
Power Station Techology
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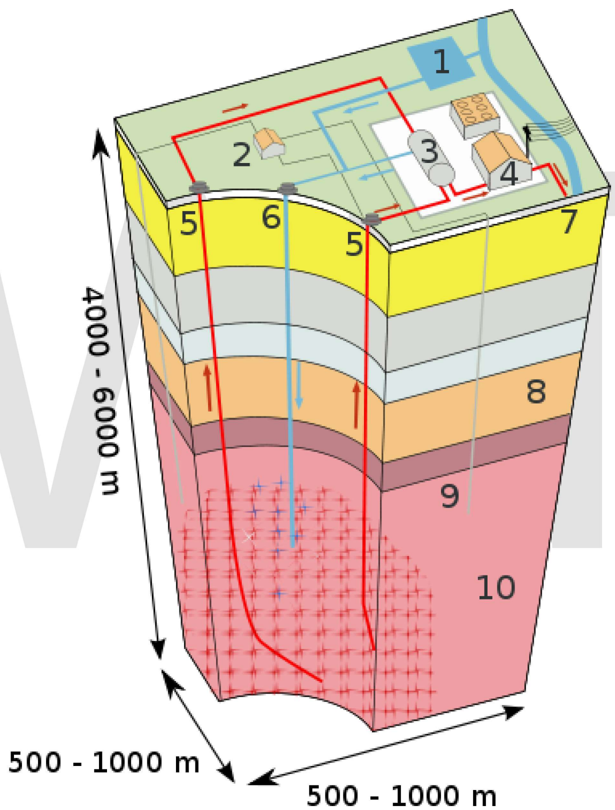
Chapter-1

Enhanced Geothermal System



Enhanced geothermal system 1:Reservoir 2:Pump house 3:Heat exchanger 4:Turbine hall 5:Production well 6:Injection well 7:Hot water to district heating 8:Porous sediments 9:Observation well 10:Crystalline bedrock

Enhanced Geothermal Systems (EGS) are a new type of geothermal power technologies that do not require natural convective hydrothermal resources. Until recently, geothermal power systems have only exploited resources where naturally occurring heat, water and rock permeability is sufficient to allow energy extraction from production wells. However, the vast majority of geothermal energy within reach of conventional techniques is in dry and non-permeable rock. EGS technologies "enhance" and/or create geothermal resources in this **hot dry rock (HDR)** through hydraulic stimulation.

When natural cracks and pores will not allow for economic flow rates, the permeability can be enhanced by pumping high pressure cold water down an injection well into the rock. The injection increases the fluid pressure in the naturally fractured rock which mobilizes shear events, enhancing the permeability of the fracture system. This process, termed hydro-shearing , used in EGS is substantially different from hydraulic tensile fracturing used in the oil & gas industries.

Water travels through fractures in the rock, capturing the heat of the rock until it is forced out of a second borehole as very hot water, which is converted into electricity using either a steam turbine or a binary power plant system. All of the water, now cooled, is injected back into the ground to heat up again in a closed loop.

EGS / HDR technologies, like hydrothermal geothermal, are expected to be baseload resources which produce power 24 hours a day like a fossil plant. Distinct from hydrothermal, HDR / EGS may be feasible anywhere in the world, depending on the economic limits of drill depth. Good locations are over deep granite covered by a thick (3–5 km) layer of insulating sediments which slow heat loss. HDR wells are expected to have a useful life of 20 to 30 years before the outflow temperature drops about 10 degrees Celsius and the well becomes uneconomic. If left for 50 to 300 years the temperature will recover.

There are HDR and EGS systems currently being developed and tested in France, Australia, Japan, Germany, the U.S. and Switzerland. The largest EGS project in the world is a 25 megawatt demonstration plant currently being developed in the Cooper Basin, Australia. The Cooper Basin has the potential to generate 5,000–10,000 MW.

EGS industry

Commercial projects are currently either operational or under development in Australia, the United States, France and Germany.

The largest project in the world is being developed in Australia's Cooper Basin by Geodynamics. The Cooper Basin project has the potential to develop 5–10 GW. Australia now has 33 firms either exploring for, drilling, or developing EGS projects. Australia's industry has been greatly aided by a national Renewable Portfolio Standard of 25% renewables by 2025, a vibrant Green Energy Credit market, and supportive R&D collaboration between government, academia, and industry.

Germany's 23 cent/kWh Feed-In Tariff (FIT) for geothermal energy has led to a surge in geothermal development, despite Germany's relatively poor geothermal resource. The Landau partial EGS project is profitable today under the FIT.

The AltaRock Energy effort is a demonstration project being conducted to prove out the company's proprietary technology at the site of an existing geothermal project owned and operated by NCPA in The Geysers, and does not include power generation. However, any steam produced by the project will be supplied to NCPA's flash turbines under a long-term contract.

Current EGS projects

Project	Type	Country	Size (MW)	Plant Type	Depth (km)	Developer	Status
Soultz	R&D	France (EU)	1.5	Binary	4.2	ENGINE	Operational
Desert Peak	R&D	United States	11–50	Binary		DOE, Ormat, GeothermEx	Development
Landau	Commercial	Germany (EU)	3	Binary	3.3	?	Operational
Paralana (Phase 1)	Commercial	Australia	7–30	Binary	4.1	Petratherm	Drilling
Cooper Basin	Commercial	Australia	250–500	Kalina	4.3	Geodynamics	Drilling
The Geysers	Demonstration	United States	(Unknown)	Flash	3.5 – 3.8	AltaRock Energy, NCPA	Suspended (Oct 2009)
Bend, Oregon	Demonstration	United States	(Unknown)		2 - 3	AltaRock Energy, Davenport Newberry, DOE	Permitting (Mar 2010)
Ogachi	R&D	Japan	(Unknown)		1.0 – 1.1		CO_2 experiments
United Downs, Redruth	Commercial	United Kingdom	10 MW	Binary	4.5	Geothermal Engineering Ltd	Fundraising
Eden Project	Commercial	United Kingdom	3 MW	Binary	3–4	EGS Energy Ltd.	Fundraising

Research and development

Australia

The Australian government has provided research funding for the development of Hot Dry Rock technology.

On 30 May 2007, then Australian opposition environmental spokesperson and current Minister for the Environment, Heritage and the Arts Peter Garrett announced that if elected at the 2007 Australian Federal Election, the Australian Labor Party would use taxpayers money to subsidise putting the necessary drilling rigs in place. In an interview, he promised:

"There are some technical difficulties and challenges there, but those people who are keen on getting Australia into geothermal say we've got this great access to resource and one of the things, interestingly, that's held them back is not having the capacity the put the drilling plants in place. And so what we intend this $50 million to go towards is to provide a one for one dollars. Match $1 from us, $1 from the industry so that they can get these drilling rigs on to site and really get the best sites identified and get the industry going."

European Union

The EU's EGS R&D project at Soultz-sous-Forêts, France, has recently connected its 1.5 MW demonstration plant to the grid. The Soultz project has explored the connection of multiple stimulated zones and the performance of triplet well configurations (1 injector/2 producers).

Portugal – Portuguese government has awarded, December 2008, an exclusive license to Geovita Ltd, to prospect and explore geothermal energy in one of the best areas in continental Portugal. An area of about 500 square kilometers that is being studied together by Geovita and Coimbra's University — Science and Technology Faculty — Earth Sciences Department, and foresees the installation of an Enhanced Geothermal System (EGS).

Induced seismicity in Basel led to the cancellation of the EGS project.

United Kingdom

Cornwall is set to host a 3MW demonstration project, based at the Eden Project, that could pave the way for a series of 50MW commercial-scale geothermal power stations in suitable areas across the country.

A commercial-scale project near Redruth is also planned. The plant, which has been granted planning permission, would generate 10MW of electricity, and 55MW of thermal energy, and is scheduled to become operational in 2013–2014.

United States

Early Days—Fenton Hill

The United States pioneered the first EGS effort—then termed Hot Dry Rock—at Fenton Hill, New Mexico with a project run by the federal Los Alamos Laboratory. It was the first attempt anywhere to make a deep, full-scale HDR reservoir, and efforts there spanned 1974 through 1992, in two phases. Ultimately, the project was unable to generate net energy, and the project was terminated.

Working at the Edges—Using EGS Technology to Improve Hydrothermal Resources

EGS funding languished for the next few years, and by the next decade, U.S. efforts focused on the less ambitious goal of improving the productivity of existing hydrothermal resources. According to the Fiscal Year 2004 Budget Request to Congress from DOE's Office of Energy Efficiency and Renewable Energy,

EGS are engineered reservoirs that have been created to extract heat from economically unproductive geothermal resources. EGS technology includes those methods and equipment that enhance the removal of energy from a resource by increasing the productivity of the reservoir. Better productivity may result from improving the reservoir's natural permeability and/or providing additional fluids to transport heat.

In Fiscal Year 2002, this vision translated into completing "preliminary designs for five competitively selected projects employing EGS technology," and the selection of one project for "full-scale development" at the Coso Hot Springs geothermal field at the U.S. Naval Weapons Air Station in China Lake, Calif., and two additional projects for "preliminary analysis from a new solicitation" at Desert Peak in Nevada and Glass Mountain in California. Funding for this effort totaled $1.5 million.

In Fiscal Year 2003, $3.5 million was appropriated to launch the Coso project, with the aim of improving the permeability of an existing poorly performing well, and to complete the conceptual design and feasibility studies at the Desert Peak and Glass Mountain sites.

The Fiscal Year 2004 request for $6 million was to "[s]tep up work on EGS cost-shared projects' at the three sites, to include "drilling and reservoir stimulation experiments" at one and drilling a production well at another.

The U.S. Department of Energy USDOE issued two Funding Opportunity Announcements (FOAs) on March 4, 2009 for enhanced geothermal systems (EGS). Together, the two FOAs offer up to $84 million over six years, including $20 million in fiscal year 2009 funding, although future funding is subject to congressional appropriations.

The DOE followed up with another FOA on March 27, 2009, of stimulus funding from the American Reinvestment and Recovery Act for $350 million, including $80 million aimed specifically at EGS proejcts,

Induced seismicity

Some induced seismicity is inevitable and, indeed, expected in EGS, which involves pumping fluids at pressure to enhance or create permeability through the use of hydro-shearing techniques. Unlike tensile failure which is the purpose of hydraulic fracturing used in the oil and gas industries, EGS seeks to induce relatively small shear failure of the rock's existing joint set to create an optimum reservoir for the transfer of heat from the rock to the water in order to produce steam. Seismicity events at the Geysers geothermal field in California have been strongly correlated with injection data.

The case of induced seismicity in Basel bears special mention because it led the city (which is a partner) to suspend the project and conduct a seismic hazard evaluation, which resulted in the cancellation of the project in December 2009.

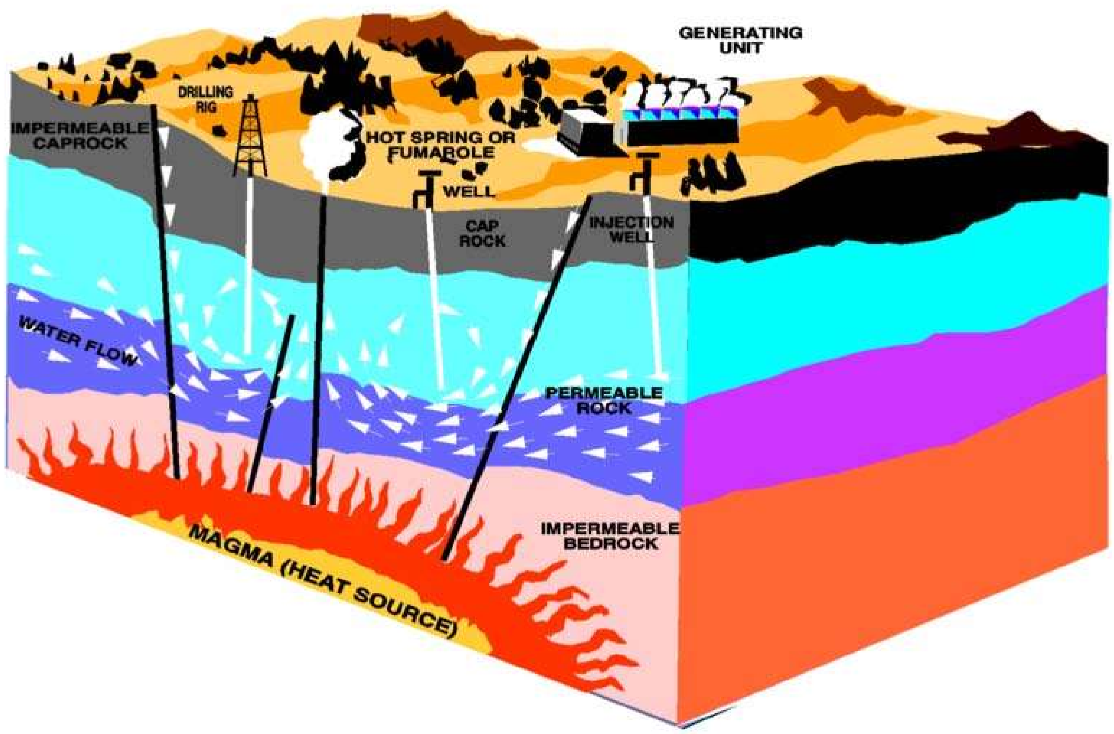
CO_2 EGS

The recently established Center for Geothermal Energy Excellence at the University of Queensland, has been awarded $18.3 million (AUS) for EGS research, a large portion of which will be used to develop CO_2 EGS technologies.

Research conducted at Los Alamos National Laboratories and Lawrence Berkeley National Laboratories examined the use of supercritical CO_2, instead of water, as the geothermal working fluid with favorable results. CO_2 has numerous advantages for EGS:

1. Greater power output
2. Minimized parasitic losses from pumping and cooling
3. Carbon sequestration
4. Minimized water use

EGS potential in the United States



Geothermal power technologies.

A 2006 report by MIT, and funded by the U.S. Department of Energy, conducted the most comprehensive analysis to date on the potential and technical status of EGS. The 18-member panel, chaired by Professor Jefferson Tester of MIT, reached several significant conclusions:

1. Resource Size: The report calculated the United States total EGS resources from 3–10 km of depth to be over 13,000 zettajoules, of which over 200 ZJ would be extractable, with the potential to increase this to over 2,000 ZJ with technology improvements — sufficient to provide all the world's current energy needs for several millennia. The report found that total geothermal resources, including hydrothermal and geo-pressured resources, to equal 14,000 ZJ — or roughly 140,000 times the total U.S. annual primary energy use in 2005.
2. Development Potential: With a modest R&D investment of $1 billion over 15 years (or the cost of one coal power plant), the report estimated that 100 GWe (gigawatts of electricity) or more could be installed by 2050 in the United States. The report further found that the "recoverable" resource (that accessible with today's technology) to be between 1.2–12.2 TW for the conservative and moderate recovery scenarios respectively.
3. Cost: The report found that EGS could be capable of producing electricity for as low as 3.9 cents/kWh. EGS costs were found to be sensitive to four main factors:

1) Temperature of the resource, 2) Fluid flow through the system measured in liters/second, 3) Drilling Costs, and 4) Power conversion efficiency.

Chapter-2

Floating Wind Turbine

The world's first full-scale floating wind turbine, Hywind, being assembled in the Åmøy Fjord near Stavanger, Norway, before deployment in the North Sea.

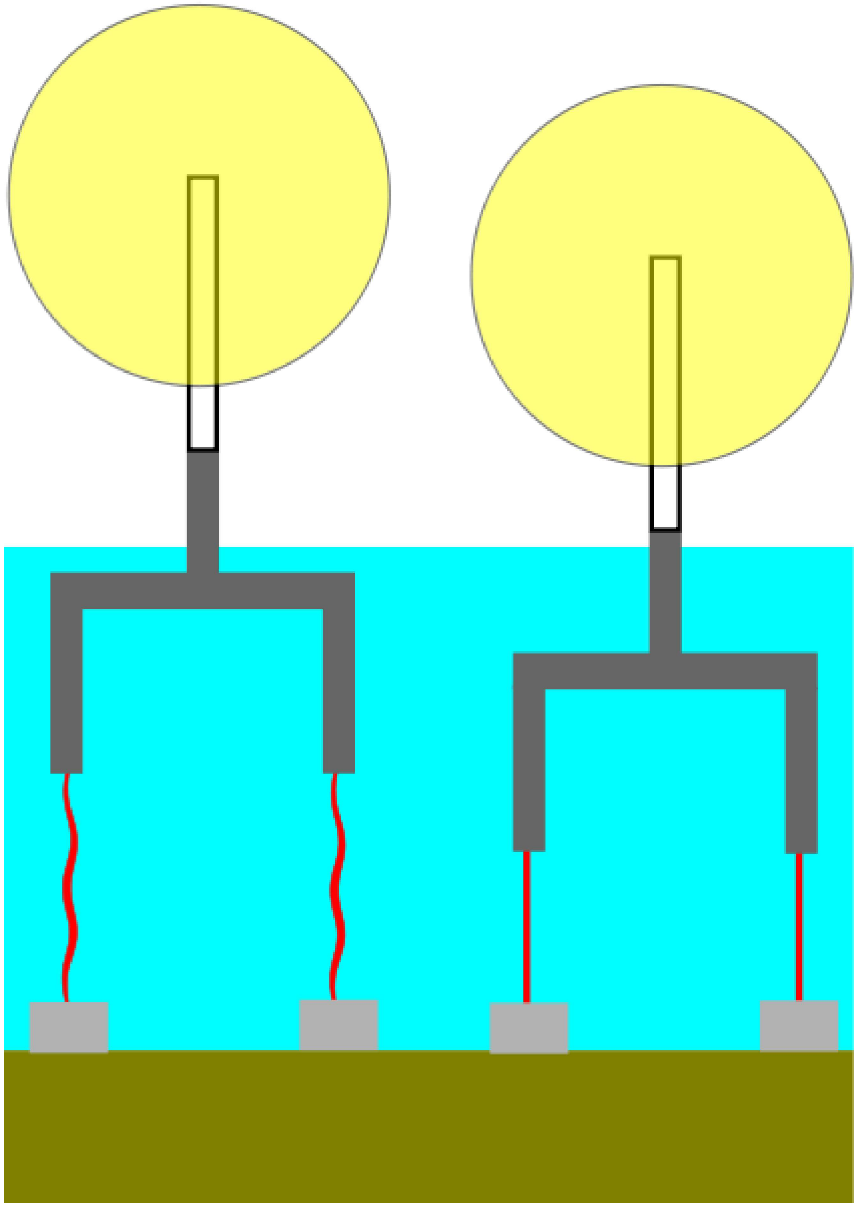
A **floating wind turbine** is an offshore wind turbine mounted on a floating structure that allows the turbine to generate electricity in water depths where bottom-mounted towers are not feasible. The wind can be stronger and steadier over water due to the absence of topographic features that may disrupt wind flow. The electricity generated is sent to shore through undersea cables. The initial capital cost of floating turbines is competitive with bottom-mounted, near-shore wind turbines while the rate of energy generation is higher out in the sea as the wind flow is often more steady and unobstructed by terrain features. The relocation of wind farms into the sea can reduce visual pollution if the windmills are sited more than 12 miles (19 km) offshore, provide better accommodation of fishing and shipping lanes, and allow siting near heavily developed coastal cities.

Floating wind parks are wind farms that site several floating wind turbines closely together to take advantage of common infrastructure such as power transmission facilities.

History

The concept for "large-scale offshore floating wind turbines was introduced by Professor William E. Heronemus at the University of Massachusetts in 1972. [I]t was not until the mid 1990's, after the commercial wind industry was well established, that the topic was taken up again by the mainstream research community." As of 2003, existing offshore fixed-bottom wind turbine technology deployments had been limited to water depths of 30-meters. Worldwide deep-water wind resources are extremely abundant in subsea areas with depths up to 600 meters, which are thought to best facilitate transmission of the generated electric power to shore communities.

Operational deep-water platforms



A tension leg mooring system as used by Blue H: left-hand tower-bearing structure (grey) is free floating, the right-hand structure is pulled by the tensioned cables (red) down towards the seabed anchors (light-grey)

As of 2009, there have been only two operational floating wind turbines used to farm wind energy over deep-water.

Blue H deployed the first floating wind turbine 113 kilometres (70 mi) off of the coast of Italy in December, 2007. It was then decommissioned at the end of 2008 after completing a planned test year of gathering operational data.

The first large-capacity, 2.3 megawatt floating wind turbine is Hywind, which became operational in the North Sea off of Norway in September 2009, and is still operational as of October 2010.

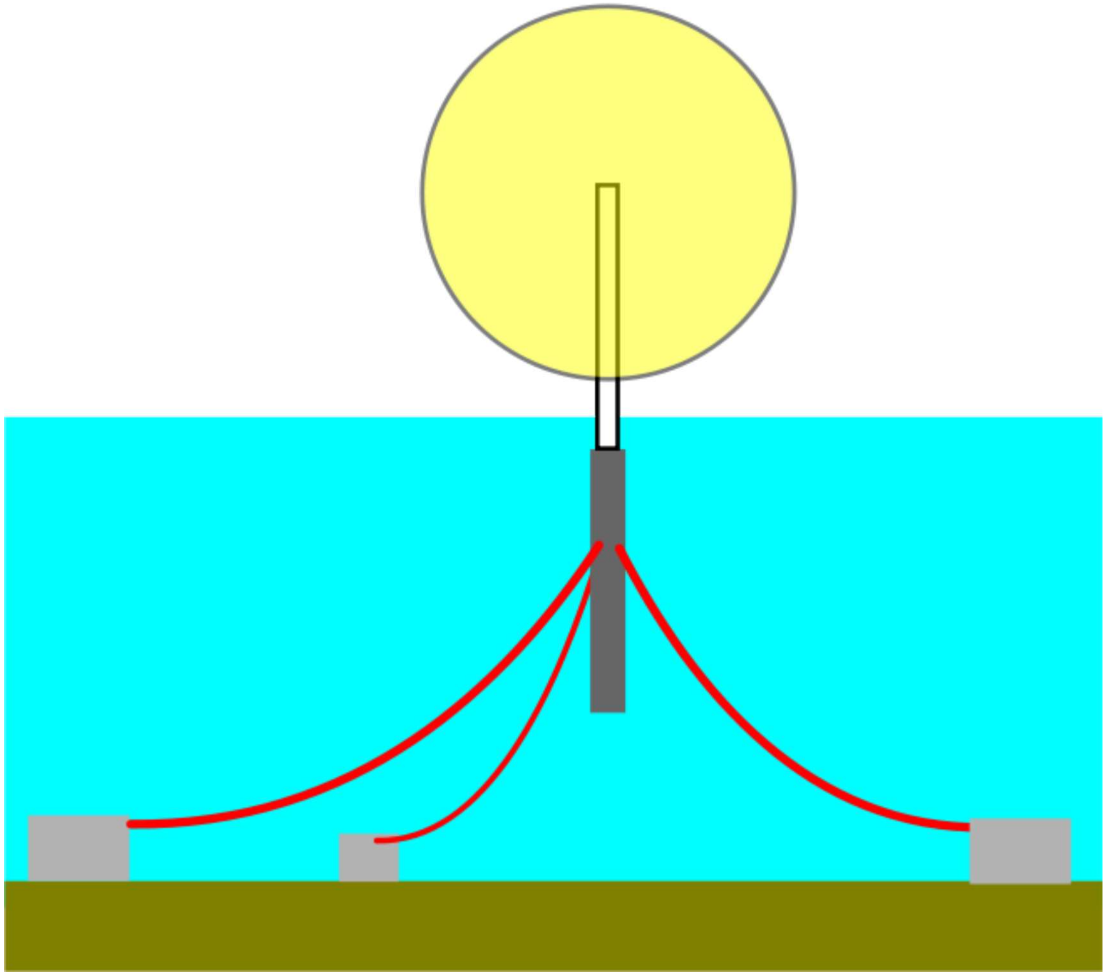
Blue H Technologies

Blue H Technologies of the Netherlands operated the first floating wind turbine, a prototype deep-water platform with an 80-kilowatt turbine off of Puglia, southeast Italy in 2008. Installed 21 km off the coast in waters 113 meters deep in order to gather test data on wind and sea conditions, the small prototype unit was decommissioned at the end of 2008. Blue H has plans to build a 38-unit deepwater wind farm at the same location.

