12

Natural Gas Market

Joseph Essandoh-Yeddu
University of Cape Coast, Energy Commission, Ghana

1. Introduction

The natural gas market is the collection of entities or players including buyers and sellers of the gas that compete among themselves or work together on different segments of the gas value and supply chain. It therefore encompasses all the players – producers, transporters, regulators, sellers and buyers and their activities in the market and industry.

Most natural gas trading shares some standard specifications which include the following:

- Specifying the buyer and seller.
- The price.
- The quantity of natural gas to be sold.
- The receipt and delivery point.
- The tenure of contract.
- Payment dates.
- Quality specifications for the gas.
- Arbitration in times of misunderstanding.

Physical contracts are usually negotiated directly between buyers and sellers but electronic bulletin boards and e-commerce trading sites are taking over the transactions in recent times.

Natural gas before the 1970s was once considered a mere byproduct of oil and thus not worth the significant capital investment required to find, gather, process and transport or distribute this resource. So for many places where oil was being prospected and natural gas was found, the wells would be ceiled for locations where local usage demand did not exist.

Driven by energy security and greenhouse gas emissions concerns, the wide spread and cleanliness of the gas has pushed it to the forefront of the fossil fuels such that it has become the clean fossil fuel of choice as well as a global commodity. This has changed the global landscape such that it has become almost equally valuable as the oil being prospected wherever it is found at present times. One important advantage that natural gas has over other fossil fuels besides, its relatively low carbon emissions, is that it leaves no solid residues and produces less other pollutants like sulphides/sulphates on combustion.

Worldwide, the natural gas industry has grown rapidly in recent years. IEA (2011) projects that the global energy share of natural gas would increase from 21% in the 2008-2010 to about 25% by 2035 (Figure 1).

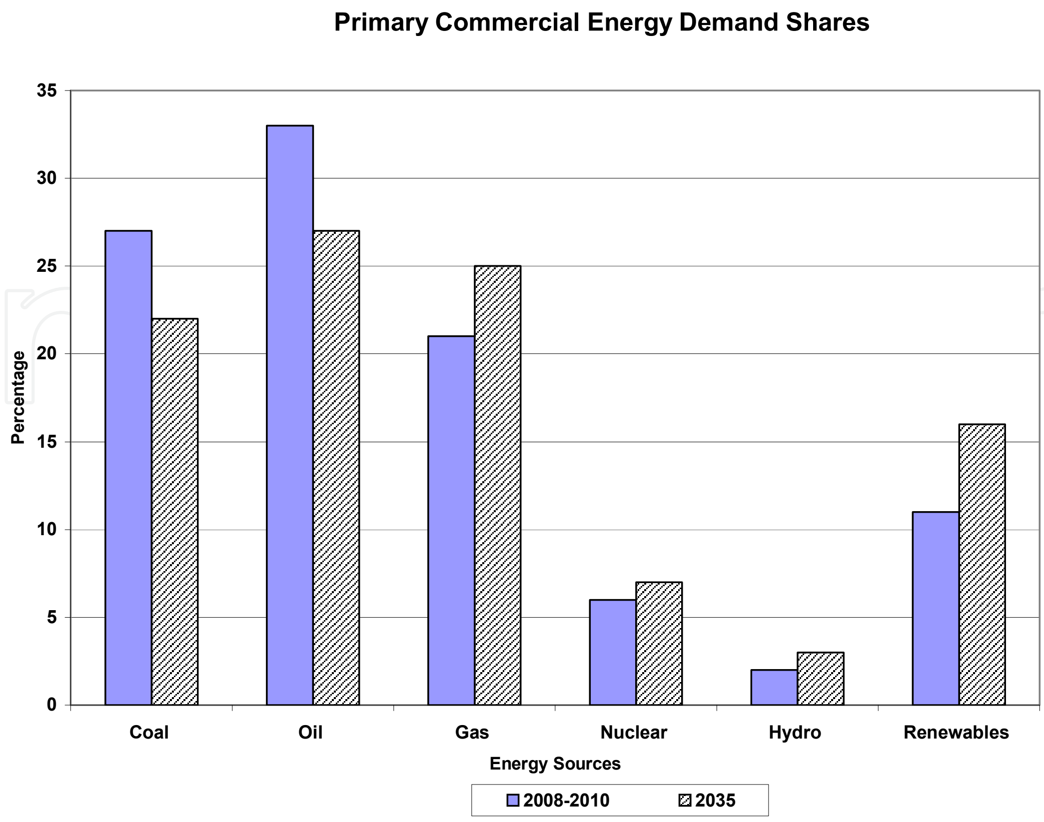

Fig. 1. Global Primary Commercial Energy Demand Shares.

Global marketed gas production has grown from an average of 1.2 trillion cubic metres[1] in the 1970s to about 3.3 trillion cubic metres in 2010. Russia and the United States with annual average production each of about 550 billion cubic metres since 2008 are the largest producers but also the largest consumers, with the United States consuming over 600 billion cubic metres and almost twice the consumption of Russia (BP, 2011).

Global average annual production had almost matched consumption since 2000; 3.05 trillion cubic metres (296 bcf/d)[2] and 3.03 trillion cubic metres (294 bcf/d) respectively. Mean annual growth rate was about 3.2% for both consumption and production.

This significant growth in gas consumption shot up the average price of the gas in the United States from about $6/MMbtu[3] in the 2000s to about $12/MMbtu in early 2008. The increasing price signals accelerated the pace of investment in unconventional gas production facilities, particularly in the United States (IEA, 2011).

The global financial and economic crisis in 2008 however led to a sudden and pronounced drop in consumption from the 3.03 trillion cubic metres in pre-2008 to about 2.94 trillion cubic metres by end of that year. Consumption growth rate between 2007-2008 was 2.4% but dropped to negative 2.2% in 2009. Average annual production of 3.05 trillion cubic metres from 2000-2008 correspondingly dropped to 2.97 trillion cubic metres in 2009.

[1] 1.09 billion tonnes of oil equivalent (BTOE) or 116.5 billion cubic feet of gas per day (bcf/d).
[2] Billion cubic feet per day
[3] MMbtu is million British thermal unit

The significant fall in gas demand had led to emergence of significant amount of over capacity in gas production in the United States, causing the average price of the gas in the country to fall to \$4.00-\$4.50/MMbtu range since the late 2008.

Consumption growth has however risen again; it jumped to 7.5% in 2010 (from negative 2.2% in 2009) dragging production to increase to 3.19 trillion cubic metres (almost 310 bcf/d) that year (from 2.97 trillion cubic metres in 2009).

Most of the world's proved natural gas reserves (about 72%) are located in two regions: the former Soviet Union (FSU) and the Middle East, although there is little production relative to the size of its reserves in the latter region. Both regions hold roughly about 56 trillion cubic metres (about 2,000 trillion cubic feet) of natural gas reserves as compared to the estimated world total reserves of 150 trillion cubic metres (5,300 trillion cubic feet) (CEE, 2006).

Despite the size of their reserves, North American region rather than the former Soviet Union and the Middle East has been the leading producer as well as consumer of the gas for decades. Nevertheless, production in the former Soviet Union region had increased significantly from 0.2 trillion cubic metres (19 bcf/d) in 1970 to 0.71 trillion cubic metres (69 bcf/d) in 2000, i.e. over 260 percent increment whilst the North American production increased only from 0.64 trillion cubic metres (62 bcf/d) to 0.74 trillion cubic metres (72 bcf/d); a mere 16% increase over the same period (CEE, 2006). The former is obviously catching up and this scenario is likely to influence the evolving gas market and industry into a new paradigm in the years to come.

2. Natural gas value chain

Generally, worldwide, natural gas market and industry comprises Upstream, Midstream and Downstream. Their various operational elements are elaborated below (Figure 2).

2.1 Upstream

Upstream activities cover exploration, field production, processing of the raw or associated gas and separation into various other molecules, gathering of the gas from feeder wells before it is pumped midstream.

Production involves extraction of discovered supplies from hydrocarbon fields either with crude oil (as associated/dissolved gas[4]) or separately (non-associated natural gas[5]).

Production time span for gas used for economic analysis is usually longer than oil and can sometimes go up to 30-35 years. During oil production, excess associated gas is disposed of by direct (venting) or by controlled burning (flaring). Under normal conditions, flaring would only take place in the start-up phase of production. Flaring of natural gas however, releases carbon dioxide, the most significant greenhouse gas into the atmosphere. Besides, the flaring gas is also a resource and commodity being wasted since it could be used for power production or as industrial feedstock or exported to earn foreign exchange, of course, all depending upon the quantities involved.

[4] Natural gas that occurs in crude oil reservoirs either as free gas (associated) or a gas in solution with crude oil (dissolved gas).
[5] Natural gas that is not in contact with no or significant quantities of crude oil in the reservoir.

