Glossary of Technical Terms and Abbreviations

TECHNICAL TERMS

Additional protocol
Relative to nonproliferation; an IAEA prerogative for monitoring of undeclared facilities

Blanket
Fast reactor blanket assemblies provide fertile fuel for breeding

Borosilicate glass
Glass "logs" encapsulating high level reprocessing waste

Breeder reactor
A reactor that creates more fissile material than it consumes

Burn up
The thermal energy production of fuel in a reactor

Cap and trade
A program for trading emissions under a national CO_2 cap

Capacity factor
Ratio of actual annual plant electrical production and maximum annual production capability

Carbon emission
Carbon in the form of carbon dioxide in the atmosphere from fossil fuel combustion

Carbon tax
A tax that would be imposed on fuel combustion proportional to carbon dioxide emission

Centrifuge
Centrifuge devices are a method of uranium enrichment

Chain reaction
A nuclear reaction that is sustained in a reactor or critical assembly

Chernobyl
Very severe accident at FSU (Ukranian) nuclear plant in 1986

Closed fuel cycle
A cycle that recovers fissile material from spent fuel, re-fabricates, and reuses it in a reactor

Core damage frequency
Frequency of an accident causing core damage

Conversion
Conversion of natural uranium — yellow-cake — to uranium hexafluride for use in an enrichment plant; and re-conversion to uranium oxide for fuel fabrication

Criticality
Sustained chain reaction

Curie
Unit of radioactive decay; 1 Curie = 3.7×10^{10} disintegrations/sec

Decay heat
Heat released by fission products and actinides from reactor operation

Deep borehole
Borehole drilled to several kilometer depth for spent fuel storage

Delayed neutrons
A fraction of fission-born neutrons delayed, easing reactor control

Depleted uranium
Uranium depleted of the U-235 isotope, e.g., enrichment plant tailings

Diffusion
Gaseous diffusion is a process for uranium enrichment

Early site permits
U. S. NRC process for approval of plant sites before actual construction applications

Enriched uranium
Uranium enriched in the U-235 isotope

Enrichment
Separations process that increases the concentration of particular isotopes, such as that of U-235 in natural uranium

Fuel fabrication
Manufacture, processing, and assembly of fuel elements for reactors

Fast reactor
Reactor designed for criticality and operation by fast neutrons

Fast reactor recycle
Reprocessing and recycle of fast reactor fuel, for breeding fuel or other purposes

Fertile fuel
Capable of conversion to a fissile material

First mover
First entity to undertake new plant construction

Fissile fuel
Capable of fission, e.g., U-233, U 235, Pu-239 (and higher odd isotopes)

Fission products
Elements resulting from fission

Geologic repository
Underground storage of spent fuel and/or reprocessing waste

Gigawatt
One billion watts

Heat rate
See BTU/kWhr below

High level waste
Spent fuel or reprocessing waste containing fission products

La Hague
French Reprocessing Plant

Large early release
Major release of radioactivity from reactor containment after a reactor accident

Megawatt
One million watts

Mining and milling
Preparation of natural uranium

Moderator
Substance causing slowing down of fast neutrons by collision; necessary for thermal reactors

Once-through fuel cycle
Fuel used in only one cycle, and there is no reprocessing

Passive systems
Use of stored energy, e.g., gravity, instead of emergency diesels

Price-Anderson act
Government-backed insurance for nuclear power plants

Probabilistic risk assessment
Analysis of reactor accident frequency

Proliferation
Use of processes or technologies to produce nuclear weapons

Pyro-processing
A high temperature electro-chemical separation process for spent fuel

Radioactivity
Emission of alpha or beta particles, or gamma rays from substances by radioactive decay

Radiotoxicity
Radioactive substance health hazard

Reactor
Device utilizing nuclear chain reaction for power production

Reactor core
Assembly of fuel elements in a reactor vessel for sustaining a chain reaction and power production

Reactor vessel head
Top end closure of a reactor vessel

Reactor-years
Measure of reactor experience

Reprocessing
Processing of spent fuel to recover its fissile material

Seed
Central region of a fast reactor core providing power and neutrons

Severe accident
A reactor accident in which fission products and actinides escape from the reactor primary system

Site banking
Obtaining regulatory approval of nuclear plant site before construction

Spent fuel
Fuel removed from reactors at end of its useful life; typically stored in water pools for cooling for ~10 years or more

Spent fuel dry storage
Stored after ~ 10 years in shielded concrete casks

Thermal efficiency
Plant net electrical output divided by thermal input

Thermal reactor
Reactor designed for criticality and operation by thermal (low speed) neutrons

Thermal reactor recycle
Reprocessing and recycle of Plutonium (and Uranium) in thermal reactors

Thorium fuel cycle
A cycle in which fertile Th-232 is converted to fissile U-233

Tonne
Metric ton — 1,000 kilograms

Waste partitioning
Separation of fission products and actinides in spent fuel

Waste transmutation
Reactor transmutation of long-lived fission products or actinides to stable elements or those that are less radiotoxic

ABBREVIATIONS AND UNITS

ARD&D
Analysis, research, development, and demonstration

BTU
British Thermal Unit, i.e., heat required to increase 1 lb. of water by 1 degree Fahrenheit

BTU/kWhr
BTUs of thermal input required to produce 1 kilowatt-hour of electricity

BWR
Boiling Water Reactor: a direct cycle LWR

CANDU
Canadian deuterium-natural uranium reactor

CCGT
Combined cycle gas turbine

CDF
Core damage frequency

Cents/kWe-hr
Cost of electricity per kilowatt-hour

CO_2
Carbon dioxide

COL
U. S. NRC Combined Operation License

$/kg
Natural uranium ore cost

$/kWe
Generating plant capital cost unit

$/MMBTU
Fuel cost unit — dollars per million BTU

$/ton carbon
Carbon tax rate on fuel combustion

DOT
U. S. Department of Transportation

EIA
Energy Information Administration, a part of U. S. DOE

EPA
U. S. Environmental Protection Agency

EPPA
MIT Emissions prediction and policy analysis project

EPRI
Electric Power Research Institute

FP
Fission products

Gen IV
International advanced reactor study underway at DOE

GFC
Gas cooled fast reactor

GHG
Greenhouse gas

GWd
Gigawatt days of thermal energy production

GWe
Gigawatts (1000 megawatt) electric capacity

HDI
United Nations Human Development Index

HEU
Highly enriched (in U-235 isotope) uranium

HLW
High level waste, either in spent fuel, or reprocessing waste

HTGR
High temperature gas cooled reactor

IAEA
International Atomic Energy Agency

INPO
Institute of Nuclear Power Operations, funded by nuclear plant operators for improvement of operations

kWe-hr
Kilowatt-hour of electricity

LER
Large early release of radioactivity from reactor containment after an accident

LMFBR
Liquid metal fast breeder reactor

LWR
Light water reactor, the major power plant type in service

MA
Minor actinides, isotopes heavier that Uranium created in reactors, except for plutonium

MOX
Mixed (Uranium and Plutonium) oxide fuel

MMBTU
Million British thermal units

MPC&A
Fissile materials, production, control, and accountability

MSR
Molten salt reactor

MT
Metric tons

MT/yr
Metric tons per year

MTIHM
Metric tons initial heavy metal (Uranium or Plutonium)

MWe
Mega (million) watts electric capacity

NEA
Nuclear Energy Agency, under the OECD

NOX
Atmospheric oxides of nitrogen

Np-237
Neptunium-237

NPT
Nuclear Nonproliferation Treaty

NSPS
New source performance standards

OECD
Organization for Economic Co-operation and Development

O&M cost
Cost of plant operation and maintenance

PRA
Probabilistic risk assessment

PUREX
Original chemical separation process yielding Plutonium

PWR
Pressurized water reactor, an indirect cycle LWR

Pu-239
Plutonium 239 isotope, a preferred weapons material

R&D
Research and development

RD&D
Research, development, and demonstration

SCWR
Supercritical water reactor

SO_2
Sulfur dioxide

Th
Thorium. Th-232 is fertile, and can be converted to fissile U-233 in a reactor

TMI 2
Three Mile Island Unit 2 nuclear plant

TRU
Transuranic elements, being those having an atomic number higher than uranium

TVA
Tennessee Valley Authority

U-235
Uranium isotope that is least abundant, and fissile/a preferred weapons material capacity

U-238
Uranium isotope that is most abundant

UOX
Uranium oxide

UREX
Separations process for recovery of uranium from spent fuel

U. S. DOE
U. S. Department of Energy

U. S. NRC
U. S. Nuclear Regulatory Commission

YMEs
Yucca Mountain equivalents, referring to fuel storage capacity

WANO
World Association of Nuclear Operators, a world-wide owners group for improvement of operations

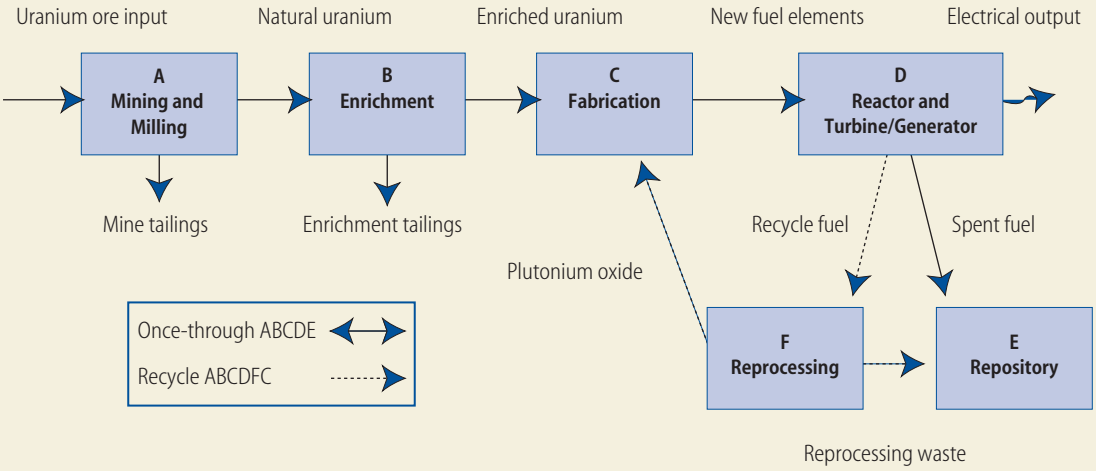
Appendix Chapter 1 — Nuclear Fuel Cycle Primer

INTRODUCTION

This is a Primer to aid understanding of the nuclear fuel cycle. It is intended to explain in layman's terms basic ideas and processes that underlie nuclear power generation, avoiding rigorous discussion of physics and engineering. The bibliography provides references for those who wish to dig deeper into the subjects. Calculations of nuclear fuel cycle quantities are explained in detail in the Chapter 4 Appendix — Fuel Cycle Calculations.

The nuclear fuel cycle consists of the steps required to produce nuclear power, including the input of fissile material, the processes that convert raw material to useful forms, the outputs of energy, and the treatment and/or disposition of spent fuel and various waste streams. The steps appear schematically in Figure A-1.1.

Figure A-1.1 Fuel Cycle Diagram



We will discuss the three main nuclear fuel cycles in the Primer: 1) the Once-through Cycle fueled by enriched uranium, 2) Thermal Reactor Recycle, and 2) Fast Reactor Recycle. We explain these terms as we come to them in the Primer. There are other possible fuel cycles, but these three are the main ones developed to date.

THE NUCLEAR REACTOR

At the heart of the nuclear fuel cycle is the nuclear reactor that generates energy through the fission, or splitting, of uranium and plutonium isotopes (Note: isotopes of an element, such as uranium, have different masses and, as a consequence, virtually identical chemistry but quite different physical behavior). The fission process is caused by neutrons in the reactor core and both liberates considerable energy and produces more neutrons. The energy released is 1 million watt-days per gram of U-235 that undergoes fission, equivalent to 2.5 million times the energy released in burning one gram of coal. The produced neutrons can in turn yield additional fission events, producing a chain reaction that sustains energy production. The probability for a neutron to cause a fission is very high for certain isotopes (in particular, U-235 and Pu-239) when the neutrons are slowed down, or moderated, with respect to the relatively high energy they possess when produced by fission. In a light water reactor (LWR), the moderation is accomplished rapidly by collision of the neutrons with hydrogen nuclei (protons) in the water molecule.

Naturally occurring uranium contains only 0.7% U-235. The rest is U-238, which does not experience fission with slow neutrons. In light water reactors, the fraction of U-235 must be increased through enrichment, typically into the 3-5% range, in order to sustain the chain reaction. In nuclear weapons, by contrast, the enrichment level is generally greater than 90%.

Although the U-238 in the fuel does not contribute directly to energy production with slow neutrons, it does sometimes capture a slow neutron, leading to production of Pu-239, which does contribute to energy production. Indeed a significant part of the energy produced with typical operation of a LWR comes from fission of the Pu-239 produced earlier in the fuel irradiation. The so-called open and closed fuel cycles differ in that the former disposes of the Pu-bearing spent fuel, while the latter captures the U and Pu energy value in irradiated fuel by chemical separation from the fission products and recycle into reactor fuel.

The fission process results in nuclear fragments that generate considerable heat and radioactivity in the spent fuel for a considerable time. These fission-products dominate the nuclear waste problem during the first century, or so. Other nuclear waste components that significantly influence fuel cycle discussions are elements heavier than uranium. Many of these are present in small amounts but, because of long lifetime, play a dominant role after a few hundred years in the residual radiotoxicity. A prime motivation for closed fuel cycles is removal of these very heavy elements.

THE ONCE-THROUGH CYCLE

The Once-through Cycle is the simplest. It appears as ABCDE in Figure A-1.1 of the Fuel Cycle Calculation Primer. It requires uranium ore as input, milling and purification of natural uranium, conversion of the uranium to a chemical form suitable for enrichment, enrichment of the U^{235} isotope[1], fuel fabrication, loading of uranium fuel assemblies in a reactor, and then reactor operation. At the end of useful life, spent fuel is removed from the reactor, stored in a pool of water for cooling and shielding of radioactivity, then removed and placed in air-cooled casks at reactor sites for interim storage, and finally

removed to geologic waste storage, as in the plan for Yucca Mountain in Nevada. Long-term isolation and heat removal from spent fuel is necessary to prevent release of radioactive isotopes to ground water near a repository. Spent fuel fission product radioactive decay and heat generation continues for hundreds of years, and in smaller quantities for many thousands of years.

URANIUM MINING

Natural uranium ore is broadly distributed in the world. Large deposits usually contain 1% or less, but there are some rich deposits in Canada and Australia containing up to 10% to 20% natural uranium. About 200 metric tons of natural uranium are required annually for a 1000 Mwe LWR, or about 100,000 metric tons of ore containing 0.2 % natural uranium. Rich deposits also leave behind less mining residue, i.e., tailings. For this reason rich deposits are usually more economical to mine than low grade deposits. Uranium mine tailings are by far the largest quantity of fuel cycle waste.

URANIUM PROCESSING AND FUEL MANUFACTURING

Processing of natural uranium into fuel rods and assemblies for Light Water Reactors (LWRs) is a complex step because of the need for enrichment of the U^{235} isotope. There are two methods of enrichment in commercial use in the nuclear industry, both depending on the fact that U^{235} is slightly lighter in atomic weight than the more plentiful U^{238} isotope. Gaseous diffusion is one method: uranium hexafluoride gas diffuses through porous barriers, in which the lighter isotope U^{235} in a molecule of gas passes the barrier more quickly than the heavier, thereby permitting isotopic separation. Many stages of separation are required to obtain the required enrichment, and the process consumes much electricity for pumping the hexafluoride gas through the plant systems.

Separation by centrifuge is the second method. In principle the process is simple: uranium hexafluoride gas flows through a rapidly spinning centrifuge; centrifugal force presses the heavier gas molecule, $U^{238}F_6$, toward the centrifuge outside wall, yielding two streams, one enriched, and the other depleted in the lighter molecule. The system transfers the enriched stream to higher stages until the required enrichment is achieved. Centrifuge separation uses much less electricity per unit of separative work than the gaseous diffusion process.

Emerging technologies, such as laser isotope separation, may eventually lower cost. However, even before reaching commercial viability, such technologies could contribute to proliferation if applied to relatively small amounts of uranium.

Conversion of enriched uranium hexafluoride gas to uranium dioxide is the next step. Zirconium is the material of choice for fuel cladding, because zirconium is a very weak absorber of neutrons, an important characteristic in reactors as we shall see. In Pressurized Water Reactors[2] (PWR), the loaded fuel rods are formed into fuel assemblies in a 17x17 square array of fuel rods, held firmly in place so that they will not shift position in the fuel assembly either in transportation or in the reactor. BWR fuel assemblies have a smaller cross-section and contain fewer fuel rods than PWR fuel assemblies.

NUCLEAR REACTOR OPERATION

Control of a nuclear chain reaction is just as important as creating it in the first place. Control rods that contain neutron absorbers such as boron are one method of control. Inserting a control rod into the reactor core captures neutrons so that they cannot then cause fission, and power generation decreases. Withdrawal of a control rod has the opposite effect. Coordinating control rod movement with measurement of power level makes possible adjustment to a desired level. Another method of control utilizes the moderator for this purpose: increasing the temperature of cooling water in LWRs causes the moderator to expand, become less dense, and therefore less effective as a moderator. A decrease in moderator density causes power to decrease. LWRs depend on this effect for an important property that aids self-regulation of power.

Most of the neutrons born of fission are prompt, that is to say they appear almost immediately at the instant of fission. A fraction of them, about 0.65% in the case of U^{235} fission, is delayed. Delayed neutrons are late arrivals, coming in delay groups with half-lives ranging from a quarter of a second to almost a minute. Delayed neutrons make possible reactor control with simple control systems. In effect delayed neutrons buy time for reactor control systems to function. Control systems, however, must assure that increases in neutron production do not exceed the delayed neutron fraction. Otherwise the reactor would become prompt critical, and fission rate would increase exponentially and very rapidly.

We briefly describe power conversion in LWRs. The PWR is an indirect cycle that transports heat from the reactor core to steam generators that raise steam in a separate, indirect cycle. Steam in the indirect cycle drives a steam turbine and electrical generator. The BWR design is direct cycle, and steam produced in the reactor flows directly to the BWR steam turbine. Both cycles have their advantages and disadvantages, but the two have remained competitive through several generations of plant designs.

HIGH TEMPERATURE GAS COOLED REACTORS (HTGR)

A brief description of the HTGR[3] follows. It differs from a conventional LWR in a number of respects, one being high temperature of operation, i.e., about 900° Centigrade at the reactor core outlet, a fact that allows a conversion efficiency of about 45% compared to 33% in the case of LWRs. Helium is the reactor core coolant, and also drives the turbine for the power conversion cycle and the compressors.

Currently there are two concepts under development for commercial use: the Prismatic Fuel Modular Reactor (GT-MHR) by General Atomics Co., and the Modular Pebble Bed Reactor (MPBR) by Eskom, the South African state electric company.

The GT-MHR has evolved from Fort St. Vrain technology, using coated micro-spheres of fuel in more or less conventional fuel assemblies, and having the capability to retain fission products at high temperatures in case of a reactor accident. It employs a direct cycle, i.e., helium from the outlet of the reactor core drives the power conversion turbine and the compressors that force helium back through the reactor. The proposed plant has a thermal rating of 600 MWth, and 286 MWe net output. The reactor vessel is of a size comparable to LWR reactor vessels. This fact, together with lower power output, has the result of small-

er core power density than is the case with LWRs (see discussion in the section on Reactor Safety in Chapter 6). Due to smaller unit output, multiple units are required to produce an output equivalent to one conventional LWR plant.

The MPBR is based on German technology developed for an experimental plant and a demonstration plant during the 1960s to 1980s. The Eskom project began in 1993, and is now in the early stages of licensing in South Africa. The plant rating is 400 MWth, and 165 MWe net output. It differs from the GT-MHR concept in its use of fuel in the form of "pebbles", i.e., a ball, coated with pyrolytic carbon, about 2 inches in diameter that contains micro-spheres of fuel that are similar to those used in the GT-MHR fuel. In operation the MPBR reactor vessel contains about 450,000 of these fuel balls. The advantage of this configuration is that it allows refueling while at power: fuel balls are continuously added to and removed from the reactor, and the plant does not require shutdown for the purpose of refueling. The MPBR also differs from the GT-MHR in its use of an indirect cycle: helium reactor coolant flows to an intermediate heat exchanger and transfers heat to the secondary power conversion cycle that drives the turbine. Because the reactor cooling and power conversion cycles are separate, there is no radioactive carryover from the reactor to the power conversion system. Due to the temperature drop across the intermediate heat exchanger, there is some loss of efficiency, but handling of the fuel balls would be considerably more difficult if a direct cycle were employed.

Both the GT-MHR and the MPBR have smaller electrical output than conventional LWRs. How can their cost compete with the LWR? The answer is that LWRs and HTGRs follow different economic scaling laws. LWR experience has shown that the incremental cost of larger plant output, i.e., $/kWe of investment, declines with larger plants. The economics of the smaller HTGRs, however, depend on factory manufacture of modules for assembly at the plant site, on shorter construction schedules, and on completing units sequentially, one year apart. The idea is that these three factors taken will make investments productive sooner and make multiple HTGR units competitive with the single unit LWR, but this is, as yet, unproven.

SPENT FUEL

When reactor operation has used as much of the new fuel enrichment as possible, fuel assemblies becomes spent fuel. Spent nuclear fuel is radioactive and heat producing. Typical LWR spent fuel today reaches a burnup of 50,000 MWD/MT[4]. One year after removal from the reactor the total radioactivity is about 3 million curies/metric ton including alpha particle, beta particle, and gamma ray decay, and the decay heat rate is about 13 kWth/metric ton (kilowatts thermal per metric ton). After 10 years these quantities decrease to about 0.6 million curies/metric ton, and 2 kwth/metric ton.

In the U. S. today, spent fuel is stored at individual reactor sites in large pools of water for at least 10 years. After that it is stored in large concrete casks that provide air cooling, shielding and physical protection. These casks can hold 20-24 Pressurized Water Reactor (PWR) fuel assemblies, or twice that number of Boiling Water Reactor (BWR) fuel assemblies. The assemblies are sealed in a helium atmosphere inside the cask to prevent corrosion. Decay heat is transferred by helium from the fuel to fins on the outside of the storage cask for air-cooling. Eventually all spent fuel will be moved from reactor sites to under-

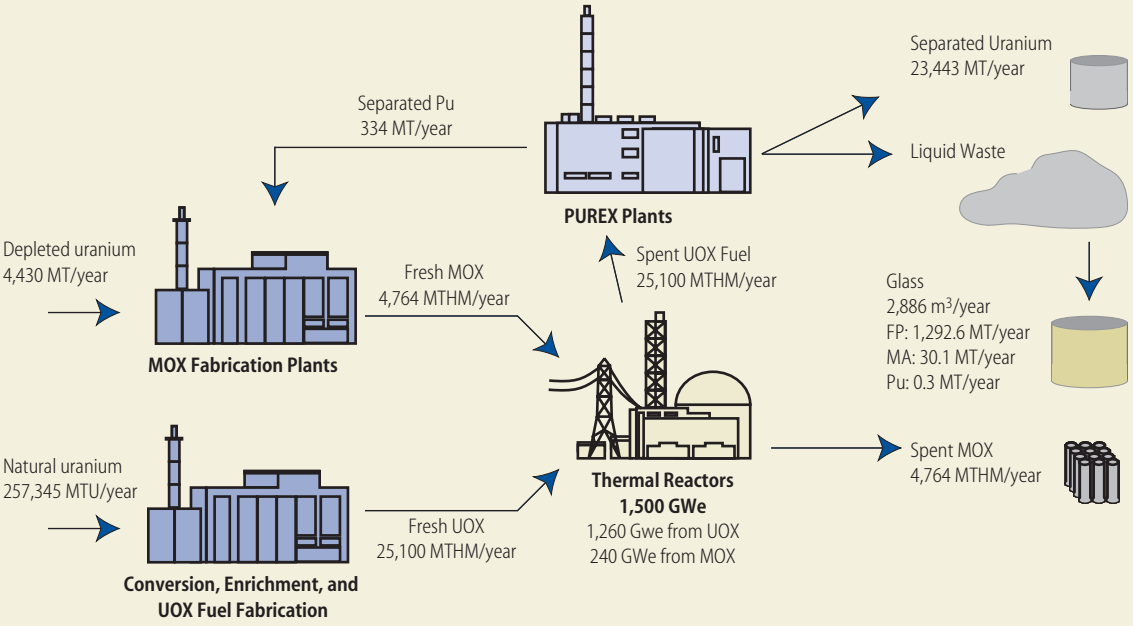
ground geologic storage, such as at Yucca Mountain in Nevada. Transportation of these assemblies will require large rail and trucking equipment, and careful traffic planning. Shipping cask development is well advanced for many fuels. Shipping casks typically are able to carry 7 PWR fuel assemblies, or 18 BWR assemblies. The casks were designed to withstand high-speed truck and railroad train collisions without loss of integrity[5], including subjection to fires along the way.