The Blue H technology utilized a tension-leg platform design and a two-bladed turbine. The two-bladed design can have a "much larger chord, which allows a higher tip speed than those of three-bladers. The resulting increased background noise of the two-blade rotor is not a limiting factor for offshore sites."

As of 2009, Blue H was building a full-scale commercial 2.4 MW_e unit in Brindisi, Italy which it expected to deploy at the same site of the prototype in the southern Adriatic Sea in 2010. This is the first unit in the planned 90 MW *Tricase* offshore wind farm, located more than 20 km off the Puglia coast line.

Hywind



A single floating cylindrical spar buoy moored by catenary cables. Hywind uses a *ballasted catenary* layout that adds 60 tonne weights hanging from the midpoint of each anchor cable to provide additional tension.

The world's first operational deep-water floating *large-capacity* wind turbine is the Hywind, in the North Sea off of Norway. The Hywind was towed out to sea in early June 2009. The 2.3 megawatt turbine was constructed by Siemens Wind Power and mounted on a floating tower with a 100 metre deep draft. The float tower was constructed by Technip. Statoil says that floating wind turbines are still immature and commercialization is distant.

The installation is owned by Statoil and will be tested for two years. After assembly in the calmer waters of Åmøy Fjord near Stavanger, Norway, the 120-meter-tall tower with a 2.3 MW turbine was towed 10 km offshore into 220-meter-deep water, 10 km southwest of Karmøy, on 6 June 2009 for a two year test deployment." Alexandra Beck Gjorv of Statoil said, "[The experiment] should help move offshore wind farms out of sight ... The global market for such turbines is potentially enormous, depending on how low we can press costs." The unit became operational in the summer of 2009. Hywind was inaugurated on 8 September 2009. As of October 2010, after a full year of operation, the Hywind turbine is still operating and generating electricity for the Norwegian grid, and still is as of February 2011.

The turbine cost 400 million kroner (around US$62 million) to build and deploy. The 13-kilometer (8-mile) long submarine power transmission cable was installed in July, 2009 and system test including rotor blades and initial power transmission was conducted shortly thereafter. The installation is expected to generate about 9 GW·h of electricity annually. The SWATH (Small Waterplane Area Twin Hull), a new class of offshore wind turbine service boat, will be tested at Hywind.

Hywind delivered 7.3 GWh in 2010, and survived 11 meter waves with seemingly no wear.

Topologies

Platform topologies can be classified into:

- *single-turbine-floater* (one wind turbine mounted on a floating structure)
- *multiple turbine floaters* (multiple wind turbines mounted on a floating structure)

Engineering considerations

Undersea mooring of floating wind turbines are accomplished with three principal mooring systems. Two common types of engineered design for anchoring floating structures include tension-leg and catenary loose mooring systems. *Tension leg mooring systems* have vertical tethers under tension providing large restoring moments in pitch and roll. *Catenary mooring systems* provide station keeping for an offshore structure yet provide little stiffness at low tensions." A third form of mooring system is the *ballasted catenary* configuration, created by adding multiple-tonne weights hanging from the midsection of each anchor cable in order to provide additional cable tension and therefore increase stiffness of the above-water floating structure.

Economics

"Technically, the [theoretical] feasibility of deepwater [floating] wind turbines is not questioned as long-term survivability of floating structures has already been successfully demonstrated by the marine and offshore oil industries over many decades. However, the economics that allowed the deployment of thousands of offshore oil rigs have yet to be demonstrated for floating wind turbine platforms. For deepwater wind turbines, a floating structure will replace pile-driven monopoles or conventional concrete bases that are commonly used as foundations for shallow water and land-based turbines. The floating structure must provide enough buoyancy to support the weight of the turbine and to restrain pitch, roll and heave motions within acceptable limits. The capital costs for the wind turbine itself will not be significantly higher than current marinized turbine costs in shallow water. Therefore, the economics of deepwater wind turbines will be determined primarily by the additional costs of the floating structure and power distribution system, which are offset by higher offshore winds and close proximity to large load centers (e.g. shorter transmission runs)."

As of 2009 however, the economic feasibility of shallow-water offshore wind technologies is more completely understood. With empirical data obtained from fixed-bottom installations off many countries for over a decade now, representative costs are well understood. Shallow-water turbines cost between 2.4 and 3 million United States dollars per megawatt to install, according to the World Energy Council.

As of 2009, the practical feasibility and per-unit economics of deep-water, floating-turbine offshore wind is yet to be seen. Initial deployment of single full-capacity turbines in deep-water locations began only in 2009.

As of October 2010, new feasibility studies are supporting that floating turbines are becoming both technically and economically viable in the UK and global energy markets. "The higher up-front costs associated with developing floating wind turbines would be offset by the fact that they would be able to access areas of deep water off the coastlne of the UK where winds are stronger and reliable."

The recent Offshore Valuation study conducted in the UK has confirmed that using just one third of the UK's wind, wave and tidal resource could generate energy equivalent to 1 billion barrels of oil per year; the same as North Sea oil and gas production. Some of the primary challenges are the coordination needed to develop transmission lines.

Proposals

Floating wind farms

The US State of Maine solicited proposals in September 2010 to build the world's first floating, commercial wind farm. The RFP is seeking proposals for 25 MW of deep-water offshore wind capacity to supply power for 20-year long-term contract period via grid-connected floating wind turbines in the Gulf of Maine. Successful bidders must enter into long-term power supply contracts with either Central Maine Power Company (CMP), Bangor Hydro-Electric Company (BHE), or Maine Public Service Company (MPS). Proposals are due by May 2011.

Some vendors who could bid on the proposed project have expressed concerns about dealing with the United States regulatory environment. Since the proposed site is in Federal waters, developers would need a permit from the Minerals Management Service, "which took more than seven years to approve a yet-to-be-built, shallow-water wind project off Cape Cod," and is also the agency under fire in June 2010 for lax oversight of deepwater oil drilling in Federal waters. "Uncertainty over regulatory hurdles in the United States ... is 'the Achilles heel' for Maine's ambitions for deepwater wind."

Floating design concepts

WindFloat

WindFloat is a floating foundation for offshore wind turbines designed and patented by Principle Power. It is to be tested in autumn 2011 off the coast of Portugal with a Vestas V80 2MW wind turbine.

The foundation attempts to improve dynamic stability at shallow draft by dampening wave and turbine induced motion utilizing a tri-column triangular platform with the wind turbine positioned on only one of the three columns. The triangular platform is then "moored with 6 lines, 4 of which are connected to the column stabilizing the turbine, thus creating an asymmetric" mooring to increase stability and reduce motion.

As the wind shifts direction and changes the loads on the turbine and foundation, pumps will shift ballast water between foundation chambers.

The project is managed by the joint venture WindPlus (led by electricity provider Energias de Portugal).

Vestas turbines will be the standard for the project.

Construction cost is expected to be below $30 million, and funded by the project partners and Fundo de Apoio à Inovação.

This technology could allow wind turbines to be sited in offshore areas that were previously considered inaccessible, areas having water depth exceeding 50 meters and more powerful wind resources than shallow-water offshore wind farms typically encounter.

Nautica Windpower

Nautica Windpower's AFT design features a downwind two-bladed rotor with passive wind alignment to reduce costs

Nautica Windpower uses a patented technology aimed at reducing system weight, complexity and costs for deep water sites. Scale model tests in open water have been conducted and structural dynamics modeling is under development for a multi-megawatt design. Nautica Windpower's Advanced Floating Turbine (AFT) uses a single mooring line and a downwind two-bladed rotor configuration that is deflection tolerant and aligns itself with the wind without an active yaw system. Two-bladed, downwind turbine designs that can accommodate flexibility in the blades will potentially prolong blade lifetime, diminish structural system loads and reduce offshore maintenance needs, yielding lower lifecycle costs.

OC3-Hywind

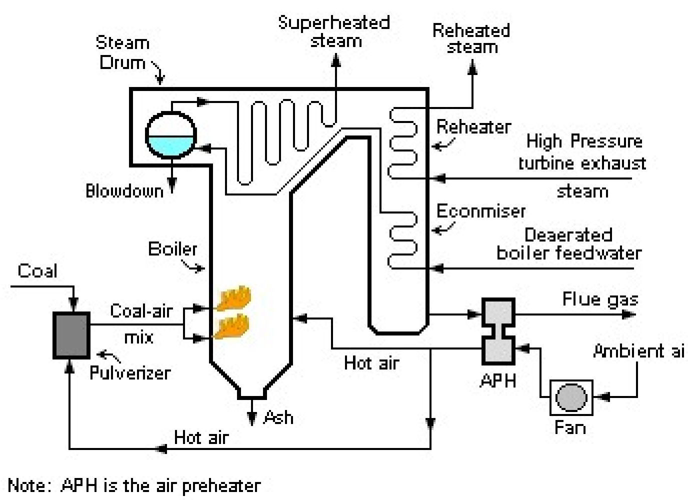
The International Energy Agency (IEA), under the auspices of their *Offshore Code Comparison Collaboration* (OC3) initiative, has completed high-level design and simulation modeling of the *OC-3 Hywind* system, a 5-MW wind turbine installed on a floating spar buoy, moored with catenary mooring lines, in water depth of 320 meters. The spar buoy platform would extend 120 meters below the surface and the mass of such a system, including ballast would exceed 7.4 million kg.

DeepWind

Risø and 11 international partners started a 4-year program called DeepWind in October 2010 to create and test economical floating Vertical Axis Wind Turbines up to 20MW. The program is supported with €3m through EUs Seventh Framework Programme. Partners include TUDelft, SINTEF, Statoil and United States National Renewable Energy Laboratory.

Chapter-3

Air Preheater



Schematic diagram of typical coal-fired power plant steam generator highlighting the air preheater (APH) location. (For simplicity, any radiant section tubing is not shown.)

An **air preheater** (APH) is a general term to describe any device designed to heat air before another process (for example, combustion in a boiler) with the primary objective of increasing the thermal efficiency of the process. They may be used alone or to replace a recuperative heat system or to replace a steam coil.

In particular, we describes the combustion air preheaters used in large boilers found in thermal power stations producing electric power from e.g. fossil fuels, biomasses or waste.

The purpose of the air preheater is to recover the heat from the boiler flue gas which increases the thermal efficiency of the boiler by reducing the useful heat lost in the flue gas. As a consequence, the flue gases are also sent to the flue gas stack (or chimney) at a lower temperature, allowing simplified design of the ducting and the flue gas stack. It also allows control over the temperature of gases leaving the stack (to meet emissions regulations, for example).

Types

There are two types of air preheaters for use in steam generators in thermal power stations: One is a tubular type built into the boiler flue gas ducting, and the other is a regenerative air preheater. These may be arranged so the gas flows horizontally or vertically across the axis of rotation.

Another type of air preheater is the *regenerator* used in iron or glass manufacture.

Tubular type

Construction features

Tubular preheaters consist of straight tube bundles which pass through the outlet ducting of the boiler and open at each end outside of the ducting. Inside the ducting, the hot furnace gases pass around the preheater tubes, transferring heat from the exhaust gas to the air inside the preheater. Ambient air is forced by a fan through ducting at one end of the preheater tubes and at other end the heated air from inside of the tubes emerges into another set of ducting, which carries it to the boiler furnace for combustion.

Problems

The tubular preheater ductings for cold and hot air require more space and structural supports than a rotating preheater design. Further, due to dust-laden abrasive flue gases, the tubes outside the ducting wear out faster on the side facing the gas current. Many advances have been made to eliminate this problem such as the use of ceramic and hardened steel.

Many new circulating fluidized bed (CFB) and bubbling fluidized bed (BFB) steam generators are currently incorporating tubular air heaters offering an advantage with regards to the moving parts of a rotary type.

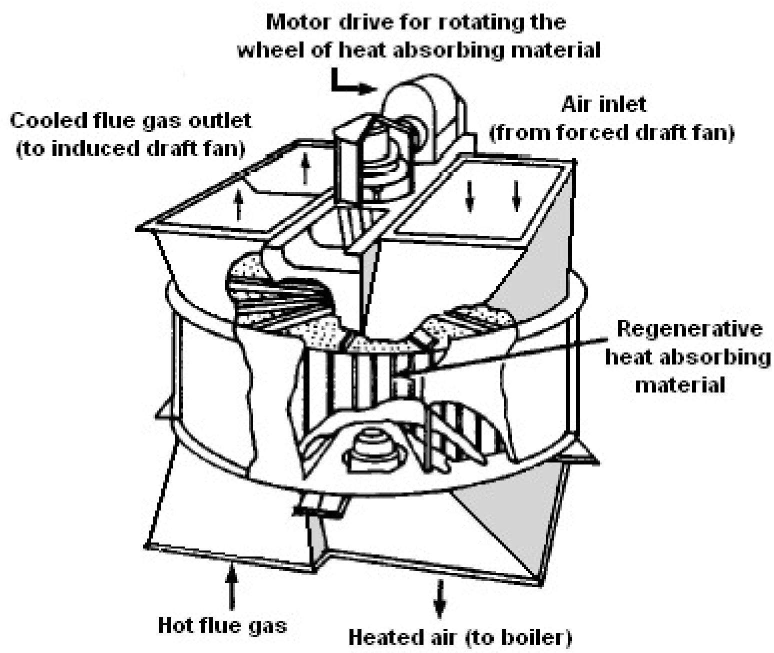
Dew point corrosion

Dew point corrosion occurs for a variety of reasons. The type of fuel used, its sulfur content and moisture content are contributing factors. However, by far the most significant cause of dew point corrosion is the metal temperature of the tubes. If the metal temperature within the tubes drops below the acid saturation temperature, usually at between 190°F (88°C)and 230°F (110°C), but sometimes at temperatures as high as 260°F (127°C), then the risk of dew point corrosion damage becomes considerable.

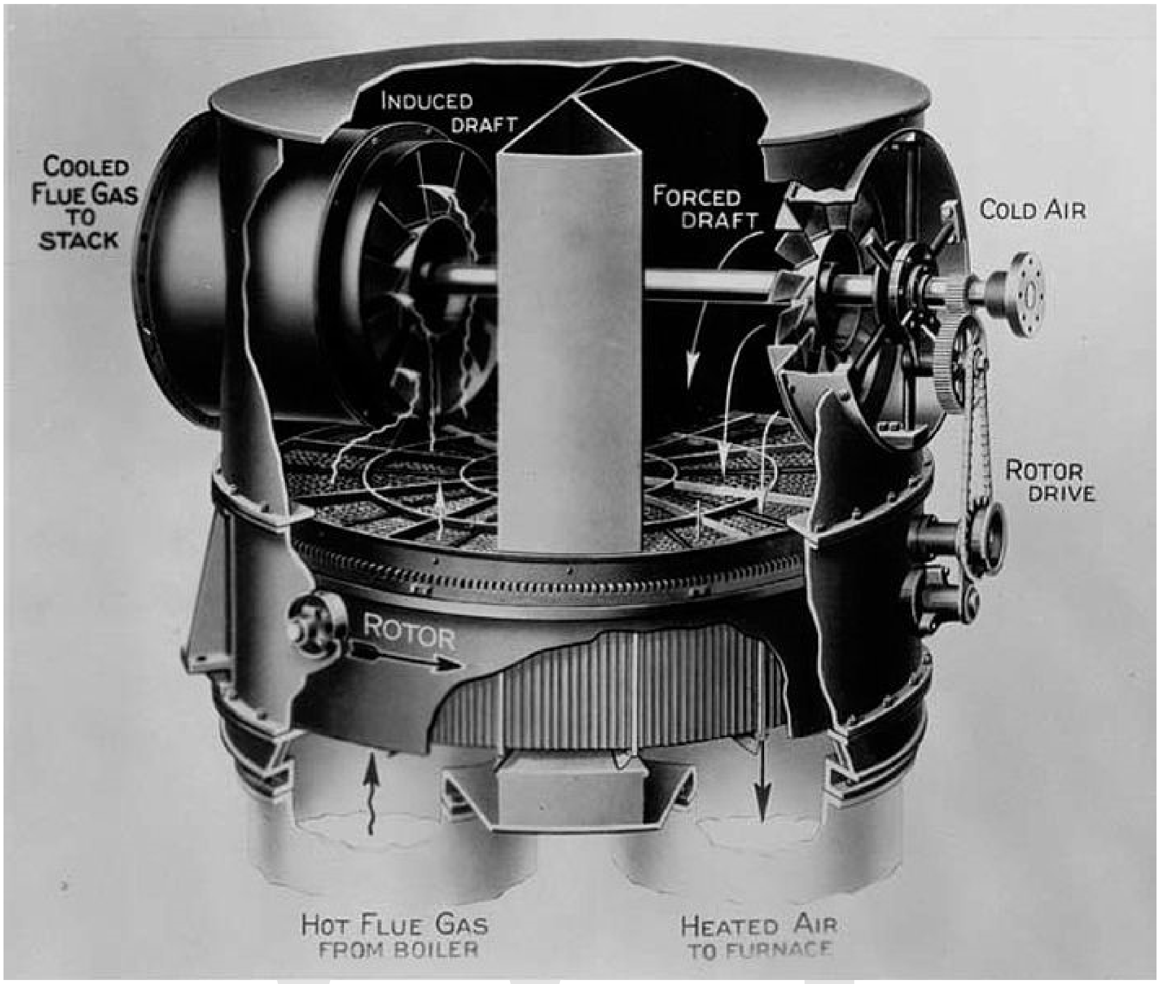
Regenerative air preheaters

There are two types of regenerative air preheaters: the rotating-plate regenerative air preheaters (RAPH) and the stationary-plate regenerative air preheaters (Rothemuhle).

Rotating-plate regenerative air preheater



Typical Rotating-plate Regenerative Air Preheater (Bi-sector type)



Principle function for the Ljungstrom regenerative preheater.

The rotating-plate design (RAPH) consists of a central rotating-plate element installed within a casing that is divided into two (*bi-sector* type), three (*tri-sector* type) or four (*quad-sector* type) sectors containing seals around the element. The seals allow the element to rotate through all the sectors, but keep gas leakage between sectors to a minimum while providing separate gas air and flue gas paths through each sector.

Tri-sector types are the most common in modern power generation facilities. In the tri-sector design, the largest sector (usually spanning about half the cross-section of the casing) is connected to the boiler hot gas outlet. The hot exhaust gas flows over the central element, transferring some of its heat to the element, and is then ducted away for further treatment in dust collectors and other equipment before being expelled from the flue gas stack. The second, smaller sector, is fed with ambient air by a fan, which passes over the heated element as it rotates into the sector, and is heated before being carried to the boiler furnace for combustion. The third sector is the smallest one and it heats air which is routed into the pulverizers and used to carry the coal-air mixture to coal boiler burners. Thus, the total air heated in the RAPH provides: heating air to remove the moisture from the pulverised coal dust, carrier air for transporting the pulverised coal to the boiler burners and the primary air for combustion.

The rotor itself is the medium of heat transfer in this system, and is usually composed of some form of steel and/or ceramic structure. It rotates quite slowly (around 3-5 RPM) to allow optimum heat transfer first from the hot exhaust gases to the element, then as it rotates, from the element to the cooler air in the other sectors.

Construction features

In this design the whole air preheater casing is supported on the boiler supporting structure itself with necessary expansion joints in the ducting.

The vertical rotor is supported on thrust bearings at the lower end and has an oil bath lubrication, cooled by water circulating in coils inside the oil bath. This arrangement is for cooling the lower end of the shaft, as this end of the vertical rotor is on the hot end of the ducting. The top end of the rotor has a simple roller bearing to hold the shaft in a vertical position.

The rotor is built up on the vertical shaft with radial supports and cages for holding the baskets in position. Radial and circumferential seal plates are also provided to avoid leakages of gases or air between the sectors or between the duct and the casing while in rotation.

For on line cleaning of the deposits from the baskets steam jets are provided such that the blown out dust and ash are collected at the bottom ash hopper of the air preheater. This dust hopper is connected for emptying along with the main dust hoppers of the dust collectors.

The rotor is turned by an air driven motor and gearing, and is required to be started before starting the boiler and also to be kept in rotation for some time after the boiler is stopped, to avoid uneven expansion and contraction resulting in warping or cracking of the rotor. The station air is generally totally dry (dry air is required for the instrumentation), so the air used to drive the rotor is injected with oil to lubricate the air motor.

Safety protected inspection windows are provided for viewing the preheater's internal operation under all operating conditions.

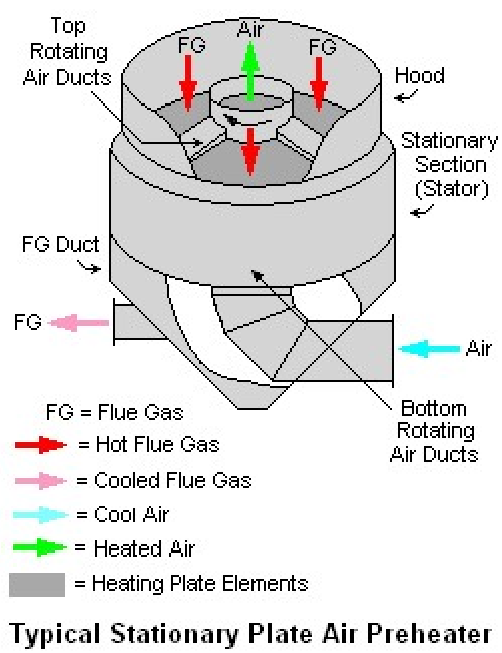
The baskets are in the sector housings provided on the rotor and are renewable. The life of the baskets depend on the ash abrasiveness and corrosiveness of the boiler outlet gases.

Problems

The boiler flue gas contains many dust particles (due to high ash content) not contributing towards combustion, such as silica, which cause abrasive wear of the baskets, and may also contain corrosive gases depending on the composition of the fuel. For example, Indian coals generally result in high levels of ash, sulfur and silica in the flue gas. The wear of the baskets therefore is generally more than other, cleaner-burning fuels.

In this RAPH, the dust laden, corrosive boiler gases have to pass between the elements of air preheater baskets. The elements are made up of zig zag corrugated plates pressed into a steel basket giving sufficient annular space in between for the gas to pass through. These plates are corrugated to give more surface area for the heat to be absorbed and also to give it the rigidity for stacking them into the baskets. Hence frequent replacements are called for and new baskets are always kept ready. In the early days, Cor-ten steel was being used for the elements. Today due to technological advance many manufacturers may use their own patents. Some manufacturers supply different materials for the use of the elements to lengthen the life of the baskets.