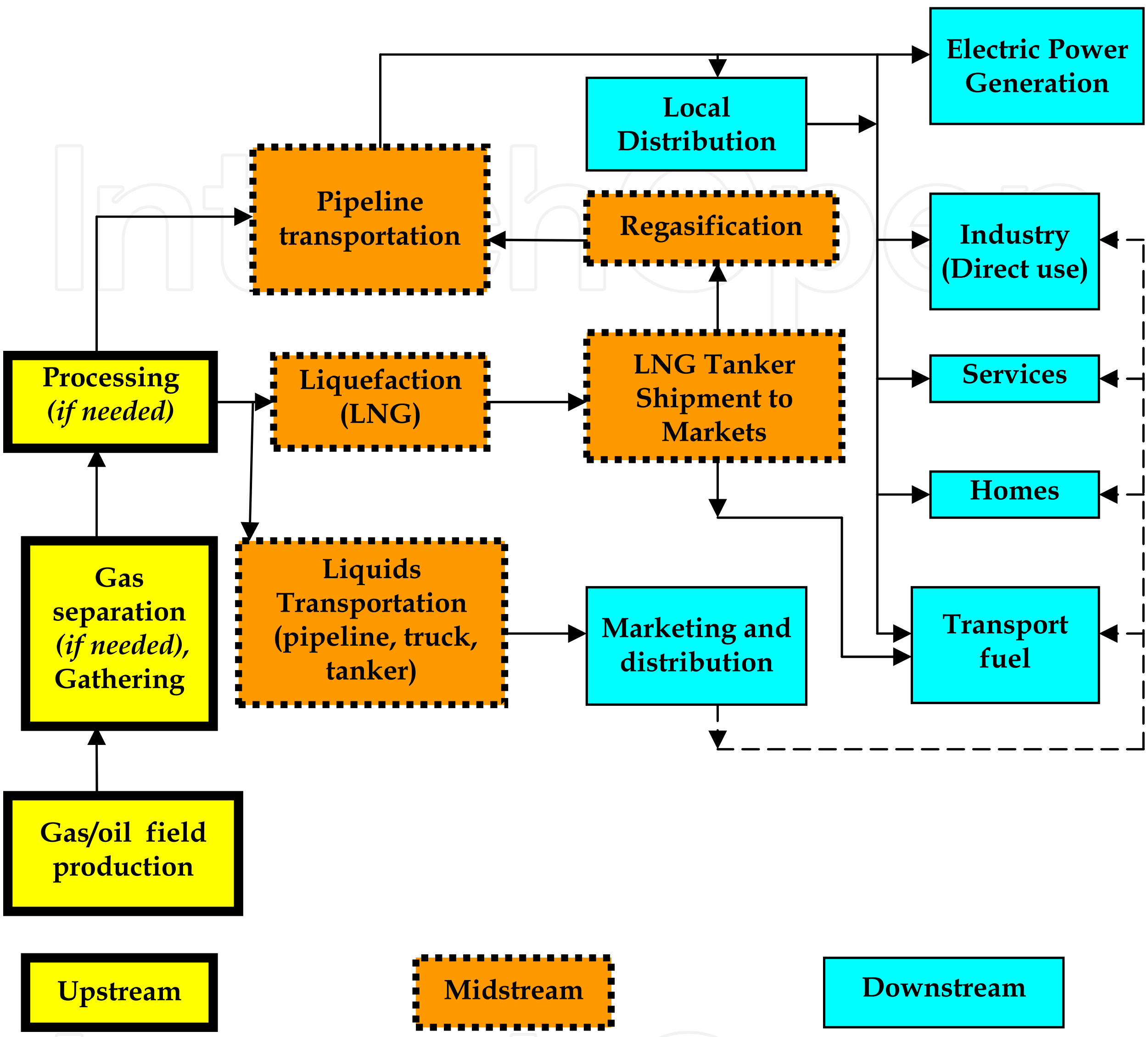

Fig. 2. Natural gas major value chain.

For where technically and economically possible and attractive therefore, the gas is re-injected into the geological formation for latter use and also for secondary recovery to enhance production. Re-injection also is a way of prolonging and increasing or maintaining the oil output. The longer however the re-injection, the likelihood of also losing some significant quantities of the gas in the geological formation, and in some extreme cases, if care is not taken, could damage the reservoir. So re-injection goes with some risk and for that matter gas flaring option technically tends to be more attractive in most cases to the field production operator.

Globally, between 10-15% of the gas produced annually is used for re-injection. Further 5-10% of the gas is flared. Owing to environmental concerns however, pressure to monetize 'flaring' gas is greatly being directed at locations where crude oil is being produced and the associated gas is being flared (IEA, 2011).

In 2010, out of the global production of about 3.2 trillion cubic metres, around 500 billion cubic metres of gas was used for re-injection About 250 billion cubic metres was lost through 'shrinkage' due to extraction of natural gas liquids including LPG[6] and for fuelling production facilities. Between 100-125 billion cubic metres was flared largely in developing countries and in large oil field operations as in Western Siberia of Russia. Much of the flaring however is expected to be reduced significantly by 2020 as most of such host countries are putting in place policies to compel operators to adopt 'zero flaring' of this potential fuel source (IEA, 2011).

Gathering involves collection of natural gas production from multiple wells connected by small diameter pipeline systems to a large pipeline for treatment.

Processing is the separation of heavier molecules and unwanted substances such as water. Out of the heavier molecules could be LPG or Natural Gas Liquids (NGLs) – ethane and larger molecules are stripped out as feedstock for petrochemical industry. LPG, a propane/butane mixture, could be obtained during the processing of **wet** natural gas[7] to obtain the **dry** natural gas[8]. If the gas stream contains impurities such as sulphide compounds then **treatment** is required. The gas is branded as **sour** if it has excessive sulphur compounds, giving it offensive odour. It is **sweet**, if it has much lower concentration of sulphur compounds, particularly, hydrogen sulphide.

2.2 Midstream

Midstream activities include pipeline transportation, liquefaction of the gas into LNG and storage of the gas. Some **upstream** activities however over lap with those of **midstream**. For instance, if the **gathering** involves delivery to a processing plant through a long-distance low pressure pipeline, it is usually placed under **midstream.** Some literature also consider **processing and treatment** of the raw gas, like gas-liquid extraction as a **midstream** activity.

Storage is usually in depleted underground reservoirs or caverns like those associated with salt domes. Storage can be located either near production or near demand. Re-enforced steel

[6] LPG is liquefied petroleum gas.

[7] A mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. When this mixture gas reaches the surface at normal temperature and pressure conditions, some of the hydrocarbon molecules become liquid. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane and pentane. Typical non-hydrocarbon gases that may be present in reservoir natural gas are water vapour, carbon dioxide, hydrogen sulphide, nitrogen and traces amounts of helium.

[8] Natural gas which remains after; (a) the liquefiable hydrocarbon portion has been removed from the gas stream, (b) any volumes of non-hydrocarbon gases have been removed where they occur in significant quantity to render the gas unmarketable. Dry natural gas is also called consumer-grade natural gas. Dry gas also indicates that the fluid does not contain enough of the heavier molecules to form liquid at surface temperature and pressure conditions.

dome engineered storage systems are also available where natural gas is stored in the form of LNG.

Pipeline transportation covers delivery of the gas from producing basins to local distribution networks and high-volume users via large diameter, high volume pipelines. Countries vary greatly with respect to allowable pipeline specifications for heat content. Some pipelines transport **dry** gas and some **wet** depending upon the standard set by the operators and the buyers.

Liquefaction, shipping and re-gasification known collectively as the LNG value chain, entails conversion of the gas to a liquid form via refrigeration to a cryogenic fluid (temperature -160°C[9]) for transportation from a producing country or region to a consuming country or region via ship.

2.3 Downstream

Midstream activities yield **downstream** activities. **Downstream** covers end-use conversion and distribution of the gas for power generation and to various sectors of the economy.

Distribution **downstream** involves retailing and final delivery of the gas via small diameter and low pressure local gas networks operated by local distribution companies (LDCs) - often called gas utilities. **End use conversion** covers direct use or conversion for use in other forms (petrochemicals, electric power or vehicle fuels).

Overall, there are also losses from **upstream** to **downstream**; for instance, about 20%, i.e. between 800-900 billion cubic metres of the gross gas volume produced globally in 2010 never reach the market (IEA, 2011).

2.4 Commercial and other practices governing the natural gas value chain

The following commercial elements and practices serve to bind the operating segments of the natural gas value chain and link suppliers, transporters and distributors with their customers. They are:

- Aggregation: Consolidation of supply obligations, purchase obligations or both as means of contractually – as opposed to physically – balancing supply and demand.
- Marketing: Purchase of gas supplies from multiple fields and resale to wholesale and retail markets.
- Retail marketing constitutes sales to final end users (typically residential, commercial, industrial, electric power and services).
- Capacity brokering: Trading of unused space on pipelines and in storage facilities.
- Information services: Creation, collection, processing, management and distribution of data related to all the other industry and market functions.
- Financing: Provision of capital funding for facility construction, market development and operation start-up.
- Risk management: Balancing of supply, demand and price risks.

[9] -256 °F

- Environmental issues: Impact of the activities of the various segments of the value chain on the ecosystem, comprising land, water bodies, and the atmosphere including the living beings within them.
- Health and Occupational Safety: impact of the various activities on the health and safety of workers in the various segments of the value chain.

2.5 Challenges for efficient and harmonious market along the value chain

The **first** challenge is to create a framework for efficient production of the gas upstream (Foss, 2005).

The **second** challenge is achieving efficiency in pipeline transportation to distribution of the gas to various consuming sectors.

The **third** challenge is developing transparent markets for natural gas supply and consumption. The evolving trend has been to separate infrastructure and product (often referred to as "unbundling") and to search for ways of providing competitive access to pipeline systems for multiple suppliers and users of natural gas (often termed "third party access" or "open access"). In these cases, pipelines become like toll roads, priced through tariff design, while the gas is priced in discrete competitive markets. Traditionally or previously, it was a "bundled" market.

When pipelines become subject to "third party access" regimes, the linking of suppliers to buyers, can be separated into competitive business activities. Such has triggered growth in marketing and trading (both of the physical product as well as financial derivatives) as separate businesses, particularly in North America.

Both the evolution of market-based policies for natural gas and international trade linkages have given rise to a **fourth challenge** which is, timely and accurate data and information on supply, demand and prices. Data and information must be accurate and timely to consistently attract the necessary long-term investment and minimize market disruptions and distortions. Unreliable forecasts create conflicts to the extent that they result in supply-demand imbalances which neither industry nor government at times has the flexibility to correct in a timely manner.

A **fifth** and increasingly **challenge** is dealing with integration, with respect to industry organization and international trade. Industry organization encompasses both vertical (meaning up and down the value chain) and horizontal (meaning over some geographic or international market region) integration. Integration of physical infrastructure across international boundaries has grown rapidly with increased demand for overland pipeline natural gas.

3. Recoverable reserves

Recoverable resources of conventional gas[10] worldwide are estimated to be about 400 trillion cubic metres based on current technology and price range and this is equivalent to more than 120 years of global consumption today (Table 1).

[10] i.e. including associated/dissolved gas

REGION	CONVENTIONAL		UNCONVENTIONAL					
			Tight Gas		Shale Gas		CBM	
	tcm	$/MMBTU	tcm	$/MMBTU	Tcm	$/MMBTU	tcm	$/MMBTU
Eastern Europe and Eurasia	136	2-6	11	3-7	N.A-	N.A	83	3-6
Middle East	116	2-7	9	4-8	14	N.A		N.A
Asia/Pacific	33	4-8	20	4-8	51	N.A	12	3-8
OECD North. America	45	3-9	16	3-7	55	3-7	21	3-8
Latin America	23	3-8	15	3-7	35	N.A	N.A	N.A
Africa	28	3-7	9	-	29	N.A	N.A	N.A
OECD Europe	22	4-9	N.A-	N.A-	16	N.A	N.A	N.A
Total	**404**	**2-9**	**84**	**3-8**	**204**	**3-7**	**118**	**3-8**

tcm: trillion cubic metres; MMBTU: million British thermal unit; CBM is coal-bed methane
Source: IEA, 2011

Table 1. Global recoverable resources of conventional gas.

