IAEA-TECDOC-1584

Advanced Applications of Water Cooled Nuclear Power Plants

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International Atomic Energy Agency

July 2007

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The originating Section of this publication in the IAEA was:

Nuclear Power Technology Development Section
International Atomic Energy Agency
Wagramer Strasse 5
P.O. Box 100
A-1400 Vienna, Austria

ADVANCED APPLICATIONS OF
WATER COOLED NUCLEAR POWER PLANTS
IAEA, VIENNA, 2008
IAEA-TECDOC-1584
ISBN 978–92–0–105808–9
ISSN 1011–4289

Printed by the IAEA in Austria
July 2008

FOREWORD

By August 2007, there were 438 nuclear power plants (NPPs) in operation worldwide, with a total capacity of 371.7 GW(e). Further, 31 units, totaling 24.1 GW(e), were under construction. During 2006 nuclear power produced 2659.7 billion kWh of electricity, which was 15.2% of the world's total. The vast majority of these plants use water-cooled reactors. Based on information provided by its Member States, the IAEA projects that nuclear power will grow significantly, producing between 2760 and 2810 billion kWh annually by 2010, between 3120 and 3840 billion kWh annually by 2020, and between 3325 and 5040 billion kWh annually by 2030.

There are several reasons for these rising expectations for nuclear power:

- *Nuclear power's lengthening experience and good performance*: The industry now has more than 12 000 reactor years of experience, and the global average nuclear plant availability during 2006 reached 83%;
- *Growing energy needs*: All forecasts project increases in world energy demand, especially as population and economic productivity grow. The strategies are country dependent, but usually involve a mix of energy sources;
- *Interest in advanced applications of nuclear energy*, such as seawater desalination, steam for heavy oil recovery and heat and electricity for hydrogen production;
- *Environmental concerns and constraints*: The Kyoto Protocol has been in force since February 2005, and for many countries (most OECD countries, the Russian Federation, the Baltics and some countries of the Former Soviet Union and Eastern Europe) greenhouse gas emission limits are imposed;
- *Security of energy supply* is a national priority in essentially every country; and
- *Nuclear power is economically competitive and provides stability of electricity price*.

In the near term most new nuclear plants will be evolutionary water cooled reactors (Light Water Reactors (LWRs) and Heavy Water Reactors (HWRs), often pursuing economies of scale. In the longer term, innovative designs that promise shorter construction times and lower capital costs could help to promote a new era of nuclear power.

About one-fifth of the world's energy consumption is used for electricity generation. Most of the world's energy consumption is for heat and transportation. Nuclear energy has considerable potential to penetrate these energy sectors now served by fossil fuels that are characterized by price volatility and finite supply. Advanced applications of nuclear energy include seawater desalination, district heating, heat for industrial processes, and electricity and heat for hydrogen production. In addition, since nuclear electricity is generally produced in a base load mode at stable prices, there is considerable near-term potential for nuclear power to contribute to the transportation sector as a carbon-free source of electricity for charging electric and plug-in hybrid vehicles.

This collaborative assessment was recommended by the IAEA Nuclear Energy Department's Technical Working Groups on Advanced Technologies for LWRs and HWRs (the TWG-LWR and TWG-HWR). The objective has been to identify opportunities and challenges for water cooled reactors to capture a substantial share of the above mentioned advanced applications. For each application, the opportunities, market context, challenges and potential solutions are addressed.

The IAEA appreciates the work of all contributors, listed at the end of this report. The special contribution of M. Petri from Argonne National Laboratory, United States of America, as Chairman of this activity is gratefully acknowledged. The IAEA Officers responsible for this report are J. Cleveland and A. McDonald of the Department of Nuclear Energy.

EDITORIAL NOTE

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SUMMARY

About one-fifth of the world's energy consumption is used for electricity generation, and today nuclear energy contributes approximately 15.2% of the world's electricity. Most of the world's energy consumption is for heat and transportation. Through advanced applications, nuclear energy has considerable potential to penetrate these energy sectors now served by fossil fuels that are characterized by price volatility, finite supply, and environmental concerns.

Advanced applications of nuclear energy include seawater desalination, district heating, heat for industrial processes, and electricity and heat for hydrogen production. In addition, in the transportation sector, since nuclear electricity is generally produced in a base load mode at stable prices, there is considerable near-term potential for nuclear power to contribute as a carbon-free source of electricity for charging electric and plug-in hybrid vehicles.

The applications highlighted in this publication rely on a source of heat and electricity. Nuclear energy from water-cooled reactors, of course, is not unique in this sense. Indeed, higher temperature heat can be produced by burning natural gas and coal or through the use of other nuclear technologies such as gas-cooled or liquid-metal-cooled reactors. Water-cooled reactors have advantages, however. Unlike fossil-fuel-based plants, water-cooled reactors do not release greenhouse gases. Water-cooled reactors are being deployed today. Other reactor types have had considerably less operational and regulatory experience and will take still some time to be widely accepted in the market.

This document examines the potential of nuclear energy to expand into these markets by presenting an overview of example applications, their opportunities, challenges and solutions. Its scope is limited to applications that can be served by water cooled reactors, as these represent more than 90% of the current fleet, and because in the near term most new nuclear plants will be evolutionary water cooled reactors [(Light Water Reactors (LWRs) and Heavy Water Reactors (HWRs)]. In the longer term, innovative designs that promise shorter construction times and lower capital costs could help to promote a new era of nuclear power, especially as non-electricity markets grow. This document does not address design safety aspects of the coupling of heat utilization systems to nuclear reactors.

The advantage of nuclear energy in alleviating the risk of climate change will not favour market penetration of advanced applications of nuclear power as long as energy policies internalising the value of carbon and other pollutants are not implemented. National policies on climate change vary from country to country, but the entry into force of the Kyoto Protocol in February 2005 does create incentives that can benefit nuclear power, depending on how they are translated into national policies.

Nuclear energy for seawater desalination

Water is essential for the sustainable development of society. Water scarcity is a global issue, and every year new countries are affected by growing water problems. Climate change is likely to further stress regions already facing dire water shortages.

Large-scale commercially available desalination processes can generally be classified into two categories: (a) distillation processes that require mainly heat plus some electricity for ancillary equipment, and (b) membrane processes that require only electricity to provide pumping power.

The energy for these plants is generally supplied in the form of either steam or electricity using fossil fuels. The intensive use of fossil fuels raises environmental concerns, and many countries are therefore considering the introduction of a nuclear power program or expansion of their existing nuclear power program.

The desalination of seawater using nuclear energy is a feasible and demonstrated option to meet the growing demand for potable water. Over 200 reactor-years of operating experience on nuclear desalination have been accumulated worldwide, and demonstration projects for nuclear desalination

are also in progress to confirm its technical and economical viability. However, today nuclear desalination contributes only 0.1 % of total desalting capacity worldwide.

Economic feasibility studies generally indicate that water costs (and associated electricity generation costs) from nuclear seawater desalination are in the same range as costs associated with fossil-fuelled desalination at their current costs. Therefore, future investment decisions will depend on site-specific cost factors and on the values of key parameters (capital cost, fuel price, interest rate, construction time, etc.) at the time of investment.

Those countries suffering from scarcity of water are, generally, not the holders of nuclear technology, do not generally have nuclear power plants, and do not have a nuclear power infrastructure. The utilization of nuclear energy in those countries will require infrastructure building and institutional arrangements for such things as financing, liability, safeguards, safety, and security and will also require addressing the acquisition of fresh fuel and the management of spent fuel.

The socio-environmental aspects of nuclear desalination need attention for its large-scale adoption. Setting up a desalination plant at nuclear reactors for providing much-needed fresh water to the public will no doubt add to social acceptance of nuclear desalination, if the quantity and quality of the fresh water are consistently assured. Also, nuclear desalination plants must be designed to assure the continued use of areas for fishing and other socio-cultural activities. Protection of the marine environment near the desalination plant site needs to be assured. The environmental impact assessment of nuclear-powered desalination systems further indicates advantages over fossil-based energy sources. These would result in enhanced economic competitiveness of nuclear desalination plants.

In summary, use of energy from nuclear reactors for seawater desalination is a demonstrated option; it is environmentally friendly and can be a sustainable energy source. Feasibility studies indicate that current costs of water produced from nuclear desalination plants are similar to those of fossil fuel based desalination plants. Thus nuclear desalination is an important option for safe, economic and sustainable supply of large amounts of fresh water to meet the ever-increasing worldwide water demand.

Nuclear energy for district heating

District heat involves the supply of space heating and hot water through a district heating system, which consists of heat plants (usually producing electricity simultaneously) and a network of distribution and return pipes. Potential applications of district heating are in climatic zones with relatively long and cold winters. In many countries, such as central and northern European countries and countries in transition economies, district heat has been widely used for decades.

District heating has the following technical requirements:

- It requires a heat distribution network to transport steam or hot water in a typical temperature range of 80-150°C;
- Owing to higher losses over longer transmission distances, the heat source must be relatively close to the customer, typically within 10–15 km;
- The district heat generation capacities are determined by the collective demands of the customers. In large cities a capacity of 600–1200 MWth is normal. The demand is much lower in small communities;
- The annual load factor is normally not higher than 50%, since heat is supplied only in the colder part of the year;
- To assure a reliable supply of heat, a backup capacity is required.

Coal and gas dominate the fuels used for district heating. Various other heat sources are also used for district heating, including biomass materials, waste incineration, and waste heat from industrial processes. Usually district heating is produced in a cogeneration mode in which waste heat from power production is used as the source of district heat.

Several countries (Bulgaria, China, Czech Republic, Hungary, Romania, the Russian Federation, Slovakia, Sweden, Switzerland and Ukraine) already have experience in nuclear district heating, so the technical aspects can be considered well proven.

In the past, the low prices of fossil fuels have stunted the introduction of single-purpose nuclear district heating plants. Although many concepts of small-scale heat-producing nuclear plants have been presented during the years, very few have been built. However, as environmental concerns mount over the use of fossil fuels, nuclear-based district heating systems have potential.

In order to be able to compete with fossil-fuel-fired heat boilers, the capital cost per installed MW of heat production capacity for a nuclear-based system must be such that the production costs are competitive. Dedicated reactors providing district heat can potentially achieve acceptable costs, due to their lower temperature operating conditions, simple design, modularization and standardization, and advanced safety systems.

Economic studies generally indicate that district heating costs from nuclear power are in the same range as costs associated with fossil-fuelled plants. Therefore, as with nuclear desalination, future investment decisions will depend on site-specific cost factors and on the values of key parameters (capital cost, fuel price, interest rate, construction time, etc.) at the time of investment.

New nuclear heat-producing plants must, of course, meet the user's requirements on availability and reliability, including alternative heat-producing capacity that could serve as backup. For this purpose, heat storage allows a matching of the heat supply to the heat demand. Today there are many examples of short-term storage, for instance, on the daily scale that relies on hot water accumulator tanks. In the future, more long-term storage facilities may be realized.

The design features of nuclear district heating plants to prevent the transfer of radioactivity into the district heating grid network have proven to be effective. These features include one or more barriers to radioactive cross contamination, e.g. in the form of a leak-tight intermediate heat transfer loop at a pressure higher than that of the steam extracted from the turbine side of the nuclear plant. These loops are continuously monitored, and isolation devices are provided to separate potentially contaminated areas.

For nuclear district heating plants, proximity to population centres implies the need for a high degree of safety including the lowering of core damage frequencies and enhancing mitigation systems in the case of an accident.

Nuclear energy for industrial process heat

Process heat involves the supply of heat required for industrial processes from one or more centralized heat generation sites through a steam transportation network. Within the industrial sector, process heat is used for a large variety of applications with different heat requirements and with temperature ranges covering a wide spectrum. Examples of industries that consume considerable amounts of heat are:

- food,
- paper,
- chemicals and fertilizers,
- petroleum and coal processing, and
- metal processing industries.

The breakdown of the total industrial heat varies from country to country, but the chemical and petroleum industries are the major consumers worldwide. These would be key target clients for possible applications of nuclear energy.

The supply of energy for industrial processes has an essential character: all industrial users need the assurance of energy supply with a high reliability, and the heat should be produced close to the point of use. Industrial process heat users do not have to be located within highly populated areas. Many of the process heat users, in particular the large ones, can be (and usually are) located outside urban areas, often at considerable distances. This makes joint siting of nuclear reactors and industrial users of process heat not only viable, but also desirable in order to drastically reduce the heat transport costs.

The nuclear process heat supply has to be reliable. As an example, the average adequate steam supply availabilities for chemical processing, oil refineries and primary metals are respectively 98%, 92% and near 100%. Such high levels can be ensured only by the combination of a highly reliable heat source and the availability of reserve capacity.

There is experience in providing process heat for industrial purposes with nuclear energy in Canada, Germany, Norway, Switzerland, and India. New plant designs that can provide heat, or both heat and electricity, are being designed in Russia, the Republic of Korea, Canada, and other countries.

Current water cooled reactors can provide process heat up to about 300ºC, and some future innovative water cooled reactor designs[1] have potential to provide heat up to approximately 550ºC.

Although nuclear industrial process heat applications have significant potential, it has not been realized to a large extent. In fact, currently only the Goesgen reactor in Switzerland and the RAPS–2 reactor in India continue to provide industrial process heat, whereas other process heat systems have been discontinued after successful use. Among the reasons cited for closure of these units, one is availability of cheaper alternate energy sources, including waste heat near the industrial complexes.

For potential future application of nuclear process heat, the main example presented in this document is the use of nuclear energy for oil sand open-pit mining and deep-deposit extraction in Canada. Alberta's oil sand deposits are the second largest oil reserves in the world, and have emerged as the fastest growing, soon to be dominant, source of crude oil in Canada. Currently, the majority of oil sand production is through open-pit mining, which is suitable for bitumen extraction when the oil sand deposits are close to the surface. The ore, a mixture of bitumen and sand, is removed from the surface by truck and shovel operation. The ore is then mixed with hot water to form a slurry that eventually undergoes a separation process to remove bitumen from the sand.

The thermal energy required for the open-pit mining process is in the form of hot water at a relatively low temperature (around 70°C), and the rest is dry process steam at around 1.0 to 2.0 MPa. The oil extraction facilities require electrical power as well. These heat requirements, as well as the electricity, can be met by water cooled reactors.

To increase production capacity, the industry is developing new technologies to extract bitumen from deep deposits. Among them, Steam-Assisted Gravity Drainage (SAGD), which uses steam to remove bitumen from underground reservoirs, appears to be the most promising approach. Recently, the in-situ recovery process has been put into commercial operation by major oil companies.

Overall, for both extraction methodologies (open pit mining and SAGD), a significant amount of energy is required to extract bitumen and upgrade it to synthetic crude oil as the feedstock for oil refineries. Currently, the industry uses natural gas as the prime energy source. As oil sand production

[1] Specifically Super-critical Water Cooled Reactors, being developed within the Generation-IV International Forum, could be deployed by around 2025-2030.

continues to expand, the energy required for production becomes a great challenge with regard to economic sustainability, environmental impact and security of supply. Therefore, the opportunity for nuclear reactors to provide an economical, reliable and virtually zero-emission source of energy for the oil sands becomes a realistic option.

Contribution of nuclear energy to transportation

Transportation represents approximately 20% of the world's energy consumption. In the United States of America, transportation is the fastest growing energy sector and in the past few years has become the nation's largest energy sector. The Organization for Economic Co-operation and Development International Energy Agency projects that global primary energy demand will grow by 50% by 2030, with 70% of that growth coming from developing countries, especially China. Half of that increase will be for electricity production and 20% for transportation. The expectation is that fossil fuels will account for 83% of this increased energy consumption.

It is clear that if nuclear energy finds a way to power a significant part of the transportation sector, it will have a major impact on global environmental sustainability. Two ways this could occur would be through the advancement of electric and plug-in hybrid electric vehicles and of vehicles fuelled with hydrogen produced by nuclear energy. This present study addressed electricity for plug-in hybrid vehicles and hydrogen for transportation.

A) Electricity for plug-in hybrid electric vehicles

Hybrid electric vehicles of various classes are now commercially available. Almost all use regenerative braking to charge an on-board battery for locomotive power. With these battery systems, vehicles can be designed to allow the gasoline engine to turn off when the vehicle is stopped or during cruising. Moreover, the smaller engines used can run at a higher percentage of their full power, which is more efficient and more economical for a given load than larger, heavier gasoline engines operating at a lower percentage of their maximum power.

Overall energy use for hybrids has been shown to be about 40% less than that for conventional vehicles, with an equivalent reduction in fossil energy use and greenhouse gas emissions (CO_2, CH_4, and N_2O).

Plug-in hybrid electric vehicles extend this technology a step further by allowing a drive battery to be charged externally. In this way, the vehicle can be driven in an all-electric mode for a certain distance with no power from the gasoline engine. This can provide significant savings in terms of petroleum usage and emissions, especially since the majority of miles driven are for short commutes. These emission reductions materialize only if the source of external electricity is clean and carbon free, of course.

The potentially large market demand for electricity for powering plug-in hybrid electric vehicles is eminently suited to current and evolutionary water-cooled nuclear power plants. The analysis provided in Chapter 5, for instance, shows that plug-in hybrid electric vehicles produce only 42% of the carbon dioxide produced by conventional vehicles and that over 11,000 lb/vehicle-year of carbon dioxide can be saved if nuclear power is used to generate plug-in hybrid electric vehicle electricity rather than coal.

Under a simplified model of potential growth in plug-in hybrid electric vehicle usage, perhaps 250 GW of electricity may be needed for overnight charging in the U.S. by 2035. New generation capacity at this scale would also require new transmission and distribution lines and substations. A similar analysis for Japan suggests the need for 35 GW of electricity for overnight charging, which is within the capacity of spare power at night.

Aside from the need for increases in generating and transmission capacity, other barriers will need to be overcome before there is widespread adoption of plug-in hybrid electric vehicles:

- Conversion of automobile technology from conventional gasoline-powered vehicles to electric and plug-in hybrid vehicles;
- Public acceptance of plug-in hybrid vehicles;
- Structuring of electricity pricing mechanisms to provide low-price electricity during off-peak demand periods to encourage use of nuclear power plants for base load generation;
- Provision of other incentives (e.g., tax benefits) for adoption of vehicles that produce less greenhouse gases and reduce reliance on petroleum fuels.

A key technical barrier is the development of lighter, less expensive, reliable batteries having a factor of 5 to 10 greater energy storage capacity that would boost all-electric distances to twenty miles or greater. Lithium-ion batteries as a substitute for nickel-metal hydride batteries are the main focus of current research and development.

Despite these barriers, automobile manufacturers are spending significant effort on developing plug-in hybrid electric vehicles. In fact, one auto manufacturer has recently announced road testing for its plug-in hybrid vehicle, which can travel eight miles on a full charge before it needs to draw power from the gasoline engine, and other plug-in hybrid manufacturers have announced targets of 20 to 40 miles on a single charge.

B) Hydrogen for transportation

Hydrogen for transportation is receiving significant attention around the world because of high petroleum prices and unreliable oil supplies. Two ways of hydrogen utilization in transportation are currently being taken into consideration – internal combustion engine (ICE) vehicles and fuel cell (FC) vehicles. While ICE vehicles represent current technology with modest modifications, fuel cell vehicles are in a stage of intensive R&D and prototype testing.

Car manufacturers are focusing more effort on fuel cell vehicles than on hydrogen ICE vehicles. Many prototypes have been introduced, some of them in small series (tens of cars). Most of the manufacturers have opted for proton exchange membrane (PEM) fuel cells because of their low-temperature operation and relatively (compared to other fuel cell types) easy manufacturing and maintenance. Current trends are mainly focused on hybridization, such as combining fuel cells with NiMH batteries, ultra capacitors, or other types of electric storage. Although this increases the complexity of the vehicle, thus increasing the cost, it brings significant advantages. The main one is covering power peaks during acceleration, when the electric motor draws high current from the Fuel Cell. A second advantage in electrical storage is increasing the driving range, because hybrid vehicles optimize fuel consumption, and also the use of braking recuperation.

It is not only important to have technical problems solved, public acceptance is also important. For this purpose, hydrogen fuelled buses have been successful. Currently there are about 60 of them serving on a daily basis in different cities including London, Hamburg, Madrid, Stuttgart, Stockholm, Porto, Amsterdam, Barcelona, Luxembourg, Reykjavik and Perth.

The lack of the hydrogen infrastructure makes fleet customers important for early hydrogen transportation markets. It is much easier to build one centralized filling station near a city bus operator or dispatch service than to service the distributed market for personal cars.

Motorcycles, scooters and electric bikes represent a smaller, but interesting, market opportunity. Such means of transportation are significant in many Asian countries, where the pollution is growing and causing health problems. Switching from fossil-based fuels to hydrogen would improve the local environment.

Nuclear energy for hydrogen production

As an alternative path to the current fossil fuel economy, a hydrogen economy is envisaged in which hydrogen would play a major role in energy systems and serve all sectors of the economy, substituting for fossil fuels. Hydrogen as an energy carrier can be stored in large quantities, unlike electricity, and converted into electricity in fuel cells, with only heat and water as by-products. It is also compatible with combustion turbines and reciprocating engines to produce power with near-zero emission of pollutants. Furthermore, hydrogen can be obtained from various primary energy sources that are domestically available in most countries. Consequently, the hydrogen economy could enhance both the security of energy supply and global environmental quality.

The current worldwide hydrogen production is roughly 50 million tonnes per year. Although current use of hydrogen in *energy systems* is very limited, its future use could become enormous, especially if fuel-cell vehicles would be deployed on a large commercial scale. The hydrogen economy is getting higher visibility and stronger political support in several parts of the world.

Today, hydrogen is used in limited quantities, and mainly in petroleum refineries and the chemical industry. In the United States, for example, these uses represented 93% of hydrogen consumption in 2003. However, hydrogen is an attractive energy carrier that might play a major role in energy systems for many economic sectors in the long term. In the medium term, the most promising area for hydrogen is in producing synthetic fuel as a substitute for gasoline in transportation. Hydrogen produced from non-fossil fuels may be a key option as the prices of hydrocarbon resources soar or their consumption becomes restricted for environmental reasons.

Hydrogen currently finds many applications as a chemical product for:

- Ammonia synthesis;
- Methanol synthesis;
- Direct reduction of iron ore;
- Fossil fuel processing (hydro cracking);
- Fischer-Tropsch hydrocarbon synthesis;
- Methanation in long-distance energy transportation; and
- Hydro-gasification.

In addition, there may be hydrogen markets for heating, stationary fuel cells, combined heat and power, and stationary gas turbines. Potentially hydrogen could be used for ground transport, aviation, marine applications, and railroad transport.

The mass utilization of fuel cells for transportation and decentralized power production will not materialize until at least 2020. Currently research focuses on catalysts, materials, equipment, production costs, durability, cold-start capability, power density, and water management.

Nuclear-generated hydrogen has important potential advantages over other sources that will be considered for a growing hydrogen economy. Nuclear hydrogen requires no fossil fuels, results in lower greenhouse-gas emissions and other pollutants, and lends itself to large-scale production. These advantages do not ensure that nuclear hydrogen will prevail, however, especially given strong competition from other hydrogen sources. There are technical uncertainties in nuclear hydrogen processes, certainly, which need to be addressed through a vigorous research and development effort.

As a greenhouse-gas-free alternative, the U.S., Japan, and other nations are exploring ways to produce hydrogen from water by means of electrolytic, thermochemical, and hybrid processes. Most of the work has concentrated on high-temperature processes such as high-temperature steam electrolysis and the sulphur–iodine and calcium-bromine cycles. These processes require higher temperatures (>750^{o}C) than can be achieved by water-cooled reactors. Advanced reactors such as the very high temperature gas cooled reactor (VHTGR) can generate heat at these temperatures, but will require several years before they are commercial deployed.

Water-cooled reactors are likely to be the nuclear power technology of choice for many years. Their outlet temperature limitation of ~350^{o}C leaves only one current option for hydrogen production: low-temperature water electrolysis. Because they require no heat input, water electrolyzers can be decoupled from the power plant. Therefore, electrolysers can be attractive as remote and decentralized hydrogen production methods. Because of the high electrical demands for the process, though, electrolysis of water is attractive only when cheap electricity is available or when particularly high-purity hydrogen is required. The use of nuclear generated electricity in off-peak periods from existing water-cooled reactors may be economically competitive, but the stranded capital costs of the electrolyzers during periods of peak electricity prices may be prohibitive.

Other hydrogen production options require higher temperatures. Short of the temperatures achievable by liquid-metal-cooled or gas-cooled reactors, few hydrogen production methods are known. Supercritical water cooled reactors have the potential to deliver heat at 550^{o}C. At this temperature, hydrogen production methods include membrane-assisted steam methane reforming and a limited number of thermo-electrochemical cycles. Experimentation has been limited on these systems. None are close to having demonstrated commercial viability. Nonetheless, process flowsheets suggest that system efficiencies can be higher than for low-temperature water electrolysis. This makes laboratory research on potential hydrogen production technologies worth pursuing.

A study has shown that significant reductions in fossil energy use and greenhouse gas emissions come from nuclear-based hydrogen production compared to natural-gas-based hydrogen production through steam methane reforming. The reductions amount to 73 – 96% in greenhouse gas emissions (CO_2, CH_4, and N_2O) and 81 – 97% in fossil energy use. Furthermore, fuel cell vehicles powered by nuclear hydrogen have substantial reductions in greenhouse gas emissions (87 – 98%) and fossil energy use (89 – 98%) compared with internal combustion engine vehicles using reformulated gasoline. Nuclear hydrogen is not completely emission-free, however, since a small amount of fossil fuel is consumed in the upstream feedstock and fuel stages.

Conclusion

In considering the deployment of nuclear energy into advanced applications, challenges and difficulties should not be overlooked; in particular, it should be acknowledged that a scientific potential is not a technical reality and that competition will drive the choice of energy sources for each application. Moving from their potential to realities is undoubtedly feasible, but will need time, investments, and policy measures to address a wide range of techno-economic and socio-political challenges. Public acceptance is a major issue for nuclear energy. Advanced applications of nuclear energy can play an important role in enhancing public acceptance.

CHAPTER 1
PRESENT STATUS AND OVERVIEW OF ADVANCED APPLICATIONS OF NUCLEAR REACTORS

Introduction

Today, nuclear power plants provide about 15.2% of the world's electricity consumption. Because electricity represents less than one third of the primary energy uses, nuclear energy provides only about 6% of total energy consumption in the world. If nuclear energy were used for purposes other than electricity generation, it could play a more significant role in global energy supply. This could have a significant impact on global goals for reduced greenhouse gas emissions, for a cleaner environment, and for less reliance on uncertain supplies of fossil fuels.

Nuclear reactors, which produce energy in the form of heat, can supply energy products other than electricity, including district and process heat, desalinated water, hydrogen, and heat for other industrial products. Although not covered in this report, nuclear reactors are unique in their ability to produce high radiation fields for medical isotope production and the conversion of plutonium and other transuranic elements to shorter-lived radioactive waste. While these applications of nuclear energy have been considered since the very beginning of nuclear energy development, they have for various reasons yet to be deployed at a significant industrial scale.

In recent years, various agencies involved in nuclear energy development programmes worldwide have carried out studies on advanced applications of nuclear power and useful reports have been published [1-4]:

- The IAEA launched a programme on co-generation applications and has published two TECDOCs (IAEA-TECDC-923 and IAEA-TECDOC-1184) and a Guidebook on Introduction of Nuclear Desalination (TRS-400) in 2000. IAEA also published a report in 2002 on the Market Potential for Non-electric Applications of Nuclear Energy (TRS-410).

- The Organization for Economic Cooperation and Development (OECD) Nuclear Energy Agency, under the guidance of the Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle (NDC), carried out a comprehensive survey of published literature on the subject matter, including reports from international organizations, national institutes and other parts of NEA and published a report summarizing the findings and recommendations [5].

- The Generation IV International Forum (GIF) project aims at development of innovative reactors with temperatures up to 1000^{o}C. The GIF road map recommends necessary R&D. One of the selected systems is the super-critical water cooled reactor SCWR [6].

- The Michelangelo Network (MICANET) was started within the 5th EUROATOM Framework Programme (FP5) with the objective to elaborate a general European R&D strategy for further development of the nuclear industry in the short, medium and long term. MICANET has been examining the role of nuclear energy in near and medium term missions; i.e. the transition phase from the present fossil era to CO_2 emission-free technologies in the future. The programme results were reported in November 2005 as a work package on "Non-electric application of nuclear energy". The network examined the possible orientation of future EURATOM R&D programmes including new aspects of nuclear energy such as combined heat and power (CHP), desalination, and hydrogen production or other fuel production as a complement to other CO_2-free energy sources [7].

The present IAEA document focuses on the potential of water-cooled nuclear reactor technology to penetrate non-electricity sectors. Nuclear power is the only large-scale carbon-free energy source that, in the near and medium term, has the potential to significantly displace limited and uncertain fossil fuels. To do this, however, nuclear power must move beyond its historical role as solely a producer of electricity. The sampling of non-electric applications in this report is not exhaustive. For instance, the use of nuclear reactors for medical therapy and radioactive isotopes is not covered. Instead, the document is intended to begin a dialogue that considers the value of water-cooled reactor technology for a broad range of non-traditional applications.

1.1. Nuclear power reactors in the world

The number of nuclear power reactors in operation and under construction in the world, as of August 2007, as reported by the IAEA Power Reactor Information System, are reproduced in Table 1.1.

Table 1.1. Distribution of reactor types

Light water reactors[1]:

In operation	359
Under construction	23
Number of countries with LWRs	27
Generating capacity, GW(e)	328.2

Heavy water moderated reactors[2]:

In operation	43
Under construction	5
Number of countries with HWRs	7
Generating capacity, GW(e)	21.7

[1] Reactors cooled and moderated by light water

[2] Reactors moderated by heavy water

Light water cooled graphite moderated reactors:

In operation	16
Under construction	1
Number of countries	2
Generating capacity, GW(e)	11.4

Liquid metal cooled fast reactors:

In operation	2
Under construction	2
Number of countries with FRs[a]	3
Generating capacity, GW(e)	1.0
Operating Experience, reactor years	171

[a] In France, Russia and Japan, where the Monju reactor, under long term shutdown, is planned to be re-started.

Gas cooled reactors:

Power reactors in operation	18
Under construction	0
Test reactors in operation	2
Number of countries with GCRs	3
Generating capacity, GW(e)	9.0

Table 1.1 shows that water cooled reactors are the work-horse of nuclear power generation. Up to now, nuclear energy has served almost exclusively as a generator of electricity. In decades to come, nuclear may be called upon to play a significant role in other energy sectors, especially as there is a drive to reduce greenhouse gas emissions in sectors traditionally served by fossil fuels. Some of the most promising applications are hydrogen production, high temperature process heat, desalination to produce fresh water, and district heating. In addition, the advent of plug-in hybrid electric vehicles may allow nuclear electricity generation to enter the transportation sector. Some experience is already available with these applications, particularly for seawater desalination and district heating.

1.2. Non-electric applications of nuclear power

Figure 1.1 shows various reactor types and their possible non-electric applications. It can be seen that most of the present day non-electric applications can be met with water cooled reactors. Some of the industrial heat requirements, however, require higher temperature heat and would need other types of reactors.

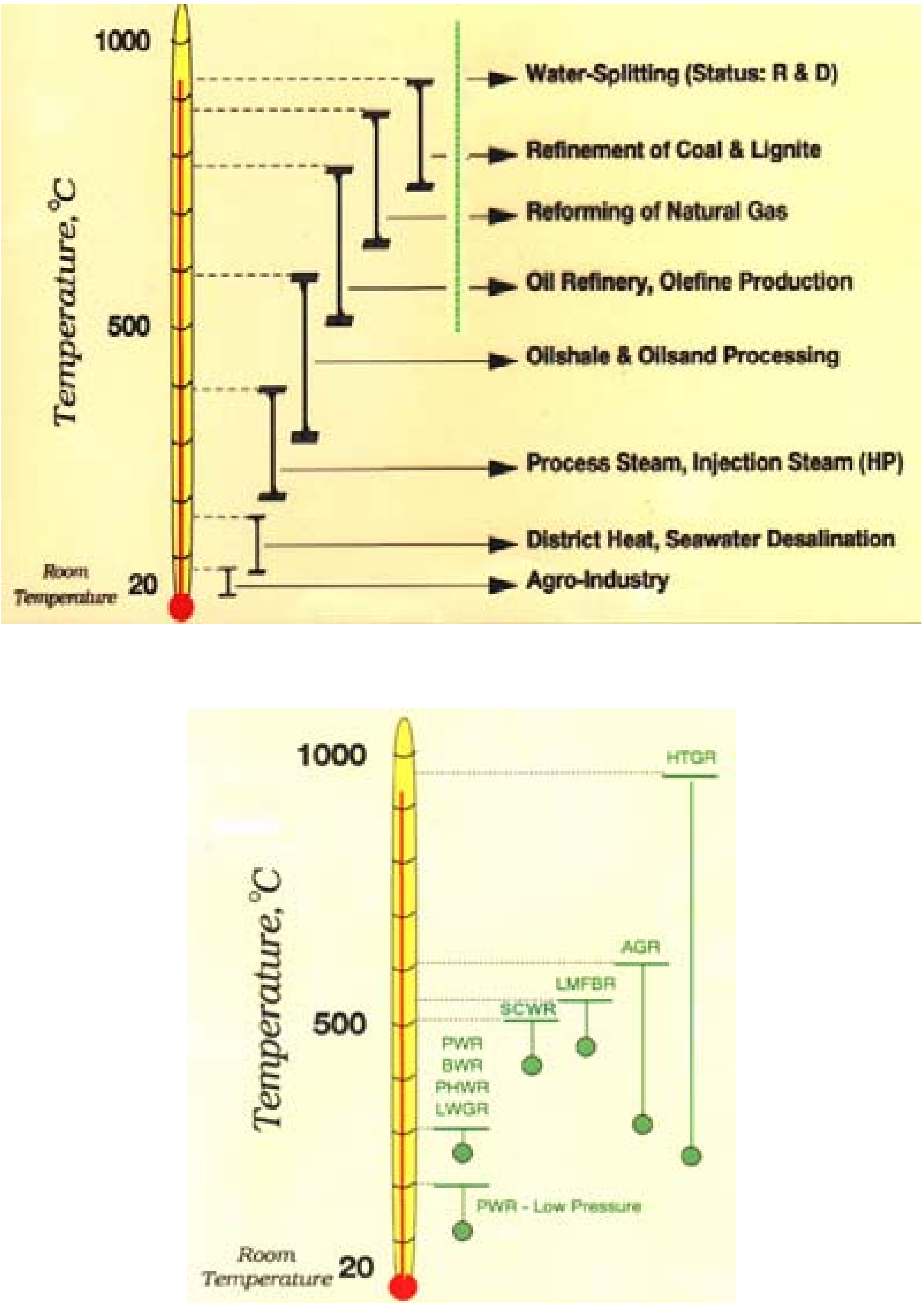

FIG. 1.1. Temperature ranges in production and use of nuclear heat.

Of the 438 nuclear power reactors operating worldwide in August 2007, those reactors which were being used for co-generation of hot water or steam for district heating, seawater desalination or industrial processes are shown in Table 1.2 (based on the IAEA Power Reactor Information System). Table 1.3 shows the energy generated by each reactor for district heating, process heating, or desalination. Salient details of these applications will be found in the succeeding chapters. Other advanced applications, such as nuclear hydrogen production, have yet to be realized.

TABLE 1.2. Reactors having non-electric applications

Country	Reactor		Type	Capacity MW(e)			Operator	NSSS Supplier	Construction Start	Grid Connection	Commercial Operation	Load Factor % (1) to 2005	Unit Capacity Factor % (1) to 2005	Non-electric Applications (2)
	Code	Name		Net	Gross	Thermal								
BULGARIA	BG -5	KOZLODUY-5	PWR	953	1000	3000	KOZNPP	AEE	1980-7	1987-11	1988-12	50.0	64.0	DH
	BG -6	KOZLODUY-6	PWR	953	1000	3000	KOZNPP	AEE	1982-4	1991-8	1993-12	58.0	72.0	DH
CZECH REP.	CZ -23	TEMELIN-1	PWR	930	975	3000	CEZ	SKODA	1987-2	2000-12	2002-6	70.0	72.0	DH
	CZ -24	TEMELIN-2	PWR	930	975	3000	CEZ	SKODA	1987-2	2002-12	2003-4	69.0	68.0	DH
HUNGARY	HU -2	PAKS-2	PWR	441	468	1375	PAKS RT.	AEE	1974-8	1984-9	1984-11	79.0	78.0	DH
	HU -3	PAKS-3	PWR	433	460	1375	PAKS RT.	AEE	1979-10	1986-9	1986-12	87.0	86.0	DH
	HU -4	PAKS-4	PWR	444	471	1375	PAKS RT.	AEE	1979-10	1987-8	1987-11	89.0	87.0	DH
INDIA	IN -5	MADRAS-1	PHWR	202	220	801	NPCIL	NPCIL	1971-1	1983-7	1984-1	49.0	58.0	DS
	IN -6	MADRAS-2	PHWR	202	220	801	NPCIL	NPCIL	1972-10	1985-9	1986-3	55.0	62.0	DS
	IN -3	RAJASTHAN-1	PHWR	90	100	693	NPCIL	AECL	1965-8	1972-11	1973-12	21.0	28.0	PH
	IN -4	RAJASTHAN-2	PHWR	187	200	693	NPCIL	AECL/DAE	1968-4	1980-11	1981-4	53.0	60.0	PH
	IN -11	RAJASTHAN-3	PHWR	202	220	801	NPCIL	NPCIL	1990-2	2000-3	2000-6	77.0	88.0	PH
	IN -12	RAJASTHAN-4	PHWR	202	220	801	NPCIL	NPCIL	1990-10	2000-11	2000-12	77.0	91.0	PH
JAPAN	JP -45	GENKAI-3	PWR	1127	1180	3423	KYUSHU	MHI	1988-6	1993-6	1994-3	86.0	85.0	DS
	JP -46	GENKAI-4	PWR	1127	1180	3423	KYUSHU	MHI	1992-7	1996-11	1997-7	86.0	85.0	DS
	JP -23	IKATA-1	PWR	538	566	1650	SHIKOKU	MHI	1973-6	1977-2	1977-9	77.0	78.0	DS
	JP -32	IKATA-2	PWR	538	566	1650	SHIKOKU	MHI	1978-2	1981-8	1982-3	81.0	81.0	DS
	JP -47	IKATA-3	PWR	846	890	2660	SHIKOKU	MHI	1986-11	1994-3	1994-12	87.0	85.0	DS
	JP -15	OHI-1	PWR	1120	1175	3423	KEPCO	WH	1972-10	1977-12	1979-3	66.0	66.0	DS
	JP -19	OHI-2	PWR	1120	1175	3423	KEPCO	WH	1972-12	1978-10	1979-12	72.0	72.0	DS
	JP -29	TAKAHAMA-3	PWR	830	870	2660	KEPCO	MHI	1980-12	1984-5	1985-1	84.0	83.0	DS
	JP -30	TAKAHAMA-4	PWR	830	870	2660	KEPCO	MHI	1981-3	1984-11	1985-6	86.0	84.0	DS
PAKISTAN	PK -1	KANUPP	PHWR	125	137	433	PAEC	CGE	1966-8	1971-10	1972-12	26.0	43.0	DS
ROMANIA	RO -1	CERNAVODA-1	PHWR	655	706	2180	SNN	AECL	1982-7	1996-7	1996-12	86.0	87.0	DH

TABLE 1.2. Reactors having non-electric applications (cont'd)

Country	Reactor		Type	Capacity MW(e)			Operator	NSSS Supplier	Construction Start	Grid Connection	Commercial Operation	Load Factor % (1) to 2005	Unit Capacity Factor % (1) to 2005	Non-electric Applications (2)
	Code	Name		Net	Gross	Thermal								
RUSSIAN FEDERATION	RU -96	BALAKOVO-1	PWR	950	1000	3000	REA	FAEA	1980-12	1985-12	1986-5	62.0	68.0	DH,PH
	RU -97	BALAKOVO-2	PWR	950	1000	3000	REA	FAEA	1981-8	1987-10	1988-1	61.0	67.0	DH,PH
	RU -98	BALAKOVO-3	PWR	950	1000	3000	REA	FAEA	1982-11	1988-12	1989-4	66.0	73.0	DH,PH
	RU -99	BALAKOVO-4	PWR	950	1000	3200	REA	FAEA	1984-4	1993-4	1993-12	71.0	78.0	DH,PH
	RU -21	BELOYARSKY-3(BN-600)	FBR	560	600	1470	REA	FAEA	1969-1	1980-4	1981-11	74.0	75.0	DH,PH
	RU -141	BILIBINO-1	LWGR	11	12	62	REA	FAEA	1970-1	1974-1	1974-4	58.0	80.0	DH
	RU -142	BILIBINO-2	LWGR	11	12	62	REA	FAEA	1970-1	1974-12	1975-2	57.0	81.0	DH
	RU -143	BILIBINO-3	LWGR	11	12	62	REA	FAEA	1970-1	1975-12	1976-2	59.0	81.0	DH
	RU -144	BILIBINO-4	LWGR	11	12	62	REA	FAEA	1970-1	1976-12	1977-1	58.0	78.0	DH
	RU -30	KALININ-1	PWR	950	1000	3000	REA	FAEA	1977-2	1984-5	1985-6	71.0	71.0	DH,PH
	RU -31	KALININ-2	PWR	950	1000	3000	REA	FAEA	1982-2	1986-12	1987-3	71.0	73.0	DH,PH
	RU -36	KALININ-3	PWR	950	1000	3200	REA	FAEA	1985-10	2004-12	2005-11	77.0	77.0	-
	RU -12	KOLA-1	PWR	411	440	1375	REA	FAEA	1970-5	1973-6	1973-12	65.0	76.0	DH,PH
	RU -13	KOLA-2	PWR	411	440	1375	REA	FAEA	1973-1	1974-12	1975-2	65.0	76.0	DH,PH
	RU -32	KOLA-3	PWR	411	440	1375	REA	FAEA	1977-4	1981-3	1982-12	72.0	82.0	DH,PH
	RU -33	KOLA-4	PWR	411	440	1375	REA	FAEA	1976-8	1984-10	1984-12	71.0	81.0	DH,PH
	RU -17	KURSK-1	LWGR	925	1000	3200	REA	FAEA	1972-6	1976-12	1977-10	57.0	60.0	DH,PH
	RU -22	KURSK-2	LWGR	925	1000	3200	REA	FAEA	1973-1	1979-1	1979-8	60.0	63.0	DH,PH
	RU -38	KURSK-3	LWGR	925	1000	3200	REA	FAEA	1978-4	1983-10	1984-3	71.0	73.0	DH,PH
	RU -39	KURSK-4	LWGR	925	1000	3200	REA	FAEA	1981-5	1985-12	1986-2	75.0	76.0	DH,PH
	RU -15	LENINGRAD-1	LWGR	925	1000	3200	REA	FAEA	1970-3	1973-12	1974-11	68.0	69.0	DH,PH
	RU -16	LENINGRAD-2	LWGR	925	1000	3200	REA	FAEA	1970-6	1975-7	1976-2	68.0	69.0	DH,PH
	RU -34	LENINGRAD-3	LWGR	925	1000	3200	REA	FAEA	1973-12	1979-12	1980-6	69.0	71.0	DH,PH
	RU -35	LENINGRAD-4	LWGR	925	1000	3200	REA	FAEA	1975-2	1981-2	1981-8	71.0	73.0	DH,PH

TABLE 1.2. Reactors having non-electric applications (cont'd)

Country	Reactor		Type	Capacity MW(e)			Operator	NSSS Supplier	Construction Start	Grid Connection	Commercial Operation	Load Factor % (1) to 2005	Unit Capacity Factor % (1) to 2005	Non-electric Applications (2)
	Code	Name		Net	Gross	Thermal								
	RU -23	SMOLENSK-1	LWGR	925	1000	3200	REA	FAEA	1975-10	1982-12	1983-9	70.0	73.0	DH,PH
	RU -24	SMOLENSK-2	LWGR	925	1000	3200	REA	FAEA	1976-6	1985-5	1985-7	73.0	76.0	DH,PH
	RU -67	SMOLENSK-3	LWGR	925	1000	3200	REA	FAEA	1984-5	1990-1	1990-10	78.0	81.0	DH,PH
SLOVAKIA	SK -13	BOHUNICE-3	PWR	408	440	1375	SE,plc	SKODA	1976-12	1984-8	1985-2	75.0	80.0	DH
	SK -14	BOHUNICE-4	PWR	408	440	1375	SE,plc	SKODA	1976-12	1985-8	1985-12	77.0	82.0	DH
SWITZERLAND	CH -1	BEZNAU-1	PWR	365	380	1130	NOK	WH	1965-9	1969-7	1969-9	82.0	87.0	DH
	CH -3	BEZNAU-2	PWR	365	380	1130	NOK	WH	1968-1	1971-10	1971-12	87.0	87.0	DH
	CH -4	GOESGEN	PWR	970	1020	2900	KKG	KWU	1973-12	1979-2	1979-11	88.0	89.0	DH
UKRAINE	UA -40	KHMELNITSKI-1	PWR	950	1000	3000	NNEGC	PAIP	1981-11	1987-12	1988-8	72.0	72.0	DH
	UA -27	ROVNO-1	PWR	381	420	1375	NNEGC	PAIP	1973-8	1980-12	1981-9	80.0	81.0	DH
	UA -28	ROVNO-2	PWR	376	415	1375	NNEGC	PAIP	1973-10	1981-12	1982-7	79.0	81.0	DH
	UA -29	ROVNO-3	PWR	950	1000	3000	NNEGC	PAIP	1980-2	1986-12	1987-5	69.0	73.0	DH
	UA -44	SOUTH UKRAINE-1	PWR	950	1000	3000	NNEGC	PAA	1977-3	1982-12	1983-10	66.0	66.0	DH
	UA -45	SOUTH UKRAINE-2	PWR	950	1000	3000	NNEGC	PAA	1979-10	1985-1	1985-4	61.0	62.0	DH
	UA -48	SOUTH UKRAINE-3	PWR	950	1000	3000	NNEGC	PAA	1985-2	1989-9	1989-12	72.0	73.0	DH
	UA -54	ZAPOROZHE-1	PWR	950	1000	3000	NNEGC	PAIP	1980-4	1984-12	1985-12	61.0	64.0	DH
	UA -56	ZAPOROZHE-2	PWR	950	1000	3000	NNEGC	PAIP	1981-1	1985-7	1986-2	64.0	68.0	DH
	UA -78	ZAPOROZHE-3	PWR	950	1000	3000	NNEGC	PAIP	1982-4	1986-12	1987-3	66.0	70.0	DH
	UA -79	ZAPOROZHE-4	PWR	950	1000	3000	NNEGC	PAIP	1983-4	1987-12	1988-4	71.0	75.0	DH
	UA -126	ZAPOROZHE-5	PWR	950	1000	3000	NNEGC	PAIP	1985-11	1989-8	1989-10	72.0	74.0	DH
	UA -127	ZAPOROZHE-6	PWR	950	1000	3000	NNEGC	PAIP	1986-6	1995-10	1996-9	77.0	80.0	DH

(1) Performance factors Load Factor (LF) and Unit Capacity Factor (UCF) calculated only for period of full commercial operation, and only through 2005.

(2)The column Non-Electrical Applications indicates the use of the facility to provide:- DS desalination, DH district heating, PH process heat.

Table 1.3-a. District heating and process heat in 2006 (1)				
Country	**Reactor**	**District heating [Gcal]**	**Process heat [Gcal]**	**Total heat [Gcal]**
Bulgaria	Kozloduy-5	121735	N/A	121735
	Kozloduy-6	17964	N/A	17964
Czech Republic	Temelin-1	42503	N/A	42503
	Temelin-2	4757	N/A	4757
Hungary	PAKS-2	2187	N/A	2187
	PAKS-3	25385	N/A	25385
	PAKS-4	214307	N/A	214307
India	Rajasthan-1	N/A	0	0
	Rajasthan-2	N/A	98952	98952
	Rajasthan-3	N/A	112421	112421
	Rajasthan-4	N/A	21186	21186
Romania	Cernavoda-1	27127	N/A	27127
Russian Federation	Balakovo-1	47980	0	47980
	Balakovo-2	0	0	0
	Balakovo-3	1000	0	1000
	Balakovo-4	2837	0	2837
	Beloyarsky-3	279279	0	279279
	Bilibino-1	45212	N/A	45212
	Bilibino-2	41344	N/A	41344
	Bilibino-3	50286	N/A	50286
	Bilibino-4	49062	N/A	49062
	Kalinin-1	337593	3510	341103
	Kalinin-2	224460	3084	227544
	Kola-1	6628	2064	8692
	Kola-2	7962	2066	10028
	Kola-3	11234	1744	12978
	Kola-4	5624	1828	7452
	Kursk-1	60540	62611	123151
	Kursk-2	96184	101255	197439
	Kursk-3	127776	116201	243977
	Kursk-4	217029	168384	385413

Table 1.3-a. District heating and process heat in 2006 (1) cont'd.				
	Leningrad-1	219273	0	219273
	Leningrad-2	26582	0	26582
	Leningrad-3	243028	0	243028
	Leningrad-4	183123	0	183123
	Novovoronezh-3	84240	0	84240
	Novovoronezh-4	135657	2680	138337
	Novovoronezh-5	0	1637	1637
	Smolensk-1	55751	34670	90421
	Smolensk-2	278585	22224	300809
	Smolensk-3	249082	21803	270885
Slovakia	Bohunice-3	224056	0	224056
	Bohunice-4	193285	0	193285
Switzerland	Beznau-1	129	N/A	129
	Beznau-2	12	N/A	12
	Goesgen	N/A	63005	63005
Ukraine	Khemlnitski-1	189517	N/A	189517
	Rovno-1	82154	N/A	82154
	Rovno-2	66929	N/A	66929
	Rovno-3	129006	N/A	129006
	South Ukraine-1	98018	N/A	98018
	South Ukraine-2	129808	N/A	129808
	South Ukraine-3	136978	N/A	136978
	Zaporozhe-1	89166	N/A	89166
	Zaporozhe-2	91991	N/A	91991
	Zaporozhe-3	43534	N/A	43534
	Zaporozhe-4	64302	N/A	64302
	Zaporozhe-5	125087	N/A	125087
	Zaporozhe-6	126772	N/A	126772

(1) 1 Gcal = 1.16 MWh.

