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Combined Cycle Power Plants

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Table of Contents

Huizhou Combined Cycle Power Plant
Photograph courtesy of Guangdong Yuedian Group

Introduction

Fossil fuel-fired power plants use either steam or combustion turbines to provide the mechanical power to electrical generators. Pressurized high temperature steam or gas expands through various stages of a turbine, transferring energy to the rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity.

The Combined Cycle power plant is a combination of a fuel-fired turbine with a Heat Recovery Steam Generator (HRSG) and a steam powered turbine. These plants are very large, typically rated in the hundreds of mega-watts. They combine the Rankine Cycle (steam turbine) and Brayton Cycle (gas turbine) thermodynamic cycles by using heat recovery boilers to capture the energy in the gas turbine exhaust gases for steam production to supply a steam turbine.

Natural gas is a major fuel source for electric generation through the use of gas turbines and steam turbines. Most grid peaking power plants and some off-grid engine-generators use natural gas. Particularly high efficiencies can be achieved through combining gas turbines with a steam turbine in combined cycle mode. Natural gas burns more cleanly than other fossil fuels, such as oil and coal, and produces less carbon dioxide per unit energy released. For an equivalent amount of heat, burning natural gas produces about 30% less carbon dioxide than burning petroleum and about 45% less than burning coal. Combined cycle power generation using natural gas is thus the cleanest source of power available using fossil fuels, and this technology is widely used wherever gas can be obtained at a reasonable cost.

Combined-cycle power plants have high thermal efficiency, high reliability and economic power generation for application in base load utility service. The features contributing to their outstanding generation economics are:

- High thermal efficiency
- Low installed cost
- Fuel flexibility – wide range of gas and liquid fuels
- Low operation and maintenance cost
- Operating flexibility – base, mid-range, daily start
- High reliability
- High availability
- Short installation time
- High efficiency in small capacity increments
- Minimum environmental impact – low stack gas emissions and heat rejection

Combined-cycle power generation equipment is manufactured in two basic configurations, single-shaft and multi-shaft. The single-shaft combined cycle system consists of one gas turbine, one steam turbine, one generator and one heat recovery steam generator (HRSG), with the gas turbine and steam turbine coupled to a single generator in a tandem arrangement. Multi-shaft combined-cycle systems have one or more gas turbine generators and HRSGs that supply steam through a common header to a separate single steam turbine generator unit. Both configurations perform their specific functions, but the single shaft configuration excels in the base load and mid-range power generation applications.

The multi-shaft combined-cycle system configuration is most frequently applied in phased installations in which the gas turbines are installed and operated prior to the steam cycle installation and where it is desired to operate the gas turbines independent of the steam system. The multi-shaft configuration was applied most widely in the early history of heat recovery combined-cycle plants primarily because it was the least departure from the familiar conventional steam power plants. The single shaft combined-cycle system has emerged as the preferred configuration for single phase applications in which the gas turbine and steam turbine installation and commercial operation are concurrent.

Depending on the power requirements at the time, the combined cycle plant may operate only the fired turbine and divert the exhaust. However, this is a substantial loss of efficiency. Large fossil fuel fired turbines are in the low 30% efficiency range, while combined cycle plants can exceed 60% efficiency.

The first combined-cycle generation units entered service in the 1960's and their numbers are expected to grow dramatically in the coming years as coal-fired plants are phased out.

In this course, we will take a detailed look at the natural gas industry including where the current and expected gas reserves are located. Then we will go into the details of how a combined cycle power plant works. Finally, we will discuss some of the environmental impacts of a combined cycle power plant. But first, let's look at the natural gas industry.

Chapter 1
Natural Gas as a Fuel Source

Natural gas is a gas consisting primarily of methane. It is found associated with other fossil fuels, in coal beds, and is created by organisms in marshes, bogs, and landfills. It is an important fuel source and a major feedstock for fertilizers.

Before natural gas can be used as a fuel, it must undergo extensive processing to remove almost all materials other than methane. The by-products of that processing include ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons, elemental sulfur, carbon dioxide, water vapor, and sometimes helium and nitrogen.

History

Before there was an understanding of what natural gas was, it posed somewhat of a mystery to man. Sometimes, such things as lightning strikes would ignite natural gas that was escaping from under the earth's crust. This would create a fire coming from the earth, burning the natural gas as it seeped out from underground. These fires puzzled most early civilizations and were the root of much myth and superstition. One of the most famous of these types of flames was found in ancient Greece around 1000 B.C. 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.

In the 1800s, natural gas was usually produced as a byproduct of producing oil, since the small, light gas carbon chains come out of solution as it undergoes pressure reduction from the reservoir to the surface. Unwanted natural gas can be a disposal problem at the well site. If there is not a market for natural gas near the wellhead it was virtually useless since it must be piped to the end user. In the 1800s and early 1900s, such unwanted gas was usually burned off at the well site. Often, unwanted gas was pumped back into the reservoir with an 'injection' well for disposal or re-pressurizing the producing formation. In locations with a high natural gas demand, pipelines were constructed to take the gas from the well site to the end consumer.

An early commercial form of natural gas was known as “town gas”. *Town gas* is a mixture of methane and other gases, mainly the highly toxic carbon monoxide that can be used in a similar way to natural gas and can be produced by treating coal chemically. Most town "gashouses" located in the eastern United States in the late nineteenth and early twentieth centuries were simple by-product coke ovens which heated bituminous coal in air-tight chambers. The gas driven off from the coal was collected and distributed through town-wide networks of pipes to residences and other buildings where it was used for cooking and lighting purposes. The coal tar that collected in the bottoms of the gashouse ovens was often used for roofing and other waterproofing purposes, and also, when mixed with sand and gravel, was used for creating bitumen for the surfacing of local streets.

Manufactured natural gas of this type was first brought to the United States in 1816, when it was used to light the streets of Baltimore, Maryland. However, this manufactured gas was much less efficient, and less environmentally friendly, than modern natural gas that comes from underground.

Chemical Composition

Natural gas is colorless, shapeless, and odorless in its pure form. It is abundant in the United States and when burned it gives off a great deal of energy and few emissions. Unlike other fossil fuels, natural gas is clean burning and emits lower levels of potentially harmful byproducts into the air.

Natural gas is a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane and pentane. Table 1 shows the "typical" make-up of natural gas. The make-up varies based on the source of the gas.

Table 1
Composition of Natural Gas

Component	Symbol	Percentage
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 amounts

As you can see from Table 1, natural gas is almost pure methane.

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 considered *wet*.

Found in reservoirs underneath the earth, natural gas is often associated with oil deposits. Once brought from underground, the natural gas is refined to remove impurities such as water, other gases, sand, and other compounds. Some hydrocarbons are removed and sold separately, including propane and butane. Other impurities are also removed, such as hydrogen sulfide (the refining of which can produce sulfur, which is then also sold separately). After refining, the clean natural gas is transmitted through a network of pipelines. From these pipelines, natural gas is delivered to its point of use.

Natural gas is a fossil fuel. Like oil and coal, this means that it is, essentially, the remains of plants and animals and micro-organisms that lived millions and millions of years ago.
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 put a great deal of pressure on the organic matter, which compresses it. This compression, combined with high temperatures found deep underneath the earth, breaks down the carbon bonds in the organic matter. As we go deeper and deeper under the earth's 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 a couple of 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.

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 toward the surface of the earth, they are likely to form methane deposits, similar to thermogenic methane.

Energy content of Natural Gas

Quantities of natural gas are measured in *standard cubic feet*, which corresponds to 16C and 14.73 psia. One standard cubic foot of natural gas produces around 1,028 British Thermal Units (BTU). The actual heating value, when the water formed does not condense, is the net heat of combustion and can be as much as 10% less.

In the United States, retail sales are often in units of therms; 1 therm = 100,000 BTU. Gas meters measure the volume of gas used, and this is converted to therms by multiplying the volume by the energy content of the gas used during that period, which varies slightly over time. Wholesale transactions are generally done in million deca-therms (MMDth). A million deca-therms is roughly a billion cubic feet of natural gas.

The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not.

The quantity known as *higher heating value* (HHV) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. In other words, HHV assumes all the water component is in liquid state at the end of combustion.

The quantity known as *lower heating value* (LHV) is determined by subtracting the heat of vaporization of the water vapor from the higher heating value. This treats any H_2O formed as a vapor and, therefore, the energy required to vaporize the water therefore is not realized as heat. LHV calculations assume that the water component of a combustion process is in vapor state at the end of combustion, as opposed to the higher heating value (HHV) which that assumes all of the water in a combustion process is in a liquid state after a combustion process.

The fact that natural gas, or natural gas fired equipment, can be quoted on either an HHV or an LHV basis is a source of endless confusion in the industry. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. There is an approximately 10% difference in values between HHV and LHV.

Natural Gas Resources

There is an abundance of natural gas in North America, but it is a non-renewable resource, the formation of which takes thousands and possibly millions of years. Therefore, understanding the availability of our supply of natural gas is important as we increase our use of this fossil fuel.

A common misconception about natural gas is that we are running out, which is not true. In fact, there is a vast amount of natural gas estimated to still be in the ground.

Fossil natural gas can be *associated* (found in oil fields) or *non-associated* (isolated in natural gas fields) and is also found in coal beds and is called coalbed methane. It sometimes contains significant quantities of ethane, propane, butane, and pentane—heavier hydrocarbons removed prior to use as a consumer fuel—as well as carbon dioxide, nitrogen, helium and hydrogen sulfide.