Unconventional resources such as shale gas and coalbed methane (CBM) are now estimated to be as large as conventional resources **(Table 1)**. Production of unconventional gas is estimated to represent about 13% of global production as at 2010 **(Table 2)**.

REGION	**PROVED RESERVES as at 2010**		**PRODUCTION**		**CONSUMPTION**		**TRADE MOVEMENT**			
							LNG Exports		**Pipeline flows**	
	tcm	**%**	**bcm**	**%**	**bcm**	**%**	**bcm**	**%**	**bcm**	**%**
North America	9.9	*5.3*	826.1	*25.9*	846.1	*26.7*	20.0	*6.7*	123.6	*18.2*
S & C America	7.4	*4.0*	161.2	*5.0*	147.7	*4.7*	9.2	*3.1*	14.3	*2.1*
Europe & Eurasia	63.1	*33.7*	1,043.1	*32.7*	1,137.2	*35.9*	87.8	*29.5*	470.0	*69.4*
Africa	14.7	*7.9*	209.0	*6.5*	105.0	*3.3*	0	*0.0*	4.9	*0.7*
Middle East	75.8	*40.5*	460.7	*14.4*	365.5	*11.5*	2.9	*1.0*	31.5	*4.6*
Asia – Pacific	16.2	*8.7*	493.2	*15.4*	576.6	*18.2*	177.8	*59.7*	33.4	*4.9*
Total	**187.1**		**3,193.3**		**3,169**		**297.6**		**677.6**	

NB: tcm is trillion cubic metres; bcm is billion cubic metres
S & C America is South and Central America
Source: BP, 2011

Table 2. Proved Reserves as against Production and Consumption of natural gas in 2010.

Production cost of unconventional gas in North America ranges from $3-7/MMBtu. Other regions could be higher (**Table 1**).

Timely and successful development of new fields however depends on complex factors including industry's capability, policy choices of host countries and market demand.

4. Natural gas demand

IEA (2011) estimates that global gas demand could reach 5.1 trillion cubic metres by 2035 from about 3 trillion cubic metres in 2010. To meet the growing demand, global gas production must increase by 1.8 trillion cubic metres annually and unconventional resources would account for about 40% of it (IEA, 2011).

At the regional level, it seems clear that United States and Canada would continue to play minor role in net global gas trade in the short to medium term due to adequate gas and over-capacity production in North America. On the other hand, rapid growth in Asian gas demand during the same period would put pressure on supply (notably LNG) and consequently, prices and would stimulate greater supply investments within the Asian region and Greenfields elsewhere, particularly in Africa.

All regions are expected to see significant gas growth in the long term (IEA, 2011).

Most important factors determining the demand for natural gas in a country include the following:

- Level of economic activity of the country.
- Richness or suitability of the gas as feedstock for industry.
- Ease and access to supply.
- Competitiveness of the gas versus other fuel sources regarding pricing and environmental considerations.
- Host government policies involving incentives and commercial framework for investors.

Level of economic activity being driven by rising household incomes and increased commercial activities would boost demand for secondary and modern energy such as electricity and gas for cooking and heating. Natural gas use in residential, commercial and transport sectors of the economy requires construction of distribution networks which could be very expensive. Higher household income levels would therefore be necessary to cover cost of delivery and service. Growing industrial sector would require more power to support the growth.

Rich or wet gas if processed could yield other Petroleum Chemicals and for that matter add more value to upstream-midstream activities culminating in industrial growth.

Ease and access to supply of the gas if the price is competitive compared to alternative fuels would attract more customers for the gas. Natural gas has become environmentally **competitive fuel** of choice for environment-conscious economies and also economically competitive for carbon constrained economies because it emits less greenhouse gas per unit combustion compared to other fossil fuels. The global push to utilize relatively clean burning natural gas for power generation has both environmental benefits and power generation diversification and have triggered strong convergence between the natural gas and electric power value chains.

Power generation is the largest gas consuming sector and the biggest driver of gas demand today and it is expected to be so for the foreseeable future. Natural gas is used in both gas turbine and combustion/steam generating plants and prices of the gas in many parts of the world had remained strongly linked to oil, due to its interchangeability with other fossil fuels as industrial and power generation fuel.

Gas demand in the power sector is however said to be more sensitive to changes in the rate of growth of GDP than its use in the other applications. It was observed that from 1990-2008 a global average increase of 1% in GDP led to 1% demand in gas for power generation (IEA, 2011).

Besides power generation, transport stands out as having significant potential to drive demand upwards. Natural gas to supplement or substitute diesel as transportation fuel is one of the measures to reduce urban transport pollution. This is available in a number of European countries but also some developing countries like India.[11]

Natural gas vehicles (NGVs) are fuelled by CNG (compressed natural gas) and LNG (liquefied natural gas). The vehicular features are similar to the conventional ones using internal combustion engine except for the fuel injection system and the size of the fuel storage tank. These differences have given rise to additional costs of $2,000-10,000 higher than the standard vehicles for the natural gas fuelled vehicles.

LNG ships are currently diesel or light crude fuelled but most could be replaced by LNG in the long term and in the foreseeable future. There are approximately 120 LNG ships currently involved in worldwide trade.

Host government policies should be geared towards the ability to facilitate investment in pipeline networks. It means having commercial frameworks in place that not only attract investors but also protect affected public interests. For regional natural gas trade to occur, contiguous countries must have commercial frameworks that are similar enough to encourage market participants to develop efficient cross-border networks as well as dealing with risks. A good example for developing countries is the West African Gas Pipeline (WAGP) that carries Nigerian gas to Benin, Togo and Ghana (WAGPCO, 2011).

5. Natural gas supply

Most of the supply of natural gas is by pipeline for overland delivery and ship for transoceanic delivery as LNG.

Most of the imported gas would come from countries forming the Gas Exporting Countries Forum which has Russia, Oman, Malaysia, Algeria, Nigeria, Equatorial Guinea, Brunei, Iran, Turkmenistan, Indonesia, Qatar and Norway as the main members.

Globally, LNG trade is divided into two international trade blocks; West of Suez Canal and East of Suez Canal. There are old and new exporters as well as new and old importers for both sides of the Suez (Figure 3). For the new, the list is still evolving.

[11] Natural gas compressed to about 200 times at standard atmosphere.

Fig. 3. Suez Canal in Egypt, linking Mediterranean sea to the Red sea.

For the countries involved as at the time of compiling the lists, the picture is as below (Tables 3 and 4):

5.1 East of Suez

Old Exporters	**Old Importers**
Indonesia	Japan
Malaysia	South Korea
Australia	Taiwan
Brunei	
New Exporters	**New Importers (started since 2005)**
Qatar	China
UAE	India
Yemen	
	Future
Future	Thailand
Iran	Pakistan

Table 3. LNG Exporters and importers east of Suez Canal.

5.2 West of Suez

Substantial LNG regasification was built in the United States early 2000s in anticipation of the country becoming a large importer of LNG. However the unexpected rise in domestic (local) gas production particularly from shale gas during the same period reduced imports to the country significantly.
The following sections would elaborate gas transportation options.

Old Exporters Algeria Nigeria Trinidad and Tobago	**Old Importers** Western Europe USA
New Exporters Equatorial Guinea Egypt Angola Norway Peru	**New Importers** Western Europe USA Brazil *Future* Ghana as hub for West Africa
Future North America	

Table 4. LNG Exporters and importers West of Suez Canal.

6. Natural gas transport

The prevailing global market structure is such that for conventional gas, most consumption takes place far away from gas producing centres, which means the gas has to be transported by overland pipelines and or as LNG via specialized ships depending upon the distance and location of the consuming market and this condition is prevalent among developing and emerging market countries that are gas rich. In some cases however, gas is stranded due to physical distances and technical complexities associated with transportation.

Within local or domestic markets, there thus must be sufficient demand and the capacity for potential consumers to pay in order to justify investment in transportation and distribution infrastructure. For most developing countries therefore, the gas is largely used in industry as feedstock or fuel, thus very little goes to the residential and the commercial sectors due to relatively low income per capita. In the developed countries on the other hand, residential, commercial and the industrial sectors compete for the gas almost equally.

6.1 Overland pipeline transportation

Overland pipelines are generally found to have lower cost per unit and higher capacity compared to shipment by rail or road and for that matter the most economical way to transport large quantities of natural gas[12] over land. Overland pipeline transportation and distribution have therefore being the dominant mode for terrestrial gas transport.

The oldest gas pipelines in the world are said to be located in the United States. The first long-distance natural gas trunklines to serve the Midwest Region from the prolific Hugoton Basin located in the Texas/Oklahoma Panhandle were built during the 1930s (U.S EIA, 2011).

[12] Also crude oil and refined products.

North America also has the world's longest gas pipeline network. The Canadian system is about 20,000 km whilst the United States has over 90,000 km of natural gas pipeline on more than 66 intrastate natural gas pipeline systems (including offshore-to-onshore and offshore Gulf of Mexico pipelines) delivering gas to local distribution companies, municipalities and to many large industrial and electric power facilities (U.S EIA, 2011).

Europe on the other hand has 28,000-29,000 km of gas pipeline network. Most of the natural gas being used in Europe is imported via pipelines from Russia, Central Asia, the Middle East and North Africa, with imports from Russia accounting for a quarter of the total supply Table 5.