Table 1.3-b. Water desalination in 2006 (1)

Country	Reactor	Thermal energy [Gcal]	Electrical energy for reverse osmosis [MWh]	Water produced [m^3]
India	Madras-1	0	0	0
	Madras-2	0	0	0
Japan	Genkai 3&4	30189	N/A	430050
	Ikata 1&2		N/A	331488
	Ikata-3		N/A	6002
	Ohi 1 and 2		N/A	930269
	Takahama 3&4		N/A	608029
Pakistan	KANUPP	0	0	0

(1) 1 Gcal = 1.16 MWh.

1.3. Past experience with non-electric applications

Figure 1.2 shows the reactor years of experience for non-electric applications in Bulgaria, China, Czech Republic, Hungary, India, Japan, Kazakhstan, Pakistan, Romania, Russian Federation, Slovakia, Switzerland and the Ukraine.

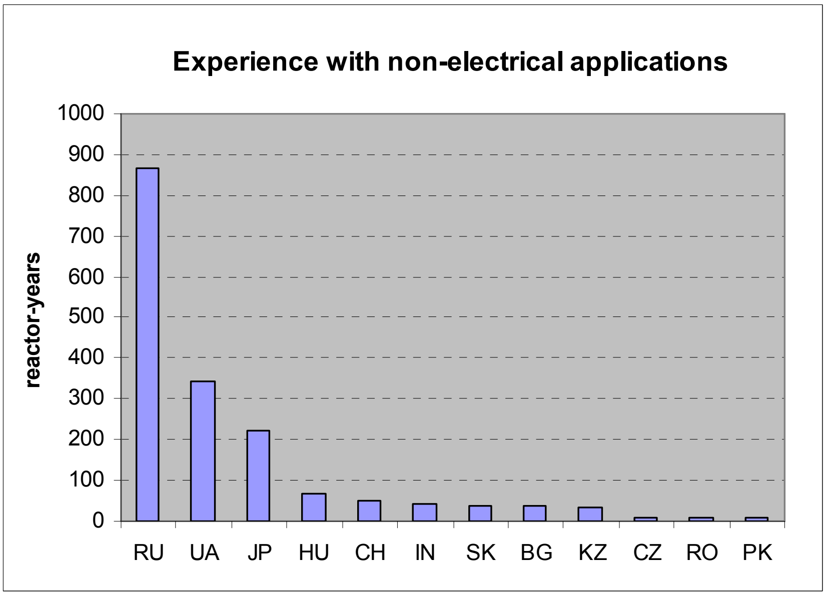

FIG. 1.2. Reactor-years of experience with non-electric applications in different countries.

A comprehensive list of various non-electric applications worldwide published in the IAEA Guidebook [3] is reproduced in Tables 1.5 through 1.10 for ready reference.

Table 1.5. Operating nuclear desalination plants in Japan

Plant name	Location	Application	Start of operation reactors / desalination	Net Power (MW(e))	Water capacity (m^3/d)	Remarks
Ikata-1,2	Ehime	Electricity/ desalination	1977-82 1975	566	2000	PWR/MED, MSF
Ikata-3	Ehime	Electricity/ desalination	1994 1992	566	2000	PWR/MSF (2 x 1000 m^3/d)
Ohi-1,2	Fukui	Electricity/ desalination	1979 1973-76	1175	3900	PWR/MSF (3 x 1300 m^3/d)
Ohi-3,4	Fukui	Electricity/ desalination	1991-93 1990	1180	2600	PWR/RO (2 x 1300 m^3/d)
Genkai-4	Fukuoka	Electricity/ desalination	1997 1988	1180	1000	PWR/RO
Genkai-3,4	Fukuoka	Electricity/ desalination	1995-97 1992	1180	1000	PWR/MED
Takahama	Fukui	Electricity/ desalination	1985 1983	870	1000	PWR/RO

Table 1.6. Nuclear desalination projects in India and Pakistan

Plant name	Location	Application	Start of Operation reactor / desal.	Net Power (MW(e))	Water capacity (m^3/day)	Remarks
Kalpakkam 1,2	Tamil Nadu	Electricity/ Desalination	Reactors:1984-86 RO:2000/2001 MSF: after 2001	2 x 170	6300	Hybrid MSF/ RO
KANUPP	Karachi	Electricity Desalination	Reactor: 1972 MED in 2007	1 x 135	4800	MED

Table 1.7. Operating nuclear heating plants

Country	Plant type or name	Location	Application	Phase	Start of operation reactors / heat	Net Power (MW(e))	Heat output capacity (MW(th))	Temp (°C) at interface (feed/return)	Remarks
Bulgaria	Kozloduy	Kozloduy	Electricity/ District heating	Commercial	1974-82 1990 1988-93	4 x 408 2 x 953	20	150/70	
China	NHR-5	Beijing	District heating	Experimental	1989 1989	-	5	90/60	
Hungary	PAKS 1-4	Paks	Electricity/ District heating	Commercial	1983-87	3 x 433 1 x 430	30	130/70	4 x V-213 WWER
Romania	PHWR CANDU-6	Cernavoda Unit 1	Electricity/ District heating	Commercial	1996	1 x 660	40 Gcal/h	150/70	
Russia		Obninsk	District heating	Commercial	1954-[b]	-	10	130/70	
Russia	WWER-1000	Novovoronezh[4]	Electricity/ District heating	Commercial	1972-73 1981	2 x 385 1 x 950	230	130/70	
Russia	WWER-1000	Balakovo	Electricity/ District heating	Commercial	1986-93[b]	4 x 950	230	130/70	
Russia	WWER-1000	Kalinin	Electricity/ District heating	Commercial	1985-87[b]	2 x 950	230	130/70	
Russia	WWER-440	Kola	Electricity/ District heating	Commercial	1973-84 [b]	4 x 411	55		
Russia	EGP-6	Bilibino	Electricity/ District heating	Commercial	1974-77 [b]	4 x 11	133	150/70	
Russia	BN-600	Belojarsk	Electricity/ District heating	Commercial	1981 [b]	2 x 560	220	130/70	
Russia	RBMK-1000	Petersburg	Electricity/ District heating	Commercial	1974-81 [b]	4 x 925	~170	130/70	
Russia	RBMK-1000	Kursk	Electricity/ District heating	Commercial	1977-86 [b]	4 x 925	~170	130/70	
Slovakia	Bohunice-3,4	Bohunice/Trnava	Electricity/ District heating	Commercial	1985 1987	2 x 408	240	150/70	2 x V-213 WWER
Switzerland	Beznau 1,2	Beznau	Electricity/ District heating	Commercial	1969-71/1983-84	1 x 365 1 x 357	80	128/50 (water)	

Table 1.8. Nuclear heating plant projects

Country	Plant type or site	Location	Application	Phase	Start of operation (year)	Power (MW(e))	Heat output (MW(th))	Temperature (°C) at interface (Feed/Return)
Bulgaria	Belene	Belene	Electricity/ District heating	Design		2 x 1000	400	150/70
China	NHR-200	Daqing City	District heating	In construction	2000	-	200	90/~60
Japan	HTTR	O-arai	Process heat	Operation	1998		30	950/395
Romania	PHWR CANDU-6	Cernavoda - Unit 2	Electricity/ District heating	In commissioning	2007	1 x 660	46	150/70
Russia	RUTA	Apatity	District heating/ Air conditioning	Design		-	4 x 55	85/60
Russia	ATEC-200		Electricity/ District heating	Design		50-180	70-40	150/70
Russia	VGM		Process Heat	Design		-	200	900/~500
Russia	KLT-40		Electricity/ District heating & Desalination	Design		35	110	
Russia	AST-500	Voronez	District heating	Construction suspended		-	500	150/70
Russia	AST-500	Tomsk	District heating	Construction suspended		-	500	150/70

Table 1.9. Operating nuclear process heat production plants

Country	Plant name	Location	Application	Start of operation reactors / heat	Phase	Power (MW (e))	Heat delivery (MW(t))	Temperature (°C) at interface (feed/return)	Remarks
Canada	Bruce-A[a]	Bruce	Process heat	1977-87 / 1981	Commercial	4 x 848	5350		D_2O production and six industrial heat customers
Germany	Stade	Stade	Electricity/ process heat	1983	Commercial	640	30	190/100	Salt refinery
Switzerland	Goesgen	Goesgen	Electricity/ process heat	1979 / 1979	Commercial	970	25	220/100	Cardboard factory
India	RAPS	Kota	Electricity/ process heat	1975 / 1980	Commercial	160	85	250	D_2

[a]Unit 2 was taken out of service in 1995, units 1, 3 and 4 were taken out of service in spring 1998.

Table 1.10. Nuclear Process Heat Production Projects

Country	Plant name	Location	Application	Start of operation reactors / heat	Phase	Heat delivery (MW(t))	Temperature (°C) at interface (feed/return)	Remarks
China	HTGR-10	Beijing	Electricity/ process heat	Criticality 1999	Construction	10	700-950/250	Experiments for HTR technology development.
Japan	HTTR	O-arai	Process heat	Criticality 1998	Construction completed	30	950/395	Experiments for HTR technology development.
Russia	VGM		Process heat		Design			

1.4. Market potential of advanced non-electric applications [4]

1.4.1. 2003 IAEA study: Market potential for non-electric application of nuclear energy [4]

An analysis of the market potential for non-electric applications of nuclear energy was carried out by IAEA and published in IAEA-TRS-410 (2003). The conclusions reached in this report are reproduced as the following.

(a) For the foreseeable future, power generation will remain the main application of nuclear energy, the main reasons being the advanced status of nuclear power production technologies and an increasing share of electricity in the total energy demand;

(b) Currently, nuclear power has little penetration in non-electric energy applications. However, a large demand for non-electric nuclear energy is expected to emerge and grow rapidly.

(c) Because of the dominance of power generation, nuclear penetration into the markets for non-electric services will proceed with cogeneration applications wherever possible. Dedicated reactors for heat generation could eventually emerge for some applications.

(d) Many non-electric applications require energy sources that are relatively small (100-1000 MW(th)) in comparison with the size of existing power reactors. The development of nuclear reactors of small and medium size would therefore facilitate non-electric applications of nuclear energy.

(e) Some non-electric applications require that the nuclear plant be located close to the customer. This will require specific safety features appropriate to the location.

(f) Economically, the non-electric applications of nuclear energy are subject to the same trends as nuclear power generation. Growing capital costs of nuclear plants have affected the cost estimations of most non-electric applications. Evolutionary and innovative design improvements in nuclear reactor concepts, coupled with stable nuclear fuel prices, will result in an improved competitiveness of non-electric nuclear applications.

(g) Depending upon the regions and conditions, nuclear energy is already competitive for district heating, desalination, and certain process heat applications.

(h) Using nuclear energy to produce hydrogen is likely to facilitate the indirect application of nuclear energy in transportation markets, most of which are not readily amenable to the direct use of nuclear reactors.

(i) Non-electric applications of nuclear energy are most likely to be implemented in countries already having the appropriate nuclear infrastructure and institutional support.

(j) The implementation of some non-electric applications (e.g., desalination) is likely to enhance the public acceptance of nuclear energy.

The following specific findings for these applications were formulated, in addition to the general conclusions above.

District heating

Nuclear applications for district heating are technically mature and exist in several countries. The future use of nuclear energy will be determined by a combination of the following factors: the size and growth of the demand for space and water heating, competition between heat and non-heat energy carriers for space and water heating, and competition between nuclear and non-nuclear heating. The availability of a heat distribution network plays an important role in the prospects for nuclear district heating.

Desalination

For desalination, low temperature heat and/or electricity are required. Consequently, all existing nuclear designs can be used; the relevant experience is already available. The use of nuclear heat assumes a close location of the nuclear plant to the desalination plant; the use of electricity generated by nuclear energy (for the RO desalination process) does not differ from any other electricity use — the energy source may be located far from the customer with the electricity being provided through the electricity grid. (It should be noted, however, that a distant location would not allow the use of low temperature steam for water preheating, which is an advantage of co-production plants.) With regard to the market size, it is expected that freshwater requirements will grow in the future, which will increase the attractiveness of nuclear desalination.

Process heat supply

For process heat supply there is a wide range of required heat parameters that determine the applicability of different reactor types. One particular concept, the high-temperature gas-cooled reactor (HTGR), can produce temperatures above 800°C and perhaps as high as 1000°C. It is, therefore, considered to be a prime candidate for nuclear process heat supply at high temperatures. The development and demonstration of such a reactor would provide a strong impetus for the process heat applications of nuclear energy.

Ship propulsion

Nuclear powered ship propulsion has been tested technically in several countries, especially for naval applications. The technology has proven non-economic for commercial applications, however, and the use of nuclear powered merchant ship propulsion has been discontinued, with the exception of the nuclear powered ships operating off the north coast of the Russian Federation. Although the market for large tankers and cargo ships is large, the future of nuclear powered ships will depend on their ability to offer competitive service in this highly competitive market. The need to observe safety and licensing requirements in receiving ports is an additional obstacle for the application of nuclear powered ship propulsion.

Hydrogen production

Two aspects must be distinguished: the penetration of hydrogen into the energy system and the use of nuclear energy for hydrogen production. In comparison with the use of fossil fuels for hydrogen production, nuclear energy has the advantages of a large resource base and the absence of most emissions, carbon dioxide in particular. In comparison with the use of renewable energy sources for hydrogen production, nuclear energy has the advantage of being a mature, available technology and has the important feature of a high energy concentration, which could allow hydrogen production to be concentrated in multi product energy centres. The share of nuclear energy in a hydrogen-based system will depend on its competitiveness with the other energy options. Successful demonstration projects, such as the use of surplus nuclear capacity for hydrogen production using cheap off-peak electricity, the operation of the first large HTGR and the creation of local hydrogen markets near existing NPPs, would help to promote the nuclear-hydrogen link.

Coal gasification

Coal gasification has the following advantages: the reduction of air emissions from coal combustion, an increased thermal efficiency of combustion, and the use of a large resource base. If coal gasification becomes widespread, economic and environmentally benign technologies for the supply of gasification energy will be required. Nuclear energy, being an industrially mature and non-polluting technology, is a valid candidate for this purpose. Such applications would be similar to the other process heat applications of nuclear energy.

Other synthetic fuels

Transportation accounts for about one quarter of the world's total energy demand and will grow significantly in the future following, in particular, industrial growth and an increase in the standards of living in developing countries. The direct use of nuclear energy for transportation is limited to the use of electric driven motors and ship and spacecraft propulsion. However, using nuclear energy for transportation indirectly, through fuel production, is possible. The related fuels, in addition to electricity and hydrogen, include alcohol fuels (methanol, ethanol, and their derivatives), compressed natural gas, liquefied natural gas, liquefied petroleum gas, and coal-derived liquid fuels. Each fuel has certain advantages and may have a place in the future fuel economy. The future fuel mix will be determined primarily by inter fuel economic competition, the availability of infrastructure, and environmental considerations such as the amount and type of greenhouse gases and other polluting emissions.

Oil extraction

Nuclear energy can be used for the extraction of unconventional oil resources such as heavy oil, oil from tar and oil sands, oil shale, and the oil remaining in depleted deposits. These unconventional oil resources are about two times larger than the resources of conventional oil. However, if the price of conventional oil is low it is not realistic to expect significant developments in the extraction of unconventional oil, except in the cases (as, for example, in Canada) in which the resources of unconventional oil are large and already developed. The case of Canada is especially notable because, on one hand, the resources of unconventional oil are very large, and, on the other, nuclear technologies suitable for such applications are available.

Table 1.11 shows the most promising countries for non-electric nuclear applications in the long term. This table includes countries in which at least two applications are ranked highest in the corresponding region.

These estimates are based on assessments that assume that applications of nuclear energy, both for power generation and for non-electric purposes, will continue to develop. This includes technical development, infrastructural support and the licensing environment, the latter being particularly important for certain applications. These estimations also assume, implicitly, that nuclear energy will remain socially acceptable.

Table 1.11. Most promising countries for the long term prospects of non-electric applications of nuclear energy

Region/country	District heating	Water desalination	Process heat	Ship propulsion
NAM				
Canada	M	L	M	M
USA	M	L	M	M
LAM				
Argentina	L	M	L	L
Brazil	L	L	L	M
Mexico	L	L	L	L
AFR				
South Africa	M	M	M	L
MEA				
Egypt	L	H	L	-
Iran	M	M	M	L
Morocco	L	H	L	-
WEU				
Belgium	M	M	M	L
Finland	M	M	M	L
France	M	M	M	M
Netherlands	M	M	M	M
Spain	M	H	M	L
Switzerland	M	M	M	L
UK	M	M	L	M
EEU				
Bulgaria	M	L	M	L
Czech Republic	M	M	M	L
Romania	M	L	L	
Slovakia	M	M	M-	-
FSU				
Belarus	M	M	M	-
Lithuania	M	M	M	L
Russian Federation	M	L	M	M
Ukraine	M	M	L	M
CPA				
China	M	H	H	M
Viet Nam	L	M	M	-
SAS				
India	M	H	M	M
Pakistan	M	H	M	L
PAS				
Indonesia	L	M	M	L
Korea, Republic of	M	M	M	M
Taiwan, China	M	L	L	M
PAO				
Japan	M	M	L	M

Abbreviations: - = negligible, L= Low, M= medium, H= high; NAM-North America, LAM-Latin America, AFR-Africa, WEU-Western Europe, EEU-Eastern Europe, FSU-Newly Independent States of the former Soviet Union, CPA- Centrally planned Asia and China, SAS-South Asia, PAS-Other Pacific Asia, PAO-Pacific OECD

1.4.2. 2004 NEA study: Non-electricity products of nuclear energy [5]

As shown in the IAEA study, the potential non-electricity product market open to nuclear energy seems to be large; district heat, process heat, and desalinated water in the near term, and hydrogen in the long term. For example, assuming that current district heat in the world would be replaced by nuclear energy, it would mean the addition of 340 1000 MWth reactors. However, the reality does not match the potential. Even though the high potential needs to be considered in a vision for the future, realistic demand needs to be assessed, which was the purpose of the OECD-NEA study of 2004 [5].

From the beginning of the project, some basic questions related to the real deployment of nuclear non-electricity products were raised, including:

- If nuclear energy has such high potential in non-electricity product markets, why has its deployment been so limited? Can one expect some dramatic changes in this market situation?

- Who will or should initiate actions for the deployment of non-electricity applications of nuclear energy: the government, R&D institutes, vendors, or suppliers? If necessary, how should vendors or suppliers be motivated? Would some policy measures (tax reduction, subsidies, or a carbon tax) really work?

- What are the thoughts of suppliers and vendors (nuclear and non-nuclear) in the current market?

- What is the role of the government? Do governments consider seriously all nuclear options in their national energy policies for greenhouse gas reduction and energy security?

Common sense provides reasonable-guess answers to the above questions, but more investigations are required to support an authoritative report. Deeper studies including market analyses are needed for enhanced understanding of realistic projected demand, which can be carried out only with the support of national experts providing relevant input data. Also, country-specific information is needed to analyze the reasons for the limited deployment of non-electrical applications of nuclear energy and to draw policy recommendations. Since few country reports were received at the time of the NEA report, that part of the study was not complete.

With its limitations, the NEA study led to the following preliminary findings and recommendations:

- There is a need to understand better the markets and to increase communication with key actors. Convincing all actors in the market (customers, suppliers, vendors, research institutes, and government) is critical for the introduction of nuclear non-electricity products in the market. In this regard, the establishment of some interest groups on nuclear applications in the market would be valuable. Considering that a large part of non-electricity energy demand is in developing countries and that developed countries would provide relevant technologies, it would be better to have some connections between developed countries and developing countries, especially in the case of nuclear desalination.

- According to the demand pattern in the individual market, the requirements for nuclear systems will be different. For example, if demand for distributed rather than centralized hydrogen production prevails, the development of small- and medium-sized reactors would be relevant. The development of nuclear non-electricity product technologies, in turn, may affect the shaping of the demand pattern through providing timely attractive options. In this connection, it is essential for the nuclear energy sector to be involved and participate actively in the discussions on non-electricity applications including the hydrogen economy.

- For successful penetration in a market, early demonstration is critical. Especially, the long-term prospects for alternative technology options for hydrogen generation will depend to a certain extent on early demonstration of feasibility and viability. For instance, nuclear-assisted steam methane reforming could be pursued as an early nuclear option, which will facilitate further market penetration of more innovative nuclear hydrogen production technologies (see Chapter 6).

- In the light of recent trends in energy markets, strong competition is expected between alternative options to supply non-electricity products. For example, there are many technical options for hydrogen production and a large number of technologies, such as steam reforming of methane, steam-coal gasification with sequestration of CO_2, and solar photovoltaic processes, are already available or under development. Nuclear non-electricity production technology should be ready for deployment and competitive within a deregulated market. Regardless, the demand for relevant reactors is unlikely to be comparable to the mass reactor orders that occurred in the 1960s and 1970s.

- The development of nuclear non-electricity product technologies, especially hydrogen production technologies, requires long-term commitment with many uncertainties. All stakeholders in government bodies and the industry have a role to play for the eventual success of relevant technologies. Coordination and joint efforts are essential in organizing R&D programmes, infrastructure building, and policy making to address the challenges of developing competitive and efficient technical processes.

- In countries wishing to rely on nuclear energy in the long term, the role of governments for the emergence of non-electrical applications of nuclear energy is important in terms of basic R&D, initial technology development and demonstration, and policy making to create a favourable business environment without interfering with market mechanisms.

- International cooperation is essential to ensure the design and implementation of nuclear systems efficient for non-electrical applications of nuclear energy such as hydrogen production. In particular, the efforts required in the field of nuclear R&D and infrastructure building, are likely to be beyond an individual country's capabilities. In this context, undertakings such as the Generation IV International Forum (GIF) and the International Partnership for the Hydrogen Economy (IPHE), for example, can enhance the synergy between national programmes and the effectiveness of the overall efforts.

1.5. Impact of externalities on cost of power from fossil/ nuclear/ renewable sources [9]

It is now generally recognized that the production and consumption of energy and related activities is linked to a wide range of environmental and social problems such as the health effects of pollution of air, water, and soil; ecological disturbances and species loss; and landscape damage. The costs of such damages are referred to as external costs or externalities.

An externality arises when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted or paid for by the main actors causing the damages. In the particular case of energy production, fuel cycle externalities are the costs imposed on the society and the environment that are not accounted for (i.e., not integrated in the market pricing system) by the producers and consumers of energy.

The term fuel cycle refers to the chain of processes linked to the generation of electricity from a given fuel. A comparative evaluation has been made for the following technologies and fuel cycles [9]:

- *Fossil fuels*: coal and oil technologies, with varying degrees of flue gas cleaning, natural gas, centralized systems and CHP etc.;

- *Nuclear*: a PWR, and associated fuel cycle services, with and without reprocessing;

- *Renewables*: solar, on-shore and off-shore wind, hydro-electricity, a wide range of biomass fuels.

Comparisons of damage costs/kWh for various technologies in EU countries are presented in Table 1.12.

Table 1.12. External costs of electricity production in the EU from existing technologies [9] (10^{-2} \$/kW.h*)

Country	Coal and lignite	Oil	Gas	Nuclear	Biomass	Hydro	Solar PV	Wind
Austria			1.3 to 3.8		2.5 to 3.8	0.13		
Belgium	5.1 to 19		1.3 to 2.5	0.64				
Denmark	5.1 to 8.9		2.5 to 3.8		1.3			0.13
Finland	2.5 to 5.1				1.3			
France	8.9 to 12.7	10.2 to 14.0	2.5 to 5.1	0.38	1.3	1.3		
Germany	3.8 to 7.6	6.4 to 10.2	1.3 to 2.5	0.25	3.81		0.76	0.063
Greece	6.4 to 10.2	3.8 to 6.4	1.3		0 to 1.01	1.3		0.32
Ireland	7.6 to 10.2							
Italy		3.8 to 7.6	3.8 to 7.6			0.38		
Netherlands	3.8 to 5.1		1.3 to 2.5	0.89	0.64			
Portugal	5.1 to 8.9		1.3 to 2.5		1.3 to 2.5	0.038		
Spain	6.4 to 10.2		1.3 to 2.5		3.8 to 6.4**			0.25
Sweden	2.5 to 5.1				0.38	0 to 0.89		
United Kingdom	5.1 to 8.9	3.8 to 6.4	1.3 to 2.5	0.32	1.3			0.19

* Sub-total of quantifiable externalities (global warming, public health, occupational health, and material damage); on the basis of 1€ = \$1.27.

** Biomass co-fired with lignite.

Table 1.12 leads to the following conclusions:

- External costs are extremely site dependent.

- In general, wind technologies are most environmentally friendly with respect to greenhouse gas pollutants and particles. However, not every site is appropriate for wind power generation, which has other environmental costs, including noise.

- Nuclear power generates the lowest external costs after wind power, even when low-probability accidents with high consequences are integrated into the calculation. These results are generated for 0% discount rates. At a 3% discount rate, the external costs from nuclear are lower.

- Photovoltaic solar power is the cleanest technology regarding its immediate use. It has, however, considerable life cycle impacts due to the fabrication of solar panels.

- Gas-fired technologies are relatively clean.

- Coal technologies are the worst in view of their high generation of CO_2. They appear to have high impacts due to primary and secondary aerosols.

Figure 1.3 shows an illustrative example of the power costs from various power plants for selected sites in Germany, with 2010 technologies [9].

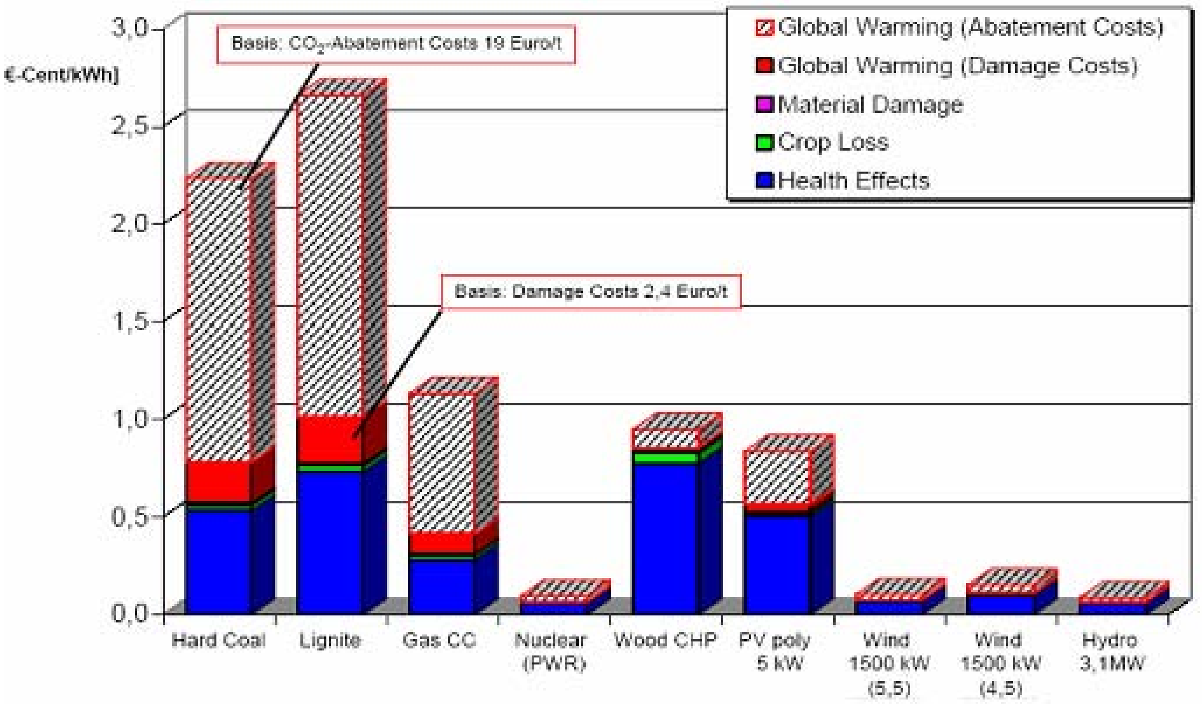

FIG. 1.3. External costs of power stations in Germany
(CO_2 =19 euros/t, 1 year of life lost = 50 000 euros) [9].

It is observed that for the fossil fuelled electricity systems, human health effects, acidification of ecosystems, and potential global warming impacts are the major sources of external costs. Although the analysed power plants are all supposed to be equipped with abatement technologies, the emissions of SO_2 and NO_x due to the subsequent formation of sulphate and nitrate aerosols leads to considerable health risks.

External costs arising from the nuclear fuel cycle are significantly lower than those estimated for fossil fuel cycles.

External costs from renewable fuel cycles and hydropower mainly result from the use of fossil fuels for material supply and during the construction phase. External costs from current PV technologies are higher than from nuclear and are close to those for gas fired plants.

Impacts from wind and hydropower cycles are the lowest.

Internalization of external costs into power costs

A logical and sustainable way to permit the choice between various technologies is to integrate the external costs with the production costs of these technologies.

Taking the above external costs and current generating costs of electricity in Germany; one would thus obtain the results shown in Figure 1.4. [9]

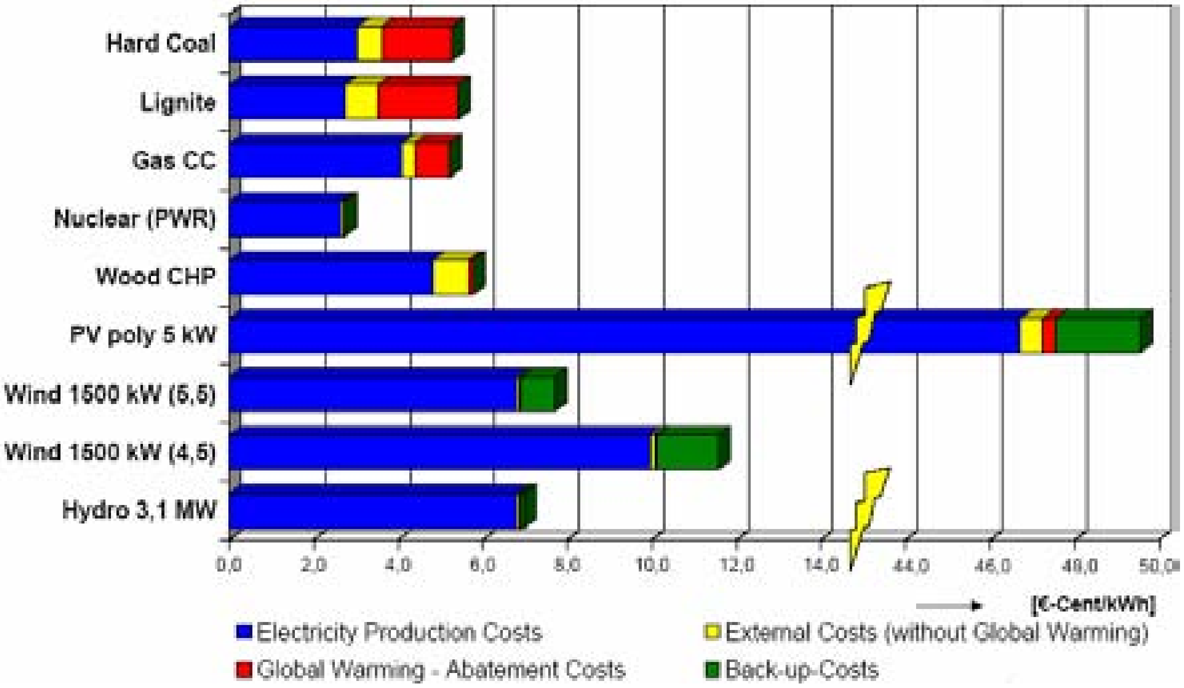

FIG. 1.4. Total costs of various electricity generating technologies in Germany [9].

It is clearly seen that the power generation costs for renewable energies, especially for solar energy, are much higher than for fossil energies or nuclear energy. It is also obvious that the full integration of external costs in the nuclear case would render it economically the most attractive option.

1.6. Conclusion

The advantage of nuclear energy in alleviating the risk of climate change will not favour market penetration of nuclear products through advanced non-electric applications of nuclear power as long as energy policies internalising the value of carbon and other pollutants are not implemented. National policies on climate change vary from country to country, but very little has been done to credit nuclear energy systems for their contribution to reducing green house gas emission. The entry into force of the Kyoto Protocol in February 2005 does, however, create incentives that can benefit nuclear power, depending on how they are translated into national policies. The Protocol’s emission trading provisions effectively give a cash value to unused emission allowances in the Russian Federation, for example, and the European Trading Scheme (ETS) creates incentives favourable to nuclear power in at least those European countries where implementation policies are not specifically biased against nuclear power.

In considering the deployment of nuclear energy for non-electric applications, challenges and difficulties should not be overlooked; in particular, it should be acknowledged that a scientific potential is not a technical reality and that competition will drive the choice of energy sources for each application. Considering the potential requirements and technical capabilities of nuclear energy systems, their non-electric applications seem rather promising. Moving from their potential to realities is undoubtedly feasible, but will need time, investments, and policy measures to address a wide range of techno-economic and socio-potential challenges.

If non-electric products of nuclear energy were to penetrate markets on a significant scale, the role of nuclear energy in supply systems could change dramatically from a marginal player to a main contributor. However, such an achievement will materialize only if considerable technical, economic, social, and political challenges are overcome. This can require a long lead time — up to several decades for some applications.

Public acceptance is a major issue for nuclear energy. However, non-electric applications, for example desalination or district heating, can play an important role in acceptance of the nuclear power by local communities.

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CHAPTER 2
NUCLEAR DESALINATION

2.1. Opportunities

Water, energy and environment are essential inputs for the sustainable development of society. These are, therefore, current national and international issues, and have been addressed by many fora. Recent statistics show that currently 2.3 billion people live in water-stressed areas and, among them, 1.7 billion live in water-scarce areas, where the water availability per person is less than 1000 m^3/year. The situation is going to worsen further; statistics show that by 2025 the number of people suffering from water stress or scarcity could swell to 3.5 billion, and 2.4 billion of them are expected to live in water-scarce regions. Water scarcity is a global issue, and every year new countries are affected by growing water problems [1].

Seventy percent of the earth is covered with water, but only 2.5% of that is fresh water. Nearly 70% of this fresh water is frozen in the icecaps of Antarctica and Greenland. Most of the rest is in the form of soil moisture or in deep inaccessible aquifers, or comes in the form of monsoons and floods that are difficult to contain and exploit. Less than 0.08% of the world's water is thus readily accessible for direct human use, and even that is very unevenly distributed.

In the light of this, the Millennium Declaration by the UN General Assembly in 2000 set a target to halve, by the year 2015, the world population who are unable to reach or to afford safe drinking water. In Vision 21, the shared vision for Hygiene, Water Supply and Sanitation has a target to provide water, sanitation and hygiene for all by 2025 [2].

Better water conservation, water management, pollution control and water reclamation are all part of the solution to projected water stress. So too are new sources of fresh water, including the desalination of seawater and brackish water. Desalination technologies have been well established since the mid-20th century and widely deployed in the Middle East and North Africa. The contracted capacity of desalination plants has increased steadily since 1965 and is now about 36 million m^3/d worldwide [3], as shown in Figure 2.1. The top line in the figure shows total operating and contracted capacity. The bottom line in the figure shows just operating capacity. This capacity could provide the world's population roughly 6 litres a day per capita of fresh potable water. If this capacity were available to the 1.5 billion in the world without direct access to drinking water, it would provide approximately 20 litres/day each.

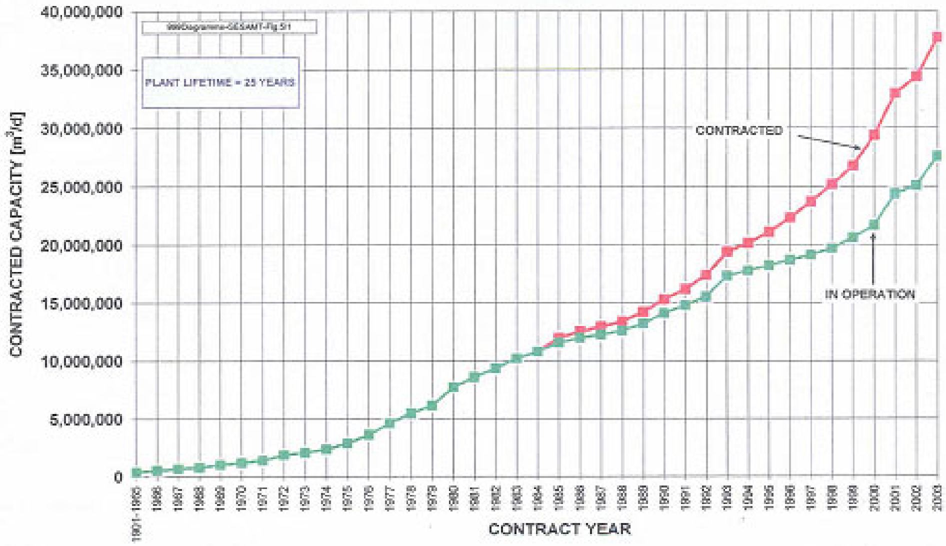

FIG. 2.1. Cumulative capacity of all land-based desalination plants (unit capacity > 100 m^3/day) (reprinted with the permission of the author) [3,6].

Large-scale commercially available desalination processes can generally be classified into two categories: (a) distillation processes that require mainly heat plus some electricity for ancillary equipment, and (b) membrane processes that require only electricity to provide pumping power. In the first category (distillation) there are two major processes: multi-stage flash (MSF) and multi-effect distillation (MED). In both, seawater is heated; the steam that evaporates is condensed and collected as freshwater; and the residual brine is discharged. In the second category (membranes) is the reverse osmosis process (RO), in which pure water passes from the high-pressure seawater side of a semi-permeable membrane to the low-pressure freshwater permeate side. The pressure differential must be high enough to overcome the natural tendency for water to move from the low concentration freshwater side of a membrane to the high concentration seawater side, in order to balance osmotic pressures.

The energy for these plants is generally supplied in the form of either steam or electricity using fossil fuels. The intensive use of fossil fuels raises environmental concerns, especially in relation to greenhouse gas emissions. The depletion of fossil sources and the future price uncertainty of fossil fuels and their better use for more vital industrial applications is also a factor to be considered for sustainability. Many countries deprived of valuable fossil resources are therefore considering the introduction of a nuclear power program or expansion of their existing nuclear power program.

2.2. Market context [4]

In recent years, the option of combining nuclear power with seawater desalination has been explored to tackle water shortage problems. The desalination of seawater using nuclear energy is a feasible option to meet the growing demand for potable water. Over 175 reactor-years of operating experience on nuclear desalination have been accumulated worldwide. Several demonstration programs of nuclear desalination are also in progress to confirm its technical and economical viability under country-specific conditions, with technical coordination or support of IAEA.

There are many reasons that favour a possible revival of nuclear power production in the years to come: the development of innovative reactor concepts and fuel cycles with enhanced safety features that are expected to improve public acceptance, the production of less expensive energy as compared to other options, the need for prudent use of fossil energy sources, and increasing requirements to curtail the production of greenhouse gases (GHGs). It is estimated that water production of 10 million m^3/d by seawater desalination using fossil fuels would release 200 million t/y of CO_2, 200 000 t/y of SO_2, 60 000 t/y of NO_x and 16 000 t/y of other hydrocarbons. For the current global desalting plant capacity of 40 million m^3/d the total emissions would be four times these values. This can be avoided if nuclear or renewable energy sources are used for desalination. It is estimated that for producing fresh water with the present desalination capacity, but by using nuclear energy, the needed nuclear capacity would be about 40 1000 MWe nuclear reactors.

Using nuclear energy for the production of freshwater from seawater and brackish aquifers (nuclear desalination) has been of interest in several IAEA Member States as a result of acute water shortage issues in many arid and semi-arid zones worldwide. This stems from their expectation of not only its possible contribution to the freshwater issue, but has also been motivated by a variety of reasons that include: likely competitiveness of nuclear desalination in areas lacking cheap hydropower or fossil resources, energy supply diversification, conservation of fossil fuel resources, and spin-off effects of nuclear technology for industrial development.

2.2.1. Nuclear desalination market - past experiences and plans [4]

The desalination of seawater using nuclear energy is a demonstrated option having over 180 reactor-years of operating experience worldwide, of which Japan now has over 150 reactor-years, with ten nuclear power plants that also produce desalinated water. Kazakhstan (the Aktau fast reactor BN-350) had accumulated 26 reactor-years of producing 80,000 m^3/day of potable water before shutting down in 1999. In the USA, the Diablo Canyon nuclear power plant produces desalinated water. Presently

India and Pakistan are setting up nuclear demonstration projects at their existing PHWRs. Operating experience for all non-electric applications including desalination, district heating and process heat is around 1000 reactor years (Table 1.2).

Table 2.1 summarizes past experience as well as current developments and plans for nuclear-powered desalination using different nuclear reactor types. Most of the technologies in Table 2.1 are land-based, but the table also includes a Russian initiative for barge-mounted floating desalination plants. Floating desalination plants could be especially attractive for responding to emergency demands for potable water.

Table 2.1. Reactor types used or considered for desalination

Reactor Type	Location	Capacity (m^3 /d)	Status
LMFR	Kazakhstan (Aktau)	80,000	In service till 1999
PWRs	Japan (Ohi, Takahama, Ikata, Genkai)	1,000-2,000	In service with operating experience of over 150 reactor-years
	Rep. of Korea	40,000	SMART integral PWR is being designed
	Russia		Floating Power Unit for electricity and heat is under construction; possible later units could be used for electricity and desalination
	USA (Diablo Canyon)	~4500	In service
BWR	Japan (Kashiwazaki)		Never in service following testing in 1980s; owing to alternative freshwater sources, dismantled in 1999
HWR	India (Madras)	6,300	Under commissioning (RO commissioned in 2002, MSF to be commissioned by the end of 2007).
	Pakistan (KANUPP)	4,800	Under construction, to be commissioned by the end of 2007
NHR	China	120,000	Under design
HTGR	South Africa, France, The Netherlands		Under consideration

Table 2.2 shows the operating nuclear desalination plants in Japan.

Table 2.2. Operating nuclear desalination plants in Japan

Plant name	Location	Application	Start of operation reactors / desal.	Net Power (MW(e))	Water capacity (m^3/d)	Remarks
Ikata-1,2	Ehime	Electricity/ desalination	1977-82 1975	566	2000	PWR/MED, MSF
Ikata-3	Ehime	Electricity/ desalination	1994 1992	566	2000	PWR/MSF (2 x 1000 m^3/d)
Ohi-1,2	Fukui	Electricity/ desalination	1979 1973-76	1175	3900	PWR/MSF (3 x 1300 m^3/d)
Ohi-3,4	Fukui	Electricity/ desalination	1991-93 1990	1180	2600	PWR/RO (2 x 1300 m^3/d)
Genkai-4	Fukuoka	Electricity/ desalination	1997 1988	1180	1000	PWR/RO
Genkai-3,4	Fukuoka	Electricity/ desalination	1995-97 1992	1180	1000	PWR/MED
Takahama	Fukui	Electricity/ desalination	1985 1983	870	1000	PWR/RO

The salient features of the existing and proposed nuclear desalination demonstration projects and a number of feasibility studies conducted by interested Member States [5] are given in Annex 1.

2.2.2. Economics [3]

Over the years, the cost of water produced in seawater desalination plants has dropped considerably, but the cost of water produced in conventional treatment plants has risen, due to over-exploitation of aquifers, intrusion of saline water in coastal areas, and generally increasing contamination of ground water. Fig 2.2 shows the water costs from global seawater desalination and conventional production (in various countries). Seawater desalination costs are already comparable to conventional water costs in water scarce/starved countries and are likely to approach each other even in the countries having cheap, abundant water sources. This makes the prospects of seawater desalination quite promising.

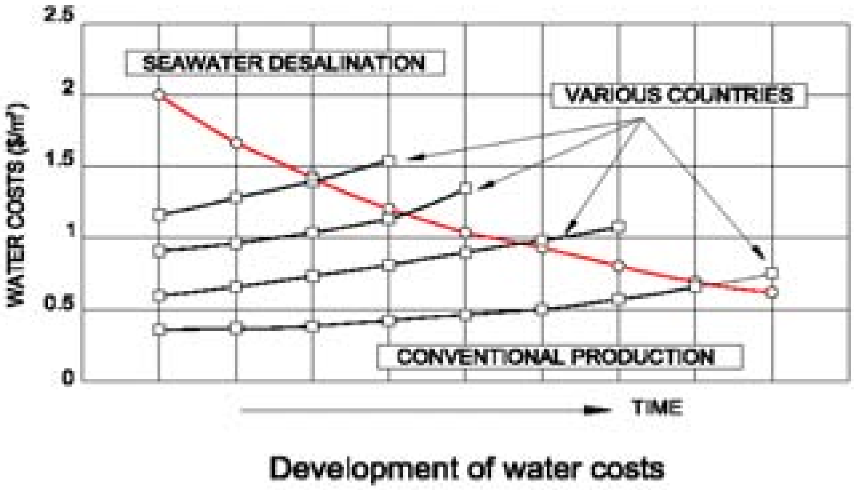

FIG. 2.2. Development of water costs (reprinted with the permissionof the author) [3].

Fig. 2.3 shows the capacity of desalination plants in various countries. As can be seen, the major contribution comes from the Middle East countries, followed by US, Spain, and the Caribbean countries. In recent years, plans for large-scale deployment of desalination in Asia and Pacific countries have been reported.

Presently, the total capacity of desalination plants worldwide is of the order of thirty-six million cubic meters/day. The major contribution comes from the Middle East countries.

Desalination processes are energy intensive, and energy is the major cost component of the water produced. As most of the current desalination is based on fossil energy sources, the cost of desalted water varies with the prevailing fuel costs in particular areas. Apart from the fossil fuel cost and its availability, the associated environmental concerns of late have kept in abeyance the launching of some large-scale desalination projects. This has led to a search for renewable and other sustainable energy sources including nuclear.

There are no officially reported cost data from existing nuclear desalination plants. Several feasibility studies, however, have been carried out by the Member States under the IAEA's coordinated research projects and technical cooperation programmes. Some results are reported in IAEA-TECDOC-1561 [6].

Preliminary techno-economic studies conducted in China for the NHR-200 reactor coupled to a 160,000 m^3/d vertical-tube evaporator multi-effect distillation (VTE-MED) plant estimated the desalted water cost to be around 0.68 US$/m^3. A similar economic evaluation of the integrated SMART-MED desalination plant of 40,000 m^3/d capacity indicated the water cost ranging from 0.70 to 0.90 US$/m^3. The projected cost of water from the Russian KLT-40 floating reactor based nuclear desalination plants is also in these same ranges. These costs are comparable with desalination costs using locally available fossil fuels.

Pre-feasibility studies have been carried out recently for the proposed nuclear desalination projects at Madura, Indonesia, and La-Skhira, Tunisia, under an IAEA technical cooperation inter-regional project (1999-2004). These indicate economic competitiveness of nuclear desalination over fossil-based plants under the specific conditions in their countries.

Despite large interest of the Member States which are considering deployment of nuclear desalination plants and IAEA's efforts in bringing about information exchange among the technology providers and the user countries, no significant progress is reported in the deployment of nuclear desalination plants. Today nuclear desalination contributes only 0.1 % of total desalting capacity worldwide.

Economic comparison with fossil desalination

Table 2.3 provides some comparative water costs of present-day fossil-based desalination plants and projected costs of water from nuclear desalination projects from recent feasibility studies in Member States.

Table 2.3. Water costs from fossil desalination plants and estimated costs from nuclear desalination

Country	**Capacity (m^3/d)**	**Process**	**Water costs (\$/m^3)**
Fossil based			
Singapore	135,000	RO	0.45
Ashkelon (Israel)	165,000	RO	0.52
Al-Taweelah (UAE) Fujairah	237,500 375,000	MED MSF-RO	0.70 0.80
Nuclear based			
Argentina (CAREM)	12,000	RO	0.72
China (NHR-200)	160,000	MED	0.68
Rep. of Korea (SMART)	40,000	MED	0.80

The projected costs for nuclear desalination appear to be marginally higher than the actual costs from present-day commercial desalination plants using fossil sources. Various aspects of cost reduction strategies in nuclear desalination are presently being proposed to make it more competitive.

Table 2.4 shows the desired objectives to be achieved for producing potable water economically from nuclear desalination plants [7].

Table 2.4. Desired objectives for economic costs

Reactor cost \$/kWe	2000 – 1000 \$/kWe construction time lifespan electricity cost	 60 - 40 months 40 - 60 years 0.06 – 0.04 \$/kWh
Desalination plant cost	1500-800 $\$/m^3$ plant life construction time water cost	 > 30 years 24 months 0.80 – 0.45 $\$/m^3$
Variables	reactor size plant capacity seawater salinity temperature	40 -600 MWe 50,000 – 200,000 m^3/d 30,000 – 45,000 ppm 18 – 35 ^oC

The broader picture, however, is that the worldwide use of desalination is still negligible compared to the demand for fresh water. To become a noticeable market for nuclear energy, desalination needs to compete successfully with alternative means of increasing fresh water supply. For nuclear desalination to be attractive in any given country, two factors must be in place simultaneously: a lack of fresh water and the ability to use nuclear energy for desalination. In most regions, only one of the two is present. Both are present for example in China, the Republic of Korea and, even more so, in India and Pakistan. These regions already account for almost half the world's population, and thus represent a potential long-term market for nuclear desalination.

