7 NATURAL GAS

Abstract

Natural gas is considered as one of the primary energy sources of the world. It mainly contains methane (CH_4) and is colorless and odorless. Natural gas has many uses and can be used in most energy sectors: residential, commercial, and industrial. In this chapter, we have discussed its total reserve worldwide, its origin, processing, transportation, and storage. Natural gas from the well head has to go through various processing steps before its final use. Like every other commodities, natural gas is also traded internationally and transported through pipelines across the countries. However, its transportation through pipe lines is limited and as a result its movement is generally confined among neighboring countries. Recently, natural gas is liquefied, called liquefied natural gas (LNG), and is transported via sea to distant countries. Consequently, natural gas is becoming a dominant energy source.

7.1 Introduction

Worldwide consumption of natural gas in 2005 was 104 trillion cubic feet and it is expected to increase to 182 trillion cubic feet in 2030. This represents a worldwide increase of 2.5% annually. Natural gas is considered to be one of the cleanest energy sources as it can be burned more efficiently compared to coal and petroleum. The worldwide reserve of natural gas and its production and consumption rate is shown in Fig. 7.1. As shown in Table 7.1, the use of natural gas in the USA is expected to increase in all sectors; however, the main increase is expected to be in industrial sectors, such as for fertilizer production, and electricity generation. The two top users of the natural gas are the USA and China. In Table 7.2 the production and consumption rate of various countries in the last five years along with

T.K. Ghosh and M.A. Prelas, *Energy Resources and Systems: Volume 1: Fundamentals and Non-Renewable Resources*, 281–381.

their reserve are given. Although the data show that a considerable amount of natural gas is available, its trade or use is more regional as delivery of the natural gas through pipeline from one region to another region is costly. The international trade of natural gas among various countries is given in Tables 7.3–7.5. At the current rate of consumption, natural gas is expected to last about 65 years, unless new reserves are discovered.

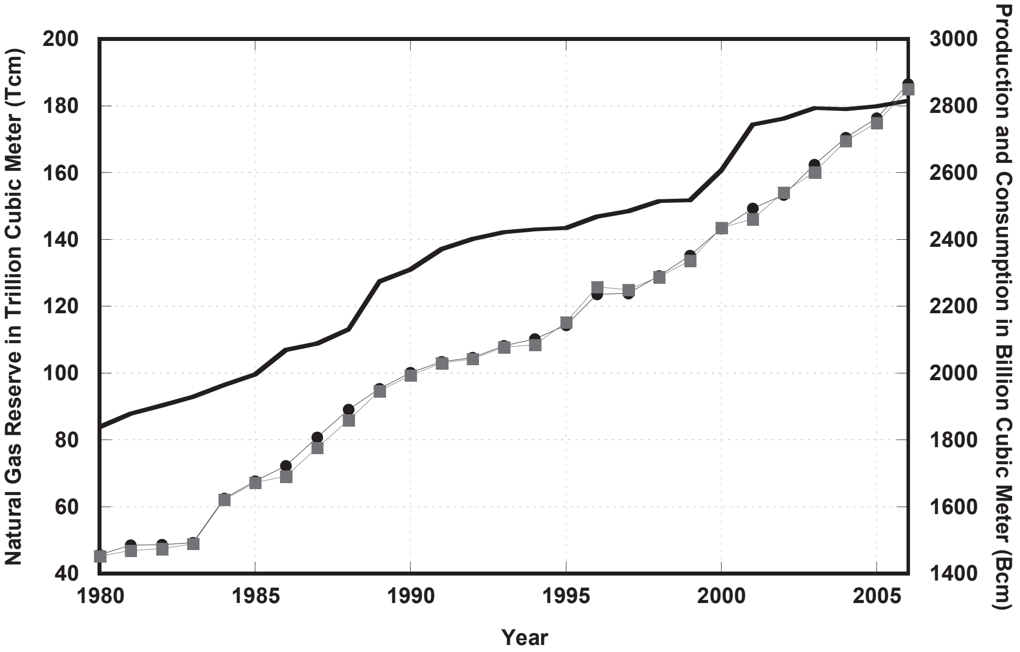


Fig. 7.1. Reserve, production, and consumption of natural gas worldwide [1].

Table 7.1. Increase of natural gas use by various sectors in the USA (in trillion cubic feet).

Consumption sectors	**Year**								
	2005	2006	2007	2008	2010	2015	2020	2025	2025
Residential	4.83	4.37	4.73	4.83	4.81	5.01	5.15	5.19	5.17
Commercial	3.00	2.83	3.02	3.05	2.96	3.20	3.37	3.53	3.67
Industrial	6.60	6.49	6.60	6.64	6.95	7.00	6.93	6.96	6.87
Electric power	5.87	6.24	6.78	6.83	6.70	6.56	5.92	5.30	4.99
Total	22.01	21.66	22.90	23.12	23.25	23.66	23.33	22.99	22.72

Source: Reference [2].

Table 7.2. Proven reserves, consumption, and percent change of natural gas use.

Countries	**Reserve at the end of 2006**		**Share of total**	**R/P ratio**	**Production in 2006 bcm**	**% Change from 2005**	**Consumption in 2006 bcm**	**% Change from 2005**
	Cubic feet	**Cubic meter**						
USA	209.15	5.93	3.3%	11.3	524.1	2.3%	619.7	–1.7%
Canada	58.77	1.67	0.9%	8.9	187.0	0.6%	96.6	5.7%
Mexico	13.70	0.39	0.2%	8.9	43.4	10.6%	54.1	13.6%
Total North America	281.62	7.98	4.4%	10.6	754.4	2.3%	770.3	0.1%
Argentina	14.65	0.42	0.2%	9.0	46.1	1.0%	41.8	3.5%
Bolivia	26.12	0.74	0.4%	66.3	11.2	7.2%	–	–
Brazil	12.28	0.35	0.2%	30.2	11.5	1.3%	21.1	6.1%
Chile	–	–	–	–	–	–	7.6	–11.5%
Colombia	4.34	0.12	0.1%	16.9	7.3	7.6%	7.3	7.6%
Ecuador	–	–	–	–	–	–	0.3	3.8%
Peru	12.00	0.34	0.2%	*	–	–	1.8	17.0%
Trinidad & Tobago	18.71	0.53	0.3%	15.1	35.0	15.6%	–	–
Venezuela	152.32	4.32	2.4%	*	28.7	–1.0%	28.7	–1.0%
Other South & Central America	2.40	0.07	□	14.3	4.8	5.0%	22.1	14.0%
Total South & Central America	242.83	6.88	3.8%	47.6	144.5	4.7%	130.6	3.9%
Austria	–	–	–	–	–	–	9.4	–6.0%
Azerbaijan	47.66	1.35	0.7%	*	6.3	18.0%	9.6	8.1%
Belarus	–	–	–	–	–	–	19.6	3.4%

(Continued)

Table 7.2. (Continued)

Countries	**Reserve at the end of 2006**		**Share of total**	**R/P ratio**	**Production in 2006 bcm**	**% Change from 2005**	**Consumption in 2006 bcm**	**% Change from 2005**
	Cubic feet	**Cubic meter**						
Belgium & Luxembourg	–	–	–	–	–	–	17.0	2.4%
Bulgaria	–	–	–	–	–	–	3.0	3.1%
Czech Republic	–	–	–	–	–	–	8.5	–0.3%
Denmark	2.72	0.08	–	7.4	10.4	–0.3%	5.1	1.8%
Finland	–	–	–	–	–	–	4.3	7.7%
France	–	–	–	–	–	–	45.2	–1.5%
Germany	5.47	0.16	0.1%	9.9	15.6	–1.2%	87.2	1.1%
Greece	–	–	–	–	–	–	3.2	15.2%
Hungary	–	–	–	–	–	–	12.5	–4.9%
Iceland	–	–	–	–	–	–	–	–
Ireland	–	–	–	–	–	–	4.5	15.6%
Italy	5.63	0.16	0.1%	14.5	11.0	–9.0%	77.1	–2.1%
Kazakhstan	105.90	3.00	1.7%	*	23.9	2.7%	20.2	3.3%
Lithuania	–	–	–	–	–	–	3.3	0.1%
The Netherlands	47.55	1.35	0.7%	21.8	61.9	–1.6%	38.3	–3.0%
Norway	102.09	2.89	1.6%	33.0	87.6	3.1%	4.4	–1.4%
Poland	3.67	0.10	0.1%	24.4	4.3	–1.3%	13.7	0.6%
Portugal	–	–	–	–	–	–	4.1	–3.9%
Romania	22.17	0.63	0.3%	51.7	12.1	0.2%	17.0	–1.7%
Russian Federation	1,682.07	47.65	26.3%	77.8	612.1	2.4%	432.1	6.7%
Slovakia	–	–	–	–	–	–	5.5	–16.0%

Countries	Reserve at the end of 2006		Share of total	R/P ratio	Production in 2006 bcm	% Change from 2005	Consumption in 2006 bcm	% Change from 2005
	Cubic feet	Cubic meter						
Spain	–	–	–	–	–	–	33.4	3.2%
Sweden							0.8	7.1%
Switzerland								–3.7%
Turkey	100.96	2.86	1.6%	46.0	62.2	5.9%	30.5	13.5%
Turkmenistan	38.83	1.10	0.6%	57.7	19.1	–1.7%	18.9	14.0%
Ukraine	100.96	2.86	1.6%	46.0	62.2	5.9%	66.4	–8.8%
UK	16.98	0.48	0.3%	6.0	80.0	–8.6%	90.8	–4.5%
Uzbekistan	66.01	1.87	1.0%	33.7	55.4	0.8%	43.2	–1.9%
Other Europe & Eurasia	15.99	0.45	0.2%	41.4	10.9	7.8%	14.7	0.7%
Total Europe & Eurasia	2,263.69	64.13	35.3%	59.8	1,072.9	1.2%	1,146.3	1.9%
Bahrain	3.18	0.09	□	8.1	11.1	3.2%	–	–
Iran	992.99	28.13	15.5%	*	105.0	4.1%	105.1	2.7%
Iraq	111.90	3.17	1.7%	*	–	–	–	–
Kuwait	62.83	1.78	1.0%	*	12.9	4.9%	12.9	4.9%
Oman	34.59	0.98	0.5%	39.0	25.1	27.0%	–	–
Qatar	895.24	25.36	14.0%	*	49.5	8.1%	19.5	4.3%
Saudi Arabia	249.68	7.07	3.9%	96.0	73.7	3.5%	73.5	3.5%
Syria	10.24	0.29	0.2%	52.3	5.5	3.3%	–	–
United Arab Emirates	213.95	6.06	3.3%	*	47.4	0.9%	41.7	1.0%
Yemen	17.12	0.49	0.3%	*	–	–	–	–

(Continued)

Table 7.2. (Continued)

Countries	Reserve at the end of 2006		Share of total	R/P ratio	Production in 2006 bcm	% Change from 2005	Consumption in 2006 bcm	% Change from 2005
	Cubic feet	Cubic meter						
Other Middle East	1.80	0.05	□	9.0	5.6	28.1%	36.4	17.5%
Total Middle East	2,593.53	73.47	40.5%	*	335.9	5.8%	289.3	4.5%
Algeria	159.00	4.50	2.5%	53.3	84.5	–4.3%	23.7	2.2%
Egypt	68.48	1.94	1.1%	43.3	44.8	29.3%	28.7	11.4%
Libya	46.45	1.32	0.7%	88.9	14.8	31.0%	–	–
Nigeria	183.91	5.21	2.9%	*	28.2	25.9%	–	–
Other Africa	42.82	1.21	0.7%	*	8.2	–	23.3	2.3%
Total Africa	500.67	14.18	7.8%	78.6	180.5	9.5%	75.8	5.5%
Australia	91.96	2.61	1.4%	67.0	–	–	28.6	3.4%
Bangladesh	15.36	0.44	0.2%	28.6	15.2	7.1%	15.2	7.1%
Brunei	11.83	0.34	0.2%	27.3	12.3	6.5%	–	–
China	86.45	2.45	1.3%	41.8	58.6	17.2%	55.6	21.6%
Hong Kong	–	–	–	–	–	–	2.4	13.2%
India	37.95	1.08	0.6%	33.9	31.8	–1.0%	39.7	4.3%
Indonesia	92.91	2.63	1.5%	35.6	74.0	0.3%	39.6	5.6%
Japan	–	–	–	–	–	–	84.6	7.0%
Malaysia	87.54	2.48	1.4%	41.2	60.2	0.4%	40.3	2.5%
Myanmar	18.99	0.54	0.3%	40.1	13.4	3.1%	–	–
New Zealand					3.9	2.2%	3.7	6.4%

Countries	Reserve at the end of 2006		Share of total	R/P ratio	Production in 2006 bcm	% Change from 2005	Consumption in 2006 bcm	% Change from 2005
	Cubic feet	Cubic meter						
Pakistan	28.17	0.80	0.4%	26.0	30.7	4.8%	30.7	4.8%
Philippines							2.6	–13.8%
Singapore							6.6	
South Korea							34.2	1.4%
Papua New Guinea	15.36	0.44	0.2%	*	–	–		
Taiwan							11.9	12.1%
Thailand	10.63	0.30	0.2%	12.4	24.3	2.8%	30.6	2.3%
Vietnam	14.12	0.40	0.2%	57.1	7.0	1.6%	–	–
Other Asia Pacific	11.90	0.34	0.2%	48.8	6.9	–5.4%	12.1	6.3%
Total Asia Pacific	523.15	14.82	8.2%	39.3	377.1	4.0%	438.5	6.5%
TOTAL WORLD	6,405.48	181.46	100%	60.3	2,865.3	3.0%	2,850.8	2.5%
of which: European Union 25	85.66	2.43	1.3%	12.8	190.0	–4.9%	467.4	–1.4%
European Union 27					202.7	–4.6%	487.4	–1.3%
OECD	561.29	15.90	8.8%	14.7	1,078.5	1.1%	1,419.8	0.3%
Former Soviet Union	2,051.28	58.11	32.0%	74.6	779.3	2.5%	621.1	4.0%
Other EMSs					1,007.5	5.6%	809.9	5.3%

More than 100 years. ^ Less than 0.05. Less than 0.05%. n/a not available.

#Excludes Estonia, Latvia and Lithuania prior to 1985 and Slovenia prior to 1991.

Annual changes and shares of total are calculated in million tonnes oil equivalent figures.

As far as possible, the data above represent standard cubic metres (measured at 15°C and 1,013 mbar); as they are derived directly from tones of oil equivalent using an average conversion factor, they do not necessarily equate with gas volumes expressed in specific national terms.

The difference between these world consumption figures and the world production statistics is due to variations in stocks at storage facilities and liquefaction plants, together with unavoidable disparities in the definition, measurement or conversion of gas supply and demand data.

Table 7.3. Natural gas trading by countries via pipeline in 2006 in North America and South & Central America (billions of cubic meter).

To	From			Total imports
	USA	**Canada**	**Mexico**	
North America				
USA	–	99.75	0.08	99.83
Canada	9.37			9.37
Mexico	9.85			9.85
Total imports	19.22	99.75	0.08	

Source: Energy Information Administration, USA

To	From		Total imports
	Argentina	**Bolivia**	
South and Central America			
Argentina	–	1.80	1.80
Brazil	0.46	9.00	9.46
Chile	5.56	–	5.56
Uruguay	0.12	–	0.12
Total imports	6.14	10.80	

Table 7.4. Natural gas trading by countries via pipeline in 2006 in Europe (billions of cubic meter).

To	From									Total imports
	Belgium	**Denmark**	**Germany**	**The Netherlands**	**Norway**	**UK**	**Russian Fed.**	**Turkmenistan**	**Other Europe & Eurasia**	
Austria	–	–	1.10	–	0.78		6.85	–	–	8.73
Belgium	–	–	1.00	7.60	8.50	0.64	0.63	–	–	18.37
Bulgaria	–	–	–	–	–	–	2.85	–	–	2.85
Croatia	–	–	–	–	–	–	0.75	–	0.40	1.15
Czech Republic	–	–	–	–	2.35	–	7.13	–	–	9.48
Finland	–	–	–	–	–	–	4.52	–	–	4.52
France	1.90	–	0.10	9.50	14.50	0.20	9.50	–	–	35.70
Germany	–	1.92	–	21.30	26.80	3.08	36.54	–	1.20	90.84
Greece	–	–	–	–	–	–	2.40	–	–	2.40
Hungary	–	–	0.83	–	–	–	8.32	–	1.80	10.95
Ireland	–	–	–	–	–	3.40	–	–	–	3.40
Italy	–	–	2.50	8.70	7.20	0.80	22.92	–	–	74.27
Latvia	–	–	–	–	–	–	1.70	–	–	1.70
Lithuania	–	–	–	–	–	–	2.90	–	–	2.90
Luxembourg	0.80	–	0.70	–	–	–	–	–	–	1.50
Netherlands	–	2.24	4.50	–	7.00	1.82	2.97	–	–	18.53
Poland	–	–	0.35	–	0.49	–	7.00	0.21	2.52	10.57
Portugal	–	–	–	–	–	–	–	–	–	2.10

(Continued)

Table 7.4. (Continued)

To	From									Total imports
	Belgium	**Denmark**	**Germany**	**The Netherlands**	**Norway**	**UK**	**Russian Fed.**	**Turkmenistan**	**Other Europe & Eurasia**	
Romania	–	–	1.30	–	–	–	3.95	–	1.00	6.25
Serbia	–	–	–	–	–	–	2.15	–	–	2.15
Slovakia	–	–	–	–	–	–	6.30	–	–	6.30
Slovenia	–	–	–	–	–	–	0.56	–	0.10	1.10
Spain	–	–	–	–	2.12	–	–	–	–	10.74
Sweden	–	0.93	0.15	–	–	–	–	–	–	1.08
Switzerland	–	–	1.20	0.90	0.08	–	0.37	–	0.50	3.05
Turkey	–	–	–	–	–	–	19.65	–	–	25.34
UK	1.80	–	1.00	0.60	14.10	–	–	–	–	17.50
Others	–	–	–	–	0.08	–	1.50	–	–	1.58

Flows are on a contractual basis and may not correspond to physical gas flows in all cases. Cedigaz (provisional).
Data excludes trade within the Former Soviet Union and United Arab Emirates.
Source: Energy Information Administration, USA

Table 7.5. Natural gas trading by countries via pipeline in 2006 in Asia (billions of cubic meter).

	From							
To	**Turkmenistan**	**Oman**	**Algeria**	**Egypt**	**Indonesia**	**Malaysia**	**Myanmar**	**Total imports**
Middle East								
Iran	5.80	–	–	–	–	–	–	5.80
Jordan	–	–	–	1.93	–	–	–	1.93
United Arab Emirates	–	1.40	–	–	–	–	–	1.40
Africa								
Tunisia	–	–	1.30	–	–	–	–	1.30
Asia Pacific								
Singapore	–	–	–	–	4.83	1.78	–	6.61
Thailand	–	–	–	–	–	–	8.98	8.98

Flows are on a contractual basis and may not correspond to physical gas flows in all cases.

Source: Cedigaz (provisional).

Data excludes trade within the Former Soviet Union and United Arab Emirates.

7.2 Formation of Natural Gas

There are a number of theories on the formation of natural gas below the earth's crust [3–19]. These theories may be classified into following three categories.

- Thermogenic methane
- Biogenic methane, and
- Abiogenic methane

The thermogenic process is the most widely accepted theory for formation of methane. According to this process, fossil fuels are formed when organic matter is compressed under the earth, at very high pressure for a very long time. As a result, natural gas is usually found with the oil deposits. The amount of methane formation depends on temperature: at low temperatures (shallower deposits), more oil is produced relative to natural gas. At higher temperatures, more natural gas is created as opposed to oil. However, if the deposits are very far underground, they mainly contain natural gas rich in methane. The formation of natural gas and oil in a reservoir is shown in Fig. 7.2.

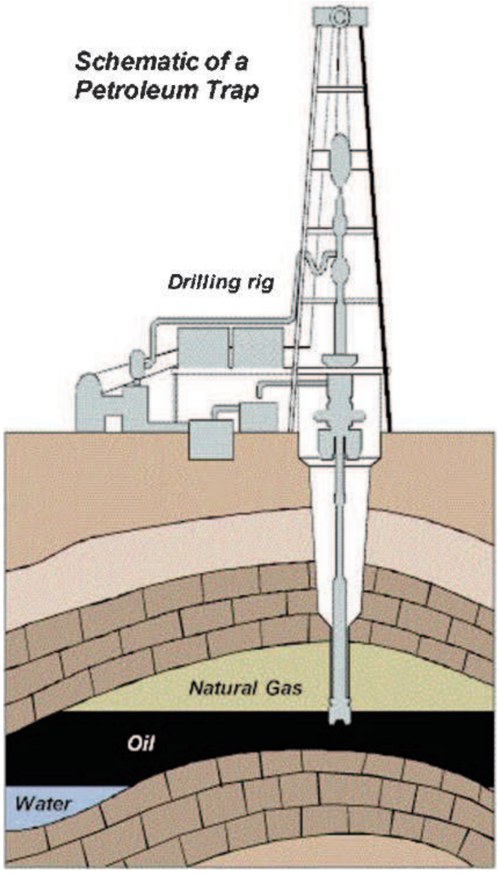


Fig. 7.2. Schematic of a petroleum trap [4].

The transformation of organic matter by microorganisms can lead to the formation of methane. Methane produced in this manner is referred to as biogenic methane, which may be distinguished by its isotopic signature from thermogenic methane [4].

A third way in which methane (and natural gas) may be formed is through abiogenic processes. Extremely deep under the earth's crust, there exist hydrogen-rich gases and carbon molecules, which under certain conditions can chemically react forming methane. A number of researchers have tried to simulate the process in order to verify the theory of abiogenic process for methane formation [5]. However several observations and measurements including high temperature fluid venting from ridges at the middle of the ocean [6], seepages from regions associated with ultramafic rocks on land, fluids from Precambrian shields, and igneous rocks suggest the formation of methane in Earth's crust by abiogenic process.

7.3 Unconventional Sources

Natural gas can also be produced from a number of other unconventional sources [21–33]. These unconventional sources may be divided into six categories:

- Deep natural gas
- Tight natural gas (tight gas sands)
- Gas-containing shales
- Coalbed methane
- Geopressurized zones, and
- Methane hydrates

Among these sources, tight gas sands, gas containing shales, and coalbed methane, are widely used commercially for methane production. Improved exploration and production technologies in the oil and gas industry have made commercial production possible. In Table 7.6 the global unconventional resources for various fossil energy sources is compared. When the gas hydrate is included, the unconventional sources of natural gas are significantly higher than oil or coal.

Discoveries of new conventional natural gas reservoirs are expected to be smaller in size and deeper, and thus more expensive and riskier to develop and produce. The use of unconventional resources is expected to increase dramatically. For example, Canada is a major producer of natural gas from conventional sources. However, as shown in Fig. 7.3 their Reserves/Production ratio is declining steadily. Their production of conventional natural gas peaked in 2000 and has been decreasing ever since. Currently, Canada is exploring production of natural gas from unconventional resources. Unconventional gas will have an important role to play in reducing the gap between demands and declining conventional gas production.

Table 7.6. Global fossil energy reserves, resources, and occurrences in giga tons of oil equivalent (Gtoe).

	Consumption		Reserves	Resources	Resource base	Additional occurrences
	1850–1990	1990				
Oil						
Conventional	90	3.2	150	145	295	
Unconventional	–	–	193	332	525	1,900
Natural gas						
Conventional	41	1.7	141	279	420	
Unconventional	–	–	192	258	450	400
Hydrates	–	–	–	–	–	18,700
Coal	125	2.2	606	2,794	3,400	3,000
Total	256	7.1	1,282	3,808	5,090	24,000

Source: Reference [34].

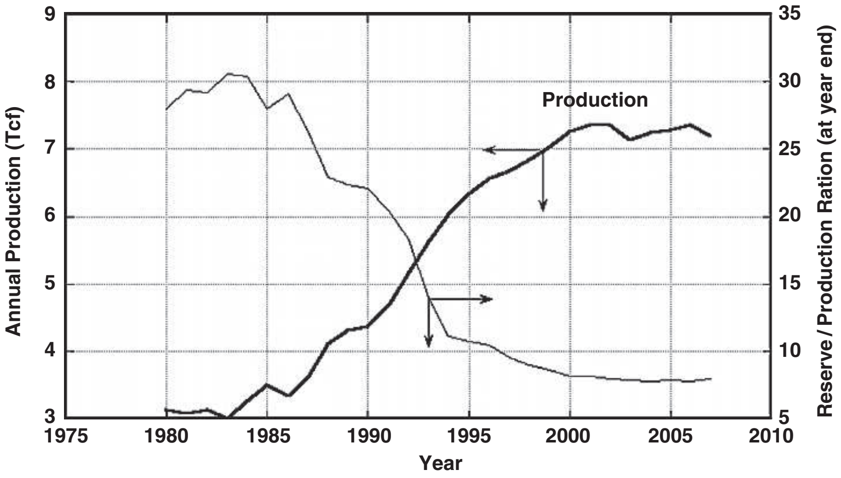


Fig. 7.3. Natural gas production and reserve/production ratio by Canada. Source of data [35, 1].

The USA is experiencing a similar trend. Unconventional gas accounted for 43% of total U.S. natural gas production in 2006. As shown in Fig. 7.4, about 43% of the total natural gas reserve in the USA is from the unconventional sources.

The main sources of unconventional gases in the USA are tight gas sands, coal bed methane and gas shale. Both the National Petroleum Council and US Geological Survey made estimates of these resources. As shown in Table 7.7, there is a significant difference between these two estimates. The difference in the estimates is from the uncertainty and accuracy of the measurement and the models used in the estimation. As shown in Fig. 7.5, currently natural gas from the tight gas sands is the most widely used among these three unconventional resources.

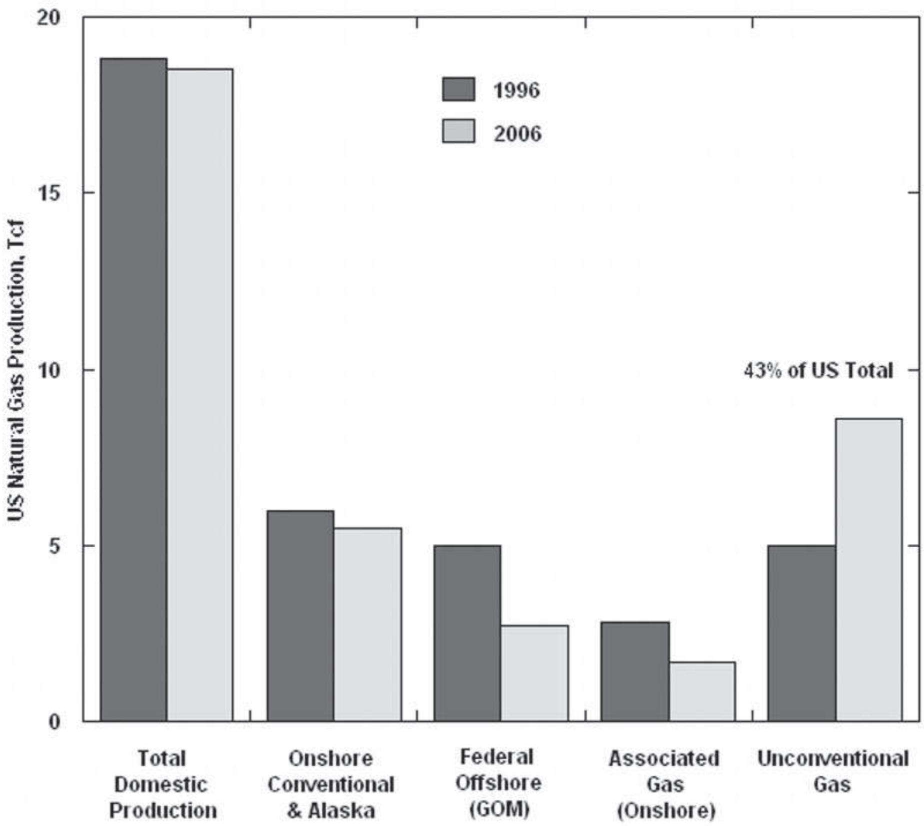


Fig. 7.4. US natural gas serve from unconventional sources [36].

