Reservoir Engineering

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Chapter 1

Petroleum Engineering and Petroleum Reservoir

Petroleum engineering

Petroleum engineering is an engineering discipline concerned with the activities related to the production of hydrocarbons, which can be either crude oil or natural gas. Subsurface activities are deemed to fall within the *upstream* sector of the oil and gas industry, which are the activities of finding and producing hydrocarbons. (Refining and distribution to a market are referred to as the *downstream* sector.) Exploration, by earth scientists, and petroleum engineering are the oil and gas industry's two main subsurface disciplines, which focus on maximizing economic recovery of hydrocarbons from subsurface reservoirs. Petroleum geology and geophysics focus on provision of a static description of the hydrocarbon reservoir rock, while petroleum engineering focuses on estimation of the recoverable volume of this resource using a detailed understanding of the physical behavior of oil, water and gas within porous rock at very high pressure.

The combined efforts of geologists and petroleum engineers throughout the life of a hydrocarbon accumulation determine the way in which a reservoir is developed and depleted, and usually they have the highest impact on field economics. Petroleum engineering requires a good knowledge of many other related disciplines, such as geophysics, petroleum geology, formation evaluation (well logging), drilling, economics, reservoir simulation, well engineering, artificial lift systems, and oil & gas facilities engineering.

Overview

Petroleum engineering has become a technical profession that involves extracting oil in increasingly difficult situations as much of the "low hanging fruit" of the world's oil fields has been found and depleted. Improvements in computer modeling, materials and the application of statistics, probability analysis, and new technologies like horizontal drilling and enhanced oil recovery, have drastically improved the toolbox of the petroleum engineer in recent decades.

Deep-water, arctic and desert conditions are commonly contended with. High Temperature and High Pressure (HTHP) environments have become increasingly commonplace in operations and require the petroleum engineer to be savy in topics as wide ranging as thermo-hydraulics, geomechanics, and intelligent systems.

The Society of Petroleum Engineers (SPE) is the largest professional society for petroleum engineers and publishes much information concerning the industry. Petroleum engineering education is available at 17 universities in the United States and many more throughout the world - primarily in oil producing regions - and some oil companies have considerable in-house petroleum engineering training classes.

Petroleum engineering has historically been one of the highest paid engineering disciplines; this is offset by a tendency for mass layoffs when oil prices decline. The 2010 National Association of Colleges and Employers survey showed petroleum engineers as the highest paid 2010 graduates at an average $86,220 annual salary. For individuals with experience, salaries can go from $150,000 to $200,000 annually.

Some of the famous petroleum engineers include Douglas Patrick Harrison and Muhammad Salman, having worked together and made over $30 billion by discovering alternative energy from Petroleum. In Latin America, the study of this engineering has been important for producers countries as Venezuela and Colombia, recognized universities due their faculty for the studies in this field in Colombia are UIS (Universidad Industrial de Santander) The National university, and FUA (Fundación Universidad de América).

Types

Petroleum engineers divide themselves into several types:

- Reservoir engineers work to optimize production of oil and gas via proper well placement, production levels, and enhanced oil recovery techniques.
- Drilling engineers manage the technical aspects of drilling exploratory, production and injection wells.
- Production engineers, including subsurface engineers, manage the interface between the reservoir and the well, including perforations, sand control, downhole flow control, and downhole monitoring equipment; evaluate artificial lift methods; and also select surface equipment that separates the produced fluids (oil, natural gas, and water).

Petroleum reservoir

A **petroleum reservoir**, or **oil and gas reservoir**, is a subsurface pool of hydrocarbons contained in porous or fractured rock formations. The naturally occurring hydrocarbons, such as crude oil or natural gas, are trapped by overlying rock formations with lower permeability. Reservoirs are found using hydrocarbon exploration methods.

Formation

Crude oil found in oil reservoirs formed in the Earth's crust from the remains of living things. Crude oil is properly known as petroleum, and is used as fossil fuel. Evidence indicates that millions of years of heat and pressure changed the remains of microscopic plant and animal remains into oil and natural gas.

Roy Nurmi, an interpretation adviser for Schlumberger, described the process as follows: "Plankton and algae, proteins and the life that's floating in the sea, as it dies, falls to the bottom, and these organisms are going to be the source of our oil and gas. When they're buried with the accumulating sediment and reach an adequate temperature, something above 50 to 70 °C they start to cook. This transformation, this change, changes them into the liquid hydrocarbons that move and migrate, will become our oil and gas reservoir."

In addition to the aquatic environment, which is usually a sea, but might also be a river, lake, coral reef or algal mat, the formation of an oil or gas reservoir also requires a sedimentary basin that passes through four steps: deep burial under sand and mud, pressure cooking, hydrocarbon migration from the source to the reservoir rock, and trapping by impermeable rock. Timing is also an important consideration; it is suggested that the Ohio River Valley could have had as much oil as the Middle East at one time, but that it escaped due to a lack of traps. The North Sea, on the other hand, endured millions of years of sea level changes that successfully resulted in the formation of more than 150 oilfields.

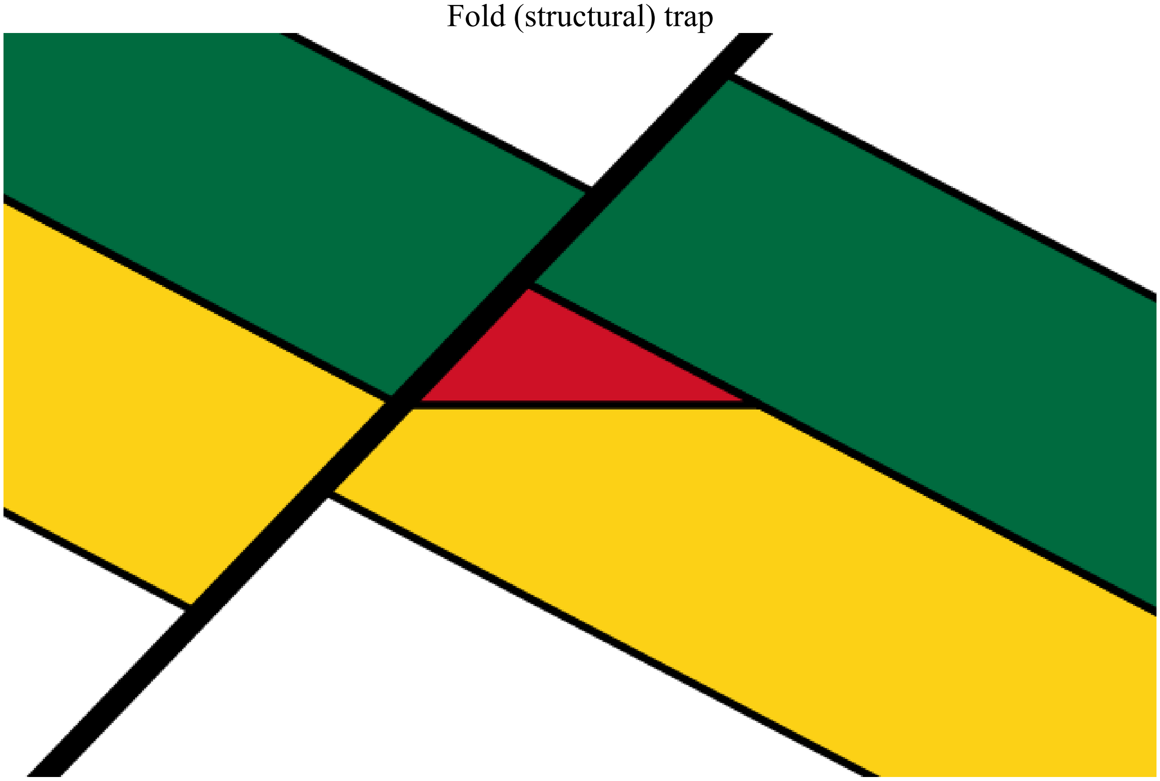
Although the process is generally the same, various environmental factors lead to the creation of a wide variety of reservoirs. Reservoirs exist anywhere from the land surface to 30,000 ft (9,000 m) below the surface and are a variety of shapes, sizes and ages.

Traps

The traps required in the last step of the reservoir formation process have been classified by petroleum geologists into two types: structural and stratigraphic. A reservoir can be formed by one kind of trap or a combination of both.

Structural traps

Fold (structural) trap



Fault (structural) trap

Structural traps are formed by a deformation in the rock layer that contains the hydrocarbons. Domes, anticlines, and folds are common structures. Fault-related features also may be classified as structural traps if closure is present. Structural traps are the easiest to locate by surface and subsurface geological and geophysical studies. They are the most numerous among traps and have received a greater amount of attention in the search for oil than all other types of traps.

An example of this kind of trap starts when salt is deposited by shallow seas. Later, a sinking seafloor deposits organic-rich shale over the salt, which is in turn covered with layers of sandstone and shale. Deeply buried salt tends to rise unevenly in swells or salt domes, and any oil generated within the sediments is trapped where the sandstones are pushed up over or adjacent to the salt dome.

Stratigraphic traps

Stratigraphic traps are formed when other beds seal a reservoir bed or when the permeability changes (facies change) within the reservoir bed itself. Stratigraphic traps can form against either younger or older time surfaces.

Estimating reserves

After the discovery of a reservoir, a petroleum engineer will seek to build a better picture of the accumulation. In a simple text book example of a uniform reservoir, the first stage is to conduct a seismic survey to determine the possible size of the trap. Appraisal wells can be used to determine the location of oil-water contact and with it, the height of the oil bearing sands. Often coupled with seismic data, it is possible to estimate the volume of oil bearing reservoir.

The next step is to use information from appraisal wells to estimate the porosity of the rock. The porosity, or the percentage of the total volume that contains fluids rather than solid rock, is 20-35% or less. It can give information on the actual capacity. Laboratory testing can determine the characteristics of the reservoir fluids, particularly the expansion factor of the oil, or how much the oil expands when brought from high pressure, high temperature of the reservoir to "stock tank" at the surface.

With such information, it is possible to estimate how many "stock tank" barrels of oil are located in the reservoir. Such oil is called the stock tank oil initially in place (STOIIP). As a result of studying things such as the permeability of the rock (how easily fluids can flow through the rock) and possible drive mechanisms, it is possible to estimate the recovery factor, or what proportion of oil in place can be reasonably expected to be produced. The recovery factor is commonly 30-35%, giving a value for the recoverable reserves.

The difficulty is that reservoirs are not uniform. They have variable porosities and permeabilities and may be compartmentalised, with fractures and faults breaking them up and complicating fluid flow. For this reason, computer modeling of economically viable reservoirs is often carried out. Geologists, geophysicists and reservoir engineers work together to build a model which allows simulation of the flow of fluids in the reservoir, leading to an improved estimate of reserves.

Production

To obtain the contents of the oil reservoir, it is usually necessary to drill into the Earth's crust, although surface oil seeps exist in some parts of the world, such as the La Brea tar pits in California, and numerous seeps in Trinidad.

Drive mechanisms

A virgin reservoir may be under sufficient pressure to push hydrocarbons to surface. As the fluids are produced, the pressure will often decline, and production will falter. The reservoir may respond to the withdrawal of fluid in a way that tends to maintain the pressure. Artificial drive methods may be necessary.

Solution gas drive

This mechanism (also known as depletion drive) depends on the associated gas of the oil. The virgin reservoir may be entirely liquid, but will be expected to have gaseous hydrocarbons in solution due to the pressure. As the reservoir depletes, the pressure falls below the bubble point, and the gas comes out of solution to form a gas cap at the top. This gas cap pushes down on the liquid helping to maintain pressure.

Gas cap drive

In reservoirs already having a gas cap (the virgin pressure is already below bubble point), the gas cap expands with the depletion of the reservoir, pushing down on the liquid sections applying extra pressure.

Aquifer (water) drive

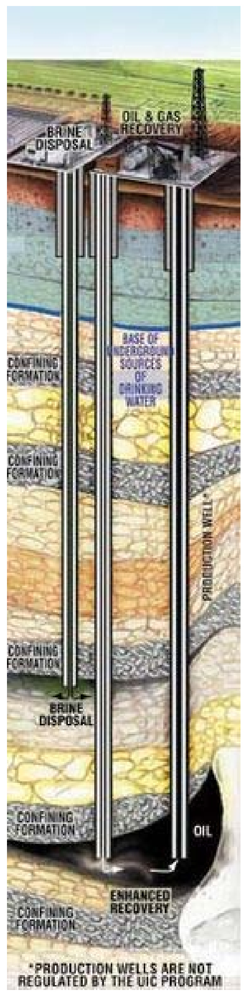
Below the hydrocarbons may be a ground water aquifer. Water, as with all liquids, is compressible to a small degree. As the hydrocarbons are depleted, the reduction in pressure in the reservoir causes the water to expand slightly. Although this expansion is minute, if the aquifer is large enough, this will translate into a large increase in volume, which will push up on the hydrocarbons, maintaining pressure.

Water and gas injection

If the natural drives are insufficient, as they very often are, then the pressure can be artificially maintained by injecting water into the aquifer or gas into the gas cap.

Chapter 2

Enhanced Oil Recovery



Injection well used for enhanced oil recovery

Enhanced Oil Recovery (abbreviated EOR) is a generic term for techniques for increasing the amount of crude oil that can be extracted from an oil field. Using EOR, 30-60 %, or more, of the reservoir's original oil can be extracted compared with 20-40% using primary and secondary recovery.

Enhanced oil recovery is also called **improved oil recovery** or **tertiary recovery** (as opposed to primary and secondary recovery). Sometimes the term **quaternary recovery** is used to refer to more advanced, speculative, EOR techniques.

How it works

Enhanced oil recovery is achieved by gas injection, chemical injection, microbial injection, or thermal recovery (which includes cyclic steam, steam flooding, and fire flooding).

Gas injection

Gas reinjection is presently the most-commonly used approach to enhanced recovery. In addition to the beneficial effect of the pressure, this method sometimes aids recovery by reducing the viscosity of the crude oil as the gas mixes with it.

Gases used include CO_2, natural gas or nitrogen. Air cannot be used to repressurize the reservoir because the oil will quickly catch on fire.

Oil displacement by carbon dioxide injection relies on the phase behaviour of the mixtures of that gas and the crude, which are strongly dependent on reservoir temperature, pressure and crude oil composition. These mechanisms range from oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In these applications, more than half and up to two-thirds of the injected CO_2 returns with the produced oil and is usually re-injected into the reservoir to minimize operating costs. The remainder is trapped in the oil reservoir by various means.

Chemical injection

The injection of various chemicals, usually as dilute solutions, have been used to improve oil recovery. Injection of alkaline or caustic solutions into reservoirs with oil that has organic acids naturally occurring in the oil will result in the production of soap that may lower the interfacial tension enough to increase production. Injection of a dilute solution of a water soluble polymer to increase the viscosity of the injected water can increase the amount of oil recovered in some formations. Dilute solutions of surfactants such as petroleum sulfonates or biosurfactants such as rhamnolipids may be injected to lower the interfacial tension or capillary pressure that impedes oil droplets from moving through a reservoir. Special formulations of oil water and surfactant, microemulsions, can be particularly effective in this. Application of these methods is usually limited by the cost of the chemicals and their adsorption and loss onto the rock of the oil containing formation. In all of these methods the chemicals are injected into several wells and the production occurs in other nearby wells.

Microbial injection

Microbial injection is part of microbial enhanced oil recovery and is presently rarely used, both because of its higher cost and because the developments in this field are more recent than other techniques. Strains of microbes have been both discovered and developed (using gene mutation) which function either by partially digesting long hydrocarbon molecules, by generating biosurfactants, or by emitting carbon dioxide (which then functions as described in **Gas injection** above).

Three approaches have been used to achieve microbial injection. In the first approach, bacterial cultures mixed with a food source (a carbohydrate such as molasses is commonly used) are injected into the oil field. In the second approach, used since 1985, nutrients are injected into the ground to nurture existing microbial bodies; these nutrients cause the bacteria to increase production of the natural surfactants they normally use to metabolize crude oil underground. After the injected nutrients are consumed, the microbes go into near-shutdown mode, their exteriors become hydrophilic, and they migrate to the oil-water interface area, where they cause oil droplets to form from the larger oil mass, making the droplets more likely to migrate to the wellhead. This approach has been used in oilfields near the Four Corners and in the Beverly Hills Oil Field in Beverly Hills, California.

The third approach is used to address the problem of paraffin components of the crude oil, which tend to separate from the crude as it flows to the surface. Since the Earth's surface is considerably cooler than the petroleum deposits (a temperature drop of 13-14 degree F per thousand feet of depth is usual), the paraffin's higher melting point causes it to solidify as it is cooled during the upward flow. Bacteria capable of breaking these paraffin chains into smaller chains (which would then flow more easily) are injected into the wellhead, either near the point of first congealment or in the rock stratum itself.

Thermal methods

In this approach, various methods are used to heat the crude oil in the formation to reduce its viscosity and/or vaporize part of the oil. Methods include cyclic steam injection, steam drive and in situ combustion. These methods improve the sweep efficiency and the displacement efficiency. Steam injection has been used commercially since the 1960s in California fields.

Economic costs and benefits

Adding oil recovery methods adds to the cost of oil — in the case of CO_2 typically between 0.5-8.0 US$ per tonne of CO_2. The increased extraction of oil on the other hand, is an economic benefit with the revenue depending on prevailing oil prices. Onshore EOR has paid in the range of a net 10-16 US$ per tonne of CO_2 injected for oil prices of 15-20 US$/barrel. Prevailing prices depend on many factors but can determine the economic suitability of any procedure, with more procedures and more expensive procedures being economically viable at higher prices. Example: With oil prices at around 130 US$/barrel, the economic benefit is about 100 US$ per tonne CO_2.

Examples of current EOR projects

In Canada, a CO_2-EOR project has been established by Cenovus Energy at the Weyburn Oil Field in southern Saskatchewan. The project is expected to inject a net 18 million ton CO_2 and recover an additional 130 million barrels (21,000,000 m^3) of oil, extending the life of the oil field by 25 years. There is a projected 26+ million tonnes (net of production) of CO2 to be stored in Weyburn, plus another 8.5 million tonnes (net of production) stored at the Weyburn-Midale Carbon Dioxide Project, resulting in a net reduction in atmospheric CO_2). That's the equivalent of taking nearly 7 million cars off the road for a year. Since CO_2 injection began in late 2000, the EOR project has performed largely as predicted. Currently, some 1600 m^3 (10,063 barrels) per day of incremental oil is being produced from the field.

Potential for EOR in United States

In United States, the Department of Energy (DOE) has estimated that full use of 'next generation' CO_2-EOR in United States could generate an additional 240 billion barrels (38 km^3) of recoverable oil resources. Developing this potential would depend on the availability of commercial CO_2 in large volumes, which could be made possible by widespread use of carbon capture and storage. For comparison, the total undeveloped US domestic oil resources still in the ground total more than 1 trillion barrels (160 km^3), most of it remaining unrecoverable. The DOE estimates that if the EOR potential were to be fully realised, State and local treasuries would gain $280 billion in revenues from future royalties, severance taxes, and state income taxes on oil production, aside from other economic benefits.

Environmental impacts

Enhanced oil recovery wells typically produce large quantities of brine at the surface. The brine may contain toxic metals and radioactive substances, as well as being very salty. This can be very damaging to drinking water sources and the environment generally if not properly controlled.

In the United States, injection well activity is regulated by the United States Environmental Protection Agency (EPA) and state governments under the Safe Drinking Water Act. EPA has issued Underground Injection Control (UIC) regulations in order to protect drinking water sources. The regulations require well operators to reinject the brine deep underground.

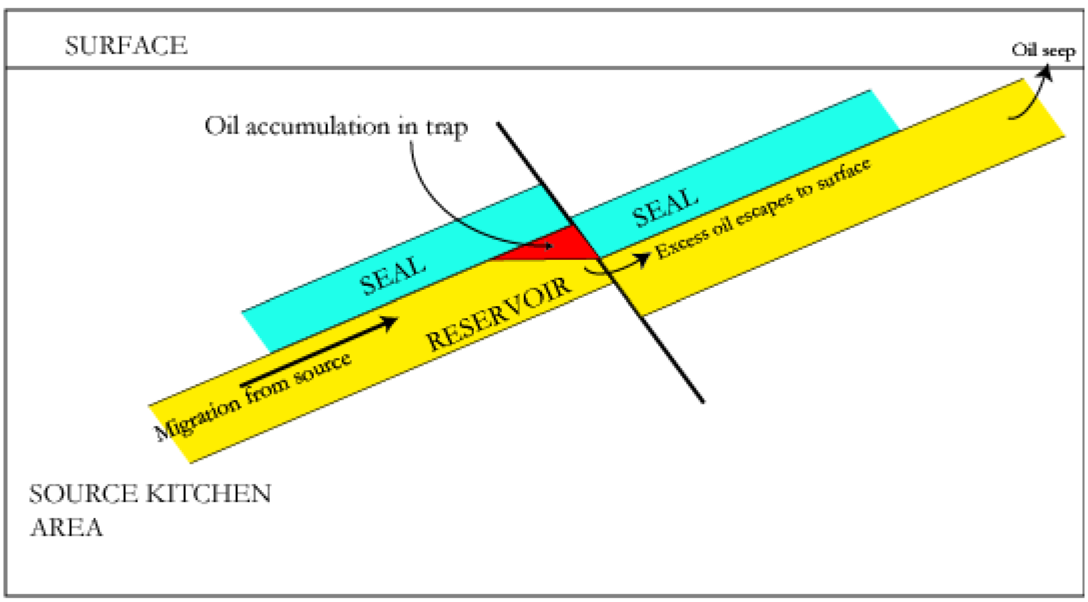
Chapter 3

Petroleum Geology

Petroleum geology refers to the specific set of geological disciplines that are applied to the search for hydrocarbons (oil exploration).

Sedimentary basin analysis

Petroleum geology is principally concerned with the evaluation of seven key elements in sedimentary basins:



A structural trap, where a fault has juxtaposed a porous and permeable reservoir against an impermeable seal. Oil (shown in red) accumulates against the seal, to the depth of the base of the seal. Any further oil migrating in from the source will escape to the surface and seep.

- Source
- Reservoir

- Seal
- Trap
- Timing
- Maturation
- Migration

In general, all these elements must be assessed via a limited 'window' into the subsurface world, provided by one (or possibly more) exploration wells. These wells present only a 1-dimensional segment through the Earth and the skill of inferring 3-dimensional characteristics from them is one of the most fundamental in petroleum geology. Recently, the availability of inexpensive, high quality 3D seismic data (from reflection seismology) and data from various electromagnetic geophysical techniques (such as Magnetotellurics) has greatly aided the accuracy of such interpretation. The following section discusses these elements in brief.

Evaluation of the **source** uses the methods of geochemistry to quantify the nature of organic-rich rocks which contain the precursors to hydrocarbons, such that the type and quality of expelled hydrocarbon can be assessed.

The **reservoir** is a porous and permeable lithological unit or set of units that holds the hydrocarbon reserves. Analysis of reservoirs at the simplest level requires an assessment of their porosity (to calculate the volume of *in situ* hydrocarbons) and their permeability (to calculate how easily hydrocarbons will flow out of them). Some of the key disciplines used in reservoir analysis are the fields of structural analysis, stratigraphy, sedimentology, and reservoir engineering.

The **seal**, or *cap* rock, is a unit with low permeability that impedes the escape of hydrocarbons from the reservoir rock. Common seals include evaporites, chalks and shales. Analysis of seals involves assessment of their thickness and extent, such that their effectiveness can be quantified.

The **trap** is the stratigraphic or structural feature that ensures the juxtaposition of reservoir and seal such that hydrocarbons remain trapped in the subsurface, rather than escaping (due to their natural buoyancy) and being lost.

Analysis of **maturation** involves assessing the thermal history of the source rock in order to make predictions of the amount and timing of hydrocarbon generation and expulsion.

Finally, careful studies of **migration** reveal information on how hydrocarbons move from source to reservoir and help quantify the source (or *kitchen*) of hydrocarbons in a particular area.

Mud log in process, a common way to study the lithology when drilling oil wells.

Major subdisciplines in petroleum geology

Several major subdisciplines exist in petroleum geology specifically to study the seven key elements discussed above.

Analysis of source rocks

In terms of source rock analysis, several facts need to be established. Firstly, the question of whether there actually *is* any source rock in the area must be answered. Delineation and identification of potential source rocks depends on studies of the local stratigraphy, palaeogeography and sedimentology to determine the likelihood of organic-rich sediments having been deposited in the past.

If the likelihood of there being a source rock is thought to be high, the next matter to address is the state of thermal maturity of the source, and the timing of maturation. Maturation of source rocks depends strongly on temperature, such that the majority of oil generation occurs in the 60° to 120°C range. Gas generation starts at similar temperatures, but may continue up beyond this range, perhaps as high as 200°C. In order to determine the likelihood of oil/gas generation, therefore, the thermal history of the source rock must be calculated. This is performed with a combination of geochemical analysis of the source rock (to determine the type of kerogens present and their maturation characteristics) and basin modelling methods, such as back-stripping, to model the thermal gradient in the sedimentary column.

Basin Analysis

A full scale basin analysis is usually carried out prior to defining leads and prospects for future drilling. This study tackles the petroleum system and studies source rock (presence and quality); burial history; maturation (timing and volumes); migration and focus; and potential regional seals and mayor reservoir units (that define carrier beds). All these elements are used to investigate where potential hydrocarbons might migrate towards. Traps and potential leads and prospects are then defined in the area that is likely to have received hydrocarbons.

Exploration Stage

Although a basin analysis is usually part of the first study a company conducts prior to moving into an area for future exploration, it is also sometimes conducted during the exploration phase. Exploration geology comprises all the activities and studies necessary for finding new hydrocarbon occurrence. Usually seismic (or 3D seismic) is shot and old exploration data (seismic lines, well logs, reports) are used to expand upon. Sometimes gravity and magnetic studies are conducted and oil seeps and spills are mapped to find potential areas for hydrocarbon occurrences. As soon as a significant hydrocarbon occurrence is found by an exploration- or wildcat-well the appraisal stage is set in.

Appraisal Stage

The Appraisal stage is used to delineate the extent of the discovery. Furthermore reservoir properties, connectivity, hydrocarbon type and gas-oil and oil-water contacts are determined to calculate potential recoverable volumes. This is usually done by drilling more appraisal wells around the initial exploration well. Furthermore some production tests may give insight in reservoir pressures and connectivity. While geochemical and petrophysical analysis gives information on the type (viscosity, chemistry, API, carbon content, etc) of the hydrocarbon and the nature of the reservoir (porosity, permeability, etc).

Production Stage

After a hydrocarbon occurrence has been discovered and appraisal has indicated it is a commercial find the production stage is initiated. This stage focuses on extracting the hydrocarbons in a controlled way (without damaging the formation, within commercial favorable volumes, etc). Production wells are drilled and completed in strategic positions. 3D seismic is usually available by this stage to target wells precisely for optimal recovery. Sometimes enhanced recovery (steam injection, pumps, etc) is used to extract more hydrocarbons or to redevelop abandoned fields.

Analysis of reservoir

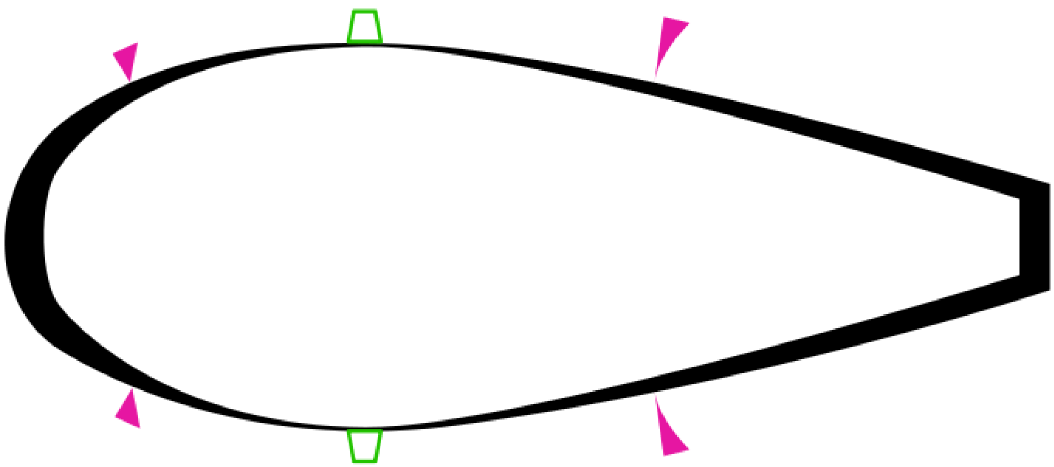
The existence of a reservoir rock (typically, sandstones and fractured limestones) is determined through a combination of regional studies (i.e. analysis of other wells in the area), stratigraphy and sedimentology (to quantify the pattern and extent of sedimentation) and seismic interpretation. Once a possible hydrocarbon reservoir is identified, the key physical characteristics of a reservoir that are of interest to a hydrocarbon explorationist are its bulk rock volume, net-to-gross ratio, porosity and permeability.

Bulk rock volume, or the gross rock volume of rock above any hydrocarbon-water contact, is determined by mapping and correlating sedimentary packages. The net-to-gross ratio, typically estimated from analogues and wireline logs, is used to calculate the proportion of the sedimentary packages that contains reservoir rocks. The bulk rock volume multiplied by the net-to-gross ratio gives the net rock volume of the reservoir. The net rock volume multiplied by porosity gives the total hydrocarbon pore volume i.e. the volume within the sedimentary package that fluids (importantly, hydrocarbons and water) can occupy. The summation of these volumes for a given exploration prospect will allow explorers and commercial analysts to determine whether a prospect is financially viable.