2.3. Challenges [8]

The following sections describe the key challenges facing nuclear desalination.

2.3.1. Economics

Economic comparisons indicate that water costs (and associated electricity generation costs) from nuclear seawater desalination are generally in the same range as costs associated with fossil-fuelled desalination at their present costs. Given the conclusion that nuclear and fossil-fuelled desalination are broadly competitive with each other, any particular future investment decision will depend on site-specific cost factors and on the values of key parameters (capital cost, fuel price, interest rate, construction time, etc.) at the time of investment. Higher fossil fuel prices would, of course, favour nuclear desalination; higher interest rates would favour less capital-intensive fossil-fuelled options.

2.3.2. Infrastructure development

Those countries suffering from scarcity of water are, generally, not the holders of nuclear technology, do not generally have nuclear power plants, and do not have a nuclear power infrastructure. The utilization of nuclear energy in those countries will require infrastructure building and institutional arrangements for such things as financing, liability, safeguards, safety, and security and will also require addressing the acquisition of fresh fuel and the management of spent fuel. The concept of multi-national fuel cycle centres as are being examined by IAEA could be used to assure a supply of nuclear material to legitimate would-be users under control of sensitive parts of the nuclear fuel cycle.

2.3.3. Public perception

The design of nuclear desalination plants address various aspects related to nuclear plant safety. The possibility of radioactive contamination of product water is also an important issue to be considered for nuclear desalination plants. The dissemination of data from existing facilities that carry out nuclear desalination would help to alleviate the concern and improve the public perception for nuclear desalination plants.

2.3.4. Socio-environmental aspects

The socio-environmental aspects of nuclear desalination need greater attention for its large-scale adoption. Setting up a desalination plant at nuclear reactors for providing much-needed fresh water to the public will no doubt add to social acceptance of nuclear desalination, if the quantity and quality of the fresh water are consistently assured.

The intakes/outflows of nuclear desalination plants must be designed to assure the continued use of areas for fishing and other socio-cultural activities. Protection of the marine environment near the desalination plant site, particularly the flora and fauna, needs to be assured. The use of the reject brine from the desalination plants for pisciculture or other uses such as the production of useful minerals is a possibility worth consideration [9].

Studies have reported on the significant reduction in water cost if a carbon tax were considered in the future if nuclear is accepted as a Clean Development Mechanism under the Kyoto Protocol. The environmental impact assessment of nuclear-powered desalination systems further indicates advantages over fossil-based energy sources. These would result in enhanced economic competitiveness of nuclear desalination plants.

2.4. Solutions [10]

2.4.1. Utilization of waste heat from nuclear reactors

2.4.1.1. Utilization of waste heat from the condensers of LWRs and HWRs for pre-heat RO (the ROph process)

The net electrical efficiencies of the power conversion systems in most water-cooled reactors are of the order of 30 to 33%. This means that nearly two thirds of the net thermal power produced in the reactors is evacuated to the heat sink through the condensers. The temperature of the water from the condensers is too low (30 to 32°C) for meaningful desalination with distillation processes. However, this relatively hot water can be fed to an innovative variant of the RO process, with preheating now known as the ROph process. In hybrid systems, it is also possible to use the cooling seawater return stream from the thermal desalination component as feed to the RO component.

The viscosity of the feedwater is inversely proportional to its temperature. Thus, as temperature increases, water viscosity decreases and RO membranes become more permeable, with a consequent increase in production.

CANDESAL first developed an advanced reverse osmosis (RO) desalination system that emphasizes a non-traditional approach to system design and operation. Key features of this advanced approach to RO system design and operation are the use of preheated feedwater, operation at high pressures, advanced feedwater pre-treatment, advanced energy recovery systems, site-specific optimization, and automatic real-time plant management systems (Fig 2.4 and 2.5).

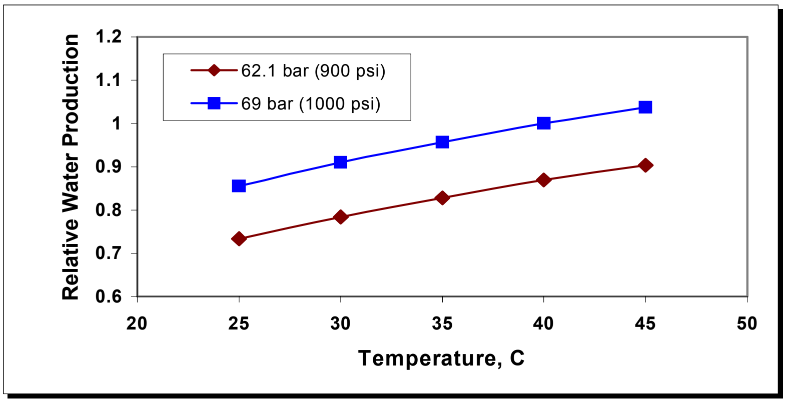

FIG. 2.4. Water production vs. temperature[10].

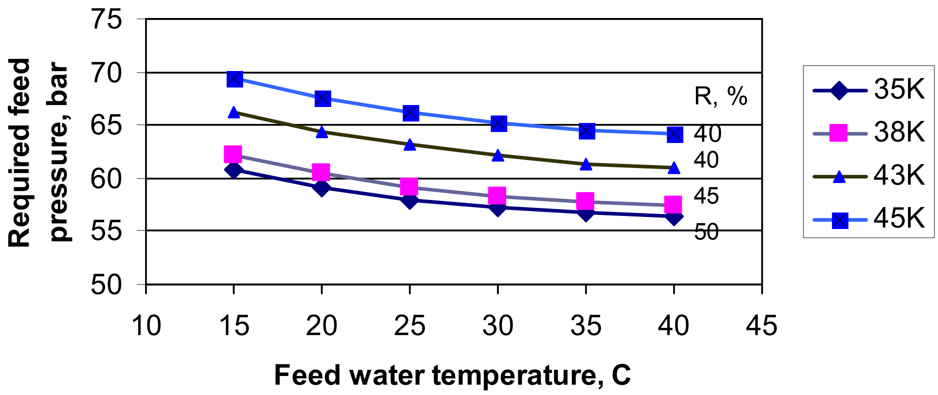

FIG. 2.5. Required feed pressure vs. salinity and temperature [6]. Here, R is the percentage of recovery of fresh water from seawater and the curves represent different salinity levels of seawater, from 35,000 ppm to 45,000 ppm.

As can be seen from Fig 2.4, there is a 2-3 % increase in water production per degree rise in seawater feed temperature. This helps in reducing the applied pressure and hence the pumping power with rising temperature (Fig 2.5). Thus, an energy saving of nearly.10% is achievable in pre-heat RO plants. An important consideration in ROph is that it can easily use the hot water from the main condensers of the water-cooled nuclear power plants.

The amount of feedwater preheating depends both on the ambient seawater temperature and the specifics of the nuclear reactor design. The only limitation is that the maximum temperature allowed by the RO membrane design limits must not be exceeded. Currently available RO membranes typically have a limit of about 45°C, though this is expected to increase as membrane performance continues to be improved by the manufacturers. Cost savings are possible at all temperatures where waste heat can be used to preheat the feedwater, but overall savings depend on a number of factors that are site specific: the salinity of the feedwater, the size of the plant, the amount of preheat available, etc.

2.4.2. Waste heat utilization from Indian PHWRs for thermal desalination

2.4.2.1. Research reactor CIRUS

For conducting a practical demonstration of waste heat utilization, BARC (India) designed a low-temperature vacuum evaporator (LTE) desalination plant and coupled it to the research reactor CIRUS.

The product water from this plant meets the make up water requirements of the reactor. The reactor produces 40 MWth using metallic fuel, a heavy-water moderator, demineralized water coolant, and seawater as the secondary coolant. To ensure protection against radioactive contamination, an intermediate circuit has been incorporated between the reactor and the LTE plant. Table 2.5 summarizes the operating data of this plant. Such experience could be used for a larger sized plant utilizing waste heat.

Table 2.5. Typical operating data of the CIRUS reactor providing waste heat for desalination

Parameter	Unit	Value
Hot water flow rate	liters/minute	1500
Hot water inlet temperature	°C	53.6
Hot water outlet temperature	°C	47.5
Seawater flow rate	liters/minute	1200
Seawater TDS	ppm	35 000
Seawater inlet temperature	°C	27.6
Seawater outlet temperature	°C	35.5
Vacuum in the evaporator	mm Hg	700
Product water flow rate	L/minute	15.5
Product water conductivity	µS/cm	7

2.4.2.2. Waste heat utilization from the 500 MWe PHWR

In the 500 MWe Indian PHWR, the heavy-water moderator is cooled from 80 to 55 °C by process water, which in turn is cooled to 35 °C by seawater that enters at 32°C and comes out at 42°C. About 100 MWth is thus available as waste heat for seawater desalination.

The details have been worked out using 55°C process water temperature, providing heat to the desalination process, to avoid any changes in the moderator system. The coupling scheme is presented in Figure 2.6.

The nuclear desalination system produces about 1000 m^3/day of desalinated water, which is about 25% more than the total makeup demineralized (DM) water requirements of the 500 MWe PHWR.

It is considered more economical to use this water as make up DM water because:

- The energy cost for the LT-MED plant is essentially zero, since it only uses waste heat;
- Direct production of distilled water eliminates the need for demineralizers and regeneration chemicals;
- The raw water, otherwise used as feed for the DM plant, can be made available for other purposes such as for drinking.

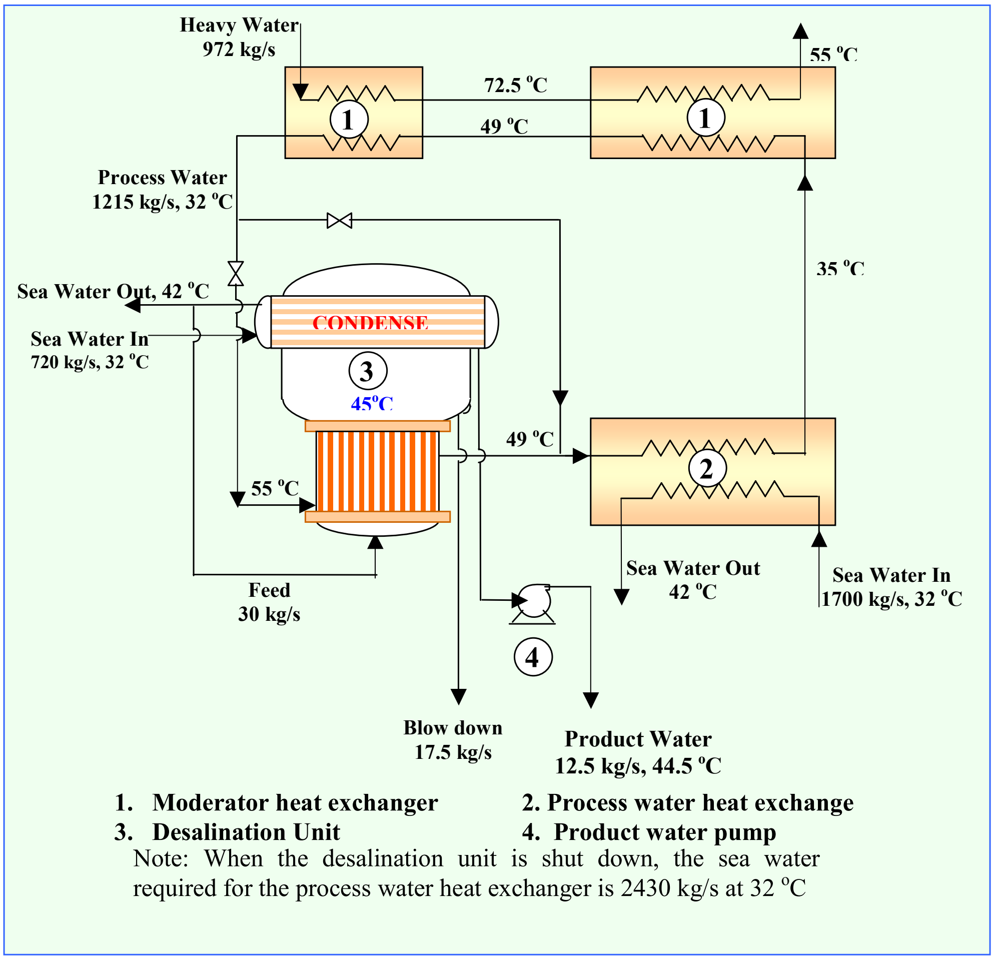

FIG. 2.6. PHWR500 coupling scheme, utilizing waste heat (reprinted from IAEA-TECDOC-1561 [6]).

2.4.3. Utilization of hybrid systems

The advantages of hybrid desalination systems will be illustrated by a specific example: that of the hybrid MSF-RO system coupled to the MAPS PHWR at Kalpakkam (India) as shown in Figure 2.7.

As one of the leading and oldest desalination processes, MSF is often preferred because of its operational simplicity and proven performance. MSF is advantageous for large desalting capacities and high purity water, in particular where inexpensive thermal energy is available.

However, its installed cost and specific power consumption remain relatively high. Since the energy cost is high in India, an MSF system, with a large gain output ratio (GOR) leading to lower water production costs, has been chosen.

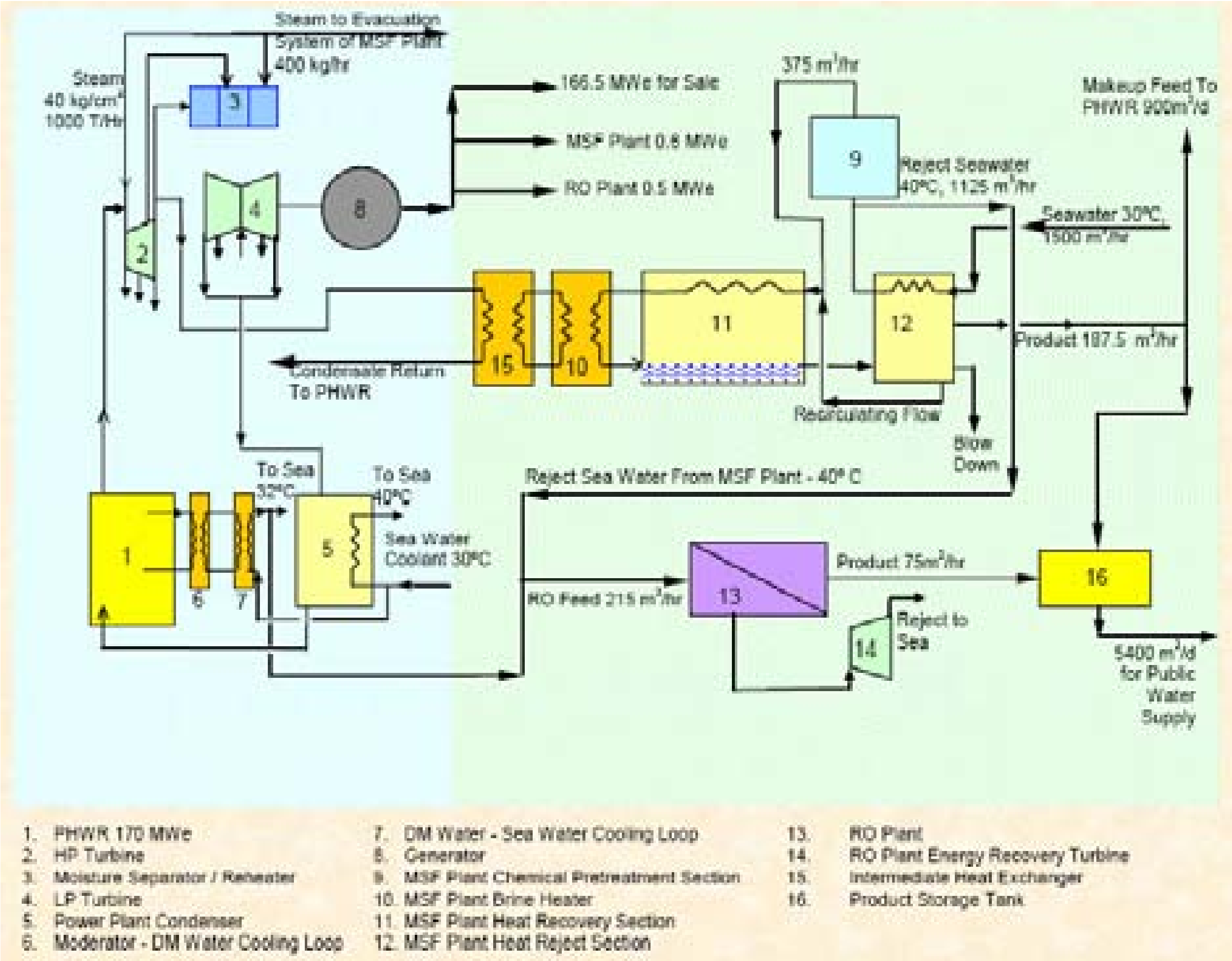

FIG. 2.7. Hybrid MSF-RO coupling to the PHWR at Kalpakkam, India (reprinted from IAEA-TECDOC-1561 [6]).

Seawater desalination by RO has proved to be most economical, as has been shown in the case studies from IAEA Member States. Apart from its need for an elaborate pre-treatment plant, RO has many advantages:

- Enhanced flexibility due to its modular structure;
- Operation at ambient temperature, reducing corrosion risks;
- Possibility of coupling with energy recovery devices, thus further reducing the costs;
- Potential for further innovations as compared to the MSF technology, which has almost reached a saturation point in its development.

Because of the particular advantages of MSF and RO technologies, it is logical to consider that a hybrid MSF-RO system may lead to greater cost reductions in water costs because of:

- The use of common, smaller seawater intake and outfall structures and other facilities;
- Flexible and improved water quality by blending distillate from the MSF plant and the permeate from the RO plant;
- Extension of membrane lifetimes as a result of blending.

Awerbuch has reported that applying a hybrid solution reduces desalinated water costs, compared with non-hybrid schemes, from as little as 2-3% to as much as 15% [11].

2.5. Conclusion

Seawater desalination provides a source of fresh water, especially for the water scarce arid and semi-arid areas of the world. The present desalination capacity of about 36 million cubic meters per day worldwide meets a very small fraction of the world's fresh water needs. There is, however, a significant potential of desalination and water reuse technology for rapid expansion to augment the fresh water resources in the water scarce areas. Use of fossil fuels for large-capacity desalination plants could lead to large emission of undesired greenhouse gases. The price uncertainties of fossil fuels and their sustainability is also an important issue. Use of energy from nuclear reactors for desalination is a demonstrated option; it is environmentally friendly and can be a sustainable energy source. Feasibility studies carried out recently indicate that present costs of water produced from nuclear desalination plants are similar to those of fossil fuel based desalination plants. The development of higher-temperature and more economical reactor designs would likely reduce the desalinated water cost. Nuclear desalination will be an important option for safe, economic and sustainable supply of large amounts of fresh water to meet the ever-increasing worldwide water demand.

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CHAPTER 3
DISTRICT HEATING

3.1. Opportunities

Assessing realistic future demand for energy products other than electricity is not an easy task. Even for heat demand, statistical data available are by far less exhaustive and robust than is the case for electricity. Furthermore, as far as district heating is concerned, the heat distribution structure and human settlement configuration are key driving factors that are difficult to predict.

District heat involves the supply of space heating and hot water through a district heating system, which consists of heat plants (usually producing electricity simultaneously) and a network of distribution and return pipes. A potential market for district heating appears in climatic zones with relatively long and cold winters. In many countries, such as central and northern European countries and countries in transition economies, district heat has been widely used for decades.

District heating accounts for 11% of total energy consumption in Central Europe and Ukraine and over 30% in Russia and Belarus. District heating accounts for almost half of the heat market in Denmark, Estonia, Finland, Poland, Romania and Sweden. District heating networks generally have installed capacities in the range of 600 to 1200 MWth in large cities to approximately 10 to 50 MWth in towns and small communities [1]. Although a large number of district heat suppliers, especially in countries with transition economies, are facing financial and technical problems, nuclear-based district heat is still expected to have great additional potential for meeting a share of heat demand in many countries that are currently using fossil fuels and are considering other sources owing to environmental concerns.

In general, district heating can offer significant benefits because, under certain conditions, it can compete economically in densely populated areas with individual heating arrangements, and because it offers the possibility of reducing air pollution in urban areas. Whereas emissions resulting from the burning of fuels can be controlled and reduced up to a point for relatively large centralized plants, this is not practical in small individual heating installations fuelled by gas, oil, coal or wood.

Although it is hard to obtain exact statistics for the current use of district heat in the world, the size of its market can be estimated in relation to the final energy demand in the residential, agricultural and commercial sector. A 2002 IAEA report [2] took this approach and calculated the total use of district heat in 1996 as 119.5 Mtoe based on the International Energy Agency (IEA) world energy database, which requires a heat production capacity of 340 000 MWth assuming an average load factor of 50%.

District heating has the following technical requirements:

- It requires a heat distribution network to transport steam or hot water in a typical temperature range of 80-150°C.

- Owing to higher losses over longer transmission distances, the heat source must be relatively close to the customer, typically within 10-15 km.

- The district heat generation capacities are determined by the collective demands of the customers. In large cities a capacity of 600-1200 MWth is normal. The demand is much lower in small communities.

- The annual load factor is normally not higher than 50%, since heat is supplied only in the colder part of the year.

- To secure a reliable supply of heat, a backup capacity is required.

Typically, coal and gas dominate the fuels used for district heating. Various other heat sources are also used for district heating, including biomass materials, waste incineration, and waste heat from industrial processes. Usually district heating is produced in a cogeneration mode in which waste heat from electric power production is used as the source of district heat.

There is plenty of experience in using nuclear heat for district heating, so the technical aspects can be considered well proven. There are no technical impediments to the application of nuclear reactors as the heat source for district or process heating. Several countries already have experience in nuclear district heating: Bulgaria, Hungary, Romania, Russia, Slovakia, Sweden, Switzerland and Ukraine.

For production of district or process heat, there are basically two options: Co-generation of electricity and heat, and heat-only reactors. All existing reactor types can be used for cogeneration of heat and electricity. Co-generation has been widely applied; there is not much experience with heat-only reactors. In principle, any portion of the heat can be extracted from co-generation reactors as district heat, subject to design limitations. Co-generation plants, when forming part of large industrial complexes, can be readily integrated into an electrical grid system to which they supply any surplus electricity generated. In turn, they would serve as a backup for assurance of the electricity supply. This means a high degree of flexibility. Heat-only reactors, on the other hand, have only the objective of heat production, not electricity generation. This limits their operational flexibility, especially during warm weather, leaving the large capital investment stranded during times when heat is not needed.

As shown by experience, availability factors of 70% to 80% or even 90% can be achieved. These values are similar to the availabilities achieved by fossil fuelled power plants. The frequency and duration of unplanned outages can be kept very low with good preventive and predictive maintenance. The availability of nuclear or fossil fuelled plants, however, can never reach the nearly 100% levels required by most large heat users. Therefore, multiple-unit co-generation power plants, modular designs, or backup heat sources are necessary to achieve the required availabilities.

Nuclear reactors are proven, safe, reliable and environmentally clean energy sources, but for commercial deployment they also have to be economically competitive with alternative energy sources. Compared to fossil fuelled sources, nuclear reactors are characterized by higher investment costs compensated by lower fuel costs. With increasing fossil fuel prices the economically competitive position of nuclear power, both for electricity generation and for heat supply, improves.

Due to economy of scale [3], nuclear economics are, in general, improved for larger units. This has led to the development and predominant deployment of large reactors in industrialized countries with large interconnected electrical grid systems. Nevertheless, there continues to be an interest in small and medium-sized power reactors (SMRs), especially for applications other than base load electricity generation.

The siting of nuclear plants is another issue. For co-generation or heat-only reactors, close location to the load centres has a strong incentive. However, the trend is to choose remote, but accessible, locations for siting nuclear plants in order to mitigate the consequences of an accident. Locating a new plant far from densely populated areas makes it easier to comply with regulatory requirements. Furthermore, plants need to be located near a ready supply of cooling water, which may not necessarily correspond to the location of the population centre.

3.2. Market context

3.2.1. Early history of nuclear district heating markets [4]

Dedicated nuclear heating systems have been designed, built and operated in China and in the Russian Federation. The plant in China is for demonstration purposes, whereas the Russian plants supply heat to various settlements in the northern parts of the country.

A 5 MW(th) test nuclear heating reactor (NHR-5) was commissioned in China and has been in operation since 1989, supplying heat to the Institute of Nuclear Energy Technology of Tsinghua University, near Beijing. The Russian Federation has operated an experimental 10 MW(th) heating reactor at Obninsk since 1954 and has developed the technology of the nuclear district heating reactor, AST-500.

Nuclear co-generation plants for electricity and district heating have been built and operated in Bulgaria, Hungary, Romania, Russian Federation, Slovakia and Switzerland. Almost 500 reactor-years of successful operational experience have been accumulated.

The Kozloduy NPP in Bulgaria has supplied heat to the town of Kozloduy since 1990. The Kozloduy NPP originally consisted of four WWER-440 reactors of 408 MW(e) and two WWER-1000 reactors of 953 MW(e). However, the four smaller reactors had to be shut down as a condition for Bulgaria's accession to the European Union. No relevant problems with district heating have been experienced.

The Paks Nuclear Power Plant (Hungary), consisting of four units of the Soviet design WWER-440 type V-230, is supplying heat to the town of Paks. The water pressure in the heat exchanger is kept higher than the steam pressure to prevent contamination of the hot water system.

The Cernavoda Nuclear Power Plant in Romania has supplied heat to the town of Cernavoda since the plant began commercial operation in 1996.

The Bohunice Nuclear Power Plant in Slovakia produces electrical energy and low-temperature heat for heating and industrial purposes. The heat supply from the nuclear power plant is used for the town of Trnava.

The district heat extraction from the Beznau NPP (Switzerland (2 × 360 MW(e) PWR) has been operated reliably and successfully since its commissioning in 1983/84. The peak heat load is about 80 MW(th), which is equivalent to about 10 MW(e) of electric power. The district heating system supplies about 2100 private, industrial and agricultural consumers through 35 km of main piping and 85 km of local distribution pipes.

The most extensive experience with district heat supply from nuclear co-generation plants has been gained in the Russian Federation. The NPPs of Bilibino, Belojarsky, Balakovo, Kalinin, Kola, Kursk and Leningrad are supplying heat from steam turbine bleeders through heat exchangers to district heating grids of towns with typically about 50 000 inhabitants, situated between 3 and 15 km from the NPP sites. The heat output capacities range from about 50 to 230 MW(th).

Table 3.1 shows the worldwide experience in nuclear district heating.

Table 3.1 Operating nuclear heating plants

Country	Plant type or name	Location	Application	Phase	Start of reactor operation	Net Power (MW(e))
Bulgaria	Kozloduy 5,6	Kozloduy	Electricity/ District heating	Commercial	1989	2 x 953
China	NHR-5	Beijing	District heating	Experimental	1989 1989	-
Czech Rep.	Temelin 1,2	Temelin	Electricity/ District heating/ Process heat	Commercial	2002	2 x 930
Hungary	PAKS 2,3,4	Paks	Electricity/ District heating	Commercial	1984	1 x 441 1 x 433 1 x 444
India	Rajasthan 1,2,3,4	Rajasthan	Process heat	Commercial		1 x 90 1 x 187 2 x 202
Romania	HWR CANDU-6	Cernavoda – Unit 1	Electricity/ District heating	Commercial	1998	1 x 660
Russia	WWER-1000	Novovoronezh	Electricity/ District heating/ Process heat	Commercial	1971-73	3 x 385 1 x 950
Russia	WWER-1000	Balakovo	Electricity/ District heating/ Process heat	Commercial	1986-93	4 x 950
Russia	WWER-1000	Kalinin	Electricity/ District heating/ Process heat	Commercial	1985-87	2 x 950
Russia	WWER-440	Kola	Electricity/ District heating/ Process heat	Commercial	1973-84	4 x 411
Russia	LWGR	Bilibino	Electricity/ District heating	Commercial	1974	4 x 11
Russia	LWGR	St. Petersburg	Electricity/ District heating/ Process heat	Commercial	1974-81	4 x 925
Russia	LWGR	Kursk	Electricity/ District heating/ Process heat	Commercial	1977-86	4 x 925
Slovakia	Bohunice-3,4	Bohunice/Trnava	Electricity/ District heating/ Process heat	Commercial	1987	2 x 408
Switzerland	Beznau 1,2	Beznau	Electricity/ District heating	Commercial	1985, 1989	1 x 365 1 x 357

3.2.2. Summary of some specific district heating systems of interest

The details of the world's first district heating plant at Stockholm, Sweden, and the latest district heating plant at Cernavoda, Romania, are given in Annex 2. Their salient features are presented below, along with information on the Russian floating reactor system.

3.2.2.1. Swedish district heating [5,6,7]

The Swedish district heating system is well developed. About half of the heating of homes and houses is done by means of district heating. Two hundred and seventy of the country's 290 communities have district heating networks. All cities and towns with more than 10,000 inhabitants have district heating networks. Very many of the smaller cities and towns have district heating networks as well.

The total Swedish district heating system uses about 60 TWh of energy to produce 48 TWh of heat and 6 TWh of electrical power, which leads to an overall system efficiency of about 90%. The fuel that is used is 45% biomass, 15% fossil, 15% electricity, 10% waste, 10% residual heat, and 5% miscellaneous.

Typically a Swedish district heating network is a hot water system with a hot temperature of 70 to 110°C, depending on the time of the year, and a return temperature 40 to 50°C lower. The distribution is done by means of pumps at the heat and power plants, but also by means of distributed pumps for the larger networks.

The following figures on production and economics are based on statistics from 2003-2005.

About 570 towns and villages in the country have district heating networks and the growth potential is still considered to be high. The total yearly heat delivery is about 50 TWh. The growth rate is estimated to be about 10 TWh by 2010. In the long run, district heating is judged to represent about 75% of the total Swedish heating need.

To reach the goal of 60 TWh of district heat in 2010 the investment is estimated to be about 500 million euros per year. This will also provide some electricity generation capacity. The domestic environmental gain is estimated to be a reduction of about 3 Mton of CO_2 . Because the expansion in Swedish district heating saves imported electricity from coal fired plants in other countries, the reduction in CO_2 release abroad is estimated to be an additional 2 Mton.

The investments in the coming years are divided in the following way:

- Heat and power generation: 300 million euros.
- Distribution network: 150 million euros.
- Distribution heat exchange centrals: 50 million euros.

The total sales income to the district heating companies is about 2000 million euros. The average income per kWh per year is about 4 cents. The range of income per kWh based on the different heating companies was from 3 cents up to 7 cents.

The economics for different district heating utilities varies widely and results in large price differences for end consumers, compared with other heating sources. Prices for heat for end consumers are often split into a fixed contract, based on demanded power, and a price per kWh.

Typical prices for heat delivered by a city owned utility are as follows:

Contract:

- For an installation of < 500 kW capacity, the customer pays 100 euros per year fixed price;
- For an installation from 500 kW and up to 3000 kW capacity, the customer pays 10 000 euros per year fixed price; and
- For an installation of >3000 kW capacity, the customer pays 100 000 euros per year fixed price.

Price per kWh, including taxes and environmental fees:

- Summer: typically 4 to 5 cents per kWh.
- Winter: typically 5 to 6 cents per kWh.

District heating tends to have more modest yearly price increases than other sources for heating.

An economical survey for a typical small apartment building showed the following situation on total heating cost per year for the whole apartment building for different fuels:

Electricity	24 k euro
Oil	28 k euro
Bio Pellets	12 k euro
Heat Pump	14 k euro
District heating	15 k euro

A major drawback is considered to be the natural monopoly that the district heating system layout creates. In the Nordic countries the rather free market on electricity is accepted and the contrast to the district heating, in this respect, is often discussed.

After the Swedish deregulation of the electrical market in 1996 there has been a move from city-owned district heating towards ownership by large electrical utilities.

A typical return on investment for a district heating utility is 6.5 %, with city-owned systems having on average higher returns. The companies' balance sheets show typical turnover figures between 30 million euros to 45 million euros.

3.2.2.2. District heating in Russia [8, 9]

In Russia, consideration has been given to the use of the VBER-300 reactor with 850 MW thermal power as the basis for land-based and floating two-unit and single-unit nuclear co-generation plants to provide heat and power supplies for some cities in the European part of Russia, Urals, and the Far East, such as Arkhangelsk, Okhotsk, Petrozavodsk, and Ussuriisk.

The main parameters of a floating nuclear power plant based on the VBER-300 are the following:

- Maximum electric power output to the power-supply system: 2×280 MW;
- Construction period: 6 years;
- Construction period for hydraulic engineering and coastal installations assigned to the project of 3-4 years;
- Total plant construction period: 7 years.

The land-based option of the nuclear co-generation plant based on the VBER-300 plant has also been developed:

- Maximum electric power output to power supply system: 2×280 MW;
- Maximum thermal power output to heat supply system: 2×530 MW;
- Electric power in co-generation mode to the power supply system: 2×185 MW.

3.2.2.3. Summary of district heating in Romania [10,11,12]

A total of five nuclear power reactors were initially intended to be built in Romania at the Cernavoda site on the Danube River. The site currently comprises Unit 1 (which has been in full commercial operation since 1996) and Unit 2 which has been connected to the grid in 2007. Units 3, 4, and 5 are in different stages of completion. All reactors are PHWRs of the CANDU-6 type.

The site is about 2 km southeast of the town of Cernavoda (20 514 inhabitants) in the lower Danube region near the Black Sea. Two large towns are located within a 30 km radius of the site, namely Medgidia (43 867 inhabitants) and Fetesti (33 197 inhabitants), and many small rural communities and villages. Around the NPP site, within a radius of 30 km and 100 km, approx. 180,000 and 1,375,000 persons respectively reside.

From early 1980s there were intentions to use the steam extracted from the turbine for district heating, and a reference study was produced in 1985 [10] with the purpose to provide approximately 1,300 MW of district heating from all five Units of the Cernavoda NPP for distances up to 100 km..

The existing nuclear district heating system provides 60% of the necessary heating for the town of Cernavoda, as well as necessary heat for the NPP site and site sub-contractor facilities. Studies were performed [11, 12] and a modernization project has to be implemented to improve the existing district heating system.

3.2.3. Economics

A comparison of the costs of nuclear heat production with those of competing technologies was reported by IAEA [2] and the estimates are shown in Table 3.2. The costs are levelized heat generation cost obtained with a method analogous to one conducted to compute levelized electricity generation costs. The study assumed the oil cost as US$ 25 per barrel of oil equivalent and the cost of coal as US$ 50/t. The other key parameters are given in the table. The data show that the assumed values for the discount rate play an important role. At a 10% discount rate even a large nuclear heating plant (NHP) is barely competitive with a large coal-fired boiler. These estimates were made in 1992. The present increasing fossil fuel price and lowering interest rates would make large nuclear heating systems more competitive. Note, however, that the effects of specific sites may well outweigh the general trends shown in Table 3.2, depending on the heat transport and distribution networks at different locations.

Table 3.2. Estimate of the competitiveness of the NHPs

Plant type	Plant size (MWth)	Assumed base construction cost (US) $/kWth	Levelized heat costs (US) $/kWth		Cost ratio: nuclear vs. gas-oil boilers		Cost ratio: nuclear vs. coal boilers	
			Discount rate: 5%	Discount rate: 10%	Discount rate: 5%	Discount rate: 10%	Discount rate: 5%	Discount rate:10%
Nuclear plants								
	50	1650	25	36	1.3	1.6	1.8	2.1
	100	1100	19	26	1.0	1.1	1.4	1.5
	200	825	16	22	0.8	1.0	1.1	1.3
	500	605	13	17	0.7	0.7	0.9	1.0
Fossil fuel plants								
Gas-oil boiler	100	440	20	23	-	-	-	-
Coal boiler	500	440	14	17	-	-	-	-

Few economic cost data are reported from the existing nuclear district heating plants [13]. Canada's experience showed that the nuclear heat cost was significantly lower than heat from natural gas or other fossil fuels. The Czech Republic's district heat systems report high construction costs for hot water pipelines from NPPs to consumers as a reason for higher heat costs. In Cernavoda, Romania, nuclear heat provided by the NPP covers 60% of the total heat consumption. The heat cost delivered to the distribution company of the municipality is about 5.5 Euro/MWh (presuming an exchange rate of 3.4 Lei per Euro), and the tariff to the public is 15.1 Euro/MWh, which is about half of the average cost of heat in Romania. In the Russian Federation, the nuclear heat plants contribute about a third of the total production of heat in the country. The cost of nuclear heat is reported to be 2-2.5 times cheaper than that from local heating boilers. In Russia and Ukraine, however, the nuclear heating cost is subsidized, leading to a low cost to consumers. In Trnava, Slovakia, nuclear heat contributed 60 % of the total heat supply. It is also reported to be cheaper than fossil-fuel heat. In Switzerland's Benzau unit, the heat cost is reported to be around 70 - 95 CHF/ MWh, which is higher than oil firing, which is around 45 - 60 CHF/ MWh. The improved environmental benefits have made this higher cost acceptable, however.

3.3. Challenges

Transporting heat is difficult and expensive. The need for a pipeline, thermal insulation, pumping, and the corresponding investments, heat losses, maintenance, and pumping energy requirements make it impractical to transport heat beyond distances of a few kilometres, or at most, some tens of kilometres. There is also a strong size effect to the system cost. Furthermore, the specific cost of transporting heat increases sharply as the amount of heat to be transported decreases. Compared to heat, the transmission and distribution of electricity is cheap, even over distances measured in hundreds of kilometres. Worldwide transport of gas through pipelines up to thousands of kilometres long is, of course, well-established.

The foremost challenge to district heating systems, whether fossil or nuclear based, is their competitiveness with small domestic heating units using oil or gas fired mini boilers or electricity, which are presently meeting consumer demands satisfactorily. These units are not subject to transport of heat and attendant problems of costs for heat transport equipment, piping insulation, and heat losses during distribution.

Nuclear plants are capital intensive. The influence of the fixed cost component is predominant in the final cost of energy and its products. Therefore, base load operation with load factors as high as achievable is needed for competition with alternate energy sources. This is only possible when the demand of the heat market to be supplied has base load characteristics, or when the combined electricity and heat market enables overall base load operation of a co-generation plant. This is particularly relevant for district heating, where the heat load is substantial and varies with season.

Because heating requirements are not needed throughout the year, the overall district heat plant's load factors are typically around 50-60% in cold climates. The co-generation plants are designed to distribute the electricity and heat loads adequately year-round, but the overall economics are affected. There is, however, an possibility to improve the situation for a plant using nuclear energy by increasing the thermal efficiency of the heat transport systems. If this could be done together with a lowered investment cost it would improve the likelihood that a nuclear-based heating system could compete economically with a fossil fuel fired system.

A benefit of district heating systems is the reduction of air pollution emissions near urban localities and the consumer centres, compared to small localized units. In this context, the role of nuclear district heating will have a higher significance as it does not contribute to any emission.

The elimination of CO_2 and flue gas emissions is, of course, a key essential driver for the use of nuclear, rather than fossil, energy. Were nuclear energy also recognized as a Clean Development Mechanism (CDM) under the Kyoto Protocol, this could lead to further improved economics of nuclear district heating.

3.4. Solutions

The challenges mentioned above are a mix of socio-political and technical ones. The technical solutions, discussed below, to meet these challenges are primarily directed towards reactor plant type and layout, their size and location, and safety aspects.

Plant type and layout

Nuclear heat-producing plants for district heating for space heating and hot tap water can, in principle, be divided into two different types:

- Dedicated heat-producing reactors, so called single-purpose systems;
- Heat and power reactors, so called dual-purpose systems.

Initial efforts in district heating considered dedicated reactors. However seasonal variation of heat requirements for district heating led to a wide use of co-generation systems.

Important factors that are limiting the benefits that could be realized by retrofitting district heating to existing power plants are the outage costs and risks for the necessary shutdown period to carry out the retrofitting work, and the fact that such plants seldom are optimally sited for the district heating network.

New nuclear heat-producing plants must, of course, be designed to have availability factors comparable or preferably higher than today's plants. The requirements on availability and reliability are particularly keen for new district heating networks, since there would be no existing heat-producing capacity that could serve as backup. For existing systems, heat production capacity through, for instance, oil boilers can serve as the backup capacity during nuclear outages.

Heat storage allows a matching of the heat supply to the heat demand. This has several advantages, including better utilization of the investments. This is true regarding both the production unit as well as the district heating network. Today there are many examples of short-term storage, for instance, on the daily scale. In the future, more long-term storage facilities may be realized. Today's storage relies on hot water accumulator tanks. More innovative concepts, such as storage in underground water layers, may also be possible.

Plant size and location

Nuclear district heating requires that the reactors be installed in the district heating network close to the consumers. In this way the thermal losses and pipeline costs can be kept low. The proximity to population centres implies the need for a high degree of safety including the lowering of core damage frequencies and enhancing mitigation systems in the case of an accident.

The design features to prevent the transfer of radioactivity into the district heating grid network have proven to be effective. These features include one or more barriers to radioactive cross contanmination, e.g., in the form of a leak-tight intermediate heat transfer loop at a pressure higher than that of the steam extracted from the turbine side of the nuclear plant. These loops are continuously monitored, and isolation devices are provided to separate potentially contaminated areas.

Another key factor is that the heat reactors need to be small compared to modern power producing reactors, since the heat demand even in big district heating networks seldom is more than 200 MW. A small size could also facilitate licensing of a location close to a population centre.

In order to be able to compete with fossil fuel fired heat boilers, the installation cost per installed MW heat for a nuclear-based system must be much lower than today's power producing plants. Reducing plant complexity is one option, which would also serve, potentially, to simplify operation, maintenance, and training.

Small dedicated reactors would have the following advantages:

- Less severe operating conditions, such as lower pressures and temperatures;
- A smaller size, which reduces the demands associated with manufacturing the main components;
- A high potential for modularization and standardization;
- Improved ease of operation, without excessive demand on qualified personnel;
- Design transparency; the safety features can be more simple and easier to understand.

The less severe operating conditions and simpler safety systems facilitate a design with a high degree of safety that relies to a large extent on passive safety systems. Such systems are often simpler with a low degree of complexity.

Lower pressures and temperatures also lower the need for sophisticated materials and, therefore, may reduce material and manufacturing costs. A clear strategy for nuclear district heating reactors must be to use industrial grade components to as large an extent as possible, instead of the customized nuclear grade components used in power producing plants, assuming that this strategy would be endorsed by the nuclear safety authorities.

A small plant has several advantages for the manufacturing industry compared to a large power plant. Mechanical components are smaller and lighter than those of a conventional nuclear power plant. This makes the manufacturing of the main components of the plant possible even in countries that do not have the workshops and experience that is normally needed for making heavy nuclear-grade components for large nuclear power plants.

In order to keep down the cost, a high degree of standardization is desirable. This may further reduce maintenance costs, as well. A relatively large proportion of both process components and control equipment could be provided as factory-assembled packages. This would keep the on-site installation costs lower.

Despite the advantages of small, single-purpose plants, it must also be said that the cost of a plant tends to increase rapidly with decreasing capacity, and the economic competitiveness of such a reactor becomes questionable. Standardization of design and construction may help overcome this disadvantage, even if individual plants are not ideally sized for the specific district heating application in mind.

Conclusions

The low prices of fossil fuels have stunted the development of small, single-purpose nuclear district heating plants. This situation is changing. Furthermore, as environmental concerns mount over the use of fossil fuels, the prospects for nuclear-based district heating are improving. Nevertheless, though many concepts of such small-scale heat-producing reactors have been presented during the years, very few have been built.

The main features of such a plant would be:

- A small capacity (for example <200MW);
- Low temperatures and pressures;
- A simple, standardized design;
- Passive safety systems.

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CHAPTER 4
INDUSTRIAL PROCESS STEAM

4.1. Opportunities

Within the industrial sector, process heat is used for a large variety of applications with different heat requirements and with temperature ranges covering a wide spectrum. Whereas in energy-intensive industries the energy input represents a considerable fraction of the final product cost, in most other processes it contributes only a few percent. Nevertheless, the supply of energy has an essential character: all industrial users need the assurance of energy supply with a degree of reliability and availability approaching 100%. In contrast to district heating, the load factors desired by industrial users do not depend on climatic conditions. The demands of large industrial users usually have base load characteristics.

The characteristics of the market for process heat are quite different from district heating, though there are some common features, particularly regarding the need for minimal heat transport distances. Industrial process heat users do not have to be located within highly populated areas. Many of the process heat users, in particular the large ones, can be, and usually are, located outside urban areas, often at considerable distances. This makes joint siting of nuclear reactors and industrial users of process heat not only viable, but also desirable in order to drastically reduce the heat transport costs – provided that the co-siting does not adversely affect the safety case for the nuclear installation.

Process heat involves the supply of heat required for industrial processes from one or more centralized heat generation sites through a steam transportation network. Within the industrial sector, at temperatures higher than those needed for district heating and seawater desalination, process heat is used for a variety of applications as shown in Figure 4.1 [1].

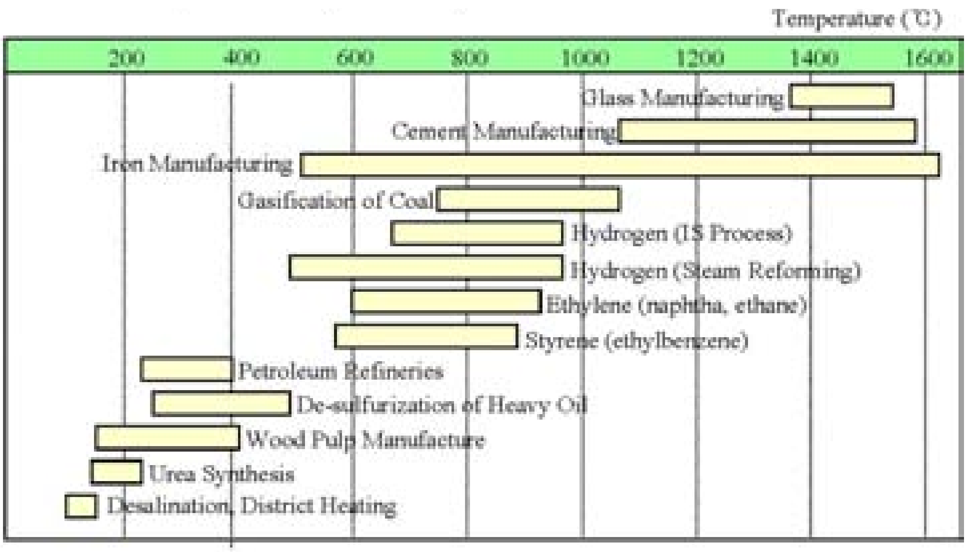

FIG. 4.1. Required temperatures for industrial processes (Figure taken from [1]).

As discussed in earlier chapters, water-cooled nuclear reactors have been used in low-temperature applications including desalination, district heating and process heat. There is a potential for their use at medium temperature ranges such as are used in the fertilizer, pulp and paper, and oil and petroleum industries, etc. However, applications shown in Fig 4.1 that require heat above about 550 ºC (the temperature achievable by super-critical water cooled reactors) would require other reactor types and shall not be discussed in this report.

In a similar way as for district heat, the 2003 IAEA report [2] took the approach that the size of the process heat market can be estimated by examining the total use of centralized process heat in 1996, which was 150.1 Mtoe according to the IEA world energy database and required a heat production capacity of 240 000 MWth assuming an average load factor of 90%.

Process heating has the following technical requirements:

- Owing to higher thermal losses over long transmission networks, the heat source must be relatively close to the customer;
- The annual load factor must be much higher than that in district heating, probably 70-90%, since process heat demand does not depend on climatic conditions;
- To secure a reliable supply of heat, a backup capacity is required.

Several co-generation nuclear power plants have supplied process heat to industrial users [3]. The largest projects implemented have been in Canada (Bruce for heavy water production and other industrial/agricultural users) and in Kazakhstan (Aktau for desalination). Other power reactors, which currently produce only electricity, could be converted to co-generation. Nevertheless, installing a new nuclear co-generation plant close to existing and interested industrial users has better prospects. Even better would be a joint project whereby both the nuclear co-generation plant and the industrial installation requiring process heat are planned, designed, built, and operated together as an integrated complex.

For reactors in the small to medium size range, and in particular for small and very small reactors, the share of process heat generation may be larger, and heat could even be the predominant product. This would affect the plant optimization criteria, and could present much more attractive conditions to the potential process heat user. Consequently, the prospects of SMRs as co-generation plants supplying electricity and process heat are considerably better than those of large reactors.

Heat-only reactors have not yet been applied on an industrial/commercial scale for the supply of process heat, though several designs have been developed.

4.2. Market context

4.2.1. Past experience

As in the case of district heat, all existing reactor types are potentially applicable to process heat needs, depending on the required temperature of the processes. There have been some experiences in providing process heat for industrial purposes with nuclear energy in Canada, Germany, Norway, Switzerland, and India. In Canada, CANDU reactors supplied steam for industries such as food processing and industrial alcohol production until their closure in 1998. In Germany, the Stade PWR supplied steam for a salt refinery located 1.5 km from the plant from December 1983 until its shutdown in November 2003. In Norway, the Halden Reactor has supplied steam to a nearby factory for many years. In Switzerland, since 1979 the Gösgen PWR has been delivering process steam to a cardboard factory located 2 km from the plant. In India, the RAPS-II PHWR at Kota supplies heat to the nearby heavy-water plant. Tables 4.1 and 4.2 present the salient features of operating nuclear process heat plants and projects [4]. A brief summary of these applications is presented in the following paragraphs.