Natural gas is commercially produced from oil fields and natural gas fields. Gas produced from oil wells is also called “casinghead gas”. The natural gas industry is producing gas from increasingly more challenging resource types: sour gas, tight gas, shale gas and coalbed methane.

Before we go too far in defining natural gas resources, we need to define a few terms used in the industry.

<u>Conventional and Unconventional Natural Gas</u>
Conventional natural gas exists in the earth, trapped in reservoirs. Historically, conventional natural gas deposits have been the most practical and easiest deposits to mine. *Unconventional natural gas* does not exist in these conventional reservoirs - rather, this natural gas takes another form, or is present in a peculiar formation that makes its extraction quite different from conventional resources. Unconventional natural gas is gas that is generally considered more difficult or less economical to extract, usually because the technology to reach it has not been developed fully or is too expensive. Examples of unconventional gas include deep gas, tight gas, shale gas, coalbed methane, geopressurized zones, and methane hydrates. Let’s look at each of these briefly.

Deep natural gas is exactly what it sounds like - natural gas that exists in deposits very far underground, beyond 'conventional' drilling depths. This gas is typically 15,000 feet or deeper underground, quite a bit deeper than conventional gas deposits, which are traditionally only a few thousand feet deep at most.

Tight Gas is gas that is stuck in a very tight formation underground, trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (i.e., tight sand).

Shale Gas exists in shale deposits, which formed 350 million of years ago. Shale is a very fine-grained sedimentary rock, which is easily breakable into thin, parallel layers. Shale represents a large and growing share of the United States recoverable resource base. We'll discuss shale gas in more detail a little later.

Coalbed methane is formed underground under similar geologic conditions as natural gas and oil. These coal deposits are commonly found as seams that run underground and are mined by digging into the seam and removing the coal. Many coal seams also contain natural gas, either within the seam itself or the surrounding rock. This coalbed methane is trapped underground and is generally not released into the atmosphere until coal mining activities unleash it.

Geopressurized zones are natural underground formations that are under unusually high pressure for their depth. These areas are formed by layers of clay that are deposited and compacted very quickly on top of more porous, absorbent material such as sand or silt. Water and natural gas that are present in this clay are squeezed out by the rapid compression of the clay and enter the more porous sand or silt deposits. The natural gas, due to the compression of the clay, is deposited in this sand or silt under very high pressure (hence the term 'geopressure'). In addition to having these properties, geopressurized zones are typically located at great depths, usually 10,000-25,000 feet below the surface of the earth. The combination of all these factors makes the extraction of natural gas in geopressurized zones quite complicated.

Methane hydrates are the most recent form of unconventional natural gas to be discovered and researched. These interesting formations are made up of a lattice of frozen water, which forms a sort of 'cage' around molecules of methane. These hydrates look like melting snow and were first discovered in permafrost regions of the Arctic. However, research into methane hydrates has revealed that they may be much more plentiful than first expected. Estimates range anywhere from 7,000 trillion cubic feet (Tcf) to over 73,000 Tcf. In fact, the USGS estimates that methane hydrates may contain more organic carbon than the world's coal, oil, and conventional natural gas - combined.

Unconventional natural gas, despite existing in non-traditional forms, is usually included in estimations of the amount of natural gas available for use. To further confuse the definitions, as unconventional gas resources become economical to recover, they are often re-classified as conventional gas. For example, shale gas is considered unconventional gas, but because of the new technology to access shale gas it will likely become known as a conventional gas resource.

Discovered and Undiscovered Technically Recoverable Resources

Recoverable resources are the subset of the total resource base that is thought to be technically recoverable; the technology exists to make its extraction possible. This subset is further divided into discovered and undiscovered resources. *Discovered recoverable resources* are those in a known location. That is, those reservoirs that geologists have actually located through exploration. Discovered recoverable resources include current production, all past production, as well as the gas that is remaining to be produced.

Undiscovered resources are those deposits that have not been pinpointed but are generally expected to exist based on geologic conditions. Geologists know, or at least have a good idea, that these natural gas reservoirs exist, although they are not able to pinpoint a specific location for a reservoir. In the U.S., the Department of the Interior and the U.S. Geological Survey (USGS) are responsible for estimating how much undiscovered recoverable natural gas there is in onshore areas and State governed offshore areas of the United States. Conversely, the Minerals Management Service, an agency with the Department of Interior, is responsible for estimating the undiscovered natural gas in Federal offshore areas. Each of these departments uses slightly different definitions, and terminology, when measuring and referring to undiscovered resources. However, as a general estimate, most agree that there is at least as much technically recoverable natural gas remaining to be found in the earth than has already been located to date.

Economically Recoverable Resources

Economically recoverable resources are those natural gas resources for which there are economic incentives for production; that is, the cost of extracting those resources is low enough to allow natural gas companies to generate an adequate financial return given current market conditions. However, it is important to note that economically unrecoverable resources may, at some time in the future, become recoverable, as soon as the technology to produce them becomes less expensive, or the characteristics of the natural gas market are such that companies can ensure a fair return on their investment by extracting this gas.

Those resources that have been discovered, and for which a specific reservoir location is known, can further be broken down into those resources that are economically recoverable, and those that are *economically unrecoverable*. This differs from technically unrecoverable resources, in that the technology exists (or is foreseeable in the near future) to get economically unrecoverable resources from the ground, but the economics do not exist to make the production of this natural gas profitable.

Reserves

Those discovered, technically and economically recoverable resources are further broken down into different types of *reserves*. Organizations measure reserves for their own use and for outside publication, often using different measuring and estimation techniques for the different types of reserves. However, in general, reserves can be broken down into two main categories - proved reserves, and other reserves.

Proved reserves are those reserves that geological and engineering data indicate with reasonable certainty to be recoverable today, or in the near future, with current technology and under current economic conditions. According to the Energy Information Administration (EIA, 'reasonable certainty' implies that there is a 90 percent probability that the natural gas actually recovered from those reserves will exceed the amount that is estimated beforehand to be recoverable.

The EIA further divides proved reserves into non-producing and producing reserves. *Producing proved reserves* are those reservoirs that are currently being produced, that is, natural gas is currently being extracted. These are probably the most certain of the estimates, as characteristics of the reserves become more apparent once a well is actually drilled, and natural gas is extracted. *Proved non-producing reserves* are further broken down into proved undeveloped reserves and proved developed non-producing reserves. Of these two categories, *proved developed non-producing reserves* are more accurate. This means that pre-production work has been done on the reservoir and a well may have been drilled to prepare for natural gas extraction, but as of yet no natural gas has been produced. *Proved undeveloped reserves* are those where not well has been drilled, but for which there is still relative certainty surrounding the amount of natural gas they contain.

Other Reserves

Other reserves are those that are less well known than proved reserves. This classification goes by many names and it is also called probable reserves, possible reserves, indicated reserves, or inferred reserves. Because the quantity and characteristics of these reserves are less well known, the extraction of this natural gas is not completely assured, although there is a relatively high probability that they will be recoverable.

It is important to note that different methodologies and systems of classification are used in the various estimates. There is no single way that every industry player uses to quantify estimates of natural gas. Therefore, it is important to delve into the assumptions and methodology behind each study to gain a complete understanding of the estimate itself.

It is tempting to believe that the proved reserves would be the most accurate indicator of available gas. This might not be true however because the gas companies have economic incentives to not overstate these 'on the books' estimations of their reserves as this classification carries with it a high degree of certainty. In order to not overstate the actual amount of natural gas, many companies list a high percentage of their reserves as unproven. It follows then that most of the natural gas that exists in the United States does not fall under the proven reserve's classification. It may be misleading, then, to look only at levels of proved reserves as an indication of how much natural gas there really is. Instead, the entire supply picture should be examined, including conventional and unconventional natural gas, discovered and undiscovered, and economically recoverable or unrecoverable.

There is a myriad of different industry participants that formulate their own estimates regarding natural gas supplies, such as production companies, independent geologists, the government and environmental groups, to name a few. While this leads to a wealth of information, it also leads to a number of difficulties. Each estimate is based on a different set of assumptions, completed with different tools, and even referred to with different language. It is thus difficult to get a definitive answer to the question of how much natural gas exists. In addition, since these are all essentially educated guesses as to the amount of natural gas in the earth, there are constant revisions being made. New technology combined with increased knowledge of particular areas and reservoirs mean that these estimates are in a constant state of flux. Further complicating the scenario is the fact that there are no universally accepted definitions for the terms that are used differently by geologists, engineers, accountants, and others.

With this confusing array of definitions, let's look at the estimates of natural gas available. The Energy Information Administration (EIA) estimates that there are 2,355 trillion cubic feet (Tcf) of technically recoverable natural gas in the United States. This includes undiscovered, unproved, and unconventional natural gas. Others have estimated the total US reserves at 1,800 – 2,000 Tcf, with the difference being how the reserves are calculated.

Proved world natural gas reserves are estimated to be around 6,879 Tcf. As can be seen from the graph in Figure 1, most of these reserves are located in the countries that make up the former USSR as well as the Middle Eastern countries, such as Iran, Qatar, Saudi Arabia, UAE, and Iraq. The United States contains only about 4% of the world's proven gas reserves.