In certain cases the unburnt deposits may occur on the air preheater elements causing it to catch fire during normal operations of the boiler, giving rise to explosions inside the air preheater. Sometimes mild explosions may be detected in the control room by variations in the inlet and outlet temperatures of the combustion air.



Schematic of typical stationary-plate regenerative air preheater

Stationary-plate regenerative air preheater

The heating plate elements in this type of regenerative air preheater are also installed in a casing, but the heating plate elements are stationary rather than rotating. Instead the air ducts in the preheater are rotated so as to alternatively expose sections of the heating plate elements to the upflowing cool air.

As indicated in the adjacent drawing, there are rotating inlet air ducts at the bottom of the stationary plates similar to the rotating outlet air ducts at the top of the stationary plates.

Stationary-plate regenerative air preheaters are also known as Rothemuhle preheaters, manufactured for over 25 years by Balke-Dürr GmbH of Ratingen, Germany.

Regenerator

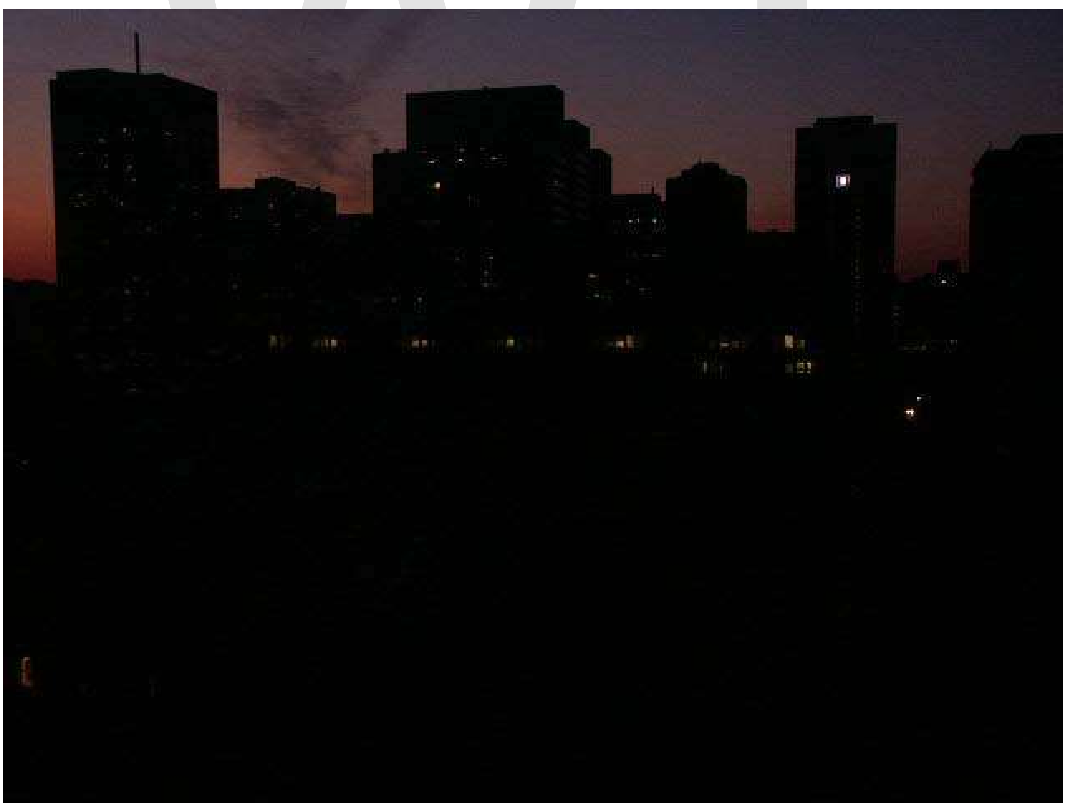
A regenerator consists of a brick checkerwork: bricks laid with spaces equivalent to a brick's width between them, so that air can flow relatively easily through the checkerwork. The idea is that as hot exhaust gases flow through the checkerwork, they give up heat to the bricks. The airflow is then reversed, so that the hot bricks heat up the incoming combustion air and fuel. For a glass-melting furnace, a regenerator sits on either side of the furnace, often forming an integral whole. For a blast furnace, the regenerators (commonly called **Cowper stoves**) sit separate to the furnace. A furnace needs no less than two stoves, but may have three. One of the stoves is 'on gas', receiving hot gases from the furnace top and heating the checkerwork inside, whilst the other is 'on blast', receiving cold air from the blowers, heating it and passing it to the blast furnace.

Chapter-4

Black Start and Deaerator

Black start

A **black start** is the process of restoring a power station to operation without relying on the external electric power transmission network.



Toronto during the Northeast Blackout of 2003, an event which required black-starting of generating stations.

Normally, the electric power used within the plant is provided from the station's own generators. If all of the plant's main generators are shut down, station service power is provided by drawing power from the grid through the plant's transmission line. However, during a wide-area outage, off-site power supply from the grid will not be available. In the absence of grid power, a so-called black start needs to be performed to bootstrap the power grid into operation.

To provide a black start, some power stations have small diesel generators which can be used to start larger generators (of several megawatts capacity), which in turn can be used to start the main power station generators. Generating plants using steam turbines require station service power of up to 10% of their capacity for boiler feedwater pumps, boiler forced-draft combustion air blowers, and for fuel preparation. It is uneconomical to provide such a large standby capacity at each station, so black-start power must be provided over designated tie lines from another station. Often hydroelectric power plants are designated as the black-start sources to restore network interconnections. A hydroelectric station needs very little initial power to start (just enough to open the intake gates), and can put a large block of power on line very quickly to allow start-up of fossil-fueled or nuclear stations.

A black start sequence

A typical sequence (based on a real scenario) might be as follows:

1. A battery starts a small diesel generator installed in a hydroelectric generating station.
2. The power from the diesel generator is used to bring the hydroelectric generating station into operation.
3. Key transmission lines between the hydro station and other areas are energized.
4. The power from the hydro dam is used to start one of the coal-fired base load plants.
5. The power from the base load plant is used to restart all of the other power plants in the system including the nuclear power plants.

Power is finally re-applied to the general electricity distribution network and sent to the consumers. Often this will happen gradually; starting the entire grid at once may be unfeasible. In particular, after a lengthy outage during summer, all buildings will be warm, and if the power were restored at once, the demand from air conditioning units alone would be more than the grid could supply. In colder climates a similar issue can occur in winter with the use of heating devices.

In a larger grid, black start will often involve starting multiple "islands" of generation (each supplying local load areas) and then synchronising and reconnecting these islands to form a complete grid. The power stations involved have to be able to accept large step changes in load as the grid is reconnected.

Procurement of black start services

In the United Kingdom the grid operator has commercial agreements in place with some generators to provide black start capacity, recognising that black start facilities are often not economic in normal grid operation.

In the North American Independent System Operators the procurement of black start varies somewhat. Traditionally black start was provided by integrated utilities and the costs were rolled into a broad tariff for cost recovery from ratepayers. In those areas which are not part of organized electricity markets this is still the usual procurement mechanism. In the deregulated environment this legacy of cost-based provision has persisted, and even recent overhauls of black start procurement practices, such as that by the ISO New England, have not necessarily shifted to competitive procurement, despite the fact that deregulated jurisdictions have a bias for market solutions rather than Cost-of-Service (COS) solutions.

In the United States, there are currently three methods of procuring black start. The most common is Cost of Service, as it is the simplest and is the traditional method. It is currently used by the California Independent System Operator (CAISO), the PJM Interconnection and the New York Independent System Operator (NYISO). Although the exact mechanisms differ somewhat the same approach is used, namely that units are identified for black start and their documented costs are then funded and rolled into a tariff for cost recovery. The second method is a new method used by the Independent System Operator of New England (ISO-NE). The new methodology is a flat rate payment which increases black start remuneration to encourage provision. The monthly compensation paid to a generator is determined by multiplying a flat rate (in $/KWyr and referred to as the $Y value) by the unit's Monthly Claimed Capability for that month. The purpose of this change was to simplify procurement and incent provision of black start. The final method of procurement is competitive procurement as used by the Electric Reliability Council of Texas (ERCOT). Under this approach ERCOT runs a market for black start services. Interested participants submit an hourly standby cost in $/hr (e.g. $70 per hour), often termed an availability bid, that is unrelated to the capacity of the unit. Using various criteria ERCOT evaluates these bids and the selected units are paid as bid, presuming an 85% availability. Each black start unit must be able to demonstrate that it can startup another unit in close proximity to begin the islanding and synchronization of the grid.

In other jurisdictions there are differing methods of procurement. The New Zealand System Operator procures the blackstart capability via competitive tender. Other jurisdictions also appear to have some sort of competitive procurement, although not as structured as ERCOT. These include the Alberta Electric System Operator, as well as Independent Electric System Operator of Ontario, both of which use a long-term "Request For Proposals" approach similar to New Zealand and ERCOT.

Limitations on black start sources

Not all generating plants are suitable for black-start capability. Wind turbines are not suitable for black start because wind may not be available when needed. Wind turbines, mini-hydro or micro-hydro plants, are often connected to induction generators which are incapable of providing power to a de-energized network. The black-start unit must also be stable when operated with the large reactive load of a long transmission line. Many high-voltage direct current converter stations cannot operate into a "dead" system, either, since they require commutation power from the system at the load end. This is not true of PWM-based (voltage-source converter) HVDC schemes.

Deaerator

A **deaerator** is a device that is widely used for the removal of air and other dissolved gases from the feedwater to steam-generating boilers. In particular, dissolved oxygen in boiler feedwaters will cause serious corrosion damage in steam systems by attaching to the walls of metal piping and other metallic equipment and forming oxides (rust). Water also combines with any dissolved carbon dioxide to form carbonic acid that causes further corrosion. Most deaerators are designed to remove oxygen down to levels of 7 ppb by weight (0.005 cm^3/L) or less.

There are two basic types of deaerators, the tray-type and the spray-type:

- The *tray-type* (also called the *cascade-type*) includes a vertical domed deaeration section mounted on top of a horizontal cylindrical vessel which serves as the deaerated boiler feedwater storage tank.

- The *spray-type* consists only of a horizontal (or vertical) cylindrical vessel which serves as both the deaeration section and the boiler feedwater storage tank.

Types of deaerators

There are many different horizontal and vertical deaerators available from a number of manufacturers, and the actual construction details will vary from one manufacturer to another. Figures 1 and 2 are representative schematic diagrams that depict each of the two major types of deaerators.

Tray-type deaerator

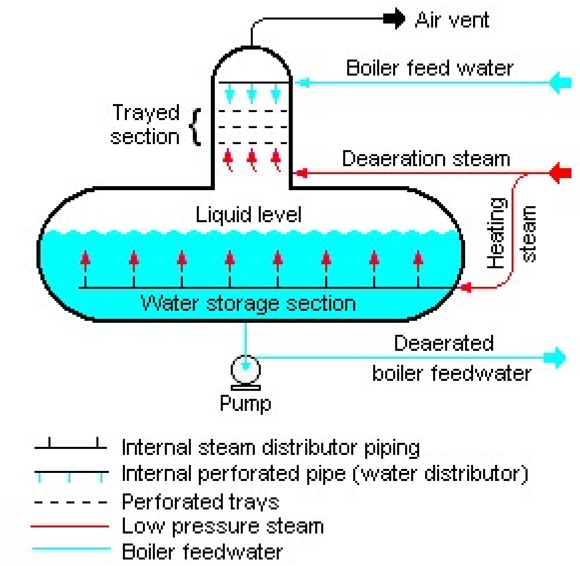


Figure 1: A schematic diagram of a typical tray-type deaerator.

The typical horizontal tray-type deaerator in Figure 1 has a vertical domed deaeration section mounted above a horizontal boiler feedwater storage vessel. Boiler feedwater enters the vertical dearation section above the perforated trays and flows downward through the perforations. Low-pressure dearation steam enters below the perforated trays and flows upward through the perforations. Some designs use various types of packing material, rather than perforated trays, to provide good contact and mixing between the steam and the boiler feed water.

The steam strips the dissolved gas from the boiler feedwater and exits via the vent at the top of the domed section. Some designs may include a vent condenser to trap and recover any water entrained in the vented gas. The vent line usually includes a valve and just enough steam is allowed to escape with the vented gases to provide a small and visible telltale plume of steam.

The deaerated water flows down into the horizontal storage vessel from where it is pumped to the steam generating boiler system. Low-pressure heating steam, which enters the horizontal vessel through a *sparger pipe* in the bottom of the vessel, is provided to keep the stored boiler feedwater warm. External insulation of the vessel is typically provided to minimize heat loss.

Spray-type deaerator

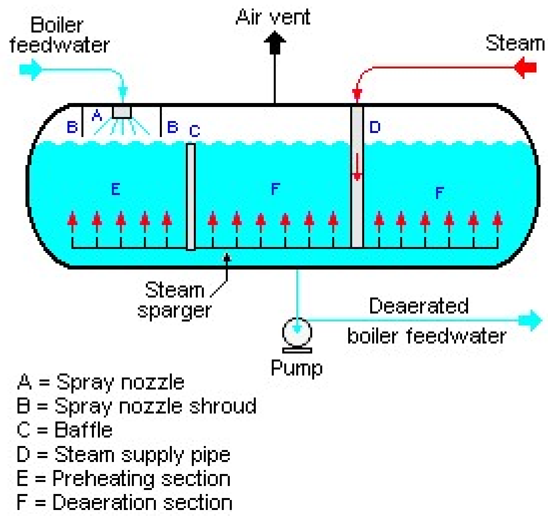


Figure 2: A schematic diagram of a typical spray-type deaerator.

As shown in Figure 2, the typical spray-type deaerator is a horizontal vessel which has a preheating section (E) and a deaeration section (F). The two sections are separated by a baffle(C). Low-pressure steam enters the vessel through a sparger in the bottom of the vessel.

The boiler feedwater is sprayed into section (E) where it is preheated by the rising steam from the sparger. The purpose of the feedwater spray nozzle (A) and the preheat section is to heat the boiler feedwater to its saturation temperature to facilitate stripping out the dissolved gases in the following deaeration section.

The preheated feedwater then flows into the dearation section (F), where it is deaerated by the steam rising from the sparger system. The gases stripped out of the water exit via the vent at the top of the vessel. Again, some designs may include a vent condenser to trap and recover any water entrained in the vented gas. Also again, the vent line usually includes a valve and just enough steam is allowed to escape with the vented gases to provide a small and visible telltale plume of steam

The deaerated boiler feedwater is pumped from the bottom of the vessel to the steam generating boiler system.

Deaeration steam

The deaerators in the steam generating systems of most thermal power plants use low pressure steam obtained from an extraction point in their steam turbine system. However, the steam generators in many large industrial facilities such as petroleum refineries may use whatever low-pressure steam is available.

Oxygen scavengers

Oxygen scavenging chemicals are very often added to the deaerated boiler feedwater to remove any last traces of oxygen that were not removed by the deaerator. The most commonly used oxygen scavenger is sodium sulfite (Na_2SO_3). It is very effective and rapidly reacts with traces of oxygen to form sodium sulfate (Na_2SO_4) which is non-scaling. Another widely used oxygen scavenger is hydrazine (N_2H_4).

Other scavengers include 1,3-diaminourea (also known as carbohydrazide), diethylhydroxylamine (DEHA), nitriloacetic acid (NTA), ethylenediaminetetraacetic acid (EDTA), and hydroquinone.

Boiler Feed Deaerators - Update

The principal governing these plants is intimate contact between the feed water and the steam which both heats the water and strips dissolved gases from it. The three ways of achieving this are : (a) spraying fine water droplets into a steam space; (b) bubbling steam through the body of water; and (c) exposing falling water to steam over extended surfaces. Contact time for both spraying and bubbling is short, so these processes are usually combined with, or replaced by, the extended liquid surface principle.

A series of horizontal trays has been the preferred extended surface design used in the USA for many years. The water drops from tray to tray through small holes; provision is made either for the steam to pass through each tray section as a vertical flow, or to flow horizontally across each tray in parallel. This second arrangement is not counter-current between water and steam and therefore is less efficient than the first.

Superior to both these arrangements is the randomly packed tower, which is fully counter-current, steam rising through the packing and progressively condensing. For the same volume, the surface area of randomly packed thin-walled cylindrical rings, typically 38x38mm, is at least ten times greater than trays with falling water 100mm apart.

The packed tower scores in the stripping of dissolved gases because of this far greater surface area. Europe is moving away from tray designs to the packed tower process. For sea-going applications the packed tower has a clear advantage because random packing has a measure of continuous flow redistribution, whereas trays suffer variable distribution with vessel pitch and roll.

Chapter-5

Anaerobic Digestion

Anaerobic digestion and regenerative thermal oxidiser component of Lübeck mechanical biological treatment plant in Germany, 2007

Anaerobic digestion is a series of processes in which microorganisms break down biodegradable material in the absence of oxygen, used for industrial or domestic purposes to manage waste and/or to release energy.

It is used as part of the process to treat wastewater. As part of an integrated waste management system, anaerobic digestion reduces the emission of landfill gas into the atmosphere.

Anaerobic digestion is widely used as a renewable energy source because the process produces a methane and carbon dioxide rich biogas suitable for energy production, helping to replace fossil fuels. The nutrient-rich digestate which is also produced can be used as fertilizer.

The digestion process begins with bacterial hydrolysis of the input materials in order to break down insoluble organic polymers such as carbohydrates and make them available for other bacteria. Acidogenic bacteria then convert the sugars and amino acids into carbon dioxide, hydrogen, ammonia, and organic acids. Acetogenic bacteria then convert these resulting organic acids into acetic acid, along with additional ammonia, hydrogen, and carbon dioxide. Finally, methanogens convert these products to methane and carbon dioxide.

The technical expertise required to maintain industrial scale anaerobic digesters coupled with high capital costs and low process efficiencies had limited the level of its industrial application as a waste treatment technology. Anaerobic digestion facilities have, however, been recognized by the United Nations Development Programme as one of the most useful decentralized sources of energy supply, as they are less capital intensive than large power plants.

History

Gas street lamp

Scientific interest in the manufacturing of gas produced by the natural decomposition of organic matter, was first reported in the seventeenth century by Robert Boyle and Stephen Hale, who noted that flammable gas was released by disturbing the sediment of streams and lakes. In 1808, Sir Humphry Davy determined that methane was present in the gases produced by cattle manure. The first anaerobic digester was built by a leper colony in Bombay, India in 1859. In 1895 the technology was developed in Exeter, England, where a septic tank was used to generate gas for the sewer gas destructor lamp, a type of gas lighting. Also in England, in 1904, the first dual purpose tank for both sedimentation and sludge treatment was installed in Hampton. In 1907, in Germany, a patent was issued for the Imhoff tank, an early form of digester.

Through scientific research anaerobic digestion gained academic recognition in the 1930s. This research led to the discovery of anaerobic bacteria, the microorganisms that facilitate the process. Further research was carried out to investigate the conditions under which methanogenic bacteria were able to grow and reproduce. This work was developed during World War II where in both Germany and France there was an increase in the application of anaerobic digestion for the treatment of manure.

Applications

Anaerobic digestion is particularly suited to organic material and is commonly used for effluent and sewage treatment. Anaerobic digestion is a simple process that can greatly reduce the amount of organic matter which might otherwise be destined to be dumped at sea, landfilled or burnt in an incinerator.

Almost any organic material can be processed with anaerobic digestion. This includes biodegradable waste materials such as waste paper, grass clippings, leftover food, sewage and animal waste. The exception to this is woody wastes that are largely unaffected by digestion as most anaerobes are unable to degrade lignin. The exception being xylophalgeous anaerobes (lignin consumers), as used in the process for organic breakdown of cellulosic material by a cellulosic ethanol start-up company in the U.S. Anaerobic digesters can also be fed with specially grown energy crops such as silage for dedicated biogas production. In Germany and continental Europe these facilities are referred to as *biogas plants*. A *co-digestion* or *co-fermentation* plant is typically an agricultural anaerobic digester that accepts two or more input materials for simultaneous digestion.

In developing countries simple home and farm-based anaerobic digestion systems offer the potential for cheap, low-cost energy for cooking and lighting. Anaerobic digestion facilities have been recognized by the United Nations Development Programme as one of the most useful decentralized sources of energy supply. From 1975, China and India have both had large government-backed schemes for adaptation of small biogas plants for use in the household for cooking and lighting. Presently, projects for anaerobic digestion in the developing world can gain financial support through the United Nations Clean Development Mechanism if they are able to show they provide reduced carbon emissions.

Pressure from environmentally related legislation on solid waste disposal methods in developed countries has increased the application of anaerobic digestion as a process for reducing waste volumes and generating useful by-products. Anaerobic digestion may either be used to process the source separated fraction of municipal waste, or alternatively combined with mechanical sorting systems, to process residual mixed municipal waste. These facilities are called mechanical biological treatment plants.

Utilising anaerobic digestion technologies can help to reduce the emission of greenhouse gasses in a number of key ways:

- Replacement of fossil fuels
- Reducing or eliminating the energy footprint of waste treatment plants
- Reducing methane emission from landfills
- Displacing industrially produced chemical fertilizers
- Reducing vehicle movements
- Reducing electrical grid transportation losses

Methane and power produced in anaerobic digestion facilities can be utilized to replace energy derived from fossil fuels, and hence reduce emissions of greenhouse gasses. This is due to the fact that the carbon in biodegradable material is part of a carbon cycle. The carbon released into the atmosphere from the combustion of biogas has been removed by plants in order for them to grow in the recent past. This can have occurred within the last decade, but more typically within the last growing season. If the plants are re-grown, taking the carbon out of the atmosphere once more, the system will be carbon neutral. This contrasts to carbon in fossil fuels that has been sequestered in the earth for many millions of years, the combustion of which increases the overall levels of carbon dioxide in the atmosphere.

If the putrescible waste processed in anaerobic digesters was disposed of in a landfill, it would break down naturally and often anaerobically. In this case the gas will eventually escape into the atmosphere. As methane is about twenty times more potent as a greenhouse gas than carbon dioxide this has significant negative environmental effects.

Digester liquor can be used as a fertiliser supplying vital nutrients to soils. The solid, fibrous component of the digested material can be used as a soil conditioner to increase the organic content of soils. The liquor can be used instead of chemical fertilisers which require large amounts of energy to produce and transport. The use of manufactured fertilisers is therefore more carbon intensive than the use of anaerobic digester liquor fertiliser. In countries, such as Spain where there are many organically depleted soils the markets for the digested solids can be equally as important as the biogas.

In countries that collect household waste, the utilization of local anaerobic digestion facilities can help to reduce the amount of waste that requires transportation to centralized landfill sites or incineration facilities. This reduced burden on transportation reduces carbon emissions from the collection vehicles. If localized anaerobic digestion facilities are embedded within an electrical distribution network, they can help reduce the electrical losses that are associated with transporting electricity over a national grid.

In Oakland, California at the East Bay Municipal Utility District’s (EBMUD) Main Wastewater Treatment Plant(MWWTP), food waste is currently co-digested with primary and secondary municipal wastewater solids and other high-strength wastes. Compared to municipal wastewater solids digestion, food waste digestion has many benefits. Anaerobic digestion of food waste pulp from the EBMUD food waste process provides a higher normalized energy benefit, compared to municipal wastewater solids:

- 730 to 1,300 kWh per dry ton of food waste applied.