Table 4.1. Operating nuclear process heat production plants

Country	Plant name	Location	Application	Start of operation reactors / heat	Phase	Power (MW (e))	Heat delivery (MW(t))	Temperature (°C) at interface (feed/return)	Remarks
Canada	Bruce-A[a]	Bruce	Process heat	1977-87 1981	Commercial	4 x 848	5350		D_2O production and six industrial heat customers
Germany	Stade	Stade	Electricity/ process heat	1983	Commercial	640	30	190/100	Salt refinery
Switzerland	Goesgen	Goesgen	Electricity/ process heat	1979 1979	Commercial	970	45	220/100	Cardboard factory
India	RAPS	Kota	Electricity/ process heat	1975/1980	Commercial	160	85	250	D_2O

[a]Unit 2 was taken out of service in 1995, units 1, 3 and 4 were taken out of service in 1998.

Table 4.2. Nuclear process heat production projects

Country	Plant name	Location	Application	Start of operation reactors / heat	Phase	Heat delivery (MW(t))	Temperature (°C) at interface (feed/return)	Remarks
China	HTR-10	Beijing	Electricity/ process heat	Criticality 1999	Construction completed	10	700-950/250	Experiments for HTR technology development.
Japan	HTTR	Oarai	Process heat	Criticality 1998	Construction completed	30	950/395	Experiments for HTR technology development, potentially including hydrogen production.
Russia	VGM		Process heat		Design			

In Canada, steam from the Bruce Nuclear Power Development (BNPD) was supplied to heavy water production plants and to an adjacent industrial park at the Bruce Energy Centre (BEC). BNPD is the world's largest nuclear steam and electricity generating complex. It includes eight CANDU nuclear reactors with a total output of over 7200 MW(e), the world's largest heavy water plant (HWP), and the Bruce Bulk Steam System (BBSS). The BBSS, capable of producing 5350 MW(th) of medium-pressure process heating steam, was built to supply the HWP from the four 848 MW(e) units of the Bruce A complex. Each of the four 2400 MW(th) reactors can supply high-pressure steam to a bank of 6 heat exchangers (24 in total), which produce medium-pressure steam for the HWP and site services. The normal capacity is approximately 1680 kg/s of medium-pressure steam from the reactors with 315 kg/s emergency backup available from oil fired boilers. In 1995, Unit 2 of the Bruce A NPP was laid up; the HWP and units 1, 3 and 4 of Bruce A were laid up in spring 1998. However, unit 4 was restarted in 2003 and unit 3 in 2004. In 2006 agreement was also reached on a four-year programme to also restart units 1 and 2.

FIG. 4.2. Bruce nuclear power development (8 x 850 MW(e) CANDU units, heavy water production, greenhouse complex using nuclear steam). (Credit: Bruce Power.)

The six private industries currently established at the park are:

(1) a plastic film manufacturer;
(2) a 30 000 m^2 (7.5 acres) greenhouse;
(3) a 12 million liter/year ethanol plant;
(4) a 200 000 ton/year alfalfa dehydration, cubing, and pelletising plant;
(5) an apple juice concentration plant; and
(6) an agricultural research facility.

In Germany, the Stade NPP PWR (1892 MW(th), 640 MW(e)) has supplied steam for a salt refinery, which is located at a distance of 1.5 km, since December 1983. The salt refinery requires 45 t/h process steam at 190°C and 1.05 MPa. This represents a thermal power of about 30 MW and is 1.6%

of the thermal output of the NPP. Since 1983, the steam supply by Stade has had high availability, and the operating experience with process steam extraction is good.

The Gösgen-Däniken nuclear power station (KKG) with a pressurized water reactor situated on the River Aare between Olten and Aarau in Switzerland and built under the overall management of Kraftwerk Union AG (KWU) is the first of its kind in the world to supply process stream. Its steam user is the nearby cardboard mill, Kartonfabrik Niedergösgen. The heavy-oil-fired boilers installed at that plant, which with their emissions were once the source of considerable atmospheric pollution, now have only standby status.

Further design details of the Gösgen process heat plant are given in Annex 4.

In India, the RAPS II reactor at Kota has been supplying 110 t/h of steam at 250°C and 4 MPa since 1980. The steam is reduced to 0.6 MPa and used in the nearby heavy-water production plant.

4.2.2. Near-term potential

The Russian Federal Agency for Atomic Energy (ROSATOM) has started construction of a floating barge-mounted heat and power co-generation nuclear plant based the ship propulsion PWR-type reactor KLT-40C in Severodvinsk. It is planned to put the plant into operation in 2010. The floating NPP can produce up to 70 MW for electric power and about 174 MW of heat for district/process heating. The lifetime of the plant is 40 years; it is designed for a continuous operation period before dockyard refurbishment of 12 years.

Demonstration of this nuclear technology is intended to allow its larger-scale application inside the country and abroad for electricity and heat production.

Another PWR, the SMART integral type reactor, is under development in the Republic of Korea for desalination. It could however also produce industrial process heat.

Application in oil extraction

Atomic Energy Canada Limited (AECL) has studied the feasibility of using CANDU energy in applications beyond traditional electricity generation, such as open pit mining and oil sand extraction.

Alberta’s oil sand deposits are the second largest oil reserves in the world, and have emerged as the fastest growing, soon to be dominant, source of crude oil in Canada. The oil sand industry currently produces more than a third of the nation’s petroleum needs, and has the potential to account for more than sixty percent of Western Canadian crude production by 2010.

Currently, the majority of oil sand production is through open-pit mining, which is suitable for bitumen extraction when the oil sand deposits are close to the surface. The ore, a mixture of bitumen and sand, is removed from the surface by truck and shovel operation. The ore is then mixed with hot water to form a slurry that eventually undergoes a separation process to remove bitumen from the sand.

The thermal energy required for the open-pit mining process is in the form of hot water at a relatively low temperature (around 70°C), and the rest is dry process steam at around 1.0 to 2.0 MPa. The oil extraction facilities require electrical power as well.

To increase production capacity, the industry is looking for new technology to extract bitumen from deep deposits. Among them, Steam-Assisted Gravity Drainage (SAGD), which uses steam to remove bitumen from underground reservoirs, appears to be the most promising approach. Recently, the in-situ recovery process has been put into commercial operation by major oil companies.

Overall, for both extraction methodologies, a significant amount of energy is required to extract bitumen and upgrade it to synthetic crude oil as the feedstock for oil refineries. Currently, the industry uses natural gas as the prime energy source for bitumen extraction and upgrading. As oil sand production continues to expand, the energy required for production becomes a great challenge with regard to economic sustainability, environmental impact and security of supply. With this background, the opportunity for nuclear reactors to provide an economical, reliable and virtually zero-emission source of energy for the oil sands becomes a realistic option.

Further details are given in Annex 3.

4.2.3. Economics

The 2003 IAEA report [2] discussed the industrial process heat market size and features. The industries that are main consumers of heat are:

- food,
- paper,
- chemicals and fertilizers,
- petroleum and coal processing, and
- primary metal industries.

The breakdown of the total industrial heat varies from country to country, but the chemical and petroleum industries are the major consumers worldwide. These would be key target clients for possible applications of nuclear energy.

With respect to economic competitiveness, many of the features described for electricity generated by nuclear energy for desalination and district heating are valid for process heat applications. There are several important considerations specific for process heat applications, which include:

- The ability to locate the heat source close to the demand,
- The relatively small-scale demand,
- The need for high reliability.

The economics of nuclear energy for process heat applications will likely be improved by the development of small, low-cost reactors. Current development trends in many countries have already begun to move in this direction.

The co-generation plants for process heat based on fossil fuels or water-cooled reactors derive much of their revenue from electricity, but add the operational flexibility to adapt to process heat markets.

Specific costs for oil extraction from Canadian oil-sands

In 2003 AECL commissioned an independent study by CERI (Canadian Energy Research Institute) to compare the economics of Advanced CANDU Reactor (ACR)-supplied energy with natural gas. This study provided an evaluation using ACR design data, the assumptions on configurations and economics, and compared equivalent amounts of energy supplied from the nuclear and natural gas options to ensure a proper comparison. The study identified comparable ACR and natural gas-supplied configurations, each delivering steam and electricity. The electricity output was set at 150 MWe (gross) to meet the facility's demand, and the remaining thermal power of the ACR was delivered as steam to the Steam-Assisted Gravity Drainage (SAGD) plant. A common economic model was also developed, using parameters such as natural gas and electricity costs based on 2003 market value, without attempting to extrapolate or forecast future prices. The natural gas price used was Cnd $4.25/GJ and the electricity price was Cnd $50/MWh. Based on these numbers, the results show nuclear steam to be 10% cheaper than that generated through natural gas.

The study examined energy price sensitivity to changes in key parameters. The nuclear case is more sensitive to capital cost changes, as might be expected. A 25% increase in capital cost would increase steam cost by 20%. The gas-fired option is extremely sensitive to fuel prices. A 25% increase in the price of natural gas would increase steam cost by nearly 25%. With the current gas price more than 50% higher than in 2003, the economic advantage of nuclear over natural gas becomes significant.

The study also examined the impact of CO_2 emissions on cost. The reference basis for CO_2 costs or credits was $15/tonne. This could add an additional 18% to the cost of natural gas-supplied steam.

All indications are that the nuclear option has a significant advantage in cost over the competition. The nuclear option also provides for cost predictability and stability, which would reduce the risks for a potential oil sand operator.

4.3. Challenges

The market for industrial heat is highly competitive. Heat is produced predominantly from fossil fuels, with which nuclear energy will have to compete. Most of the industries using fossil fuel as a heat source have abundant waste heat available and it is being economically used in various process streams.

Similar to nuclear district heating, the close siting of a nuclear plant to the customer is preferable, as the heat transportation costs grow significantly with distance. This will require specific safety features appropriate to the location and the application. Until now few technical problems in coupling nuclear reactors to various applications have been identified, though some safety-related issues of coupled systems may need more study.

The nuclear process heat supply has to be reliable. As an example, the average adequate steam supply availabilities for chemical processing, oil refineries and primary metals are respectively 98%, 92% and near 100%. Such high levels can be ensured only by the combination of a highly reliable heat source and the availability of reserve capacity.

The supply of industrial heat is more uniform throughout the year than that of district heat, mainly because of the absence of seasonal variation. Accordingly, the average load factors of industrial boilers are relatively high, between 70 to 90%. Nuclear reactors, which are typically run in base load operation, will be quite useful in this context.

Although nuclear industrial process heat applications have significant potential, it has not been realized to a large extent. In fact, presently only the Goesgen reactor in Switzerland and RAPS–2 in India continue to provide industrial process heat while other process heat systems have been discontinued after successful use (see Table 1.2). Among the reasons cited for closure of these units, one is availability of cheaper alternate energy sources, including waste heat near the industrial complexes. The nuclear slow down in many industrialized countries could be another reason.

Studies are being carried out in Canada for oil extraction from its vast oil sand resources. These studies consider using present day and advanced water-cooled reactors as a heat source. Currently natural gas is used for this application. Although these studies have been motivated by a need for an environmentally sound energy option, the ultimate challenge in the utilization of nuclear steam for this application is the economics.

4.4. Solutions

4.4.1. Oil extraction from Canadian oil sands

Application to open-pit mining

When a CANDU plant is adapted to supply thermal power to open-pit mining processes, the low temperature and pressure requirements allow extraction steam from the turbine to be used as the heat source. This boosts the overall system efficiency. Steam extracted from the low-pressure turbine at low pressure is used to heat water in steam-to-water heat exchangers. The hot water is supplied to the bitumen extraction facility; most of the water is recovered after the process, treated and sent back as the feedwater to the hot water heaters. The condensate from these hot water heaters returns to the turbine's feedwater system. The thermal power of the water counts for about 80% of total thermal power demanded by the open-pit processes.

There are two steam heaters operating at different pressures. The higher pressure one uses main steam directly from the steam generators and the lower pressure one uses extraction steam from the high-pressure turbine as a heating source to generate process steam at 2.0 MPa and 1.0 MPa respectively. The process steam is piped to the bitumen extraction process, and mostly used in mixture heat exchangers without condensate return. Therefore, feedwater to these steam heaters is mainly from the make-up water. The condensate from these steam heaters returns to the turbine's feedwater heating system. The thermal power of the process steam represents about 20% of total thermal power requirement. Therefore, the amount of the steam used in these steam heaters is not as significant as the low-pressure turbine extraction steam used in the hot water heaters.

In contrast to condensing steam turbines that are used in conventional nuclear power plants, the steam turbines used in this configuration are of the automatic extraction type. Steam is extracted from high-pressure and low-pressure turbines as the heating steam. The appropriate means have to be provided to control the amount and the pressure of steam extracted. The turbine design allows the thermal and electrical output from the plant to vary within a certain range if required. This is a proven technology in fossil-fuelled co-generation power plants and has been used for decades.

A system simulation has been performed for the year-round weather conditions for the production of 330,000 bbl/day of bitumen, which is a manageable size of an open-pit mining project. For the average weather condition (in April), the thermal power demand is 1440 MWt, and the electricity demand is 300 MWe (including the oil facility and nuclear plant demands). A CANDU-6 plant is able to provide the required thermal power for this condition, while generating 367 MWe (gross) electricity. In summer, the thermal demand decreases to 1220 MWt, and consequently the electrical output increases to 420 MWe (gross). In the coldest month (January), the total thermal power demand from the oil sand facility is as high as 1670 MWt, and the CANDU-6 plant generates 316 MWe (gross) electricity while producing enough hot water and steam to meet the thermal requirements of the bitumen production. During a year, the nuclear plant generates electricity within a range from 316 MWe to 420 MWe, while being able to meet the entire thermal power requirement. This offers a limited capability to deliver electricity to the grid. The simulation results are shown in Table 4.3.

Table 4.3. **Simulation results: CANDU-6 for open-pit mining application**

Month	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**
Electricity (gross) MWe	316	331	348	367	385	403	420
Thermal Power MWt	1670	1590	1520	1440	1370	1300	1220

Other technical aspects for adapting a CANDU reactor for open-pit mining processes are similar to those for the Steam-Assisted Gravity Drainage process discussed in the next subsection, and there are no insoluble issues identified.

An economic analysis for this configuration is currently in progress.

Application to advanced mining technology

As described earlier, Steam-Assisted Gravity Drainage (SAGD), which uses steam to remove bitumen from underground reservoirs, is an advanced process being used to exploit deep deposits of oil sands.

A typical SAGD application involves twin horizontal wells drilled in parallel, with one a few meters above the other, as shown in Fig 4.3. The upper well is called the injection well and the lower one the production well. Medium pressure steam is injected into the underground deposit area through the injection well to heat the reservoir of bitumen-sand mixture by conduction. The heating reduces the viscosity of the bitumen, increases its mobility, and establishes pressure communication between the two wells along their length, so that a flow of fluids (a mixture of bitumen and condensed water) can occur and be collected through the production well. The production liquid is transported to a central facility, where the bitumen is separated and the condensate is collected, treated, and sent back to the boilers.

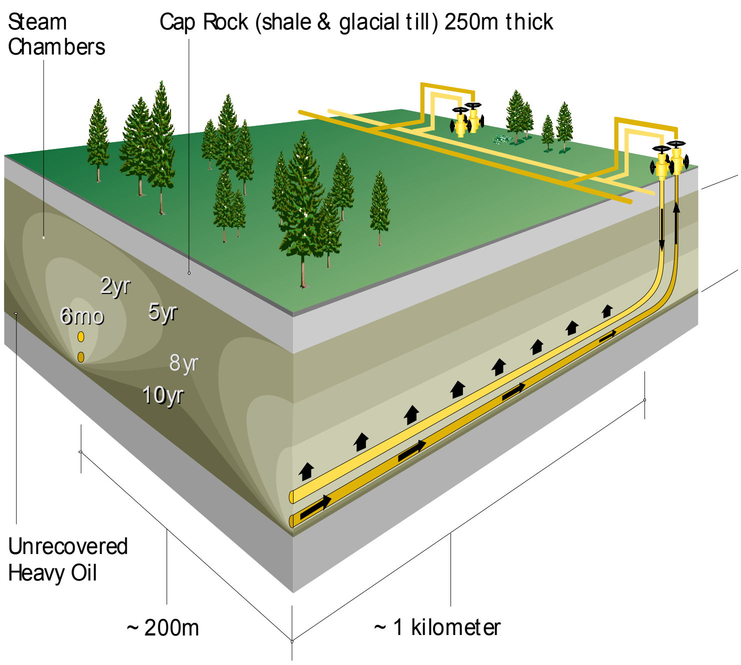

FIG. 4.3. Steam assisted gravity drainage process (reprinted with the permission of AECL).

The required steam injection pressure depends on the circumstances of the oil field and the life cycle of the well, and varies from 2 to 6 MPa. At the initial stages of production (two to three months), each well requires steam at higher pressure than that required during normal operation. Each barrel of bitumen requires 2–3 barrels of steam (steam volume is corrected to 4°C and 1 bar). Generally, about 18% of the energy content of the oil produced is used to provide heat for the extraction process; a further 5% is used in generating hydrogen to upgrade the bitumen to synthetic crude oil.

In addition to steam demand, SAGD production facilities are also significant consumers of electricity.

Adaptation of ACR-1000 for Steam Assisted Gravity Drainage

The primary product of a water-cooled nuclear power plant is steam from the steam generators. Depending on the requirements of specific projects, the plant can be adapted to provide steam only, or a mixture of steam and electricity for various steam/electricity ratios. With the steam-only option, the steam generated from a plant is totally dedicated to supply steam to oil sand processes, and no electricity is generated. Hence, the turbine island is totally eliminated from the plant, and replaced by the facilities dedicated to steam and feedwater supplies. The steam/electricity option splits main steam from the steam generators into two streams: one is dedicated to supply steam to the oil sand facility and the other is channeled to generate electricity. As a result, the turbine capacity becomes smaller than that of a standard plant.

As an example, the ACR-1000 design is an evolutionary development of CANDU technology. The net electrical output from a standard ACR-1000 will be approximately 1000 MWe. The main steam pressure is 6.5 MPa. The license requirements for an ACR SAGD project were examined and found to pose no major issues. Since the Bruce A nuclear plant in Ontario has supplied nuclear-generated steam to various facilities outside the exclusion area, no major impediments to getting regulatory approval are foreseen.

For the steam-only option, there will be no on-site source of station service power for the nuclear unit. Therefore, a large combustion turbine generator or other local generation source will be required to back-up offsite power to satisfy power supply reliability requirements.

Water sources in the northern Alberta oil sand areas are scarce. It would be necessary for any individual project to minimize its water usage to meet overall regional water use planning guidelines. The study has looked into the use of air-cooled heat exchangers to take the heat load, which is normally removed by once-through water in the traditional CANDU plants. This was found to be feasible for up to 350 MWe electricity generation capacity. The possibility of using more conventional cooling towers was also examined and found to be feasible.

The remote location and severe weather conditions of oil sand sites raise concerns about the constructability of a large plant. The ACR design is highly modularized, and the use of prefabricated modules will be maximized. This approach minimizes the on-site construction activities, enabling schedule compression, and reduces the size of the on-site labour force. The module sizes and weights have been selected for suitability for road transportation to northern Alberta. No major construction issues are predicted.

Overall, the studies indicate that construction and operation of an ACR to meet the energy demand for SAGD projects are technically feasible.

4.4.2. Massachusetts Institute of Technology (MIT) study [5]

The following summarizes the study:

Introduction

The two general classes of oil sand recovery are mining and in-situ methods. In mining, the oil sand ore is recovered by electric or hydraulic shovels and transported by heavy trucks before the bitumen can be extracted. For in-situ methods, most of the bitumen is separated from the oil sands in the deposit by injecting steam into the ground to separate the bitumen from sand. The bitumen is then pumped to the surface for further processing.

A 2005 MIT study analyzed the feasibility of integrating a nuclear power plant with Steam Assisted Gravity Drainage (SAGD). Natural gas-fired plants provide the energy for projects today, but concerns are heightening within the industry over increased carbon dioxide emissions, volatile natural gas prices, and depletion of natural gas reserves. Nuclear power is an emission-free alternative to natural gas, but the key to implementation hinges on whether nuclear systems can compete economically with natural gas-fired plants in the oil sand industry. Successful integration of emission-free nuclear technology with oil sand operation will remove the dependence of the price of oil from oil sands on the volatile and high price of natural gas and also address the problem of CO_2 emissions.

Energy requirements

Extraction facilities can be divided into three categories: those that only require process heat, those that require process heat and electricity, and those that require process heat, electricity and hydrogen to upgrade the bitumen to syncrude on site. In order to compare the different scenarios, a processing plant capable of producing 100 000 barrels of bitumen per day was assumed as a reference design. 100 000 barrels of bitumen can be upgraded to approximately 87 000 barrels of synthetic crude. The thermal requirements for each scenario were calculated and compared to the available output of several reactor systems.

The first scenario requires only process heat to be produced on site. Electricity is assumed to be taken from the grid. The bitumen after dilution is pumped to a processing plant. The thermal energy requirements for this scenario range from 820 MWth to 1264 MWth.

The second scenario requires electricity in addition to process heat. The energy requirement for this scenario includes 1200 MWth heat and 250 MWe.

The third scenario is a self-contained facility that produces its own electricity and process heat and refines the product on-site from bitumen to synthetic crude. This scenario includes the production of hydrogen using high-temperature electrolysis for refining. The energy requirement for this scenario includes 1300 MWth and 740 MWe.

Nuclear reactor design options

Eleven different reactor systems were considered by MIT for this application; three were selected for the mission of providing the energy needs required. These include the Canadian ACR-700, the Westinghouse AP-600 and the South African 400 MWth PBMR. An evaluation of design-specific characteristics that benefit and impede the oil sand extraction process was used to distinguish reactors.

Economics

The study showed that nuclear energy would be feasible, practical and economical for use at an oil sand facility. Nuclear energy is two to three times cheaper than natural gas for each of the three scenarios analyzed. Also, by using nuclear energy instead of natural gas, a plant producing 100,000 barrels of bitumen per day would prevent up to 100 mega tonnes of CO_2 per year from being released into the atmosphere.

Nuclear obstacles

There are several obstacles to implementing nuclear power in oil sand operations. Public perception could offer resistance to the project, but a well-planned education effort could address the issue. Owing to unfamiliarity with nuclear plants in the oil sand industry, it is expected that a qualified nuclear utility will be needed to operate the nuclear plant and provide heat and electricity as merchant products for the oil sand extraction and refining company.

4.4.3. Long-term possibilities

The Generation IV International Forum (GIF), an international group of ten countries and Euratom is exploring the development of six systems that could be deployed by 2030 or earlier. Their capabilities to produce non-electricity products are shown in Table 4.4.

Table 4.4. Generation IV reactor concepts

	Neutron spectrum	Coolant	Temperature (°C)	Fuel cycle	Size(s) (MWe)
Gas-cooled Fast Reactors (GFR)	Fast	Helium	850	closed, on site	288
Lead-cooled Fast Reactors (LFR)	Fast	Pb-Bi	550-800	closed, regional	50-150 300-400 1200
Molten Salt Reactors (MSR)	Epithermal	Fluoride salts	700-800	closed	1000
Sodium-cooled Fast Reactors (SFR)	Fast	Sodium	550	closed	150-500 500-1500
Supercritical Water cooled Reactors (SCWR)	Thermal or fast	Water	550	open (thermal) closed (fast)	1500
Very High Temperature Gas Reactors (VHTR)	Thermal	Helium	1000	open	250

Of these concepts, the one water-cooled reactor concept is the supercritical water cooled reactor (SCWR).

The SCWR system features two fuel cycle options: an open cycle with a thermal neutron spectrum reactor and a closed cycle with a fast-neutron spectrum reactor and full actinide recycle. In either option, the reference plant has a 1700 MWe power level and a reactor outlet temperature of 550°C. This is a very high-pressure water-cooled reactor that operates above the thermodynamic critical point of water to give a thermal efficiency about one third higher than today's light water reactors from which the design evolves. The supercritical water directly drives the turbine, without any secondary steam system. It is primarily envisioned for missions in electricity production, with an option for actinide management. Given its R&D needs in materials compatibility and reactor control, the SCWR system is estimated to be deployable by 2025.

The SCWR could provide process heat at temperatures up to about 550 ºC.

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CHAPTER 5
NUCLEAR ELECTRICITY FOR TRANSPORTATION: HYBRID-ELECTRIC VEHICLES

5.1. Opportunities

The reduction of gasoline consumption by using hybrid gasoline and electric drive engines in automobiles and light utility vehicles (four-wheel vehicles that include minibuses, delivery vans, pickup trucks, and SUVs (sport utility vehicles)) may be an idea whose time has come. Electric-drive engines have the potential to significantly reduce both the cost of vehicle fuel and emissions of greenhouse gases in the transportation sector, and can reduce the ever-growing pressure for the countries with oil reserves to find and distribute more oil to both developed and developing countries. Furthermore, the technologies for some of the alternative routes, particularly the use of hybrid-electric vehicles, is currently available with minimal changes to the normal transportation infrastructure. The plug-in feature, when used, allows charging of the vehicle batteries from utility electric power sources, and it is this application of nuclear electricity that could have an impact on greenhouse gas emissions and dependence by the transportation sector on petroleum. The United States and Japan were chosen for detailed studies of the benefits and impacts of substituting electricity for petroleum fuels by using plug-in hybrid vehicles.

Consideration was given to other transportation systems, primarily railroads. In Japan, less than 5% of the transportation energy on an oil equivalent basis is used for rail transportation, of which virtually all already uses electricity. In the United States, the distances are so great between most major cities that the capital cost of electrical transmission structures militate against its use except in a few locations in the northeastern United States. No consideration was given to air transportation because the weight of the electrical motors and batteries would be prohibitive.

In this chapter, the opportunities to use nuclear power plants, particularly water-cooled reactors , are investigated. The situations in the United States and Japan are developed in detail, and the lessons learned are extended to the situation in Europe, and especially China and India where the use of automobiles and light utility vehicles is currently small, but growing rapidly.

Analyses of the current opportunities will be based on simplified models that deal with quantitative information available from reliable government sources: the U.S. Department of Energy (DOE) Energy Information Administration (EIA) in the United States and the Ministry of Land Transportation and Infrastructure (MLIT) in Japan. Average performance data (20 miles per gallon of gasoline—mpg) will be used to illustrate the overall behaviour of all the vehicles in the United States with full realization that smaller, lighter vehicles will perform better, and larger, heavier vehicles will not perform as well.

The models used in the analysis of the situation in the United States are based on three recent publications [1, 2, 3]. Data from DOE-EIA are used to define an average gasoline-fueled light vehicle as a reference vehicle against which the various hybrids and hydrogen-fueled vehicle alternatives can be compared. Analyses of fuel quantities, fuel costs, and greenhouse gas emissions will be used for comparisons.

The models used in the analysis of the situation in Japan are also based on recent publications [4, 5, 6]. Data from the MLIT are used to define an average behaviour of target motor vehicles (personal-use passenger vehicles, called “registered” vehicles and “light” vehicles). The methodology used for the analysis is similar to the one used for the analysis for the United States [2].

5.1.1. Opportunities in the United States

5.1.1.1. Hybrid vehicles

The hybrid-electric vehicle is not a new concept. Hybrids were first conceived and vehicles constructed about 100 years ago. Even though it was demonstrated to be a viable concept technically, the hybrid vehicle received relatively little attention until the late 1960s when it was considered by some to be a possible way of meeting the newly established emission reduction requirements for automobiles. However, the real stimulus for pursuing hybrids with an organized effort and significant funding came as a result of the OPEC petroleum embargo and resulting energy crisis of 1973–74. The U.S. Congress passed Public Law 94-413, the Electric and Hybrid Vehicle Research, Development, and Demonstration Act of 1976, which directed the newly established Department of Energy (DOE) to pursue, among other activities, the technologies associated with electric and hybrid-electric vehicles. While these activities were underway, the energy crisis subsided simultaneously with automobile manufacturers making dramatic improvements in conventional vehicle fuel efficiency and emission of pollutants. The introduction and wide spread deployment of engine-controlling microprocessors along with continued improvements in exhaust after-treatment led to a near doubling of Environmental Protection Agency (EPA) fuel mileages and an order of magnitude reduction in exhaust emissions. As a result, there was little corporate interest in pursuing the heavier, more fuel efficient, less polluting, but more complex and more expensive hybrid vehicles. Even so, the considerable work that had been completed showed that hybrids could simultaneously improve fuel efficiency and further reduce greenhouse gas emissions compared to current conventional vehicles.

It was the Japanese automobile industry that introduced conventional hybrid-electric vehicles to the world with the Toyota *Prius* and Honda *Insight* and *Civic* models.

Today, four general types of hybrids are commonly recognized. Micro-hybrid, mild-hybrid, and full-hybrid vehicles are commercially available; plug-in hybrids have been demonstrated, but are still under development. Regenerative braking is used on almost all types of hybrids. It converts some of the kinetic energy of a moving vehicle to electrical energy and stores it in the battery for later use, rather than converting it to wasted heat by friction between the brake discs and brake pads. However, friction brakes are also required to come to a complete stop. The identifying characteristics of the four types are:

Micro-Hybrid. When the vehicle stops, the engine is turned off to save fuel. When the driver pushes the accelerator, the integrated starter/alternator initiates acceleration of the vehicle and simultaneously starts the gasoline engine. The integrated starter/alternator assists the engine in accelerating the vehicle until the desired speed is reached. The gasoline engine alone propels the vehicle during cruising. Fuel efficiency is about 10% better than for a comparable standard vehicle (22 mpg vs. 20 mpg).

Mild-Hybrid. The electric motor (starter) and alternator are separate units. The electric motor assists the gasoline engine, but generally does not propel the vehicle alone except in “start and stop” traffic. The electrical components are larger and the gasoline engine is smaller than in the micro-hybrid. Fuel efficiency is about 20–25% better than for a comparable standard vehicle (24-25 mpg vs. 20 mpg).

Full-Hybrid. All the electric components are larger than in the mild-hybrid so that it can operate on the battery alone for longer periods of time. The gasoline engine is somewhat smaller, and the fuel efficiency is typically 40–45% better than for a comparable standard vehicle (28–29 mpg vs. 20 mpg).

Plug-in Hybrid. The battery typically needs a much larger capacity than in the full-hybrid, and the vehicle needs an “all electric” range that is about 5 times greater than that of a full-hybrid. The gasoline engine may be somewhat smaller, and the digital control system to optimize the various driving situations is more complex. Gasoline mileage has little meaning since the vehicle may use little or no gasoline for short trips, only electrical energy in the battery that came from an electric utility.

These four types of hybrid have many common components, such as regenerative braking, gasoline engine, electric motor, alternator, battery pack, and central digital-control system. Moving from the micro-hybrid to the plug-in hybrid, the size of the electrical components becomes larger and their use increases, the gasoline (or diesel) engine becomes somewhat smaller, the performance (acceleration) increases, and the fuel economy increases. However, larger electrical components are heavier, more complex, and more expensive. Furthermore, the decrease in the size of the gasoline engine is often less than the increase in size of the electrical components.

The reason that hybrid vehicles accelerate so well is that torque, which provides acceleration, is very high at stall and low speed for electric motors. Torque produced by a gasoline engine increases with engine speed from a low value at low rpm (revolutions per minute) to a maximum in the 1500–2500 rpm range, after which it falls off somewhat. Hence, in hybrids, the combination of an electric motor and a gasoline engine together provides higher torque and better acceleration than is available in comparable conventional vehicles of equal horsepower, even though the hybrids usually weigh more and have smaller gasoline engines.

The reason that hybrids are so fuel efficient is that the amount of fuel consumed per unit of energy output (specific fuel consumption—pounds or gallons per horsepower-hour output) generally decreases with power level until it reaches a minimum at 65–85% of maximum power. Multi-speed or continuously variable speed drives are used to keep the engine operating near its most efficient speed. Thus, a smaller engine running at a higher percentage of its full power is more efficient and more economical for a given load than a larger, heavier gasoline engine operating at a lower percentage of its maximum power.

The Electric Power Research Institute (EPRI), the research organization of the U.S. electric-utility industry, has conducted a research program for plug-in hybrids using batteries that are charged primarily with electricity generated by utilities. Generating the electricity needed to charge these batteries is a primary new market for nuclear electricity, as discussed in this chapter [7].

5.1.1.2. Opportunities for reducing greenhouse gas emissions from transportation

The principal greenhouse gases are water vapour (60–65%) and CO_2 (20–25%). Water vapour stays in the atmosphere for a relatively short time, a matter of hours or days, whereas CO_2 has an average residence period of about a century. As a result, the amount of water vapour remains relatively constant at a level related to the rate at which it is produced by weather phenomena, while CO_2 tends to accumulate as the amount emitted increases. All other greenhouse gases (10–20%) such as methane, ozone, nitrous oxide, carbon monoxide, and fluorocarbons tend to have lesser effects on the atmosphere over time because of smaller quantities or short residence times. Hence, the only greenhouse gas considered in this analysis is CO_2.

Greenhouse gas emissions from gasoline vehicles in the United States of America

Combustion of gasoline emits 19.56 pounds of CO_2 per gallon of gasoline. Since the average gas mileage in our model is 20 miles/gallon, the annual emission of carbon dioxide is

19.56 lb CO_2 per gallon / 20 miles/gallon = 0.978 lb/mile

Or

0.978 lb/mile x 12,260 miles/year = 12,000 lb CO_2 /vehicle-year for gasoline vehicles[5]

---

[5] The total miles per day and per vehicle year are:

[9 x 10^6 barrels/day x 42 gallons/barrel x 20 miles/gallon] = 7.56 x 10^9 miles/day;

[7.56 x 10^9 miles/day x 365 days/year] / [225 x 10^6 vehicles] = 12,260 miles/vehicle year.

Clearly, the amount of CO_2 for smaller vehicles would be less than for larger vehicles because the gasoline mileage is greater. However, the model for this analysis deals with average vehicles that achieve 20 miles per gallon, the reference performance used for all comparisons.

Emissions for traditional hybrid vehicles

Since all the energy to propel traditional types of hybrid vehicles is provided by gasoline, this analysis utilizes the increased fuel mileages assigned in an earlier publication [2], which reduces the total CO_2 emissions for traditional hybrid vehicle accordingly, as shown in Table 5.1.

Table 5.1. Emissions for hybrid vehicles

Type Hybrid	***Gasoline Mileage***	***CO_2 per Mile***	***CO_2 per Vehicle-Year***
	Miles/gal	lb	lb
Micro-Hybrid	22	0.889	10,900
Mild-Hybrid	25	0.782	9,600
Full-Hybrid	29	0.674	8,270

These values are for hybrid vehicles of a size corresponding to an average vehicle that attains 20 miles/gallon. A larger or smaller vehicle would have proportionally higher or lower emissions.

A more thorough analysis of the environmental impacts of hybrid electric vehicles was performed in 1997 using the lifecycle analysis software GREET, the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model. GREET was developed at Argonne National Laboratory to evaluate well-to-wheels energy and emission impacts of motor vehicle technologies powered with various transportation fuels. The model and associated documents are posted at http://www.transportation.anl.gov/software/GREET/index.html. The 1997 study looked at total lifecycle energy use and emissions from the vehicle cycle, the fuel cycle, and vehicle operations for several hybrid electric vehicle designs and compared them with results for conventional vehicles. Greenhouse gas emissions from the hybrids were found to be 40% lower than those from conventional vehicles. Volatile organic compound emissions were reduced by 15 to 28%, carbon monoxide by 7 to 37%, and particulate matter with sizes smaller than 10 micrometers (PM_{10}) by a small amount. On the other hand, NOx emissions were calculated to increase by 28 to 67%, and SOx by a factor of 6 to 14. In large part those increases were due to the processing of nickel needed for nickel-metal hydride batteries. The transition to lithium-ion batteries should reduce those pollutants.

Overall energy use for hybrids was shown to be about 40% less than that for conventional vehicles, with an equivalent reduction in fossil energy use and greenhouse gas emissions (CO_2, CH_4, and N_2O).

No plug-in hybrid vehicles were examined in 1997. Those studies are underway now and results are expected shortly.

Emissions for plug-in hybrid vehicles

The model used for greenhouse gas evaluations for a plug-in hybrid vehicle is the same model used in sections 5.2.1.3 and 5.2.1.4 for cost analysis. The total distance travelled per day by all 4-wheel gasoline-fueled vehicles is 7.56 x 10^9 miles/day. (See Section 5.2.1.2.) Subtracting the 5.625 x 10^9 miles per day travelled on electricity[6] gives 1.935 x 10^9 miles/day as the distance per day travelled as a full-hybrid. This means that 74.4% of the distance was travelled using electricity as fuel and 25.6% of the distance was travelled using gasoline.

The emission of carbon dioxide by plug-in hybrid vehicles is made up of two parts: that emitted directly for 25.6% of the total mileage using gasoline and that emitted in the generation of 74.4% of the total energy provided by electricity. The direct emissions due to the operation in full hybrid models given in Table 5.1 for 25.6% of the miles is

8,270 lb CO_2 /vehicle year x 0.256 = 2,120 lb/vehicle year

If the electricity is supplied by nuclear, solar, wind, hydro or renewables, no carbon dioxide is generated in the process of electricity production (though greenhouse gases are emitted in other stages of the lifecycle of the energy source, for example in the mining and enrichment of uranium or in the manufacturing of solar photovoltaic cells). Hence, the total emissions are 2,120 lb/vehicle year.

If the electricity is generated by fossil fuels (natural gas, oil or coal), the resulting generation of carbon dioxide must be added to that generated directly. Carbon dioxide emissions generated per kWh of electricity by fossil fuels are given in Table 5.2 based on data from the Department of Energy, Energy Information Administration.

In Section 5.2.1.4, it is established that 0.603 kWh/mile is a reasonable average expenditure of electrical energy for hybrid vehicles that would be comparable to a vehicle getting 20 miles per gallon of gasoline using an internal combustion engine. It is readily shown that the average distance travelled by each plug-in hybrid vehicle while operating on electricity alone would be 9,125 miles/year.[7] Hence, the electricity used is

9,125 miles/year x 0.603 kWh/mile = 5,502 kWh/vehicle year.

Table 5.2. Emission rates for fossil fuels

Fuel to Generate Electricity	***% of Total Generation***	***CO_2 Emission Rate lb/kWh***
Coal	51.0	2.100
Oil	3.2	1.970
Natural Gas	15.2	1.320
Renewables	0.6	0 (net)
Non-Fossil*	30.0	0

*(Nuclear 20%; Hydro 7%; Wind 2%; Solar <1%)

If this value is multiplied by the amount of CO_2 emission per kWh for the three fossil fuels given in Table 5.2 and added to the 2,120 lb/vehicle-year of CO_2 for operation in the full hybrid mode, the results given in Table 5.3 for the various fuels are obtained.

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[6] The miles per day driven on electricity is:
[225 x 10^6 vehicles x (15 + 35)/2 miles/vehicle day] = 5.625 x 10^9 miles/day.

[7] The average distance per year on electricity is:

[(15 + 35)/2 miles/vehicle day x 365 days/year] = 9125 miles /vehicle year.

Table 5.3. Emissions for plug-in hybrid vehicles

Fuel to Generate Electricity	*Emissions of CO_2 lb/vehicle-year*
Coal	13,650
Oil	12,950
Natural Gas	9,400
Nuclear	2,120
Solar	2,120
Wind	2,120
Hydro	2,120
Renewables (Net)	2,120

It is clear that if some 200-250 new 1000 MWe power plants, as calculated later in this chapter, or even a fraction of this number, are to be built to provide electricity for plug-in hybrid-electric vehicles, they should not use fossil fuels. Indeed, a strong case can be made that nuclear energy is the only practical choice. Both solar and wind are intermittent and would require large amounts of energy storage and recovery systems that are almost as complex as generation systems. There are relatively few, if any, remaining practical hydro sites in the United States, and renewables on this scale would utilize an enormous amount of land that will be needed for food production for a growing population.

5.1.2. Opportunities in Japan

5.1.2.1. Situation of automotive fuels and electric power in Japan

In 2004 Japan imported about 96% of its energy from abroad, including 99.7% of its petroleum (of which 89.5% is from the Middle East), and 96.5% of its natural gas. The transport sector consumes about a quarter of the total energy in Japan. Most of the consumption is petroleum fuels (98% in FY2000) such as gasoline or diesel oil used for automobiles.

Electricity also makes up a quarter of total energy demand. Electricity in Japan is generated from a diverse set of sources, including nuclear 31.5%, coal 25.4%, natural gas 24.0%, petroleum 10.3%, and hydro 8.4% (2005 statistics). Thus, in the power generation sector, the dependence on fossil fuels is only about 60%. Hence, the security of the energy supply and the reduction of CO_2 emission are being improved by decreasing the petroleum and carbon fuel consumption through a growth in non-carbon electricity sources.

Similarly, if automobiles are powered by electricity by using plug-in type vehicles, the energy supply can be diversified to become less dependent on petroleum. Along with the increase of plug-in vehicles in the future, the new electric demand for charging the batteries would hopefully be supplied by nuclear power, thus making the energy supply more secure and reducing CO_2 emissions in Japan.

5.1.2.2. Driving patterns of Japanese passenger vehicles

There are about 77.4 million vehicles altogether in Japan. From the size and the driving pattern of these vehicles, the categories suitable for plug-in hybrid electric vehicles are the personal-use passenger vehicles, of which there were 54.4 million vehicles as of 2003. They are classified into the ”registered” vehicles, which are ordinary-sized cars and ”light” vehicles, which are smaller cars with engine capacities under 660 cm^3 and which have some benefits in terms of taxes and other costs.

The average daily travel distances of these categories of vehicle are estimated from the statistical survey data from MLIT on the relationship of passengers carried for various distances.

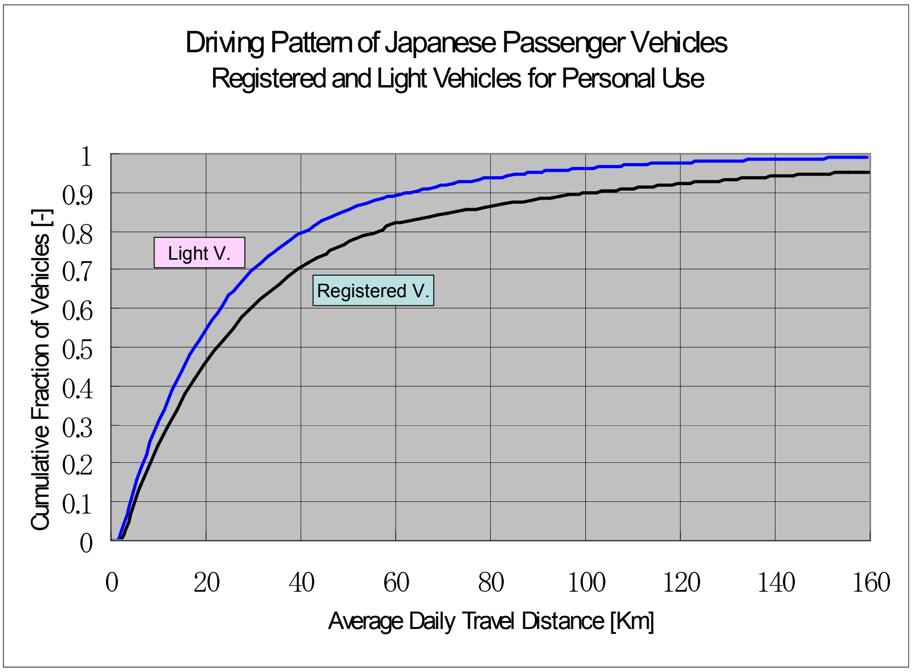

FIG. 5.1. Driving patterns of Japanese passenger vehicles.

From Figure 5.1 on the driving pattern of Japanese passenger vehicles, it is presumed that on average Japanese vehicles are driven about 20 km (18 km for light vehicles and 22 km for registered vehicles). The average daily travel distance of Japanese vehicles is about 62% of that of US light vehicles, which is about 20 miles or 32 km per day, as previously mentioned.

5.1.2.3. Expectation for plug-in hybrid electric vehicles in Japan

As the self-sufficiency of energy is currently very low in Japan, shifting the energy for the transportation sector to nuclear energy, though it may take a long time, would significantly improve its energy security. For nuclear energy supply to serve the transportation sector several technologies have been suggested, including plug-in type vehicles, hydrogen fuel cell or combustion engines, or the use of synthetic fuels. Among these, the introduction of plug-in hybrid vehicles into the automotive market is expected to be the most realistic and is considered the leading option for this purpose.

As the weight of Japanese vehicles is lighter and the daily distance travelled is shorter in Japan as compared to the U.S., especially for the category of "light vehicle," it would be easier to introduce plug-in hybrid vehicles in Japan because a smaller battery could give a larger electric run fraction.

5.1.3. Opportunities in other countries

A recent comparison of gasoline consumption for several countries gives a useful view of the world situation. In an article entitled **"**Situation is Obscenely Out of Whack**"** [8] the data in Table 5.4 were given for the consumption of gasoline per person per year for transportation.

Table 5.4. Consumption of Gasoline throughout the World [8]

Consumption of Gasoline per person per year	
United States	453 gallons
Europe (includes diesel fuel)	133 gallons
Japan	124 gallons
World Average	47 gallons
World Average (w/o U.S.)	28 gallons
China	10 gallons
India	2 gallons

The discrepancy between the gasoline consumption in United States and the rest of the world is clearly shown. In many respects, the situation is a reflection of the historic low price and the large domestic production of oil. Given the rapidly growing demand for oil in the developing countries, particularly China and India, and the signs of declining production in many of the oil-producing countries, including the United States, there is an urgent need for reducing the use of oil. Substitution of electricity for oil by the use of plug-in hybrid vehicles is an attractive way of achieving this goal without disrupting the existing transportation infrastructures in the developed countries, particularly the United States.

Opportunities in the European Community

For the last several decades, the price of gasoline has been much higher in Europe than in the United States, because of a large tax each European country has imposed. Since the OPEC embargo in 1973 until 2005, the price of gasoline has varied between \$3 and \$6 per gallon in Europe while the price in the United States has varied between \$1 and \$2 per gallon. Europeans have adjusted to the higher prices by buying smaller, more efficient automobiles and using a much higher percentage of diesel powered light vehicles. The recent availability of biodiesel fuel that virtually eliminates diesel pollutants may accelerate this trend. In addition, Europe has adopted efficient public transportation systems. As a result, the steep rise in oil prices in 2005–2006 has had significantly less impact on transportation costs in Europe than in the United States. Hence, there may be less urgency to consider hybrid vehicles in Europe than in the United States. Indeed, the principal European automobile manufacturer seriously investigating hybrid vehicles today is DaimlerChrysler, and none have hybrid vehicles for sale or lease.

Opportunities in China and India

China and India have populations of about 1.4 and 1.0 billion, respectively, and are growing. Their economies are growing extremely rapidly, and both are developing a large economic middle class that are buying automobiles and other light vehicles. If these vehicles utilize oil-based fuels, the current world mismatch between supply and demand will be exacerbated, and the price of oil will continue to rise. A strategy by China and India to minimize the use of gasoline through substitution of electricity would be beneficial to all countries and help stabilize the price of gasoline in China and India as well as in the rest of the world. China has an aggressive program of installing new nuclear (and other) power plants that could be utilized to provide electricity to charge automotive batteries at night. Indeed, with all the new power plants they are building, their excess capacity at night may be adequate to charge vehicle batteries, which would contribute to keeping the nuclear power plants at continuous base load operation.

5.2. Market context

5.2.1. Market context in the United States of America

5.2.1.1. Status of hybrid-electric vehicles

Today, there are several automotive manufacturers, including Ford, General Motors, Honda, Toyota, and Lexus that offer conventional hybrid (micro-hybrid, mild-hybrid, and full hybrid) vehicles. Generally, these vehicles (except the micro-hybrids) sell at prices that are $5000 to $10 000 higher than corresponding traditional models, and that typically are not offered at discounted prices. Some models provide gas mileages that are significantly better than their corresponding traditional models; others offer only minor gasoline mileage improvements, but rather, offer outstanding acceleration.

General Motors, Ford and Toyota are the principal automotive manufacturers which have expressed interest in plug-in hybrids. GM and Ford displayed plug-in hybrid electric vehicles using lithium-ion batteries at the Detroit Automobile show in early 2007. However, as indicated in section 5.3.1, few automakers intend to produce consumer test vehicles as GM had done with their EV1 electrical vehicles. Toyota, however, announced on July 25, 2007, that it is donating several prototypes of its Plug-in HV to the University of California-Irvine and the University of California-Berkeley for road testing. In addition, Toyota stated that the Japanese Ministry of Land, Infrastructure and Transport (MLIT) has now approved testing of plug-in hybrid vehicles on Japanese public roads. The Plug-in HV has a battery range of 8 miles on a full charge, which is significantly less than the 30-mile all-electric range achieved by EDrive with its modification of the Prius with larger lithium ion batteries. Toyota has indicated that the Plug-in HV is not ready for commercialization, because it uses low-energy nickel-metal hydride batteries, rather than more advanced lithium-ion batteries. The company sees battery technology as the key technical barrier to the viability of plug-in hybrid vehicles. Toyota and General Motors have announced targets of 20 to 40 miles on a single charge for plug-in hybrids.