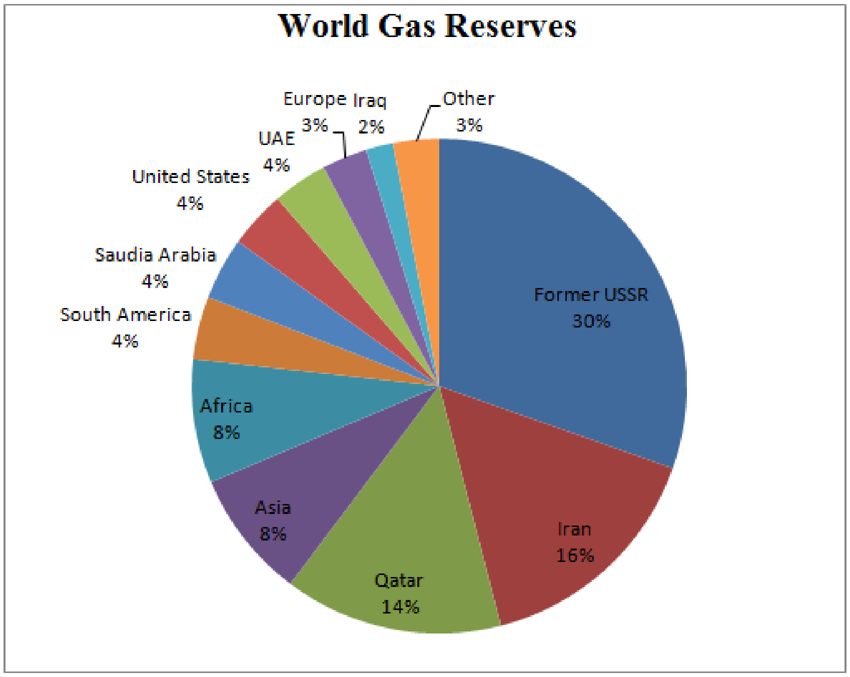
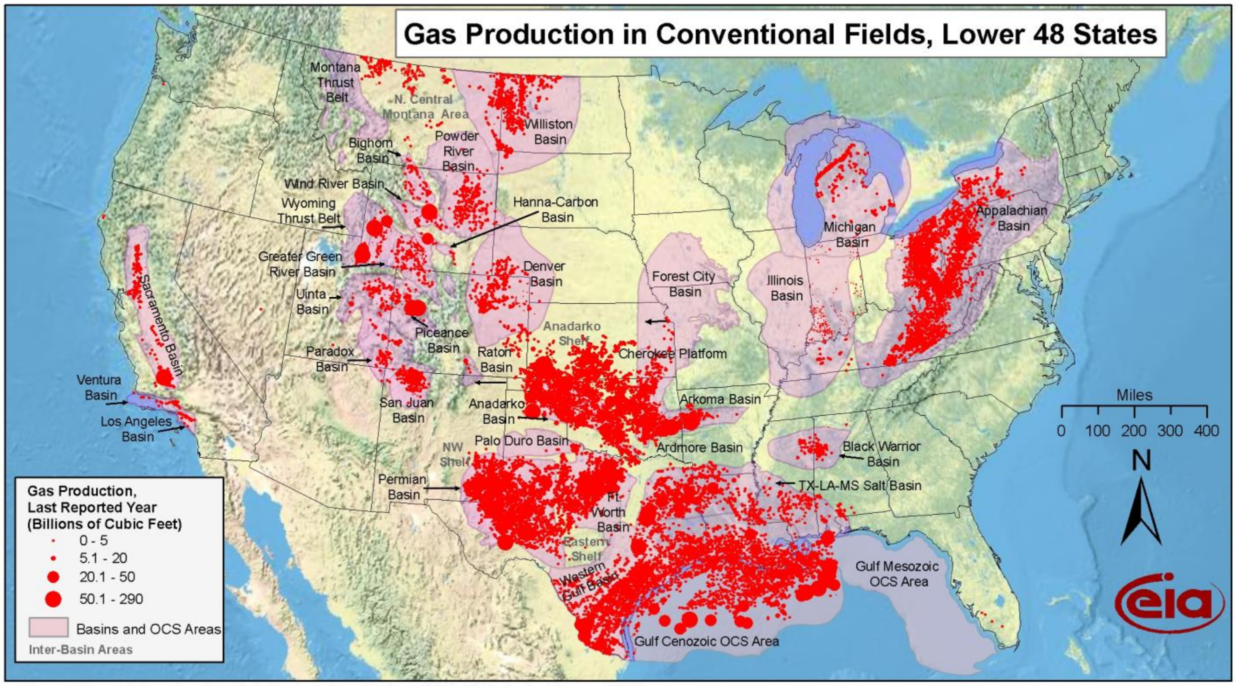


Figure 1

United States Natural Gas Fields

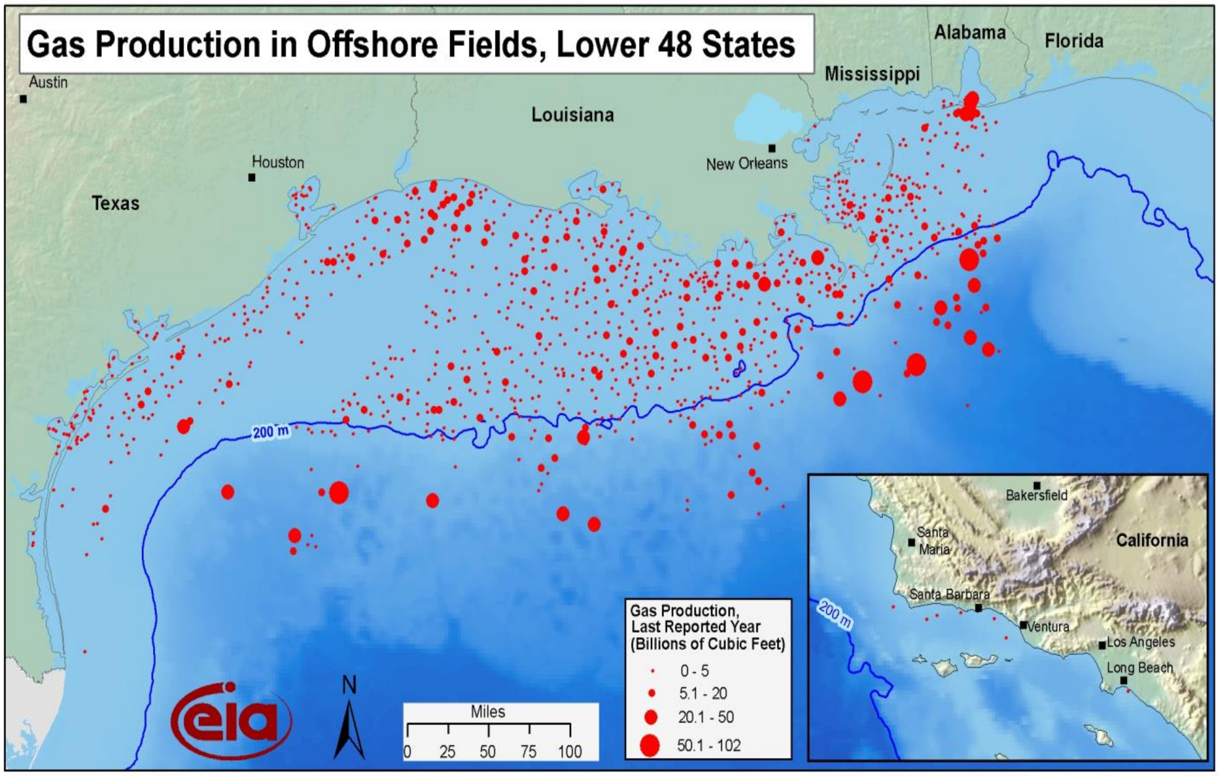
Most of the natural gas that is found in North America is concentrated in relatively distinct geographical areas, or basins. Given this distribution of natural gas deposits, those states that are located on top of a major basin have the highest level of natural gas reserves. As can be seen on the map in Figure 2 below, the U.S. natural gas reserves historically have been concentrated around Texas and the Gulf of Mexico.



Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009

Figure 2

Offshore production on natural gas is primarily located in the Gulf of Mexico, with some off the coast of California, as shown is Figure 3 below.



