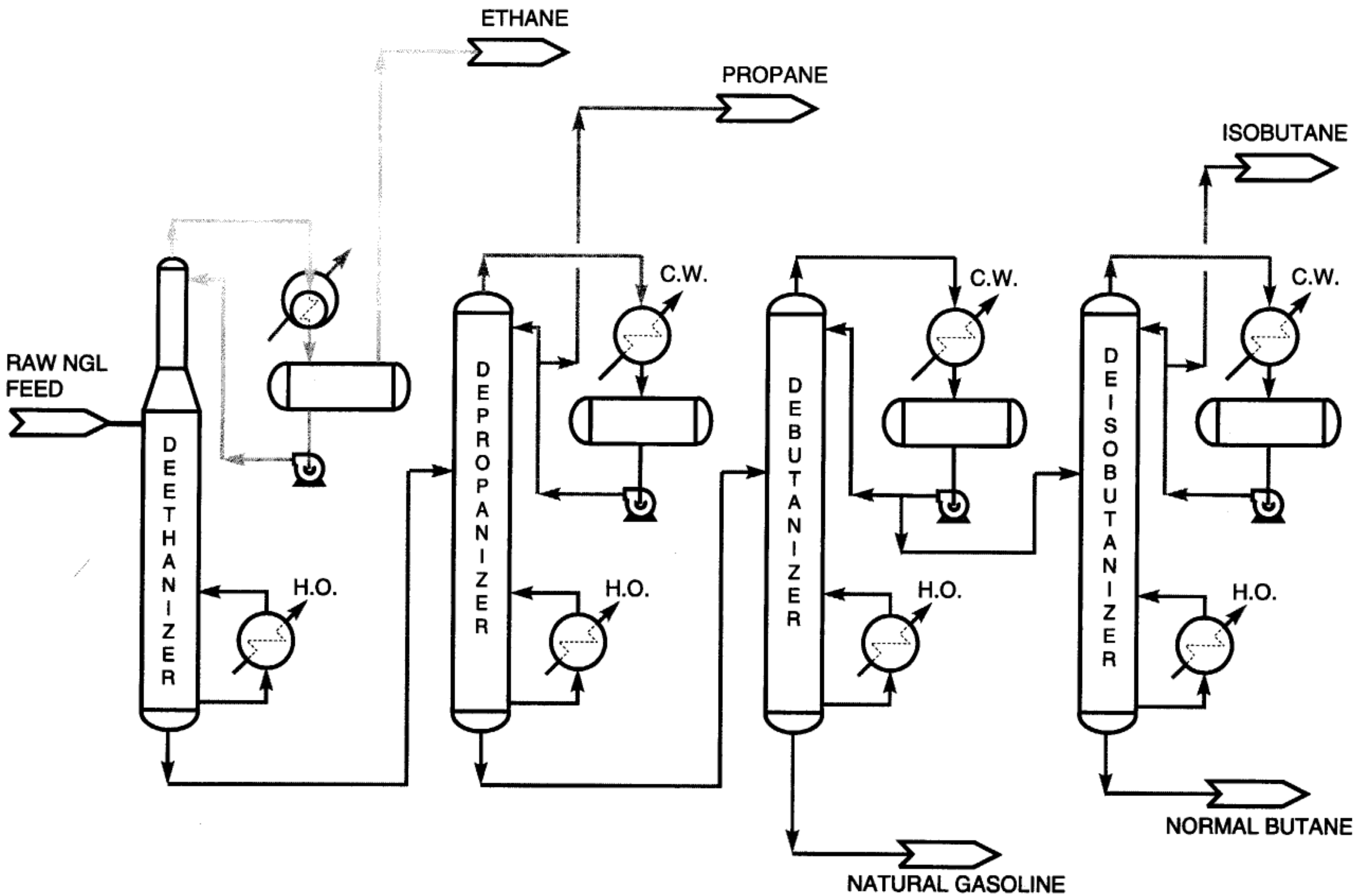
• Gas dehydration process - TEG