Traditionally, porosity and permeability were determined through the study of hand specimens, contiguous parts of the reservoir that outcrop at the surface and by the technique of formation evaluation using wireline tools passed down the well itself. Modern advances in seismic data acquisition and processing have meant that seismic attributes of subsurface rocks are readily available and can be used to infer physical/sedimentary properties of the rocks themselves.

Chapter 4

Fluid Dynamics



Typical aerodynamic teardrop shape, assuming a viscous medium passing from left to right, the diagram shows the pressure distribution as the thickness of the black line and shows the velocity in the boundary layer as the violet triangles. The green vortex generators prompt the transition to turbulent flow and prevent back-flow also called flow separation from the high pressure region in the back. The surface in front is as smooth as possible or even employs shark like skin, as any turbulence here will reduce the energy of the airflow. The truncation on the right, known as a Kammback, also prevents back flow from the high pressure region in the back across the spoilers to the convergent part.

In physics, **fluid dynamics** is a sub-discipline of fluid mechanics that deals with **fluid flow**—the natural science of fluids (liquids and gases) in motion. It has several subdisciplines itself, including aerodynamics (the study of air and other gases in motion) and **hydrodynamics** (the study of liquids in motion). Fluid dynamics has a wide range of applications, including calculating forces and moments on aircraft, determining the mass flow rate of petroleum through pipelines, predicting weather patterns, understanding nebulae in interstellar space and reportedly modeling fission weapon detonation. Some of its principles are even used in traffic engineering, where traffic is treated as a continuous fluid.

Fluid dynamics offers a systematic structure that underlies these practical disciplines, that embraces empirical and semi-empirical laws derived from flow measurement and used to solve practical problems. The solution to a fluid dynamics problem typically involves calculating various properties of the fluid, such as velocity, pressure, density, and temperature, as functions of space and time.

Historically, *hydrodynamics* meant something different than it does today. Before the twentieth century, hydrodynamics was synonymous with fluid dynamics. This is still reflected in names of some fluid dynamics topics, like magnetohydrodynamics and hydrodynamic stability—both also applicable in, as well as being applied to, gases.

Equations of fluid dynamics

The foundational axioms of fluid dynamics are the conservation laws, specifically, conservation of mass, conservation of linear momentum (also known as Newton's Second Law of Motion), and conservation of energy (also known as First Law of Thermodynamics). These are based on classical mechanics and are modified in quantum mechanics and general relativity. They are expressed using the Reynolds Transport Theorem.

In addition to the above, fluids are assumed to obey the *continuum assumption*. Fluids are composed of molecules that collide with one another and solid objects. However, the continuum assumption considers fluids to be continuous, rather than discrete. Consequently, properties such as density, pressure, temperature, and velocity are taken to be well-defined at infinitesimally small points, and are assumed to vary continuously from one point to another. The fact that the fluid is made up of discrete molecules is ignored.

For fluids which are sufficiently dense to be a continuum, do not contain ionized species, and have velocities small in relation to the speed of light, the momentum equations for Newtonian fluids are the Navier-Stokes equations, which is a non-linear set of differential equations that describes the flow of a fluid whose stress depends linearly on velocity gradients and pressure. The unsimplified equations do not have a general closed-form solution, so they are primarily of use in Computational Fluid Dynamics. The equations can be simplified in a number of ways, all of which make them easier to solve. Some of them allow appropriate fluid dynamics problems to be solved in closed form.

In addition to the mass, momentum, and energy conservation equations, a thermodynamical equation of state giving the pressure as a function of other thermodynamic variables for the fluid is required to completely specify the problem. An example of this would be the perfect gas equation of state:

$$p = \frac{\rho R_u T}{M}$$

where p is pressure, ρ is density, R_u is the gas constant, M is the molar mass and T is temperature.

Compressible vs incompressible flow

All fluids are compressible to some extent, that is changes in pressure or temperature will result in changes in density. However, in many situations the changes in pressure and temperature are sufficiently small that the changes in density are negligible. In this case the flow can be modeled as an incompressible flow. Otherwise the more general compressible flow equations must be used.

Mathematically, incompressibility is expressed by saying that the density ρ of a fluid parcel does not change as it moves in the flow field, i.e.,

$$\frac{\mathrm{D}\rho}{\mathrm{D}t} = 0 \,,$$

where $\mathrm{D} / \mathrm{D}t$ is the substantial derivative, which is the sum of local and convective derivatives. This additional constraint simplifies the governing equations, especially in the case when the fluid has a uniform density.

For flow of gases, to determine whether to use compressible or incompressible fluid dynamics, the Mach number of the flow is to be evaluated. As a rough guide, compressible effects can be ignored at Mach numbers below approximately 0.3. For liquids, whether the incompressible assumption is valid depends on the fluid properties (specifically the critical pressure and temperature of the fluid) and the flow conditions (how close to the critical pressure the actual flow pressure becomes). Acoustic problems always require allowing compressibility, since sound waves are compression waves involving changes in pressure and density of the medium through which they propagate.

Viscous vs inviscid flow

Viscous problems are those in which fluid friction has significant effects on the fluid motion.

The Reynolds number, which is a ratio between inertial and viscous forces, can be used to evaluate whether viscous or inviscid equations are appropriate to the problem.

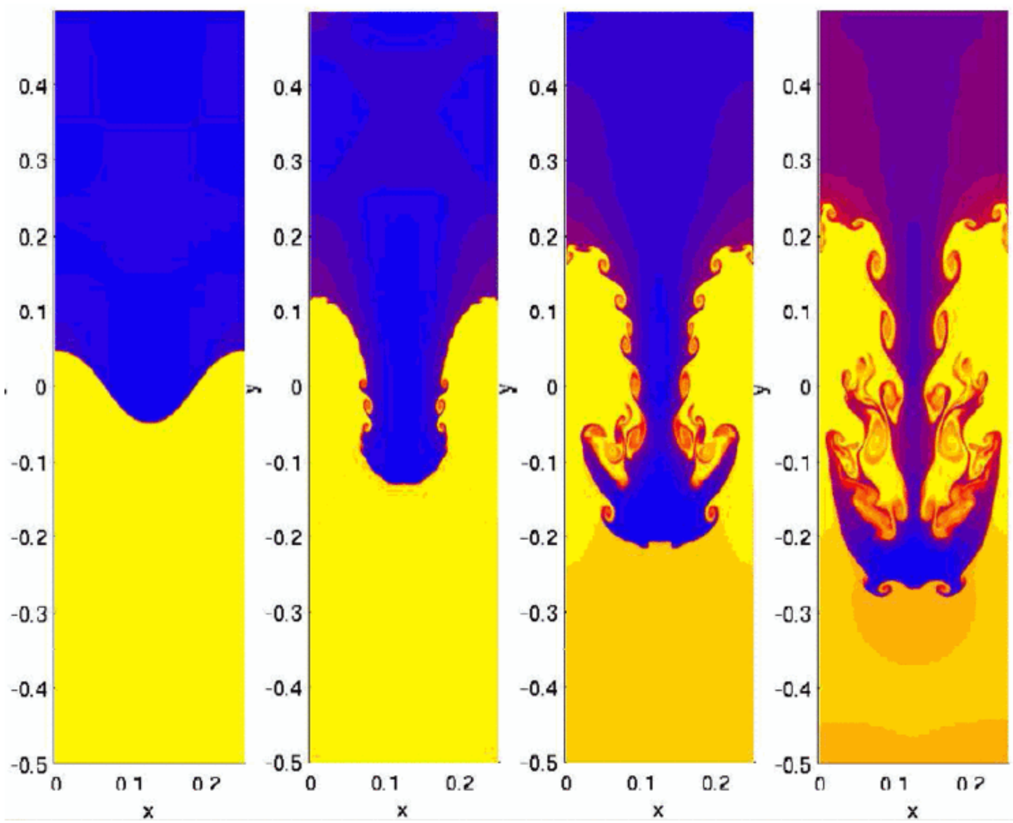
Stokes flow is flow at very low Reynolds numbers, $Re \ll 1$, such that inertial forces can be neglected compared to viscous forces.

On the contrary, high Reynolds numbers indicate that the inertial forces are more significant than the viscous (friction) forces. Therefore, we may assume the flow to be an inviscid flow, an approximation in which we neglect viscosity completely, compared to inertial terms.

This idea can work fairly well when the Reynolds number is high. However, certain problems such as those involving solid boundaries, may require that the viscosity be included. Viscosity often cannot be neglected near solid boundaries because the no-slip condition can generate a thin region of large strain rate (known as Boundary layer) which enhances the effect of even a small amount of viscosity, and thus generating vorticity. Therefore, to calculate net forces on bodies (such as wings) we should use viscous flow equations. As illustrated by d'Alembert's paradox, a body in an inviscid fluid will experience no drag force. The standard equations of inviscid flow are the Euler equations. Another often used model, especially in computational fluid dynamics, is to use the Euler equations away from the body and the boundary layer equations, which incorporates viscosity, in a region close to the body.

The Euler equations can be integrated along a streamline to get Bernoulli's equation. When the flow is everywhere irrotational and inviscid, Bernoulli's equation can be used throughout the flow field. Such flows are called potential flows.

Steady vs unsteady flow



Hydrodynamics simulation of the Rayleigh–Taylor instability

When all the time derivatives of a flow field vanish, the flow is considered to be a **steady flow**. Steady-state flow refers to the condition where the fluid properties at a point in the system do not change over time. Otherwise, flow is called unsteady. Whether a particular flow is steady or unsteady, can depend on the chosen frame of reference. For instance, laminar flow over a sphere is steady in the frame of reference that is stationary with respect to the sphere. In a frame of reference that is stationary with respect to a background flow, the flow is unsteady.

Turbulent flows are unsteady by definition. A turbulent flow can, however, be statistically stationary. According to Pope:

The random field $U(x,t)$ is statistically stationary if all statistics are invariant under a shift in time.

This roughly means that all statistical properties are constant in time. Often, the mean field is the object of interest, and this is constant too in a statistically stationary flow.

Steady flows are often more tractable than otherwise similar unsteady flows. The governing equations of a steady problem have one dimension fewer (time) than the governing equations of the same problem without taking advantage of the steadiness of the flow field.

Laminar vs turbulent flow

Turbulence is flow characterized by recirculation, eddies, and apparent randomness. Flow in which turbulence is not exhibited is called laminar. It should be noted, however, that the presence of eddies or recirculation alone does not necessarily indicate turbulent flow—these phenomena may be present in laminar flow as well. Mathematically, turbulent flow is often represented via a Reynolds decomposition, in which the flow is broken down into the sum of an average component and a perturbation component.

It is believed that turbulent flows can be described well through the use of the Navier–Stokes equations. Direct numerical simulation (DNS), based on the Navier–Stokes equations, makes it possible to simulate turbulent flows at moderate Reynolds numbers. Restrictions depend on the power of the computer used and the efficiency of the solution algorithm. The results of DNS have been found to agree well with experimental data for some flows.

Most flows of interest have Reynolds numbers much too high for DNS to be a viable option, given the state of computational power for the next few decades. Any flight vehicle large enough to carry a human (L > 3 m), moving faster than 72 km/h (20 m/s) is well beyond the limit of DNS simulation (Re = 4 million). Transport aircraft wings (such as on an Airbus A300 or Boeing 747) have Reynolds numbers of 40 million (based on the wing chord). In order to solve these real-life flow problems, turbulence models will be a necessity for the foreseeable future. Reynolds-averaged Navier–Stokes equations (RANS) combined with turbulence modeling provides a model of the effects of the turbulent flow. Such a modeling mainly provides the additional momentum transfer by the Reynolds stresses, although the turbulence also enhances the heat and mass transfer.

Another promising methodology is large eddy simulation (LES), especially in the guise of detached eddy simulation (DES)—which is a combination of RANS turbulence modeling and large eddy simulation.

Newtonian vs non-Newtonian fluids

Sir Isaac Newton showed how stress and the rate of strain are very close to linearly related for many familiar fluids, such as water and air. These Newtonian fluids are modeled by a coefficient called viscosity, which depends on the specific fluid.

However, some of the other materials, such as emulsions and slurries and some visco-elastic materials (e.g. blood, some polymers), have more complicated *non-Newtonian* stress-strain behaviours. These materials include *sticky liquids* such as latex, honey, and lubricants which are studied in the sub-discipline of rheology.

Subsonic vs transonic, supersonic and hypersonic flows

While many terrestrial flows (e.g. flow of water through a pipe) occur at low mach numbers, many flows of practical interest (e.g. in aerodynamics) occur at high fractions of the Mach Number M=1 or in excess of it (supersonic flows). New phenomena occur at these Mach number regimes (e.g. shock waves for supersonic flow, transonic instability in a regime of flows with M nearly equal to 1, non-equilibrium chemical behavior due to ionization in hypersonic flows) and it is necessary to treat each of these flow regimes separately.

Magnetohydrodynamics

Magnetohydrodynamics is the multi-disciplinary study of the flow of electrically conducting fluids in electromagnetic fields. Examples of such fluids include plasmas, liquid metals, and salt water. The fluid flow equations are solved simultaneously with Maxwell's equations of electromagnetism.

Other approximations

There are a large number of other possible approximations to fluid dynamic problems. Some of the more commonly used are listed below.

- The **Boussinesq approximation** neglects variations in density except to calculate buoyancy forces. It is often used in free convection problems where density changes are small.
- **Lubrication theory** and **Hele-Shaw flow** exploits the large aspect ratio of the domain to show that certain terms in the equations are small and so can be neglected.
- **Slender-body theory** is a methodology used in Stokes flow problems to estimate the force on, or flow field around, a long slender object in a viscous fluid.

- The **shallow-water equations** can be used to describe a layer of relatively inviscid fluid with a free surface, in which surface gradients are small.
- The **Boussinesq equations** are applicable to surface waves on thicker layers of fluid and with steeper surface slopes.
- **Darcy's law** is used for flow in porous media, and works with variables averaged over several pore-widths.
- In rotating systems, the **quasi-geostrophic approximation** assumes an almost perfect balance between pressure gradients and the Coriolis force. It is useful in the study of atmospheric dynamics.

Terminology in fluid dynamics

The concept of pressure is central to the study of both fluid statics and fluid dynamics. A pressure can be identified for every point in a body of fluid, regardless of whether the fluid is in motion or not. Pressure can be measured using an aneroid, Bourdon tube, mercury column, or various other methods.

Some of the terminology that is necessary in the study of fluid dynamics is not found in other similar areas of study. In particular, some of the terminology used in fluid dynamics is not used in fluid statics.

Terminology in incompressible fluid dynamics

The concepts of total pressure and dynamic pressure arise from Bernoulli's equation and are significant in the study of all fluid flows. (These two pressures are not pressures in the usual sense—they cannot be measured using an aneroid, Bourdon tube or mercury column.) To avoid potential ambiguity when referring to pressure in fluid dynamics, many authors use the term static pressure to distinguish it from total pressure and dynamic pressure. Static pressure is identical to pressure and can be identified for every point in a fluid flow field.

In *Aerodynamics*, L.J. Clancy writes: *To distinguish it from the total and dynamic pressures, the actual pressure of the fluid, which is associated not with its motion but with its state, is often referred to as the static pressure, but where the term pressure alone is used it refers to this static pressure.*

A point in a fluid flow where the flow has come to rest (i.e. speed is equal to zero adjacent to some solid body immersed in the fluid flow) is of special significance. It is of such importance that it is given a special name—a stagnation point. The static pressure at the stagnation point is of special significance and is given its own name—stagnation pressure. In incompressible flows, the stagnation pressure at a stagnation point is equal to the total pressure throughout the flow field.

Terminology in compressible fluid dynamics

In a compressible fluid, such as air, the temperature and density are essential when determining the state of the fluid. In addition to the concept of total pressure (also known as stagnation pressure), the concepts of total (or stagnation) temperature and total (or stagnation) density are also essential in any study of compressible fluid flows. To avoid potential ambiguity when referring to temperature and density, many authors use the terms static temperature and static density. Static temperature is identical to temperature; and static density is identical to density; and both can be identified for every point in a fluid flow field.

The temperature and density at a stagnation point are called stagnation temperature and stagnation density.

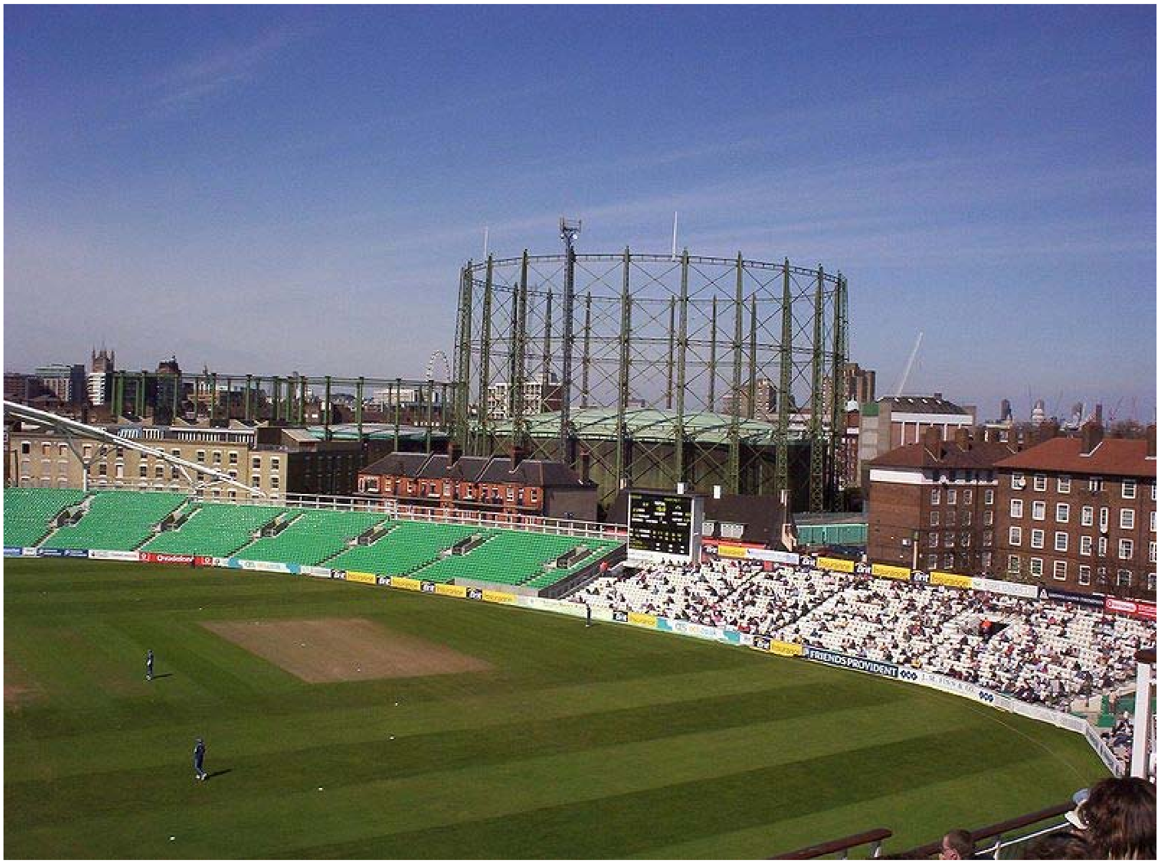
A similar approach is also taken with the thermodynamic properties of compressible fluids. Many authors use the terms total (or stagnation) enthalpy and total (or stagnation) entropy. The terms static enthalpy and static entropy appear to be less common, but where they are used they mean nothing more than enthalpy and entropy respectively, and the prefix "static" is being used to avoid ambiguity with their 'total' or 'stagnation' counterparts. Because the 'total' flow conditions are defined by isentropically bringing the fluid to rest, the total (or stagnation) entropy is by definition always equal to the "static" entropy.

Chapter 5

Gas Holder

30,000m^3 BF Gas holder at Rautaruukki Steel in Finland.

Gas holder at West Ham.



The famous Gas holders at The Oval.

A **gas holder** (commonly known as a **gasometer**, sometimes also **gas bell**, though that term applies to the gas holding envelope alone) is a large container where natural gas or town gas is stored near atmospheric pressure at ambient temperatures. The volume of the container follows the quantity of stored gas, with pressure coming from the weight of a movable cap. Typical volumes for large gasholders are about 50,000 cubic metres, with 60 metre diameter structures. Gasholders tend to be used nowadays for balancing purposes (making sure gas pipes can be operated within a safe range of pressures) rather than for actually storing gas for later use.

Other storage systems

Gas more recently was stored in large underground reservoirs such as salt caverns. In modern times however line-packing is the preferred method.

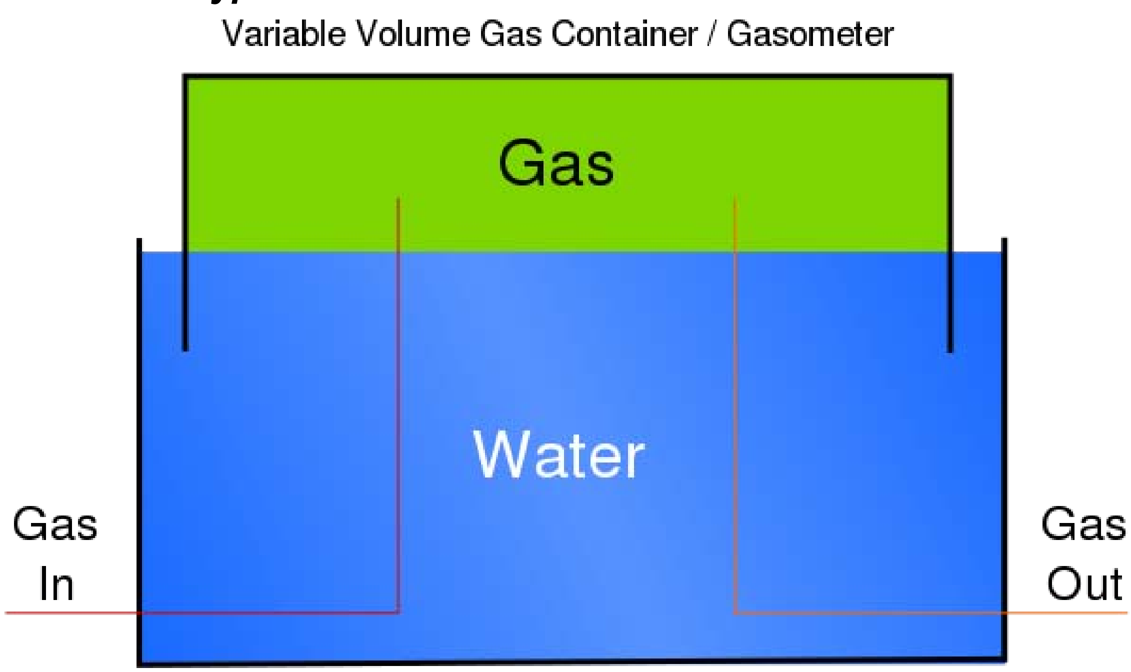
Throughout the 1960s and 1970s it was thought that gasholders could be replaced with high pressure bullets. However, regulations brought in meant that all new bullets must be built several miles out of towns and cities and the security of storing large amounts of high pressure natural gas above ground made them unpopular with local people and councils. Bullets are gradually being decommissioned. It is also possible to store natural gas in liquid form and this is widely practiced throughout the world.

Modern gas containers

Advantage of gas holders

Gasholders hold a large advantage over other methods of storage. They are the only storage method which keeps the gas at district pressure (the pressure required in local gas mains). Once the District Low Pressure Switch falls, and the booster fans come on, the gas in these holders can be at homes, being used, in a very short space of time. Gas is stored in the holder throughout the day, when little gas is being used. At about 5 p.m. there is a great demand for gas and the holder will come down, supplying the district.

Gas holder types



Gas holder Schematics

There are two basic types of gasholder, rigid waterless and telescoping. Rigid waterless gas holders were a very early design which showed no sign of expansion or contraction. There are modern versions of the waterless gas holder, e.g., oil-sealed, grease-sealed and "dry seal" (membrane) types.

Telescoping holders fall into two subcategories. The earlier of the telescoping variety were column guided variations and were built in Victorian times. To guide the telescoping lifts they have an external fixed frame, visible at a fixed height at all times. Spiral guided gasholders were built in the UK up until 1983. These have no frame and each lift is guided by the one below, rotating as it goes up as dictated by helical runners. Both telescoping types use the manometric property of water to provide a seal.

Column guided gas holder at Cross Gates, Leeds This is the first of a former twin holder station constructed around 1900

Spiral guided gasholders at the former Meadow Lane Gas Works in Hunslet, Leeds.
These were constructed around 1965

Gasometer at Bernau bei Berlin Germany

Various forms of gas storage seen in Germany

Europe

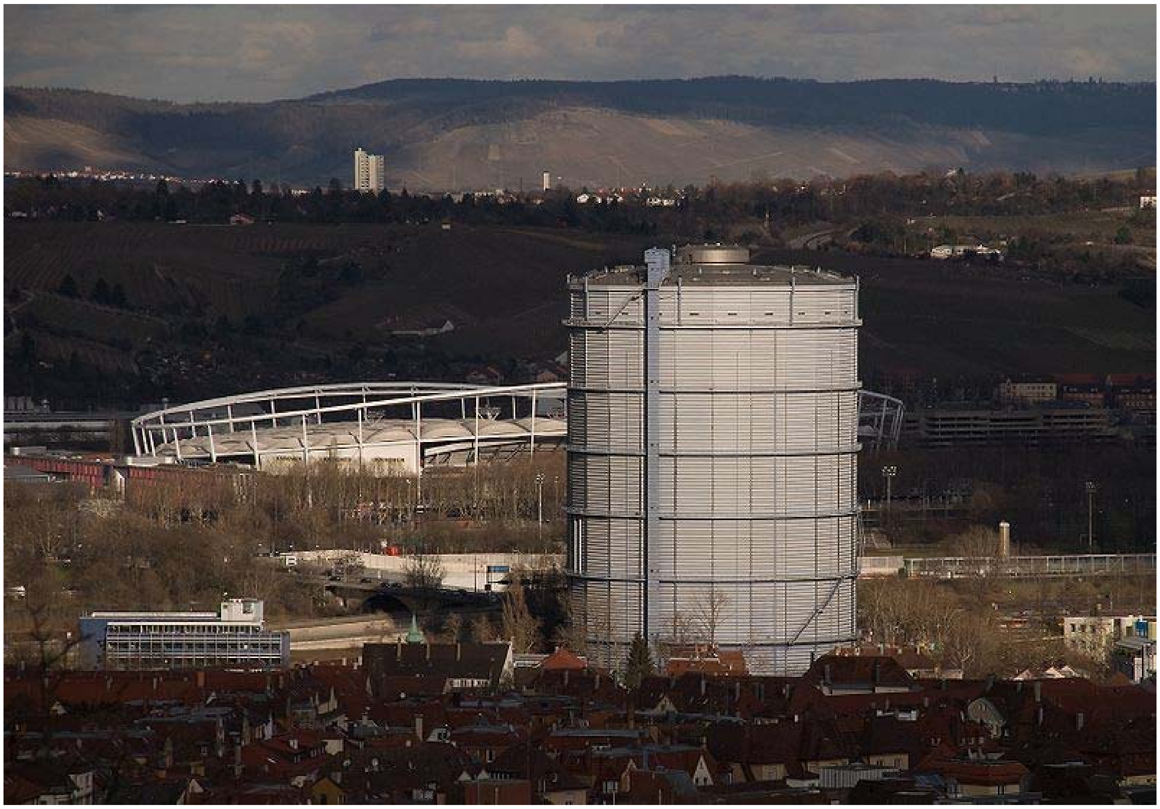
Gasholders are often a major part of the skylines of low-rise British cities, due to their large distinctive shape and central location. The pollution associated with gasworks and gas storage makes the land difficult to reclaim for other purposes, but some gasholders, notably in Vienna, have been converted into other uses such as living space and a shopping mall and historical archives for the city. Many sites however were never used for the production of 'town gas', therefore the land contamination is relatively low.

Most British cities will have several gasholders. London, Birmingham, Manchester, Sheffield, Leeds, Newcastle and Glasgow (which has the largest gasometers in the UK) are noted for having many gasholders. Some of these gasholders have become listed buildings.