Table 7.7. Comparison of unconventional gas resource estimates in US lower 48 states in trillion cubic feet (Tcf).

	Advanced resources (2006)*		**National Petroleum Council (2003)****	**US Geological Survey (2006)**
	Proved reserves	**Undeveloped resources**		
Tight gas sands	73	379	131	177
Coalbed methane	20	73	46	67
Gas shales	12	128	29	60
TOTAL	105		206	304

*With data through 2005; **For accessible undeveloped resources, current technology, with data through 1998; *** Estimates for undeveloped continuous resources with data from 1995–2006.
Source: Reference [37].

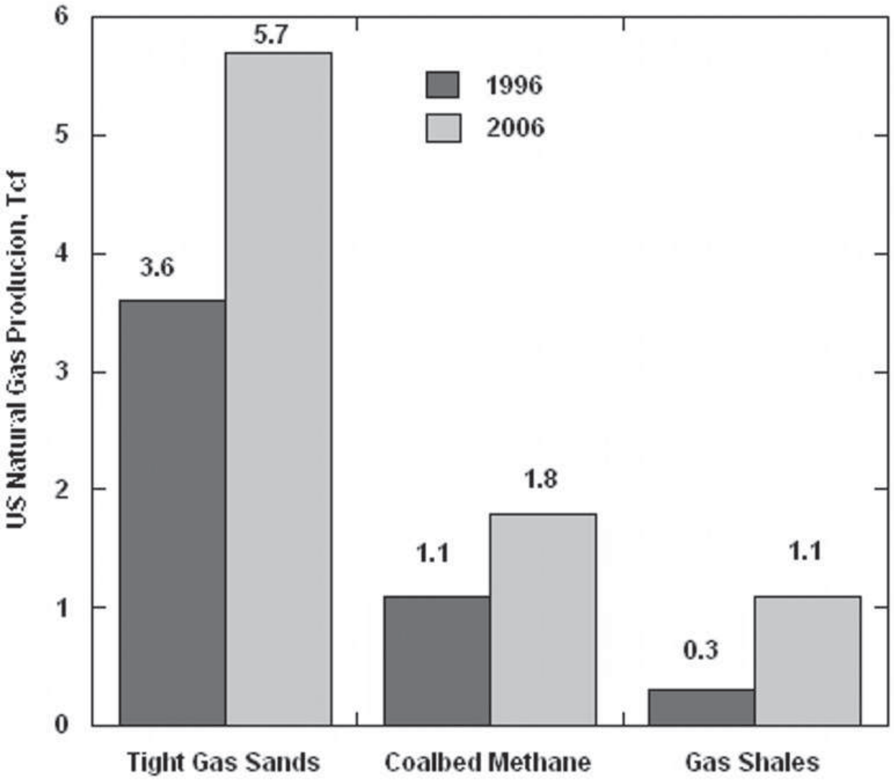


Fig. 7.5. US natural gas production from unconventional sources [36].

7.3.1 *Deep Natural Gas*

Natural gas that exists at a depth of greater than 15,000 ft is generally called Deep Natural Gas [38–44]. In 2000, the U.S. Geological Survey conducted a study to access undiscovered conventional gas and oil resources in eight regions of the world outside the U.S. The potential reserves that may be available within the next thirty years were studied. This study estimated worldwide natural gas volumes and its distribution at depth >4:5 km (15,000 ft). Two hundred forty-six assessment units in 128 priority geologic provinces, 96 countries, and two jointly held areas were assessed using a probabilistic total petroleum system approach. The distribution of the deep natural gas resources in the USA is given in Table 7.8.

Worldwide estimates of deep gas of undiscovered conventional gas resource outside the U.S. are about 844 trillion cubic feet below 4.5 km (about 15,000 ft). (The U.S. Geological Survey World Petroleum Assessment 2000 Project) and are given in Table 7.9.

Table 7.8. Estimates of undiscovered natural gas by region for depths of 15,000 ft or greater from the 1995 U.S Geological Survey (USGS) National Petroleum Assessment. Data are mean estimates [45].

Region	**Conventional gas resources (Bcf)**	**Continuous-type gas resources (Bcf)**	**Total gas resources (Bcf)**
Alaska	17,936	0	17,936
Pacific	550	2,636	3,186
Rocky Mountains	1,946	55,212	57,158
Colorado Plateau	130	570	700
West Texas-Eastern New Mexico	4,705	0	4,705
Gulf Coast	27,439	0	27,439
Midcontinent	2,264	0	2,264
Eastern	294	0	294
Total	55,264	58,418	113,682

Data includes associated gas from oil accumulations and non associated gas. Onshore regions and state waters only. Unconventional gas includes gas in low-permeability (tight) sandstones. Resource estimates based on current technology case only. Estimates do not include undiscovered gas from small fields (less than 6 Bcf). Refer to Gautier and others (1996) for detailed explanation of assessment.

As can be noted from Table 7.9, the former Soviet Union has the most deep natural gas, followed by Europe. The advancement of technologies for deep drilling, exploration, and extraction is making these sources economical.

7.3.2 Tight Natural Gas

When natural gas is trapped in a very tight formation underground, it is called tight natural gas [47–55]. The basin is unusually impermeable, and includes hard rock or sandstone or limestone formations and non-porous (generally called tight sand). Although a formal definition for “Tight Gas” reservoirs has not been developed, some researchers tried to characterize a tight gas reservoir based on the permeability of gas. Law and Curtis (2002) defined low-permeability (tight) reservoirs as having permeability less than 0.1 milliDarcies (mD). According to the German Society for Petroleum and Coal Science and Technology (DGMK), tight gas reservoirs are those reservoirs with an average effective gas permeability of less than 0.6 mD. Some ‘ultra tight’ gas reservoirs may have in-situ permeability as low as 0.001 mD.

Table 7.9. Summary data by region for estimated deep undiscovered conventional gas resources in the world from US Geological survey.

Region	Deep AUs/ provinces	Total gas (Tcf) (gas > 4.5 km/gas > 7.5 km)	Total gas (Tcf) (all depths)	Average percent	Average maximum depth of deep gas (ft)	Dominant province(s)	Significant regional example: AU, province, mean undisc. conv. resource, primary reservoir(s)
Former Soviet Union – Region 1	37/12	343/0.5	1,611	21	5,857	North, Middle, and South Caspian Basin provinces	Central Offshore, South Caspian Basin, 71 Tcf, Tertiary shelf turbidites and Jurassic reef carbonates
Mideast-North Africa – Region 2	24/11	131/0	1,370	10	5391	Red Sea Basin, Zagros Fold Belt, Sirte Basin, Rub Al Khali Basin	Paleozoic Reservoirs, Rub Al Khali Basin, 47 Tcf, Permian sandstones
Asia Pacific – Region 3	20/12	38/0.1	379	10	5915	Kutei Basin, Sichuan Basin, Tarim Basin	Tarim Basin Excluding; Marginal Foldbelts; Tarim Basin, 23 Tcf; Ordovician carbonates
Europe – Region 4	18/8	142/0.7	312	46	6500	North Sea Graben, Pannonian Basin, Carpathian-Balkanian Basin, Vestford-Helgeland Basin	Mid-Norway Continental Margin, Vestford-Helgeland, 70 Tcf, mixed clastics-carbonates
N. America Region 5 (excluding USA)	12/4	22/0	155	14	5667	Villahermosa Uplift Alberta Basin	Tamabra-Like Debris-Flow Breccia Limestone Overlying Evaporites, Villahermosa Uplift, 6.9 Tcf, Cretaceous through Tertiary carbonate reservoirs
US portion – Region 5	101/43	55/not calculated for US	259	21	5898	Gulf Coast, Rocky Mts., Northern Alaska	Eastern Thrust Belt, Northern Alaska, 9 Tcf, Mississippian through Early Cretaceous carbonate and clastic reservoirs

Region	Deep AUs/ provinces	Total gas (Tcf) (gas > 4.5 km/gas > 7.5 km)	Total gas (Tcf) (all depths)	Average percent	Average maximum depth of deep gas (ft)	Dominant province(s)	Significant regional example: AU, province, mean undisc. conv. resource, primary reservoir(s)
Central and S. America – Region 6	42/22	88/11	487	18	6425	Eastern Venezuela Basin, Campos Basin, Middle Magdalena, Santa Cruz-Tarija Basin	Sub-Andean Fold and Thrust Belt, Santa Cruz-Tarija Basin, 10 Tcf, Silurian through Tertiary clastic reservoirs
Sub-Saharan Africa –Region 7	10/5	14/0	235	6	5200	West Central-Coastal Niger Delta	Akata Reservoirs, Niger Delta, 8.6 Tcf, Tertiary turbidite reservoirs
South Asia – Region 8	10/7	11/0.1	120	9	6100	Ganges–Brahmaputra Delta, Indus, Bombay	Central Basin, Ganges–Brahmaputra Delta, 5.3 Tcf, Tertiary turbidite sandstone reservoirs
Total	274/124	844/12.4	4928	17	5941		

Source: Reference [46].

Worldwide, tight gas sand resources are speculated to be significant, but no systematic evaluation has been carried out on a global scale. According to an estimate by Holditch [56], worldwide reserve of tight gas may be about 7,406 Tcf (Table 7.10).

Table 7.10. Distribution of worldwide unconventional gas reserves (in Tcf).

Region	Coalbed methane	Shale gas	Tight sand gas	Total
North America	3,017	3,842	1,371	8,228
Latin America	39	2,117	1,293	3,448
Western Europe	157	510	353	1,019
Central and Eastern Europe	118	39	78	235
Former Soviet Union	3,957	627	901	5,485
Middle East and North Africa	0	2,548	823	3,370
Sub-Saharan Africa	39	274	784	1,097
Pacific (Organization for Economic Cooperation and Development)	470	2,313	705	3,487
Other Asia Pacific	0	314	549	862
South Asia	39	0	196	235
WORLD	9,051	16,112	7,046	32,560

Source: References [56, 57].

The Energy Information Administration (EIA) estimated that as of January 1, 2000, 253.83 Tcf of technically recoverable deep natural gas exists in the U.S. This is a significant increase from 1998 estimate which was 37.27 Tcf (Table 7.11). This reserve of tight gas represents over 21% of the total recoverable natural gas in the USA. However, The USDOE, USGS, and other organizations have completed resource assessments of U.S. basins with tight gas accumulations indicating that a vast amount (~6,000 Tcf) of natural gas resources exists. Figure 7.6 shows the tight gas basin location in the USA.

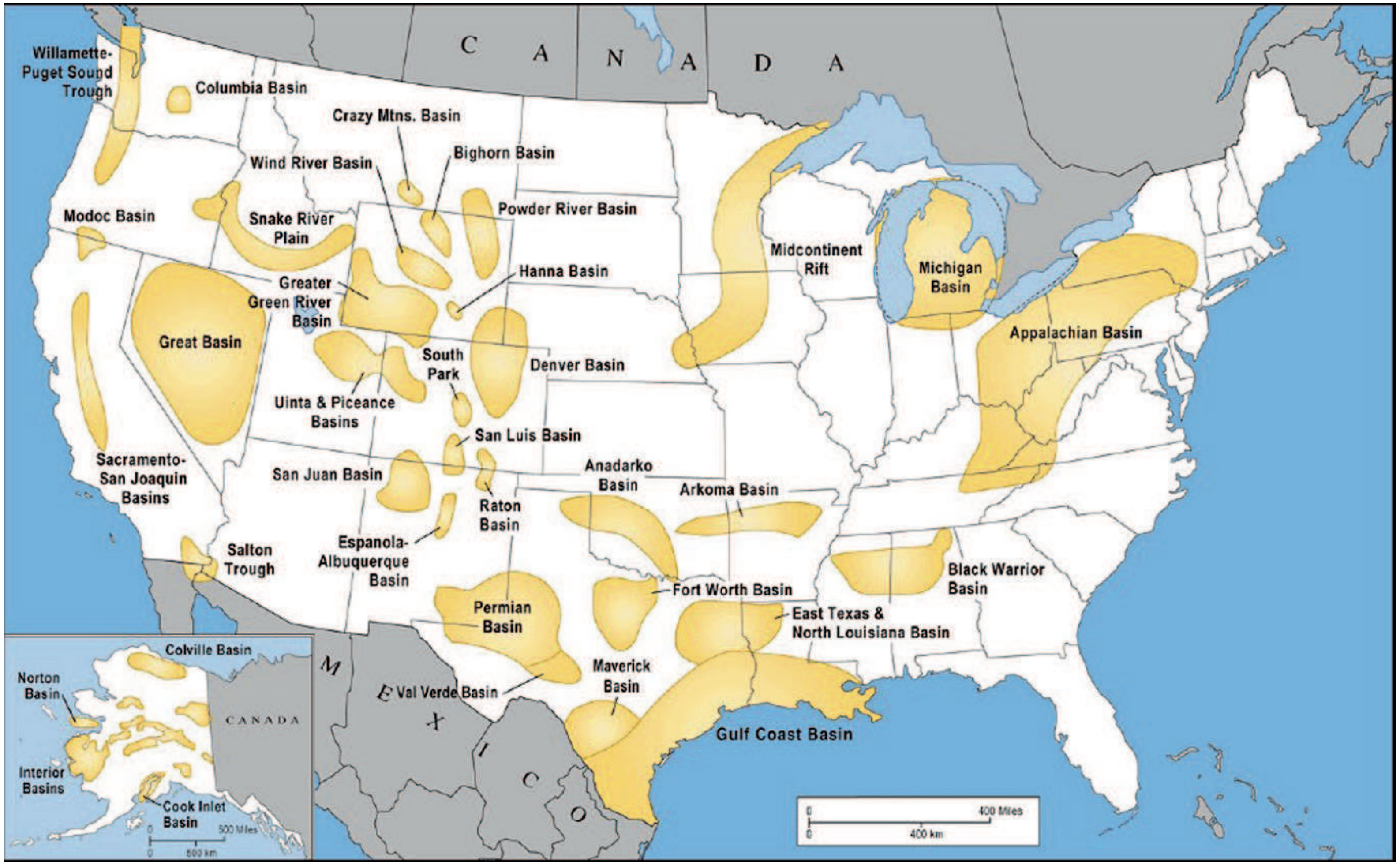


Fig. 7.6. Locations of tight gas basins in the USA [72].

Table 7.11. Tight gas reserve in various basins in the USA.

Tight gas basin	Reserve, billion ft^3 (as of 1998)	Tight gas basin	Reserve, billion ft^3 (as of 1998)
Arkla Basin	600	Piceance Basin	1,070
East Texas	4,500	Anadarko Basin	2,280
Texas Gulf Coast	3,600	Permian Basin	2,800
Wind River Basin	600	San Juan Basin	8,150
Green River Basin	6,000	Williston Basin	300
Denver Basin	900	Appalachian Basin	4,730
Uinta Basin	740		
Total	36,270		

Source: Reference [58].

Also it may be noted from Fig. 7.7 that some states in the USA are already producing natural gas from these basins.

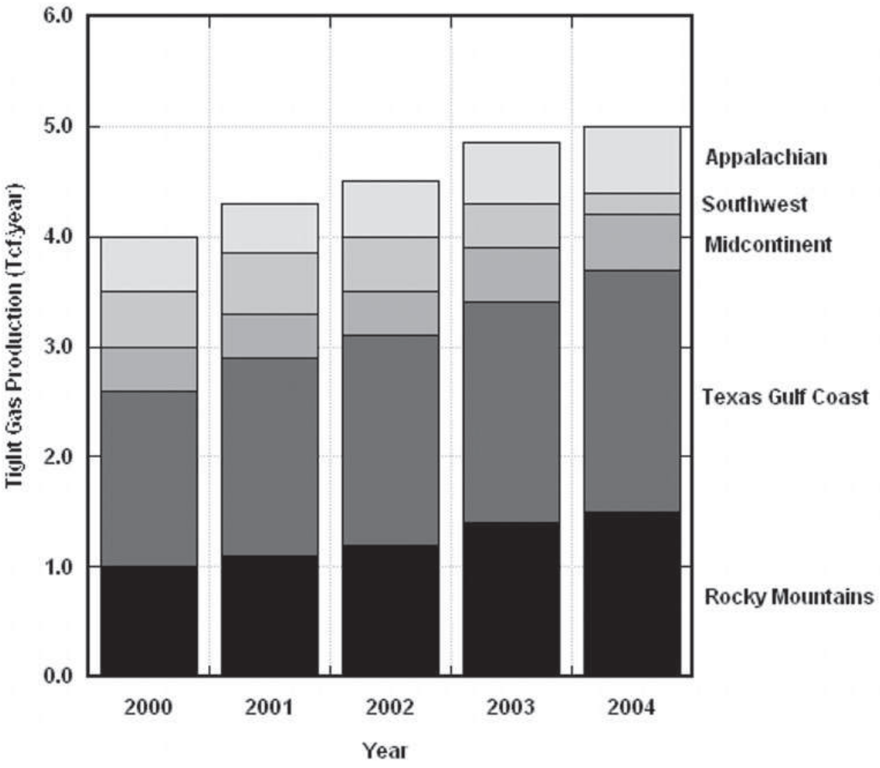


Fig. 7.7. Tight gas production in the USA.

7.3.3 Gas Containing Shales

Shale formations acts both as a source of natural gas and as its reservoir [60, 61]. Natural gas is stored in shale in three forms: free gas in rock pores, free gas in natural fractures, and adsorbed gas on organic matter and mineral surfaces. The process and cost of gas production depend on the shale formation. Recently, advanced drilling, completion, stimulation, and operating technologies have greatly improved the productivity and development economics of gas shale resources. Worldwide estimate of natural gas resources in shales is given in Table 7.12.

Table 7.12. Worldwide estimate of shale gas reserve.

Region	Gas resource in fractured shales (Tcf)
NAM-North America	3,842
LAM-Latin America	2,117
WEU-Western Europe	510
EEU- Eastern Europe	39
FSU-Former Soviet Union	627
MEA-Middle East Africa	2,548
AFR-Africa	274
CPA- Central Pacific	3,528
PAO- Asia and China	2,313
PAS- Other Asia Pacific	314
WORLD	16,112

Source: Reference [57].

Most of the natural gas containing Devonian shale in the U.S. is located around the Appalachian Basin. However, other basins including Michigan basin, Illinois basin, Fort Worth basin, and San Juan Basin are commercially used for shale gas production in the USA .The EIA estimates that there is 55.42 Tcf of technically recoverable shale gas in the USA, representing about 5% of total recoverable resources. The regions in the USA where these basins are located and used for commercial production are shown in Fig. 7.8.

7.3.4 Coal Bed Methane

Many coal seams also contain natural gas, either within the seam itself or in surrounding rocks [62–105]. It is assumed that during the coalification process, as plant materials are progressively converted to coal, large quantities of methane-rich gas is also generated which are stored within the coal. Because of its large internal surface area, coal can store six to seven times more gas than the equivalent rock volume of a conventional gas reservoir.

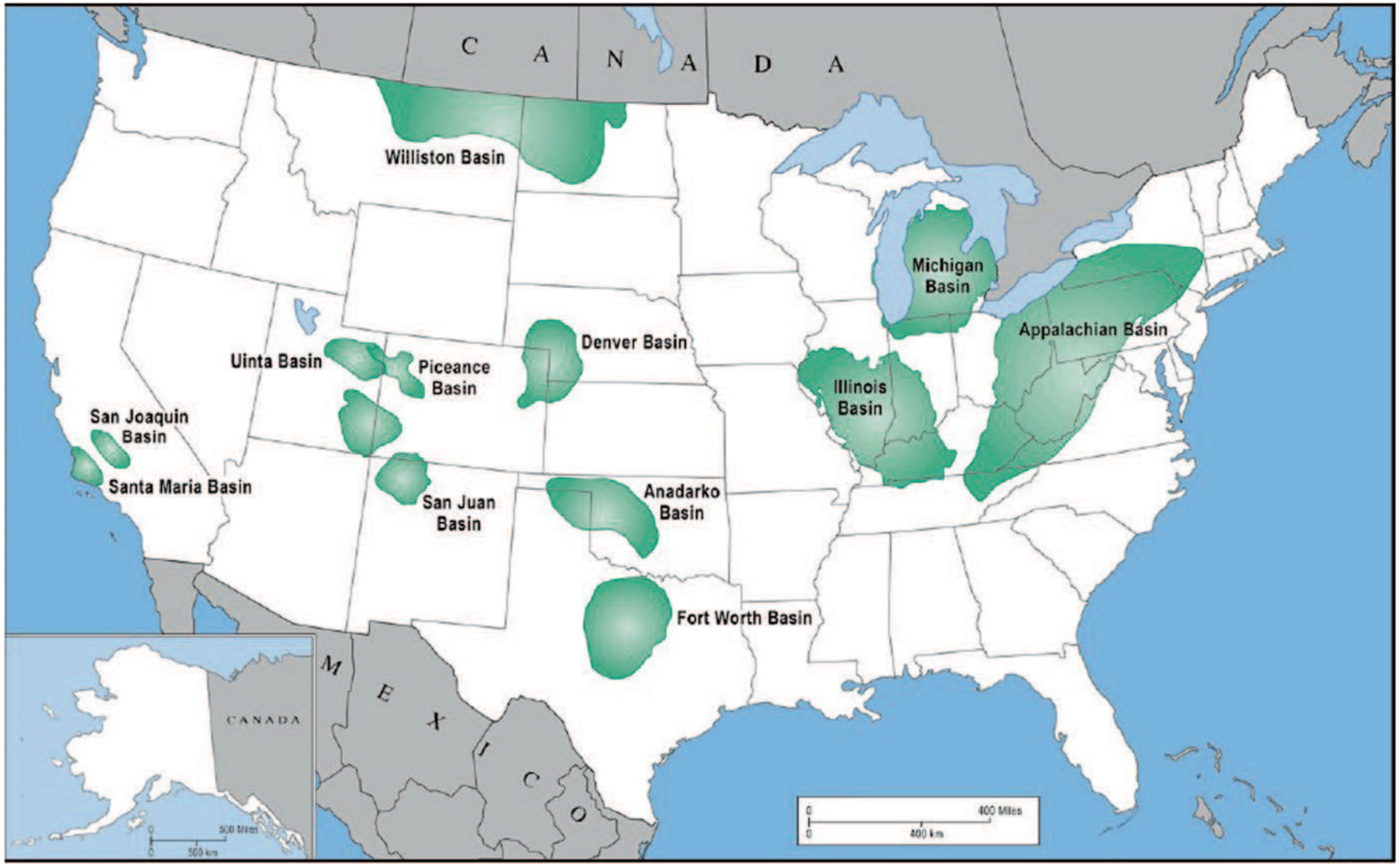


Fig. 7.8. Location of shale gas basins in the USA [72].

The amount of natural gas present in coal increases with coal rank, with depth of the coalbed, and with reservoir pressure. The fractures and pores in coal are generally filled with water. Although the deeper the coalbed, the less water is present, the water becomes more saline. This methane is usually released when coal mining starts. Various phases of coalbed methane production are shown in Fig. 7.9. This methane can be extracted and injected into natural gas pipelines. With the current technology, this methane can be captured or produced economically. However, there are significant environmental challenges, including loss of methane to the atmosphere during underground mining, and disposal of large quantities of water, sometimes saline, that are unavoidably produced with the gas. The coalbed methane is produced by reducing the pressure of the well, and this is generally accomplished by removing water from the coalbed. Figure 7.10 shows general construction of a well for coalbed methane production.

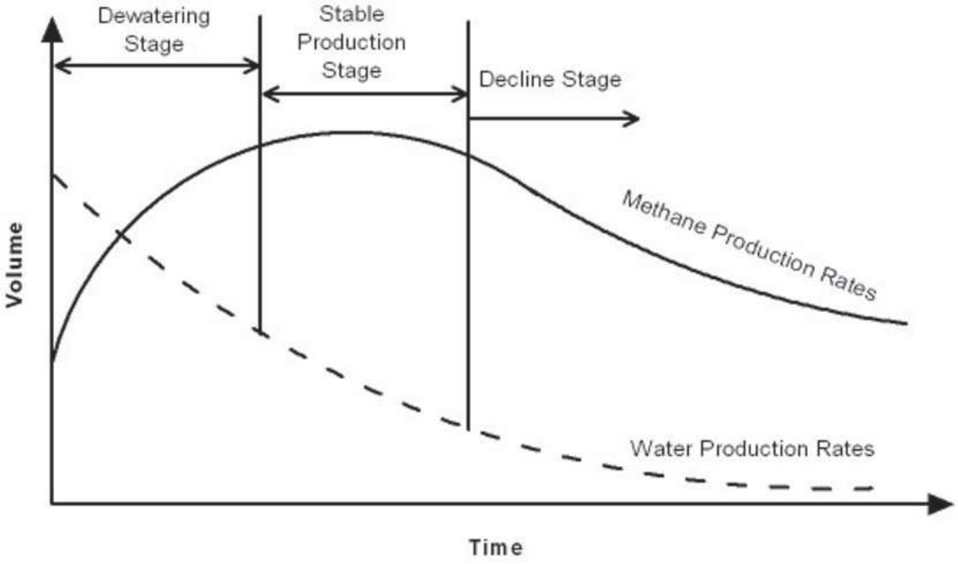


Fig. 7.9. Typical methane production curve from a coalbed [62].

Preliminary worldwide coalbed methane resources are estimated to be in between 5,800 and 24,215 Tcf. The largest potential resources, which also have the largest degree of uncertainty, are in the Former Soviet Union. Estimated resources worldwide are shown earlier in Table 7.10.

The rate of coalbed methane resource development within individual countries will be highly variable due to local economic factors and government energy priorities and policies.

The reserve and production of coal bed methane in the USA are given in Table 7.13.

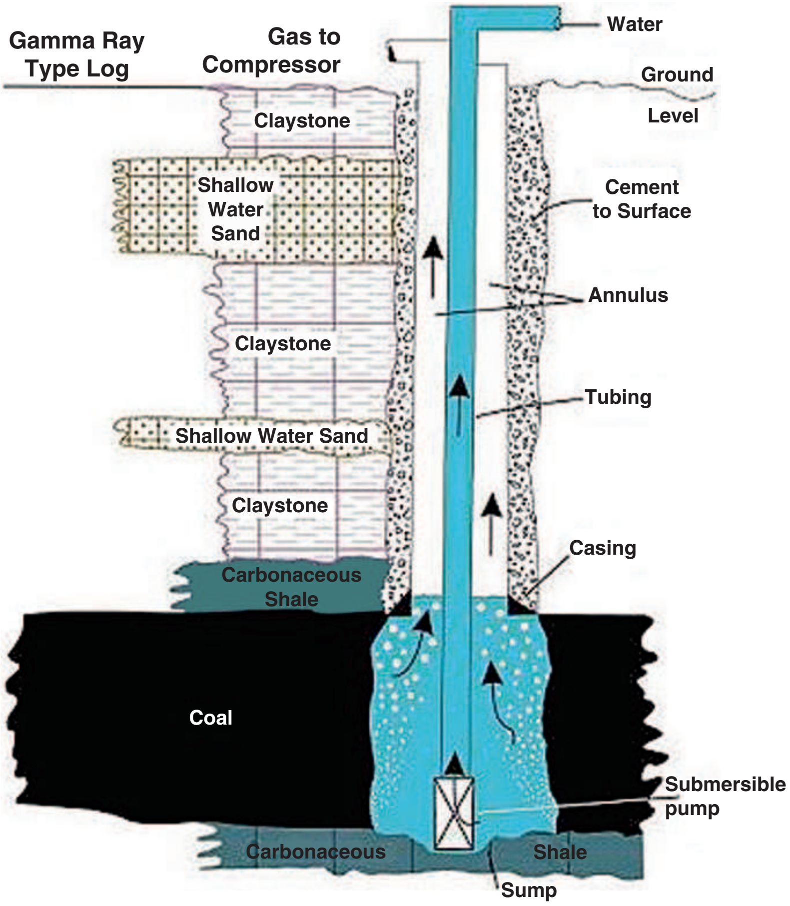


Fig. 7.10. Coalbed methane production [106].

