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MSc Energy Systems and the Environment

Thesis Title:

"Investigation of the expansion of the natural gas network and uses in Greece, as well as the impendent need for carbon capture and sequestration"

By

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Abstract

Many countries around the world in an effort to cope with the rising demand of energy and the low emission legislation at the same time, have introduced natural gas. Greece first introduced natural gas quite recently, in 1997. The purpose of this thesis is to investigate the expansion of the natural gas network and applications in Greece till today, as well as the future steps to be followed. Also to investigate the methods that have to be applied in order to deal with CO_2 emissions, due to the fact that natural gas appears not to be the ultimate solution to the emission problem.

This thesis is divided into three chapters. In chapter 1 an introduction to natural gas is made in order to make the reader familiar with natural gas, with useful background information about its origin, history and components. Then the main processes followed in terms of the exploration, extraction, processing, transport and storage of natural gas, are explained Finally, information is provided concerning the uses of it in each sector worldwide.

In chapter 2 we move to the facts related to the present situation of natural gas in Greece. The imports, the natural gas network infrastructure and the uses of natural gas in the country in every sector today are described, as well as the role of the country in the European natural gas supply. Throughout the chapter the country's future plans are mentioned and commented, while finally some recommendations are made for the best exploitation of natural gas in the country.

In chapter 3, an introduction in the need to deal with CO_2 emissions is made, related to natural gas and other fossil fuel combustion (which are predominant in Greece). The main carbon capture methods are presented and also the carbon sequestration methods that can be applied, with their implications. A direct comparison of sequestration methods is made (quite rare in literature) in order to enable a straightforward understanding of their differences and provide a useful tool for their potential application. Finally the most appropriate carbon sequestration method is proposed for Greece.

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CHAPTER 1

1. Introduction

Natural gas belongs to the category of fossil fuels and exists throughout the world in large magnitude. When it is combusted it can produce great deals of energy. The rising need for energy has elevated the natural gas importance nowadays. Natural gas is a vital component of the world's supply of energy.

It is one of the cleanest, safest, and most useful of all energy sources. Unlike other fossil fuels, natural gas when combusted emits lower levels of potentially harmful by products into the air. The significance of this matter can be realized if we consider the rising need nowadays to switch to clean energy technologies. In order this problem to be tackled realistically renewables have to be coupled with such a technology.

1.1 Origin theories

There are many theories about the origin of natural gas. The most widely accepted theory says that fossil fuels are formed when organic matter (such as the remains of a plant or animal) is compressed under the earth, at very high pressure for a very long time. This is referred to as thermogenic methane. Similar to the formation of oil, thermogenic methane is formed from organic particles that are covered in mud and other sediment. Over time, more and more sediment and mud and other debris are piled on top of the organic matter. This sediment and debris puts a great deal of pressure on the organic matter, which compresses it. This compression, combined with high temperatures found deep underneath the earth, break down the carbon bonds in the organic matter. As one gets deeper and deeper under the earths crust, the temperature gets higher and higher. At low temperatures, more oil is produced relative to natural gas. At higher temperatures, however, more natural gas is created, as opposed to oil. That is why natural gas is usually associated with oil in deposits that are 1 to 2 miles below the earth's crust. Deeper deposits, very far underground, usually contain primarily natural gas, and in many cases, pure methane.

Natural gas can also be formed through the transformation of organic matter by tiny micro organisms. This type of methane is referred to as biogenic methane. Methanogens, tiny methane producing micro organisms, chemically break down organic matter to produce methane. These micro organisms are commonly found in areas near the surface of the earth that are void of oxygen. These micro organisms also live in the intestines of most animals, including humans. Formation of methane in this manner usually takes place close to the surface of the earth, and the methane produced is usually lost into the atmosphere. In certain circumstances, however, this methane can be trapped underground, recoverable as natural gas. An example of biogenic methane is landfill gas. Waste-containing landfills produce a relatively large amount of natural gas, from the decomposition of the waste materials that they contain. New technologies are allowing this gas to be harvested and used to add to the supply of natural gas.

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. As these gases gradually rise towards the surface of the earth, they may interact with minerals that also exist underground, in the absence of oxygen. This interaction may result in a reaction, forming elements and compounds that are found in the atmosphere (including nitrogen, oxygen, carbon dioxide, argon, and water). If these gases are under very high pressure as they move towards the surface of the earth, they are likely to form methane deposits, similar to thermogenic methane.

1.2 History of natural gas

The first known observations of natural gas seeps were made in Iran prior to 2000 BCE. Sometimes lightning strikes would ignite natural gas that was escaping from under the earth's crust and this would create a fire coming from the earth. The gas seeps, first ignited by lightning, provided the fuel for the “eternal fires” of the fire-worshiping religion of the ancient Persians.

One of the most famous of these types of flames was found in ancient Greece, on Mount Parnassus approximately 1,000 BCE. A goat herdsman came across what looked like a 'burning spring', a flame rising from a fissure in the rock. The Greeks, believing it to be of divine origin, built a temple on the flame. This temple housed a priestess who was known as the Oracle of Delphi, giving out prophecies she claimed were inspired by the flame.

But only the Chinese started realizing the real use on natural gas, as there is evidence that the Chinese used natural gas in certain regions as early as the fourth century BCE. Pockets of flammable gas were first discovered trapped under the Earth in areas used by the Chinese to extract brine. The Chinese quickly discovered the flammable nature of these pockets, and came to use them as convenient ways to both heat the brine they were extracting and to prepare food. In about the second century CE, the Chinese began routing gas from deposits to other areas, sometimes as much as a day’s travel away. To do this, they tapped deposits of gas and routed it through pipes made of bamboo, sometimes crossing under and over roads to reach their destinations. As this became more common, the Chinese discovered that certain deposits of gas were unsafe to use because they were not mixed with air. These unsafe pockets of gas were put through a very complicated refining process utilizing the world’s first carburettor. After being mixed with air in this ingenious way, the gas could be used quite safely.

In recent years Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light houses, as well as streetlights.

Natural gas was also used in America to illuminate the streets of Baltimore in 1816. Soon after, in 1821, William Hart dug the first successful American natural gas well in Fredonia, New York. His well was 27 feet deep, quite shallow compared to today's wells. In 1885, Robert Bunsen invented what is now known as the Bunsen burner. He managed to create a device that mixed natural gas with air in the right proportions, creating a flame that could be safely used for cooking and heating. The invention of the Bunsen burner opened up new opportunities for the use of natural gas throughout the world.

Without any way to transport it effectively, natural gas discovered pre-WWII was usually just allowed to vent into the atmosphere, or burnt, when found alongside coal and oil, or simply left in the ground when found alone. One of the first lengthy pipelines was constructed in 1891, which was 120 miles long, and carried natural gas from wells in central Indiana to the city of Chicago. However, this early pipeline was very rudimentary, and was not very efficient at transporting natural gas. It wasn't until the 1920's that any significant effort was put into building a pipeline infrastructure. However, it wasn't until after the World War II that welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable pipelines. This post-war pipeline construction boom lasted well into the 60's, and allowed for the construction of thousands of miles of pipeline in America.

Once the transportation of natural gas was possible, new uses for natural gas were discovered. These included using natural gas to heat homes and operate appliances such as water heaters and oven ranges. Industry began to use natural gas in manufacturing and processing plants. Also, natural gas was used to heat boilers used to generate electricity. The transportation infrastructure had made natural gas easy to obtain, and it was becoming an increasingly popular form of energy.

1.3 Composition

Natural gas is colourless, shapeless, and odourless in its pure form. It is composed primarily of methane CH_4, which is the first homologue of the hydrocarbon paraffin series, with minor amounts of the following homologues: ethane C_2H_6, propane C_3H_8, butane C_4H_{10} and so on.

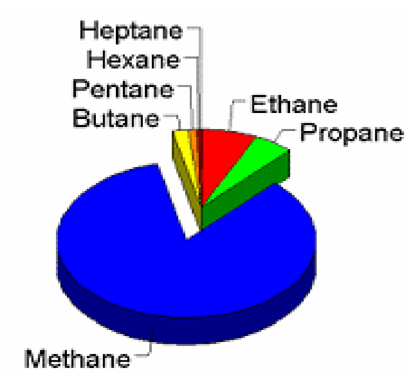

Figure 1.1: Natural gas primary composition

The non hydrocarbon components may include nitrogen N_2, hydrogen H_2, carbon dioxide CO_2, hydrogen sulphide H_2S, water vapour, any unusual impurities and traces of rare gases, especially helium in very small amounts.

Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.

The exact composition of natural gas depends on the area of extraction. But usually the percentage of the components does not vary much. A typical natural gas composition is shown in the table below:

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Table 1: Typical natural gas composition

As fore mentioned the main component of natural gas is methane (CH_4). Methane is a molecule made up of one carbon atom and four hydrogen atoms as shown in figure 1.2:

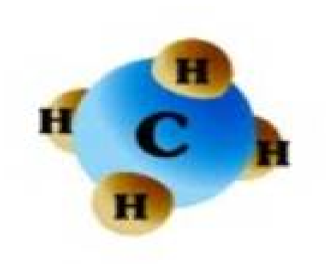

Figure 1.2: A methane molecule

Methane is lighter than air. Its density at a temperature of 0 C and pressure of 1 bar may vary from 0.678 up to 0.7157 kg/m3, while its density relative to air is 0.5545.

When natural gas reaches an application (e.g. a house), methane may be contained in percentages that reach 90 to 99.5 %.

1.4 Natural gas units

Natural gas can be measured in a number of different ways. As a gas, it can be measured by the volume it takes up at normal temperatures and pressures, commonly expressed in cubic feet. Production and distribution companies commonly measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or even trillions of cubic feet (Tcf).

While measuring by volume is useful, natural gas can also be measured as a source of energy. Like other forms of energy, natural gas is commonly measured and expressed in British thermal units (Btu). One Btu is the amount of natural gas that will produce enough energy to heat one pound of water by one degree at normal pressure. To give an idea, one cubic foot of natural gas contains about 1,027 Btus.

When natural gas is delivered to a residence, it is measured by the gas utility in 'therms' for billing purposes. A therm is equivalent to 100,000 Btu's, or just over 97 cubic feet, of natural gas.

2. Natural gas processes

In order to better understand natural gas an investigation of the main processes followed may be proven very helpful. The processes are:

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

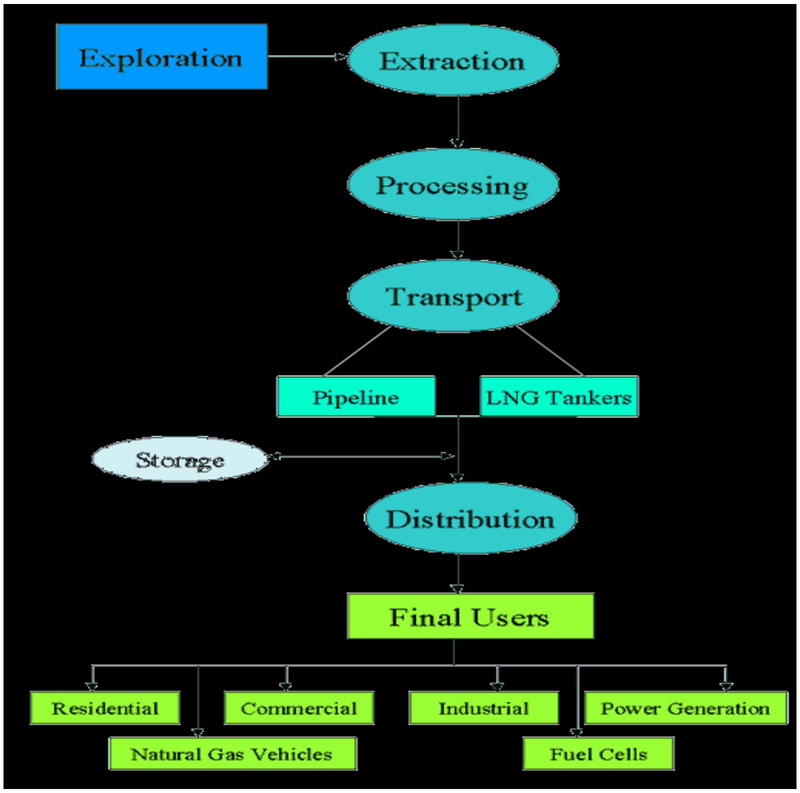

Figure 1.3: Natural gas processes

In the following pages they are explained in detail so that we can get a good idea about each process.

2.1 Exploration

In the early days of energy exploration, the only way of locating underground natural gas deposits was to search for visible evidence of these underground formations, like seeps. However, because such a low proportion of oil and natural gas deposits actually seep to the surface, this made for a very inefficient and difficult exploration process.

As demand for natural gas energy increased, so did the necessity for more accurate methods of locating deposits. Today, much more sophisticated techniques are employed. These new technologies have driven an incredible increase in the success rate of locating natural gas reservoirs. However, the process of exploring for these reservoirs is still characterized by uncertainty, due to the complexity of searching for something that is often thousands of feet below ground. Ultimately, exploration companies must drill to determine whether oil or natural gas actually lies underground.

The most successful method for determining the existence of natural gas underground is the seismic method. The basic concept of seismology is quite simple. As the Earth's crust is composed of different layers, each with its own properties, energy (in the form of seismic waves) travelling underground interacts differently with each of these layers. These seismic waves, emitted from a source, will travel through the earth, but also be reflected back towards the source by the different underground layers. It is this reflection that allows for the use of seismology in discovering the properties of underground geology. Geophysicists are able to artificially create vibrations on the surface and record how these vibrations are reflected back to the surface.

What was usually used the early years to create these vibrations was explosions. A hole of few inches diameter and several feet deep was drilled near the surface, then packed with dynamite and sealed off with mud. The charge was detonated, sending a point source shock wave propagating into deep layers of sedimentary rocks. The elastic wave that was generated was reflected off the interface of various strata, propagating with definite velocity and angle toward the surface, where a large number of very sensitive devices called geophones would pick it up and record it on a strip chart. Then the data were analysed and conclusions were extracted.

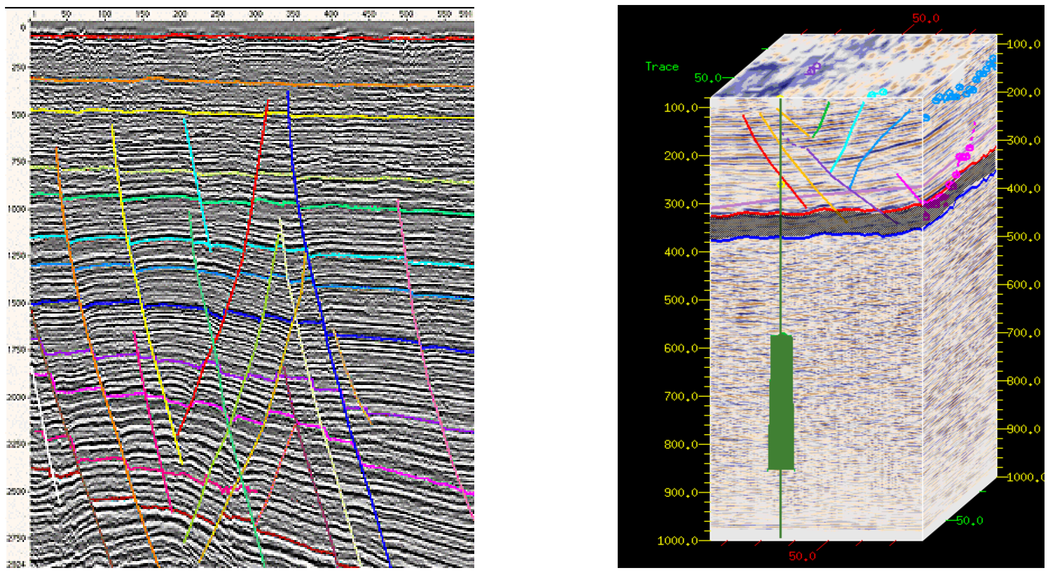

Figure 1.4: Old 2-D provided data (left), Recent way of 3-D provided data (right)

The method followed nowadays is very similar. The only change is that due to environmental consideration no explosion takes place. Instead the fore mentioned wave is produced through vibrations caused by giant vibrator trucks, in which a pad in the middle of the truck rests directly on the ground to raise the truck so that the pad supports the full weight of the vehicle. The truck then vibrates to put energy into the ground.

Figure 1.5: A vibrator truck

When investigation for the existence of natural gas below the seabed floor takes place, instead of trucks, a ship is used to pick up the seismic data and instead of geophones, hydrophones are used, which are designed to pick up seismic waves underwater. These hydrophones are towed behind the ship in various configurations depending on the needs of the geophysicist. Instead of using dynamite or impacts on the seabed floor, the seismic ship uses a large air gun, which releases bursts of compressed air under the water, creating seismic waves that can travel through the Earth's crust and generate the seismic reflections that are necessary.

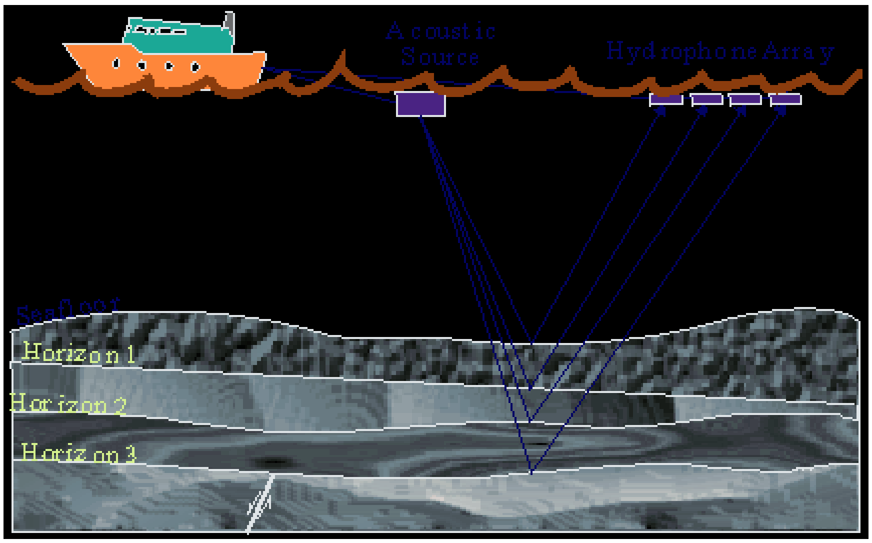

Figure 1.6: Offshore seismic exploration

Another method for natural gas exploitation is the gravitational method. It is dependent on mass distributions in the outer crust of the earth that are related either directly or indirectly to the accumulation of the particular mineral sought. Modern gravity meters can, under operational conditions, detect changes in the earth's field in the order of 1 part in 100 million. The gravitational field can be recorded not only by the conventional land meter and under-water meter, but also by ship borne meters, airborne meters and down-hole meters. The gravitational field is very complex, for this reason, and a variety of geological solutions may be possible. It is the responsibility of the geophysicist interpreting the data to eliminate as many of the ambiguities as possible, and arrive at the solution that most nearly fits the conditions. Sophisticated digital computer techniques are available for relating gravity anomalies to geological features. These techniques enable the geophysicist o analyze more data faster in his quest for the solution that represents the existing geological conditions. The gravitational field of the earth offers a wide variety of possibilities for study, particularly from the point of view of potential theory. The basic instrumentation is relatively inexpensive, and innumerable possibilities exist for improvement in the handling of data.

A last method of natural gas exploitation is the magnetic method, which is almost entirely limited to the airborne technique. The objective of the aeromagnetic method is to map the geomagnetic field in such detail that the magnetic interface can be determined and related to the geological column. The magnetic method is less complex than the gravity method in that the majority of local magnetic anomalies are associated with igneous rocks. Anomalies from other sources are generally readily identifiable, but magnetic anomalies on the other hand are more complex in form than gravity anomalies because their expression changes with latitude and orientation. A reasonably accurate map of the contact between sedimentary and igneous rocks can be constructed that is valuable in outlining basinal configurations, and thicknesses of sediments. With the advent of the high sensitivity magnetometer, magnetics is finding more and more need for computer applications in the processing of basic data and in interpretation. Since this is a relatively new area for computers it offers a challenging future for the trained geophysicist.

2.2 Extraction

After the exploration process is completed and a potential well of natural gas is found, it is time for the extraction process to take place. As mentioned before the exploration has some uncertainty considering the volume of natural gas that exists in a discovered well. So economic issues play a significant role on whether or not try to extract natural gas from that point, because it might be a really small reservoir and at the same time the methods to follow are very costly. Also some security permits must be obtained in order to drill to that site and the legislation problems have to be solved.

If the decision of natural gas extraction is taken, the well has to be drilled in order to access the natural gas reservoir and extract its content. The drilling method that will be chosen depends on:

- The nature of the formation
- The characteristics of the subsurface geology
- The depth and size of the target deposit

These kinds of reservoirs can be found both onshore and offshore. In onshore sites technology enables companies to drill to depths as big as 25,000 ft, while in offshore sited the depth is limited to 7,000 ft. But the extraction technology used has many similarities between these two sites. An example of onshore drilling is shown in figure 1.7:

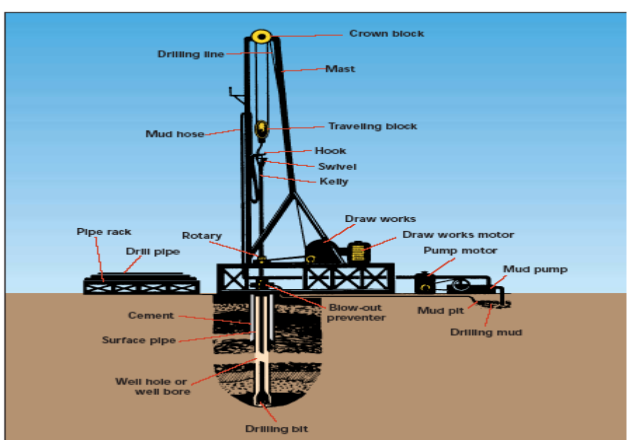

Figure 1.7: Onshore drilling technique

Investigating the onshore case we find out that there are two main technologies applied for drilling to reach a natural gas reservoir and they are percussion drilling and rotary drilling, which is the most promising technology nowadays. Percussion drilling is characterized by repeatedly raising and dropping a heavy metal bit into the Earth's surface, eventually pounding a hole downwards into the ground. The bit used, usually a blunt, chisel shaped instrument, can vary with the type of rock that is being drilled. Water is used in the well hole to combine with all of the drill cuttings, and is periodically bailed out of the well when this 'mud' interferes with the effectiveness of the drill bit. This process is most appropriate for shallow and low pressure formations.

For deep and high pressure formations, the method applied is the rotary drilling. The rotary drilling method also differs from the percussion method in that it relies on a sharp bit to literally drill through earth and rock layers. In rotary drilling, a rotating bit attached to a length of hollow drill pipe bores a hole in the ground by chipping and cutting rock. There are many different varieties of drilling bits, each with a different specialty. In addition there are hybrid bits that combine features from different variations. Also, when deep wells are to be drilled, through different layers of rock, several different bits might be used on a single well. The decision to change bits is not made easily, however, because it takes time and extra equipment to remove the entire drill pipe and bit, and then to reassemble it using a different bit. An example of a rotary drilling bit is shown on figure 1.8:

Figure 1.8: Diamond studded drilling bit

A rotary drilling system consists except the rotary drilling bits, also of three other main components: prime movers, hoisting equipment and circulating system. The prime movers provide power to the entire rig. They usually are diesel engines but in some cases they are natural gas or gasoline engines that provide electricity to the rest of the components.