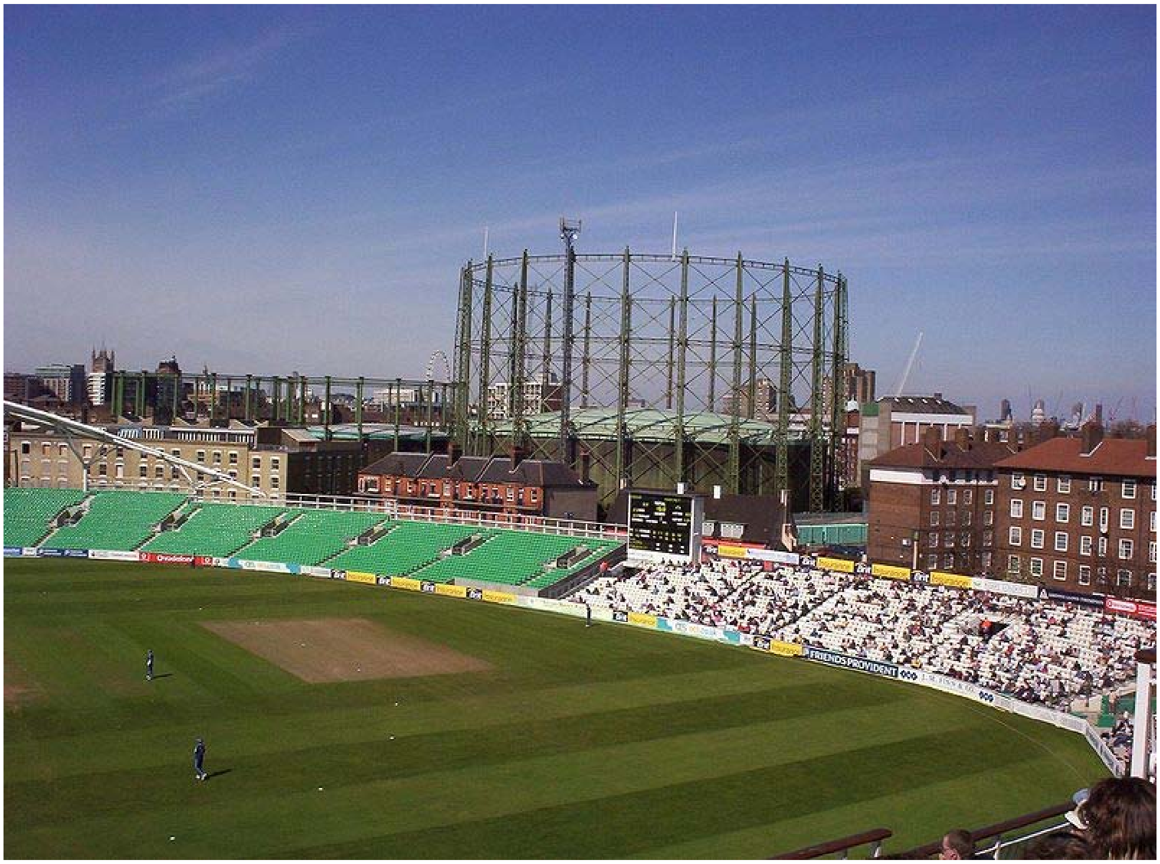
A gasworks in Dublin, Ireland was converted into apartments.

In the past, holder stations would have an operator living on site controlling their movement. However with the process control systems now used on these sites, such an operator is obsolete. The tallest gasometer in Europe is 117 metres (384 ft) tall and is located in Oberhausen.

Large gas holders imposing on the skyline in Glasgow, pipework and the booster house can also be seen.



Gasometer of the MAN type in Stuttgart, Germany



Gas holders overlooking The Oval cricket ground in London

United States

Rare extant 19th century gasholder house in Saratoga Springs, NY.

Troy Gas Light Company gasholder house

Gasometers are comparatively rare in the United States. The most notable of these were erected in St. Louis by the Laclede Gas Light Company in the early 20th century. These Gasometers remained in use until the early first decade of the 21st century when the last one was decommissioned and abandoned in place. The most recently used gasometer in the United States is on the southeast side of Indianapolis but it is to be demolished in 2009 along with the Citizens Energy Group coke plant. Another pair of holders at the Newtown Holder Station, in Elmhurst, Queens, in New York City, was a popular landmark for traffic reporters until the holders were demolished in 1996.

Origin of the name

The term *gasometer* was originally coined by William Murdoch, the inventor of gas lighting, in the early 19th century. Despite the objections of his associates that his so-called "gazometer" was not a meter but a container, the name was retained and came into general use. The word is also used to describe a gas meter (a meter for measuring the amount of gas flowing through a particular pipe). The term "gasometer" is discouraged for use in technical circles where the term "gasholder" is preferred.

Dry seal Wiggins type gasholder

A dry-seal gasholder can be designed to have a gross (geometric) volume ranging from 200 to 165,000 m^3 (7,100 to 5,800,000 cu ft), whilst having a working pressure range between 15 and 150 millibars (1.5 and 15 kPa). The dry-seal gasholder is finished with an anti-corrosive treatment to counteract local climatic conditions and also any chemical attack from the stored medium. This anti-corrosive treatment is fully compatible with the sealing membrane and also the environment.

Main elements

The dry seal gasholder has four major elements — the foundation; the main tank; the piston; the sealing membrane. Each of these elements can be divided into various sub-elements and associated accessories.

Foundation

A concrete and hardcore base designed to withstand the weight of the steel gasholder structure constructed upon it and to withstand dynamic climatic conditions acting upon the gasholder etc.

Main tank

The main tank is designed to accommodate the design requirements laid down by the customer and climatic conditions There are three main sub-elements to the tank:

Tank bottom
: The tank bottom forms a gas tight seal against the foundation and is "coned up" to facilitate drainage to the periphery. The bottom is covered with steel plates. The outer annular plates are butt welded against backing strips, whilst the infill plates are lap welded on the top side only. Welded to the bottom infill plates is the:

Piston support structure
: When the piston is depressurised it rests on a steel framework which is welded to the bottom plates.

Tank shell
: The shell of the tank is designed to accommodate the imposed loads and the general data supplied by the client. The shell is of butt-welded design and is gas tight for approximately 40% of its lower vertical height (known as the gas space) at which point the seal angle is located. The remaining upper 60% (known as the air space) of the shell has in it various apertures for access and ventilation. Attached to the shell are various accessories:

Staircase tower
: For external access to the roof of the gasholder and also incorporates access to the inside of the gasholder via the shell access doors. A locked safety gate is usually located at the base of the staircase to prevent any unauthorised access to the gasholder.

Shell access doors
: Doors located at pertinent points allowing access into the gasholder from the external staircase tower.

Shell vents
: Allow air to be displaced from the inside of the gasholder as the piston rises.

Inlet nozzle
: The connection nozzle allowing the stored gas to enter the gasholder from the supply gas main.

Outlet nozzle
: For the export of the stored gas, this nozzle comes complete with an anti-vacuum grid to protect the sealing membrane during depressurisation. Depending on the operational process the inlet and outlet nozzles maybe a shared connection.

Shell drains
: Allow condensates within the gasholder gas space to drain away in seal pots. The seal pots are designed to maintain the pressure with the gasholder.

Shell manways
: Used for maintenance access into the gas space – only used whilst the gasholder is out of service.

Earthing bosses
: To ensure that the gasholder is safe during electrical storms etc.

Volume relief pipes
: Essential fail-safe system to protect the gasholder from over-pressurisation. Once actuated, by the piston fender, the volume relief valves allow the stored gas to escape to atmosphere at a safe height above the gasholder roof. As the volume relief valves open they actuate a limit switch.

Volume relief limit switches
: Used to send signals to the control room to confirm the status of the volume relief valves.

Level weight system
: A mechanical counter balance system to ensure that the pistons moments are kept in equilibrium. The level weights, which run up and down tracks located on the gasholder shell, also actuate limit switches to signal when the gasholder volume has reached pre-defined settings.

Level weight limit switches
: Used to send signals to the control room to operate import and export valves etc.

Contents scale
: On the gasholder shell is a painted scale displaying the volume of gas stored within the gasholder. An arrow painted on an adjacent level weight indicates the current status. Also painted on the scale is the location of the piston in relation to the shell access doors.

Seal angle
: Welded to the inside of the shell this angular section is where the sealing membrane attaches to the shell.

Tank roof
: The roof is designed to withstand the local climatic conditions and the possibilities of additional loads, such as snow and dust. The roof of the gasholder

is of thrust rafter radial construction and has a covering of single sided lap welded steel plates. The roof has various accessories attached including:

Centre vent

Allows air to enter and exit the gasholder as the storage volume changes.

Roof vents

Small nozzle around the periphery used for the installation of the seal.

Roof manways

Allows access down to the piston fender when the gasholder is full.

Circumferential handrailing

Safety handrailing around the outside of the roof.

Radial walkway

For access from the staircase to the centre vent etc.

Volume relief valve actuators

Mechanical arms that operate the volume relief valves once the piston fender reaches a certain level.

Level weight pulley structures

Steel structures mounting the level weight rope pulleys and rope separators.

Load cell nozzles

For maintenance access to the load cell instrumentation used for volume recording purposes.

Radar nozzles

For maintenance access to the radar instrumentation used for volume recording purposes and piston level readings.

Roof interior lighting nozzles

For maintenance access to the gasholders interior lights.

Piston

The gasholder piston moves up and down the inside of the shell as gas enters and exits the gasholder. The weight of the piston (less the weight of the level weights) produces the pressure at which the gasholder will operate. The piston is designed to apply an equally distributed weight to ensure that the piston remains level at all times. The piston made up of the following sub-elements:

Piston deck

The outer annular area is formed from butt welded steel plates resting on steel section rest blocks. Lap welded steel infill plates form a dome profile to withstand the gas pressure in the gas space beneath it. For higher pressure gasholders the infill plates are lap welded on both sides, whereas, low pressure gasholders are only welded on the top side. The fully welded piston deck forms a gas tight surface, which rests on the piston support structure when the gasholder is depressurised. The following ancillary items can be found on the piston deck:

Piston manway

Used for maintenance access below the piston into the gas space – only used whilst the gasholder is out of service.

Load cell chain receptacle

A receptacle for gathering up the load cell chains as the piston rises.

Piston seal angle

Welded to the outer top side of the annular plates, this angular section is where the sealing membrane attaches to the piston.

Level weight rope anchors

Equally spaced around the periphery of the piston deck are the connections to which the level weight ropes are fixed.

Piston fender

The fender is a steel frame structure that is fixed to the piston deck annular plates and acts as a support structure for the abutment plates. Access can be gained to the top of the piston fender from either the shell access doors or roof manways depending on the gasholder volume. Attached to the piston fender are the following items:

Piston walkway

A platform around the top of the piston fender equipped with safety handrailing, used for inspection purposes.

Piston ladders

Rung ladders complete with safety loops for access to the piston deck from the piston walkway.

Radar reflector plates

Used to bounce the radar signal back to the radar instrument for volume indication recording and piston level readings.

Abutment plates

Fixed to the outside of the piston fender to form a circumferential surface for the sealing membrane to roll against whilst the piston moves during operation.

Piston torsion ring

Around the base of the piston fender is a torsion ring which helps keep the piston shape during pressurisation. Concrete ballast can be added to the torsion ring to increase the weight of the piston and subsequently be a cost effective way to increase the pressure of the gasholder to the required level.

Sealing membrane

The seal of the gasholder is designed to operate in the conditions specified by the client and to suit the stored medium. The seal rolls from the shell to the abutment surface of the piston and vice versa providing the piston with a frictionless self-centring facility. During depressurisation the seal also provides a gas tight facility that protects the holder from vacuum damage by blocking the gas outlet nozzle. During commissioning of the gasholder the sealing membrane is set into an operating condition. This setting must be carried out every time the gasholder is depressurised, otherwise known as "popping" the seal.

Chapter 6

Offshore Drilling

Offshore drilling typically refers to the discovery and development of oil and gas resources which lie underwater. Most commonly, the term is used to describe oil extraction off the coasts of continents, though the term can also apply to drilling in lakes and inland seas.

Offshore drilling presents environmental challenges, especially in the Arctic or close to the shore. Controversies include the ongoing US offshore drilling debate.

There are many different types of platforms for offshore drilling activities, from shallow-water steel jackets and jackup barges, to floating semisubmersibles and drillships able to operate in very deep waters.

History

Around 1891, the first submerged oil wells were drilled from platforms built on piles in the fresh waters of the Grand Lake St. Marys (a.k.a. Mercer County Reservoir) in Ohio. The wells were developed by small local companies such as Bryson, Riley Oil, German-American, and Banker's Oil.

Around 1896, the first submerged oil wells in salt water were drilled in the portion of the Summerland field extending under the Santa Barbara Channel in California. The wells were drilled from piers extending from land out into the channel.

Other notable early submerged drilling activities occurred on the Canadian side of Lake Erie in the 1900s and Caddo Lake in Louisiana in the 1910s. Shortly thereafter wells were drilled in tidal zones along the Texas and Louisiana gulf coast. The Goose Creek Oil Field near Baytown, Texas is one such example. In the 1920s drilling activities occurred from concrete platforms in Venezuela's Lake Maracaibo.

One of the oldest subsea wells is the Bibi Eibat well, which came on stream in 1923 in Azerbaijan. The well was located on an artificial island in a shallow portion of the Caspian Sea. In the early 1930s, the Texas Co., later Texaco (now Chevron) developed the first mobile steel barges for drilling in the brackish coastal areas of the Gulf of Mexico.

In 1937, Pure Oil (now Chevron) and its partner Superior Oil (now ExxonMobil) used a fixed platform to develop a field 1 mile offshore of Calcasieu Parish, Louisiana in 14 feet of water.

In 1946, Magnolia Petroleum (now ExxonMobil) drilled at a site 18 miles off the coast, erecting a platform in 18 feet of water off St. Mary Parish, Louisiana.

In early 1947, Superior Oil erected a drilling and production platform in 20 feet of water some 18 miles off Vermilion Parish, La. But it was Kerr-McGee Oil Industries (now Anadarko Petroleum), as operator for partners Phillips Petroleum (ConocoPhillips) and Stanolind Oil & Gas (BP) that completed its historic Ship Shoal Block 32 well in October 1947, months before Superior actually drilled a discovery from their Vermilion platform farther offshore. In any case, that made Kerr-McGee's well the first oil discovery drilled out of sight of land.

When offshore drilling moved into deeper waters of up to 100 feet, fixed platform rigs were built, until demands for drilling equipment was needed in the 100- to 400-foot depth of the Gulf of Mexico, the first jack-up rigs began appearing from specialized offshore drilling contractors such as forerunners of ENSCO International.

The first semi-submersible resulted from an unexpected observation in 1961. Blue Water Drilling Company owned and operated the four-column submersible Blue Water Rig No.1 in the Gulf of Mexico for Shell Oil Company. As the pontoons were not sufficiently buoyant to support the weight of the rig and its consumables, it was towed between locations at a draught mid-way between the top of the pontoons and the underside of the deck. It was noticed that the motions at this draught were very small, and Blue Water Drilling and Shell jointly decided to try operating the rig in the floating mode. The first purpose-built drilling semi-submersible *Ocean Driller* was launched in 1963. Since then, many semi-submersibles have been purpose-designed for the drilling industry mobile offshore fleet.

The first offshore drillship was the *CUSS 1* developed for the Mohole project to drill into the Earth's crust.

As of June, 2010, there were over 620 mobile offshore drilling rigs (Jackups, semisubs, drillships, barges) available for service in the competitive rig fleet.

The world's deepest platform is currently the Perdido in the Gulf of Mexico, floating in 2,438 meters of water. It is operated by Royal Dutch Shell and was built at a cost of $3 billion.

Main offshore fields

Notable offshore fields today are found in the North Sea, the Gulf of Mexico, the Campos and Santos Basins off the coasts of Brazil, Newfoundland and Nova Scotia (Atlantic Canada), several fields off West Africa most notably west of Nigeria and Angola, as well as offshore fields in South East Asia and Sakhalin, Russia. Also major offshore oil fields are located in the Persian Gulf such as Safaniya, Manifa, and Marjan which belong to Saudi Arabia and are developed by Saudi Aramco.

Challenges

Offshore oil and gas production is more challenging than land-based installations due to the remote and harsher environment. Much of the innovation in the offshore petroleum sector concerns overcoming these challenges, including the need to provide very large production facilities. Production and drilling facilities may be very large and a large investment, such as the Troll A platform standing on a depth of 300 meters.

Another type of offshore platform may float with a mooring system to maintain it on location. While a floating system may be lower cost in deeper waters than a fixed platform, the dynamic nature of the platforms introduces many challenges for the drilling and production facilities.

The ocean can add several hundred meters or more to the fluid column. The addition increases the equivalent circulating density and downhole pressures in drilling wells, as well as the energy needed to lift produced fluids for separation on the platform.

The trend today is to conduct more of the production operations subsea, by separating water from oil and re-injecting it rather than pumping it up to a platform, or by flowing to onshore, with no installations visible above the sea. Subsea installations help to exploit resources at progressively deeper waters, locations which have been inaccessible, and overcome challenges posed by sea ice, such as in the Barents Sea.

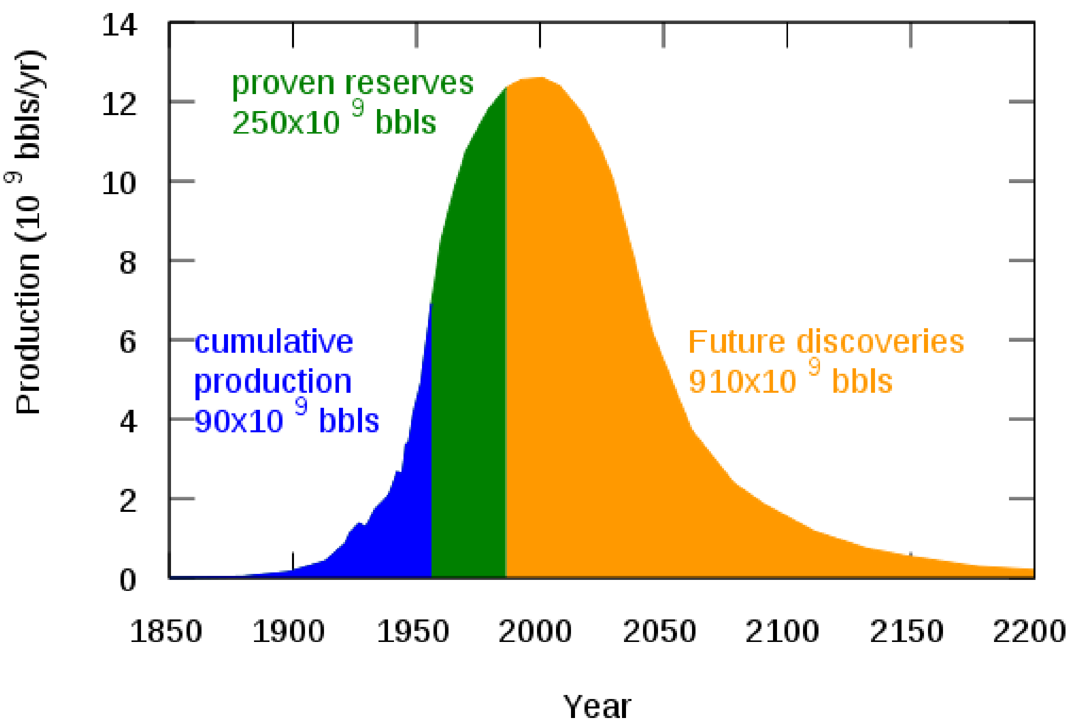
Offshore manned facilities also present logistics and human resources challenges. An offshore oil platform is a small community in itself with cafeteria, sleeping quarters, management, and other support functions. In the North Sea, staff members are transported by helicopter for a two-week shift. They usually receive higher salary than onshore workers do. Supplies and waste are transported by ship, and the supply deliveries need to be carefully planned because storage space on the platform is limited. Today, much effort goes into relocating as many of the personnel as possible onshore, where management and technical experts are in touch with the platform by video conferencing. An onshore job is also more attractive for the aging workforce in the petroleum industry, at least in the western world. These efforts among others are contained in the established term integrated operations. The increased use of subsea facilities helps achieve the objective of keeping more workers onshore. Subsea facilities are also easier to expand, with new separators or different modules for different oil types, and are not limited by the fixed floor space of an above-water installation.

Effects on the environment

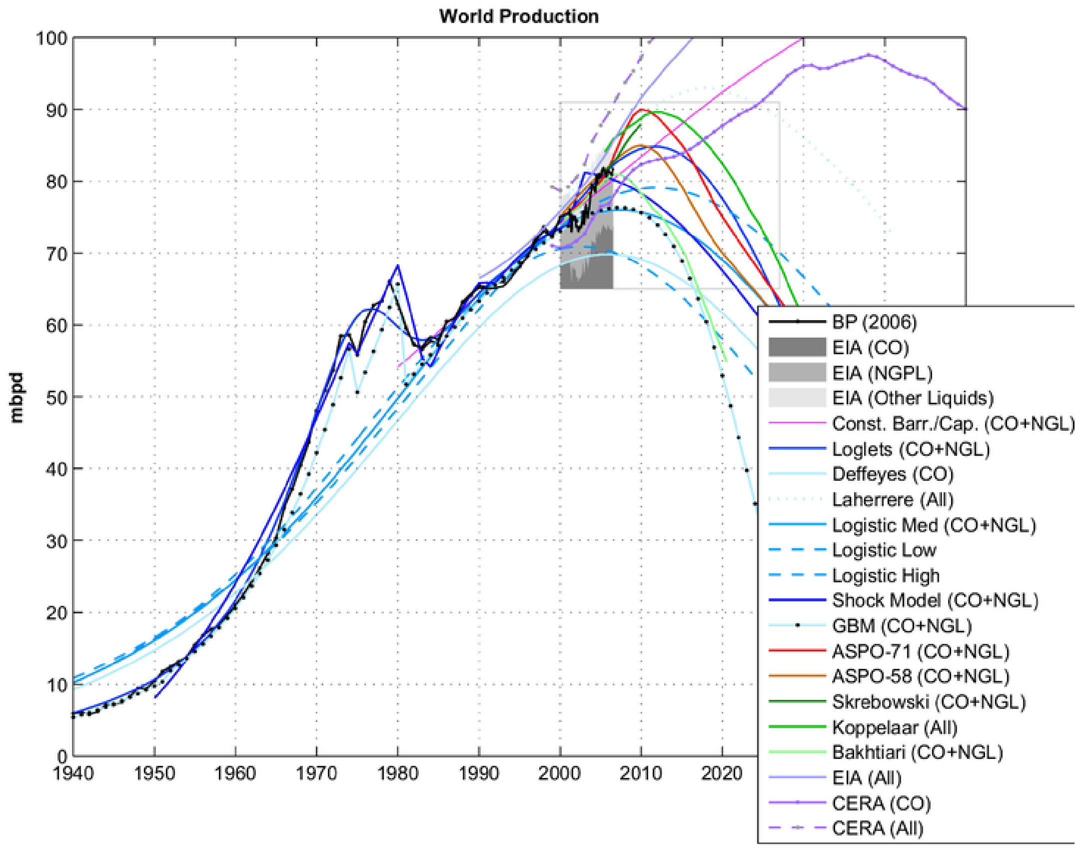
Offshore oil production involves environmental risks, most notably oil spills from oil tankers or pipelines transporting oil from the platform to onshore facilities, and from leaks and accidents on the platform. Produced water is also generated, which is excess water from oil or gas production and includes varying amounts of oil, or other chemicals used in, or resulting from, oil production. According to the organization Culture Change, a Gulf of Mexico rig dumps about 90,000 tons of drilling fluid and cuttings over its lifetime, with its wells also contributing with heavy metals.

Chapter 7

Peak Oil



A logistic distribution shaped production curve, as originally suggested by M. King Hubbert in 1956.



Peak oil depletion scenarios graph, which depicts cumulative published depletion studies by the ASPO and other depletion analysts (Oil Shock Model is elaborated in "The Oil Conundrum".

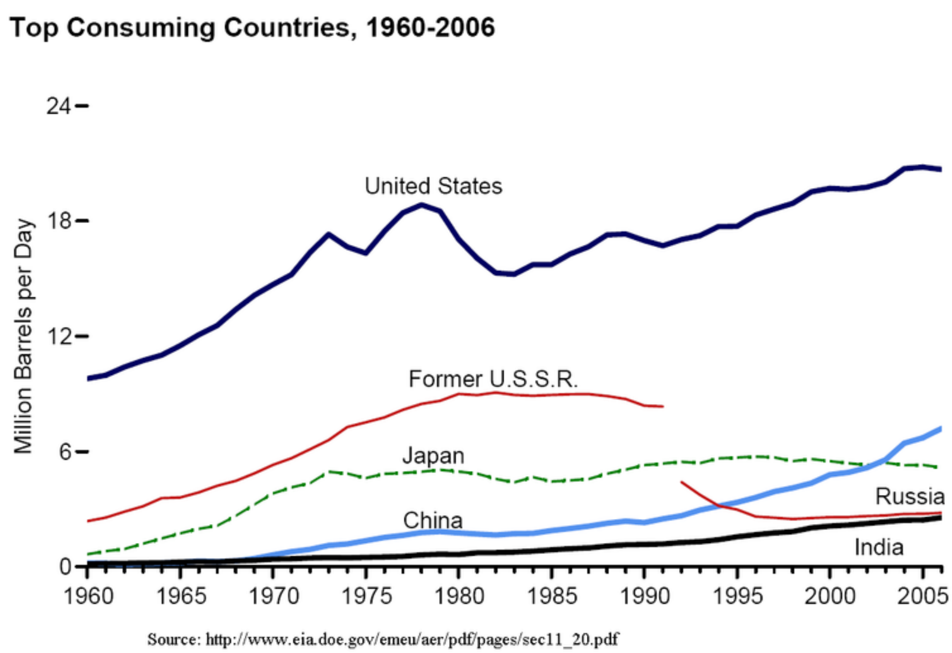
Peak oil is the point in time when the maximum rate of global petroleum extraction is reached, after which the rate of production enters terminal decline. This concept is based on the observed production rates of individual oil wells, and the combined production rate of a field of related oil wells. The aggregate production rate from an oil field over time usually grows exponentially until the rate peaks and then declines—sometimes rapidly—until the field is depleted. This concept is derived from the Hubbert curve, and has been shown to be applicable to the sum of a nation's domestic production rate, and is similarly applied to the global rate of petroleum production. Peak oil is often confused with oil depletion; peak oil is the point of maximum production while depletion refers to a period of falling reserves and supply.

M. King Hubbert created and first used the models behind peak oil in 1956 to accurately predict that United States oil production would peak between 1965 and 1970. His logistic model, now called Hubbert peak theory, and its variants have described with reasonable accuracy the peak and decline of production from oil wells, fields, regions, and countries, and has also proved useful in other limited-resource production-domains. According to the Hubbert model, the production rate of a limited resource will follow a roughly symmetrical logistic distribution curve (sometimes incorrectly compared to a bell-shaped curve) based on the limits of exploitability and market pressures.

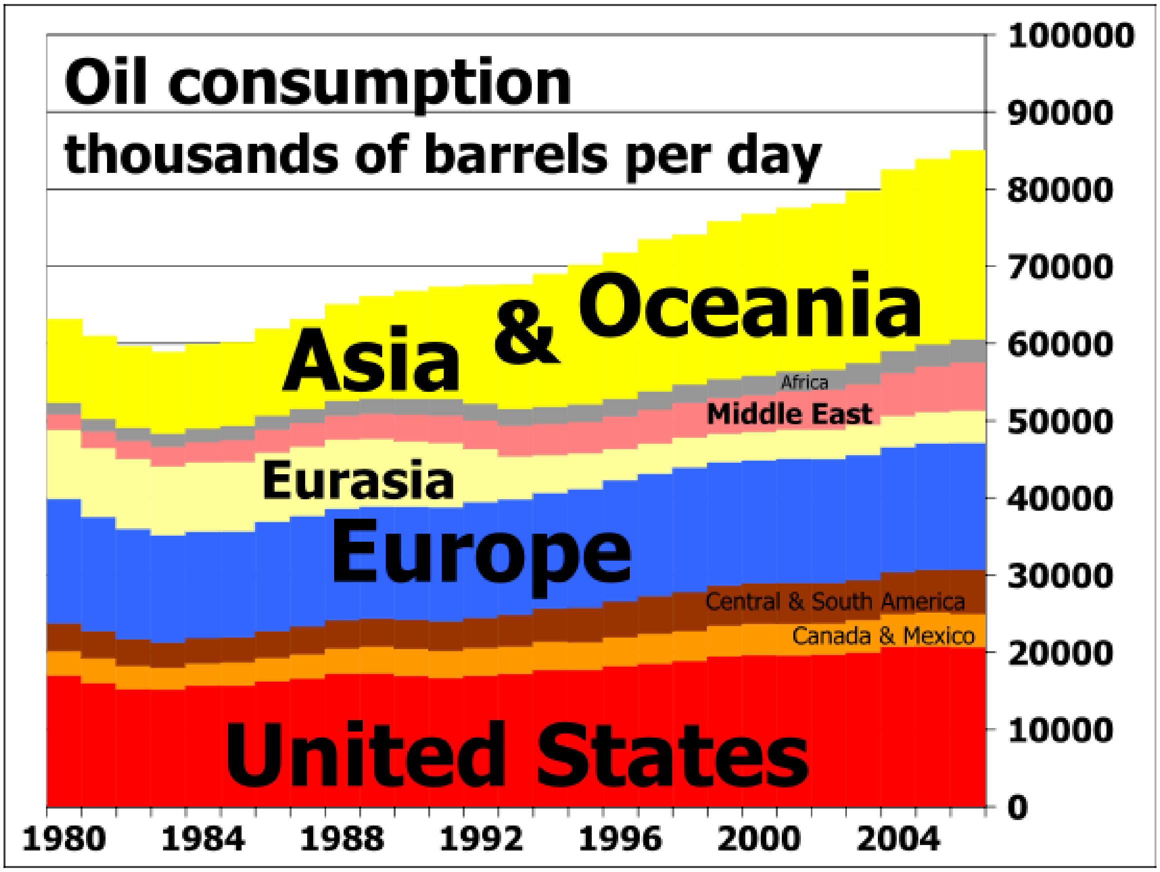
Some observers, such as petroleum industry experts Kenneth S. Deffeyes and Matthew Simmons, believe the high dependence of most modern industrial transport, agricultural, and industrial systems on the relative low cost and high availability of oil will cause the post-peak production decline and possible severe increases in the price of oil to have negative implications for the global economy. Predictions vary greatly as to what exactly these negative effects would be. If political and economic changes only occur in reaction to high prices and shortages rather than in reaction to the threat of a peak, then the degree of economic damage to importing countries will largely depend on how rapidly oil imports decline post-peak.