Table 7.13. Coalbed methane reserve in the USA.

Year	Reserve	Production
2000	15,708	1,379
2001	17,531	1,562
2002	18,491	1,614
2003	18,743	1,600
2004	18,390	1,720
2005	19,892	1,732

Source: Reference [107].

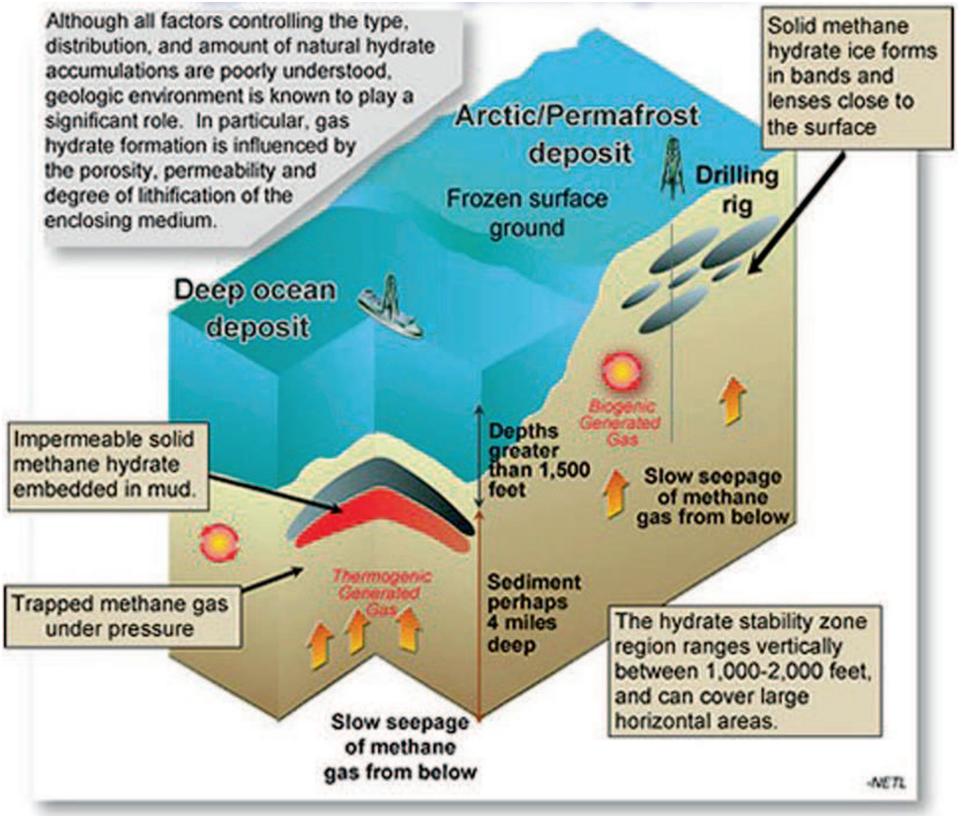
7.3.5 Geopressurized Natural Gas

Of all the unconventional sources of natural gas, geopressurized zones are estimated to hold the greatest amount of gas [108–122]. Most of the geopressurized natural gas in the USA is located in the Gulf Coast region. The amount technically recoverable is under dispute, however, it is estimated to be around 1,110 Tcf.

Geopressured reservoirs or aquifers are deep underground reservoirs containing brine. The brine is usually saturated with methane. The methane content could be in the range of 30–80 ft^3 per barrel of reservoir fluid.

7.3.6 Methane Hydrates

Methane hydrates were first discovered in permafrost regions of the Arctic (Fig. 7.11). Methane hydrates (or clathrate hydrates) are ice-like crystalline molecule formed from mixtures of water and methane gas molecules and provide the greatest reservoir for organic carbon on earth (Fig. 7.12). The water (host) molecules, upon hydrogen bonding, form lattice structures with several interstitial cavities. The guest (methane) gas molecules then occupy the lattice cavities, and when a minimum number of cavities are filled, the crystalline structure becomes stable and solid gas hydrates are formed, even at temperatures well above the melting point of water ice. When gas hydrates dissociate (melt), the crystalline lattice breaks down into liquid water (or converts to ice if conditions are below the freezing point of water) and the gas is released [123–126].



Although all factors controlling the type, distribution, and amount of natural hydrate accumulations are poorly understood, geologic environment is known to play a significant role. In particular, gas hydrate formation is influenced by the porosity, permeability and degree of lithification of the enclosing medium.

Solid methane hydrate ice forms in bands and lenses close to the surface

Impermeable solid methane hydrate embedded in mud.

Trapped methane gas under pressure

The hydrate stability zone region ranges vertically between 1,000-2,000 feet, and can cover large horizontal areas.

Fig. 7.11. Types of gas hydrate deposits. (Adapted from [127]).

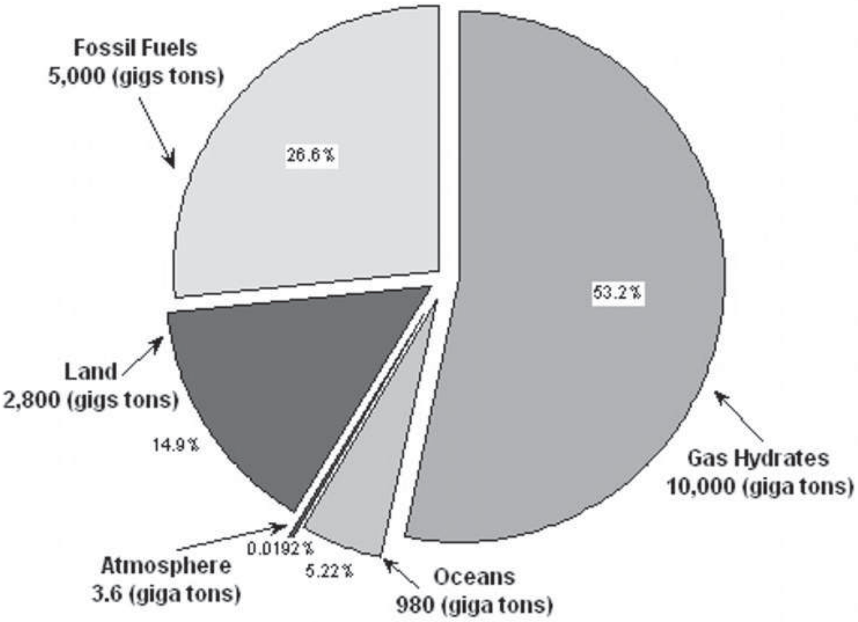


Fig. 7.12. Organic carbon reserve on earth excluding carbon in sediments and rocks. (Printed with permission from [125]).

The two common forms of gas hydrates are known as structures-I and II, which have been investigated by x-ray diffraction methods by von Stackelberg and Müller [126]. These structures are shown in Fig. 7.13.

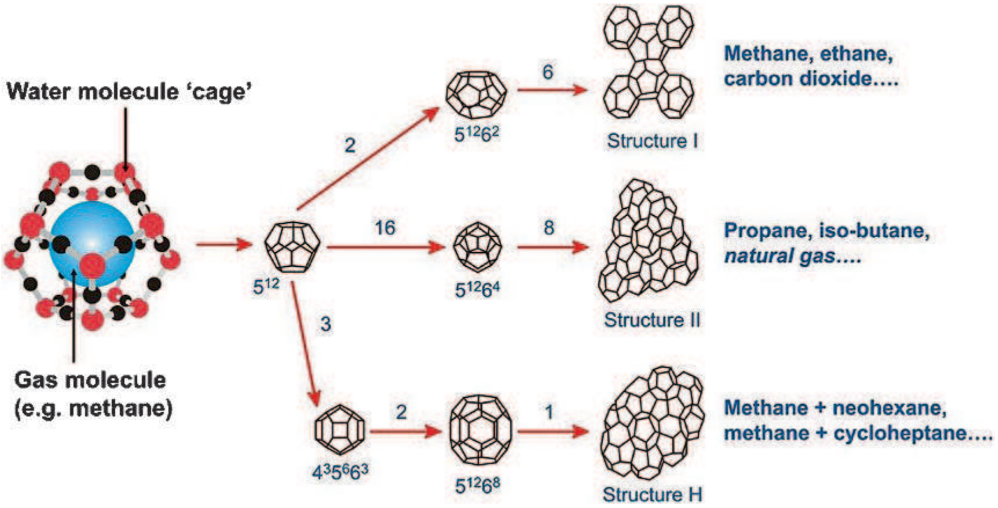


Fig. 7.13. Various types of methane gas hydrates. (Printed with permission from [126]).

Methane forms a **structure I hydrate** with two dodecahedral (20 vertices thus 20 water molecules) and six tetrakaidecahedral (24 water molecules) water cages per unit cell. The hydratation value of 20 can be determined experimentally by MAS NMR [128].

The formation of methane hydrates depends on a host of parameters; presence of free water, temperature, and pressure [129–138]. A phase diagram depicting where methane hydrates may form in the ocean floor is shown in Fig. 7.14.

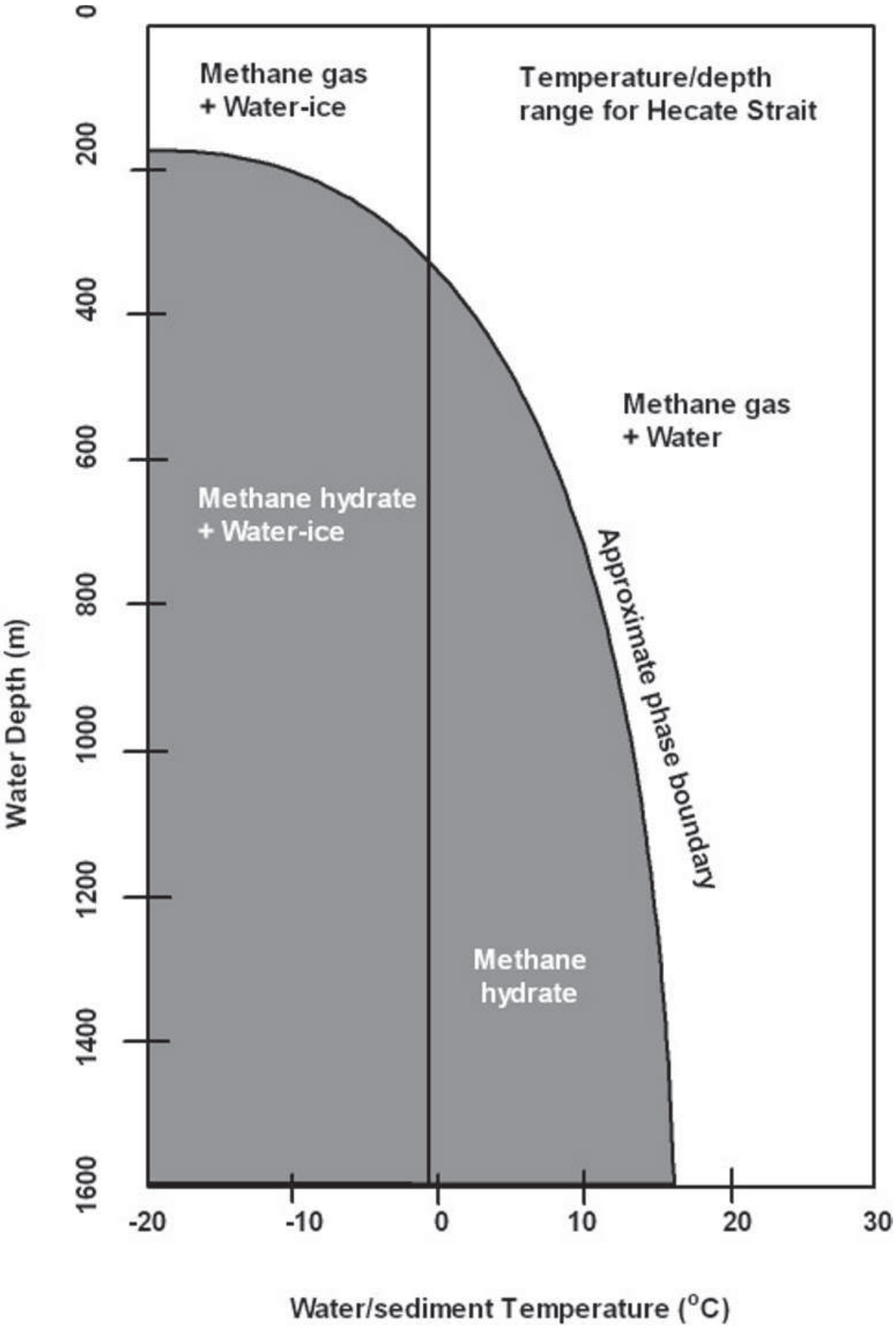


Fig. 7.14. Methane hydrate phase diagram. (Printed with permission [138]).

Estimates of methane hydrate reserve worldwide range anywhere from 7,000 Tcf to over 73,000 Tcf [139–157]. The oceanic deposit is estimated to be 30,000–49,100,000 Tcf, where as in Continental it is estimated to be in the range 5,000–12,000,000 Tcf. It may be noted that the conventional reserve of methane is about 13,000 Tcf. However, The worldwide estimate of methane hydrate reserves is extremely variable. As shown in Table 7.14, the estimate varied from 0.16 to 30,530 Tcf.

Table 7.14. Revised inventory of global estimates of methane in submarine gas hydrate (x 10^{13}).

Best or average value	References
3053	Trofimuk et al. (1973)
1573	Cherskiy and Tsarev (1977)
~ 1550	Nesterov and Salmanov (1981)
1135	Trofimuk et al. (1975)
~120	Trofimuk et al. (1979)
~45.4	Harvey and Huang (1995)
40	Kvenvolden and Claypool (1988)
26.4	Gornitz and Fung (1994)
20	MacDonald (1990), Kvenvolden (1988)
15	Makogon (1981), Trofimuk et al. (1981, 1983a, b), Makogon (1997)
6.8	Holbrook et al. (1996)
4	Milkov et al. (2003)
3.1	McIver (1981)
2.5	Milkov (2004)
>0.2	Soloviev (2002)
>0.016	Trofimuk et al. (1977) [184]

Adapted from [178].

The production of methane from hydrates is challenging and new technologies and production methods need to be developed. USGS scientists believe that we will most likely not see significant worldwide gas production from hydrates for the next 30–50 years. Gas recovery from hydrates is hindered because they occur as a solid in nature and are commonly widely dispersed in hostile Arctic and deep marine environments. However, they also noted that some countries may invest and expedite the production process due to their own need within the next 5–10 years. The detailed estimate of actual reserve has been conducted by few countries so far and is given in Table 7.15.

Table 7.15. National and regional estimates of the amount of gas within hydrates in cubic feet.

Country	Amount of gas in hydrates	Reference
USA	$317{,}700 \times 10^{12}$	Collett (1995)
Blake Ridge,	635×10^{12}	Dillion et al. (1993)
USA	$2{,}471 \times 10^{12}$	Dickens et al. (1997)*
North Slope, Alaska	$2{,}824 \times 10^{12}$	Holbrook al. (1996)*
	$2{,}012 \times 10^{12}$	Collett (2000)*
	$1{,}313 \times 10^{12}$	Collett (2000)
	590×10^{12}	Collett (2000)
India	$4{,}307 \times 10^{12}$	ONGC (1997)
Andaman Sea	$4{,}307 \times 10^{12}$	ONGC (1997)
Nankai Trough, Japan	$1{,}765 \times 10^{12}$	MITI/JNOC (1998)

*Includes associated gas [187].

7.4 Composition of Natural Gas

Natural gas mainly consists of methane (CH_4). However, a number of higher hydrocarbons such as ethane, propane, butane, pentane, and hexane along with inert gases including nitrogen and carbon dioxide can be present in the gas stream. A typical composition of natural gas is shown in Table 7.16. The composition can vary, although not significantly, based on its source and supplier. Natural gas may also contain hydrogen sulfide (H_2S) in varying amount and is called “Sour Natural Gas” if the hydrogen sulfide content is greater than 5.7 mg/m^3 at standard pressure and temperature. The sour natural gas needs to be processed further (this is also called sweetening the gas) before the gas can be utilized. Various processes are available for sweetening the gas and are discussed later in this chapter.

Table 7.16. Typical composition of natural gas.

Component	Typical analysis (mol%)	Range (mol%)
Methane	94.9	87.0–96.0
Ethane	2.5	1.8–5.1
Propane	0.2	0.1–1.5
iso-Butane	0.03	0.01–0.3
Normal-butane	0.03	0.01–0.3
iso-Pentane	0.01	Trace–0.14
Normal-pentane	0.01	Trace–0.04
Hexanes plus	0.01	Trace–0.06
Nitrogen	1.6	1.3–5.6
Carbon dioxide	0.7	0.1–1.0

(Continued)

Table 7.16. (Continued)

Component	Typical analysis (mol%)	Range (mol%)
Oxygen	0.02	0.01–0.1
Hydrogen	Trace	Trace – 0.02
Hydrogen sulfide	Trace	0–5%
Nitrogen	Trace	0–5%
Rare gases, Ar, He, Ne, Xe	Trace	
Specific gravity	0.585	0.57–0.62
Gross heating value (MJ/m^3), dry basis*	37.8	36.0–40.2

*The gross heating value is the total heat obtained by complete combustion at constant pressure of a unit volume of gas in air, including the heat released by condensing the water vapour in the combustion products (gas, air, and combustion products taken at standard temperature and pressure). In the Union Gas system, the typical sulfur content is 5.5 mg/m^3. This includes the 4.9 mg/m^3 of sulfur in the odorant (mercaptan) added to gas for safety reasons. The water vapor content of natural gas in the Union Gas system is less than 80 mg/m^3, and is typically 16–32 mg/m^3.

Source: Union Gas Limited, Ontario, Canada.

7.5 Combustion Properties of Natural Gas

The typical combustion properties of natural gas are shown in Table 7.17. The properties shown are an overall average of the Union Gas system. These values can vary from supplier to supplier.

Table 7.17. Typical combustion properties of natural gas.

Properties	Values
Ignition point	593°C*
Flammability limits	4–16% volume percent in air
Theoretical flame temperature (stoichiometric air/fuel ratio)	1,960°C
Maximum flame velocity	0.3 m/s
Relative density (specific gravity)	0.585
Wobbe index	1,328

7.6 Natural Gas Production

The natural gas that is delivered into our homes begins with the exploration of the earth's surface to locate a reservoir for the natural gas. Once a reservoir is discovered, it goes through a number of processes before it is delivered to homes or customers. These processes may be divided into the following categories:

- Exploration
- Extraction
- Processing
- Transportation
- Storage
- Distribution
- Marketing

7.6.1 Exploration

The search for petroleum or natural gas starts with the geologists, who use surveying and mapping to understand the surface and sub-surface characteristics, to determine which areas are most likely to contain a petroleum or natural gas reservoir [186–192]. Geologists use many tools including the outcroppings of rocks on the surface or in valleys and gorges. Geologic information obtained from the rock cuttings and samples obtained from the digging of irrigation ditches, water wells, and other oil and gas wells are used to determine areas for further exploration.

Geophysicists mainly use three methods for oil and gas exploration: magnetic, gravity, and seismic exploration. The magnetometer and gravity meter are used to locate hidden, subsurface petroleum traps [194]. In seismic exploration, sound is transmitted into the ground by an explosive, such as dynamite, or by a thumper truck. Currently, seismology is the main tool used by geologists to explore an area for petroleum or natural gas [195–204]. Both on-shore and off-shore seismology techniques are available to geologists. Following exploration by these methods, exploratory wells and loggings are done to gain a better understanding of not only of the geology, but also of the total reserve.

7.6.1.1 Magnetometers

In magnetic exploration a magnetometer is used to determine the strength of the earth's magnetic field at a specific point on the earth's surface. Magnetic properties vary based on the composition of the earth's layer. Underground formations can be measured using Magnetometers to generate geological and geophysical data. Magnetometers can measure the small differences in the Earth's magnetic field, which can be determined with an aerial pass of a magnetometer or on the ground using a type of magnetometer called a vertical field balance. From these readings, experts determine if there is oil or gas, because there exists a correlation between low magnetic readings and rocks that contain oil.

7.6.1.2 Gravimeters

Using gravimeters, geophysicists measure and record the difference in the Earth's gravitational field at various underground locations. Minute differences in gravitational field exist due to the different underground formations and rock types. This information can help the geophysicists to determine the existence of potential reservoir for petroleum or natural gas.

Gravitational methods can also be done aerially with a gravimeter or on the ground using a more precise instrument called a gravity gradiometer. The data from gravitational methods is valuable because differences in the gravitational field indicate a difference in the density of the ground which correlates to rocks that contain oil. Both of these methods are relatively low impact system because they only involve either not touching the ground at all, or by setting up stations approximately 100 yards apart using low-impact transportation. Thus the impact of non-seismic techniques is significantly lower than the impact that would be caused by drilling unnecessary wells.

7.6.1.3 Exploratory Wells

Once the survey by various instruments discussed above convince geologists that there are enough indication of a high probability of petroleum formation, exploratory wells are drilled. The presence of suspected oil and gas deposits is generally confirmed by the exploratory (These wells are called wildcat wells) drilling of deep holes. The drill cuttings and fluids are analyzed by geologists to gain a better understanding of the geologic features of the area. Drilling an exploratory well is expensive and also time consuming, since wildcat wells are deeper and drilled in areas having no prior history of oil or gas deposits. Construction of access roads and drill pads are typically required to conduct these exploratory drilling operations increasing the cost of operation. A typical drilling rig is shown in Fig. 7.15.

7.6.2 Logging

Samples collected from the exploratory wells go through a series of tests, generally referred to as "Logging" to allow geologists and drill operators to monitor the progress of the well drilling and to gain a better picture of subsurface formations [205–209]. The quantitative analysis of well logs can provide the following information:

– Porosity
– Water saturation, fluid type (oil/gas/water)
– Lithology

- Permeability
- Hydrocarbons-in-place
- Reserves (the recoverable fraction of hydrocarbons in-place)
- Mapping of reservoir

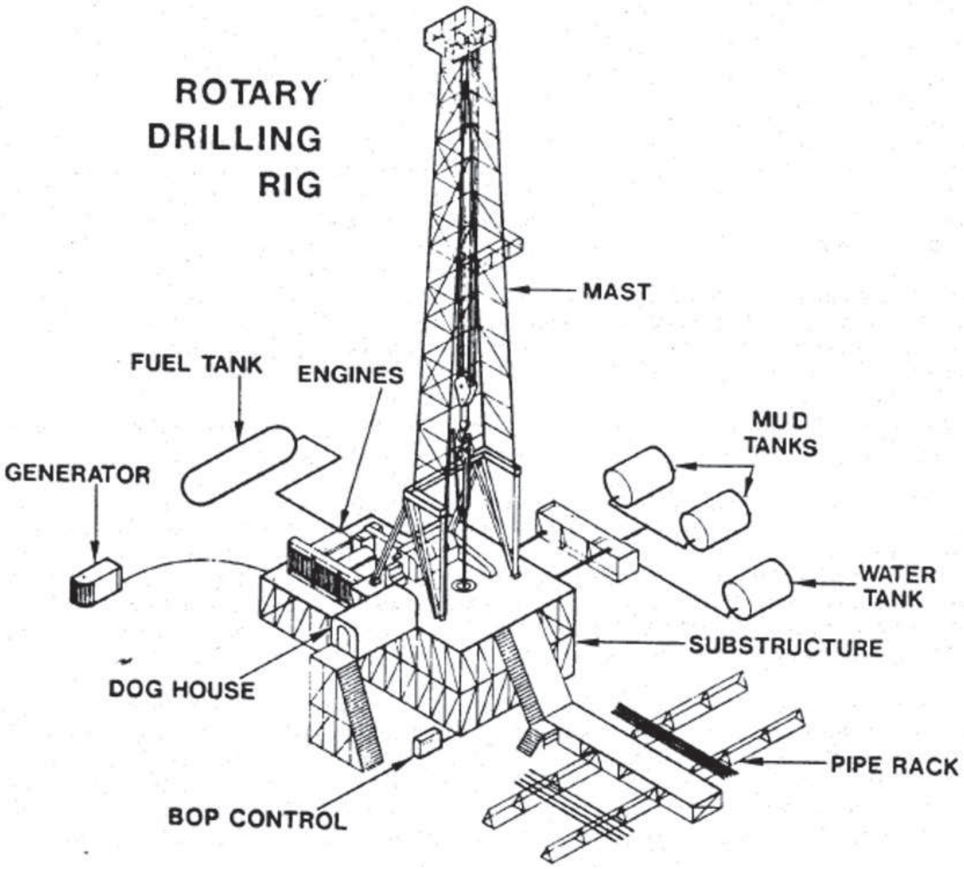


Fig. 7.15. Rotary drilling rig arrangements. Source: Reference [205].

A typical logging system is shown in Fig. 7.16.

There are over 100 different logging tests that can be used to monitor the drilling process and to make decision if the drilling should be continued. The most common types of logs are:

- Standard log
- Resistivity log
- Spontaneous potential log
- Gamma ray log
- Neutron log
- Density log
- Sonic (acoustic) log

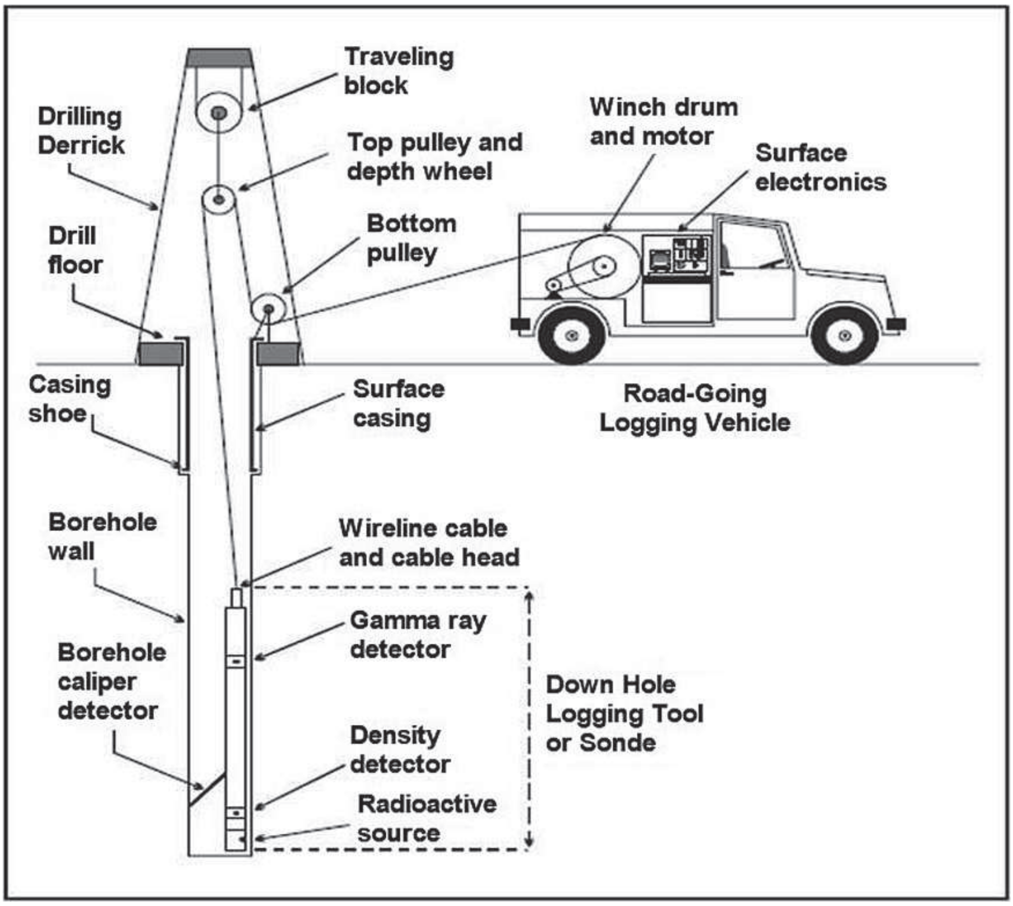


Fig. 7.16. A typical logging system with main components. (Source: Reference [210]).