Pipeline	Origin of Gas	Capacity bcf (bcm)*	Completed	Distance Km
Trans-Austria	LNG - Austria	1695 (48)	1960s[13]	380
Trans-Europa	Northsea to Germany	565 (16)[14]	1974	968
Transitgas	Switzerland	NA	1974[15]	293
Frigg U.K	Northsea to Scotland	NA	1977	362
MEGAL	Chech/ Autrian to France	777 (22)	1980	1,115
FLAGS	Northsea to U.K	NA	1982	451
Trans-Mediterranean	Tunisia to Italy	1060 (30)	1983	2,475
West-Siberian [16]	Russia	1100 (31)	1984	4,500
STATpipe	Northsea-Norway	671 (19)	1985	890
Fulmar	Northsea to Scotland	160 (4.4)	1986	290
MIDAL	Northsea to Germany	459 (13)	1992	702
NOGAT	Northsea to Netherlands	NA	1992	62
STEGAL	Germany	NA	1992	314
CATS[17]	Northsea to U.K	618 (17.5)	1993	404
ZeepipeI-III	Northsea to Belgium	918 (26)	1993	1,416
Rehden-Hamburg	Germany	NA	1994	132
Eorupipe1	Northsea	635 (18)	1995	660
Netra	Northsea to Germany	NA	1995	408
Maghreb-Europe	North Africa	424 (12)	1996	1,620
Yamal-Europe	Russia	1165 (33)	1997	4,196
WEDAL	Germany – Belgium	353 (10)	1998	319
JAGAL	Russia to Germany	847 (24)	1999	338
Europipe11	Norway to Germany	847 (24)	1999	658
Blue Stream	Russia	16 (0.47)	2003	1,207
Green Stream	Libya (North Africa)	283 (8)	2003-2004	520
South Caucasus	Caspian Sea	247 (7)	2006	700
BBL	Netherlands to U.K	668 (19.2)	2006	230
Franpipe	NA	706 (20)	1998	840
Langeled	Norway	2.5 (0.07)	2007	1,200
South Wales	NA	NA	2007	197
Gazela	Russia border to Czech	NA	2011	176
	Total			**28,023**

bcf is billion cubic feet; NA is information not available

Table 5. Major existing and operative gas pipelines in Europe.

13 Extension completed in 2007
14 Upgraded in 1998 and 2009
15 Upgraded continued up to 2003
16 Also called Urengoy–Pomary–Uzhgorod or Trans-Siberian pipeline to Europe
17 Also called Central Area Transmission System

Australia has around 5,000 km gas pipeline network whilst Asia including Middle East has about 15,000 km pipeline network in operation as of 2011.

The longest gas pipeline in sub-Saharan Africa is the West African Gas Pipeline. The 678 km pipeline was completed in 2006 and transports natural gas from Nigeria to Ghana through Benin and Togo (WAPCO, 2011).

6.1.1 New pipeline projects

Relatively few pipelines are under construction and most are still planned as indicated in **Table 6**.

REGION	PIPELINE NAME	DELIVERY POINT	CAPA CITY bcm	STATUS	STATE DATE
Russia	Altai	China	30	Planned	2015
	Russian-Asian Pacific	Korea	10	Planned	2015-17
	Nord Stream	N.W. Europe	27.5	Under construction	2011 end
	Nord Stream 2	N.W. Europe	27.5	Planned	2012
	South Stream	S.E. Europe	63	Planned	2015 end
Caspian / Middle East	Nabucco	S.E Europe	26-31	Planned	2017
	ITGI	S.E. Europe	12	Planned	2017
	TAP	Italy	10+10	Planned	2017
	IGAT 9	Europe	37	Planned	2020+
Caspian	CAGP	China	+30	Under construction	2012
	CAGP Expansion	China	+20	Planned	Post CAGP
	TAP1	Pakistan	30	Planned	2015+
Middle East / Turkey	IPI	India	8	Planned	2015+
	Arab Gas Pipeline	Middle East / Turkey	10	Partially built	n.a
Asia Pacific	Myanmar-China	China	12	Under construction	2013
Africa	GALS1	Europe	8	Planned	2015

Start date are as reported by sponsors
CAGP is Central Asian Gas Pipeline; TAPI is Trans-Afghanistan Pipeline; IRI is Iran-Pakistani India; ITGI is Interconnection Turkey Greece Italy; TAP is Trans Adriatic Pipeline; IGAT is Iranian Gas Trunkline; GALSI is Gasdotto-Algeria-Sardegna-Italia. Source: IEA, 2011

Table 6. New pipelines planned and under-construction in the world.

6.2 Liquefied natural gas transportation

Although pipelines can be built under the sea, that process is economically and technically demanding, so the majority of gas at sea is transported by LNG tanker ships which is also seen as flexible compared to pipeline[18].

[18] LNG is natural gas that has been compressed 600 times its volume at standard atmospheric conditions (STP) and cooled to an extremely cold temperature (-260° F/ -162.2° C).

Around 75% of the inter-regional global trade is by LNG shipment as compared to pipeline.

LNG ships vary in size from 20,000 cubic metres to over 145,000 cubic metres cargo capacity but the majority of modern vessels are between 125,000 cubic metres and 140,000 cubic metres capacity (58,000 to 65,000 tonnes).

From LNG Liquefaction Plants, ships travel to demand markets to unload the LNG at specially designed terminals where it is pumped from the ship to insulated storage tanks and regasification Plant, where it is warmed up and converted back to gas before being delivered into the local gas pipeline network. Specially designed vehicle trucks are also used to deliver LNG to other storage facilities in different locations.

The liquefaction segment along the value chain is the most expensive and could constitute about 40% of the total LNG value chain cost. The regas segment is the least expensive depending upon the technology opted for (Table 7).

Production	**Liquefaction**	**Shipping**	**Regasification & Storage**
\$0.5-1.0/MMBtu	\$0.8-1.2/MMBtu	\$0.4-1.0/MMBtu	\$0.3-0.5/MMBtu
13—27%	22-40%	10-27%	8-15% *(15-30% for storage)*
Total value chain cost = \$2.00-\$3.70; with cost escalation = \$2.60 - \$4.80 *between 2006-2010*			

Source: Center for Energy Economics, UT-Austin, USA, 2008

Table 7. LNG Value Chain Costs.

LNG delivery from the vessels is accomplished through the following technologies:

i. Permanent LNG re-gasification plants.
ii. Floating Re-gasification plants using grounded LNG vessels which have retired from services.
iii. Temporary or stop-gap through "Energy Bridge Re-gasification Vessels" (EBRVs)

Permanent LNG discharge/re-gasification terminal: Development of permanent LNG re-gasification plant requires at least two years if funding for EPC[19] is readily available.

Energy Bridge Regasification Vessels: The energy bridge re-gasification is the LNG technology that delivers the gas in the shortest possible time; i.e. within a year. Energy Bridge Regasification Vessels, or EBRVs™, are purpose-built LNG tankers that incorporate onboard equipment for the vapourisation of LNG and delivery of high pressure natural gas. These vessels load in the same manner as standard LNG tankers at traditional liquefaction terminals, and also retain the flexibility to discharge the gas in two distinct ways. These are through:

- the EBRV's connection with subsea buoy in the hull of the ship; and
- a high pressure gas manifold located in front of the vessel's LNG loading arms.

Floating Re-gasification plants: Average lifetime of most LNG vessels is 25 years. This means LNG vessels built in the 1980s have become less competitive for transport services. Such an LNG ship is retired and reconfigured as floating LNG re-gasification facility.

[19] EPC is Engineering, Procurement and Construction.

Typical LNG ship has capacity of 120,000-125,000 liquid cubic metres (lcm). The larger the containment the greater the application for floating storage and regasification applications. Some 59 ships built worldwide before 1983 with containment between 122,000-133,000 lcm are due for retirement.

The LNG market and industry is expanding rapidly. LNG liquefaction capacity was 270 bcm in 2008 increasing to 370 bcm as of 2011 of which Qatar accounts for over 25%. This is expected to expand to 450 bcm in 2015 and doubled by 2020. New projects under construction are due to be on stream from 2014-2016 (Table 8).

COUNTRY	PLANT	CAPACITY		START DATE
		bcm	MTPA	
Algeria	Skikda (rebuild)	6.1	4.5	2013
	Gassi Touil	6.4	4.7	2013
Angola	Angola	7.1	5.2	2012
Australia	Pluto	6.5	4.8	2011
	Gorgon	20.4	15.0	2014
	Gladstone_LNG	10.6	7.8	2014
	Queensland Curtis	11.6	8.5	2015
	Donggi Senoro	2.7	2.0	2014
Papua New Guinea	PNG LNG	9.0	6.6	2014

Note: Start dates are as reported by project sponsors. MTPA is million tonnes per annum. Source: IEA, 2011.

Table 8. Liquefaction plants under construction by country.

500 bcm additional liquefaction capacity is being evaluated for 2015-2020 of which about 75% of it has been earmarked for construction in Australia, Russia, Nigeria and Iran (IEA, 2011).

6.3 Downstream gas delivery to customers

From the transmission pipelines, the gas reaches the consumers through the distribution network. Direct access to gas supply to maintain higher pipeline load factors improves efficiency of operations. However, occasionally, natural gas delivery commitments to downstream customers could be wholly or partially curtailed due to:

- force majeure conditions;
- compressor (station or unit) unavailability;
- line break; and
- supply unavailability for other reasons other than those mentioned above.

For short term (lasting up to 12 hours or 24 hours) "upset" conditions therefore, **linepack** could be used to address the shortfall. The usefulness of the **linepack** would depend on the duration, magnitude and location of this transient condition.

For long term supply disruptions (lasting days, weeks or months), however, storage facilities or an LNG storage system might be required. Depleted oil or gas reservoirs, aquifers or salt caverns are examples of such storage facilities.

If longer (over 6 months) disruptions are anticipated, alternative gas supply network is essential. In general, a mix of overland pipeline and LNG source, with an associated re-gasification unit, for a country or region is recommended.

Because of some of these challenges, domestic or local pipeline transportation of natural gas tends to be characterized by state intervention in various forms to manage market power and to protect the public interest as well.

The next question posed *is at what price is the gas delivered? How is the pricing of the gas computed and what kinds of contracts are made for the supply and delivery of the gas?*

7. Gas pricing, ownership and supply contracts

7.1 Pricing

Natural gas, particularly LNG is generally priced in CIF[20]. Formula 1 is the general pricing formula:

$$\textbf{Total price = Gas head price + Transportation price + Other prices.} \tag{1}$$

Where Other prices could be distribution or profit margin, taxes and depreciation.

Some of the gas pricing mechanisms that have been introduced into the market are as follows:

- *Cost of Service*
- *Spot Price*
- *Netback Pricing*
- *"S-shaped" price curve*
- *Barter trade*
- *Price-Index provision*
- *Seasonal and weather-normalised rates*
- *Gas Swaps*
- *Production or Supply Payment*

7.1.1 Cost of service

The cost of service (COS)[21] of a project is defined as the minimum price required to provide for capital recovery, covering operating costs and paying taxes, royalties and production sharing, etc. The traditional gas market is based on long term contract and has used COS for pricing. COS is also basis for price regulation in most countries including approving appropriate return on investments.