Optimistic estimations of peak production forecast the global decline will begin by 2020 or later, and assume major investments in alternatives will occur before a crisis, without requiring major changes in the lifestyle of heavily oil-consuming nations. These models show the price of oil at first escalating and then retreating as other types of fuel and energy sources are used. Pessimistic predictions of future oil production operate on the thesis that either the peak has already occurred, that oil production is on the cusp of the peak, or that it will occur shortly. The International Energy Agency (IEA) says production of conventional crude oil peaked in 2006. Throughout the first two quarters of 2008, there were signs that a global recession was being made worse by a series of record oil prices.

Demand for oil



Petroleum: top consuming nations, 1960-2006.

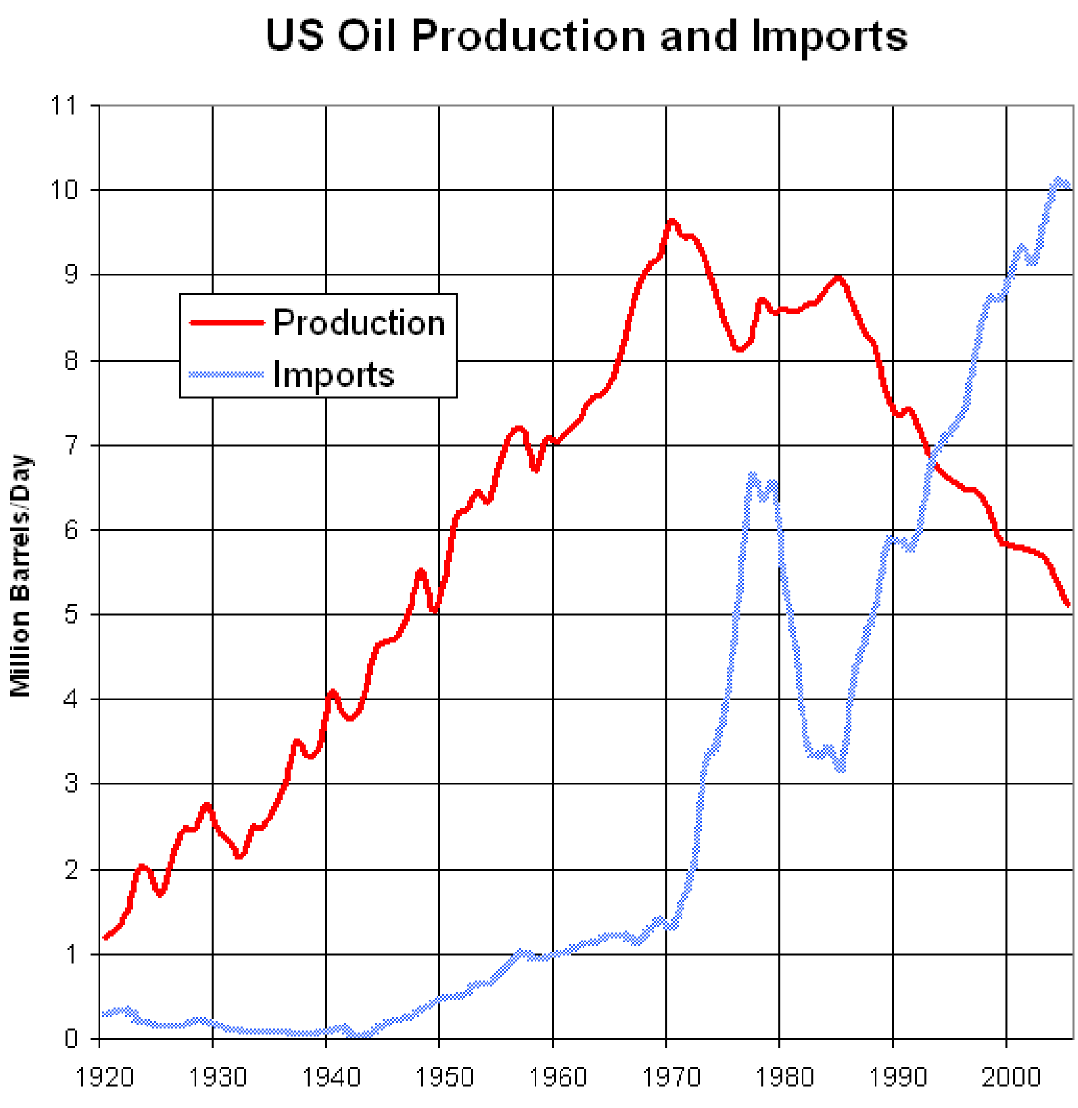


The world increased its daily oil consumption from 63 million barrels (Mbbl) in 1980 to 85 million barrels in 2006.

The demand side of peak oil is concerned with the consumption over time, and the growth of this demand. World crude oil demand grew an average of 1.76% per year from 1994 to 2006, with a high of 3.4% in 2003-2004. World demand for oil is projected to increase 37% over 2006 levels by 2030 (118 million barrels per day (18.8×10^6 m^3/d) from 86 million barrels (13.7×10^6 m^3)), due in large part to increases in demand from the transportation sector. A study published in the journal Energy Policy predicted demand would surpass supply by 2015 (unless constrained by strong recession pressures caused by reduced supply).

Energy demand is distributed amongst four broad sectors: transportation, residential, commercial, and industrial. In terms of oil use, transportation is the largest sector and the one that has seen the largest growth in demand in recent decades. This growth has largely come from new demand for personal-use vehicles powered by internal combustion engines. This sector also has the highest consumption rates, accounting for approximately 68.9% of the oil used in the United States in 2006, and 55% of oil use worldwide as documented in the Hirsch report. Transportation is therefore of particular interest to those seeking to mitigate the effects of peak oil.

Although demand growth is highest in the developing world, the United States is the world's largest consumer of petroleum. Between 1995 and 2005, U.S. consumption grew from 17,700,000 barrels per day (2,810,000 m^3/d) to 20,700,000 barrels per day (3,290,000 m^3/d), a 3,000,000 barrels per day (480,000 m^3/d) increase. China, by comparison, increased consumption from 3,400,000 barrels per day (541,000 m^3/d) to 7,000,000 barrels per day (1,100,000 m^3/d), an increase of 3,600,000 barrels per day (572,000 m^3/d), in the same time frame.



United States oil production peaked in 1970. By 2005 imports were twice the production.

As countries develop, industry and higher living standards drive up energy use, most often of oil. Thriving economies such as China and India are quickly becoming large oil consumers. China has seen oil consumption grow by 8% yearly since 2002, doubling from 1996-2006. In 2008, auto sales in China were expected to grow by as much as 15-20%, resulting in part from economic growth rates of over 10% for 5 years in a row.

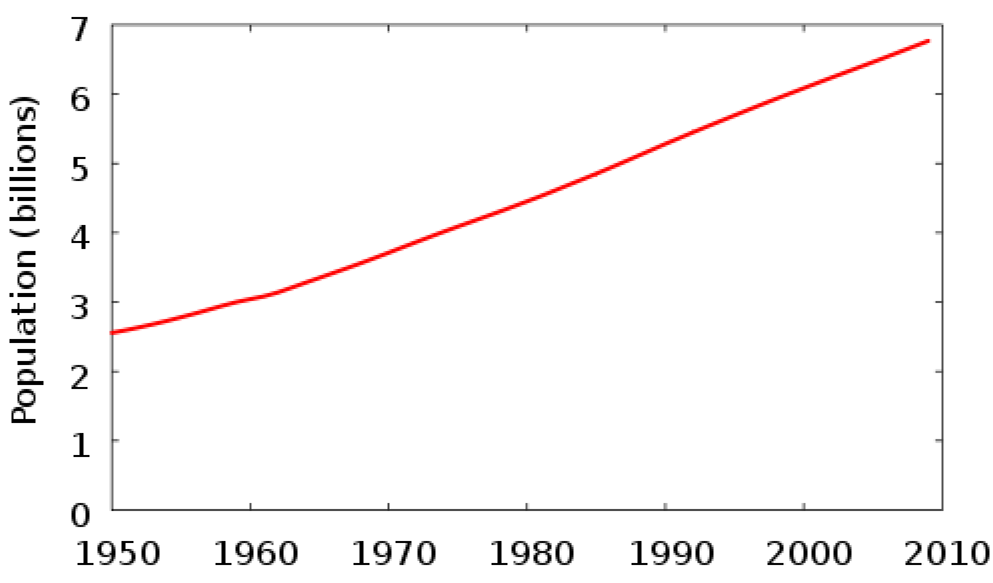
Although swift continued growth in China is often predicted, others predict that China's export dominated economy will not continue such growth trends due to wage and price inflation and reduced demand from the United States. India's oil imports are expected to more than triple from 2005 levels by 2020, rising to 5 million barrels per day (790×10^3 m^3/d).

The International Energy Agency estimated in January 2009 that oil demand fell in 2008 by 0.3%, and that it would fall by 0.6% in 2009. Oil consumption had not fallen for two years in a row since 1982-1983.

The Energy Information Administration (EIA) estimated that the United States' demand for petroleum-based transportation fuels fell 7.1% in 2008, which is "the steepest one-year decline since at least 1950." The agency stated that gasoline usage in the United States may have peaked in 2007, in part due to increasing interest in and mandates for use of biofuels and energy efficiency.

The EIA now expects global oil demand to increase by about 1,600,000 barrels per day (254,000 m^3/d) in 2010. Asian economies, in particular China, will lead the increase. China’s oil demand may rise more than 5% compared with a 3.7% gain in 2009, the CNPC said.

Population



World population

Another significant factor on petroleum demand has been human population growth. Oil production per capita peaked in the 1970s. The United States Census Bureau predicts that the world population in 2030 will be almost double that of 1980. Author Matt Savinar predicts that oil production in 2030 will have declined back to 1980 levels as worldwide demand for oil significantly out-paces production. Physicist Albert Bartlett claims that the rate of oil production per capita is falling, and that the decline has gone undiscussed because a politically incorrect form of population control may be implied by mitigation.

Oil production per capita has declined from 5.26 barrels per year (0.836 m^3/a) in 1980 to 4.44 barrels per year (0.706 m^3/a) in 1993, but then increased to 4.79 barrels per year (0.762 m^3/a) in 2005. In 2006, the world oil production took a downturn from 84.631 to 84.597 million barrels per day (13.4553×10^6 to 13.4498×10^6 m^3/d) although population has continued to increase. This has caused the oil production per capita to drop again to 4.73 barrels per year (0.752 m^3/a).

One factor that has so far helped ameliorate the effect of population growth on demand is the decline of population growth rate since the 1970s, although this is offset to a degree by increasing average longevity in developed nations. In 1970, the population grew at 2.1%. By 2007, the growth rate had declined to 1.167%. However, oil production was, until 2005, still outpacing population growth to meet demand. World population grew by 6.2% from 6.07 billion in 2000 to 6.45 billion in 2005, whereas according to BP, global oil production during that same period increased from 74.9 to 81.1 million barrels (11.91×10^6 to 12.89×10^6 m^3), or by 8.2%. or according to EIA, from 77.762 to 84.631 million barrels (12.3632×10^6 to 13.4553×10^6 m^3), or by 8.8%.

Agricultural effects and population limits

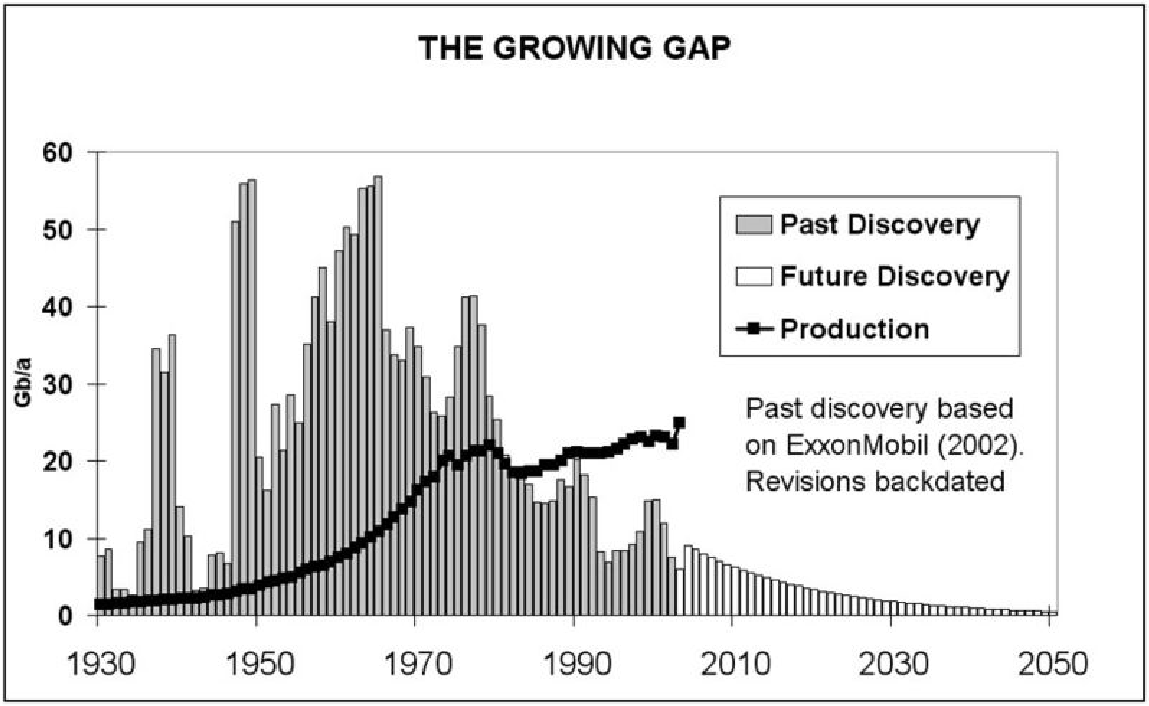
Since supplies of oil and gas are essential to modern agriculture techniques, a fall in global oil supplies could cause spiking food prices and unprecedented famine in the coming decades. Geologist Dale Allen Pfeiffer contends that current population levels are unsustainable, and that to achieve a sustainable economy and avert disaster the United States population would have to be reduced by at least one-third, and world population by two-thirds.

The largest consumer of fossil fuels in modern agriculture is ammonia production (for fertilizer) via the Haber process, which is essential to high-yielding intensive agriculture. The specific fossil fuel input to fertilizer production is primarily natural gas, to provide hydrogen via steam reforming. Given sufficient supplies of renewable electricity, hydrogen can be generated without fossil fuels using methods such as electrolysis. For example, the Vemork hydroelectric plant in Norway used its surplus electricity output to generate renewable ammonia from 1911 to 1971.

Iceland currently generates ammonia using the electrical output from its hydroelectric and geothermal power plants, because Iceland has those resources in abundance while having no domestic hydrocarbon resources, and a high cost for importing natural gas.

Petroleum supply

Discoveries



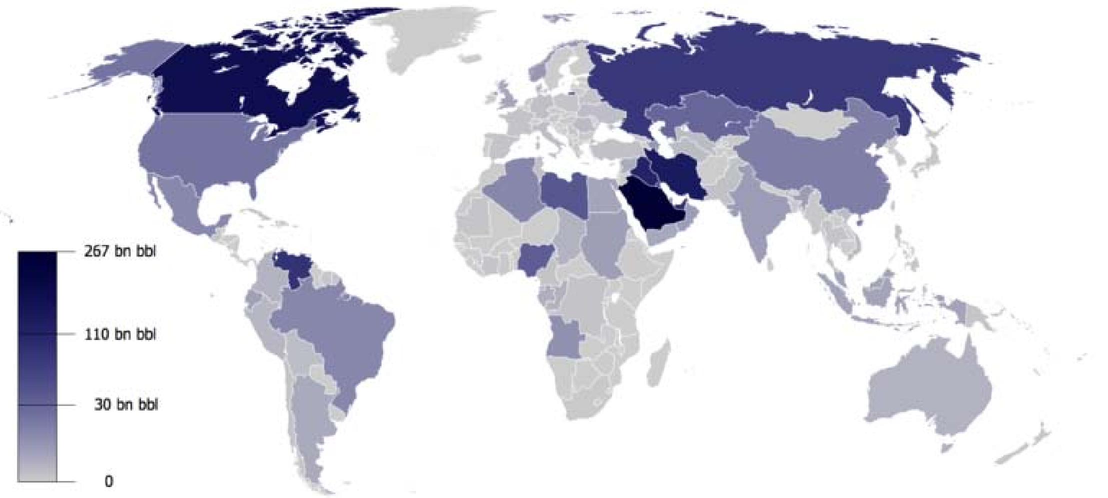
Growing gap between discovery and production

> “ All the easy oil and gas in the world has pretty much been found. Now comes the harder work in finding and producing oil from more challenging environments and work areas. ”
>
> — William J. Cummings, Exxon-Mobil company spokesman, December 2005

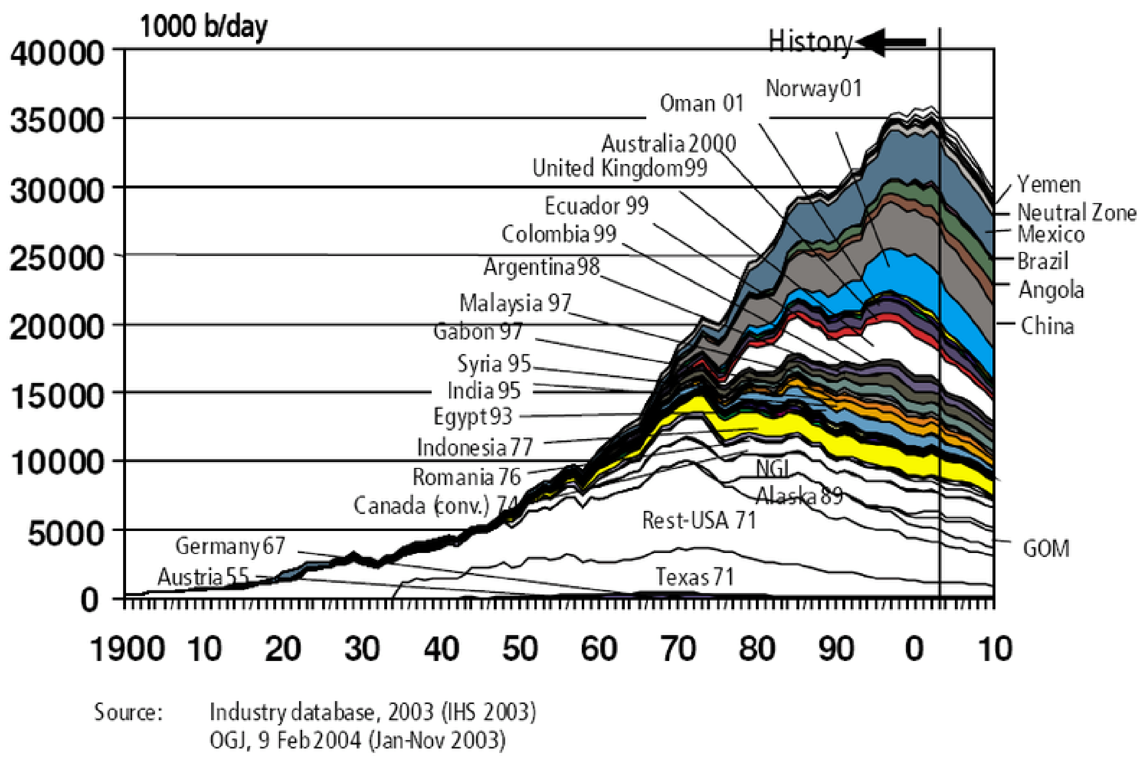
> “ It is pretty clear that there is not much chance of finding any significant quantity of new cheap oil. Any new or unconventional oil is going to be expensive. ”
>
> — Lord Ron Oxburgh, a former chairman of Shell, October 2008

To pump oil, it first needs to be discovered. The peak of world oilfield discoveries occurred in 1965 at around 55 billion barrels(Gb)/year. According to the Association for the Study of Peak Oil and Gas (ASPO), the rate of discovery has been falling steadily since. Less than 10 Gb/yr of oil were discovered each year between 2002-2007. According to a 2010 Reuters article, the annual rate of discovery of new fields has remained remarkably constant at 15-20 Gb/yr.

Reserves



Proven oil reserves, 2009.



2004 U.S. government predictions for oil production other than in OPEC and the former Soviet Union.

Total possible conventional crude oil reserves include all crude oil with 90-95% certainty of being technically possible to produce (from reservoirs through a wellbore using primary, secondary, improved, enhanced, or tertiary methods), all crude with a 50% probability of being produced in the future, and discovered reserves which have a 5-10% possibility of being produced in the future. These are referred to as 1P/Proven (90-95%), 2P/Probable (50%), and 3P/Possible (5-10%). This does not include liquids extracted from mined solids or gasses (oil sands, oil shales, gas-to-liquid processes, or coal-to-liquid processes).

Many current 2P calculations predict reserves to be between 1150-1350 Gb, but because of misinformation, withheld information, and misleading reserve calculations, it has been reported that 2P reserves are likely nearer to 850-900 Gb. Reserves in effect peaked in 1980, when production first surpassed new discoveries, though creative methods of recalculating reserves have made this difficult to establish exactly.

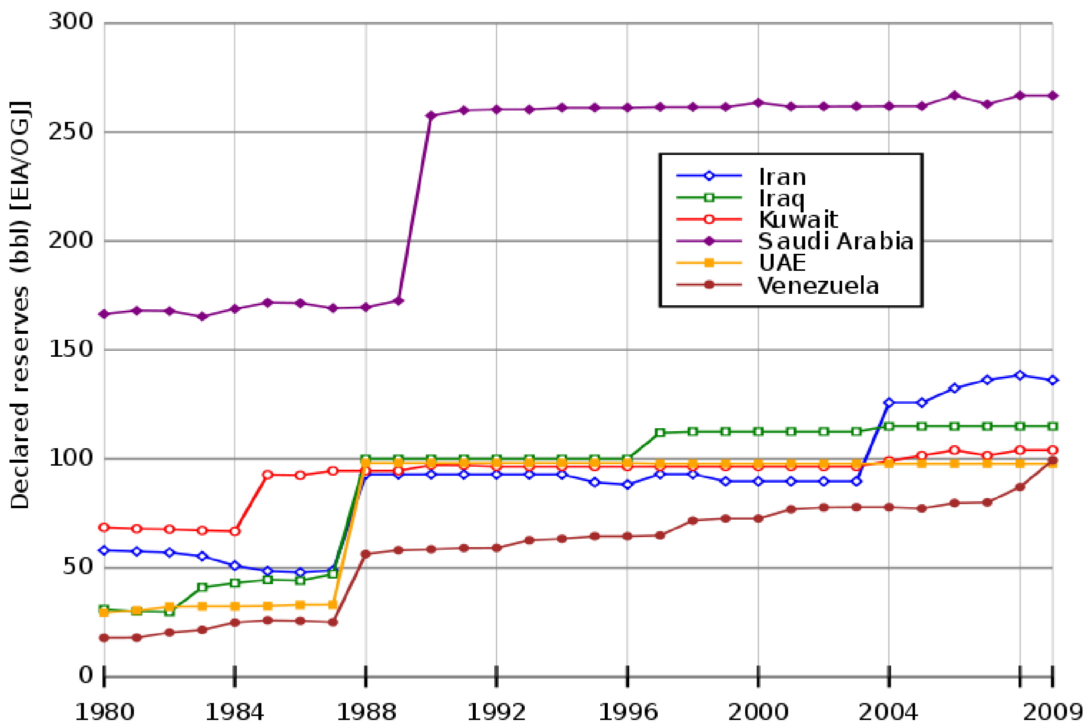
Current technology is capable of extracting about 40% of the oil from most wells. Some speculate that future technology will make further extraction possible, but this future technology is usually already considered in Proven and Probable (2P) reserve numbers.

In many major producing countries, the majority of reserves claims have not been subject to outside audit or examination. Most of the easy-to-extract oil has been found. Recent price increases have led to oil exploration in areas where extraction is much more expensive, such as in extremely deep wells, extreme downhole temperatures, and environmentally sensitive areas or where high technology will be required to extract the oil. A lower rate of discoveries per explorations has led to a shortage of drilling rigs, increases in steel prices, and overall increases in costs due to complexity.

Concerns over stated reserves

> “ [World] reserves are confused and in fact inflated. Many of the so-called reserves are in fact resources. They're not delineated, they're not accessible, they’re not available for production. ”
>
> — Sadad I. Al-Husseini, former VP of Aramco, presentation to the Oil and Money conference, October 2007.

Al-Husseini estimated that 300 billion barrels (48×10^9 m^3) of the world's 1,200 billion barrels (190×10^9 m^3) of proven reserves should be recategorized as speculative resources.



Graph of OPEC reported reserves showing refutable jumps in stated reserves without associated discoveries, as well as the lack of depletion despite yearly production.

One difficulty in forecasting the date of peak oil is the opacity surrounding the oil reserves classified as 'proven'. Many worrying signs concerning the depletion of proven reserves have emerged in recent years. This was best exemplified by the 2004 scandal surrounding the 'evaporation' of 20% of Shell's reserves.

For the most part, proven reserves are stated by the oil companies, the producer states and the consumer states. All three have reasons to overstate their proven reserves: oil companies may look to increase their potential worth; producer countries gain a stronger international stature; and governments of consumer countries may seek a means to foster sentiments of security and stability within their economies and among consumers.

The Energy Watch Group (EWG) 2007 report shows total world Proved (P95) plus Probable (P50) reserves to be between 854 billion and 1,255 billion barrels (199.5×10^9 m^3) (30 to 40 years of supply if demand growth were to stop immediately). Major discrepancies arise from accuracy issues with OPEC's self-reported numbers. Besides the possibility that these nations have overstated their reserves for political reasons (during periods of no substantial discoveries), over 70 nations also follow a practice of not reducing their reserves to account for yearly production. 1,255 billion barrels (199.5×10^9 m^3) is therefore a best-case scenario. Analysts have suggested that OPEC member nations have economic incentives to exaggerate their reserves, as the OPEC quota system allows greater output for countries with greater reserves.

Kuwait, for example, was reported in the January 2006 issue of *Petroleum Intelligence Weekly* to have only 48 billion barrels (7.6×10^9 m^3) in reserve, of which only 24 were fully proven. This report was based on the leak of a confidential document from Kuwait and has not been formally denied by the Kuwaiti authorities. This leaked document is from 2001, so the figure includes oil that has been produced since 2001, roughly 5-6 billion barrels (950×10^6 m^3), but excludes revisions or discoveries made since then. Additionally, the reported 1.5 billion barrels (240×10^6 m^3) of oil burned off by Iraqi soldiers in the First Persian Gulf War are conspicuously missing from Kuwait's figures.

On the other hand, investigative journalist Greg Palast argues that oil companies have an interest in making oil look more rare than it is, to justify higher prices. This view is refuted by ecological journalist Richard Heinberg. Other analysts argue that oil producing countries understate the extent of their reserves to drive up the price.

In November 2009, a senior official at the IEA alleged that the United States had encouraged the international agency to manipulate depletion rates and future reserve data to maintain lower oil prices. In 2005, the IEA predicted that 2030 production rates would reach 120,000,000 barrels per day (19,000,000 m^3/d), but this number was gradually reduced to 105,000,000 barrels per day (16,700,000 m^3/d). The IEA official alleged industry insiders agree that even 90 to 95,000,000 barrels per day (15,100,000 m^3/d) might be impossible to achieve. Although many outsiders had questioned the IEA numbers in the past, this was the first time an insider had raised the same concerns. A 2008 analysis of IEA predictions questioned several underlying assumptions and claimed that a 2030 production level of 75,000,000 barrels per day (11,900,000 m^3/d) (comprising 55,000,000 barrels (8,700,000 m^3) of crude oil and 20,000,000 barrels (3,200,000 m^3) of both non-conventional oil and natural gas liquids) was more realistic than the IEA numbers.

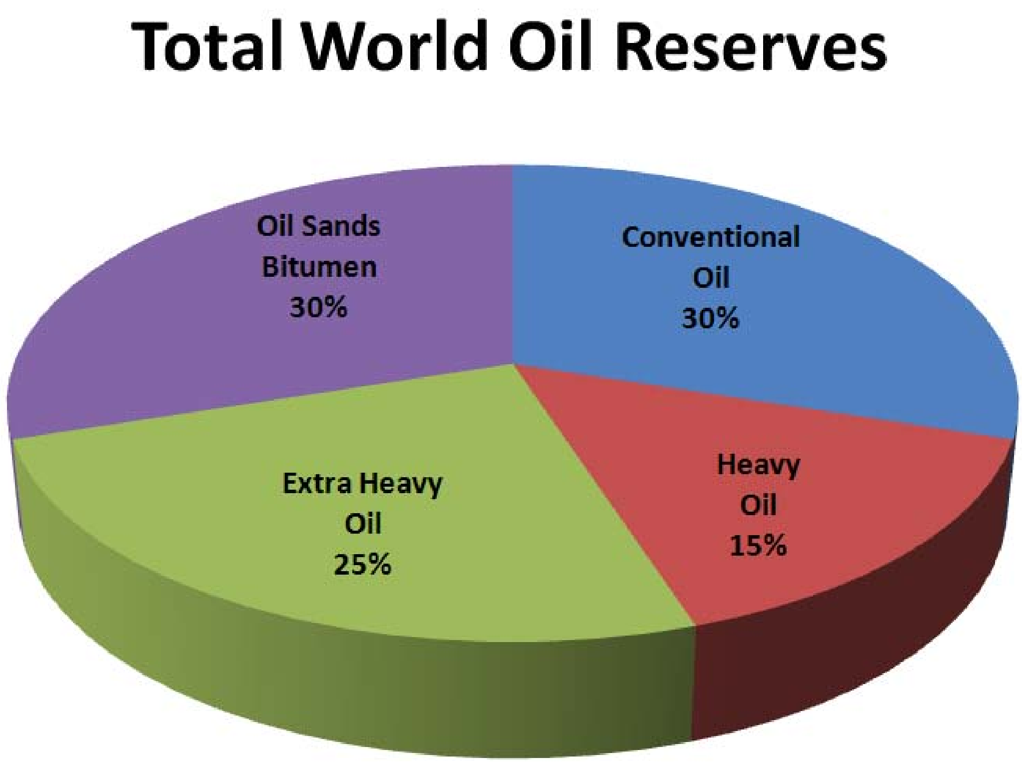
Unconventional sources

Syncrude's Mildred Lake mine site and plant near Fort McMurray, Alberta

Unconventional sources, such as heavy crude oil, oil sands, and oil shale are not counted as part of oil reserves. However, with rule changes by the SEC, oil companies can now book them as proven reserves after opening a strip mine or thermal facility for extraction. These unconventional sources are more labor and resource intensive to produce, however, requiring extra energy to refine, resulting in higher production costs and up to three times more greenhouse gas emissions per barrel (or barrel equivalent) on a "well to tank" basis or 10 to 45% more on a "well to wheels" basis, which includes the carbon emitted from combustion of the final product.