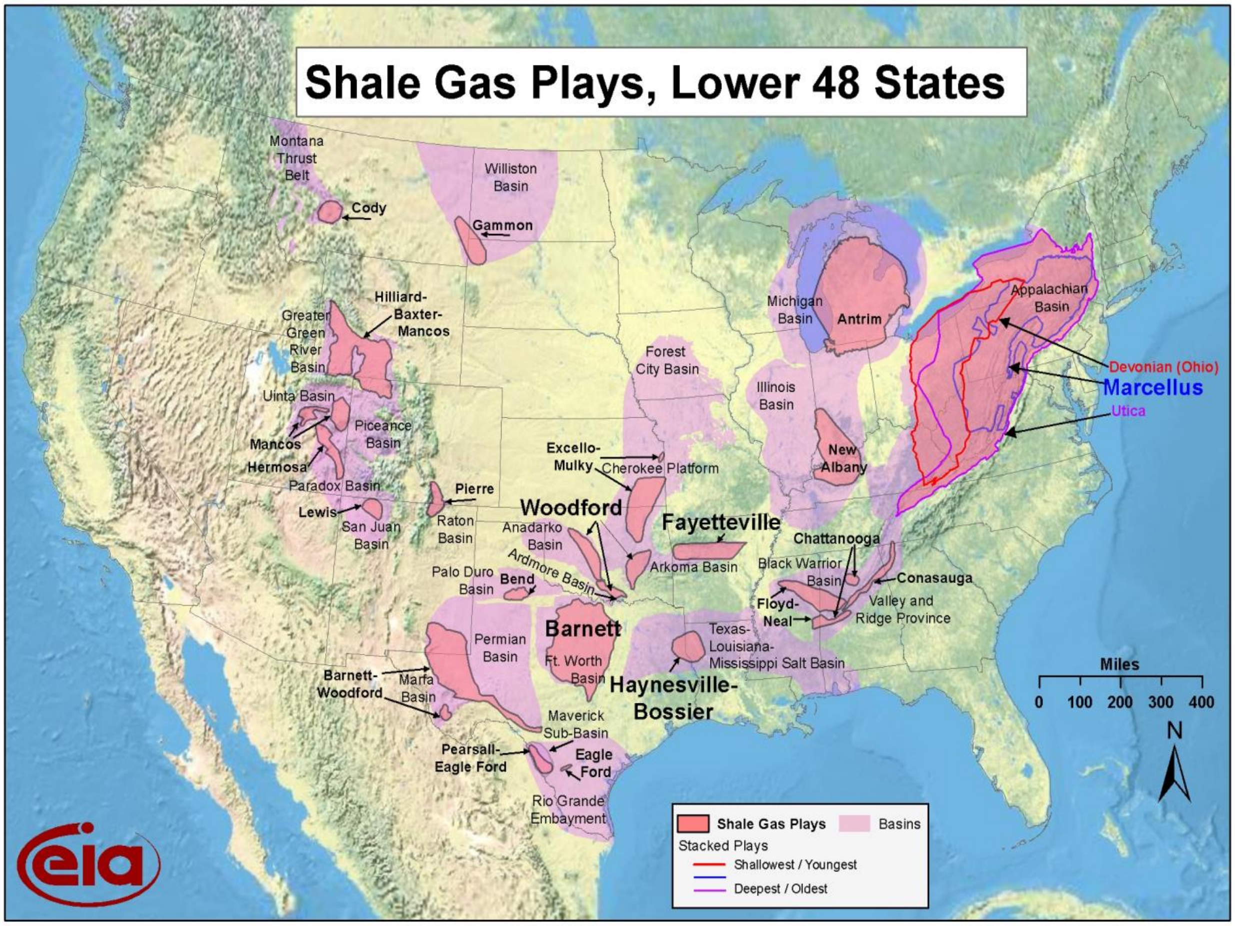
Source: Energy Information Administration based on data from MMS, HPDI, CA Dept of Oil , Gas & Geothermal
Updated: April 8, 2009

Figure 3

Shale Gas

As previously mentioned, gas shales are fine grained, organic-rich, sedimentary rock formations that trap natural gas. Gas shale rock has characteristically small pores that are relatively impermeable to natural gas flow unless they are naturally or artificially fractured to create channels connecting the pores. Shale rock is considered so impermeable that geologists sometimes say it makes marble feel "spongy" in comparison.

Shale gas is present across much of North America in basins of both extreme and moderate size. Currently most shale development in the United States is concentrated in the Marcellus (Appalachia), Barnett (Texas), Haynesville (Louisiana), Fayetteville (Arkansas), and Woodford (Oklahoma) shale plays. As of 2010, there are at least 22 major shale plays in the U.S., spread diversely over more than 20 states. See Figure 4 below.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Figure 4

Geologists have known of the presence of natural gas in shale rock for years, but until recently, could not cost-effectively extract it. Two factors came together in recent years to make shale gas production economically viable:

(1) Advances in horizontal drilling; and
(2) Advances in hydraulic fracturing.

Together, these factors have transformed shale formations from marginal sources of natural gas to substantial contributors to the natural gas supply portfolio, ushering in a robust resurgence in domestic natural gas production. Looking at Figure 5, we can see that shale gas will likely play a prominent role in new natural gas deliveries in the future. From this chart we see that shale gas, which was only a small percentage of gas production in 2005, may compromise up to 45% of the natural gas production in the United States by 2035.

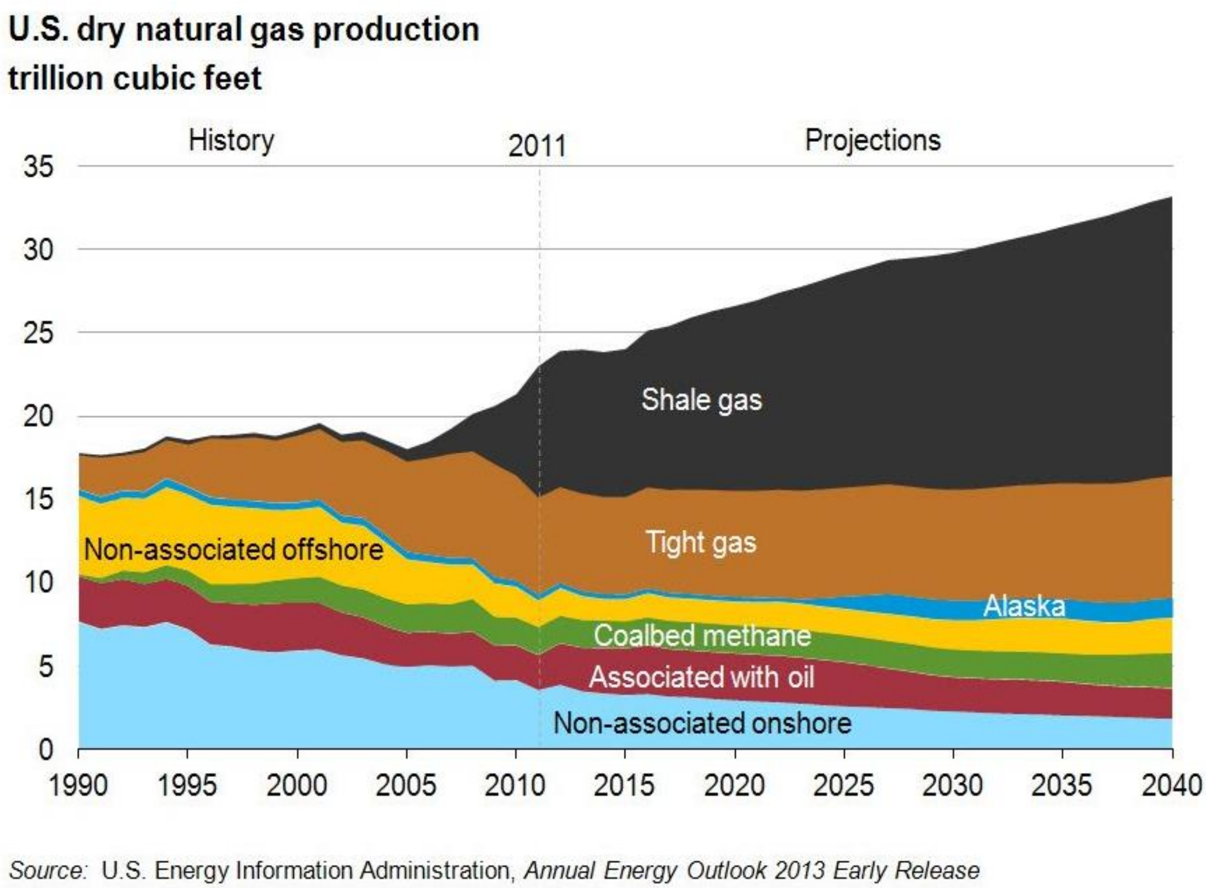


Figure 5

With the onset of shale gas development, production has been diversified across the country and supply is closer to various demand centers. For example, the Marcellus Shale basin covers portions of New York, Pennsylvania, West Virginia and Ohio. As a result, supply is less susceptible to weather disruptions in the Gulf of Mexico. The geographic diversity of U.S. shale gas resources and advances in technology helps ensure a stable and deliverable natural gas supply.

Biogas

Another developing form of natural gas is from *Biogas*. When methane-rich gases are produced by the anaerobic decay of non-fossil organic matter (biomass), these are referred to as biogas. Sources of biogas include swamps, marshes, and landfill, as well as sewage sludge and manure by way of anaerobic digesters, in addition to enteric fermentation particularly in cattle.

Methane released directly into the atmosphere would be considered a pollutant. However, methane in the atmosphere is oxidized, producing carbon dioxide and water. Methane in the atmosphere has a half life of seven years, meaning that every seven years, half of the methane present is converted to carbon dioxide and water.

Other sources of methane, the principal component of natural gas, include landfill gas, biogas and methane hydrate. Biogas, and especially landfill gas, is already used in some areas, but their use could be greatly expanded. Landfill gas is a type of biogas, but biogas usually refers to gas produced from organic material that has not been mixed with other waste.

Landfill gas is created from the decomposition of waste in landfills. If the gas is not removed, the pressure may get so high that it works its way to the surface, causing damage to the landfill structure, unpleasant odor, vegetation die-off and an explosion hazard. The gas can be vented to the atmosphere, flared or burned to produce electricity or heat.

Once water vapor is removed, about half of landfill gas is methane. Almost all of the rest is carbon dioxide, but there are also small amounts of nitrogen, oxygen and hydrogen. There are usually trace amounts of hydrogen sulfide and siloxanes, but their concentration varies widely. Landfill gas cannot be distributed through utility natural gas pipelines unless it is cleaned up to less than 3% CO_2, and a few parts per million H_2S, because CO_2 and H_2S corrode the pipelines. It is usually more economical to combust the gas on site or within a short distance of the landfill using a dedicated pipeline. Water vapor is often removed, even if the gas is combusted on site. If low temperatures condense water out of the gas, siloxanes can be lowered as well because they tend to condense out with the water vapor. Other non-methane components may also be removed in order to meet emission standards, to prevent fouling of the equipment or for environmental considerations. Co-firing landfill gas with natural gas improves combustion, which lowers emissions.