- 560 to 940 kWh per dry ton of municipal wastewater solids applied.

Power generation

Biogas from sewage works is sometimes used to run a gas engine to produce electrical power; some or all of which can be used to run the sewage works. Some waste heat from the engine is then used to heat the digester. It turns out that the waste heat is generally enough to heat the digester to the required temperatures. The power potential from sewage works is limited – in the UK there are about 80 MW total of such generation, with potential to increase to 150 MW, which is insignificant compared to the average power demand in the UK of about 35,000 MW. The scope for biogas generation from non-sewage waste biological matter – energy crops, food waste, abattoir waste etc. is much higher, estimated to be capable of about 3,000 MW. Farm biogas plants using animal waste and energy crops are expected to contribute to reducing CO_2 emissions and strengthen the grid while providing UK farmers with additional revenues.

Some countries offer incentives in the form of, for example, Feed-in Tariffs for feeding electricity onto the power grid in order to subsidize green energy production.

Grid injection

Biogas grid-injection is the injection of biogas into the natural gas grid. As an alternative, the electricity and the heat can be used for on-site generation, resulting in a reduction of losses in the transportation of energy. Typical energy losses in natural gas transmission systems range from 1–2%, whereas the current energy losses on a large electrical system range from 5–8%.

In October 2010, Didcot Sewage Works became the first in the UK to produce biomethane gas supplied to the national grid, for use in up to 200 homes in Oxfordshire.

The process

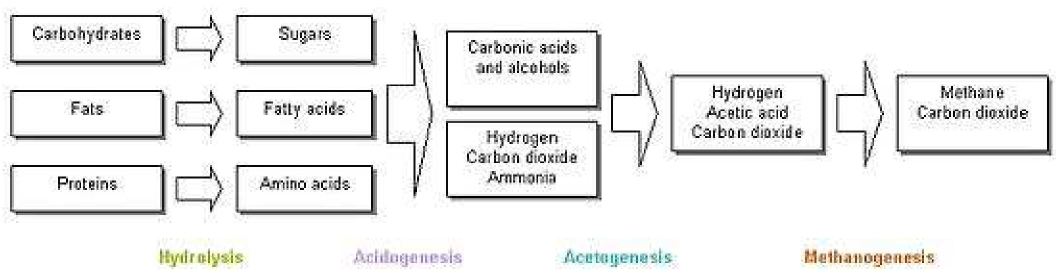
There are a number of microorganisms that are involved in the process of anaerobic digestion including acetic acid-forming bacteria (acetogens) and methane-forming archaea (methanogens). These organisms feed upon the initial feedstock, which undergoes a number of different processes converting it to intermediate molecules including sugars, hydrogen, and acetic acid, before finally being converted to biogas.

Different species of bacteria are able to survive at different temperature ranges. Ones living optimally at temperatures between 35–40 °C are called mesophiles or mesophilic bacteria. Some of the bacteria can survive at the hotter and more hostile conditions of 55–60 °C, these are called thermophiles or thermophilic bacteria. Methanogens come from the domain of archaea. This family includes species that can grow in the hostile conditions of hydrothermal vents. These species are more resistant to heat and can therefore operate at high temperatures, a property that is unique to thermophiles.

As with aerobic systems the bacteria in anaerobic systems the growing and reproducing microorganisms within them require a source of elemental oxygen to survive. In an anaerobic system there is an absence of gaseous oxygen. Gaseous oxygen is prevented from entering the system through physical containment in sealed tanks. Anaerobes access oxygen from sources other than the surrounding air. The oxygen source for these microorganisms can be the organic material itself or alternatively may be supplied by inorganic oxides from within the input material. When the oxygen source in an anaerobic system is derived from the organic material itself, then the 'intermediate' end products are primarily alcohols, aldehydes, and organic acids plus carbon dioxide. In the presence of specialised methanogens, the intermediates are converted to the 'final' end products of methane, carbon dioxide with trace levels of hydrogen sulfide. In an anaerobic system the majority of the chemical energy contained within the starting material is released by methanogenic bacteria as methane.

Populations of anaerobic microorganisms typically take a significant period of time to establish themselves to be fully effective. It is therefore common practice to introduce anaerobic microorganisms from materials with existing populations, a process known as "seeding" the digesters, and typically takes place with the addition of sewage sludge or cattle slurry.

Stages



The key process stages of anaerobic digestion

There are four key biological and chemical stages of anaerobic digestion:

1. Hydrolysis
2. Acidogenesis
3. Acetogenesis
4. Methanogenesis

In most cases biomass is made up of large organic polymers. In order for the bacteria in anaerobic digesters to access the energy potential of the material, these chains must first be broken down into their smaller constituent parts. These constituent parts or monomers such as sugars are readily available by other bacteria. The process of breaking these chains and dissolving the smaller molecules into solution is called hydrolysis. Therefore hydrolysis of these high molecular weight polymeric components is the necessary first step in anaerobic digestion. Through hydrolysis the complex organic molecules are broken down into simple sugars, amino acids, and fatty acids.

Acetate and hydrogen produced in the first stages can be used directly by methanogens. Other molecules such as volatile fatty acids (VFA's) with a chain length that is greater than acetate must first be catabolised into compounds that can be directly utilised by methanogens.

The biological process of acidogenesis is where there is further breakdown of the remaining components by acidogenic (fermentative) bacteria. Here VFAs are created along with ammonia, carbon dioxide and hydrogen sulfide as well as other by-products. The process of acidogenesis is similar to the way that milk sours.

The third stage anaerobic digestion is acetogenesis. Here simple molecules created through the acidogenesis phase are further digested by acetogens to produce largely acetic acid as well as carbon dioxide and hydrogen.

The terminal stage of anaerobic digestion is the biological process of methanogenesis. Here methanogens utilise the intermediate products of the preceding stages and convert them into methane, carbon dioxide and water. It is these components that makes up the majority of the biogas emitted from the system. Methanogenesis is sensitive to both high and low pHs and occurs between pH 6.5 and pH 8. The remaining, non-digestible material which the microbes cannot feed upon, along with any dead bacterial remains constitutes the digestate.

A simplified generic chemical equation for the overall processes outlined above is as follows:

$$C_6H_{12}O_6 \rightarrow 3CO_2 + 3CH_4$$

Configuration

Farm-based maize silage digester located near Neumünster in Germany, 2007. Green inflatable biogas holder is shown on top of the digester

Anaerobic digesters can be designed and engineered to operate using a number of different process configurations:

- Batch or continuous
- Temperature: Mesophilic or thermophilic
- Solids content: High solids or low solids
- Complexity: Single stage or multistage

Batch or continuous

A batch system is the simplest form of digestion. Biomass is added to the reactor at the start of the process in a batch and is sealed for the duration of the process. Batch reactors suffer from odour issues that can be a severe problem when they are emptied. Typically biogas production will be formed with a normal distribution pattern over time. The operator can use this fact to determine when they believe the process of digestion of the organic matter has completed. As the batch digestion is simple and requires less equipment and lower levels of design work it is typically a cheaper form of digestion.

In continuous digestion processes organic matter is constantly added (continuous complete mixed)or added in stages to the reactor (continuous plug flow; first in – first out). Here the end products are constantly or periodically removed, resulting in constant production of biogas. A single or multiple digesters in sequence may be used. Examples of this form of anaerobic digestion include continuous stirred-tank reactors (CSTRs), Upflow anaerobic sludge blanket (UASB), Expanded granular sludge bed (EGSB) and Internal circulation reactors (IC).

Temperature

There are two conventional operational temperature levels for anaerobic digesters, which are determined by the species of methanogens in the digesters:

- *Mesophilic* which takes place optimally around 30-38 °C or at ambient temperatures between 20-45 °C where mesophiles are the primary microorganism present
- *Thermophilic* which takes place optimally around 49-57 °C at elevated temperatures up to 70 °C where thermophiles are the primary microorganisms present

A limit case has been reached in Bolivia, with anaerobic digestion in temperature working conditions less than 10 °C. The anaerobic process is very slow, taking more than three times the normal mesophilic time process. In experimental work at University of Alaska Fairbanks, a 1000 litre digester using psychrophiles harvested from "mud from a frozen lake in Alaska" has produced 200–300 litres of methane per day, about 20–30 % of the output from digesters in warmer climates.

There are a greater number of species of mesophiles than thermophiles. These bacteria are also more tolerant to changes in environmental conditions than thermophiles. Mesophilic systems are therefore considered to be more stable than thermophilic digestion systems.

As mentioned above, thermophilic digestion systems are considered to be less stable, the energy input is higher, and more energy is removed from the organic matter. However, the increased temperatures facilitate faster reaction rates and hence faster gas yields. Operation at higher temperatures facilitates greater sterilization of the end digestate. In countries where legislation, such as the Animal By-Products Regulations in the European Union, requires end products to meet certain levels of reduction in the amount of bacteria in the output material, this may be a benefit.

Certain processes shred the waste finely and use a short high temperature and pressure pre-treatment (pasteurization / hygienisation) stage that significantly enhances the gas output of the following standard mesophilic stage. The hygienisation process is also applied in order to reduce the pathogenic micro-organisms in the feedstock. Hygienisation / pasteurization may be achieved by using a Landia BioChop hygienisation unit or similar method of combined heat treatment and solids maceration.

A drawback of operating at thermophilic temperatures is that more heat energy input is required to achieve the correct operational temperatures. This increase in energy may not be outweighed by the increase in the outputs of biogas from the systems. It is therefore important to consider an energy balance for these systems.

Solids

Typically there are three different operational parameters associated with the solids content of the feedstock to the digesters:

- High-solids (dry—stackable substrate)
- High-solids (wet—pumpable substrate)
- Low-solids (wet—pumpable substrate)

High-solids (dry) digesters are designed to process materials with a high-solids content between ~25-40%. Unlike wet digesters that process pumpable slurries, high solids (dry – stackable substrate) digesters are designed to process solid substrates deposited in tunnel-like chambers with a gas-tight door. They typically have few moving parts, require minimal or no pre-grinding or shredding, and do not use water addition.

Wet digesters can either be designed to operate in a high solids content, with a total suspended solids (TSS) concentration greater than ~20%, or a low solids concentration less than ~15%.

High-solids (wet) digesters process a thick slurry that requires more energy input to move and process the feedstock. The thickness of the material may also lead to associated problems with abrasion. High-solids digesters will typically have a lower land requirement due to the lower volumes associated with the moisture.

Low-solids (wet) digesters can transport material through the system using standard pumps that require significantly lower energy input. Low-solids digesters require a larger amount of land than high-solids due to the increase volumes associated with the increased liquid-to-feedstock ratio of the digesters. There are benefits associated with operation in a liquid environment as it enables more thorough circulation of materials and contact between the bacteria and their food. This enables the bacteria to more readily access the substances they are feeding off and increases the speed of gas yields.

Number of stages

Two-stage, low-solids, UASB digestion component of a mechanical biological treatment system near Tel Aviv, process water is seen in balance tank and sequencing batch reactor, 2005

Digestion systems can be configured with different levels of complexity:

- One-stage or single-stage
- Two-stage or multistage

A single-stage digestion system is one in which all of the biological reactions occur within a single sealed reactor or holding tank. Utilising a single stage reduces construction costs, however facilitates less control of the reactions occurring within the system. Acidogenic bacteria, through the production of acids, reduce the pH of the tank. Methanogenic bacteria, as outlined earlier, operate in a strictly defined pH range. Therefore the biological reactions of the different species in a single stage reactor can be in direct competition with each other. Another one-stage reaction system is an anaerobic lagoon. These lagoons are pond-like earthen basins used for the treatment and long-term storage of manures. Here the anaerobic reactions are contained within the natural anaerobic sludge contained in the pool.

In a two-stage or multi-stage digestion system different digestion vessels are optimised to bring maximum control over the bacterial communities living within the digesters. Acidogenic bacteria produce organic acids and more quickly grow and reproduce than methanogenic bacteria. Methanogenic bacteria require stable pH and temperature in order to optimise their performance.

Typically hydrolysis, acetogenesis and acidogenesis occur within the first reaction vessel. The organic material is then heated to the required operational temperature (either mesophilic or thermophilic) prior to being pumped into a methanogenic reactor. The initial hydrolysis or acidogenesis tanks prior to the methanogenic reactor can provide a buffer to the rate at which feedstock is added. Some European countries require a degree of elevated heat treatment in order to kill harmful bacteria in the input waste. In this instance there may be a pasteurisation or sterilisation stage prior to digestion or between the two digestion tanks. It should be noted that it is not possible to completely isolate the different reaction phases and often there is some biogas that is produced in the hydrolysis or acidogenesis tanks.

Residence

The residence time in a digester varies with the amount and type of feed material, the configuration of the digestion system and whether it be one-stage or two-stage.

In the case of single-stage thermophilic digestion residence times may be in the region of 14 days, which comparatively to mesophilic digestion is relatively fast. The plug-flow nature of some of these systems will mean that the full degradation of the material may not have been realised in this timescale. In this event digestate exiting the system will be darker in colour and will typically have more odour.

In two-stage mesophilic digestion, residence time may vary between 15 and 40 days.

In the case of mesophilic UASB digestion hydraulic residence times can be (1hour-1day) and solid retention times can be up to 90 days. In this manner the UASB system is able to separate solid an hydraulic retention times with the utilisation of a sludge blanket.

Continuous digesters have mechanical or hydraulic devices, depending on the level of solids in the material, to mix the contents enabling the bacteria and the food to be in contact. They also allow excess material to be continuously extracted to maintain a reasonably constant volume within the digestion tanks.

Feedstocks

Anaerobic lagoon & generators at the Cal Poly Dairy, United States 2003

The most important initial issue when considering the application of anaerobic digestion systems is the feedstock to the process. Digesters typically can accept any biodegradable material, however if biogas production is the aim, the level of putrescibility is the key factor in its successful application. The more putrescible the material the higher the gas yields possible from the system.

Substrate composition is a major factor in determining the methane yield and methane production rates from the digestion of biomass. Techniques are available to determine the compositional characteristics of the feedstock, whilst parameters such as solids, elemental and organic analyses are important for digester design and operation.

Anaerobes can breakdown material to varying degrees of success from readily in the case of short chain hydrocarbons such as sugars, to over longer periods of time in the case of cellulose and hemicellulose. Anaerobic microorganisms are unable to break down long chain woody molecules such as lignin. Anaerobic digesters were originally designed for operation using sewage sludge and manures. Sewage and manure are not, however, the material with the most potential for anaerobic digestion as the biodegradable material has already had much of the energy content taken out by the animal that produced it.

Therefore, many digesters operate with *co-digestion* of two or more types of feedstock. For example, in a farm-based digester that uses dairy manure as the primary feedstock the gas production may be significantly increased by adding a second feedstock; e.g. *grass* and *corn* (typical on-site feedstock), or various organic byproducts, such as *slaughterhouse waste*, *fats oils and grease* from restaurants, *organic household waste*, etc. (typical off-site feedstock).

A second consideration related to the feedstock is moisture content. Dryer, stackable substrates, such as food- and yard- waste, are suitable for digestion in tunnel-like chambers. Tunnel style systems typically have near zero wastewater discharge as well so this style system has advantages where the discharge of digester liquids are a liability. The wetter the material the more suitable it will be to handling with standard pumps instead of energy intensive concrete pumps and physical means of movement. Also the wetter the material, the more volume and area it takes up relative to the levels of gas that are produced. The moisture content of the target feedstock will also affect what type of system is applied to its treatment. In order to use a high solids anaerobic digester for dilute feedstocks, bulking agents such as compost should be applied to increase the solid content of the input material. Another key consideration is the carbon:nitrogen ratio of the input material. This ratio is the balance of food a microbe requires in order to grow. The optimal C:N ratio for the 'food' a microbe is 20–30:1. Excess N can lead to ammonia inhibition of digestion.

The level of contamination of the feedstock material is a key consideration. If the feedstock to the digesters has significant levels of physical contaminants such as plastic, glass or metals then pre-processing will be required in order for the material to be used. If it is not removed then the digesters can be blocked and will not function efficiently. It is with this that mechanical biological treatment plants are designed. The higher the level of pre-treatment a feedstock requires, the more processing machinery will be required and hence the project will have higher capital costs.

After sorting or screening to remove any physical contaminants, such as metals and plastics, from the feedstock the material is often shredded, minced and mechanically or hydraulically pulped to increase the surface area available to microbes in the digesters and hence increase the speed of digestion. The maceration of solids can be achieved by using a chopper pump to transfer the feedstock material into the airtight digester where anaerobic treatment takes place.

Products

There are three principal products of anaerobic digestion: biogas, digestate and water.

Biogas

Typical composition of biogas

Matter	%
Methane, CH_4	50–75

Carbon dioxide, CO_2	25–50
Nitrogen, N_2	0–10
Hydrogen, H_2	0–1
Hydrogen sulfide, H_2S	0–3
Oxygen, O_2	0–2

Biogas holder with lightning protection rods and back-up gas flare

Biogas carrying pipes

Biogas is the ultimate waste product of the bacteria feeding off the input biodegradable feedstock (the methanogenesis stage of anaerobic digestion is performed by archaea - a micro-organism on a distinctly different branch of the phylogenetic tree of life to bacteria), and is mostly methane and carbon dioxide, with a small amount hydrogen and trace hydrogen sulfide. (As-produced, biogas also contains water vapor, with the fractional water vapor volume a function of biogas temperature). Most of the biogas is produced during the middle of the digestion, after the bacterial population has grown, and tapers off as the putrescible material is exhausted. The gas is normally stored on top of the digester in an inflatable gas bubble or extracted and stored next to the facility in a gas holder.

The methane in biogas can be burned to produce both heat and electricity, usually with a reciprocating engine or microturbine often in a cogeneration arrangement where the electricity and waste heat generated are used to warm the digesters or to heat buildings. Excess electricity can be sold to suppliers or put into the local grid. Electricity produced by anaerobic digesters is considered to be renewable energy and may attract subsidies. Biogas does not contribute to increasing atmospheric carbon dioxide concentrations because the gas is not released directly into the atmosphere and the carbon dioxide comes from an organic source with a short carbon cycle.

Biogas may require treatment or 'scrubbing' to refine it for use as a fuel. Hydrogen sulfide is a toxic product formed from sulfates in the feedstock and is released as a trace component of the biogas. National environmental enforcement agencies such as the U.S. Environmental Protection Agency or the English and Welsh Environment Agency put strict limits on the levels of gasses containing hydrogen sulfide, and if the levels of hydrogen sulfide in the gas are high, gas scrubbing and cleaning equipment (such as amine gas treating) will be needed to process the biogas to within regionally accepted levels. An alternative method to this is by the addition of ferrous chloride $FeCl_2$ to the digestion tanks in order to inhibit hydrogen sulfide production.

Volatile siloxanes can also contaminate the biogas; such compounds are frequently found in household waste and wastewater. In digestion facilities accepting these materials as a component of the feedstock, low molecular weight siloxanes volatilise into biogas. When this gas is combusted in a gas engine, turbine or boiler, siloxanes are converted into silicon dioxide (SiO_2) which deposits internally in the machine, increasing wear and tear. Practical and cost-effective technologies to remove siloxanes and other biogas contaminants are available at the present time. In certain applications, *in situ* treatment can be used to increase the methane purity by reducing the carbon dioxide content.

In countries such as Switzerland, Germany and Sweden the methane in the biogas may be concentrated in order for it to be used as a vehicle transportation fuel or alternatively input directly into the gas mains. In countries where the driver for the utilisation of anaerobic digestion are renewable electricity subsidies, this route of treatment is less likely as energy is required in this processing stage and reduces the over all levels available to sell.

Digestate

Digestate is the solid remnants of the original input material to the digesters that the microbes cannot use. It also consists of the mineralised remains of the dead bacteria from within the digesters. Digestate can come in three forms; fibrous, liquor or a sludge-based combination of the two fractions. In two-stage systems the different forms of digestate come from different digestion tanks. In single stage digestion systems the two fractions will be combined and if desired separated by further processing.

Acidogenic anaerobic digestate

The second by-product (acidogenic digestate) is a stable organic material consisting largely of lignin and cellulose, but also of a variety of mineral components in a matrix of dead bacterial cells; some plastic may be present. The material resembles domestic compost and can be used as compost or to make low grade building products such as fibreboard. The solid digestate can also be utilized as feedstock for ethanol production.

The third by-product is a liquid (methanogenic digestate) that is rich in nutrients and can be used as a fertiliser dependent on the quality of the material being digested. Levels of potentially toxic elements (PTEs) should be chemically assessed. This will be dependent upon the quality of the original feedstock. In the case of most clean and source-separated biodegradable waste streams the levels of PTEs will be low. In the case of wastes originating from industry the levels of PTEs may be higher and will need to be taken into consideration when determining a suitable end use for the material.

Digestate typically contains elements such as lignin that cannot be broken down by the anaerobic microorganisms. Also the digestate may contain ammonia that is phytotoxic and will hamper the growth of plants if it is used as a soil improving material. For these two reasons a maturation or composting stage may be employed after digestion. Lignin and other materials are available for degradation by aerobic microorganisms such as fungi helping reduce the overall volume of the material for transport. During this maturation the ammonia will be broken down into nitrates, improving the fertility of the material and making it more suitable as a soil improver. Large composting stages are typically used by dry anaerobic digestion technologies.

Wastewater

The final output from anaerobic digestion systems is water. This water originates both from the moisture content of the original waste that was treated but also includes water produced during the microbial reactions in the digestion systems. This water may be released from the dewatering of the digestate or may be implicitly separate from the digestate.

The wastewater exiting the anaerobic digestion facility will typically have elevated levels of biochemical oxygen demand (BOD) and chemical oxygen demand (COD), these are measures of the reactivity of the effluent and show an ability to pollute. Some of this material is termed 'hard COD' meaning it cannot be accessed by the anaerobic bacteria for conversion into biogas. If this effluent was put directly into watercourses it would negatively affect them by causing eutrophication. As such further treatment of the wastewater is often required. This treatment will typically be an oxidation stage where air is passed through the water in a sequencing batch reactors or reverse osmosis unit.

Chapter-6

Capacity Factor

The net **capacity factor** of a power plant is the ratio of the actual output of a power plant over a period of time and its output if it had operated at full nameplate capacity the entire time. To calculate the capacity factor, total energy the plant produced during a period of time and divide by the energy the plant would have produced at full capacity. Capacity factors vary greatly depending on the type of fuel that is used and the design of the plant. The capacity factor should not be confused with the availability factor, capacity credit (firm capacity) or with efficiency.