The hoisting equipments main component is the derrick, a tall tower structure that extends vertically from the well. On this are integrated the tools that are used to raise and lower all the rest equipment of the rotary drilling system. The height of a rigs derrick can often be a clue as to the depth of the well being dug. Drill pipe traditionally comes in 30ft sections, which are joined together as the well is dug deeper and deeper. This means that even if a well is 20,000 feet deep, the drill string must still be taken out in 30 foot sections. However, if the derrick is tall enough, multiple joints of drill pipe may be removed at once, speeding up the process a great deal.

The circulating system consists of drilling fluid, which is circulated down through the well hole throughout the drilling process. Its purpose is to cool the drill bit, plaster the walls of the hole to prevent cave-ins, carry crushed rock to the surface, and prevent "blowouts" by equalizing pressure inside the hole. Most fluids have a clay base, and are customized for the specific formations that are encountered at a given site. The cake that forms from the fluids serves to coat the walls of the well bore until a steel casting can be put in place to prevent collapse.

Similar techniques are employed in offshore drilling, except that the drilling equipment is part of a steel platform that either sits on the ocean floor, or floats on the surface and is anchored to the ocean floor. They can drill to reach natural gas reservoirs in depths up to 10,000 ft, much less than the onshore ones. The first step in drilling an offshore well is to establish a mechanism for attaching the floating drilling platform to the base of the ocean, but at the same time allow for pitching and rolling caused by the ocean’s surface. Examples of offshore drilling systems as well as the depths they can reach are shown in figure 1.9:

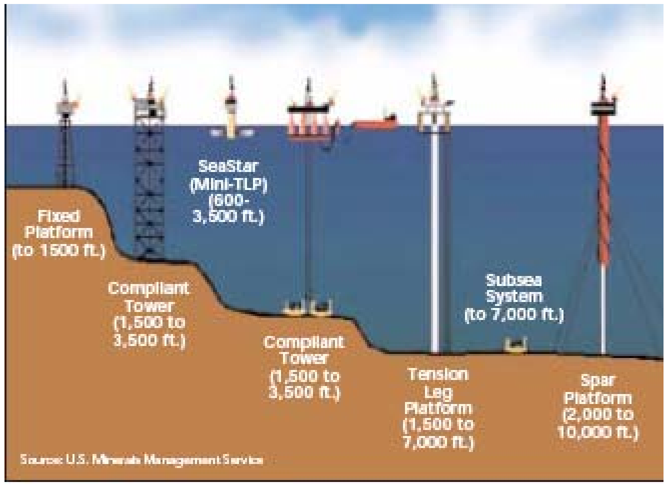

Figure 1.9: Offshore drilling systems

Next, a wide, relatively shallow hole is drilled into the ocean floor. This hole is filled with a casting, which serves as a permanent base for the drilling template. The drilling template looks a bit like a cookie cutter, a box with several large round holes cut into it. This template will eventually serve as the guide for multiple wells. The drilling template, secured to the sea floor and attached to the drilling platform above with cables, allows for accurate drilling to take place, but allows for the movement of the platform above, which will inevitably be affected by shifting wind and water currents. Several other pieces of equipment are also attached to the drilling template, including a blow out preventer, which prevents oil or other pollutants from flowing out into open water.

Several kinds of platforms can be attached to the drilling base, once it is in place. The type of platform varies with regard to the depth of water, distance from shore, and the turbidity of the waters over the well. For inland drilling, a drilling barge can serve as a suitable platform, while other, larger rigs are needed for open water drilling.

Near shore, submersible or semi submersible rigs are generally used. These rigs can be moved from site to site by pushing air into a lower hull, which causes them to float high on the water. However, when they are in place, the lower hull is flooded, which causes the platform to sink partially into the sea, thus becoming more stable. These platforms are also held in place by heavy weights, and anchor cables which anchor them to the sea floor.

Drill ships can also be used to drill in deeper waters. They appear similar to ordinary ships, but they have a drilling rig located in the centre of their hull. While drilling, these ships are kept in position by dynamic positioning, where the ship uses satellite navigation and multi-directional propulsion to remain directly above the well site.

Permanent platforms are the largest and most complex offshore structures. These massive platforms are placed in areas where multiple wells will be drilled, and production is high. They can be constructed in over 500 feet of water because of their massive size. They must be durable, able to withstand waves over 60 feet high, and winds in excess of 90 knots. The cost of these platforms routinely exceeds 1 billion dollars.

The latest advance is tension leg platforms. Tension legs are hollow steel tendons that allow no vertical platform movement, but some minor horizontal movement, free to move about with wind and current. They can be less expensive than other forms of support. They can often be economically relocated and re-used for other fields when the original field is depleted.

We should mention here that as is seems most offshore drilling systems appear to be vertical. But a recently developed technique that is gaining respect and is applied in offshore drilling systems is horizontal drilling. Horizontal drilling techniques allow increased access to potential reserves and have a significant impact on drilling capabilities. Drilling begins vertically, but the drill bit can be turned so that drilling can continue at an angle of up to 90 degrees. This technique extends the drill's reach, enabling it to reach separate pockets of gas.

Finally when a drilling technique is applied onshore or offshore and the natural gas reservoir is reached, it is time for some last processes to take place. This is because of the fact that a drilling process can disturb and even alter the situation existing prior to drilling in the underground rock layers at various depths. If suitable technical precautions are not undertaken, fluids, mud etc, can migrate upwards to the rock strata in which pressure is lower, invade edge waters, damage rock reservoirs containing hydrocarbons and even reach and pollute potable water supplies. In some cases even a well gusher can result.

The amount of technical planning and actions to be followed in order to achieve conversion of a perforated well into a hydrocarbon producing well is called well completion, and this is the last step of the extraction process.

When the drill operations are completed, the drill pipe and bit are pulled from the well, and metal pipe (casing) is lowered into the hole and cemented in place. A small-diameter tubing string is centred in the well bore and held in place with packers. This tubing will carry the hydrocarbons from the reservoir to the surface. This step of inserting a metal pipe and cementing it and the side walls is very important as it ensures:

- The maintenance of constant well bore
- The maintenance of well flow area free from restrictions which may be caused by the natural tendency of perforated soil strata or soft rock layers to invade the well hole
- The avoidance of natural gas pollution as a consequence of mixing fluids and extraneous substances migrating from elsewhere

The production tubing that is run inside the casing is attached to the wellhead. The wellhead consists of a series of valves at the surface of the well that regulate gas pressure and prevent leakage. If the gas reservoir has enough pressure and permeability, natural gas will flow to the surface naturally due to the pressure differential. If natural pressure is not great enough to force the oil to the surface, pumps may be used.

In some cases, special treatments are used to increase natural gas production rates. An example of well treatment is hydraulic fracturing, which is the injection of water into the well to open up cracks within the underground formation. After water has opened a crack, a solid material like sand or beads is injected to the crack open. These cracks allow the gas to flow to the surface more easily.

2.3 Processing

After natural gas comes out of the ground, it goes to a processing plant where it is cleaned of impurities and separated into its various components. Approximately 90 percent of natural gas is composed of methane, but it also contains small amounts of other gases such as propane and butane as mentioned before. Natural gas produced from underground reservoirs must be processed to remove water, impurities (such as hydrogen sulphide and carbon dioxide.), and heavier hydrocarbons known as natural gas liquids (like ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) etc).

The first step of the natural gas processing process is to remove mud from it and separate from oil. Mud as well as other large particle impurities, are removed easily with the use of scrubbers. Natural might be mixed with oil sometimes in the underground reservoir but it is easily separated of it due to the pressure differential that occurs when a reservoir is drilled. In certain instances, however, specialized equipment is necessary to separate oil and natural gas. An example of this type of equipment is the Low-Temperature Separator (LTX). This 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. Wet gas enters the separator, being cooled slightly by a heat exchanger. The gas then travels through a high pressure liquid 'knockout', which serves to remove any liquids into a low-temperature separator. The gas then flows into this low-temperature separator through a choke mechanism, which expands the gas as it enters the separator. This rapid expansion of the gas allows for the lowering of the temperature in the separator. After liquid removal, the dry gas then travels back through the heat exchanger and is warmed by the incoming wet gas. By varying the pressure of the gas in various sections of the separator, it is possible to vary the temperature, which causes the oil and some water to be condensed out of the wet gas stream.

The next step is water vapour that exists with natural gas removal, known as dehydration. There are mainly two main methods, quite complex, to achieve that. The first one is solid dehydration. It is using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant. Typical desiccants are alumina, silica gel or molecular sieves and are characterized porous structure. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

• Advantages of solid desiccants:

– Dew points as low as –150 ºF.

– They are less affected by small changes in gas pressure, temperature and flow rate.

– They are less susceptible to corrosion or foaming.

• Disadvantages solid desiccants:

– Higher capital cost and higher pressure drops.

– Mechanical breaking of desiccant particles.

– High regeneration heat requirements and high utility costs.

The second dehydration method is known as glycol dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapour from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will absorb the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, which is brought into contact with the wet gas stream in what is called the 'contactor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it be reused in the dehydration process.

- Advantages of glycol over solid desiccants:
  - Lower installed cost
  - Lower pressure drop
  - Glycol dehydration is continuous rather than batch.
  - Glycol makeup is easily accomplished.
  - Glycol units require less regeneration heat per pound of water removed.

- Disadvantages of glycol over solid desiccants:
  - Glycol is susceptible to contamination.
  - Glycol is corrosive when contaminated or decomposed.

The glycol solutions that can be used are: Ethylene glycol (EG), Di-ethylene glycol (DEG), Tri-ethylene glycol (TEG) and Tetra-ethylene glycol (TREG). The most commonly used is Tri-ethylene glycol (TEG) as it has gained universal acceptance as the most cost effective choice because:

- TEG is more easily regenerated.
- TEG has a higher decomposition temperature of 404 ºF, while DEG is 328 ºF.
- Vaporization losses are lower than EG or DEG.
- TEG is not too viscous above 70 ºF.

Another significant process to purify natural gas is the separation of natural gas liquids. Natural gas liquids are removed from the natural gas feed to recover the heavier hydrocarbons and to allow the treated gas to move through the pipeline network. There are two main techniques for removing natural gas liquids from the natural gas stream: the absorption method and the cryogenic process.

The absorption method of natural gas liquids extraction is very similar to using glycol dehydration. The main difference is that in this case absorbing oil is used instead of glycol and has an affinity for natural gas liquids in much the same manner as glycol has an affinity for water. As the natural gas is passed through an absorption tower, it is brought into contact with the absorption oil which soaks up a high proportion of the natural gas liquids. The rich absorption oil, now containing natural gas liquids, exits the absorption tower through the bottom. The rich oil is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the natural gas liquids, but below that of the oil. This process allows for the recovery of around 75 percent of butanes, and 85 - 90 percent of pentanes and heavier molecules from the natural gas stream.

While absorption methods can extract almost all of the heavier natural gas liquids, the lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. This is achieved with the use of cryogenic processes in which the natural gas is cooled to very low temperatures with the use of Freon or propane to cool the gas. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. Cryogenic recovery processes are done at temperatures lower than -150 °F. The reason is shown on the table below:

Natural Gas Liquids Boiling Points

Chemical	Boiling Point
Methane	**-259 °F**
Ethane	**-128 °F**
Propane	**- 44 °F**
Isobutane	**10.9 °F**
Normal Butane	**31.1 °F**
Isopentane	**82.2 °F**
Normal Pentane	**96.9 °F**

Table 2: Natural gas liquids boiling points

As we can see the boiling point of all the rest chemicals, except methane, are higher than-150 °F. This enables methane to remain in gaseous form as explained before. These low temperatures allow the plant to recover over 90% of the ethane in the natural gas.

The acceptability of this process is obvious as all of the new gas processing plants use cryogenic recovery technology.

A last technique in natural gas processing is the sulphur removal. Sulphur exists in natural gas as hydrogen sulphide (H_2S) and is removed primarily to prevent corrosion and to address the environmental and safety concerns associated with transport of natural gas that contains H_2S. The primary process for removing hydrogen sulphide from natural gas is quite similar to the processes of glycol dehydration and natural gas liquids absorption. The H_2S is removed from the gas stream by contacting the gas with an amine solvent. The sour gas is run through a tower, which contains the amine solution, which has an affinity for sulphur, and absorbs it much like glycol absorbing water.

The more common solvents are mono-ethanolamine (MEA) and di-ethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulphur compounds from natural gas as it passes through. The effluent gas is virtually free of sulphur compounds. Like the process for natural gas liquids extraction and glycol dehydration, the amine solution that is used can be regenerated allowing it to be reused to treat more sour gas.

2.4 Transport

Once natural gas is processed it has to be transported to the area where it will be used. The transport of natural gas from a gas well to our homes and businesses mainly requires an extensive network of interconnected pipelines, designed to move natural gas quickly and effectively, sometimes over great distances. Pipelines are one of the safest means of distribution of energy because the pipeline system is fixed and underground. Compared to other energy sources, natural gas transportation is very efficient because the portion of energy lost from origin to destination is low.

There are essentially three main types of transportation pipelines: gathering pipelines, transmission pipelines, and distribution pipelines. The order in which they are sited is shown in the following figure:

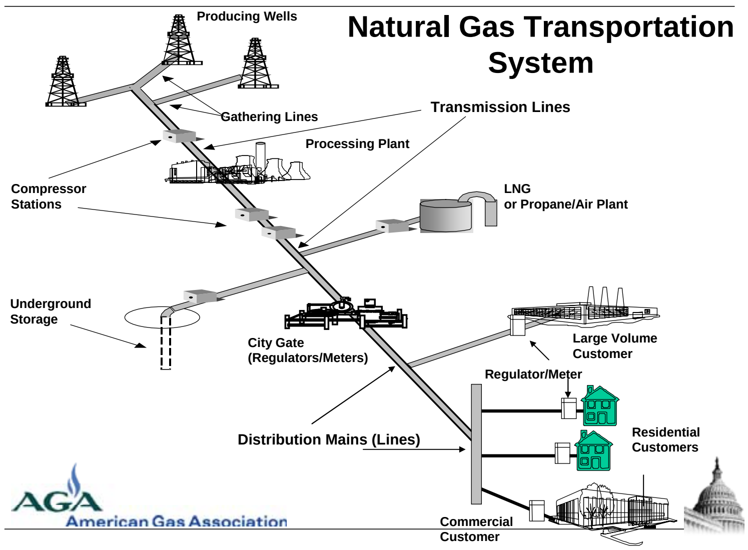

Figure 1.10: Natural gas transportation system

First raw natural gas produced from wells is generally collected through a series of low-pressure pipelines referred to as a gathering system. Gathering pipelines, in turn, link natural gas production areas to central collection points. The pipelines in a gathering system start out small. Then, as gathering lines from different wellheads converge, the downstream lines become larger, to transport the growing volume of gathered gas. This is analogous to small creeks or streams which converge and flow together creating major rivers downstream. A complex gathering system can consist of thousands of miles of pipes, networking upwards of 100 wells in an area. Sometimes natural gas from a particular well may have a high sulphur and carbon dioxide content, as mentioned previously, being very corrosive. If so, special gathering pipes must be installed to ensure its safe transportation to a gas processing facility.

Then from the gas processing plant, natural gas is gathered into increasingly larger pipelines, almost always underground, until it reaches the large transmission pipelines where it is often transported over large distances. Natural gas transmission pipeline systems are generally the middle transportation link between gathering systems and distribution systems. They transport large volumes of natural gas from production and gathering areas to processing and treatment facilities and from there sometimes thousands of miles to other areas where it is provided to electric power generating stations or to local distribution companies.

Finally, from the transmission pipelines, the gas flows into a low-pressure distribution system. Local natural gas distribution pipelines are usually smaller in diameter than natural gas transmission pipelines and many are constructed out of plastic rather than steel. They consist of smaller service lines that are normally installed underground, usually along or under streets and roadways.

An important component of the natural gas transport system, are the compressor stations. They are generally built every 50 to 100 miles along the length of a transmission pipeline and are powered by electric motors or by natural gas fired engines and compress or squeeze incoming gas and push it out at a higher pressure. This is essential, because high pressure provides the motive force to keep the natural gas flowing in the pipelines. Then natural gas is fed back to the pipeline where as it travels to big distances its pressure is decreased. The next compression station met by natural gas will boost again its pressure to ensure its flowing.

Another component of the natural gas system are the metering stations. These stations allow pipeline companies to monitor and manage the natural gas in their pipes. Essentially, these metering stations measure the flow of gas along the pipeline, and allow pipeline companies to 'track' natural gas as it flows along the pipeline. These metering stations employ specialized meters to measure the natural gas as it flows through the pipeline, without impeding its movement

Also we should mention that pipelines include a great number of valves along their entire length, usually every 5 to 15 miles. These valves are usually open and allow natural gas to flow freely. Their role is to stop gas flow along a certain section of pipe if there are some maintenance reasons.

Constructing a pipeline system is a very complicating procedure that requires much research and careful planning, before it is applied. It involves economical, environmental and safety issues to be faced. If the decision is taken and planning is completed, its time for the pipeline to be installed. The steps that have to be followed to complete this procedure are described below, in the order in which they are followed:

i. The area in which the pipeline will be installed has to be prepared. This procedure will start much earlier than the rest (usually a year earlier). What happens is that the area is cleared off rocks, trees or other impediments.
ii. The trench digging takes place but with caution because the removed layers have to be stored so they can be replaced later
iii. The pipe is then laid end-to-end beside the trench, in a process called stringing and bending. The joints of the pipe are bent to fit the terrain using a special machine, and the pipe is prepared for welding.
iv. Then the pipe joints are weld together. All welds are inspected and certified by ultrasonic testing machines or X-ray machines that provide a detailed view of the weld. As each weld is confirmed as acceptable, the weld area is then coated with a similar material to that of the pipe joint.
v. Long welded lengths of pipe are lowered into the trench by large machinery. These long lengths are connected to each other in the pipeline trench.
vi. The earth that was removed earlier is then replaced in the same order in which it was removed. Pipeline companies work diligently to return the area to the same state as it was prior to pipeline construction
vii. Finally the pipeline undergoes a number of safety tests before it begins transporting natural gas. These tests further ensure the integrity of the pipe and the welds.

But the construction of a pipeline or even an entire pipeline transport system is only the beginning. There are a large number of actions to be taken in order to ensure the right operation of a pipeline transmission system having to do with safety issues. These procedures are summarized below:

- *Aerial patrols*: Pipeline companies use aerial patrols to monitor construction activity along the pipeline installation area as unauthorized digging is the greatest threat to pipeline safety. Also the pilot keeps an eye out for signs of environmental change around the pipeline as lack of vegetation can be an indication of a small gas leak in the pipeline.
- *Pipeline markers*: Pipeline companies place markers along the pipelines to alert the public to the presence of the natural gas pipeline. The markers are placed at road crossings, railroad crossings, and other highly visible places in order to reduce the possibility of damage or interference with the pipeline.
- *Cathodic protection:* Besides externally coating the line pipe to prevent corrosion, pipeline companies also install cathodic protection, a corrosion inhibitor system created by imposing a small, electrical voltage on the pipeline. Cathodic protection test stations are placed at intervals along the pipeline to allow corrosion engineers to monitor the electric potential placed on the pipeline.
- *Pipeline pigging:* In some pipeline systems gas companies can insert special devices called pigs into the pipeline to evaluate pipe wall thickness and roundness of the pipe. These devices can provide indications of corrosion and dents, allowing the pipeline company to repair or replace the damaged area.
- *Leak detection*: In areas where the gas is not odorized, the pipeline company conducts leak detection surveys in residential areas and at highway and railroad crossings along the pipeline, in order to locate pinhole leaks in a natural gas pipeline.
- *Preventative Maintenance*: Operation maintenance crews inspect and service each mainline valve at least once each year. The valve is partially opened or closed to ensure it operates properly. Maintenance crews also mow the right-of-way to prevent trees and shrubs from obstructing aerial inspection of the pipeline
- *Gas Sampling*: To ensure the quality of the natural gas in the pipeline, companies periodically take samples of gas for analysis in the laboratory. The lab technician determines the hydrocarbon content (methane, ethane, propane, butane, etc), and the amount of water and other impurities such as nitrogen, carbon dioxide and

sulphur dioxide. Corrosion engineers use the gas analysis to identify components that could create internal pipe corrosion.

But although pipelines are the main way of natural gas transport, recently two offshore technologies have attracted interest and started being applied. The one of them is by ships carrying liquefied natural gas. Such a ship is shown on figure 1.11 below:

Figure 1.11: Tanker carrying liquefied natural gas

Liquefied natural gas tankers are bulk cargo ships which require unique design and materials to handle the very low-temperature gas. This method of transportation relies on the fact that as natural gas is cooled to its liquefaction point (-260 °F) it occupies just 1/600th of its gaseous volume at room temperature. Most of these tankers range in size from about 40,000 to 165,000 cubic meters, but what is usually applied is approximately 130,000 cubic meter ship. Each ship of this size carries large quantities of liquefied natural gas, enough to heat a city with population of 100,000 for 1 month! These tankers carry their cargo of liquefied natural gas from the remote processing plants to receiving re-gasification terminals close to the markets.

Some unique properties of liquefied natural gas which affect the design of tankers or terminals are:

- It has an extremely low temperature of –260 ° F.
- It weighs slightly less than half the weight of water and could therefore float.
- At normal ambient temperatures, it evaporates very rapidly and expands to about 600 times its liquid volume.

- In the vapour state, and when still very cold, the gas is heavier than air and, in the event of a spill, would hug to the earth's surface for a period of time until substantially dissipated.
- When the vapour warms up, reaching temperatures of about –100° F, it is lighter than air and would rise and dissipate in the air.
- In the vapour state, it is not poisonous, but could cause asphyxiation due to the absence of oxygen.
- In the vapour state, concentrations of 5 to 15 percent natural gas are flammable.

But shipping liquefied natural gas by tanker is an ideal solution in cases where pipeline export is ruled out for technical, economic or indeed geopolitical reasons. Although the process is expensive, it allows carry natural gas over very long distances.

The other way of transport of natural gas through the sea is by ships that carry compressed natural gas. An example of such ship is shown below:

Figure 1.12: Ship carrying compressed natural gas

Compressed natural gas is natural gas that has been compressed into a high-pressure container for transportation. It is then placed in big ships in order to transport it over distances up to 2,500 or even 3,000 miles. The new compressed natural gas technology offers effective transport of natural gas in medium distances as an alternative to the transportation methods of liquefied natural gas and pipeline.

This technology is also actually a gas transportation solution that fills the gap between the pipeline and liquefied natural gas concepts, for other many reasons. This is because in numerous instances worldwide, gas reserves are stranded because neither liquefied natural gas nor pipelines can economically exploit them. Liquefied natural gas generally requires an onshore liquefied natural gas plant and fairly large volumes, making it difficult for it to commercially serve offshore reserves, small markets, or small reserves. This is because many worldwide gas-producing fields lack suitable infrastructure for liquefying natural gas, and terminal re-gasification facilities are similarly limited. On the other hand pipelines are often defeated by dealing with long marine distances, small reserves or difficult marine environments.

Also carrying by ships compressed natural gas is recognized as very cost effective method. Relatively long distances between the gas sources and markets or difficulties associated with accessing remote, deepwater offshore fields may make pipelines prohibitively expensive for otherwise promising gas projects. Also the fact that compressed natural gas does not require a gas liquefaction plant and re-gasification at the discharge location, as it can be discharged directly, shows the magnitude of cost savings in terms of infrastructure.