Having described removal of spent fuel to storage in a geologic repository, we have completed description of the once-through fuel cycle.

THERMAL REACTOR RECYCLE

Plutonium production in the once-through fuel cycle represents a significant energy resource, but requires reprocessing of spent fuel to recover the plutonium and to fabricate new fuel. Recycling of fuel can be done in thermal reactors, or in fast reactors. We consider first thermal reactor recycle, which appears as ABCDFC in Figure A-1.1.

Figure A-1.2 Closed Fuel Cycle: Plutonium Recycle (MOX option - one recycle) — Projected to 2050



Thermal recycle adds another process in comparison with the once-through cycle, i.e., fuel reprocessing mentioned in the preceding paragraph. France, Japan, Russia, and the United Kingdom have reprocessing plants in operation. In 1976–77 Presidents Ford and Carter stopped commercial reprocessing in the U. S. The technology employed in commercial reprocessing to the present has its roots in the Manhattan Project during World War II. It includes the following steps: a) waiting for spent fuel radioactive decay to reduce radiation and heat generation; b) remote cladding removal ("de-cladding") so as to separate it from the fuel; c) dissolving the fuel pellets in nitric acid; and finally d) separation of uranium and plutonium by solvent extraction. When separation is complete, the uranium and plu-

tonium products are returned to the fuel preparation and fabrication steps of the once-through cycle. For recycle fuel fabrication, however, shielded fabrication lines are needed for worker protection. One of the options for waste management in the separations process is to collect the fission products and actinides, and seal them in glass "logs" for waste disposal in long-term geologic storage. The quantity of radioactive material contained in the glass logs is approximately the same as the amounts remaining in spent fuel assemblies of the once-through cycle (i.e., the fission product inventory is the same).

If the enriched uranium and plutonium are recovered from spent fuel and re-fabricated into mixed oxide (MOX) fuel rods and assemblies, the result at best will be a reduction of new fuel required by about 30% compared to the once-through fuel cycle, recycled uranium and plutonium making up the difference. Spent fuel reprocessing is very costly, and, given the market price of natural uranium ore for the foreseeable future and the cost of enrichment, thermal recycle is not an economic choice.

SAFETY AND SAFEGUARDS

Consideration of safety and safeguards is necessary in design and operation of a reprocessing plant, because of the large inventory of radioactive fuel cycle waste and fissile material. The radioactive materials must be controlled and contained. In contrast to a reactor, a reprocessing plant must not go "critical" and have a fission chain reaction. This requires strict control over all materials in the plant at all times. Quantities and mixtures of fissile materials must be limited so that there is insufficient material present at any time to become critical, and start a nuclear chain reaction. Fire and explosion must be precluded, and leaks of tanks that store or carry fissile materials or radioactive waste must be prevented, or at the least detected and contained. Worker safety and control of plant personnel radiation exposure is a major requirement. Reprocessing plants may produce considerable quantities of radioactive and toxic chemical wastes that arise in the reprocessing process.

FAST REACTOR RECYCLE

A fast breeder reactor is capable by design of producing more fissile isotopes than it consumes, thus making it possible to provide a growing energy resource that does not require a continuing supply of U^{235} or Pu^{239} after an initial investment of fissile fuel at the beginning of its life. Breeder reactor cores typically have two regions: a "seed" region on the inside of the core, and a "blanket" region surrounding the "seed". "Seed" fuel assemblies consist of fissile fuel, 15%-20% fissile plutonium, and this region provides power and fission neutrons to maintain criticality, while "blanket" assemblies contain fertile fuel, U^{238}, for breeding of new plutonium. A diagram for the fast reactor fuel cycle appears in Figure A-1.1. Although the details of fast reactor fuel reprocessing differ from thermal reactor recycle, the two have similar reprocessing diagrams and process steps.

There are important differences between fast and thermal reactors, including the high energy fast neutrons, and the need to eliminate neutron moderators, i.e., water, and other materials that cause neutrons to lose energy and become thermal neutrons. As a result certain liquid metals such as sodium, or lead-bismuth, are used for cooling the fast reactor fuel instead of water. Because the probability of neutron absorption in fissile fuel is low in

a fast reactor, the reactor core must have a high concentration of fissile isotopes. Comparison of fast reactor and LWR cores shows that there is more fissile material per unit of volume than in LWRs. Fuel enrichment for fast reactors is higher, i.e., 15%-20%, than it is in LWRs. The core is compact, and there must be both high coolant flow rate and large heat transfer area to remove heat from the core. This is accomplished by means of closely packed fuel rods of smaller diameter than in LWRs. We note that neutron balance requires very close attention in fast reactors fueled by Pu^{239}, because the fraction of delayed neutrons is only ⅓ of the U^{235} delay fraction. As a result, a fast reactor can become prompt critical with just ⅓ of the reactivity increase needed to make a U^{235} thermal reactor prompt critical.

Fast reactor technology is very demanding, and more capital intensive than LWR technology. A fast reactor power generation economy would also bring reprocessing and large amounts of fissile material with weapons potential into commercial use. Such a development would raise major safeguards and security concern, which is discussed in Chapter 8.

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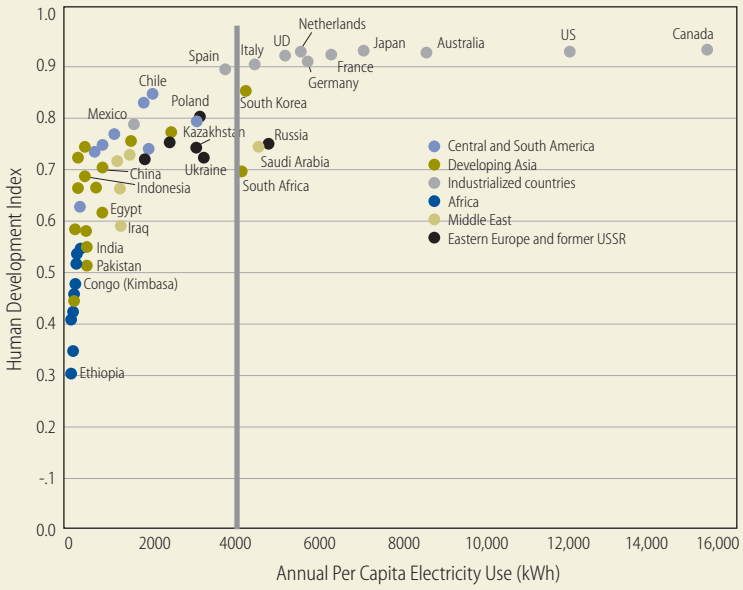
NOTES

1. Natural uranium consists of 0.71% U^{235} by weight, and the remainder is U^{238}.
2. The PWR is one of the two types of LWR, the other being the Boiling Water Reactor (BWR).
3. The UK has extensive experience with CO_2 cooled gas reactors. In the U. S. Fort St. Vrain operated for 11 years before shut down in 1989. The Fort St. Vrain reactor coolant also was CO_2, with an intermediate heat exchanger, and a steam driven turbine.
4. The heat energy produced by fission is called burnup, and is expressed in megawatt-days per metric ton (MWD/MT). The designation "per metric ton" generally refers to "heavy metal" meaning the tons of total fissile and fertile material as metal; mostly uranium in the case of LWRs
5. Terrorist attack on spent fuel shipment was not considered originally, and this possibility requires safety review.

Appendix Chapter 2 — Global Electricity Demand and the Nuclear Power Growth Scenario

The United States National Academy of Engineering declared electrification as the leading engineering accomplishment of the twentieth century. This recognition, for a century of extraordinary technological developments, acknowledges the profound impact of electricity on quality of life and suggests that governments around the world will continue to attach very high priority to providing adequate electricity infrastructure and supply to their citizens, within their means to make such investments. Today the per capita consumption of electricity spans three orders of magnitude, as shown in Figure A-2.1 (S. Benka, Physics Today (April 2002) p.38). The empirical dividing line between advanced and developing economies, as represented by the United Nations Human Development Index (HDI), is 4000 kWh per person per year electricity use. The HDI is based on health, education, and economic criteria.

Figure A-2.1 Correlation between HDI and Per Capita Electricity Consumption



The underlying assumption in our mid-century electricity demand scenario is that the developed countries continue with a modest annual increase in per capita electricity use and the developing countries move to the 4000 kWh per person per year benchmark if at all feasible. Specifically, we have taken developed country annual per capita electricity growth rates between 0.5% and 1%, values that bracket EIA expectations for the United States over the next twenty years (EIA Annual Energy Outlook, 2001); over the last quarter century, the growth rate averaged about 2%, falling to 1.5% in 2000 and expected to decline further in the years ahead. We present the 1% case in our table below. We take the same per capita growth rate for the Former Soviet Union countries. Although these are not necessarily robust economies today, they do enjoy substantial per capita electricity use already. Total electricity production is then computed using the United Nations population projections to mid-century.

For the developing economies, we assume that the investments needed to reach the 4000 kWh per capita benchmark will be a high priority. When this is combined with the UN population projections, the total electricity production growth rate is then calculated. For example, China needs a 2.9% annual growth rate in per capita electricity use and a 3.2%

annual growth rate in total electricity production to mid-century in order to reach the per capita benchmark.

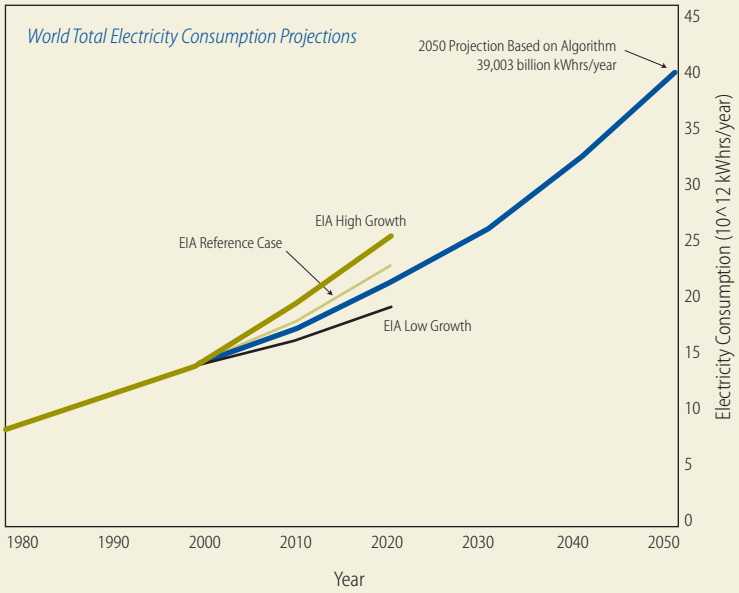
For the countries further down the curve in Figure A-2.1, this algorithm would produce unreasonable growth rates. In other words, the per capita benchmark is not realistically achievable in the mid-century time frame. We have limited total electricity growth rate to 4.7% per year, which is 0.5% higher than the EIA's projected average (to 2020) for all developing countries combined (recall that we have lower growth rates for the more advanced developing countries).

This algorithm suggests a classification into various categories:

- Developed countries (e.g., US, Japan, Germany,…)
- Former Soviet Union (e.g., Russia,…)
- More advanced developing countries: those that can achieve 4000 kWh per person per year within the cap on annual electricity production growth rate (e.g., China, Brazil, Mexico, Iran, Egypt,…)
- Less advanced developing countries: those that cannot achieve the per capita benchmark within the cap, but can reach "acceptable" levels in the 1500 to 4000 kWh per capita range (e.g., India, Indonesia, Pakistan, Philippines, Vietnam,…)
- Least developed countries: those that reach less than 1000 kWh per person per year even at the cap (e.g., Nigeria, Bangladesh, Democratic Republic of the Congo, Ethiopia,…).

The result for individual countries, excluding the large number of nations with populations below three million, is shown in Table A-2.1 (reference: C. M. Jones, MIT M.S. thesis, 2003; a listing for all countries can be found there).

Figure A-2.2 Comparison of TEC Projections (1% per year per capita increase)



It is easy to see the inverse correlation between level of development and population increase within the developing country categories as constructed above. The global electricity use generated by this algorithm lies between the EIA's "business-as-usual" and "low growth" scenarios, as shown in Figure A-2.2.

Finally, we use this pattern of electricity demand to estimate the nuclear power market share for each country in the context of a robust global growth scenario. This is certainly not a prediction of rapid growth in nuclear power. Rather, it is an attempt to understand what the distribution of nuclear power deployment would be if robust growth were realized, perhaps driven by a broad commitment to reducing greenhouse gas emissions and a con-

current resolution of the various challenges confronting nuclear power's acceptance in various countries.

Within this context, our judgment on nuclear power market share is based on various country-specific factors, such as current nuclear power deployment, urbanization, stage of economic development, and energy resource base. Table A-2.1 explicitly shows the range of market share taken for each country, leading to the nuclear power demand map that shaped some of our recommendations, particularly those dealing with nonproliferation concerns.

Several comments are in order. First, we do not anticipate any nuclear power deployment in the least developed countries. Second, the developed nations remain the locus for a major part of nuclear power deployment in the growth scenario. In particular, the United States, because of the very large demand increase associated with its economic strength and projected large population increase, must experience very substantial expansion of its nuclear reactor fleet if the global growth scenario is to be realized. In addition, nations such as Germany, where there is currently strong anti-nuclear sentiment, would almost certainly need to participate. This is indicative of the substantial difficulty inherent in having nuclear power expand several-fold by mid-century.

Among the developing nations, India and China clearly are the major contributors to growth of nuclear power in the growth scenario. However, as nuclear weapons states, these are not the drivers of our nonproliferation considerations. Rather, it is the remaining countries in the "more advanced" and "less advanced" developing categories that shape our nonproliferation discussion. These countries account for about 10% of deployed mid-century nuclear power in the global growth scenario.

Table A-2.1a Electricity Consumption Projections (Developed World)

COUNTRY	TOTAL POPULATION (millions)		TOTAL ELECTRICITY CONSUMPTION (billion kWhrs)		PER CAPITA CONSUMPTION (kWhrs/per)		NUCLEAR PRODUCTION (billion kWhrs)						NUCLEAR EQ. "CAPACITY" (GWe)			%/year TEC	%/year LOW NUCLEAR	%/year HIGH NUCLEAR
DEVELOPED WORLD	2000	2050	2000	2050*	2000	2050*	2000	%	2050 L	% L	2050 H	% H	2000	2050 L	2050 H			
USA	283	397	3,621.0	8,349	12,785	21,026	717	20%	2,505	30%	4,174	50%	82	286	477	1.7%	2.5%	3.6%
France	59	62	408.5	701	6,896	11,342	315	77%	561	80%	596	85%	36	64	68	1.1%	1.2%	1.3%
Japan	127	109	943.7	1,334	7,425	12,212	274	29%	534	40%	800	60%	31	61	91	0.7%	1.3%	2.2%
Germany	82	71	501.7	712	6,117	10,061	151	30%	285	40%	427	60%	17	33	49	0.7%	1.3%	2.1%
Korea, South (ROK)	47	52	254.1	461	5,436	6,980	97	38%	230	50%	323	70%	11	26	37	1.2%	1.8%	2.4%
United Kingdom	59	59	345.0	563	5,807	9,551	79	23%	169	30%	281	50%	9	19	32	1.0%	1.5%	2.6%
Canada	31	40	499.8	1,080	16,249	26,724	60	12%	324	30%	540	50%	7	37	62	1.6%	3.4%	4.5%
Spain	40	31	201.2	259	5,040	8,289	56	28%	104	40%	156	60%	6	12	18	0.5%	1.2%	2.1%
Sweden	9	8	139.2	201	15,740	25,887	51	37%	101	50%	141	70%	6	11	16	0.7%	1.3%	2.0%
Belgium	10	10	78.1	120	7,623	12,537	45	58%	72	60%	96	80%	5	8	11	0.9%	0.9%	1.5%
Taiwan	22	23	139.0	233	6,277	8,054	35	25%	93	40%	140	60%	4	11	16	1.0%	2.0%	2.8%
Finland	5	5	82.0	122	15,848	26,064	23	28%	49	40%	73	60%	3	6	8	0.8%	1.5%	2.4%
Switzerland	7	6	52.6	68	7,338	12,069	19	37%	34	50%	47	70%	2	4	5	0.5%	1.1%	1.8%
Netherlands	16	16	100.7	165	6,349	10,441	4	4%	17	10%	33	20%	0	2	4	1.0%	2.9%	4.3%
Norway	4	5	112.5	202	25,172	41,399	0	0%	20	10%	40	20%	0	2	5	1.2%	—	—
Australia	19	27	188.5	429	9,849	16,198	0	0%	43	10%	86	20%	0	5	10	1.7%	—	—
New Zealand	4	4	33.3	64	8,818	14,503	0	0%	6	10%	13	20%	0	1	1	1.3%	—	—
Austria	8	6	54.8	72	6,778	11,147	0	0%	7	10%	14	20%	0	1	2	0.5%	—	—
Denmark	5	5	33.9	53	6,377	10,488	0	0%	0	0%	0	0%	0	0	0	0.9%	—	—
Israel	6	10	34.9	96	5,777	9,501	0	0%	10	10%	19	20%	0	1	2	2.0%	—	—
Ireland	4	5	20.8	48	5,475	9,005	0	0%	0	0%	0	0%	0	0	0	1.7%	—	—
China, Hong Kong	7	8	35.4	63	4,975	8,182	0	0%	0	0%	0	0%	0	0	0	1.2%	—	—
Italy	58	43	283.7	348	4,932	8,111	0	0%	35	10%	70	20%	0	4	8	0.4%	—	—
Greece	11	9	46.1	64	4,345	7,146	0	0%	0	0%	0	0%	0	0	0	0.7%	—	—
Subtotal	**924**	**1,010**	**8,211**	**15,810**	**8,888**	**15,659**	**1,926**	**23%**	**5,197**	**33%**	**8,071**	**51%**	**220**	**593**	**921**	**1.3%**	**2.0%**	**2.9%**

Table A-2.1b Electricity Consumption Projections (More Advanced Developing)

COUNTRY *DEVELOPIING WORLD More Advanced*	TOTAL POPULATION (millions)		TOTAL ELECTRICITY CONSUMPTION (billion kWhrs)		PER CAPITA CONSUMPTION (kWhrs/per)		NUCLEAR PRODUCTION (billion kWhrs)						NUCLEAR EQ. "CAPACITY" (GWe)			%/year TEC	%/year LOW NUCLEAR	%/year HIGH NUCLEAR
	2000	2050	2000	2050*	2000	2050*	2000	%	2050 L	% L	2050 H	% H	2000	2050 L	2050 H			
Kuwait	2	4	29.0	100	15,157	24,927	0	0%	0	0%	0	0%	0	0	0	2.5%	—	—
United Arab Emirates	3	4	36.0	84	13.811	22,714	0	0%	0	0%	0	0%	0	0	0	1.7%	—	—
Singapore	4	5	25.9	49	6,458	10,620	0	0%	0	0%	0	0%	0	0	0	1.3%	—	—
Saudi Arabia	20	60	114.9	554	5,645	9,284	0	0%	0	0%	0	0%	0	0	0	3.2%	—	—
Puerto Rico	4	5	19.1	39	4,869	8,008	0	0%	0	0%	0	0%	0	0	0	1.4%	—	—
Bulgaria	8	5	34.4	32	4,330	7,121	15	44%	16	50%	23	70%	2	2	3	–0.1%	0.1%	0.8%
South Africa	43	47	181.5	326	4,191	6,893	13	7%	65	20%	130	40%	1	7	15	1.2%	3.3%	4.8%
Portugal	10	9	41.1	61	4,108	6,756	0	0%	6	10%	12	20%	0	1	1	0.8%	—	—
Hungary	10	7	35.1	43	3,521	5,791	14	40%	22	50%	26	60%	2	2	3	0.4%	0.9%	1.2%
Libya	5	10	18.0	56	3,411	5,609	0	0%	6	10%	11	20%	0	1	1	2.3%	—	—
Brazil	170	247	360.6	989	2,116	4,000	4	1%	148	15%	297	30%	0	17	34	2.0%	7.7%	9.2%
Mexico	99	147	182.8	587	1,849	4,000	7	4%	88	15%	176	30%	1	10	20	2.4%	5.1%	6.6%
Iraq	23	54	25.4	214	1,106	4,000	0	0%	0	0%	0	0%	0	0	0	4.4%	—	—
Costa Rica	4	7	5.9	29	1,465	4,000	0	0%	0	0%	0	0%	0	0	0	3.2%	—	—
Ecuador	13	21	9.7	85	764	4,000	0	0%	0	0%	0	0%	0	0	0	4.4%	—	—
Cuba	11	11	13.8	43	1,235	4,000	0	0%	0	0%	0	0%	0	0	0	2.3%	—	—
Algeria	30	51	21.8	205	721	4,000	0	0%	20	10%	41	20%	0	2	5	4.6%	—	—
Thailand	63	82	90.3	330	1,437	4,000	0	0%	33	10%	66	20%	0	4	8	2.6%	—	—
Syria	16	36	17.7	145	1,092	4,000	0	0%	0	0%	0	0%	0	0	0	4.3%	—	—
Egypt	68	114	64.7	455	953	4,000	0	0%	46	10%	91	20%	0	5	10	4.0%	—	—
Malaysia	22	38	58.6	151	2,637	4,000	0	0%	15	10%	30	20%	0	2	3	1.9%	—	—
Chile	15	22	37.9	89	2,491	4,000	0	0%	0	0%	0	0%	0	0	0	1.7%	—	—
Mongolia	3	4	2.7	17	1,078	4,000	0	0%	0	0%	0	0%	0	0	0	3.7%	—	—
Turkey	67	99	114.2	395	1,713	4,000	0	0%	40	10%	79	20%	0	5	9	2.5%	—	—
Oman	3	9	7.5	35	2,968	4,000	0	0%	0	0%	0	0%	0	0	0	3.1%	—	—
Croatia	5	4	12.6	17	2,716	4,000	0	0%	0	0%	0	0%	0	0	0	0.6%	—	—
Peru	26	42	18.3	168	713	4,000	0	0%	0	0%	0	0%	0	0	0	4.5%	—	—
China	1,275	1,462	1,206.3	5,848	946	4,000	12	1%	877	15%	1,754	30%	1	100	200	3.2%	9.0%	10.5%
Argentina	37	55	80.8	218	2,182	4,000	6	7%	44	20%	87	40%	1	5	10	2.0%	4.2%	5.6%
Lebanon	3	5	8.6	20	2,472	4,000	0	0%	0	0%	0	0%	0	0	0	1.7%	—	—
Uruguay	3	4	7.4	17	2,203	4,000	0	0%	0	0%	0	0%	0	0	0	1.7%	—	—
Albania	3	4	5.4	16	1,716	4,000	0	0%	0	0%	0	0%	0	0	0	2.2%	—	—
Jordan	5	12	7.1	47	1,443	4,000	0	0%	0	0%	0	0%	0	0	0	3.8%	—	—
Korea, North (DROK)	22	28	31.1	112	1,395	4,000	0	0%	22	20%	45	40%	0	3	5	2.6%	—	—
Venezuela	24	42	75.1	169	3,107	4,000	0	0%	17	10%	34	20%	0	2	4	1.6%	—	—
Dominican Republic	8	12	8.8	48	1,052	4,000	0	0%	0	0%	0	0%	0	0	0	3.4%	—	—
Poland	39	33	119.3	133	3,091	4,000	0	0%	13	10%	27	20%	0	2	3	0.2%	—	—
Jamaica	3	4	6.3	15	2,433	4,000	0	0%	0	0%	0	0%	0	0	0	1.8%	—	—
Zimbabwe	13	24	10.5	94	830	4,000	0	0%	0	0%	0	0%	0	0	0	4.5%	—	—
Colombia	42	71	40.3	283	958	4,000	0	0%	0	0%	0	0%	0	0	0	4.0%	—	—
Tunisia	9	14	9.6	56	1,011	4,000	0	0%	0	0%	0	0%	0	0	0	3.6%	—	—
Bosnia and Herzegovina	4	3	2.6	14	648	4,000	0	0%	0	0%	0	0%	0	0	0	3.4%	—	—
Iran	70	121	111.9	486	1,591	4,000	0	0%	97	20%	194	40%	0	11	22	3.0%	—	—
Romania	22	18	45.7	73	2,036	4,000	5	10%	15	20%	22	30%	1	2	2	0.9%	2.3%	3.2%
Yugoslavia	11	9	31.5	36	2,989	4,000	0	0%	0	0%	0	0%	0	0	0	0.3%	—	—
Panama	3	4	4.7	17	1,629	4,000	0	0%	0	0%	0	0%	0	0	0	2.6%	—	—
El Salvador	6	11	4.1	41	648	3,749	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—