The U.S. government offers up to $3,400 in credits against income taxes for the first 60,000 U.S. taxpayers who purchase certain certified hybrid vehicle models from any manufacturer. Generally the certification is related to the improvement in gasoline mileage and decrease in greenhouse gas emissions. The combination of this tax credit and the reduction in the cost of fuel (i.e. use of lower-cost electricity in place of expensive gasoline) may be adequate to recover the higher price of some hybrid vehicles (but not others) over a few years. Toyota, for instance, has already reached the 60,000 limit, and the tax credits are being phased out over a year for both Toyota and Lexus models.

The primary motivation for buying the more efficient hybrid vehicles such as the Toyota Prius and Honda Civic appears to be better gas mileage. However, trends in newer hybrids (Toyota Highlander and Honda Accord) have been to emphasize performance (0 to 60 mph in about 7 seconds), whereas gas mileage is only a little better than their conventional counterparts. Honda recently discontinued its most efficient hybrid, the two-passenger Honda Insight, apparently because it sold less than 1000 vehicles in the last year. The total number of hybrid vehicles sold in the United States in 2005 was 205,749 of which 52% were the Toyota Prius. Even so, this is a small fraction of the ~15 million total vehicles sold annually in the United States. Given the present pattern of traditional hybrid designs and sales, the overall impact on the amount of gasoline used for transportation in the United States is not likely to be significant. Estimates for market penetration in a decade or two range from 3% by J. D. Power Forecasting to 80 % by Booz Allen Hamilton, with the DOE EIA predicting a conservative 7% of total sales. If an average of 30% improvement in gas mileage and a 30% market penetration by conventional hybrids is assumed, the savings of gasoline would be only about 0.6 of the 9.0 million barrels per day currently used, a 6.9% saving. This is not the kind of fuel saving that is needed in the United States to significantly reduce the U. S. dependence on foreign imports. The conclusion is that the traditional hybrid vehicles will not significantly reduce fuel consumption in the United States. Only plug-in hybrid-electric (or perhaps hydrogen fueled) vehicles can save enough gasoline to significantly reduce gasoline consumption to the extent needed.

Given the situation described above in which the market penetration for conventional hybrids appears limited with the primary emphasis of recent models on performance rather than fuel economy, we must look to the plug-in hybrids to achieve a significant saving of fuel. It is theoretically possible to save almost 75% of the fuel currently used, some 6.7 of 9.0 million barrels per day if all vehicles suddenly became plug-in hybrids operating in the average manner described in the model. If there were only a 30% market penetration by plug-in hybrids, there would be a savings of about 2 of the 9 million barrels per day, about three times the savings of traditional hybrid vehicles.

5.2.1.2. U.S. light-vehicle transportation statistics and model

Estimates based on extrapolated DOE-EIA data[8] from the 1990s indicate that there are approximately 225 million four-wheel, light-transportation vehicles in the U.S; 133 million are passenger automobiles and 92 million are light truck vehicles (including SUVs, minivans, pickup trucks, and delivery vans). It is further estimated by EIA that on any given day, on average, 50% of U.S. vehicles are driven less than 20 miles. Using these statistics, a simple model can be developed to calculate the potential saving of fuel by the use of hybrids operating in a plug-in mode. The model assumes that only the electric motor, operating on batteries charged from electric-utility sources, is used to power a vehicle until the battery has discharged to a level requiring charging of the battery to maintain normal full-hybrid performance (estimated to be 35 miles). Beyond that point, the gasoline (or diesel) engine and electric motor would operate together in the normal full-hybrid mode.

Model for plug-in operation

As before, the standard automobiles and light truck vehicles are grouped and assumed to achieve an overall average of 20 miles per gallon of gasoline.[9] It is assumed that in two to three decades (i.e., 2025 to 2035), all these vehicles are hybrids capable of the plug-in mode of operation.[10] This involves charging the batteries of a hybrid vehicle overnight using electricity from an electrical outlet, typically in the owner's garage. It is assumed that when batteries are fully charged, these hybrids can operate using only the electric motor for at least the first 35 miles. For this type of operation, the controls of current full-hybrids would need to be modified so as not to use the gasoline engine to recharge the batteries beyond the level necessary to sustain normal hybrid operation. The vehicles envisioned by the authors for plug-in operation are those manufactured by automotive companies to meet today's safety and quality standards, and are equipped with normal features such as automatic transmission, air conditioning, and power steering. Hence, a more powerful electric motor (kW) and better and higher-capacity batteries (kWh) would be required.[11] This could lead to the use of a smaller gasoline engine. Solid-state digital controls capable of optimizing performance and economy while minimizing the use of fuel should make the performance and economics of these vehicles more than competitive with comparable standard vehicles while drastically reducing both fuel consumption and greenhouse gas emissions.

[8] Unless otherwise indicated, data on U.S. vehicles are from the DOE Energy Information Administration's (EIA) statistics available on the internet (see Bibliography).

[9] DOE EIA data show that in 2003, automobiles averaged 22.3 miles per gallon and light trucks averaged 17.7 mpg.; hence, 20 mpg is a reasonable weighted-average value for all vehicles (see Bibliography).

[10] This assumption was made in order to evaluate the total potential savings of fuel associated with using hybrid vehicles operating in the plug-in mode. Fuel savings will be reduced in relation to the percent of light vehicles that are not plug-in hybrids.

[11] Most current commercial full-hybrid vehicles would have to have batteries with at least five times more capacity (kWh) and probably more power (kW) to operate at highway speeds for this distance.

5.2.1.3. Model to calculate fuel saved by the plug-in mode of operation

The model assumes that each day one-half of the 225 million light-hybrid vehicles operate only for 15 miles on batteries alone while the other half operate on batteries alone for their first 35 miles and then automatically switch to normal full-hybrid mode (in which gasoline powers the vehicles for the remaining miles that day). This means that electrical energy provided by a utility to recharge batteries would drive these vehicles for a grand total of 5.625 billion miles per day or an average of 9,215 miles per vehicle year.[12] If the comparable standard (non-hybrid) light vehicle averages 20 miles per gallon, then 225 million light vehicles would use 281 million gallons of fuel per day to travel 5.625 billion miles per day. Hence, it is theoretically possible, based on this simple model, to replace 281 million gallons (6.7 million barrels) of fuel per day with electricity by using hybrid vehicles operating in the plug-in mode.[13] This represents 74.4% of the estimated nine million barrels of oil per day now used to produce gasoline for standard automobiles and light-truck based vehicles.[14] These results are consistent with work carried out by the Electric Power Research Institute in cooperation with Daimler Chrysler. [7] Clearly reductions in both imported oil for transportation fuels and emitted atmospheric pollutants would be dramatic with widespread acceptance of full-hybrids operating in the plug-in mode with power from non-carbon sources. However, realistically, some of the *saved* fuel would still be needed, because in the two to three decades needed for full implementation, the number of vehicles and the number of miles driven per vehicle in the U.S. could increase significantly—perhaps 50% or more in total miles.

5.2.1.4. Fuel cost savings

At a price of \$3.00 per gallon, the fuel cost is \$0.15 per mile for standard light vehicles averaging 20 mpg. Since a gallon of gasoline contains 36.65 kWh of thermal energy, 1.833 kWh is used per mile. However, the efficiency of an internal combustion engine operating over a range of speeds plus energy losses in the transmission, drive, and tires results in an "overall gasoline thermal energy to miles travelled efficiency" of about 20%.[15] Hence, the average mechanical energy expended at the pavement for driving the vehicle is only 0.367 kWh per mile. If the overall efficiency of the electric drive including charger, batteries, motor, generator, and drive is 70%, the electrical energy purchased from the utility is 0.524 kWh per mile. Because the proposed plug-in mode of operation would probably require larger batteries and perhaps a larger electric motor, adding a few hundred pounds of weight to the vehicle, this value could be increased by 15% to 0.603 kWh per mile. At a price of \$0.08 per kWh[16], the cost of electricity to drive a mile in a hybrid vehicle is only \$0.048. This is \$0.102 per mile less than the \$0.150/mile for gasoline. For the half of light hybrid drivers in our model who travel 15 miles per day (5,475 miles per year) using electricity, the annual savings would be \$558 per year. For the other half of the light-hybrid drivers who travel 35 miles per day (12,770 miles per year) using electricity before shifting into full-hybrid mode, the savings would be \$1303 per year. There would also be some additional saving of gasoline, calculated to be 108 gallons/year, associated with full-

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[12] [225 x 10^6 vehicles] x [(15 +35)/2 miles/vehicle day] = 5.625 x 10^9 miles/day;
[5.625 x 10^6 miles/day x 365 days/year] / 225 x 10^6 vehicles = 9125 miles/vehicle year.

[13] 5.625 x 10^9 miles/day / 20 miles/gallon = 281 x 10^6 gallons/day or 6.70 x 10^6 barrels/day.

[14] Changing the model assumptions would give different numerical results, but would not affect the overall conclusion that it is possible to save a large majority of the petroleum fuel used for U.S. light vehicles today through the wide-scale use of plug-in hybrid vehicles.

[15] Estimate of this efficiency by Toyota Motor Company is 16%, which is used in the analysis of Japanese vehicles later in this chapter.

[16] This price is the estimated interruptible price in which the utility could interrupt the charging of vehicle batteries during short periods of peak electrical demand in exchange for a reduced cost of electricity. The consequences to the driver are estimated to be negligible, perhaps a few extra gallons of gasoline per year.

hybrid operation for the remaining distance travelled by the second half of the vehicles. This amounts to$324 per year for $3.00 per gallon gasoline. Hence, the total savings would be $1627/year at $3/gallon for the second half of the vehicles.[17]

5.2.1.5. Impact of tax on electricity used in vehicles

It is inevitable that if electricity becomes a significant source of energy for automotive and light-truck vehicle travel, it will be taxed by an amount sufficient to recover the tax revenue lost on petroleum-based fuels by governmental authorities at the national, state, and local levels. If we assume that the current total tax on these fuels is about $0.35 per gallon and the total consumption of fuel is 103 billion gallons per year (281 million gallons per day), the total tax would be $36.0 billion per year. Using information provided earlier, the calculated total kWh of electricity consumed in the plug-in mode would be 1.238 trillion kWh per year. The equivalent tax is about $0.029 per kWh, thereby increasing the cost of electricity used on the road from $0.080 to $0.109 per kWh. Hence, the fuel cost per mile for the light-hybrid vehicles increases from $0.0483 to $0.0657 per mile, which is still less than half of the $0.150 per mile for standard vehicles using $3 per gallon of gasoline. These electrical costs are equivalent to $0.97 and $1.32 per gallon respectively without and with taxes.

The annual savings for gasoline at $3 per gallon are substantial, but they may not be large enough to justify the additional cost of a plug-in hybrid vehicle. However, if the cost of gasoline increases to $5 or $6 per gallon, prices that are common in Europe today and a realistic possibility in the U.S. if oil imports are not significantly reduced or if taxes are imposed to reduce greenhouse gas emissions, the savings become much larger. These annual savings with and without taxes for gasoline prices ranging from $1 to $7 per gallon are shown in Figure 5.2.

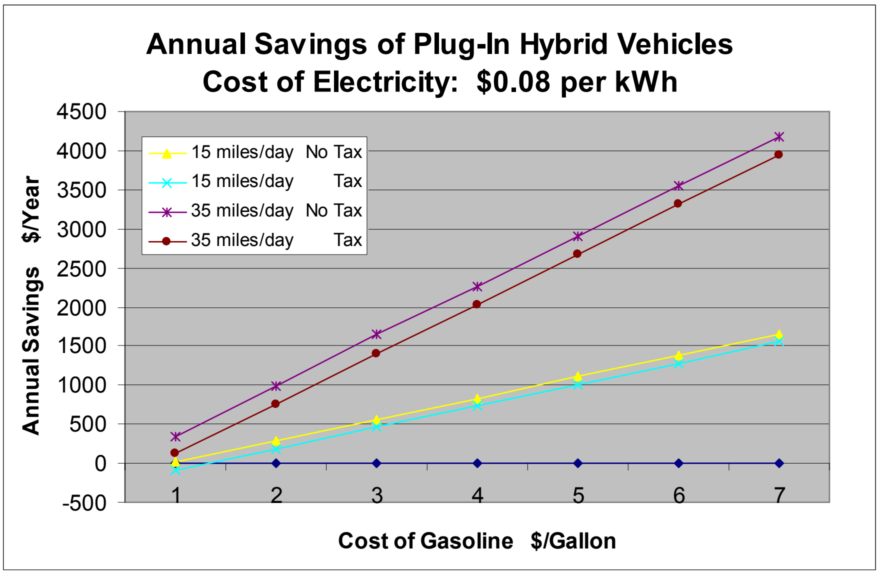

FIG. 5.2. Annual savings of plug-in hybrid.

[17] [(7.560 x 10^9 – 5.625 x 10^9) miles/day x 365 days/year x $3/gal] / [225 x 10^6 vehicles x 29 miles/gal] = $324/vehicle year.

5.2.1.6. Home electrical service required

Now let us look at the electrical supply required to support plug-in hybrid-electric vehicles. Light-hybrid vehicles that travel 35 miles per day on electricity using 0.603 kWh/mile would use 21.1 kWh per day. If batteries are to be charged in eight hours at night using a 110-volt system, the required capacity would be about 24 amps. However, charging batteries requires more current when the batteries are deeply discharged, so the peak currents could be higher. Even so, it seems reasonable that most modern homes would have adequate spare capacity to provide at least 30 amps at 110 volts during the night. Apartment dwellers or urban dwellers who rely on street-side parking or public parking facilities may not have ready access to electricity for overnight charging. Infrastructure would need to be developed to accommodate such consumers.

5.2.1.7. Electric utility generating capacity

Plug-in hybrid electric vehicles may represent a significant new demand for electricity. It is important to know, then, the total potential electrical generating capacity required. Multiplying the 5.625×10^9 miles per day for all the light hybrids using electricity times the 0.603 kWh per mile results in 3.39 billion kWh per day. Charging the batteries in eight hours would require 424 million kWe or 424 GWe. This equals the output of 424 power plants of 1,000 MWe size. Because the entire generating capacity of the United States today is about 950 GWe, it is clear that there would not be sufficient spare capacity available at night or any other time to charge the batteries of all the hybrids that could exist in 2035. Although not all charging would occur in the same eight-hour period because of time zones and the availability of some existing excess capacity, significant new generating capacity—perhaps 200 to 250 new 1,000 MWe nuclear or other non-polluting plants—would have to be built to charge the batteries for complete conversion to plug-in hybrids. New transmission and distribution lines and substations would also be needed to deliver the electrical power. Building 200 to 250 new 1,000 MWe power plants and associated power delivery facilities in two to three decades would be a daunting task, but certainly feasible.

5.2.2. Opportunities in Japan

5.2.2.1. Model evaluation of plug-in hybrid-electric vehicles in Japan

The effect of introducing plug-in hybrid electric vehicles (PHEV) in Japan is evaluated for the category of personal use passenger vehicles.

Target vehicles for evaluation

As described earlier, in Japan passenger cars are classified into two categories: the ”registered” vehicle and the ”light” vehicle. Typical statistical data of these vehicles are shown in Table 5.5, which are derived from the 2003 Report by the Ministry of Land Infrastructure and Transport, Japan (MLIT).

Table 5.2.1. Data used for evaluation of PHEV

	Registered vehicles	Light vehicles
Number of cars	42,620,000	11,820,000
Average distance traveled per working day per car, km	40.7	27.9
Working ratio *, %	66.9	72.7
Average distance traveled per day per car, km	27.2	20.3
Average distance traveled per year per car, km	9,900	7,400
Fuel consumption per car per Km **, liter/km	0.12	0.09

* Working ratio＝(Working days x cars / Existing days x cars) x 100
** Gasoline engine

Methodology and input data

The methodology and most of the parameters used are similar to the U.S. analysis just described. [2] Nevertheless, there are some differences from the U.S. analysis:[18]

- The average electric run fraction is estimated from the statistical data from MLIT;
- The tank-to-wheel efficiency for ICEVs is based on the information from Toyota Motor Company.

Input data used for the evaluation are as follows:

- Tank-to-wheel efficiency for ICEVs: 16%;
- Battery-to-wheel efficiency for PHEVs: 70% (Adding 15% to the required energy because of the extra weight for PHEVs);
- Gasoline price: 122 Yen/litre including a gasoline tax of 53.8 Yen/litre;
- Electricity price: 10 Yen/kWh (A typical price of the midnight special fee for 11pm to 7am including the basic charge);
- CO_2 emission for gasoline: 2.32 kg-CO_2/liter gasoline (Guideline by the Ministry of Environment);
- CO_2 emission for electric power: 0.381 kg-CO_2/kWh (Performance data of Tokyo Electric Power Company in 2004).

Electric run fraction

In this evaluation, the average daily travel distance is estimated from the statistical survey data by MLIT on the relationship of passengers carried for various distances for the categories of vehicle as described in Section 5.1.2 In Fig. 5.1. is shown the cumulative fraction of vehicles with average daily travel distances for the two categories of vehicles.

The average fraction, by distance, of traveling in the electric vehicle mode (electric-run) relative to the capacity of the equipped battery can be estimated from the relation of Fig. 5.1. The relation obtained for the average electricity-run fractions is shown in Fig. 5.3 for the registered vehicles and the light vehicles. From the figure, it is estimated that 70% of the electric-run fraction by distance can be obtained by installing a battery with a capacity of about 60km for the registered vehicles and about 35 km for the light vehicles.

[18] Abbreviations

ICEV: Internal Combustion Engine Vehicle

PHEV: Plug-in Hybrid Electric Vehicle

HEV: Hybrid Electric Vehicle or Gas-Electric Vehicle

BEV: Battery Electric Vehicle

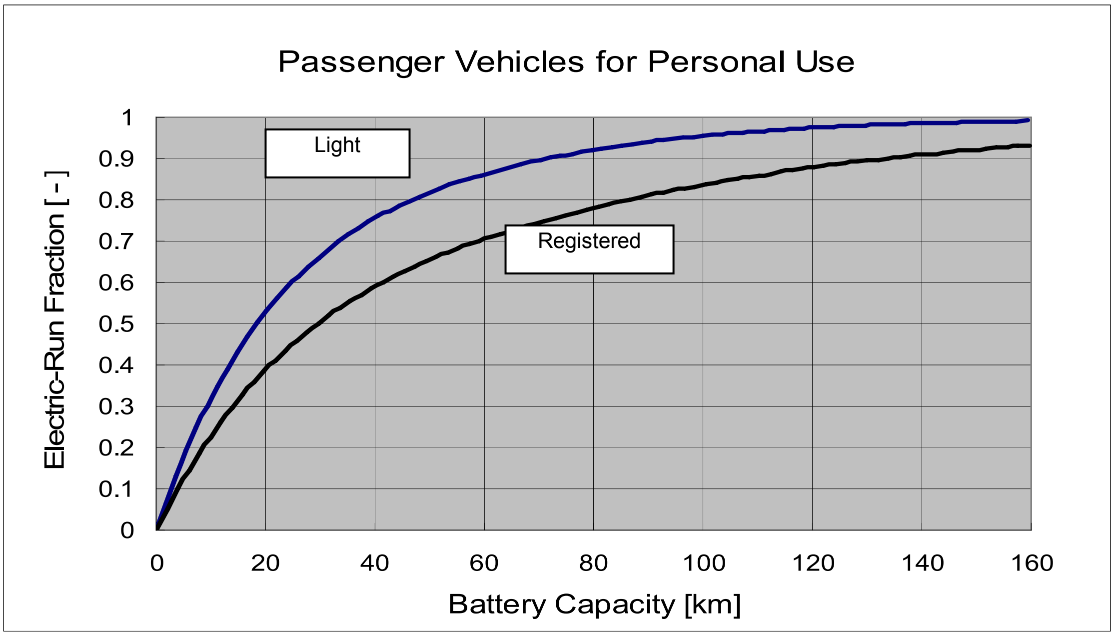

FIG. 5.3. Relation of electric-run fraction with battery capacity.

Running cost

The running costs of ICEVs, PHEVs in the electric-run mode, and PHEVs in the mixed electric-run/hybrid-electric mode are evaluated and compared as follows:

The running costs for registered vehicles are:

- ICEV: 14.6 Yen/km
- PHEV in the electric-run mode: 3.0 Yen/km
- PHEV in the 70% electric-run mode and 30% hybrid-electric mode: 4.0 Yen/km

The running costs for the light vehicles are:

- ICEV: 11.0 Yen/km
- PHEV in the electric-run mode: 2.3 Yen/km
- PHEV in the 70% electric-run mode and 30% hybrid-electric mode: 3.0 Yen/km

The running cost of PHEVs in the electric-run mode is about 1/5 of that for a gasoline ICEV, and the running cost of PHEVs in the 70% electric-run mode and 30% hybrid-electric mode is 1/3.6. If the gasoline tax is excluded, this ratio becomes 1/2.7 and 1/2.6, respectively.

5.2.2.2. Electric power requirements in Japan

If all the vehicles (both registered vehicles and light vehicles for a total of 54 million vehicles) become PHEVs in the 70% electric-run mode, the total electricity requirement for 8-hour charging is about 35 GW (35 units of 1,000 MW plant). Since there is about a 50-GW difference between the peak hours and the midnight hours currently in Japan, most of the power for all PHEVs could be supplied by the spare power.

Since nuclear power is presently used as the base load in Japan, the additional power requirements would have to be supplied by operating fossil fuel plants at night. For energy security and global environment, it is better to shift the power supply structure, in the course of introducing PHEVs, to a greater nuclear share by replacing the fossil fuel plants by new nuclear plants.

5.2.3. Energy utilization efficiencies of various power trains

Energy flow to the vehicles with various power trains, such as internal combustion engine vehicles (ICEVs), hybrid electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and hydrogen fuel cell vehicles (FCVs), is shown in Fig. 5.4.

The energy carriers such as hydrocarbons (gasoline, diesel oil, etc.), electricity, and hydrogen are produced from primary sources, such as fossil fuels, nuclear energy, and renewable energies.

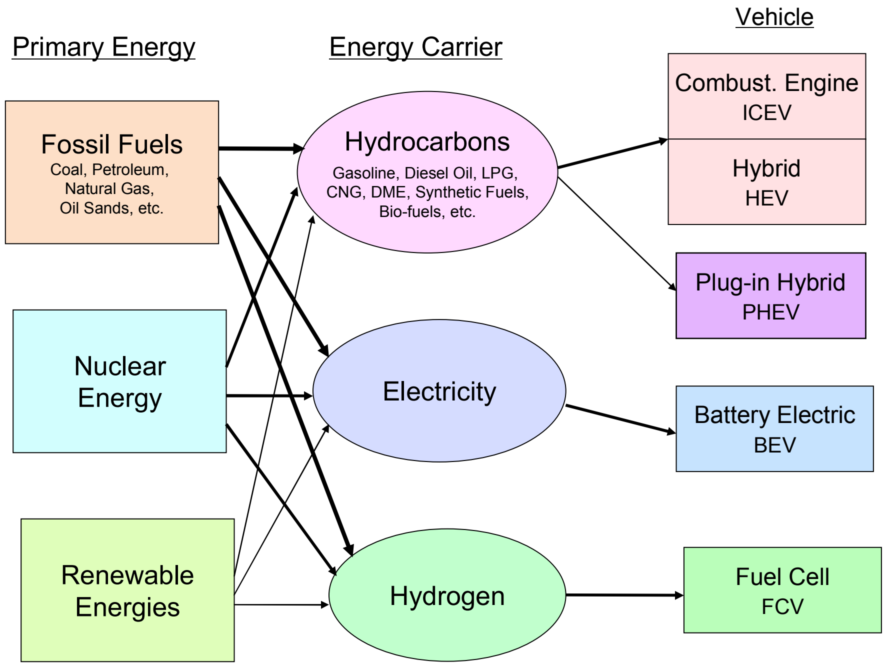

FIG. 5.4. Energy flows to vehicles with various power trains.

Table 5.5. Energy utilization efficiency for various power train vehicles well-to-wheel efficiency – fossil fuels

<table>
<tr><th></th><th colspan="2">Well to Tank Efficiency</th><th colspan="2">Tank to Wheel Efficiency</th><th colspan="2">Well To Wheel Efficiency</th></tr>
<tr><td>Gasoline Engine Vehicle
ICEV</td><td rowspan="3">Oil Field</td><td>88 %</td><td rowspan="3">Tank</td><td>16 %</td><td rowspan="6">Wheel</td><td>14 %</td></tr>
<tr><td>Gasoline Hybrid Vehicle
HEV</td><td rowspan="2">88 %</td><td rowspan="2">32~37 %</td><td>28~32 %</td></tr>
<tr><td rowspan="2">Plug-in Hybrid Vehicle
PHEV</td><td rowspan="2">(29~30 %)</td></tr>
<tr><td rowspan="3">Natural Gas Field</td><td rowspan="2">50 %</td><td rowspan="2">Battery</td><td rowspan="2">70 %</td></tr>
<tr><td>Battery Electric Vehicle
BEV</td><td>35 %</td></tr>
<tr><td>H_2 Fuel Cell Vehicle
FCV</td><td>58~70 %</td><td>Tank</td><td>50~60 %</td><td>29~42 %</td></tr>
</table>

- The values for ICEV, HEV, FCV are from a Toyota Motors's 2003 presentation. The values for FCV are for the hybrid specification.
- Electric Power for BEV is based on the natural gas ACC power generation of 55% thermal efficiency, 5% loss from well to station, and 5% loss for electricity transmission and distribution.
- EV battery-to-wheel efficiency is based on Uhrig (ANS, 2005).
- PHEV adds 15% to the energy required by weight increase. PHEV well to wheel efficiency is estimated for 70% EV run.
- The heating values are based on the Lower Heating Value (LHV).

The lifecycle energy utilization efficiencies of vehicles are usually expressed by Well-to-Wheel (WTW) efficiencies, of which typical values are shown in Table 5.5. In this table, for gasoline engine vehicles the ”well” means the oil wells producing crude oils, and for battery powered electric vehicles and hydrogen fuel cell vehicles the ”well” means the gas fields producing natural gas currently used for hydrogen generation. From Table 5.5, the FCV has the highest efficiency and the BEV is the second highest. The PHEV efficiency would be somewhere between BEV and HEV.

The energy utilization efficiencies for BEVs and FCVs using nuclear energy as a primary source are shown in Table 5.6. Here, the efficiencies for three kinds of nuclear reactor are examined, namely LWR (Light Water Reactor, typical of low-temperature reactors), SFR/SCWR (Sodium-cooled Fast Reactor / Super Critical Water Reactor, typical of medium-temperature reactors), and VHTR (Very High Temperature Gas-cooled Reactor, typical of high-temperature reactors).

As for the LWR-based energy flow paths to vehicles, one path is the electricity from a LWR being supplied to the BEV, and the other is hydrogen from water electrolysis by LWR electricity being supplied to the FCV. As for the SFR/SCWR-based energy flow paths to vehicles, one path is electricity from a SFR/SCWR being supplied to the BEV, and the other path is hydrogen from SFR/SCWR-heated steam reforming of natural gas being supplied to the FCV. As for the VHTR-based energy flow paths to vehicles, one path is electricity from a VHTR being supplied to the BEV, and the other path is hydrogen from a thermochemical splitting of water by VHTR heat being supplied to the FCV.

As shown in Table 5.6, in either the LWR or the VHTR case, the path to BEVs is more efficient than the path to FCVs. This is due to the following two reasons:

(1). Both the electricity generation and the hydrogen production by electrolysis or thermochemical splitting of water have to go through the a heat engine cycle in which the conversion efficiency is limited by thermodynamic laws (the Carnot-cycle efficiency providing an upper limit);

(2). The drive train efficiency is higher in a BEV (70%) than in an FCV (50-60%).

In contrast to the above assessment for LWR and HTGR systems, in the SFR/SCWR case the path to FCVs provides a higher efficiency than the path to BEVs, as hydrogen is produced by the process of nuclear-heated steam reforming of natural gas (methane). In this hydrogen production process, the chemical energy of methane and nuclear heat is converted to the chemical energy of hydrogen with no limitations of thermodynamic cycle efficiency. This is the same as in the case of hydrogen production from natural gas shown in Table 5.5.

In the case of nuclear-heated steam reforming of methane, it is inevitable that the process produces CO_2 though the total amount produced is reduced by about 30% as compared to the case of conventional methane-combusted steam reforming of methane.

A medium-temperature reactor with an outlet temperature 500 - 600 ºC such as an SCWR or an SFR is the best suited for the membrane reformer hydrogen production method using palladium (Pd) as membrane material. The Pd-membrane reformer has been developed by Tokyo Gas as a production method for a hydrogen fueling station [9, 10]. The nuclear-heated membrane reformer that combines the membrane reformer with a nuclear reactor has been designed by Mitsubishi HI and others and evaluated to be economically competitive with conventional methane-combusted steam reforming of methane [11]. HTGRs and other higher-temperature reactors could also be used in this application with the excess heat available for other purposes such as electricity production or process heating uses. That case has not been assessed here.

Table 5.6. Energy utilization efficiency for electric and fuel cell vehicles 'nuclear reactor to wheel' efficiency

Nuclear Reactor	Electricity / Hydrogen Vehicle Power Train	Efficiency Reactor → Battery/Tank	Efficiency Battery/Tank →Wheel	Overall Efficiency Reactor →Wheel
L W R	Steam Turbine BEV	30%	70%	21%
	Electrolysis FCV	23%	50~60%	12~14%
SFR / SCWR	Steam Turbine BEV	39%	70%	27%
	Nuclear-Heated Steam Methane Reforming FCV	77%*	50~60%	38~46%*
VHTR	Gas Turbine BEV	45%	70%	31%
	Thermochemical FCV	45%	50~60%	23~27%

- Thermal efficiency: LWR steam turbine 32%, SFR steam turbine 41%, VHTR gas turbine 47%
- Efficiency of H_2 production: Electrolysis 80% from electricity and Thermochemical from heat 50% (LHV) Reforming 85% (* Based on the sum of both primary energies)
- Transmission & distribution loss for electricity: 5%, Compression & transportation loss for H_2: 10%

It can be concluded that, in the nuclear energy based energy flow to vehicles, the path to electric vehicles is more efficient than the path to hydrogen fuel cell vehicles, except in the case of using hydrogen produced by nuclear-heated steam reforming of methane.

5.2.4. Greenhouse gas emissions in Japan

The CO_2 emissions of ICEVs, PHEVs in the electric-run mode, and PHEVs in the mixed electric-run/hybrid-electric mode are evaluated and compared as follows:

The CO_2 emissions for registered vehicles are:

- ICEV: 0.278 kg-CO_2/km
- PHEV in the electric-run mode: 0.115 kg-CO_2/km
- PHEV in the 70% electric-run mode and 30% hybrid-electric mode: 0.117 kg-CO_2/km

The CO_2 emissions for the light vehicles are:

- ICEV: 0.209 kg-CO_2/km
- PHEV in the electric-run mode: 0.0866 kg-CO_2/km
- PHEV in the 70% electric-run mode and 30% hybrid-electric mode: 0.0877 kg-CO_2/km

The CO_2 emissions of both PHEVs in the electric-run mode and PHEVs in the 70% electric-run mode and 30% hybrid-electric mode is about 1/2.4 of that for gasoline ICEVs.

5.3. Challenges

This section discusses technical barriers, and Section 5.4 addresses potential solutions. Certainly there are separate barriers associated with transportation infrastructure and with the electric power industry, but these are outside the scope of this document. Some of these barriers are:

- Conversion of automobile technology from conventional gasoline-powered vehicles to electric and plug-in hybrid vehicles;
- Public acceptance of plug-in hybrid vehicles;
- Structuring of electricity pricing mechanisms to provide low-price electricity during off-peak demand periods to encourage use of nuclear power plants for base load generation;
- Provision of other incentives (e.g., tax benefits) for adoption of vehicles that produce less greenhouse gases and reduce reliance on petroleum fuels.
- Building of carbon-free electricity generation capacity and electricity transmission and distribution systems.

5.3.1. Barriers to be overcome in the United States of America

Barriers to plug-in hybrid vehicles

Only a few plug-in hybrids are in existence in the United States, and until recently none of them came from an automotive manufacturer. E-Drive Systems has converted several Toyota Prius models by replacing the nickel metal hydride battery with a lithium-ion battery system having thousands of small cells with about seven times the energy storage capacity of the Prius nickel metal hydride battery. A modified control system has been added to optimize the performance while minimizing the use of gasoline. The cost of the conversion is about $10,000 for each vehicle. DaimlerChrysler initially built five Sprinter delivery vans that they distributed for testing (three in the United States of America). Recently, they announced that they were building several dozen Sprinter vans for testing under a wide variety of circumstances throughout the world. It is clear that the plug-in hybrid has a long way to go before it can displace a significant fraction of the 9 million barrels of fuel used every day in the United States.

The focus on delivery vans by DaimlerChrysler is a logical approach. The potential savings of fuel costs by fleets of such vehicles operated from a central facility — the Postal Service, delivery services, military organizations, or similar commercial and government organizations with fleets of vehicles where centralized battery charging could become a routine part of the daily maintenance and service — should be greater than the initial extra cost. The critical item for improving the performance of plug-in hybrid vehicles is lighter, less expensive, reliable, more robust batteries having a factor of 5 to 10 greater energy storage capacity.

General Motors displayed a plug-in hybrid vehicle named Volt at the Detroit Auto Show in early 2007 [12]. It has a series configuration in which the electric motor drives the vehicle full time, and the engine (3-cylinder, 1000 cm^3 displacement), capable of using gasoline or ethanol E85, only drives the generator to charge the 400 pound lithium ion battery. It is effectively an electric vehicle with a motor-generator that can travel 40 miles without charging and can be fully charged in six hours on 110 volt electricity. Indeed, the Volt has considerable similarity to the defunct GM electric EV1 vehicle (made infamous in the movie "Who Killed the Electric Car?"). This appears to be the simplest and quickest way to develop a new plug-in hybrid by using their experience with the EV1. GM is still developing hydrogen as an automotive fuel and has suggested that they might use a hydrogen-fueled fuel cell in place of a gasoline engine on their PHEV. However, GM has not announced any plans to build plug-in vehicles for lease or sale, and has indicated that there is need for improved and lower cost batteries to make plug-in vehicles commercially viable. Volt is the first variant built upon GM's E-flex system that will enable them to utilize the same chassis for multiple electric drive systems.

Ford Motor Company also displayed its PHEV concept at the 2007 Detroit Auto Show. Called the Airstream because its style resembles the iconic "Airstream" aluminum recreational vehicles, it uses lithium batteries with an all-electric travelling range of 25 miles that are charged using a fuel cell. The hydrogen fuel cell drive train operates under electric power all the time. It has half the weight and cost of today's fuel cells and, unlike most fuel cells, it can operate under extreme winter conditions.

5.3.2. Barriers to be overcome in Japan

As summarized by Professor Hisashi Ishitani of Keio University at the closing speech of EVS-22 Workshop on "Plug-In Hybrid Electric Vehicle Workshop" that was held on October 25, 2006, in Yokohama, Japan, the view of Japanese industry and academia on plug-in hybrid electric vehicles can be expressed as follows:

(1) It is expected that PHEVs are an effective measure to solve the CO_2 and energy issue, and also a practical and possible transition from HEVs to FCVs;

(2) The challenge is the cost and durability of batteries. It is necessary to support the development of this technology;

(3) It is better to put forward the introduction of PHEVs, focusing on the petroleum savings and CO2 reduction, by an available set-up (like the hybrid mode) than a pure-EV mode, which may be difficult in the early stage;

(4) It is essential not to repeat the failures in development of BEVs and FCVs. As PHEVs are seen to be based on current technology, it is vital to take one step forward at a time by assessing the accomplishments along the way.

As stated in the press release of Toyota Motor Corporation in June 2006, Toyota will advance its research and development of plug-in hybrid vehicles and is working on a next-generation vehicle that can extend the distance traveled by the electric motor alone and that is expected to have a significant effect on reducing CO_2 and helping to abate atmospheric pollution. Toyota also said on other occasions that PHEVs would not be feasible for mass production without a breakthrough in battery technology, and that, with today's best technologies, PHEVs are not commercially viable.

Toyota reiterated this point on July 25, 2007, when it announced it is donating several prototypes of its Plug-in HV to the University of California-Irvine and the University of California-Berkeley for road testing. The Plug-in HV has a battery range of only 8 miles on a full charge, because of its use of low-energy nickel-metal hydride batteries, rather than more advanced lithium-ion batteries, which are not yet available for these purposes.

In August, 2006, the Study Group on Next Generation Vehicle Batteries in the Ministry of Economy, Trade and Industry (METI) issued a report, "Recommendations for the Future of Next-Generation Vehicle Batteries" (The main text is written in Japanese, though an English summary is available) [13].

In Annex 5 of this report, the battery cost and the competitiveness of PHEVs with ICEVs and HEVs are evaluated for setting the R&D goals of battery development. The comparison was made on the sum of vehicle purchase cost and fuel/electricity cost for a 10-year vehicle life. One example on Prius-class vehicles shows that, for the PHEV to become comparable with ICEVs and HEVs, it is necessary to reduce the cost of lithium-ion battery from the current cost (200 K Yen/kWh) by a factor of about 7 (to 30 KYen/kWh).

This example shows that intensive efforts toward development of battery technology are necessary for the introduction of economically competitive PHEVs into the market. The report recommends that, for introducing PHEVs around 2015, it is necessary to conduct a battery development project that is completed by about 2010. The recommended action plan by the Study Group is described in Section 5.4.2.

5.4. Solutions

5.4.1. Solutions in the United States of America

Hybrid battery technology

Today, most commercial hybrid vehicles have sealed nickel metal hydride batteries. They are significantly better than traditional lead-acid batteries, but are relatively heavy, expensive, and do not show a capability of becoming much less expensive in mass production. The power of nickel batteries comes from the raw material, which is getting more expensive because of increased demands. The primary alternative under consideration today is the lithium-ion battery, made up of thousands of lithium cells, each one of them the size of a common "AA" battery. The Volvo 3CC concept car, unveiled in 2004, was an all-electric vehicle that relied exclusively on 3000 lithium-ion cells and provided the equivalent of 105 horsepower with zero emissions. The benefits of the lithium-ion batteries are derived from the mass processing that can scale to the high volumes required for the rapidly growing hybrid vehicle market without a corresponding increase in price. Larger and fewer lithium ion-cells would have been more attractive, but they do not exist commercially yet. Furthermore, as lithium cells that use cobalt-oxide cathode material become larger, they sometimes encounter thermal-runaway transients in which they burn or explode. Substituting phosphate for cobalt seems to prevent this problem, but reduces the output power. Even so, progress is being made to address these problems. Estimates are that it will take three to five years before such batteries are available in large size and are powerful enough, cheap enough, and reliable enough for mass-produced vehicles. Meanwhile, lithium ion battery packs with thousands of cells continue to be the primary technology under consideration for PHEVs in the near future.

5.4.1.1. Research and development in the United States of America

R & D in batteries

As an example of research progress in the U.S., recently U.S. patent #06979513 entitled "Battery Including Carbon Foam Current Collectors" (assigned to Firefly Energy Corporation, Peoria, Illinois, a spinout from Caterpillar Tractor Corporation) appeared on the "Battery Digest" web site.[19] This patent has similarities to an earlier patent issued to Alvin Snaper regarding foam plates in lead acid batteries.[20] The fundamental concept of both patents is a replacement of the lead plate current collectors. With both concepts, active materials are deposited on a high-surface-area substrate, reducing total weight and possibly offering additional advantages of corrosion resistance and higher power density. The high surface area greatly increases the current density, leading to much greater current delivery. Furthermore, the Firefly carbon foam substrate has a very high thermal conductivity, thereby overcoming the thermal build-up reported in larger lithium ion batteries.

5.4.2. Solutions in Japan

The METI Study Group recommended two action plans for the future of next-generation vehicle batteries in August 2006, namely the R&D Strategies and the Infrastructure Building Strategies.

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[19] Inventors: Kelley and Votoupal. Assignee: Firefly Energy Corporation.

[20] This description is taken from the Batteries Digest Web Site at http://batteriesdigest.com/id492.htm.

Action Plan – R&D Strategies

This action plan is composed of three phases: (i) Improvement phase, (ii) Advanced phase, (iii) Innovation phase. At each phase are specified the types of vehicles expected to be developed, performance and cost target of batteries, and the role of industry, government and academia. As shown in Table 5.7, the PHEV is supposed to be introduced around 2015 with a battery of 1.5 times performance and 1/7 cost of current batteries. The New Energy and Industrial Technology Development Organization (NEDO) will be the secretariat for coordinating universities, research institutes, automobile manufacturers, battery manufacturers, material manufacturers, and electric power companies.

Table 5.7. Japan's battery development action plan [13]

1. R&D Strategies

	Current status	Improved batteries (2010)	Advanced batteries (2015)	Innovative batteries (2030)
Vehicles expected to be realized	Small-sized EVs for electric power companies	Business use commuter EVs More Fuel Efficient HVs	Household commuter EVs Fuel cell vehicles Plug-in hybrid vehicles	Standard-sized EVs
Performance	1	1	1.5 times	7 times
Cost	1	1/2	1/7	1/40
Development system	Industry initiative	Industry initiative	Industry-government-academia collaboration	Universities and research institutions

2. Infrastructure Building Strategies

Promotion measures
- ○ Supporting expansion of other battery applications to promote mass production
- ○ Provide incentives for the diffusion of next-generation vehicles

Preparing of battery charger infrastructure
- ○ The appropriate state of policy supporting system for the diffusion of battery charge stands

Setting standards (test mode, safety, and infrastructure)
- ○ Designing safety regulation/standards for batteries
- ○ Consider standardizing interface of both batteries and battery charge stations

Standardization of batteries (Battery size, etc.)
- ○ Consider standardizing battery size

Deregulation
- ○ Consider establishing electricity rate for EVs

Demonstration experiments

This action plan is to be implemented along with the battery R&D plan, and is composed of building software and hardware infrastructures such as incentive measures for vehicle popularization, regulatory framework, standardization, safety standards, and battery charge stations, as shown in Table 5.7. The secretariat of this action plan will be the Japan Automobile Research Institute (JARI) and METI. The R&D strategies to implement this action plan, shown in Table 5.8, were taken from the report, "Recommendations for the Future of Next Generation Vehicle Batteries," carried out by the Study Group on Next Generation Vehicle Batteries, Ministry of Economy, Trade and Industry, Japan, in August 2006.

Table 5.8. Research and Development, Action Plan for Next Generation Battery Technology Development

	Phase	Time	Target Vehicle Type	Goals of Battery		
				Performance	Cost	Required R&D Items
1	Improvement	ca. 2010	Limited Purpose Commuter BEV Battery Range 80Km, 2 Seater	Same as Present 100Wh/Kg 1000W/Kg	1/2 of Present	Li-ion Battery Carrier: N.R. Material: P.R. Design: R.
			High Performance Hybrid HEV Fuel Economy 30% Up	Same as Present 70Wh/Kg 2000W/Kg	1/2 of Present	
2	Advanced	ca. 2015	Commuter BEV Battery Range 150Km, 4 Seater	1.5 Times of Present 150Wh/Kg 1200W/Kg	1/7 of Present	Li-ion Battery Carrier: N.R. Material: R. Design: R.
			Plug-in Hybrid Electric PHEV Battery Range 40Km	1.5 Times of Present 100Wh/Kg 2000W/Kg	1/7 of Present	
3	Innovative	2030~	Full-fledged Electric BEV Battery Range 480Km	7 Times of Present 700Wh/Kg 1000W/Kg	1/40 of Present	New Principle Battery Carrier, Material and Design: All Required

N.R.= Not Required, P.R.= Partly Required, R.= Required

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CHAPTER 6
ELECTRICITY AND HEAT FOR HYDROGEN PRODUCTION

As an alternative path to the current fossil fuel economy, a hydrogen economy is envisaged in which hydrogen would play a major role in energy systems and serve all sectors of the economy, substituting for fossil fuels. Hydrogen as an energy carrier can be stored in large quantities, unlike electricity, and converted into electricity in fuel cells, with only heat and water as by-products. It is also compatible with combustion turbines and reciprocating engines to produce power with near-zero emission of pollutants. Furthermore, hydrogen can be obtained from various primary energy sources that are domestically available in most countries. Consequently, the hydrogen economy could enhance both the security of energy supply and global environmental quality.

The current worldwide hydrogen production is roughly 50 million tonnes per year. Although current use of hydrogen in *energy systems* is very limited, its future use could become enormous, especially if fuel-cell vehicles would be deployed on a large commercial scale. The hydrogen economy is getting higher visibility and stronger political support in several parts of the world. In his "State of the Union Address" in 2003, the US President announced a $1.2 billion hydrogen initiative to reverse the growing dependence on foreign oil and reduce greenhouse gas emissions. The Japanese Prime Minister and the Chair of the European Commission have also made official statements strongly supporting the emergence of a hydrogen economy.

There are many ongoing national programmes aimed at the development of a hydrogen economy, such as the Hydrogen Initiative of the United States, the European Hydrogen and Fuel Cell Technology Platform, and fuel cell/hydrogen programmes in Japan and the Republic of Korea. There are also various international efforts for the realization of a hydrogen economy. Under the leadership of the United States, 15 countries and the European Commission launched the International Partnership for the Hydrogen Economy (IPHE) in 2003 to discuss common areas of interest in, and obstacles to, the hydrogen economy in the fields of research, development, and demonstration projects; hydrogen policy and regulation; and the commercialization of hydrogen-based energy technologies.

Today, hydrogen is used in limited quantities, and mainly in petroleum refineries and the chemical industry. In the United States, for example, these uses represented 93% of hydrogen consumption in 2003. However, hydrogen is an attractive energy carrier that might play a major role in energy systems for many economic sectors in the long term. In the medium term, the most promising area for hydrogen is in producing synthetic fuel as a substitute for gasoline in transportation. Hydrogen produced from non-fossil fuels may be a key option as the prices of hydrocarbon resources soar or their consumption becomes restricted for environmental reasons.

The advantages of hydrogen-based energy systems will depend on the hydrogen production systems implemented. Hydrogen will be a clean, environmentally friendly and sustainable energy carrier only if its production is sustainable, i.e., if its production does not induce irreversible environmental damages or exhaust non-renewable natural resources. Nuclear-produced hydrogen offers unique characteristics in terms of environmental friendliness and energy efficiency.

The development of hydrogen-based energy systems will require building not only hydrogen production facilities and end-use devices, but also infrastructure for the distribution of hydrogen. Such structural changes in production and use of energy will take time. This implementation period could facilitate the penetration of nuclear energy in the hydrogen supply market, allowing for the design and deployment of advanced nuclear energy systems (e.g., very high temperature reactors) better adapted to hydrogen production than the current generation of nuclear power plants.

An adequate and affordable supply of hydrogen is a prerequisite for successful implementation of a hydrogen economy. Although hydrogen is abundant in the world, it has to be extracted from compounds containing hydrogen such as fossil fuels, biomass, or water with thermal, electrolytic or photolytic energy. Table 6.1 shows some technological options that are or will be available for hydrogen production.

As shown in Table 6.1, nuclear energy is suitable for hydrogen production since nuclear reactors can produce both the heat and electricity required for it. Furthermore, it is the most commercially mature non-fossil fuel energy source capable of producing hydrogen on a large industrial scale with significantly lower CO_2 emissions.

Several technological options are possible for nuclear hydrogen production, including:

- Electrolysis of water using electricity from nuclear reactors;
- Steam reforming of natural gas using high-temperature heat from nuclear reactors;
- High-temperature electrolysis of steam using high-temperature heat and electricity from nuclear reactors;
- Thermo-chemical water splitting using high-temperature heat and electricity from nuclear reactors.

Table 6.1. Hydrogen production options

<table>
<tr><th>Raw Feedstock Options</th><th>Typical Processed Feedstock</th><th>Production Process Options</th><th>Process Energy Source Options</th><th>Production Strategy Options</th></tr>
<tr><td>Fossil Fuels
Coal
Natural gas
Oil</td><td>Syngas
Gasoline
Diesel fuel
Methanol
Ammonia
Direct use of raw stock</td><td rowspan="4">Thermal
Reforming
Steam reforming
Partial oxidation
Gasification
Pyrolysis
Thermochemical
Electrochemical
Electrolysis
Photoelectro-chemical
Biological
Photo-biological
Aerobic fermentation
Radiolysis</td><td rowspan="4">Thermal
Fossil
Renewable
Nuclear
Electricity
Fossil
Renewable
Nuclear
Photolytic
Solar
Radiolysis
Nuclear</td><td rowspan="4">Distributed
Fuelling stations
Individual buildings
On-board
Semi-distributed
Market-centred
Central
Resource-centred</td></tr>
<tr><td>Biomass
Lignocellulose
Starch
Vegetable oils
Black liquor</td><td>Ethanol
Methanol
Biodiesel
Biogas
Sugars
Direct use of raw stock</td></tr>
<tr><td>Waste Material
Municipal solid waste
Stack gases
Waste water</td><td>Direct use of raw stock</td></tr>
<tr><td>Water</td><td>Direct use of raw stock</td></tr>
</table>

Hydrogen can be obtained more efficiently by significantly raising the temperature of water. The electrolysis of steam at higher temperatures (800-1000°C) offers several advantages including a lower electricity requirement and higher efficiency resulting from increasing oxygen ion transport through the electrolyte and improving catalytic activity at the electrodes.

Although nuclear energy has the potential to play a significant role in a hydrogen economy, there are uncertainties about when hydrogen demand will be large enough to justify deployment of nuclear plants dedicated to hydrogen production or dual-production units capable of generating electricity and producing hydrogen. Furthermore, many existing and advanced power generation and hydrogen production technologies will compete with nuclear energy for hydrogen production, and market competition will select the most profitable options.