Standard Log

Standard logging consists of examining and recording the physical properties of the drill cuttings (rock that is displaced by the drilling of the well) and core samples taken from the underground soil. These cuttings and cores are often examined using microscopes with a magnification greater than 2,000 times.

Resistivity Log

This log measures the bulk resistivity of the formation to determine the types of fluids present in the reservoir rocks. Resistivity is a function of porosity and pore fluid in a rock. A non-porous rock or hydrocarbon containing formation has high resistivity. By contrast, if the rock formation is porous and contain saline water, the resistivity will be low. This log is therefore used as an indicator of formation lithology. There are many different types of resistivity logs, which differ mainly in the depth to which the measurements are made. These logs are listed below.

AIT (Array Induction Tool): It measures five depths of investigation.
DIL (Dual Induction Log): This log is used for deep and medium depths of investigation.
DLL (Dual Latero Log): This log is used for deep and medium depths of investigation.
SFL (Spherically Focused Log): This log is used for a shallow depth of investigation.
SGR (Shallow Guard Log): This log is used for a shallow depth of investigation.

Spontaneous Potential (SP) Log

This log provides data on permeability of the rock. The electrical current that occurs naturally between the boreholes drilling fluid and the formation water that is held in pores of the reservoir rock is measured. Porous sandstones have high permeability compared to impermeable shale and thus can distinguish them. The SP log can also be used for locating bed boundaries.

Gamma Ray Log

Rocks contain various naturally occurring radioactive materials that emit gamma rays at various energy levels depending on the type of isotopes present in the rock. In this log the radioactivity of a formation is measured using a gamma detector. Gamma ray logs are one of the most commonly used logs for sequence stratigraphic analysis. Shale commonly have high radioactivity compared to sandstones. Also coarse grain sand, which contains little mud, is less radioactive compared to fine sand that contain significant amount of mud. The gamma ray activity is measured in an API unit, a unit of counting rate for the gamma-ray log. The difference between the high and low radioactivity sections in the API calibration pit is defined as 200 API units. One API unit is defined as the 1/200th of the difference in radioactivity from the gamma ray between zones of high and low radioactivity in the API Gamma Ray calibration pit in Houston, Texas, USA. In shale, radioactivity can be about 200 API units.

Neutron Log

This is also known as compensated neutron log (CNL). A neutron source, typically a californium-252 spontaneous fission source, is placed in the bore hole and a gamma detector picks up the radiation from scattering or capture reactions. The porosity of a formation is measured by using this log. The amount of hydrogen atoms present in the reservoir pores that are filled with either water or hydrocarbon (oil) is measured. The log is calibrated to limestone. The linear limestone porosity units are calibrated using the API Neutron pit in 19% porosity. The water filled limestone is defined as 1000 API units. Along with the density log, the lithology of the formation is determined using the neutron log data.

Density Log

The density log measures the density of the formation rocks for determination of porosity. Different lithologies can also be determined using density log as the density of rocks differs based on its contents, such as 1.2–1.8 g/cm^3 for coal, 2.65 g/cm^3 for pure quartz, and up to 2.75 g/cm^3 for limestone. The density logs generally overestimate the porosity of rocks that contain gas and result in “crossover” of the log curves when paired with neutron logs.

Sonic (Acoustic) Log

This log measures the speed of sound in the formation, which can be correlated to both porosity and lithology of the formation. Sound waves travel faster through high-density shale than through lower-density sandstones. Sonic log value for sandstone is in the range of 51–56 μs/ft.

NMR (Nuclear Magnetic Resonance) Log

This log measures the magnetic response of fluids present in the pore spaces of the reservoir rocks. Both porosity and permeability are determined from the data. The measurements are largely based on the fluid and the pore space characteristics. A better understanding of the fluids and pores is possible compared to other conventional logs like density, neutron, and sonic.

Dipmeter Logs

This log determines the orientations of sandstone and shale beds in the well. The direction and angle of formation dip in relation to the borehole is obtained. The data provides the geologic structure of the formation. The dipmeters can provide a detailed image of the rocks on all sides of the well hole.

Caliper Logging

Caliper logging provides a continuous recording of borehole diameter versus depth. These logs are generally run in uncased wells, but can be also used within casing. Caliper logs are also used to locate caved zones, casing, and the absence of casing; and permit the recognition of mud cake. (i.e., permeable zones).

A number of different logs have been used in the oil and gas industry. These logs are presented in Table 7.18.

Table 7.18. Different types of logs and their purposes.

Log type	Log code	General name for log order	Definition
Electric log	EL	Electric log	Open hole log with an SP curve and typically a non-induced resistivity curve
Induction log	IL	Electric log	SP log with one or more induced resistivity curves (including focused and laterologs)
Micro log	ML	Micro log	Micro-resistivity log
Gamma ray log	GR	Gamma-ray log	Log which only records natural radioactivity (logs with other curves are a different log type)
Neutron log	NTR	Neutron porosity log	Records hydrogen concentration in the formation; usually has a gamma ray curve; does not include density-neutron logs
Density log	DL	Density porosity log	Records electron density in the formation; usually has a gamma ray curve; does not include density-neutron logs
Density-neutron log	DNL	Density porosity log	Porosity log with at least one density curve and at least one neutron curve
Sonic log	SL	Sonic porosity log	Porosity log based on transit time of sound waves through the formation
Magnetic resonance log	MRL	Magnetic resonance porosity log	Porosity log based on measuring the signal generated by polarized hydrogen protons
Computed log	CUL		Any log that attempts to characterize the formation by computer analyses of multiple other logs that have been run in the well
EPT log	EPT		Measures propagation and attenuation of electromagnetic waves through a formation
Dipmeter log	DIP	Dipmeter log	Records the attitude (dip angle and dip direction) of rock layers in the borehole
Gamma ray Spectral log	SPC		Uses gamma ray energy spectrum to record potassium, uranium, and thorium in the formation
Caliper log	CAL		Measures width of the borehole
Fracture ID log	FID		A special presentation of dipmeter micro resistivity measurements that identifies fractures
Borehole imaging log	BIL		High-resolution imaging of borehole circumference using closely spaced log measurements, typically of micro resistivity or sonic transit time

(Continued)

Table 7.18. (Continued)

Log type	Log code	General name for log order	Definition
Production log	PRL	Production log	Any of various logs used in completing a well for production
RFT (repeat formation test) log	RFT		Records formation pressure data (and obtains a small rock sample) of the formation
Temperature log	TMP		Records temperature of drilling mud in the borehole
TVD log	TVD	TVD log	Records position and attitude of borehole in deviated wells

Source: Reference [211].

7.6.3 Extraction

In the extraction phase, the following issues are taken into account.

- Economic considerations
- Permitting, leasing, and royalties
- Technology based on onshore or offshore drilling

If the site and size of the basin is found large enough to be economically feasible, permitting, leasing, and royalty issues are finalized. Finally a decision is made regarding the drilling technology. There are two main types of onshore drilling: Percussion, or ‘cable tool’ drilling and rotary drilling. Cable tool drilling consists of raising and dropping a heavy metal bit into the ground that punches a hole down through the Earth. Cable tool drilling is usually used for shallow, low pressure formations. In rotary drilling, a sharp rotating metal bit is used to drill through the Earth’s crust. This type of drilling is used primarily for deeper wells that may be under high downhole pressure.

7.6.3.1 Well Completion

Before natural gas or oil is extracted from underground, the well must be *completed* for commercial production. The steps involved for completion of a production well are as follows:

- Well casing
- Completion
- Wellhead
- Lifting and well treatment

A series of metal tubes are installed in the freshly drilled hole to strengthen the sides of the well hole, ensuring that no oil or natural gas seeps out of the well hole as it is brought to the surface, and to keep other fluids or gases from seeping into the formation through the well. This process is called the well casing and there are five different types of well casing. They are installed in the following order:

- Conductor casing
- Surface casing
- Intermediate casing
- Liner string
- Production casing

Conductor casing is installed first to prevent the top of the well from caving in and to circulate the drilling fluid up from the bottom of the well. They are generally 20–50 ft long. The surface casing is installed next and fits inside the top of the conductor casing. It can be more than 2,000 ft long, and is smaller in diameter than the conductor casing. Both the conductor and surface casings are cemented into place. The primary objective of surface casing is to prevent fresh water contamination from the drilling activities. The surface casing serves as a conduit for drilling mud returning to the surface, and helps protect the drill hole from being damaged during drilling. Intermediate casing is used to protect the well from various unexpected activities from underground such as pressure change, and saltwater deposit. The intermediate casing may also be cemented into place for added protection. Liner strings are sometimes used instead of intermediate casing and generally are not cemented. Production casing, also known as oil string or long string is installed last. It extends from the surface of the well to the petroleum producing formation. The diameter of the production casing depends on the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later time.

7.6.3.2 Completion

There are six types of completion as listed below. The types of completion to be used in any formation depend on the characteristics of the formation and the targeted products.

- Open hole completion
- Conventional perforated completion
- Sand exclusion completion
- Permanent completion
- Multiple zone completion
- Drainhole completion

Open hole completion is the most basic type of completion in which the casing is placed directly in the formation. The end of the casing is open to the formation and no protective filter is installed. The formations that are acid fractured generally use this type of completion.

In conventional perforated completion, the side of the casing is perforated to allow for the flow of hydrocarbons into the well hole. The perforation is carried out in situ using a jet perforating technique. This involves small, electrically ignited charges, lowered into the well. When ignited, these charges penetrate through the casing, cementing, and any other barrier between the formation and the open well forming tiny holes.

If the formation contains large amount of loose sand, sand exclusion completion is used. A screen is used to prevent flow of sand inside the casing. Sand inside the well hole can cause many complications, including erosion of casing and other equipment.

Permanent completion involves permanent installation of the casing, cementing, perforating, and other completion work. This is done only once and can reduce the cost significantly. In this method there is no room for error.

Multiple zone completion is generally used for oil well and if more than two formations are present in close vicinity. This type of completion is preferred if all the formations will be used for production. Oil can be extracted from the formations simultaneously without mixing them, thus reducing the production cost significantly. One of the main challenges is to keep various formations separated.

Drainhole completions are commonly associated with oil wells than with natural gas wells. A horizontal well is drilled from the vertical drill allowing hydrocarbons to drain into the well.

7.6.3.3 Wellhead

Natural gas in the well can be at a pressure well above 20,000 psi. The wellhead consists of various equipment mounted at the opening of the well on the surface that regulate and monitor the extraction of natural gas and oil from the underground formation. These instruments should be capable of withstanding the above pressure. The wellhead consists of three components: the casing head, the tubing head, and the ‘Christmas tree’. The casing head generally supports the entire casing and also provides the sealing between casing and the surface. The tubing head provides the sealing between the tubes and also provides the mechanical support to the tubes in the well. The Christmas tree is referred to the various valves and fitting that are used in the casing head and tube head to monitor the flow of the gas or oil on the surface.

7.6.3.4 Lifting and Well Treatment

Once the well is completed, the production of natural gas can proceed. Natural gas flows to the surface due to the pressure difference. Once the flow of natural gas is started, the Most Efficient Recovery (MER) rate is established. As more and more natural gas is extracted from the formation, the production rate of the well decreases. This is known as the decline rate. At this point, lifting equipment and well stimulation may be necessary to maintain the production rate of a well. However, this is generally more common with the oil well or oil wells that have associated natural gas, than with the natural gas only well.

7.6.4 Processing

The natural gas that is fed into the gas pipeline for delivery to the consumer must meet certain specifications in order for the pipeline grid to operate properly. Therefore, natural gas produced at the wellhead, which contains various contaminants and natural gas liquids, must be processed, before delivering to the high-pressure, long-distance pipelines. These specifications are given in Table 7.19. The natural gas processing subject has been discussed in great details in a number of books [211–218].

Table 7.19. Typical composition of natural gas before refining.

Component	Chemical formula	Volume (%)
Methane	CH_4	>85
Ethane	C_2H_6	3-8
Propane	C_3H_8	1–2
Butane	C_4H_{10}	<1
Pentane	C_5H_{12}	<1
Carbon dioxide	CO_2	1–2
Hydrogen sulfide	H_2S	<1
Nitrogen	N_2	1–5
Helium	He	<0.5

If the natural gas does not meet these specifications various operational problems, pipeline deterioration, or even pipeline rupture may occur.

The various processing steps before delivering the natural gas into the pipeline are shown in Fig. 7.17. Some of these steps may be optional depending on the composition of the wellhead gas. The natural gas processing system may be divided into seven major sections.

- Gas-oil separator
- Oil and condensate removal
- Dehydration
- Contaminant removal
- Nitrogen extraction
- Separation of natural gas liquids (NGL)
- Fractionation

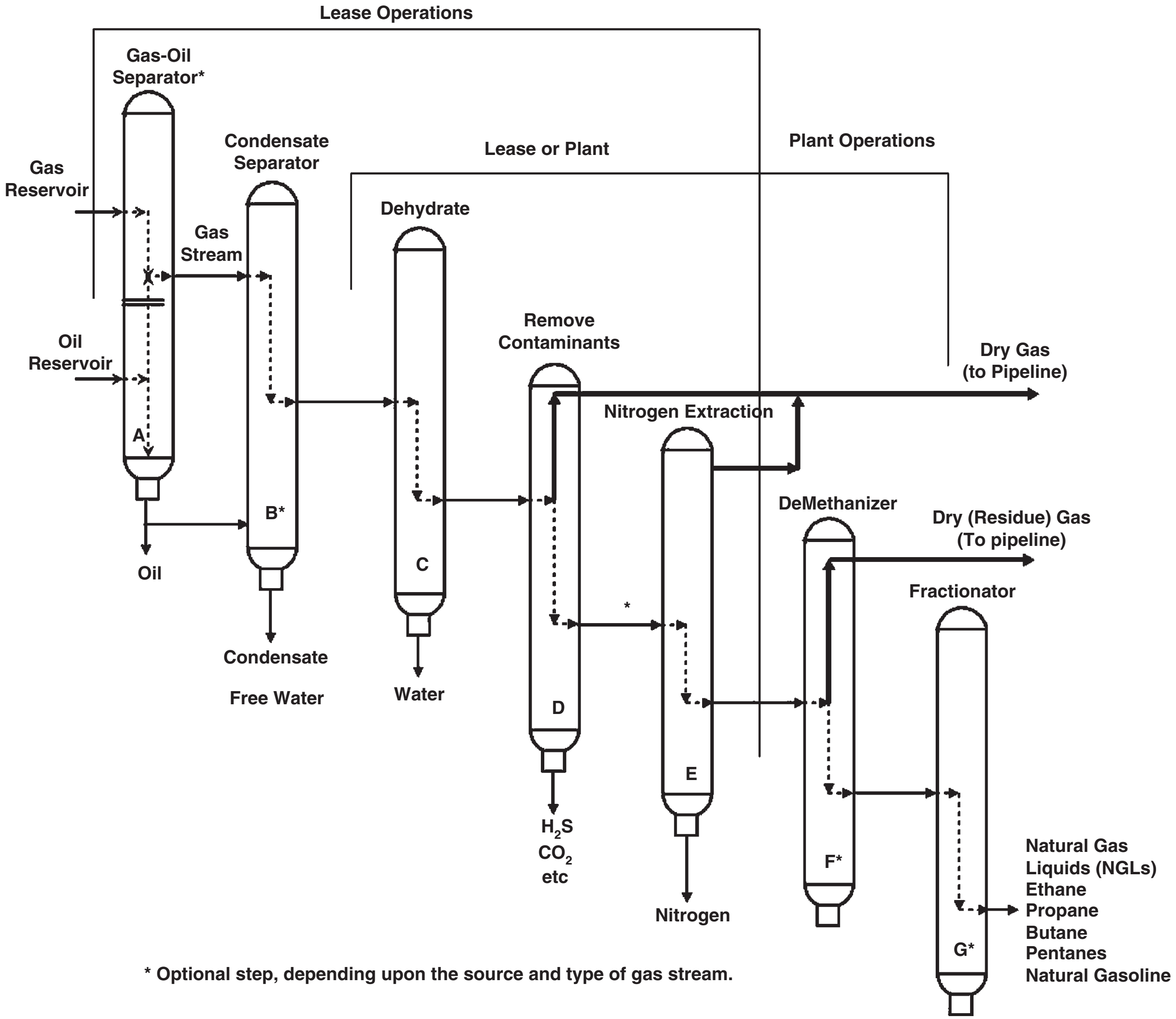


Fig. 7.17. A typical natural gas processing plant. (Adapted from [218]).

7.6.4.1 Gas-Oil Separation

Pressure reduction at the wellhead is generally sufficient for separation of gas from oil using a conventional closed tank. The gas is separated from liquid hydrocarbons (oil) due to the difference in specific gravity. In some cases, however, a multi-stage gas-oil separation process is needed to separate the gas stream from the crude oil. These gas-oil separators are commonly closed cylindrical shells, horizontally mounted with inlets at one end, an outlet at the top for removal of gas, and an outlet at the bottom for removal of oil. Separation is accomplished by alternately heating and cooling by compression of the flow stream through multiple steps. Some water and condensate are also removed by this process. The design of a horizontal separator is shown in Fig. 7.18.

7.6.4.2 Oil and Condensate Removal

Condensates are removed from the gas stream at the wellhead through the use of mechanical separators. The stream can be fed directly into the separator from the wellhead, if the gas-oil separation process is not needed. A Low-Temperature Separator (LTX) is most often used for wells producing high pressure gas along with light crude oil or condensate. These separators use pressure differentials to cool the wet natural gas and separate the oil and condensate. The gas stream enters the processing plant at high pressure (600 lb per in.^{2} gauge (psig) or greater) through an inlet slug catcher where free water is removed from the gas, after which it is directed to a condensate separator. Extracted condensate is routed to on-site storage tanks. The gas stream is rapidly expanded through a choke valve resulting in a decrease in the temperature. As gas cools, liquids present in the stream condensed out from the stream. Often, after liquid removal, the dry gas flows back through the heat exchanger and is warmed by the incoming wet gas. A schematic diagram of a low temperature separator is shown in Fig. 7.19.

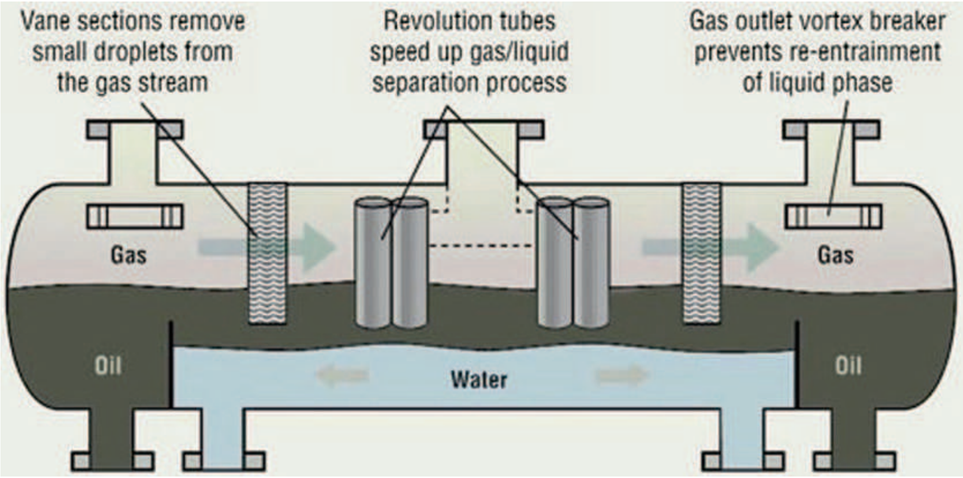


Fig. 7.18. Horizontal dual flow separator [221].

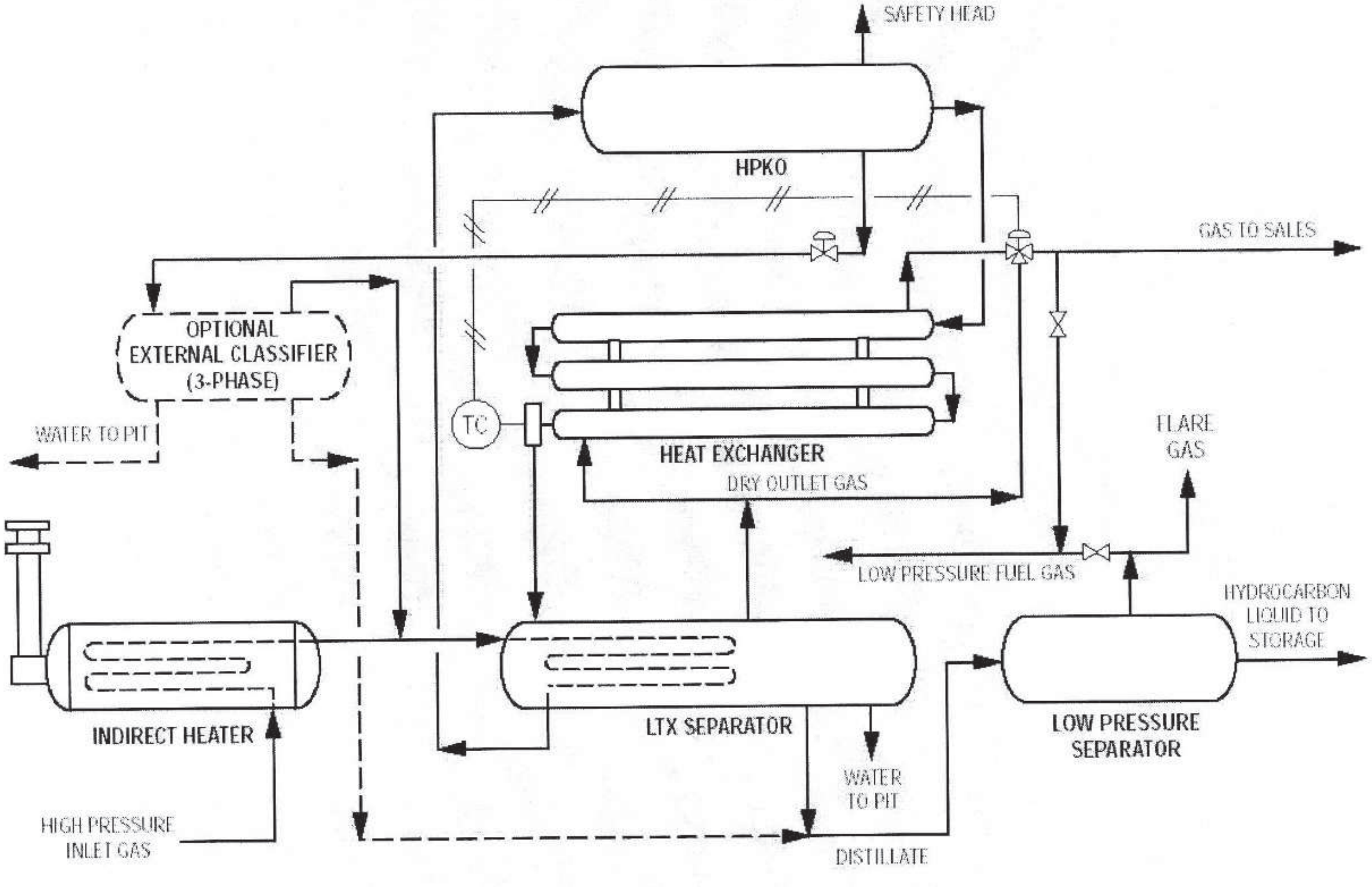


Fig. 7.19. LTX hydrocarbon liquid recovery system [219].

7.6.4.3 Dehydration

The dehydration process is used mainly to eliminate water vapor from the gas stream which may cause the formation of hydrates. Hydrates are solid particles that can cause a number of problems during flow through pipelines including blockage and damage to pressure boosting pumps. Under certain temperature and pressure, methane and other alkanes in the gas stream can form hydrates if free water is present in the gas stream. Two most common methods used by the natural gas industry to remove free water are: the use of ethylene glycol (glycol injection) and solid desiccant dehydration.

Glycol Dehydration (Glycol Injection) [221–240]

Water vapor from the natural gas stream is removed by contacting it with either diethylene glycol (DEG) or triethylene glycol (TEG) in a counter-current contractor. Lean glycol stream containing about 99% glycol is sprayed from the top of the contractor, while the gas stream is fed from the bottom. The water from the wet natural gas stream is absorbed by the glycol. The dry gas from the top of the contractor is send to the next processing unit. The diluted glycol solution (called the rich glycol stream) is fed to another contractor where water vapor is removed by heating the solution while dry air is blown through the contractor to generate the glycol solution to its original concentration. The regenerated glycol solution is recycled back to the first contractor. The schematic diagram of a glycol dehydration system is shown in Fig. 7.20.

One of the concerns with the glycol dehydration system is that the rich glycol stream also contains various impurities along with a small amount of methane. During regeneration of the lean glycol stream, these impurities and methane are released to the atmosphere. The addition of flash tank separator-condensers can recover 90–99% of the dissolved methane. In the flash tank separator the pressure of the glycol stream is reduced suddenly allowing dissolved low boiling point constituents (methane and other hydrocarbons) of the solution to flash or vaporize.

In order to provide good contact between the gas and the liquid, the tower either has trays or packed with the inert packing.

Solid Desiccant Dehydration [241–246]

In this process, natural gas is passed through a tower, from top to bottom, packed with solid desiccants. Typical desiccants used in the natural gas dehydration include activated alumina, granular silica gel or molecular sieve materials. Solid-desiccant dehydrators are generally more effective than glycol dehydrators since a very low dew point of the processed gas can be obtained. These types of

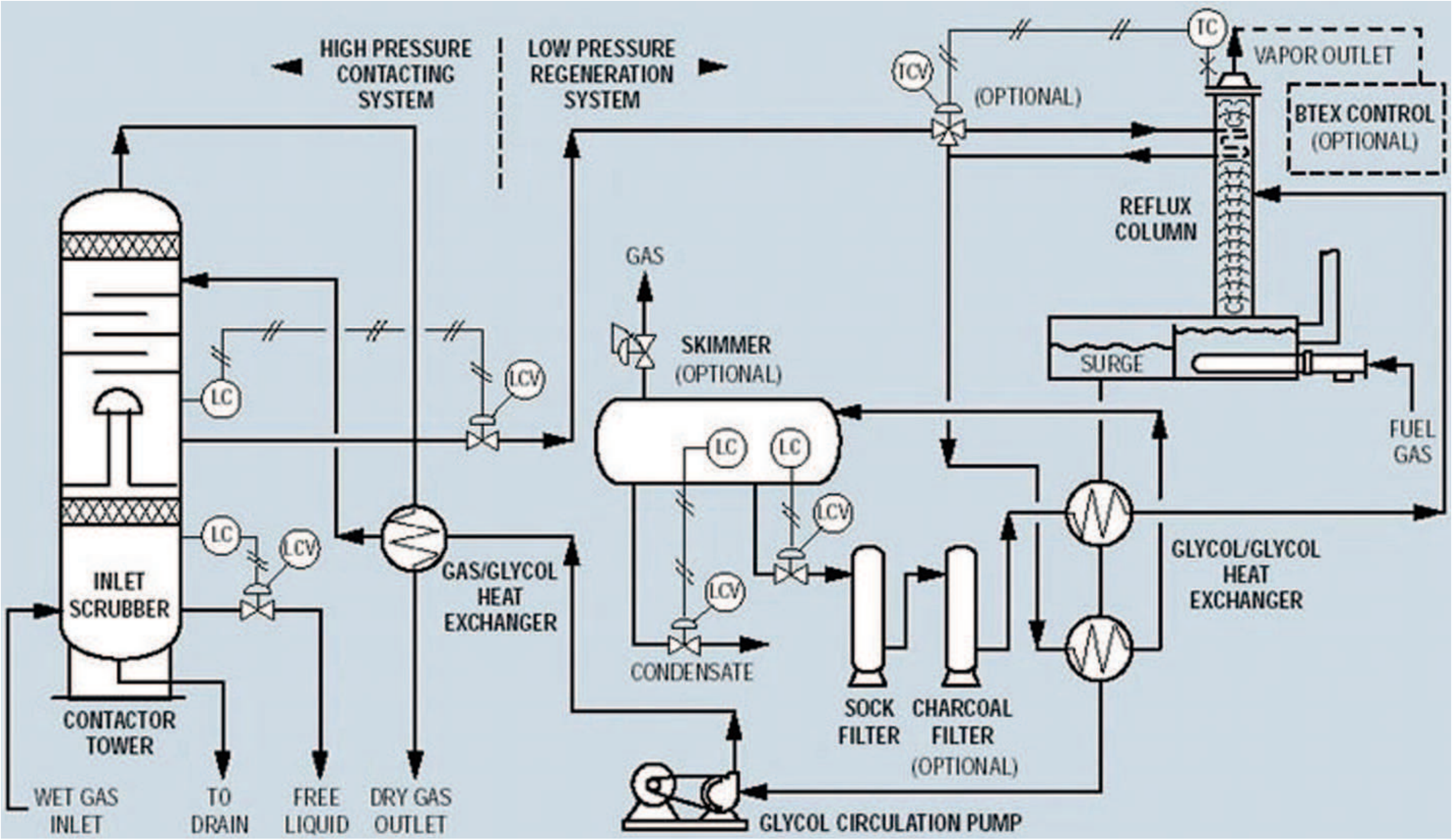


Fig. 7.20. Glycol dehydration system [219].

dehydration systems are best suited for large volumes of gas under very high pressure. They can be used on a pipeline downstream of a compressor station. Generally two or more desiccant beds (towers) are required for continuous operation. After a certain period of time (i.e., after treating certain volume of the natural gas) the bed becomes exhausted. At this point the water content of the treated gas may not meet the required specification, and the gas stream is diverted to the second bed. The exhausted bed needs to be regenerated. To regenerate the desiccant bed, a heated gas, generally air is passed through the desiccant bed removing the water from the desiccant. Following regeneration, the bed is cooled and is ready for the use. A molecular sieve based system developed by UOP is shown in Fig. 7.21.