Table A-2.1c Electricity Consumption Projections (Less Advanced Developing)

COUNTRY *DEVELOPING WORLD* Less Advanced	TOTAL POPULATION (millions)		TOTAL ELECTRICITY CONSUMPTION (billion kWhrs)		PER CAPITA CONSUMPTION (kWhrs/per)		NUCLEAR PRODUCTION (billion kWhrs)						NUCLEAR EQ. "CAPACITY" (GWe)			%/year TEC	%/year LOW NUCLEAR	%/year HIGH NUCLEAR
	2000	2050	2000	2050*	2000	2050*	2000	%	2050 L	% L	2050 H	% H	2000	2050 L	2050 H			
India	1,009	1,572	509.9	5,099	505	3,243	15	3%	765	15%	1,530	30%	2	87	175	4.7%	8.1%	9.6%
Philippines	76	128	37.8	378	500	2,946	0	0%	38	10%	76	20%	0	4	9	4.7%	—	—
Morocco	30	50	14.3	143	480	2,849	0	0%	14	10%	29	20%	0	2	3	4.7%	—	—
Honduras	6	13	3.6	36	560	2,797	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Indonesia	212	311	86.1	861	406	2,765	0	0%	172	20%	344	40%	0	20	39	4.7%	—	—
Sri Lanka	19	23	6.2	62	325	2,669	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Bolivia	8	17	3.6	36	433	2,125	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Zambia	10	29	5.8	58	560	1,995	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Vietnam	78	124	24.0	240	307	1,937	0	0%	24	10%	48	20%	0	3	5	4.7%	—	—
Nicaragua	5	11	2.2	22	429	1,896	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Guatemala	11	27	4.8	48	421	1,807	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Pakistan	141	344	58.3	583	413	1,694	1	1%	87	15%	175	30%	0	10	20	4.7%	10.5%	12.1%
Paraguay	5	13	2.0	20	355	1,552	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—

Table A-2.1d Electricity Consumption Projections (Least Developed)

COUNTRY *DEVELOPING WORLD* Least Advanced	TOTAL POPULATION (millions)		TOTAL ELECTRICITY CONSUMPTION (billion kWhrs)		PER CAPITA CONSUMPTION (kWhrs/per)		NUCLEAR PRODUCTION (billion kWhrs)						NUCLEAR EQ. "CAPACITY" (GWe)			%/year TEC	%/year LOW NUCLEAR	%/year HIGH NUCLEAR
	2000	2050	2000	2050*	2000	2050*	2000	%	2050 L	% L	2050 H	% H	2000	2050 L	2050 H			
Papua New Guinea	5	11	1.5	15	319	1,397	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Ghana	19	40	5.5	55	284	1,369	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Ivory Coast	16	32	3.6	36	222	1,103	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Cameroon	15	32	3.4	34	227	1,044	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Kenya	31	55	4.4	44	145	801	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Myanmar	48	69	4.5	45	94	656	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Senegal	9	23	1.2	12	130	541	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Nigeria	114	279	14.8	148	130	530	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Bangladesh	137	265	12.5	125	91	473	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Tanzania	35	83	2.6	26	75	316	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Yemen	18	102	3.0	30	162	291	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Sudan	31	64	1.8	18	59	288	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Nepal	23	52	1.4	14	62	273	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Congo, DR	51	204	4.6	46	90	225	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Angola	13	53	1.1	11	84	208	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Uganda	23	102	1.3	13	56	129	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Ethiopia	63	186	1.5	15	24	81	0	0%	0	0%	0	0%	0	0	0	4.7%	—	—
Subtotal *	**4,614**	**7,395**	**4,224**	**21,315**	**916**	**2,882**	**91**	**2%**	**2,690**	**13%**	**5,347**	**25%**	**10**	**307**	**610**	**3.3%**	**7.0%**	**8.5%**

** For all developing countries in Tables A2.1 b, c, and d.*

Table A-2.1e Electricity Consumption Projections (Former Soviet Union)

COUNTRY	TOTAL POPULATION (millions)		TOTAL ELECTRICITY CONSUMPTION (billion kWhrs)		PER CAPITA CONSUMPTION (kWhrs/per)		NUCLEAR PRODUCTION (billion kWhrs)						NUCLEAR EQ. "CAPACITY" (GWe)			%/year TEC	%/year LOW NUCLEAR	%/year HIGH NUCLEAR
Former Soviet Union	2000	2050	2000	2050*	2000	2050*	2000	%	2050 L	% L	2050 H	% H	2000	2050 L	2050 H			
Russia	145	104	767.1	904	5,272	8,671	115	15%	271	30%	452	50%	13	31	52	0.3%	1.7%	2.8%
Ukraine	50	30	151.7	120	3,061	4,000	65	43%	60	50%	72	60%	7	7	8	–0.5%	–0.2%	0.2%
Slovakia	5	5	25.2	36	4,668	7,678	12	48%	22	60%	25	70%	1	2	3	0.7%	1.2%	1.5%
Czech Republic	10	8	54.7	74	5,325	8,758	10	19%	22	30%	30	40%	1	3	3	0.6%	1.5%	2.1%
Lithuania	4	3	6.9	12	1,866	4,000	5	77%	10	80%	10	85%	1	1	1	1.1%	1.2%	1.3%
Slovenia	2	2	10.6	13	5,342	8,786	4	35%	7	50%	8	60%	0	1	1	0.5%	1.2%	1.6%
Armenia	4	3	4.9	13	1,291	4,000	2	32%	5	40%	6	50%	0	1	1	1.9%	2.4%	2.8%
Estonia	1	1	5.4	5	3,848	6,329	0	0%	0	0%	0	0%	0	0	0	–0.2%	—	—
Tajikistan	6	10	12.5	39	2,060	4,000	0	0%	0	0%	0	0%	0	0	0	2.3%	—	—
Kazakhstan	16	15	48.3	61	2,989	4,000	0	0%	6	10%	12	20%	0	1	1	0.5%	—	—
Uzbekistan	25	41	41.9	162	1,684	4,000	0	0%	16	10%	32	20%	0	2	4	2.7%	—	—
Moldova	4	4	3.7	14	851	4,000	0	0%	0	0%	0	0%	0	0	0	2.8%	—	—
Kyrgyzstan	5	8	9.8	30	1,995	4,000	0	0%	3	10%	6	20%	0	0	1	2.3%	—	—
Belarus	10	8	26.8	33	2,629	4,000	0	0%	3	10%	7	20%	0	0	1	0.4%	—	—
Georgia	5	3	7.9	13	1,499	4,000	0	0%	1	10%	3	20%	0	0	0	1.0%	—	—
Turkmenistan	5	8	7.7	34	1,627	4,000	0	0%	3	10%	7	20%	0	0	1	3.0%	—	—
Azerbaijan	8	9	16.7	36	2,075	4,000	0	0%	4	10%	7	20%	0	0	1	1.5%	—	—
Subtotal	**306**	**261**	**1,202**	**1,598**	**3,925**	**6,118**	**213**	**18%**	**433**	**27%**	**677**	**42%**	**24**	**49**	**77**	**0.6%**	**1.4%**	**2.3%**
TOTALS	**5,844**	**8,666**	**13,636**	**38,723**	**2,333**	**4,468**	**2,230**	**16%**	**8,321**	**21%**	**14,094**	**36%**	**255**	**950**	**1,609**	**2.1%**	**2.7%**	**3.8%**

*** Table represents 1% per year increase in electricity consumption from 2000 to 2050**

**** 2050 after cutoff numbers**

***** Countries ranked by 2000 nuclear production**

Appendix Chapter 4 — Fuel Cycle Calculations

THERMAL ONCE-THROUGH URANIUM FUEL CYCLE

The majority of the world's nuclear electricity production is based on the once-through fuel cycle using enriched uranium in light water reactors (LWR). This fuel cycle is represented in Figure A-4.1 below. Note that the specific numerical mass flows and enrichments in Figure A-4.1 are for a burnup of 33 GWd/MTIHM, which was the average burnup for U.S. reactors about 2 decades ago. In the rest of this section, we use a burnup of 50 GWd/MTIHM, which is currently the average for U.S. PWRs.

Figure A-4.1 can be greatly simplified by lumping together all the front-end operations, all the back-end operations, and neglecting losses (typically about 0.5% in any given stage. In addition, the enrichment tails are of little interest because, although they are produced in significant amounts, they are low level wastes and can be managed easily. Figure A-4.2 shows a simplified representation of the once-through fuel cycle for 1500 GWe of LWR reactors operating under today's conditions of 50 GWd/MTIHM burnup and 90% capacity factor. The enrichment tails, which are low level wastes produced in significant amounts, are not explicitly considered here. The mass flows that appear in Figure A-4.2 are obtained from the analysis presented next. Note that Figure A-4.2 and the calculations that follow apply to PWRs (for simplicity, we assume PWR characteristics for all LWRs. BWRs differ principally in that the fuel requires lower initial enrichment and achieves lower burnup, which would slightly decrease the required natural uranium feed and slightly increase the mass of spent fuel produced).

Figure A-4.2 Once-through Fuel Cycle (simplified)

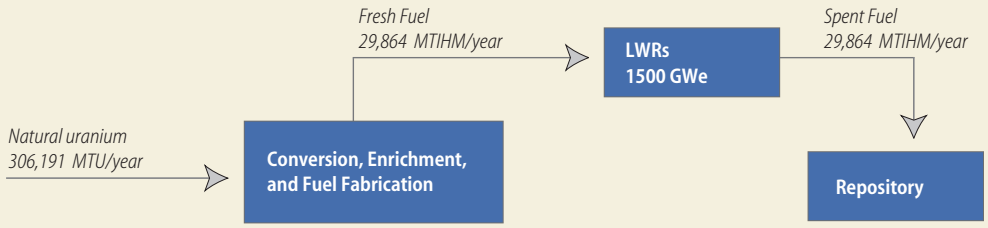
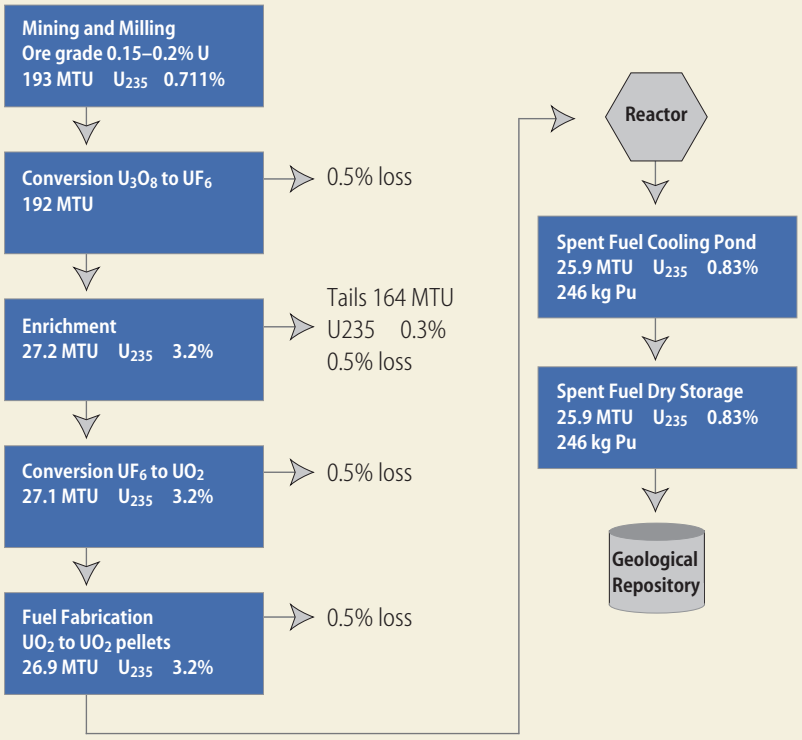


Figure A-4.1 Once-through Fuel Cycle



Source: Adapted from Appendix C, Norman Rasmussen MIT & Allen Croff ORNL, Nuclear Wastes, National Research Council, p.135 (1996).

The amount of energy produced per unit mass of fuel[1] is called the fuel burnup, measured in GWd/MTIHM[2]. The burnup will vary with reactor design and fuel management schemes. In the U.S, pressurized water reactors (PWR) reach a burnup of approximately 50 GWd/MTIHM. This value is used for the calculations presented in this section. The mass of fuel that must be loaded into the reactors per year[3] is obtained as:

$$M = \frac{Q}{B_d} \qquad [1]$$

where:
M: mass of fuel loaded per year (MTIHM/year)
Q: annual thermal energy output (GWd/year)
Bd: discharge burnup (GWd/MTIHM)

The annual thermal energy output is given by the following expression:

$$Q = \frac{P_e \cdot CF \cdot 365}{\eta_{th}} \qquad [2]$$

where:
Pe: installed electric capacity (GWe)
CF: capacity factor
η_{th}: thermal efficiency (effectively GWe/GWth)

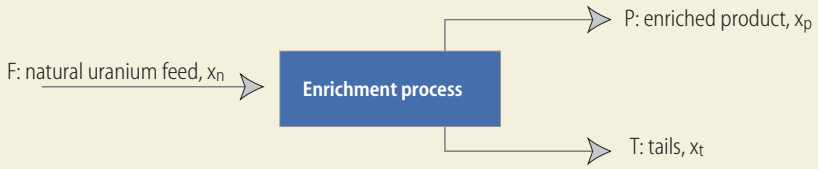
Combining equations [1] and [2], we obtain:

$$M = \frac{P_e \cdot CF \cdot 365}{\eta_{th} \cdot B_d} \qquad [3]$$

The capacity factor of nuclear power plants in the U.S. is about 90% and the thermal efficiency of LWR power plants is approximately 33%. Hence, using equation [3] with an installed capacity of 1500 GWe, we find that the mass of fuel loaded in the reactors every year is 29,864 MTIHM.

The mass of natural uranium required for fuel production can be obtained by considering the enrichment process (the variable x designates enrichment):

Figure A-4.3 Enrichment Process



The enrichment of natural uranium is x_n=0.711% and the enrichment of tails is assumed to be x_t=0.30%. From mass conservation of U-235 in the enrichment process:

$$\frac{F}{P} = \frac{X_p - X_t}{X_n - X_t} \qquad [4]$$

Hence, for a given product mass of enriched uranium, *P*, the mass of natural uranium feed required, *F*, depends on the enrichment x_p. For PWRs, the required enrichment for a given burnup can be approximated using the following correlation[4] (valid for enrichments up to 20%):

$$x_p = 0.41201 + 0.11508 \cdot \left(\frac{n+1}{2n} \cdot B_d\right) + 0.00023937 \cdot \left(\frac{n+1}{2n} \cdot B_d\right)^2 \qquad [5]$$

where n is the number of fuel batches, i.e. the fraction of the core refueled per cycle is 1/n.

The number of batches is selected according to the fuel management scheme adopted by the reactor operator. In the U.S., the number is typically approximately 3. Using equation [5] with n=3 and B_d=50 GWd/MTIHM, the resulting U-235 enrichment is x_p=4.51%. Using (4), we find F/P=10.25, and hence the mass of natural uranium required is 306 191 MT/yr for the needed 29,864 MTIHM/yr of enriched uranium to load the 1500 GWe reactor fleet.

The contents of spent fuel discharged from the reactors can be roughly divided into 4 categories: 1) uranium; 2) plutonium; 3) fission products (FP); 4) minor actinides (MA). The content of spent fuel irradiated to 50 GWd/MTIHM is as follows: 93.4% uranium (with a U-235 enrichment of 1.1%), 5.15% fission products, 1.33% plutonium, and 0.12% minor actinides.[5]

Since the mass of spent fuel unloaded per year is 29,864 MTIHM[6], the total amounts of these materials discharged in a year for a 1500 GWe installed capacity are: 27 893 MT of uranium, 1538 MT of fission products, 397 MT of plutonium, and 36 MT of minor actinides as tabulated in Table A-4.1.

Table A-4.1 Spent Fuel Material Flows — Once-through (1500 GWe at 90% capacity)

	50 GWd/MTIHM	100 GWd/MTIHM
Spent Fuel (MTIHM/yr)	29,864	14,932
Spent Fuel Composition		
U	93.4% (27 893 MT/yr)	87.43% (13 055 MT/yr)
FP	5.15% (1538 MT/yr)	10.30% (1538 MT/yr)
Pu	1.33% (397 MT/yr)	1.97% (294 MT/yr)
MA	0.12% (36 MT/yr)	0.30% (45 MT/yr)

High Burnup Case

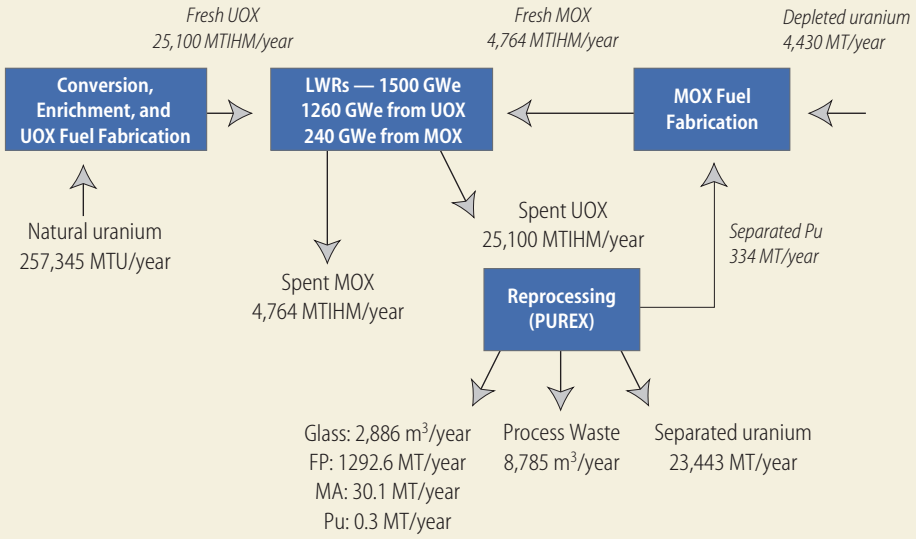
If the burnup is increased to 100 GWd/MTIHM, the mass of fuel loaded and discharged per year is reduced by a factor of 2 to 14,932 MTIHM/yr. The enrichment required, using (5), is 9.15%, giving a natural uranium consumption of 321,447 MT/yr for the current typical 3-batch fuel management scheme. This value is 5% higher than with current burnup. If a 5-batch fuel management scheme is adopted in this case, the required enrichment is 8.18%, giving a natural uranium consumption of 286,231 MT/yr (8% lower than with current burnup).

It is important to note that the gross amount of fission products generated to produce a given amount of electricity is independent of fuel burnup because the energy yield of fission is always 1000 $GWd/MTHM_{fissioned}$. Therefore, in the case of high burnup fuel, the same amount of material must be fissioned and the same quantity of fission products is generated, but the fission products are simply concentrated in a smaller mass of fuel. The content of spent fuel at 100 GWd/MTIHM is as follows: 87.43% uranium (with a U-235 enrichment of 1.66%), 10.30% fission products, 1.97% plutonium, and 0.30% minor actinides.[7] The total amount of material discharged per year is therefore: 13 055 MT of uranium, 1538 MT of fission products, 294 MT of plutonium, 45 MT of minor actinides as tabulated in Table A-4.1. We note that the amount of plutonium discharged per year is lower than for a burnup of 50 GWd/MTIHM.

THERMAL FUEL CYCLE WITH SINGLE-PASS PLUTONIUM RECYCLING

The plutonium present in spent fuel can be recycled and used as fissile material in new nuclear fuel. Recycled plutonium is mixed with natural or depleted uranium to make MOX fuel (Mixed OXide fuel), typically composed of 7% PuO_2 and 93% UO_2. A fuel cycle where all the UOX spent fuel (but none of the MOX spent fuel) is recycled for MOX fabrication is represented in Figure A-4.4.[8] The mass flows that appear in Figure A-4.4 are obtained from the analysis presented next.

Figure A-4.4 Plutonium Single-recycle — 1,500 GWe Fleet



The LWR fleet considered is fueled with both UOX and MOX. By design, an individual reactor can be fueled by UOX only or by a mix of UOX and MOX. In practice, current reactors employing UOX and MOX are fueled with a 2:1 ratio of UOX to MOX fuel.

For simplicity, we assume that MOX fuel is irradiated to the same burnup as UOX fuel, 50 GWd/MTIHM.[9] We shall also assume that all power plants have a thermal efficiency of 33% and a capacity factor of 90%. If all the spent UOX fuel was reprocessed and all the plutonium it contains was recycled to make MOX fuel, the fraction of nuclear capacity that could be based on MOX can be determined as follows:

Using equation [3] to determine the mass of spent UOX discharged per year:

$$\text{Mass of spent UOX} = \frac{(P_e)_{UOX} \cdot 0.9 \cdot 365}{0.33 \cdot 5.0} \quad \text{[MTIHM per year]}$$

Recalling that spent UOX fuel has plutonium content of 1.33% and assuming that 99.9% of this plutonium can be recovered by PUREX (equivalently 0.1% of the plutonium is lost during reprocessing):

$$\text{Pu recycled from spent UOX} = \frac{(P_e)_{UOX} \cdot 0.9 \cdot 365}{0.33 \cdot 5.0} \cdot 0.0133 \cdot 0.999 \quad \text{[MT Pu per year]}$$

The mass of MOX fuel needed per year is also determined using equation [3]:

$$\text{Mass of MOX} = \frac{(P_e)_{MOX} \cdot 0.9 \cdot 365}{0.33 \cdot 5.0} \cdot \text{[MTIHM per year]}$$

And since MOX fuel has an initial plutonium content of 7%:[10]

$$\text{Pu needed for MOX} = \frac{(P_e)_{MOX} \cdot 0.9 \cdot 365}{0.33 \cdot 5.0} \cdot 0.07 \quad \text{[MT Pu per year]}$$

If we now require that the amount of plutonium recycled from spent UOX be equal to the amount of plutonium needed for MOX fabrication, we find:

$$\frac{(P_e)_{UOX}}{(P_e)_{MOX}} = \frac{0.07}{0.0133 \cdot 0.999} = 5.27$$

Note that the value that is most frequently used for this ratio is 7 in current conditions. This is because the plutonium content of spent fuel is usually taken as 1% (this is a good approximation for UOX fuel irradiated to a burnup of 30 to 40 GWd/MTIHM).