Hydrogen is a clean fuel, and the demand for it is increasing. To achieve its full potential, hydrogen production has to be emission free, either directly or indirectly. The only available technology today to meet this criterion is water electrolysis powered by emission-free electricity – either nuclear or renewable power. Several alternative technologies are being developed. Most of them would need an advanced high-temperature nuclear reactor as a heat source that is necessary for one or more steps in the hydrogen generation process. A few proposed technologies can use lower temperature heat that is available from the current generation of nuclear reactors.

Direct thermolysis of water requires temperatures over 2500°C. To lower the required temperatures, multi-step thermochemical water splitting processes are being explored. Hundreds of potential thermochemical cycles have been assessed in terms of their viability and performance. Several are undergoing active research around the world, including the iodine-sulphur (IS), bromine-calcium (Br-Ca) and copper-chlorine (Cu-Cl) cycles.

Currently hydrogen is produced mainly by steam reforming of natural gas/methane. Only a small fraction of hydrogen in the world (about 4%) is produced by electrolysis. Steam methane reforming (SMR) is a catalytic process involving the reaction of natural gas with steam to produce a mixture of hydrogen and CO_2, requiring temperatures in the range 500 to 950°C. It results in considerable releases of CO_2 both through burning of natural gas for supplying the heat for the endothermic reaction and through the shift reaction while generating hydrogen. CO_2 capture and sequestration would add to the costs. Nuclear-assisted steam reforming has potential for large-scale hydrogen production in the near term, though CO_2 still remains as a waste product. It would allow savings of natural gas of about 30% and could represent an important transition technology. In addition, research is underway using membrane techniques that can recirculate product gases and further reduce the CO_2 from steam reforming. Nuclear assisted steam reforming of methane could constitute a strategy for a successful continuum towards other CO_2-free production approaches being considered.

The other short-term option (over the next 5-15 years) is the production of hydrogen by electrolysis. Currently, electrolyser efficiencies are in the range of 60-80% and may reach 90%. In addition, electrolysers can be attractive as remote and decentralized hydrogen production methods. Because of the high electrical demands for the process, though, electrolysis of water is attractive only when cheap electricity is available or when particularly high-purity hydrogen is required. The use of nuclear generated electricity in off-peak periods from existing water-cooled reactors may be economically competitive, but the stranded capital costs of the electrolyzers during periods of peak electricity prices may be prohibitive.

6.1. Opportunities

The currently used commercial method for hydrogen production, steam-methane reforming (SMR), is starting to be less attractive, not only because of increasing natural gas prices and uncertain availability, but also because of considerable greenhouse gas emission. Low-temperature water electrolysis is one technology currently available for hydrogen production using the electricity generated from nuclear power plants without producing greenhouse gases. In August 2006 the U.S. Department of Energy (DOE) announced that it intends to provide approximately $1.4 million for two projects for industry partnerships to study the economic feasibility of producing hydrogen at existing commercial nuclear power plants. A study of the economics of producing hydrogen at existing nuclear power plants using commercially available production technology will be performed by Electric Transportation Applications (ETA), which is located in Phoenix, Arizona. ETA will partner with DOE's Idaho National Laboratory and Arizona Public Service.

A second feasibility study of hydrogen production using alkaline electrolysis powered by existing nuclear power plants will be performed by GE Global Research, which is located in Niskayuna, New York. Their work plan is based on low-cost alkaline electrolyzer technology developed by GE, in part through DOE's Hydrogen Program. Partners for this project include DOE's National Renewable Energy Lab and the Entergy Corporation.

About one-third of the world's primary energy is converted to electricity at present. The remaining two-thirds is consumed for such non-electric applications as process heat for industry, space heating, and transportation. The ratio of electricity will increase to about one-half at the end of 21st century. Still, one-half of all energy will be used for non-electric purposes. As it is essential to reduce the use of fossil fuels for the global environment, it is important to explore the possibility of nuclear energy's replacing fossil fuels for non-electric applications. One way to fulfil this need is to produce hydrogen by nuclear energy. Under this scenario, far more nuclear energy will be required than is currently anticipated.

According to the estimates of World Energy Council (WEC Case B) [1], the world's primary energy demand in 2100 will be about four times that in 1990, with nuclear energy supplying 24% of the total primary energy for electricity production. This nuclear supply corresponds to an equivalent of about 5,200 units, each with a capacity of 1000 MWe. The supply of fissile fuel to these plants is feasible as assessed by the World Energy Council, assuming an ultimate resource of natural uranium of 16.3 Mton, as reported in the NEA/IAEA Red Book [2], and the recycling use of plutonium by fast breeder reactors (FBR) with a breeding ratio of 1.2 to 1.3 introduced from 2030 - 2050 [3].

In order to reduce global greenhouse gas emissions and begin displacing fossil fuels, optimizing the recycling use of plutonium in breeder reactors could increase nuclear energy supply by 50% by 2050 and 100% by 2100. By effectively utilizing nuclear energy, this excess supply capacity of nuclear energy could replace fossil fuel's share as shown in Table 6.2 [4].

Table 6.2 Primary energy supply for 1990-2100
WEC-B case and in a proactive nuclear deployment case (in parentheses)
(Energy in Gt_{oe} [10^9ton oil equivalent])

	1990	**2050**	**2100**
Fossil	6.9	12.7 (11.4)	15.0 (5.0)
Nuclear	0.45	2.7 (4.0)	8.3 (18.3)
Renewables	1.6	4.4	11.4
Total	**9.0**	**19.8**	**34.7**

In such a scenario, the global use of fossil fuel in 2100 would become smaller than it was in 1990, thus helping to stabilize atmospheric carbon dioxide concentrations even in the face of growth of global energy use by a factor of four.

In the WEC estimate, electricity is the only application of nuclear energy. The extra nuclear capacity could be used for other energy applications, such as hydrogen production.

Many processes have been proposed for the production of hydrogen using nuclear energy [5]. The leading processes presently under research and development are nuclear-heated steam reforming of natural gas or other hydrocarbons, thermo-chemical splitting of water by nuclear heat, high-temperature electrolysis of steam by nuclear electricity and heat, and electrolysis of water by nuclear electricity (Fig. 6.1).

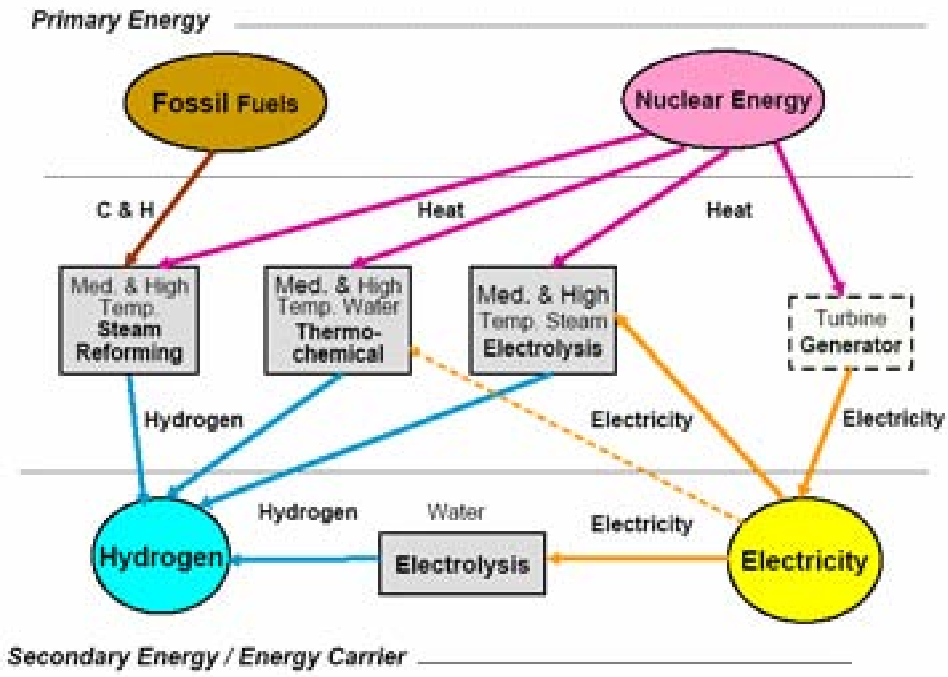

FIG.6. 1. Methods for hydrogen production by nuclear energy.

Though it is unclear what course the commercialization of nuclear production of hydrogen will take, one path could be as follows:

- In the near term, electricity produced by water-cooled reactors could be used to electrolyze water using commercially available technology.
- In the intermediate term, medium-temperature reactors could contribute to steam reforming of natural gas. Higher temperature reactors would enable the use of steam electrolysis for higher conversion efficiencies.
- In the long term, the development of thermo-chemical water splitting cycles or steam electrolysis could be deployed. Such processes would need to be coupled with reactors that deliver heat at an appropriate temperature.

The concept of using nuclear heat for the endothermic steam reforming reaction of natural gas (or possibly other fossil fuels) can save approximately 30% of the natural gas, which would otherwise be burned as a heat source [6]. If the technology for medium-temperature (500 to 600ºC) steam reforming becomes commercial, then the synergistic method that combines the steam reforming process with nuclear heat could be effectively utilized to produce hydrogen (together with water electrolysis) until other water-splitting methods become commercially available. Section 6.4.1.3 will describe lower-temperature reforming technology in more detail.

6.2. Market context

Hydrogen has many and versatile uses as a secondary raw chemical material and as a secondary energy carrier. With 48% of its consumption, it plays a significant role in non-energetic applications as a chemical raw material and intermediate product for industrial and petrochemical processes. Furthermore, it is largely used in energetic applications indirectly; e.g., in the production of clean synthetic fuels (20%) or directly as a fuel for producing process heat in the chemical industries (32%).

Of the annual world production of approximately $5.5x10^{11}$ Nm^3 of hydrogen, about 70% is consumed in the chemical industries. It possesses the potential to generate mechanical energy, heat, or electricity for future large-scale use.

6.2.1. Hydrogen as a raw material in chemical processes

The chemical hydrogen economy started already at the turn of the 20th century when coke furnaces generated process gas and town gas with up to 60% hydrogen content. Since then a variety of non-energetic and indirectly energetic applications has been developed for hydrogen as a part of synthesis gas such as:

- Ammonia synthesis
- Methanol synthesis
- Direct reduction of iron ore
- Fossil fuel processing (hydro cracking)
- Fischer-Tropsch hydrocarbon synthesis
- Methanation in long-distance energy transportation
- Hydro-gasification

Ammonia synthesis

More than half of the hydrogen used in the chemical industries (or 40% of the world production), approx. $2 \cdot 10^{11}$ Nm^3, is consumed in ammonia synthesis:

$$N_2 + 3H_2 \rightarrow 2NH_3$$

Feed gas for the steam reformer is methane or gasoline. High dilution with steam is chosen to keep the methane content at a low level. Adding air in a secondary reformer leads to partial oxidation of the residual methane and CO. After separation of the CO_2, the product gas is a mixture of nitrogen and hydrogen whose ratio (ideally 1:3) is adjusted by the operating conditions. The system pressure is about 5 MPa; the synthesis temperature is 400°C.

The production of one tonne of ammonia requires about 2000 Nm^3 of hydrogen as well as approximately 800 kWh for compression of the synthesis gas and provision of the nitrogen (by air liquefaction).

Modern industrial production of ammonia uses the Haber-Bosch process to produce a daily output of 1000-2000 t of liquid NH_3, corresponding to a hydrogen consumption of 80 000-160 000 Nm^3 /h. The use of high gasification pressures minimizes the need for subsequent compression. Ammonia is worldwide used as a fertilizer with facilities for storage, safe handling, transportation, and distribution being available. It is also being considered as a hydrogen rich fuel for automobile transportation to replace CO_2 producing fuels.

Methanol synthesis

World demand for methanol is around 32 million tones per year and increasing modestly by about 2 to 3 percent per year, but with significant changes in the profile of the industry. Since the early 1980s, larger plants using new efficient low-pressure technologies are replacing less-efficient small facilities. The industry has also moved from supplying captive customers, especially for the production of formaldehyde that typically represents one-half of world demand and serving primarily the home market, to large globally oriented corporations.

Methanol synthesis consumes about 5% of the world's hydrogen production. Methanol is used in the chemical industry as an intermediate product. It is gaining further attention as a secondary energy carrier with less CO_2 emission; e.g., as a direct vehicle fuel or as a basis for the production of hydrogen-rich gas to feed fuel cells.

Methanol production starts with a compression of the CO, CO_2 (produced mainly by coal combustion), and H_2 mixture to about 10 MPa, which is then introduced into a fixed-bed catalytic reactor at temperatures of 220-280°C and pressures of 5-20 MPa:

$$CO + 2\,H_2 \rightarrow CH_3OH$$

$$CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O$$

The reactions are exothermic and volume reducing; thus, low temperatures and high overpressures are desirable. A catalyst is required to maximize methanol output. The specific consumption is 2300 Nm^3 of CO and H_2 per ton of methanol.

Today's reactors a have capacity of up to 3000 t/d of methanol.

Methanol production generates a surplus of hydrogen which can, by adding CO_2, be utilized to increase the methanol yield and thus reduce CO_2 emission into atmosphere:

$$3\,CH_4 + 2H_2O + CO_2 \rightarrow 4\,CH_3OH$$

In a subsequent step, hydrocarbon fuel synthesis can be performed:

$$n\,CH_3OH \rightarrow (CH_2)_n + n\,H_2$$

A CO_2-neutral solution is obtained if the CO_2 released during combustion of the methanol is recovered during the methanol production step. CO_2-free coal-to-methanol production would require H_2 as a supplemental feed and a non-fossil fuel source of high-temperature heat (e.g., nuclear power).

New catalysts allow the methanol synthesis to take place at lower temperatures (80 - 120 °C) and lower pressures. A drawback is the rapid deactivation of the catalyst in the presence of strong alkalis.

In Japan, the conventional method of methanol synthesis has been modified by adopting a fluidized granular catalyst bed rather than a fixed bed, which allows the possibility to enlarge the size of the reactor, to reduce the power required, and to exchange the catalyst during operation.

Direct reduction of iron ore

Blast furnace technology has been used for more than a century for raw iron production. The stack gas generated during the process was usually considered a waste gas. Its constituents and typical fractions are CO (~ 40 %), N_2 (~ 40 %), CO_2 (~12 %), H_2O (~ 6 %), and H_2 (~ 2 %).

Direct reduction of iron ore to sponge iron that can then be converted to steel in an electric arc furnace is a process that takes place outside a blast furnace, avoiding the use of coke. This process is more favorable than the traditional raw iron production by means of coke. The chemical reactions are:

(1)	$Fe_2O_3 + 3\,H_2 \rightarrow 2\,Fe + 3\,H_2O$
(2)	$Fe_2O_3 + 3\,H_2 \rightarrow 2\,Fe + 3\,H_2O$
	$Fe_2O_3 + 3\,CO \rightarrow 2\,Fe + 3\,CO_2$

The reactions demand 610 Nm^3 of hydrogen or 604 Nm^3 of carbon monoxide per ton of iron. Process 1, the H-iron process**,** operates at 500 °C and 3 - 4 MPa and needs pure hydrogen (98 %) and a high dilution of the reformer feed gas with steam. Process 2, the Korf-Midland-Ross process**,** operates at

800 °C and 0.3 MPa and requires low steam dilution to prevent carbon deposition and a low methane level (< 2 %) in the reformer product gas. The optimal H_2 to CO ratio is a compromise between a favourable energy balance of the endothermic and exothermic reactions, and reaction kinetics, as well as environmental impact by the CO_2 produced.

Heat treatment of ferrous metals is made in a hydrogen-nitrogen atmosphere with 3-30 % H_2 to increase metal ductility, improve machinability, and alter electric and magnetic properties.

Fossil fuel processing

Steady utilization of hydrogen in refineries commenced more than 50 years ago. It is mainly used for hydro-cracking and fuel burning of excess by-products and hydro-treating, comprising pre-treatment of reformer feed and treatment of heavier streams in upgrading processes including the removal of sulphur compounds, halides, metals, nitrogen or oxygen; the saturation of olefins, diolefins, cyclo-olefins, or aromatics; and the decyclization or ring-opening. The cracking of heavy crude oil is done to produce lighter hydrocarbons or refined products such as high-octane gasoline.

In the process of coal hydrogenation, which is a high-pressure (30 - 70 MPa) catalytic process at a temperature of 500 °C, hydrogen is used to convert coal to gasoline:

$$C + H_2 \rightarrow -CH_2-$$

Hydrogen is also used to remove sulphur, oxygen, and nitrogen. Rigid specifications concerning the contents of the catalyst poison CO (< 10 ppm) have to be met. A purity of 98 % hydrogen is desirable. With an input of 2000 - 2600 Nm^3 of hydrogen and 1.7 t of coal, an output of 1 t of gasoline is obtained. In addition, 600 kWh of electricity are necessary for H_2 compression and coal preparation.

Oxo synthesis is an exothermal catalytic process in which a H_2-CO mixture, as the product gas of the steam reforming process, is used to produce aldehydes, which are then hydrided to the respective alcohols. The oxo process works at 3 - 30 MPa and 100 - 180 °C.

The hydrogen demand in cleaning and upgrading of coal and oil is listed in Table 6.3 for various processes.

Table 6.3. Hydrogen demand for coal upgrading or product improvement

Process	**Hydrogen demand mol H_2 per mol CH_2 (CH_3OH)**
Crude oil desulphurization	2 - 5
Hydrotreatment	5 - 10
Hydrocracking	15 - 30
Residue hydrogenation	25 - 30
Very heavy oil → syncrude	30 - 40
Oil sand → syncrude	30 - 45
Oil shale → liquid products	80 - 125
Coal gasification (CH_3OH)	100 - 160

Fischer-Tropsch Synthesis

The catalytic hydrogenation of carbon monoxide resulting in the formation of paraffin-olefin mixtures of different C-numbers is what is called Fischer-Tropsch synthesis. The product spectrum depends on the operating conditions and the catalysts and on the partial pressures of CO and H_2 in the synthesis gas:

$$CO + 2\,H_2 \rightarrow (\text{- CH2 -}) + H_2O$$
for Co cataIyst

$$2\,CO + H_2 \rightarrow (\text{- CH2 -}) + CO_2$$
for Fe catalyst

Until now Fischer-Tropsch technology has been unable to compete economically with conventional fuel and was limited to isolated circumstances. Recent process innovations, however, give hope to a comeback for the exploitation of coal and untapped gas fields in remote regions as an alternative to liquefied natural gas (LNG) processing. Shell and Sasol are currently the only companies to operate Fischer-Tropsch plants on a commercial basis, though many projects are in various stages of completion.

Others

A significant application of hydrogen in the food industry is the hardening of fats and oils by catalytic hydrogenation for the purpose of extended durability. The process takes place at pressures of 20- 40 MPa and at temperatures of 200-400 °C.

Other fields of hydrogen applications are in the metallurgical industry as a reducing medium for nickel production, for autogenous welding and cutting, in the glass industry when clean combustion is required, and in the electronics industry for the epitaxial growth of polysilicon. For the fabrication of semiconductor elements, vaporized liquid hydrogen is used as a doping gas because of its cleanness.

A field with growing interest is the ability of hydrogen for scavenging oxygen, e.g., in boiling water reactors where traces of oxygen in the feedwater have been found to cause intergranular stress corrosion cracking. The injection of hydrogen can reduce oxygen to a level of < 100 ppb.

6.2.2. *Hydrogen as a fuel*

The first application of hydrogen as a "transportation fuel" was in the late 18th century for flying balloons with the first lift off of a balloon ("Charliere") filled with 40 m^3 of H_2. The H_2 was produced by spilling sulphuric acid onto iron. The balloon travelled a distance of 25 km and a height of up to about 1 km.

Hydrogen has a principal advantage over electricity – storability. This gives an opportunity to use hydrogen in many applications, where the usage of electricity is impossible or limited.

Heating

Catalytic or flameless combustion of hydrogen exhibits many advantages in comparison with flame combustion. It occurs at low temperatures (ambient - 800 K), is safe and leads to a very high conversion of the burning gas (99.9 %). NO_X formation, which usually occurs in conventional combustion at temperatures of about 1700 K, is here almost completely suppressed. The catalytic combustion in diffusion burners occurs in the presence of small amounts of Pt or Pd catalyst. It is adequate, for example, for kitchen appliances such as cookers, ovens, water heaters, and space heaters. Drawbacks are the possible non-uniformity of the temperature distribution at the catalyst surface, rapid changes in the operational state, and relatively small heat flux densities.

High-temperature fuel cells and combined heat and power

Combined heat and power (CHP) is an ideal market for high-temperature fuel cells, which produce both electricity and heat. Such units are suitable for hospitals, hotels, airports, telecoms, and banks where the security of power delivery is important. This is one of the first markets for hydrogen fuel cells, which exists and grows. For instance, approximately 200 units of 200 kW Phosphoric Acid Fuel Cell (PAFC) systems from ONSI Corp. have been purchased since its commercial introduction in 1990, and a growing number of the Hot Module 245 kW Molten Carbonate Fuel Cell (MCFC) have been delivered from MTU CFC Solutions GmbH.

Stationary gas turbines

Hydrogen is an ideal fuel for gas turbines. Owing to its rapid mixing with air, a smaller combustion chamber is sufficient and the efficiency is higher compared with conventional fuels. Gas turbines modified for liquid hydrogen operation yield an up to 10 % higher thermal efficiency and output compared with fossil-fuelled turbines. For systems with advanced heat exchange, efficiencies of more than 50 % are estimated to be achievable. The remainder-free combustion is stable and favourable for lifetime and maintenance. Of disadvantage is NO_X production. The internal stoichiometric combustion of hydrogen and oxygen heats up the argon gas, which actuates the turbine for power generation. The water vapour produced is condensed and removed from the circuit whereas the argon is returned to the combustor. Innovative developments of gas turbines capitalize on the experience of aerospace propulsion systems. Performance goals are operational flexibility and control of combustion temperature by pre-mixing steam. No particular difficulties are expected for a conversion of a stationary gas turbine to H_2 fuel.

A modified gas turbine cycle, a H_2-fuelled chemical-looping combustor, has been proposed in Japan. A solid metal oxide, e.g., NiO, replaces air or oxygen as an oxidizer. An increase in the efficiency up to 66.8 % is predicted compared with 61.6 % as the best figure for H_2/O_2 cycles.

The hydrogen-oxygen steam generator is a novel power plant component derived from rocket technology to provide instantaneously spinning reserve capacity upon demand. H_2 and O_2 stored underground or in high-pressure tanks are injected into a combustion chamber and ignited. Combustion takes place at pressures of 2 - 20 MPa. The reaction heat is directly transferred to additional feedwater that is introduced. Steam of the required temperature of 500 - 1000 °C is obtained and routed to the intermediate pressure steam turbine, thus increasing the electric power by 20 MW within seconds. However, lack of demand for such direct power reserve and a relatively high cost have led DLR (German Aerospace Research Center) to abandon this development. Comparable research projects are currently pursued only in Japan and Russia.

Natural gas and hydrogen

Quite an effort has been dedicated to the possibility of mixing hydrogen with natural gas, which leads to cleaner burning and relatively easy transport, but problems still remain in the field of pipeline corrosion, since hydrogen in higher concentrations (> 5%) causes hydrogen embrittlement. Even this relatively small proportion of hydrogen in natural gas would mean large quantities.

When considering this option, one must take into the consideration the so-called Wobbe number. If different gases are mixed, the different properties of each component that makes up the mix must be considered. Pure hydrogen has a caloric value of ~13MJ/m^3, most natural gases have a much higher value in the range of 35-40 MJ/m^3. This means roughly three times more hydrogen than natural gas must be burned to produce the same amount of heat.

Hydrogen in transportation

Hydrogen for transportation is receiving significant attention around the world because of high petroleum prices and unreliable oil supplies.

Ground transport

Two ways of hydrogen utilization in cars are currently being taken into consideration – internal combustion engine (ICE) vehicles and fuel cell (FC) vehicles. While ICE vehicles represent current technology with modest modifications, fuel cell vehicles are in a stage of intensive R&D and prototype testing.

Consideration of hydrogen as a fuel for the internal combustion engine started in the early 1920s. Internal combustion engines that run on hydrogen are on the order of 25 - 30 % more efficient than gasoline ICEs, because they take advantage of the fast-burn and far-lean combustion characteristics of hydrogen. ICEs for earth-bound vehicles are seen by many to be superior to battery or fuel cell powered vehicles in terms of range, acceleration, and power-to-weight ratio. Internal combustion engines extract about 30% of the stored fuel energy. Operation with hydrogen is possible in a wide range of mixtures with air. At extremely lean conditions, it provides a low emission level and a high thermal efficiency in the low power range. Cryogenic hydrogen provides a higher energy storage density (though still less than gasoline) and a considerable cooling effect. The technology still suffers from inadequate on-board storage technology.

The first hydrogen ICE vehicle reported was a Ford pickup truck in 1971 in the USA. The first European car running on liquid hydrogen (LH_2) was demonstrated by the German DFVLR (now DLR) in 1979, which also built the first LH_2 system for vehicle refuelling. Today the biggest effort shows BMW with a fleet of the 745h (4.4-liter V8) and Mazda with its own concept with a rotary (Wankel) engine, which runs both on gasoline and hydrogen.

Car manufacturers are focusing more effort on fuel cell vehicles than on hydrogen ICE vehicles. Many prototypes have been introduced, some of them in small series (tens of cars). Most of the manufacturers have opted for proton exchange membrane (PEM) fuel cells because of their low-temperature operation and relatively (compared to other fuel cell types) easy manufacturing and maintenance. (See section 6.3 for fuel cell details.) Current trends are mainly focused on hybridization, such as fuel cell with NiMH batteries, ultra capacitors, or other types of electric storage. Although this increases the complexity of the vehicle, thus increasing the cost, it brings significant advantages. The main one is covering power peaks during acceleration, when the electric motor draws high current from the FC. If fuel cell should cover these peaks itself, it would have to be much bigger than is needed for cruising. A second advantage in electrical storage is increasing the driving range, because hybrid vehicles optimize fuel consumption, and also the use of braking recuperation.

Some car-manufacturers are also considering in the mid term to employ fuel cells instead of classical Pb-type accumulators, where the hydrogen needed is reformed from the gasoline onboard.

It is not only important to have technical problems solved, public acceptance is also important. For this purpose, hydrogen fuelled buses have been successful. Currently there are about 60 of them serving on a daily basis in different cities around the world. The biggest such project is the CUTE project, which runs 27 busses in 9 EU cities (London, Hamburg, Madrid, Stuttgart, Stockholm, Porto, Amsterdam, Barcelona, and Luxembourg). This project is connected with the ECTOS project (3 busses in Reykjavik, Iceland) and ECOBUS (3 busses in Perth, Australia). The CUTE project finished in 2005 with good results. There were no critical technical problems, the availability for the customers was unexpectedly high (over 80%), and public attitudes were positive. There is a follow-on project now, called HyFleet CUTE, which adds 14 internal combustion buses and continues with an operation of 33 fuel cell buses. More information is available at http://www.global-hydrogen-bus-platform.com/.

The lack of the hydrogen infrastructure makes fleet customers important for early hydrogen transportation markets. It is much easier to build one centralized filling station near a city bus operator or dispatch service than to service the distributed market for personal cars.

Motorcycles, scooters and electric bikes represent a smaller, but interesting, market opportunity. Such means of transportation are significant in many Asian countries, where the pollution is growing and causing health problems. Switching from fossil-based fuels to hydrogen would improve the local environment.

Aviation

Liquid hydrogen was early recognized as an important rocket fuel for use in space flights. The H_2 / O_2 system together with the H_2 / F_2 system provide some of the most energetic propellants. LH_2 and liquid oxygen (LOX) are pressurized by a pump and burnt in a preburner chamber (stage 1). The resulting high-temperature high-pressure gas operates the pump. The exhaust gas from the pump is routed to the main combustion chamber where it is burnt once again using the remaining LOX (stage 2). Ram engines for future reusable space transportation can be operated with atmosphere oxygen up to a height of 40 km. Air-breathing engines with supersonic combustion (scramjet) offer an excellent thrust potential. Hydrogen in space transportation is being used by the USA, Russia, Europe, China, Japan, and India.

Considering weight and volume restrictions in aviation, liquid hydrogen has been shown to be attractive as an aircraft fuel. The wide range of flammability of hydrogen in air enables a stable combustion chamber operation far beyond the limits of hydrocarbons. The lighter fuel load compared with conventional fuel results in a gross weight reduction allowing the use of a smaller engine. Together with its high combustion heat per mass unit, fast ignition and high heat sink capacity, hydrogen is a good candidate, in particular, for supersonic applications. In addition, it avoids all pollutants of fossil fuels except for NO_X. Compared with kerosene, the flight-related energy content of LH_2 is nearly 2.8 times larger on a mass basis and it could be used as a coolant. Also the engine lifetime is expected to be higher and maintenance requirements to be reduced. The main penalty, however, is the required storage volume of the hydrogen, which is by a factor of about 4 larger than for kerosene.

Liquid hydrogen is superior to kerosene in terms of safety. A hydrogen fuel fire is expected to be less dangerous and the endangered area is much smaller; a kerosene fire lasts much longer.

Both Airbus and Boeing are considering hydrogen as a fuel option. In terms of fuels cells, the nearest application in airplanes will probably be for headlights, which can be fuelled by hydrogen reformed onboard from kerosene.

Sea applications

Under some circumstances hydrogen has application in ship propulsion using low-temperature fuel cells. The operation of submarines powered by PEM FC systems has been successfully demonstrated. Such systems can result in substantial noise reduction compared with steam-driven systems, which is important for naval operations.

Japan is investigating a dual 500 kW PEM FC system operating on methanol reformate gas. US research is focusing on 250 kW and 2.5 MW shipboard power units. Naval applications are being realized in Australia, Canada, and Germany. Within the Euro-Quebec project, a passenger boat is currently under construction equipped with a PEM FC electric drive and three 200 1iter LH_2 storage tanks. The German Howaldtswerke Deutsche Werft AG, Kiel has recently investigated the use of fuel cells in powering merchant ships.

Railroad transport

A fuel cell propulsion system for locomotives is being considered as an option in future railroad technology. New emission standards for locomotives has led to a revival of research activities from the past. Locomotives can better accommodate larger fuel storage volumes than road vehicles, making hydrogen fuel storage less of an issue.

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6.3. Challenges

Fuel cell – introduction

Fuel cells provide an elegant method of converting chemical energy into electric power and heat. Their rapid development in recent years relates to the interest in hydrogen as the energy vector of future. To understand current technological barriers of fuel cells one must first be familiar with the basic principles of their function and structure.

Fuel cell – principle

The basic principle of fuel cell operation is the reaction between oxygen and hydrogen that produces water, electric power, and heat. The efficiency of this process is about 50 % (depending on temperature, pressure, and current). Such high efficiency is caused by the direct energy transformation:

$$H_2 + \frac{1}{2} O_2 \rightarrow H_2O + \text{Heat} + \text{Electricity} \qquad (1)$$

This process is unconstrained by the Carnot efficiency limits of the classical heat-engine method of power production:

fuel → heat → kinetic power → electric power

where each energy transformation includes appreciable losses.

Figure 6.3 shows the schematic arrangement and function of a proton-exchange membrane (PEM) fuel cell. The fuel cell consists of three basic parts: the anode, electrolyte and cathode. In a typical PEM fuel cell, hydrogen is continuously fed to the anode where it dissociates into a proton and an electron. Protons pass through a proton-conducting electrolyte to the cathode. Electrons have the same target, but they are led through an external electrical circuit where they can perform useful work. Oxygen is led to the cathodic site (usually as air) where it reacts with protons and electrons to form water.

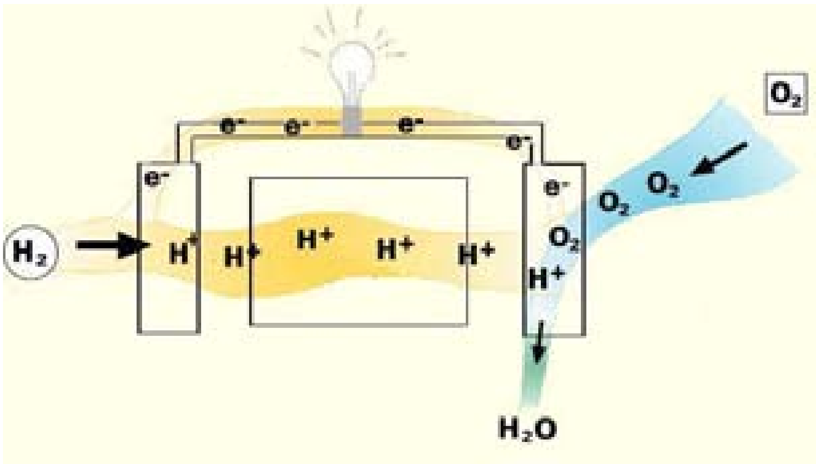

FIG. 6.3. Schematic arrangement and function of proton-conducting fuel cells.

Power and rate of reaction

Activation energy must be supplied from the outside to overcome the energy barrier in reaction 1. If the probability that a molecule will have sufficient energy to break the energy barrier is small then the reaction will be slow (which is the case under regular conditions). There are four basic ways to increase the rate of a reaction:

- Temperature increase;
- Pressure increase;
- Catalyst usage;
- Enlargement of the electrode surface.

The first three cases apply to the majority of chemical reactions in general. The last case — electrode surface enlargement —is a special case within electrochemistry and is important for fuel cells. Since a contact must occur between the gas and the electrolyte on the electrode surface (to allow electrons to be passed through the electrode and protons through the electrolyte) the size of the interface between the phases is crucial for the reaction rate and, thus, for fuel cell power.

The surface area size does not depend on length and width only —current fuel cells electrodes have surface areas roughly about 1000 times bigger than flat surfaces, because they are porous in nature. In addition the electrode surface must contain the catalyst and often must be resistant to aggressive acid environments under high temperatures. The power of the fuel cells is often reported with respect to the electrode surface area, for example in mW/cm^2.

Fuel cell types

Fuel cells are classified based on the electrolyte type and operating temperature.

Polymer Electrolyte Membrane Fuel Cell (PEMFC): Also known as a proton-exchange membrane fuel cell, the PEMFC uses a polymer membrane electrolyte (usually based on acid fluoropolymers) that allows the transfer of hydrogen ions, but not gases. Because water is the sole liquid in this fuel cell type, corrosion issues are minimized. The key for operation efficiency is water management. The conditions must be set in such way that the product —water —does not evaporate faster than it is produced. This is crucial because a high degree of membrane hydration is a requirement for good proton conductivity. The operating temperature is limited by the type of polymer used, usually below 120°C (though new materials allowing temperatures up to 200°C are being developed and tested). The fuel in this case is usually pure hydrogen, though hydrogen-rich compounds such as methanol in direct methanol fuel cells (DMFC) are possible. Platinum or Pt/Rh and other materials are used as catalysts. Carbon monoxide is a significant poison for this type of catalyst; therefore it must be ensured that its concentration in the fuel is not higher than 5 ppm.

Alkaline Fuel Cell (AFC): The electrolyte for an AFC is typically 85 wt% KOH for fuel cells operating at higher temperatures (~250°C) and the 35-50 wt% KOH for lower operating temperatures (< 120°C). The electrolyte is kept in a matrix, which is made of asbestos in most cases. The advantage of this fuel cell type is the possibility to use a wide spectrum of (cheap) catalysts (Ni, Ag, MeO, corundum, and noble metals). The purity of the fuel and oxidizing agent is the most important issue, because even a small amount of carbon dioxide (CO_2) causes fast degradation of the electrolyte. (CO_2 reacts with KOH to form K_2CO_3.) Similar to the PEMFC the carbon monoxide is also a catalyst poison.

Phosphoric Acid Fuel Cell (PAFC): This fuel cell type operates at 150-220°C and uses 100% phosphoric acid as an electrolyte. Phosphoric acid, H_3PO_4, has reduced proton conductivity at lower temperatures and the CO problem (catalytic poisoning of platinum) becomes more significant. The phosphoric acid is more stable than other common acids and, therefore, is able to operate over a wide range of temperatures. In addition, the usage of 100% acid minimizes the partial pressure of water vapors; thus, it is not difficult to maintain correct water management. The matrix for the holding the electrolyte is SiC in most cases.

Molten Carbonate Fuel Cell (MCFC): The electrolyte is a mixture of alkali carbonates, which is held in an $LiAlO_2$ matrix. The operating temperature ranges from 500°C to 700°C. In this range the mixture of carbonates will create a highly conductive molten salt where, the conductivity is provided by migrating carbonate ions. Because of the high temperatures it is not necessary to use noble metals for catalysts. Nickel is used for the anode and NiO is used for the cathode.

Solid-Oxide Fuel Cell (SOFC): In a solid-oxide fuel cell the electrolyte is a solid non-porous metal oxide, often Y_2O_3 stabilized with ZrO_2. The operating temperature ranges from 600°C to 1000°C and conductivity is provided by oxygen anions. The anode material is Co-ZrO_2 or Ni-ZrO_2; $LaMnO_3$ doped with strontium is typically used for the cathode. The solid nature of the electrolyte is significant for the simplification of the system. As opposed to all other fuel cell types, there are only two phases (solid and gaseous) in this fuel cell type.

Protons or hydroxyl anions are the main charge carriers in the low-temperature fuel cell types (PEMFC, AFC, and PAFC), the carbonate and oxygen ions take this role in the case of the high-temperature fuel cells. The general differences between individual fuel cell types are given in Table 6.4.

Table 6.4. The basic characteristics of individual fuel cell types according to the electrolyte

	PEMFC	AFC	PAFC	MCFC	SOFC
Electrolyte	Ion-exchanging membrane	35-100% potassium hydroxide	Phosphoric acid in asbestos	Molted carbonates	Ceramic
Operating temperature	80°C	65-220°C	205°C	650°C	600-1000°C
Charge carrier	H^+	OH^-	H^+	CO_3^{2-}	O^{2-}
Base material	C	C	C	Stainless steel	Ceramic
Catalyst	Pt	Pt	Pt	Ni	Perovskites

Summary on technologic barriers of fuel cells

The mass utilization of fuel cells for transportation and decentralized power production will not materialize until at least 2020. The US DOE has set some target fuel cell parameters, which must be met in 2010 for successful commercialization, including lifetime and power density.

Currently research focuses on the following areas:

- **Catalysts:** Catalysts differ according to fuel cell type. PEMFCs typically use catalysts based on different forms of carbon coated with platinum or Pt/Rh. Platinum is rare and expensive, though, so there is much effort to devise ways to reduce the Pt loading while keeping the same catalytic activity and lifetime.

- **Materials:** There are relatively adverse conditions inside a fuel cell for the majority of typical industrial materials. The high acidity given by the high concentration of H^+ ions, as well as high temperatures in the case of high-temperature fuel cells, creates a particularly harsh environment. A compromise must be reached, then, between the mechanical resistance, chemical stability, physical properties and the performance and price of materials. In case of the high-temperature fuel cells with temperatures from 500°C to 1000°C, the designers face the additional problem of thermal expansion mismatches between dissimilar materials, especially for start-up, shut-down, and other transient conditions.

- **Equipment**: fuel cell systems need specific balance-of-plant components (compressors, blowers, etc.) that differ from those currently used.

- **Production Cost**: The problem with fuel cell cost is, in part, related to the current lack of mass production. Costs are expected to go down as fuel cell markets expand. Further research on the use of less expensive materials and simpler fabrication techniques are hoped to lower costs, as well.

- **Durability**: For tomorrow's customer of fuel cell vehicles, durability means delivering the same level of performance and reliability they expect from today's internal combustion engine vehicles. Fuel cell stack lifetimes will have to increase substantially before large-scale commercialization of fuel cell vehicles is possible.

- **Cold-start capability**: Managing the water produced by fuel cells presents a special challenge in freezing temperatures. Current technology is capable of starts from –20° to –30°C, but power suffers at these temperatures. Work is being done on lowering the time needed for achieving 50% of the fuel cell rated power. (Currently it takes 100s for –20°C.)

- **Fuel cell stack power density**: Especially for transportation purposes, it is important to minimize fuel cell size and weight. The US DOE target for 2010 is 2 kW/liter, whereas today it is possible to get around 1.2 kW/liter.

- **Water management:** This is a specific problem for PEMFC, s since the membranes must be sufficiently moisturized to reach sufficient protonic conductivity. Too much moisture, though, and flooding of electrodes pores can lead to a rapid power reduction as gases lose access to the electrodes. The moistening is performed mainly by external bubbling of hydrogen in water or by direct injection of water to the membrane. Apart from necessary extra equipment for external moistening, there are also problems with starting in cold weather conditions, as discussed above.

- **SOFC problems**: One of the major advantages of SOFCs over other types of fuel cells is that internal reforming of simple hydrocarbon fuels is in principle possible. Current SOFCs, however, suffer from two major limitations when dealing with internal reforming. The first is coke formation that deactivates the anode catalyst, which is typically a Ni-YSZ cermet. The second is poisoning of the catalyst by sulphur compounds. These problems are particularly challenging for logistic fuels such as JP-8 that are rich in heavy hydrocarbons and sulphur compounds. Even if JP-8 fuel is externally reformed, it is possible that small concentrations of unconverted JP-8 components will reach the SOFC feed stream, especially during transient operation such as start-up.

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6.4. Solutions

Hydrogen production using water cooled reactor technology requires processes that are consistent with the temperatures that can be achieved by evolutionary water cooled reactors (~300°C) or supercritical water reactors (~550°C).

6.4.1. Hydrogen production technologies

6.4.1.1. Steam methane reforming (SMR)

Steam methane reforming (SMR) is currently the primary commercial technology for hydrogen production. The SMR process requires high process temperatures, which are usually provided by burning natural gas. The process reactions are as follows:

Reforming: $CH_4 + H_2O \rightarrow CO + 3H_2$, endothermic (750-800°C) (1)

Shift: $CO + H_2O \rightarrow CO_2 + H_2$, exothermic (350°C) (2)

The cost of steam methane reforming is rising as natural gas prices rise. In addition, SMR results in releases of carbon dioxide from the shift reaction (as a product) and from the reforming reaction when natural gas is burned to provide the necessary heat. Heat from nuclear reactors has been considered as an alternative to the burning of natural gas — potentially reducing carbon dioxide emissions by 30%.

Water cooled reactors and supercritical water cooled reactors cannot reach the temperatures required for conventional reforming technology. The heat from these types of reactors can be used, however, if the reforming technology is modified.

6.4.1.2. Steam Reforming of Dimethyl Ether

Toshiba of Japan has proposed that steam reforming of dimethyl ether (DME), a derivative from fossil fuels or biomass, could be used to produce hydrogen with 300°C heat from water cooled reactors [7,8].

DME is synthesized from natural gas from small or medium-sized gas fields, coal seam gas, and natural gas with a large CO_2 fraction. The synthesis of DME from natural gas is inexpensive compared to the liquefaction of natural gas since the liquefaction process for natural gas requires a temperature lower than 113 K and a relatively large plant. DME has the potential to be synthesized from biomass without additional CO_2 emissions.

DME is usually produced by a partial oxidation process of natural gas without emitting CO_2, as shown by the following formula:

$$2CH_4 + O_2 \rightarrow CH_3OCH_3 + H_2O, \quad (3)$$

The DME reforming reaction is as follows:

$$(1/2)CH_3OCH_3 + (3/2)H_2O \rightarrow CO_2 + 3H_2 \quad -24.4 \text{ kJ/ } (H_2 \text{ mol}) \quad (4)$$

The produced hydrogen fraction is high at temperatures of 285-300°C, according to thermodynamic data. Specifically, Toshiba has developed, together with Shizuoka University, a DME reforming catalyst that gives 98% conversion of DME to hydrogen at 285°C. The catalyst is Cu-Zn/Al_2O_3 powder made with a sol-gel method.

With 40 MW of heat supply about 10^8 kg H_2 /year of hydrogen production is possible, which is of the same scale as the largest hydrogen plant in the world. To date, the demonstrated production rate is 4.10 kg H_2 /day.

6.4.1.3. Steam reforming of methane at reduced temperatures

A conventional steam methane reforming (SMR) system for hydrogen production is composed of a steam reformer, a shift converter, and a hydrogen purifier based on pressure swing adsorption (PSA). A mixture of methane and steam is introduced into a nickel-based catalyst bed in the steam reformer, where the SMR reaction proceeds at 750 to 800°C. The reformed gas is supplied to a shift converter, where carbon monoxide and water are converted into carbon dioxide and additional hydrogen (equation 2). The reformed gas is then passed to a PSA separator to separate the hydrogen.

A membrane reformer system, composed of a steam reformer equipped with catalytic membrane modules with a palladium-based alloy and a separate nickel-based catalyst, can perform the reforming reaction, the shift reaction, and the hydrogen separation process simultaneously, without an independent shift converter and a PSA separator. By this simultaneous generation and separation of hydrogen, the membrane reformer system can be much more compact and can provide higher efficiency than conventional ones. The simultaneous progress of hydrogen generation and separation drives the chemical reaction forward and thus can lower the reaction temperature to 500 to 600°C. This allows the use of less expensive heat-resistant materials and enhances long-term durability. Moreover, these lower temperatures offer the opportunity to couple lower-temperature heat sources to the SMR process.

The enthalpies for the steam-methane reforming-shift (SMR) reaction to produce hydrogen are as follows:

- Reforming reaction:

$$CH_4 + H_2O = CO + 3H_2 \qquad -206 \text{ kJ/mol} \tag{5}$$

- Shift reaction:

$$CO + H_2O = CO_2 + H_2 \qquad +41 \text{ kJ/mol} \tag{6}$$

- Combined reforming-shift reaction:

$$CH_4 + 2H_2O = CO_2 + 4H_2 \qquad -165 \text{ kJ/mol} \tag{7}$$

For heat supplied by a nuclear reactor, the consumption of methane for the nuclear-heated SMR reaction is 3.3 ÷ 4 = 83%, or 17% less, of that of the conventional SMR reaction for producing the same amount of hydrogen. In conventional SMR approximately 2.7 moles of hydrogen are produced from 1 mole of methane feed. In the case of a nuclear-heated reformer, for which no methane is consumed for combustion, 4 moles of hydrogen can be produced from 1 mole of methane. Therefore, the nuclear-heated SMR process will save about 30% methane consumption, or reduce by about 30% the carbon dioxide emissions, compared with a conventional SMR process.

Nuclear-heated reforming using a membrane reformer system offers several advantages:

- Nuclear heat from medium-temperature reactors (below 600°C) can be used.
- No combustion of methane is needed for the endothermic heat of the reforming reaction, and consequently produces no related carbon dioxide emissions, resulting in an approximately 30% reduction of overall carbon dioxide emissions.
- Separation of carbon dioxide for future sequestration is facilitated since separation of the carbon dioxide reaction product is built into the process.

- A smaller surface area for membrane modules is possible, since the recirculation of reaction product gases (including residual hydrogen) in a closed loop configuration makes the average driving force for hydrogen diffusion through membrane higher.

A concept for the nuclear production of hydrogen that combines sodium-cooled fast reactors (SFRs) with the membrane reformer technology has been studied jointly by Mitsubishi Heavy Industries Ltd. (MHI), Advanced Reactor Technology Co. (ARTEC), Tokyo Gas Company (TGC), and Nuclear Systems Association (NSA).[9,10]

TGC demonstrated in 2004-2005 the operation of a methane-combusting membrane reformer at a hydrogen fueling station for fuel cell vehicles in downtown Tokyo. The system performance, efficiency, and long-term reliability were confirmed by producing >99.99% hydrogen at 3.6 kg/h for more than 3,000 hours with hydrogen production efficiency of about 80% (high heating value) [68% lower heating value].

In the conceptual design, the nuclear plant is a type of sodium fast reactor with mixed oxide fuel and a power output of 240 MW_t that would produce 18,000 kg/h. The hydrogen production cost of this process was assessed to be competitive with those of conventional, methane-combusting, steam methane reformer plants.

6.4.1.4. High-Temperature Water Cracking

As a greenhouse-gas-free alternative to SMR, the U.S. Department of Energy is exploring ways to produce hydrogen through the cracking of water by means of electrolytic, thermochemical, and hybrid processes. Most of the work has concentrated on high-temperature processes such as high-temperature steam electrolysis and the sulphur–iodine and calcium-bromine cycles [11,12 and 13]. These processes have a high probability of successful technical development, but they require higher temperatures (750^{o}C and higher) than can be achieved by water cooled reactors. Advanced reactors such as the very high temperature gas cooled reactor (VHTGR) can generate heat at these temperatures, but will require many years for commercial deployment. The high-temperature thermo-chemical cycles impose significant thermal demands on the system materials, regardless of the reactor design, and, therefore, require the development and certification of new engineering materials.

6.4.1.5. Low-Temperature Water Electrolysis

Low-temperature water electrolysis is commercially available today for generating hydrogen with no external heat input, making it suitable to be supported by nearer-term water cooled reactors. Low-temperature water electrolysis results in the direct decomposition of H_2O into H_2 and O_2. Its market adoption has been limited by two factors. First, since all the energy for water cracking is derived from electricity, the cost of electricity from current low-temperature reactors makes water electrolysis uncompetitive with steam methane reforming. The development of lower-cost, carbon-free electricity generation (through, for example, high-temperature nuclear reactors that can achieve generating efficiencies greater than 45%) might make lower-cost electricity and, consequently, make low-temperature electrolysis more cost effective. The second factor limiting the use of this technology is its reliance on noble metal catalysts such as platinum. The high price and scarcity of noble metals make large scale use of current water electrolysis systems impractical. Research in water electrolysis technology, which will be described shortly, holds the promise to reduce these two barriers.