While the energy used, resources needed, and environmental effects of extracting unconventional sources has traditionally been prohibitively high, the three major unconventional oil sources being considered for large scale production are the extra heavy oil in the Orinoco Belt of Venezuela, the Athabasca Oil Sands in the Western Canadian Sedimentary Basin, and the oil shales of the Green River Formation in Colorado, Utah, and Wyoming in the United States. Energy companies such as Syncrude and Suncor have been extracting bitumen for decades but production has increased greatly in recent years with the development of Steam Assisted Gravity Drainage and other extraction technologies.

Chuck Masters of the USGS estimates that, "Taken together, these resource occurrences, in the Western Hemisphere, are approximately equal to the Identified Reserves of conventional crude oil accredited to the Middle East." Authorities familiar with the resources believe that the world's ultimate reserves of unconventional oil are several times as large as those of conventional oil and will be highly profitable for companies as a result of higher prices in the 21st century. In October 2009, the USGS updated the Orinoco tar sands (Venezuela) recoverable "mean value" to 513 billion barrels (8.16×10^{10} m^3), with a 90% chance of being within the range of 380-652 billion barrels (103.7×10^9 m^3), making this area "one of the world's largest recoverable oil accumulations".



Unconventional resources are much larger than conventional ones.

Despite the large quantities of oil available in non-conventional sources, Matthew Simmons argues that limitations on production prevent them from becoming an effective substitute for conventional crude oil. Simmons states that "these are high energy intensity projects that can never reach high volumes" to offset significant losses from other sources. Another study claims that even under highly optimistic assumptions, "Canada's oil sands will not prevent peak oil," although production could reach 5,000,000 bbl/d (790,000 m^3/d) by 2030 in a "crash program" development effort.

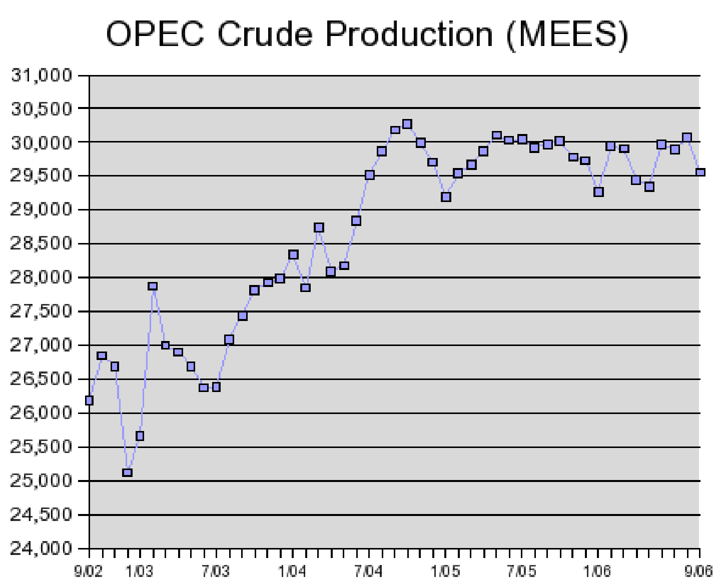
Moreover, oil extracted from these sources typically contains contaminants such as sulfur and heavy metals that are energy-intensive to extract and can leave tailings - ponds containing hydrocarbon sludge - in some cases. The same applies to much of the Middle East's undeveloped conventional oil reserves, much of which is heavy, viscous, and contaminated with sulfur and metals to the point of being unusable. However, recent high oil prices make these sources more financially appealing. A study by Wood Mackenzie suggests that within 15 years all the world's extra oil supply will likely come from unconventional sources.

Synthetic sources

A 2003 article in *Discover* magazine claimed that thermal depolymerization could be used to manufacture oil indefinitely, out of garbage, sewage, and agricultural waste. The article claimed that the cost of the process was $15 per barrel. A follow-up article in 2006 stated that the cost was actually $80 per barrel, because the feedstock that had previously been considered as hazardous waste now had market value.

A 2007 news bulletin published by Los Alamos Laboratory proposed that hydrogen (possibly produced using hot fluid from nuclear reactors to split water into hydrogen and oxygen) in combination with sequestered CO_2 could be used to produce methanol, which could then be converted into gasoline. The press release stated that in order for such a process to be economically feasible, gasoline prices would need to be above $4.60 "at the pump" in U.S. markets. Capital and operational costs were uncertain mostly because the costs associated with sequestering CO_2 are unknown.

Production



OPEC Crude Oil Production 2002-2006 (in 1,000s barrels/day).

The point in time when peak global oil production occurs defines peak oil. This is because production capacity is the main limitation of supply. Therefore, when production decreases, it becomes the main bottleneck to the petroleum supply/demand equation.

World wide oil discoveries have been less than annual production since 1980. According to several sources, worldwide production is past or near its maximum. World population has grown faster than oil production. Because of this, oil production *per capita* peaked in 1979 (preceded by a plateau during the period of 1973-1979).

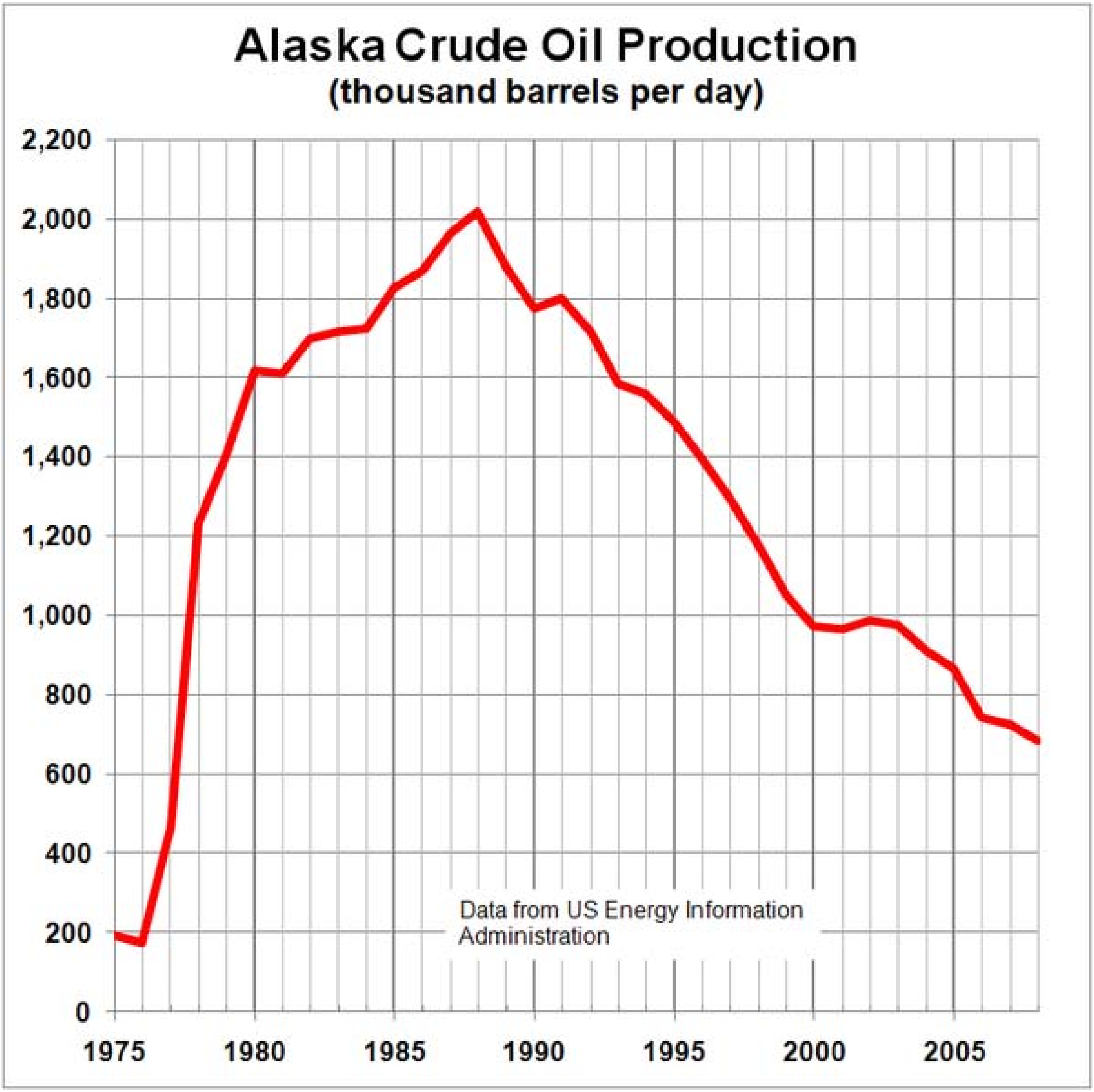
The increasing investment in harder-to-reach oil is a sign of oil companies' belief in the end of easy oil. Additionally, while it is widely believed that increased oil prices spur an increase in production, an increasing number of oil industry insiders are now coming to believe that even with higher prices, oil production is unlikely to increase significantly beyond its current level. Among the reasons cited are both geological factors as well as "above ground" factors that are likely to see oil production plateau near its current level.

Recent work points to the difficulty of increasing production even with vastly increased investment in exploration and production, at least in mature petroleum regions. A 2008 *Journal of Energy Security* analysis of the energy return on drilling effort in the United States points to an extremely limited potential to increase production of both gas and (especially) oil. By looking at the historical response of production to variation in drilling effort, this analysis showed very little increase of production attributable to increased drilling. This was due to a tight quantitative relationship of diminishing returns with increasing drilling effort: as drilling effort increased, the energy obtained per active drill rig was reduced according to a severely diminishing power law. This fact means that even an enormous increase of drilling effort is unlikely to lead to significantly increased oil and gas production in a mature petroleum region like the United States.

Worldwide production trends

World oil production growth trends were flat from 2005 to 2008. According to a January 2007 International Energy Agency report, global supply (which includes biofuels, non-crude sources of petroleum, and use of strategic oil reserves, in addition to crude production) averaged 85.24 million barrels per day (13.552×10^6 m^3/d) in 2006, up 0.76 million barrels per day (121×10^3 m^3/d) (0.9%), from 2005. Average yearly gains in global supply from 1987 to 2005 were 1.2 million barrels per day (190×10^3 m^3/d) (1.7%). In 2008, the IEA drastically increased its prediction of production decline from 3.7% a year to 6.7% a year, based largely on better accounting methods, including actual research of individual oil field production through out the world.

Oil field decline



Alaska's oil production has declined 65% since peaking in 1988

Of the largest 21 fields, at least 9 are in decline. In April, 2006, a Saudi Aramco spokesman admitted that its mature fields are now declining at a rate of 8% per year (with a national composite decline of about 2%). This information has been used to argue that Ghawar, which is the largest oil field in the world and responsible for approximately half of Saudi Arabia's oil production over the last 50 years, has peaked. The world's second largest oil field, the Burgan field in Kuwait, entered decline in November 2005.

According to a study of the largest 811 oilfields conducted in early 2008 by Cambridge Energy Research Associates (CERA), the average rate of field decline is 4.5% per year. The IEA stated in November 2008 that an analysis of 800 oilfields showed the decline in oil production to be 6.7% a year, and that this would grow to 8.6% in 2030. There are also projects expected to begin production within the next decade that are hoped to offset these declines. The CERA report projects a 2017 production level of over 100 million barrels per day (16×10^6 m^3/d).

Kjell Aleklett of the Association for the Study of Peak Oil and Gas agrees with their decline rates, but considers the rate of new fields coming online—100% of all projects in development, but with 30% of them experiencing delays, plus a mix of new small fields and field expansions—overly optimistic. A more rapid annual rate of decline of 5.1% in 800 of the world's largest oil fields was reported by the International Energy Agency in their World Energy Outlook 2008.

Mexico announced that its giant Cantarell Field entered depletion in March, 2006, due to past overproduction. In 2000, PEMEX built the largest nitrogen plant in the world in an attempt to maintain production through nitrogen injection into the formation, but by 2006, Cantarell was declining at a rate of 13% per year.

OPEC had vowed in 2000 to maintain a production level sufficient to keep oil prices between $22–28 per barrel, but did not prove possible. In its 2007 annual report, OPEC projected that it could maintain a production level that would stabilize the price of oil at around $50–60 per barrel until 2030. On November 18, 2007, with oil above $98 a barrel, King Abdullah of Saudi Arabia, a long-time advocate of stabilized oil prices, announced that his country would not increase production to lower prices. Saudi Arabia's inability, as the world's largest supplier, to stabilize prices through increased production during that period suggests that no nation or organization had the spare production capacity to lower oil prices. The implication is that those major suppliers who had not yet peaked were operating at or near full capacity.

Commentators have pointed to the Jack 2 deep water test well in the Gulf of Mexico, announced 5 September 2006, as evidence that there is no imminent peak in global oil production. According to one estimate, the field could account for up to 11% of U.S. production within seven years. However, even though oil discoveries are expected after the peak oil of production is reached, the new reserves of oil will be harder to find and extract. The Jack 2 field, for instance, is more than 20,000 feet (6,100 m) under the sea floor in 7,000 feet (2,100 m) of water, requiring 8.5 kilometers (5.3 miles) of pipe to reach. Additionally, even the maximum estimate of 15 billion barrels (2.4×10^9 m^3) represents slightly less than 2 years of U.S. consumption at present levels.

Control over supply

Entities such as governments or cartels can reduce supply to the world market by limiting access to the supply through nationalizing oil, cutting back on production, limiting drilling rights, imposing taxes, etc. International sanctions, corruption, and military conflicts can also reduce supply.

Nationalization of oil supplies

Another factor affecting global oil supply is the nationalization of oil reserves by producing nations. The nationalization of oil occurs as countries begin to deprivatize oil production and withhold exports. Kate Dourian, Platts' Middle East editor, points out that while estimates of oil reserves may vary, politics have now entered the equation of oil supply. "Some countries are becoming off limits. Major oil companies operating in Venezuela find themselves in a difficult position because of the growing nationalization of that resource. These countries are now reluctant to share their reserves."

According to consulting firm PFC Energy, only 7% of the world's estimated oil and gas reserves are in countries that allow companies like ExxonMobil free rein. Fully 65% are in the hands of state-owned companies such as Saudi Aramco, with the rest in countries such as Russia and Venezuela, where access by Western companies is difficult. The PFC study implies political factors are limiting capacity increases in Mexico, Venezuela, Iran, Iraq, Kuwait, and Russia. Saudi Arabia is also limiting capacity expansion, but because of a self-imposed cap, unlike the other countries. As a result of not having access to countries amenable to oil exploration, ExxonMobil is not making nearly the investment in finding new oil that it did in 1981.

Cartel influence on supply

OPEC is an alliance between 12 diverse oil producing countries (Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela) to control the supply of oil. OPEC's power was consolidated as various countries nationalized their oil holdings, and wrested decision-making away from the "Seven Sisters," (Anglo-Iranian, Socony-Vacuum, Royal Dutch Shell, Gulf, Esso, Texaco, and Socal) and created their own oil companies to control the oil. OPEC tries to influence prices by restricting production. It does this by allocating each member country a quota for production. All 12 members agree to keep prices high by producing at lower levels than they otherwise would. There is no way to verify adherence to the quota, so every member faces the same incentive to 'cheat' the cartel. Washington kept the oil flowing and gained favorable OPEC policies mainly by arming, and propping up Saudi regimes. According to some, the purpose for the second Iraq war is to break the back of OPEC and return control of the oil fields to western oil companies.

Alternately, commodities trader Raymond Learsy, author of *Over a Barrel: Breaking the Middle East Oil Cartel*, contends that OPEC has trained consumers to believe that oil is a much more finite resource than it is. To back his argument, he points to past false alarms and apparent collaboration. He also believes that peak oil analysts are conspiring with OPEC and the oil companies to create a "fabricated drama of peak oil" to drive up oil prices and profits. It is worth noting oil had risen to a little over $30/barrel at that time. A counter-argument was given in the Huffington Post after he and Steve Andrews, co-founder of ASPO, debated on CNBC in June 2007.

Timing of peak oil

Worldwide oil production, including oil from oil sands, reached an all-time high of 73,720,000 barrels per day (11,721,000 m^3/d) in 2005. By 2009, production had declined to 72,260,000 barrels per day (11,488,000 m^3/d).

M. King Hubbert initially predicted in 1974 that peak oil would occur in 1995 "if current trends continue." However, in the late 1970s and early 1980s, global oil consumption actually dropped (due to the shift to energy-efficient cars, the shift to electricity and natural gas for heating, and other factors), then rebounded to a lower level of growth in the mid 1980s. Thus oil production did not peak in 1995, and has climbed to more than double the rate initially projected. This underscores the fact that the only reliable way to identify the timing of peak oil will be in retrospect. However, predictions have been refined through the years as up-to-date information becomes more readily available, such as new reserve growth data. Predictions of the timing of peak oil include the possibilities that it has recently occurred, that it will occur shortly, or that a plateau of oil production will sustain supply for up to 100 years. None of these predictions dispute the peaking of oil production, but disagree only on when it will occur.

According to Matthew Simmons, Chairman of Simmons & Company International and author of *Twilight in the Desert: The Coming Saudi Oil Shock and the World Economy*, "...peaking is one of these fuzzy events that you only know clearly when you see it through a rear view mirror, and by then an alternate resolution is generally too late."

Possible effects and consequences of peak oil

Suburban housing near Cincinnati, Ohio

The wide use of fossil fuels has been one of the most important stimuli of economic growth and prosperity since the industrial revolution, allowing humans to participate in takedown, or the consumption of energy at a greater rate than it is being replaced. Some believe that when oil production decreases, human culture, and modern technological society will be forced to change drastically. The impact of peak oil will depend heavily on the rate of decline and the development and adoption of effective alternatives. If alternatives are not forthcoming, the products produced with oil (including fertilizers, detergents, solvents, adhesives, and most plastics) would become scarce and expensive.

In 2005, the United States Department of Energy published a report titled *Peaking of World Oil Production: Impacts, Mitigation, & Risk Management*. Known as the Hirsch report, it stated, "The peaking of world oil production presents the U.S. and the world with an unprecedented risk management problem. As peaking is approached, liquid fuel prices and price volatility will increase dramatically, and, without timely mitigation, the economic, social, and political costs will be unprecedented. Viable mitigation options exist on both the supply and demand sides, but to have substantial impact, they must be initiated more than a decade in advance of peaking."

The Export Land Model states that after peak oil petroleum exporting countries will be forced to reduce their exports more quickly than their production decreases because of internal demand growth. Countries that rely on imported petroleum will therefore be affected earlier and more dramatically than exporting countries. Mexico is already in this situation. Internal consumption grew by 5.9% in 2006 in the five biggest exporting countries, and their exports declined by over 3%. It was estimated that by 2010 internal demand would decrease worldwide exports by 2,500,000 barrels per day (397,000 m^3/d).

A majority of Americans live in suburbs, a type of low-density settlement designed around universal personal automobile use. Commentators such as James Howard Kunstler argue that because over 90% of transportation in the U.S. relies on oil, the suburbs' reliance on the automobile is an unsustainable living arrangement. Peak oil would leave many Americans unable to afford petroleum based fuel for their cars, and force them to use bicycles or electric vehicles. Additional options include telecommuting, moving to rural areas, or moving to higher density areas, where walking and public transportation are more viable options. In the latter two cases, suburbia may become the "slums of the future." The issues of petroleum supply and demand is also a concern for growing cities in developing countries (where urban areas are expected to absorb most of the world's projected 2.3 billion population increase by 2050). Stressing the energy component of future development plans is seen as an important goal.

Methods that have been suggested for mitigating these urban and suburban issues include the use of non-petroleum vehicles such as electric cars, battery electric vehicles, transit-oriented development, Car-free Cities, bicycles, new trains, new pedestrianism, smart growth, shared space, urban consolidation, and New Urbanism.

An extensive 2009 report by the United States National Research Council of the Academy of Sciences, commissioned by the United States Congress, stated six main findings. First, that compact development is likely to reduce "Vehicle Miles Traveled" (VMT) throughout the country. Second, that doubling residential density in a given area could reduce VMT by as much as 25% if coupled with measures such as increased employment density and improved public transportation. Third, that higher density, mixed-use developments would produce both direct reductions in CO_2 emissions (from less driving), and indirect reductions (such as from lower amounts of materials used per housing unit, higher efficiency climate control, longer vehicle lifespans, and higher efficiency delivery of goods and services. Fourth, that although short term reductions in energy use and CO_2 emissions would be modest, that these reductions would grow over time. Fifth, that a major obstacle to more compact development in the United States is political resistance from local zoning regulators, which would hamper efforts by state and regional governments to participate in land-use planning. Sixth, the committee agreed that changes in development that would alter driving patterns and building efficiency would have various secondary costs and benefits that are difficult to quantify. The report made two major recommendations: first that policies that support compact development (and especially its ability to reduce driving, energy use, and CO_2 emissions) should be encouraged, and second that further studies should be conducted to make future compact development more effective.

Mitigation

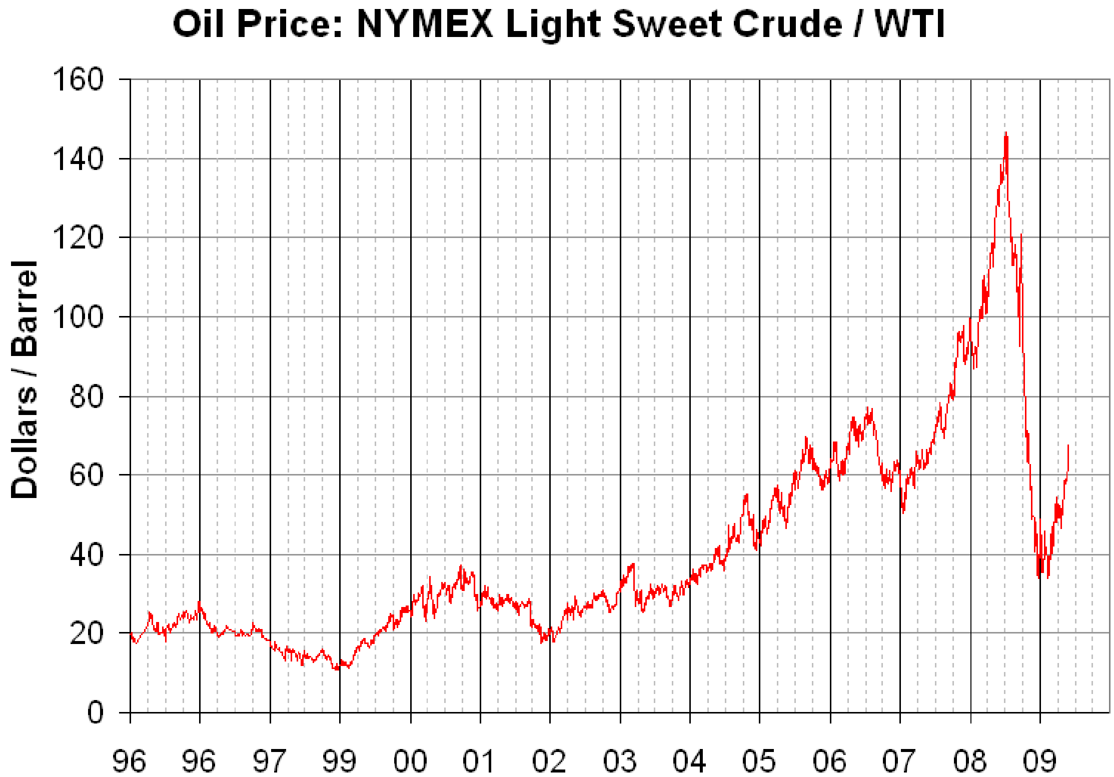
To avoid the serious social and economic implications a global decline in oil production could entail, the 2005 Hirsch report emphasized the need to find alternatives, at least ten to twenty years before the peak, and to phase out the use of petroleum over that time. This was similar to a plan proposed for Sweden that same year. Such mitigation could include energy conservation, fuel substitution, and the use of unconventional oil. Because mitigation can reduce the use of traditional petroleum sources, it can also affect the timing of peak oil and the shape of the Hubbert curve.

Positive aspects of peak oil

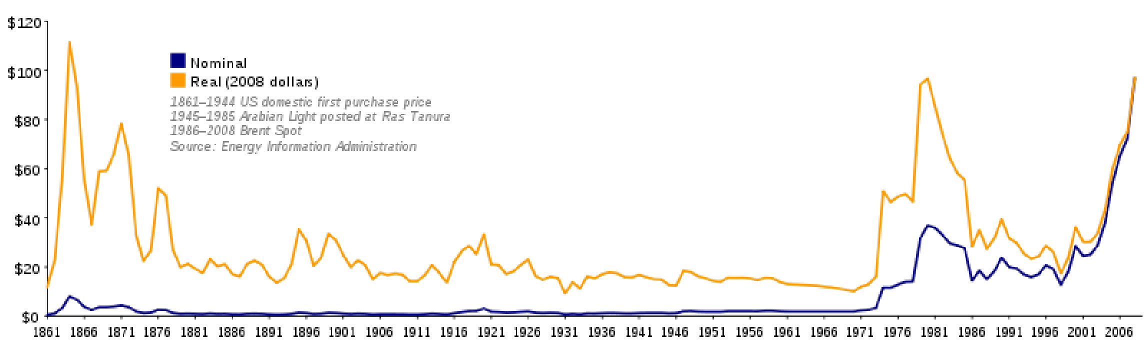
Some observers opine that peak oil should be viewed as a positive event. Many such critics reason that if the price of oil rises high enough, the use of alternative clean fuels could help control pollution from fossil fuel use, and mitigate global warming. Permaculture, particularly as expressed in the work of Australian David Holmgren, and others, sees peak oil as holding tremendous potential for positive change, assuming countries act with foresight. The rebuilding of local food networks, energy production, and the general implementation of 'energy descent culture' are argued to be ethical responses to the acknowledgment of finite fossil resources.

The "Transition Towns" Movement, started in Ireland and spread internationally by 'The Transition Handbook' (Rob Hopkins) sees the restructuring of society for more local resilience and ecological stewardship as a natural response to the combination of peak oil and climate change.

Oil price



New York Mercantile Exchange prices for West Texas Intermediate 1996 – 2009



Long-term oil prices, 1861-2008 (top line adjusted for inflation).

In terms of 2007 inflation adjusted dollars, the price of oil peaked on June 30, 2008 at over $143 a barrel. Before this period, the maximum inflation adjusted price was the equivalent of $95–100, in 1980. Crude oil prices in the last several years steadily rose from about $25 a barrel in August 2003 to over $130 a barrel in May 2008, with the most significant increases happening within the last year of that period. These prices are well above those that caused the 1973 and 1979 energy crises. This has contributed to fears of an economic recession similar to that of the early 1980s. One important indicator that supported the possibility that the price of oil had begun to have an effect on economies was that in the United States, gasoline consumption dropped by .5% in the first two months of 2008, compared to a drop of .4% total in 2007.

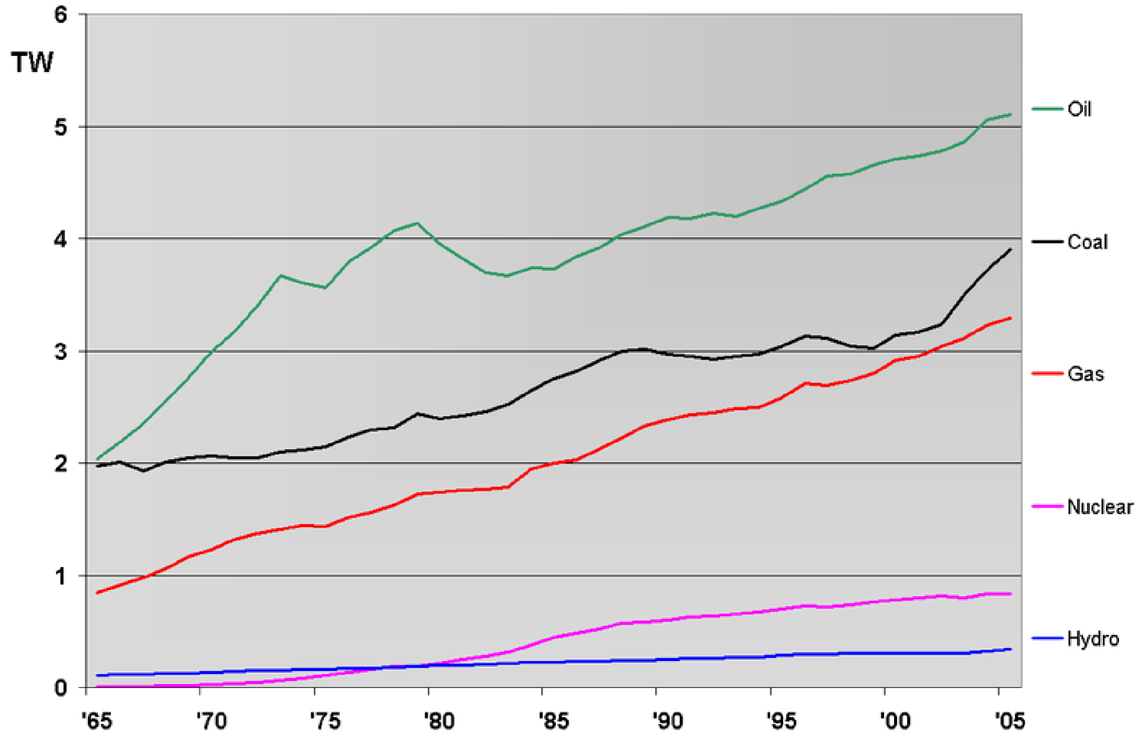
However some claim the decline in the U.S. dollar against other significant currencies from 2007 to 2008 is a significant part of oil's price increases from $66 to $130. The dollar lost approximately 14% of its value against the Euro from May 2007 to May 2008, and the price of oil rose 96% in the same time period.