Once the UOX to MOX ratio is known, the mass flows in Figure A-4.4 are obtained using equations [3] through [5] as follows: for a total capacity of 1500 GWe and a UOX:MOX ratio of 5.27, we have 1260 GWe based on UOX and 240 GWe based on MOX. Using equation [3] we find a throughput of 25 100 MTIHM/yr for UOX and 4 764 MTIHM/yr for MOX. Using equation [4], the mass of natural uranium required for UOX fabrication is 257 345 MT/yr.

The spent UOX is sent to reprocessing. For the PUREX Process, we assume that all the fission products, all of the minor actinides, and 0.1% of the plutonium present in the spent UOX fuel are separated and incorporated in borosilicate glass. The volume of borosilicate glass is 0.115 m^3 per MTIHM of fuel reprocessed. In addition, PUREX generates radioactive process waste at a rate of 0.35 m^3 per MTIHM of fuel reprocessed.[11] Assuming once again that the spent UOX contains 93.4% uranium, 5.15% fission products, 1.33% plutonium, and 0.12% minor actinides, we find that the borosilicate glass contains 1292.6 MT/yr of fission products, 30.1 MT/yr of minor actinides, and 0.3 MT/yr of plutonium. The amount of separated uranium is 23 443 MT/yr, and 334 MT/yr of separated plutonium is available for MOX fabrication. Since the total mass of MOX is 4 764 MTIHM/yr, the depleted uranium requirement is 4 430 MT/yr.

The total plutonium content of MOX fuel decreases by approximately 30% during irradiation in the reactor;[12] since fresh fuel has plutonium content of 7%, the spent fuel has a content of approximately 4.9%. As seen in Figure A-4.4, 4 764 MTIHM of MOX is discharged from the reactors each year, so the total amount of plutonium discharged is approximately 233 MT/yr. This is a reduction of 40% compared to a once-through cycle (recall that the mass of plutonium discharged in the once-through case was 397 MT/yr). Indeed, although the spent MOX fuel has a higher plutonium content than spent UOX (4.9% vs. 1.23%), the mass of spent MOX discharged is much smaller and the total amount of plutonium in spent fuel is lower. In addition, the plutonium discharged in spent MOX has a degraded isotopic composition (i.e. more Pu-238 and Pu-240) and is therefore less suitable for weapon production. However, because the PUREX process produces separated plutonium, the MOX cycle is generally viewed unfavorably in terms of proliferation resistance.

We note that the natural uranium consumption in this case is only about 15% lower than in the once-through case. Hence the MOX option has only a modest impact in improving utilization of uranium resources. This could be improved if the uranium separated by the PUREX process was recycled and re-enriched to make new fuel. At present, separated uranium is not recycled because its isotopic composition would complicate enrichment plant operations (e.g. significant U-236 is present) and because uranium ore is inexpensive. If uranium ore prices increased or enrichment costs decreased, re-enrichment of separated uranium for production of UOX fuel could become an attractive option. Currently, however, separated uranium is stockpiled for possible future use. Multiple-pass recycling is another option that, although not attractive under current conditions, could further reduce uranium consumption.

Finally, we note that approximately 25,100 MTIHM of spent fuel need to be reprocessed every year in this 1500 GWe scenario. The La Hague COGEMA reprocessing plant has a capacity of 1,700 MTHM /y. Therefore this scenario requires about 15 La Hague equivalent reprocessing plants. Table A-4.2 tabulates these spent fuel material flows for this single pass plutonium recycle case.

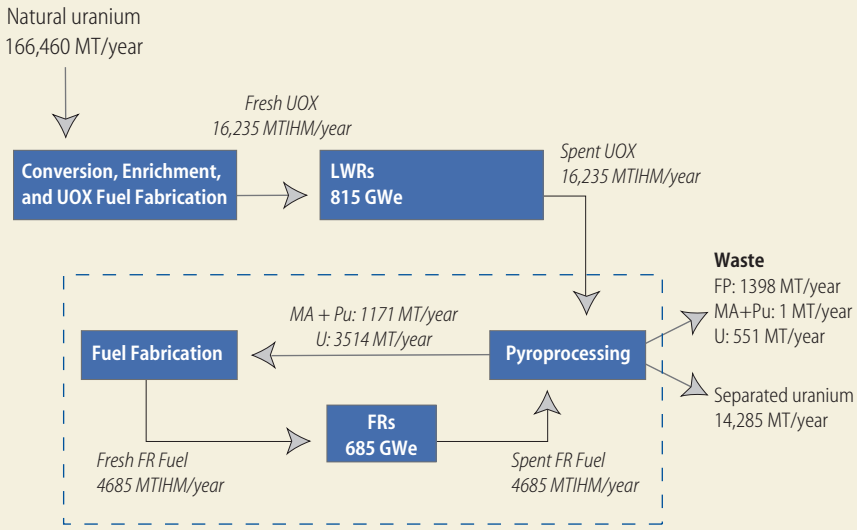
Table A-4.2 Spent Fuel Material Flows—Single-Pass Pu Recycling (1500 GWe at 90% capacity)

Reprocessed UOX	25,100 MTIHM/yr
Separated U	23,443 MT/yr
Borosilicate Glass	
FP	1292.6 MT/yr
MA	30.1 MT/yr
Pu	0.3 MT/yr
Spent MOX (MTIHM/yr)	4 764 MT/yr
Pu (4.9%)	233 MT/yr

BALANCED FUEL CYCLE WITH FAST AND THERMAL REACTORS

The main purpose of recycling spent fuel in the MOX fuel cycle is to recover fissile plutonium and use it to produce energy. However, if fast reactors[13] (FR) are used, all the plutonium and minor actinides can be recycled, incorporated into new fuel, and fissioned in a fast neutron flux. In this way, uranium resources are utilized much more efficiently, and the radiotoxicity of spent nuclear fuel is greatly reduced. A fuel cycle where FRs are used in tandem with LWRs is shown in Figure A-4.5 (note that we assume that all the spent fuel, including the LWR spent fuel, is pyroprocessed):

Figure A-4.5 FR/LWR Balanced Fuel Cycle — 1,500 GWe Fleet



The mass of fuel loaded each year in the LWRs and the FRs is determined using equation (3). For the FR, a burnup of 120 GWd/MTIHM, a thermal efficiency of 40%, and a capacity factor of 90% are assumed. The composition of heavy metal in FR fuel is taken as 75% uranium and 25% transuranics (plutonium and minor actinides). If we assume that the FRs are operated as burners such that the transuranics content of the fuel decreases by 20% during irradiation,[14] the ratio of FR capacity to LWR capacity can be determined as follows:

The annualized mass of FR fuel is given by equation [3]:

$$\text{Mass of FR fuel} = \frac{(\text{Pe})_{FR} \cdot 0.9 \cdot 365}{0.4 \cdot 120} \quad \text{[MTIHM per year]}$$

The mass of plutonium and minor actinides that must be supplied for the fabrication of FR fuel is (recalling that FR fuel contains 25% transuranics):

$$\text{Pu + MA needed for FR} = \frac{(\text{Pe})_{FR} \cdot 0.9 \cdot 365}{0.4 \cdot 120} \cdot 0.25 \quad \text{[MT Pu + MA per year]}$$

Since the transuranics content of the fuel has been assumed to decrease by 20% during irradiation, we have:

$$\text{Pu + MA from spent FR fuel} = \frac{(Pe)_{FR} \cdot 0.9 \cdot 365}{0.4 \cdot 120} \cdot 0.25 \cdot (1 - 0.2) \text{ [MT Pu + MA per year]}$$

The mass of spent UOX is obtained using equation [3]:

$$\text{Mass of spent UOX} = \frac{(P_e)_{UOX} \cdot 0.9 \cdot 365}{0.33 \cdot 50}$$

Since spent UOX contains 1.33% plutonium and 0.12% minor actinides, the annualized mass of plutonium and minor actinides is:

$$\text{Pu + MA from spent UOX} = \frac{(Pe)_{UOX} \cdot 0.9 \cdot 365}{0.33 \cdot 50} \cdot 0.0145 \text{ [MT Pu + MA per year]}$$

Assuming that 99.9% of the Pu and MA can be recovered in pyroprocessing, we get:

$$\text{Pu + MA for FR fuel} = 0.999 \cdot \left[\begin{array}{c}\text{Pu + MA from}\\ \text{spent FR fuel}\end{array}\right] + \left[\begin{array}{c}\text{Pu + MA from}\\ \text{spent UOX}\end{array}\right]$$

From the expression above, we find the ratio of installed electric power capacity of FRs to LWRs:

$$\frac{(P_e)_{FR}}{(P_e)_{UOX}} = \frac{0.0145 \cdot 0.4 \cdot 120}{0.25 \cdot 0.33 \cdot 50 \cdot \left({}^{1}/_{0.999} - (1 - 0.2)\right)} = 0.84$$

Therefore, if total nuclear capacity is 1500 GWe, the FR capacity can be taken as 685 GWe and the LWR capacity can be taken as 815 GWe. Using equation (3), we find that the mass of fuel required for the LWRs and FRs is 16,235 MTIHM/yr and 4,685 MTIHM/yr respectively. Using equation (4), we find that the amount of natural uranium required for UOX fuel fabrication is 166,460 MT/yr, about 60% less than for the once-through case.

Note that the FR:LWR capacity ratio is dependent on the assumptions made regarding FR fuel composition: if the fraction of transuranics in FR fuel coming from reprocessed UOX was lower than 20%, there would be a lower LWR share of total capacity. Furthermore, if the total transuranics content of FR fuel were reduced below 25%, the LWR capacity would decrease.

With full actinide recycle, the bulk of the wastes from pyroprocessing is composed of fission products (the waste also contains 0.1% of the actinides, which come from losses during reprocessing). The quantity of fission products generated in a given year by the FRs can be obtained by assuming that, in a fast reactor, fission produces 1000 GWd/MTHM$_{fissioned}$ on average. Hence, using equation (2) to get the annual thermal output, Q (GWd), and dividing by 1000 GWd/MTHM$_{fissioned}$, we obtain the annualized production of fission products:

$$FP_{FR} = \frac{685 \cdot 0.9 \cdot 365}{0.4 \cdot 1000} = 562 \text{ [MT FP per year]}$$

The reprocessed LWR fuel (16,235 MT/yr) contains 5.15% fission products, or 836 MT/yr, leading to a total discharge in fission products of 1398 MT/yr for this fuel cycle.

The production of the FR fuel (4,685 MTIHM/yr), assuming it is composed of 25% transuranics and 75% uranium, requires 1171 MT of transuranics and 3,514 MT of uranium. Assuming 0.1% losses in transuranics during reprocessing, the input of transuranics to pyroprocessing must be 1172 MT (1 MT of this amount will end up in the waste).

Table A-4.3 Spent Fuel Material Flows — Balanced FR/LWR (1500 GWe at 90% capacity)

Reprocessed UOX	16,235 MTIHM/yr
Reprocessed FR fuel	4,685 MTIHM/yr
Separated U	14,285 MT/yr
Pyroprocessing waste:	
FP	1398 MT/yr
Actinides (Pu+MA)	1 MT/yr
Uranium	551 MT/yr

The amount of separated uranium can be obtained as follows: the total mass of spent FR fuel is 4,685 MTIHM/yr. The spent fuel contains 563 MT of fission products and 80% of the initial 1171 MT of transuranics, or 937 MT. The remaining mass, or 3,185 MT, is uranium. The spent UOX fuel (16,235 MTIHM/yr) contains 93.4% uranium (see Table A-4.1), or 15 164 MT. Therefore, the total uranium input to pyroprocessing is 18,349 MT. Due to process limitations in pyroprocessing, 3% of this amount, or 551 MT, is discharged with the waste. Since only 3,513 MT are required for FR fuel fabrication, the amount of separated uranium to be stockpiled is 14,285 MT/yr. Table A-4.3 tabulates these spent fuel material flows for this balanced FR/LWR fuel cycle.

Current Situation: Once-Through with Some Plutonium Recycle

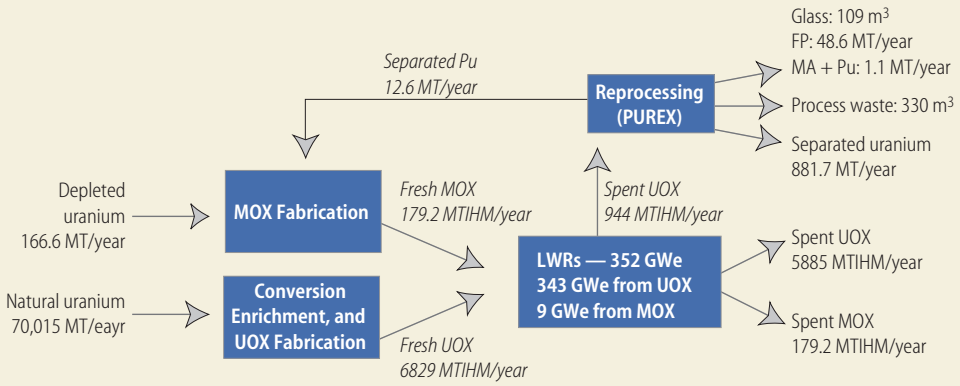
The simple models developed so far to evaluate mass flows in various fuel cycles can be applied to the current world nuclear fleet. Of course, this will only yield a rough estimate of the actual quantities involved because the models are greatly simplified.

Table A-4.4 Spent Fuel Material Flows — Existing World Fleet Modeled as LWRs on a Once-through Fuel Cycle with Some Pu Recycle (352 GWe at 90% capacity)

Spent UOX	5 885 MTIHM/yr
Pu (1.33%)	78 MT/yr
Spent MOX	179.2 MTIHM/yr
Pu (4.9%)	9 MT/yr
Reprocessed UOX	944 MTIHM/yr
Separated U	881.7 MT/yr
Borosilicate Glass:	
FP	48.6 MT/yr
Pu+MA	1.1 MT/yr

As of 2002, the installed world nuclear capacity based on thermal reactors is approximately 352 GWe. For simplicity, we will assume that all reactors are LWRs, and we apply the same assumptions as before for burnup (50 GWd/MTIHM), capacity factor (90%), and thermal efficiency (33%). MOX fuel currently represents approximately 2.5% of world nuclear fuel production,[15] so we assume that 9 GWe of installed capacity is based on MOX.

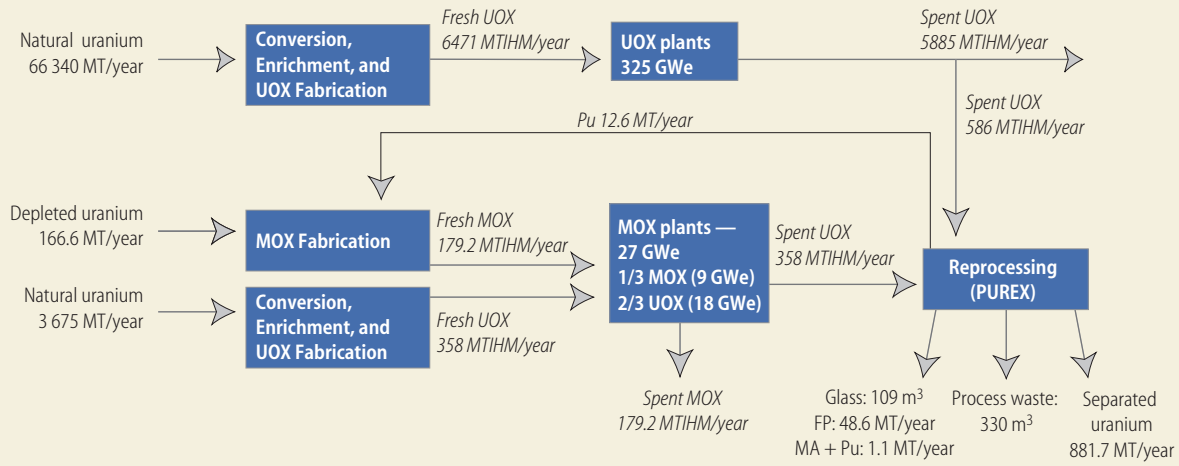
Figure A-4.6 Once-through Cycle with Some Plutonium Recycling — 352 GWe Fleet



The mass flows in Figure A-4.6 are calculated using equations (3) to (5), recalling that spent UOX fuel is composed of 93.4% uranium, 5.15% FP, 1.33% Pu, and 0.12% MA and that fresh MOX has a plutonium content of 7%. The spent fuel material flows for this fuel cycle are summarized in Table A-4.4.

It is interesting to consider how plants and their fuel cycles are deployed to generate this 9 GWe from MOX fuel. In the current world situation, plants run either only on UOX fuel (we refer to them as UOX plants) or on a mix of UOX and MOX fuel (we refer to them as MOX plants). The U.S. and Asia rely on UOX plants, whereas Europe and Russia reliesy on a mix of both types. Further, the MOX plants currently have ⅓ of their core loaded with MOX and ⅔ loaded with UOX. Hence the total capacity of these plants is 27 GWe (although of course only 9 GWe is generated from MOX fuel). Figure A-4.7 shows the current fuel cycle with UOX and MOX plants represented separately.

Figure A-4.7 Once-through Cycle with some Plutonium Recycling — 352 GWe Fleet



The total UOX consumption (6,829 MTIHM/yr) is split between the UOX and MOX plants according to UOX-based capacity. Hence, 325/343 of this amount, or 6,471 MTIHM/yr, is required for the UOX plants. The UOX consumption in the MOX plants is therefore 358 MTIHM/yr. A total of 944 MTIHM/yr of spent UOX needs to be reprocessed to produce enough plutonium for MOX fabrication. Therefore, if all the spent UOX from the MOX plants were to be reprocessed (358 MTIHM/yr), 586 MTIHM/yr of spent fuel from the UOX plants must also be reprocessed.

The uranium requirement and waste production can be tabulated according to plant type as follows:

Table A-4.5 Uranium Consumption and Waste Production by Plant Type — Existing 352 GWe Fleet

	U_{nat} feed MT/yr	HLW discharged MT/yr	Pu discharged MT/yr
UOX Plants 325 GWe	66 340	Spent UOX : 6471	Discharged in spent UOX: 86.1
MOX Plants 27 GWe	3 675	Spent MOX: 179.2 Glass: 109 m^3 (48.6 FP, 1.1 MA+Pu) Process Waste : 330 m^3	Consumed for MOX fabrication: 12.6 Discharged in spent MOX: 8.8

Note that all the wastes from reprocessing are assigned to the MOX plants, even though a large fraction of the reprocessed fuel comes from the UOX plants. This is because the reprocessing operations would not be required if it were not for the MOX plants. Note also that the amount of spent fuel from the UOX plants shown in the table (6,471 MTIHM/yr) is the total amount discharged (i.e. including the spent fuel that will be reprocessed). Therefore, the amount of spent fuel from the UOX plants that goes to reprocessing (586 MTIHM/yr) must be subtracted from this number to get the amount of spent UOX that goes to the repository.

Finally, the figures in Table A-4.5 can be expressed on a per GWe basis by dividing the numbers in the first and second rows by 325 GWe and 27 GWe, respectively. This gives an idea of the uranium consumption and waste production for a 1 GWe plant.

Table A-4.6 Uranium Consumption and Waste Production by Plant Type — per GWe

	U_{nat} feed MT/yr	HLW discharged MT/yr	Pu discharged MT/yr
UOX Plants Per GWe	204	Spent UOX : 19.9	Discharged in spent UOX: 265
MOX Plants Per GWe	136 (=2/3·204)	Spent MOX: 6.6 (=1/3·19.9) Glass: 4.0 m^3 (1.8 FP, 0.04 MA+Pu) Process Waste : 12.2 m^3	Consumed for MOX fabrication: 467 Discharged in spent MOX: 327

NOTES

1. Mass of nuclear fuel refers to the mass of the heavy metals present in the fuel. For example, for a fuel consisting of uranium oxide (UO_2) with zirconium cladding, the mass of a given amount of fuel would refer only to the mass of uranium present in the fuel. The mass of the oxygen and of the cladding would not be included.
2. GWd/MTIHM: gigawatt days per metric ton of initial heavy metal; we always refer to the initial mass of heavy metal in the fuel because the heavy metal atoms are fissioned as the fuel is irradiated, and therefore their mass decreases with time.
3. This is the total amount of fuel loaded in the reactors per year. The actual cycle time for US PWRs is now typically 18 months.
4. Xu, Zhiwen, "Design Strategies for Optimizing High Burnup Fuel in Pressurized Water Reactors", MIT doctoral thesis, January 2003. See equation 2.8
5. Xu, Zhiwen, "Design Strategies for Optimizing High Burnup Fuel in Pressurized Water Reactors", MIT Department of Nuclear Engineering doctoral thesis, January 2003. See detailed MCODE results.
6. We of course are neglecting the reduction in the fuel mass discharged due to conversion of mass to energy in the fission process, e.g. a loss of 1.4 MT in this case.
7. Xu, Zhiwen, "Design Strategies for Optimizing High Burnup Fuel in Pressurized Water Reactors", MIT Department of Nuclear Engineering doctoral thesis, January 2003. See detailed MCODE results.
8. The fuel cycle we are considering in this section is not self-generated recycle (SGR). In SGR, all the spent fuel, including the spent MOX, would be reprocessed for plutonium extraction. As of 2002, in all countries using plutonium recycle, the spent MOX fuel is not again reprocessed, in part due to the degraded isotopic composition of plutonium in spent MOX. However, further recycling of plutonium may be carried out in the future.
9. Currently, MOX fuel in LWR is generally irradiated to a burnup lower than 50 GWd/MTIHM, but parity with UOX is anticipated as experience is gained.
10. We assume Pu is mixed with depleted U-238; admixing with natural uranium or spent fuel uranium would provide some U-235 and reduce the Pu requirement slightly.
11. COGEMA, B.BARRE, State of the Art in Nuclear Fuel Reprocessing, SAFEWASTE 2000, October 2000. Values are for the year 2000 (taken from table 3).
12. OECD/NEA, "Plutonium Fuel — An Assessment", 1989. See table 12 B.
13. The question of whether thermal or fast reactors are preferable for burning actinides is still being debated. It should be noted, however, that full actinide recycle in a thermal spectrum is theoretically possible.
14. These values (25% for MA+Pu content and 20% for makeup fraction) are representative of FR burners. For example, see table V (LWR Spent-Fuel Feed) in R.N. Hill, D.C. Wade, J.R. Liaw, and E.K. Fujita, "Physics Studies of Weapons Plutonium Disposition in the the Integral Fast Reactor Closed Fuel Cycle", Nuclear Science and Engineering, 121, 17–31 (1995).
15. World Nuclear Association, "Mixed Oxide Fuel", February 2002, (http://www.world-nuclear.org/info/inf29.htm). This article reports that MOX production reached 190 MTIHM in 2000.

Appendix Chapter 5 — Economics

Appendix 5.A — Calculation of the Levelized Cost of Electricity

The real levelized cost of electricity production is used to assess the economic competitiveness of alternative generating technologies.[1] The real levelized cost of a project is equivalent to the constant dollar ("real") price of electricity that would be necessary over the life of the plant to cover all operating expenses, interest and principal repayment obligations on project debt, taxes and provide an acceptable return to equity investors over the economic life of the project. The real levelized cost of alternative generating technologies with similar operating characteristics (e.g. capacity factors) is a metric used to identify the alternative that is most economical.

A project's real levelized cost can be computed using discounted cash flow analysis, the method employed in the model described below. Revenues and expenses are projected over the life of the project and discounted at rates sufficient to satisfy interest and principal repayment obligations to debt investors and the minimum hurdle rate (cost of equity capital) required by equity investors.

An alternate method, based on traditional regulated utility revenue requirement calculations, is often used to calculate levelized costs for generating technologies. This approach has two problems: First, it fails to account properly for inflation and yields levelized nominal cost numbers that cannot easily be compared across technologies with different capital intensities. Second, it imposes a particular capital cost repayment profile that, while consistent with the way regulated investments were treated, is not consistent with the merchant generation investment environment that now characterizes the U.S., Western Europe and a growing number of other countries.