The U.S. Department of Energy’s goal for electrolysis is a capital cost of $300/kW for a 250 kg/d plant (with 73% system efficiency). Under this program goal, a large centralized plant would produce hydrogen at $2.00/kg [14]. Current costs are two-to-three times that value. The DOE research program is focusing on ways to improve efficiency and reduce the cost of electrolyzers.

Commercial water electrolysis technologies fall into two categories: (1) solid polymer cells using proton exchange membranes (PEMs) and (2) liquid electrolyte cells, most commonly using a potassium hydroxide (KOH) solution. PEM electrolyzers are essentially PEM fuel cells operating in reverse polarization mode. Protons diffuse in the PEM electrolyte whereas oxygen ions diffuse in the liquid electrolyte of these systems.

Currently the cost of hydrogen from PEM and KOH systems are roughly comparable. Reaction efficiency tends to be higher for the KOH system because of better conductivity of the liquid electrolyte. But this advantage is offset by the higher purification and compression energy requirements compared to PEM systems, especially at small scales. Thus, the development of relatively higher temperature, higher conductivity, and lower cost electrolyte membranes for PEM cells remains a goal for reducing the cost of hydrogen produced. Another major contributor to the cost of both PEM and KOH electrolyzers is the extensive use of rare and expensive noble metal catalyst materials for their electrodes. This current need limits the large scale use of this technology. Development of alternative catalyst structures with less expensive materials would significantly influence the economics of hydrogen production through electrolysis. Moreover, new advances in high-pressure systems are being explored to lower the cost by reducing the need for hydrogen gas compression.

Several groups are pursuing the development of low-temperature, high-pressure electrolysis systems to mitigate the high cost of hydrogen compression. For instance, a high-pressure, low-temperature water electrolyzer system is being developed by Giner Electrochemical Systems of Newton, Massachusetts [15,16]. The Giner system is currently operable at a 3000 psi (14 MPa) differential pressure, with hydrogen production at 3000 psig and oxygen production at atmospheric pressure. Their goal is to increase the operating differential pressure to 5000 psi (35 MPa) through advanced design features (such as the use of a polymer-supported membrane) and to replace high-cost components with lower-cost materials and fabrication methods. The use of higher pressures does require the use of higher cell voltages in the electrolyzer. Nevertheless, it is more energy efficient to run the electrolyzer at high pressures than to operate a cell at low pressures and then use a compressor to achieve the hydrogen pressure required for efficient distribution and delivery. Giner developed an economic model of electrolyzer capital and operating costs to determine the cost of hydrogen as a function of the price of electricity and the capital and operating costs of the electrolyzer plant components. The scenario they investigated was a neighbourhood refueling station with a hydrogen production rate of 432 kg/day. The electrical load for such a station is approximately 1 MW. Giner determined that to meet the DOE target cost of hydrogen produced (US$ 2.00-3.00/ kg H_2) [6.4.1.8] they would need to have an installed equipment cost of US$1100 per kW_e, a plant that operates at 90% capacity with a ten-year plant life, and an electricity price of less than 3.6 ¢/kWh. This price is only 20% lower than the price for commercial off-peak electricity in the metropolitan Chicago area (approximately 4.5 ¢/kWh) [17]. To meet the installed equipment cost target, they would need to have a large cell active area to reduce the number of cells and ancillary components. Giner is also turning its attention to a moderate-pressure electrolyzer that would operate at 1200 psig and may more easily reach the cost targets.

In parallel, Teledyne Energy Systems of Hunt Valley, Maryland, is developing an alkaline hydrogen generator that has a high overall efficiency, a low maintenance cost, and a final output pressure of 5000 psig (35MPa) [18]. This work is being done as a part of the U.S. DOE program on Design for Manufacture and Assembly. Again, operation at higher pressures greatly reduces the energy-intensive need otherwise to compress hydrogen. In a recent assessment, however, Teledyne has concluded that the increased costs of manufacturing a high-pressure electrolyzer (and the added safety systems required) may not offset the reduced gas compression costs.

Because of the need for electricity for water electrolysis, its efficiency and economics depend on electricity production efficiency and price. The electrochemical efficiency of present electrolysis units can vary between 65 to 90%. It is currently possible to couple an electrolysis unit to a nuclear power plant in order to produce electrolytic hydrogen. Thermal efficiencies typical for current water cooled reactors (approximately 34%) result in relatively low thermal-to-hydrogen energy efficiencies. The overall efficiency for electrolysis supported by water cooled reactors is limited to 21-30%. Significantly higher efficiencies, up to about 40%, can be achieved if an advanced, higher-temperature power conversion system, such as in the direct-cycle supercritical water reactor design or for He or supercritical CO_2 turbine systems with thermal efficiencies of about 45%, provide the electricity for low-temperature electrolysis.

Since low-temperature water electrolyzer technology does not require heat input, the interface between the electrolyzer unit and a nuclear plant requires only the transfer of electricity. Thus, the heat load from the nuclear reactor is needed only for electricity production. This feature can allow the electrolyzer to be placed at a large distance from the reactor if required for safety without any loss of efficiency due to heat losses. This also allows for distributed or regional hydrogen production that could be customized for different markets and would minimize hydrogen transportation costs. However, advanced water electrolyzers at relatively higher temperatures require heat input that would have to be retrieved from the balance of the plant, which would require on-site hydrogen production.

Cogeneration of both hydrogen and electricity is a feature of low-temperature electrolysis, with excess electricity available for the grid. Since low-temperature electrolyzers have fast start-up times, it is possible to control the operation such that the rates of hydrogen and electricity production can be varied in order to follow electricity and hydrogen demands without changing the nuclear reactor thermal power. This means that load following and hydrogen production can be accomplished without the need for energy storage methods. A regenerative low-temperature PEM system [19] to produce hydrogen and electricity reversibly can be a candidate component of a nuclear hydrogen plant with cogeneration capability.

6.4.1.6. High-Temperature Steam Electrolysis (HTSE)

In high-temperature electrolysis, part of the energy required to decompose H_2O is supplied in the form of heat and, hence, overall thermal energy efficiency is improved over that of low-temperature electrolysis. Estimates show that the thermal efficiency can be as high as 48% if the electrolysis is carried out at 850^{o}C compared with approximately 25% for low-temperature water electrolysis [20]. Even at lower temperatures, steam electrolysis efficiency can be appreciably greater than that of conventional electrolysis. Solid oxide electrolysis cells are typically operated at temperatures of 800^{o}C to 1000^{o}C to maximize the transport of oxygen ions through the solid-oxide electrolyte (e.g., yttria-stabilized zirconia). If suitable solid electrolytes are developed with high ionic conductivity for oxygen ions at lower temperatures (say 400 – 500^{o}C), the electrolysis process can be operated at these lower temperatures with substantial improvement in hydrogen-to-thermal-energy conversion. Such temperatures can be obtained with supercritical water cooled reactors.

Alternatively, process heat from a water cooled reactor could be supplemented with electrical resistance heating to achieve the desired elevated electrolysis cell operating temperature. Indeed, the Idaho National Laboratory recently assessed the possibility of coupling a high-temperature steam electrolysis system to a CANDU heavy-water reactor [20]. High-temperature electric heaters were added to maintain an electrolyzer temperature of 830^{o}C. Hydrogen production efficiency was estimated to be approximately 30% (lower heating value).

The energy (enthalpy change ΔH) necessary to electrolyze water into hydrogen and oxygen is expressed as follows;

$$\Delta H = \Delta G + T\,\Delta S$$

Where ΔG (Gibb's free energy change) is supplied by electricity and TΔS is supplied by heat. In Figure 6.4 is shown the temperature dependency of ΔH, ΔG and TΔS in an electrolysis process.

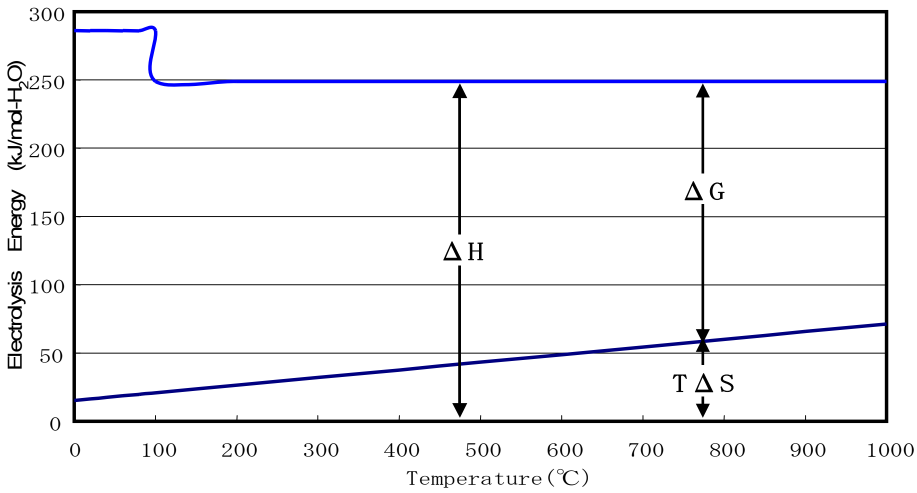

FIG. 6.4. Energy of water electrolysis as a function of temperature [21].

The theoretical hydrogen production efficiency (η) of HTSE is defined as follows:

$$\eta = HHV/(\Delta G/\varphi + T\Delta S) \quad (8)$$

HHV: High heating value of hydrogen;
$\Delta G/\varphi$: Heat necessary to generate electricity to be supplied to the HTSE cell;
φ: Power generation efficiency of electric plant.

Figure 6.5 shows the theoretical hydrogen production efficiency for a HTSE coupled with a super critical water reactors (SCWR) with a power generation efficiency of 40% and for water electrolysis using a proton-conducting membrane (PEM) electrolyzer at 100°C with the same power generation efficiency. As temperature increases, ΔG decreases and TΔS increases as shown in Figure 6.4, so the theoretical hydrogen production efficiency increases. A HTSE coupled with a SCWR as a heat and electricity source provides an efficiency of approximately 51% (HHV) at 500°C, a value greater that that for water electrolysis, which is about 42% (HHV). This analysis of theoretical efficiency does not account for other inefficiencies in a practical hydrogen production system. [21]

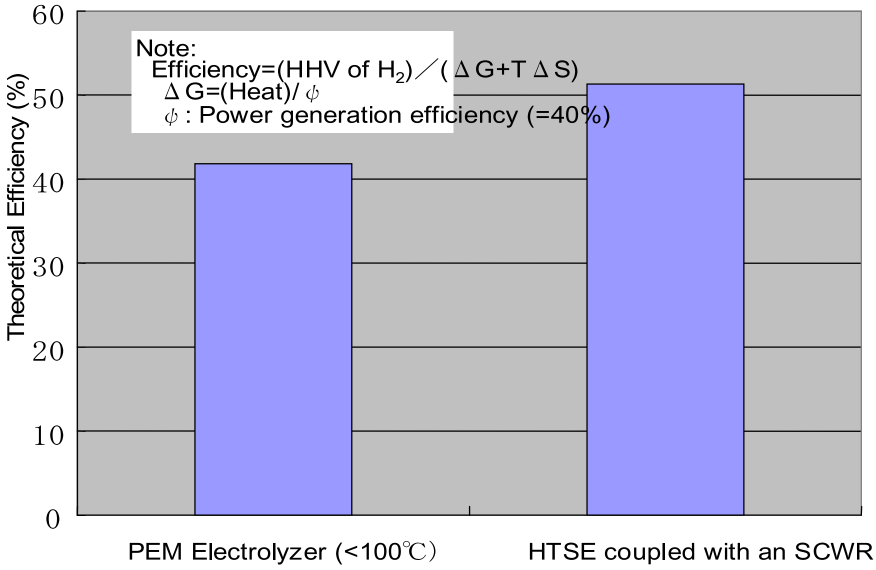

FIG. 6.5. Theoretical HHV Efficiency Comparison of Low-Temperature PEM Water Electrolyzer with a High-Temperature Steam Electrolyzer Coupled with a Supercritical Water Reactor. [21]

The HTSE process is conceptually the same as conventional electrolysis, but differs in its hydrogen production mechanism (Figure 6.6). Steam (about 90% by volume) and small amount of hydrogen are introduced at the porous cathode. Hydrogen is added to maintain a reducing atmosphere at the cathode. At the cathode steam breaks into oxygen and hydrogen ions when a suitable electrical potential is applied. The oxygen ions are conducted through the gas-tight electrolyte to the anode. Hydrogen gas is liberated at the cathode. Hydrogen is separated from steam in a condenser. At the anode, oxygen ions are converted into oxygen and liberated. An interconnect plate provides flow channels for the incoming and outgoing steam/hydrogen mixture and also for oxygen produced at the anode.

The development of HTSE electrolyzers involves the development of suitable materials and components for the cathode, electrolyte, and anode. Durability, reliability, and fabricability of thin electrolytes and sealants have to be addressed.

HTSE is suited for use with an advanced, higher-temperature nuclear reactor system. While a portion of heat from such systems can be used to produce steam, the remaining can be used for high efficiency electrical conversion for producing electricity. High-temperature electrolysis has the potential to achieve practical thermal-to-hydrogen conversion efficiencies of 40 to 50% while avoiding the challenging chemistry and corrosion issues associated with thermochemical production processes.

HTSE can be coupled to water-cooled reactors if supplemental heating is provided, though this results in a loss of system efficiency.

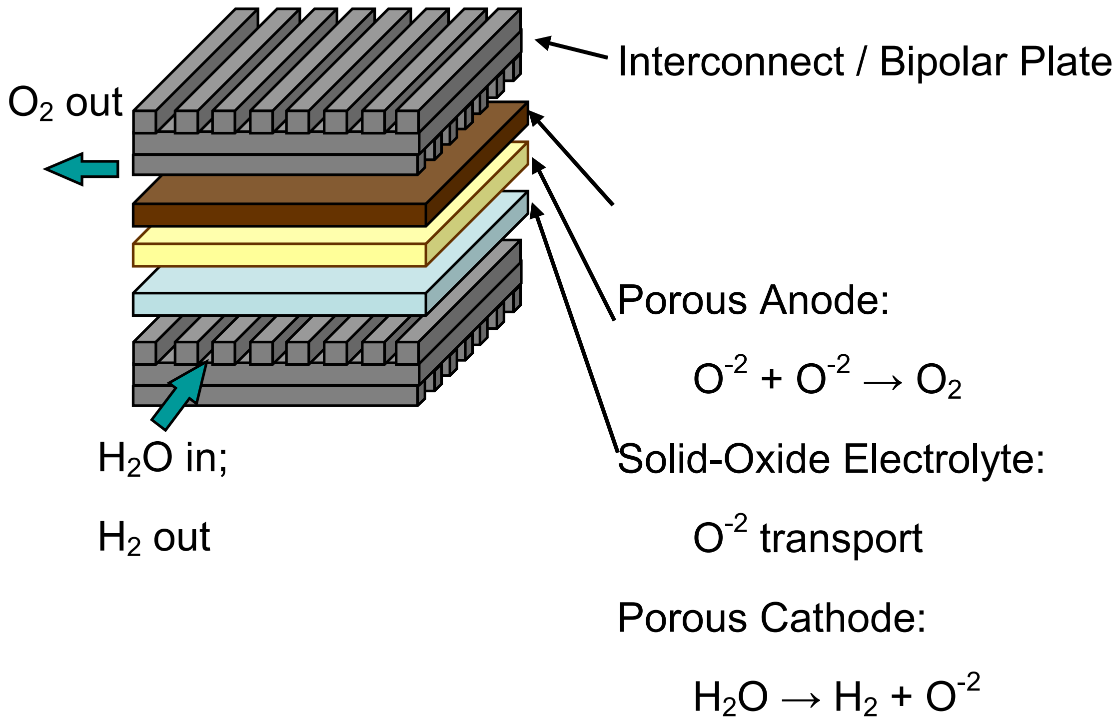

FIG. 6.6. Schematic of a solid-oxide electrolysis cell. (Courtesy of J. D. Carter, Argonne National Laboratory.)

6.4.1.7. Thermochemical and Hybrid Processes

Thermochemical and hybrid thermo-electrochemical cycles have the potential for hydrogen production with higher efficiencies than low-temperature water electrolysis. Over 200 thermochemical and hybrid electro-thermochemical reaction cycles for producing hydrogen have been identified in the literature [22]. Only eleven of those identified in Reference [22] have maximum reaction temperatures below 550°C. These lower-temperature cycles can reduce the thermal burden, mitigate demands on materials, and potentially be coupled with nearer-term nuclear reactors.

Five such cycles have been the subject of active research within the past five years: a family of copper-chloride cycles (530° - 550°C) [23], an active metal (potassium-bismuth) cycle (475 - 675°C) [24], a magnesium-chloride cycle (500°C) known as the Reverse Deacon Cycle [25], a U-Eu-Br heavy-element halide cycle [26], and a hybrid sulphur-based cycle [27]. Argonne National Laboratory has done exploratory work on all five thermochemical cycles.

The Cu-Cl cycle offers a number of potential advantages over other cycles: (1) the maximum cycle temperature (530°- 550°C) allows the use of a wider range of heat sources; (2) the intermediate chemicals are relatively safe, inexpensive, and abundant; (3) minimal solids handling is needed; and (4) all reactions have been proven in the laboratory and no significant side reactions have been observed. As a hybrid cycle, one of the reactions is electrochemical, which imposes a sizeable energy cost. However, the electrolytic step requires voltages significantly lower than needed for direct water electrolysis.

The copper-chloride cycle that has been examined at Argonne National Laboratory [23] consists of three thermal reactions and one electrolytic reaction:

(1) $2Cu(s) + 2HCl(l) = 2CuCl(l) + H_2(g)$ 430 - 475°C

(2)	$4CuCl(s) = 2CuCl_2(aq) + 2Cu$	electrochemically at 25 - 75°C
(3)	$2CuCl_2(s) + H_2O(g) = CuO*CuCl_2(s) + 2HCl(g)$	325 - 375°C
(4)	$CuO*CuCl_2(s) = 2CuCl(l) + 1/2O_2(g)$	480 - 550°C

Hydrogen and oxygen are produced thermally in the reaction between Cu and HCl (Reaction 1), and between CuO and $CuCl_2$ (Reaction 4), respectively, at temperatures up to 450 and 550°C. Water enters the system as steam and reacts with $CuCl_2$ to produce HCl and $CuO{\cdot}CuCl_2$ at 350-400°C (Reaction 3). The electrochemical reaction consists of the disproportionation of CuCl (Reaction 2) to give Cu metal for recycle to the hydrogen production reaction and $CuCl_2$ to produce HCl and oxygen through steps 3 and 4.

Experimental work has been done at Argonne to study the reaction kinetics for the hydrogen and oxygen production reactions. The experiments were conducted in beds of solid material with a continuous flow of excess gaseous reactants. The individual steps in the Cu-Cl cycle have been demonstrated, the kinetics of the hydrogen and oxygen generation reactions have been studied, and the temperatures of the reaction steps have been measured.

The reaction between HCl and Cu is a heterogeneous exothermic and reversible reaction. Reports in the literature suggested that the reaction proceeds rapidly at 230°C, the temperature at which 93% of HCl is decomposed and the Gibbs free energy change is -5.66 kcal/mol. Experiments at Argonne, however, detected no hydrogen production at this temperature. At this temperature the kinetics of the reaction are slow, and the rates of reaction are controlled by the mass transfer of HCl through a passivating film of CuCl formed on the Cu surface. Hydrogen starts to be produced in significant amounts at temperatures above 350°C. The kinetics of the reaction are further accelerated at temperatures higher than 430°C, the temperature at which CuCl melts, facilitating the interaction between HCl and Cu.

Experiments were performed with several sizes and shapes of Cu particles to find the best experimental conditions for complete Cu conversion to CuCl and H_2. Studies were done with 3, 10 and 100 μm particle sizes. There was complete conversion with 3 μm Cu particles, but only 75 percent conversion with 10 μm particles and only 55 percent conversion with 100 μm particles.

The oxygen production reaction (Reaction 4) was studied in a vertical reactor connected to a mass spectrometer to monitor the oxygen evolution. Because $CuO{\cdot}CuCl_2$, the product of Reaction 3, can be synthetically obtained from stoichiometric amounts of $CuCl_2$ and CuO at temperatures between 370 and 470°C, the kinetic study was performed using mixtures of CuO and $CuCl_2$. At 500°C, the yield of O_2 was 85% and at 530°C the reaction was virtually complete. From mechanistic studies it was found that the overall oxygen generation reaction proceeds in two steps: (1) the decomposition of $CuCl_2$ to CuCl and Cl_2 and (2) the reaction of CuO with Cl_2. In the reaction between CuO and $CuCl_2$, oxygen starts to evolve at 450°C (the temperature at which pure $CuCl_2$ starts to decompose) and Cl_2 is liberated. The Cl_2 reacts with the CuO and produces CuCl and free oxygen. From this work, the kinetics of the cycle have been established.

All the work described above has been at a small laboratory scale. No integrated-cycle test has yet been conducted. The next work that must be done to prove the viability of the process is to develop an appropriate electrochemical cell for Reaction 2. Only after a viable engineering design of an appropriate electrochemical cell is developed can an accurate economic analysis of this cycle be achieved. Nevertheless, a preliminary engineering flowsheet analysis for the cycle suggests that it is capable of reaching 40% efficiency (lower heating value) [28].

An active metal alloy cycle was invented at Argonne National Laboratory and is currently being studied by Argonne and Pennsylvania State University. Active metal alloy cycles are conceptually among the simplest of the hydrogen generation cycles [24]. One form of the active metal alloy cycle is the potassium-bismuth cycle. It consists of only two reactions:

(1) 2K3Bi (l) + 6H2O (g) = 6KOH (l) + 3H2(g) 475 – 675oC

(2) 6KOH (l) + 2Bi (l) = 3H2 (g) + 3O2 (g) + 2K3Bi (l) electrochemically

Indeed, it may be possible to design a system that performs both reactions in a single vessel, making operations simple and with low capital cost. Bismuth, however, is a relatively rare element, so the cycle may not be suitable for commercial operations. Similar cycles with other active metal alloys (e.g., the Na-Sn cycle) may overcome this limitation.

Little is known about the thermodynamics and chemistry of the K-Bi cycle. No experimental data exist to determine potential side products, the optimum operating temperature, or the necessary overpotential of the electrochemical reaction. Under a number of simplifying assumptions, the efficiency of the cycle was estimated to lie between 29 and 46% (lower heating value).

Proof-of-concept experiments are planned for the two reactions in this cycle. The work will start with the design, fabrication, and testing of an electrochemical cell that will be tested over a range of temperatures. The gaseous products will be analyzed to determine if side reactions exist.

The magnesium–chloride Reverse Deacon Cycle that was studied at Argonne National Laboratory and then Idaho National Laboratory [24] is a three-step process:

(1) $MgCl_2 + H_2O = 2HCl + MgO$ 450°C

(2) $MgO + Cl_2 = MgCl_2 + ½ O_2$ 500°C

(3) $2HCl = H_2 + Cl_2$ electrochemically at 80°C

$MgCl_2$ is impregnated into the structure of a microporous material such as a zeolite. This essentially results in the Mg compounds being in the form of dispersed nanoparticles. Reactants can readily diffuse into the zeolite to react with all of the Mg compounds and products can readily diffuse out of the zeolite. No solid particle degradation occurs, provided that the zeolite is stable in the presence of water and HCl at temperatures up to 500°C. Silicalite has been tested and was durable in the presence of these species at 500°C and supported the $MgCl_2$ hydrolysis reaction.

$MgCl_2$-loaded silicalite (10 wt%) was prepared. Under flowing steam, HCl was successfully generated through reaction 1. Reaction 2 has not been tested to date, but is thermodynamically favourable. Side reactions may demand a temperature higher than 500°C, though. Reaction 3 has been demonstrated and optimized by Weidner et al. at the University of South Carolina. The current optimized cell emf for the HCI electrolysis is about 1.5V. Further R&D into this cycle depends on further optimization of the performance of the electrochemical cell. Further proof-of-principle tests would also have to be run to demonstrate the chlorination of MgO and to determine chemical viability in terms of kinetics, yields, and absence of important competing reactions. There is no ongoing work on this cycle.

Another possible low temperature cycle is the magnesium-iodine cycle, a purely thermochemical cycle that was first studied in Japan [29,30,31,32,33], where proof-of-concept experiments were completed and process design was started. The results of the early studies showed high yields and sufficient kinetics for all reactions. A reassessment of this cycle in the U.S. is continuing at Argonne National Laboratory and the University of South Carolina [28,34,35]. The maximum temperature for the Mg-I cycle, however, is 600°C, beyond the range of water-cooled reactors, so the cycle will not be discussed further here.

A fourth low-temperature hydrogen production cycle is actively being studied. The cycle is based on heavy-element halide chemistry with a maximum reaction temperature of 300°C — the lowest known temperature for a purely thermochemical hydrogen production cycle [25]:

(1) $2(UO_2Br_2•3H_2O) = 2“UO_3•H_2O(s)” + 4HBr(g) +2H_2O(g)$ 300°C

(2)	$4EuBr_2 + 4HBr = 4EuBr_3 + 2H_2(g)$		exothermic
(3)	$4EuBr_3 = 4EuBr_2 + 2Br_2(g)$		300°C
(4)	2"$UO_3 \bullet H_2O$ (s)" $+ 2Br_2 + 4H_2O = 2(UO_2Br_2 \bullet 3H_2O) + O_2(g)$		exothermic

This reaction sequence is consistent with present relevant chemical knowledge. That knowledge, however, is for related, but not identical reactions with the exception of Reaction 1. The notation "$UO_3 \bullet H_2O(s)$" is used in the above reaction scheme because the exact stoichiometry of the species has not been determined [36]. Reactions 2 and 4 are expected to be exothermic and to proceed spontaneously. Reactions 1 and 3 are endothermic and require application of heat to the drive the reaction to the desired products.

Work was performed at Argonne National Laboratory to

(1) Determine the chemical products that result from thermal decomposition of $UO_2Br_2{\cdot}3H_2O$ (Reaction 1);

(2) Investigate and model the factors that influence reaction of Eu^{2+} ions with H^+ ions in aqueous hydrobromic acid to generate H_2 gas (Reaction 2);

(3) Study the thermal reduction of $EuBr_3$ to $EuBr_2$ (Reaction 3) and establish the degree of completion at 300°C and whether a potentially interfering EuOBr impurity is produced;

(4) Determine the chemical consequences of reacting hydrated uranium trioxide ("$UO_3{\cdot}H_2O$ (s)") with an excess amount of "bromine water" (elemental bromine (Br_2) dissolved in H_2O) (Reaction 4);

No integrated-cycle test has been performed. The work demonstrated the production of HBr through Reaction 1 with the reaction going to completion at 300°C. The studies on Reaction 2 showed that $EuBr_2$ reacts with aqueous HBr to produce hydrogen. Nevertheless, the rate of the reaction is slow (typically several hours are required for completion) under the experimental conditions that have been investigated to date. By analogy with literature studies on similarly sluggish H_2 production reaction rates from V^{2+} and Cr^{2+} ions in acid solution, it is likely that Eu^{2+} reacts slowly because the lowest energy path to produce H_2 requires a complex in which two Eu^{2+} ions simultaneously transfer one electron each to a neighboring proton only if those protons have a separation distance that is close to the H-H bond distance in the H_2 molecule. Such a "four center" reaction has low probability in fluid solution. This mechanism, however, suggests increased reaction probability with increasing concentration of both Eu^{2+} and H^+. Alternatively, a suitable catalyst could be introduced.

For Reaction 3, vacuum pyrolysis was found to allow the reaction to proceed without the complications that can arise from water entrained in the system. For Reaction 4 bromine and water can react to form HOBr, which can interfere with the desired reaction.

Thermodynamic data are largely unknown for this system. Such data would be required to assess the efficiency of the system. As with other thermochemical cycles, an engineering application of the U-Eu-Br cycle would need to consider corrosiveness of the chemicals. The low operating temperature of 300°C, however, may make these concerns more tractable than for higher-temperature cycles.

A fifth hybrid thermo-electrochemical hydrogen production system in the medium temperature range has been developed by the Japan Atomic Energy Agency (JAEA) to produce hydrogen from water by using the heat from a sodium cooled fast reactor (SFR) that could be applied to the SCWR [26].

The system is based on a sulphuric acid (H_2SO_4) synthesis and decomposition process that was developed earlier as the "Westinghouse process." The sulphur trioxide (SO_3) decomposition process is facilitated by electrolysis using a solid electrolyte that conducts oxygen ions. In this way, the operation temperature can be reduced by 200°C-300°C compared to the Westinghouse process.

The system is composed of the following three reactions.

(1) $2H_2O + SO_2 = H_2SO_4 + H_2$; using electricity at 80°C

(2) $H_2SO_4 = H_2O + SO_3$; using heat at >450°C

(3) $SO_3 = SO_2 + 1/2\ O_2$; using heat and electricity at 550°C

Alternatively, the SO_3 electrolysis step could be applied to the sulphur-iodine thermochemical cycle to reduce the maximum temperature required. In that case, the first electrolysis step shown above (reaction 1) would be replaced by a purely thermochemical reaction that would involve iodine.

The theoretical thermal efficiency of the system based on chemical reactions shown above was evaluated within the range of 35% to 55%, depending on the H_2SO_4 concentration and heat recovery [26]. The highest efficiency was achieved when the concentration of H_2SO_4 was 100% and full heat recovery was considered. The lowest efficiency was calculated with the H_2SO_4 concentration of 65% and without heat recovery. The thermal efficiency of the hydrogen production plant with an SFR of 395MWt was evaluated to be 42%, where electrolysis efficiencies of reactions (1) and (3) were assumed to be 90 and 85%, respectively [37]. This thermal efficiency was higher than that for water electrolysis, which was 38% assuming a power generation efficiency of 42% and an electrolysis efficiency of 90%.

An apparatus to substantiate the hydrogen production system was manufactured and several hydrogen production experiments were performed. The maximum duration of any single period of operation was about 5 hours, and the total operation duration was about 9 hours [38]. In the experiments, stable generation of hydrogen and oxygen was observed, and hydrogen and oxygen production rates in the experiments were about 5mL/h and about 2.5mL/h, respectively. No severe corrosion of inner surface of the SO_3 electrolysis cell and the YSZ electrolyte was observed, but corrosion of the inner surface of the outlet piping (gold plated stainless steel) was observed. Improvement of the apparatus is planned to increase hydrogen production rate (1 normal liter per hour) and to operate for longer durations. In parallel, Argonne National Laboratory is developing improved SO_3 electrolysis cells to lower the needed voltage and increase overall efficiency for reaction 3.

The remaining issues are: (1) development of higher performance electrolysis cells, (2) confirmation of the durability of the electrode and the solid electrolyte in an SO_3 atmosphere, and (3) scale-up of the hydrogen production rate.

6.4.2. Hydrogen production economics

6.4.2.1. Nuclear power in the hydrogen economy

The hydrogen production cost by centralized electrolysis (with off-site hydrogen demand) at a collocated nuclear power station and electrolysis plant was evaluated in Japan recently [39]. A Japanese utility group, the Federation of Electric Power Companies, issued in 2004 the estimation of electricity costs for varieties of power sources in various operating and financing conditions. For nuclear power plants, the generation cost is 5.1 Yen/kWh at a capacity factor of 85%, 5.3 Yen/kWh at 80% and 5.9 Yen/kWh at 70% when the operation period is 40 years and the discount rate is 3%.

The capacity of the hydrogen producing plant was assumed to be 2,700 kg per hour. Conditions, including the above power generation cost, were applied to a simplified formula for estimating the hydrogen production cost. The following hydrogen production costs were obtained: 301 Yen/kg at a capacity factor of 85%, 314 Yen/kg at 80% and 349 Yen/kg at 70%. With the compression cost (34

Yen/kg), the delivery cost (50-100 km: 168 Yen/kg), and the station running cost (168 Yen/kg) added to the hydrogen production cost, the hydrogen supplying cost was estimated to be 671-719 Yen/kg.

The total cost of hydrogen supply can be divided into a production cost, a delivery cost, and a station cost. Further, each of these costs is composed of a fixed cost and a variable cost. In this study, the fixed cost was calculated by multiplying a capital rate by a capital cost. The capital rate was calculated by summing the following items: plant depreciation with a legal plant life assuming a remaining capital cost of 10%, a property tax of 1.4%, an insurance of 0.6%, maintenance and repair of 3%, a remuneration of 2.5%, and a general control charge of 1%. A plant construction fee was excluded, because it varies largely depending on the construction site and it is less than 10% of the capital cost in most cases. The variable cost is the sum of a raw material fee, a utility fee, and a labor fee.

Hydrogen production cost using steam methane reforming was evaluated as a cost target. The plant size was assumed to be 18,000 kg/h with a capital cost of 27 GYen based on the largest ammonia plant in Japan. The hydrogen production cost was estimated to be 143 Yen/kg, assuming an operation rate of 90%, a plant life of 10 years, and utility and labour fees of 1.6% and 0.7% of the capital cost, respectively. The cost of natural gas was assumed to be 1.8 Yen/Mcal. With a CO_2 sequestration cost of 30-70 \$/t-CO_2, the production cost would increase to 177 Yen/kg H_2 assuming 33 Yen/kg H_2 or 3.6Yen/kg-CO_2 for CO_2 sequestration.

Capital costs were estimated for water electrolysis with outputs of 27, 270 and 2,800 kg/h. The scale law with the power of 0.68 was used for the capital cost based on the reported capital costs. The incidental costs for construction were not included in the capital costs. A plant life and a labour fee were assumed to be 10 years and 0.7% of the capital cost, respectively. The cost of water was assumed to be 200 Yen/t. Generation power for hydrogen production was assumed to be 48 kW/kg.

The study assumed that the electrolytic facility was co-located with a nuclear power plant; the electricity cost was assumed to be the power generation cost of light water reactors (LWRs). The power generation cost of LWRs was evaluated as functions of an operation rate and a discount rate. The typical cost was 5.3 Yen/kWh at a capacity factor of 80% and a discount rate of 3%. The cheapest cost was 4.8 Yen/kWh at a capacity factor of 85% and a discount rate of 0%. So the cost was changed accordingly from 4.8 Yen/kWh to 5.3 Yen/kWh. The operation rate and power of the hydrogen production plant were assumed to be the same as those of the LWR.

Hydrogen production costs for LWRs with thermal powers of 3,000, 3,500, and 4,000 MWt were calculated. The hydrogen production rates for powers of 3,000, 3,500, and 4,000 MWt were 20,500, 23,900, and 27,300 kg/h, respectively. The power generation costs were assumed to be 4.8 Yen/kWh with a capacity factor of 85%, 5.1 Yen/kWh with an operation rate of 85%, and 5.3 Yen/kWh with a capacity factor of 80%. It was found that for all cases the hydrogen production costs using a nuclear facility to provide electricity for electrolysis would be in the range of 224-280 Yen/kg, which exceeds the target cost of 177 Yen/kg. Although the cost of natural gas depended on the economic situation, the power generation cost would need to be reduced to meet the target cost.

Hydrogen has to be delivered from the production site to the user site if a centralized production facility is used. There are three ways to carry hydrogen: a trailer for pressurized hydrogen, a tank lorry for liquid hydrogen, or a pipeline for pressurized hydrogen. The volumes of hydrogen transported by the trailer and the tank lorry were assumed to be 244 and 1,296 kg/trip, respectively. Delivery costs were evaluated by changing the thermal power of the nuclear power plant and the transportation distance.

If the thermal power was more than 1,000 MWt, the pipeline was cost effective regardless of the transportation distance. The delivery by the tank lorry was expensive because it required an expensive liquefaction and shipping facility.

The delivery cost of the pipeline was evaluated based on a capital cost of 360 MYen/km and a booster cost of 33.6 kYen/km. The capital rate was assumed to be 0.18. The delivery cost of the pipeline decreased with the amount of hydrogen and increased with the delivery distance. The delivery distance was assumed to be 400 km in this calculation.

The capacity of a hydrogen station was estimated to be 90 kg/h, if the same amount of thermal energy as that of a gas station was treated. However, fuel cell vehicles are 2.5 to 3 times more efficient than a gasoline engine driven automobile. Therefore, the capacity of the hydrogen station was assumed to be 27 kg/h.

Station costs were evaluated using a progress ratio, F, which indicates how much costs decrease when an accumulation of products doubles. Station cost, Y, was calculated as follows, after X-1 stations had been identified:

$$Y = A\, X^{-B} \quad , \tag{1}$$

where A is the cost of the first station and B is the cost reduction ratio (= -log (F)/log2). Using this equation with X=10,000, the station cost for compressed hydrogen storage was calculated to be 248 Yen/kg. Here the operation rate and the station life were assumed to be 90% and 8 years, respectively. The cost was still higher than the cost of 168 Yen/kg for a gasoline station.

For hydrogen to become economically advantageous, the hydrogen supply cost should be less than gasoline's cost. The hydrogen cost equivalent to the gasoline cost was calculated to be 581 Yen/kg assuming a tax for volatile oil, a gasoline cost of 110 Yen/l, and the fact that fuel cell vehicles have 2.5 times higher efficiency than gasoline cars.

From the analysis that has been done, it has been found that hydrogen supplied from a centralized electrolysis facility and delivered to a fuelling station by pipeline is competitive with gasoline that is priced between 110 and 115 Yen/l. In the case of a gasoline cost of 110 Yen/l, the minimum conditions to meet this cost were a capacity factor of 85 %, a power generation cost of 4.8 Yen/kWh and a thermal power of 4,000MWt. If the gasoline cost increased to 115 Yen/l, the equivalent hydrogen cost would be 56.6 Yen/kg. Therefore, the hydrogen supply cost for fuel cell vehicles would meet the gasoline cost. Hydrogen production by centralized electrolysis is economically feasible, but a reduction of the station costs is necessary to compete with gasoline because station costs make up about 50% of the hydrogen supply cost.

6.4.2.2. The use of off-peak electricity to produce hydrogen

Two economic analyses of electrolysis systems have been done in the U.S. [15,40] to determine the capital and operating costs that would be necessary to meet target hydrogen costs. These analyses can be extended to consider the costs of hydrogen production with off-peak electricity.

In these studies the cost of the hydrogen produced by electrolysis was compared with the DOE target cost for hydrogen, US$2.00-3.00 per kg [14]. A more relevant comparison would be between the cost of hydrogen produced by electrolysis and the cost of hydrogen produced by steam methane reforming (SMR). In Reference [41] there is an assessment of hydrogen cost produced by SMR for a range of natural gas prices up to US$12.00 per MMBTU. For natural gas at US$4.00 per MMBTU, which was the typical price for natural gas in the U.S. for many years, the cost of hydrogen is US$1.00 per kg. Recently the price of natural gas at the wellhead reached US$12.00 per MMBTU [42]. For that price, the cost of hydrogen is US$2.25 per kg. A study by S. S. Penner [43] also included an analysis of hydrogen cost as a function of natural gas price. In that analysis the cost of hydrogen is US$1.29 for natural gas at US$4.00 per MMBTU and the cost of hydrogen is US$3.58 for natural gas at US$12.00 per MMBTU. In summary, these studies bracket the cost of hydrogen at US$1.00-1.29 for natural gas at its historic price and at US$2.25-3.58 for natural gas at its current price. The DOE target cost of hydrogen thus is consistent with hydrogen produced by SMR with natural gas at its current cost.

One of the key components in these analyses was the cost of electricity. Although the studies did not specifically address the use of off-peak electricity, the range of electricity costs that has been considered is representative of that which would be appropriate for off-peak electricity production.

There are two significant studies that have analyzed the cost of hydrogen production by electrolysis. One of them [40] concentrated on electrolyzer units that are now commercially available. The other [15] was done as part of the development of a high-pressure electrolyzer that would be useable in future hydrogen generation and distribution systems.

The first study reviewed the information available on thirty-seven currently available electrolyzer units from five manufacturers. Two analyses were made. An initial cost analysis was done for all thirty-seven units to determine the effects of electricity price on hydrogen costs. Thirty-four of the electrolyzers reviewed were bipolar alkaline, low-pressure systems (less than 200 psig, 1.4 MPa) and the analysis did not take into account any electrical energy for the compressors that might be necessary to increase the pressure to several thousand psig (tens of MPa) for a distribution system. Three of the electrolyzers reviewed were unipolar alkaline electrolyzers that produce a hydrogen product pressure up to 10,000 psig (69 MPa); however these were among the smallest of the units reviewed and their scale precludes them from being used in any large application.

For each electrolyzer, the specific system energy requirement was used to determine how much electricity is needed to produce hydrogen; no capital, operating, or maintenance costs were included in the calculation. The researchers found that, at current electrolyzer efficiencies, electricity costs must be approximately 4.0 to 5.5 ¢/kWh to be able to produce hydrogen for less than US$3.00 per kg. The analysis demonstrated that, regardless of any additional costs, electricity costs are a major cost contributor.

A detailed economic analysis was done for three systems, representing small (20 kg/day), medium (100 kg/day) and large (1000 kg/day) hydrogen production systems. The cost of electricity used in this analysis was 4.83 ¢/kWh, which was considered to be a rate available to industrial users. This rate is slightly higher than the current rate for commercial off-peak electricity in the metropolitan Chicago area [17]. The hydrogen selling prices for the three systems were found to be US$19.01, US$8.09 and US$4.15 per kg, respectively. It was found that for the large system the electricity cost represents 58 % of the cost of the hydrogen, with capital costs representing 32%. For the medium system, the cost of the electricity is 35% of the cost of the hydrogen and the capital costs become the major factor at 55%. For the small system, the capital costs increase to 73 % of the hydrogen costs and the electricity costs are 17%. This analysis showed that electricity price is a contributor to the hydrogen price for all systems, but the capital costs are more significant for small-sized electrolyzers. The hydrogen selling price for the two small and medium systems is far above the U.S. Department of Energy target price of US$2.00-3.00 per kg and above the cost of hydrogen produced by SMR. Even the large system has a price that is 35 % higher than the DOE target price and 50% higher that the cost of hydrogen produced by natural gas SMR. This demonstrates that it is necessary to have an appreciable scale to the operation to make it economical.

The largest electrolyzer that was examined in this study produces 380,000 kg of hydrogen per year. If these systems were to be used in a large hydrogen generation plant, the limited hydrogen production capability of each unit would mean that a significant number of electrolyzer units would be required. For example, a 500,000 kg/day hydrogen generation plant would require the use of 500 of these units, which are the largest units available today, and would demand 1150 MWe. A plant of this scale would be typical of the hydrogen generation plant that would be required to supply a medium-sized ammonia or methanol plant. In this scenario, it would be more efficient to use electrolyzers that are 10 to 100 times as large as today’s units, if the economies of scale remain proportional.

The second study [15] was done by Giner Electrochemical Systems as a part of their efforts to develop a low-cost, high-pressure hydrogen generation system. They developed an economic model that allowed them to determine the cost of hydrogen as a function of the cost of electricity and the capital and operating costs of the electrolyzer plant components. The scenario investigated was a neighborhood refueling station with a hydrogen production rate of 432 kg/day. The electrical load for such a station is approximately 1 MW. They determined that to meet the DOE target cost of hydrogen produced they would need to have an installed equipment cost of US$1100 per kW, a plant that operates at 90% capacity with a ten year plant life, and an electricity cost of less than 3.6 ¢/kWh. This cost is only 20% lower than the cost for commercial off-peak electricity in the metropolitan Chicago area (i.e., approximately 4.5 ¢/kWh [18]. To meet the installed equipment cost target, they would need to have a large cell active area to reduce the number of cells and ancillary components. They would also need to be able to achieve moderate (400 psig, 3 MPa) to high (2000 psig, 14 MPa) pressure in their electrolyzer cell. They claimed to need no breakthroughs in compressor technology to achieve their goal since the cell technology that they are pursuing is itself a high-pressure cell technology.

The models that were used in both of the studies considered above used a plant operating capacity factor that is typical of base load operation, not off-peak operation. The two studies called for 97 % and 90 % capacity factors, respectively. To treat this situation properly, analyses similar to those discussed above would need to be done with a plant operating capacity that would be more typical of a plant operated with off-peak electricity (approximately 40 percent). If the model used by the National Renewable Energy Laboratory were modified to use an operating factor of 40 %, the hydrogen selling price for a large system would approach US$7 per kg (approximately 70% greater than the price calculated in the original study and a price that is more than twice the DOE target price.) In addition, if the plant operated only with off-peak electricity, the plant output would be only 40% of the reference plant. Consequently, it would be necessary to have a plant 2.5 times larger to achieve the same daily production of hydrogen. In addition, it would be necessary to have hydrogen storage capacity available to provide hydrogen supply during the periods when the off-peak production facility is not operating.

Another way to consider results of such analyses is that they would show that the cost of electricity would have to be reduced markedly (approximately a factor of 10) to compensate for the re-distribution of the capital costs and the operating and maintenance costs over a lower hydrogen production base. For the Giner Electrochemical Systems study, for example, the installed cost of the system would have to be reduced to approximately US$500 to compensate for the reduced duty cycle that is achievable with off-peak electricity.

With regard to both of these studies, there is no firm basis for the cost of off-peak electricity because there is little relevant experience with the pricing for off-peak electricity in a high demand environment, such as might occur if there is a large demand for off-peak hydrogen production. In some areas of the U.S. off-peak electricity is used for pumped storage of water to provide additional electricity during seasons in which there is high demand for electricity during peak periods. Off-peak electricity is also used in some large cities to chill water at night for daytime cooling of office buildings and other commercial facilities. In neither of those situations has there been any significant increase in the cost of off-peak electricity; however, neither of those situations has produced a significant demand on the available power during off-peak periods.

A study has been made in Japan on the cost of hydrogen that would be produced by a filling station that produces hydrogen by water electrolysis [44,45,46,47]. The plant that was selected for study would have a full-time capacity of 640 kg/day. Two modes of operation were considered. In one mode the hydrogen generation portion of the station was assumed to operate full time. In the other mode, the hydrogen generation portion of the station was assumed to operate only during those hours when electricity would be available at off-peak rates. The analysis that was done used a construction cost of 204 million Yen, a 10-year depreciation cost, a fixed annual operation cost of 7.5% of the plant construction cost and a similar operating cost prorated on the fraction of the time that the plant is operated. It was assumed that the energy required to produce hydrogen by electrolysis is 48 kWh/kg. The current TEPCO rates for electricity were used in the analysis. It was found that the cost of hydrogen is 760 Yen/kg if the plant is operated full time. If the plant is operated only at those times when electricity is available at off-peak rates (between 10 P.M. and 8 A.M.), the cost of the hydrogen produced is 900-1200 Yen/kg. These findings are consistent with the findings in the U.S. analysis reported above.

6.4.3. Hydrogen production with a combination of nuclear electricity and wind electricity

Wind-generated electricity has the similar capital cost as nuclear, but it is variable and intermittent. Using electrolysis to transfer wind-generated electricity to hydrogen production could be a way to beat its limitation. That is, excess wind-based electricity not needed for the grid could be shed through the use of electrolyzers. But the low capacity factor of wind electricity (from approximately 25% to 40%, depending on the site) would result in large idle periods for the electrolysis facility, which imposes a serious cost penalty and makes electrolytic hydrogen production by wind electricity un-economical.

One solution could be to use wind-generated electricity to supplement base-load nuclear-generated electricity and hydrogen production, because electrolytic cells can accommodate electrical currents 36% higher than its nominal operating level, producing more hydrogen. To allow this, the cell design has to be modified to handle additional gas, and accordingly, the capital cost can be assumed to rise from 300 to 330 US$/kW. Variable-current operation imposes fluctuation in conversion efficiency, which was calculated by a model provided by Stuart Energy Systems [48]:

$$\text{Energy use (kW-h/kg } H_2) = 41.66 + 7.955*A + 4.545/A + 1.1,$$

where A is the current density relative to the standard design. A study was performed to determine how much additional wind (the ratio of additional wind to nuclear) could be added to the nuclear base, and how much electricity (conversion ratio) is used for hydrogen production to make the case economical.

The wind data used in the analysis were from two sites with similar wind speeds (Types G and H) and variability in Wales, with the capacity factors of 41.5% and 32.6%, respectively. The Alberta and Ontario electricity market price data in 2003 were used.

The portion of electricity used for hydrogen production (referred to as a conversion ratio) continued to be a specified percentage of the total. For example, a wind installation of 35% of the nuclear capacity with a lesser average wind speed (Type H) would add an average of 11.4% to the total power production so that the model is required to produce 11.4% more hydrogen, and the storage capacity is proportionally increased.

The analysis examined a range of additional wind power values up to 45%. For each value, the objective function of optimization is the minimum price of hydrogen that will give total revenue of 3 US¢/kW-h for all electricity. This procedure was applied over a wide range of conversion ratios.

It is important to appreciate that the average value of electricity in Alberta in 2003 was almost 4.5 US¢/kW-h while the average value in Ontario was only 3.86 US¢/kW-h. The higher average value for electricity makes the contribution from sale of electricity larger so that the selling price for hydrogen needed to meet the revenue target of 3 US¢/kW-h is lower for the Alberta case.

The results indicated that cases with 70% to 80% of the conversion ratio make the best opportunities for adding wind to a nuclear base, and that the case with 50% and 60% hydrogen production turned out to be quite accommodating to wind, because the addition only makes sense where the electrolysis installation is big enough to be able to use more than the entire output from nuclear generation. The case with 70% hydrogen production (and 30% sold as electricity) tends to be the best conversion ratio for accommodating the addition of wind. For the Alberta situation, additional hydrogen generated from wind can be sold at a lower price than in Ontario in order to meet the revenue target. The ratio of the additional wind power the facility can handle economically depends on conversion ratio, the wind type, and the electricity market. In both provinces, the 2000 US$/t of H_2 target price can be met with Types G and H winds comfortably for the ratio of additional wind to nuclear is up to 30%, with the 70% of conversion ratio.