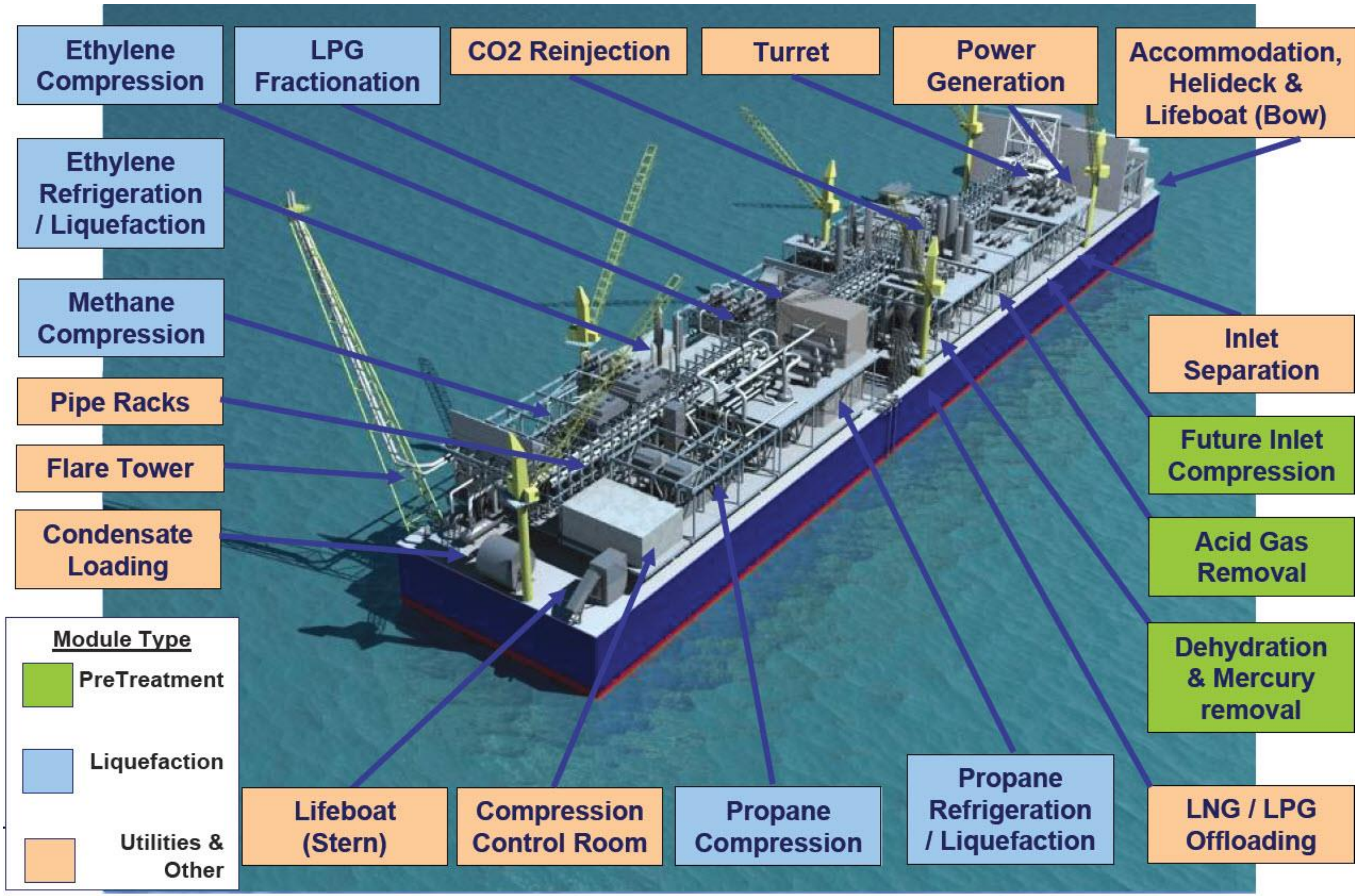
- Mechanical refrigeration system with EG injection