Looking finally at the complete transport chain from gas well to consumer there is potential for more large savings. A fleet of compressed natural gas ships will serve as both storage and transport vehicles and can discharge directly into the land based gas grid via an onshore or offshore discharge terminal, an offshore platform or offshore buoys. Looking at the energy loss of transport of gas from the gas well to the consumer compressed natural gas loses are up to 5-8%, while for liquefied natural gas are about 15% and for pipeline 3-5%. Hence, compressed natural gas appears also to be a more environmentally friendly way of transport than liquefied natural gas where additional energy is lost in the liquefaction and re-gasification process.

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2.5 Storage

A very important technology for the natural gas is its storage and has an increased necessity nowadays. Natural gas storage is applied to serve both natural gas companies and the consumers for a number of reasons.

The first reason that this technology is applied is to maximise the system capacity. The exploration, production, and transportation of natural gas usually takes a long time, and the natural gas that reaches its destination is not always needed right away, so it has to be stored. Often it is stored in facilities that are located near market centres that do not have a ready supply of locally produced natural gas.

Additionally we should bear in mind that natural gas demand fluctuates greatly, depending on the season. In many occasions the natural gas supply exceeds the demand, so the excess natural gas has to be removed as it is unnecessary for that time. This is usually happening during the summer months, when the need for heating requirements is much less than that the winter period, although recently the summer demand is increasing too. Storage of natural gas plays a vital role in ensuring that any excess supply delivered during the summer months is available to meet the increased demand of the winter months. Certain types of storage reservoirs can deal effectively with these seasonal fluctuations.

Also natural gas demand fluctuates highly with the day or even hour. Some times a sudden, short term additional need for natural gas is experienced and more natural gas has to be provided instantly. Certain types of storage facilities, are designed also for this case, ensuring high-deliverability for short periods of time, meaning that natural gas can be withdrawn from storage quickly should the need arise

Another reason of storing natural gas is for economic reasons. So what usually happens is storing gas when prices are low and withdrawing and selling it when prices are high. This usually happens because of the fact that in high demand periods the natural gas price boosts rapidly. As a consequence the companies that store natural gas make additional profit following this tactic.

One method of storing natural gas is in large aboveground tanks, known as liquefied natural gas storage tanks. First the natural gas is converted to a liquid, commonly known as liquefied natural gas, by cooling it until it reaches its liquefaction point (-260 degrees Fahrenheit). Then its volume decreases as much as 600 times and it is stored without the need for compression. Because liquefied natural gas must maintain such a low temperature, it requires unique insulation and storage techniques. What is usually applied is a large tank including an inner and an outer tank. The inner tank is usually constructed of approximately 10 percent nickel steel to stand up to the cold liquefied natural gas, while the outer tank is constructed of carbon steel. The space between the two tanks is filled with insulation to minimize ambient heat from entering and consequently causing evaporation.

Liquefied natural gas storage facilities offer several advantages over alternative storage options. Because liquefied natural gas storage facilities can be located above ground, operators have many more opportunities for locating liquefied natural gas storage facilities in comparison with traditional underground storage alternatives that depend on underground geological conditions. Secondly, liquefied natural gas storage facilities are often constructed with a higher degree of deliverability (the amount of gas the facility can send out under peak conditions relative to stock in inventory) than traditional underground storage facilities.

But nevertheless the most predominant method of storing natural gas is in deep underground storage facilities. Any underground storage facility is reconditioned to create a sort of storage vessel underground before natural gas is injected into it. Natural gas is injected into the formation and, as the pressure builds as more natural gas is added, the underground formation becomes a sort of pressurized natural gas container. The higher the pressure in the storage facility, the more readily gas may be extracted. Conversely, once enough gas has been extracted the pressure drops enough that it is insufficient to push the natural gas out of the storage facility. This means that, in any underground natural gas storage facility, there will be a certain amount of gas that may never be extracted.

There are three main facilities that are most commonly applied for the storage of natural gas:

- Depleted gas reservoirs
- Aquifers
- Salt caverns

The most common type of underground storage is in depleted gas reservoirs. They are those formations that have already been tapped of all their recoverable natural gas. This leaves an underground formation, geologically capable of holding natural gas. In addition, using an already developed reservoir for storage purposes allows the use of the extraction and distribution equipment left over from when the field was productive. Having this extraction network in place reduces the cost of converting a depleted reservoir into a storage facility.

The factors that determine whether or not a depleted reservoir will make a suitable storage facility are both geographic and geologic. Geographically, depleted reservoirs must be relatively close to consuming regions. They must also be close to transportation infrastructure, including natural gas transmission and distribution pipeline systems. Geologically, depleted reservoir formations must have high permeability and porosity. The porosity of the formation determines the amount of natural gas that it may hold, while its permeability determines the rate at which natural gas flows through the formation, which in turn determines the rate of injection and withdrawal of working gas. But their common advantage is the fact that geological characteristics are already well known.

Depleted gas reservoirs are the most common type of base load storage facility. These reservoirs are larger than any other formation, but their delivery rates are relatively low, meaning that the natural gas which can be extracted each day is limited. Instead, these facilities provide a prolonged, steady supply of natural gas, so they are ideal for dealing with seasonal demand.

Of the three types of underground storage, depleted reservoirs, on average, are the cheapest and easiest to develop, operate, and maintain, although these reservoirs are sometimes very old and require a substantial amount of well maintenance and monitoring in order to ensure working gas is not being lost via well bore leaks into other permeable reservoirs.

Another type of underground storage reservoir that can be applied for natural gas is deep aquifers. The aquifers are into underground porous, permeable rock formations, which are initially filled with water. The gas is injected at the top of the water formation and displaces the water down structure.

Aquifer storage has a few advantages such as the fact that aquifers are typically sited close to the end user market. Also they have high deliverability of natural gas and can deal effectively not only with seasonal demand, like depleted gas reservoirs, but be applied to deal with peak load demand requirements as well.

But these advantages are not enough to make these formations an attractive storage solution for natural gas. They are the most expensive type of natural gas storage facility for a number of reasons. First, the geological characteristics of aquifer formations are not as thoroughly known, as with depleted reservoirs. A significant amount of time and money goes into discovering the geological characteristics of an aquifer, and determining its suitability as a natural gas storage facility. Also the area of the formation, the composition and porosity of the formation itself, and the existing formation pressure must all be discovered prior to development of the formation. In addition, the capacity of the reservoir is unknown, and may only be determined once the formation is further developed.

Also another disadvantage making these types of formations least desirable, is that in order to develop a natural aquifer into an effective natural gas storage facility, all of the associated infrastructure must also be developed. This includes installation of wells, extraction equipment, pipelines, dehydration facilities, and possibly compression equipment. As aquifers are more expensive to develop than depleted reservoirs, these types of storage facilities are usually used only in areas where there are no nearby depleted reservoirs.

Finally the last but not least option for natural gas storage is the salt caverns. They are formed from existing salt deposits by drilling a well down into the salt formation, and cycling large amounts of water through the completed well. The water dissolves some of the salt in the deposit, and is cycled back up the well, leaving a large empty space. Typically, salt domes used for natural gas storage are between 6,000 and 1,500 feet beneath the surface, although in certain circumstances they can come much closer to the earth's surface

Although this process to create a salt cavern is quite expensive, a salt cavern offers an underground natural gas storage vessel with very high deliverability. Salt caverns are the most common type of peak load storage facility, although aquifers may be used to meet these demands as well. These facilities cannot hold as much natural gas as depleted gas reservoirs, but they can deliver smaller amounts of gas more quickly, and can also be refilled in a shorter amount of time than the depleted gas reservoirs.

3. Uses

Natural gas demand has increased rapidly recently. In many sectors of everyday life, natural gas proves its significant importance through a number of uses, making it a vital component of our lives. Natural gas is used today:

- Residentially,
- Commercially
- Industrially,
- In electricity generation, and
- Other applications, mainly including the transportation sector.

In the graph below we can see the percentages of each of these uses, as they were presented by EIA for the year 2002:

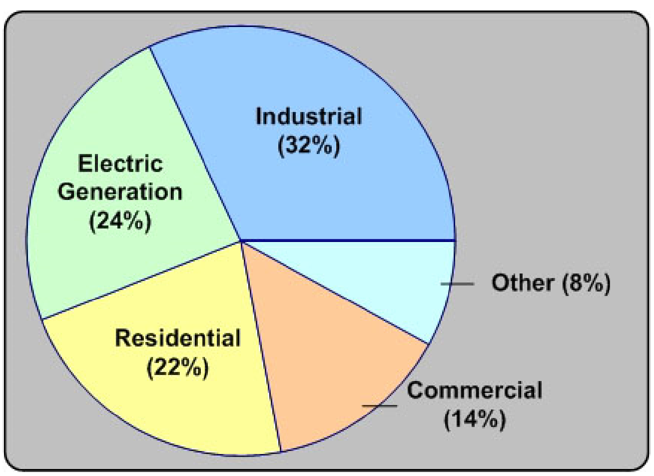

Figure 1.13: Natural gas use by sector

We can see from the graph that the main application today is in industry, followed by the use for electricity generation. Then with a slight difference follows the residential sector and less the commercial applications. The smallest percentage is witnessed for other application, mainly consisting of transport sector as explained before, which is reasonable if we consider that the natural gas technologies to support vehicles are recently developed.

With the raise of demand for natural gas, the amounts of natural gas are expected to rise. This rise will not be equally distributed in the sectors, as some of them may require larger amounts of natural gas more rapidly than others depending on the technology development. In the figure below we can see the natural gas demand growth as it was witnessed from the year 1971 till 2002, and also a prediction is being made for the year 2030:

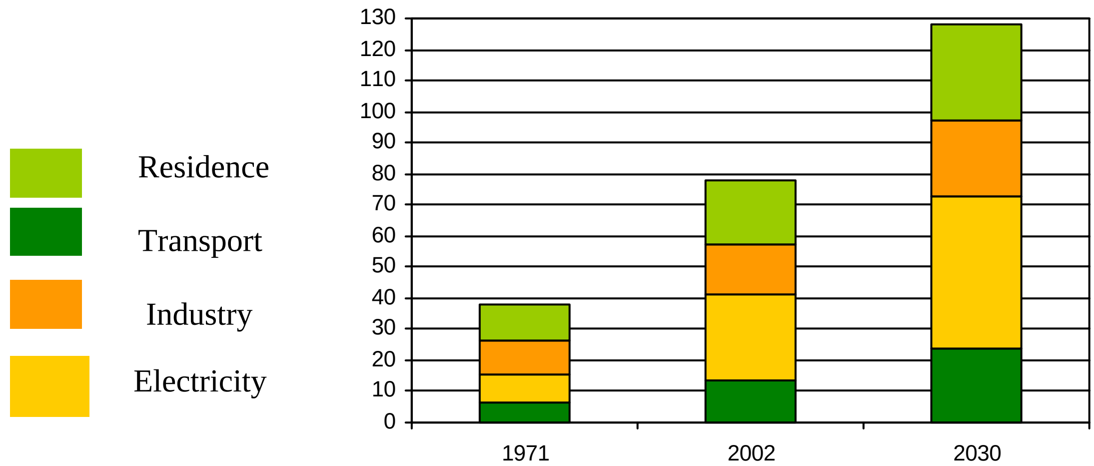

Figure 1.14: Natural gas demand growth

As we can see the overall natural gas demand has been double over the last 30 years and is expected to grow more than three times comparing to the initial point (1971), till the year 2030. Demand in all sectors has risen and the most rapid rise has been witnessed in the electricity generation sector.

By the year 2030 natural gas will continue proving its significance in all sectors constantly in an analogue way. More residences will switch to natural gas, the application to industry will rise and electricity generation will depend more in natural gas in an effort to adopt environmental friendly technologies. Also larger use in the transport sector is expected, with the development of natural gas technologies for vehicles.

The uses of natural gas per sector will be summarized in the following paragraphs.

3.1 Residential

Residential applications are the most commonly known use of natural gas. This is because of the large number of uses it can have in a house such as for cooking, washing and drying, water warming, heating and air conditioning. Domestic appliances are increasingly improved in order to use natural gas more economically and safely.

As mentioned before in figure 1.13 residential use of natural gas counts a percentage of 22% of the overall use. This number is large and also promising for a larger expansion of natural gas in domestic applications. Today 55 percent of all U.S. households use natural gas, a figure that has accelerated in recent years. Also, over 70 percent of new homes built in the U.S. use natural gas. If we consider these impressing numbers of natural gas use in residences in the U.S. along with the fact that there exists a large natural gas network, we can easily expect such numbers to occur in the future and to other countries as their natural gas network is expanded.

Families look forward to and energy solution for their homes that is cost saving. The low cost of natural gas makes it a very attractive choice for houses to use.

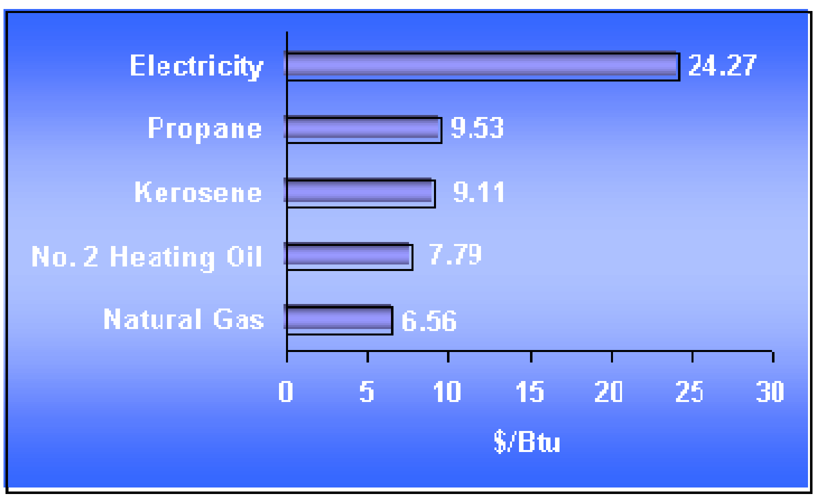

Figure 1.15: Residential Energy Costs per Btu (in U.S.)

As indicated in the figure above natural gas is not only competitive to other energy solutions, but in the case of electricity it is almost four times cheaper! This point becomes even stronger if we consider also that the operating costs of natural gas equipment are generally lower than those of other energy sources. Natural gas appliances also have longer expected life than others and require small maintenance costs.

Natural gas is used in residences for heating and cooking. Cooking with a natural gas range or oven can provide many benefits, including easy temperature control, self ignition and self cleaning, as well as being approximately one-half the cost of cooking with an electric range. The newer generations of natural gas ranges allow for some of the most efficient, economical, and versatile cooking appliances ever. Also natural gas furnaces can achieve efficiencies reaching even 90%.

Also natural gas can be used for cooling, as natural gas air conditioners exist in the market. Although natural gas air conditioner units are initially more expensive than a comparable electric unit, they are considerably more efficient and require less maintenance. Modern residential air conditioner units use close to 30 percent less energy than in years past, and have an expected working life of 20 years with very little maintenance.

But cooking, heating and cooling are not the only uses for natural gas in residences. Electricity can also be provided to houses with the use of natural gas, in order to cover the rest of the energy needs in a house. This is achieved with the use of distributed generation technologies. Distributed generation refer to using natural gas to generate electricity right on the doorstep. Natural gas fuel cells and micro generators (Combined Heat and Power) both offer the residential consumer the capacity to disconnect from their local electric distributor, and generate just enough electricity to meet their needs. Although this technology is still in its infancy, it is very promising in being able to offer independent, reliable, efficient, environmentally friendly electricity for the residential needs.

3.2 Commercial

The commercial sector uses natural gas with a percentage of approximately 12%, a number which is predicted to grow according to the prediction mentioned earlier (figure 1.14).

Main commercial users of natural gas are food service providers, hotels, healthcare facilities, office buildings, supermarkets, retailers, restaurants, malls, computer data centres and schools. They all use natural gas for space-heating, lighting, water-heating, cooling, dehumidification or cooking, according to the needs each one of them has to cover.

In the commercial sector the needs appear to be the same with the residential sector. But in this case, because of the larger size of the buildings and the variety and specific nature of activities undertaken by commercial users, larger quantities of thermal and electrical energy are required. So the techniques will remain the same as in the residential sector, but they have to be more powerful.

Important role in meeting these requirements play the micro generators (Combined Heat and Power plants). The combined production of heat energy and electrical energy, which can be adapted to meet these needs in the commercial sector, brings significant savings in running costs, especially in countries where the electricity is produced thermally. The combined heat and power plants have electrical efficiency of more than 30% and overall efficiency of over 85%, which makes them an attractive solution for this sector too.

Also fuel cells, thanks to their characteristics, are a very good solution for energy production in highly urbanized areas, such as those where the commercial activities take place.

3.3 Industrial

Industry is the biggest consumer of natural gas among all sectors, with a percentage of 32% and big potential for larger expansion. Projections of IEA show in the figure below the raise and the use of natural gas in industry compared to other alternative fuels, since 1970 till 2020:

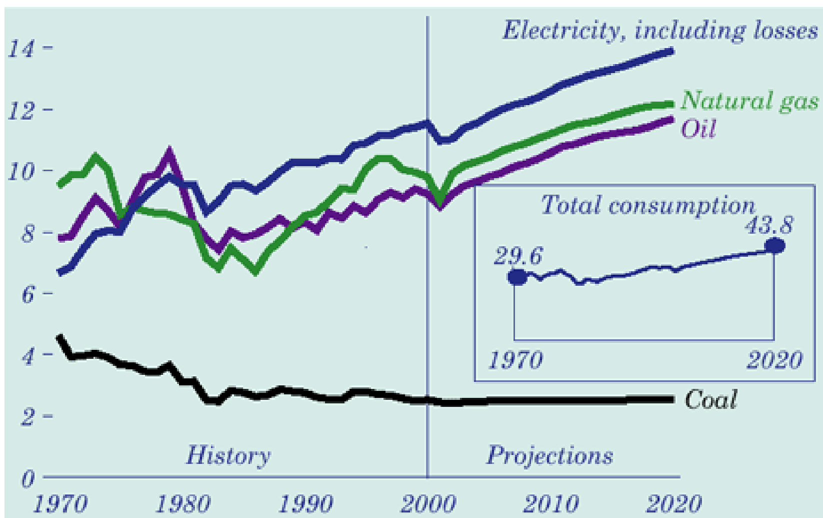

Figure 1.16: Industrial energy consumption by fuel in U.S.

As it is shown from the graph, coal has a minor and decreasing role in industry over the years. Electricity is the main component of providing energy to the industry and is expected to maintain this position over the next fifteen years. But natural gas, as well as oil, increases its significance for the industry, with the natural gas leading with a small difference.

In order for an industry to switch to some other fuel several criteria must be ensured to be met. Fuel price must be low, something that has been proven for natural gas. Also issues of reliability of supply and safety must be dealt effectively. Low operating costs must be low, something that is true for the case of natural gas as the maintenance costs are low. Finally compliance with emissions regulation must be met, which is most possible for the natural gas as most low emission fuel among the other alternatives.

Natural gas is used as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass, and to process certain foods. Gas is also used to treat waste materials, for incineration, drying, dehumidification, heating and cooling, and cogeneration. Natural gas is a critical building block for many products, including specialty chemicals like ammonia-based fertilizers.

Various technologies are applied in industry in order to use natural gas in the most useful way. Infrared (IR) heating units provide an innovative and economic method of using natural gas to generate heat in an industrial setting. They are very useful in the metals industry, as they provide innovative ways to increase the efficiency of powder-coating manufacturing processes. Infrared heaters use natural gas to more efficiently and quickly heat materials used in this process.

Direct contact water heating is an application that works by having the energy from the combustion of natural gas transferred directly from the flame into the water. Normal industrial water heaters operate in the 60 - 70 percent energy efficiency range, but direct contact water heaters can achieve efficiencies up to 99.7 percent, leading to huge cost savings.

Industrial consumers benefit greatly from operating natural gas Combined Heat and Power (CHP) and Combined Cooling, Heat and Power (CCHP) systems, similar to those used commercial settings. For instance, natural gas may be used to generate electricity needed in a particular industrial setting. The excess heat and steam produced from this process can be harnessed to fulfil other industrial applications, including space heating, water heating, and powering industrial boilers. Since industry is such a heavy user of energy, providing increased efficiency can save a great deal of money.

Natural gas co-firing technologies are also helping to increase industrial energy efficiency, and reduce harmful atmospheric emissions. Co-firing is the process in which natural gas is used as a supplemental fuel in the combustion of other fuels, such as coal, wood, and biomass energy. Since the energy needed to power the natural gas boiler remains constant, adding natural gas to the combustion mix can reduce harmful emissions.

3.4 Electricity generation

Natural gas is used in electricity generation in a percentage of 24%, which is higher that the residential and the commercial sector use. The role of natural gas in electricity generation has been increasingly important mostly due to its environmentally clean character.

Today's share of natural gas in electricity production is shown in the graph below:

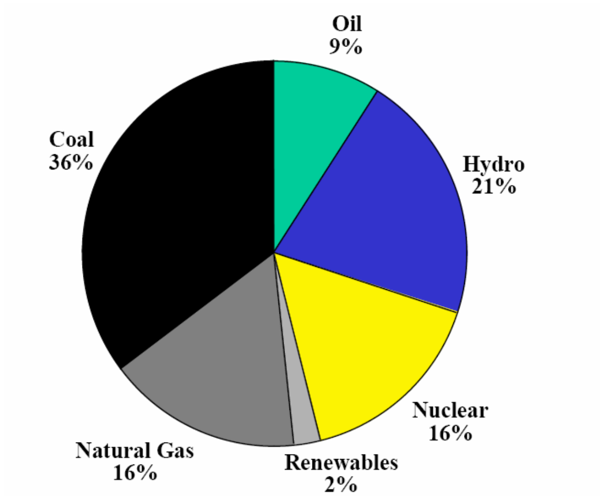

Figure 1.17: World electricity production by fuel

Natural gas provides a solution for electricity generation with a percentage of 16% among the overall use of fuels. Coal seems to be the most predominant fuel for this purpose, but we should bear in mind that this is because many countries economies still depend on it. This is about to change due to the obligations for application of low emission technologies.

As mentioned in the previous paragraphs natural gas can be used to generate electricity in a number of ways. Combined heat and power plants, natural gas fuel cells and other technologies with a variety of sizes can be used to generate electricity for individual applications in the residential, commercial or industrial sector, according to the demand in each circumstance.

But a large share in electricity generation refers to a more centralised power generation with the use of natural gas. Electric utilities and independent power producers are increasingly using natural gas to provide energy for their power plants. In general, natural gas fuelled power plants have lower capital costs, are built faster, work more efficiently and emit less pollution than other fossil fuel power plants. Technological improvements in design, efficiency and operation of them, make natural gas power plants an attractive option for electricity generation.

The most basic natural gas fired electric generation consists of a steam generation unit, where natural gas is burned in a boiler to heat water and produce steam, which then turns a turbine to generate electricity. These basic steam generation units have fairly low energy efficiency. Typically, only 35 percent of the thermal energy used to generate the steam is converted into electrical energy in these types of units.

Gas turbines and combustion engines are also used to generate electricity. In these types of units, instead of heating steam to turn a turbine, hot gases from burning natural gas are used to turn the turbine and generate electricity. Gas turbines have the advantage in that they can provide power within minutes after start-up whereas the steam cycle takes several hours to create enough steam to drive the steam turbine. Gas turbines are useful during times of peak electricity demand when extra power must be added for a short period during the day. They can be turned on during peak demand periods to quickly add electricity to the grid and turned off when the demand drops to normal levels. However, they are still traditionally slightly less efficient than large steam-driven power plants.