Biogas is usually produced using agricultural waste materials, such as otherwise unusable parts of plants and manure. Biogas can also be produced by separating organic materials from waste that otherwise goes to landfills. Such method is more efficient than just capturing the landfill gas it produces. Using materials that would otherwise generate no income, or even cost money to get rid of, improves the profitability and energy balance of biogas production.

Mining

Although there are several ways that methane, and thus natural gas, may be formed, it is usually found underneath the surface of the earth. As natural gas has a low density, once formed it will rise toward the surface of the earth through loose, shale type rock and other material. Some of this methane will simply rise to the surface and dissipate into the air. However, a great deal of this methane will rise up into geological formations that 'trap' the gas under the ground. These formations are made up of layers of porous, sedimentary rock (kind of like a sponge that soaks up and contains the gas), with a denser, impermeable layer of rock on top.

This impermeable rock traps the natural gas under the ground. If these formations are large enough, they can trap a great deal of natural gas underground, in what is known as a reservoir. There are a number of different types of these formations, but the most common is created when the impermeable sedimentary rock forms a 'dome' shape, like an umbrella that catches all of the natural gas that is floating to the surface.

There are a number of ways that this sort of 'dome' may be formed. For instance, faults are a common location for oil and natural gas deposits to exist. A fault occurs when the normal sedimentary layers 'split' vertically, so that impermeable rock shifts down to trap natural gas in the more permeable limestone or sandstone layers. Essentially, the geological formation, which layers impermeable rock over more porous, oil and gas rich sediment, has the potential to form a reservoir. To successfully bring these fossil fuels to the surface, a hole must be drilled through the impermeable rock to release the fossil fuels under pressure. Note that in reservoirs that contain oil and gas, the gas, being the least dense, is found closest to the surface, with the oil beneath it, typical followed by a certain amount of water. With natural gas trapped under the earth in this fashion, it can be recovered by drilling a hole through the impermeable rock. Gas in these reservoirs is typically under pressure, allowing it to escape from the reservoir on its own.

Storage and transport

Because of low density, it is not easy to transport or store natural gas. Many existing pipelines in North America are close to reaching their capacity. Natural gas is often stored underground inside depleted gas reservoirs from previous gas wells, salt domes, or in tanks as liquefied natural gas. The gas is injected in a time of low demand and extracted when demand picks up. Storage nearby end users helps to meet volatile demands, but such storage may not always be practicable.

One solution for the difficulty in transporting natural gas is to convert it into a liquid. Cooling natural gas to about -260°F at normal pressure results in the condensation of the gas into liquid form, known as *Liquefied Natural Gas* (LNG). LNG can be very useful, particularly for the transportation of natural gas, since LNG takes up about1/600th the volume of gaseous natural gas. While LNG is reasonably costly to produce, advances in technology are reducing the costs associated with the liquification and regasification of LNG. Because it is easy to transport, LNG can serve to make economical those stranded natural gas deposits for which the construction of pipelines is uneconomical.

LNG, when vaporized to gaseous form, will only burn in concentrations of between 5 and 15 percent mixed with air. In addition, LNG, or any vapor associated with LNG, will not explode in an unconfined environment. Thus, in the unlikely event of an LNG spill, the natural gas has little chance of igniting an explosion. *Liquificatio*n also has the advantage of removing oxygen, carbon dioxide, sulfur, and water from the natural gas, resulting in LNG that is almost pure methane.

The increased use of LNG is allowing for the production and marketing of natural gas deposits that were previously economically unrecoverable. Although it currently accounts for only about one percent of natural gas used in the United States, it is expected that LNG imports will provide a steady, dependable source of natural gas for U.S. consumption. According to the EIA, the U.S. imported 0.17 Tcf of natural gas in the form of LNG in 2002. LNG imports are expected to increase to levels of 0.65 Tcf of natural gas by 2025.

LNG is typically transported by specialized tanker with insulated walls, and is kept in liquid form by auto-refrigeration, a process in which the LNG is kept at its boiling point, so that any heat additions are countered by the energy lost from LNG vapor that is vented out of storage and used to power the vessel.

LNG that is imported to the United States comes via ocean tanker. The U.S. gets a majority of its LNG from Trinidad and Tobago, Qatar, and Algeria, and also receives shipments from Nigeria, Oman, Australia, Indonesia, and the United Arab Emirates. LNG carriers transport liquefied natural gas (LNG) across oceans, while tank trucks can carry liquefied or compressed natural gas (CNG) over shorter distances.

Gas is turned into liquid at a liquefaction plant and is returned to gas form at regasification plant at the terminal. Ship borne regasification equipment is also used. LNG is the preferred form for long distance, high volume transportation of natural gas, whereas pipeline is preferred for transport for distances up to 2,500 miles over land and approximately half that distance offshore.

The ability to convert natural gas to LNG, which can be shipped on specially built ocean-going ships, provides U.S. consumers with access to vast natural gas resources worldwide. LNG is an odorless, non-toxic and non-corrosive liquid, and if spilled, LNG would not result in a slick. Absent an ignition source, LNG evaporates quickly and disperses, leaving no residue.
There is no environmental cleanup needed for LNG spills on water or land.

Liquefied natural gas (LNG) imports represent an increasingly important part of the natural gas supply picture in the United States. LNG takes up much less space than gaseous natural gas, allowing it to be shipped much more efficiently.

Chapter 2
Combined Cycle Power Plant Design

The term *combined cycle power plant* describes the combination of a gas turbine generator (Brayton cycle) with a turbine exhaust waste heat boiler and a steam turbine generator (Rankine cycle) for the production of electric power.

Simple cycle gas turbine generators, when operated as independent electric power producers, are relatively inefficient with heat rates of 12,000 to 15,000 Btu per kilowatt-hour. Consequently, simple cycle gas turbine generators are used only for peaking or standby service when fuel economy is of small importance. Condensing steam turbine generators have heat rates of over 13,000 Btu per kilowatt-hour and are relatively expensive to install and operate and the efficiency of such units is poor compared to the 8,500 to 9,000 Btu per kilowatt-hour heat rates typical of a large, coal-fired power plant.

In a combined cycle gas turbine (CCGT) plant, a gas turbine generator generates electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. The gas turbine exhausts relatively large quantities of gases at temperatures over 500C and the exhaust gases from each gas turbine is ducted to a waste heat boiler. The heat in these gases, ordinarily exhausted to the atmosphere, generates high pressure superheated steam. This steam will be piped to a steam turbine generator. The resulting “combined cycle” heat rate is in the 7,500 to 10,500 Btu per net kilowatt-hour range, or roughly one-third less than a simple cycle gas turbine generator.

Most new gas power plants in North America are combined cycle power plants. In a thermal power plant, high-temperature heat as input to the power plant, usually from burning of natural gas, is converted to electricity as one of the outputs and low-temperature heat as another output. A combined cycle is characteristic of a power producing engine or plant that employs more than one thermodynamic cycle. Heat engines are only able to use a portion of the energy their fuel generates. The remaining heat from combustion is generally wasted. Combining two or more thermodynamic cycles, such as the Brayton cycle and Rankine cycle, results in improved overall efficiency.

The steam turbine cycle generates one third of the power output and the gas turbine produces two-thirds of the output of the combined cycle power plant. Normally there are two electrical generators, one each driven by the gas turbine and the steam turbine.

Combined Cycle Power Plant Energy Output

2/3's Gas Turbine + 1/3 Steam Turbine

In a thermal power plant, such as a coal-fired plant, water is the working medium. High pressure steam requires strong, bulky components. High temperatures require expensive alloys made from nickel or cobalt, rather than inexpensive steel. These alloys limit practical steam temperatures to 655C while the lower temperature of a steam plant is fixed by the boiling point of water. Because of these limits, a steam plant has a fixed upper efficiency of 35 to 42%.

An open circuit gas turbine cycle has a compressor, a combustor and a turbine. For gas turbines the amount of metal that must withstand the high temperatures and pressures is small, and lower quantities of expensive materials can be used. In this type of cycle, the input temperature to the turbine is relatively high (900 to 1,400C). The output temperature of the flue gas is also high (450 to 650C). This is therefore high enough to provide heat for a second cycle which uses steam as the working fluid.

In a combined cycle power plant, the heat of the gas turbine's exhaust is used to generate steam by passing it through a heat recovery steam generator (HRSG) with a steam temperature between 420 and 580C. The condenser of the steam turbine is usually cooled by water from a lake, river, sea or cooling towers.

For large scale power generation, a typical plant would include a 400 MW gas turbine coupled to a 200 MW steam turbine yielding a total of 600 MW of capacity. A typical power plant might be comprised of two to six units.

By combining both gas and steam cycles, high input temperatures and low output temperatures can be achieved. The efficiency of the cycles adds, because they are powered by the same fuel source. So, a combined cycle plant has a thermodynamic cycle that operates between the gas-turbine's high firing temperature and the waste heat temperature from the condensers of the steam cycle.

The HRSG can be designed with *supplementary firing* of fuel after the gas turbine in order to increase the quantity or temperature of the steam generated. Without supplementary firing, the efficiency of the combined cycle power plant is higher, but supplementary firing lets the plant respond to fluctuations of electrical load. Supplementary burners are also called *duct burners*.

Additional peaking capacity can be obtained by use of various power augmentation features. For example, an additional 20 to 50 megawatts can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental cost is low, and the additional electrical output can be valuable during peak load periods. However, the most efficient power generation cycles are those with unfired HRSGs with modular pre-engineered components. These unfired steam cycles are also the lowest in cost.