Sample calculations

Baseload power plant

A base load power plant with a capacity of 1,000 megawatts (MW) might produce 648,000 megawatt-hours (MW·h) in a 30-day month. The number of megawatt-hours that would have been produced had the plant been operating at full capacity can be determined by multiplying the plant's maximum capacity by the number of hours in the time period. 1,000 MW × 30 days × 24 hours/day is 720,000 MW·h. The capacity factor is determined by dividing the actual output with the maximum possible output. In this case, the capacity factor is 0.9 (90%).

$$\frac{648,000 \text{ MW}\cdot\text{h}}{(30 \text{ days}) \times (24 \text{ hours/day}) \times (1000 \text{ MW})} = 0.9 \approx 90\%$$

Wind farm

The Burton Wold Wind Farm consists of ten Enercon E70-E4 wind turbines @ 2 MW nameplate capacity for a total installed capacity of 20 MW. In 2008 the wind farm generated 43,416 MW·h of electricity. (Note 2008 was a leap year.) The capacity factor for this wind farm in 2008 was just under 25%:

$$\frac{43,416\ \text{MW}\cdot\text{h}}{(366\ \text{days})\times(24\ \text{hours/day})\times(20\ \text{MW})} = 0.2471 \approx 25\%$$

Hydroelectric dam

As of 2010, Three Gorges Dam is the largest power generating station in the world by nameplate capacity. In 2009, not yet fully complete, it had 26 main generator units @ 700 MW and two auxiliary generator units @ 50 MW for a total installed capacity of 18,300 MW. Total generation in 2009 was 79.47 TW·h, for a capacity factor of just under 50%:

$$\frac{79,470,000\ \text{MW}\cdot\text{h}}{(365\ \text{days})\times(24\ \text{hours/day})\times(18,300\ \text{MW})} = 0.4957 \approx 50\%$$

Hoover Dam has a nameplate capacity of 2080 MW and an annual generation averaging 4.2 TW·h. (The annual generation has varied between a high of 10.348 TW·h in 1984, and a low of 2.648 TW·h in 1956.) Taking the average figure for annual generation gives a capacity factor of:

$$\frac{4,200,000\ \text{MW}\cdot\text{h}}{(365\ \text{days})\times(24\ \text{hours/day})\times(2,080\ \text{MW})} = 0.23 = 23\%$$

Reasons for reduced capacity factor

There are several reasons why a plant would have a capacity factor lower than 100%. The first reason is that it was out of service or operating at reduced output for part of the time due to equipment failures or routine maintenance. This accounts for most of the unused capacity of base load power plants. Base load plants have the lowest costs per unit of electricity because they are designed for maximum efficiency and are operated continuously at high output. Geothermal plants, nuclear plants, coal plants and bioenergy plants that burn solid material are almost always operated as base load plants.

The second reason that a plant would have a capacity factor lower than 100% is that output is curtailed because the electricity is not needed or because the price of electricity is too low to make production economical. This accounts for most of the unused capacity of peaking power plants. Peaking plants may operate for only a few hours per year or up to several hours per day. Their electricity is relatively expensive. It is uneconomical, even wasteful, to make a peaking power plant as efficient as a base load plant because they do not operate enough to pay for the extra equipment cost, and perhaps not enough to offset the embodied energy of the additional components.

A third reason is a variation on the second: the operators of a hydroelectric dam may uprate its nameplate capacity by adding more generator units. Since the supply of fuel (i.e. water) remains unchanged, the uprated dam obtains a higher peak output in exchange for a lower capacity factor. Because hydro plants are highly dispatchable, they are able to act as load following power plants. Having a higher peak capacity allows a dam's operators to sell more of the annual output of electricity during the hours of highest electricity demand (and thus the highest spot price). In practical terms, uprating a dam allows it to balance a larger amount of intermittent energy sources on the grid such as wind farms and solar power plants, and to compensate for unscheduled shutdowns of baseload power plants, or brief surges in demand for electricity.

Load following power plants

Load following power plants, also called intermediate power plants, are in between these extremes in terms of capacity factor, efficiency and cost per unit of electricity. They produce most of their electricity during the day, when prices and demand are highest. However, the demand and price of electricity is far lower during the night and intermediate plants shutdown or reduce their output to low levels overnight.

Capacity factor and renewable energy

When it comes to several renewable energy sources such as solar power, wind power and hydroelectricity, there is a third reason for unused capacity. The plant may be capable of producing electricity, but its fuel (wind, sunlight or water) may not be available. A hydroelectric plant's production may also be affected by requirements to keep the water level from getting too high or low and to provide water for fish downstream. However, solar, wind and hydroelectric plants do have high availability factors, so when they have fuel available, they are almost always able to produce electricity.

When hydroelectric plants have water available, they are also useful for load following, because of their high *dispatchability*. A typical hydroelectric plant's operators can bring it from a stopped condition to full power in just a few minutes.

Wind farms are variable, due to the natural variability of the wind. Because a wind farm may have hundreds of widely spaced wind turbines, the farm as a whole tends to be robust against the failure of individual turbines. In a large wind farm, a few wind turbines may be down for planned or unplanned maintenance at a given time, but the remaining turbines are generally available to capture power from the wind.

Solar energy is variable because of the daily rotation of the earth and because of cloud cover. However, according to the SolarPACES programme of the International Energy Agency (IEA), solar power plants designed for solar-only generation are well matched to summer noon peak loads in areas with significant cooling demands, such as Spain or the south-western United States., although solar PV does not reduce the need for generation of network upgrades given that air conditioner peak demand often occurs in the late afternoon or early evening when solar output is zero. SolarPACES states that by using thermal energy storage systems the operating periods of solar thermal power (CSP) stations can be extended to meet baseload needs. The IEA CSP Technology Roadmap (2010) suggests that "in the sunniest countries, CSP can be expected to become a competitive source of bulk power in peak and intermediate loads by 2020, and of base-load power by 2025 to 2030".

Geothermal has a higher capacity factor than many other power sources, and geothermal resources are available 24 hours a day, 7 days a week. While the carrier medium for geothermal electricity (water) must be properly managed, the source of geothermal energy, the Earth's heat, will be available for the foreseeable future. Geothermal power can be looked at as a nuclear battery where the heat is produced via the decay of radioactive elements in the core and mantle of the earth.

Typical capacity factors

- Wind farms 20-40%.
- Photovoltaic solar in Massachusetts 12-15%.
- Photovoltaic solar in Arizona 19%
- Hydroelectricity, worldwide average 44%, range of 20% - 75% depending on water availability
- Nuclear energy 90.5% (USA 2009)

Chapter-7

Combined Cycle

In electric power generation a **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. The principle is that the exhaust of one heat engine is used as the heat source for another, thus extracting more useful energy from the heat, increasing the system's overall efficiency. This works because heat engines are only able to use a portion of the energy their fuel generates (usually less than 50%).

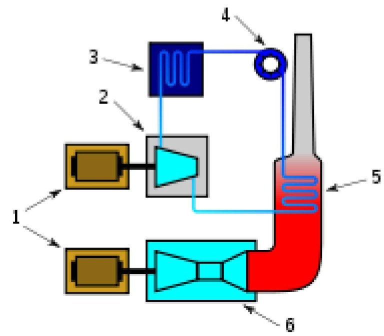
The remaining heat (e.g., hot exhaust fumes) from combustion is generally wasted. Combining two or more thermodynamic cycles results in improved overall efficiency, reducing fuel costs. In stationary power plants, a successful, common combination is the Brayton cycle (in the form of a turbine burning natural gas or synthesis gas from coal) and the Rankine cycle (in the form of a steam power plant). Multiple stage turbine or steam cylinders are also common.

Historically successful combined cycles have used hot cycles with mercury vapor turbines, magnetohydrodynamic generators or molten carbonate fuel cells, with steam plants for the low temperature bottoming cycle. Bottoming cycles operating from a steam condenser's heat are theoretically possible, but uneconomical because of the very large, expensive equipment needed to extract energy from the small temperature differences between condensing steam and outside air or water. However, it is common in cold climates (such as Finland) to drive community heating systems from a power plant's condenser heat. Such cogeneration systems can yield theoretical efficiencies above 95%.

In automotive and aeronautical engines, turbines have been driven from the exhausts of Otto, Diesel, and Crower cycles. These are called turbo-compound engines. Aside from turbochargers, they have failed commercially because their mechanical complexity and weight are less economical than multistage turbines. Stirling engines are also a good theoretical fit for this application.

In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, a gas turbine generator generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity. This last step enhances the efficiency of electricity generation. Many new gas power plants in North America and Europe are of this type. Such an arrangement used for marine propulsion is called *combined gas (turbine) and steam (turbine) (COGAS)*.

Design principle



Working principle of a combined cycle power plant

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

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

In a combined cycle power plant, the heat of the gas turbine's exhaust is used to generate steam by passing it through a heat recovery steam generator (HRSG) with a live steam temperature between 420 and 580 °C. The condenser of the Rankine cycle is usually cooled by water from a lake, river, sea or cooling towers. This temperature can be as low as 15 °C

In an automotive powerplant, an Otto, Diesel, Atkinson or similar engine would provide one part of the cycle and the waste heat would power a Rankine cycle steam or Stirling engine, which could either power ancillaries (such as the alternator) or be connected to the crankshaft by a turbo compounding system.

Typical size of CCGT plants

For large scale power generation, a typical set would be a 270 MW gas turbine coupled to a 130 MW steam turbine giving 400 MW. A typical power station might comprise of between 1 and 6 such sets. Plant size is important in the cost of the plant. The larger plant sizes benefit from economies of scale (lower initial cost per kilowatt) and improved efficiency.

A single shaft combined cycle plant comprises a gas turbine and a steam turbine driving a common generator. In a multi shaft combined cycle plant, each gas turbine and each steam turbine has its own generator. The single shaft design provides slightly less initial cost and slightly better efficiency than if the gas and steam turbines had their own generators. The multi shaft design enables 2 or more gas turbines in conjunction with a single steam turbine, which can be more economical than a number of single shaft units.

The primary disadvantage of multiple stage combined cycle power plant is that the number of steam turbines, condensers and condensate systems-and perhaps the cooling towers and circulating water systems increases to match the number of gas turbines. For multiple shaft combined cycle power plant there is only one steam turbine, condenser and rest of the heat sink for up to three gas turbines, only their size increases. Having only one large steam turbine and heat sink results in low cost because of economics of scale. Further a large steam turbine also allows the use of high pressure and efficient steam cycle. Thus the overall plant size and the associated number of gas turbines required have a major impact on whether single shaft combined cycle power plant or multiple shaft combined cycle power plant is more economical.

Gas turbines of about 150 MW size are already in operation manufactured by at least four separate groups-General Electric and its licensees, Alstom, Siemens, and Westinghouse/Mitsubishi. These groups are also developing, testing and/or marketing gas turbine sizes of about 200 MW. Combined cycle units are made up of one or more such gas turbines, each with a waste heat steam generator arranged to supply steam to a single steam tubine, thus formatting a combined cycle block or unit. Typical Combined cycle block sizes offered by three major manufacturers (Alstom, General Electric and Siemens) are roughly in the range of 50 MW to 500 MW and costs are about $600/kW.

Efficiency of CCGT plants

(When talking about the efficiency of heat engines and power stations the convention should be stated ie HHV (aka Gross Heating Value etc) or LCV (AKA Net Heating value) AND whether Gross output (at the generator terminals) or Net Output (at the power station fence) are being considered. The two are of course separate but both must be stated. Failure to do so causes endless confusion.)

In general in service Combined Cycle efficiencies are over 50 percent on an on a lower heating value and Gross Output basis. Most combined cycle units, especially the larger units, have peak, steady state efficiency efficiencies of 55 - 59%. Research aimed at

1370°C (2500°F) turbine inlet temperature has led to even more efficient combined cycles and 60 percent efficiency has been reached for at least one combined cycle unit, (e.g. the combined cycle unit of Baglan Bay, a GE H-technology gas turbine with a NEM 3 pressure reheat boiler. Utilising steam from the HRSG to cool the turbine blades). Other GT manufacturers also claim to have broken the 60% efficiency for combined cycle (e.g. Siemens).

By combining both gas and steam cycles, high input temperatures and low output temperatures can be achieved. The efficiency of the cycles add, because they are powered by the same fuel source. So, a combined cycle plant has a thermodynamic cycle that operates between the gas-turbine's high firing temperature and the waste heat temperature from the condensers of the steam cycle. This large range means that the Carnot efficiency of the cycle is high. The actual efficiency, while lower than this, is still higher than that of either plant on its own. The actual efficiency achievable is a complex area.

The electric efficiency of a combined cycle power station, calculated as electric energy produced as a percent of the lower heating value of the fuel consumed, may be as high as 58 percent when operating new, ie unaged, and at continuous output which are ideal conditions. As with single cycle thermal units, combined cycle units may also deliver low temperature heat energy for industrial processes, district heating and other uses. This is called cogeneration and such power plants are often referred to as a Combined Heat and Power (CHP) plant.

Boosting Efficiency

The efficiency of CCGT and GT can be boosted by pre-cooling combustion air. This is practiced in hot climates and also has the effect of increasing power output. This is achieved by evaporative cooling of water using a moist matrix placed in front of the turbine, or by using Ice storage air conditioning. The latter has the advantage of greater improvements due to the lower temperatures available. Furthermore, ice storage can be used as a means of load control or load shifting since ice can be made during periods of low power demand and, potentially in the future the anticipated high availability of other resources such as renewables during certain periods.

Supplementary firing and blade cooling

Supplementary firing may be used in combined cycles (in the HRSG) raising exhaust temperatures from 600°C (GT exhaust) to 800 or even 1000°C. Using supplemental firing will however not raise the combined cycle efficiency for most combined cycles. Only for one pressure boilers it may raise the efficiency if fired up to approximately 700- 750°C. For multiple pressure boiler however supplemental firing is often used to improved peak power production of the unit, or to enable large steam production to compensate failing of e.g. a second unit.

Maximum supplementary firing refers to the maximum fuel that can be fired with the oxygen available in the gas turbine exhaust. The steam cycle is conventional with reheat and regeneration. Hot gas turbine exhaust is used as the combustion air. Regenerative air preheater is not required. A fresh air fan which makes it possible to operate the steam plant even when the gas turbine is not in operation,increases the availability of the unit.

The use of large supplementary firing in Combined Cycle Systems with high gas turbine inlet temperatures causes the efficiency to drop. For this reason the Combined Cycle Plants with maximum supplementary firing are only of minimal importance today, in comparison to simple Combined Cycle installations. However, they have two advantages that is a) coal can be burned in the steam generator as the supplementary fuel, b) has very good part load efficiency.

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

More fuel is sometimes added to the turbine's exhaust. This is possible because the turbine exhaust gas (flue gas) still contains some oxygen. Temperature limits at the gas turbine inlet force the turbine to use excess air, above the optimal stoichiometric ratio to burn the fuel. Often in gas turbine designs part of the compressed air flow bypasses the burner and is used to cool the turbine blades.

Supplementary firing raises the temperature of the exhaust gas from 800 to 900 degree Celsius. Relatively high flue gas temperature raises the condition of steam (84 bar, 525 degree Celsius) thereby improving the efficiency of steam cycle.

Fuel for combined cycle power plants

The turbines used in Combined Cycle Plants are commonly fuelled with natural gas , which is found in abundant reserves on every continent. Natural gas is becoming the fuel of choice for private investors and consumers because it is more versatile than coal or oil and can be used in 90% of energy applications .Chile which once depended on hydropower for 70% of its electricity supply, is now boosting its gas supplies to reduce reliance on its drought afflicted hydro dams .Similarly China is tapping its gas reserves to reduce reliance on coal, which is currently burned to generate 80% of the country's electric supply.

Where the extension of a gas pipeline is impractical or cannot be economically justified, electricity needs in remote areas can be met with small scale Combined Cycle Plants, using renewable fuels. Instead of natural gas, Combined Cycle Plants can be filled with biogas derived from agricultural and forestry waste, which is often readily available in rural areas.

Combined cycle plants are usually powered by natural gas, although fuel oil, synthesis gas or other fuels can be used. The supplementary fuel may be natural gas, fuel oil, or coal. Biofuels can also be used. Integrated solar combined cycle power stations combine the energy harvested from solar radiation with another fuel to cut fuel costs and environmental impact. The first such system to come online is Yazd power plant, Iran and more are under construction at Hassi R'mel, Algeria and Ain Beni Mathar, Morocco. Next generation nuclear power plants are also on the drawing board which will take advantage of the higher temperature range made available by the Brayton top cycle, as well as the increase in thermal efficiency offered by a Rankine bottoming cycle.

Low-Grade Fuel for Turbines: Gas turbines burn mainly natural gas and light oil. Crude oil, residual, and some distillates contain corrosive components and as such require fuel treatment equipment. In addition, ash deposits from these fuels result in gas turbine debating's of up to 15 percent they may still be economically attractive fuels however, particularly in combined-cycle plants.

Sodium and potassium are removed from residual, crude and heavy distillates by a water washing procedure. A simpler and less expensive purification system will do the same job for light crude and light distillates. A magnesium additive system may also be needed to reduce the corrosive effects if vanadium is present. Fuels requiring such treatment must have a separate fuel-treatment plant and a system of accurate fuel monitoring to assure reliable, low-maintenance operation of gas turbines.

Configuration of CCGT plants

The combined-cycle system includes single-shaft and multi-shaft configurations. The single-shaft system consists of one gas turbine, one steam turbine, one generator and one Heat Recovery Steam Generator (HRSG), with the gas turbine and steam turbine coupled to the single generator in a tandem arrangement on a single shaft. Key advantages of the single-shaft arrangement are operating simplicity, smaller footprint, and lower startup cost. Single-shaft arrangements, however, will tend to have less flexibility and equivalent reliability than multi-shaft blocks. Additional operational flexibility is provided with a steam turbine which can be disconnected, using an synchro-self-shifting (SSS) Clutch, for start up or for simple cycle operation of the gas turbine.

Multi-shaft systems have one or more gas turbine-generators and HRSGs that supply steam through a common header to a separate single steam turbine-generator. In terms of overall investment a multi-shaft system is about 5% higher in costs.

Single- and multiple-pressure non-reheat steam cycles are applied to combined-cycle systems equipped with gas turbines having rating point exhaust gas temperatures of approximately 540 °C or less. Selection of a single- or multiple-pressure steam cycle for a specific application is determined by economic evaluation which considers plant installed cost, fuel cost and quality, plant duty cycle, and operating and maintenance cost.

Multiple-pressure reheat steam cycles are applied to combined-cycle systems with gas turbines having rating point exhaust gas temperatures of approximately 600 °C.

The most efficient power generation cycles are those with unfired HRSGs with modular pre-engineered components. These unfired steam cycles are also the lowest in cost. Supplementary-fired combined-cycle systems are provided for specific application.

The primary regions of interest for cogeneration combined-cycle systems are those with unfired and supplementary fired steam cycles. These systems provide a wide range of thermal energy to electric power ratio and represent the range of thermal energy capability and power generation covered by the product line for thermal energy and power systems. by Engr. Bilal Pervez

Integrated gasification combined cycle (IGCC)

An integrated gasification combined cycle, or IGCC, is a power plant using synthetic gas (syngas). Syngas can be produced from a number of sources, including coal and fermentation of biomass.

Automotive use

Any turbocharged engine is effecively a combined cycle with the turbo charger extracting extra energy from the exhaust gases, and which could be used to drive the wheels, however it is more convenient to use this extracted energy to force air into the engine which reduces the suction loss and thereby improves the efficiency overall.

Combined cycles have traditionally only been used in large power plants. BMW, however, has proposed that automobiles use exhaust heat to drive steam turbines. This can even be connected to the car or truck's cooling system to save space and weight, but also to provide a condenser in the same location as the radiator and preheating of the water using heat from the engine block. However, stirling engines can also be used if light weight is a priority (such as in a sports car or racing application), because they use air rather than water as the working fluid.

It may be possible to use the pistons in a reciprocating engine for both combustion and steam expansion like in the Crower six stroke.

Aeromotive use

Some versions of the Wright R-3350 were produced as turbo-compound engines. Three turbines driven by exhaust gases, known as *power recovery turbines*, provided nearly 600 hp at takeoff. These turbines added power to the engine crankshaft through bevel gears and fluid couplings.

Chapter-8

Hydropower

Saint Anthony Falls, United States.

Hydropower, **hydraulic power** or **water power** is power that is derived from the force or energy of moving water, which may be harnessed for useful purposes. Prior to the development of electric power, hydropower was used for irrigation, and operation of various machines, such as watermills, textile machines, sawmills, dock cranes, and domestic lifts.

Another method used a trompe to produce compressed air from falling water, which could then be used to power other machinery at a distance from the water.

In hydrology, hydropower is manifested in the force of the water on the riverbed and banks of a river. It is particularly powerful when the river is in flood. The force of the water results in the removal of sediment and other materials from the riverbed and banks of the river, causing erosion and other alterations.

History

Early uses of waterpower date back to Mesopotamia and ancient Egypt, where irrigation has been used since the 6th millennium BC and water clocks had been used since the early 2nd millennium BC. Other early examples of water power include the Qanat system in ancient Persia and the Turpan water system in ancient China.

Waterwheels and mills

Hydropower has been used for hundreds of years. In India, water wheels and watermills were built; in Imperial Rome, water powered mills produced flour from grain, and were also used for sawing timber and stone; in China, watermills were widely used since the Han Dynasty. The power of a wave of water released from a tank was used for extraction of metal ores in a method known as hushing. The method was first used at the Dolaucothi gold mine in Wales from 75 AD onwards, but had been developed in Spain at such mines as Las Medulas. Hushing was also widely used in Britain in the Medieval and later periods to extract lead and tin ores. It later evolved into hydraulic mining when used during the California gold rush.

In China and the rest of the Far East, hydraulically operated "pot wheel" pumps raised water into irrigation canals. At the beginning of the Industrial revolution in Britain, water was the main source of power for new inventions such as Richard Arkwright's water frame. Although the use of water power gave way to steam power in many of the larger mills and factories, it was still used during the 18th and 19th centuries for many smaller operations, such as driving the bellows in small blast furnaces (e.g. the Dyfi Furnace) and gristmills, such as those built at Saint Anthony Falls, which uses the 50-foot (15 m) drop in the Mississippi River.

In the 1830s, at the peak of the canal-building era, hydropower was used to transport barge traffic up and down steep hills using inclined plane railroads.

Hydraulic power pipes

Hydraulic power networks also existed, using pipes carrying pressurized liquid to transmit mechanical power from a power source, such as a pump, to end users. These were extensive in Victorian cities in the United Kingdom. A hydraulic power network was also in use in Geneva, Switzerland. The world famous Jet d'Eau was originally the only over pressure valve of this network.

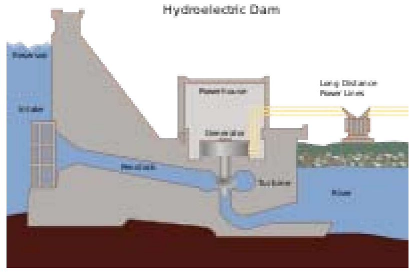
Compressed air hydro

Where there is a plentiful head of water it can be made to generate compressed air directly without moving parts. A falling column of water is mixed with air bubbles generated through turbulence at the inlet. This is allowed to fall down a shaft into a subterranean chamber where the air separates from the water. The weight of falling water compresses the air in the top of the chamber. A submerged outlet from the chamber allows water to flow to the surface at a lower height than the intake. An outlet in the roof of the chamber supplies the compressed air to the surface. A facility on this principal was built on the Montreal River at Ragged Shutes near Cobalt, Ontario in 1910 and supplied 5,000 horsepower to nearby mines.

Modern usage

There are several forms of water power currently in use or development. Some are purely mechanical but many primarily generate electricity. Broad categories include:

Hydroelectricity



A conventional dammed-hydro facility (hydroelectric dam) is the most common type of hydroelectric power generation.