[20] Unlike oil which is generally priced in FOB. CIF is abbreviation for Cost, Insurance and Freight, whilst FOB is abbreviation for Free on Board.
[21] Also called "Rate of Return"

The regulated company's revenue requirements are the total funds that the company may collect from customers and it is calculated by multiplying the company's rate base by an allowed rate of return (ROR) and adding this product to the company's operating costs (OC) as shown in formula 2.

$$\textbf{Revenue Requirement} = (\textbf{Rate base} \times \textbf{ROR}) + \textbf{OC} - (\textbf{Taxes} + \textbf{Depreciation}) \qquad (2)$$

The Rate base is the total value of the company's capital investments, which may include constructional work in progress. The allowed ROR constitutes a profit sufficient to pay interest on accumulated debt and to provide a negotiated acceptable return to investors.

A negotiated acceptable or what is termed as a fair return is determined through a comparable earning tests, where a company's earnings are measured against those of a firm facing comparable risks[22]. Operating costs include expenses on gas, labour, management, maintenance and commercials. Taxes and depreciation are also part of the company's revenue requirments.

Regulators are faced with the challenges of determining the price appropriate and acceptable to the seller to cover cost operations and future investments. Also, there is a challenge in allocating costs and acceptable prices/tariffs to the different customer classes. The regulator therefore first seeks to determine how much of an applicant's captial stock should be included in its Rate base, then attempts to determine which elements of test year costs and revenues should be allowed for regulatory purposes and whether to allow specific changes since the test year. The final step is to determine what the fair ROR is for the company.

7.1.2 Spot price

Spot price is the price of a commodity such as the gas on the spot and is dependent upon time and location. The spot price of gas say in Takoradi, Ghana at 01.00 GMT could be different from the spot price of gas of the same quality in Takoradi, Ghana at 02.00 GMT.

Spot market is characterized by:

1. Short purchase contract term, usually 18 months.
2. Best-effort delivery.
3. Negotiated price reflecting current market conditions.
4. Arranging transportation separately from the sales and usually provided on an interruptible basis.

There is an increasing frequency of spot sales. Participants in the **spot market** include:

1. Local distribution companies (LDCs) who buy the gas from the pipeline companies.
2. Marketers/Traders who buy the gas on the **spot market** to resell to LDCs and large customers. Some marketers do not sell gas themselves. Instead, they bring buyers and sellers together and help negotiate arrangements for transportation of the gas.

[22] A discounted cash flow approach, where a company's capital costs are estimated by analyzing conditions in the financial market, or other methods.

3. Pipeline operators at times purchase **spot market** gas and mix it in their supply portfolios in an effort to lower weighted average cost of their gas.
4. Industry, large commercial consumers and electric utilities may purchase **spot market** gas to increase supply security, but they have to arrange transportation of the gas to their vicinities.

As spot sales increase and proliferate, they are likely to undermine, if not topple the long term contract and price structure which had been an important feature of the traditional gas market.

7.1.3 Netback pricing

Netback pricing is retail price less all costs and expenses. The marketer after taking care of all associated costs, expenses and agreed profit margin, returns to the producer the balance. It encourages the marketer and the producer to increase market share and also receive a fixed profit margin.

Netback Pricing was first introduced by Saudi Arabia in 1985 and it was a revolution because the setting of the pricing was shifted from the producer to the consumer and it was the case until early 2000s when FUTURES market took over.

7.1.4 "S-shaped" price curve

This somehow operates on the principle of price ceiling and price floor. At below an agreed price floor of say \$6 per MMBtu, the buyer agrees to pay an additional premium for the gas. However above price ceiling of say \$10 per MMBtu, it is the reverse, the seller pays a premium to the buyer. The end result is a win-win situation where the buyer enjoys a discount at high prices and the seller is protected against low gas prices. The **S-shaped** pricing mechanism is likely to be used more in the future, particularly as civil society voice becomes louder to see fair share of profit for particularly host developing countries with the finite resource.

7.1.5 Barter trade

Barter trade is simply the exchange of gas for other commodities needed by the gas-exporting country. Existing barter agreements include Russian gas for Polish potatoes and Russian gas for Ukrainian consumer goods food and machinery.

7.1.6 Price-Index provision

Besides the base pricing described above, there is also the **indexing**. Meaning the pricing formula usually consists of two main parts, the base price and indexing. The major consideration for pricing in the case of gas is that is largely used as fuel and so the price is on energy basis and so indexed to price movement of other alternative fuels, such as crude oil, gasoline and fuel oil. Price-index provision ensures that the gas delivered is competitively priced compared to alternate fuels.

Besides price indexing and to cope with competition from alternative fuels and to avoid losing customers, some pipeline operators would provide special tariffs to keep multi-or dual fuel capable industrial customers from switching during period of high gas prices. They could offer incentives such as waiving transportation rate on the gas to reduce the tariff.

7.1.7 Seasonal and weather-normalised rates

Seasonal rates are where the price of natural gas is influenced by the seasonality of gas demand and supply. It is one of the new pricing mechanism for gas particularly in temperate regions. For weather-normalised rates, the price of natural gas is locked into an agreed weather and this can help reduce the effect of abnormal weather patterns on utility earnings.

Tariffs charged by pipelines and LDCs reflect gas sales and transportation volumes. The higher the volumes, the better the sales. However, residential demand is largely weather-sensitive in cold/ temperate climates. Meaning the warmer the weather the less the demand and vice versa. Abnormal weather patterns have therefore been the single most important factor for supplies to largely residential customers. To minimize the impact of weather on revenues, some gas utilities use the **weather-normalised rate** for customer billing; rates are increased when weather conditions are warmer to cover drop in demand; conversely, rates are reduced when weather is colder than normal.

7.1.8 Gas swaps

Besides, **weather-normalised rate**, an LDC may enter into agreements with a large industrial customer with dual-fuel capacity and high-load factors. In the summer when demand for gas is lower for the LDC, the industrial customers may utilize the LDC's excess supplies. Conversely, in winter periods when demand for gas is higher from the LDC, the industrial customer switch to their alternative fuels to enable the LDC meets their contracted volume supplies. Such **gas swap** contracts result in savings for both the LDCs and the customers.

7.1.9 Production or supply payment

In production or supply payment, the buyer makes upfront cash payment for gas to be produced or supplied over a long term in most cases, years. The major features of production payment are:

1. It represents a new capital source for the gas industry.
2. It is basically risk-free to producers. Further, the buyer only has recourse to the given field specified in the agreement.
3. The buyer is better off locking in firm title to reserves at a known price to back their sale commitments to guide against period of rising prices.

7.2 Ownership contracts

The different types of ownership or operational contracts regulating the gas market are:

- Concession

- Production Sharing Contract or Agreement, i.e. PSC or PSA
- Joint Venture
- Service Contract

Concession

Concession is an agreement that is royalty based. It means the host country government gets most of its share through royalty. Royalty is another name for Production Tax and it is related to gross revenue. Gross revenue less royalty equals NET revenue. Royalty also means, the government of host country gets its pay first. The advantage is that host country or government's risk is zero, because production loss or profit, the government takes the royalty. The next deductions from the net revenue include operating costs, depreciation, amortization and intangible drilling costs. Revenue remaining after royalty and the deductions is called **taxable income**. The remaining revenue after taxation is the **contractors take.**

Production – Sharing Contracts (PSC)

For purely Production Sharing Contract (PSC) or Agreement (PSA) as sometimes called, the operating company takes all the risks but manages the production, etc. Government in turn may take off taxes on all imported equipment and provide other tax incentives. After all the deductions by the operating company, there remains the NET revenue and this is what is shared between the operating company or entity and the government. The net revenue is called the profit hydrocarbon and in this case the **profit gas** and is split between the contractor and the government, according to the terms of the PSC negotiated. It means the company takes its money first before government/host country comes in, whilst in **concession** the government takes its money first.

The title of the hydrocarbons however, remains with the host country government (Johnston, D. 1994). With growing awareness of good governance, the state may also maintain the management control and, or would require the operator to submit annual work programmes for scrutiny and approval. Most PSC/PSAs are placing limit on cost recovery such that if the deductions amounts to more than the allowed limit, the balance would be carried forward and recovered later. In some cases, the host country would push royalty payment into the PSC/PSA, and may go by different names such as War Tax levy in Columbia (Johnston, D. 1994). In this case, the profit gas is Net Recovery less Cost Recovery. The operator's share of the profit gas may also be subject to taxation.

Joint venture

Joint Venture is a partnership where the parties share the risks and the rewards together. In **joint venture,** there is always a reference to WI (working interest) meaning – sharing of all costs and expenditures.

Investment in the gas industry in general is capital intensive and has long lead time and often involves financial risks. Investment through Joint Ventures therefore spreads the risks among parties and therefore reduces the share of responsibility of individual parties involved.

Service contract

Service contract means producing and may be selling in this case the gas on contract for the host country or government. In a typical **service contract** therefore, all the gas belongs to the host country or government. The operating company is paid for every per volume or energy of gas produced.

A kind of service contract is **Technical Assistance Contract** (TAC). TACs are often referred to as rehabilitation, redevelopment or enhanced oil recovery projects. They are associated with existing fields of production and sometimes, but to a lesser extent, abandoned fields. The contractor takes over operations including equipment and personnel if applicable. The assistance that includes capital provided by the contractor is principally based on special know-how such as steam or water flood expertise.

Rate of return / R- factor contract

Some countries have developed progressive taxes or sharing arrangements based on project rate of return (ROR). The effective government-take increases as the project ROR increases. The sliding-scale taxes and other attempts at flexibility may be based on profitability and production rates depending upon negotiation. To be truly progressive however, it should be based upon profitability.

Some contracts use what is called an R factor. **R** factors deal with all variables that affect project economics and it is expressed as:

$$Rfactor = \frac{Accrued.net.earnings}{Accrued.total.\exp enditures} \tag{3}$$

7.2.1 Some basic elements of operating contracts

The existing market is apparently being driven by a hybrid of **concession** and **PSC/PSA**.

PSC/PSA in the long term becomes **Service** contract, provided no new major investment is made in the production business, otherwise in most cases equipment purchased or imported under the contract become the property of the state at the end of the project. This is because, under most PSC/PSAs the contractor cedes ownership rights to the government for equipment, platforms, pipelines and facilities upon commissioning or startup. The government as owner is theoretically responsible for the cost of abandonment. Anticipated cost of abandonment is accumulated through a sinking fund that matures at the time of abandonment. The costs are recovered prior to abandonment so that funds are available when needed.

PSC/PSA is also being phased out in preference for **Joint Venture** contracts and that is the likely contract for the gas industry and market in the future, because host or producing (usually developing) nations demand quick cash revenue turnovers and these are assured under Joint-ventures. Most national oil companies (NOCs) are therefore moving into **Joint – Ventures**.