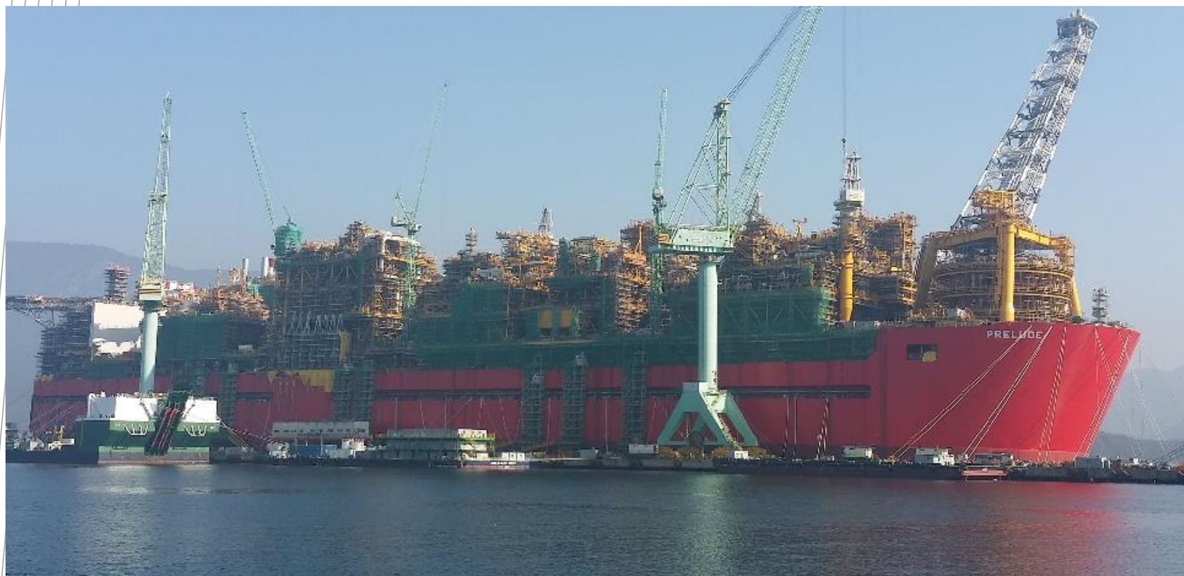
- NGL fractionation



Gas processing plant in LNG FPSO



Construction in yard



Thank you!

- Liquid products may be classified into two general categories stock tank fluids from separators and fractionated products.
  1) The former is normally sold to a pipeline and is subject only to any pipeline limitations such as BS&W**,** specific gravity, vapor pressure, and presence of "light ends."
    : It is sometimes referred to as a "slop" product to distinguish it from those products falling in the second category.
    : In essence, the composition of this product will be fixed by the equilibrium relationships at the pressure and temperature of the storage tank.
  2) All other liquid products are a result of a fractionation which separates a raw mixture into its component parts based on vapor pressure and other component physical properties.
    : These are commonly called natural gas liquids and are produced from what are called NGL plants. If the effluent gas from an NGL plant is totally liquefied, it is called liquefied natural gas (LNG).
- The amount of processing done at the production site depends on the amount of fluids, available transportation to market, and local conditions.
- Offshore, swamps, jungle or arctic type locations limit the feasibility of more complicated systems. The accent is on merely doing the least necessary at the site to transport the production to more favorable surroundings for future processing.

Example

- What is the liquid ***shrink*** from a 100 MMscfd turboexpander with the following inlet gas composition and recoveries.

	A	B	C(1)	D(2)	E(3)	F = D × E
	Inlet Gas (mol%)	Recover (%)	Volume (scf/gal)	Liquid Rec. (GPD)	GHV-Liq (Btu/gal)	Liq. Shrink (MMBtu/day)
N_2	0.83					
CO_2	0.18	25.0	58.807	765	0	0
C_1	88.88	0.2	59.135	3006	59 728	1792
C_2	5.74	84.9	37.476	130 285	65 869	8582
C_3	2.49	92.3	36.375	67 290	90 830	6112
iC_4	0.73	99.5	30.639	23 707	98 917	2345
nC_4	0.62	99.7	31.791	19 444	102 913	2001
iC_5	0.14	99.9	27.380	5108	108 754	556
nC_5	0.09	100.0	27.673	3252	110 084	358
C_6	0.12	100.0	24.379	4922	115 061	566
C_7	0.11	100.0	21.725	5063	118 623	608
C_8	0.11	100.0	19.575	5619	121 393	682
Total	100.00			268 461		23 595

- The liquid *shrink* from recovering 268 461 GPD of NGL is 23 595 MMBtu/day. Notice that the volume (scf/gal) is referenced to standard conditions of 60°F and 14.696 psia.
- If the base conditions are different from standard conditions, then column C can be corrected by the following equation.