But the peak of technology in natural gas fired power plants are what are known as combined-cycle power plants. In these types of generating facilities, there is both a gas turbine and a steam unit, all in one. The gas turbine operates in much the same way as a normal gas turbine, using the hot gases released from burning natural gas to turn a turbine and generate electricity. In combined-cycle plants, the waste heat from the gas-turbine process is directed towards generating steam, which is then used to generate electricity much like a steam unit. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than steam units or gas turbines alone, achieving thermal efficiencies of up to 60 percent. The combined cycle plant takes advantage of the efficiencies of running both cycles simultaneously to produce power very cost effectively during those peak periods thereby saving the utility from having to purchase power to meet spikes in demand.

3.5 Transportation

Natural gas can be used also in transportation sector, but with the smallest percentage among other sectors. The idea of using natural gas to fuel vehicles is not new as the first efforts were made in 1930. But nowadays this use is widely adopted by many countries. In the figure below we can see for example the number of natural gas vehicles used today in Europe:

Figure 1.18: Natural gas vehicles in Europe

As shown from the figure above the total natural gas vehicles are estimated to be approximately 576,000. According to the International Natural Gas Vehicles Association natural gas vehicles fleet accounts for about one and a half million vehicles worldwide.

Natural gas can be used as a motor vehicle fuel in two ways: as compressed natural gas, which is the most common form, and as liquefied natural gas. Compressed natural gas is used in light-duty passenger vehicles and pickup trucks, medium-duty delivery trucks, and in transit and school buses. LNG, on the other hand, is favoured for heavy-duty applications, such as transit buses, train locomotives and long-haul semi-trucks. The estimated total use of natural gas per application in Europe only is shown below:

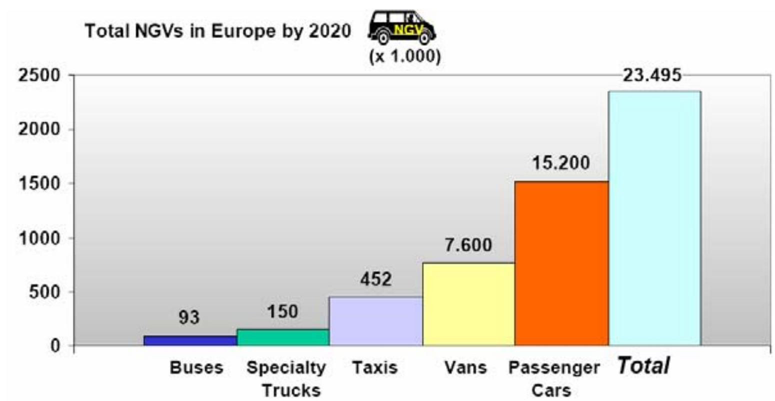

Figure 1.19: Estimated natural gas vehicles in Europe by 2020

We can see that due to environmental concerns, as natural gas is a low emission fuel, and small natural gas prices, the number of natural gas vehicles is expected to boost. The main role will be played by passenger cars, followed by vans and taxis. A minor proportion will be in the case of trucks and buses.

In the case of compressed natural gas vehicles, natural gas is compressed to high pressure (about 20 MPa) and fed to the vehicles tank (usually special cylinders).When the engine is started, natural gas flows into a fuel line and then enters a regulator where its pressure is reduced. After that the natural gas feeds into the engine through a fuel injection system where it’s combined with air, where the fuel/air mixture is adjusted to burn most efficiently and with the least possible emissions. Natural gas burns in the engine just like gasoline. Compressed natural gas vehicles can be refuelled by attaching a hose at the fuelling point and providing more compressed natural gas.

The emissions of the combustion of natural gas are much lower than if instead gasoline was combusted. The savings when using natural gas instead of gasoline, per component are summarised in the graph below:

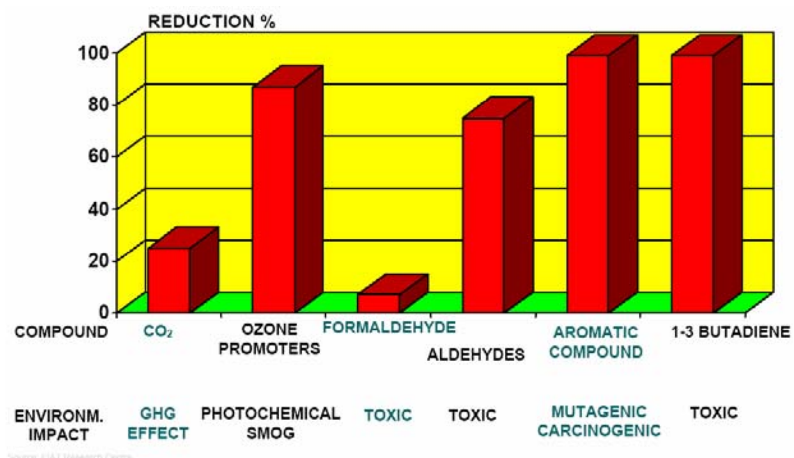

Figure 1.20: Compressed natural gas/gasoline emission comparison

But beyond environmental benefits of the use of compressed natural gas in vehicles there are also large cost savings, due to the lower prices of this fuel compared to other alternatives that are traditionally applied. The magnitude of this savings is obvious if we notice the graph below:

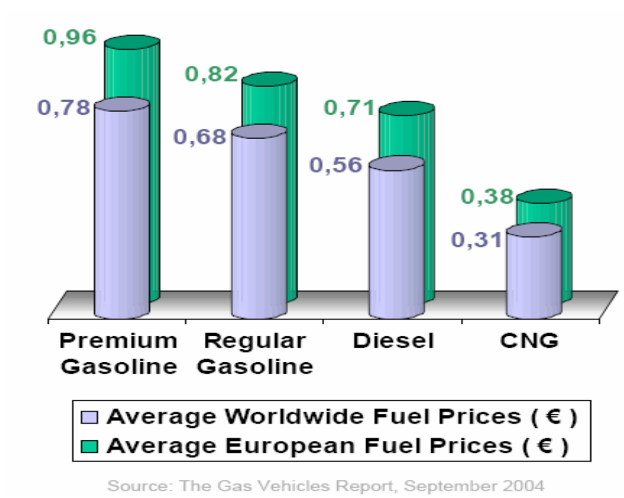

Figure 1.21: Average prices per fuel

The other fore mentioned case that natural gas is used in transport, is in liquefied natural gas vehicles. In the case of liquefied natural gas, natural gas turns into a liquid for easy storage or transport by extreme cooling to minus 260 degrees Fahrenheit. Liquefied natural gas is almost pure methane and, because it is a liquid, has an energy storage density much closer to gasoline than compressed natural gas. The requirements of keeping the liquid very cold, along with its volatility, make its applications more limited for transportation purposes. As a result, it is typically used in heavy-duty applications such as transit buses, heavy-duty long-haul trucks or locomotives.

There are no major differences in liquefied natural gas vehicle performance, operation, and utility when compared with diesel. The high ignition quality of liquefied natural gas is similar to that of diesel, providing for similar durability and engine life overall. But, some maintenance savings are anticipated for vehicles using liquefied natural gas when compared with gasoline-powered vehicles, because of the reduced frequency of oil changes required. Also liquefied natural gas vehicles make approximately half the noise of ordinary diesel engine vehicles. Emission reductions and cost savings are similar as in the case of compressed natural gas, making this technology more attractive than the alternative fuel options, like gasoline.

But liquefied natural gas vehicles have some advantages even over compressed natural gas vehicles. Liquefied natural gas vehicles weigh less than compressed natural gas vehicles, and therefore can carry up ¾ of a tone more cargo per payload. Also liquefied natural gas vehicles cost less to manufacture than compressed natural gas vehicles. Additionally, liquefied natural gas is portable, so is liberated from the pipes to build stations, whereas compressed natural gas stations are constrained to areas supplied by pipelines.

Generally natural gas when it is about to be used in the transportation sector, many concerns arise related to safety. The truth is that, as with all vehicle fuels, natural gas can be used safely if simple, common sense procedures are followed. So it does not hide any additional risks than the other fuels that are traditionally used, while sometimes the use of natural gas proves to be safer.

Natural gas vehicles have an excellent safety record for because of the properties of the fuel itself. Natural gas has a high ignition temperature, about 1,200 degrees Fahrenheit, compared with about 600 degrees Fahrenheit for gasoline. It also has a narrow range of flammability that is, in concentrations in air below about 5 percent and above about 15 percent, natural gas will not burn. The high ignition temperature and limited flammability range make accidental ignition or combustion of natural gas unlikely.

Natural gas powered vehicles are designed and built to be safe both in normal operation and in crashes. New natural gas vehicles are subjected to the same crash tests as other vehicles. But we should consider that natural gas cylinders are much thicker and stronger than gasoline or diesel tanks, and are subjected to a number of federally required severe abuse tests, such as heat and pressure extremes, gunfire, collisions and fires, in order to ensure their durability.

Finally, natural gas vehicles fuel systems are sealed, which prevents any spills or evaporative losses. But even if a leak were to occur in a natural gas vehicle fuel system, the natural gas would dissipate into the atmosphere, because it is lighter than air, causing no harm.

CHAPTER 2

1. Introduction

Greece is a relatively small country with a population of approximately 11 million people. But in recent years with the economic development witnessed, the energy demand seems to increase in all sectors. According to the Greek government this change over the years 1990 till 2020 was estimated as:

Συνολική Ενεργειακή Ζήτηση Ελλάδας Final Energy Demand of Greece 1990-2020											
Εκ. ΤΙΠ/ Mtoe	1990	1995	2000	2005	2010	2015	2020	'90-'00	'90-'10	'95-'10	'10-'20
								Ετήσια Μεταβολή (%) / Annual Change (%)			
Συνολική Ενεργειακή Ζήτηση ανά Τομέα/ Final Energy Demand by Sector (Mtoe)	15.0	16.3	18.9	21.7	24.3	26.4	27.9	2.4	2.4	2.7	1.4
Βιομηχανία/Industry	3.8	4.0	4.7	5.2	5.3	5.3	5.2	2.1	1.7	1.9	-0.1
- Μέταλα/metals	0.8	0.8	0.9	0.9	0.9	0.8	0.8	0.3	0.0	0.6	-0.7
- Χημικά/chemicals	0.3	0.2	0.3	0.4	0.4	0.4	0.4	1.0	1.9	4.8	1.0
- Αλλες Ενεργειακές Βιομηχανίες/ - Other Energy Intensive Industries	1.5	1.6	2.1	2.5	2.5	2.5	2.5	3.4	2.7	3.2	-0.3
- Αλλοι Βιομηχανικοί τομείς/ - Other Industrial Sectors	1.2	1.4	1.4	1.5	1.5	1.5	1.5	1.9	1.2	0.4	0.2
Οικιακός/Residedential	3.8	3.9	4.4	4.8	5.2	5.6	6.2	1.5	1.5	1.8	1.8
Τριτογενής/Tertiary	1.6	1.9	2.3	3.0	3.7	4.5	5.3	4.1	4.4	4.4	3.6
Μεταφορές/Transport	5.8	6.4	7.5	8.8	10.1	11.0	11.2	2.6	2.8	3.1	1.0

Table 3: Energy demand rise per sector

What is important to be noticed from this table, is that in the 1990-2000 decade, there was an increase in the energy demand in all sectors, with a mean value of 2.4 % per year. During the next decade and until the end of it the mean magnitude of demand increase is expected to remain constant per year, with some diversifying between certain sectors, while in the last case (2010-2020) there is predicted a slight decrease in it. So it’s easy to realize that the energy demand during the whole period of time is experiencing an overall major rise, possibly due to the development of the country.

Natural gas was not introduced in Greece until 1997. Till then the country showed a high dependency in fossil fuels, in order to manage the energy requirements. For example in electricity generation, the main ways used were brown coal (lignite) combustion, oil combustion and the use of hydropower or renewables:

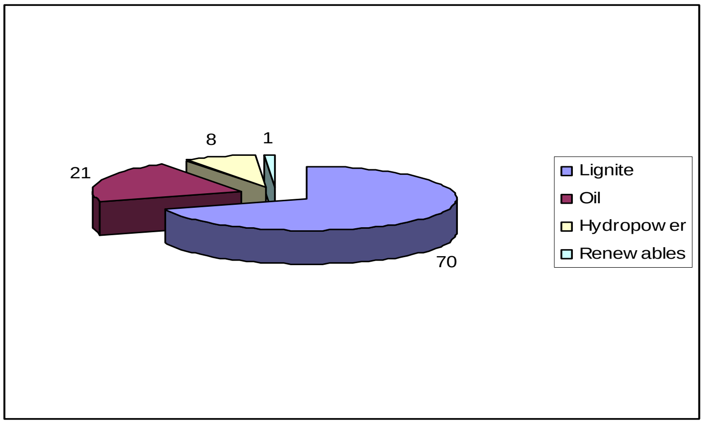

Figure 2.1: Percentage (%) per source for electricity generation in 1998

From the chart above we can see that the main role was played by lignite (70%), followed by oil (21%). A large amount of power plants based on coal or oil are distributed in the whole country, covering almost exclusively the electricity needs. Also hydropower was used in a reasonable magnitude (8%), as the mainland landscape offered much potential for this technology. Renewables are just making a minor contribution in electricity generation applied usually in remote islands in an autonomous way. Among renewables, wind energy possesses the biggest share in application, as high velocity winds in some islands offered this opportunity, followed by limited the use of solar energy systems.

But after the introduction of natural gas in Greece in 1997 this situation tends to change rapidly, as recorded and predicted from the Greek government:

Συνολική Ενεργειακή Κατανάλωση (Διάθεση) Ελλάδας Gross Inland Consumption of Greece 1990-2020											
Εκ. ΤΙΠ/ Mtoe	1990	1995	2000	2005	2010	2015	2020	'90-'00	'90-'10	'95-'10	'10-'20
								Ετήσια Μεταβολή (%) / Annual Change (%)			
Συνολική Ενεργειακή Κατανάλωση ανά Τομέα/ Gross Inland Consumption by sector	22.8	24.7	28.7	32.6	35.8	38.4	40.5	2.3	2.3	2.5	1.2
Στερεά Καύσιμα/Solids	8.1	8.8	9.6	10.3	10.3	9.8	10.9	1.7	1.2	1.1	0.6
Υγρά Καύσιμα/Oil	12.8	14.0	15.9	18.0	19.5	20.7	21.3	2.1	2.1	2.3	0.9
Φυσικό Αέριο/Natural gas	0.1	0.0	1.5	2.5	4.2	5.7	6.1	26.7	18.6	35.5	3.8
Άλλες μορφές/Other	1.7	1.9	1.7	1.8	1.8	2.2	2.3	0.3	0.4	-0.2	2.2
ΑΠΕ/ Renewables in Primary Energy	1.6	1.8	1.7	1.7	1.7	2.0	2.1	0.5	0.4	-0.2	2.0

Table 4: Energy consumption per fuel

The idea behind the introduction of natural gas in Greece, is to make capable the country to deal effectively with the increase of energy demand mentioned earlier, coupled with the need to constrain the use of high emission technologies related to coal and oil. Compliance to the low emission legislation and environmental friendly policy development seemed incapable to be succeeded without natural gas, as renewables were unable to cope with the rising demand.

During the first decade (1990-2000), fossil fuels were used predominantly in Greece, with oil experiencing a higher percentage of increase of consumption. Oil is expected to continue its rise in consumption with almost a constant rate of 2.1% per year over the first 2 decades, and falling to 0.9% in the last one. But the increase in solid consumption is falling during the whole period constantly.

Renewables have also an increased role, which is constrained mostly due to the technology immaturity, high costs of application, and incapability to meet the demand in large scale. Though they have expanded their application with a mean rate of 0.5% per year for the first decade (1990-2000) and are expected to be more applied in the future.

What seems to affect the change in the scenery is the natural gas, which affects mostly the fossil fuel consumption and less the renewables. If it wasn't the natural gas we would expect bigger rates of consumption growth for the fossil fuels, with negative effects to the environment. Since 1997 that natural gas was first applied in Greece, it had an annual change of +26.9% per year for the first three years. What is more impressing is the fact that this rise is expected to be as high as 35.5% per year for the first 13 years of application (1997 until 2000). Predictions for the period 2010 till 2020 talk about an annual increase of 3.8% annually.

This means that natural gas has proven its significance and is expected to achieve its goal of meeting future demand, with limiting the use of fossil fuels at the same time.

2. The Greek natural gas company

The company that is responsible for natural gas in Greece belongs to the Greek State and is called The Public Gas Corporation (DEPA). It was established in September 1988 as a subsidiary of the then Public Petroleum Corporation (now called Hellenic Petroleum) for the purpose of importing, transporting and distributing natural gas in Greece. Today Hellenic Petroleum owns only the 35% of the company and the remaining 65% belongs to the Greek State.

The Greek State also, right after the DEPA establishment, created three gas supply companies, known as EPAs. DEPA owns ever since 51% of the Gas Supply Companies (EPAs) via its subsidiary Gas Distribution Companies (EDAs).

Figure 2.2: Existing EPAs

Today there are three existing EPAs (see figure 2.2): one in Thessalonica and one in Thessaly (Larissa, Volos), where the private company Italgas holds the remaining 49% share, and a third one in Attica (Athens), owned 49% by a joint venture of the private companies Cinergy and Shell. DEPA is in the process of establishing three more EPAs covering Central Greece, Central Macedonia and Eastern Macedonia –Thrace (both areas in the northern region).

What also was established by the Greek State in July 2000, was The Regulatory Authority for Energy (RAE). It is an independent agency, with a mixed advisory and decision-making role. In electricity matters, such as codes, regulations, end-user tariffs and licensing for generation, the RAE gives an opinion, but finally The Ministry of Development makes the final decisions. The RAE has full competence in supervising the Transmission System Operator on third party access matters, setting end-use natural gas tariffs, unbundling, imposing fines and settling disputes. The RAEs goal is to support the general goals of security of supply, environmental protection and national and regional economic competitiveness. The RAE also provides an opinion on long-term energy planning, which comes under of the Ministry of Development and in order to be implemented must be approved by the Greek Parliament.

3. Greek natural gas situation internationally

In order to better understand the Greek natural gas situation perhaps it would be better if we could compare its position with the natural gas scenery worldwide and then narrowing the view to the national scenery.

In the table below we can see the natural gas consumption (in million cubic meters) as deducted from the “Statistical Review of World Energy 2005", by the BP company:

rank	country	1980	1990	2000	2003	2004	percent of total
1.	USA	566,500	552,500	669,700	645,300	646,700	24.05%
2.	Russian Federation	na	420,100	377,200	392,900	402,100	14.95%
3.	United Kingdom	44,800	52,400	96,800	95,400	98,000	3.64%
4.	Canada	52,200	66,800	83,000	92,200	89,500	3.33%
5.	Iran	6,900	22,700	62,900	82,900	87,100	3.24%
6.	Germany	57,400	59,900	79,500	85,500	85,900	3.19%
7.	Italy	25,400	43,400	64,900	70,700	73,300	2.73%
8.	Japan	26,100	51,200	76,200	76,500	72,200	2.68%
9.	Ukraine	na	127,800	73,100	71,200	70,700	2.63%
10.	Saudi Arabia	9,700	33,500	49,800	60,100	64,000	2.38%
11.	Uzbekistan	na	36,800	47,100	47,200	49,300	1.83%
12.	Mexico	25,800	27,200	38,500	45,800	48,200	1.79%
13.	France	26,200	29,300	39,700	43,300	44,700	1.66%
14.	Netherlands	33,600	34,400	39,200	40,300	43,500	1.62%
15.	United Arab Emirates	4,900	16,900	31,400	37,900	39,600	1.47%
16.	China	13,000	14,700	24,500	32,800	39,000	1.45%
17.	Argentina	11,500	20,300	33,200	34,600	37,900	1.41%
18.	Indonesia	7,000	20,100	32,300	33,400	33,700	1.25%
19.	Malaysia	1,100	9,900	24,300	31,800	33,200	1.23%
20.	India	1,200	12,500	26,900	29,900	32,100	1.19%
21.	South Korea	-	3,400	21,000	26,900	31,600	1.18%
22.	Thailand	-	5,500	20,500	27,500	28,700	1.07%
23.	Venezuela	14,800	22,000	27,900	25,200	28,100	1.04%
24.	Spain	2,000	5,600	16,900	23,600	27,300	1.02%

25.	Egypt	1,800	6,800	18,300	24,600	25,700	0.96%
26.	Pakistan	6,600	11,200	18,900	23,400	25,700	0.96%
27.	Australia	10,000	17,200	23,600	24,300	24,500	0.91%
28.	Turkey	-	3,400	14,100	20,900	22,100	0.82%
29.	Algeria	11,400	20,300	19,800	21,400	21,200	0.79%
30.	Brazil	1,000	3,800	9,300	15,900	18,900	0.70%
31.	Romania	36,000	30,800	17,100	18,300	18,800	0.70%
32.	Belarus	na	13,800	16,200	17,200	18,500	0.69%
33.	Belgium & Luxembourg	11,500	10,600	14,900	16,000	16,300	0.61%
34.	Turkmenistan	na	9,800	12,600	14,600	15,500	0.58%
35.	Kazakhstan	na	12,500	9,700	13,000	15,200	0.57%
36.	Qatar	5,200	6,300	9,700	12,200	15,100	0.56%
37.	Bangladesh	1,300	4,800	10,000	12,300	13,200	0.49%
38.	Poland	9,700	9,900	11,100	11,200	13,200	0.49%
39.	Hungary	7,800	9,600	10,700	13,100	13,000	0.48%
40.	Taiwan	1,700	1,900	6,700	8,700	10,100	0.38%
41.	Kuwait	4,100	6,200	9,600	9,100	9,700	0.36%
42.	Austria	5,000	6,400	8,100	9,400	9,500	0.35%
43.	Czech Republic	3,700	5,400	8,300	8,700	8,800	0.33%
44.	Azerbaijan	na	15,800	5,400	8,000	8,500	0.32%
45.	Chile	700	1,700	5,200	7,100	8,200	0.30%
46.	Singapore	-	-	1,700	5,300	7,800	0.29%
47.	Slovakia	3,600	5,900	6,500	7,000	6,800	0.25%
48.	Colombia	3,200	4,100	5,900	6,000	6,300	0.23%
49.	Denmark	-	2,000	4,900	5,400	5,400	0.20%
50.	Norway	800	2,100	4,000	4,300	4,600	0.17%
51.	Finland	900	2,500	3,700	4,500	4,400	0.16%
52.	Republic of Ireland	800	2,100	3,800	4,100	4,100	0.15%
53.	New Zealand	800	4,300	5,500	4,100	3,600	0.13%
54.	Bulgaria	3,500	5,900	3,300	2,600	3,100	0.12%
55.	Lithuania	na	5,600	2,700	3,100	3,100	0.12%
56.	Portugal	-	-	2,400	3,000	3,100	0.12%
57.	Switzerland	1,000	1,800	2,700	2,900	3,000	0.11%
58.	Philippines	-	-	-	2,700	2,500	0.09%
59.	Greece	-	200	1,900	2,300	2,400	0.09%
60.	China – Hong Kong SAR	-	-	2,500	1,500	2,200	0.08%
61.	Peru	700	400	300	500	900	0.03%
62.	Sweden	-	700	700	800	800	0.03%
63.	Ecuador	-	100	100	100	100	0.00%
	World	1,452,400	1,993,800	2,438,300	2,603,500	2,689,300	100%

Table 5: Statistical Review of World Energy 2005

From the table above we can see that Greece is in one of the last positions (59th position) in terms of natural gas consumption compared to the world. Its contribution is limited to the 0.09% of the total, with only 2,400 million cubic meters natural gas consumed out of the total 2,689,300 million cubic meters worldwide.