In summary, the characteristics of the contract types are as below (Table 9):

Contract type	Characteristic
Concession	Royalty for Government first.
PSC/PSA	Share of profit gas but company takes money first.
Joint Venture	Net Revenue interest.
Service Contract	All gas belongs to Government.
Rate of Return	Rate of return

Table 9. Summary characteristics of ownership contracts.

Many aspects of government/contractor relationship may be negotiated but some are normally determined by legislation. Elements not determined by legislation must be negotiated. Even though, it is usually better to have more aspects that are subject to negotiation, flexibility is the watchword.

Elements like r**oyalty is** taken right off the gross revenues and therefore contributes to their lack of popularity with the industry since they can cause production to become uneconomic prematurely. This works to the disadvantage of both the industry and government. One remedy that has become popular is to scale royalties and other fiscal elements to accommodate marginal situations. The most common approach is an incremental sliding scale based on average daily production. A sample sliding scale royalty could be as below (Table 10).

Average	Daily production	Royalty
First tranche	Up to 100 mmscf/d	5%
Second tranche	101-200 mmscf/d	10%
Third tranche	Above 200 mmscf/d	15%

Table 10. Sample sliding scale royalty.

Cost recovery may include the following items:

- *Tangible and intangible capital costs.*
- *Interest on financing (usually with limitations).*
- *Sunk costs*
- *General and Administrative Cost.*
- *Investment Credits and Uplifts*

Tangible vs. intangible capital costs: Sometimes a distinction is made between depreciation of fixed capital assets and amortization of intangible capital costs. Under some concession agreements, intangible exploration and development costs are not amortized. They are expensed in the year they are incurred and treated as ordinary operating expenses. Instances where intangible capital costs are written off immediately can be an important financial incentive. Amortizing intangible costs can take longer to recover, if not carefully negotiated.

Interest cost recovery: Sometimes interest expense is allowed as a deduction. Some contracts limit the amount of interest expense by using a theoretical capitalization structure such as a maximum 70% debt (Derman, A. and Johnston, D. 1999).

General and administrative costs: Many contracts allow the contractor to recover some office administrative and overhead expenses. Non operators are normally not allowed to recover such costs. Most unrecovered costs are carried forward and are available for recovery in subsequent periods. The same is true for unused deductions.

Sunk cost is applied to past costs that have not been recovered. Exploration sunk costs can have a significant impact on field development economics and can strongly affect the development decision. For this reason, many contracts may not allow pre-production costs to begin depreciation or amortization prior to the beginning of production.

Investment credits and uplifts allow the contractor to recover an additional percentage of capital costs through cost recovery. For example, an uplift of 20% on capital expenditures of $100 million would allow the contractor to recover $120 million. Uplifts can create incentives for the industry. Uplifts are the key of rate of return contracts.

Most contracts have a limit to the amount of revenues the contractor may claim for cost recovery but would allow unrecovered costs to be carried forward and recovered in succeeding years. In summary, the hierarchy of cost recovery can make a difference in cash flow calculations.

The basic elements of operating contracts besides royalty and cost recovery include work commitment, bonus payments, domestic obligation, ring fencing, commerciality, reinvestment obligations, tax and royalty holidays.

Work commitment refers to the obligations an exploration company incurs once a PSC/PSA is formalized and they are generally measured in kilometres of seismic data and the number of wells to be drilled in the exploration phase.

Cash bonuses are lump sums paid by the contractor to acquire a particular license. These cash bonuses are the main element in bidding rounds of very prospective acreage. **Production bonuses** are paid when production from a given contract area or field reaches a specified level.

Domestic obligation: Many contracts specify that a certain percentage of the contractor's profit oil be sold to the government. The sales price to the government is usually at a discount to world prices.

Ring fencing: Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is *ring fenced*. This element of a contract can have a huge impact on the recovery costs of exploration and development. From the government perspective, any consideration for costs to cross a ring fence means that the government may in effect subsidize unsuccessful operations. Allowing exploration costs to *cross the fence* may therefore be negotiated.

Commerciality deals with who determines whether or not a discovery is economically feasible and should be developed. Some regimes allow the contractor to decide whether or not to commence development operations. Other systems have a commerciality requirement where the contractor has to prove that the development of a discovery is economically beneficial for both the contractor and the government. The benchmark for obtaining commercial status for a discovery cannot be developed unless it is granted commercial status by the host government. The grant of the commercial status marks the end of the exploration phase and the beginning of the development phase of a contract.

Reinvestment obligations: Some contracts require the contractor to set aside a specified percentage of income for further exploratory work within the license.

Tax and royalty holidays: The purpose of tax and royalty holidays by the host country is to attract additional investment.

7.3 Supply contracts

There are four main types of physical trading supply contracts, namely, **swing, base-load, firm** and **futures contracts.**

Swing contract

Swing contracts are usually short term contracts and not longer than a month. It is also called 'interruptible'contracts. Under this type of contract, both the buyer and the seller agree that delivery of the gas can be interrupted on short notice; no legal commitment. They are the most flexible and are usually put in place when either the supply of gas from the seller, or demand for gas from the buyer are unreliable.

Base-load contract

Base-load contracts are similar to swing contracts in that neither the buyer nor seller is obligated to deliver or receive the exact quantities specified. However, it is agreed that both parties would attempt to deliver or receive the specified volume on a best-efforts basis. In addition, both parties generally agree not to terminate the agreement due to market price movements. There is however no legal recourse for either party if they believe the other party did not make the best effort to fulfill agreement. Such contracts rely instead on the relationship (being it personal or professional) between the buyer and the seller.

Firm contract

Firm contracts are different from swing and base-load contracts in that there is legal recourse available to either party, should the other party fails to meet its obligations under the agreement. These contracts are used primarily when both the supply and demand for the specified quantity of the gas are not likely to change.

Futures contract

Futures is one of the derivatives used in the financial markets for both commodities and securities.

Futures contract entitles the buyer of the gas through the contract to take delivery of it at an agreed location and at an agreed date specified in the contract in the future and it compels the seller to deliver the commodity to the buyer at the specified date in the future under the same conditions. Because the contract is tradable, i.e. can be bought and sold in open market, its value changes as the supply of and demand of these contracts changes.

A common feature for futures contracts is that they are standardized such that each futures contract represents the same quantity and quality, valued in the same pricing format, to be delivered and received at the same agreed delivery location and date. The only variable in a futures contract as to when it is bought and sold is *the price of the contract.*

The success of the natural gas market depends on factors including uncertainty in supply and demand, large trading volumes and price volatility. For this reason, futures traders base their price offers on the spot market prices and the markets also allow companies to hedge their price risks.

The major delivery locations in the United States are the Henry Hub in Louisiana and Waha Hub in West Texas. The high volume of trading activity and the high degree of volatility in prices at these two locations have made them points of choice for traders.

The New York Mercantile Exchange (NYMEX) introduced and began trading in natural gas futures with Henry Hub in 1990. The Kansas City Board of Trade (KSBT) also began trading in natural gas futures in 1995 with Waha Hub as the delivery point.

The International Petroleum Exchange (IPE) opened its gas futures for trading in 1997. More companies are now trading their gas futures through IPE. IPE quoted prices are increasing being used as guide by a number of firms in Europe and are gradually becoming a benchmark for gas market in Europe. IPE operates a 12-month range gas futures contract and it is likely to be extended to 15 months.

8. Gas market and industry structure

8.1 Traditional regulation

In the traditional regulatory environment, the main gas transmission entities have mostly been state owned. The state entity supplies gas to one or more distribution entities that are charged with the distribution of the gas to retail customers in specific concessional areas exclusively. In some cases, the transmission monopoly is legally separate from the distribution entity. Supply contracts between the transmission monopoly and the distribution entities are usually long term and are regulated by government agency. A distribution entity in turn has legal monopoly over the supply to retail customers in a concessional area. The gas supply to the public is also regulated by a government regulatory agency and it covers regulation of prices, return on investment, etc. Some regulatory agencies are fully or partially decentralized to the state, regional or district/local level.

The traditional gas marketing system also bound producers, pipelines, local distribution companies (LDCs) and consumers together with long-term contracts, with little room to respond to changes in the market place.

The government controlled price regulation and political pressures on price levels sometimes lead to operational inefficiencies. As demand grows however, pressure to remove subsidies would increase.

Bundled service

The traditional gas market is characterized by **bundled service –** production, transmission and distribution vertically connected and owned by one entity or a consortium. **Bundled service** certainly gives more monopoly to one company, but provides less complication for a new or emerging industry in a country.

8.2 Unbundling service: The new and future regulation

Unbundling is the process of separating natural gas services and supply into components with each component priced separately. Natural gas companies go through varying degrees of organizational unbundling based on market maturity, monopolistic power of the incumbent and the regulatory regime in place.

Unbundled service is usually appropriate for older, matured markets, typically with hundreds of customers. It is not uncommon to amend regulations to cater for unbundled service as the market gains maturity and more new customers (particularly the commercial and residential customers) come on stream. In the United States for instance, unbundling of the market and transportation services for interstate pipelines did not occur till 1993 (FERC Order 636), even though the networks had been in place for over 50 years. In South America, unbundling was born out of increased consumer groups and industry maturity.

The main objective is to prevent cross subsidy, abuse of market and rather maximize efficiency. The purpose of unbundling is to secure non-discriminatory treatment for companies seeking access to pipeline, by ensuring that a vertically integrated transport company does not discriminate in favour of its own gas supply business.

Unbundling ensures that cost is correctly allocated to transportation. This cost clarity provides a basis for establishing use-of-system charges. Unbundling enables customers to pick and create their own services package. Marketers can package the variety of options and sell these services to consumers without discrimination. This leads to the facilitation of competition, also allowing which components of the value chain could be offered for privatization should the need arise and consequently increased efficiency.

Unbundling would characterize the new and future gas market structure.

8.3 Privatization of the gas industry

Privatization allows governments to attract private capital and encourage private investments in its business portfolios. Objectives are to:

- Restructuring poorly run state-owned entities.
- Raising cash to relieve budgetary deficits.
- Raising foreign capital to repay foreign debt.
- Spreading ownership of operations.

Other advantages include attracting new technologies, increased competition and improved efficiency in operations.