The spreadsheet model used to calculate real levelized costs for nuclear, coal, and natural gas-fired power plants is described in the following sections. Table A-5.A.1 defines variables used throughout the appendix. The cash flows are first generated in nominal dollars in order to calculate income taxes properly and then adjusted to constant real prices using the assumed general inflation rate (3% in the examples below).

Table A-5.A.1 Model Variables

C_O	Overnight cost ($/kWe)	HR	Heat rate (BTU/kWh)
T_C	Construction time (years)	C_{Fuel}	Unit cost of fuel ($/mmBTU)
C_{TOT}	Total construction cost ($/kWe)	C_{Waste}	Nuclear waste fee (mills/kWh)
D/V	Debt fraction of initial investment	C_{OMf}	Fixed O&M ($/kWe/yr)
E/V	Equity fraction of initial investment	C_{OMv}	Variable O&M (mills/kWh)
r_D	Nominal cost of debt	C_{Incr}	Incremental capital costs ($/kWe/yr)
r_E	Nominal cost of equity	C_{Decom}	Decommissioning cost ($million)
N	Plant life (years)	τ_{Carbon}	Carbon emissions tax ($/tonne-C)
L	Plant net capacity (MWe)	I_{Carbon}	Carbon intensity of fuel (kg-C/mmBTU)
Φ	Capacity factor	R_n	Revenues in period n
p_n	Nominal price of electricity in period n	I_n	Interest payment in period n
τ	Marginal composite corporate income tax rate	$C_{n,Op}$	Total operating expenses in period n

CAPITAL INVESTMENT

Power plants require significant capital investments before electricity production can begin. The cash flow model allocates the overnight cost of the plant, C_O, specified in $/kWe of the year production begins (2002), over the construction period, T_C, allowing for an additional period after construction for final licensing and testing. By convention, all investment expenditures are counted at the beginning of the year in which they occur, and all revenues and operating expenses are assumed to occur at the end of the year. Numerous construction expenditure profiles are available in the model, including a uniform profile and one that peaks at mid-construction, characterized by a sinusoidal function. The annual capital expenditures for the nuclear plant costing $2,000/kWe in base year prices (2002) and a combined-cycle gas turbine (CCGT) plant costing $500/kWe are presented in Table A-5.A.2.

Table A-5.A.2 Representative Construction Outlays (nominal dollars)

YEAR	-5 $/kWe	-4 $/kWe	-3 $/kWe	-2 $/kWe	-1 $/kWe	TOTAL OUTLAY (mixed $/kWe)	OVERNIGHT COST (2002 $/kWe)	TOTAL COST (2002 $/kWe)
Nuclear	165	444	566	471	185	1,831	2,000	2,557
CCGT	0	0	0	236	243	478	500	549

Nuclear: 5 year construction period, sinusoidal profile, i = 3%
CCGT: 2 year construction period, uniform profile, i = 3%

Note that the overnight cost is specified in constant dollars of the year production begins (year 2002 $), and so the capital expenditure in each year is deflated to current-year (nominal) dollars. This explains why the total outlay in nominal dollars is numerically smaller than the overnight cost.

$$X_n = F_n C_O (1 + i)^n$$

where X_n is the outlay in year n (n = 0 in 2002, n < 0 during construction), F_n is the fraction of the overnight cost allocated to year n, and i is the rate of general inflation. In order to finance construction, the project takes on debt obligations and attracts equity investors with certain requirements. Debt and equity each have an expected minimum rate of return and debt has a specified repayment period. The interest on debt and imputed interest on equity are added to the overnight cost to find the total cost of construction.

$$C_{TOT} = \sum_{n<0} X_j (1 + r_{eff})^{-n} \qquad r_{eff} = \frac{D}{V} r_D + \frac{E}{V} r_E$$

employing an effective interest rate r(eff). The total cost of construction does not represent true cash flows but is a measure of construction cost taking into account the time value of money. The total costs in the Table A-5.A.2 correspond to 50/50 debt/equity, r_D = 8%, r_E = 15% for the nuclear case (r_{eff} = 11.5%) and 60/40 debt/equity, r_D = 8%, r_E = 12% for the CCGT case (r_{eff} = 9.6%).

ASSET DEPRECIATION

Once put in service, the power plant depreciates according to a specified schedule. The treatment of depreciation is important in the calculation of the annual tax liability, since asset depreciation is a tax-deductible expense. In the base case model we use accelerated depreciation, based on Modified Accelerated Cost Recovery System (MACRS) guidelines, assuming a 15 year asset life. The total capital expenditure (excluding interest and equity appreciation) during construction is used as the depreciable asset base. The depreciable asset base is based on nominal rather than real expenditures. So, for example, if the base year overnight construction cost is $2,000/kW and inflation is 3% per year, the depreciable asset base will be less than the overnight cost in base year prices, to reflect the fact that actual expenditures will be made during earlier years with lower nominal prices.

REVENUES

The sole source of revenue for the power plant is the sale of electricity. The price of electricity in 2002 is determined in an iterative process such that required returns to investors are met. This price, *p*, is equivalent to the levelized cost of the plant. In order to represent a real levelized cost, the price of electricity escalates at the rate of general inflation.

Annual revenue is the product of the quantity of electricity produced and its price. The plant's net capacity and capacity factor determine the annual electric generation.

$$Q = \frac{L}{10^3} \cdot \Phi \cdot 8{,}760 \ \frac{hours}{year} \quad (GWh/year)$$

$$R_n = Qp_n \qquad p_n = p_n\,(1 + i)^n$$

where the rated capacity, *L*, is specified in MWe. A 1,000 MWe plant with an annual capacity factor of 85% produces 7,446 GWh of electricity per year.

OPERATING EXPENSES

Operating expenses are incurred throughout the operational life of the plant and include fuel, operating and maintenance costs, and decommissioning funds. Carbon emissions taxes and incremental capital expenditures similarly are treated as operating expenses. (Treating incremental capital expenditures as operating expenses instead of additions to the depreciable asset base is a simplification to avoid having to specify additional depreciation schedules. Because expenditures are assumed to occur every year, the error introduced is small.) Non-fuel operating expenses can be broken down into fixed and variable cost components and are generally assumed to increase at the rate of inflation, though in some cases a real escalation rate is included. The assumed escalation of real fuel prices is a variable input to the model. This is particularly useful in the CCGT case where increases in natural gas prices have a large impact on the levelized cost of generation. Table A-5.A.3 lists the plant's operating expenses along with their arithmetic expressions.

Table A-5.A.3 Operating Expenses

EXPENSE	VALUE IN YEAR n ($million)	NOTATION
Fuel	$\frac{C_{Fuel} \cdot HR \cdot Q \cdot (1+e_f)^n}{10^6}$	$C_{n,\,fuel}$
Waste fund[a]	$\frac{C_{Waste} \cdot Q \cdot (1+i)^n}{10^3}$	$C_{n,\,waste}$
Fixed O&M	$C_{OMf} \cdot \frac{L}{10^6} \cdot (1+e_{om})^n$	$C_{n,\,omf}$
Variable O&M	$\frac{C_{OMv} \cdot Q \cdot (1+e_{om})^n}{10^6}$	$C_{n,\,omv}$
Decommissioning[a, b]	$C_{Decom} \cdot (1+i)^N \cdot SFF_0$	$C_{n,\,decom}$
Incremental capital	$C_{Incr} \frac{L}{10^3} \cdot (1+i)^n$	$C_{n,\,incr}$
Carbon emissions tax	$\frac{\tau_{Carbon}\, I_{Carbon} \cdot HR \cdot Q \cdot (1+i)^n}{10^9}$	$C_{n,\,carbon}$

a. Specific to nuclear plants
b. SFF_0 is the sinking fund factor for N years at the risk free rate.

Total operating expenses are:

$$C_{n,Op} + C_{n,fuel} + C_{n,waste} + C_{n,omf} + C_{n,omv} + C_{n,decom} \quad \$million$$

Total operating expenses, $C_{n,\,op}$, incremental capital expenditures, and carbon emissions taxes are subtracted from revenues before computing the annual tax liability. Two other adjustments are made to taxable income. Asset depreciation, D_n, and interest payments I_n to creditors are both treated as tax-deductible expenses and thus reduce taxable income. The tax liability, T_n, is simply the product of taxable income and the composite marginal corporate income tax rate,, assumed to be 38% in the base cases.[2]

$$T_n = \tau\left[R_n - C_{n,Op} - C_{n,incr} - C_{n,carbon} - D_n - I_n\right]$$

A production tax credit is available in the model to simulate, along with the carbon emissions tax, public policies to curb CO_2 emissions.

INVESTOR RETURNS

The model solves for a constant real price of electricity sufficient to provide adequate returns to both debt and equity investors.[3] Interest on debt accrues during construction and is repaid with the principal in equal annual payments over the specified term of the debt. Equity holders invest funds during construction and receive profits net of taxes and debt obligations during plant operation. Net profits over the life of the project are such that the internal rate of return (IRR) of the equity holders' cash flows equals the required nominal return; 15% in the nuclear base case and 12% in the fossil cases. The model includes a constraint that the debt payment obligations specified are made in full each year (the project is not allowed to default on debt obligations). For example, assume that the

Table A-5.A.4 Base Case Input Parameters

YEAR	NUCLEAR	COAL	NGCC
Inflation rate	3%	3%	3%
Interest rate	8%	8%	8%
Expected return to equity investor	15%	12%	12%
Debt fraction	50%	60%	60%
Tax rate	38%	38%	38%
Debt term	10 years	10 years	10 years
Net capacity	1,000 MWe	1,000 MWe	1,000 Mwe
Capacity factor	85%	85%	85%
Plant life	40 years	40 years	40 years
Heat rate	10,400	9,300	7,200
Overnight cost	$2,000/kWe	$1,300/kWe	$500/kWe
Construction period	5 years	4 years	2 years
Post-construction period	—	—	—
Depreciation schedule	Accelerated, 15 years	Accelerated, 15 years	Accelerated, 15 years
Decommissioning cost	$350 million	—	—
Incremental capital costs	$20/kWe/yr	$15/kWe/yr	$6/kWe/yr
Fuel costs	$0.47/mmBTU	$1.20/mmBTU	$3.50/mmBTU
Real fuel escalation	0.5%	0.5%	1.5%
Nuclear waste fee	1 mill/kWh	—	—
Fixed O&M	$63/kWe/yr	$23/kWe/yr	$16/kWe/yr
Variable O&M	0.47 mills/kWh	3.38 mills/kWh	0.52 mills/kWh
O&M real escalation rate	1.0%	1.0%	1.0%
Carbon intensity	—	25.8 kg-C/mmBTU	14.5 kg-C/mmBTU
Carbon tax	—	—	—

Note: Compiled from public information, including reports from the Energy Information Administration.

model solves for a constant real price of electricity that satisfies the return required by equity holders. In most cases, the solution would be deemed the levelized cost of electricity. However, if the resultant operating income (revenues less operating expenses) is insufficient to cover the entire debt payment in any year, the electricity price is raised until all debt payments can be made. If the debt service constraint is binding, the realized return on equity will then exceed the minimum required return specified.

Since the purpose of the levelized cost calculation is to compare alternative generating technologies and assess their potential contribution to future energy supply, the technologies compared must generate electricity over equivalent time periods. In order to maintain the level basis for comparison, plants are not allowed to shut down prematurely when operating expenses exceed revenues, as in the case of escalating natural gas prices. The result in these situations is a cash flow stream for the project that does not reflect expected business decisions. Nonetheless, for comparison of future electricity supply options, it is more appropriate to include the effect of high natural gas prices in the out years than to exclude it by running the plant shorter than its projected life. In this case, the plant must still meet all debt obligations and a minimum return on investment to equity investors.

Table A-5.A.5 Nuclear Base Case Cash Flows (nominal dollars)

YEAR	1	2	3	5	10	20	30	40
Electricity price (cents/kWh)	6.91	7.12	7.33	7.78	9.02	12.12	16.28	21.88
Revenue ($million)	515	530	546	579	672	903	1,213	1,631
Operating expenses ($million)								
- Fuel cost	38	39	40	43	51	73	103	145
- Waste fee	8	8	8	9	10	13	18	24
- Fixed O&M	66	68	71	77	94	139	206	306
- Variable O&M	4	4	4	4	5	8	11	17
- Decommissioning	9	9	9	9	9	9	9	9
- Incremental cap.	21	21	22	23	27	36	49	65
Operating income	370	381	391	414	475	625	817	1,063
Depreciation (tax)	92	174	157	127	108	0	0	0
Interest payments	92	86	79	64	13	0	0	0
Debt principal repayment	80	86	93	108	159	0	0	0
Taxable income	186	121	156	223	354	625	817	1,063
Income tax payment	71	46	59	85	135	237	310	404
Net profit	127	163	160	157	169	387	506	659

Table A-5.A.6 CCGT Base Case Cash Flows (nominal dollars)

YEAR	1	2	3	5	10	20	30	40
Elec. price (cents/kWh)	4.25	4.38	4.51	4.78	5.54	7.45	10.01	13.45
Revenue ($million)	317	326	336	356	413	555	746	1,003
Operating expenses ($million)								
- Fuel cost	196	205	215	234	293	457	712	1,111
- Waste fee	—	—	—	—	—	—	—	—
- Fixed O&M	16	17	18	19	23	34	51	76
- Variable O&M	4	4	4	5	6	9	13	19
- Decommissioning	—	—	—	—	—	—	—	—
- Incremental cap.	6	6	7	7	8	11	15	20
Operating income	94	93	93	91	83	45	-45[a]	-223[a]
Depreciation (tax)	24	45	41	33	28	0	0	0
Interest payments	26	24	22	18	4	0	0	0
Debt principal repayment	22	24	26	30	44	0	0	0
Taxable income	44	24	30	40	51	45	0	0
Income tax payment	17	9	11	15	20	17	0	0
Net profit	29	36	33	28	16	28	-45[a]	-223[a]

a. For the purposes of comparing energy supply options, plant operation is not terminated when operating costs exceed revenues.

Appendix 5.B – Nuclear Power Plant Construction Costs

This section contains a summary of available information on nuclear power plant construction costs. The information includes construction cost estimates by government and industry sources, actual cost data from recent experience abroad, and some recent indications of the current market valuation of nuclear plants. The data are somewhat sparse but are helpful in determining what nuclear plants cost to build now, what they are projected to cost in the future, and what cost will make nuclear viable in a competitive electricity generation market. Cost figures are presented in a variety of formats (overnight costs, total construction costs, levelized costs) in the sources cited and are generally presented in the format given by the source.

CONSTRUCTION COST FORECASTS

EIA — Annual Energy Outlook 2003[4]

Cost and performance characteristics for nuclear plants in the Annual Energy Outlook are based on current estimates by government and industry analysis. Two cost cases are analyzed, the reference case and an advanced nuclear cost case, where overnight costs are reduced to be consistent with the goals endorsed by DOE's Office of Nuclear Energy.

In the reference case, overnight construction costs are predicted to be $2,044/kWe in 2010 and $1,906/kWe in 2025, specified in 2001 dollars. Construction costs are assumed to decline over time based on a representative learning curve. The overnight costs reported include a 10% project contingency factor and a 10% technological optimism factor, which is applied to the first four units to reflect the tendency to underestimate costs for a first-of-a-kind unit. The report indicates a five year lead time for construction. Predicted overnight costs for the advanced nuclear case are $1,535/kWe in 2010, dropping to $1,228/kWe by 2025, also reported in 2001 dollars. The advanced case does not include a technological optimism factor.

DOE-NE — 2010 Roadmap Study[5]

The economic analysis in the 2010 Roadmap study takes a parametric approach to nuclear capital costs, but states that engineering, procurement, and construction costs vary between $800 and $1,400 / kWe. Adding 20 percent for owner's costs and project contingency, the approximate range for overnight costs is $1,000–$1,600 / kWe in 2000 dollars. Construction is assumed to occur over 42 months, with six months between construction and commercial operation.

In addition to the parametric analysis, the 2010 Roadmap study evaluated eight advanced nuclear plant designs as candidates for near term deployment. The cost estimates for the new designs were provided by vendors with various levels of confidence and detail. A brief summary of relevant information for the eight designs is tabulated in Table A-5.B.1.

Table A-5.B.1

DESIGN	OVERNIGHT COST	OTHER RELEVANT INFORMATION
GE ABWR	$1,400–$1,600/kWe	48 month construction (Japan) Real construction experience
GE ESBWR	Lower than ABWR	Availability goal of 92% Simplified design to reduce cost
Framatome SWR-1000	$1,150–$1,270/kWe FOAK[a] 15-20% reduction for NOAK[b]	Cost excludes cooling tower 48 month construction, 91% avail.
Westinghouse AP600	$2,175/kWe FOAK $1,657/kWe NOAK	5 years from order placement to commercial operation
Westinghouse AP1000	$1,365/kWe FOAK $1,040/kWe NOAK	Cost assumes twin units, includes owner's costs and contingency
Westinghouse IRIS	$687–$1,224/kWe FOAK $746–$1,343/kWe NOAK	100-300 MWe plant availability 85-99%
Pebble Bed Modular Reactor	$1,250/kWe NOAK	110 MW units
General Atomics GT-MHR	$1,122/kWe 25% reduction for NOAK	Cost includes contingency and owner's costs

a. FOAK - First-of-a-kind
b. NOAK - Nth-of-a-kind

NEA/IEA — Projected Costs of Generating Electricity[6]

The estimates of construction and operating costs for power plants contained within the NEA/IEA report are compiled from OECD countries and are based on a combination of engineering estimates, paper analyses, and industry experience. The authors decompose the cost submissions and recompile them using standard assumptions and two real discount rates, 5% and 10%. Not every country includes the same cost items in its totals, making comparisons across countries difficult, and all costs are converted to US dollars using a spot exchange rate. Cost estimates are listed for the United States and for the entire OECD range. (See Table A-5.B.2.) Costs for closed fuel cycles are not included in the range of estimates. The costs reported in the NEA/IEA report are identical to those in the NEA report *Nuclear Power in the OECD*, published in 2001.

Table A-5.B.2

PARAMETER	UNITED STATES	OECD
Base year for costs	1996	1996
Capacity factor	75%	75%
Overnight cost[a]	$1,585 / kWe	$1,585 – $2,369 / kWe
Overnight cost (2002 dollars)	$1,831 / kWe	$1,831 – $2,737 / kWe
Total construction cost (2002 dollars)	$2,139 / kWe	$2,139 – $3,101 / kWe
Construction period	4 years	4 – 9 years

a. Includes owner's costs and a contingency factor.

Finland

The Finnish parliament in May 2002 approved construction of a new nuclear power plant by the electric utility Teollisuuden Voima Oy (TVO), based in part on the economic analysis of generation options by Risto Tarjanne of the Lappeenranta University of Technology, Finland.[7] A fifth nuclear unit is seen as the superior generation choice to limit imports of Russian natural gas, allow Finland to meet Kyoto Protocol commitments, and guarantee cheap electric power to the Finnish industry. It is important to note that TVO is a non-profit company that provides electricity to its industrial shareholders at cost, effectively providing a long-term power purchase agreement not likely available to plant owners in a competitive environment.

The economic analysis supporting the decision to build a fifth nuclear reactor compares the economics of a new nuclear plant to a pulverized coal plant, a combined-cycle gas turbine plant, and a peat-fired plant. Low nuclear construction and operating costs, high plant performance, and a 5% real discount rate contributed to nuclear power being the superior choice. The study assumed an initial nuclear investment cost of 1,749 euros/kWe, including interest during construction, and a five year construction period. Using an exchange rate of 1.0 euro / U.S. dollar and inflating to 2002 dollars, the total construction cost used in the analysis is roughly $1,830/kWe, implying an overnight cost of about $1,600/kWe. [8]

UK Energy Review

The UK Performance and Innovation Unit's Energy Review addresses the construction cost of nuclear plants by evaluating submitted estimates from British Energy and BNFL.[9] The report first notes that the construction cost for Sizewell B, completed in 1994, was £3,000/kWe in 2000 money ($US 5,000/kWe at current exchange rates), including first- of-a-kind (FOAK) costs (£2,250/kW excluding FOAK costs or $US3,700/kWe at current exchange rates), for a total cost of generation around 6p/kWh or 9.6 ¢US/kWh at current exchange rates (excluding FOAK costs). Industry (British Energy and BNFL) now predicts that the Westinghouse AP1000 could generate electricity at 2.2-3.0 p/kWh or 3.3 to 4.8 ¢US/kWh ignoring FOAK costs. The construction costs assumed in these estimates were considered commercially confidential and were not included in the report. The PIU report notes that the construction costs provided by the industry were better than the best recent estimates from OECD countries,[10] and that operating availability estimates were questionably high. The PIU analysis suggests a range of 3p/kWh to 4p/kWh (or 4.8 to 6.4 ¢US/kWh for future nuclear cost of generation, consistent with total construction costs of roughly £1,400–1,700/kWe in 2000 money, or about $2,300–$2,900/kWe at current exchange rates.

RECENT MARKET VALUATION OF NUCLEAR PLANTS

Sale of Seabrook Nuclear Station – 2002

In 2002, 88.2% ownership of Seabrook Nuclear Station (1,024 MWe) was transferred to Florida Power & Light through a competitive auction process. The sale price was $749.1 million for the operating plant ($730/kWe), plus $25.6 million for components from an uncompleted unit and $61.9 million for nuclear fuel. The deal included no power purchase agreement. FP&L will receive the current balance of the decommissioning trust fund, esti-

mated at $232.7 million. The NRC operating license for Seabrook is set to expire in October 2026, allowing for more than 20 years of service with the possibility of a 20-year license extension. This implies that the market value of a fully licensed and operating nuclear power plant with a good performance record is less than half of the most optimistic cost estimates for building a new nuclear power plant and only about 30% more than the cost of CCGTs being built in New England during this time period. This in turn implies that merchant investors in nuclear power plants believe either (a) that future operating costs are much higher than is assumed in engineering cost studies or (b) that the commercial risks associated with even a licensed and operating plant are so high that a very high cost of capital is imputed to future cash flows, or a combination of both. Comparable analyses of other recent nuclear power plant sales come to very similar conclusions. The market value of nuclear plants is far below their replacement cost, a result that is inconsistent with merchant investment in new nuclear plants.

Browns Ferry Unit 1 Restart – TVA

In May 2002, the TVA board of directors approved a plan to restart Browns Ferry Nuclear Unit 1, idle since 1985. The decision was based on recent improvements in nuclear operating performance and costs at TVA plants and a reduced estimate of the cost to restart the unit. The analysis tiered from Energy Vision 2020, TVA's resource integration plan, which in 1995 recommended deferring a decision on Browns Ferry Unit 1 until more data could be collected on operating performance and costs. Browns Ferry Unit 1 has an active NRC operating license that will expire in 2013, but TVA plans to apply for a 20-year license extension if the unit is recovered.

The new analysis estimates that the restart of BFN Unit 1 will cost between $1.56 and $1.72 billion in 2002 dollars and will take 5 years to complete.[11] This corresponds to an overnight capital cost of about $1,280/kWe. The 2002 TVA report indicates that the levelized cost of the project will be less than that of an alternative natural gas-fired combined cycle plant, based on a financial research report quoting the levelized cost of a combined cycle plant as $51.00/MWh.[12]

The crucial factors that makes nuclear competitive in this case are (a) that the expenditures are required to upgrade an existing plant that already has significant capital facilities in place and (b) TVA's assumed low cost of capital. The restart will be financed entirely with debt, TVA is able to borrow money very cheaply, and the company doesn't pay federal income taxes or local property and sales taxes.[13] Coupling their low cost of capital with recent experience of high performance and low operating costs, nuclear appears to be the low-cost option.