$$C_B = C_S \left(\frac{P_S}{P_B}\right)\left(\frac{T_B}{T_S}\right)$$

$\mathrm{C_B}$ = volume corrected to base conditions

C_S = volume at standard conditions (60 oF, 14.69 psia)

$\mathrm{P}_S = \text{standard pressure, } 14.69 \text{ pisa}$

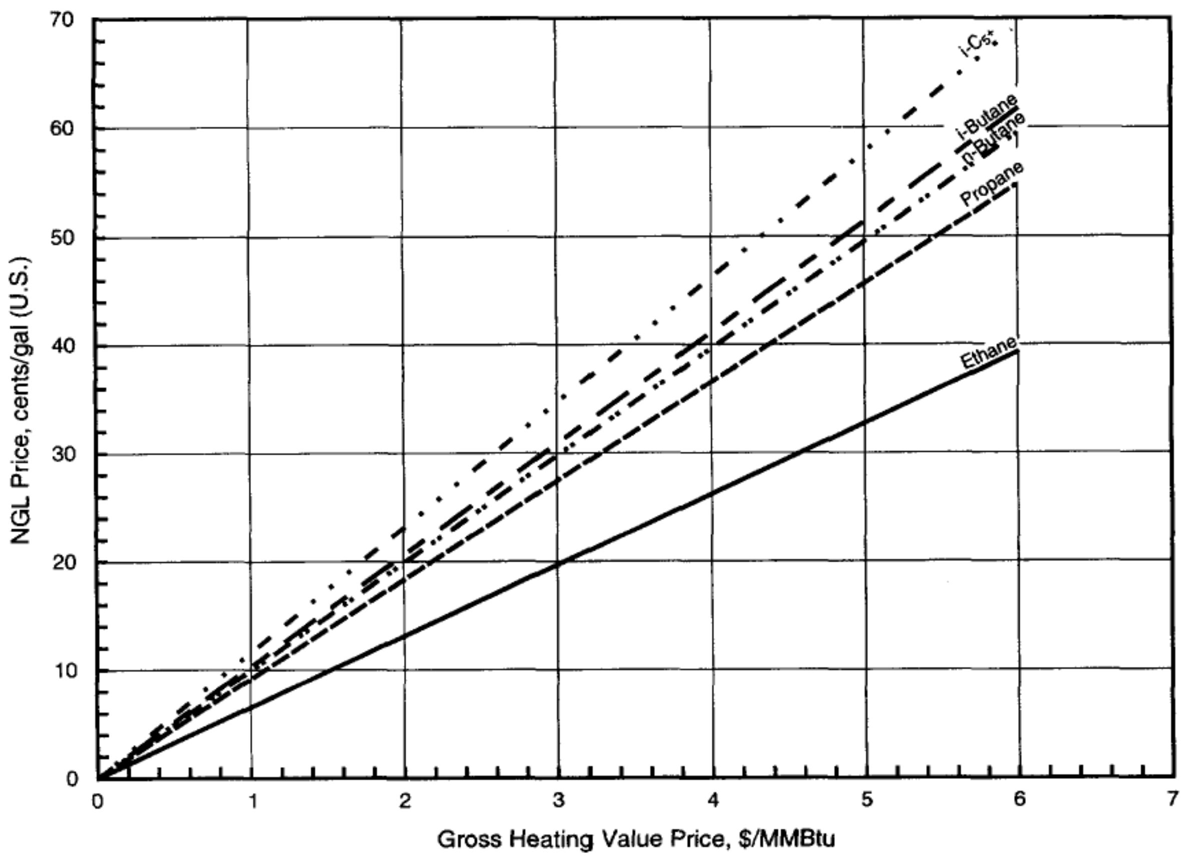
P_B = base pressure from contract, psia

$C_B = \text{standard temperature oR} = 460 + 60 \text{ oF}$

$C_B = \text{base temperature from contract, oR}$

- Also notice that the gross heating value can be calculated based on fuel as liquid or as gas. The difference between these values is the latent heat of vaporization. Using the gross heating value for fuel as a gas, benefits producers in a keep-whole contract while processors are benefited by fuel as liquid GHV values.
- In this example the effect is $87 M/yr at $1.50/MMBtu shrink value

- From these values we can also determine the breakeven price relationship between recovery and rejection of individual components.
- This breakeven analysis does not include transportation and fractionation fees and operating costs.



Shrinkage value of NGL products based on fuel as ideal liquid