7.6.4.4 Contaminant and Acid Gas Removal

Hydrogen sulfide (H_2S), CO_2, water vapor, helium, and oxygen present in the natural gas stream must be removed prior to feeding to the pipeline. In the presence of water, CO_2 forms carbonic acid which is corrosive. CO_2 also reduces the BTU value of gas and if the concentration of CO_2 is more than 2–3%, the gas is unmarketable. H_2S is an extremely toxic gas that is also very corrosive to equipment. Amine sweetening processes remove these contaminants so that the gas is marketable and suitable for transportation.

Amine Treatment Process [248–254]

Amine has a natural affinity for both CO_2 and H_2S allowing this to be a very efficient and effective removal process. A number of amine compounds are used for sweetening of the natural gas. Sweetening of natural gas referred to removal of acid gases: H_2S, and CO_2. Each of the amines offers distinct advantages to specific treating problems. These amines are listed below.

MEA (Monoethanolamine)
  Mainly used in low pressure natural gas treatment applications requiring stringent outlet gas specifications.
MDEA (Methyldiethanolamine)
  It has a higher affinity for H_2S than CO_2 which allows some CO_2 “slip” while retaining H_2S removal capabilities.
DEA (Diethanolamine)
  It is used for medium to high pressure treatment facility and does not require reclaiming, as required for MEA and DGA systems.
FORMULATED (SPECIALTY) SOLVENTS
  A variety of blended or specialty solvents are available in the market for removal for H_2S and CO_2.

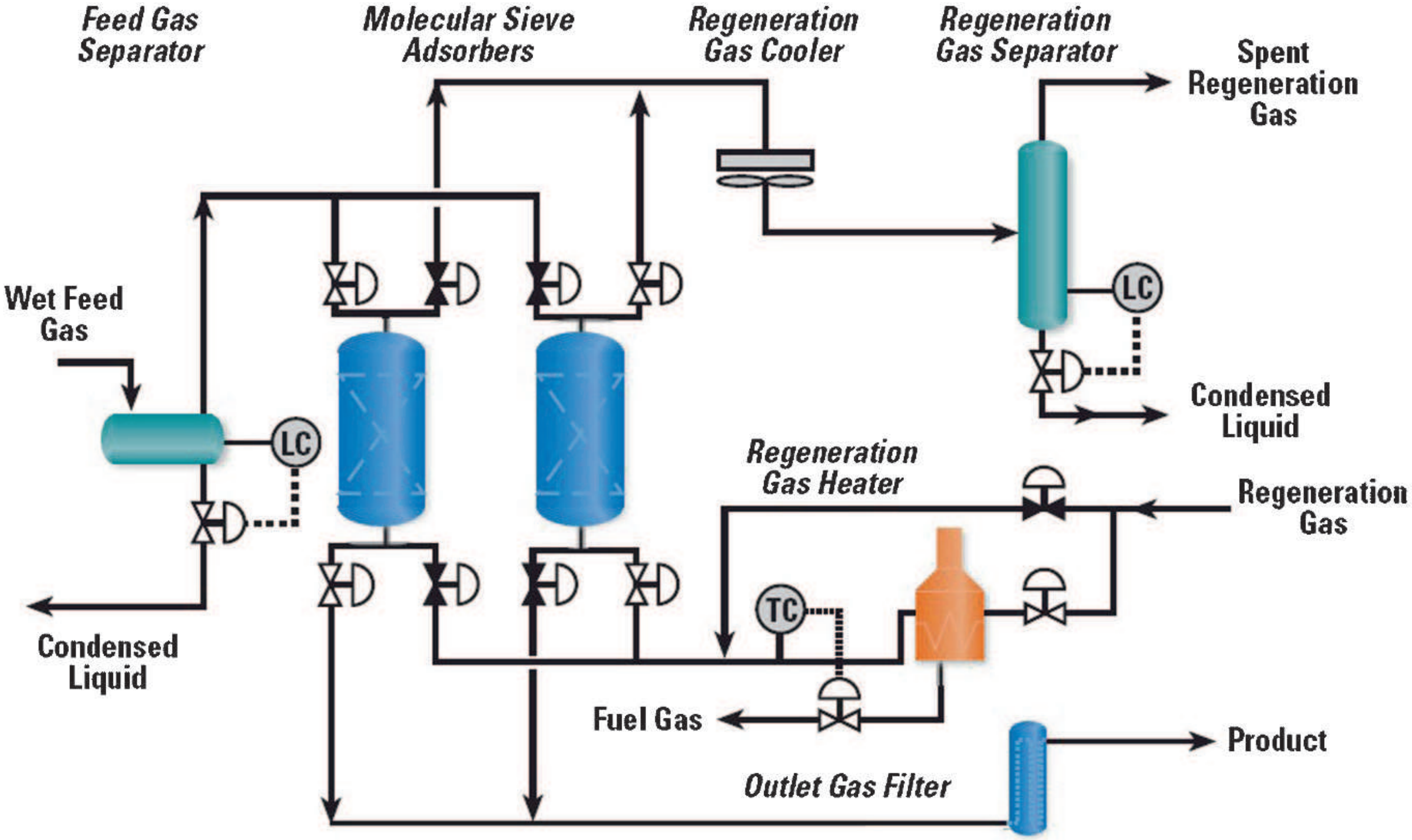


Fig. 7.21. Desiccant based natural gas dehydration system [247].

The reactions of amines with H_2S and CO_2 are summarized below

$2\ RNH_2 + H_2S = (RNH_3)_2S$
$2\ RNH_2 + CO_2 = RNHCOONH_3R$

where:
R = mono, di, or tri-ethanol

The recovered hydrogen sulfide gas stream may be: (1) vented, (2) flared in waste gas flares or modern smokeless flares, (3) incinerated, or (4) utilized for the production of elemental sulfur using the Claus process or sulfuric acid. If the recovered H_2S gas stream is not to be utilized as a feedstock for commercial applications, the gas is usually passed to a tail gas incinerator in which the H_2S is oxidized to SO_2 and is then released to the atmosphere through a stack.

The gas sweetening process is illustrated in Fig. 7.22. Sour gas enters at the bottom of the contactor or absorber tower and the lean amine solution is sprayed from the top. Purified gas flows from the top of the tower. The amine solution containing the absorbed acid gases is now considered rich stream. The lean amine and rich amine flow through the heat exchanger in counter current direction, heating the rich amine. Rich amine is then further heated in the regeneration still column by steam. The steam rising through the still liberates H_2S and CO_2, regenerating the amine. Steam and acid gases separated from the rich amine are condensed and cooled. The condensed water is separated in the reflux accumulator and returned to the still. Hot, regenerated, lean amine is cooled in a solvent aerial cooler and circulated to the contactor tower, completing the cycle.

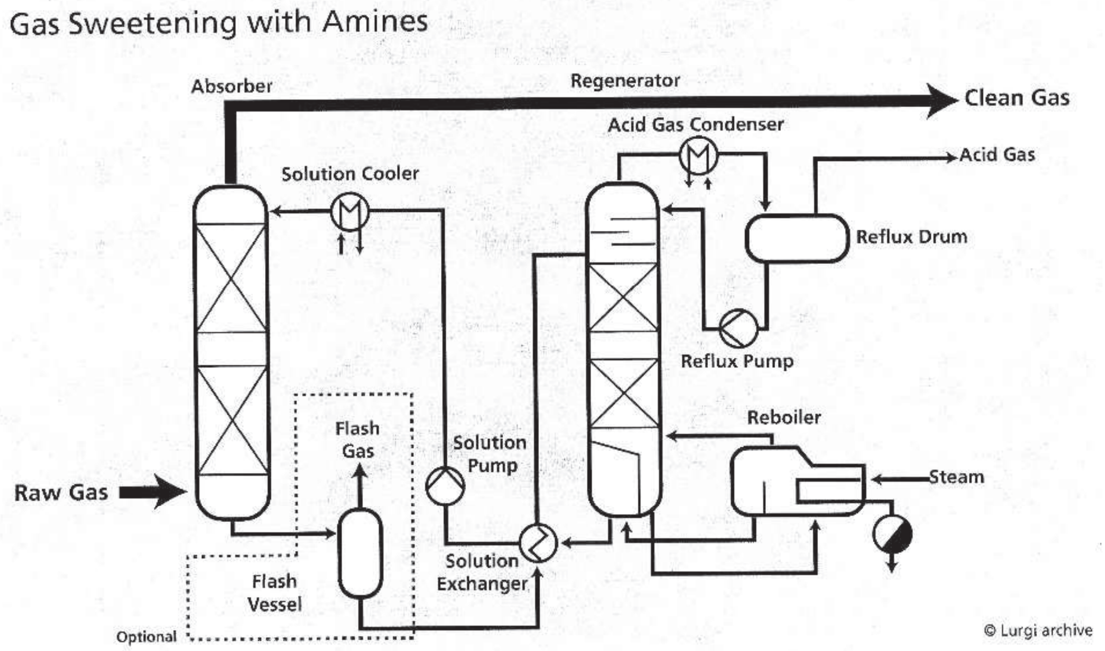


Fig. 7.22. A gas sweetening process flow diagram using amines. (Adapted from Lurgi (1/9/2009) Gas sweetening with amines. www.lurgi.com/website/fileadmin/user_upload/1_PDF/2_Technologie/englisch/10_Aminwaesch en-E.pdf).

7.6.4.5 Nitrogen Extraction

Once hydrogen sulfide and carbon dioxide are removed to the acceptable level, the stream is fed to a Nitrogen Rejection Unit (NRU). The stream could be further dehydrated in a NRU using molecular sieve beds. The nitrogen is cryogenically separated and vented. Another type of NRU unit separates methane and heavier hydrocarbons from nitrogen using an absorbent solvent. The absorbed methane and heavier hydrocarbons are flashed off from the solvent by depressurizing the stream. The liquid from the flash regeneration step is returned to the top of the methane absorber as lean solvent. Helium, if any, can be extracted from the gas stream through membrane diffusion in a Pressure Swing Adsorption (PSA) unit.

7.6.4.6 Natural Gas Liquid Recovery

The NGL can be recovered from the stream using two methods: cryogenic and absorption (non-cryogenic) methods. The absorption and cryogenic expander processes together account for around 90% of total natural gas liquids production.

In the absorption process, extraction is carried out using a lean oil absorption-mechanical refrigeration system. The refrigerated absorption process enhanced the extraction efficiency. Recently, both refrigeration and pre-saturation methods have been developed for further enhancement of the efficiency. The introduction of Joule Thompson valves and turbo expanders in 1960s made significant contributions to the achievement of cryogenic conditions. The use of reflux and the heat integration allowed high NGL recoveries.

7.6.4.7 Oil Absorption Process

In this method, the natural gas is contacted with a lean oil (molecular weight of about 150) in an absorber column at a temperature of about 100°F. An absorbing oil that has high affinity for NGLs is used in the absorption column. The rich oil exiting the bottom of the absorber flows into a rich oil depropanizer which separates the propane and lighter components and returns them to the gas stream. The rich oil is then fractionated in a column, where the NGL's (C_4+) are recovered as an overhead product and the lean oil is recycled to the absorber column. This process allows for the recovery of around 75% of butanes, and 85 – 90% of pentanes and heavier molecules from the natural gas stream. A schematic flow diagram of the system is shown in Fig. 7.23.

Extraction of NGL can be enhanced by using refrigerated low molecular weight oil. The typical temperature with propane refrigerant is about –42°C. A lean oil having molecular weight in the range of 100–110 is generally used in this process. In the refrigerated oil absorption method, total recovery can be more than 90%, and ethane extraction can be around 40%. Extraction of the other, heavier NGLs can be close to 100% using this process. A typical flow diagram of the process is shown in Fig. 7.24.

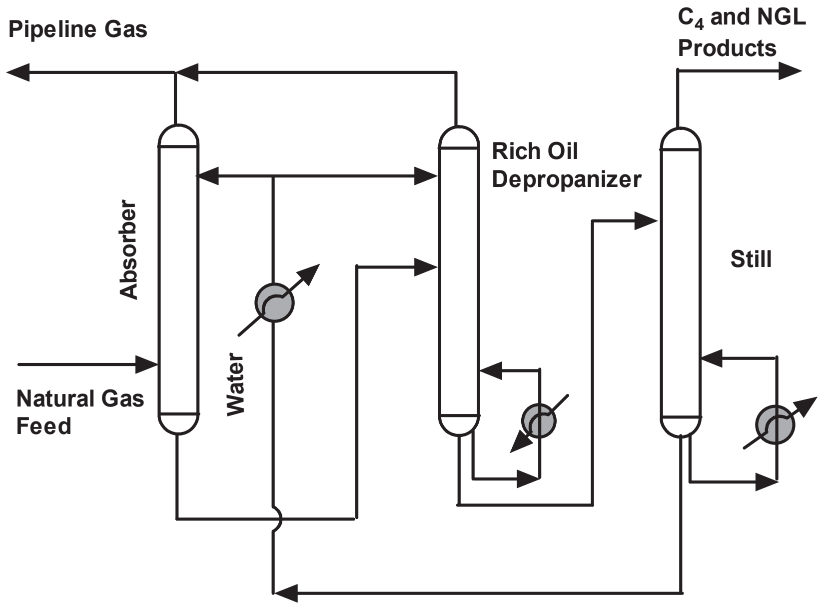


Fig. 7.23. Recovery of NGL using oil absorption method. (Printed with permission from Mehra YR (2004) Market driven evolution of gas processing technologies for NGLs. Advanced Extraction Technologies. http://www.aet.com/gtip1.htm [255]).

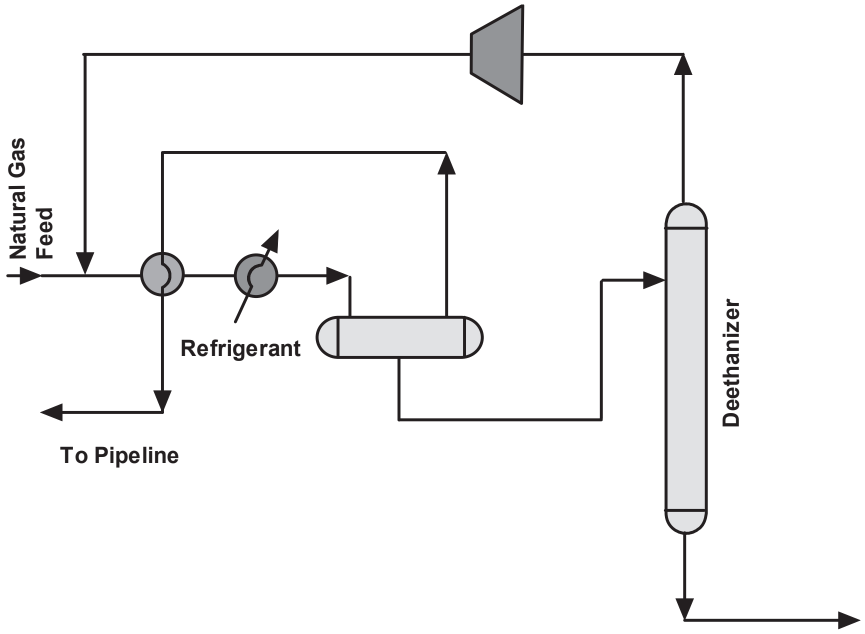


Fig. 7.24. A schematic diagram of a process for enhancement of NGL recovery using refrigeration process. (Printed with permission from Mehra YR (2004) Market driven evolution of gas processing technologies for NGLs. Advanced Extraction Technologies. http://www.aet.com/gtip1.htm [255]).

A number of refrigeration processes have been developed to further lower the temperature. These methods include Cascade Refrigeration Process, Joule Thompson (JT) Expansion Process, and Turbo Expansion Process. Also, several proprietary NGL extraction processes are available in the market. The extraction efficiency was enhanced using various extraction schemes such as lean column reflux and maximum heat integration. The integration between the natural gas recovery process and liquefaction process is possible while maintaining high efficiencies for both the processes.

7.6.4.8 Fractionation

The recovered NGL is further separated into different fractions to increase their product value. The process is called fractionation. The process occurs in stages and in a number of columns connected in series. The liquid feed is heated and fed to a deethanizer. This step separates the ethane from the NGL stream. In the next step, propane is separated in the depropanizer. The Debutanizer is the next step of the process. This step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream. Finally, a Butane Splitter or deisobutanizer is used to separate iso- and normal- butanes.

7.6.5 Natural Gas Transport

Natural gas is transported and delivered to the consumer from the production facilities mainly through a complex net work of pipelines. There are essentially three major types of pipelines along the transportation route: the gathering system, the interstate pipeline, and the distribution system. The gathering system consists of low pressure, low diameter pipelines that transport raw natural gas from the wellhead to the processing plant. Pipelines can be characterized as interstate or intrastate. Interstate pipelines carry natural gas across state boundaries, in some cases across the country. Intrastate pipelines, on the other hand, transport natural gas within a particular state. Natural gas pipelines are subject to regulatory oversight, which in many ways determines the manner in which pipeline companies must operate. The USA natural gas pipeline grid includes more than 210 mainline natural gas pipeline systems. In 2005,109 were classified as interstate systems by the Federal Energy Regulatory Commission (FERC). The remaining 101 were intrastate natural gas pipeline systems, whose operations are confined to a single State. The combined natural gas pipeline capacity on mainline intrastate systems is about 33 Bcf/d.

Interstate natural gas pipeline systems account for more than 148 Bcf/d of total USA natural gas transportation capacity and approximately 213,000 miles of pipeline. Furthermore, the top 30 interstate natural gas pipeline companies alone account for more than 78%, or about 115 Bcf/d of the interstate natural gas pipeline capacity [256]. The network of the pipelines in the USA is shown in Fig. 7.25.

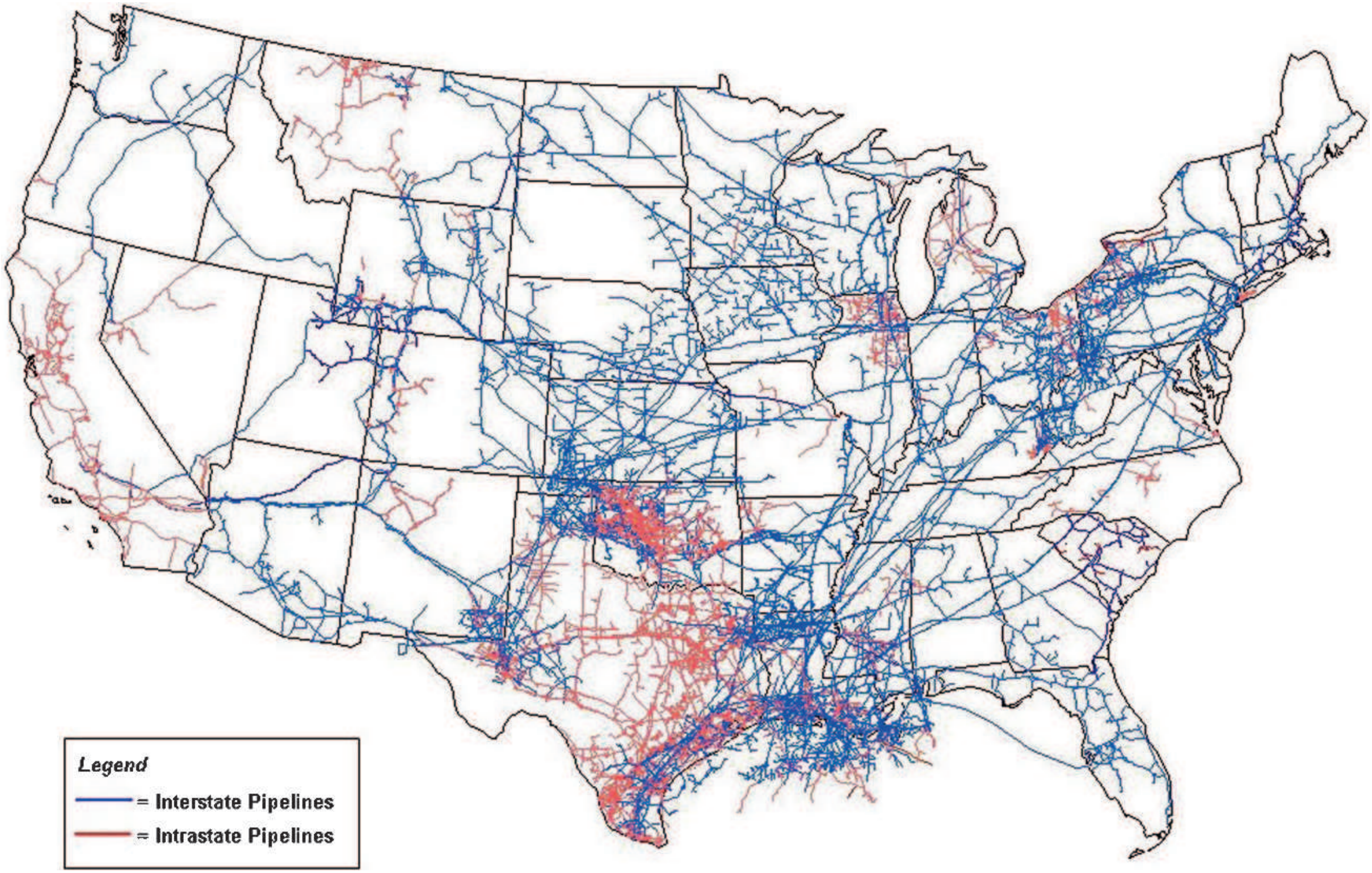


Fig. 7.25. Natural gas pipeline network for distribution of natural gas in the USA. (Adapted from Energy Information Administration, USA).

As can be seen from Fig. 7.26, the pipeline capacity remained more or less stagnant in the USA for the last several years. However, a major expansion is planned over the next several years. The increased capacity will require addition of physical pipeline to the network. The planned addition of pipeline mileage is shown in Fig. 7.27.

The natural gas pipeline network runs through several regions and also the capacity depends on the demand of the particular region. Fig. 7.28 shows the capacity of natural gas pipeline in various regions.

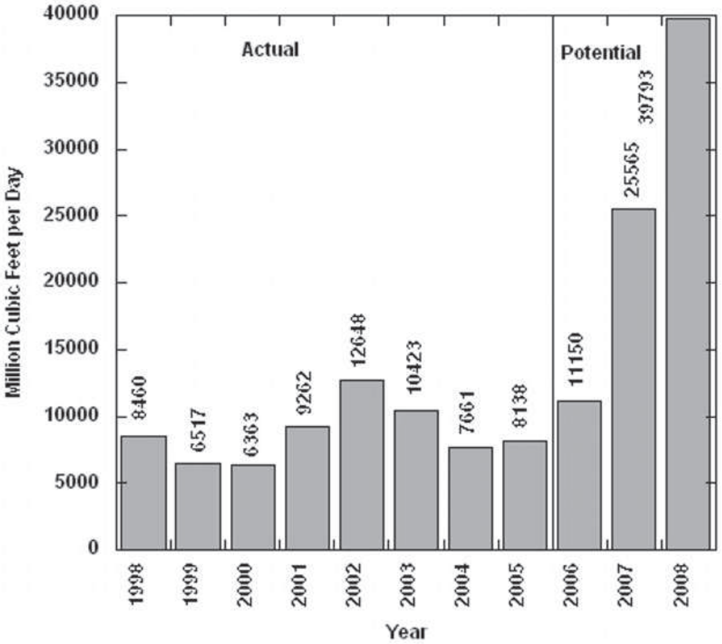


Fig. 7.26. The capacity of the pipeline and expected expansion in the USA for transportation of natural gas.

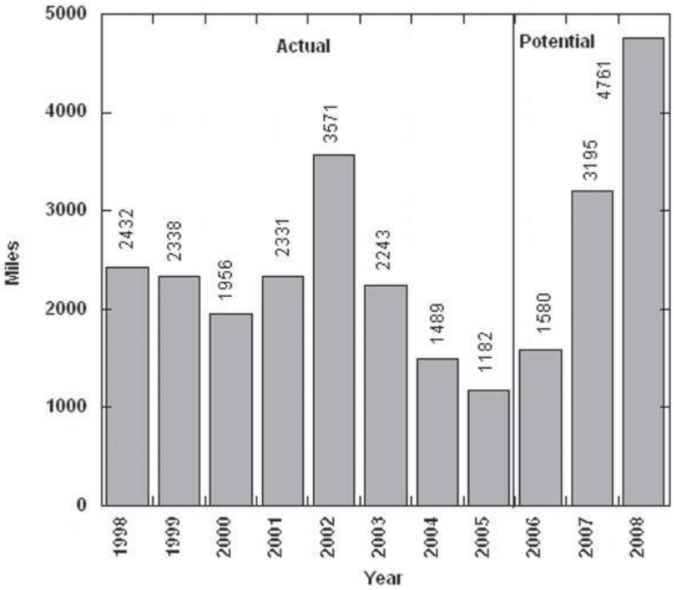


Fig. 7.27. Addition to natural gas pipeline mileage in the USA. (Source: Energy Information Administration, GasTran natural gas transportation information system, Natural gas pipeline projects database).