RECENT NUCLEAR CONSTRUCTION ABROAD

A few countries are actively building nuclear plants using new nuclear designs and advanced construction techniques to which estimated cost reductions are attributed. Unfortunately, actual cost data for these projects is difficult to acquire. Project costs for newly operating plants in Japan and South Korea are discussed in this section and should provide some evidence as to whether projected cost reductions are being realized.

It is important to note the difficulty in comparing costs of construction projects across countries. Differences in the relative costs of local resources and construction technologies, government regulations, labor productivity, and the fact that a large fraction of nuclear plant costs depend on local labor and construction resources and are not tradeable across countries are such that the costs of construction projects in different countries must be compared with great care. Currency exchange rates may not accurately reflect the relative costs of goods and services that are not traded internationally, and are susceptible to rapid fluctuations that obscure real costs.[14] An alternative approach to international comparison is the use of purchasing power parities (PPP) that adjust for price level differences between countries and thus attempt to equalize the purchasing power of different currencies. The Japanese and Korean construction cost data below are interpreted using PPPs compiled by the OECD and Eurostat for gross fixed capital formation, including construction, machinery, and equipment.[15] The PPPs are assembled every three years based on prices of representative goods, services, and projects, provided by participating countries. The use of PPPs for international comparisons of construction projects does not resolve all regional differences, but is generally expected to be more consistent and perhaps more accurate than using current exchange rates alone.

Japanese Nuclear Plant Construction

Japan is one of the few countries actively building nuclear plants at this time.

Construction costs for recent nuclear plants by Tohoku and Kyusyu utilities were compiled for us by a Japanese analyst from public information and are tabulated below.

Table A-5.B.3

OWNER	NAME OF PLANT	CAPACITY	COMMERCIAL OPERATION DATE	TOTAL PROJECT COST (109 YEN)	U.S. EQUIVALENT[a]
Tohoku Electric	Onagawa 3 (BWR)	825 MWe	January 2002	314	$2,409/kWe
Kyusyu Electric	Genkai 3 (PWR)	1,180 MWe	March 1994	399	$2,818/kWe
	Genkai 4 (PWR)	1,180 MWe	July 1997	324	$2,288/kWe

Note: Compiled from public information by the MIT Center for Energy and Environmental Policy Research.
a: Using PPP of 158 yen / U.S. dollar.

Recent data for BWR plants built for Tokyo Electric Power Company (TEPCO) at its Kashiwazaki-Kariwa Nuclear Power Station is given next. Units 3 and 4, both 1,000 MWe BWR designs, were completed in 1993 and 1994 respectively. More interesting for our purposes, units 6 and 7, GE 1,356 MWe ABWR designs, were completed in 1996 and 1997. Approximate costs of constructing the reactors come from multiple sources, all of which give values within a modest range of each other: TEPCO annual reports, publicly available data on reactor costs from TEPCO, and direct communications with TEPCO.

Data contained in TEPCO's Annual Reports were analyzed as follows. Incremental capital costs were estimated based on the average increase in nuclear asset values in years in which reactors were not added to the asset base. This quick approach resulted in incremental capital costs on the order of current data in the United States. Subtracting incremental capital costs from the annual increase in nuclear assets produced an estimate of the construc-

tion cost for each plant in the year it began construction. Several factors may skew the construction cost estimate, but they are not seen as significant within the scope of the study. Estimates of interest during construction in Japan during this time period are low, and so whether or not it is capitalized and included in the asset balance will have only a minor effect. Inflation was ignored, as it has been low in Japan over this period as well. The annual reports yielded construction costs of 320-340 billion yen each for units 3 and 4, and 400-420 billion yen each for units 6 and 7. Using a PPP of 158 yen / U.S. dollar,[16] construction costs were equivalent to $US1,800–$US2,000/kWe for the ABWR units.

TEPCO presents rough figures for construction costs of each plant on its website. The approximate costs presented are 325 billion yen for Kashiwazaki-Kariwa (KK) 3, 334 billion yen for KK4, 418 billion yen for KK6, and 367 billion yen for KK7. These values are close to those derived from the annual reports, with the exception of KK7 at $1,710/kWe, using the same PPP as above. Information compiled for us by a Japanese analyst from public information confirms these estimates: 433 billion yen for KK6 ($2,020/kWe) and 384 billion yen for KK7 ($1,790/kWe).

Korean Nuclear Plant Construction

South Korea possesses 18 operating nuclear reactors with two more planned to connect to the grid in 2004/2005. The latest reactors, Yonggwang 5 & 6, are 1,000 MWe PWRs, using the Korean Standard Nuclear Power Plant (KSNP) design, based on the Combustion Engineering System 80. The Yonggwang plant is owned and operated by Korea Hydro & Nuclear Power, a subsidiary of Korea Electric Power (KEPCO). KEPCO is a state-run monopoly that is in the process of privatizing its power generation business. The construction was financed through debt.

Construction of the two reactors cost an estimated 3.91 trillion Korean won. The overnight cost is estimated at 3.11 trillion won at 2002 price levels.[17] Using a PPP of 867 won / U.S. dollar,[18] the unit overnight cost is equivalent to about $1,800 / kWe and the total construction cost is equivalent to about $2,300 / kWe. Care should be taken when attempting to apply these cost figures to construction in other parts of the world, because the challenges of international comparisons discussed above become more significant when developing countries are being considered.

Appendix 5.C — Nuclear Power Plant Operating Costs

Nuclear power plant operating costs are generally assumed to be more predictable than those of fossil plants, due to relatively stable fuel prices. This appendix presents several estimates of historical operating costs and projections of future costs for nuclear plants. The focus is on non-fuel operating and maintenance (O&M) costs. Some sources record non-fuel operating costs while others include the cost of fuel. For purposes of comparison, nuclear fuel costs can be assumed to be in the range of 5-6 mills/kWh.

Recent performance of nuclear plants indicates that *non-fuel* O&M costs averaged between 12 and 18 mills/kWh. Costs for the best plants have been below 8 mills/kWh while costs for the worst plants have exceeded 25 mills/kWh. Projections of future costs tend toward the low end of this range and below, with some projections as low as 5 mills/kWh for non-fuel O&M.

EIA — ELECTRIC POWER ANNUAL 2001

The Energy Information Administration (EIA) reports average operating costs for major U.S. investor-owned electric utilities in its *Electric Power Annual.*[19] The current Annual reports average operating costs for the period 1990–2001, based on utility filings of FERC Form 1, *Annual Report of Major Electric Utilities, Licensees, and Others.* Non-fuel O&M costs for nuclear plants averaged 18 mills/kWh, adjusted to 2002 dollars, for the period 1990–2001, and have declined in each of the past five years. For the five year period ending in 2001, non-fuel O&M costs averaged 16 mills/kWh and the average has dropped to 14 mills/kWh since 2000. For comparison, fossil steam plant O&M costs averaged around 6 mills/kWh for the 12 year period, excluding fuel costs.

Table A-5.C.1 Nuclear Power Plant Operating Costs, 1990–2001

(mills/kWh)	1999	2000	2001	1990–2001 AVERAGE	1997–2001 AVERAGE
Non-fuel O&M	14.1	13.3	13.3	15.3	14.9
- 2002 dollars	**15.2**	**14.0**	**13.6**	**18.1**	**16.1**
Fuel costs	5.2	5.0	4.7	5.7	5.1
Total operating costs	19.2	18.3	18.0	21.0	20.0

Source: EIA, Electric Power Annual 2001

EIA — NUCLEAR POWER PLANT OPERATING COSTS

The EIA report, *An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update,*[20] provides more detailed information on nuclear plant operating costs, though the analysis is limited to pre-1994 data. As in the *Electric Power Annual,* utility data are collected from FERC Form 1 filings and historical trends in operating costs are analyzed. Between 1974 and 1984, real non-fuel O&M costs escalated at an annual rate of 12%, and increased regulatory action was cited as the major factor causing the cost escalation. Over the last five years of the sample period (1989–1993), O&M costs escalated by less than 1% annually, with a cost of $96/kW in 1993 (equivalent to 13 mills/kWh for 85% capacity factor).

The 1995 report offers a number of interesting statistics about nuclear O&M costs. First, the report lists O&M costs for individual plants over the last four years. From these data, it can be seen that O&M costs for the best performer are just over half (56%) of the average costs across the fleet. Costs for the lowest cost quartile are 20% below average, 16% above average for the highest cost quartile, and 86% above average for the worst performer.

Second, a regression analysis determines that plant aging, NRC regulatory activity, and regulatory incentives to improve performance were the three most important factors influencing changes in O&M costs over time.[21] It is estimated that 67% of the reported O&M costs are labor related, with the remaining 33% for expenditures on maintenance materials and supplies.

Third, and most important for assessing the total cost of nuclear generation, the report lists cost items that are not included in the reported O&M costs. Insurance premiums for property damage, third-party damages, and replacement power in case of an accident are not included. Additionally, NRC regulatory fees and some payroll taxes and fringe benefits are not included because they are reported in aggregate for the utility. A study performed by Oak Ridge National Laboratory estimated that the reported O&M costs understate the actual costs by up to 30%.[22]

NUCLEAR ENERGY INSTITUTE (NEI)

NEI presents 3-year rolling average production costs for U.S. nuclear plants based on data from the Utility Data Institute and the Electric Utility Cost Group.[23] The table shows consistent cost reductions across the fleet. The fleet average production cost for 1998–2000 was 17.4 mills/kWh, including fuel costs. However, the lowest cost quartile achieved total O&M costs of about 13 mills/kWh and the second lowest cost quartile 15 mills/kWh.

Table A-5.C.2 3-year Rolling Average O&M Costs for U.S. Nuclear Plants

(mills/kWh)	1st QUARTILE	2nd QUARTILE	3rd QUARTILE	4th QUARTILE
1996–1998	14.3	16.9	20.4	38.8
1997–1999	13.3	15.8	18.4	28.0
1998–2000	12.7	15.0	17.3	24.6

OPERATING COST PROJECTIONS

The most recent projections from EIA are for fixed nuclear O&M costs of $58/kW and variable O&M costs of 0.43 mills/kWh.[24] Assuming an 85% average capacity factor, this is equivalent to 8 mills/kWh (excluding fuel). The economic analysis in the Department of Energy 2010 Roadmap study pushes operating costs down further by projecting non- fuel O&M costs around 5 mills/kWh for near term deployment plants.[25] The report notes that this is in line with the best currently operating plants. And TVA, in its evaluation of the proposed restart of Browns Ferry Unit 1, projects O&M costs below 8 mills/kWh, based on recent experience at its other nuclear facilities. These operating cost projections are significantly below the actual operating cost numbers drawn from recent experience displayed above.

Appendix Chapter 5.D — Costs of Reprocessing

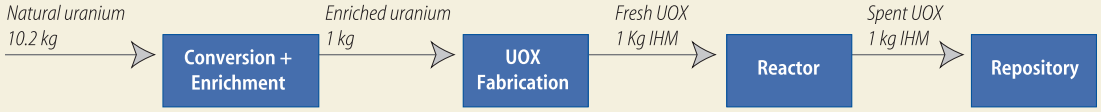
Spent UOX fuel typically contains a little over 1% Pu. Through reprocessing (PUREX process), it is possible to recover this plutonium and use it to make MOX fuel for use in LWRs. However, because of the high costs of reprocessing and of MOX fuel fabrication, the cost of repository disposal must be very high in order for the MOX option to become economically competitive with the once-through UOX cycle. We support this conclusion with the following analysis.

Fuel Cycle Cost Model — A simple expression for the fuel cycle cost is as follows:

$$FCC = \sum_i M_i \cdot C_i + \sum M_i \cdot C_i \cdot \phi \cdot \Delta T_i \quad [\$]$$

where:
FCC = Fuel Cycle Cost [$]
M_i = mass processed at stage i [kg or kg SWU]
C_i = unit cost at stage i [$/kg or $/kg SWU]
ϕ = carrying charge factor (yr^{-1})
ΔT_i = delay between the investment for stage i and the midpoint of the irradiation of the fuel (years)[26]

UOX cycle — The once-through UOX cycle is represented below (for 1 kgIHM[27] of fuel):



Assumptions

- U235 content of natural U: 0.711%
- Enrichment tails assay: 0.3%
- Fresh fuel enrichment: 4.5%
- Losses are neglected
- Burnup: 50 MWD/kgHM
- Capacity factor: 0.9
- Thermal efficiency: 0.33

The Separative work per unit of enriched product can be obtained as:[28]

$$\frac{\text{kg SWU}}{\text{kg product}} = (2x_p - 1) \cdot \ln\left(\frac{x_p}{1 - x_p}\right) + \frac{x_p - x_{nat}}{x_{nat} - x_t} \cdot (2x_t - 1) \cdot \ln\left(\frac{x_t}{1 - x_t}\right) - \frac{x_p - x_t}{x_{nat} - x_t} \cdot (2x_{nat} - 1) \cdot \ln\left(\frac{x_{nat}}{1 - x_{nat}}\right)$$

where:
x_p = product enrichment
x_{nat} = natural enrichment
x_t = tails assay

Using the values presented above for x_p, x_{nat}, and x_t, we get 6.23 kg SWU/kg product.[29]

The fuel cycle cost can now be calculated (for 1 kgIHM of fresh UOX fuel):

Table A-5.D.1 Once-through UOX Fuel Cycle Cost

	M_i	C_i	ΔT_i (yr)	DIRECT COST $M_i \cdot C_i$ ($)	CARRYING CHARGE $M_i \cdot C_i \cdot \phi \cdot \Delta T_i$ ($)
Ore purchase	10.2 kg	30 $/kg	4.25	307	130
Conversion	10.2 kg	8 $/kg	4.25	82	35
Enrichment	6.23 kg SWU	100 $/kg SWU	3.25	623	202
Fabrication	1 kgIHM	275 $/kgIHM	2.75	275	76
Storage and disposal	1 kgIHM	400 $/kgIHM[30, a]	–2.25	400	-90
			Total	1686	353
			Grand Total		2040

a. The cost of waste storage and disposal is assumed to be paid at the end of irradiation, even though the unit cost of $400/kgIHM is a proxy for the 1 mill/kWehr paid by utilities during irradiation.

The calculations are based on the following assumptions:

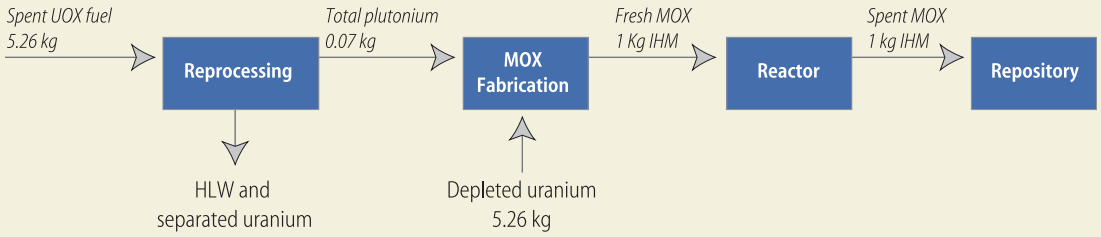
- Fuel irradiation time : 4.5 years
- Lead times:
  - 2 years for ore purchase
  - 2 years for conversion
  - 1 year for enrichment
  - 0.5 year for fuel fabrication
- Carrying charge factor: $\phi = 0.1$ per year.

The cost is thus $2,040/kgIHM. We can obtain the fuel cycle cost in ¢/kWh(e) as follows:

$$\frac{kgIHM}{0MWd} \cdot \frac{1MW}{1000kW} \cdot \frac{1d}{24h} \cdot \frac{1kW}{0.33kW(e)} = 5.15 \cdot 10^{-3} \frac{\$}{kWh(e)}$$

The fuel cycle cost is therefore 0.515 ¢/kWh(e).

MOX cycle — The MOX cycle can be represented as follows (for 1 kgIHM of fuel):



Assumptions

- Pu content of spent UOX 1.33%
- Pu content of fresh MOX: 7%
- Losses are neglected
- Burnup: 50 MWD/kgIGM
- Capacity factor: 0.9
- Thermal efficiency: 0.33

We now calculate the fuel cycle cost (per kgIHM fresh MOX fuel):

Table A-5.D.2 Single Recycle MOX Fuel Cycle Cost

	M_i (kgIHM)	C_i ($/kgIHM)	ΔT_i(yr)	DIRECT COST $M_i \cdot C_i$ ($)	CARRYING CHARGE $M_i \cdot C_i \cdot \phi \cdot \Delta T_i$ ($)
Credit for UOX SF	5.26	–400	4.25	–2105	–895
Reprocessing	5.26	1000	4.25	5263	2237
HLW storage and disposal	5.26	300	3.25	1579	513
MOX Fabrication	1	1500	3.25	1500	488
MOX Storage and disposal	1	400	–2.25	400	–90
			Total	6637	2253
			Grand Total	8890	

Assumptions

- Fuel irradiation time : 4.5 years
- Lead times:
  - 2 years for acceptance of spent UOX fuel,
  - 2 years for reprocessing,
  - 1 year for storage of HLW from reprocessing;
  - 1 year for MOX fuel fabrication
- The cost of acquiring depleted uranium is neglected

- Both the cost of separated uranium storage and the potential value of separated uranium material are not included in the analysis. Under current conditions, separated uranium is not used for fuel fabrication because using natural uranium is less expensive. Separated uranium is simply stored for possible use in the future. Since cost of storing separated uranium is very modest due to its low radioactivity, we ignore it in this analysis.
- The cost of HLW storage and disposal is assumed to be 25% lower than the cost of spent fuel storage and disposal. The HLW contains most of the fission products (including Sr-90 and Cs-137) and all the minor actinides present in the processed spent fuel, hence storage and disposal requirements are not expected to be much improved compared to spent fuel. However, because HLW has a lower volume and very small plutonium content, modest savings can be expected.
- The cost of storage and disposal for spent MOX fuel is assumed to be the same as for spent UOX fuel. Indeed, spent MOX is not reprocessed due to the degraded isotopic composition of its plutonium. We therefore consider it to be a liability comparable to spent UOX fuel.
- $\phi = 0.1$ per year

The fuel cycle cost is therefore $8,890/kgHM, or 2.24 ¢/kWh(e). This is approximately 4.5 times higher than for the once-through UOX cycle under U.S. conditions.

The incremental MOX fuel cost compared to UOX fuel cost will contribute to an increase in the cost of electricity in proportion to the ratio of MOX to UOX fuel in the entire fleet. Accordingly the incremental electricity cost for the fleet will be:

0.515 cents/kWe-hr (1260/1500)+2.24 cents/kWe-hr(240/1500) = 0.791 cents/kWe-hr

or a blended increase in the cost of electricity of 0.28 cents/kWe-hr in the MOX/UOX cycle compared to the once through UOX cycle.[31]

CONDITIONS FOR COMPETITIVENESS OF THE MOX OPTION

It is important to determine under what conditions the MOX fuel cycle becomes cost competitive with the once through UOX cycle. Cost components to consider are: (1) cost of natural uranium, (2) cost of reprocessing, (3) cost of MOX fabrication, and (4) cost of waste storage and disposal. Table A-5.D.3 presents the value that would make the fuel cycle cost of both options equal (breakeven value) for each of these four cost parameters.

Table A-5.D.3 Breakeven Values

COST COMPONENT	ORIGINAL VALUE	REQUIRED VALUE	REQUIRED/ORIGINAL
Natural uranium	$30/kgU	$560/kgU	19
Reprocessing	$1,000/kgIHM	$90/kgIHM	0.09
MOX fabrication	$1,500/kgIHM	Impossible	N/A
Waste storage and disposal	$400/kgIHM (SF) $300/kgIHM (HLW)	$1,130/kgIHM $100/kgIHM	2.8 0.33

The cost of natural uranium is not likely to reach such high levels in the foreseeable future. The cost of reprocessing will probably never drop down to the required value of $90/kgHM. As for waste storage and disposal, it is not reasonable to expect that the cost will be 11 times higher for UOX and MOX spent fuel than for HLW from reprocessing; indeed, although the volume of the HLW is much smaller, it still contains most of the fission products and all the minor actinides from the spent fuel. Therefore, its heat load in the first few hundred years should be comparable to that of spent fuel. It can also be observed from Table A-5.D.2 that, even if we assume that HLW storage and disposal can be done at zero cost, the total cost of the MOX option is still $6798/kgIHM (obtained by subtracting the cost of HLW disposal, $1579+$513, from the total cost, $8890). This is equivalent to 1.72 ¢/kWh(e), or more than 3 times the cost of the once-through option. It should be noted, however, that the original values selected for the costs of waste storage and disposal are not an absolute reference: important differences exist between countries because this cost depends on how difficult the nuclear waste problem is perceived to be. For some countries, the cost of waste disposal may very well be much higher than the reference values used here.

Finally, we consider the effect of changing our cost assumptions for ore purchase, reprocessing, MOX fabrication, and waste storage and disposal simultaneously. We find that the fuel cycle cost of the two options is equal under the following revised assumptions:

Table A-5.D.4 Breakeven Values (components adjusted simultaneously)

COST COMPONENT	UNIT	ORIGINAL VALUE	REQUIRED VALUE
Ore purchase	$/kg	30	50
Reprocessing	$/kgIHM	1,000	600
MOX fabrication	$/kgIHM	1,500	1,100
Storage and disposal:			
Spent Fuel	$/kgIHM	400	600
HLW	$/kgIHM	300	100
Fuel cycle cost (both options)		6.3 mills/kWh	

Table A-5.D.4 shows that, by revising several cost assumptions in favor of plutonium recycling, we obtain equal fuel cycle costs for both options. Although the required ore purchase price is high and costs for reprocessing, MOX fabrication, and HLW disposal can be characterized as optimistic, they fall within the range of uncertainty defined by other fuel cycle cost studies (see Table A-5.D.6).

COMPARISON WITH OTHER ESTIMATES

There have been a number of studies on the economics of reprocessing with significant differences in assumptions. The most comprehensive study has been carried out by the OECD/NEA.[32] This study thoroughly evaluated the cost of the once-through and plutonium recycling fuel cycles, and concluded that the cost of the once-through option is about 15% lower (based on the assumptions presented in Table A-5.D.5). Thus, the findings of the OECD differ significantly from the result presented earlier, where the cost of the once-through option was found to be about 4 times lower.

There are several differences between the methodology used in the OECD study and the simple fuel cycle cost model used in this appendix. The OECD model is more detailed and the methodology for dealing with carrying charges is more involved. In addition, it sometimes uses different assumptions about the workings of the fuel cycles. For example, a credit is given for the irradiated uranium recovered in reprocessing, implying that it is used for fuel fabrication. In spite of such differences, assumptions regarding unit costs remain the dominant factor influencing fuel cycle cost estimates. The OECD study uses costs that are much more favorable to the reprocessing option. In fact, using the OECD assumptions in our model results in nearly equal costs for both fuel cycles. This is shown in Table A-5.D.5.

Table A-5.D.5 Fuel Cycle Cost Using OECD Estimates

COST COMPONENT	OECD ESTIMATE
Ore Purchase	50 $/kgHM
Conversion	8 $/kgHM
Enrichment	110 $/kg SWU
UOX fabrication	275 $/kgHM
SF storage and disposal	570 $/kgHM
Reprocessing	620 $/kgHM
HLW storage and disposal	60 $/kgHM
MOX fabrication	1,100 $/kgHM
FUEL CYCLE COST	
Once-through:	6.43 mills/kWh
MOX option:	6.80 mills/kWh

Table A-5.D.5 shows that OECD unit costs for the various back-end operations diverge significantly from the ones that were assumed in Tables A-5.D.1 and A-5.D.2. Such differences can be expected, as fuel cycle cost studies generally show very large uncertainties on such estimates. Indeed, few data on the cost of reprocessing and recycling operations are publicly available, and spent fuel or HLW disposal has not been implemented anywhere in the world, so the costs associated with these operations cannot be determined precisely. Furthermore, estimates are difficult to make for several reasons. First, engineering cost estimates for this type of activity are notoriously uncertain. Second, since fuel cycle facilities are high capital cost plants, the cost of capital assumption is very important.[33] Third, the cost estimates per unit product depend on assumption about both plant productivity and on allocation of fixed construction and development costs to unit output. Finally, the ultimate disposal cost for either spent fuel or HLW is not established. Certainly little confidence can be placed in any estimate on the *difference* in disposal costs for HLW and spent fuel.