But its worth to notice that Greece is one of the few countries that started using natural gas so late. Also what is promising is the fact that over the last four years of the statistical review (2000-2004) Greece had a 26.3% increase in natural gas consumption (from 1,900 million cubic meters in 2000 to 2,300 million cubic meters in 2004, which is significant.

We should also mention here that Greece in terms of infrastructure for natural gas is still very poor, due to the fact that it is a relatively new technology. The European natural gas infrastructure is shown in figure 2.3:

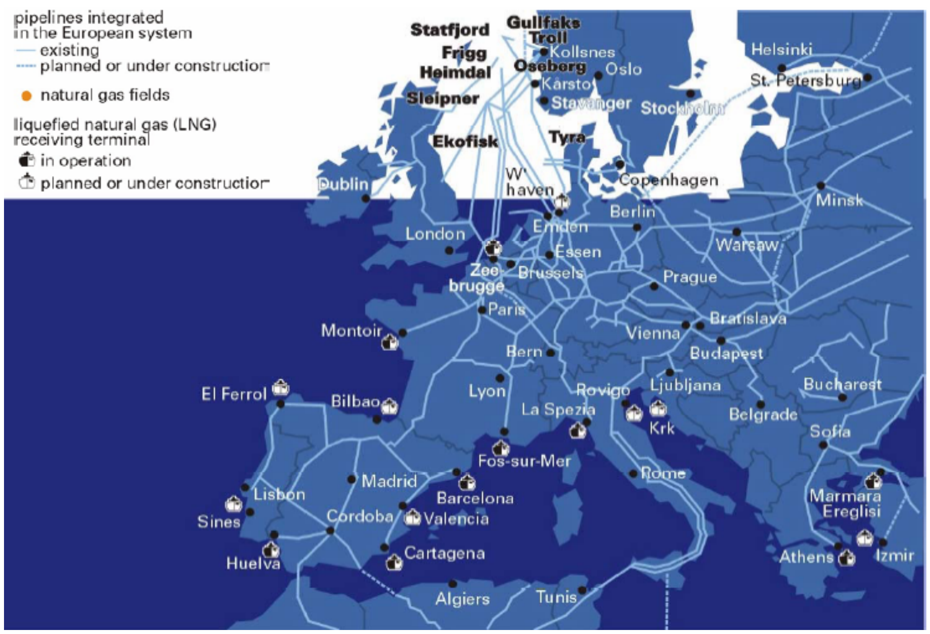

Figure 2.3: European natural gas pipelines and LNG terminals

Greece possesses only one liquefied natural gas terminal and the pipeline infrastructure is yet very limited, compared to the density of the pipeline network witnessed to other European countries.

3.1 Imports

Much of the natural gas used in Europe comes from indigenous production. In 2003 a percentage of 62% (out of an overall of 485 billion cubic meters) came from indigenous production in Europe as shown in the figure below:

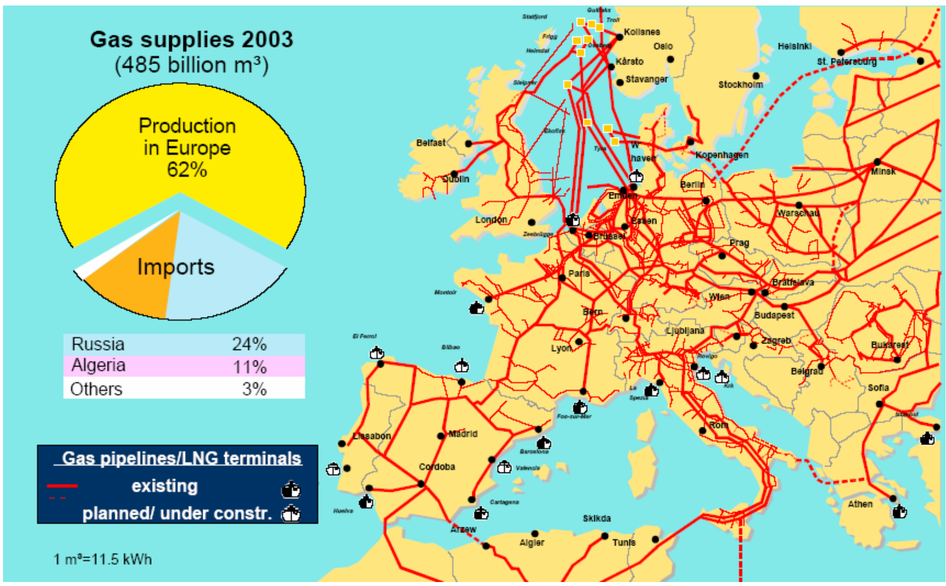

Figure 2.4: European natural gas imports

But imports came to fill the gap of the rest natural gas needed. From the overall 38% of imported natural gas 23% came from Russia, 11% from Algeria and only a 3% from other countries.

As it is expected Russia and Algeria are the main countries from which Greece imports natural gas. Greece started importing natural gas from Russia in 1997 and today 74% of the imported natural gas comes from Russia. It is compressed natural gas, transported through pipeline, passing through Bulgaria in a quantity of 2.4 billion cubic meters annually. As it was signed in 1997, Russia will export this quantity of natural gas to Greece till the year 2016.

The rest of the natural gas imported (26%) comes from Algeria, as liquefied natural gas. It is transported with large liquefied natural gas carriers (tankers) to the terminal of Revithousa (close to Athens). Greece began to receive liquefied natural gas (LNG) from Algeria in November 1999. It is a 21 years contract and the Public Gas Corporation (DEPA), on behalf of Greece, will purchase approximately 0.68 billion cubic meters of natural gas per year for the whole period of the contract (with a possibility of rising this number in the future).

The composition and the main characteristics of the Russian and Algerian imported natural gas, as deducted according to the Public Gas Corporation (DEPA) which is responsible for the imports, are:

COMPOSITION Contents (%) in :	**RUSSIAN NATURAL GAS**	**ALGERIAN NATURAL GAS**
Methane (C1)	98	91.2
Ethane (C2)	0.6	6.5
Propane (C3)	0,2	1.1
Butane (C4)	0,2	0.2
Pentane (C5) and heavier gases	0.1	-
Nitrogen (N2)	0.8	1
Carbon Dioxide (CO2)	0.1	-

Characteristics:

Net Calorific Value	8,600 kcal/Nm^3	9,640 kcal/Nm^3
Gross calorific value	9,200 kcal/Nm^3	10,650 kcal/Nm^3

Table 6: Imported gas composition and characteristics

3.2 Transmission – Distribution

The existing natural gas transmission and distribution system of Greece can be seen in the figure below:

Figure 2.5: Greek transmission and distribution system

The total infrastructure of the transmission system was developed by the Public Gas Corporation of Greece (DEPA) and consists mainly, as we can see from the map above, of the main high-pressure (70 bar) gas transmission pipeline from the Greek-Bulgarian border all the way to Attica (the area around Athens). It has a total length of 512 km, while the diameter of the pipeline is 36" for approximately the first 100 km from the north, and 30" for the rest. Also part of the transmission system are the high-pressure branch pipelines of a total length of 450 km. They connect the main transmission system with Serres, Drama, Xanthi and Komotini, as well as Thessaloniki and Volos, and some areas in Attica, as can be seen from the map.

The transmission system includes metering and regulating stations all across the way, in order to meter the gas and regulate the pressure. Also there is a remote-control system, to control functioning and telecommunications, for the supervision and control of the natural gas transmission system. Operation and Maintenance Control Centres are situated in Attica, Thessaloniki and Thessaly as well as in the Xanthi region (which is currently under construction).

Also as liquefied natural gas is imported from Algeria to the small island of Revithousa, as mentioned before, natural gas is transmitted from the liquefied natural gas terminal of Revithousa to Athens through a twin submarine pipeline.

On the other hand the distribution system consists of steel medium-pressure (19 bar) networks, in Attica, Thessaloniki, Larisa, Volos and Inophyta. Also polyethylene low-pressure (4 bar) networks, exist in the cities of Athens, Piraeus, Thessaloniki, Larisa, and Volos.

In terms of distribution system length and expansion, we should notice that initially in the Athens area, an existing network of 550 km (formerly the property of the Athens Municipal Gas Company) was acquired by the Public Gas Corporation (DEPA) in 1997. By the end of 1999, 1,013 km of low-pressure networks had been constructed, of which 695 km were in Attica, 183 km in Thessaloniki, 68 km in Larisa, and 68 km in Volos. But ever since DEPA has made responsible the gas supply companies for the expansion of their local distribution networks, in order to achieve a goal of 6,500 km overall distribution systems length.

The share of contribution of Athens to this goal is the achievement of a 3,500 km distribution system, by 2008. In 2003, approximately 1,300 km of natural gas distribution system were completed, and according to the gas distribution company of Athens (EPA Attikis), which is responsible for this construction, the remaining 2,200 km of network will be delivered on time.

4. Greece as a gate for natural gas to Europe

Greece, mainly because to its strategic geographical position, is expected to play a significant role as a gate connecting Europe and Eastern countries natural gas. This advantage in geographical position will be beneficial not only for Greece, but mainly for the European natural gas supply.

Recently Greece signed last year an agreement with Turkey for the construction of a long pipeline, connecting the two countries, as shown in the following map:

Figure 2.6: The under construction new pipeline

Today this pipeline for transmitting natural gas from Turkey to Greece is under construction. This is a 186 miles long pipeline, with 36" minimum diameter, running from Ankara in Turkey to Komotini in Greece and is designed to transport natural gas from Azerbaijan to Europe. The pipeline initially will deliver 500 million cubic meters of natural gas from Azerbaijan to Greece, via Turkey, beginning in early 2007.

Furthermore this pipeline will be connected to two other planned and under construction gas pipelines. The first of these will run for 373 miles, through 42" diameter pipelines, across northern Greece from Komotini to the northwest Greek port of Stavrolimena, where it will connect with a 137-mile long and 24" diameter underwater pipeline from the Ionian Sea to Italy. The underwater section is being built by Greece's Public gas corporation (Depa) and Italy's gas company Edison SpA. The construction of these two pipelines is mainly funded by the European Union as well as the Greek and Italian governments. This project, of these two pipelines is expected to be completed at the same period with the Greece-Turkey pipeline (2007).

So finally after the connection of the system of pipelines connecting Turkey-Greece-Italy, Greece will be the gate of providing natural gas from Eastern countries to Europe. After the whole project is completed the volume of natural gas transported from Turkey to Europe through Greece, is targeted to rise significantly and be as high as 11 billion cubic meters annually.

Another potential project which is nowadays under serious consideration is the connection of Greece with Albania, in order to provide to it and the Balkans generally with natural gas. This project is almost sure that it will be applied sometime in the near future. Compared with the previous case, this is a much smaller project, but its significance should not be overlooked. The route of the natural gas pipeline is shown in a thick black line in the following figure:

Figure 2.7: The potential Greece-Albania pipeline

This project involves the construction of a 160 km long and 30” diameter high pressure pipeline from Thessaloniki in Greece to the Albanian border. The gas quantities that could be provided in this case to Albania could be around 1 to 1.5 billion cubic meters of natural gas per year.

What could also be promising, and is currently considered, would be the construction of a liquefied natural gas terminal in the city of Kavala (see figure 2.7), which is a major Mediterranean port, strategically located in Northern Greece. The Kavala liquefied natural gas terminal corresponds, by far, to the shortest liquefied natural gas transportation distance from the Middle East to Europe, and, thus, to the lowest unit transportation cost. Also it would enable Russian pipeline gas to be exported (as liquefied natural gas) to non-conventional destinations, such as Israel.

5. Uses

The demand for natural gas in Greece, as mentioned earlier, is rising rapidly. As in the whole world applications described in chapter 1, in Greece natural gas is applied in the following sectors:

- Residential and commercial
- Industry
- Transportation, and
- Electricity generation

The percentage of natural gas use in Greece (according to DEPA 2003) for each of these sectors is shown in figure 2.8 below:

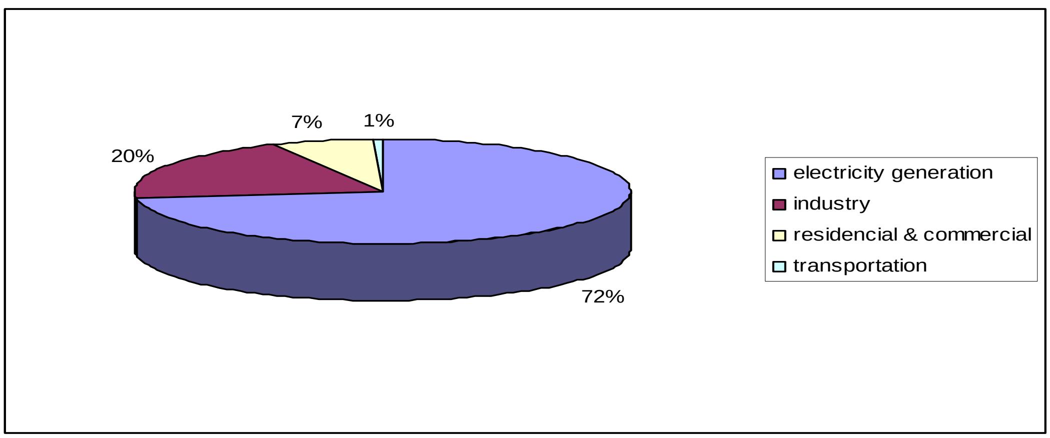

Figure 2.8: Natural gas uses in Greece per sector

Natural gas is used in Greece mainly in power generation and the industry, with power generation having 72% of the total, and industry 20%. From the remaining 8%, 7% is used in the commercial and residential sector while only 1% is used in the transportation sector. This is reasonable as the latter sectors were the last in which natural gas was applied, as the urgent initial need for natural gas was for the industry and electricity generation.

5.1 Residential and commercial

In the residential and commercial sectors natural gas is used for space heating, hot water supply and electricity. These uses are summarised for a typical household in the graph below:

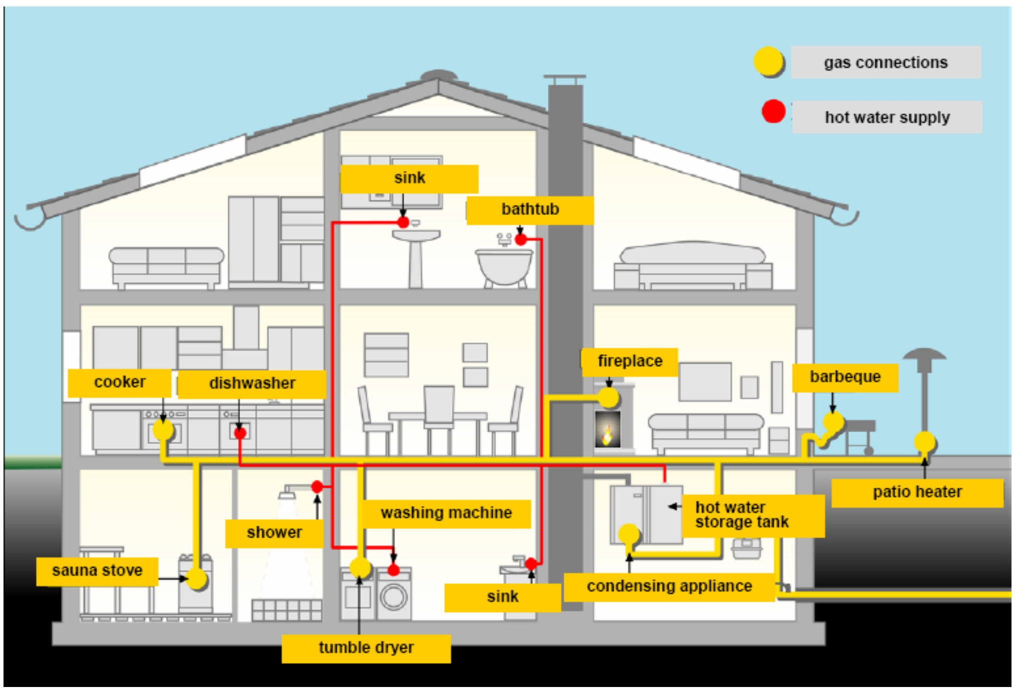

Figure 2.9: Typical household applications of natural gas

In the commercial sector in Greece natural gas is most commonly applied in hotels, restaurants, bakeries, laundries and other commercial buildings. Recently much attention is given from the authorities so that large sport centres and hospitals are connected to the natural gas grid.

As noted in paragraph 2, the ones that are responsible for the expansion of the distribution networks and the promotion of natural gas in each area are the Gas Supply Companies (EPAs). So in Athens the EPA Attikis has constructed today 1,700 km of natural gas distribution network, capable to provide with natural gas 350,000 residences out of a total of 1.2 million. But only 60,000 residences (5% of the total in Attiki) and only 2,200 commercial buildings are connected today to the natural gas distribution network, mainly due to the limited information provision from the gas company to the public about safety issues and benefits of switching to natural gas. Many people are still worried about these issues and prefer to continue using traditional fuels.

Similar and even more disappointing figures are extracted also from the two other EPAs, the EPA of Thessaloniki and the EPA of Thessaly. This is mainly due to the fact that their distribution networks are limited as they are under construction, as EPA Thessaloniki has constructed today a natural gas distribution network of 340 km out of the total 660 km planned for 2006 and EPA Thessaly has constructed today a natural gas distribution network of 207 km out of the total 490 km length planned also for 2006.

Also what is promising for the future is for example the fact that according to the Public Gas Corporation (DEPA), the number of new residences and commercial buildings that connected to the natural gas distribution system of Athens in 2004 was as high as 7,000. Predictions for the year 2005 talk about more than 14,000 new residences and commercial buildings to be connected to the natural gas distribution system. This seems to be realistic as the first six months of 2005, more than half of the predicted (more than 7,000) were connected to the network. So the consumption of natural gas in the residential and commercial sector is expected to expand rapidly over the next year, with the expansion of the natural gas distribution networks.

5.2 Industrial

The Public Gas Corporation (DEPA) provides today with natural gas almost 70 industries in Greece. Also a large number of industries placed in various places all around the country (Thessaloniki, Athens, Komotini, Lamia, Serres, Xanthi etc) are in negotiations with DEPA about switching to natural gas.

Natural gas is used in the Greek industries, like worldwide, for two main applications: as a fuel and as a raw material for the production of chemicals. In the first case (as fuel) natural gas is most commonly used in aluminium, cement, ceramics and glassworks industries. As a raw material it is usually applied for the production of hydrogen, methanol and ammonia.

ICAP of Greece, which is the official and most valid source for industrial information, released a questionnaire to all the Greek industries, asking for their preference for energy sources. The answers to it are summarised in the graph below:

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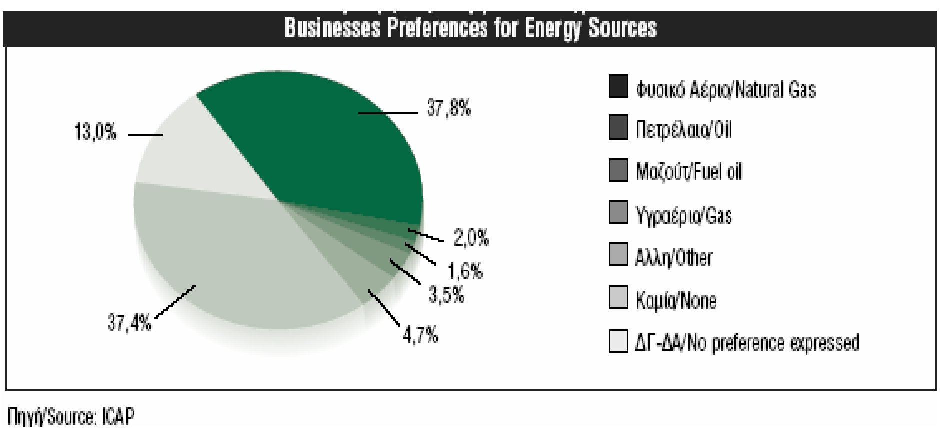

Figure 2.10: Greek business preferences in energy sources

Natural gas was on the top of Greek businesses preferences, with oil and other sources following. This fact is very promising for the future as it shows that a large number of industries are in favour of natural gas and so we can safely assume that they will switch to it soon.

Also in second phase they were asked to provide the reasons why they preferred natural gas instead of other energy sources. The criteria set were the lower cost, protection of the environment, easier supply, better performance, competitive price and easier access, and the result deducted were:

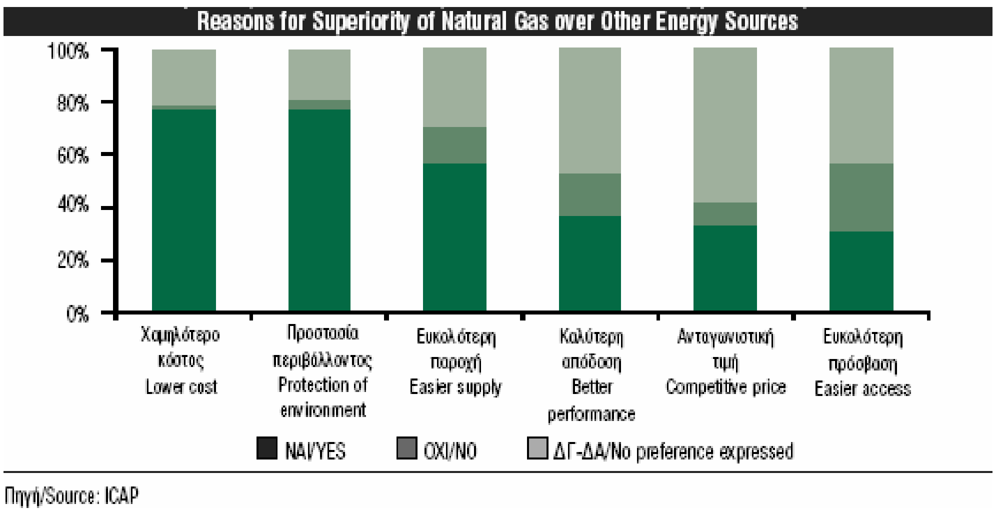

Figure 2.11: Reasons for preferring natural gas

The results showed that the main reason for choosing natural gas (reaching 80%) is the lower cost and the fact that it is a more environmentally friendly option. Approximately 60% recognised the easier supply of natural gas as an advantage, while only around 40% showed certainty about its better performance, with an equal uncertainty percentage. The uncertainty percentage becomes even higher in terms of competitive price and easier access to natural gas compared to other energy sources.

These figures should be considered by the Public Gas Corporation (DEPA) and a strategic planning should be made in order to attract more industries. Emphasis should be shown to providing more extended information to them, provide more antagonistic prices and easier access to industries remote from the existing natural gas network.

5.3 Transportation

The introduction of natural gas in Greece offered a great opportunity to the country to use it in transportation applications. The only application of natural gas considered yet in the transportation sector, relates to the urban buses in the city of Athens. In July, 2000, in an effort to improve the capital's atmospheric pollution and the image of public transport, the Athens Urban Transport organization OASA and the Transport Ministry of Greece decided to buy from Renault, 295 buses that run on compressed natural gas. Nowadays these buses run in a large number of routes in the Athens city centre, and a further expansion of the compressed natural gas fleet is being considered.

These compressed natural gas buses have second generation engines and are considered to be among the least polluting buses in the world. Although these buses are more energy consuming than those that run on diesel, as they burn 15-20 percent more fuel, they have much lower emissions of particulates, nitrogen oxide, carbon monoxide, sulphur dioxide and not to mention that they are also quite noiseless. Despite the fact that these buses that run on natural gas have lower efficiency engines, are more expensive to buy, require costly refuelling stations and have higher operation and maintenance costs than the traditionally used diesel ones, they have in the end of the day important economic benefits, mainly because of the price of their fuel. Natural gas in Greece costs only the 1/3 of the price of diesel making them in the end of the day much cost saving.