Operational Efficiency

The efficiency of a steam turbine is based on the quantity and the absolute temperature of the heat received and the heat rejected. This means that a turbine supplied with steam at 500C and exhausting it at 100C is more efficient than one receiving the steam at 400C and exhausting at 100C. Also, a turbine receiving steam at 500C and exhausting at 100C is less efficient than one receiving the steam at the same temperature (500C) but exhausting it at 75C. This not only explains the value of the condenser but also that of high steam pressure. Without the condenser, the lowest temperature at which steam can be exhausted is 100C, since that is the temperature of steam at atmospheric pressure. By means of the condenser, however, a vacuum can be created so that the steam will exhaust at a pressure below atmospheric pressure, which will allow a lower steam temperature.

What is important in the operation of a turbine, then, is the temperature range through which the heat energy falls in its passage through the turbine. The thermal efficiency of the turbine depends upon this temperature range. In an ideal engine, with no heat or friction losses, and no auxiliary power demands on the engine, the efficiency can be defined by this equation,

$$Eff = \frac{(T_1 - T_2)}{T_1} * 100$$

Where,
Eff = Thermal efficiency, percent.
T_1 = Input steam temperature, degrees Kelvin.
T_2 = Exiting steam temperature, degrees, Kelvin.

For example, assuming that the input temperature to a steam turbine is 500C and the exiting steam temperature is 100C, then the theoretical efficiency is (Note that the temperatures are in degrees Kelvin, which is degrees Celsius plus 273),

$$\text{Eff} = \frac{(773 - 373)}{773} * 100$$

Eff = 52%.

Now, if a condenser is used that will increase the back pressure on the turbine and allow the exiting steam to obtain a final temperature of 35C, then the theoretical efficiency becomes,

$$\mathbf{Eff} = \frac{(773 - 308)}{773} * 100$$

Eff = 60%.

Combined Cycle Power Plant Configurations

The combined-cycle concept includes both single-shaft and multi-shaft configurations. The single-shaft system consists of one gas turbine, one steam turbine, one generator and one Heat Recovery Steam Generator (HRSG), with the gas turbine and steam turbine coupled to the single generator in a tandem arrangement on a single shaft. A single-train combined-cycle plant consisting of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator is called a "1 x 1" configuration. A typical system using "FA-class" combustion turbines - the most common technology in use for large combined-cycle plants - can produce about 270 megawatts of capacity at reference ISO conditions. Key advantages of the single-shaft arrangement are operating simplicity, smaller footprint, and lower startup cost. Single-shaft arrangements, however, will tend to have less flexibility and equivalent reliability than multi-shaft blocks. Additional operational flexibility is provided with a steam turbine which can be disconnected for start up or for simple cycle operation of the gas turbine.

Multi-shaft systems have one or more gas turbine-generators and HRSGs that supply steam through a common header to a separate single steam turbine-generator. Multi-shaft systems are increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple combustion turbines provide improved part-load efficiency. A "2 x 1" configuration using FA-class technology will produce about 540 megawatts of capacity at ISO conditions. In terms of overall investment, a multi-shaft system is about 5% higher in costs.

Operational Capabilities

Combined Cycle Power Plants can be modulated to provide fairly rapid response to changing load conditions. Varying the amount of fuel to the gas turbine will have an immediate impact on its power output. However, varying the amount of fuel to a gas turbine will decrease efficiency quickly as output is reduced from full load because of the steep heat rate curve of the gas turbine and the multiplying effect on the steam turbine. Also, steam temperature can rapidly fall below the recommended limit for the steam turbine.

Some supplementary firing may be used for a combined cycle power plant operating at full load. Supplementary firing is cut back as the load decreases; if load decreases below the combined output when supplementary firing is zero, fuel to the gas turbine must also be cut back. This gives somewhat less efficiency at combined cycle full load and a best efficiency point at less than full load; i.e., at 100 percent waste heat operation with full load on the gas turbine.

Use of a multiple gas turbine coupled with a waste heat boiler will give the widest load range with minimum efficiency penalty. Individual gas turbine-waste heat units can be shut down as the load decreases with load-following between shutdown steps by any or both of the above methods.

Gas dampers can be installed to bypass variable amounts of gas from turbine exhaust directly to atmosphere. With this method, gas turbine exhaust and steam temperatures can be maintained while steam flow to steam turbine generator is decreased as is the load. This has the added advantage that if both atmospheric bypass and boiler dampers are installed; the gas turbine can operate while the steam turbine is down for maintenance. Also, if full fuel firing for the boiler is installed along with a standby forced draft fan, steam can be produced from the boiler while the gas turbine is out for maintenance.

This plan allows the greatest flexibility when there is only one gas turbine-boiler-steam turbine train. It does introduce equipment and control complication and is more costly; and efficiency decreases as greater quantities of exhaust gas are by passed to atmosphere.

Major Components

A combined cycle power plant is a complicated machine and is made of many different components from the air intake system, boiler, turbines, heat recovery, and water processing plants. In this section we will review the three major components of a combined cycle power plant which includes: Combustion turbine, steam turbine, and the heat recovery steam generator.

Combustion Turbines

The first cycle in a combined cycle power plant is the simple cycle combustion turbine. A simple cycle power plant is also called an *open cycle* and the combustion turbine plants operate on the Brayton cycle. In a gas turbine, large volumes of air are compressed to high pressure in a multistage compressor and mixed with combustion gas in the combustion chambers which power an axial turbine that drives the compressor and the generator before exhausting to the atmosphere. In this way, the combustion gases in a gas turbine power the turbine directly, rather than requiring heat transfer to a water/steam cycle to power a steam turbine, as in the steam plant. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the natural gas fuel is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor through a single shaft. Combustion turbines are able to burn a wide range of liquid and gaseous fuels from crude oil to natural gas.

The combustion turbines energy conversion typically ranges between 25% to 35% efficiency as a simple cycle. The simple cycle efficiency can be increased by installing a recuperator or waste heat boiler onto the turbine's exhaust. A *recuperator* captures waste heat in the turbine exhaust stream to preheat the compressor discharge air before it enters the combustion chamber. *A waste heat boiler* generates steam by capturing heat from the turbine exhaust. These boilers are known as heat recovery steam generators (HRSG). High-pressure steam from these boilers is used to generate power with steam turbines, which is where the term "combined cycle" originated.

Natural gas combustion turbine development increased in the 1930's as a means of jet aircraft propulsion. In the early 1980's, the efficiency and reliability of gas turbines had progressed sufficiently to be widely adopted for stationary power applications. Gas turbines range in size from 30 kW, which are known as *micro-turbines* to 250 MW *industrial frames*.

The gas turbine share of the world power generation market has climbed from 20 % to 40 % of capacity additions over the past 20 years with this technology seeing increased use for base load power generation. Most of this growth can be accredited to large (>500 MW) combined cycle power plants that exhibit low capital cost and high thermal efficiency.

<u>Steam Turbines</u>

The second cycle in a combined cycle power plant is the steam turbine. Steam turbine power plants operate on a Rankine cycle. In a conventional steam turbine, the steam is created by a boiler, where pure water passes through a series of tubes to capture heat from the firebox and then boils under high pressure to become superheated steam. The heat in the firebox is normally provided by burning fossil fuel (e.g. coal, fuel oil or natural gas). However, the heat can also be provided by biomass, solar energy or nuclear fuel. The superheated steam leaving the boiler then enters the steam turbine, where it powers the turbine and connected generator to make electricity.

After the steam expands through the turbine, it exits the back end of the turbine, where it is cooled and condensed back to water in the condenser. This condensate is then returned to the boiler through high-pressure feed pumps for reuse. Heat from the condensing steam is normally rejected from the condenser to a body of water, such as a river or cooling tower.

Steam turbine plants generally have a history of achieving up to 95% availability and can operate for more than a year between shutdowns for maintenance and inspections. Their unplanned or forced outage rates are typically less than 2% or less than one week per year. Modern large steam turbine plants (over 500 MW) have efficiencies approaching 40-45%.

Heat Recovery Steam Generator

A heat recovery steam generator or HRSG (pronounced "Her Sig") is an energy recovery heat exchanger that recovers heat from a hot gas stream. It produces steam that can be used in a process or used to drive a steam turbine. The HRSG also separates the caustic compounds in the flue gases from the equipment that uses the waste heat. HRSG's are a key component in combined cycle power plants.

A common application for an HRSG is in a combined-cycle power station, where hot exhaust from a gas turbine is fed to an HRSG to generate steam which in turn drives a steam turbine.

This combination produces electricity more efficiently than either the gas turbine or steam turbine alone. Another application for an HRSG is in diesel engine combined cycle power plants, where hot exhaust from a diesel engine, as primary source of energy, is fed to an HRSG to generate steam which in turn drives a steam turbine. The HRSG is also an important component in cogeneration plants. Cogeneration plants typically have a higher overall efficiency in comparison to a combined cycle plant.

Modular HRSG consist of four major components: the evaporator, superheater, economizer and water preheater. The different components are put together to meet the operating requirements of the unit. The most important component is the *Evaporator Section*. Without this coil, the unit would not be an HRSG. In a HRSG, a main heat transfer component is referred to as a 'section'. When the section is broken into more than one segment, i.e., such as for a change in tube size, material, extended surface, location, etc., it is referred to as 'coils. So, an evaporator section may consist of one or more coils. In these coils, water, passing through the tubes is heated to the saturation point for the pressure it is flowing.