8.3.1 Methods of privatization

i. Public offering of shares

Under this method, the government sells to the general public all or part of the shares it holds in a state-owned company. In both cases, widespread shareholding of the entity or enterprise is created.
When only a portion of the shares is sold, the result is a joint state-private ownership of the entity, or what is currently termed as Public Private Partnership.

ii. Private sale of shares

Under this method, the government sells all or part of its holdings in a state-owned company to a single purchaser or group of purchasers. The transaction can be direct acquisition or through a third party such as a broker.

iii. Asset acquisition

The transaction comprises sale of assets instead of shares. Assets can be sold individually to downsize the entity or, sold bundled to form a new corporate entity. The sale of asset can be by open competitive bidding or direct negotiation with the purchaser.

iv. Fragmentation

Fragmentation involves the breaking up or re-organisation of a state-owned entity into several separate entities or into a holding company with several subsidiaries. This method permits piecemeal privatization and allows other different methods of privatization to be applied to different component parts, thereby potentially maximizing the benefits of the overall process. Fragmentation also allows large state-owned entities into separate enterprises and eventually creating competition in the market.

v. Expanding state owned entities with private investment

Under this method, the government instead of disposing of any of its equity rather invites the private sector to buy into the venture. As with Public offering of shares, it results in a Private – Public Partnership joint venture.

vi. Management/Employee buy-out

Under this method, a group of managers or employees acquires a controlling interest in the entity or enterprise. The management/employee leverage use credit to finance the acquisition whilst the collective assets of the acquired enterprise is used as collateral.
This method provides means of transferring the ownership to management and employees and could be a solution for state-owned companies that are difficult to sell or very strategic to the economy, community or the nation. A strong cash-flow potential however is usually the pre-requisite for securing credit for the buy-out.

vii. Management contracts

Under this method, functions related to the entity's operations are contracted out to external usually private management group. There is usually no transfer of ownership and no divestiture of state assets. It has the potential to increase efficiency and effective use of state assets and it is seen as one of the feasible options for introducing private equity into state-owned enterprise especially in developing countries.

Examples of countries with privatization of gas sector

Argentina in 1985 embarked on privatization drive that led to the sale of its national gas transmission systems and a state-owned gas distribution company.

Belgium deregulated its gas sector in the year 2000 and allowed private participation in its local gas market.

Russian gas industry is dominated by GAZPROM, a state-owned company and it is known to be the largest in the world. In 1993, GAZPROM became a state-owned joint stock company and began privatization in 1994. Management/employees as well as local investors were allowed to buy shares whilst the government retained 40% of the shares. 9% of GAZPROM shares were set aside for foreign ownership.

9. The future market

In the evolving and future market and to the customer, cost of the gas and cost of transportation are the major considerations to determine the least-cost gas supply plan. This new marketing paradigm is putting a lot of pressure on gas producers, pipeline operators and LDCs to compete with each other eventually improving efficiency and potentially leading to decrease in cost of supply. New industry players including spot gas marketers and brokers of pipeline capacity create additional links between suppliers and customers. These developments are expected to intensify competition in the gas market and would have major implications for the industry in the future.

The focus of restructuring and regulatory reform in the evolving market therefore would be to reduce state regulations and introduce more competitive market whilst concurrently reforming the regulations to induce more efficiency in performance.

From the on-going restructuring worldwide, six lessons could be deduced which could also serve as guidelines for restructuring of the traditional gas industry. They are as follows:

i. Privatizing state-owned entities with the objective to create efficiency;
ii. Promoting competition in the supply of gas services by
    a. Opening up access to new suppliers; and
    b. Deregulating prices
iii. Ensuring that transmission access rules and associated prices are in most cases non-discriminatory to all applicants to support competition, except for foundation customers and where in special cases targeted at promoting local industry.
iv. Developing pricing arrangements that provide revenues to expand efficient investments maintain decent return on investments.
v. Providing sustainable return on investment for distribution companies but deemed fairly affordable for consumers.
vi. Putting in place regulatory and contractual mechanisms that ensure that market agreements are honoured.

9.1 Mergers and acquisitions in the gas industry

Merger in simple term means legally combining strengths but minimizing weaknesses. The end results include extending cooperative life. Acquisition simply means the entity being acquired has conceded weakness on its part.

Combining two corporate cultures could however cause serious challenges and could lead to failure if not managed well. Fundamental considerations for mergers and acquisition should therefore be:

1. Relate to the core business and that there is expertise to run the expanded business.
2. Supplement or extend current operations.
3. Not raise end-user tariff significantly, in most cases, it should lead to reduction in cost of doing business and eventually decrease end-user tariff.

9.1.1 Targets for mergers and acquisitions

Most attractive targets and successful ventures in the gas industry have been

- Parties involved are in a closely related business.

- The parties involved complement each other's weaknesses.
- Financing does not create unreasonably high debt-to-equity ratio.
- Employees of both parties receive a fair deal and most are happy with the merger or acquisition.

For natural gas pipelines and local distribution companies (LDCs), expansion through mergers and acquisitions offer numerous benefits including:

i. Reducing over all management costs.
ii. Creating large customer base.
iii. Opening access to new supply sources.
iv. Increase economies of scale.
v. Penetrating new markets and offering new services.
vi. Reducing or avoiding new investments by gaining access to new facilities.
vii. Cutting costs by eliminating duplicate services.
viii. Establishing name and recognition with customers.
ix. Flexibility in transporting large volumes of gas due to increase market share.
x. Expanded operational areas.

Unsuccessful mergers and acquisition on the other hand are characterized by the fact that the acquiring party:

- Pays too much for the acquisition. *Over-value of the acquired assets can cause acquisition failures. This can come about when the evaluator mistakenly over-values the entity being acquired.*
- Over estimate the market projections.
- Combine two different corporate cultures.
- Had limited access to information before merger or acquisition, in other words, lack of transparency.

9.2 National gas and international gas companies

National gas companies

National gas companies (NGCs) are currently and generally the same as the national oil companies (NOCs) of the host countries, since the gas market is still evolving compared to the oil market. NOCs usually represent the interest of their governments in the petroleum market. They act as gatekeepers and control access to the majority of resources for future oil and or gas production.

Many NOCs came into being during a period of relatively large-scale state intervention in their countries' economies, a process which only began to reverse in the 1980s-1990s (Stevens, 2003). It was envisaged in those times that market forces would not be sufficient to propel poor developing host countries out of their poverties. With most natural resources vested in the government, it was thought that only the state could marshall the resources required for the massive economic development. In recent times however, additional reasons have been (i) emergence of nationalism; (ii) hydrocarbon listed as a strategic resource; and (iii) commercially risky and technologically complex sector (Foss, 2005a; Foss, 2005b; Mommer, 2002).

The overall goal of an NOC therefore is to ensure the effective development of the hydrocarbon sector of the country and as well contribute to the country's socio-economic development.

The immediate objectives include:

- Earning revenue for the country;
- attracting new technology;
- ensuring infrastructure development;
- creating employment; and
- the latest addition, minimising damage to the environment.

NOCs differ from country to country based on the following:

- the level of government or state control or ownership.
- The extent of private shares.
- Their financial health.
- Access to international credit.
- Their operational experience and skills.

The more experience, skillful and higher the access to international credit, the more likely such an NOC would go international and become an IOC (International Oil Company).

International oil companies

The traditional examples of IOCs are Exxon-Mobil and Chevron of the United States, BP of United Kingdom, Royal Shell of the Netherlands, Elf and Total of France. The new entries include the PetroChina of China, Petrobras of Brazil, Petromas of Malaysia and Norsk Hydro of Norway.

The primary objectives of an IOC in a host country are:

- To look for good geology to find the resource, in this case gas.
- To expand operations.
- To maximize return on equity to shareholders, simply saying to make money.

What most IOCs consider before entering a host country after the presence of a good geology has been confirmed, include:

- Political stability.
- Respect for honouring contractual obligations, i.e. contract is not unilaterally changed in the middle of the course.
- Robust and transparent legal system, i.e. company believes that it shall receive a fair hearing during legal cases.
- Fulfilling bilateral cooperation between partners in the business and the host country.

Cooperate social responsibility goals have since 1990s been playing greater role in their host country operations.

9.3 Future of national and international gas/oil companies

More NOCs would move away from just exporting raw gas to adding value to the commodity. Nations with rich natural gas resources have aggressively added new petrochemicals capacity for the production of methanol and other industrial chemicals. It has been observed that a country like Trinidad and Tobago has been very successful in attracting foreign investments. In the mid-1970s, the country had a paradigm shift with respect to the focus of the hydrocarbon production – monetization of natural gas. Since 1975, the natural gas has been used to manufacture methanol and ammonia and exported to the United States.

A shift from "raw gas exporting" to "value-added" however would depend upon host Government policies and the type of instruments used to implement the policies, since they have impact on local gas consumption and fuel choices, directly or indirectly. For instance environmental policies to promote cleaner alternative fuels may encourage greater gas use locally if available through favourable taxation and financial incentives for development of infrastructure. Lower taxes on gas prices and CNG vehicles but high on diesel fuelled vehicle could help reduce local consumption of diesel and consequently local pollution in mega cities such as found in India.

With time and as nationalism sentiments grow, traditional IOCs such a Exxon-Mobil would be pushed out of most host developing countries whilst more NOCs would become IOCs. For instance, Petrobras of Brazil, Petromax of Malaysia and PetroChina of China which were formally NOCs have become the major new IOCs.

For IOCs therefore to exist in future, **first**, they must be at the cutting edge of technology where the NOCs are nowhere near. This can only be achieved through research and development (R&D). R&D investment however does not come cheap and does not yield immediate results; it may take between five to ten years.

IOCs that are short-sighted would not invest in R&D and by this posture, would be those which would cease to exist.

As oil and gas resources are becoming dear to explore and produce, the NOCs would look for IOCs with the requisite technologies. IOCs in the future therefore would be looked at as 'banks' of technologies and the knowhow. Therefore robust IOCs shall be the 'banks' with the skills.

Secondly, IOCs that takes on social responsibility and show respect to the environment are likely to survive for long in developing countries. This has become necessary because even though contractual commitments to host governments are honoured and the latter is supposed to take care of the social needs of its people, host governments usually renege on their commitments to the immediate communities. The IOCs may need not take on social responsibility programmes directly but could either set up a separate social enterprise or team up with a known one to implement the social and or environmental programmes.

The last but not the least, is local content. IOCs with programmes to train and employ local manpower are likely to have prolonged stay in developing countries as the latter exert pressure usually backed by civil society to increase local content share of the IOCs' operations.