Also the Public Gas Corporation (DEPA) has constructed a natural gas refuelling station in Ano Liosia (Athens region). It can serve the needs of 300 natural gas buses per day and has five refuelling bays with a capacity of 5,000 Nm^3/h natural gas, making it the largest in Europe. The station has been designed to ensure complete control of all its processes and its safe functioning. Also today the construction of the second natural gas refuelling station in Anhtoussa (Athens region) is already underway and is going to be competed soon, providing more flexibility for the buses refuelling.

5.4 Electricity generation

As mentioned in paragraph 5, a vast majority of the imported natural gas in Greece (with a percentage 72% among all sectors), is used in electricity generation. Natural gas is used in industries for their autonomous electricity generation. But what is the most important to mention in terms of electricity generation in Greece is the large scale use of natural gas for this purpose by large power plants.

The liberalization of the power industry together with the significant financial and environmental advantages of natural gas (in an effort to meet the Kyoto Protocol's greenhouse gas emission targets) has led to the construction of new natural gas fired power stations. The Public Gas Corporation (DEPA) has already build and are in use thermoelectric stations in Keratsini and Lavrio (Attiki), as well as a relatively new combined cycle unit in Komotini, fuelled with natural gas. Four more natural gas fired plants were decided in May 2005 to be constructed in areas all round the country (in Keratsini, Aliveri, Megalopoli and Ptolemaida).

The technologies used today in electricity generation in Greece are shown below, according their loads:

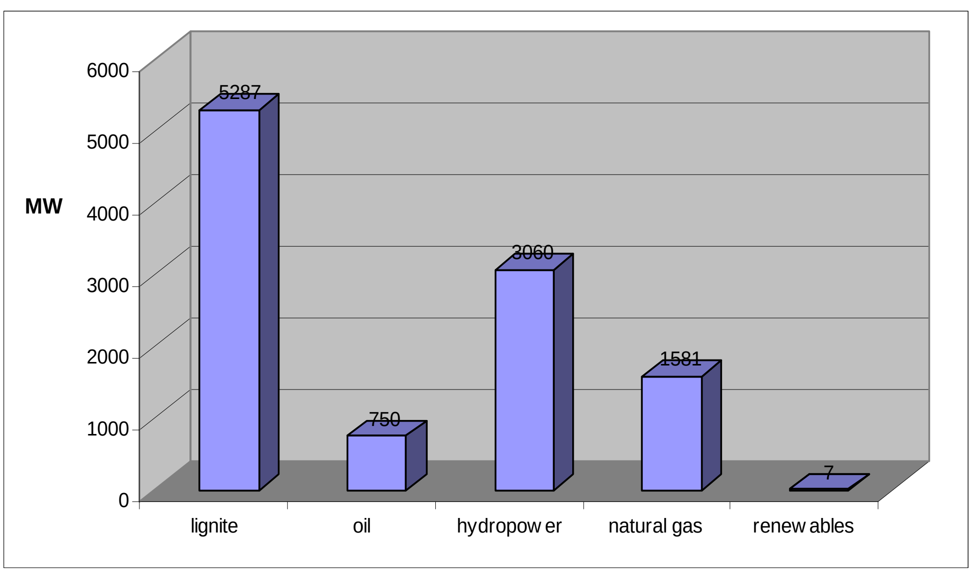

Figure 2.12: Electricity generation technologies according to overall loads

From the chart above we can see that the main way of electricity generation today is still coal (lignite) fired power plants with a magnitude of load of 5,207 MW, with hydropower in the second place with an overall 3060 MW, which is reasonable as they are the most traditional technologies in this sector. Although natural gas is quite new in Greece it stands on the third place providing an overall load of 1501 MW, followed by a small contribution of oil fired power plants (usually sited in islands) and a negligible 7 MW from renewables.

But the future of natural gas in electricity sector in Greece is even more promising, according to the Ruhrgas company that estimated the changes in natural gas consumption for the western European countries from the year 2002 till 2010:

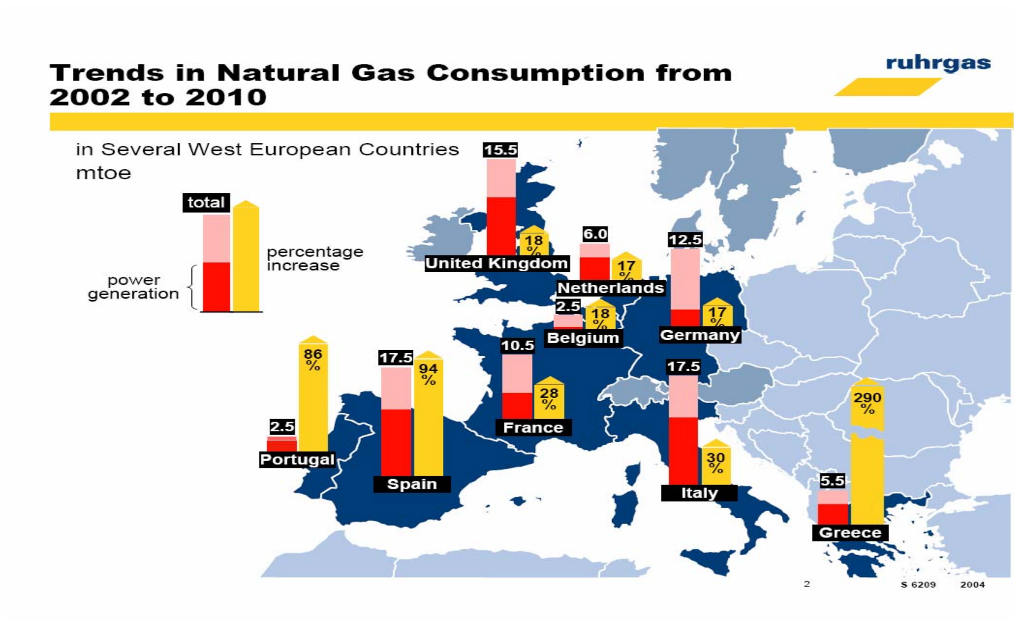

Figure 2.13: Increase in electricity generation in West Europe by 2010

As we can see in terms of natural gas consumption in electricity generation, Greece is in one of the lowest positions with only Portugal and Belgium consuming less natural gas for this purpose. What is really optimistic and impressing is the boost predicted for Greece for the year 2010 that is expected to be as increased as 290% (reaching 15.95 mtoe), while the second highest is expected for Spain with only 94%, placing Greece in 2010 at a more than average position among Western European countries after Spain (33.95 mtoe), Italy (22.75 mtoe) and UK (18.29 mtoe).

6. Recommendations

After investigating the natural gas development and expansion in Greece, we conclude that the natural gas future in the country is very promising, although in an early stage. Future plans of the Public Gas Corporation (DEPA) have been analysed, but perhaps a few more should be investigated, mainly in economic terms, as their environmental impact would be for sure beneficial:

- The construction of a natural gas refuelling station in Thessaloniki. Thessaloniki is the second biggest city in Greece (with population more than a million people), after Athens, with a large public transportation network. As this city is supplied with natural gas, the construction of a natural gas refuelling station there would provide the opportunity to use natural gas public transport vehicles (as happened in Athens for buses).

- The use of natural gas in waste management trucks in both cities (Athens and Thessaloniki). The government would be responsible for this application as all waste management trucks belong to the government.

- The Greek government should allow and encourage (through economical motives) the use of private vehicles using engines fuelled with natural gas. Today's pricing policy in the country has deterred even taxi owners from substituting their diesel vehicles with natural gas fuelled ones.

- The expansion of the existing natural gas network through Corinth to Tripoli and Patras (see the map in figure 2.14). Tripoli has the big advantage that outside it (in Megalopolis) exists one of the largest power plants that can be converted to combined cycle power plant, in order to generate large quantities of electricity. Patras on the other hand, is the third biggest city in Greece (with population about

300,000 people), promising not only a large number of natural gas consumers in it, but also just outside the city region that a large industrial area exists.

Figure 2.14: Map of Greece

- Finally, the construction of a liquefied natural gas terminal in the island of Crete (south Greece) should be considered. Crete is using today oil fired power plants to cover its electricity demands, which can be easily converted to natural gas combined cycle plants. Such a measure in this large island, would lead to significant environmental benefits.

CHAPTER 3

1. Introduction

Before 1850, the level of greenhouse gases in the atmosphere was relatively static. What appears to have changed the equilibrium was the Industrial Age. Atmospheric concentrations of the greenhouse gases CO_2, methane, nitrous oxide, and some others have increased by 10 to 25% since the start of the Industrial Age.

The "Greenhouse Effect" is the gradual warming of the Earth's surface due to increased entrapment of solar radiation in the atmosphere. The reason for this entrapment is the accumulation of greenhouse gasses in the Earth's atmosphere. The most important greenhouse gases are water vapour (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), tropospheric ozone (0_3), and man-made chlorofluorocarbons (CFCh and CF_2 Ch). Among these gases, the relative contribution of CO_2 to the greenhouse effect is 63.6%. The main source of CO_2 is emissions from fossil fuel combustion. In recent years, an estimated 6.1 billion tons of carbon are released into the atmosphere each year by the burning of fossil fuels. Increased CO_2 concentration in the atmosphere due to emissions of CO_2 from fossil fuel combustion has caused concerns about global warming. Therefore reduction of atmospheric CO_2 emissions is an important option for reducing greenhouse gases and global warming.

Predictions of global energy use in the next century suggest a continued increase in carbon emissions and rising concentrations of CO_2 in the atmosphere unless major changes are made in the way we produce and use energy—in particular, how we manage carbon. For example, the widely cited energy scenario developed by the Intergovernmental Panel on Climate Change (IPCC 1996) predicts that future global emissions of CO_2 to the atmosphere will increase from 7.4 billion tones of atmospheric carbon (GtC) per year in 1997 to approximately 26 GtC/year by 2100. Although the effects of increased CO_2 levels on global climate are uncertain, there is scientific consensus that a doubling of atmospheric CO_2 concentrations could have a variety of serious environmental consequences in the next century.

1.1 Fossil fuels vs. renewables

The significant emission reductions required would require a large-scale shift in energy systems from fossil fuels to new alternative energy sources and substantial improvements in energy efficiency. It is, however, not very likely that such large shifts will be technically and economically feasible in the near future. One reason for this is that the development of the required technologies depends on a large and sustained research and development effort, which is likely to require some decades. Furthermore, even if the technology should become available, and at competitive costs, it will take decades to replace the existing real capital stock of the global energy system, buildings and infrastructure because of its inertia and vastness.

In order to decrease the carbon intensity of energy consumption, no panacea exists. Hence, all non-carbon emitting options should probably, for the moment at least, remain parts of an energy mix as diversified as possible. Among these are very different (both conventional and still relatively unconventional) energy resources, such as hydropower, nuclear energy, renewables and decarbonised fossil fuels. Hydropower possesses a number of environmental drawbacks and is unlikely to be expandable so as to maintain its current relative share in an increasing world energy supply. Nuclear energy's future is unclear, since it faces a variety of problems related to radioactive waste, reactor accidents, nuclear proliferation, economic competition and public perception. Renewables (such as wind, solar and biomass energy) seem promising in many respects, but when and to what extent they can significantly contribute to global energy supply remains to be seen, impeded for the moment by relatively high costs and/or large land-use or resource requirements, and because it is unresolved whether renewables can be effective in ascertaining energy supply security Therefore, expanding the decarbonisation of fossil fuels to options beyond a transition from carbon-intensive fossil fuels (coal and oil) to carbon-poor ones (natural gas) is currently being appreciated, but also with an increased interest in carbon capture and sequestration techniques applied to it.

1.2 CO2 emissions from power plants

The removal of CO_2 directly from industrial or utility plants and subsequently storing it in secure reservoirs, is called carbon capture and storage (CCS). The rationale for carbon capture and storage is to enable the use of fossil fuels while reducing the emissions of CO_2 into the atmosphere, and thereby mitigating global climate change.

By far the largest potential sources of CO_2 today are fossil-fuelled power production plants. Power plants emit more than one-third of the CO_2 emissions worldwide. Power plants are usually built in large centralized units, typically delivering 500–1000MW of electrical power. A 1000-MW coal-fired power plant emits between 6 and 8 Mt/yr of CO_2, an oil-fired single-cycle power plant emits about two thirds of that, and a natural gas combined-cycle power plant emits about one-half of that as is shown in figure 3.1 below:

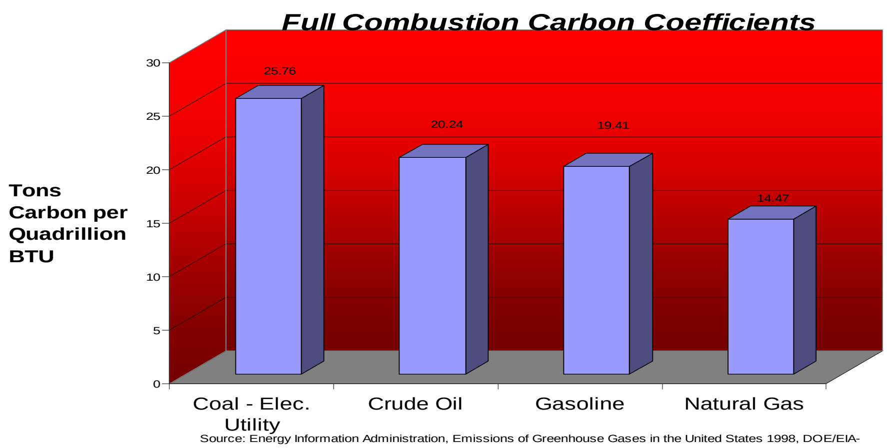

Figure 3.1: CO_2 emissions by fossil fuel

Although the natural gas seems to be a good substitute to other fossil fuels, with an important role in reducing CO_2 emissions from power plants, we should bear in mind that it cannot replace them, as many economies still depend on them (e.g. coal). But the combustion of natural gas is not totally harmless to the environment and as its use is expanded, carbon capture and sequestration technologies become necessary be applied to it too.

1.3 Carbon capture and sequestration potential

The US department of energy has made a prediction of the future electricity generation by fuel till the end of the century. The effects on technologies with and without CO_2 capture are shown in figures 3.2 and 3.3 below:

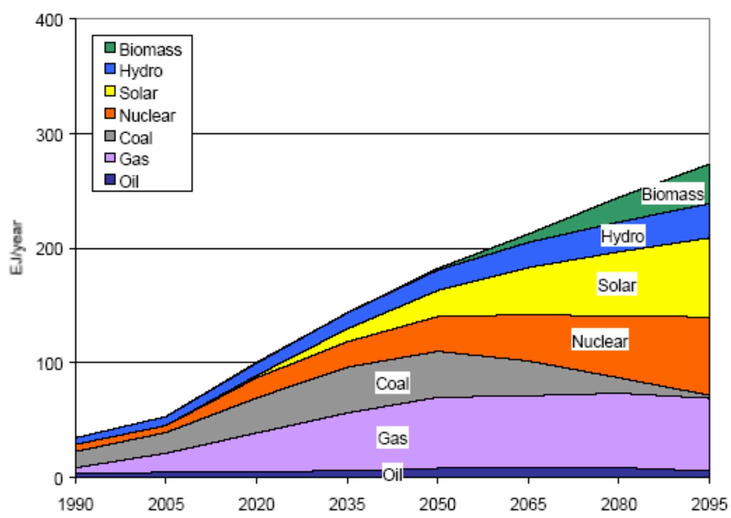

Figure 3.2: Electricity generation by type without CO_2 capture (globally)

From figure 3.2 we notice that hydro power use continues to rise till the end of the century. Biomass makes small but important contribution to the total electricity generation, while solar and nuclear energy play a significant role, especially on the second half of the century. Coal use is reduced after the same point, which is expected because of the CO_2 emission problems they face, but in contrary at the same time natural gas use seems to be slightly increased.

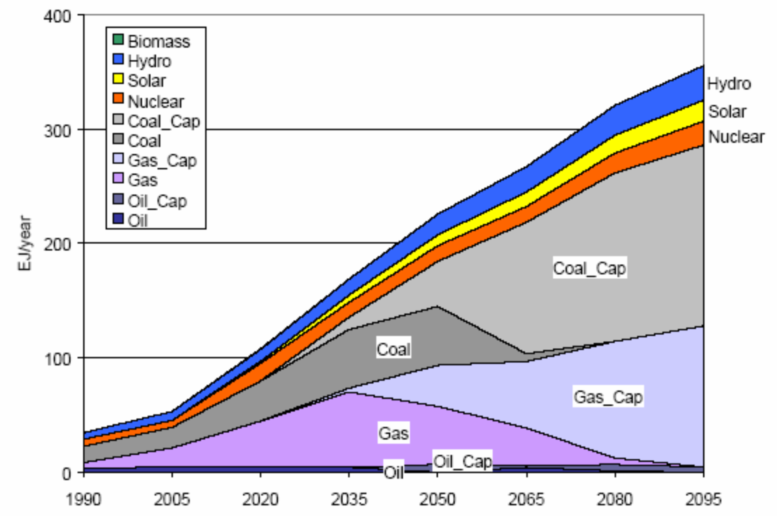

Figure 3.3: Electricity generation by type with CO_2 capture (globally)

From figure 3.3 where CO_2 capture techniques are applied, we can see that renewable technologies expand further, promising a future solution. Coal can continue being used with clean coal technologies playing an important role in the emission problem. Also natural gas use rises further and carbon capture technologies seem to deal with the whole amount that is used, before the end of the century.

Carbon capture and sequestration technologies prove their importance and governments seem to realize the potential they pose for the future electricity production. We should also note that:

- These technologies provide a long-term greenhouse gas mitigation option that allows for continued large-scale use of our abundant fossil energy resources.
- With continued research, these technologies have the potential to provide a cost-effective mitigation option in response to policies aimed at limiting greenhouse gas emissions and ultimately stabilizing greenhouse gas concentrations in the atmosphere.

2. Capture processes

Carbon capture is the removal of CO_2 directly from industrial or utility plants, so that they comply with the environmental restrictions. Carbon capture is the first stage that has to be completed in order to be followed with sequestration.

CO_2 capture processes from power production fall into three general categories:

(1) Pre-combustion capture (where natural gas is converted to hydrogen and CO_2 in a reformer. The CO_2 is compressed for storage and the hydrogen is mixed with air for combustion, emitting only nitrogen and water)

(2) Oxy-fuel combustion (where oxygen is separated from air and then burned with hydrocarbons to produce an exhaust with a high concentration of CO_2 for storage)

(3) Post-combustion capture (where CO_2 is removed from exhaust gas after combustion)

These technologies are presented in figure 3.4 below:

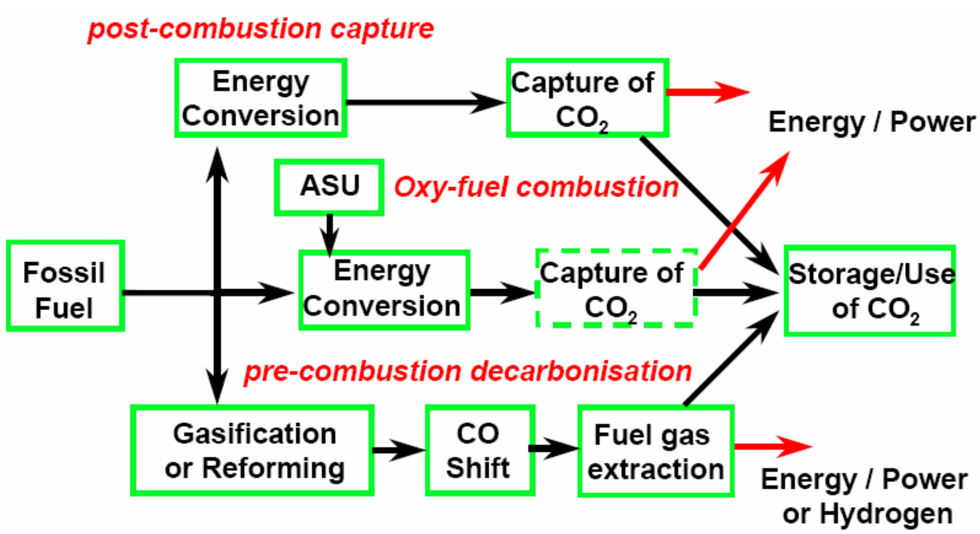

Figure 3.4: Carbon capture processes

Each of these technologies carries both an energy and an economic penalty, but their application is necessary nowadays.

2.1 Pre-combustion capture

Pre-combustion capture is usually applied in integrated coal gasification combined cycle power plants. This process includes gasifying the coal to produce a synthesis gas composed of CO and H_2, while reacting the CO with water (water–gas shift reaction) to produce CO_2 and H_2. The CO_2 is then captured and stored, and the H_2 is being sent to a turbine to produce electricity. Because the primary fuel sent to the gas turbine is now hydrogen, some can be bled off as a fuel for separate use, such as in hydrogen fuel cells to be used in transportation vehicles. This process is shown below on figure 3.5:

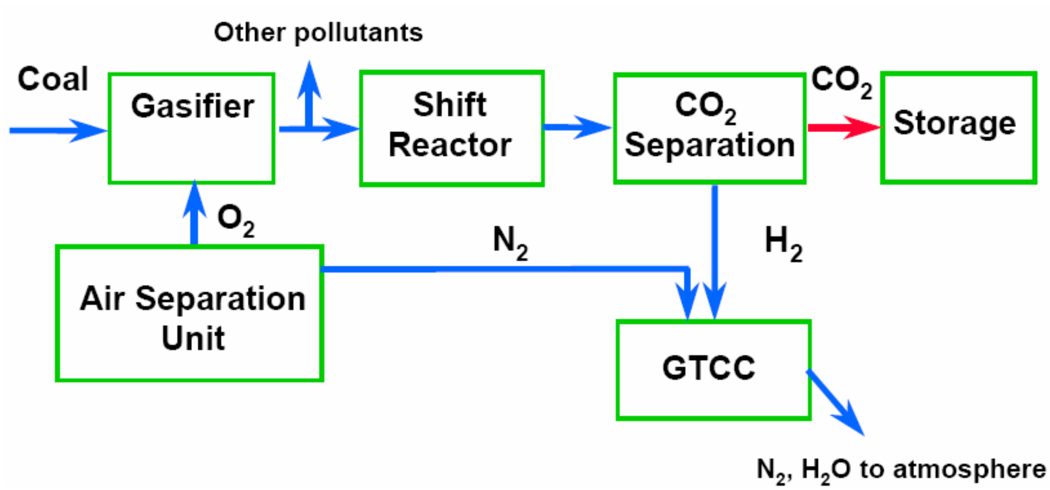

Figure 3.5: Pre-combustion capture

The pre-combustion process could also be utilized when natural gas is the primary fuel. Here, a synthesis gas is formed by reacting natural gas with steam to produce CO_2 and H_2. However, it is unproved whether pre-combustion capture is preferable to the standard post-combustion capture for the case of using natural gas.