- Conventional hydroelectric, referring to hydroelectric dams.
- Run-of-the-river hydroelectricity, which captures the kinetic energy in rivers or streams, without the use of dams.
- Pumped-storage hydroelectricity, to pump up water, and use its head to generate in times of demand.
- Tidal power, which captures energy from the tides in horizontal direction.
    - Tidal stream power, usage of stream generators, somewhat similar to that of a wind turbine.
    - Tidal barrage power, usage of a tidal dam.
    - Dynamic tidal power, utilizing large areas to generate head.

Marine energy

A Pelamis wave device under test at the European Marine Energy Centre (EMEC), Orkney, Scotland.

- Marine current power, which captures the kinetic energy from marine currents.
- Osmotic power, which channels river water into a container separated from sea water by a semi-permeable membrane.
- Ocean thermal energy, which exploits the temperature difference between deep and shallow waters.

- Tidal power, which captures energy from the tides in horizontal direction. Also a popular form of hydroelectric power generation.
    - Tidal stream power, usage of stream generators, somewhat similar to that of a wind turbine.
    - Tidal barrage power, usage of a tidal dam.
    - Dynamic tidal power, utilizing large areas to generate head.
- Wave power, the use ocean surface waves to generate power.

Calculating the amount of available power

A hydropower resource can be measured according to the amount of available power, or energy per unit time. In large reservoirs, the available power is generally only a function of the hydraulic head and rate of fluid flow. In a reservoir, the head is the height of water in the reservoir relative to its height after discharge. Each unit of water can do an amount of work equal to its weight times the head.

The amount of energy, *E*, released when an object of mass *m* drops a height *h* in a gravitational field of strength *g* is given by

$$E = mgh$$

The energy available to hydroelectric dams is the energy that can be liberated by lowering water in a controlled way. In these situations, the power is related to the mass flow rate.

$$\frac{E}{t} = \frac{m}{t}gh$$

Substituting *P* for $^E/_t$ and expressing $^m/_t$ in terms of the volume of liquid moved per unit time (the rate of fluid flow, φ) and the density of water, we arrive at the usual form of this expression:

$$P = \rho \phi g h$$

or

A simple formula for approximating electric power production at a hydroelectric plant is:

P = hrgk

where P is Power in kilowatts, h is height in meters, r is flow rate in cubic meters per second, g is acceleration due to gravity of 9.8 m/s2, and k is a coefficient of efficiency ranging from 0 to 1. Efficiency is often higher with larger and more modern turbines.

Some hydropower systems such as water wheels can draw power from the flow of a body of water without necessarily changing its height. In this case, the available power is the kinetic energy of the flowing water.

$$P = \frac{1}{2} \rho \phi v^2$$

where *v* is the speed of the water, or with

$$\phi = A v$$

where *A* is the area through which the water passes, also

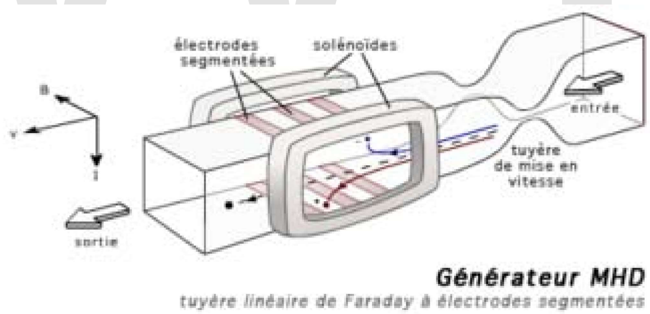
$$P = \frac{1}{2} \rho A v^3$$

Over-shot water wheels can efficiently capture both types of energy.

Chapter-9

MHD Generator

The **MHD** (magnetohydrodynamic) **generator** or **dynamo** transforms thermal energy or kinetic energy directly into electricity. MHD generators are different from traditional electric generators in that they can operate at high temperatures without moving parts. MHD was developed because the exhaust of a plasma MHD generator is a flame, still able to heat the boilers of a steam power plant. So high-temperature MHD was developed as a topping cycle to increase the efficiency of electric generation, especially when burning coal or natural gas. MHD dynamos are the complement of MHD propulsors, which have been applied to pump liquid metals and in several experimental ship engines.



MHD generator
Key
segmentees - segmented electrodes
solenoides - solenoids
sortie - output
entree - entry
tuyere de mise en vitesse - acceleration nozzle

The basic concept underlying the mechanical and fluid dynamos is the same. The fluid dynamo, however, uses the motion of fluid or plasma to generate the currents which generate the electrical energy. The mechanical dynamo, in contrast, uses the motion of mechanical devices to accomplish this. The functional difference between an MHD generator and an MHD dynamo is the path the charged particles follow.

MHD generators are now practical for fossil fuels, but have been overtaken by other, less expensive technologies, such as combined cycles in which a gas turbine's or molten carbonate fuel cell's exhaust heats steam for steam turbine. The unique value of MHD is that it permits an older single-cycle fossil-fuel power plant to be upgraded to high efficiency.

Natural MHD dynamos are an active area of research in plasma physics and are of great interest to the geophysics and astrophysics communities. From their perspective the earth is a global MHD dynamo and with the aid of the particles on the solar wind produces the aurora borealis. The differently charged electromagnetic layers produced by the dynamo effect on the Earth's geomagnetic field enable the appearance of the aurora borealis. As power is extracted from the plasma of the solar wind, the particles slow and are drawn down along the field lines in a brilliant display over the poles.

Principle

The Lorentz Force Law describes the effects of a charged particle moving in a constant magnetic field. The simplest form of this law is given by the vector equation.

$$\mathbf{F} = Q \cdot (\mathbf{v} \times \mathbf{B})$$

where

- **F** is the force acting on the particle,
- Q is charge of particle,
- **v** is velocity of particle,
- **B** is magnetic field.

The vector **F** is perpendicular to both **v** and **B** according to the Right hand rule.

Power generation

Typically for a large scale power station to approach operational efficiency in computer models, steps must be taken to increase the electrical conductivity of the conductive substance. The heating of a gas to plasma or the addition of other easily ionizable substances like the salts of alkali metals accomplishes this increase in conductivity. In practice a number of issues must be considered in the implementation of a **MHD generator**: Generator efficiency, Economics, and Toxic byproducts. These issues are affected by the choice of one of the three MHD generator designs. These are the Faraday generator, the Hall generator, and the disc.

Faraday generator

The Faraday generator is named after the man who first looked for the effect in the Thames river. A simple Faraday generator would consist of a wedge-shaped pipe or tube of some non-conductive material. When an electrically conductive fluid flows through the tube, in the presence of a significant perpendicular magnetic field, a charge is induced in the field, which can be drawn off as electrical power by placing the electrodes on the sides at 90 degree angles to the magnetic field.

There are limitations on the density and type of field used. The amount of power that can be extracted is proportional to the cross sectional area of the tube and the speed of the conductive flow. The conductive substance is also cooled and slowed by this process. MHD generators typically reduce the temperature of the conductive substance from plasma temperatures to just over 1000 °C.

The main practical problem of a Faraday generator is that differential voltages and currents in the fluid short through the electrodes on the sides of the duct. The most powerful waste is from the Hall effect current. This makes the Faraday duct very inefficient. Most further refinements of MHD generators have tried to solve this problem. The optimal magnetic field on duct-shaped MHD generators is a sort of saddle shape. To get this field, a large generator requires an extremely powerful magnet. Many research groups have tried to adapt superconducting magnets to this purpose, with varying success.

Hall generator

The most common answer is to use the Hall effect to create a current that flows with the fluid. The normal scheme is to place arrays of short, vertical electrodes on the sides of the duct. The first and last electrodes in the duct power the load. Each other electrode is shorted to an electrode on the opposite side of the duct. These shorts of the Faraday current induce a powerful magnetic field within the fluid, but in a chord of a circle at right angles to the Faraday current. This secondary, induced field makes current flow in a rainbow shape between the first and last electrodes.

Losses are less than a Faraday generator, and voltages are higher because there is less shorting of the final induced current. However, this design has problems because the speed of the material flow requires the middle electrodes to be offset to "catch" the Faraday currents. As the load varies, the fluid flow speed varies, misaligning the Faraday current with its intended electrodes, and making the generator's efficiency very sensitive to its load.

Disc generator

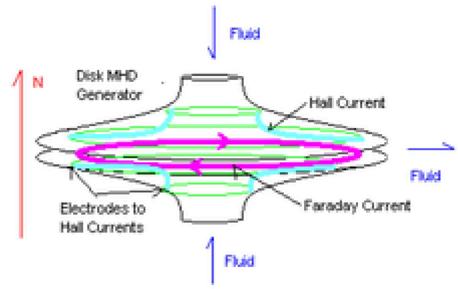


Diagram of a Disk MHD generator showing current flows

The third, currently most efficient answer is the Hall effect disc generator. This design currently holds the efficiency and energy density records for MHD generation. A disc generator has fluid flowing between the center of a disc, and a duct wrapped around the edge. The magnetic excitation field is made by a pair of circular Helmholtz coils above and below the disk. The Faraday currents flow in a perfect dead short around the periphery of the disk. The Hall effect currents flow between ring electrodes near the center and ring electrodes near the periphery.

Another significant advantage of this design is that the magnet is more efficient. First, it has simple parallel field lines. Second, because the fluid is processed in a disk, the magnet can be closer to the fluid, and magnetic field strengths increase as the 7th power of distance. Finally, the generator is compact for its power, so the magnet is also smaller. The resulting magnet uses a much smaller percentage of the generated power.

Generator efficiency

As of 1994, the 22% efficiency record for closed-cycle disc MHD generators was held by Tokyo Technical Institute. The peak enthalpy extraction in these experiments reached 30.2%. Typical open-cycle Hall & duct coal MHD generators are lower, near 17%. These efficiencies make MHD unattractive, by itself, for utility power generation, since conventional Rankine cycle power plants easily reach 40%.

However, the exhaust of an MHD generator burning fossil fuel is almost as hot as the flame of a conventional steam boiler. By routing its exhaust gases into a boiler to make steam, MHD and a steam Rankine cycle can convert fossil fuels into electricity with an estimated efficiency up to 60 percent, compared to the 40 percent of a typical coal plant.

A magnetohydrodynamic generator might also be heated by a Nuclear reactor (either fission or fusion). Reactors of this type operate at temperatures as high as 2000 °C. By pumping the reactor coolant into a magnetohydrodynamic generator before a traditional heat exchanger an estimated efficiency of 60 percent can be realised. One possible conductive coolant is the molten salt reactor's molten salt, since molten salts are electrically conductive.

MHD generators have also been proposed for a number of special situations. In submarines, low speed MHD generators using liquid metals would be nearly silent, eliminating a source of tell-tale mechanism noise. In spacecraft and unattended locations, low-speed metallic MHD generators have been proposed as highly reliable generators, linked to solar, nuclear or isotopic heat sources.

Economics

MHD generators have not been employed for large scale mass energy conversion because other techniques with comparable efficiency have a lower lifecycle investment cost. Advances in natural gas turbines achieved similar thermal efficiencies at lower costs, by having the turbine's exhaust drive a Rankine cycle steam plant. To get more electricity from coal, it is cheaper to simply add more low-temperature steam-generating capacity.

A coal-fueled MHD generator is a type of Brayton power cycle, similar to the power cycle of a combustion turbine. However, unlike the combustion turbine, there are no moving mechanical parts; the electrically conducting plasma provides the moving electrical conductor. The side walls and electrodes merely withstand the pressure within, while the anode and cathode conductors collect the electricity that is generated. All Brayton cycles are heat engines. Ideal Brayton cycles also have an ideal efficiency equal to ideal Carnot cycle efficiency. Thus, the potential for high energy efficiency from an MHD generator. All Brayton cycles have higher potential for efficiency the higher the firing temperature. While a combustion turbine is limited in maximum temperature by the strength of its air/water or steam-cooled rotating airfoils; there are no rotating parts in an open-cycle MHD generator. This upper bound in temperature limits the energy efficiency in combustion turbines. The upper bound on Brayton cycle temperature for an MHD generator is not limited, so inherently an MHD generator has a higher potential capability for energy efficiency.

The temperatures at which linear coal-fueled MHD generators can operate are limited by factors that include: (a) the combustion fuel, oxidizer, and oxidizer preheat temperature which limit the maximum temperature of the cycle; (b) the ability to protect the sidewalls and electrodes from melting; (c) the ability to protect the electrodes from electrochemical attack from the hot slag coating the walls combined with the high current or arcs that impinge on the electrodes as they carry off the direct current from the plasma; and (d) by the capability of the electrical insulators between each electrode. Coal-fired MHD plants with oxygen/air and high oxidant preheats would probably provide potassium seeded plasmas of about 4200 deg. F, 10 atmospheres pressure, and begin expansion at Mach 1.2. These plants would recover MHD exhaust heat for oxidant preheat, and for combined cycle steam generation. With aggressive assumptions, one DOE-funded feasibility study of where the technology could go, 1000 MWe Advanced Coal-Fired MHD/Steam Binary Cycle Power Plant Conceptual Design, published in June 1989, showed that a large coal-fired MHD combined cycle plant could attain a HHV energy efficiency approaching 60 percent -- well in excess of other coal-fueled technologies, so the potential for low operating costs exists.

However, no testing at those aggressive conditions or size has yet occurred, and there are no large MHD generators now under test. There is simply an inadequate reliability track record to provide confidence in a commercial coal-fueled MHD design.

U25B MHD testing in Russia using natural gas as fuel used a superconducting magnet, and had an output of 1.4 megawatts. A coal-fired MHD generator series of tests funded by the U.S. Department of Energy in 1992 produced MHD power from a larger superconducting magnet at the Component Development and Integration Facility (CDIF) in Butte, Montana. None of these tests were conducted for long-enough durations to verify the commercial durability of the technology. Neither of the test facilities were in large-enough scale for a commercial unit.

Superconducting magnets are used in the larger MHD generators to eliminate one of the large parasitic losses: the power needed to energize the electromagnet. Superconducting magnets, once charged, consume no power, and can develop intense magnetic fields 4 teslas and higher. The only parasitic load for the magnets are to maintain refrigeration, and to make up the small losses for the non-supercritical connections.

Because of the high temperatures, the non-conducting walls of the channel must be constructed from an exceedingly heat-resistant substance such as yttrium oxide or zirconium dioxide to retard oxidation. Similarly, the electrodes must be both conductive and heat-resistant at high temperatures. AVCO's coal-fueled MHD generator at the CDIF with tests of water-cooled copper electrodes capped with platinum, tungsten, stainless steel, and electrically conducting ceramics.

Toxic byproducts

MHD reduces overall production of hazardous fossil fuel wastes because it increases plant efficiency. In MHD coal plants, the patented commercial "Econoseed" process developed by the U.S. recycles potassium ionization seed from the fly ash captured by the stack-gas scrubber. However, this equipment is an additional expense. If molten metal is the armature fluid of an MHD generator, care must be taken with the coolant of the electromagnetics and channel. The alkali metals commonly used as MHD fluids react violently with water. Also, the chemical byproducts of heated, electrified alkali metals and channel ceramics may be poisonous and environmentally persistent.

History

Michael Faraday first proposed the idea in his "Bakerian lecture for 1832" to the Royal Society. He carried out experiments at Waterloo Bridge, measuring current from the flow of the Thames in the Earth's magnetic field. The first practical MHD power research was funded in 1938 in the U.S. by Westinghouse in its Pittsburgh, Pennsylvania laboratories, headed by Bela Karlovitz. The initial patent on MHD is by B. Karlovitz, U.S. Patent No. 2,210,918, "Process for the Conversion of Energy", August 13, 1940.

World war II interrupted development. In 1962, the First International Conference on MHD Power was held in Newcastle on Tyne, UK by Dr. Brian C. Lindley of the International Research and Development Company Ltd. The group set up a steering committee to set up further conferences and disseminate ideas. In 1964, the group set up a second conference in Paris, France, in consultation with the European Nuclear Energy Agency.

Since membership in the ENEA was limited, the group persuaded the International Atomic Energy Agency to sponsor a third conference, in Salzburg, Austria, July 1966. Negotiations at this meeting converted the steering committee into a periodic reporting group, the ILG-MHD (international liaison group, MHD), under the ENEA, and later in 1967, also under the International Atomic Energy Agency. Further research in the 1960s by R. Rosa established the practicality of MHD for fossil-fueled systems.

In the 1960s, AVCO Everett Aeronautical Research began a series of experiments, ending with the Mk. V generator of 1965. This generated 35 MW, but used about 8MW to drive its magnet. In 1966, the ILG-MHD had its first formal meeting in Paris, France. It began issuing a periodic status report in 1967. This pattern persisted, in this institutional form, up until 1976. Toward the end of the 1960s, interest in MHD declined because nuclear power was becoming more widely available.

In the late 1970s, as interest in nuclear power declined, interest in MHD increased. In 1975, UNESCO became persuaded the MHD might be the most efficient way to utilise world coal reserves, and in 1976, sponsored the ILG-MHD. In 1976, it became clear that no nuclear reactor in the next 25 years would use MHD, so the International Atomic Energy Agency and ENEA (both nuclear agencies) withdrew support from the ILG-MHD, leaving UNESCO as the primary sponsor of the ILG-MHD.

Serbian development

Over more than a ten year span, Serbian engineers in Bosnia had built the first experimental Magneto-Hydrodynamic facility power generator in 1992. It was here it was first patented.

U.S. development

In the 1980s, the U.S. Department of Energy began a vigorous multiyear program, culminating in a 1992 50MW demonstration coal combustor at the Component Development and Integration Facility (CDIF) in Butte, Montana. This program also had significant work at the Coal-Fired-In-Flow-Facility (CFIFF) at University of Tennessee Space Institute.

This program combined four parts:

- 1. An integrated MHD topping cycle, with channel, electrodes and current control units developed by AVCO, later known as Textron Defence of Boston. This system was a Hall effect duct generator heated by pulverized coal, with a potassium ionisation seed. AVCO had developed the famous Mk. V generator, and had significant experience.

- 2. An integrated bottoming cycle, developed at the CDIF.
- 3. A facility to regenerate the ionization seed was developed by TRW. Potassium carbonate is separated from the sulphate in the fly ash from the scrubbers. The carbonate is removed, to regain the potassium.
- 4. A method to integrate MHD into preexisting coal plants. The Department of Energy commissioned two studies. Westinghouse Electric performed a study based on the Scholtz Plant of Gulf Power in Snead, Florida. The MHD Development Corporation also produced a study based on the J.E. Corrette Plant of the Montana Power Company of Billings, Montana.

Initial prototypes at the CDIF were operated for short durations, with various coals: Montana Rosebud, and a high-sulphur corrosive coal, Illinois No. 6. A great deal of engineering, chemistry and material science was completed. After final components were developed, operational testing completed with 4,000 hours of continuous operation, 2,000 on Montana Rosebud, 2,000 on Illinois No. 6. The testing ended in 1993.

Japanese development

The Japanese program in the late 1980s concentrated on closed-cycle MHD. The belief was that it would have higher efficiencies, and smaller equipment, especially in the clean, small, economical plant capacities near 100 megawatts (electrical) which are suited to Japanese conditions. Open-cycle coal-powered plants are generally thought to become economical above 200 megawatts.

The first major series of experiments was FUJI-1, a blow-down system powered from a shock tube at the Tokyo Institute of Technology. These experiments extracted up to 30.2% of enthalpy, and achieved power densities near 100 megawatts per cubic meter. This facility was funded by Tokyo Electric Power, other Japanese utilities, and the Department of Education. Some authorities believe this system was a disc generator with a helium and argon carrier gas and potassium ionization seed.

In 1994, there were detailed plans for FUJI-2, a 5MW (electrical) continuous closed-cycle facility, powered by natural gas, to be built using the experience of FUJI-1. The basic MHD design was to be a system with inert gases using a disk generator. The aim was an enthalpy extraction of 30% and an MHD thermal efficiency of 60%. FUJI-2 was to be followed by a retrofit to a 300 MWe natural gas plant.

Australian development

In 1986, Professor Hugo Karl Messerle at The University of Sydney researched coal-fueled MHD. This resulted in a 28 MWe topping facility that was operated outside Sydney. Messerle also wrote one of the most recent reference works, as part of a UNESCO education program.

A detailed obituary for Hugo is located on the Australian Academy of Technological Sciences and Engineering (ATSE) website.

Italian development

The Italian program began in 1989 with a budget of about 20 million $US, and had three main development areas:

- 1. MHD Modelling.
- 2. Superconducting magnet development. The goal in 1994 was a prototype 2 m long, storing 66 MJ, for an MHD demonstration 8 m long. The field was to be 5 teslas, with a taper of 0.15 T/m. The geometry was to resemble a saddle shape, with cylindrical and rectangular windings of niobium-titanium copper.
- 3. Retrofits to natural gas powerplants. One was to be at the Enichem-Anic factor in Ravenna. In this plant, the combustion gases from the MHD would pass to the boiler. The other was a 230 MW (thermal) installation for a power station in Brindisi, that would pass steam to the main power plant.

Chinese development

A joint U.S.-China national programme ended in 1992 by retrofitting the coal-fired No. 3 plant in Asbach. A further eleven-year program was approved in March 1994. This established centres of research in:

- 1. The Institute of Electrical Engineering in the Academica Sinica, Beijing, concerned with MHD generator design.
- 2. The Shanghai Power Research Institute, concerned with overall system and superconducting magnet research.
- 3. The Thermoenergy Research Engineering Institute at the Nanjing's Southeast University, concerned with later developments.

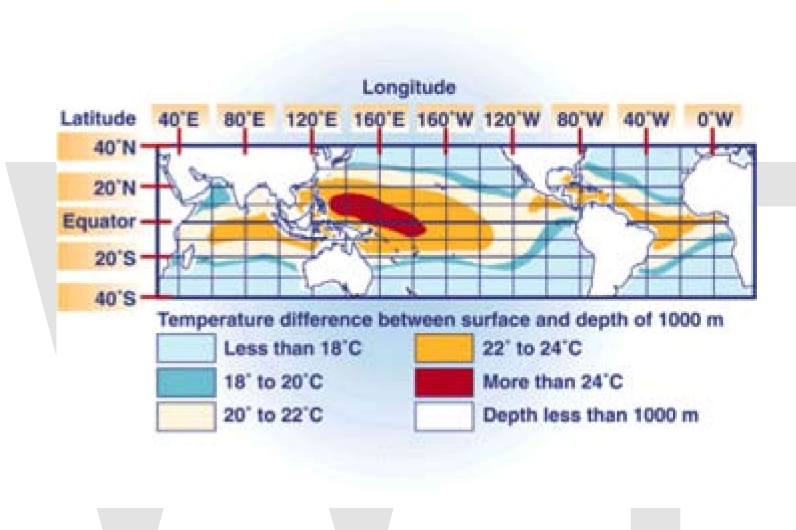
The 1994 study proposed a 10 MW (electrical, 108 MW thermal) generator with the MHD and bottoming cycle plants connected by steam piping, so either could operate independently.

Russian developments

By 1994, Russia had developed and operated the coal-operated facility U-25, at the High-Temperature Institute of the Russian Academy of Sciences in Moscow. U-25's bottoming plant was actually operated under contract with the Moscow utility, and fed power into Moscow's grid. There was substantial interest in Russia in developing a coal-powered disc generator.