10. Market options for developing countries

10.1 Policy and regulatory environment

Policy and regulatory environment would be a key driver for the growth of the natural gas market in any country. To ensure growth of the market, the policy and regulatory regime should first of all reflect fair returns to all stakeholders, including government and other stakeholders. The appropriate role of each stakeholder should be spelt out clearly without ambiguity (Energy Commission, 2007).

Secondly, the policy and regulatory regime should be transparent, predictable, clearly defined and open to all investors that meet laid down criteria. The nation's interest is best served by a well defined policy regime that is open to all eligible investors. The policy and regulatory regime should also be simple to administer and not imposing lengthy bureaucracy on private investors. Lengthy bureaucracy could breed corruption since civil and public officials at times take advantage of the long wait-time to promise ‘short-cuts’ to potential investors. Simplicity in administration is necessary to reduce the costs of compliance to both the investor and relevant government agencies. A policy regime that is loosely defined and subject to discretionary interpretation by public servants can prove costly and can lead to investor uncertainty, the uneven treatment of investment proposals, and can encourage counterproductive behaviour on the part of private sector interests.

10.2 Implementation models

In most developed countries, the Local Distribution Companies (LDCs) are typically owned and operated by municipalities and private enterprises with very little or no public/state sector involvement.

In the developing countries, however they seem to be two models: the **South American Model**, where there is equity participation by both the public and private sectors and the **South-East Asia Model** where most of the transmission and distribution systems are owned and operated by State-owned enterprises. Examples of the South American models are Bolivia (Transredes), Colombia (Promigas), Peru (Suez), Argentina (Metrogas), Chile (Metrogas). Examples of the South East Asia model are found in Pakistan, Bangladesh, India and Thailand.

The South-East Asia models require total funding from the state with all the associated risks. The shortcomings of this model are the inefficiencies in operation and conflicts between the regulatory and operating government entities.

The South American models (and indeed the developed world models), however, require little state involvement.

Since 1990s, most of the countries that subscribed to the South East Asia model are gradually transitioning to the South American Model, one that relies increasingly upon reduced government control and on a more market-responsive pricing climate to encourage foreign and private sector investments. This is expected to push faster the development of the gas sector.

10.3 National transmission and distribution system models

The national transmission and distribution systems in most developing countries have been designed based on (a) the public sector model and (b) the private-public partnership model (Energy Commission, 2007).

10.3.1 Public sector model

A public/state entity with complete operational autonomy, would on behalf of the Government, build and operate the infrastructure. The government would have 100% ownership of the assets. A consortium of LDC and EPCM (Engineering, Procurement, Construction, Management) team may install the facilities and transfer operational control of the network to local employees of the government entity, over a defined period of time under BOT[23] arrangement.

[23] Build Operate and Transfer

To be effective, this entity should operate at arm's length from the Government or sector ministry and should be managed by an expert and or, commercially oriented Board of Directors. Despite "best" efforts by most of the developing countries, the public sector models (Figure 4) have mostly been beset with operational failures around the world.

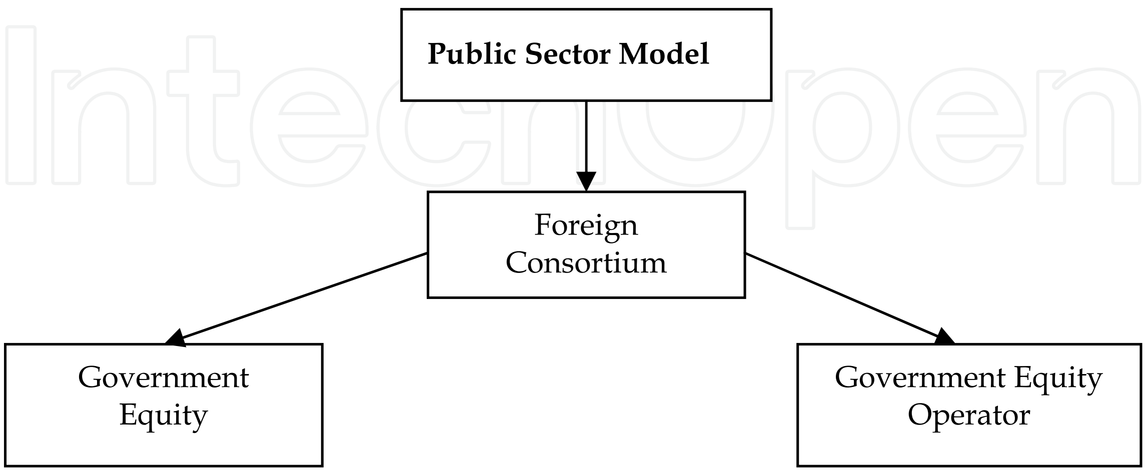

Fig. 4. Public Sector Model.

10.3.2 Public Private Partnership model

The **Public-Private Partnership** model (Figure 5) is usually a joint venture company, with majority private ownership, who builds, own and operate the transmission and distribution network.

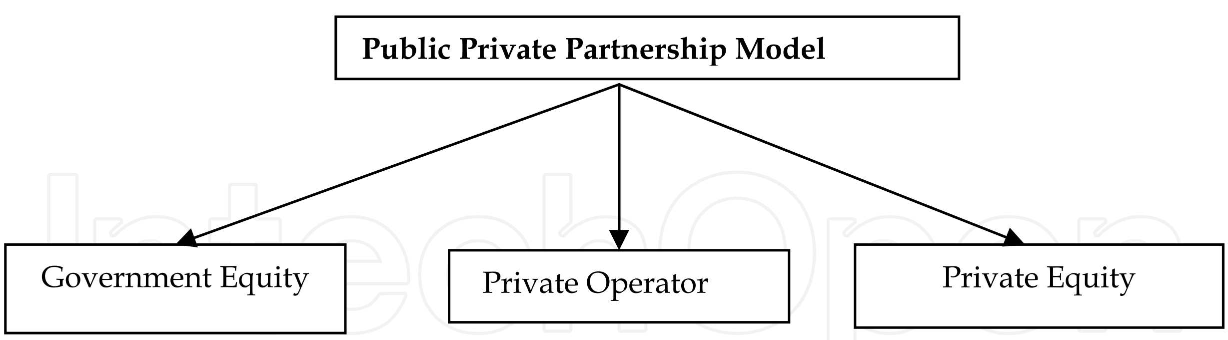

Fig. 5. Public Private Partnership Model.

The government typically may have minority or majority equity interest in the assets, however the minor the better since such usually limit the potential political influence. A consortium of LDC and EPCM team usually install the facilities and transfer operational control of the network to a private local company, over an agreed time period. The private consortium could be a partnership of local and foreign entities.

Table 11 summarizes the main characteristics between state or public ownership and public-private partnership (PPP).

ITEM	STATE/PUBLIC OWNERSHIP	PUBLIC-PRIVATE PARTNERSHIP
Set up	100% Government	Joint venture
Operation	Government entity	Private operating entity
Global Models	Asian Model: e.g. *India, Bangladesh, China, Thailand*	South American Model: e.g. *Bolivia, Colombia, Chile, Peru*
Observed Operational Efficiency	Inefficient, Government interference, subsidies, poor operational oversight	More efficient, commercially driven
System Growth	Expansion of low capacity system likely	Expansion only likely for high capacity load factor systems
Industry Rate of Maturity	Low rate of maturity	High rate of maturity

Table 11. Main characteristics between state/public ownership and public-private partnership.

Most foreign investors would prefer to enter into a joint venture arrangement with a State-owned entity to facilitate certain aspects of infrastructure development, such as land acquisition and landowner issues. A joint venture arrangement with the State could also reduce the risk associated with particular investments.

11. Conclusions

The global energy sector is beset with uncertainties in terms of supply security, development cost, greenhouse gas emissions and other environmental pollution. The flexibility of natural gas as a fuel, its lower carbon dioxide emission compared with other fossil fuels, its emerging global abundant reserves, relatively quick and lower development field cost make natural gas the most favourable fossil fuel in recent times.

The gas industry with its traditional structure of rigid regulations is being replaced by a regime that relies on market forces and is redefining the future gas industry. The structural and regulatory changes that are affecting the global natural gas transmission sector are designed to create competition, expand regional and international gas trade, and to reform the regulation of the transmission and distribution functions to allow for non-discriminatory access to pipelines. Concurrently, these structural changes are being accompanied by ownership changes in light of the global trend towards privatization. Amongst a series of developments, the most evident are the changes in asset structure of the industry, the changing role of gas pipelines, emergence of natural gas commodity markets, fuel switching capability and competition and new pricing mechanism.

In many instances, gas is stranded because of a lack of sufficient demand in locations where the gas is produced. Stranding of gas in locations far removed from big consuming markets calls for construction of pipelines or use of LNG vessels depending upon the distance and location of the consuming market. To complement the global expansion of overland pipeline, LNG investments are also fast growing. For nations that do not have large enough domestic demand relative to the size of their resource base, or that have not developed petrochemicals capacity for conversion of natural gas to other products, LNG is an important means of deriving value for their natural resource endowments through international trade.

Government policies and the type of instruments used to implement the policies however, have impact on gas consumption and fuel choices locally, directly or indirectly. Favourable policies would expand local demand and therefore could add value to the gas being produced by opening up local petrol-chemical industries. With time, there would be significant increase in local demand by the economy and consequently, reduce exports of raw gas. This is the likely market scenario for the future gas industry, particularly, in developing countries with abundant commercial gas resource.

Market and regulatory models for gas markets have been proposed for developing countries.

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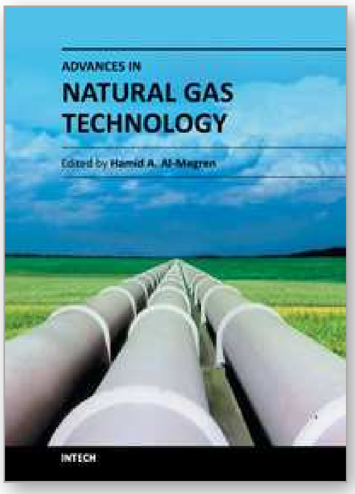

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Natural gas is a vital component of the world's supply of energy and an important source of many bulk chemicals and speciality chemicals. It is one of the cleanest, safest, and most useful of all energy sources, and helps to meet the world's rising demand for cleaner energy into the future. However, exploring, producing and bringing gas to the user or converting gas into desired chemicals is a systematical engineering project, and every step requires thorough understanding of gas and the surrounding environment. Any advances in the process link could make a step change in gas industry. There have been increasing efforts in gas industry in recent years. With state-of-the-art contributions by leading experts in the field, this book addressed the technology advances in natural gas industry.