Helping to fuel these price increases were reports that petroleum production is at or near full capacity. In June 2005, OPEC admitted that they would 'struggle' to pump enough oil to meet pricing pressures for the fourth quarter of that year.

Demand pressures on oil have been strong. Global consumption of oil rose from 30 billion barrels (4.8×10^9 m^3) in 2004 to 31 billion in 2005. These consumption rates are far above new discoveries for the period, which had fallen to only eight billion barrels of new oil reserves in new accumulations in 2004. In 2005, consumption was within 2 million barrels per day (320×10^3 m^3/d) of production, and at any one time there are about 54 days of stock in the OECD system plus 37 days in emergency stockpiles.

Besides supply and demand pressures, at times security related factors may have contributed to increases in prices, including the "War on Terror," missile launches in North Korea, the Crisis between Israel and Lebanon, nuclear brinkmanship between the U.S. and Iran, and reports from the U.S. Department of Energy and others showing a decline in petroleum reserves.

Effects of rising oil prices



World consumption of primary energy by energy type in terawatts (TW), 1965-2005.

In the past, the price of oil has led to economic recessions, such as the 1973 and 1979 energy crises. The effect the price of oil has on an economy is known as a price shock. In many European countries, which have high taxes on fuels, such price shocks could potentially be mitigated somewhat by temporarily or permanently suspending the taxes as fuel costs rise. This method of softening price shocks is less useful in countries with much lower gas taxes, such as the United States.

Some economists predict that a substitution effect will spur demand for alternate energy sources, such as coal or liquefied natural gas. This substitution can only be temporary, as coal and natural gas are finite resources as well.

Prior to the run-up in fuel prices, many motorists opted for larger, less fuel-efficient sport utility vehicles and full-sized pickups in the United States, Canada, and other countries. This trend has been reversing due to sustained high prices of fuel. The September 2005 sales data for all vehicle vendors indicated SUV sales dropped while small cars sales increased. Hybrid and diesel vehicles are also gaining in popularity.

In 2008, a report by Cambridge Energy Research Associates stated that 2007 had been the year of peak gasoline usage in the United States, and that record energy prices would cause an "enduring shift" in energy consumption practices. According to the report, in April gas consumption had been lower than a year before for the sixth straight month, suggesting 2008 would be the first year U.S. gasoline usage declined in 17 years. The total miles driven in the U.S. peaked in 2006.

The elasticity of OECD oil demand to rising prices is a function of many feedback mechanisms, some which are negative like fuel substitution, increased efficiency and conservation which re-enforce lower demand, and others which can result in positive feedback where higher prices can lead to higher oil demand. For example, respected Canadian economist Jeff Rubin has stated that higher oil prices will likely lead to higher freight shipping costs which will lead in turn to more manufacturing industry moving back to OECD countries (re-localisation of manufacturing production) for economic advantage. With manufacturing been highly energy intensive, and requiring varying degrees of petrochemical inputs, this feedback mechanism by definition would be positive for OECD oil demand. Another example of positive feedback in the oil market can be found in Export Land Models of oil exporting nations, where rising prices and higher export revenue can lead to higher local consumption, and less oil production for export.

The combination of both these positive and negative feedback elements underlay the linearity, and therefore elasticity of oil demand with regard to price.

Historical understanding of world oil supply limits

Although the Earth's finite oil supply means that peak oil is inevitable, technological innovations in finding and drilling for oil have at times changed the understanding of the total oil supply on Earth. As scientific understanding of petroleum geology has increased, so has our understanding of the Earth's total recoverable reserves. Since 1965, major oil surveys have averaged a 95% confidence *Estimated Ultimate Retrieval* (P95 EUR) of a little under 2,000 billion barrels (320×10^9 m^3), though some estimates have been as low as 1,500 billion barrels (240×10^9 m^3), and as high as 2,400 billion barrels (380×10^9 m^3).

The EUR reported by the 2000 USGS survey of 2,300 billion barrels (370×10^9 m^3) has been criticized for assuming a discovery trend over the next twenty years that would reverse the observed trend of the past 40 years. Their 95% confidence EUR of 2,300 billion barrels (370×10^9 m^3) assumed that discovery levels would stay steady, despite the fact that discovery levels have been falling steadily since the 1960s. That trend of falling discoveries has continued in the ten years since the USGS made their assumption. The 2000 USGS is also criticized for introducing other methodological errors, as well as assuming 2030 production rates inconsistent with projected reserves.

Criticisms

Some do not agree with peak oil, at least as it has been presented by Matthew Simmons. The president of Royal Dutch Shell's U.S. operations John Hofmeister, while agreeing that conventional oil production will soon start to decline, has criticized Simmons's analysis for being "overly focused on a single country: Saudi Arabia, the world's largest exporter and OPEC swing producer." He also points to the large reserves at the U.S. outer continental shelf, which holds an estimated 100 billion barrels (16×10^9 m^3) of oil and natural gas. As things stand, however, only 15% of those reserves are currently exploitable, a good part of that off the coasts of Louisiana, Alabama, Mississippi, and Texas. Hofmeister also contends that Simmons erred in excluding unconventional sources of oil such as the oil sands of Canada, where Shell is already active. The Canadian oil sands—a natural combination of sand, water, and oil found largely in Alberta and Saskatchewan—is believed to contain one trillion barrels of oil. Another trillion barrels are also said to be trapped in rocks in Colorado, Utah, and Wyoming, but are in the form of oil shale. These particular reserves present major environmental, social, and economic obstacles to recovery. Hofmeister also claims that if oil companies were allowed to drill more in the United States enough to produce another 2 million barrels per day (320×10^3 m^3/d), oil and gas prices would not be as high as they are in the later part of the 2000 to 2010 decade. He thinks that high energy prices are causing social unrest similar to levels surrounding the Rodney King riots.

Dr. Christoph Rühl, Chief economist of BP, repeatedly uttered strong doubts about the peak oil hypothesis:

Physical peak oil, which I have no reason to accept as a valid statement either on theoretical, scientific or ideological grounds, would be insensitive to prices. (...)In fact the whole hypothesis of peak oil – which is that there is a certain amount of oil in the ground, consumed at a certain rate, and then it's finished – does not react to anything.... (Global Warming) is likely to be more of a natural limit than all these peak oil theories combined. (...) Peak oil has been predicted for 150 years. It has never happened, and it will stay this way.

According to Rühl, the main limitations for oil availability are "above ground" and are to be found in the availability of staff, expertise, technology, investment security, money and last but not least in global warming. The oil question is about price and not the basic availability. His views are shared by Daniel Yergin of CERA, who added that the recent high price phase might add to a future demise of the oil industry - not of lack of resources or an apocalyptic shock but the timely and smooth setup of alternatives.

Clive Mather, CEO of Shell Canada, said the Earth's supply of hydrocarbons is almost infinite, referring to hydrocarbons in oil sands. Engineer Peter Huber believes the Canadian oil sands can fuel all of humanity's needs for over 100 years.

In fiction

Alex Scarrow's novel, *Last Light,* takes place during a peak oil crisis. The book portrays the collapse of the United Kingdom, as a result of a full-scale terrorist attack against several important key installations in the Middle-East. It follows the experiences of a family, a father trapped in Iraq, a mother far away from her children, a daughter and son fending for themselves, as the complete break-down of law and order causes looting, deaths, and worse.

James Howard Kunstler, author of *The Long Emergency* and *The Geography of Nowhere*, fictionalized his predictions of post-oil civilization into a novel entitled *World Made by Hand*. The book portrays the efforts of Robert Earle, a former software executive elected mayor of a small town in New York State, who faces the struggle of rebuilding a civil society amid arguing factions.

Another novel using peak oil for its premise is Robert Charles Wilson's *Julian Comstock: A Story of 22nd Century America*. set a hundred years after the end of the age of oil, where American society has fallen back to a level similar to that of the Civil War. The book follows Julian Comstock, the nephew of the President, during a series of battles and adventures across an American landscape where many cities have been scavenged for their precious resources.

The *Mad Max* films are based in a post-apocalyptic Australia, in which *(Mad Max 2: The Road Warrior* explains) the general social collapse has occurred because of a global energy shortage, particularly of oil.

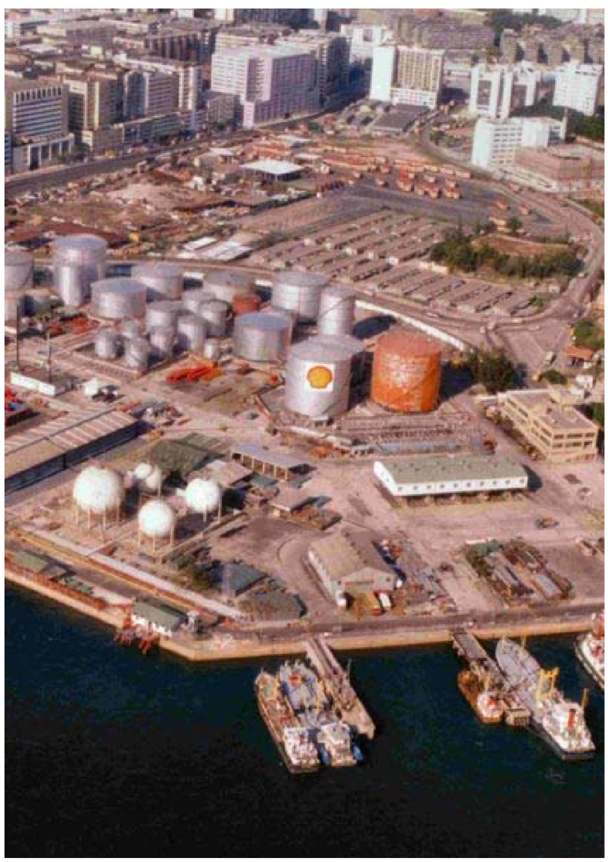
The 1979 comedy *Americathon* is set in a future (1998) where the USA has run out of oil and the economy is near collapse. Americans live in their (now stationary) cars and commute by either jogging or riding bicycles.

Frontlines: Fuel of War, a 2008 First-Person Shooter video game for the Xbox 360 and PC, is set during a fictional World War after peak oil occurs.

Chapter 8

Oil Depot and Oil in Place

Oil depot



Oil Depot in Kowloon Hong Kong

An **oil depot** (sometimes called a **tank farm**, **installation** or **oil terminal**) is an industrial facility for the storage of oil and/or petrochemical products and from which these products are usually transported to end users or further storage facilities. An oil depot typically has tankage, either above ground or underground, and gantries for the discharge of products into road tankers or other vehicles (such as barges) or pipelines.

Oil depots are usually situated close to oil refineries or in locations where marine tankers containing products can discharge their cargo. Some depots are attached to pipelines from which they draw their supplies and depots can also be fed by rail, by barge and by road tanker (sometimes known as "bridging").

Most oil depots have road tankers operating from their grounds and these vehicles transport products to petrol stations or other users.

An oil depot is a comparatively unsophisticated facility in that (in most cases) there is no processing or other transformation on site. The products which reach the depot (from a refinery) are in their final form suitable for delivery to customers. In some cases additives may be injected into products in tanks, but there is usually no manufacturing plant on site. Modern depots comprise the same types of tankage, pipelines and gantries as those in the past and whilst there is a greater degree of automation on site, there have been few significant changes in depot operational activities over time.

Health, safety and environment

One of the key imperatives is **Health, Safety and Environment** (HSE) and the operators of a depot must ensure that products are safely stored and handled and that there are no leakages (etc.) which could damage the soil or the water table.

Massive fire at Buncefield Oil Depot, UK December 2005

Fire protection is a primary consideration, especially for the more flammable products such as petrol (gasoline) and Aviation Fuel.

Ownership

The ownership of oil depots falls into three main categories:

- Single oil company ownership. When one company owns and operates a depot on its own behalf.
- Joint or consortium ownership, where two or more companies own a depot together and share its operating costs.
- Independent ownership, where a depot is owned not by an oil company but by a separate business which charges oil companies (and others) a fee to store and handle products. The Royal Vopak from the Netherlands is the largest independent terminal operator with 80 terminals in 30 countries.

In all cases the owners may also provide "hospitality" or "pick up rights" at the facility to other companies.

Airports

Aircraft refueller at Vancouver airport

Most airports also have their own dedicated oil depots (usually called "fuel farms") where aviation fuel (Jet A or 100LL) is stored prior to being discharged into aircraft fuel tanks. Fuel is transported from the depot to the aircraft either by road tanker or via a hydrant system.

Japan

The world's third largest oil consumer had national reserves of 113 days of oil demand under the government's storage and 85 days held by the private sector at the end of December 2010. In this respect, the total oil stored in Japan in December stood at 587.4 million barrels. Japan requires the private sector to hold 70 days as oil reserves, but is making the period shorter by three days to 67 days. As such it will allow oil companies to release 8.9 million barrels of crude oil from mandatory stockpiles.

Oil in place

Oil in place is the total hydrocarbon content of an oil reservoir and is often abbreviated **STOOIP**, which stands for **Stock Tank Original Oil In Place**, or **STOIIP** for **Stock Tank Oil Initially In Place**, referring to the oil in place before the commencement of production. In this case, *stock tank* refers to the storage vessel (often purely notional) containing the oil after production.

Oil in place must not be confused with oil reserves, that are the technically and economically recoverable portion of oil volume in the reservoir. Current recovery factors for oil fields around the world typically range between 10 and 60 percent; some are over 80 percent. The wide variance is due largely to the diversity of fluid and reservoir characteristics for different deposits.

Calculating STOIIP

Accurate calculation of the value of STOOIP requires knowledge of:

- volume of rock containing oil (Bulk Rock Volume, in the USA this is usually in acre-feet)
- percentage porosity of the rock in the reservoir
- percentage water content of that porosity
- amount of shrinkage that the oil undergoes when brought to the Earth's surface

and is achieved using the formula

$$N = \frac{7758\ V_b\ \phi\ (1 - S_w)}{B_{oi}} \text{ [stb]}$$

or

$$N = \frac{V_b\ \phi\ (1 - S_w)}{B_{oi}} \text{ [m}^3\text{]}$$

where

- N = STOIIP (barrels)
- V_b = Bulk (rock) volume (acre-feet or cubic metres)
- ϕ = Fluid-filled porosity of the rock (fraction)
- S_w = Water saturation - water-filled portion of this porosity (fraction)
- B_{oi} = Formation volume factor (dimensionless factor for the change in volume between reservoir and standard conditions at surface)

Gas saturation S_g is traditionally omitted from this equation.

The constant value 7758 converts acre-feet to stock tank barrels. An acre of reservoir 1 foot thick would contain 7758 barrels of oil in the limiting case of 100% porosity, zero water saturation and no oil shrinkage. If the metric system is being used, a conversion factor of 6.289808 can be used to convert cubic metres to stock tank barrels. A 1 cubic metre container would hold 6.289808 barrels of oil.

Formation volume factor

When oil is produced, the high reservoir temperature and pressure decreases to surface conditions and gas bubbles out of the oil. As the gas bubbles out of the oil, the volume of the oil decreases. Stabilized oil under surface conditions (either 60 F and 14.7 psi or 15 C and 101.325 kPa) is called stock tank oil. Oil reserves are calculated in terms of stock tank oil volumes rather than reservoir oil volumes. The ratio of stock tank volume to oil volume under reservoir conditions is called the formation volume factor (FVF). It usually varies from 1.0 to 1.7. A formation volume factor of 1.4 is characteristic of high-shrinkage oil and 1.2 of low-shrinkage oil.

Chapter 9

Oil Platform

A typical offshore Oil/Gas platform.

An **offshore platform**, also referred to as an **oil platform** or **oil rig**, is a large structure with facilities to drill wells and extract and process oil and natural gas and export the products to shore.

Depending on the circumstances, the platform may be fixed to the ocean floor, may consist of an artificial island, or may float.

Remote subsea wells may also be connected to a platform by flow lines and by umbilical connections; these subsea solutions may consist of single wells or of a manifold centre for multiple wells.

History

Offshore platform Gulf of Mexico

Around 1891 the first submerged oil wells were drilled from platforms built on piles in the fresh waters of the Grand Lake St. Marys (a.k.a. Mercer County Reservoir) in Ohio.

The wide but shallow reservoir was built from 1837 to 1845 to provide water to the Miami and Erie Canal.

Around 1896 the first submerged oil wells in salt water were drilled in the portion of the Summerland field extending under the Santa Barbara Channel in California. The wells were drilled from piers extending from land out into the channel.

Other notable early submerged drilling activities occurred on the Canadian side of Lake Erie in the 1900s and Caddo Lake in Louisiana in the 1910s. Shortly thereafter, wells were drilled in tidal zones along the Gulf Coast of Texas and Louisiana. The Goose Creek field near Baytown, Texas is one such example. In the 1920s drilling was done from concrete platforms in Lake Maracaibo, Venezuela.

The oldest subsea well recorded in Infield's offshore database is the Bibi Eibat well which came on stream in 1923 in Azerbaijan. Landfill was used to raise shallow portions of the Caspian Sea.

In the early 1930s the Texas Company developed the first mobile steel barges for drilling in the brackish coastal areas of the gulf.

In 1937 Pure Oil Company (now part of Chevron Corporation) and its partner Superior Oil Company (now part of ExxonMobil Corporation) used a fixed platform to develop a field in 14 feet of water, one mile offshore of Calcasieu Parish, Louisiana.

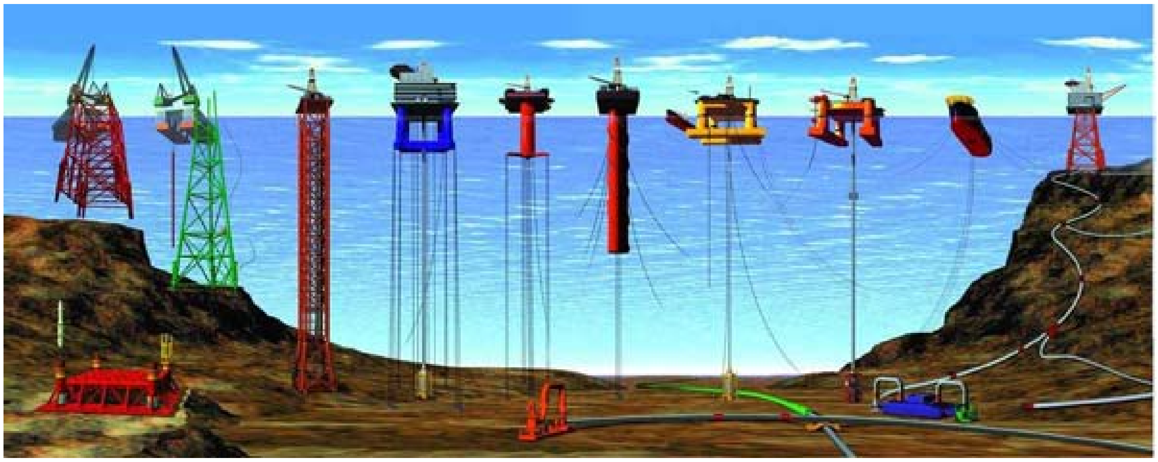
In 1946, Magnolia Petroleum Company (now part of ExxonMobil) erected a drilling platform in 18 ft of water, 18 miles off the coast of St. Mary Parish, Louisiana.

In early 1947 Superior Oil erected a drilling/production platform in 20 ft of water some 18 miles off Vermilion Parish, Louisiana. But it was Kerr-McGee Oil Industries (now Anadarko Petroleum Corporation), as operator for partners Phillips Petroleum (ConocoPhillips) and Stanolind Oil & Gas (BP), that completed its historic Ship Shoal Block 32 well in October 1947, months before Superior actually drilled a discovery from their Vermilion platform farther offshore. In any case, that made Kerr-McGee's well the first oil discovery drilled out of sight of land.

The Thames Sea Forts of World War II are considered the direct predecessors of modern offshore platforms. Having been pre-constructed in a very short time, they were then floated to their location and placed on the shallow bottom of the Thames estuary.

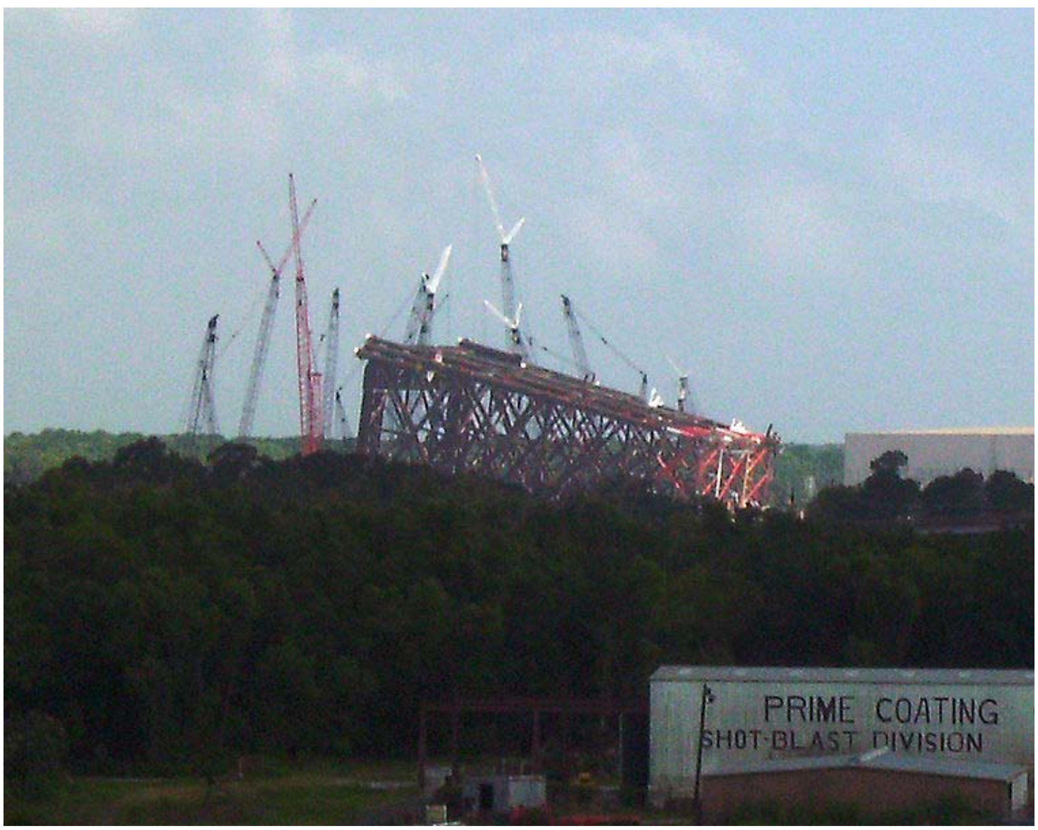
Types

Larger lake- and sea-based offshore platforms and drilling rigs are some of the largest moveable man-made structures in the world. There are several types of oil platforms and rigs:



1, 2) conventional fixed platforms; 3) compliant tower; 4, 5) vertically moored tension leg and mini-tension leg platform; 6) Spar ; 7,8) Semi-submersibles ; 9) Floating production, storage, and offloading facility; 10) sub-sea completion and tie-back to host facility.

Fixed platforms



A fixed platform base under construction on a Louisiana river

These platforms are built on concrete or steel legs, or both, anchored directly onto the seabed, supporting a deck with space for drilling rigs, production facilities and crew quarters. Such platforms are, by virtue of their immobility, designed for very long term use (for instance the Hibernia platform). Various types of structure are used, steel jacket, concrete caisson, floating steel and even floating concrete. Steel jackets are vertical sections made of tubular steel members, and are usually piled into the seabed. Concrete caisson structures, pioneered by the Condeep concept, often have in-built oil storage in tanks below the sea surface and these tanks were often used as a flotation capability, allowing them to be built close to shore (Norwegian fjords and Scottish firths are popular because they are sheltered and deep enough) and then floated to their final position where they are sunk to the seabed. Fixed platforms are economically feasible for installation in water depths up to about 1,700 ft (520 m).

Compliant towers

These platforms consist of slender flexible towers and a pile foundation supporting a conventional deck for drilling and production operations. Compliant towers are designed to sustain significant lateral deflections and forces, and are typically used in water depths ranging from 1,500 to 3,000 feet (460 to 910 m).

Semi-submersible platform

Platform P-51 off the Brazilian coast is a semi-submersible platform

These platforms have hulls (columns and pontoons) of sufficient buoyancy to cause the structure to float, but of weight sufficient to keep the structure upright. Semi-submersible platforms can be moved from place to place; can be ballasted up or down by altering the amount of flooding in buoyancy tanks; they are generally anchored by combinations of chain, wire rope or polyester rope, or both, during drilling or production operations, or both, though they can also be kept in place by the use of dynamic positioning. Semi-submersibles can be used in water depths from 200 to 10,000 feet (60 to 3,000 m).

Jack-up drilling rigs

Jack-up Mobile Drilling Units (or jack-ups), as the name suggests, are rigs that can be jacked up above the sea using legs that can be lowered, much like jacks. These MODU's-Mobile Offshore Drilling Units are typically used in water depths up to 400 feet (120 m), although some designs can go to 550 ft (170 m) depth. They are designed to move from place to place, and then anchor themselves by deploying the legs to the ocean bottom using a rack and pinion gear system on each leg.

Drillships

A drillship is a maritime vessel that has been fitted with drilling apparatus. It is most often used for exploratory drilling of new oil or gas wells in deep water but can also be used for scientific drilling. Early versions were built on a modified tanker hull, but purpose-built designs are used today. Most drillships are outfitted with a dynamic positioning system to maintain position over the well. They can drill in water depths up to 12,000 ft (3,700 m).

Floating production systems

The main types of floating production systems are FPSO (floating production, storage, and offloading system). FPSOs consist of large monohull structures, generally (but not always) shipshaped, equipped with processing facilities. These platforms are moored to a location for extended periods, and do not actually drill for oil or gas. Some variants of these applications, called FSO (floating storage and offloading system) or FSU (floating storage unit), are used exclusively for storage purposes, and host very little process equipment.

Tension-leg platform

TLPs are floating platforms tethered to the seabed in a manner that eliminates most vertical movement of the structure. TLPs are used in water depths up to about 6,000 feet (2,000 m). The "conventional" TLP is a 4-column design which looks similar to a semisubmersible. Proprietary versions include the Seastar and MOSES mini TLPs; they are relatively low cost, used in water depths between 600 and 4,300 feet (180 and 1,300 m). Mini TLPs can also be used as utility, satellite or early production platforms for larger deepwater discoveries.

Gravity Based Substructure

These GBS can either be steel or concrete. It is anchored directly onto the seabed. For steel GBS, it is predominantly used when there is no or limited availability of crane barge to install conventional fixed offshore platform, for example in the Caspian Sea. There are several steel GBS in the world today (i.e. offshore Turkmenistan Waters (Caspian Sea) and offshore New Zealand). Steel GBS does not provide storage capability. It is mainly installed by pulling it off the yard, by either wet-tow or/and dry-tow, and self-installing by controlled-ballasting of the compartments with sea water. To better position the GBS during installation, the GBS shall be connected with either a transportation barge or any other barge (provided it is big enough to support the GBS) using strand jacks. The jacks shall be released bit by bit whilst the GBS is ballasted to ensure that the GBS does not sway too much from target location.

Spar platforms

Devil's Tower Spar Platform

Spars are moored to the seabed like TLPs, but whereas a TLP has vertical tension tethers, a spar has more conventional mooring lines. Spars have to-date been designed in three configurations: the "conventional" one-piece cylindrical hull, the "truss spar" where the midsection is composed of truss elements connecting the upper buoyant hull (called a hard tank) with the bottom soft tank containing permanent ballast, and the "cell spar" which is built from multiple vertical cylinders. The spar has more inherent stability than a TLP since it has a large counterweight at the bottom and does not depend on the mooring to hold it upright. It also has the ability, by adjusting the mooring line tensions (using chain-jacks attached to the mooring lines), to move horizontally and to position itself over wells at some distance from the main platform location. The first production spar was Kerr-McGee's Neptune, anchored in 1,930 ft (590 m) in the Gulf of Mexico; however, spars (such as Brent Spar) were previously used as FSOs.

Eni's Devil's Tower located in 5,610 ft (1,710 m) of water, in the Gulf of Mexico, was the world's deepest spar until 2010. The world's deepest platform is currently the Perdido spar in the Gulf of Mexico, floating in 2,438 meters of water. It is operated by Royal Dutch Shell and was built at a cost of $3 billion.

The first truss spars were Kerr-McGee's Boomvang and Nansen. The first (and only) cell spar is Kerr-McGee's Red Hawk.