Several other studies provide estimates of the unit costs for various fuel cycle operations. The OECD/NEA provides revised estimates in a recent study on advanced fuel cycles.[34] The Gen-IV Fuel Cycle Crosscut Group offers a range of estimates in its report.[35] Fetter, Bunn, and Holdren have offered an analysis of the economics of reprocessing versus direct disposal of spent nuclear fuel.[36] Finally, the National Research Council's study on Nuclear Waste[37] has an appendix on recycling economics. Note that the unit costs presented in these studies implicitly carry three charges: the direct cost of the activity, a capital charge that depends upon the assumed rate of return, and a capital charge for the "work in progress," i.e. the hold-up time for material flow through the system (for example, if it takes two years or three years of plutonium inventory to maintain a given material flow at

a reprocessing plant, this influences the cost of reprocessing). We include in Table A-5.D.6 our "best guess" for the value of the parameters but stress, in the strongest possible terms, as can be seen from the difference in estimates made by other studies, the tremendous uncertainty in these numbers.

Table A-5.D.6 Comparison of Cost for Once-through and Recycle Process Steps

		ESTIMATED COST (lower bound - nominal - upper bound)			
COST COMPONENT	UNIT	OECD/NEA[34] (2002)	DOEGEN-IV[35]	Fetter, Bunn, Holdren[36]	Our Best Guess
Ore Purchase	$/kg	20-30-40	20-30-80	33	30
Conversion	$/kg	3-5-7	3-5-8	4-6-8	8
Enrichment	$/kg SWU	50-80-110	50-80-120	50-100-150	100
UOX fabrication	$/kgIHM	200-250-300	200-250-350	150-250-350	275
SF storage and disposal	$/kgIHM	410-530-650	210-410-640	0-150-300 (more than HLW)	400
UOX reprocessing	$/kgIHM	700-800-900	500-800-1,100	500-1000-1600	1,000
MOX reprocessing	$/kgIHM	700-800-900	500-800-1,100	—	—
HLW storage and disposal	$/kgIHM	63-72-81	80-200-310	0-150-300 (less than SF)	300
MOX fabrication	$/kgIHM	900-1,100-1,300	600-1,100-1,750	700-1,500-2,300	1,500

CONCLUSION

The simple fuel cycle cost model shows that the MOX option is roughly 4 times more expensive than once-through UOX, using estimated costs under U.S. conditions. Thermal recycle can be shown to be competitive with the once-through option only if the price of uranium is high and if optimistic assumptions are made regarding the cost of reprocessing, MOX fabrication, and HLW disposal.

The case is often advanced that disposing of reprocessed high level waste will be less expensive than disposing of spent fuel directly. But there can be little confidence today in any estimate of such cost savings, especially if disposal of TRU waste associated with thermal recycle facilities and operations is taken into account. Furthermore, our cost model shows that even if the cost of disposing of reprocessed high-level waste were zero, the basic conclusion that reprocessing is uneconomic would not change.

It should be noted that the cost increment associated with reprocessing and thermal recycle is small relative to the total cost of nuclear electricity generation. In addition, the uncertainty in any estimate of fuel cycle costs is extremely large.

Appendix 5.E — Price and Availability of Uranium

URANIUM RESOURCES AND RESERVES

The most authoritative source for estimates of uranium resources is the OECD/IAEA Red Book.[38] Figures from the latest edition are shown in Table 1.

Table A-5.E.1 OECD Conventional Uranium Resources (million metric tons, as of January 2001)

KNOWN CONVENTIONAL RESOURCES COST RANGES			REPORTED UNDISCOVERED CONVENTIONAL RESOURCES COST RANGES	
<40$/kgU	40 – 80$/kgU	80 – 130$/kg	<130$/kgU	Cost Range Unassigned
2.1	1.0	0.8	6.8	5.5
Total Uranium Resources: 16.2				

The term "reserves" refers to the known conventional resources that can be extracted using current technology under current economic conditions at various recovery costs. For example, from Table 1, reserves recoverable at costs = $40/kgU amount to about 2 million metric tons of uranium (MTU), enough for about 30 years at the current consumption rate.[39] However, reserves are only a small fraction of the total uranium resource base, which also includes known deposits that are not economic to recover at present prices or are surmised to exist with varying degrees of uncertainty in the vicinity of well-mapped deposits or by similarity of one unexplored geologic structure to other mapped and productive ones. When uranium prices rise, presently uneconomic resources will become economic to recover and mining companies will also have an incentive to delineate presently unmapped resources. As a result, new reserves will be created that can be used to fuel a growing installed nuclear capacity.

A quantitative example of the increased reserves that would be created as a result of higher prices has been given by the Uranium Information Centre in Australia: a doubling of the uranium price – which has been declining steadily since the late 1970s; see Figure 1 – from present contract levels could be expected to create about a tenfold increase in measured resources.[40] The term "measured resources" in this context refers to reserves extractable at costs = $80/kgU, which from Table 1 amount to about 3 million MTU. Thus, a doubling of uranium prices from about $30/kgU to $60/kgU could be expected to increase these reserves to approximately 30 million MTU. This can be compared with the requirements of the following 1500 GWe mid century scenario: installed nuclear capacity grows linearly from the current 350 GWe to 1500 GWe over 50 years and, after this growth period, no new plants are built and existing ones are operated for the rest of their lifetimes. The total production over the growth period is 41,625 GWe•y (assuming a capacity factor of 0.9), requiring 9.5 million MTU (assuming a uranium consumption of 226.5 MTU/GWe•y). Nuclear capacity then begins to decline: the newest plants still have 50 years of production ahead of them, but the units built at the beginning of the growth period must be decommissioned. Assuming an average remaining life of 25 years for the fleet, total electricity production over the decline period is 33,750 GWe•y, requiring 7.5 million MTU. The total uranium consumption for this scenario is therefore 17 million MTU. The 30 million MTU

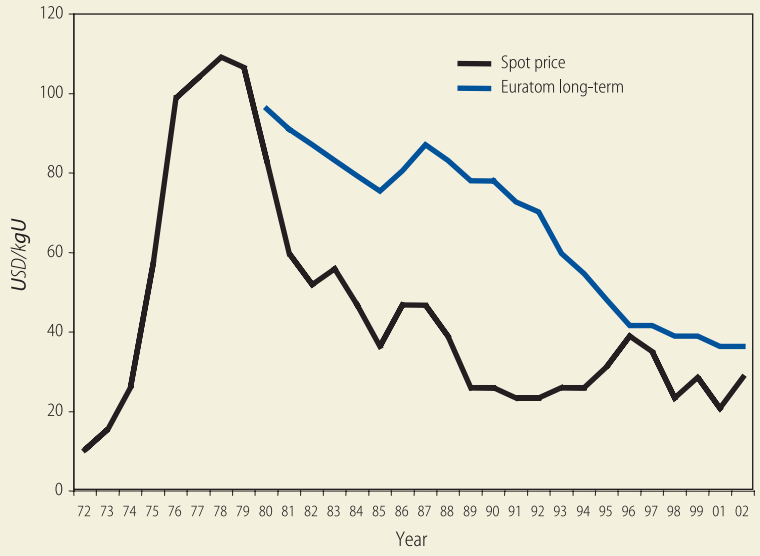
of reserves available if the uranium price doubled are more than sufficient to support this scenario.

INCREASED RESERVES FROM HIGH AND LOW GRADE ORES

The increase of reserves as a result of higher uranium prices could come from both high and low grade ores. The former are the "unconformity-related" deposits discovered starting in the late 1960s in Australia and Canada where typical ore concentrations exceed 10%. The world's largest, highest grade uranium mine at McArthur River in Saskatchewan, Canada is of this type. Estimates of reserves at McArthur River increased by more than 50% in 2001,[41] and further increases in reserves can be expected as a result of further exploration at this mine and other unconformity-related deposits. But such exploration followed by increased production is unlikely at today's uranium prices. Indeed, according to Bernard Michel, the former CEO of Cameco Corp., the McArthur River mine operator, uranium's current low price is "unsustainable".[42]

Most of the terrestrial uranium resource consists of large quantities of low grade ore. For example, phosphate deposits, which typically carry 10 to 300 parts per million of uranium, are believed to hold 22 million tons of uranium. A 1980 Scientific American article[43] suggests that the distribution of uranium resources as a function of ore grade is such that, in the region of current commercial interest, a reduction in ore grade by a factor of 10 increases the amount of available uranium by a factor of 300. Equivalently, for a decrease in ore grade by a factor of 2, uranium resources expand by a factor of 5.

Figure A-5.E.1 Uranium Prices, 1972–2001
annual basis



INCREASED URANIUM PRICES AND THE COMPETITIVENESS OF NUCLEAR ELECTRICITY

Table 2 shows that an increase in the price of uranium ore from 30$/kg to 60$/kg corresponds to an increase in ore price of about 1.10 mills/kWh. This corresponds to a modest increase of 2.2% in the cost of nuclear electricity.

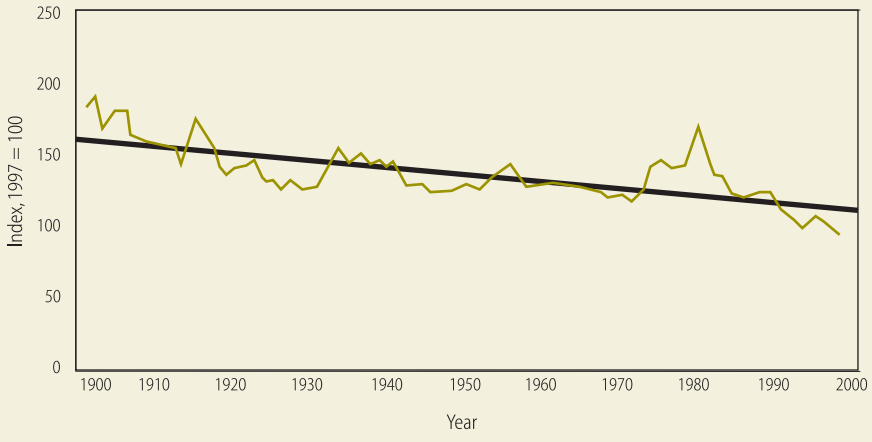
Table A-5.E.2 Cost of Uranium Ore as a Fraction of Cost of Electricity

	ORE PRICE (mills/kWh)			
ORE PRICE ($/kg)	Direct cost[a]	Carrying charge[b]	Total	% BUSBAR COST[c]
30	0.78	0.33	1.11	2.2%
50	1.29	0.55	1.84	3.7%
60	1.55	0.66	2.21	4.4%
100	2.59	1.10	3.68	7.4%
130	3.36	1.43	4.79	9.6%
200	5.17	2.20	7.37	14.7%

a. Assuming uranium consumption of 226.5 kg/MWey for LWRs.
b. Assuming a lead time of 4.25 years and a carrying charge factor of 0.1
c. Assuming busbar cost of 50 mills/kWh, or 5 ¢/kWh.

Furthermore, even if uranium prices increase as the most attractive deposits are depleted, there is good reason to expect that prices will not soar to prohibitively high levels. Historical data show that, over the past century, advances in exploration and extraction technologies have made it possible to recover lower grades and other less attractive resources at constant or even decreasing costs in constant dollars. The U.S. Geological Survey[44] provides data showing that the U.S. mine production composite price index has decreased throughout the 20th century, even as consumption of minerals increased significantly (see Figure 2). The USGS observes that advances in technology have been more than sufficient to overcome obstacles to supply. The USGS also provides striking data on the price and production levels of 4 selected commodities over the 20th century (see Table 3).

Figure A-5.E.2 Composite mineral price index for 12 selected minerals, 1900 to 1998, in constant 1997 dollars. Selected mineral commodities include 5 metals (copper, gold, iron ore, lead, and zinc) and seven industrial mineral commodities (cement, clay, crushed stone, lime, phosphate rock, salt, and sand and gravel).



Although uranium is different from other extractive resources because of its national security implications, we do not believe that this fact changes the fundamental process by which higher prices not only lead to exploration efforts but also create an incentive to innovate, which leads to technological progress and tends to hold prices down.

Table A-5.E.3 20th Century World Production and Price for 4 Selected Commodities

COMMODITY	PERIOD	INCREASE IN PRODUCTION (percent)	DECREASE IN CONSTANT DOLLAR PRICE (percent)
Aluminum	1900–1998	3,250	89.7
Copper	1900–1998	2,465	75.0
Potash	1919–1998	3,770	93.9
Sulfur	1907–1998	6,000	89.4

NOTES

1. By "real" we mean that all cash flows are expressed in constant dollars that have been adjusted for the effects of general inflation over the life of the project. However, the cash flows themselves must first be calculated using nominal dollars (including inflation) in order to properly calculate income tax obligations since tax depreciation is based on nominal construction costs and nominal interest payments are a tax deductible expense.
2. Taxable income may be reduced by allowing carry forward of net operating losses, most likely in early years of operation where both interest payments and tax depreciation allowances are substantial.
3. The model can be readily adapted to allow real prices for electricity to grow at a constant rate over time, but this complicates somewhat comparison of alternative technologies.
4. Energy Information Administration, *Annual Energy Outlook 2003 With Projections to 2025,* DOE/EIA-0383(2003), January 2003.
5. U.S. Department of Energy Office of Nuclear Energy, Science and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010,* October, 2001.
6. *Nuclear Energy Agency / International Energy Agency, Projected Costs of Generating Electricity,* Update 1998.
7. Tarjanne, Risto and Rissanen, Sauli, *Nuclear Power: Least-Cost Option for Baseload Electricity in Finland,* The Uranium Institute 25th Annual Symposium, 2000.
8. The exchange rate between euros (EUR) and U.S. dollars (USD) has fluctuated between 0.85 and 1.18 EUR / USD over the past two years. For our purposes, a central value of 1 EUR / USD is acceptable.
9. UK Performance and Innovation Unit, *The Economics of Nuclear Power: PIU Energy Review Working Paper,* 2001.
10. International Energy Agency, *Nuclear Power in the OECD,* 2001.
11. Tennessee Valley Authority, *Final Supplemental Environmental Impact Statement for Browns Ferry Nuclear Plant Operating License Renewal,* March, 2002.
12. Williams Capital Group Equity Research, July 2001.
13. The TVA Act requires TVA to compensate state and local governments with tax equivalent payments.
14. In the case of South Korea, the exchange rate between Korean won (KRW) and U.S. dollars (USD) ranged from 800 to 1,800 KRW / USD during the construction phase of the recent nuclear project.
15. OECD, *Purchasing Power Parities and Real Expenditures: 1999 Benchmark Year,* 2002.
16. The currency exchange rate was 119 yen / U.S. dollar on May 28, 2003.
17. Construction costs for Yonggwang Units 5 and 6 were obtained through personal communication with Professor Soon Heung Chang of Korea Advanced Institute of Science and Technology (KAIST).
18. The currency exchange rate was 1,200 won / USD on May 28, 2003.
19. *Energy Information Administration, Electric Power Annual 2001*, DOE/EIA-0348(01), March 2003.
20. *Energy Information Administration, An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update,* SR/OIAF/95-01, April 1995.
21. Energy Information Administration (EIA), 1995.

22. Ibid.
23. Statistics reported by NEI were extracted from the February 2002 NEI Annual Briefing for the Financial Community, "Nuclear Energy 2002: Solid Value… Significant Upside"
24. Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003*, DOE/EIA-0554 (2003), January 2003.
25. U.S. Department of Energy Office of Nuclear Energy, Science and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010*, October, 2001.
26. Note that T_i can vary depending on the fuel management strategy
27. The unit used for mass of nuclear fuel the "kilogram of initial heavy metal", denoted kgIHM. We always refer to the initial mass of heavy metal in the fuel because the heavy metal atoms are fissioned as the fuel is irradiated, and therefore their mass decreases with time.
28. See, for example, Tsoulfanidis and Cochran, "The Nuclear Fuel Cycle", ANS, 1999, p. 62.
29. Alternatively, a simple linear relationship can be used to approximate the SWU requirement. For a tails assay of 0.3%, the following holds:

$$\frac{\text{kg SWU}}{\text{kg product}} = 2.07 \cdot x_p - 3.23$$

Using the same values as above for x_p, x_{nat}, and x_t, we get 6.09 kg SWU/kg product.

30. This value corresponds to the fee of 1 mill per kilowatt-hour of nuclear electricity generated paid to the DOE by each utility operating a nuclear power plant:

$$\frac{0.001\$}{kWh(e)} \cdot \frac{0.33kWh(e)}{1kWh} \cdot \frac{24h}{1d} \cdot \frac{1000kW}{1MW} \cdot \frac{50MWd}{1kg1HM} \approx 400 \frac{\$}{kgIHM}$$

31. We thank Matt Bunn for reminding us of the effect of increased MOX cost on blended electricity cost.
32. OECD/NEA "The Economics of the nuclear fuel cycle," 1994.
33. For example, the NRC study (footnote 7) estimates the levelized reprocessing cost for a 900 MTHM /year plant varies for different owner operators as follows: government $800/kgHM, utility $1300/kgHM, private venture $2000/kgHM.
34. OECD/NEA, "Accelerator-driven Systems and Fast Reactors in Advanced Nuclear Fuel Cycles", 2002
35. DOE, "Generation 4 Roadmap - Report of the Fuel Cycle Crosscut Group", 2001
36. Fetter, Bunn, Holdren, "The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel", 1999
37. "Nuclear Waste – Technologies for separations and transmutation," Committee on Separation Technology and Transmutation systems, National Research Council, National Academy of Sciences, Appendix J, 1996
38 OECD/NEA & IAEA, "Uranium 2001: Resources, Production, and Demand", 2002
39. Current light water reactors consume approximately 226.5 MTU/GWe•y of electricity generated, hence the demand for today's fleet of 350 GWe is approximately 70,000 MTU per year, assuming a capacity factor of 90%.
40. Uranium Information Center, "Nuclear Electricity", 6th edition, Chapter 3 (2000). Available on the web at http:www.uic.com.au/ne3.htm.
41. See www.cameco.com/investor/news_releases/2001-jan-25.html.
42. R. Martin, "Nuclear Rock", Time Magazine, Feb. 16th, 2003.
43. K.S. Deffeyes and I.D. MacGregor, "World Uranium Resources", Scientific American, Vol. 242, No.1, Jan. 1980.
44. David Wilburn, Thomas Goonan, Donald Bleiwas, Eric Rodenburg, "Technological Advancement – A Factor in Increasing Resource Use", U.S. Geological Survey, 2001.

Appendix Chapter 7 — Waste Management

Appendix 7.A — International Programs in High Level Waste Management and Disposal

Most countries with nuclear power programs – and all the major ones — have adopted as their preferred technical approach to the final disposal of high-level waste the emplacement of sealed waste-bearing canisters in mined structures ('geologic repositories') hundreds of meters below the earth's surface. No country has yet established an operating repository for high-level waste, and all have encountered difficulties with their programs. In many countries public and political opposition to proposed nuclear waste facilities and to the transportation of nuclear waste by road or rail has been intense, and public opinion polls reveal deep skepticism around the world about the technical feasibility of safely storing nuclear waste over the long periods for which it will remain hazardous. Many people think that no new nuclear power plants should be built until the waste issue has been resolved. In several major nuclear countries laws have been enacted whose practical effect will be to slow or even prevent the licensing of future nuclear power plants in the absence of demonstrable progress towards waste disposal. In other countries where decisions have been taken to phase nuclear power out completely, the nuclear waste problem has been prominently cited as a rationale.

Although geologic disposal is the announced technical strategy in almost every country, there are important differences in how countries are planning to implement it. Nowhere is repository development proceeding very quickly, but some countries are seeking to move forward as rapidly as domestic political and institutional constraints will allow, while others are pursuing a more leisurely approach. So far only two countries, the United States and Finland, have identified specific sites for their repositories

The U.S., Canada, and Finland are among a group of countries that are planning to dispose of their spent fuel directly. A second group of countries, which includes the U.K. and France, is reprocessing its spent fuel, and will dispose of the vitrified high-level waste from reprocessing operations. A third group is storing its spent fuel temporarily in central storage facilities, and has postponed the decision on whether or not to reprocess until a later date. A few countries — notably including Japan and Russia — have announced prohibitions on the direct disposal of spent fuel. There has been a long-running debate about the relative advantages of disposing of spent fuel directly versus reprocessed waste. We comment on this debate in the main body of this report.

National waste disposal programs also vary along several other important technical dimensions, including: (1) the candidate geologic media in which the repository will be located; (2) the geochemical environment; (3) the relative reliance on engineered

versus natural barriers to radionuclide transport; (4) the thermal design of the facility – including the age of the waste at the time of emplacement.

A summary of international plans and programs in high-level waste disposal is contained in Table A-7.A.1.

Table A-7.A.1 High-level Waste Disposal Plans of Leading Nuclear Countries

COUNTRY	MANAGEMENT RESPONSIBILITY	PREFERRED/ SELECTED GEOLOGIC MEDIUM	EARLIEST ANTICIPATED REPOSITORY OPENING DATE	STATUS
United States	DOE	Volcanic tuff	2010	Site selected (Yucca Mountain, NV); application for construction license
Finland	Power companies (Posiva Oy)	Crystalline bedrock	2020	Site selected (Olkiluoto, SW Finland) — decision ratified by Parliament in May 2001
Sweden	Power companies (SKB)	Crystalline rock	2020	Searching for a suitable site
Switzerland	Power company coop (Nagra)	Crystalline rock or clay	2020 or later	Searching for a suitable site
France	Ind. Pub. Auth. (ANDRA)	Granite or clay	2020 or later	Developing repository concept
Canada	Crown Corp. (AECL)	Granite	2025 or later	Reviewing repository concept
Japan	National agency (NUMO)	Not selected	2030	Searching for suitable site
United Kingdom	Under review	Not selected	After 2040	Delaying decision until 2040
Germany	Federal contractor company (DBE)	Salt	No date specified	Moratorium on repository development for 3–10 years

Appendix 7.B — The Feasibility of Geologic Disposal

The concept of deep geologic disposal of high level wastes has been studied extensively in many national and international research programs for several decades. Considerable technical progress has been made over this period. Although practical experience in building and operating geologic repositories for high-level waste is still mainly limited to a few pilot-scale facilities, there is today a high level of confidence within the scientific and technical community that the geologic repository approach is capable of safely isolating the waste from the biosphere for as long as it poses significant risks. This view has been stated and supported in several recent national and international assessments [1-4]. It is based on: (1) an understanding of the processes and events that could transport radionuclides from the repository to the biosphere; (2) mathematical models that enable the long-term environmental impact of repositories to be quantified; and (3) natural analog studies which support the models and their extrapolation to the very long time-scales required for waste isolation. Natural analogs also provide evidence that key processes important to modeling the performance of geologic systems over long time periods have not been overlooked [5].

A geologic repository must provide protection against every plausible scenario in which radionuclides might reach the biosphere and expose the human population to dangerous doses of radiation. Various possibilities must be considered, including the risk of volcanic activity and the possibility of human intrusion into the repository, either inadvertent or intentional. Of the possible pathways to the biosphere, the one receiving most attention involves the entry of groundwater into the repository, the corrosion of the waste containers, the leaching of radionuclides into the groundwater, and the migration of the contaminated groundwater towards locations where it might be used as drinking water or for agricultural purposes.

Although the details vary among national programs, the basic approach to repository design in every case is based on a multibarrier containment strategy, combining a suitable geologic, hydrologic, and geochemical environment with an engineered barrier system that takes advantage of the main features of that environment. A well-chosen geologic environment will support and enhance the functioning of the engineered barrier system, while protecting it from large perturbations such as tectonic activity or fluctuations in groundwater chemistry due to glaciation or other climate changes [1].