In conclusion, the combination of nuclear and wind does appear capable of absorbing wind's variability and to produce hydrogen from wind-produced electricity far more cost-effectively than would be possible with wind alone. It also accommodates the seasonal variability of wind.

6.4.4. The environmental benefits of fuel cell vehicles supplied by nuclear-generated hydrogen

Argonne National Laboratory performed an analysis of the environmental impacts of hydrogen fuel cell vehicles using the lifecycle analysis software GREET, the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model. GREET, as described in Chapter 5, was developed at Argonne National Laboratory to evaluate well-to-wheels energy and emission impacts of motor vehicle technologies powered with various transportation fuels. The model and associated documents are posted at http://www.transportation.anl.gov/software/GREET/index.html.

In this study, four nuclear hydrogen production pathways were examined [49]:

(1) Hydrogen production at refuelling stations by electrolysis using light water reactor electricity;

(2) Centralized hydrogen production using the sulphur-iodine thermochemical cycle using heat from a high-temperature gas-cooled reactor (HTGR).

(3) Centralized hydrogen production using high-temperature steam electrolysis using HTGR heat and electricity.

(4) Hydrogen production at refuelling stations by electrolysis using HTGR electricity.

All stages of the lifecycle were considered:

- Uranium ore mining and milling;
- Uranium yellowcake transportation;
- Uranium conversion;
- Uranium enrichment;
- Uranium fuel fabrication;
- Uranium fuel transportation;

- Electricity or hydrogen production in the nuclear power plants;
- Hydrogen transportation;
- Hydrogen compression;
- Hydrogen fuel cell vehicle operations.

The study showed that significant reductions in fossil energy use and greenhouse gas emissions come from nuclear-based hydrogen production compared to natural-gas-based hydrogen production through steam methane reforming. The reductions amount to 73 – 96% in greenhouse gas emissions (CO_2, CH_4, and N_2O) and 81 – 97% in fossil energy use. Furthermore, fuel cell vehicles powered by nuclear hydrogen have substantial reductions in greenhouse gas emissions (87 – 98%) and fossil energy use (89 – 98%) compared with internal combustion engine vehicles using reformulated gasoline. Nuclear hydrogen is not completely emission-free, however, since a small amount of fossil fuel is consumed in the upstream feedstock and fuel stages.

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ANNEX I
RECENT NUCLEAR DESALINATION DEMONSTRATION PROJECTS [7]

I-1. Nuclear desalination demonstration project, Kalpakkam, India

Bhabha Atomic Research Centre (BARC) has been engaged in R&D work in thermal and membrane desalination technologies for the past several years. A number of pilot plants have been tested successfully. Utilizing the design and operational experience of these plants, a hybrid multi-stage flash / reverse osmosis (MSF-RO) seawater desalination plant of 6300 m^3/day capacity coupled to a nuclear power station based on pressurized heavy water reactor (PHWR) on the southeast coast of India is being set up to demonstrate the reliability and economics of hybrid desalination technology as an alternative to meet water shortages. The hybrid desalination demonstration plant (Fig. A.1-1) comprises a 4500 m^3/d MSF desalination plant and a 1800 m^3/day RO plant. A part of the high-purity product water from the MSF will be used to prepare makeup boiler-grade water for the power station. Blending of the product water from the RO and MSF plants will provide requisite-quality drinking water. The RO plant has been operating since 2006 and the MSF plant is to be connected in 2007.

FIG. I-1. Hybrid MSF-RO desalination demonstration plant, Kalpakkam.

The setup of a hybrid system at same location may contribute significantly in reducing the operation and maintenance (O&M) costs of desalted water by taking advantage of producing both process- and drinking-quality water, using common pre-treatment to a considerable extent, and the possibility of using reject streams from one plant to the other. A hybrid system using ultra-filtration and nano-filtration (UF/NF) as a pre-treatment of seawater coupled to multi-step flash / multi-effect distillation (MSF/MED) or RO has a high potential in the future.

I-2. Coupling of LT-MED with KANUPP, Pakistan

In order to demonstrate the technical and economic viability of nuclear desalination, a small capacity Low-Temperature Multi-Effect Distillation (LT-MED) plant is under construction in Pakistan to be coupled to the Karachi Nuclear Power Plant (KANUPP), which is a Pressurized Heavy Water Reactor (PHWR) of 137 MWe capacity (Fig. I-2). The main objectives of this project are to collect technical and economic data, and to obtain experience in design, manufacturing, operation and maintenance of thermal desalination plants. The project is expected to foster public acceptance, as well. The experiences in different phases of this project will pave the way for indigenization of MED type desalination plants, which will ultimately culminate in large-scale desalination plants to be coupled with future nuclear power plants along the coastal belt.

In first phase of the project an LT-MED plant of capacity 1600 m^3 /day is being coupled with KANUPP. Different options were studied for tapping steam from the steam cycle of the power plant as a heat source for the desalination plant. The bled steam, from the high-pressure turbine, that was originally used for feedwater heating in one of heat exchangers has been selected as a heat source for the desalination plant, owing to its having the least effect on power plant generation capacity. Because of the risk of possible radioactive contamination of the product water, coupling of desalination plant with nuclear power plant is carried out by employing an intermediate loop with a pressure reversal concept. Demineralized pressurized water is circulated in the intermediate coupling loop. This circulating water takes heat from the condensing steam in the feedwater heater to the reboiler to produce motive steam for the MED plant. A pressurizer is used in the intermediate coupling loop to maintain the pressure. The total number of effects of MED is 8 and the Gained Output Ratio (GOR) is 6. Provision of manual radioactive monitoring is incorporated in the intermediate coupling loop to ensure the final product water free from radionuclides.

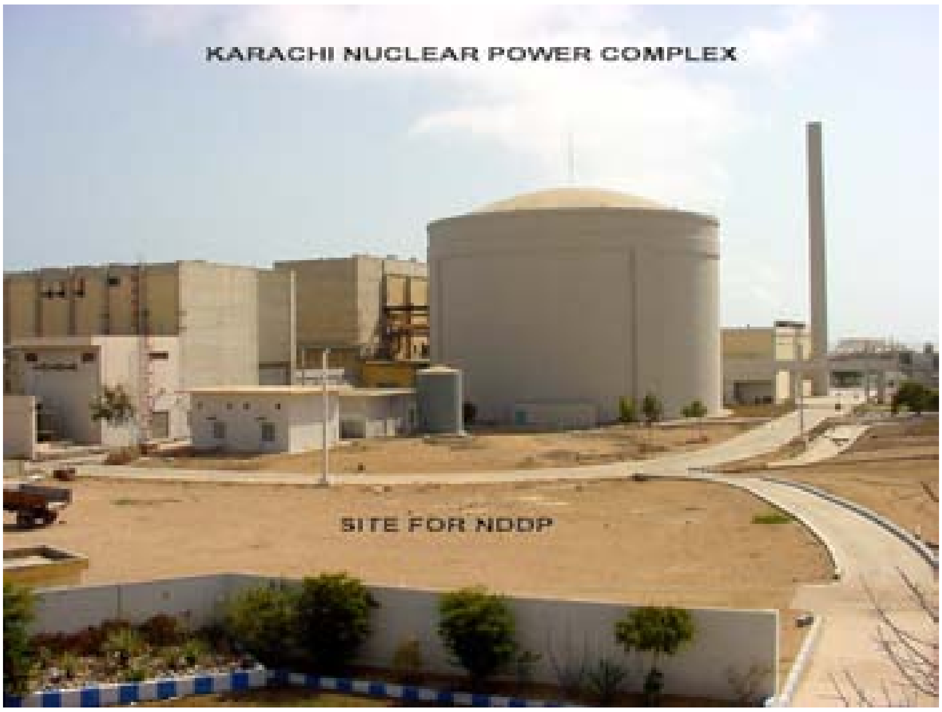

FIG. I-2. Karachi Nuclear Power Complex and the site of NDDP.

I-3. Coupling of MED-TVC with SMART for nuclear desalination

The SMART desalination plant has been developed for water production and electricity generation. The integrated SMART plant would consist of several units of a Multi-Effect Desalination Process combined with a Thermal-Vapour Compressor (MED-TVC). The thermal vapour compressor was combined with the MED process to improve the energy utilization of the processed steam (Fig. I-3).

In a nuclear desalination, a radioactive contamination of the product water is one of the most important issues with respect to the safety and public acceptance. In this regard, the units of the desalination plant are coupled with the SMART power system through an intermediate heat transfer loop. The major function of the intermediate heat transfer loop is to protect the desalination plant from radioactive contamination and produce a medium-pressure motive steam by using the steam extracted from the turbine. Radioactivity monitoring systems were also installed in the water production system and the intermediate loop where the concentration of radioactivity is higher than that in the desalination plant. These systems will provide an enhanced capability for radioactivity detection.

Since the desalination plants are connected thermally with the SMART power system, the transients of the desalination system can directly influence the operation of the SMART plant. A slow transient, such as a gradual reduction in the energy demand of the desalination system, can be easily accommodated for by the SMART system through either the load-following capability or a cut-back of the energy supply to the desalination system. Thus, only fast transients induced by the desalination system become important events to be considered for the safety of the SMART desalination plant. For disturbances of the SMART desalination plant, several events were identified as potential disturbances imposed by the desalination plant. The impacts of these disturbances on the Design Basis Accidents and Performance Related Basis Events of the SMART plant were evaluated by a conservative bounding approach of the key safety parameters and the results showed no additional safety concerns for the SMART desalination plant.

Construction of a SMART plant with one-fifth scaled power and a desalination plant has been launched in Korea. The plant is expected to be in operation in 2008.

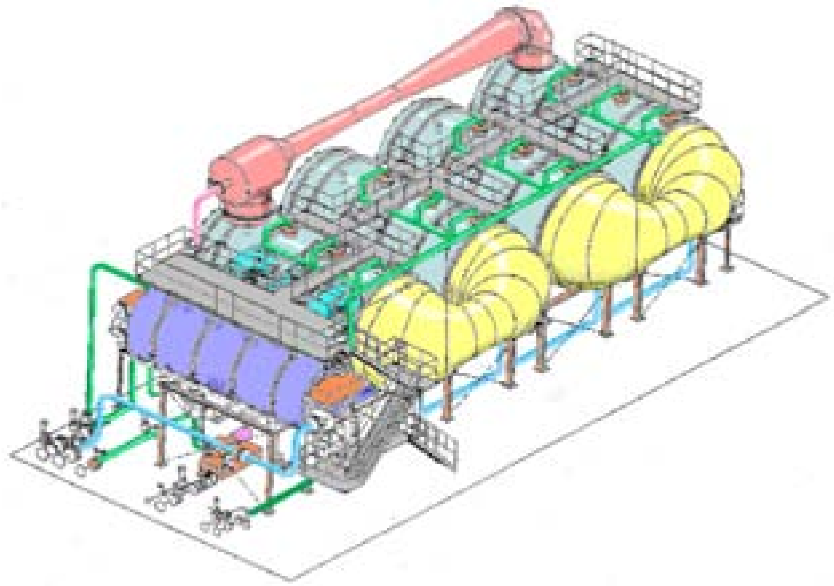

FIG.I-3. SMART MED-TVC desalination plant.

I-4. El Dabaa RO experimental facility, Egypt

The Egyptian Nuclear Power Plants Authority (NPPA) is considering to construct an experimental Reverse Osmosis (RO) facility at its site in El-Dabaa, Egypt, to validate the concept of feedwater preheating, to achieve the following objectives:

- **Overall**: to investigate experimentally whether the projected performance and economic improvements of preheated feedwater can be realized in actual operation.

- **Long-term**: to study the effect of feedwater temperature and pressure on RO membrane performance characteristics as a function of time.

- **Short-term (~ 3 years)**: to study the effect of feedwater temperature and pressure on RO membrane performance characteristics over a range of temperatures (20-45°C) and pressures (55-69 bars).

The test facility would consist of two identical units: one unit operating at ambient seawater temperature and the other with preheated feedwater up to 45°C. This configuration is considered practical with 4-inch membranes, and has the benefit of giving direct comparison of performance characteristics for the preheated and non-preheated cases over the entire range of test conditions.

The test facility consists of the following main components:

- **Beach wells and pumps**: This ensures clean feedwater with minimum pre-treatment requirements and lower operational costs.

- **Pre-treatment system**: The system is designed to allow for the various pre-treatment requirements for the different commercial membranes to be tested.

- **Water heating system (for one unit only)**: The feedwater will be heated by a fresh water/seawater heat exchanger. The hot fresh water will be obtained from an electric water heater; the hot brine and permeate will be used to preheat the feedwater, utilizing permeate/seawater and brine/seawater heat exchangers.

- **High-pressure pump with energy recovery and hydraulic coupling**: The experiments involve different types of membranes, requiring different operating pressures and feed flows. Therefore, the high-pressure pump is coupled with a hydraulic coupling to obtain the required pressure and flow rates.

The experimental program was developed with IAEA technical assistance in the design stage as well as in the preparation of the technical specifications and tender documents. The commissioning of the test facility has been completed.

The results of this experimental work could have a strong influence on how the international nuclear desalination community perceives the value/benefit of feedwater preheating, and hence there is a common international interest in this project. Therefore, NPPA remains committed to making the results of the experimental program beneficial to the nuclear desalination community.

FIG. I-4. El Dabaa RO experimental facility.

I-5. Russian Federation

The Russian Federal Agency for Atomic Energy (ROSATOM) has started construction of a floating barge-mounted heat and power co-generation nuclear plant based the ship propulsion PWR-type reactor KLT-40C in Severodvinsk. It is planned to put the plant into operation in 2010.

The barge where the NPP is mounted has the following dimensions: length – 144 m, width – 30 m, displacement – 21500 t. Two KLT-40C reactors are housed in separate steel containments. The floating NPP can produce up to 70 MW for electric power and about 174 MW of heat for district/process heating. The lifetime of the plant is 40 years; it is designed for a continuous operation period before dockyard refurbishment of 12 years.

Demonstration of this nuclear technology is intended to allow its larger-scale application inside the country and abroad for electricity and heat production.

I-6. Feasibility studies

People's Republic of China

The construction of a nuclear desalination demonstration plant (SNDP) with a production capacity of 160,000 m^3/d in the Shandong Peninsula of China was proposed in 2000. The pre-feasibility of SNDP was completed in 2001 and was reviewed and approved by the central government in 2002 and 2003, respectively. Hao-Xin Investment Co. is the owner and the Institute of Nuclear and New Energy Technology at Tsinghua University is the engineering contractor. The feasibility study started in March 2003. The SNDP consists of an NHR-200 coupled to a MED process. The NHR-200 as a nuclear heating reactor with 200 MW capacity is designed with a number of advanced features, such as an integral arrangement, full natural circulation, self-pressurization, in-vessel control rod drive, and passive safety systems in order to achieve very high safety margins. Therefore, no off-site emergency actions such as sheltering, evacuation, relocation and decontamination are expected to be necessary.

Two desalination processes were considered and compared in the feasibility study. One is the high-temperature vertical-tube evaporator multi-effect distillation (VTE-MED) process and the other is multi-effect distillation thermal vapour compression (MED-TVC) process. A tower-type arrangement for the VTE-MED has been adopted. Two trains of VTE-MED are coupled with the NHR-200. Each train consists of 3 towers, in which 7 modules of evaporators compose one effect in parallel and 32 effects of evaporators are vertically arranged to achieve a high GOR of 22.

Alternatively, four units of the MED-TVC process are coupled with the NHR-200. Each unit has a desalination capacity of 30,000 m^3/day and consists of 14 effects of evaporators. The motive steam from the steam generator is supplied through the thermal vapour compressor (steam ejector) and extracts low-pressure steam from the sixth effect of evaporator. In this way, a GOR of 15 will be achieved.

Techno-economic feasibility studies by interested IAEA Member States

Other countries undertaking feasibility studies on the technical and economic viability of seawater desalination coupled to nuclear power include Algeria, Egypt, Indonesia, Jordan, Morocco, Tunisia and UAE.

ANNEX II
NUCLEAR DISTRICT HEAT IN SWEDEN AND ROMANIA

II-1. The ASEA-Atom SECURE reactor

The development of the SECURE-reactor (Safe and Environmentally Clean Urban Reactor) started as a joint research project between Sweden and Finland in 1976 to 1977. Later on the development work continued within AB ASEA-Atom. In the early 1980s it had evolved into a rather mature reactor model.

The design principles were to have an economically sound nuclear heating plant that is well suited for location close to population centres. Such urban siting reduces the investment cost for the district heating network and contributes to better operating economy by reducing the thermal losses from the district heating pipe work.

The low temperature and pressure of a heating reactor offers wide freedom as regards the design. This has been fully used for the design of the SECURE reactor. It has built-in safety based on basic laws of physics. By utilizing such inherent safety for assuring the shut down and cooling of the reactor, dependence on active components such as electrical or mechanical devises is avoided. Therefore the issue of availability of such equipment will be irrelevant.

Table A.2-1 lists the members of the SECURE family of reactors developed by ASEA-Atom in the 1980s.

Table II-1. SECURE family of reactors

SECURE-LH	Heat-producing plant with a reactor coolant temperature slightly above 100°C
SECURE-H	Heat-producing plant with a reactor coolant temperature in the range of 200°C
SECURE-PIUS (Process Inherent Ultimate Safety)	Power producing plant with a reactor coolant temperature in the range of 300°C

In the SECURE concept, the primary coolant circuit delivers heat to an intermediate circuit within the station. Heat exchangers that deliver heat to the district heating network are located in the auxiliary systems building.

A safety evaluation of the SECURE reactor was carried out in 1977. The assessment was divided into the following parts of the reactor:

(1) Inherently safety properties
(2) Underground siting
(3) Pre-stressed concrete pool vessel
(4) Control and protection systems
(5) Reactor shutdown
(6) Residual heat removal

The evaluation concluded that it appeared possible to build a low-temperature reactor of a new type with lower environmental risk than the power reactors operating at that time.

The cost characteristic of the heating reactor was such that the reactor was best suited for supplying base load heat, with fossil fuel hot water stations meeting the peak load. Typical demand duration curves for the heat consumption in built-up areas in Scandinavia show that a supply of 100°C water can satisfy the vast majority of the heat demand.

A cost comparison between a SECURE station and a coal-fired station for heat production done in the late 1980s showed that SECURE was more cost effective (Table A.2-2).

Table II-2. SECURE cost comparison (1 amu = 1 arbitrary monetary unit)

	SECURE	Coal-Fired Plant
Construction (amu/kW)	2460	1600
Capital (amu/kWh)	3.9	2.6
Fuel (amu/kWh)	2.4	6.7
Operation and maintenance (amu/kWh)	1.3	2.0
Total (amu/kWh)	7.6	11.3

Studies of conversion of existing nuclear power plants in Sweden for delivery of district heat have been undertaken over the years for both Barsebäck and Forsmark.

In 1976 a project aimed at building a new unit 3 (3000 MWt) in Barsebäck with the possibility for combined heat and power generation was conducted. Within this project an alternative of rebuilding the existing units 1 and 2 (1800 MWt) was also investigated.

For units 1 and 2 the existing turbines would have to be rebuilt so there could be a possibility to tap steam from the turbine into heat exchangers for the district heating. It turned out that this rebuilding was expensive at the existing units, especially when the loss of production during the long reconstruction outage was taken into account. Therefore it was concluded that it was not economically sound to modify the existing NPPs.

II-2. Existing district heating system in operation at Cernavoda NPP

The existing District Heating System, which is in operation at Cernavoda NPP for the time being, provides 60% of the necessary heating for Cernavoda, as well as the necessary heat for sub-contractors' facilities, the plant town site and the NPP site (Unit 1, Unit 2, and different warehouses and shops located in the Unit 3 building). During 1997–2005, about 590 000 MWh were delivered, out of which 331 000 MWh were provided to Cernavoda. A peak of 60 500 MWh was delivered to the town during the year 1999. The maximum winter-time heat provided to the town and the NPP site represented 46 MW, the peak being covered from the auxiliary boilers.

A steam flow rate of about 80 tonnes/hour is extracted for district heating from the main steam line, before the high-pressure cylinder and condensed through heat exchangers located on NPP site, with a maximum capacity of 2 x 23 MW. Due to the lower temperature of the cooling water during winter time, the electrical power output of the unit is not seriously affected. The peaks are covered with expensive steam provided by the auxiliary oil burning boilers. They provide backup heat when unit 1 is not available.

Considering the continuous pressure from the municipality to extend the district heating network, S.N. Nuclearelectrica SA decided to review the studies performed during '80s in order to develop a modern district heating system, extracting steam, partially processed through the steam turbine, from Units 1 and 2. By extracting heat from two units, a higher redundancy will be achieved.

The technical solutions envisaged by new studies are considering steam from both units, considering the possibility to extract a maximum of 12% from the main steam flow for each turbine. The heat demand and hot water parameters to be considered are provided by Table A.2-3.

Table II-3. District heating demand and main parameters

Winter/summer regime	**Heat demand (MW)**	**Hot water temperature departure/ arrival (^oC)**
Max. winter	46	150/70
Average winter	35	120/70
Min. summer	7	75/40

Conclusions

The solution drawn-up during the 1980s for district heating using the capacity of Cernavoda NPP was thorough, but unrealistic. Those studies presumed there would be five units in operation at the Cernavoda site and considered an overly long network for heat transport and a large number of consumers supplied with heat from the plant.

The current solution, provisionally implemented for supplying heat from NPP Unit 1 to the town of Cernavoda and to the NPP site, is based on steam extracted upstream from the turbine. Such a solution is simple and rather cheap, but has a low overall energy efficiency and does not allow further expansion of the system.

The new studies envisage the extraction of the steam from the turbines of both Unit 1 and Unit 2, as well as the installation of new heat exchangers and other equipment, for the extended use in district heating for the town of Cernavoda. This solution will provide a higher reliability in supplying heat and better energy efficiency. Considering the actual context of oil crisis and the provisions of the international conventions and protocols dealing with greenhouse gases reduction, the district heating using extracted steam from a nuclear power plant represents an efficient solution to reduce dependence from hydrocarbons, enhancing the security of supply for Romania.

Also, the development of this solution will respond to the expectations of the local community and will strengthen the relationship between the plant and the municipality of Cernavoda, contributing to higher acceptance of the nuclear energy in the neighbourhood of the nuclear power plant.

II-3. Barriers to overcome – problems of retrofitting an existing plant

Designing a new nuclear power plant having the possibility to deliver electricity and heat is not a complicated process. It is possible also to retrofit an existing plant, initially designed for electricity production only, to co-produce heat for district heating purposes.

REFERENCE FOR ANNEX II

[1] INSTITUTE FOR POWER STUDIES AND DESIGN – ISPE, "Cernavoda District Heating Modernization - Pre-feasibility Study", ISPE, Bucharest (October 2004).

ANNEX III
CANDU ENERGY FOR STEAM ASSISTED GRAVITY DRAINAGE

Traditional open-pit mining has been used by industry for many years to remove oil sands from shallow deposits. To increase production capacity, the industry is looking for new technology to exploit bitumen from deep deposits. Among them, SAGD (Steam-Assisted Gravity Drainage) appears to be the most promising approach. It uses steam to remove bitumen from underground reservoirs. Recently, the SAGD recovery process has been put into commercial operation by major oil companies.

III-1. Generic SAGD process

A typical SAGD application involves twin horizontal wells drilled in parallel, with one a few meters above the other, as shown in Fig I-1. The upper well is called the injection well and the lower one the production well. Medium-pressure steam is injected into the underground deposit area through the injection well to heat the reservoir of bitumen-sand mixture by conduction. The heating reduces the viscosity of the bitumen, increases its mobility, and establishes pressure communication between the two wells along their length, so that a flow of fluids (a mixture of bitumen and condensed water) can occur and be collected through the production well. The production liquid is transported to a central facility, where the bitumen is separated and the condensate is collected, treated, and sent back to the boilers.

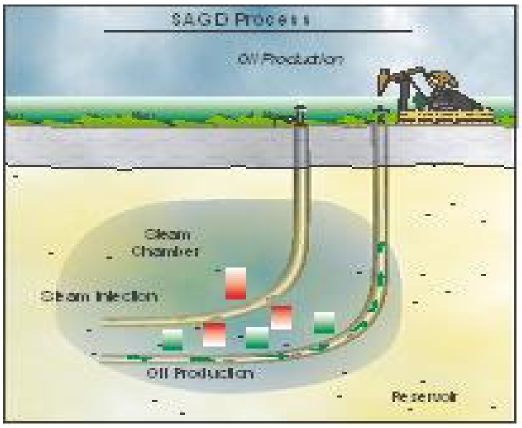

FIG.III-1. SAGD process.

The required steam injection pressure depends on the circumstances of the oil field and the life of the well, and varies from 2 to 5.5 MPa. At the initial stages of production (two to three months), each well requires steam at higher pressure than required during normal operation. Each barrel of bitumen requires 2-3 barrels of steam (steam volume is corrected to 4°C and 1 bar - cold water equivalent), as the quality of the deposit changes with location and time. Generally, about 18% of the energy content of the oil produced is used up in the extraction process, while a further 5% is used in generating hydrogen to upgrade the bitumen to synthetic crude oil.

In addition to steam demand, SAGD production facilities are also significant consumers of electricity.

III-2. Adaptation of ACR-1000 for SAGD

Atomic Energy Canada Limited has assessed the use of the ACR-1000 as a source of heat and electricity for oil sand extraction and processing. The ACR-1000 design is an evolutionary development of the familiar CANDU technology, adding innovations to enhance economics, operations, and safety margins. The net electrical output from a standard ACR-1000 will be close to 1100 MWe, depending on local cooling water temperature. The main steam pressure is 6.0 MPa.

Depending on the requirements of specific projects, the ACR-1000 can be adapted to provide steam only, or a mixture of steam and electricity at various steam/electricity ratios.

With the steam-only option, the steam generated from an ACR plant could be dedicated to supply steam to oil sand processes, and no electricity is generated. Hence, the turbine island is eliminated from the plant and replaced by the facilities dedicated to steam and feedwater supplies.

The steam/electricity mix option splits main steam from the steam generators into two streams: one would be dedicated to supply steam to the oil sand facility and the other would be channelled to generate electricity. As a result, the turbine capacity becomes smaller than that of a standard ACR plant.

The steam-only option for an ACR-1000 plant can supply steam to produce 53,200 m^3/day (334,000 bbl/day) of bitumen, assuming an SOR (Steam-to-Oil Ratio) of 2.5. For the steam/electricity mix option, the steam supply capacity depends on the electricity output. As an example, if the plant produces 300 MWe (gross) of electricity, the remaining steam supply will suffice to produce 38,800 m^3/day (244,000 bbl/day) of bitumen.

For each option, two basic system configurations, which relate to the steam supply method, have been examined. Schematic system diagrams for steam/electricity mix option are shown in Fig III-2 and Fig III-3. In both configurations, the ACR NSP (Nuclear Steam Plant) remains a standard design.

These configurations are described below.

- In the 3-cycle configuration, the steam supply to the oil sands facility is through saline heat exchangers (SHXers). The main steam from the Steam Generator (SG) secondary side is divided; part of it goes to the turbine system and the rest goes to the SHXers. Inside the SHXers the main steam heats incoming water and generates steam at the desired pressure and quality. After use in the saline heat exchanger, the hot steam condenses and the condensate is pumped back to the SGs as feedwater. The steam generated in the saline heat exchangers is sent to the oil sand facility. The steam is later recovered in the form of water, treated, and returned to the SHXers.

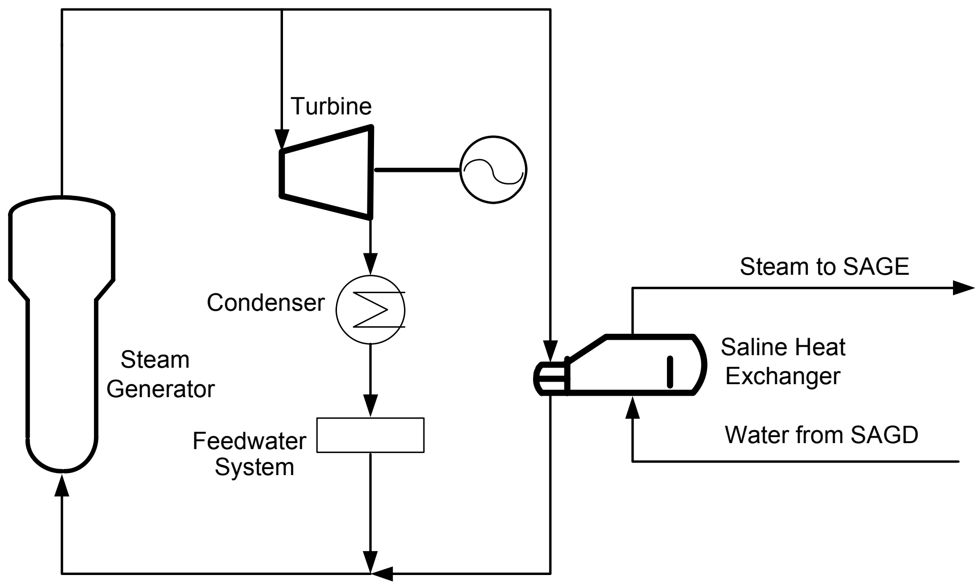

FIG. III-2. Three-cycle configuration.

- In the 2-cycle configuration, the main steam from SG's secondary side is directly distributed and injected into the well; the water is recovered at the oil sand facilities. This water does not meet the SG feedwater requirements in quality and temperature. It has to be retreated, and heated in the feedwater system before entering the SGs. Compared with the 3-cycle configuration, this system is simpler, and the steam pressure is higher by eliminating the saline heat exchangers.

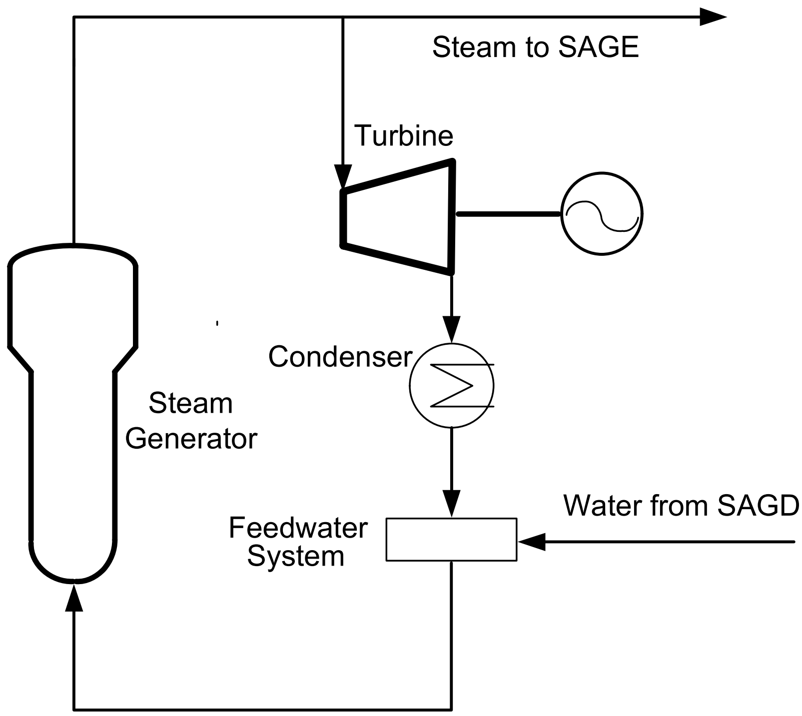

FIG. III-3. Two-cycle configuration.

III-3. CANDU for open-pit mining

Currently, the majority of oil sand production is through open-pit mining, which is suitable for bitumen extraction when the oil sand deposits are close to the surface. The ore, a mixture of bitumen and sand, is removed from the surface by truck and shovel operation. The ore is then mixed with hot water to form a slurry that eventually undergoes a separation process to remove bitumen from the sand.

The majority of the thermal energy required for the open-pit mining process is in the form of hot water at a relatively low temperature (around 70°C), and the rest is dry process steam at around 1.0 and 2.0 MPa. The oil extraction facilities require electricity as well.

When a nuclear plant is adapted to supply thermal power to open-pit mining processes, the low temperature and pressure requirements of the thermal demands allow extraction steam from the turbine to be used as the heating source. This boosts the overall system efficiency.

Figure III-4 demonstrates a typical configuration for adapting a CANDU-6 plant to an open-pit mining application. Steam extracted from the low-pressure turbine is used to heat water in the steam-to-water heat exchangers. In order to maximize the plant efficiency, the water returned from the oil sand facility enters the condenser first to recover the waste heat in the condenser. It then goes through the water heaters to be heated further to the required temperature. The hot water is supplied to the bitumen extraction facility; most of the water is recovered after the process, treated and sent back. The condensate from these water heaters returns to the turbine's feedwater system. The thermal power of the water counts for about 80% of total thermal power demanded by the open-pit processes.

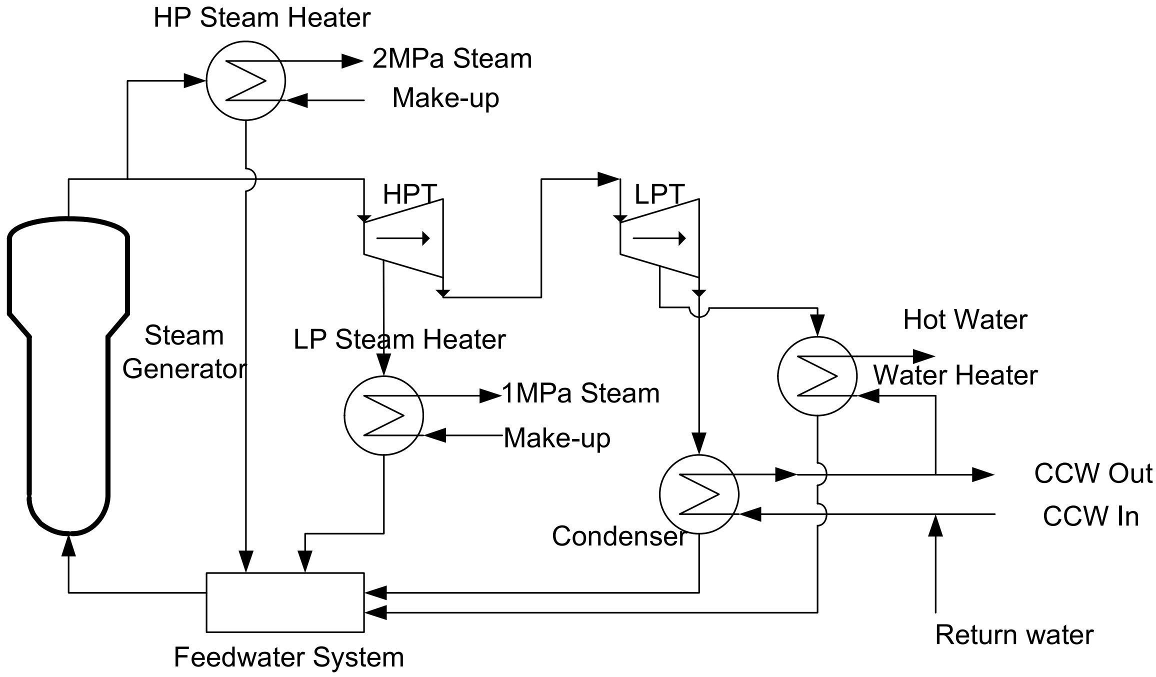

FIG. III-4. Schematic system of a CANDU plant adopted for open-pit mining.

There are two steam heaters operating at different pressures. The higher pressure one uses main steam directly from the SGs and the lower pressure one uses extraction steam from the high-pressure turbine as a heating source to generate process steam at 2.0 MPa and 1.0 MPa. The process steam is piped to the bitumen extraction process and mostly used in mixture heat exchangers without condensate return. Therefore, feedwater to these steam heaters is mainly from the make-up water. The condensate from these steam heaters returns to the turbine's feedwater heating system. The thermal power of the process steam represents about 20% of total thermal power requirement. Therefore, the amount of the steam used in these steam heaters are not as significant as the low-pressure turbine extraction steam used in the water heaters.

While the hot water flow rate remains the same for all seasons, the hot water and feedwater temperatures vary as the ambient temperature changes. For a typical site in the Fort McMurray region, the hot water temperature requirement is 72-75°C in winter and 65-67°C in summer, and the feedwater temperature varies from an average of 8°C in winter to 23°C in summer. The requirement of the process steam quantity changes slightly. The make-up temperature ranges from 2°C in winter to 24°C in summer. As a result of temperature changes, the thermal power demand fluctuates seasonally.

Taking 330,000 bbl/day of bitumen production, a manageable size of an open-pit mining project, a system simulation has been performed for the year-round weather conditions for this configuration. For the average weather condition (in April), the thermal power demand is 1400 MWt, and the electricity demand is 300 MWe (including the oil facility and nuclear plant demands). A CANDU-6 plant is able to provide the required thermal power for this condition while generating 460 MWe (gross) electricity. In summer, the thermal demand reduces to 1200 MWt, and consequently the electrical output increases 470 MWe (gross). In the coldest month (January), the total thermal power demand from the oil sands facility is as high as 1670 MWt, and the CANDU-6 plant generates 380 MWe (gross) electricity while producing enough hot water and steam to meet the thermal requirements of the bitumen production. During a year, the nuclear plant generates electricity within a range from 380 MWe to 470 MWe, while being able to meet the entire thermal power requirement. This offers a limited capability to deliver electricity to the grid.

III-4. Turbine design requirement

Since the steam flow rate distribution in the system varies from the conventional electricity generation plant, the turbine design has to be modified to adjust to this change.

Turbine type

For SAGD steam supply, the thermal power is generally supplied by the main steam and steam is not extracted from turbine except for the feedwater-heating purpose. Therefore, a condensing type turbine is suitable for this application, provided that the main steam is divided between the turbine system and the thermal load.

For open-pit mining applications, some steam is extracted from the turbine to heat the water and steam that are supplied to thermal power users. Therefore, an extraction steam turbine is used.

III-5. Safety and licensing

The licensibility requirements for an ACR SAGD project were examined and found to pose no major issues. Since Bruce A nuclear plant in Ontario has supplied nuclear-generated steam to various facilities outside the exclusion area, no major impediment to getting regulatory approval is foreseen.

III-6. Weather challenge

Oil sand deposits are located in Northern Alberta, Canada, a location substantially colder than those for most conventional nuclear power plants. Consideration has to be given to the demanding aspects of construction that are expected to be encountered in such climates.

The CANDU design is highly modularised, and the use of prefabricated modules will be maximized. This approach minimizes on-site construction activities, enabling schedule compression, and reduces the size of the on-site labour force. The module sizes and weights have been selected for suitability for road transportation to northern Alberta.

Improved cold weather construction methods now allow year-round construction. This includes the use of shelters and provision for heating and the use of temporary weather coverings to protect the workers, equipment and structures when an “open top” reactor building construction method is used.

III-7. Water scarcity

Oil sand sites usually have limited water resources. This is a factor of consideration in building a nuclear plant, since nuclear plants usually need a large amount of cooling water. Cooling water is mainly required for the following usages:

- Dissipation of heat from the turbine exhaust steam through the condenser, and dissipation of heat generated in other equipment and systems during the normal operation;
- Dissipation the decay heat from the reactor, during outages and abnormal conditions.

During normal operation, the vast majority of the cooling water requirement is the condenser cooling water, which takes the heat load from the turbine exhaust steam. When a nuclear plant is designed for thermal and electrical cogeneration purposes, the condenser heat load is reduced. The amount of cooling-water reduction occurs depends on how much the thermal power load is and how the system is designed. To reduce the water demand further, AECL has investigated technologies to minimize the requirement for the cooling water, including the use of cooling towers and air cooling.

Overall, the study has found that the water scarcity issue can be overcome with a moderate level of investment.

ANNEX IV
LARGE SCALE PROCESS STEAM SUPPLY FROM GÖSGEN-DÄNIKEN NUCLEAR POWER STATION IN SWITZERLAND

The Gösgen-Däniken nuclear power station (KKG) with a gross electric output of 970 MW is the largest nuclear station in Switzerland, meeting approximately 17% of the country's total power requirements and providing process steam for a nearby industrial plant. The power station was handed over to KKG in October 1979 following an 80-month construction and commissioning period and has since formed part of the country's electricity grid with a high availability record. Kraftwerk Union AG was in charge of construction of this plant as chief contractor.

Steam user

The Gösgen-Däniken nuclear power station (KKG) is the first of its kind in the world to supply process stream. Its steam user is the nearby cardboard mill, Kartonfbrik Niedergösgen (KANI).

The cardboard mill is situated approximately 2 km away from the nuclear power station. The mill recycles used paper to manufacture base paper for corrugated cardboard and requires the steam chiefly for heating the drying cylinders. This process causes the steam to condense and the condensate is subsequently de-aerated at 105°C in a de-aerating plant and returned as feedwater to the evaporator plant at the nuclear power station. Losses (amounting to about 10%) are made up from the chemical water treatment plant operated by KANI.

The two heavy-oil-fired boilers installed at the KANI plant, which with their emissions were once the source of considerable atmospheric pollution, now have only standby status. A warm-up line maintains them ready for immediate start-up, thus ensuring that they can take over steam supply within 15 to 30 minutes if the supply from KKG is interrupted.

Environmental protection and heating oil conservation

The system implemented in Gösgen with a nuclear power station providing process steam makes a significant contribution to pollution control. The ecological impact on the atmosphere as a result of the sulphur dioxide and solid matter emitted in the flue gases of the heavy-oil-fired boilers of the KANI plants has now been eliminated. Moreover, the reliable process steam supply from KKG represents an effective substitute for heating oil, thus ensuring almost complete independence from this fossil fuel. Further, maintenance work on KANI's central heat generation system is reduced.

Approx. 68 kg of heavy oil would be required to generate 1 t of process steam using the heavy-oil-fired boilers installed at KANI. At the current rate of steam consumption of 10 kg/s, this represents savings of almost 59,000 kg of heavy oil daily.

The steam requirement of 22.2 kg/s envisaged for the plant in its final extension would entail burning 130,000 kg of heavy oil per day. If the heavy oil is assumed to have a sulphur content of only 0.5%, it becomes clear what the combustion of 130,000 kg of heavy oil daily would mean in terms of atmospheric pollution through sulphur dioxide emission.

Design requirements

The evaporator plant was designed by KWU for a maximum steam delivery of 22.2 kg/s. Process steam pressure downstream of the evaporator plant is to be maintained at a constant 14 bar throughout the entire load range and should be not less than 12 bar (saturated steam) at the point of transfer to KANI (corresponding to be operating pressure of the KANI boilers). The amount of steam actually extracted can fluctuate between 0 and 22.2 kg/s.

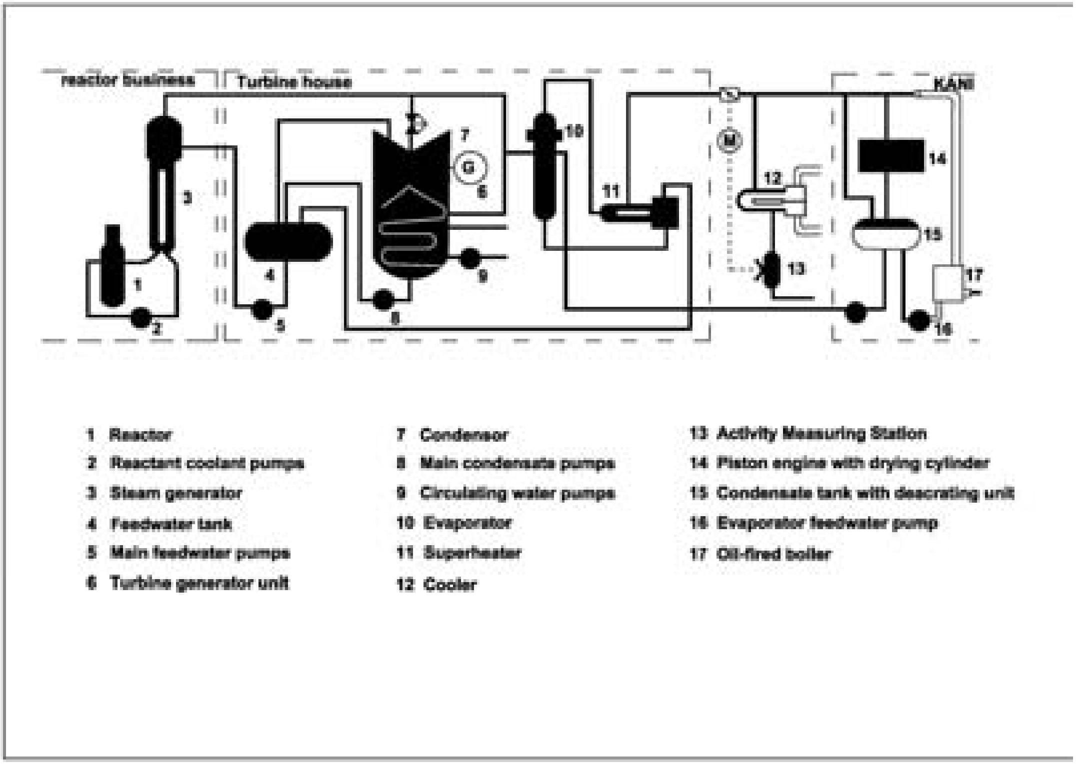

FIG. IV-1. Flow diagram of the evaporator plant.

The evaporator plant must be fully automatic; i.e., it must be possible to regulate any fluctuations in steam flow rate easily and rapidly and without any manual intervention being necessary. Malfunction of the evaporator plant must not affect the normal operation of the nuclear power station.

Thermodynamic design

The evaporator plant is heated with the live steam tapped between the steam generators and the turbine. In this way, electricity generation is separated from process steam production; i.e. the evaporator plant can continue to operate after a turbine trip as long as the steam generators carry on supplying sufficient heating steam.

The heating steam drains are used to superheat the outside steam supply and are subsequently returned to the power station water/steam cycle through the feedwater tank.

ANNEX V
EVALUATION OF BATTERY COST COMPETITIVENESS OF ALTERNATIVE TRANSPORTATION TECHNOLOGIES

In the next two tables, the battery cost and the competitiveness of PHEV with ICEV and HEV are evaluated for setting R&D goals for battery development. The comparison was made on the sum of vehicle purchase cost and fuel/electricity cost for a 10-year vehicle life. One example on Prius-class vehicles shows that, for the PHEV to become comparable with ICEVs and HEVs, it is necessary to reduce the cost of lithium-ion batteries from the present cost (200 K Yen/KWh) by a factor of about 7 (to 30 KYen/KWh). This information was obtained from a report, “Recommendations for the Future of Next-Generation Vehicle Batteries,” by the Study Group on Next-Generation Vehicle Batteries, Ministry of Economy, Trade and Industry, Japan, August 2006.

Table V-1. Action plan for next generation battery technology development: approximation for setup of cost target for light vehicles

	ICEV Gasoline Engine Light Vehicle *(Reference)*	BEV Limited Purpose Commuter Battery Range 80 km Year 2010	ICEV Gasoline Engine Light Vehicle *(Reference)*	BEV Personal Commuter Battery Range 150 km Year 2015
	For Business 18,000 km/year		For Personal 7,000 km/year	
10-Year Total Cost	2,260 KYen	2,380 KYen	1,490 KYen	1,710 KYen
Vehicle Cost	1,000 KYen	2,200 KYen	1,000 KYen	1,650 KYen
Battery Cost		*Cost 1/2* 800 KYen		*Cost 1/7* 450 KYen
Base Vehicle Cost		1,000 KYen		1,000 KYen
Other Cost		400 KYen		200 KYen
10-Year Gasoline/Electricity Cost	1,260 KYen	180 KYen	490 KYen	70 KYen

Gasoline: Gasoline Consumption 20 km/liter Gasoline Price 140 Yen/liter

Electricity: Electricity Consumption 10 km/kWh Electricity Rate 10 Yen/kWh

Table V-2. Action plan for next generation battery technology development: approximation for setup of cost target for registered vehicles

		ICEV Gasoline Engine Passenger Vehicle *(Reference)*	HEV High Performance Hybrid Year 2010	PHEV 40 km Battery Cruising Range Plug-in Hybrid Year 2015	BEV 480 km* Battery Cruising Range Full-fledged Electric Vehicle Year 2030
		10,000 km/year			
10-Year Total Cost		2,630 KYen *	2,650 KYen	2,650 KYen	2,580 KYen
Vehicle Cost		1,700 KYen *	2,300 KYen *	2,400 KYen	2,500 KYen
	Battery Cost		*Cost 1/2* 100 KYen	*Cost 1/7* 120 KYen	*Cost 1/40* 200 KYen
	Base Vehicle Cost		1,700 KYen	2,000 KYen	2,000 KYen
	Other Cost		500 KYen	280 KYen	300 KYen
10-Year Gasoline/Electricity Cost		930 KYen	350 KYen	Electricity 40 KYen Gasoline 210 KYen	83 KYen

* Revised from the original figure for consistency

Gasoline: Gasoline Consumption ICEV 15 km/liter Gasoline Price 140 Yen/liter

Gasoline Consumption HEV 40 km/liter Gasoline Price 140 Yen/liter

Electricity: Electricity Consumption PHEV 10 km/kWh Electricity Rate 10 Yen/L
Electricity Consumption EV 12 km/kWh** Electricity Rate 10 Yen/L
(** As of Year 2030)

Battery Capacity: HEV 1 kWh

PHEV 4 kWh

(Gasoline Running 60%, Electricity Running 40% by Distance)

EV 40kWh

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