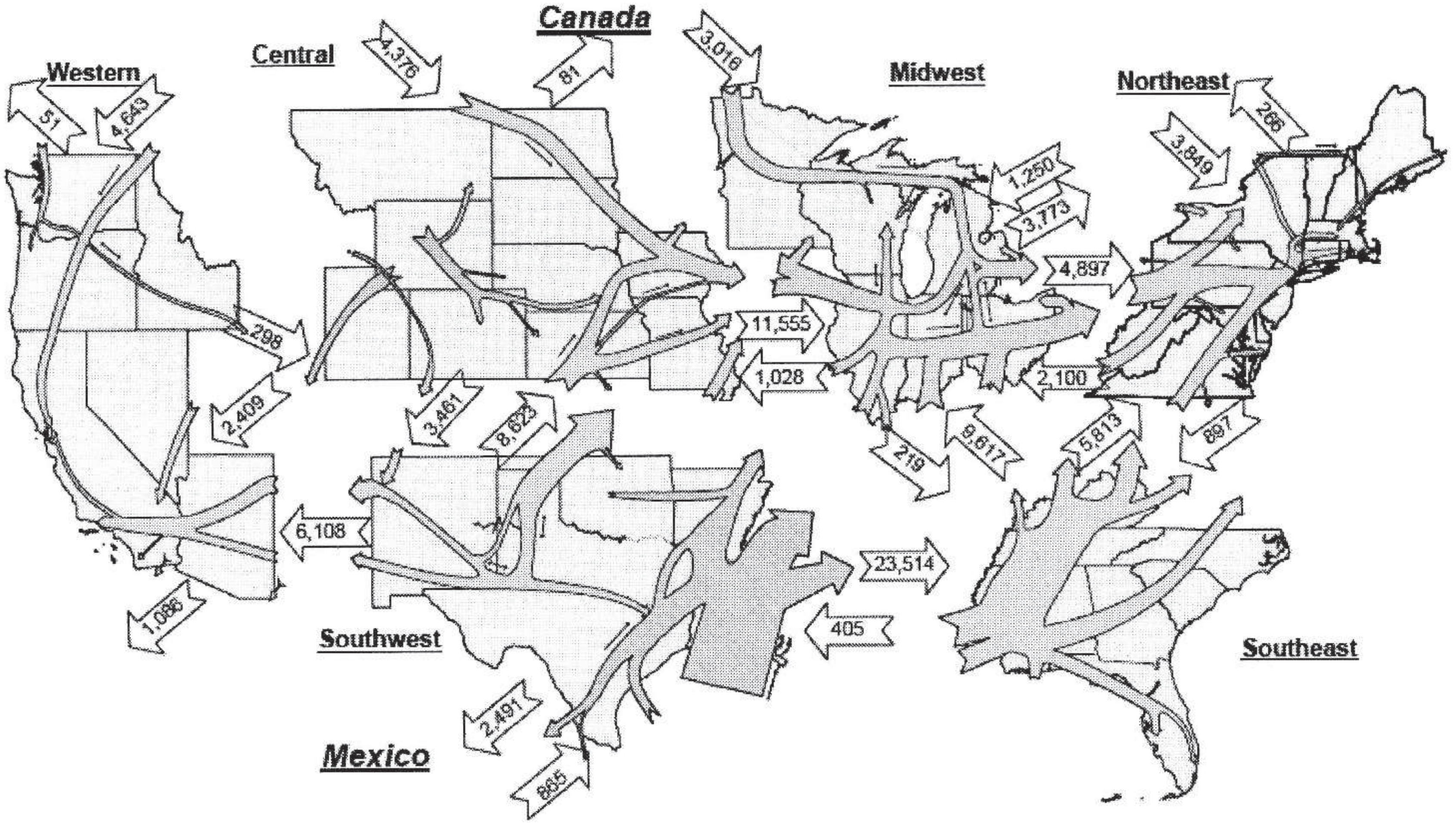


Fig. 7.28. Capacity of natural gas transportation in the North America. (Adapted from Energy Information Administration, USA).

7.6.5.1 International Transportation of Natural Gas

Natural gas is becoming a major energy source through out the world. However, a majority of countries sell their known resources. As a result, the international transportation of natural gas through pipelines is becoming a major method for trading natural gas. In Europe, Russia is the major exporter of natural gas. The pipelines that exists or being planned in Europe for transportation of natural gas are shown in Fig. 7.29. Figure 7.30 shows the pipeline in various parts of Europe. Recently, Europe is planning to transport natural gas from the Fareast through Turkey. The proposed pipeline is shown in Fig. 7.31. Various international pipelines that are under construction or proposed are given in Table 7.20.

Table 7.20. International pipeline under construction or proposed.

Company name	Project name and location	Length (miles)	Cost ($ US million)	In service date
AFRICA				
NNPC/Sonatrach	TransSaharan Gas Ppeline No. Africa-Ben Saf-Almeria, Spain	2,772	$6 billion	Feasibility
Saipem (Shell Dev)	Niger Delta	214	$420	2008
ASIA PACIFIC				
Western Australian Gov Continental Gas Pipeline. Trans	Trans Continental Gas Pipeline Offshore Australia to Hobart	1,827	$3 billion	Feasibility
China National Petroleum Corp.	Xingang Province to Guangzhou,	N/A	N/A	Feasibility
Dampier Bunbury Pipeline Co.	Dampier Bunbury Pipeline expansion	122	$430	2009
PT Perusahaan Gas Negara (PGN)	South to North Samatra	328	$574	2008
	Kepodang-Tambak Lorok	130	$105	
	Sengkang-Makassar Indonesia	173	$110	
	East Java-West, Java	442		2010
	E. Kalamantan to C. Java	768		2010

Company name	**Project name and location**	**Length (miles)**	**Cost ($ US million)**	**In service date**
PT Perusahaan Gas Negara (PGN)	E. Kalamantan to Central Java	434	$1.6 billion	2007–2008
Soopec	Sichuan Province China	1,008	$4.7 billion	2008
Gas Authority of India	Dahej-Uran Pipeline	310	$330	2007–2009
FSU-EASTERN EUROPE				
Botas, D.E.P.A. & Edison Gas	IGI Pipe line Greece to Italy	504	N/A	2010
FSI Energy	KoRus Sakhalin Pipeline Russia	1,575	$3 billion	N/A
Governments of Hungary/ Croatia	Adriatic Coastto Hungary	214	N/A	Feasibility
KazMunaiGaz	Kazakhstan to china	1,890	N/A	2010
Nabucco Gas Pipeline Int'l. Ltd	Nabucco Pipeline Turkey to Austria	2142	N/A	2011
Starstroi (Sakhalin Energy)	Sakhalin II pipeline	504	N/A	2008
MIDDLE EAST				
Abu Dhabi Gas Industries Co(GASCO)	Habshan–Bu Hasa Pipeline UAE	32	$35	N/A
National Iranian Oil Co	Iran-Pakistan- India Pipeline	1,735	$4 billion	2010
AMEC SPIE Capag	Yemen Gas Pipeline	202	$200	2008
Qatar/ Pakistan*	Gulf South Asia Pipeline Qatar to Pakistan	1,021	$2.7 billion	N/A
WESTERN EUROPE & EU COUNTRIES				
Gassco*	Norway to Sweden	N/A	$1.3 billion	2008

Source: Reference [257].

The exports and imports of natural gas by various countries are given in Appendix VII.

Fig. 7.29. Proposed pipeline for transportation of natural gas. (Adapted from Energy Information Administration, USA, Natural Gas, Russia).

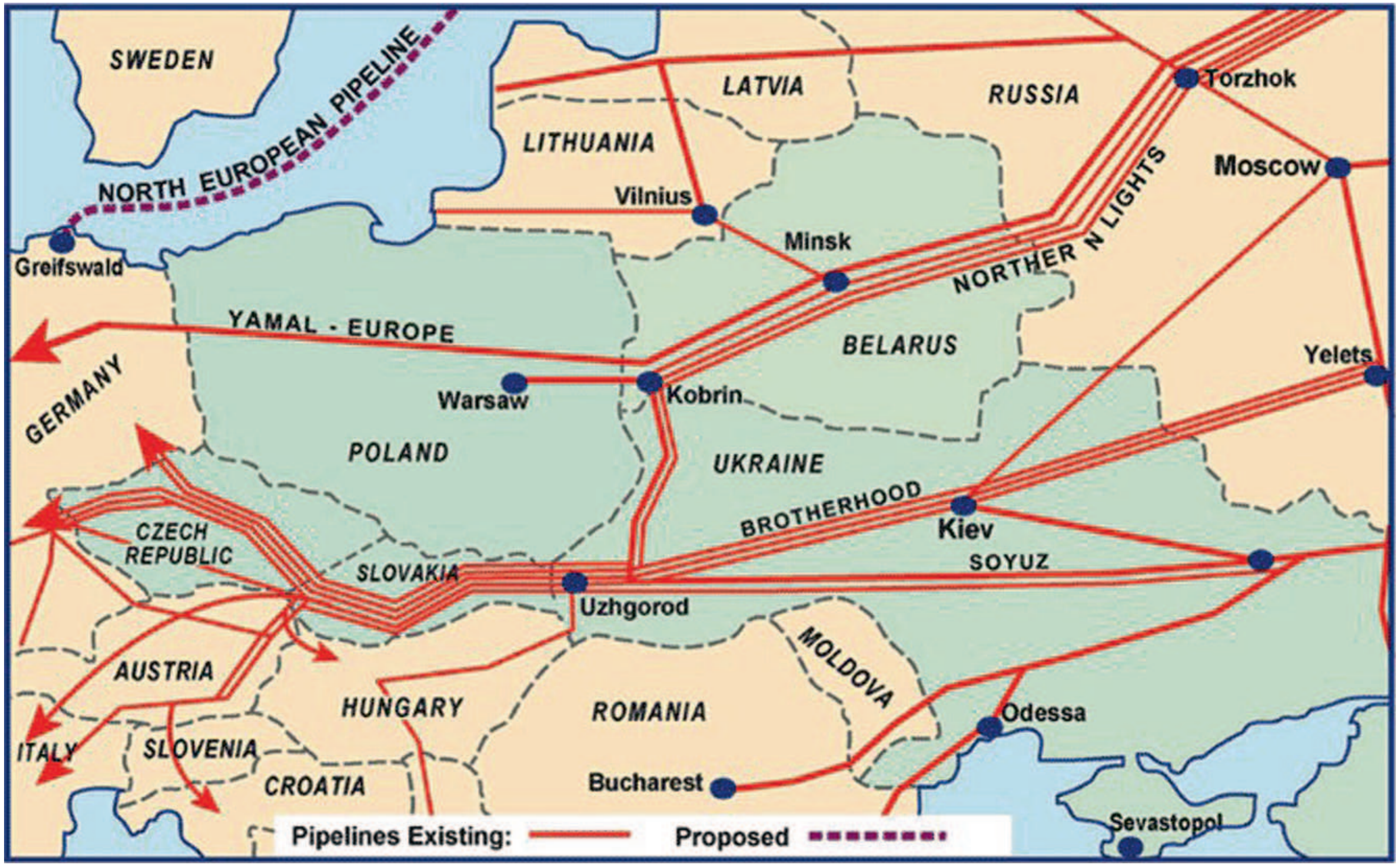


Fig. 7.30. Natural gas pipeline in Europe. (Adapted from Energy Information Administration, USA).

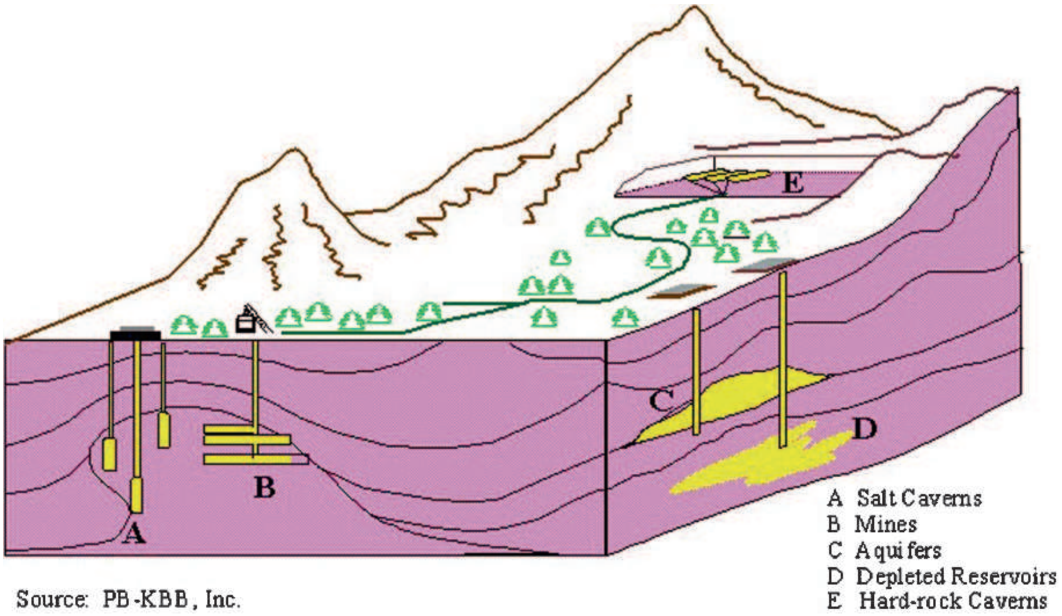
Fig. 7.31. Proposed pipeline through Turkey. (Adapted from Energy Information Administration, USA).

7.6.6 Storage of Natural Gas

Natural gas storage facilities serve two purposes: they provide both the base load requirements and meet the peak load requirements. In order to ensure long term steady and reliable supply of natural gas, it is stored underground. There are three main types of underground storage facilities [258–266]:

- Depleted gas reservoirs
- Aquifers
- Salt caverns

However, mines and hard rock caverns are also considered for storage. These methods are shown in Fig. 7.32.



Source: PB-KBB, Inc.

Fig. 7.32. Methods for storage of natural gas [267].

7.6.6.1 Depleted Gas Reservoirs

These are original underground formation basins for natural gas. Once they are depleted, these formations are used for holding or storage of natural gas. Since the extraction network is already in place, the cost of converting a depleted reservoir into a storage facility is very economical. Depleted reservoirs are attractive because their geological characteristics are already well known and a history exists regarding their operation and maintenance.

7.6.6.2 Aquifers

These are underground porous, permeable rock formations that are natural water reservoirs. These formations are reconditioned and used as natural gas storage facilities. However, these aquifers need to be characterized fully, particularly their composition and porosity before reconditioning. Once an aquifer is selected for gas storage, various infrastructures, including extraction equipment, pipelines, dehydration facilities, and compression equipment must be installed. Because of these requirements, aquifers are the least desirable and most expensive type of natural gas storage facility.

7.6.6.3 Salt Caverns

Underground salt formations are another medium for natural gas storage. Salt caverns are highly non-porous and therefore loss of injected natural gas is minimal. The salt cavern storage facilities are typically located between 1,500 and 6,000 ft beneath the surface.

Base load facilities are capable of holding enough natural gas to satisfy long term seasonal demand requirements. Depleted gas reservoirs are the most common type of base load storage facility. These reservoirs are larger; however the amount of natural gas that can be used from them each day is limited. The main objective is to provide steady supply of natural gas.

Table 7.21. Underground storage.

	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Total storage capacity	8,240,886	8,415,326	8,207,074	8,205,716	8,255,042	8,268,443
Salt caverns	189,043	218,483	225,958	234,601	239,990	250,532
Aquifers	1,263,711	1,195,141	1,234,007	1,237,132	1,238,158	1,350,689
Depleted fields	6,788,130	7,001,700	6,747,108	6,733,983	6,776,894	6,667,222
Total number of active fields	413	418	407	391	393	394
Salt caverns	28	28	29	30	30	30
Aquifers	49	39	38	43	43	44
Depleted fields	336	351	340	318	320	320

Source: Energy Information Administration, Underground natural gas storage capacity.

Peak load storage facilities, on the other hand, are designed to have high-deliverability for short periods of time. Peak load facilities are intended to meet sudden, short-term demand increases. Salt caverns are the most common type of peak load storage facility, although aquifers may be used to meet these demands as well.

Storage facilities in the USA can be found almost in all the states, but they are most concentrated in the consuming north east region of the country. The underground storage capacity by facility types are listed in Table 7.21. The distribution of these facilities in various states are given in Fig. 7.33.

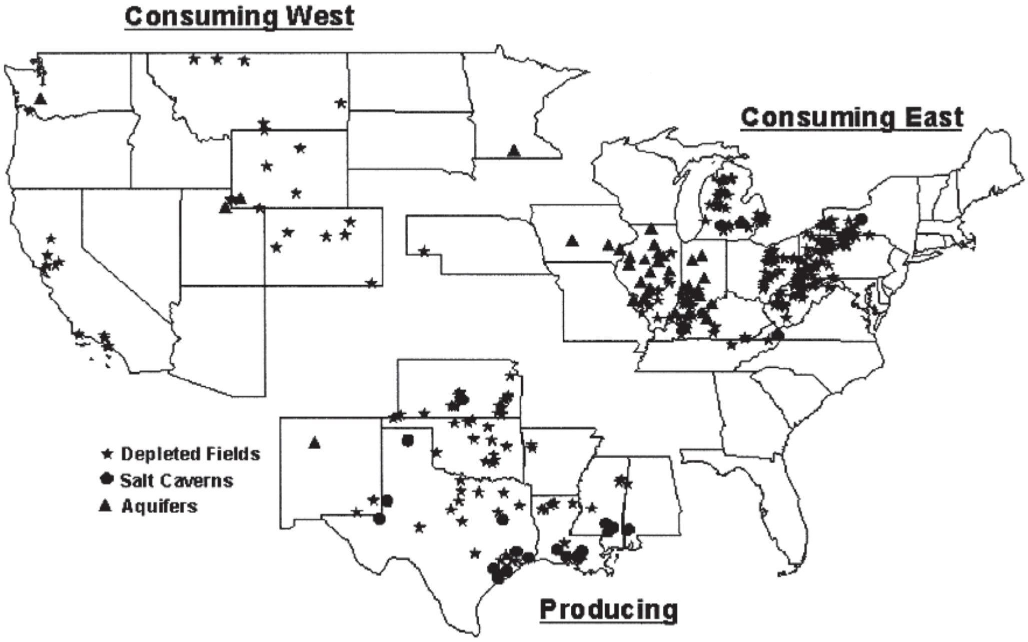


Fig. 7.33. Underground natural gas storage facilities in the lower 48 states. (Source: Energy Information Administration (2004) Gas tran geographic information system Underground Storage Database).

The natural gas is delivered to the consumer from the storage facility rather than from the gas processing plant directly. The natural gas is injected into the underground storage facility to maintain what is known as 'base gas' or 'cushion gas'. This is the volume of gas that must remain in the storage facility to provide the required pressurization to extract the remaining gas. The remaining of the gas may be called the working gas capacity. Working gas is the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility. This is the natural gas that is being stored and withdrawn; the capacity of storage facilities normally refers to their working gas capacity. Periodically, underground storage facility operators may reclassify portions of working gas as base gas after evaluating the operation of their facilities. The working gas capacity by storage facility is shown in Fig. 7.34. However, as can be seen from Fig. 7.35, for daily use salt cavern and aquifers are used more than depleted reservoirs.

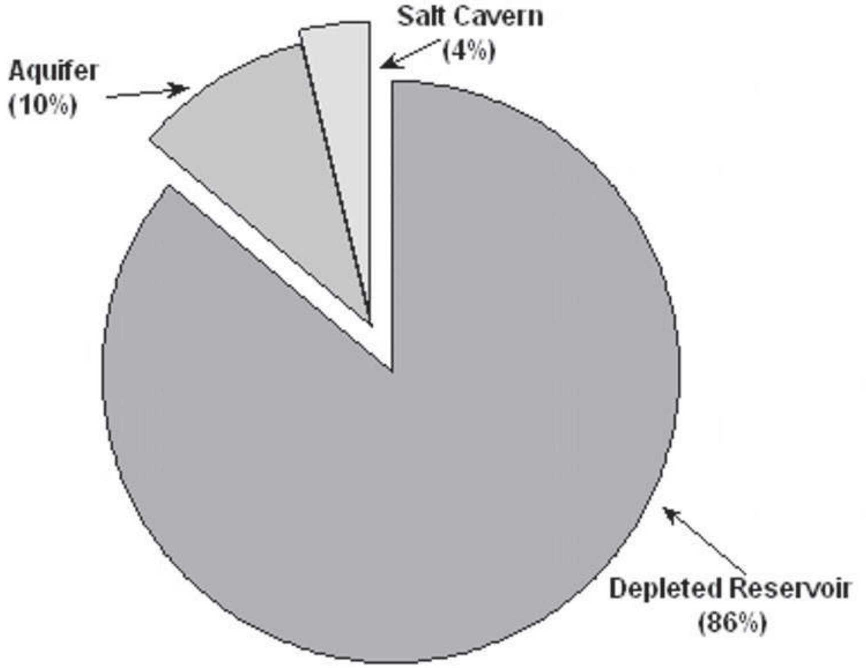


Fig. 7.34. Working gas capacity in the USA Source: Working gas capacity by type of storage. (Source: Energy Information Administration, Natural Gas Storage in the USA, 2001).

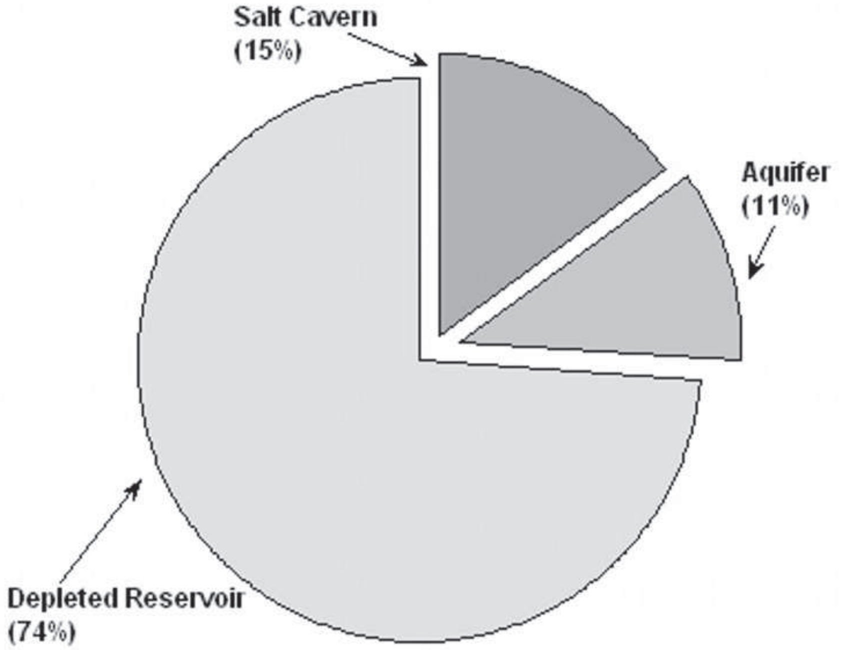


Fig. 7.35. Daily deliverability by type of storage. (Source: Energy Information Administration, Natural Gas Storage in the USA, 2001).

7.6.7 Distribution

Natural gas from intrastate pipeline is delivered to local distribution companies, which is called citigates. The pricing of natural gas is generally determined at this point. The price breakdown is shown in Fig. 7.36. Typically, local distribution companies take ownership of the natural gas at the citygate, and deliver it to each individual customer's location of use. This requires an extensive network of small-diameter distribution pipe.

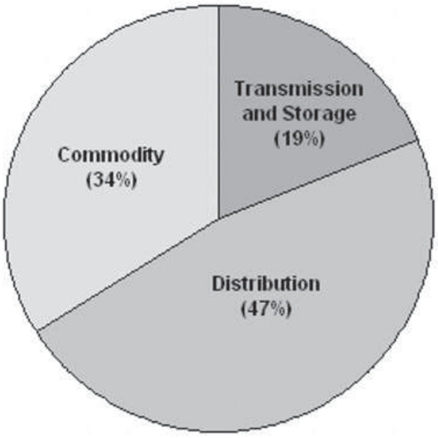


Fig. 7.36. Component of natural gas price. (Source: Energy Information Administration).

Traditionally, local distribution companies have been awarded exclusive rights to distribute natural gas in a specified geographic area. They are also responsible for billing, safety inspection, and providing natural gas hookups for new customers. Local distribution companies must maintain the highest safety standards and are responsible for fixing problems with the distribution network. Some of the safety features that local distribution companies must provide include:

- Leak detection equipment
- Safety education programs
- Technicians on call
- Emergency preparedness
- One call systems

7.6.8 Natural Gas Use

Natural gas provides almost 24% of the total energy need in the USA, which is second to petroleum (39%). Fig. 7.37 shows the contribution of natural gas to the total energy need of the USA.

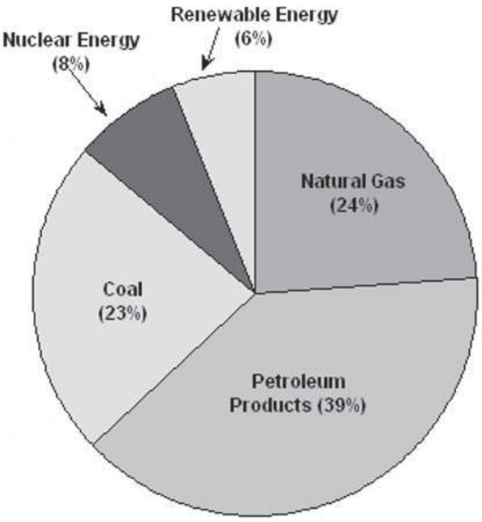


Fig. 7.37. Natural Gas use compare to other energy use. (Source: Energy Information Administration. Annual Energy Outlook 2007).

Natural gas is used basically by all sectors. Fig. 7.38 gives an idea of the proportion of natural gas use per sector. Although the industrial sector uses the greatest proportion of natural gas in the United States, the residential sector and electric power generation using natural gas follow very closely.

The uses of natural gas may be divided into the following categories:

1. Residential uses
2. Commercial uses
3. Industrial uses
4. Natural gas use for vehicles
5. Electricity generation

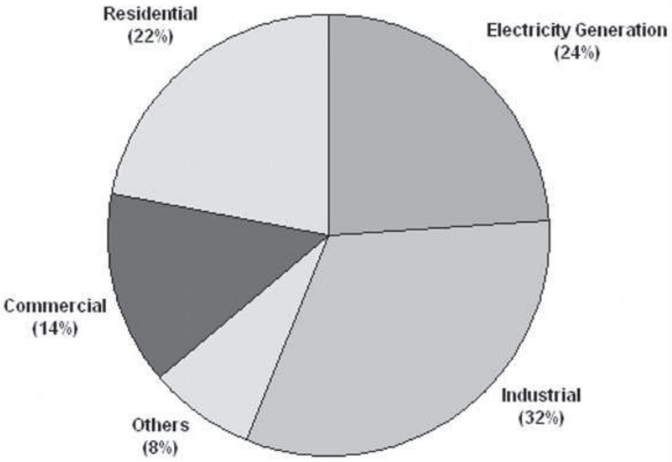


Fig. 7.38. Natural gas use by various sectors in the USA. (Source: Energy Information Administration. Annual Energy Outlook 2007).

7.6.8.1 Residential Uses

One of the main reasons for the wide spread use of natural gas in the residential sector is its cost compared to other sources (Fig. 7.39). The best known uses for natural gas around the home are for heating and cooking. According to the American Gas Association, in 2000, about 51% of homes in the USA (or 49.1 million households) used natural gas for heating. Also a high proportion of new homes are being built with natural gas heating. A report in 2003 by the U.S. Census Bureau on new housing indicated that 70% of single family homes completed in 2003 used natural gas for heating, followed by 27% that used electric heat, and 2% used heating oil. The new generations of natural gas ranges are efficient, economical, and versatile. In addition to heating homes, natural gas can also be used to help cool houses, through natural gas powered air conditioning. Other examples of natural gas appliances include space heaters, clothes dryers, pool and jacuzzi heaters, fireplaces, barbecues, garage heaters, and outdoor lights. All of these appliances offer a safe, efficient, and economical alternative to electricity or other fuel.