Chapter-10

Ocean Thermal Energy Conversion



Temperature differences between the surface and 1000m depth in the oceans

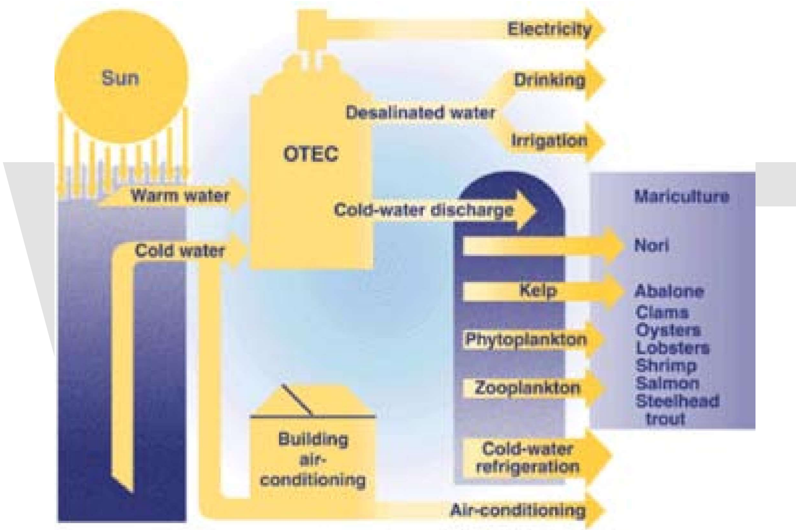
Ocean thermal energy conversion (*OTEC* or *OTE*) uses the difference between cooler deep and warmer shallow or surface ocean waters to run a heat engine and produce useful work, usually in the form of electricity.

A heat engine gives greater efficiency and power when run with a large temperature difference. In the oceans the temperature difference between surface and deep water is greatest in the tropics, although still a modest $20^{o}C$ to $25^{o}C$. It is therefore in the tropics that OTEC offers the greatest possibilities. OTEC has the potential to offer global amounts of energy that are 10 to 100 times greater than other ocean energy options such as wave power. OTEC plants can operate continuously providing a base load supply for an electrical power generation system.

The main technical challenge of OTEC is to generate significant amounts of power efficiently from small temperature differences. It is still considered an emerging technology. Early OTEC systems were of 1 to 3% thermal efficiency, well below the theoretical maximum for this temperature difference of between 6 and 7%. Current designs are expected to be closer to the maximum. The first operational system was built in Cuba in 1930 and generated 22 kW. Modern designs allow performance approaching the theoretical maximum Carnot efficiency and the largest built in 1999 by the USA generated 250 kW .

The most commonly used heat cycle for OTEC is the Rankine cycle using a low-pressure turbine. Systems may be either closed-cycle or open-cycle. Closed-cycle engines use working fluids that are typically thought of as refrigerants such as ammonia or R-134a. Open-cycle engines use vapour from the seawater itself as the working fluid.

OTEC can also supply quantities of cold water as a by-product . This can be used for air conditioning and refrigeration and the fertile deep ocean water can feed biological technologies. Another by-product is fresh water distilled from the sea.



OTEC diagram and applications

History

Attempts to develop and refine OTEC technology started in the 1880s. In 1881, Jacques Arsene d'Arsonval, a French physicist, proposed tapping the thermal energy of the ocean. D'Arsonval's student, Georges Claude, built the first OTEC plant, in Cuba in 1930. The system generated 22 kW of electricity with a low-pressure turbine.

In 1931, Nikola Tesla released "Our Future Motive Power", which described such a system. Tesla ultimately concluded that the scale of engineering required made it impractical for large scale development.

In 1935, Claude constructed a plant aboard a 10,000-ton cargo vessel moored off the coast of Brazil. Weather and waves destroyed it before it could generate net power. (Net power is the amount of power generated after subtracting power needed to run the system.)

View of a land based OTEC facility at Keahole Pointon the Kona coast of Hawaii (United States Department of Energy)

In 1956, French scientists designed a 3 MW plant for Abidjan, Ivory Coast. The plant was never completed, because new finds of large amounts of cheap oil made it uneconomical.

In 1962, J. Hilbert Anderson and James H. Anderson, Jr. focused on increasing component efficiency. They patented their new "closed cycle" design in 1967.

Although Japan has no potential sites, it is a major contributor to the development of the technology, primarily for export. Beginning in 1970 the Tokyo Electric Power Company successfully built and deployed a 100 kW closed-cycle OTEC plant on the island of Nauru. The plant became operational 1981-10-14, producing about 120 kW of electricity; 90 kW was used to power the plant and the remaining electricity was used to power a school and other places. This set a world record for power output from an OTEC system where the power was sent to a real power grid.

The United States became involved in 1974, establishing the Natural Energy Laboratory of Hawaii Authority at Keahole Point on the Kona coast of Hawaii. Hawaii is the best U.S. OTEC location, due to its warm surface water, access to very deep, very cold water, and Hawaii's high electricity costs. The laboratory has become a leading test facility for OTEC technology.

India built a one MW floating OTEC pilot plant near Tamil Nadu, and its government continues to sponsor research.

Cycle types

Cold seawater is an integral part of each of the three types of OTEC systems: closed-cycle, open-cycle, and hybrid. To operate, the cold seawater must be brought to the surface. The primary approaches are active pumping and desalination. Desalinating seawater near the sea floor lowers its density, which causes it to rise to the surface.

The alternative to costly pipes to bring condensing cold water to the surface is to pump vaporized low boiling point fluid into the depths to be condensed, thus reducing pumping volumes and reducing technical and environmental problems and lowering costs.

Closed

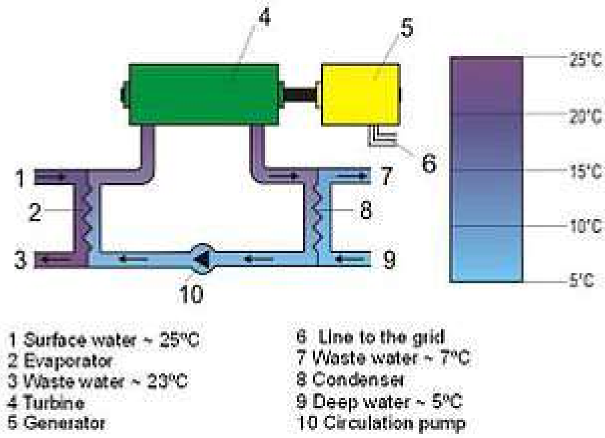


Diagram of a closed cycle OTEC plant

Closed-cycle systems use fluid with a low boiling point, such as ammonia, to power a turbine to generate electricity. Warm surface seawater is pumped through a heat exchanger to vaporize the fluid. The expanding vapor turns the turbo-generator. Cold water, pumped through a second heat exchanger, condenses the vapor into a liquid, which is then recycled through the system.

In 1979, the Natural Energy Laboratory and several private-sector partners developed the "mini OTEC" experiment, which achieved the first successful at-sea production of net electrical power from closed-cycle OTEC. The mini OTEC vessel was moored 1.5 miles (2 km) off the Hawaiian coast and produced enough net electricity to illuminate the ship's light bulbs and run its computers and television.

Open

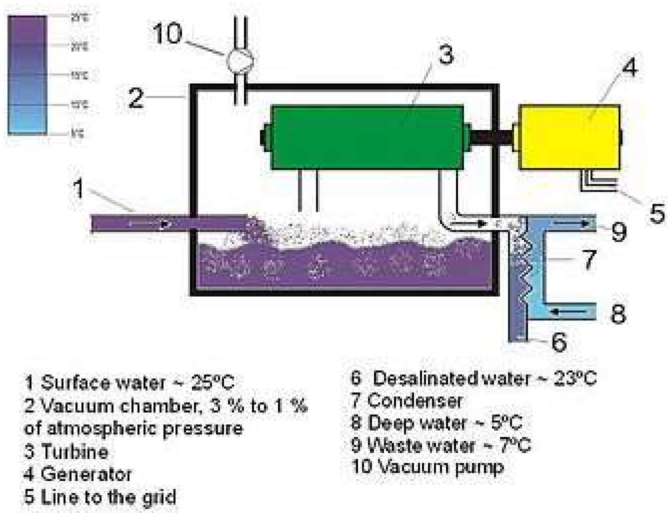


Diagram of an open cycle OTEC plant

Open-cycle OTEC uses warm surface water directly to make electricity. Placing warm seawater in a low-pressure container causes it to boil. The expanding steam drives a low-pressure turbine attached to an electrical generator. The steam, which has left its salt and other contaminants in the low-pressure container, is pure fresh water. It is condensed into a liquid by exposure to cold temperatures from deep-ocean water. This method produces desalinized fresh water, suitable for drinking water or irrigation.

In 1984, the *Solar Energy Research Institute* (now the National Renewable Energy Laboratory) developed a vertical-spout evaporator to convert warm seawater into low-pressure steam for open-cycle plants. Conversion efficiencies were as high as 97% for seawater-to-steam conversion (overall efficiency using a vertical-spout evaporator would still only be a few per cent). In May 1993, an open-cycle OTEC plant at Keahole Point, Hawaii, produced 50,000 watts of electricity during a net power-producing experiment. This broke the record of 40 kW set by a Japanese system in 1982.

Hybrid

A hybrid cycle combines the features of the closed- and open-cycle systems. In a hybrid, warm seawater enters a vacuum chamber and is flash-evaporated, similar to the open-cycle evaporation process. The steam vaporizes the ammonia working fluid of a closed-cycle loop on the other side of an ammonia vaporizer. The vaporized fluid then drives a turbine to produce electricity. The steam condenses within the heat exchanger and provides desalinated water.

Working fluids

A popular choice of working fluid is ammonia, which has superior transport properties, easy availability, and low cost. Ammonia, however, is toxic and flammable. Fluorinated carbons such asCFCs and HCFCs are not toxic or flammable, but they contribute to ozone layer depletion. Hydrocarbons too are good candidates, but they are highly flammable; in addition, this would create competition for use of them directly as fuels. The power plant size is dependent upon the vapor pressure of the working fluid. With increasing vapor pressure, the size of the turbine and heat exchangers decreases while the wall thickness of the pipe and heat exchangers increase to endure high pressure especially on the evaporator side.

Land, shelf and floating sites

OTEC has the potential to produce gigawatts of electrical power, and in conjunction withelectrolysis, could produce enough hydrogen to completely replace all projected global fossil fuel consumption. Reducing costs remains an unsolved challenge, however. OTEC plants require a long, large diameter intake pipe, which is submerged a kilometer or more into the ocean's depths, to bring cold water to the surface.

Left: Pipes used for OTEC. Right: Floating OTEC plant constructed in India in 2000

Land-based

Land-based and near-shore facilities offer three main advantages over those located in deep water. Plants constructed on or near land do not require sophisticated mooring, lengthy power cables, or the more extensive maintenance associated with open-ocean environments. They can be installed in sheltered areas so that they are relatively safe from storms and heavy seas. Electricity, desalinated water, and cold, nutrient-rich seawater could be transmitted from near-shore facilities via trestle bridges or causeways. In addition, land-based or near-shore sites allow plants to operate with related industries such as mariculture or those that require desalinated water.

Favored locations include those with narrow shelves (volcanic islands), steep (15-20 degrees) offshore slopes, and relatively smooth sea floors. These sites minimize the length of the intake pipe. A land-based plant could be built well inland from the shore, offering more protection from storms, or on the beach, where the pipes would be shorter. In either case, easy access for construction and operation helps lower costs.

Land-based or near-shore sites can also support mariculture. Tanks or lagoons built on shore allow workers to monitor and control miniature marine environments. Mariculture products can be delivered to market via standard transport.

One disadvantage of land-based facilities arises from the turbulent wave action in the surf zone. Unless the OTEC plant's water supply and discharge pipes are buried in protective trenches, they will be subject to extreme stress during storms and prolonged periods of heavy seas. Also, the mixed discharge of cold and warm seawater may need to be carried several hundred meters offshore to reach the proper depth before it is released. This arrangement requires additional expense in construction and maintenance.

OTEC systems can avoid some of the problems and expenses of operating in a surf zone if they are built just offshore in waters ranging from 10 to 30 meters deep (Ocean Thermal Corporation 1984). This type of plant would use shorter (and therefore less costly) intake and discharge pipes, which would avoid the dangers of turbulent surf. The plant itself, however, would require protection from the marine environment, such as breakwaters and erosion-resistant foundations, and the plant output would need to be transmitted to shore.

Shelf-based

To avoid the turbulent surf zone as well as to move closer to the cold-water resource, OTEC plants can be mounted to the continental shelf at depths up to 100 meters (328 ft).

A shelf-mounted plant could be towed to the site and affixed to the sea bottom. This type of construction is already used for offshore oil rigs. The complexities of operating an OTEC plant in deeper water may make them more expensive than land-based approaches. Problems include the stress of open-ocean conditions and more difficult product delivery. Addressing strong ocean currents and large waves adds engineering and construction expense. Platforms require extensive pilings to maintain a stable base. Power delivery can require long underwater cables to reach land. For these reasons, shelf-mounted plants are less attractive.

Floating

Floating OTEC facilities operate off-shore. Although potentially optimal for large systems, floating facilities present several difficulties. The difficulty of mooring plants in very deep water complicates power delivery. Cables attached to floating platforms are more susceptible to damage, especially during storms. Cables at depths greater than 1000 meters are difficult to maintain and repair. Riser cables, which connect the sea bed and the plant, need to be constructed to resist entanglement.

As with shelf-mounted plants, floating plants need a stable base for continuous operation. Major storms and heavy seas can break the vertically suspended cold-water pipe and interrupt warm water intake as well. To help prevent these problems, pipes can be made of flexible polyethylene attached to the bottom of the platform and gimballed with joints or collars. Pipes may need to be uncoupled from the plant to prevent storm damage. As an alternative to a warm-water pipe, surface water can be drawn directly into the platform; however, it is necessary to prevent the intake flow from being damaged or interrupted during violent motions caused by heavy seas.

Connecting a floating plant to power delivery cables requires the plant to remain relatively stationary. Mooring is an acceptable method, but current mooring technology is limited to depths of about 2,000 meters (6,562 ft). Even at shallower depths, the cost of mooring may be prohibitive.

Some proposed projects

OTEC projects under consideration include a small plant for the U.S. Navy base on the Britishoverseas territory island of Diego Garcia in the Indian Ocean. OCEES International, Inc. is working with the U.S. Navy on a design for a proposed 13-MW OTEC plant, to replace the current diesel generators. The OTEC plant would also provide 1.25 million gallons per day (MGD) of potable water. A private U.S. company has proposed building a 10-MW OTEC plant on Guam.

Hawaii

Lockheed Martin's Alternative Energy Development team has partnered with Makai Ocean Engineering to complete the final design phase of a 10-MW closed cycle OTEC pilot system which will become operational in Hawaii in the 2012-2013 time frame. This system is being designed to expand to 100-MW commercial systems in the near future. In November, 2010 the U.S. Naval Facilities Engineering Command (NFEC) awarded Lockheed Martin a US$4.4 million contract modification to develop critical system components and designs for the plant, adding to the 2009 $8.1 million contract and two Department of Energy grants totaling $1 million in 2008 and March 2010.

Related activities

OTEC has uses other than power production.

Air conditioning

The 41 °F (5 °C) cold seawater made available by an OTEC system creates an opportunity to provide large amounts of cooling to operations near the plant. The water can be used in chilled-water coils to provide air-conditioning for buildings. It is estimated that a pipe 1 foot (0.30 m) in diameter can deliver 4,700 gallons per minute of water. Water at 43 °F (6 °C) could provide more than enough air-conditioning for a large building. Operating 8,000 hours per year in lieu of electrical conditioning selling for 5-10¢ per kilowatt-hour, it would save $200,000-$400,000 in energy bills annually.

The InterContinental Resort and Thalasso-Spa on the island of Bora Bora uses an OTEC system to air-condition its buildings. The system passes seawater through a heat exchanger where it cools freshwater in a closed loop system. This freshwater is then pumped to buildings and directly cools the air.

Chilled-soil agriculture

OTEC technology supports chilled-soil agriculture. When cold seawater flows through underground pipes, it chills the surrounding soil. The temperature difference between roots in the cool soil and leaves in the warm air allows plants that evolved in temperate climates to be grown in the subtropics. Dr. John P. Craven, Dr. Jack Davidson and Richard Bailey patented this process and demonstrated it at a research facility at the Natural Energy Laboratory of Hawaii Authority (NELHA). The research facility demonstrated that more than 100 different crops can be grown using this system. Many normally could not survive in Hawaii or at Keahole Point.

Aquaculture

Aquaculture is the best-known byproduct, because it reduces the financial and energy costs of pumping large volumes of water from the deep ocean. Deep ocean water contains high concentrations of essential nutrients that are depleted in surface waters due to biological consumption. This "artificial upwelling" mimics the natural upwellings that are responsible for fertilizing and supporting the world's largest marine ecosystems, and the largest densities of life on the planet.

Cold-water delicacies, such as salmon and lobster, thrive in this nutrient-rich, deep, seawater. Microalgae such as *Spirulina*, a health food supplement, also can be cultivated. Deep-ocean water can be combined with surface water to deliver water at an optimal temperature.

Non-native species such as Salmon, lobster, abalone, trout, oysters, and clams can be raised in pools supplied by OTEC-pumped water. This extends the variety of fresh seafood products available for nearby markets. Such low-cost refrigeration can be used to maintain the quality of harvested fish, which deteriorate quickly in warm tropical regions.

Desalination

Desalinated water can be produced in open- or hybrid-cycle plants using surface condensers to turn evaporated seawater into potable water. System analysis indicates that a 2-megawatt plant could produce about 4,300 cubic metres (150,000 cu ft) of desalinated water each day. Another system patented by Richard Bailey creates condensate water by regulating deep ocean water flow through surface condensers correlating with fluctuating dew-point temperatures. This condensation system uses no incremental energy and has no moving parts.

Hydrogen production

Hydrogen can be produced via electrolysis using OTEC electricity. Generated steam with electrolyte compounds added to improve efficiency is a relatively pure medium for hydrogen production. OTEC can be scaled to generate large quantities of hydrogen. The main challenge is cost relative to other energy sources and fuels.

Mineral extraction

The ocean contains 57 trace elements in salts and other forms and dissolved in solution. In the past, most economic analyses concluded that mining the ocean for trace elements would be unprofitable, in part because of the energy required to pump the water. Mining generally targets minerals that occur in high concentrations, and can be extracted easily, such as magnesium. With OTEC plants supplying water, the only cost is for extraction. The Japanese investigated the possibility of extracting uranium and found developments in other technologies (especially materials sciences) were improving the prospects.

Political concerns

Because OTEC facilities are more-or-less stationary surface platforms, their exact location and legal status may be affected by the United Nations Convention on the Law of the Sea treaty (UNCLOS). This treaty grants coastal nations 3-, 12-, and 200-mile zones of varying legal authority from land, creating potential conflicts and regulatory barriers. OTEC plants and similar structures would be considered artificial islands under the treaty, giving them no independent legal status. OTEC plants could be perceived as either a threat or potential partner to fisheries or to seabed mining operations controlled by the International Seabed Authority.

Cost and economics

For OTEC to be viable as a power source, the technology must have tax and subsidy treatment similar to competing energy sources. Because OTEC systems have not yet been widely deployed, cost estimates are uncertain. One study estimates power generation costs as low as US $0.07 per kilowatt-hour, compared with $0.05 - $0.07 for subsidized wind systems.

Beneficial factors that should be taken into account include OTEC's lack of waste products and fuel consumption, the area in which it is available, (often within 20° of the equator) the geopolitical effects of petroleum dependence, compatibility with alternate forms of ocean power such as wave energy, tidal energy and methane hydrates, and supplemental uses for the seawater.

Mathematics of OTEC

Variation of ocean temperature with depth

The total insolation received by the oceans (covering 70% of the earth's surface, with clearness index of 0.5 and average energy retention of 15%) is 5.457 x e^{10} Megajoules/year (MJ/yr) x .7 x .5 x .15 = 2.87 x e^{10} MJ/yr

We can use Lambert's law to quantify the solar energy absorption by water,

$$-\frac{dI(y)}{dy} = \mu I$$

where, y is the depth of water, I is intensity and μ is the absorption coefficient. Solving the above differential equation,

$$I(y) = I_0 \exp(-\mu y)$$

The absorption coefficient μ may range from 0.05 m^{-1} for very clear fresh water to 0.5 m^{-1} for very salty water.

Since the intensity falls exponentially with depth y, heat absorption is concentrated at the top layers. Typically in the tropics, surface temperature values are in excess of 25 °C (77 °F), while at 1 kilometers (1 mi), the temperature is about 5–10 °C (41–50 °F). The warmer (and hence lighter) waters at the surface means there are no thermal convection currents. Due to the small temperature gradients, heat transfer by conduction is too low to equalize the temperatures. The ocean is thus both a practically infinite heat source and a practically infinite heat sink.

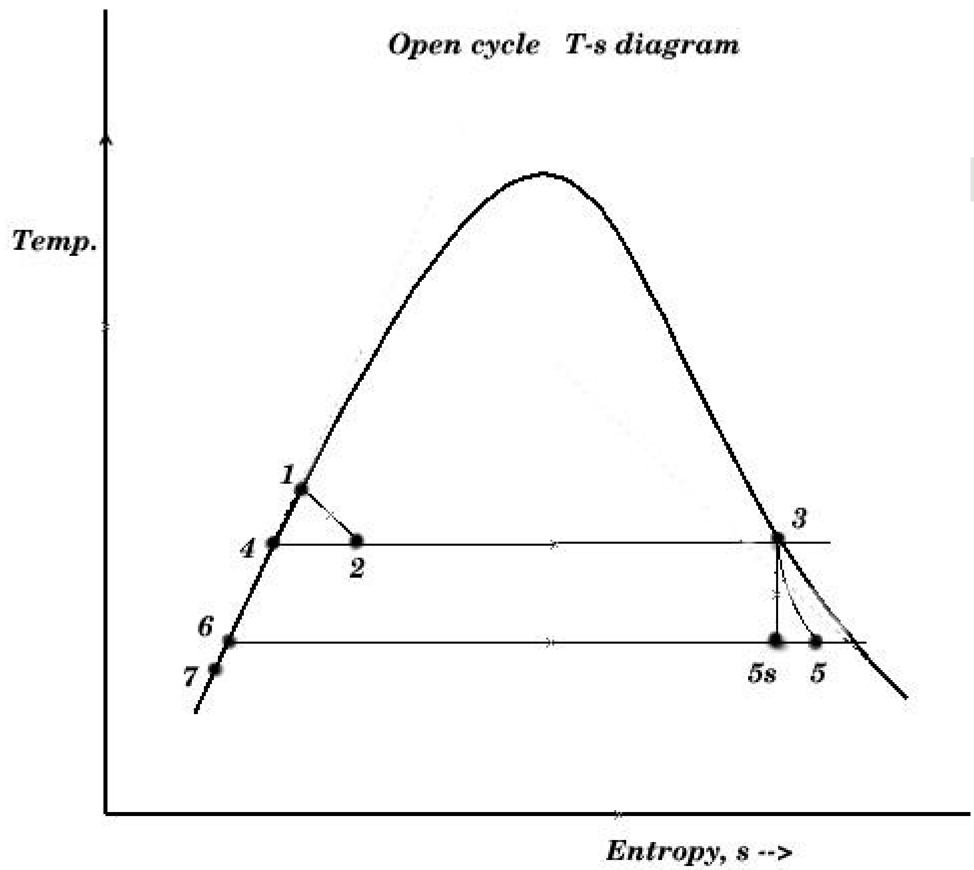
This temperature difference varies with latitude and season, with the maximum in tropical, subtropical and equatorial waters. Hence the tropics are generally the best OTEC locations.