The process for natural gas is better viewed in figure 3.6:

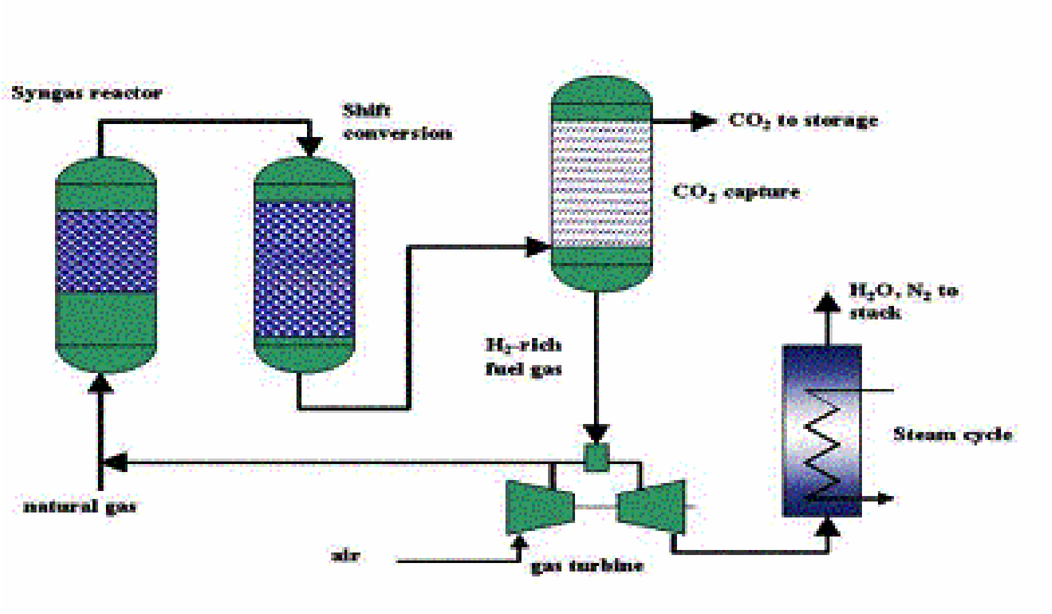

Figure 3.6: Pre-combustion capture for natural gas

Generally, during the pre-combustion process CO_2 is captured before the combustion takes place, which offers some advantages: First, CO_2 is not yet diluted by the combustion air and we meet higher CO_2 concentrations than in other carbon capture processes. Second, the CO_2-containing stream is usually at elevated pressure. Therefore, more efficient separation methods can be applied, e.g., using pressure-swing absorption in physical solvents, such as methanol. Also more compact equipment are therefore required and there exist higher driving forces for CO_2 separation.

One of the biggest barriers to this pathway is that currently electricity generation is cheaper in pulverized coal power plants than in integrated coal gasification combined cycle plants. Also of significant importance too is the fact that pre-combustion capture process in order to be applied requires a radical change in the power plants design, which is a big barrier.

2.2 Oxy-fuel combustion

When a fossil fuel (coal, oil, and natural gas) is combusted in air, the fraction of CO_2 in the flue gas ranges from 3 to 15%, depending on the carbon content of the fuel and the amount of excess air necessary for the combustion process. The separation of CO_2 from the rest of the flue gases (mostly N_2) by chemical or physical means is capital and energy intensive. An alternative is to burn the fossil fuel in pure or enriched oxygen. In such a fashion, the flue gas will contain mostly CO_2 and H_2O. A part of the flue gas needs to be recycled into the combustion chamber in order to control the flame temperature. From the non recycled flue gas, water vapour can be readily condensed, and the CO_2 can be compressed and piped directly to the storage site. Of course, the separation process has now shifted from the flue gas to the intake air: oxygen must be separated from nitrogen in the air. The air separation unit alone may consume about 15% of a power plant's electric output, requiring a commensurate increase of fossil fuel to be consumed for achieving the rated electric output of the plant. In the air separation unit, air is separated into liquid oxygen, gaseous nitrogen, argon, and other minor ingredients of air. The latter are marketable by-products of the oxy-fuel plant. A presentation of this process is shown on figure 3.7:

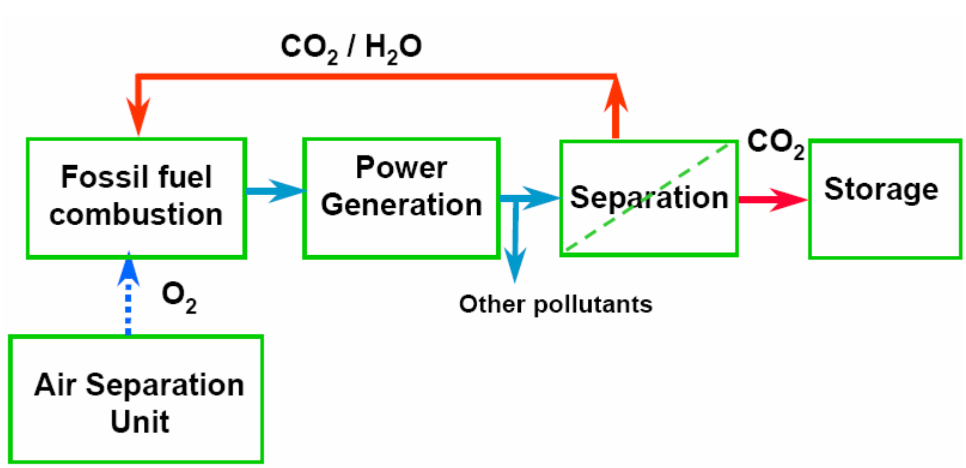

Figure 3.7: Oxy-fuel combustion

The main advantages of this method are that conventional combustors may be used and also that this method provides the ability to store SOx and NO_2 along with the CO_2.

But this method has also some important disadvantages. The cost of oxygen production is high and this makes this method not economically attractive. Also large quantities of flue gas need to be recycled. We should also note that there exists potential for advanced oxygen separation membranes with lower energy consumption.

2.3 Post-combustion capture

Post-combustion capture involves scrubbing CO_2 out of flue gas after the fossil fuel is combusted. This process is shown on figure 3.8 below:

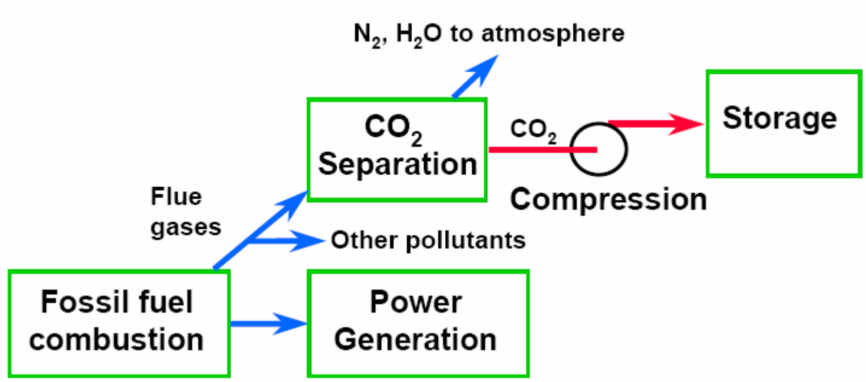

Figure 3.8: Post-combustion process

This flue gas is usually at atmospheric pressure with a low concentration (5-15%) of CO2 due to all the nitrogen in the air used for combustion. There are also small amounts of excess oxygen and sometimes of sulphur dioxide (SO_2) and nitrogen oxides (NOx). CO_2 capture at these low CO_2 concentrations and system pressure usually involves reversible chemical reactions which require heat in order to regenerate and recycle the chemicals used to capture the CO_2, known as absorbents. The most common technology for capture uses a chemical amine solution to absorb the CO_2. Chemical absorption, refers to a process in which a gas (in this case, CO_2) is absorbed in a liquid solvent by formation of a chemically bonded compound. When used in a power plant to capture CO_2, the flue gas is bubbled through the solvent in a packed absorber column, where the solvent preferentially removes the CO_2 from the flue gas. Afterward, the solvent passes through a regenerator unit, where the absorbed CO_2 is stripped from the solvent by counter flowing steam at 100–1201C. Water vapour is condensed, leaving a highly concentrated (over 99%) CO_2 stream, which is be compressed for storage. The lean solvent is cooled to 40–651C and is recycled into the absorption column. The most commonly used absorbent for CO_2 absorption is monoethanolamine (MEA). The fundamental reaction for this process is:

$$C_2H_4OHNH_2 + H_2O + CO_2 \leftrightarrow C_2H_4OHNH_3^+ + HCO_3^-$$

During the absorption process, the reaction proceeds from left to right, while during regeneration, the reaction proceeds from right to left

This option is generally considered for existing boiler systems, especially when the flue gas is low in SO_2 and NOx due to clean natural gas being used for combustion, or for flue gas from coal boilers that already have FGD (flue gas desulphurization) and SCR (selective catalytic reduction) systems that remove these gases.

The post-combustion capture process for natural gas power plants is shown on the figure below:

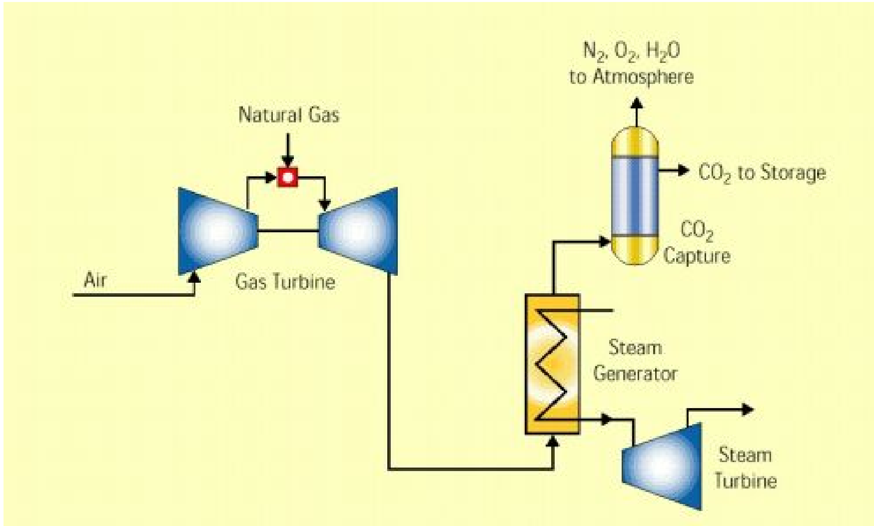

Figure 3.9: Gas turbine combined cycle with post-combustion capture of CO_2

The advantage of post-combustion capture is that it is applicable in many power generation technologies, especially in natural gas power plants. It is well established technology and exists the last few decades, so it bears no risk.

But the disadvantage of it is that large equipment are required and some scale up of the power plants, which mean increased cost. The energy required for this process should also be mentioned as a drawback. . The large steam requirements of the amine stripper plus the power requirements of the CO_2 compressor (needed to deliver the CO_2 to pipelines) lead to a significant drop in net capacity and efficiency. This loss in net capacity and efficiency is usually in the range of 25-30% relative to the same combustion system without CO_2 capture.

In order to reduce the capital and energy costs and the size of the absorption and regenerator (stripper) columns, new processes are being developed. One example is the membrane-absorption process, whereby a micro porous membrane made of poly (tetra-fluoroethylene) separates the flue gas from the solvent. The membrane allows for greater contacting area within a given volume, but by itself the membrane does not perform the separation of CO_2 from the rest of the flue gases. It is the solvent that selectively absorbs CO_2.

3. Sequestration

Following the capture process, CO_2 needs to be stored. The process in which CO_2 is stored, in order to avoid being emitted or remaining to the atmosphere is called sequestration.

The sequestration process is very important for the power plants. Fossil fuels will continue to be used, in large magnitude, in energy production in the 21st century. Increased concentrations of carbon dioxide (CO_2) due to carbon emissions are expected unless energy systems reduce the carbon emissions to the atmosphere. This can be achieved with the use of sequestration methods that after the removal of CO2 from the power plants, they store it in places that is no longer harmful to the environment.

3.1 Sequestration issues

There are a number of issues relative to the sequestration, and must be investigated thoroughly before such a method is to be applied:

- People should bear in mind that the CO_2 storage is not a short term solution. The storage period should be carefully planned so it can last for hundreds or even thousands of years.
- The cost of storage, including the cost of transportation from the source to the storage site, is critical for any power plant as it is relatively high, so it should be minimized.
- The risk of accidents should be eliminated, because in such an unlucky case vast amounts of CO_2 will be released back to the atmosphere.
- The environmental impact should be minimal.
- The storage method should comply with national or international laws and regulations.

3.2 Sequestration methods

The main sequestration methods that are applied nowadays are shown in the figure 3.10 below:

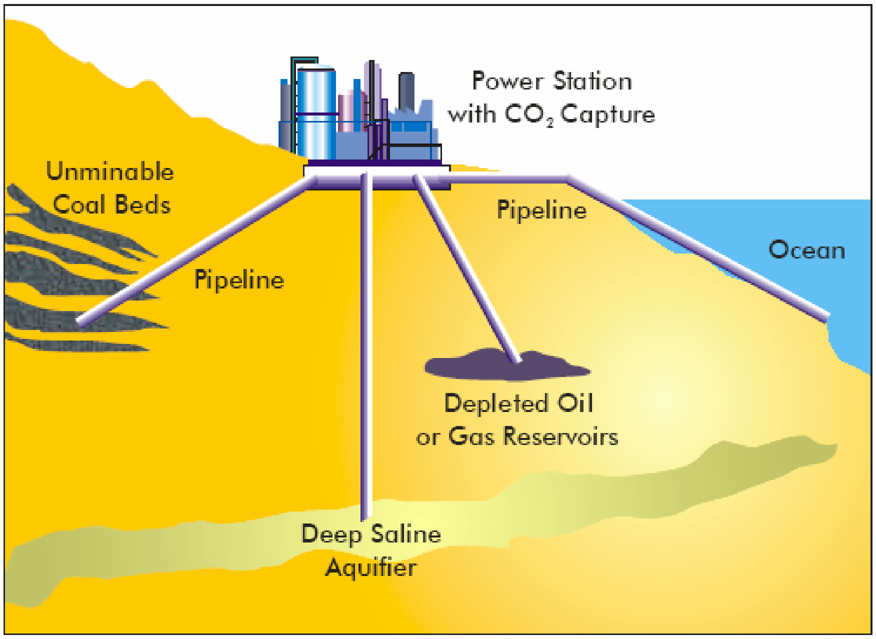

Figure 3.10: CO_2 sequestration methods

As we can see from figure 3.10, the most commercial are in:

1. Oil and gas reservoirs
2. Deep saline aquifers
3. The ocean
4. Coal beds

All these processes are explained analytically in the next paragraphs.

3.2.1 Oil and gas reservoirs

Carbon dioxide can be injected into depleted oil and gas reservoirs for sequestration. Depleted oil and gas reservoirs appear to be the most promising land storage option, at least in the near-term. Because these reservoirs have already demonstrated their ability to contain pressurized fluids for long periods of time, their storage integrity is likely to be good.

Following more than a century of intensive petroleum exploitation, thousands of oil and gas fields are approaching the ends of their economically productive lives. Some of these exhausted fields could act as storage sites for CO_2. As in the case of producing fields, the general concept of CO_2 disposal in depleted oil and gas reservoirs is that the hydro geological conditions that allowed the hydrocarbons to accumulate in the first place will also permit the accumulation and trapping of CO_2 in the space vacated by the produced hydrocarbons The cap rock that prevented the escape of oil and gas over geological time, should retain the sequestered CO_2 for thousands of years , as long as it is not damaged as a result of over pressuring during the CO_2 injection, by the presence of unsealed, improperly completed or abandoned wells tectonic activity or pH change.

Existing infrastructure and reservoir properties make storage of CO_2 in depleted oil and gas reservoirs a simpler option than other forms of CO_2 sequestration. Closed, under pressured oil reservoirs that have not been invaded by water should have good sequestration capacity. The oil and gas industry has significant experience in the management of such reservoirs, but is particularly concerned about long-term liability issues.

Currently abandoned oil and gas reservoirs in the US could hold about 2.9 billion tones of CO_2, while the ultimate reserves of oil and gas would hold roughly 100 billion tones of CO_2. These compare with current US power plant emissions of about 1.7 billion tones of CO_2 per year. The global sequestration capacity in abandoned reservoirs is estimated to be 130 to 500 giga tones of carbon. This capacity is equivalent to 20-80 years of current global carbon consumption via fossil fuels, since about six giga tones of carbon are emitted into the atmosphere globally each year from fossil fuels.

However, the actual effective capacity is uncertain given that changes to the reservoir may have occurred due to water/brine intrusion or geo-structural alteration. Although these formations contained pressurized fluids for geological periods, the release of gas may have altered the formations and affected reservoir integrity. We should also note that with only few exceptions, most oil and gas reservoirs are not located near primary sources of CO_2 production, so a new CO_2 pipeline network would be needed to connect to power plants with suitable storage sites. The costs, environmental impacts and safety issues associated with such a network need to be considered in any analysis of this storage option. Due largely to differences in required pipelining, storage costs will be very site-specific.

In some cases, production from an oil or natural gas reservoir can be enhanced by pumping CO_2 gas into the reservoir to push out the product, which is called enhanced oil recovery. CO2 can be injected into depleted oil reservoirs to enhance oil recovery from the reservoir. CO2 will dissolve into the residual oil in place, which lowers the viscosity of the oil. The lower viscosity enables the oil to flow more easily, which makes it possible to extract more oil from reservoirs. The process for oil recovery is shown on figure 3.11:

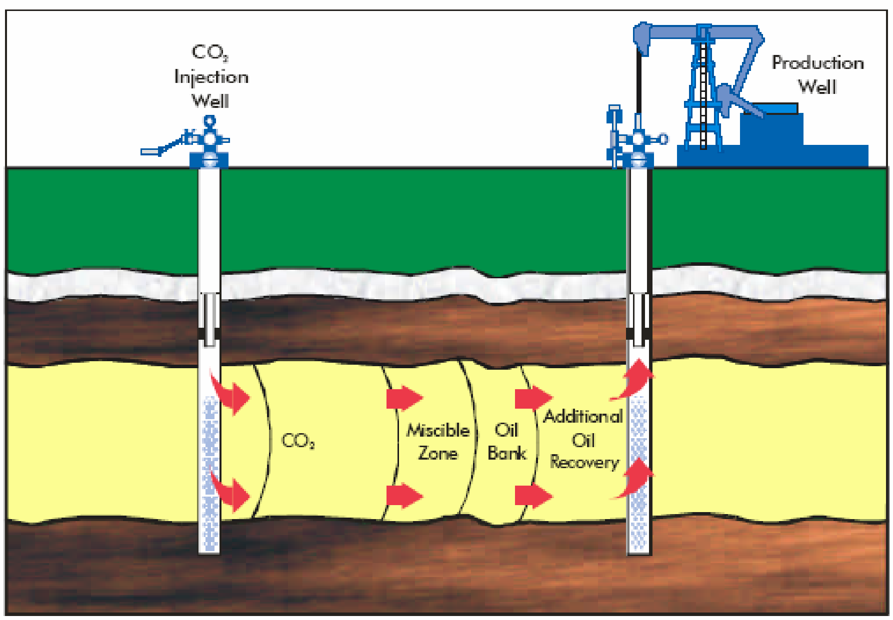

Figure 3.11: Enhanced oil recovery

The United States is the world leader in enhanced oil recovery technology, using about 32 million tons of CO_2 per year for this purpose. From the perspective of the sequestration, enhanced oil recovery represents an opportunity to sequester carbon at low net cost, due to the revenues from recovered oil. Sometimes this revenue is much bigger that expected, not only covering the CO_2 capture and injection costs, but also providing more profit.

In an enhanced oil recovery application, the integrity of the CO_2 that remains in the reservoir is well-understood and very high, as long as the original pressure of the reservoir is not exceeded. Also nowadays very sophisticated computer models have been developed in the oil and gas industry to predict displacement behaviour and trapping of CO_2 for enhanced oil recovery.

But this method is applied similarly in natural gas fields. As gas is being removed from natural gas reservoirs, the pressure of the reservoir decreases. As the pressure within the reservoir decreases, it becomes more difficult to recover more gas. By injecting CO_2 into the natural gas reservoir, the pressure of the reservoir is increased, and more gas can be recovered. CO_2 could also be sequestered in two types of natural gas fields: abandoned fields and depleted but still active fields where gas recovery could be enhanced by CO_2 injection.

The economical advantages from these methods are similar with the oil recovery ones, as natural gas is recovered and further used. Not only we manage to recover natural gas from these fields and store CO_2 safely at the same time, but also the CO_2 capture and injection costs are in some extend covered by the exploitation of the recovered natural gas.

Deciding which abandoned gas fields could best be used for CO_2 sequestration would require a comprehensive review of the current conditions in abandoned fields and the economics of their rehabilitation. This could require major investigation, but fortunately the necessary technology to carry out such a review is available and well known to the gas industry.

3.2.2 Deep saline aquifers

Deep aquifers may be the largest long-term underground sequestration option. Such aquifers are saline and are widely distributed below both the continents and the ocean floor. Their potential sequestration capacity may be thousands of giga tones of carbon, corresponding to as much as a thousand years of carbon production from fossil fuels at current rates of use. They can be better viewed in the next figure:

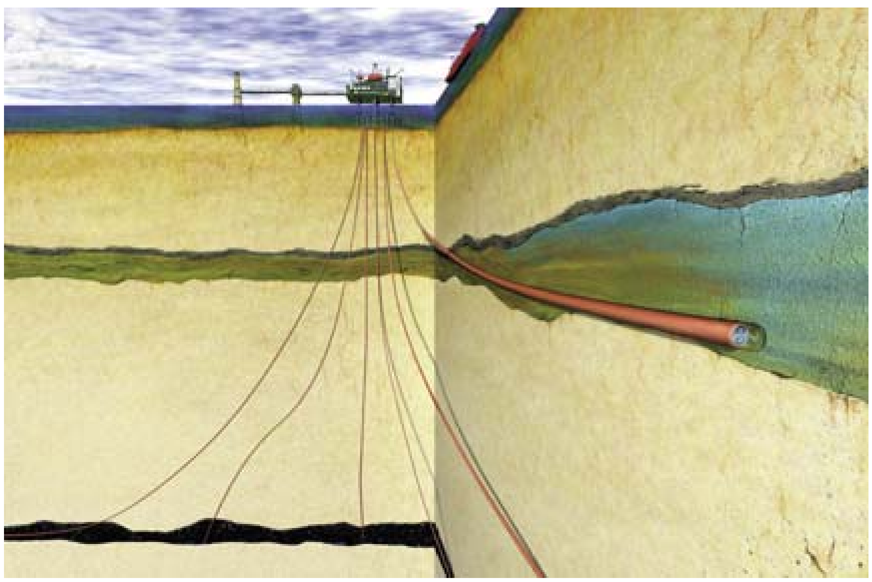

Figure 3.12: Deep saline aquifer

There is much research being done nowadays in order to investigate what percentage of deep subterranean and sub seabed saline formations could be suitable for CO_2 storage. The density of CO_2 depends on the depth of injection, which is usually larger that 800 m (2500 ft). When injected in these depths the specific gravity of CO_2 is lower than that of the ambient aquifer brine, so due to buoyancy effects, it will rise up and gradually spread out forming a layer of CO_2 under the cap rock. In the early stages of geochemical reaction, dissolution is expected to be the predominant process, with the surface area of CO_2 in contact with the formation water will control the rate of dissolution. It is believed that during an injection period of 25 years, between 10 and 25% of the CO_2 will be dissolved .The un-dissolved portion of the injected CO_2 will segregate and form a plume at the top of the aquifer as a result of density differences .The CO_2 plume will be driven by both hydrodynamic flow and by its buoyancy. The greater the density and viscosity differences between CO_2 and the formation fluid, the faster the un-dissolved CO_2 will separate and flow up in the aquifer. Thus, CO_2 should be injected under high pressures to ensure high density of the CO_2 and high CO_2 solubility rate in formation water. Once outside the radius of influence of the injection well, both the dissolved and immiscible CO_2 will travel with the natural velocity of the formation water. The geological time-scale trapping of CO_2 in deep regional aquifers, caused by very low flow velocity, is termed hydrodynamic trapping, because it depends on the hydrodynamic regime of formation waters.