The *Superheater Section* of the HRSG is used to dry the saturated vapor being separated in the steam drum. In some units it may only be heated to a little above the saturation point where in other units it may be superheated to a significant temperature for additional energy storage. The Superheater Section is normally located in the hotter gas stream, in front of the evaporator.

The *Economizer Section*, sometimes called a preheater or preheat coil, is used to preheat the feedwater being introduced to the system to replace the steam being removed from the system via the superheater or steam outlet and the water loss through blowdown. It is normally located in the colder gas downstream of the evaporator. Since the evaporator inlet and outlet temperatures are both close to the saturation temperature for the system pressure, the amount of heat that may be removed from the flue gas is limited due to the approach to the evaporator, known as the *pinch*, whereas the economizer inlet temperature is low, allowing the flue gas temperature to be taken lower.

With a combined cycle plant, no air preheater is needed for the boiler. Hence, the only way to reduce final stack gas exit temperature to a sufficiently low level is to absorb the heat in the feedwater with economizer recovery equipment. Inlet feedwater temperature must be limited to do this.

See the attached illustration (Figure 6) of a Modular HRSG provided by the Cleaver-Brooks Company.

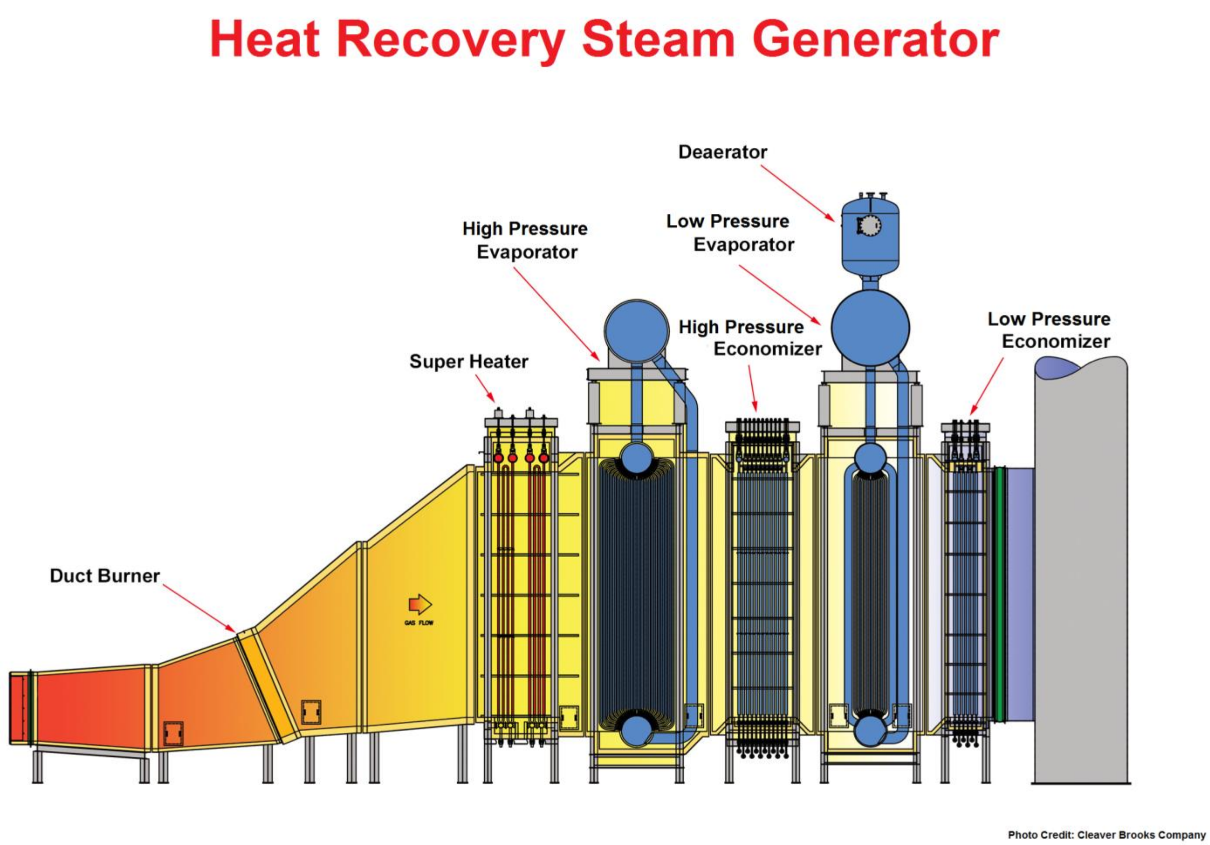


Figure 6

Modular HRSGs can be categorized in a number of ways such as the direction of exhaust gas flows or the number of pressure levels. Based on the flow of exhaust gases, HRSGs are categorized into vertical and horizontal types. In *horizontal type HRSGs*, exhaust gas flows horizontally over vertical tubes whereas in *vertical type HRSGs* exhaust gas flow vertically over horizontal tubes.

Based on pressure levels, HRSGs can be categorized into single pressure and multi-pressure units. *Single pressure HRSGs* have only one steam drum and steam are generated at single pressure level whereas *multi-pressure HRSGs* employ two (double pressure) or three (triple pressure) steam drums. Triple pressure HRSGs consist of three sections: an LP (low pressure) section, a reheat/IP (intermediate pressure) section, and an HP (high pressure) section. Each section has a steam drum and an evaporator section where water is converted to steam. This steam then passes through super-heaters to raise the temperature and pressure past the saturation point.

A specialized type of HRSG without boiler drums is the *Once Through Steam Generator*. In this design, the inlet feedwater follows a continuous path without segmented sections for economizers, evaporators and super-heaters. This provides a high degree of flexibility as the sections are allowed to grow or contract based on the heat load being received from the gas turbine. The absence of drums allows for quick changes in steam production and fewer variables to control and is ideal for cycling and base load operation.

Some HRSGs include *supplemental*, or *duct firing*. The burners provide additional energy to the HRSG, which produces more steam and hence increases the output of the steam turbine. Generally, duct firing provides electrical output at lower capital cost. It is therefore often utilized for peaking operations. Gas turbine mass flows are fairly constant, but exhaust temperature falls off rapidly as load is reduced. Therefore, decreasing amounts of steam are generated in the waste heat boiler. Variations in gas turbine generator output affect the output from the steam turbine generator unless supplementary fuel is fired to adjust the temperature. Supplementary fuel firing, however, decreases combined cycle efficiency because of the increased boiler stack gas losses associated with the constant mass flow of the turbine.

HRSGs can also have diverter valves to regulate in the inlet flow into the HRSG. This allows the gas turbine to continue to operate when there is no steam demand or if the HRSG needs to be taken offline.

Emissions controls may also be located in the HRSG. Some may contain a Selective Catalytic Reduction (SCR) system to reduce nitrogen oxides and/or a catalyst to remove carbon monoxide. The inclusion of an SCR dramatically affects the layout of the HRSG. NOx catalysts perform best in temperatures between 340C and 400C. This usually means that the evaporator section of the HRSG will have to be split and the SCR placed in between the two sections. Some low temperature NOx catalysts have recently come to market that allows for the SCR to be placed between the Evaporator and Economizer sections.

Overview of a Combined Cycle Power Plant

In this section we will look at the complete operating cycle for a typical 600 MW combined cycle power plant from the air intake to the exhaust system. Please refer to Figure 7, on the next page to follow the discussion. The numbers in this section correspond to the labels on the drawing in Figure 7.

1. Air Inlet

The amount of air needed for combustion in a typical 600 MW combined cycle power plant is in the range of 800,000 cubic feet per minute. This air is drawn though the large air inlet section where it is cleaned, cooled and controlled, in order to reduce noise.