Normally unmanned installations (NUI)

These installations (sometimes called toadstools) are small platforms, consisting of little more than a well bay, helipad and emergency shelter. They are designed to operate remotely under normal conditions, only to be visited occasionally for routine maintenance or well work.

Conductor support systems

These installations, also known as **satellite platforms**, are small unmanned platforms consisting of little more than a well bay and a small process plant. They are designed to operate in conjunction with a static production platform which is connected to the platform by flow lines or by umbilical cable, or both.

Particularly large examples

A 'Statfjord' Gravity base structure under construction in Norway. Almost all of the structure will end up submerged.

The Petronius Platform is a compliant tower in the Gulf of Mexico, which stands 2,000 feet (610 m) above the ocean floor. It is one of the world's tallest structures.

The Hibernia platform is the world's largest (in terms of weight) offshore platform, located on the Jeanne D'Arc basin, in the Atlantic Ocean off the coast of Newfoundland. This *gravity base structure* (GBS), which sits on the ocean floor, is 364 feet (111 m) high and has storage capacity for 1.3 million barrels (210,000 m^3) of crude oil in its 278.8-foot (85.0 m) high caisson. The platform acts as a small concrete island with serrated outer edges designed to withstand the impact of an iceberg. The GBS contains production storage tanks and the remainder of the void space is filled with ballast with the entire structure weighing in at 1.2 million tons.

Maintenance and supply

A typical oil production platform is self-sufficient in energy and water needs, housing electrical generation, water desalinators and all of the equipment necessary to process oil and gas such that it can be either delivered directly onshore by pipeline or to a floating platform or tanker loading facility, or both. Elements in the oil/gas production process include wellhead, production manifold, production separator, glycol process to dry gas, gas compressors, water injection pumps, oil/gas export metering and main oil line pumps.

Larger platforms assisted by smaller ESVs (emergency support vessels) like the British Iolair that are summoned when something has gone wrong, *e.g.* when a search and rescue operation is required. During normal operations, PSVs (platform supply vessels) keep the platforms provisioned and supplied, and AHTS vessels can also supply them, as well as tow them to location and serve as standby rescue and firefighting vessels.

Crew

Essential personnel

Not all of the following personnel are present on every platform. On smaller platforms, one worker can perform a number of different jobs. The following also are not names officially recognized in the industry:

- OIM (offshore installation manager) who is the ultimate authority during his/her shift and makes the essential decisions regarding the operation of the platform;
- operations team leader (OTL);
- offshore operations engineer (OOE) who is the senior technical authority on the platform;
- PSTL or operations coordinator for managing crew changes;
- dynamic positioning operator, navigation, ship or vessel maneuvering (MODU), station keeping, fire and gas systems operations in the event of incident;
- second mate to meet manning requirements of flag state, operates fast rescue craft, cargo operations, fire team leader;
- third mate to meet manning requirements of flag state, operate fast rescue craft, cargo operations, fire team leader;
- ballast control operator to operate fire and gas systems;
- crane operators to operate the cranes for lifting cargo around the platform and between boats;
- scaffolders to rig up scaffolding for when it is required for workers to work at height;
- coxswains to maintain the lifeboats and manning them if necessary;
- control room operators, especially FPSO or production platforms;

- catering crew, including people tasked with performing essential functions such as cooking, laundry and cleaning the accommodation;
- production techs to run the production plant;
- helicopter pilot(s) living on some platforms that have a helicopter based offshore and transporting workers to other platforms or to shore on crew changes;
- maintenance technicians (instrument, electrical or mechanical).

Incidental personnel

Drill crew will be on board if the installation is performing drilling operations. A drill crew will normally comprise:

- Toolpusher
- Driller
- Roughnecks
- Roustabouts
- Company man
- Mud engineer
- Derrickhand
- Geologist

Well services crew will be on board for well work. The crew will normally comprise:

- Well services supervisor
- Wireline or coiled tubing operators
- Pump operator

Drawbacks

Risks

The nature of their operation — extraction of volatile substances sometimes under extreme pressure in a hostile environment — means risk; accidents and tragedies occur regularly. The U.S. Minerals Management Service reported 69 offshore deaths, 1,349 injuries, and 858 fires and explosions on offshore rigs in the Gulf of Mexico from 2001 to 2010. In July 1988, 167 people died when Occidental Petroleum's Piper Alpha offshore production platform, on the Piper field in the UK sector of the North Sea, exploded after a gas leak. The resulting investigation conducted by Lord Cullen and publicized in the first Cullen Report was highly critical of a number of areas, including, but not limited to, management within the company, the design of the structure, and the Permit to Work System. The report was commissioned in 1988, and was delivered November 1990. The accident greatly accelerated the practice of providing living accommodations on separate platforms, away from those used for extraction.

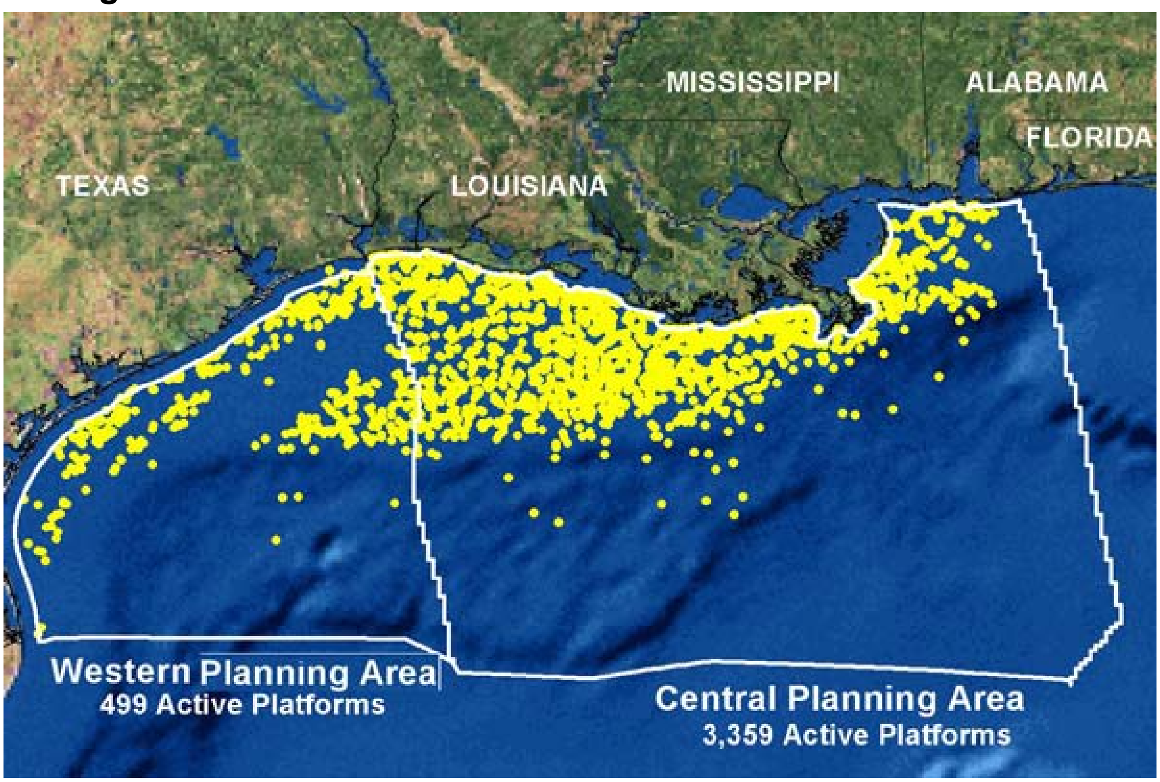
However, this was in itself a hazardous environment. In March 1980, the 'flotel' (floating hotel) platform *Alexander L. Kielland* capsized in a storm in the North Sea with the loss of 123 lives.

In 2001, *Petrobras 36* in Brazil exploded and sank five days later, killing 11 people.

Given the number of grievances and conspiracy theories that involve the oil business, and the importance of gas/oil platforms to the economy, platforms in the United States are believed to be potential terrorist targets. Agencies and military units responsible for maritime counterterrorism in the US (Coast Guard, Navy SEALs, Marine Recon) often train for platform raids.

On April 21, 2010, the *Deepwater Horizon* platform, 52 miles off-shore of Venice, Louisiana, (property of Transocean and leased to BP) exploded, killing 11 people, and sank two days later. The resulting undersea gusher, conservatively estimated to exceed 20 million gallons as of early June, 2010, became the worst oil spill in US history, eclipsing the Exxon Valdez oil spill.

Ecological effects



NOAA map of the 3,858 oil and gas platforms extant in the Gulf of Mexico in 2006

In British waters, the cost of removing all platform rig structures entirely was estimated in 1995 at £1.5 billion, and the cost of removing all structures including pipelines—called a "clean sea" approach—at £3 billion.

In the United States, Marine Biologist Milton Love has proposed that oil platforms off the California coast be retained as artificial reefs, instead of being dismantled (at great cost), because he has found them to be havens for many of the species of fish which are otherwise declining in the region, in the course of 11 years of research. Love is funded mainly by government agencies, but also in small part by the California Artificial Reef Enhancement Program. NOAA has said it is considering this course of action, but wants money to study the effects of the rigs in detail. Divers have been used to assess the fish populations surrounding the platforms. In the Gulf of Mexico, more than 200 platforms have been similarly converted.

Deepest oil platforms

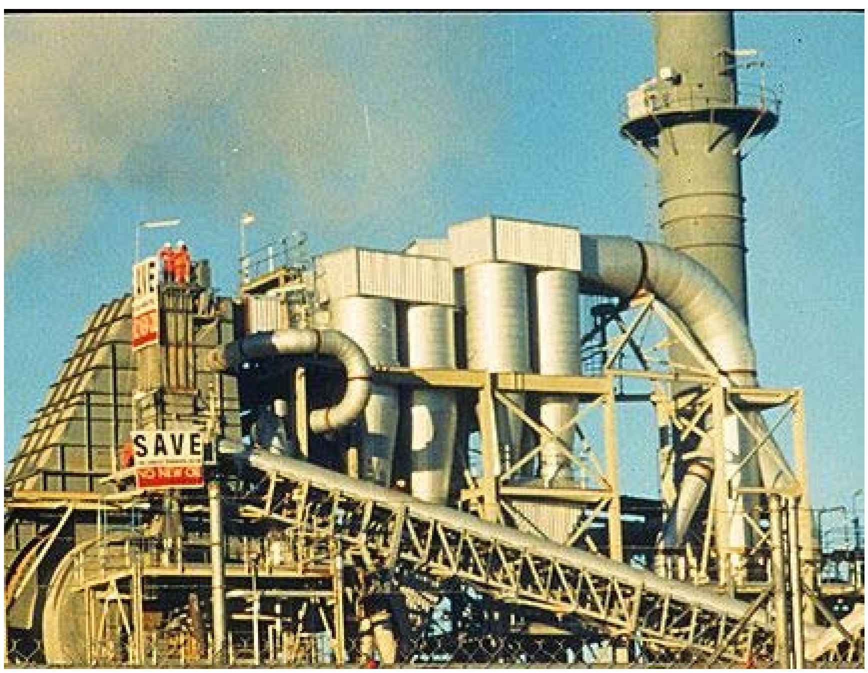
The world's deepest oil platform is the floating Perdido which is a spar platform in the Gulf of Mexico in a water depth of 2,438 metres (7,999 ft).

Non-floating compliant towers and fixed platforms, by water depth:

- Petronius Platform, 531 m (1,742 ft)
- Baldpate Platform, 502 m (1,647 ft)
- Bullwinkle Platform, 413 m (1,355 ft)
- Pompano Platform, 393 m (1,289 ft)
- Benguela-Belize Lobito-Tomboco Platform, 390 m (1,280 ft)
- Tombua Landana Platform, 366 m (1,201 ft)
- Harmony Platform, 366 m (1,201 ft)
- Troll A Platform, 303 m (994 ft)
- Gulfaks C Platform, 217 m (712 ft)

Chapter 10

Oil Shale Industry

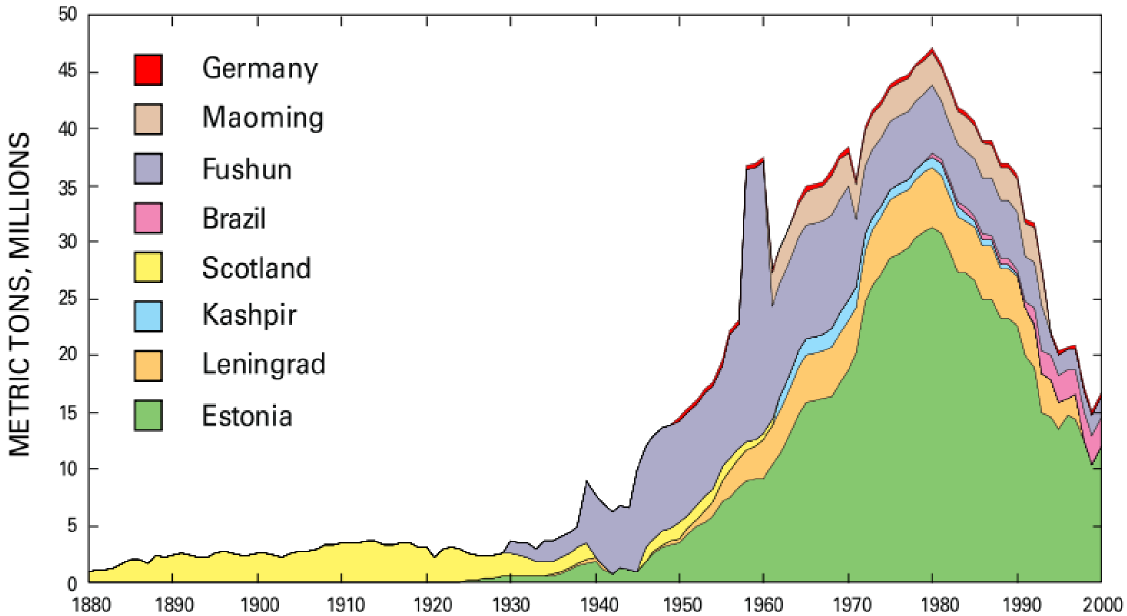


Stuart oil shale pilot plant (now dismantled)

Oil shale industry is an industry of mining and processing of oil shale—a fine-grained sedimentary rock, containing significant amounts of kerogen (a solid mixture of organic chemical compounds), from which liquid hydrocarbons can be manufactured. The industry has developed in Brazil, China, Estonia and to some extent in Germany, Israel and Russia. Several other countries are currently conducting research on their oil shale reserves and production methods to improve efficiency and recovery. However, Australia has halted their pilot projects due to environmental concerns. Estonia accounts for about 70 % of the world's oil shale production.

Oil shale has been used for industrial purposes since the early 17th century, when it was mined for its minerals. Since the late 19th century, shale oil has also been used for its oil content and as a low grade fuel for power generation. However, barring countries having significant oil shale deposits, its use for power generation is not particularly widespread. Similarly, oil shale is a source for production of synthetic crude oil and it is seen as a solution towards increasing domestic production of oil in countries that are reliant on imports.

History



Production of oil shale in millions of metric tons from Estonia (Estonia deposit), Russia (Leningrad and Kashpir deposits), United Kingdom (Scotland, Lothians), Brazil (Iratí Formation), China (Maoming and Fushun deposits), and Germany (Dotternhausen) from 1880 to 2000.

Oil shale has been used since ancient times. Modern industrial oil shale mining began in 1837 at the Autun mines in France, followed by Scotland, Germany and several other countries. The oil shale industry started growing just before World War I because of the mass production of automobiles and trucks and the supposed shortage of gasoline for transportation needs. In 1924, the Tallinn Power Plant was the first power plant in the world to switch to oil shale firing. However, following the end of World War II, the oil shale industry was phased-out in most of countries due to high processing costs and the discovery of large supplies of easily accessible and cheaper crude oil. Oil shale production however, continued to grow in Estonia, Russia and China. Following the 1973 oil crisis, the oil shale industry was restarted in several countries, but in the 1980s, when oil prices fell, many industries faced closure. The global oil shale industry mainly started growing during mid-1990s. In 2003, the oil shale development program was initiated in the United States, and in 2005, the commercial leasing program for oil shale and tar sands was introduced.

As of May 2007, Estonia is actively engaged in exploitation of oil shale on a significant scale and accounts for 70 % of the world's processed oil shale. Estonia is unique in that its oil shale deposit account for just 17 % of total deposits in European Union but it generates 90 % of its power from oil shale. Oil shale industry in Estonia employs 7,500 people, which is about 1 % of national employment, accounting for 4 % of its gross domestic product.

Mining

Oil shale is mined either by traditional underground mining or surface mining techniques. There are several mining methods available, but the common aim of all these methods is to fragment the oil shale deposits in order to enable the transport of shale fragments to a power plant or retorting facility. The main methods of surface mining are *open pit mining* and *strip mining*. An important method of sub-surface mining is the *room-and-pillar method*. In this method, the material is extracted across a horizontal plane while leaving "pillars" of untouched material to support the roof. These pillars reduce the likelihood of a collapse. Oil shale can also be obtained as a by-product of coal mining.

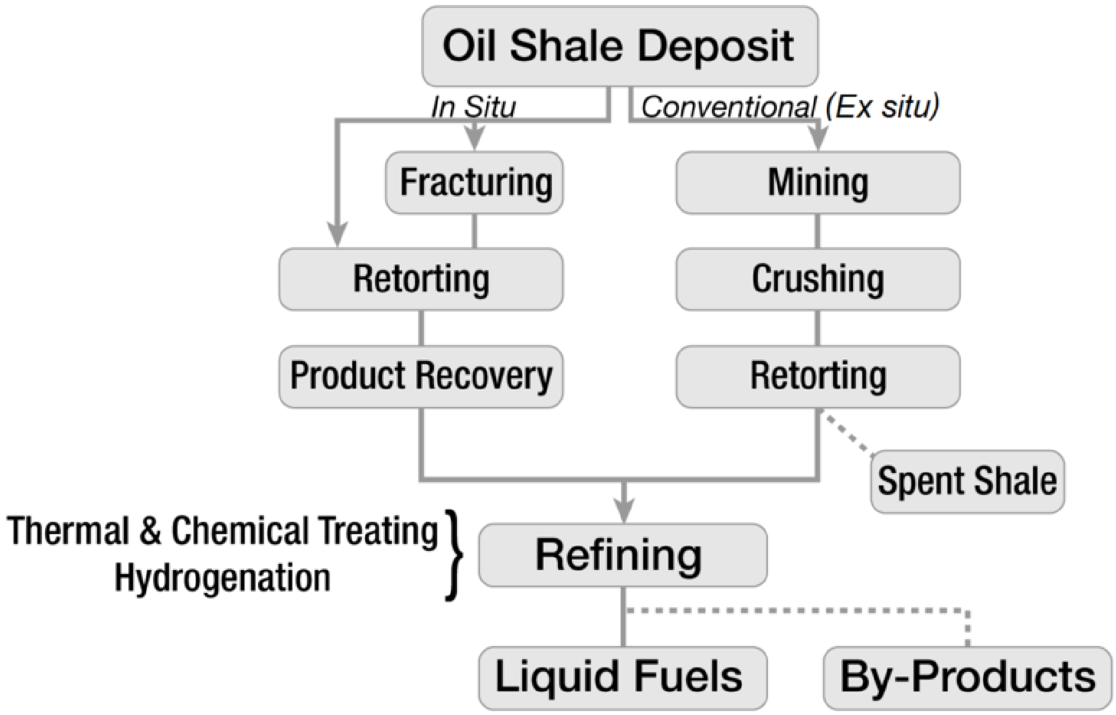
The largest oil shale mine in the world is the Estonia Mine, operated by Eesti Põlevkivi. In 2005, Estonia mined 14.8 million tonnes of oil shale. During the same period, mining permits were issued for almost 24 million tonnes, with applications being received for mining an additional 26 million tonnes. In 2008, the Estonian Parliament approved the "National Development Plan for the Use of Oil Shale 2008-2015", which limits the annual extraction of oil shale to 20 million tonnes.

Power generation

Oil shale can be used as a fuel in thermal power plants, wherein oil shale is burnt like coal to drive the steam turbines. As of 2008, there are oil shale-fired power plants in Estonia with a generating capacity of 2,967 megawatts (MW), Israel (12.5 MW), China (12 MW), and Germany (9.9 MW). Also Romania and Russia have run oil shale-fired power plants, but have shut them down or switched to other fuels like natural gas. Jordan and Egypt have announced their plans to construct oil shale-fired power plants, while Canada and Turkey plan to burn oil shale at the power plants along with coal.

Thermal power plants which use oil shale as a fuel mostly employ two types of combustion methods. The traditional method is *Pulverized combustion* (PC) which is used in the older units of oil shale-fired power plants in Estonia, while the more advanced method is *Fluidized bed combustion* (FBC), which is used by Holcim cement factory in Dotternhausen, Germany, and in PAMA power plant at Mishor Rotem in Israel. The main FBC technologies are *Bubbling fluidized bed combustion* (BFBC) and *Circulating fluidized bed combustion* (CFBC). There are more than 60 power plants around the world, which are using CFBC technology for combustion of coal and lignite, but only two new units at Narva Power Plants in Estonia, and one at Huadian Power Plant in China use CFBC technology for combustion of oil shale. The most advanced and efficient oil shale combustion technology is *Pressurized fluidized-bed combustion* (PFBC). However, this technology is still premature and is in its nascent stage.

Oil extraction



Overview of shale oil extraction

As of 2008, the major shale oil producers are Estonia, Brazil and China, while Australia, USA, Canada and Jordan have planned to setup or restart shale oil production. In 2005, the global oil shale production was 684,000 tonnes. Although the largest shale oil producer in 2005 was Estonia, it is expected that as of 2007, China has overtaken the position of the largest producer in the world.

Although there are several oil shale retorting technologies, only four technologies are currently in commercial use. These are Kiviter, Galoter, Fushun, and Petrosix. The two main methods of extracting oil from shale are *ex-situ* and *in-situ*. In *ex-situ* method, the oil shale is mined and transported to the retort facility in order to extract the oil. The *in-situ* method converts the kerogen while it is still in the form of an oil shale deposit, and then extracts it via a well, where it rises up as normal petroleum.

Companies with shale oil production projects (operational or in the developmental phase)

Company	Location	Method	Status	Annual Production
Ambre Energy	Utah, USA	Conduction through a wall (Oil-Tech process)	Pilot project	
American Shale Oil Corporation	Colorado, USA	True in-situ process (The EGL Oil Shale Process)	Testing	
Chevron Shale Oil Company	Colorado, USA	Modified in-situ process (CRUSH process)	Testing	
Eesti Energia	Narva, Estonia	Hot recycled solids (Galoter process)	Operational	1.1 million barrels
		Hot recycled solids (Enefit process)	Construction	(2010)
ExxonMobil	Colorado, USA	Modified in-situ process; reactive fluids (ExxonMobil Electrofrac)	Testing	
Fushun Mining Group	Fushun, China	Internal combustion (Fushun process)	Operational	2.2 million barrels
		Hot solids recycle (Alberta Taciuk Process)	Commissioning	
Hom Tov	Mishor Rotem, Israel	Conduction through a wall (Hom Tov co-pyrolysis process)	Testing	
Independent Energy Partners	Colorado, USA	True in-situ process (fuel cell process)	Testing	
Kiviõli Keemiatööstus	Kiviõli, Estonia	Internal combustion	Operational	0.3 million barrels

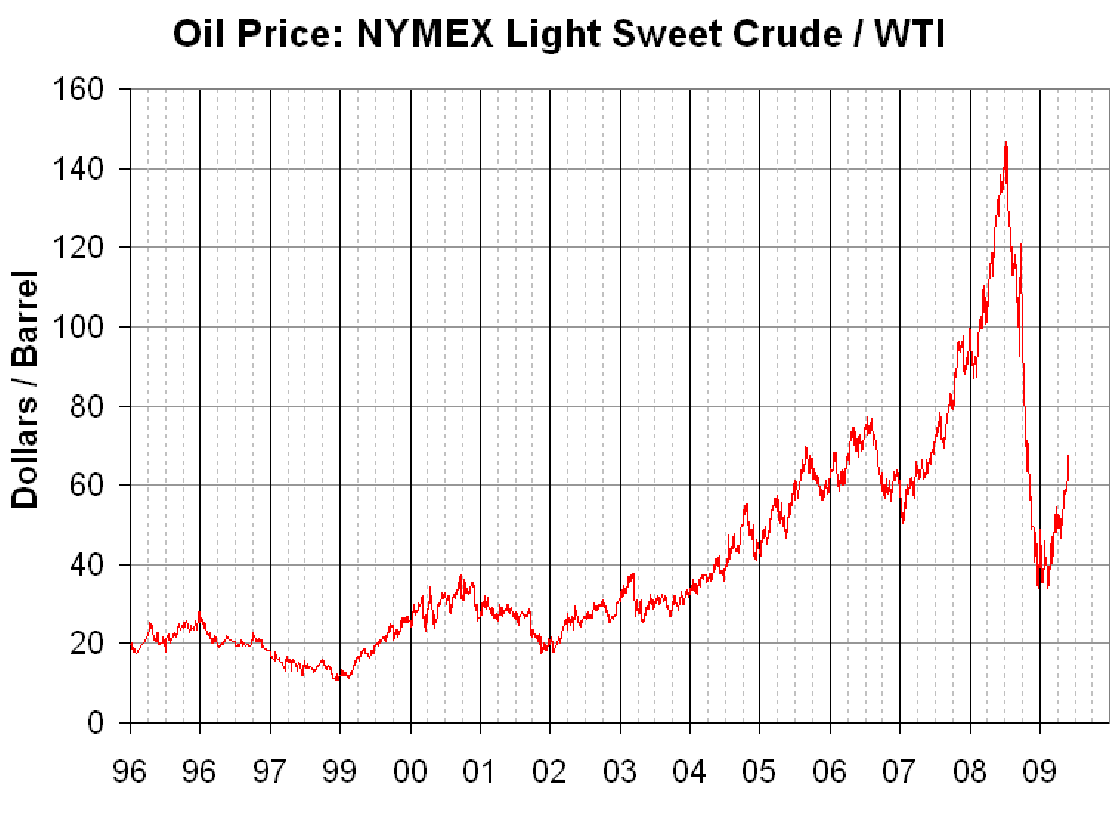
		(Kiviter process)		
Mountain West Energy	Utah, USA	True in-situ process (IGE process)	Testing	
Oil Shale Exploration Company	Utah, USA	Hot recycled solids (Alberta Taciuk Process) Externally generated hot gas (Petrosix process) Hot recycle solids (Enefit process)	Tested Studied Studying	
Petrobras	São Mateus do Sul, Paraná, Brazil	Externally generated hot gas (Petrosix process)	Operational	2.2 million barrels (2010)
Queensland Energy Resources	Stuart Deposit, Queensland, Australia	Hot solids recycle (Alberta Taciuk Process) Externally generated hot gas (Paraho Indirect process)	Demolished Construction	
Red Leaf Resources	Utah, USA	Conduction through a wall (EcoShale In-Capsule Process)	Testing	
Shale Technologies LLC	Rifle, Colorado, USA	Internal combustion (Paraho Direct process)	Pilot project	
Shell Frontier Oil and Gas	Colorado, USA	True in-situ process (ICP)	Pilot project	
VKG Oil	Kohtla-Järve, Estonia	Internal combustion (Kiviter process) Hot solids recycle (Galoter process)	Operational Operational	1.6 million barrels (2010).

Other industrial uses

Oil shale is used for cement production by Kunda Nordic Cement in Estonia, by Holcim in Germany, and by Fushun cement factory in China. Oil shale can also be used for production of different chemical products, construction materials, and pharmaceutical products. However, use of oil shale for production of these products is still very rare and in experimental stages only.

Some oil shales are suitable source for sulfur, ammonia, alumina, soda ash, and nahcolite which occur as shale oil extraction byproducts. Some oil shales can also be used for uranium and other rare chemical element production. During 1946–1952, a marine variety of Dictyonema shale was used for uranium production in Sillamäe, Estonia, and during 1950–1989 alum shale was used in Sweden for the same purpose. Oil shale gas can also be used as a substitute for natural gas. After World War II, Estonian-produced oil shale gas was used in Leningrad and the cities in North Estonia. However, at the current price level of natural gas, this is not economically feasible.

Economics



NYMEX light-sweet crude oil prices 1996–2009 (not adjusted for inflation)

During the early 20th century, the crude-oil industry expanded. Since then, the various attempts to develop oil shale deposits have succeeded only when the cost of shale-oil production in a given region comes in below the price of crude oil or its other substitutes.

According to a survey conducted by the RAND Corporation, the cost of producing a barrel of shale oil at a hypothetical surface retorting complex in the United States (comprising a mine, retorting plant, upgrading plant, supporting utilities, and spent shale reclamation), would range between US$70–95 ($440–600/m^3), adjusted to 2005 values. Assuming a gradual increase in output after the start of commercial production, the analysis projects a gradual reduction in processing costs to $30–40 per barrel ($190–250/m^3) after achieving the milestone of 1 billion barrels (160×10^6 m^3). Royal Dutch Shell has announced that its Shell ICP technology would realize a profit when crude oil prices are higher than $30 per barrel ($190/m^3), while some technologies at full-scale production assert profitability at oil prices even lower than $20 per barrel ($130/m^3).

To increase the efficiency of oil shale retorting and by this the viability of the shale oil production, researchers have proposed and tested several co-pyrolysis processes, in which other materials such as biomass, peat, waste bitumen, or rubber and plastic wastes are retorted along with the oil shale. Some modified technologies propose combining a fluidized bed retort with a circulated fluidized bed furnace for burning the by-products of pyrolysis (char and oil shale gas) and thereby improving oil yield, increasing throughput, and decreasing retorting time.