Another alternative for the CO_2 trapping is the mineral trapping. Injection of CO_2 into a silicastic formation may lead to precipitation of carbonate minerals, in effect storing CO_2 in a stable form. The following chemical reaction is an example of mineral trapping of CO_2:

$$\mathbf{CaAl_2Si_2O_8 + CO_2 + 2H_2O \Rightarrow Al_2Si_2O_5\,(OH)_4 + CaCO_3}$$

Experiments carried out to test the validity of mineral trapping of CO_2, concluded that these reactions are expected to take hundreds of years or more to complete. Due to the long residence time of CO_2-charged formation waters within the aquifer, these reactions may eventually trap over 90% of the injected CO_2.

Sequestration of CO_2 in deep saline formations does not produce by products like in the enhanced oil recovery method that could provide some economical revenues, but it has other advantages. The sequestration capacity available in deep aquifers is many times larger if carbon dioxide can be sequestered in large horizontal reservoirs instead of being limited to reservoirs that are analogous to the traps in which oil and gas are found. The idea that large horizontal reservoirs will provide secure sequestration is relatively new and has led to an increase in confidence that long-term sequestration of a significant fraction of the next several centuries of carbon dioxide production from human activity may be feasible.

The estimated carbon storage capacity of saline formations for example in the United States is large, making them a viable long-term solution. It has been estimated that deep saline formations in the United States could potentially store up to 500 billion tones of CO_2, which appears to be a large solution to the CO_2 storage problem. This capacity is much bigger than the ones that are provided with the use of not only oil and gas reservoirs, but also coal beds. If we consider the magnitude of deep aquifers worldwide and also the fact that approximately 2% of the total effective volume in a deep aquifer can be made available for CO_2 storage, we understand that from a capacity perspective, deep saline aquifers offer a significant potential for CO_2 storage

We should note that it is significant importance that issues of environmental acceptability and safety of CO_2 storage in saline formations should be investigated thoroughly, although this is a relatively safe method as CO_2 cannot escape from its storage point rapidly. But in case that some CO_2 escapes the storage point could possibly contaminate drinking water supplies.

Generally injection of CO_2 into a brine formation is unlikely to be accompanied by removal of water from the formation, like in the case of enhanced oil recovery where oil was withdrawn while CO_2 was injected in the storage field. Injection will therefore lead to an increase in formation pressure over a large area. To what extent large-scale pressurization will affect cap rock integrity, cause land surface deformation, and induce seismicity is not yet clarified enough.

Although much work is needed to better understand and characterize sequestration of CO_2 in deep saline formations, a significant baseline of information and experience already exists.

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3.2.3 The Ocean

The atmosphere and the ocean are in contact over 70% of the globe and there is a continuous exchange of inorganic carbon between them. Oceans are, at present time, removing about six giga tones CO_2 per year from the atmosphere. Disposing CO_2 coming from power plants in the deep ocean would accelerate this ongoing but slow natural process and would reduce both peak atmospheric CO_2 concentrations and their rate of increase.

The world's oceans represent the largest potential sink for carbon dioxide. They already contain about 40,000 giga tones of carbon, largely as bi carbonate and carbonate ions. Estimates of ultimate sequestration capacity in the world's oceans are in the range of 1,000-10,000 giga tones of carbon, the equivalent of 200 to 2,000 years of current carbon emissions from fossil fuels.

Deep ocean water is unsaturated with respect to CO_2. It is estimated that if all the emitted CO_2 were injected into the deep ocean, it would change the ocean carbon concentration by less than 2%, and lower its pH by less than 0.15 units, which appears not to be really a big affection.

In order to understand ocean storage of CO_2, some properties of CO_2 and seawater need to be clarified. For efficiency and economics of transport, CO_2 would be discharged in its liquid phase. If discharged above about 500m depth (that is, at a hydrostatic pressure less than 50 atm), liquid CO_2 would immediately flash into a vapour and bubble up back into the atmosphere. Between 500 and about 3000 m, liquid CO_2 is less dense than seawater, therefore it would ascend by buoyancy. Because of the higher compressibility of CO_2 compared to seawater, below about 3000 m liquid CO_2 becomes denser than seawater, and if it is released there, it would descend to greater depths. There CO_2 can be stored safely for long time.

There are two primary methods under serious consideration for injecting CO_2 into the ocean:

- One involves dissolution of CO_2 at mid depths (1500– 3000 m) by injecting it from a bottom-mounted pipe from shore or from a pipe towed by a moving CO_2 tanker.
- The other, is to inject CO_2 below 3000 m, where it will form a relatively immobile ‘‘lake.’’. The concept of a CO_2 lake is based on a desire to minimize leakage to the atmosphere, as in this form it can't escape.

These methods are included in figure 3.13:

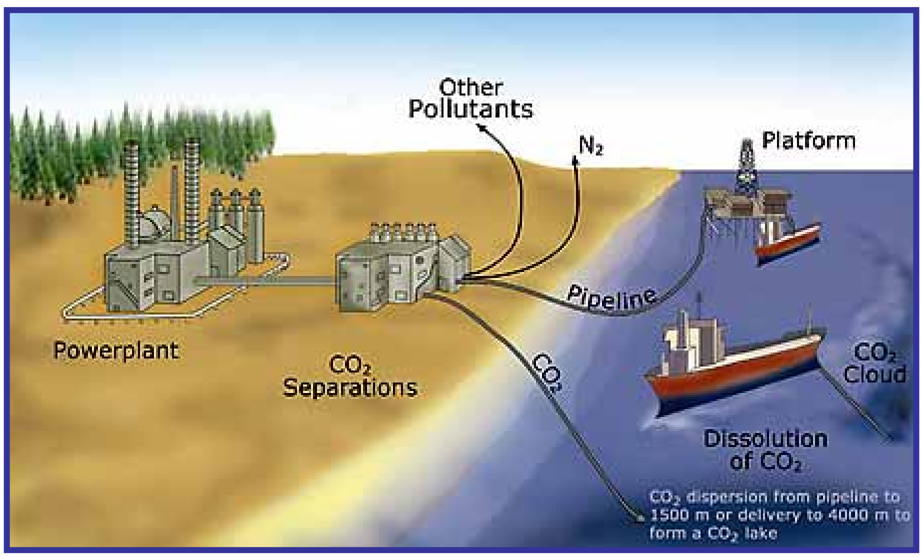

Figure 3.13: Sequestration in the ocean

In order for ocean storage of carbon dioxide to become a workable strategy for mitigating climate change, certain criteria must be met. First, this sequestration technology must become cost effective. Nowadays the ocean sequestration technology is quite expensive and poses a barrier for power plants to apply it. For example for sub sea pipelines to 1000m depth, the cost is estimated about $1.2 million per kilometre or even more. The effectiveness of ocean sequestration is proven to depend on the depth to which CO_2 is stored, as the deeper the CO_2 is stored, the more effectively it is sequestered. But injecting CO_2 in big depths requires more advanced technologies to be applied and so increased costs.

Second, legislation issues have to be overcome. The ocean is international in domain and is protected by international treaties or agreements such as MARPOL or the Law of the Sea. Nowadays although in a few places ocean sequestration takes place, it is usually forbidden to sequester CO_2 in the ocean and much effort is being done in order to find a solution to deal with these legislation issues.

Third, the ocean plays an important role in sustaining the biosphere, so any change in ocean ecosystem function must be viewed with extreme caution. The most significant environmental impact is expected to be associated with lowered pH as a result of the reaction of CO_2 with seawater, although there could also be direct impact from the CO_2 itself. Non-swimming marine organisms residing at depths of about 1000 m or greater are most likely to be affected adversely by more acidic seawater, while the magnitude of the impact will depend on both the level of pH change and the duration of exposure. The microbial community may also be affected, causing unknown impacts on biogeochemical processes that play a crucial role in the ocean carbon cycle. Unfortunately we lack sufficient knowledge of the consequences of ocean sequestration, but such knowledge is critical to responsible use the oceans as a carbon sequestration option. Long term studies on the impact of ocean sequestration on ecosystem dynamics and global biogeochemical cycling are needed.

Finally, public perception of ocean sequestration is undoubtedly an issue for its broader acceptability. Much of the public, believe that the oceans must remain as pristine as possible. The fisheries industry will also be concerned about possible economic impacts resulting from ocean sequestration activities. Discharging CO_2 into the deep ocean appears to elicit significant opposition, especially by some environmental groups. Often, discharging CO_2 is equated with dumping toxic materials into the ocean, ignoring that CO_2 is not toxic, that dissolved carbon dioxide and carbonates are natural ingredients of seawater anyway. CO_2 injection into the deep and intermediate ocean must become environmentally acceptable to the public at large. But even if the scientific research indicates low risk, the public will need clear information to understand and accept its implications.

3.2.4 Coal beds

Coal beds are a potential storage medium for CO_2. CO_2 can be injected into suitable coal seams where it will be adsorbed onto the coal, stored in the pore matrix of the coal seams, and locked up permanently. Large quantities of CO_2 can be stored this way in coal beds.

But the most promising aspect of this technology is that coal formations provide an opportunity to sequester CO_2 and increase the production of natural gas at the same time. The injection of carbon dioxide into deep coal seams can lead, simultaneously, to the displacement of methane adsorbed on coal surfaces and its replacement by adsorbed carbon dioxide. This process has the potential to sequester large volumes of CO_2 while improving the efficiency and profitability of commercial natural gas operations. This process can be viewed for a power plant below:

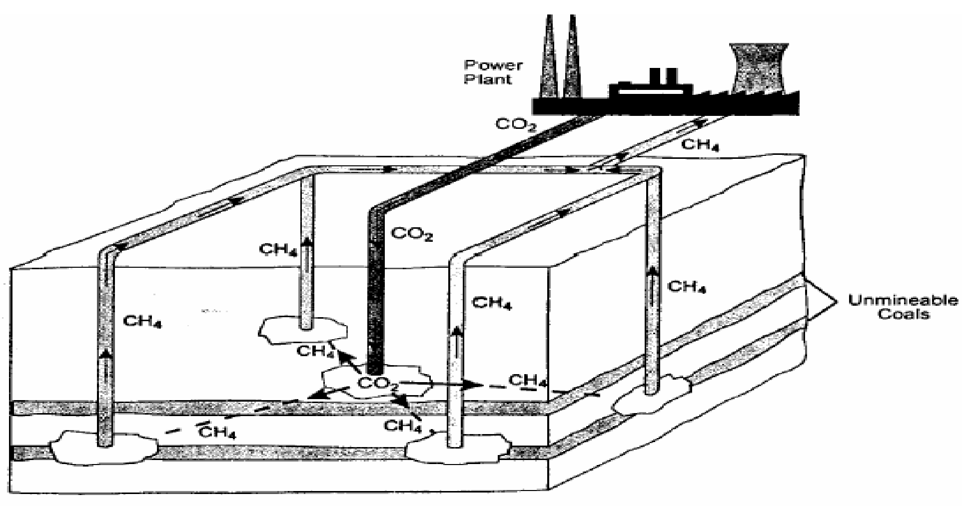

Figure 3.14: Methane recovery from CO_2 sequestration

In order to better understand this process we should look at coal beds morphology. Coal beds contain both primary (micro pore and meso pore) and secondary (macro pore, shown in the figure 3.15 as cleats) porosity system. More than 98% of the gas-in-place volume exists in the primary porosity system. The primary porosity system is impermeable and dominated by sorption phenomena due to the small size of pores. Mass transfer for each gas molecular species is dominated by diffusion that is driven by the concentration gradient. Flow through the secondary porosity system is dominated by Darcy law that relates flow rate to permeability and pressure gradient.

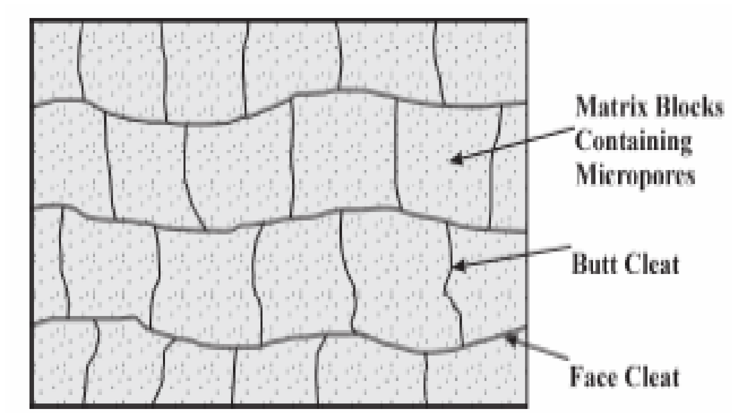

Figure 3.15: Coal bed morphology

In the CO_2 sequestration with enhanced coal bed methane recovery, CO_2 is injected into the coal. Upon sorption, the absorbed CO_2 drives CH_4 from the micro pores and meso pores, into macro pores. Increase in pressure in macro pores due to CO_2 injection causes the CH_4 flows to production well. The CO_2 is trapped in the micro pores and meso pores in the coal and is not released unless the injected gas front reaches the production wells. CO_2 injection in and CH_4 recovery from coal seams will use high-pressure techniques. In order to determine which coal seams would be good disposal sites and under what environmental conditions the sequestered CO_2 would remain stable in coal, a better understanding and much research on the high pressure interactions of coal and CO_2 is essential.

Thus, CO_2 can be used to enhance the recovery of coal bed methane, in a process similar to the enhanced oil recovery. In some cases, this can be very cost-effective or even cost free, because the additional methane removal can offset the cost of the CO_2 storage operations. Also this method is really cost saving as already many of the large unmineable coal seams are placed near electricity generating facilities that are large point sources of CO_2 gas. As a result, limited pipeline transport of CO_2 gas would be required. Integration of coal bed methane with a coal-fired electricity generating system can provide an option for additional power generation with low emissions.

Sequestrations of CO2 in coal seams, while enhancing methane recovery, is an attractive option, but the physical characteristics of the coals, for the purpose of CO2 enhanced coal bed methane recovery, are largely unknown. Recent studies have shown that continued injection of CO_2 in coal beds induced a decrease in the permeability of the cleat system surrounding the injection well area. In general, desorption of the methane causes shrinkage of the coal matrix, which in turn, causes the cleats to open, thereby allowing the CO_2 injection rate to increase and the methane to flow to the producing well. At the same time, replacement of the methane by the injected CO_2 is believed to cause the coal matrix to swell. This swelling will partially block the cleat system and negatively affect the main flow parameters. The fracturing of the coal and the swelling, have opposite effects on the CO_2 injectivity. So much research has to take place in this field in order to find an effective solution to this problem.

3.3 Comparison of methods

After explaining in detail the most applicable sequestration methods, it would be necessary to summarise their issues in order to achieve a better understanding of their issues and a straightforward comparison between them.

The factors affecting the decision, of which method should be applied, are multiple and depend mainly on each situation separately. They have to be weighted according to the importance of each factor, in order to choose the right carbon sequestration method to be applied.

In the next page an attempt is made in order to present these main issues and make their evaluation easier. The factors selected are appreciated as the most critical, and they are:

- The capacity of each reservoir
- The availability of each reservoir
- Retention time, as the time that CO_2 can be held by them safety
- Previous experience from past application of them
- Compatibility with power plants, with respect to distance from them
- Economical issues, and
- Environmental issues, including legislation problems

OPTION	***CAPACITY***	***AVAILABILITY***	***RETENTION TIME***	***PREVIOUS EXPERIENCE***	***COMPATIBILITY WITH POWER PLANTS***	***ECONOMICAL***	***ENVIRONMENTAL***
SALINE	Larger than coal and oil and gas reservoirs	Large	Thousands of years	Poor, research needed	Excellent	Modest	Danger of potential water contamination
OCEAN	Largest	Largest	Smallest, hundreds of years	Modest, research in safety issues needed	Modest, only if they are close to coastlines are applied	Most expensive	-Potential pH change, affecting marine life -Negative public perception -Legislation issues
COAL	Large quantities	Large, but unclear how many can be used effectively	Thousands of years	Limited, method under development	Excellent	Very cost saving if methane recovery is applied	No risk
OIL AND GAS RESERVOIRS	Limited	Only in areas with reservoirs	As long as the reservoir is not damaged	Excellent, widely practiced	Low, usually sited far from power plants	Very cost saving if enhanced oil recovery is applied	No risk

Table 7: Comparison of sequestration methods

3.4 Proposed method for Greece

As explained in chapter 2, natural gas is a new technology for Greece that has been recently applied. The main electricity needs are covered predominantly from coal fired power plants.

Although natural gas seems to be the answer to the emission problem, as its combustion emits lower portions of greenhouse gases, it is a temporary solution. With the expected rapid expansion of natural gas technologies in the country, its emissions will have to be treated too.

A large number of coal beds exist in the whole country, so possibly the best solution for Greece in terms of carbon sequestration, would be injection in coal beds. As shown from the comparison method they are a safe, environmental friendly option with large capacity. If this method is applied for carbon sequestration coupled with enhanced methane recovery the economic revenues will be big, as more natural gas can be produced in a cost effective manner.

The main consideration though, is which coal beds can be used for this purpose, depending on the CO_2 and coal high pressure interactions. Fortunately what is widely used in Greece is a good quality coal, called brown coal (lignite), which according to the recent studies is the most effective for this kind of sequestration technology integrity and has high enhanced methane recovery efficiency.

Although the methods investigating the high pressure interaction between CO_2 and coal are in embryonic stage, through experiments they can predict the exact efficiency of each coal bed, in order to select the best for this case. So much more work is expected on this field in the future, in order to optimise this process.

4. Overall economic issues

Power plants emit more than one-third of the CO_2 emissions worldwide, making them a prime candidate for carbon capture. Although the quantity is large, the cost of capture is significant because the CO_2 concentrations are low (usually, 3–5% in gas plants and 13–15% in coal plants).

Carbon capture and sequestration costs can be considered in terms of capture, compression, transport, and injection. In order to better understand the contribution of each step followed perhaps an example would be useful. A good such example of the costs of capture and storage of CO_2 for coal and natural gas fired power plants, was developed by IEA Greenhouse Gases R&D Programme. It indicates that the overall cost of capture and storage for a 500 MW coal or gas fired power plant, in which some carbon capture and sequestration techniques are applied, ranges from $40 to $60 per tone of CO_2 emissions avoided. The main components of this calculation are:

- CO2 capture and compression: $30 to $50 per tone of CO_2
- Transportation by pipeline: $1 to $3 per tone of CO_2 per 100 km
- Storage : $1 to $3 per tone of CO_2

Nevertheless these costs are expected to fall as the technology matures and the scale of application increases.

But we shouldn't forget the fact that there is also the cost to produce additional electricity to make up for lost generation capacity in order to deal with these steps. This means that more fuel combustion must take place in order to generate the additional electricity required. This effect is shown for natural gas and coal fired power plants, with or without sequestration, in the figure 3.16 below:

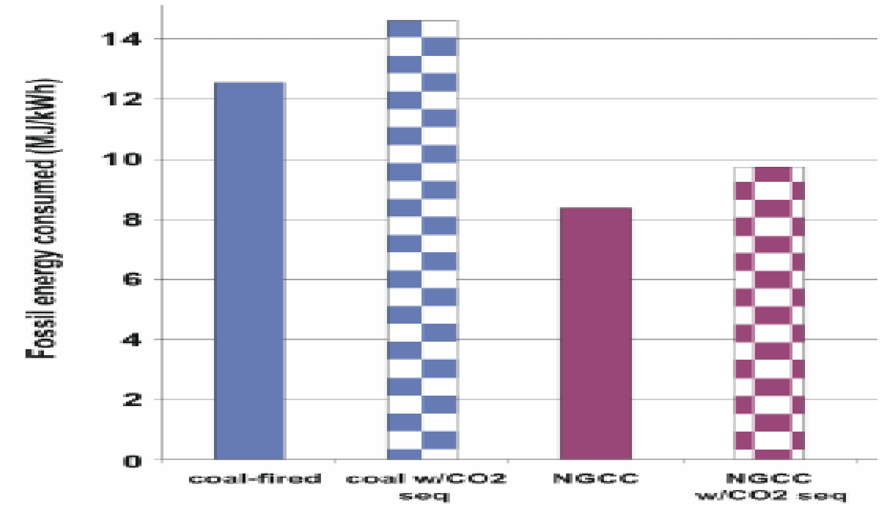

Figure 3.16: Energy consumed with or without sequestration

We can notice that natural gas seems to be a better option, as the raise in energy consumed in the sequestration scenario is lower than for coal. The energy consumed for the coal case rises approximately 14%, while for the natural gas case seems to be approximately 10%. But this extra cost can be avoided sometimes if specific storage options are selected, like oil reservoirs with enhanced oil recovery or coal beds with methane recovery.

Also what is important to be noted is the magnitude in which electricity prices are affected because of these costs. The effect of the processes followed in order to achieve CO_2 capture and then sequestration, on electricity prices was calculated in January 2004, by National Renewable Energy Laboratory (NREL) and is presented step by step in the table below:

System	Cost of electricity (¢/kWh)				
	Prior to CO_2 sequestration	Cost of CO_2 capture & compression	Cost of CO_2 transport & storage	Cost of replacement power	Total cost
Coal-fired	2.5	2.8	0.9	1.1	7.3
NGCC	4.5	1.7	0.6	0.7	7.5

Table 8: Cost of the processes

Although the cost of electricity seems to be for the natural gas case slightly higher than the coal case, still natural gas is a good choice to use if we consider that it can be applied without sequestration for many years and still comply with the emission regulations. When it is necessary, sequestration techniques may be used to natural gas in the future, saving some years costs of the non use of coal with sequestration techniques. Also if applied some time later it might be even more cost effective, as sequestration techniques are expected to be cheaper in the short future, as it has been fore mentioned.

5. Conclusions

Carbon capture and sequestration techniques are of great importance for the future. But we must bear in mind that carbon capture and sequestration are not an alternative to better energy efficiency or increased use of non carbon energy sources.

The main points of carbon capture and sequestration technologies are:

- They have few applications until nowadays, but are expected to expand rapidly in the short future.
- They are uniquely compatible with today's fossil energy infrastructure and can help smooth the transition from today's fossil-based energy system to a more climate-friendly future energy system.
- Coal and gas will continue to be used in large scale, which is positive as many countries economies depend on them.
- They can deal with the emission problem effectively in low prices compared to the use of renewables or nuclear energy.
- Each process has its own complicated issues that have to be considered in order to be decided if it can be applied.

- The storage period is very important to be for really long periods (hundreds or thousands of years).
- Storage capacity for CO_2 is huge, especially for coal beds and deep saline aquifers.
- The cost of these processes includes all transitional steps, like capture, compression, transport, and injection.
- Sequestration technique is selected according also to the place the power plant is situated (so that transportation costs of CO_2 are eliminated).
- Although the cost of capture and storage is high nowadays, as these technologies become more mature and widespread it will be decreased.
- Costs can be even lower if sequestration techniques with oil or methane recovery are applied.
- The possibility of CO_2 being released from the storage point back to the atmosphere should be eliminated. Such an occasion poses a risk even if it doesn't happen in a rapid way, but is released slowly.
- The storage method should comply with national or international laws and regulations. The main problems in this field are faced by the ocean sequestration and much research has to be done so that we can be sure of the effects.
- People must be informed about importance, the safety and the environmental issues of these processes.

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