Open/Claude cycle

In this scheme, warm surface water at around 27 °C (81 °F) enters an evaporator at pressure slightly below the saturation pressures causing it to vaporize.

$$H_1 = H_f$$

Where H_f is enthalpy of liquid water at the inlet temperature, T_1.



This temporarily superheated water undergoes volume boiling as opposed to pool boiling in conventional boilers where the heating surface is in contact. Thus the water partially flashes to steam with two-phase equilibrium prevailing. Suppose that the pressure inside the evaporator is maintained at the saturation pressure, T_2.

$$H_2 = H_1 = H_f + x_2 H_{fg}$$

Here, x_2 is the fraction of water by mass that vaporizes. The warm water mass flow rate per unit turbine mass flow rate is $1/x_2$.

The low pressure in the evaporator is maintained by a vacuum pump that also removes the dissolved non-condensable gases from the evaporator. The evaporator now contains a mixture of water and steam of very low vapor quality (steam content). The steam is separated from the water as saturated vapor. The remaining water is saturated and is discharged to the ocean in the open cycle. The steam is a low pressure/high specific volume working fluid. It expands in a special low pressure turbine.

$$H_3 = H_g$$

Here, H_g corresponds to T_2. For an ideal isentropic (reversible adiabatic) turbine,

$$s_{5,s} = s_3 = s_f + x_{5,s} s_{fg}$$

The above equation corresponds to the temperature at the exhaust of the turbine, T_5. $x_{5,s}$ is the mass fraction of vapor at state 5.

The enthalpy at T_5 is,

$$H_{5,s} = H_f + x_{5,s} H_{fg}$$

This enthalpy is lower. The adiabatic reversible turbine work = H_3-$H_{5,s}$.

Actual turbine work W_T = (H_3-$H_{5,s}$) x *polytropic efficiency*

$$H_5 = H_3 - \text{ actual work}$$

The condenser temperature and pressure are lower. Since the turbine exhaust is to be discharged back into the ocean, a direct contact condenser is used to mix the exhaust with cold water, which results in a near-saturated water. That water is now discharged back to the ocean.

H_6=H_f, at T_5. T_7 is the temperature of the exhaust mixed with cold sea water, as the vapour content now is negligible,

$$H_7 \approx H_f \ \ at \ T_7$$

The temperature differences between stages include that between warm surface water and working steam, that between exhaust steam and cooling water, and that between cooling water reaching the condenser and deep water. These represent external irreversibilities that reduce the overall temperature difference.

The cold water flow rate *per* unit turbine mass flow rate,

$$m_c = \frac{\dot{H}_5 - H_6}{H_6 - H_7}$$

Turbine mass flow rate, $\dot{M}_T = \frac{\text{turbine work required}}{W_T}$

Warm water mass flow rate, $\dot{M}_w = \dot{M}_T \dot{m}_w$

Cold water mass flow rate $\dot{M}_c = \dot{M}_T \dot{m}_C$

Closed/Anderson cycle

Developed starting in the 1960s by J. Hilbert Anderson of Sea Solar Power, Inc. In this cycle, Q_H is the heat transferred in the evaporator from the warm sea water to the working fluid. The working fluid exits the evaporator as a gas near its dew point.

The high-pressure, high-temperature gas then is expanded in the turbine to yield turbine work, W_T. The working fluid is slightly superheated at the turbine exit and the turbine typically has an efficiency of 90% based on reversible, adiabatic expansion.

From the turbine exit, the working fluid enters the condenser where it rejects heat, $-Q_C$, to the cold sea water. The condensate is then compressed to the highest pressure in the cycle, requiring condensate pump work, W_C. Thus, the Anderson closed cycle is a Rankine-type cycle similar to the conventional power plant steam cycle except that in the Anderson cycle the working fluid is never superheated more than a few degrees Fahrenheit. Owing to viscous effects, working fluid pressure drops in both the evaporator and the condenser. This pressure drop, which depends on the types of heat exchangers used, must be considered in final design calculations but is ignored here to simplify the analysis. Thus, the parasitic condensate pump work, W_C, computed here will be lower than if the heat exchanger pressure drop was included. The major additional parasitic energy requirements in the OTEC plant are the cold water pump work, W_{CT}, and the warm water pump work, W_{HT}. Denoting all other parasitic energy requirements by W_A, the net work from the OTEC plant, W_{NP} is

$$W_{NP} = W_T + W_C + W_{CT} + W_{HT} + W_A$$

The thermodynamic cycle undergone by the working fluid can be analyzed without detailed consideration of the parasitic energy requirements. From the first law of thermodynamics, the energy balance for the working fluid as the system is

$$W_N = Q_H + Q_C$$

where $W_N = W_T + W_C$ is the net work for the thermodynamic cycle. For the idealized case in which there is no working fluid pressure drop in the heat exchangers,

$$Q_H = \int_H T_H ds$$

and

$$Q_C = \int_C T_C ds$$

so that the net thermodynamic cycle work becomes

$$W_N = \int_H T_H ds + \int_C T_C ds$$

Subcooled liquid enters the evaporator. Due to the heat exchange with warm sea water, evaporation takes place and usually superheated vapor leaves the evaporator. This vapor drives the turbine and the 2-phase mixture enters the condenser. Usually, the subcooled liquid leaves the condenser and finally, this liquid is pumped to the evaporator completing a cycle.

Technical difficulties

Dissolved gases

The performance of direct contact heat exchangers operating at typical OTEC boundary conditions is important to the Claude cycle. Many early Claude cycle designs used a surface condenser since their performance was well understood. However, direct contact condensers offer significant disadvantages. As cold water rises in intake pipe, the pressure decreases to the point where gas begins to evolve. If a significant amount of gas comes out of solution, placing a gas trap before the direct contact heat exchangers may be justified. Experiments simulating conditions in the warm water intake pipe indicated about 30% of the dissolved gas evolves in the top 8.5 meters (28 ft) of the tube. The trade-off between pre-dearation of the seawater and expulsion of non-condensable gases from the condenser is dependent on the gas evolution dynamics, deaerator efficiency, head loss, vent compressor efficiency and parasitic power. Experimental results indicate vertical spout condensers perform some 30% better than falling jet types.

Microbial fouling

Because raw seawater must pass through the heat exchanger, care must be taken to maintain good thermal conductivity. Biofouling layers as thin as 25 to 50 micrometres (0.00098 to 0.0020 in) can degrade heat exchanger performance by as much as 50%. A 1977 study in which mock heat exchangers were exposed to seawater for ten weeks concluded that although the level of microbial fouling was low, the thermal conductivity of the system was significantly impaired. The apparent discrepancy between the level of fouling and the heat transfer impairment is the result of a thin layer of water trapped by the microbial growth on the surface of the heat exchanger.

Another study concluded that fouling degrades performance over time, and determined that although regular brushing was able to remove most of the microbial layer, over time a tougher layer formed that could not be removed through simple brushing. The study passed sponge rubber balls through the system. It concluded that although the ball treatment decreased the fouling rate it was not enough to completely halt growth and brushing was occasionally necessary to restore capacity. The microbes regrew more quickly later in the experiment (i.e. brushing became necessary more often) replicating the results of a previous study. The increased growth rate after subsequent cleanings appears to result from selection pressure on the microbial colony.

Continuous use of 1 hour per day and intermittent periods of free fouling and then chlorination periods (again 1 hour per day) were studied. Chlorination slowed but did not stop microbial growth; however chlorination levels of .1 mg per liter for 1 hour per day may prove effective for long term operation of a plant. The study concluded that although microbial fouling was an issue for the warm surface water heat exchanger, the cold water heat exchanger suffered little or no biofouling and only minimal inorganic fouling.

Besides water temperature, microbial fouling also depends on nutrient levels, with growth occurring faster in nutrient rich water. The fouling rate also depends on the material used to construct the heat exchanger. Aluminium tubing slows the growth of microbial life, although the oxide layer which forms on the inside of the pipes complicates cleaning and leads to larger efficiency losses. In contrast, titanium tubing allows biofouling to occur faster but cleaning is more effective than with aluminium.

Sealing

The evaporator, turbine, and condenser operate in partial vacuum ranging from 3% to 1% of atmospheric pressure. The system must be carefully sealed to prevent in-leakage of atmospheric air that can degrade or shut down operation. In closed-cycle OTEC, the specific volume of low-pressure steam is very large compared to that of the pressurized working fluid. Components must have large flow areas to ensure steam velocities do not attain excessively high values.

Parasitic power consumption by exhaust compressor

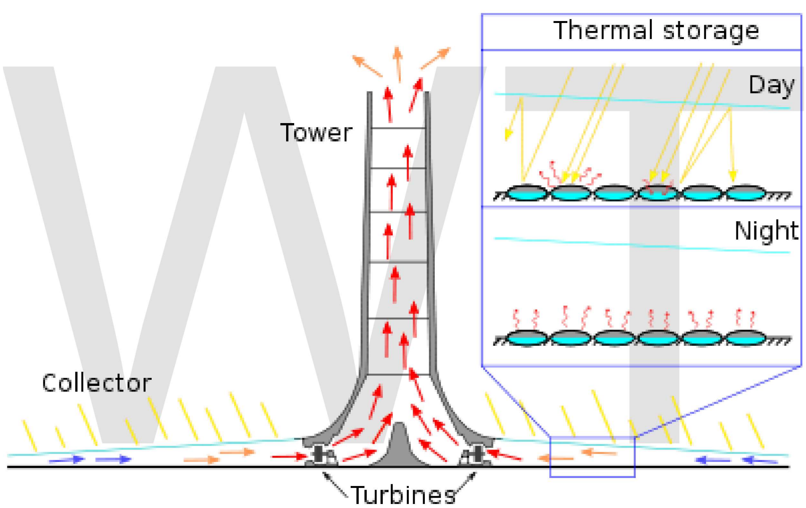
An approach for reducing the exhaust compressor parasitic power loss is as follows. After most of the steam has been condensed by spout condensers, the non-condensible gas steam mixture is passed through a counter current region which increases the gas-steam reaction by a factor of five. The result is an 80% reduction in the exhaust pumping power requirements.

Cold air/warm water conversion

In winter in coastal Arctic locations, seawater can be 40 °C (104 °F) warmer than ambient air temperature. Closed-cycle systems could exploit the air-water temperature difference. Eliminating seawater extraction pipes might make a system based on this concept less expensive than OTEC.

Chapter-11

Solar Updraft Tower



Schematic presentation of a Solar updraft tower

The **solar updraft tower** is a renewable-energy power plant. It combines three old and proven technologies: the chimney effect, the greenhouse effect and the wind turbine. Air is heated by sunshine and contained in a very large greenhouse-like structure around the base of a tall chimney, and the resulting convection causes air to rise up the updraft tower. This airflow drives turbines, which produce electricity.

Description

The generating ability of a solar updraft power plant depends primarily on two factors: the collector area and the chimney height. With a larger collector area, a greater volume of air is warmed to flow up the chimney; collector areas as large as 7 kilometres (4.3 mi) in diameter have been considered. With a larger chimney height, the pressure difference increases the stack effect; chimneys as tall as 1,000 metres (3,281 ft) have been considered.

Heat can be stored inside the collector area greenhouse to be used to warm the air later on. Water, with its relatively high specific heat capacity, can be filled in tubes placed under the collector, increasing the energy storage as needed.

Turbines can be installed in a ring around the base of the tower, with a horizontal axis, as planned for the Australian project and seen in the diagram above; or—as in the prototype in Spain—a single vertical axis turbine can be installed inside the chimney.

Carbon dioxide is emitted only negligibly while operating, but is emitted more significantly during manufacture of its construction materials, particularly cement. Net energy payback is estimated to be 2–3 years.

A solar updraft tower power station would consume a significant area of land if it were designed to generate as much electricity as is produced by modern power stations using conventional technology. Construction would be most likely in hot areas with large amounts of very low-value land, such as deserts, or otherwise degraded land.

A small-scale solar updraft tower may be an attractive option for remote regions in developing countries. The relatively low-tech approach could allow local resources and labour to be used for its construction and maintenance.

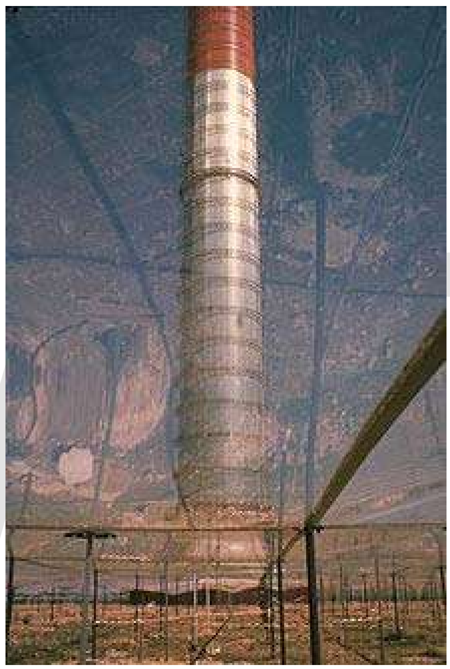
History

In 1903, Isidoro Cabanyes, a colonel in the Spanish army, proposed a solar chimney power plant in the magazine *La energía eléctrica*. One of the next earliest descriptions of a solar chimney power plant was written in 1931 by a German author, Hanns Günther. Beginning in 1975, Robert E. Lucier applied for patents on a solar chimney electric power generator; between 1978 and 1981 these patents (since expired) were granted in Australia, Canada, Israel, and the USA.

First Prototype in Spain

SUT as seen from La Solana

SUT powerplant prototype in Manzanares, Spain, seen from a point 8 km to the South



Solar Chimney Manzanares view through the polyester collector roof

Solar Chimney Manzanares-view of the tower through the collector glass roof

View from the tower on the roof with blackened ground below the collector. One can see the different test materials for canopy cover, and 12 large fields of unblackened ground for agricultural test area.

In 1982, a small-scale experimental model of a solar draft tower was built in Manzanares, Ciudad Real, 150 km south of Madrid, Spain at 39°02′34.45″N 3°15′12.21″W / 39.0429028°N 3.2533917°W. The power plant operated for approximately eight years. The draft tower's guy-wires, which were not protected against corrosion, failed due to rust and broke in a storm. This caused the tower to fall over. The plant was decommissioned in 1989.

Inexpensive materials were used in order to evaluate their performance. The solar tower was built of iron plating only 1.25 mm thick under the direction of a German engineer, Jörg Schlaich. The project was funded by the German government.

The chimney had a height of 195 metres and a diameter of 10 metres with a collection area (greenhouse) of 46,000 m² (about 11 acres (45,000 m^2), or 244 m diameter) obtaining a maximum power output of about 50 kW. Different materials were used for testing, such as single or double glazing or plastic (which turned out not to be durable enough), and one section was used as an actual greenhouse, growing plants under the glass. During its operation, optimization data was collected on a second-by-second basis with 180 sensors measuring inside and outside temperature, humidity and wind speed. This was an experimental setup that did not sell energy to produce income.

Jinshawan Project

In December 2010, a solar updraft tower in Jinshawan in Inner Mongolia, China started operation, producing 200-kilowatts of electric power. The 1.38 billion RMB (USD 208 million) project was started in May 2009 and its aim is to build a facility covering 277 hectares and producing 27.5 MW by 2013. The greenhouses will also improve the climate by covering moving sand, restraining sandstorms.

Ciudad Real Torre Solar

There is a proposal to construct a solar updraft tower in Ciudad Real, Spain, entitled *Ciudad Real Torre Solar*. If built, it would be the first of its kind in the European Union and would stand 750 metres tall – nearly twice as tall as the current tallest structure in the EU, the Belmont TV Mast – covering an area of 350 hectares (about 865 acres). It is expected to put out 40 MW of electricity.

Australian proposal

EnviroMission has, since 2001, proposed to build a solar updraft tower power generating station known as *Solar Tower Buronga* at a location near Buronga, New South Wales. Technical details of the project are difficult to obtain and the present status of the project is uncertain. In Enviromission's 2009 Financial Statements it is reported that the option fee covering the purchase of the *Solar Tower Buronga* site has been written off as the company does not intend to purchase the land. This is in keeping with the company's stated intention to concentrate on commercialising its technology in the USA rather than Australia.

Botswana test facility

Based on the need for plans for long-term energy strategies, Botswana's Ministry of Science and Technology designed and built a small-scale solar chimney system for research. This experiment ran from 7 October to 22 November 2005. It had an inside diameter of 2 m and a height of 22m and was manufactured from glass-reinforced polyester material, with a collection base area of approximately 160 m^2. The roof was made of a 5 mm thick clear glass that was supported by a steel framework.

Namibian proposal

In mid 2008, the Namibian government approved a proposal for the construction of a 400 MW solar chimney called the 'Greentower'. The tower is planned to be 1.5 km tall and 280 m in diameter, and the base will consist of a 37 km^2 greenhouse in which cash crops can be grown.

Turkish model

A model solar updraft tower was constructed in Turkey as a civil engineering project. Functionality and outcomes are obscure.

Arizona Projects

In October 2010, EnviroMission announced further plans to build two 200 MW Solar Updraft Towers in Western Arizona. Southern California Public Power Authority (SCPPA) has agreed to negotiate a power-purchase agreement with EnviroMission for electricity from its Arizona power plants, should they get built. As at January 2011, the company has secured $29.8 million in debt and equity from AGS Capital Group.

Conversion rate of solar energy to electrical energy

The solar updraft tower has power conversion rate considerably lower than many other designs in the (high temperature) solar thermal group of collectors. The low conversion rate of the Solar Tower is balanced to some extent by the low investment cost per square metre of solar collection.

According to model calculations, it was estimated that a 100 MW plant would require a 1000 m tower and a greenhouse of 20 km^2. A 200 MW power plant with the same 1000-metre-high tower would need a collector 7 kilometres in diameter (total area of about 38 km^2). One 200MW power station will provide enough electricity for around 200,000 typical households and will abate over 900,000 tons of greenhouse producing gases from entering the environment annually. The 38 km^2 collecting area is expected to extract about 0.5 percent, or 5 W/m^2 of 1 kW/m^2, of the solar power that falls upon it. Note that in comparison, concentrating thermal (CSP) or photovoltaic (CPV) solar power plants have an efficiency ranging between 20% to 31.25% (sterling dishes) although these approaches do not 100% utilize land area due and this should be considered when contemplating efficiency versus foot print. Because no data is available to test these models on a large-scale updraft tower there remains uncertainty about the reliability of these calculations.

The performance of an updraft tower may be degraded by factors such as atmospheric winds, by drag induced by the bracings used for supporting the chimney, and by reflection off the top of the greenhouse canopy.

It is possible to combine the land use of a solar updraft tower with other uses, in order to make it more cost effective, and in some cases, to increase its total power output. Examples are the positioning of solar collectors or Photovoltaics underneath the updraft tower collector. This could be combined with agricultural use.

Arctic solar draft tower

A Solar updraft power plant located at high latitudes such as in Canada, could produce up to 85 per cent of the output of a similar plant located closer to the equator, but only if the collection area is sloped significantly southward. The sloped collector field is built at suitable mountain hills, which also functions as a chimney. Then a short vertical chimney is added to install the vertical axis air turbine. The results showed that solar chimney power plants at high latitudes may have satisfactory thermal performance.

Related and adapted ideas

- The inverse of the solar updraft tower is the downdraft-driven energy tower. Evaporation of sprayed water at the top of the tower would cause a downdraft by cooling the air and driving wind turbines at the bottom of the tower.

- The Solar_boiler technology placed directly above the turbine at the base of the tower to increase the amount of draught.

- The solar chimney could be constructed up a mountainside using inclined terrain for support; this could draw power from the updraft out of a thermal inversion, and improve urban air quality.

- The atmospheric vortex proposal replaces the physical chimney by a controlled or 'anchored' cyclonic updraft vortex. Depending on the column gradient of temperature and pressure, or buoyancy, and stability of the vortex, very high-altitude updraft may be achievable. As an alternate to a solar collector, industrial and urban waste-heat could be used to initiate and sustain the updraft in the vortex.

- A saltwater thermal sink in the collector could 'flatten' the diurnal variation in energy output, while airflow humidification in the collector and condensation in the updraft could increase the energy flux of the system.

- Release of humid ground-level air from an atmospheric vortex or solar chimney at altitude could form clouds or precipitation, potentially altering local hydrology. Local de-desertification, or afforestation could be achieved if a regional water cycle were established and sustained in an otherwise arid area.

- Fitted with a vortex chimney scrubber, the updraft could be cleaned of particulate air pollution. The solar cyclone distiller could extract atmospheric water by condensation in the updraft of the chimney.

- This cyclonic water distiller could adapt the solar collector-chimney system for large-scale desalination of brine, brackish- or waste-water pooled in the collector base.

- If the chimney updraft is an ionized vortex, then the electro-magnetic field could be tapped for electricity, using the airflow and chimney as a generator.

- Energy production and water desalination could be used to support carbon-fixing or food-producing local agriculture, and for intensive aquaculture and horticulture under the solar collector as a greenhouse.

Financial feasibility

Here we, discusses only the simplest, classical design of a solar updraft tower power plant, and variations are not considered.

A solar updraft power station would require a large initial capital outlay, but would have relatively low operating cost. However, the capital outlay required is roughly the same as next-generation nuclear plants such as the AP-1000 at roughly $5 per W of capacity. Like other renewable power sources there would be no cost for fuel. The cost per energy is largely determined by interest rates and years of operation, varying from 5 eurocent per kWh for 4% and 20 years to 15 eurocent per kWh for 12% and 40 years.

A disadvantage of a solar updraft tower is the much lower conversion efficiency than concentrating solar power stations have, thus requiring a larger collector area and leading to higher cost of construction and maintenance.

Financial comparisons between solar updraft towers and concentrating solar technologies contrast a larger, simpler structure against a smaller, more complex structure. The "better" of the two methods is the subject of much speculation and debate.

A Solar Tower is expected to have less of a requirement for standby capacity from traditional energy sources than wind power does. Various types of thermal storage mechanisms (such as a heat-absorbing surface material or salt water ponds) could be incorporated to smooth out power yields over the day/night cycle. Most renewable power systems (wind, solar-electrical) are variable, and a typical national electrical grid requires a combination of base, variable and on-demand power sources for stability. However, since distributed generation by intermittent power sources provides "smoothing" of the rate of change, this issue of variability can also be addressed by a large interconnected electrical super grid, incorporating wind farms, hydroelectric, and solar power stations.

There is still a great amount of uncertainty and debate on what the cost of production for electricity would be for a solar updraft tower and whether a tower (large or small) can be made profitable. Schlaich et al. estimate a cost of electricity between 7 (for a 200 MW plant) and 21 (for a 5 MW plant) euro cents per kWh, but other estimates indicate that the electricity cannot possibly be cheaper than 25-35 cents per kWh. Compare this to LECs of approximately 3 Euro cents per KWh for a 100 MW wind or natural gas plant. No reliable electricity cost figures will exist until such time as actual data are available on a utility scale power plant, since cost predictions for a time scale of 25 years or more are unreliable.