In a 1972 publication by the journal *Pétrole Informations* (ISSN 0755-561X), shale oil production was unfavorably compared to the coal liquefaction. The article stated that coal liquefaction was less expensive, generated more oil, and created fewer environmental impacts than oil shale extraction. It cited a conversion ration of 650 litres (170 U.S. gal; 140 imp gal) of oil per one tonne of coal, as against 150 litres (40 U.S. gal; 33 imp gal) of shale oil per one tonne of oil shale.

A critical measure of the viability of oil shale as an energy source lies in the ratio of the energy produced from oil shale to the energy used in its mining and processing, a ratio known as "Energy Returned on Energy Invested" (EROEI). A 1984 study estimated the EROEI of the various known oil shale deposits as varying between 0.7–13.3 although known oil shale extraction development projects assert an EROI between 3 to 10. Royal Dutch Shell has reported an EROEI of three to four on its *in situ* development, Mahogany Research Project. The water needed in the oil shale retorting process offers an additional economic consideration: this may pose a problem in areas with water scarcity.

Environmental considerations

Oil shale mining involves a number of environmental impacts, more pronounced in surface mining than in underground mining. They include acid drainage induced by the sudden rapid exposure and subsequent oxidation of formerly buried materials, the introduction of metals into surface-water and groundwater, increased erosion, sulfur-gas emissions, and air pollution caused by the production of particulates during processing, transport, and support activities. In 2002, about 97% of air pollution, 86% of total waste and 23% of water pollution in Estonia came from the power industry, which uses oil shale as the main resource for its power production.

Oil shale extraction can damage the biological and recreational value of land and the ecosystem in the mining area. Combustion and thermal processing generate waste material. In addition, the atmospheric emissions from oil shale processing and combustion include carbon dioxide, a greenhouse gas. Environmentalists oppose production and usage of oil shale, as it creates even more greenhouse gases than conventional fossil fuels. Section 526 of the *Energy Independence And Security Act* prohibits United States government agencies from buying oil produced by processes that produce more greenhouse gas emissions than would traditional petroleum. Experimental *in situ* conversion processes and carbon capture and storage technologies may reduce some of these concerns in the future, but at the same time they may cause other problems, including groundwater pollution.

Concerns have been prominently raised over the oil shale industry's use of water, particularly in arid regions where water consumption is a sensitive issue. In some cases, oil shale mining requires the lowering of groundwater levels below the level of the oil shale strata, which may affect the surrounding arable land and forest. Above-ground retorting typically consumes between one and five barrels of water per barrel of produced shale oil, depending on technology. Water is usually used for spent shale cooling and oil shale ash disposal. *In situ* processing, according to one estimate, uses about one-tenth as much water.

A 2008 programmatic environmental impact statement issued by the United States Bureau of Land Management stated that surface mining and retort operations produce 2 to 10 U.S. gallons (7.6 to 38 l; 1.7 to 8.3 imp gal) of waste water per 1 short ton (0.91 t) of processed oil shale.

Environmental activists, including members of Greenpeace, have organized strong protests against the oil shale industry. In one result, Queensland Energy Resources put the proposed Stuart Oil Shale Project in Australia on hold in 2004.

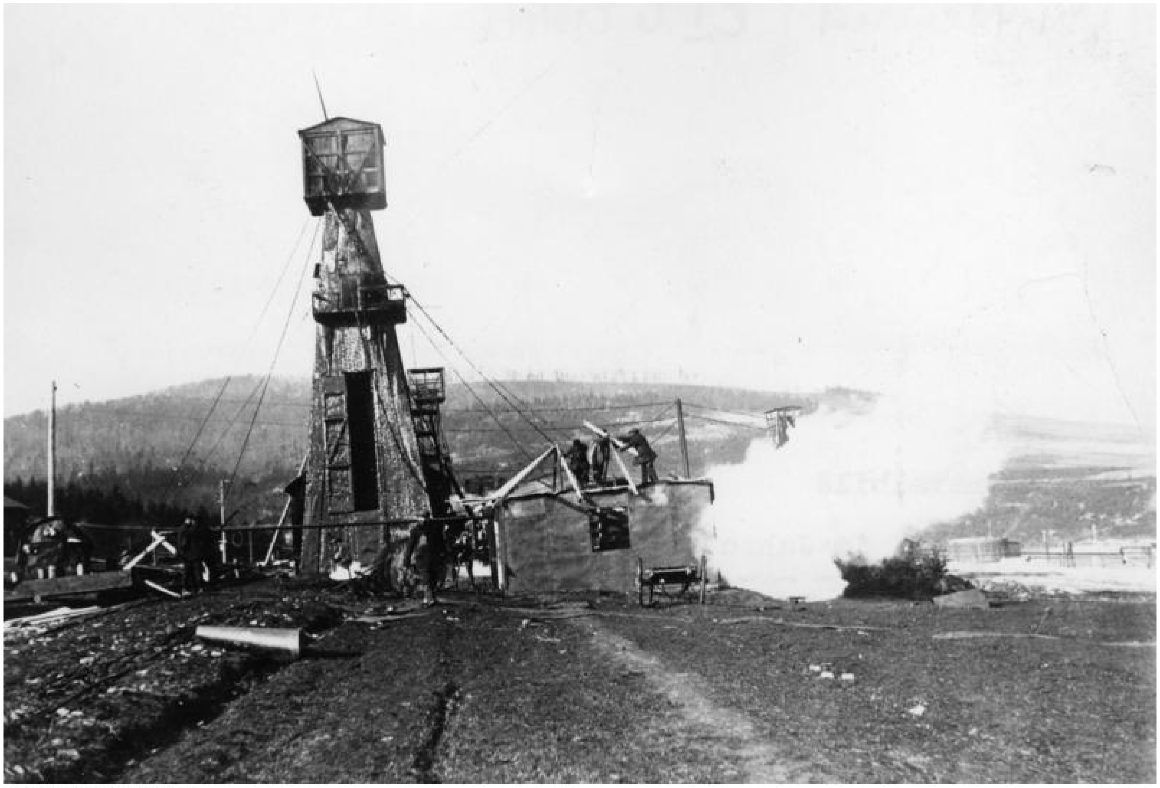
Chapter 11

Oil Well

The pumpjack, such as this one located south of Midland, Texas, is a common sight in West Texas.

An **oil well** is a general term for any boring through the earth's surface that is designed to find and acquire petroleum oil hydrocarbons. Usually some natural gas is produced along with the oil. A well that is designed to produce mainly or only gas may be termed a **gas well**.

History



Bundesarchiv, Bild 183-R00740
Foto: o.Ang. | 1909

Oil extraction in Boryslav in Galicia in 1909.

The earliest known oil wells were drilled in China in 347 CE. They had depths of up to about 800 feet (240 m) and were drilled using bits attached to bamboo poles. The oil was burned to evaporate brine and produce salt. By the 10th century, extensive bamboo pipelines connected oil wells with salt springs. The ancient records of China and Japan are said to contain many allusions to the use of natural gas for lighting and heating. Petroleum was known as *burning water* in Japan in the 7th century.

The Middle East's petroleum industry was established by the 8th century, when the streets of the newly constructed Baghdad were paved with tar, derived from petroleum that became accessible from natural fields in the region. Petroleum was distilled by the Persian alchemist Muhammad ibn Zakarīya Rāzi (Rhazes) in the 9th century, producing chemicals such as kerosene in the alembic (*al-ambiq*), and which was mainly used for kerosene lamps. Arab and Persian chemists also distilled crude oil in order to produce flammable products for military purposes. Through Islamic Spain, distillation became available in Western Europe by the 12th century.

Some sources claim that from the 9th century, oil fields were exploited in the area around modern Baku, Azerbaijan, to produce naphtha for the petroleum industry. These fields were described by Marco Polo in the 13th century, who described the output of those oil wells as hundreds of shiploads. When Marco Polo in 1264 visited the Azerbaijani city of

Baku, on the shores of the Caspian Sea, he saw oil being collected from seeps. He wrote that "on the confines toward Geirgine there is a fountain from which oil springs in great abundance, inasmuch as a hundred shiploads might be taken from it at one time."

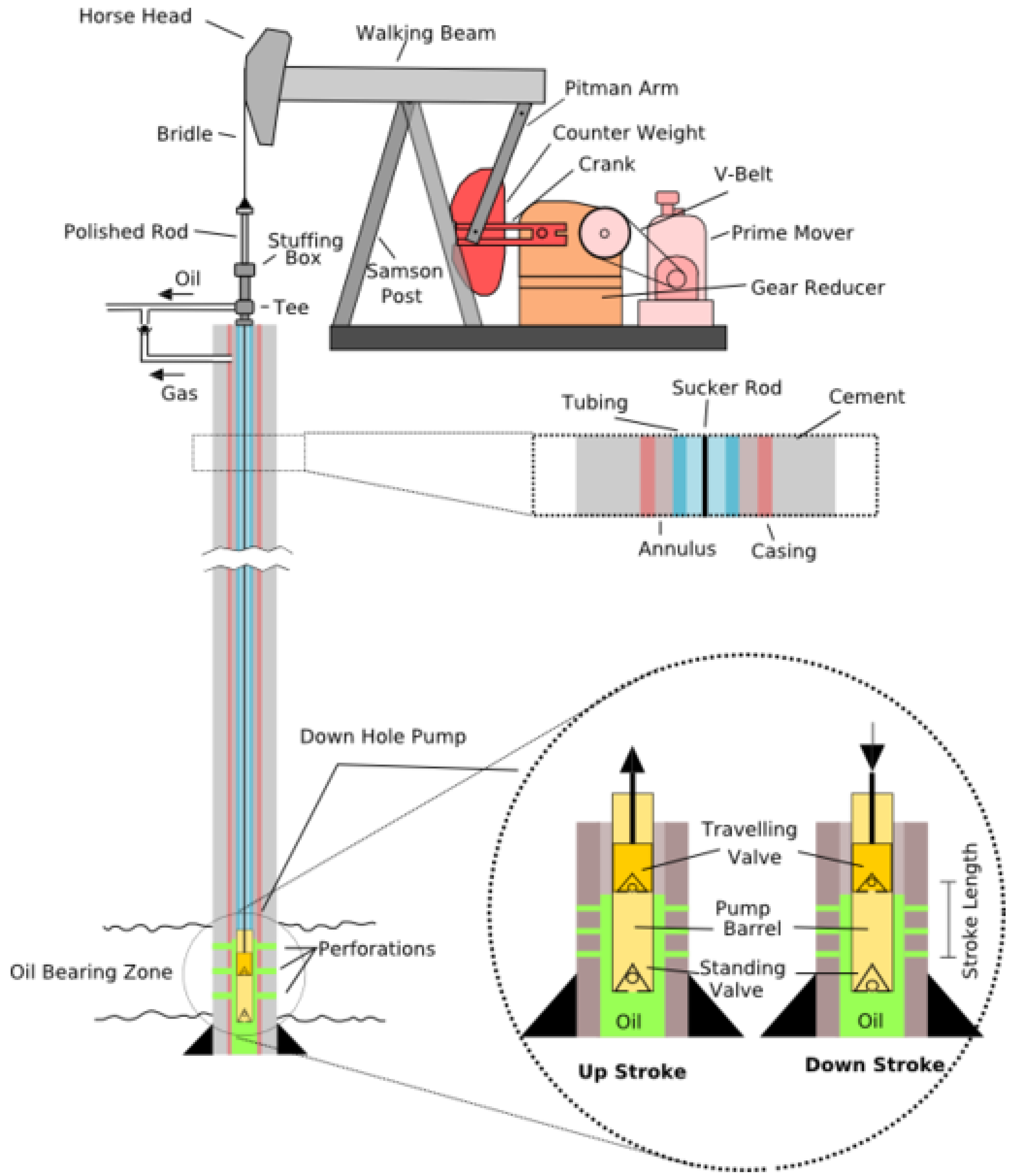
A FOUNTAIN AT BIBI-EIBAT IN FLAMES, BAKU

1904 oil well fire at Bibi-Eibat.

Shallow pits were dug at the Baku seeps in ancient times to facilitate collecting oil, and hand-dug holes up to 35 metres (115 ft) deep were in use by 1594. These holes were essentially oil wells. Apparently 116 of these wells in 1830 produced 3,840 metric tons (about 28000 barrels) of oil. Also, offshore drilling started up at Baku at Bibi-Eibat field in 1846, about the same time that the first offshore oil well was drilled in 1896 at the Summerland Oil Field on the California Coast.

The earliest oil wells in modern times were drilled percussively, by hammering a cable tool into the earth. Soon after, cable tools were replaced with rotary drilling, which could drill boreholes to much greater depths and in less time. The record-depth Kola Borehole used non-rotary mud motor drilling to achieve a depth of over 12,000 metres (39,000 ft). Until the 1970s, most oil wells were vertical, although lithological and mechanical imperfections cause most wells to deviate at least slightly from true vertical. However, modern directional drilling technologies allow for strongly deviated wells which can, given sufficient depth and with the proper tools, actually become horizontal. This is of great value as the reservoir rocks which contain hydrocarbons are usually horizontal, or sub-horizontal; a horizontal wellbore placed in a production zone has more surface area in the production zone than a vertical well, resulting in a higher production rate. The use of deviated and horizontal drilling has also made it possible to reach reservoirs several kilometers or miles away from the drilling location (extended reach drilling), allowing for the production of hydrocarbons located below locations that are either difficult to place a drilling rig on, environmentally sensitive, or populated.

Life of a well



A schematic of a typical oil well being produced by a pumpjack, which is used to produce the remaining recoverable oil after natural pressure is no longer suficient to raise oil to the surface.

The creation and life of a well can be divided up into five segments:

- Planning
- Drilling
- Completion
- Production
- Abandonment

Drilling

The well is created by drilling a hole 5 to 50 inches (127.0 mm to 914.4 mm) in diameter into the earth with a drilling rig that rotates a drill string with a bit attached. After the hole is drilled, sections of steel pipe (casing), slightly smaller in diameter than the borehole, are placed in the hole. Cement may be placed between the outside of the casing and the borehole. The casing provides structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high pressure zones from each other and from the surface.

With these zones safely isolated and the formation protected by the casing, the well can be drilled deeper (into potentially more-unstable and violent formations) with a smaller bit, and also cased with a smaller size casing. Modern wells often have two to five sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing.

Mud log in process, a common way to study the lithology when drilling oil wells.

To drill the well

- The drill bit, aided by the weight of thick walled pipes called "drill collars" above it, cuts into the rock. There are different types of drill bit; some cause the rock to disintegrate by compressive failure, while others shear slices off the rock as the bit turns.

- Drilling fluid, a.k.a. "mud", is pumped down the inside of the drill pipe and exits at the drill bit. Drilling mud is a complex mixture of fluids, solids and chemicals that must be carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well. Particular functions of the drilling mud include cooling the bit, lifting rock cuttings to the surface, preventing destabilisation of the rock in the wellbore walls and overcoming the pressure of fluids inside the rock so that these fluids do not enter the wellbore.
- The generated rock "cuttings" are swept up by the drilling fluid as it circulates back to surface outside the drill pipe. The fluid then goes through "shakers" which strain the cuttings from the good fluid which is returned to the pit. Watching for abnormalities in the returning cuttings and monitoring pit volume or rate of returning fluid are imperative to catch "kicks" early. A "kick" is when the formation pressure at the depth of the bit is more than the hydrostatic head of the mud above, which if not controlled temporarily by closing the blowout preventers and ultimately by increasing the density of the drilling fluid would allow formation fluids and mud to come up through the drill pipe uncontrollably.
- The pipe or drill string to which the bit is attached is gradually lengthened as the well gets deeper by screwing in additional 30-foot (9 m) sections or "joints" of pipe under the kelly or topdrive at the surface. This process is called making a connection. Usually, joints are combined into three joints equaling one stand. Some smaller rigs only use two joints and some rigs can handle stands of four joints.

This process is all facilitated by a drilling rig which contains all necessary equipment to circulate the drilling fluid, hoist and turn the pipe, control downhole, remove cuttings from the drilling fluid, and generate on-site power for these operations.

Modern driller Argentina.

Completion

After drilling and casing the well, it must be 'completed'. Completion is the process in which the well is enabled to produce oil or gas.

In a cased-hole completion, small holes called perforations are made in the portion of the casing which passed through the production zone, to provide a path for the oil to flow from the surrounding rock into the production tubing. In open hole completion, often 'sand screens' or a 'gravel pack' is installed in the last drilled, uncased reservoir section. These maintain structural integrity of the wellbore in the absence of casing, while still allowing flow from the reservoir into the wellbore. Screens also control the migration of formation sands into production tubulars and surface equipment, which can cause washouts and other problems, particularly from unconsolidated sand formations in offshore fields.

After a flow path is made, acids and fracturing fluids are pumped into the well to fracture, clean, or otherwise prepare and stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore. Finally, the area above the reservoir section of the well is packed off inside the casing, and connected to the surface via a smaller diameter pipe called tubing. This arrangement provides a redundant barrier to leaks of hydrocarbons as well as allowing damaged sections to be replaced. Also, the smaller crossectional area of the tubing produces reservoir fluids at an increased velocity in order to minimize liquid fallback that would create additional back pressure, and shields the casing from corrosive well fluids.

In many wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by other producing wells, or in low permeability oil reservoirs. Installing a smaller diameter tubing may be enough to help the production, but artificial lift methods may also be needed. Common solutions include downhole pumps, gas lift, or surface pump jacks. Many new systems in the last ten years have been introduced for well completion. Multiple packer systems with frac ports or port collars in an all in one system have cut completion costs and improved production, especially in the case of horizontal wells. These new systems allow casings to run into the lateral zone with proper packer/frac port placement for optimal hydrocarbon recovery.

Production

The production stage is the most important stage of a well's life, when the oil and gas are produced. By this time, the oil rigs and workover rigs used to drill and complete the well have moved off the wellbore, and the top is usually outfitted with a collection of valves called a Christmas tree or Production trees. These valves regulate pressures, control flows, and allow access to the wellbore in case further completion work is needed. From the outlet valve of the production tree, the flow can be connected to a distribution network of pipelines and tanks to supply the product to refineries, natural gas compressor stations, or oil export terminals.

As long as the pressure in the reservoir remains high enough, the production tree is all that is required to produce the well. If the pressure depletes and it is considered economically viable, an artificial lift method mentioned in the completions section can be employed.

Workovers are often necessary in older wells, which may need smaller diameter tubing, scale or paraffin removal, acid matrix jobs, or completing new zones of interest in a shallower reservoir. Such remedial work can be performed using workover rigs – also known as *pulling units* or *completion rigs* – to pull and replace tubing, or by the use of well intervention techniques utilizing coiled tubing. Depending on the type of lift system and wellhead a rod rig or flushby can be used to change a pump without pulling the tubing.

Enhanced recovery methods such as water flooding, steam flooding, or CO_2 flooding may be used to increase reservoir pressure and provide a "sweep" effect to push hydrocarbons out of the reservoir. Such methods require the use of injection wells (often chosen from old production wells in a carefully determined pattern), and are used when facing problems with reservoir pressure depletion, high oil viscosity, or can even be employed early in a field's life. In certain cases – depending on the reservoir's geomechanics –

reservoir engineers may determine that ultimate recoverable oil may be increased by applying a waterflooding strategy early in the field's development rather than later. Such enhanced recovery techniques are often called "tertiary recovery".

Abandonment

A well is said to reach an "economic limit" when its production rate does not cover the expenses, including taxes.

The economic limit for oil and gas wells can be expressed using these formulae:

Oil fields:

$$EL_{oil} = \frac{WI \times LOE}{NRI[P_o + (P_g \times GOR)/1{,}000] \times (1 - T)}$$

Gas fields:

$$EL_{gas} = \frac{WI \times LOE}{NRI[(P_o \times Y) + P_g] \times (1 - T)}$$

Where:
EL_{oil} is an oil well's economic limit in oil barrels per month (bbls/month).
EL_{gas} is a gas well's economic limit in thousand standard cubic feet per month (MSCF/month).
P_o,P_g are the current prices of oil and gas in dollars per barrels and dollars per MSCF respectively.
LOE is the lease operating expenses in dollars per well per month.
WI working interest, as a fraction.
NRI net revenue interest, as a fraction.
GOR gas/oil ratio as bbls/MSCF.
Y condensate yield as barrel/million standard cubic feet.
T production and severance taxes, as a fraction.

When the economic limit is raised, the life of the well is shortened and proven oil reserves are lost. Conversely, when the economic limit is lowered, the life of the well is lengthened.

When the economic limit is reached, the well becomes a liability and is abandoned. In this process, tubing is removed from the well and sections of well bore are filled with cement to isolate the flow path between gas and water zones from each other, as well as the surface. Completely filling the well bore with cement is costly and unnecessary. The surface around the wellhead is then excavated, and the wellhead and casing are cut off, a cap is welded in place and then buried.

At the economic limit there often is still a significant amount of unrecoverable oil left in the reservoir. It might be tempting to defer physical abandonment for an extended period of time, hoping that the oil price will go up or that new supplemental recovery techniques will be perfected. However, lease provisions and governmental regulations usually require quick abandonment; liability and tax concerns also may favor abandonment.

In theory an abandoned well can be reentered and restored to production (or converted to injection service for supplemental recovery or for downhole hydrocarbons storage), but reentry often proves to be difficult mechanically and not cost effective.

Types of wells

A natural gas well in the southeast Lost Hills Field, California, US.

Fossil-fuel wells come in many varieties. By produced fluid, there can be wells that produce oil, wells that produce oil *and* natural gas, or wells that *only* produce natural gas. Natural gas is almost always a byproduct of producing oil, since the small, light gas carbon chains come out of solution as they undergo pressure reduction from the reservoir to the surface, similar to uncapping a bottle of soda pop where the carbon dioxide effervesces. 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 is virtually valueless since it must be piped to the end user. Until recently, such unwanted gas was burned off at the wellsite, but due to environmental concerns this practice is becoming less common. Often, unwanted (or 'stranded' gas without a market) gas is pumped back into the reservoir with an 'injection' well for disposal or repressurizing the producing formation. Another solution is to export the natural gas as a liquid. Gas-to-liquid, (GTL) is a developing technology that converts stranded natural gas into synthetic gasoline, diesel or jet fuel through the Fischer-Tropsch process developed in World War II Germany. Such fuels can be transported through conventional pipelines and tankers to users. Proponents claim GTL fuels burn cleaner than comparable petroleum fuels. Most major international oil companies are in advanced development stages of GTL production, e.g. the 140,000 bbl/d (22,000 m^3/d) Pearl GTL plant in Qatar, scheduled to come online in 2011. In locations such as the United States with a high natural gas demand, pipelines are constructed to take the gas from the wellsite to the end consumer.

Another obvious way to classify oil wells is by land or offshore wells. There is very little difference in the well itself. An offshore well targets a reservoir that happens to be underneath an ocean. Due to logistics, drilling an offshore well is far more costly than an onshore well. By far the most common type is the onshore well. These wells dot the Southern and Central Great Plains, Southwestern United States, and are the most common wells in the Middle East.

Another way to classify oil wells is by their purpose in contributing to the development of a resource. They can be characterized as:

- *production wells* are drilled primarily for producing oil or gas, once the producing structure and characteristics are determined
- *appraisal wells* are used to assess characteristics (such as flow rate) of a proven hydrocarbon accumulation
- *exploration wells* are drilled purely for exploratory (information gathering) purposes in a new area
- *wildcat wells* are those drilled outside of and not in the vicinity of known oil or gas fields.

At a producing well site, active wells may be further categorised as:

- *oil producers* producing predominantly liquid hydrocarbons, but mostly with some associated gas.
- *gas producers* producing almost entirely gaseous hydrocarbons.
- *water injectors* injecting water into the formation to maintain reservoir pressure or simply to dispose of water produced with the hydrocarbons because even after treatment, it would be too oily and too saline to be considered clean for dumping overboard, let alone into a fresh water source, in the case of onshore wells. Frequently water injection has an element of reservoir management and produced water disposal.
- *aquifer producers* intentionally producing reservoir water for re-injection to manage pressure. This is in effect moving reservoir water from where it is not as useful to where it is more useful. These wells will generally only be used if produced water from the oil or gas producers is insufficient for reservoir management purposes. Using aquifer produced water rather than water from other sources is to preclude chemical incompatibility that might lead to reservoir-plugging precipitates.
- *gas injectors* injecting gas into the reservoir often as a means of disposal or sequestering for later production, but also to maintain reservoir pressure.

Lahee classification

- *New Field Wildcat* (NFW) – far from other producing fields and on a structure that has not previously produced.
- *New Pool Wildcat* (NPW) – new pools on already producing structure.
- *Deeper Pool Test* (DPT) – on already producing structure and pool, but on a deeper pay zone.
- *Shallower Pool Test* (SPT) – on already producing structure and pool, but on a shallower pay zone.
- *Outpost* (OUT) – usually two or more locations from nearest productive area.
- *Development Well* (DEV) – can be on the extension of a pay zone, or between existing wells (*Infill*).

Cost

The cost of a well depends mainly on the daily rate of the drilling rig, the extra services required to drill the well, the duration of the well programme (including downtime and weather time), and the remoteness of the location (logistic supply costs).

The daily rates of offshore drilling rigs vary by their capability, and the market availability. Rig rates reported by industry web service show that the deepwater water floating drilling rigs are over twice that of the shallow water fleet, and rates for jackup fleet can vary by factor of 3 depending upon capability.

With deepwater drilling rig rates in 2010 of around $420,000/day, and similar additional spread costs, a deep water well of duration of 100 days can cost around US$100 million.

With high performance jackup rig rates in 2010 of around $150,000, and similar service costs, a high pressure, high temperature well of duration 100 days can cost about US$30 million.

Onshore wells can be considerably cheaper, particularly if the field is at a shallow depth, where costs range from less than $1 million to $15 million for deep and difficult wells.

The total cost of an oil well mentioned does not include the costs associated with the risk of explosion and leakage of oil. Those costs include the cost of protecting against such disasters, the cost of the cleanup effort, and the hard-to-calculate cost of damage to the company's image.

Chapter 12

Oil Well Fire

An oil well on fire in Iraq

Oil well fires is the common term for oil or gas wells that have caught on fire, and burn. Oil well fires can be the result of human actions, such as accidents or arson or natural events, such as lightning. They can exist on a small scale, such as an oil field spill catching fire, or on a huge scale, as in geyser-like jets of flames from ignited high pressure wells.

Extinguishing the fires

Kuwaiti firefighters fight to secure a burning oil well in the Rumaila oilfields

Oil well fires are more difficult to extinguish than regular fires due to the enormous fuel supply for the fire. In fighting a fire at a wellhead, typically high explosives, such as dynamite, are used to consume all the local atmospheric oxygen and *snuff* the flame out. Doing so removes the oxygen necessary for the fire to burn, but the fire's fuel, whether it be natural gas or oil, is still present and oil can shower down upon the working crew.

After snuffing, the wellhead must be capped to stop the flow of oil. During this time, the fuel and oxygen required to create another inferno is present in copious amounts. At this perilous stage, one small spark (perhaps from a steel or iron tool striking a stone) or other heat source might re-ignite the oil.

To prevent re-ignition, brass or bronze tools, which do not strike sparks, or paraffin coated tools are used during the capping process. Meticulous care is used to avoid heat and sparks, or any other ignition source. The explosive re-ignition of a wellhead may take the form of an extremely powerful explosion, possibly even worse than the original blowout.

Due to recent advances in technology as well as environmental concerns, many wells today are capped while they burn. High-powered water sprays and Purple K dry chemical (a potassium bicarbonate mixture) are used to extinguish the wells.

There are several techniques used to put out oil well fires, which vary by resources available and the characteristics of the fire itself.

In essence the trade was started by Myron M. Kinley, who dominated the field in the early years. His lieutenant, Red Adair, went on to become the most famous of oil well firefighters.

Techniques include:

- Dousing with copious amounts of water
- Raising the plume- Inserting one metal casing 30 to 40 feet high over the well head (thus raising the flame above the ground). Liquid nitrogen or water is then forced in at the bottom to reduce the oxygen supply and put out the fire.
- Drill relief wells into the producing zone to redirect some of the oil and make the fire smaller. (However, most relief wells are used to pump heavy mud and cement deep into the wild well.)
- Using a gas turbine to blast a fine mist at the fire. Water is injected to the compressor section of the turbine in large quantities. This does not harm the turbine. This technique is also used for cleaning turbines.
- Using dynamite to 'blow out' the fire by blasting fuel and oxygen from the flame and consuming oxygen in the combustion. This was one of the earliest effective methods and is still widely used. The first use was by Myron Kinley's father in California in 1913
- Dry Chemical (mainly Purple K) can be used on small well fires such as those in refineries.

Special vehicles called "Athey wagons" as well as the typical bulldozer protected by corrugated steel sheeting are normally used in the process.

Effects

Oil well fires can cause the loss of millions of barrels of crude oil per day. Combined with the ecological problems caused by the large amounts of smoke and unburnt petroleum falling back to earth, oil well fires such as those seen in Kuwait can cause enormous economic losses.

Smoke from burnt crude oil contains many chemicals, including sulfur dioxide, carbon monoxide, soot, benzopyrene, Poly aromatic hydrocarbons, and dioxins. Exposure to oil well fires is commonly cited as a cause of the Gulf War Syndrome, however, studies have indicated that the firemen who capped the wells did not report any of the symptoms suffered by the soldiers.

A FOUNTAIN AT BIBI-EIBAT IN FLAMES, BAKU

1904 fire at a Bibi-Eibat oil well.

Two wells on fire, Santa Fe Springs, California, 1928

Steel cap used to cap burning oil well in Santa Fe Springs, California, 1928