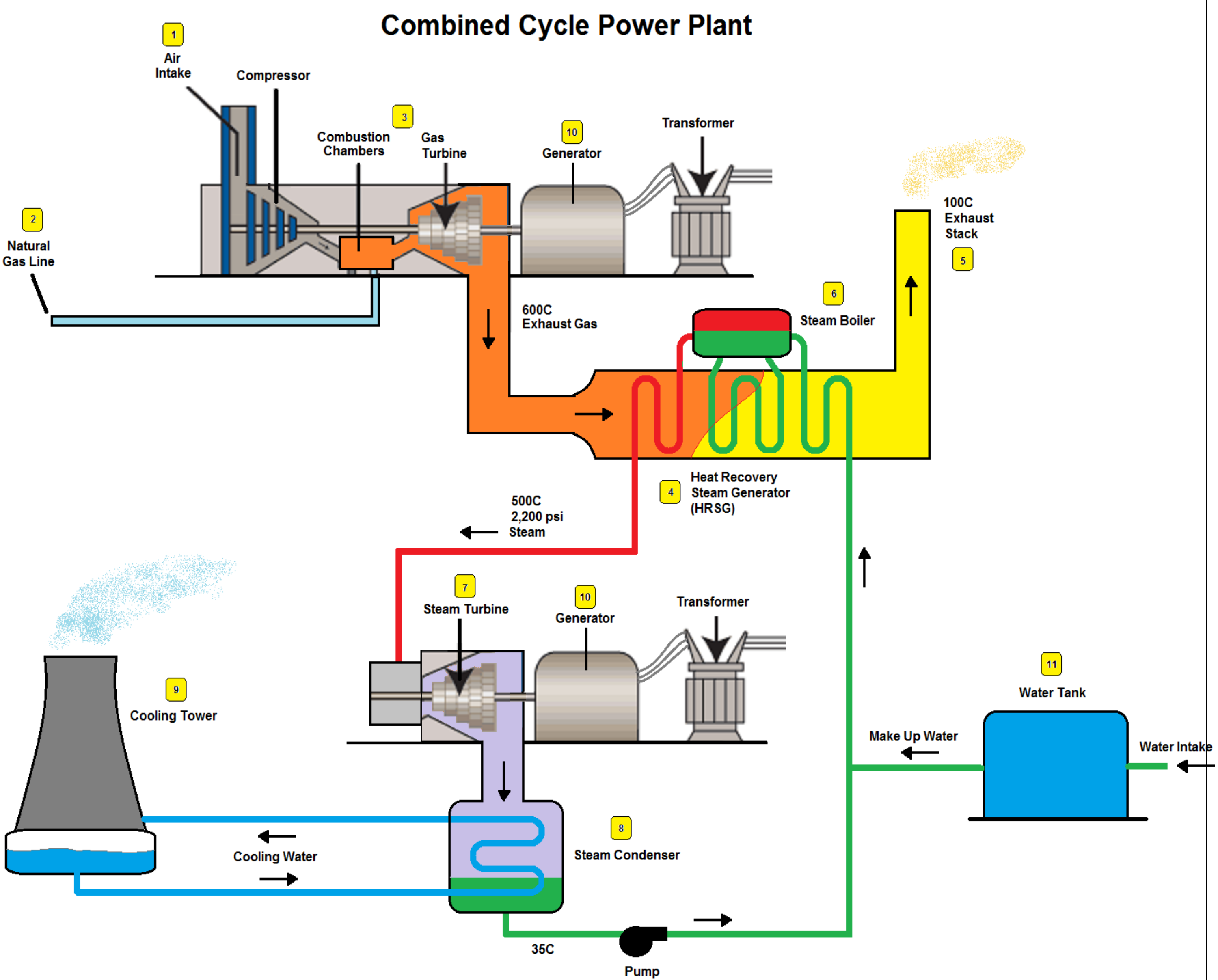
2. Natural Gas

The natural gas fuel comes from a high-pressure natural gas pipeline. A turbine may consume up to 2,000 MMBTU of natural gas per hour. Gas compressors pump the natural gas though the facilities' fuel gas system where it is delivered to the gas turbine and maybe the HRSG duct burners at the proper temperature, pressure and purity.

3. Combustion Turbine

The air then enters the gas turbine where it is compressed, mixed with natural gas and ignited, which causes it to expand. The pressure created from the expansion spins the turbine blades, which are attached to a shaft and a generator, creating electricity. The combustion turbine produces enormous amounts of waste heat that would normally be vented into the atmosphere.

Figure 7



Combined Cycle Power Plant
1
Air Intake
Compressor
3
Combustion Chambers
Gas Turbine
10
Generator
Transformer
2
Natural Gas Line
100C Exhaust Stack
5
600C Exhaust Gas
6
Steam Boiler
4
Heat Recovery Steam Generator (HRSG)
500C 2,200 psi Steam
7
Steam Turbine
10
Generator
Transformer
9
Cooling Tower
11
Water Tank
Make Up Water
Water Intake
Cooling Water
8
Steam Condenser
35C
Pump

4. Heat Recovery Steam Generator (HRSG)

The hot exhaust gas exits the combustion turbine at about 600C and then passes through the Heat Recovery Steam Generator (HRSG).

In the HRSG, there are layers of tall tube bundles, filled with high purity water. The hot exhaust gas coming from the turbines passes through these tube bundles, which act like a radiator, boiling the water inside the tubes, and turning that water into steam.

A typical plant gas turbine – HRSG combination may deliver over one million pounds of steam per hour, which is piped to the steam turbine.

5. Exhaust Stack

The gas exhaust from the gas turbine then exits the HRSG through the exhaust stack at less than 100C after having given up most of its heat to the steam process.

To control the emissions in the exhaust gas so that it remains within permitted levels as it enters the atmosphere, the exhaust gas may pass though an SCR located in the HRSG. One catalyst control Carbon Monoxide (CO) emissions and the other catalyst controls Nitrous Oxide (NOx) emissions. In addition to the SCR, some plants use aqueous Ammonia (a mixture of 22% ammonia and 78% water) is injected into system to even further reduce levels of NOx.

6. Boiler and Feedwater System.

Because of the requirement for relatively low temperature feedwater to the combined cycle boiler, usually only one or two stages of feedwater heating are needed. In some cycles, separate economizer circuits in the steam generator are used to heat and de-aerate feedwater while reducing boiler exit gas to an efficient low level.

7. Steam Turbine

Steam enters the turbine with temperatures as high as 500C at pressures of up to 2,200 psia. The pressure of the steam is used to spin turbine blades that are attached to a rotor and a generator, producing additional electricity.

After the steam is spent in the turbine process, the residual steam leaves the turbine at low pressure and low heat, about 35C. This exhaust steam passes into a condenser, to be turned back into water.

8. Condenser

The purpose of the condenser is to turn low energy steam back into pure water for use in the Heat Recovery Steam Generator.

9. Cooling Tower

The cooling tower is used to cool the circulating water that passes through the condenser. The cool basin water absorbs all of the heat from the residual steam after being exhausted from the steam turbine and it is then piped back to the top of the cooling tower.

As the cool water drops into the basin, hot wet air goes out of the stacks. Normally, hot moist air mixes with cooler dry air, and typically a water vapor plume can be formed.

The cooling tower evaporates about 75% of the processed, recycled water and the remainder is returned to the water source.

10. Generators and Transformers

The Gas Turbine and Steam Turbine generators produce power at relatively low voltages, typically less than 25,000 volts. The transformers are used to step the voltage up to transmission voltages of between 115,000 and 230,000 volts.

A small amount of generation is directed to *Auxiliary transformer,* which convert the generated voltage to a lower voltage, so it may be used by the plant to power pumps, fans, and motors. The auxiliary power used for the plant may be in the range of 15 MW.

11. Water Tanks

Water tanks are used in some plants to store water for treatment prior to running through the plant. The water from the water tank is pumped to the water treatment building where it then passes through a reverse osmosis unit, a membrane de-carbonator, and mixed resin bed de-mineralizers to produce several hundred gallons per minute of ultra pure water.

Chapter 3
Environmental

Natural gas produces far lower amounts of sulfur dioxide (SO_2) and nitrous oxides (NO_X) than any other fossil fuel. Still NOx, along with carbon dioxide (CO_2) are the primary environmental concerns with natural gas-fired combined cycle power plants. The plants also use large amounts of water, which is becoming a major issue in many regions of the country.

Carbon Dioxide Emissions

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. A typical combined cycle power plant produces about 0.8 lb CO_2 per kilowatt-hour output, whereas new coal-fired power plants produce about 2.0 lb CO_2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO_2 production.

Natural gas is often described as the cleanest fossil fuel, producing less carbon dioxide per unit of energy delivered than either coal or oil, and far fewer pollutants than other fossil fuels. However, in absolute terms it does contribute to global carbon emissions, and this contribution is projected to grow. In recent years CO2 from coal has fallen almost 9% while CO2 for natural gas have increased by about 1% and continues to grow.

In addition, natural gas itself is a greenhouse gas far more potent than carbon dioxide when released into the atmosphere, although released in much smaller quantities. Natural gas is mainly composed of methane, which has a radiative forcing twenty times greater than carbon dioxide. This means one ton of methane in the atmosphere traps in as much radiation as 20 tons of carbon dioxide. Carbon dioxide still receives the lion's share of attention over greenhouse gases because it is released in much larger amounts. Still, it is inevitable in using natural gas on a large scale that some of it will leak into the atmosphere.

Water Consumption

Water consumption for power plant condenser cooling appears to be an issue of increasing importance. Significant reduction in plant water consumption can be achieved by the use of closed-cycle *dry cooling*, but at a cost and performance penalty. Over time it appears likely that an increasing number of new combined-cycle projects will use dry cooling.

Nitrous Oxide (NO_X)

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). A few rare combined cycle power plants operate on fuel oil which may produce sulfur dioxide.

Because the turbine combustors in a combined cycle power plant operate at very high temperatures the units produce high levels of NOx.

Nitrogen oxide abatement is accomplished by use of “dry low-NOx” combustors and a selective catalytic reduction system within the HSRG. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst within the HSRG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas.

For environmentally sensitive applications where extremely low NOx emissions are required, selective catalytic reduction (SCR) can be readily adapted to single-shaft combined-cycle systems. SCRs require a gas temperature range lower than the gas turbine exhaust gas temperature, so they are installed in the HRSG in the appropriate zone to suit their operating temperature range. The single-shaft combined-cycle does not have an exhaust gas bypass stack, so the exhaust gas passes through the SCR for reducing NOx emissions at all times.

Regulations require that NOx be limited to no more than nine parts per million and modern combined cycle power plants typically achieve NOx emissions of less than two parts per million.

Summary

Natural gas is a vital fuel for maintaining America's thriving, robust economy and new natural gas resources will continue to allow natural gas to be a choice fuel for electric power generation for many years. To meet growing demand and to diversify our energy supply, the United States needs to continue to exploit the benefits of shale gas as well as bring in natural gas from overseas in the form of liquefied natural gas (LNG). For more than 50 years, LNG has been safely and securely shipped to our shores, where it is used as a reliable fuel for a variety of purposes including electricity generation, heating and cooling homes, cooking food, and much more.

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade and will continue to be a significant source of central station power generation for many years. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combined-cycle plants. Secondary factors include water availability, ambient air quality and elevation.

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