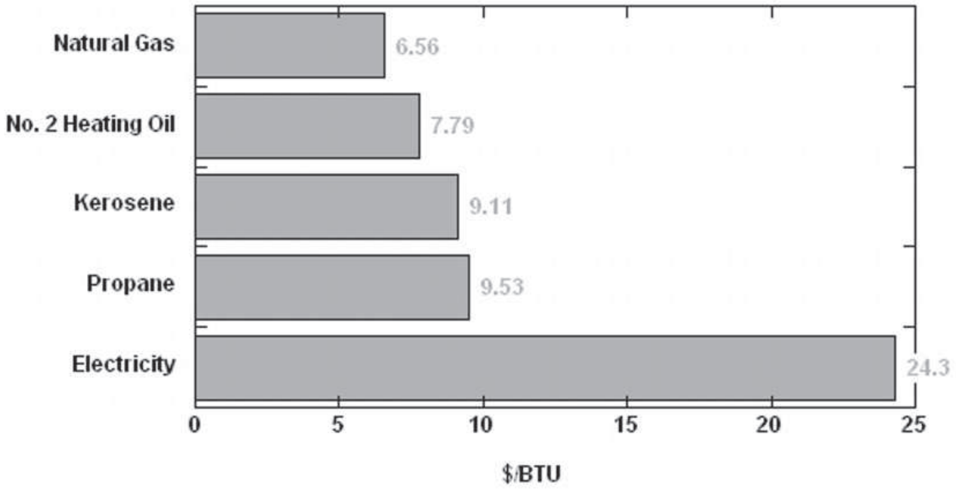


Fig. 7.39. Cost of various energy sources used by residential sector. (Source: US Department of Energy).

7.6.8.2 Commercial Uses

Commercial uses of natural gas are very similar to residential uses. The commercial sector that includes public and private facilities, such as office buildings, schools, churches, hotels, restaurants, and government buildings use significant amount of natural gas. The main uses of natural gas in this sector include space heating, cooking, water heating, and cooling. The percentage usage of various sectors is shown in Fig. 7.40.

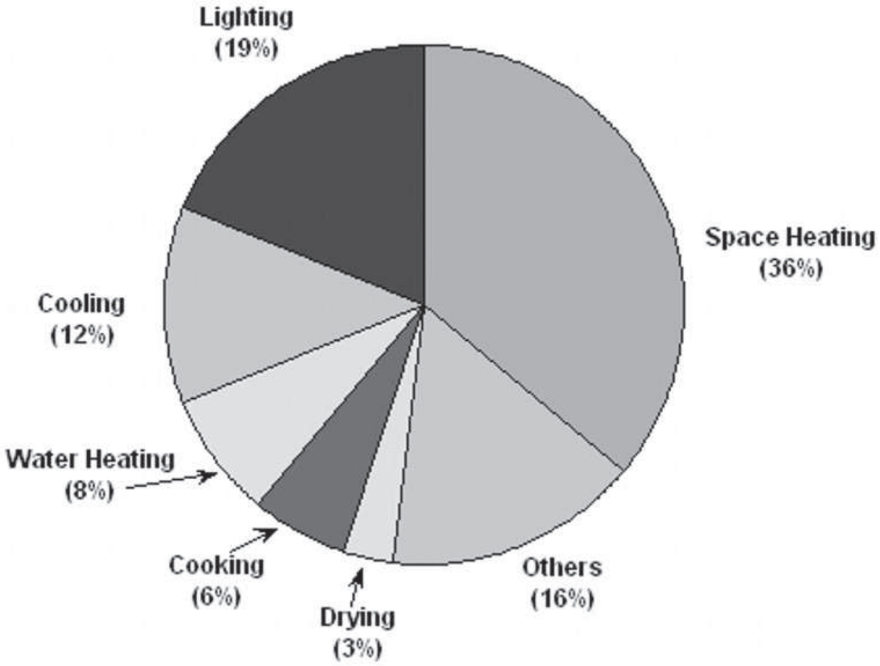


Fig. 7.40. Commercial use of natural gas. (Source: Washington Policy and Analysis, Inc., Fueling the Future 2000).

Natural gas based cooling systems are becoming more popular because of their energy efficiency and also some systems have the capability to enhance indoor air quality. There are three types of natural gas based cooling processes. Engine driven chillers use a natural gas engine and waste heat from the gas engine can be used for heating applications, increasing energy efficiency. The second system is called absorption chillers, which provide cool air by evaporating a refrigerant like water or ammonia. The heat is provided by using natural gas. These absorption chillers are best suited to cooling large commercial buildings, like office towers and shopping malls. The third type of commercial cooling system consists of gas-based desiccant systems. In this system, a desiccant first removes water vapor from the humid air. The humidity of the dry air is then adjusted by spraying water vapor into the stream. The exhausted desiccants are regenerated by using the natural gas. The desiccant can co-adsorb various indoor pollutants along with water vapor, thus enhancing the indoor air quality.

Recently combined heating and power (CHP) or combined cooling, heating and power (CCHP) systems are found to be more energy efficient than the single unit. The energy savings come from the heat that is released from natural gas powered electricity generators. The heat can be harnessed to run space or water heaters, or commercial boilers.

7.6.8.3 Industrial Use

Industry uses energy from various sources, but they are the largest consumer of natural gas, accounting for almost 43% of the total natural gas use (see Fig. 7.41). The graph below shows current as well as projected energy consumption by fuel in the industrial sector.

Natural gas is consumed primarily in the pulp and paper, metals, chemicals, petroleum refining, stone, clay and glass, plastic, and food processing industries. These businesses account for over 84% of all industrial natural gas use. Natural gas is also used for waste treatment and incineration, metals preheating (particularly for iron and steel), drying and dehumidification, glass melting, food processing, and fueling industrial boilers. Other industrial applications of natural gas include infrared heating, direct contact water heating, industrial combined heat and power, and industrial co-firing.

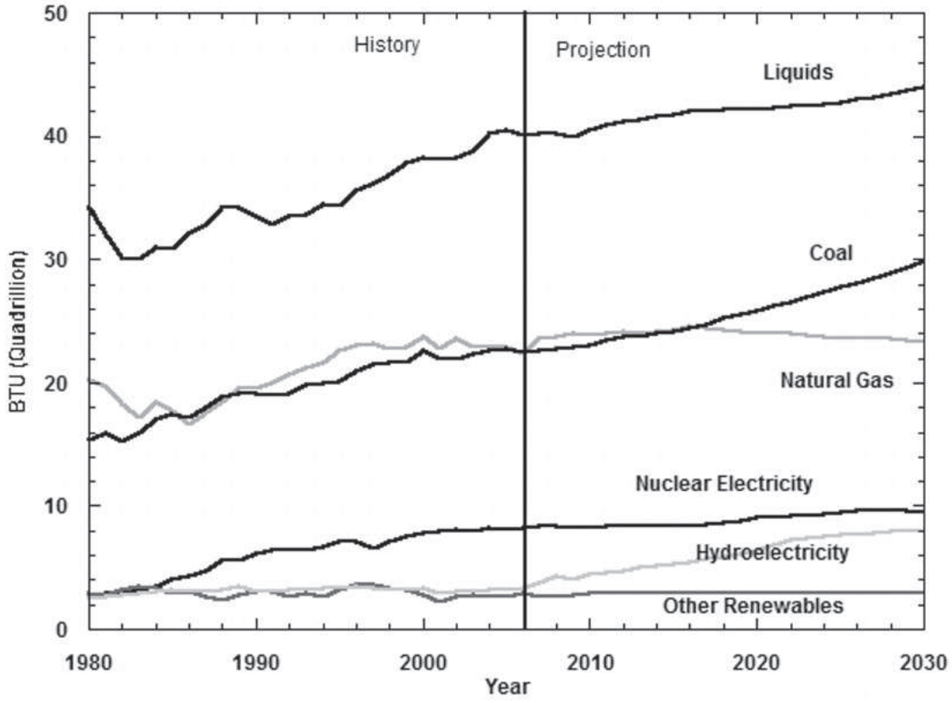


Fig. 7.41. Current and projected use of various energy sources including natural gas by industries. (Source: Energy Information Administration. Annual Energy Outlook 2007 with Projections to 2030).

7.6.8.4 Natural Gas Vehicles [268–272]

According to the Natural Gas Vehicle Coalition, there are currently 130,000 Natural Gas Vehicles (NGVs) on the road in the United States, and more than 2.5 million NGVs worldwide. In fact, the transportation sector accounts for 3% of all natural gas used in the United States. All types of vehicles including passenger cars, trucks, buses, vans, and heavy-duty utility vehicles have been designed and produced to run using natural gas. Despite various advances, a number of disadvantages of natural gas vehicles prevent their mass-production. Limited range, trunk space, higher initial cost, and lack of refueling infrastructure pose impediments to the future spread of natural gas vehicles.

7.6.8.5 Electricity Generation

In 2000, 23,453 MW of new electric capacity was added in the U.S. Of this, almost 95%, or 22,238 MW was generated using natural gas (see Fig. 7.42).

A number of new facilities are 'combined-cycle' units. Both a gas turbine and a steam turbine are used for power generation. The hot gases released from burning natural gas turn a gas turbine and generate electricity. In combined-cycle plants, the waste heat from the gas-turbine is used for generating steam, which is then used to generate electricity using a steam turbine. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants can achieve 50–60% thermal efficiencies.

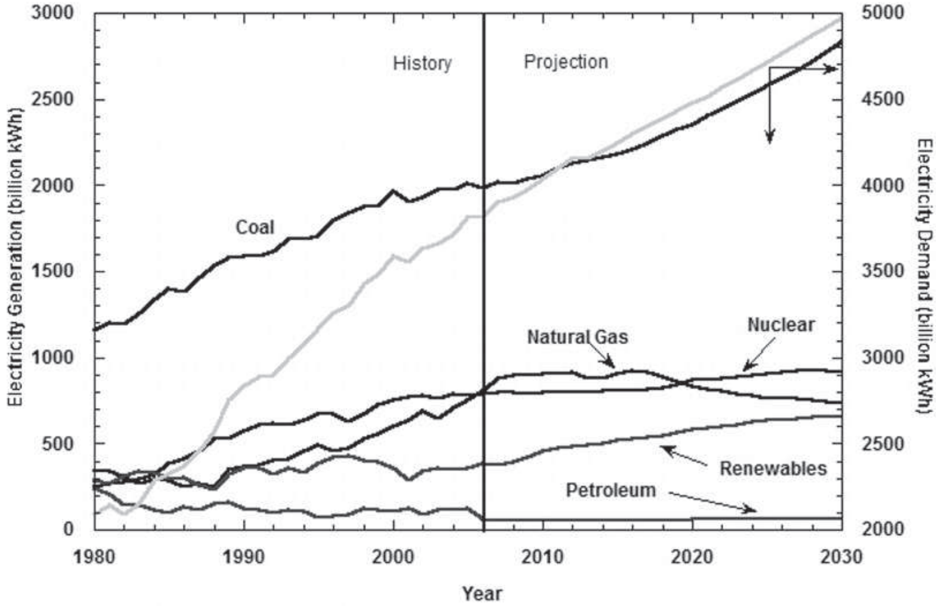


Fig. 7.42. Use of natural gas in electricity generation. (Source: Energy Information Administration. Annual Energy Outlook 2007 with Projections to 2030).

7.6.8.6 Natural Gas Use for Fertilizer Production

About 5–6% of natural gas produced in the world is used for fertilizer production. Most of natural gas is used as feedstock in the production of ammonia, which is next used for production of various nitrogen-fertilizers. There is at present no economic alternative to natural gas as a feedstock. As can be seen from Table 7.22, the cost of using other resources for fertilizer production is significantly higher than natural gas.

Methane (CH_4) in the natural gas is dissociated to produce hydrogen, which is then reacted with nitrogen over a catalyst to produce ammonia (NH_3). Natural gas must be free from any sulfur compounds. If sulfur compounds remain in the natural gas stream, they can poison the catalysts that are used in the remaining steps. Sulfur compounds are removed either by adsorption on activated carbon in the temperature range of 15–50°C or by reaction with a zinc oxide catalyst at 350–400°C. After the sulfur compounds are removed, natural gas is reformed with steam over a nickel catalyst according to the following two reactions to produce Syngas.

$$CH_4 + H_2O – CO + 3H_2$$
$$CO + H_2O – CO_2 + H_2.$$

The exit gas is heated to a temperature in the range of 750 to 850°C and pressurized in the range of about 28–35 atm (415–515 psi) before introducing it in the secondary reformer. Air, which is the source of nitrogen, is introduced in this stage. Oxygen from air reacts with CO releasing heat that drive the second reaction, which generates CO_2. The product of the second reforming stage is a mixture of carbon oxides, H_2, N_2, and other impurities. Carbon oxides are removed next. First CO is converted to CO_2 by the shift reaction, followed by a CO_2 removal step. An iron oxide-chromium oxide catalyst is used in the shift reaction. The CO_2 removal operation is done in two steps – a bulk CO_2 removal in which CO_2 concentration is reduced to a few parts per million and a final purification step. The most common bulk CO_2 removal operation is performed by scrubbing the gas with a methyldiethanolamine or monoethanolamine solution. If an ammonia production plant is associated with a nearby urea plant, the CO_2 may be recovered and used for urea production. The final gas mixture before introducing it into an ammonia production reactor must be ultra-pure. Therefore, any traces of CO_2 and CO must be removed from the gas stream. This is normally done by reacting CO_2 and CO with H_2 gas over a nickel catalyst (the reverse of the reforming reactions) converting them to CH_4. A cryogenic purification method is used to remove the methane from the gas stream. The clean gas mixture containing only N_2 and H_2 is compressed to between 136 and 340 atm (2,000 and 5,000 psi) and then passed over an iron catalyst where the nitrogen and hydrogen react to form ammonia by the following reaction:

$$N_2 + 3H_2 – 2NH_3.$$

After production, ammonia may be used to produce a variety of downstream products, which include ammonium nitrate, ammonium sulfate, nitric acid, and urea.

Table 7.22. Comparison of energy cost for fertilizer production normalized to the cost of natural gas.

Items	Natural gas	Heavy oil	Coal
Energy consumption	1.0	1.3	1.7
Investment cost	1.0	1.4	2.4
Production cost	1.0	1.2	1.7

Source: Reference [273].

7.7 Liquefied Natural Gas (LNG)

LNG is natural gas that is cooled at atmospheric pressure at a temperature -260°F (−161°C). At this condition, it is liquid. The liquefaction is accomplished using a refrigeration process in a plant. The unit where LNG is produced is called a train. Liquefying natural gas reduces its volume by a factor of 610. The reduction in volume makes the gas practical to transport and store. LNG is mostly methane (85–95%) and the rests are ethane, propane and butane (5–15%) A small amount of nitrogen can be also present. Depending on the country of origin, the composition can vary slightly. As a result, its heating value will also change. The composition of LNG based on its origin is given in Table 7.23.

Table 7.23. Variation in the LNG composition based on it origin.

Origin	Methane (%)	Ethane (%)	Propane (%)	Butane (%)	Nitrogen (%)
Algeria	87.6	9.0	2.2	0.6	0.6
Australia	89.3	7.1	2.5	1.0	0.1
Malaysia	89.8	5.1	3.3	1.4	0.3
Nigeria	91.6	4.6	2.4	1.3	0.1
Oman	87.7	7.5	3.0	1.6	0.2
Qatar	89.9	6.0	2.2	1.5	0.4
Trinidad & Tobago	96.9	2.7	0.3	0.1	0.0

Source: Reference [274].

Liquefaction of LNG makes it possible to trade it internationally, since it can be transported in specially built tanks in doublehulled ships to a receiving terminal where it is stored in heavily insulated tanks. The LNG is then sent to regasifiers which turn the liquid back into a gas that enters the pipeline system for distribution to customers as part of their natural gas supply. In the USA, net imports of LNG are expected to increase from 0.6 Tcf in 2004 to more than 6 Tcf in 2025.

This will be almost 21% of total U.S. natural gas demand. As can be seen from Table 7.24, LNG imports to the USA are increasing steadily and it is projected to increase faster in the future.

Table 7.24. LNG import to the USA in the last several years.

Year	Amount of LNG imported (MMcf)	Year	Amount of LNG imported (MMcf)
1990	84,193	2000	226,036
1991	63,596	2001	238,126
1992	43,116	2002	228,730
1993	81,685	2003	506,519
1994	50,778	2004	652,015
1995	17,918	2005	631,260
1996	40,274	2006	583,537
1997	77,778		
1998	85,453		
1999	163,430		

The LNG is imported into the USA from various countries via ships. As can be seen from Fig. 7.42, LNG is imported from a number of countries over the last 30 years, however, the demand increased dramatically in the last several years. This resulted in a new international shipping routes (Fig. 7.43).

Fig. 7.43. International route of LNG transportation. The thickness of the line represents relative LNG volume movement. (Adapted from [275]).

7.8 Liquefaction Process

The Phillips Cascade and Air Products APCI processes are mostly used for liquefaction of natural gas [276–278]. Several new processes have been recently proposed for liquefaction, and they are;

Axen/IFP (DMR) – LIQUEFIN^{TM} [279–280]
Linde AG (Statoil) – MFC® [281]
Turbo-Expander (BHP)
Blck & Vetch Pritchard Inc. – PRICO® [282]

7.8.1 Phillips Cascade Process

The Phillips cascade process is a three-stage process [283–284]. Three pure components are used for refrigeration; (1) Propane pre-cooling, (2) Ethylene, and (3) Methane. A schematic diagram of the Phillips cascade process is shown in Fig. 7.44. The refrigeration circuits are cascaded to provide maximum LNG production. Each circuit uses two compressors. The LNG from the last-stage flash drum is sent to the tanks by the transfer pumps, where it is stored at about 70 mbar and - 161°C. Advantages of this process are low installation costs, and the use of a two - train - in - one reliability concept. However, the increase use of gas turbines and compressors also increases the maintenance costs.

7.8.2 APCI Process

This process utilizes two cooling stages. In the first stage, propane is used as a cooling fluid and a mixed refrigerant is used in the second stage [285]. Generally a mixture of ethanol, propane, methanol and nitrogen obtained after splitting the C2+ is used as refrigerant. The composition of the mixture of coolants is based on the composition of natural gas in the plant. Natural gas, after passing through the pretreatment systems, is cooled in the propane vaporizer. The pressure of the propane is adjusted so that it remains cool, and no condensation occurs. The second stage is the main cryogenic coolant, which cools the natural gas through a closed circuit of mixed coolants. After liquefying, it is subcooled for storing. A schematic diagram of the process is shown in Fig. 7.45.

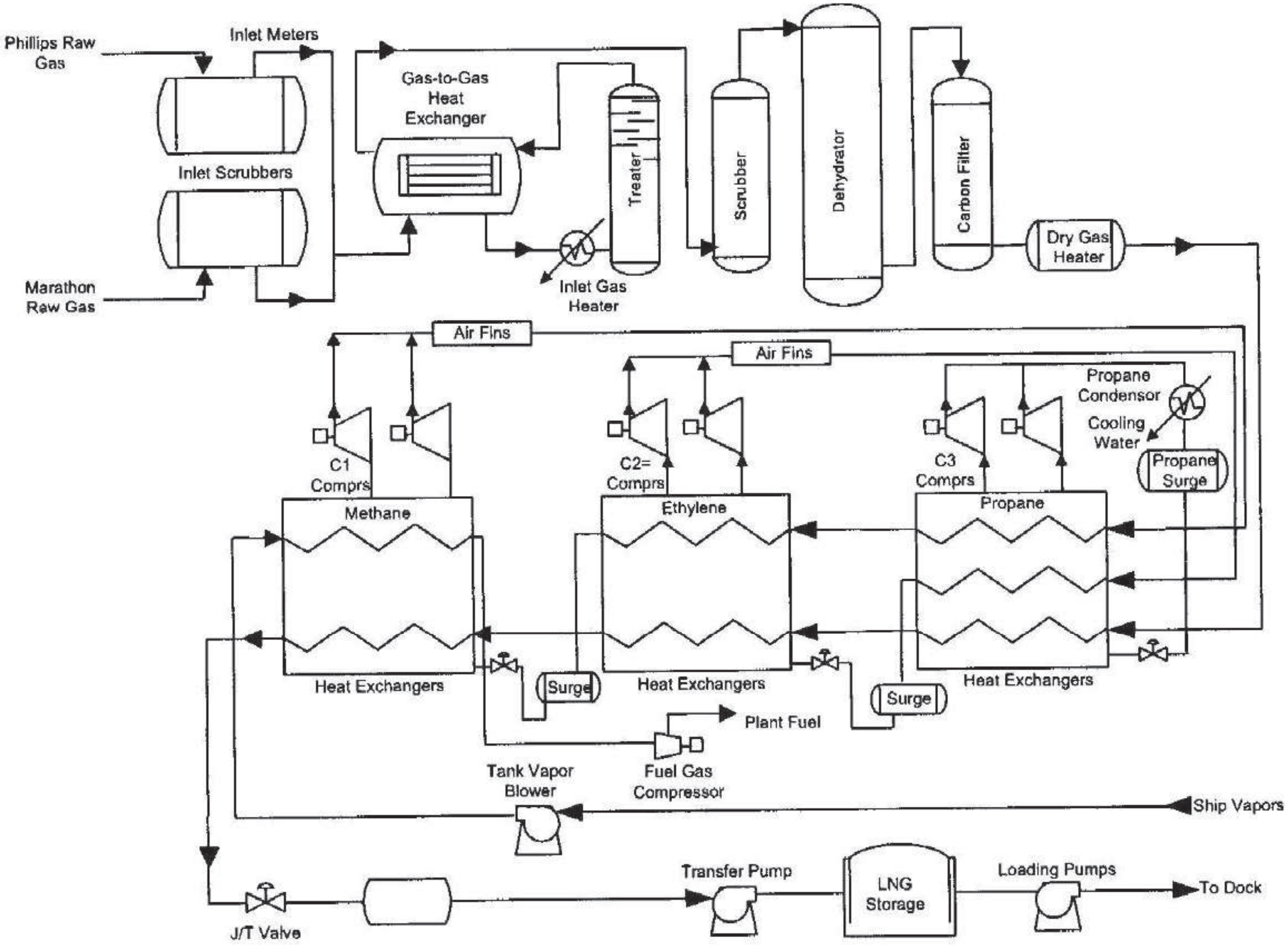


Fig. 7.44. Phillips cascade process for liquefaction of natural gas. (Reprinted with permission from [277]).

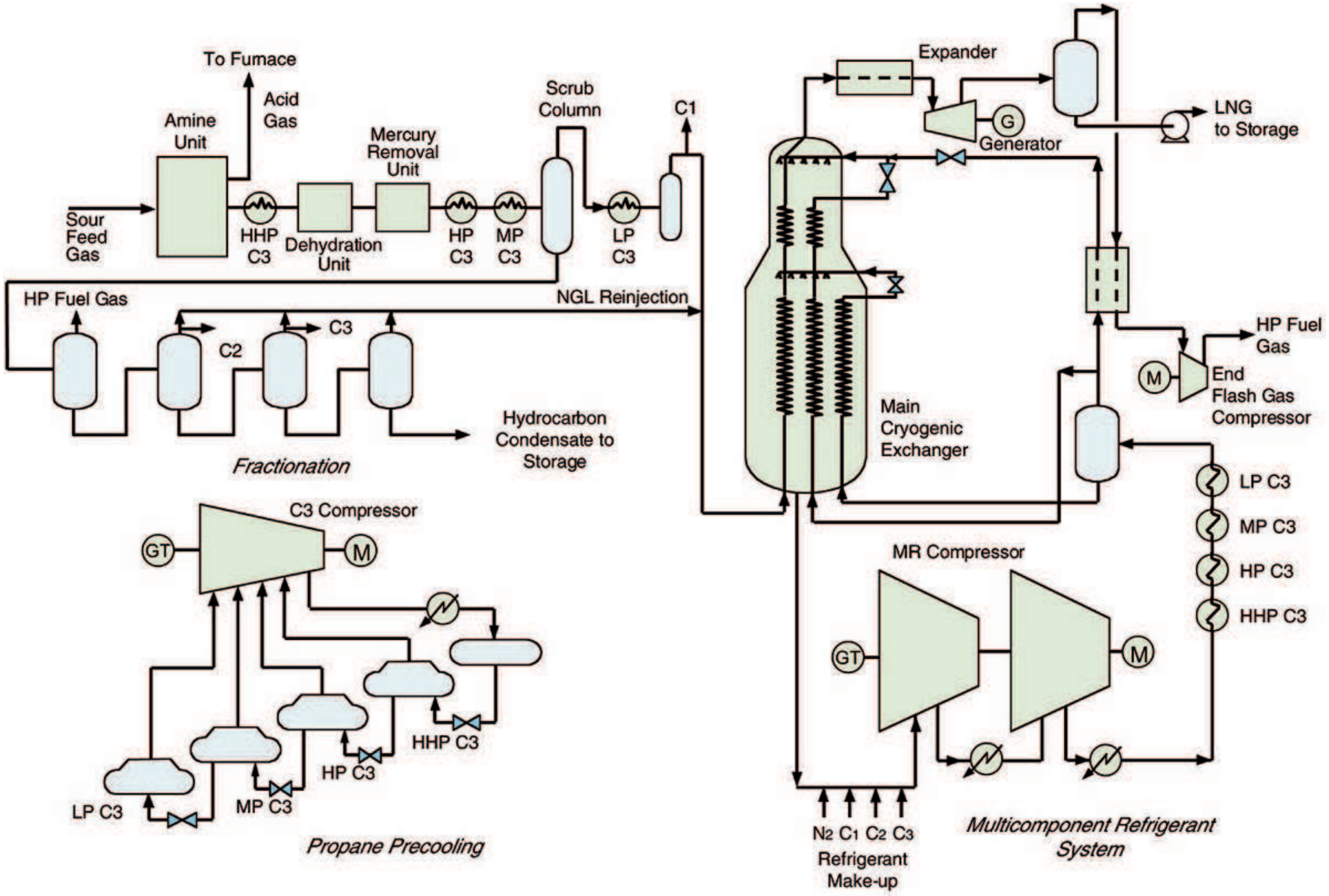


Fig. 7.45. APCI propone precooled mixed refrigerant typical process. (Reprinted with permission from [270]).

7.9 Transportation and Storage of LNG

Specially designed containers are used for shipping of LNG. The majority of the new containers for LNG transportation via sea are in the size range of 120,000–140,000 m^3. New containers with a capacity up to 260,000 m^3 are now currently being constructed by several builders. There are four containment systems in use.

7.9.1 Moss Tanks

These are spherical aluminum tanks and are designed by Moss Maritime, Norway. The cross-sectional view of a Moss tank is shown in Fig. 7.46 and its design characteristics are presented in Fig. 7.47.

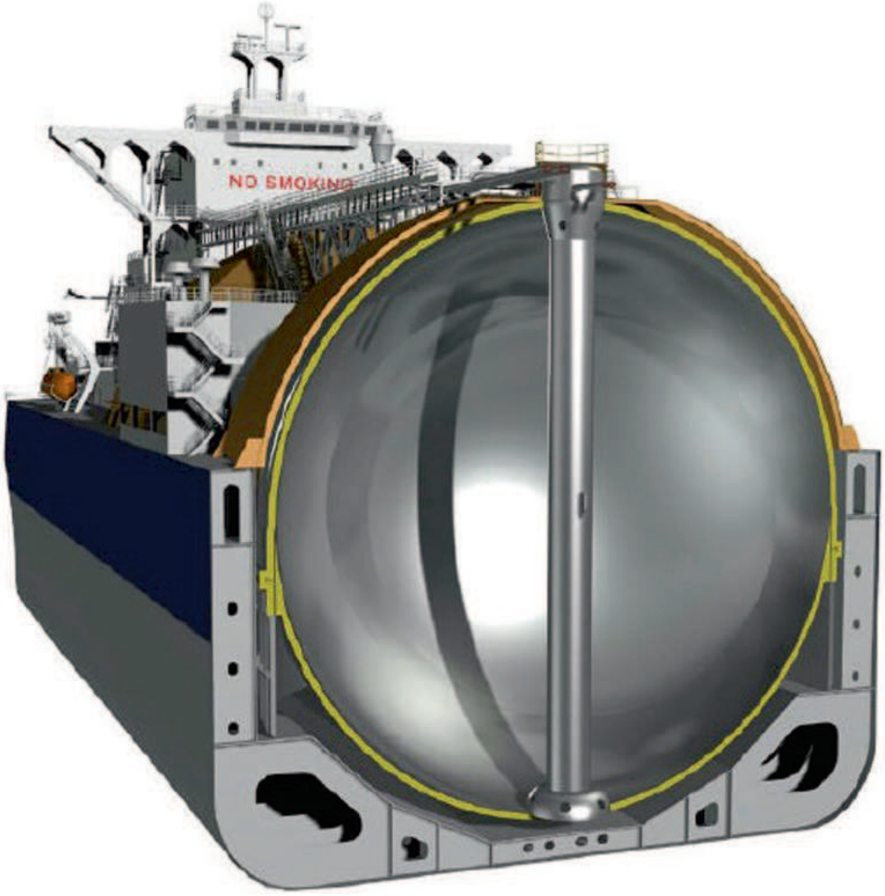


Fig. 7.46. The Kvaerner/Moss Rosenberg tank design for LNG transportation. (Adapted from Frivik P-E (2003) The Importance of Knowledge in the Changing Nature of Natural Gas Supply–Contributions from Academia and Applied Research in Industrial LNG Development. IEA Advisory Group on Oil and Gas Technology. Economic Analysis Division of the International Energy Agency Initiation of Global Dialogue on “the Future of Natural Gas Supply and Use” Exploring the Impact of Financial and Technological Drivers Washington DC, 22 January 2003 [286]).

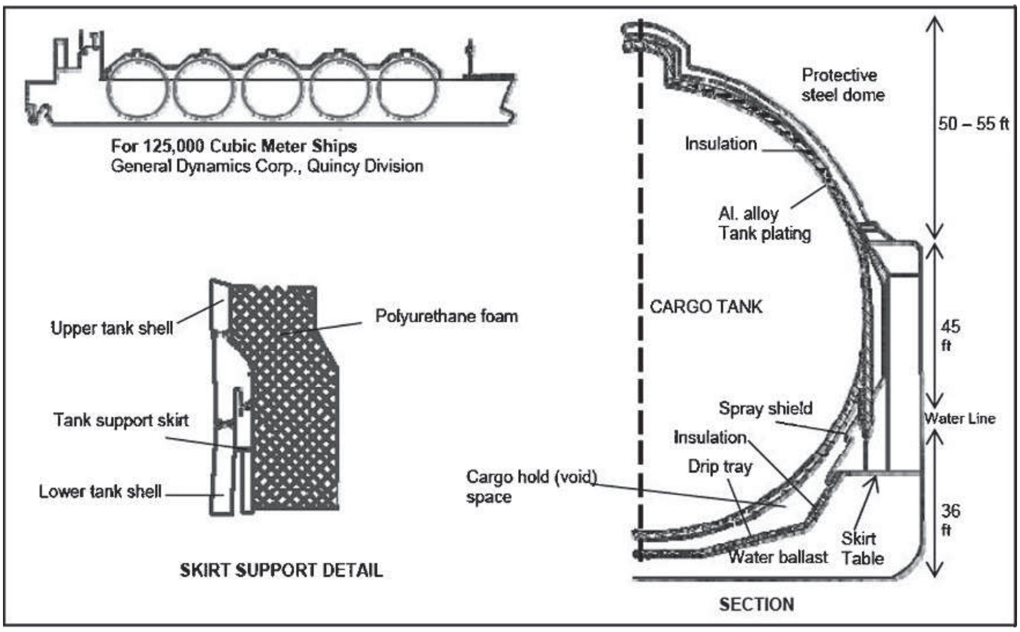


Fig. 7.47. Free standing spherical LNG transportation tank. (Adapted from [287]).

7.9.2 IHI Tanks

The tank is made of aluminum and is built by Ishikawajima-Harima Heavy Industries, Japan. The IHI tank is shown in Fig. 7.48.

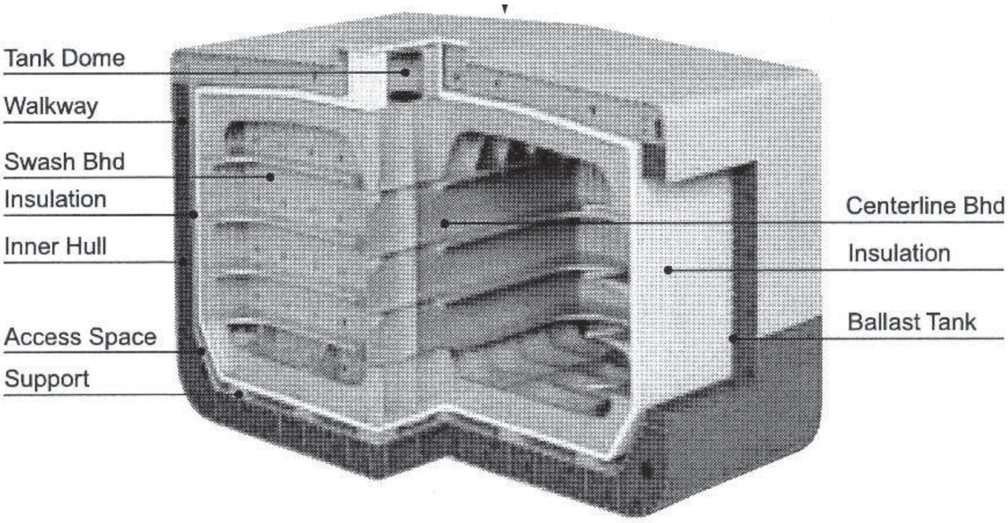


Fig. 7.48. Floating production storage & offloading unit for LNG shipment. (Adapted from [288]).

7.9.3 GT96

The GT96 is designed by Gaz Transports. The tank consists of two membranes: a primary and secondary thin membrane. Both the membranes are made of invar which has negligible thermal contraction in the temperature range the tanks operate. The insulation is made out of plywood boxes filled with perlite. The design features are shown in Fig. 7.49.

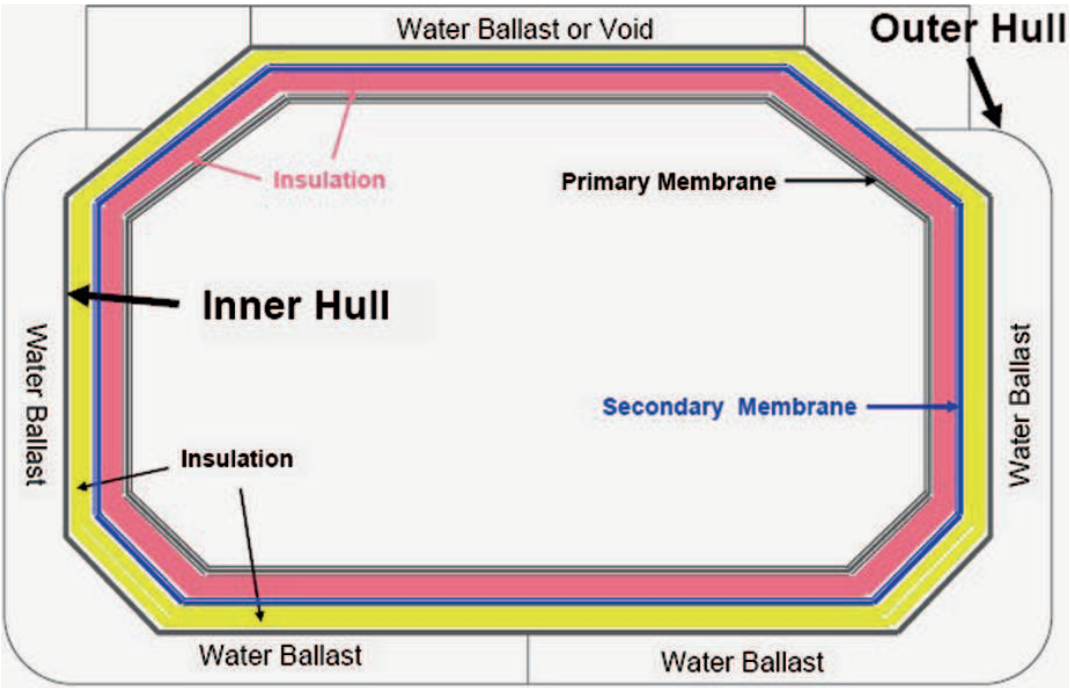


Fig. 7.49. Design features of a membrane tank. (Adapted from [289]).

7.9.4 TGZ Mark III

The TGZ Mark III is a membrane type and is manufactured by Technigaz. The membrane is made out of stainless steel with baffles, which allow the thermal contraction when the tank is cooled down. The interior design of TGZ Mark III tank is illustrated in Fig. 7.50.

7.10 LNG Storage Facility

There are basically two types of LNG (liquid natural gas) storage tanks: above ground, and underground.

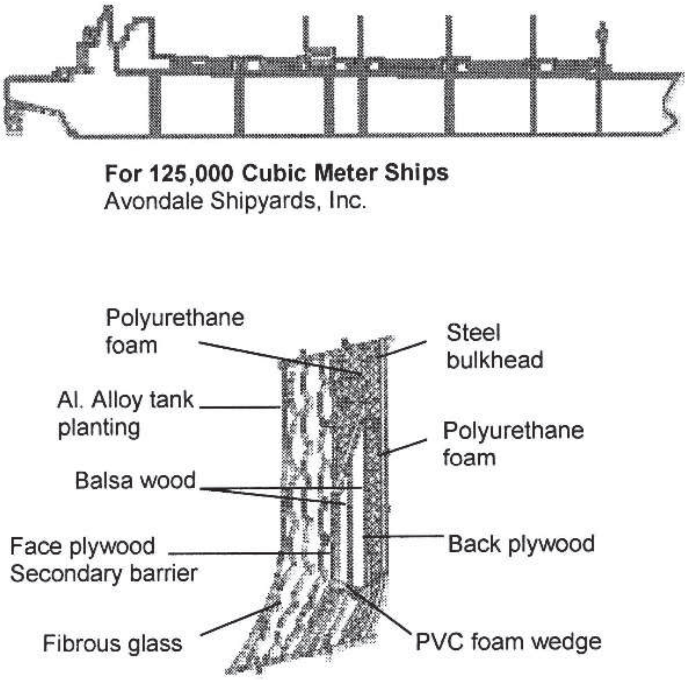


Fig. 7.50. Free standing prismatic LNG tank. (Adapted from [287]).

7.10.1 Underground Storage Tank

The underground storage tanks are composed of continuous diaphragm walls, side walls and base mat slabs, and each tank has different requirements of performances.

7.10.2 Above Ground Storage Tank

There are three types of above ground LNG storage tanks:

Single containment
Double containment
Full containment

A Single containment tank is generally a single tank (Fig. 7.51). In some design an outer container is included. However, only the inner tank is required to meet the low temperature ductility requirements for storage of LNG.

A double containment tank consists of both the inner tank and the outer tank (Fig. 7.52). Both the tanks are capable of independently containing the refrigerated liquid.

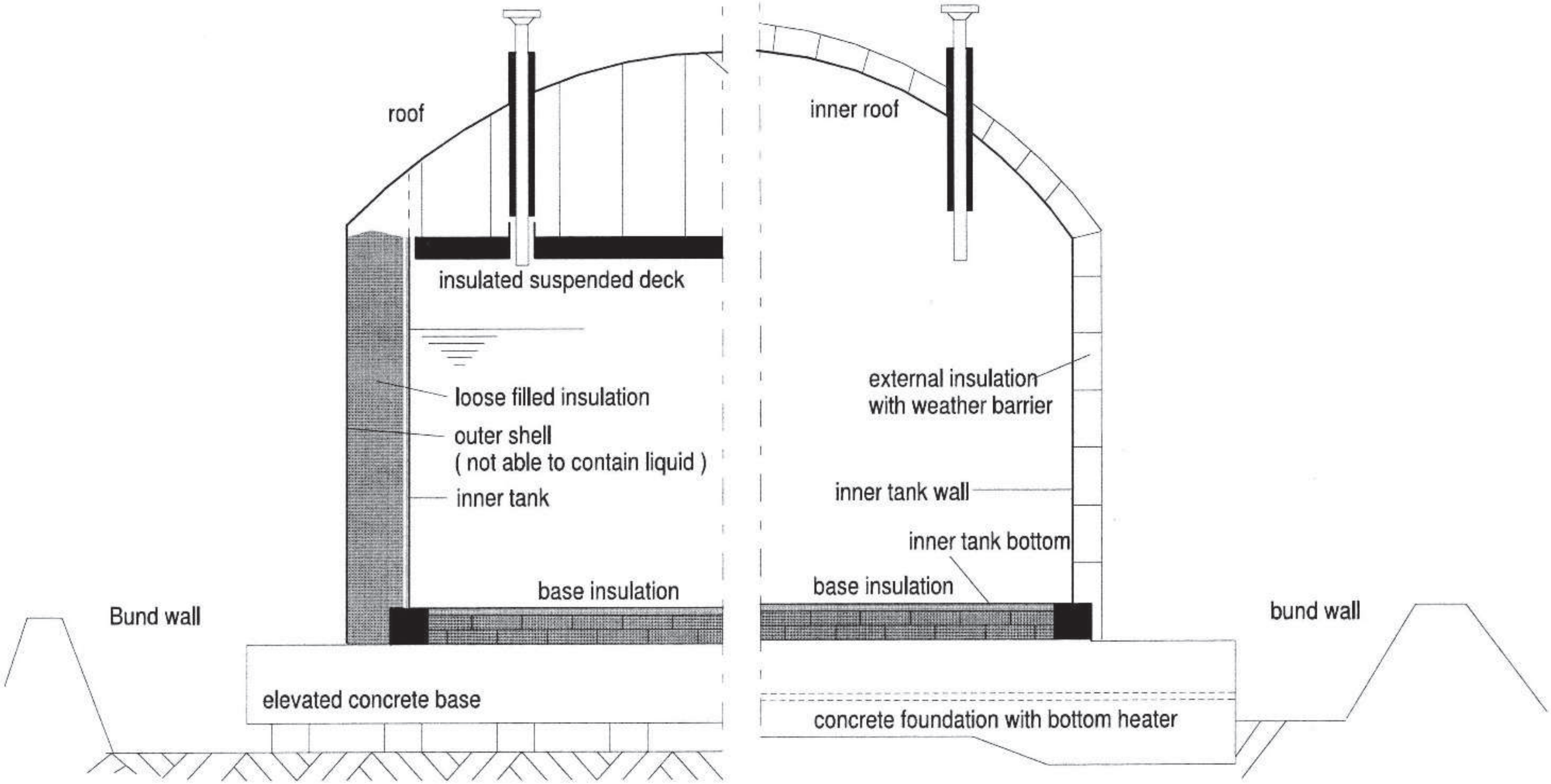


Fig. 7.51. Single containment type LNG storage tank. (Printed with permission [283]).

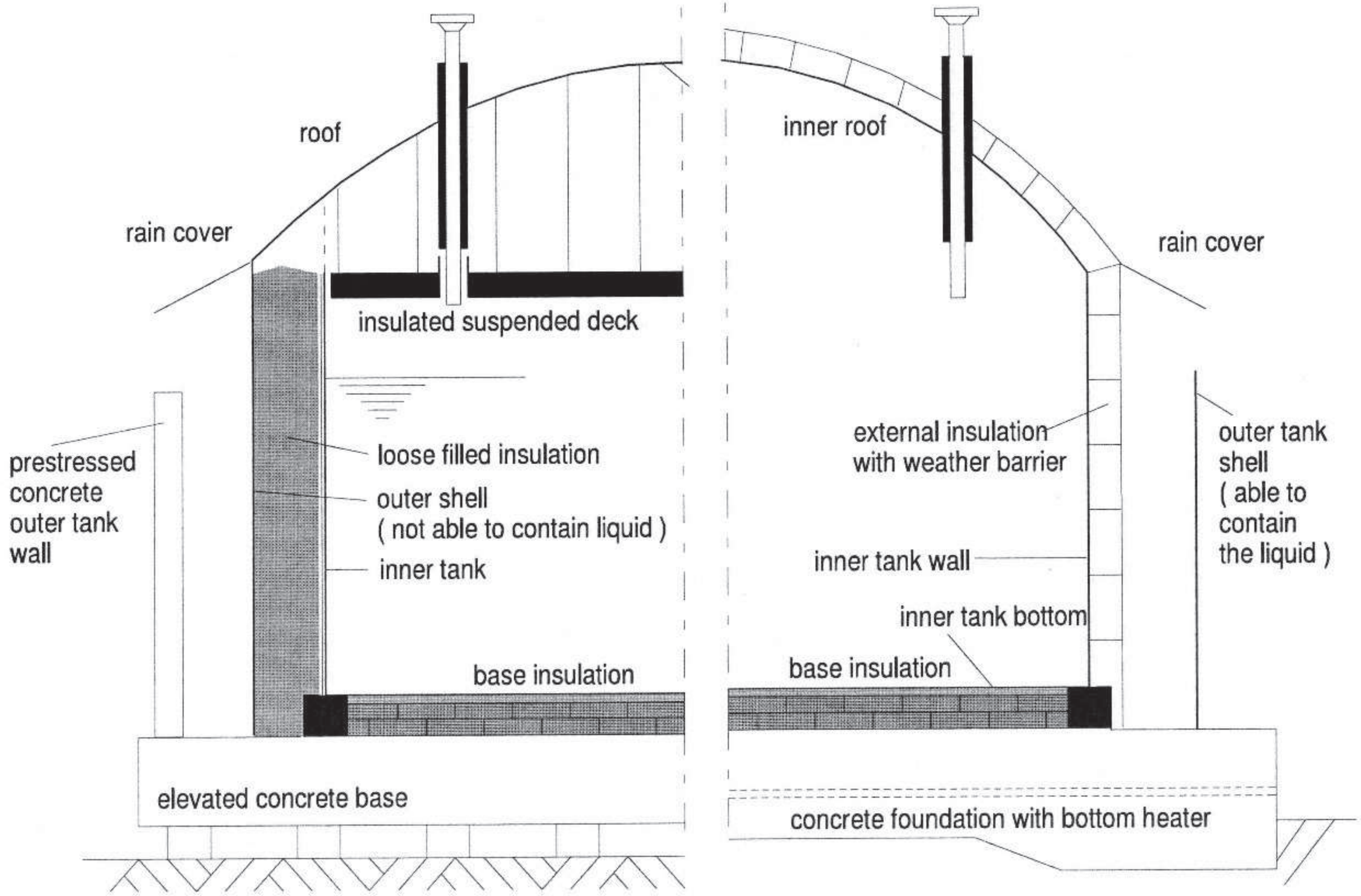


Fig. 7.52. Double containment type LNG storage tank. (Printed with permission from [283]).

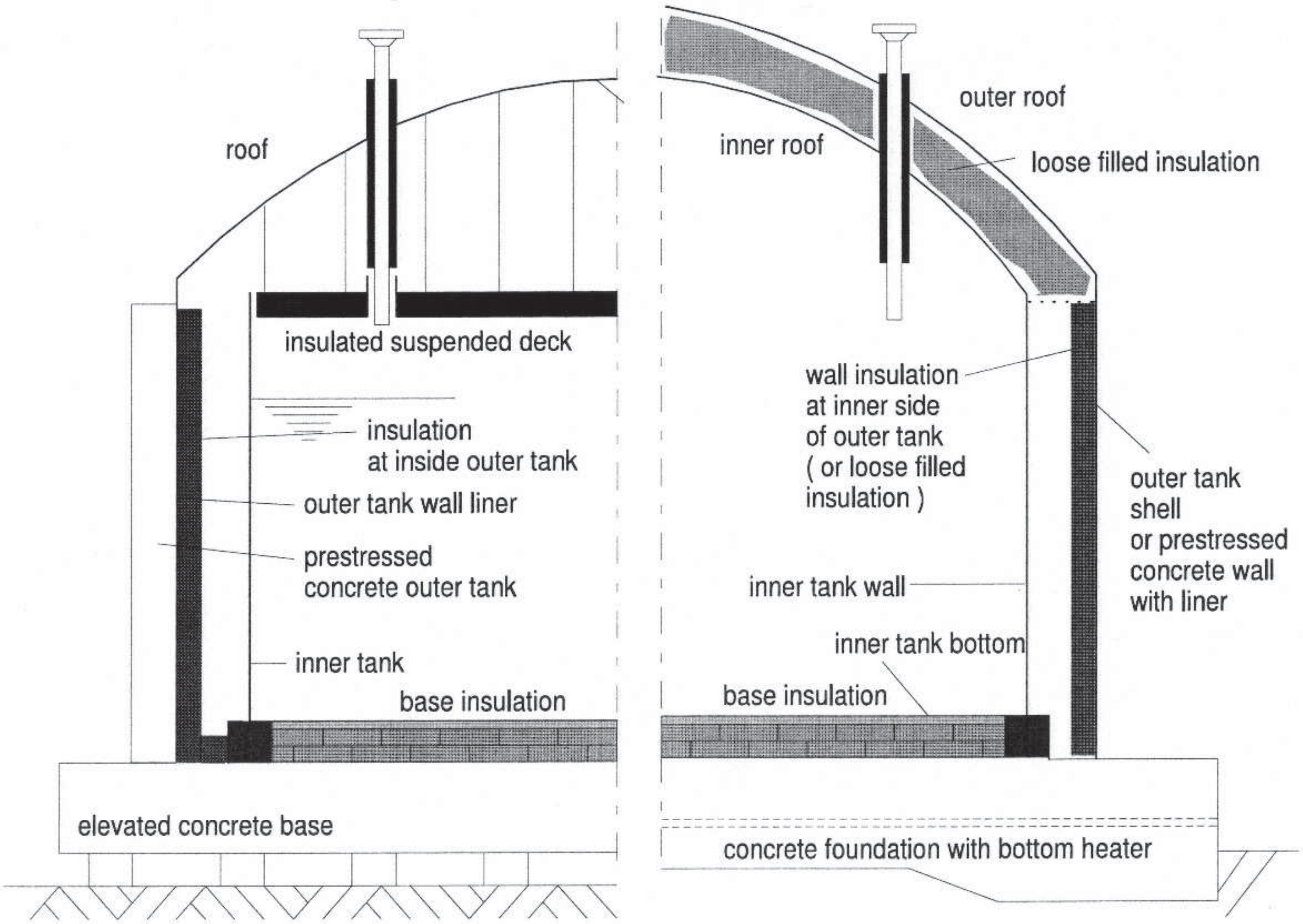


Fig. 7.53. Full containment type LNG storage tank. (Printed with permission from [283]).

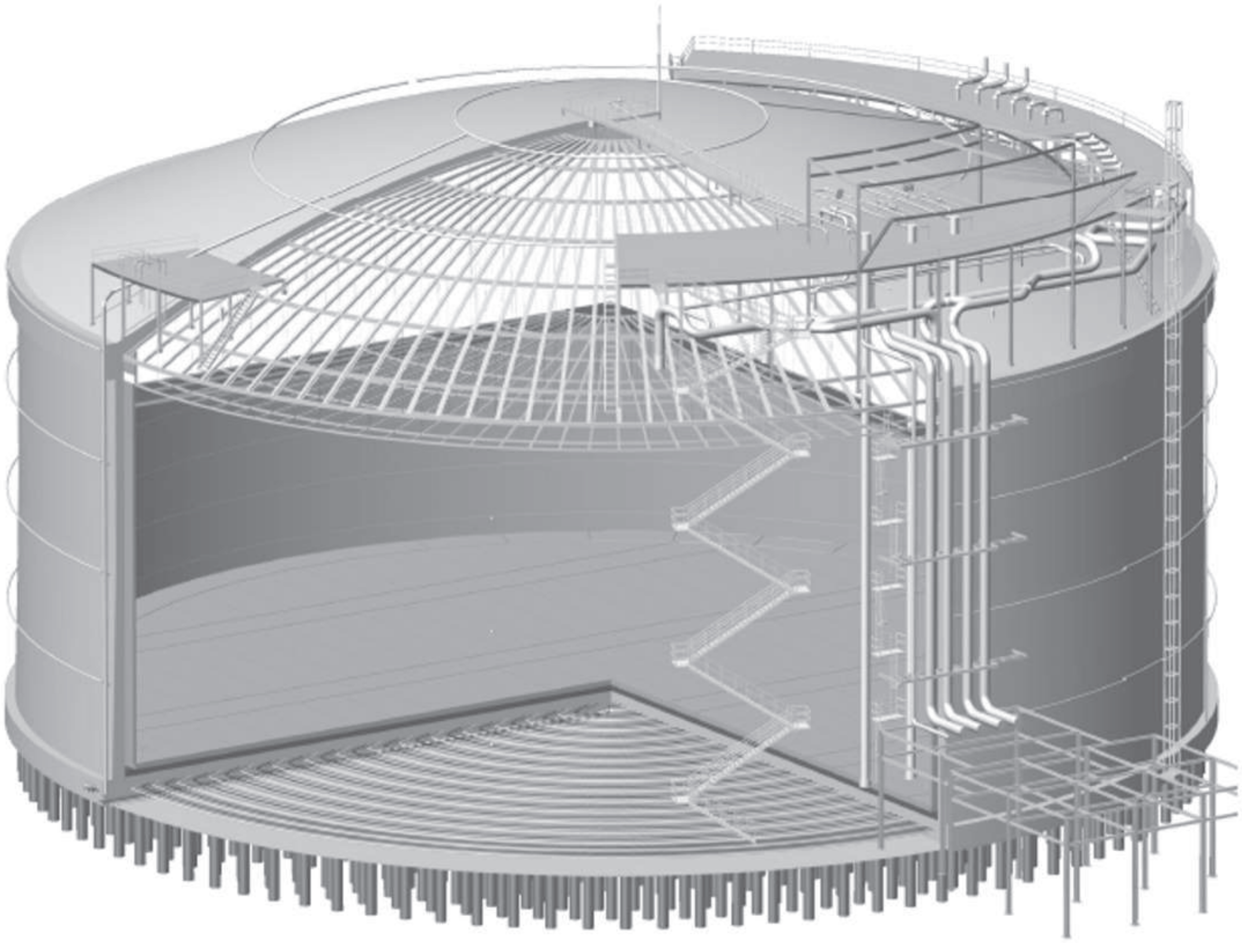


Fig. 7.54. Structural view of the above ground full containment LNG storage tank. (Adapted from [284]).

A full containment tank (Fig. 7.53) is similar in design to the double containment tank. It differs from the double containment tank in that the outer tank of a full containment tank is capable of both containing the refrigerated liquid and controlled venting of the vapor resulting from product leakage in the case of an accident. The structural aspects of the tank are shown in Fig. 7.54. The full containment type is regarded as the most advanced type and can also be constructed, in-ground or under-ground. The inner tank is manufactured with 9% nickel steel and the outer tank is composed of reinforced concrete and pre-stressed concrete. The 9% nickel steel is capable of withstanding cryogenic conditions. The concrete outer tank is designed to resist various external loads including seismic load. Insulating materials are placed between the inner and outer tank to preserve the stored LNG.

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Problems

1. What are the major factors affecting natural gas prices?
2. What greenhouse gas emissions are associated with natural gas in the U.S.?
3. How is natural gas stored? How is LNG used? Why use LNG?
4. Can the use of natural gas be an answer to global warming?
5. How feasible is natural gas fueled passenger car?
6. What are the challenges for use of natural gas in a vehicle?
7. Does use of natural gas affect the environment?
8. Does production of natural gas affect the environment?
9. How is natural gas distributed to consumers?
10. Are there adequate supplies of natural gas to meet future needs?
11. What percentage of natural gas is used for electricity generation? Should we build more power plants based on natural gas? What are the issues?
12. There is an attempt to promote natural gas as an alternative to petroleum. Discuss if this is viable and if there is enough resources to replace petroleum?
13. Discuss various uses of natural gas and how these will be affected if natural gas becomes unavailable at an affordable price.
14. Why it important to dry the natural gas before sending it through pipeline?
15. During natural gas processing various sulfur compounds are removed, but before selling to the consumer again a certain type of sulfur compound is added to the gas. Explain the reasons behind this practice.
16. What are the losses from the storage of natural gas?
17. Methane hydrates are considered as the major source of natural gas in the future. Discuss the issues related to its extraction from its source. What are the likely consequences?