The design proposed for the Finnish repository in the granitic rock at Olkiluoto highlights this systems approach [6]. The Finnish design, which is based on the earlier KBS-3 concept developed for the Swedish nuclear waste program, calls for the direct disposal of spent nuclear fuel assemblies in copper-iron canisters, surrounded by highly compacted bentonite clay, in vertical emplacement holes in crystalline bedrock at a depth of about 500 meters (see Figures A7.B.1 and A-7.B.2). The canister consists of a massive 1-meter diameter cast iron insert, surrounded by a 5-cm thick copper mantle (see Figure A-7.B.3.) The copper overpack serves as the primary containment barrier. The waste inventory in each canister is chosen such that the temperature at the canister surface will not exceed 100C. (The peak temperature occurs 10 to 20 years after repository closure.) In the chemically reducing environment characteristic of the Olkiluoto host rock, the copper is expected to corrode extremely slowly, delaying the release of radionuclides from the canisters for hundreds of thousands of years.[1] The compacted bentonite backfill provides a low permeability, strongly sorbing buffer layer, further delaying the release of most radionuclides into the surrounding rock. The bentonite pore size is small enough to effectively block the transport of any colloids which may form. The mineral content of the bentonite backfill is tailored to help accelerate the restoration of chemically reducing conditions in the vicinity of the canister following emplacement.[2] The cast iron canister insert will help to maintain a chemically reducing environment inside the canister even if ground water penetrates the copper overpack.[3] The primary function of the granitic host rock in this design is to provide a chemically and physically stable environment, thus enhancing the ability of the copper and bentonite engineered barriers to perform as expected.

Figure A-7.B.1 KBS-3 Repository Concept

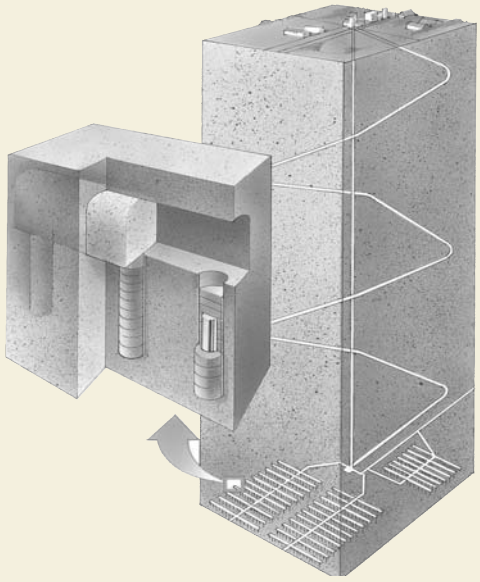
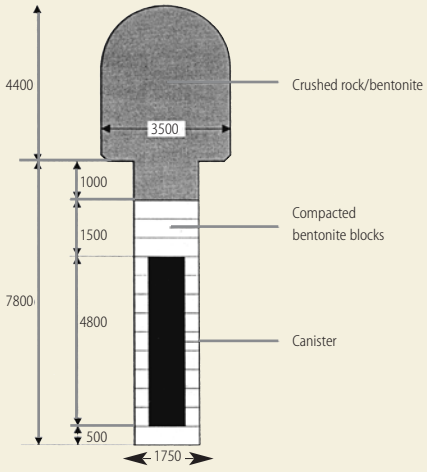


Figure A-7.B.2 Deposition Hole for Okliluoto Waste Canister

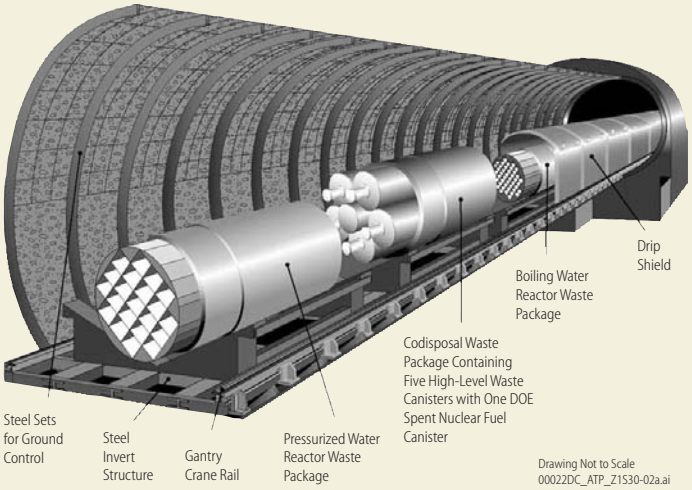


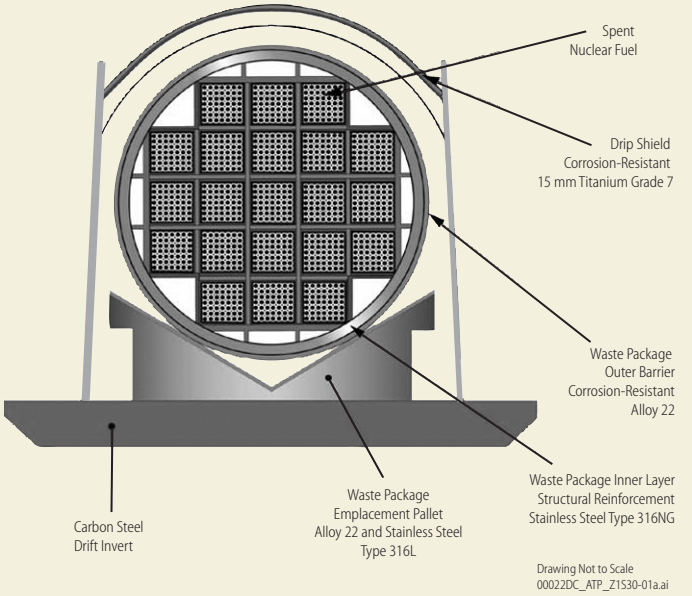
(from TILA-99, dimensions in mm)

Figure A-7.B.3 Prototype Canister

(Holds 12 assemblies from the Olkiluoto BWR power plant)

Figure A-7.B.4 Views of the Engineered Barriers at Yucca Mountain





processes which would lead to the release of radionuclides from the near-field to the far-field environment (copper corrosion, dissolution of the waste form, radionuclide transport through clay) are all well understood under expected repository conditions and this understanding is supported by natural analog studies [8,9]. This in turn has enabled the development of credible models describing the performance of the engineered barrier system.

The proposed U.S. repository at Yucca Mountain in Nevada, uniquely among current repository concepts, is located above the water table in the unsaturated zone – that is, the pores and fractures in the rock are only partially filled with water.[11] The presence of air trapped in rock pores and fractures and the flux of air through fracture systems will maintain an oxidizing environment surrounding the waste packages. The main repository design at Yucca Mountain has evolved in recent years to place more reliance on engineered barriers for overall radionuclide containment. In the present design (see Figure A-7.B.4) these consist of the waste packages themselves, cylindrical stainless steel canisters 5 meters in length, each containing 20-40 spent fuel assemblies, surrounded by a 2-centimeter thick shell of corrosion-resistant Alloy 22 (a nickel- based alloy), and protected by a 'drip shield' — a 1.5 centimeter thick canopy made of corrosion- resistant titanium that is designed to divert water infiltrating the repository from coming into contact with the waste canisters.

In one variant of the design, water will be kept away from the packages by ensuring that the temperature at the surface of the packages will exceed 100C, at least for the first 1000 years. Other engineered barrier systems have been proposed which would take advantage of the unsaturated conditions by creating zones favoring the flow of groundwater around the waste [12,13], or which attempt to control the water chemistry in the vicinity of the wastes[15].

If current plans come to fruition, the repositories at Yucca Mountain and Olkiluoto will have been in service for some time by mid-century. The experience with the earliest full-scale repositories can be expected to have a significant influence on future public attitudes toward the feasibility of high-level waste disposal. Whether these facilities experience trouble-free commissioning and operation or, less desirably, a series of unplanned-for developments will have an important bearing not only on the facilities themselves but also on public attitudes towards future siting efforts elsewhere.

Appendix 7.C — Radioactivity, Decay Heat, and Radiotoxicity Decay Profiles of Spent Fuel

Figures 7.1–7.3 in the main text respectively describe the radioactivity, decay heat, and radiotoxicity decay profiles of spent PWR fuel with a burnup of 50 MWD/kg HM. They were constructed from data generated by Zhiwen Xu in the course of his Ph.D. research at MIT [17].

The radiotoxicity is a proxy for the risk posed by the spent fuel in a geologic repository. It is defined as the total volume of water required to dilute all of the radionuclides contained in 1 MT of spent fuel down to their maximum permissible concentrations, where the maximum permissible concentration is in turn determined such that an individual could safely obtain his total water intake from such a source. Thus,

$$\text{radiotoxicity at time t} = \sum_{i}^{\text{all radionuclides}} \left(\frac{\lambda_i N_i(t)}{MPC_i^{water}} \right)$$

where $\lambda_I N_i(t)$ is the quantity of radioisotope i present in 1 MT of waste at time t (in Bq/MT), and MPC_i is the maximum permissible concentration of isotope i in water (in Bq/m^3.)

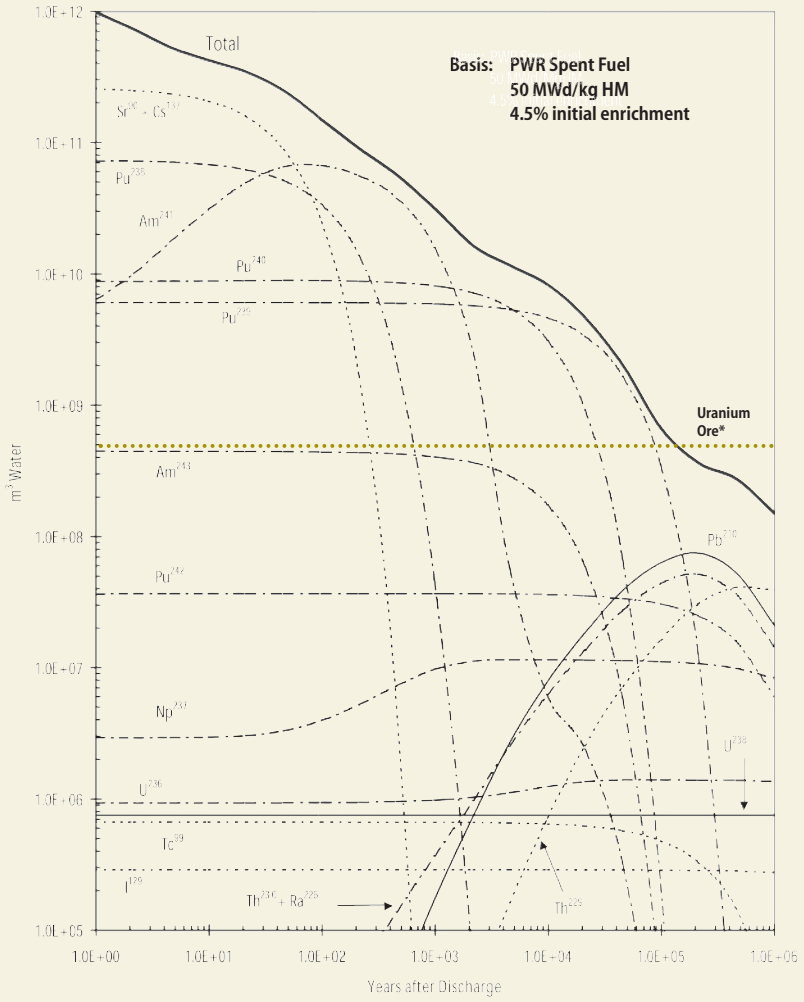
The calculation of the maximum permissible concentration for each radionuclide was based on the assumption that an adult would ingest water containing the radionuclide at a constant rate of 2 liters per day over the course of a year. The concentration limit was determined by imposing the requirement that the individual should receive a committed effective dose of no greater than 50 millirems from this source. The limits were computed using the radionuclide ingestion dose coefficients for adults published by the International Commission on Radiological Protection [18].

To illustrate for the case of strontium-90: The ICRP-72 ingestion dose coefficient for ^{90}Sr = 2.8 x 10^{-8} Sv/Bq. Thus, the total allowable annual intake for a committed effective dose of 5 x 10^{-4} Sv (or 50 mrem) = 5 x 10^{-4} /(2.8 x 10-8) = 1.786 x 10^4 Bq/yr. The maximum allowable concentration of ^{90}Sr is then just

$$\frac{1.786 \times 10^4 \ (Bq/year)}{0.002 \ (m^3/day) \times 365 \ (days/year)} = 2.45 \times 10^4 \ Bq/m^3$$

The radiotoxicity decay profile for spent fuel is shown in Figure A-7.C.1. Also shown for comparison is the radiotoxicity of an 'equivalent' amount of natural uranium ore — that is, the quantity of uranium ore that would have to be mined in order to generate the metric ton of spent fuel. According to the figure, after about 150,000 years the spent fuel will be no more hazardous than the parent ore, implying that a high-level waste repository should be designed to isolate the spent fuel for approximately that length of time. Of course, such comparisons take no account of the different environmental risk factors for

Figure A-7.C.1 Radiotoxicity Decay Profile for Spent PWR Fuel (m³ water/MT fuel)



The radiotoxicity index corresponds to an ingested dose of 50 mrem/year and was calculated using ICRP-72 adult dose coefficients (1996)

* Amount of ore mined to produce 1 MT fuel @ 4.5% U-235 enrichment

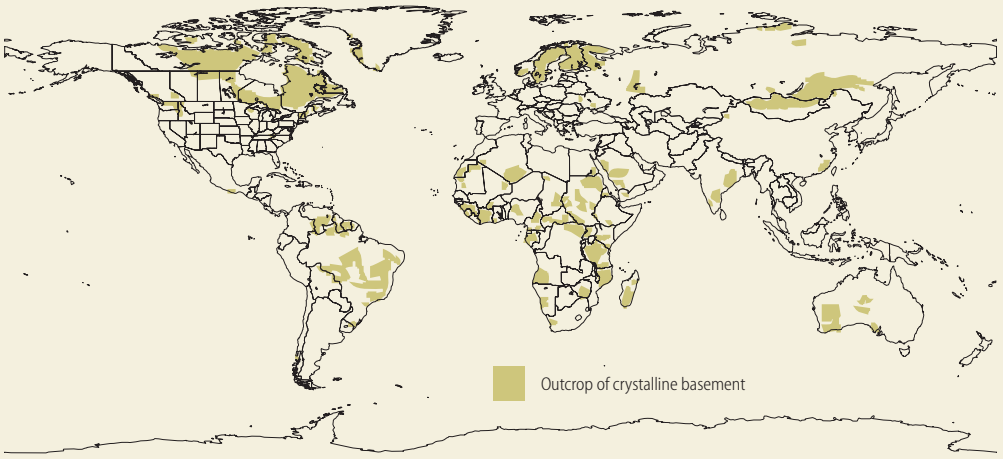
these materials. Uranium ores (and other naturally occurring hazardous materials) are deposited randomly, frequently in permeable strata, and with groundwater often present in abundance. By contrast, high-level waste will be buried at depths of several hundred meters in locations selected for geological stability, low groundwater flows, and remoteness from population centers. On the other hand, a high-level waste repository is a man- made structure, with shafts and boreholes linking it to the biosphere. Moreover, as noted previously the presence of heat-generating materials has the potential to disrupt the geohydrological environment and accelerate the corrosion of the waste canisters. All of these factors — and others besides — must be considered in assessing the actual risk posed by a waste repository. In short, although frequently used as an indicator of the radiological risk posed by the waste, the radiotoxicity index is an imperfect proxy of limited utility.

Appendix 7.D — Deep Borehole Disposal

An alternative to the construction of mined geologic repositories is to place waste canisters in deep boreholes drilled into stable crystalline rock several kilometers below the earth's surface. [1,19-24] At these depths, vast areas of crystalline basement rock are known to be extremely stable, having experienced no tectonic, volcanic, or seismic activity for billions of years. At such depths, moreover, the chemical environment is strongly reducing, and if any groundwater is present at all it is likely to be highly saline. Preferred locations for waste boreholes are in tectonically stable cratons and plutons in regions where there has been no major faulting and which are relatively easily accessible from the surface (i.e., the overburden of sedimentary rock should ideally be less than 1 kilometer thick.)

A detailed Swedish study of the deep borehole concept conducted about 15 years ago proposed a hole 80 centimeters in diameter at depth, into which would be placed canisters of length 4.4 meters and diameter 50 centimeters, with each canister separated from its neighbors by plugs of compressed bentonite clay. [19] If each canister contained the rods from two PWR fuel assemblies, a single borehole 4 kilometers deep, with the lower 2 kilometers filled with waste canisters, could store 10-15 years of spent fuel discharged by a 1000 MWe PWR. In other words, such a reactor might require 3-4 such holes to store the spent fuel discharged over its lifetime. The Swedes calculated that about 35 boreholes would be required to accommodate the forecast quantity of waste from Sweden's 11 nuclear power plants.

Figure A-7.D.1 Distribution of Crystalline Basement Rock Exposed to the Surface



Prepared by Grant Heiken, Los Alamos Scientific Laboratory, Earth and Environmental Sciences Division

The deep borehole concept was one of several high-level waste disposal schemes under consideration before the mined repository approach emerged as the preferred strategy in the U.S. and elsewhere in the 1980s.[4] Since then it has attracted little attention and few development resources, but in the meantime there have been significant advances in relevant technologies. Drilling to depths of a few kilometers, still quite rare in the 1970s and 1980s, is now fairly routine in the oil and gas industry, and major advances in well logging techniques permit more accurate characterizations of geophysical and geochemical parameters at depth.

An initial screening suggests that large areas of the world may have geology appropriate for deep waste boreholes.[5] Figure A-7.D.1 shows the global distribution of crystalline basement rock that is exposed at the surface. In practice, crystalline rock that is located within 2 km of the surface provides adequate access for deep drilling.

that is exposed at the surface. In practice, crystalline rock that is located within 2 km of the surface provides adequate access for deep drilling.

Suitable host rock also occurs beneath the sea floor. For this reason the concept may be particularly interesting for densely populated countries like Japan, Korea, and Taiwan. Since most of the power reactors in these countries (and indeed in most countries) are located on or close to the coast, the possibility arises of constructing artificial offshore islands from which to drill beneath the seabed. Such islands could also serve as temporary storage venues for the spent fuel, eliminating the requirement for on-land waste transportation and storage.

The pervasiveness of suitable geology for deep boreholes introduces the possibility of dispersed waste disposal sites, thus reducing the need for spent fuel transportation. Co-locating boreholes with at least some reactor sites may be technically feasible. Alternatively, the boreholes could be consolidated at a central location. For example, a borehole array occupying an area of 4 km^2, roughly equal to the subsurface footprint of the Yucca Mountain repository, could accommodate more than the Yucca Mountain spent fuel inventory.[6]

NOTES

* The radiotoxicity calculations presented in Appendix 7.C were carried out by Dr. Brett Mattingly, who also provided valuable research support in the preparation of this Appendix.

1. Several modeling studies of copper canister corrosion under expected repository conditions have been performed in Sweden, Finland, and Canada. Each of these studies has estimated an expected copper canister lifetime exceeding one million years. [7]. Natural analog studies also indicate that elemental copper corrodes at extremely slow and predictable rates in such conditions. [8]
2. Free oxygen is introduced into the near-field environment during waste emplacement operations. Oxidation of pyrite in the bentonite backfill helps to restore a reducing environment around the canister within a few hundred years at most. During this oxic phase, the copper mantle is not expected to corrode by more than 2.5 mm. Copper corrosion under reducing conditions occurs via sulfide attack. Dissolved sulfide concentrations will be limited by equilibrium with sulfide impurities in the bentonite. The copper corrosion rate under reducing conditions is much slower than under oxidizing conditions[6,7].
3. A reducing environment strongly inhibits the dissolution and transport of actinides in groundwater. The solubility of the long-lived fission product isotope Tc-99 is also significantly decreased in reducing conditions[14,16].
4. Other options considered at that time were disposal in surface facilities, extra-terrestrial disposal, ice sheet disposal, and disposal in the sedimentary layer under the deep ocean floor. Of these, only the sub-seabed disposal option has attracted any subsequent attention
5. Grant Heiken, Los Alamos Scientific Laboratory, Earth and Environmental Sciences Division, personal communication, November 15, 2002.
6. For example, suppose the borehole drillsites were arrayed on a grid measuring 2 km x 2 km with a spacing of 0.5 km. Suppose in addition that ten holes, each 5 km deep, were drilled from each drillsite, with the lower 3 km of each hole filled with waste canisters. If each canister is 5 meters in length and contains 1 PWR assembly, or equivalently about 0.5MT of spent fuel, the total spent fuel inventory in the borehole repository would be about 75,000 MT – somewhat more than the legal limit at Yucca Mountain. The storage capacity of the repository could be further increased by increasing the number of boreholes per drillsite, increasing the active length of each borehole, and increasing the packing density of the spent fuel rods in each canister by reconstituting the assemblies. If each of these parameters was doubled, say, the total capacity of the borehole repository would be more than 8 times that of Yucca.

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Appendix Chapter 9 — Public Attitudes

EUROPEAN ATTITUDES TOWARD NUCLEAR POWER

Our projection under the global growth scenario is that the U.S. will have the largest expansion in its nuclear fleet, followed by Europe and Japan. Some European countries have committed to eliminating or lessening their reliance on nuclear power for political reasons.

Attitudes toward nuclear power vary greatly across European countries ("European and Energy Matters, 1997," EUROBAROMETER 46.0, Directorate General for Energy, European Commission, February 1997). The survey additionally reports the following interesting trends:

> "On the country level, Finland, The United Kingdom and Sweden report with the highest frequencies to think the development of nuclear power stations is worthwhile. Compared to the figures of 1993, there are big downward shifts in Belgium and Italy in the proportions of respondents that say they think the development of nuclear power stations is worthwhile."
>
> The socio-demographic groups that to the highest extent think this is worthwhile are:
>
> - Those who finished their full time education at the age of 20 or after; and
> - Those with political preferences toward the right.
>
> Also, there is a noticeable difference of 8 points between the men and women that say the development of nuclear power stations is worthwhile, was recorded.
>
> The countries that to the highest extent state the development of nuclear power stations involves unacceptable risks are Austria, Greece, Denmark and Ireland.
>
> Big upward shifts in the percentages recorded, occurred in Denmark, West Germany, Greece, Spain, Ireland, Italy, Luxembourg and The United Kingdom. A noticeable downward shift was recorded in France.
>
> The socio-demographic groups that most often say it involves an unacceptable risk are those with left political preferences and those who are still studying.
>
> The French, the Dutch and the Swedes record the higher proportions of respondents stating that the development of nuclear power stations should be neither developed, nor abandoned."

Our analysis of U.S. survey data finds much weaker correlation of demographics with attitudes toward nuclear power than is evident in the Eurobarometer data. Indeed, once we control for perceptions of the technologies, the correlations vanish altogether. We suspect that the same is true in Europe: opinions are driven by economics, environmental harms, and solutions to the waste problem[1]. Replicating our survey in Europe and other countries is important for understanding the nature of public attitudes toward nuclear power and other energy options. For a discussion of the roots of French opinions toward nuclear power see: http://www.pbs.org/wgbh/pages/frontline/shows/reaction/readings/french.htmlattributes

MIT ENERGY SURVEY

Sample Statistics. Knowledge Networks drew a random sample of 1800 people from their panel to participate in an energy survey; 1358 completed the survey. Survey respondents were 18 years or over, with the median respondent about 45 years old. The typical person had income between $40,000 and $50,000. Thirty-one percent completed high school; 28 percent had some college; and 24 percent had a bachelor's degree or higher. Three-quarters of the respondents were white; 62 percent were married; 52 percent were female.

Question Wordings and Distribution of Responses On Future Use:

Question 11: To make more electricity to meet the country's needs over the next 25 years, new power plants will have to be built. Companies and government agencies need to start planning today. How should we meet this demand?

DISTRIBUTION OF RESPONSES (all groups):

FUEL	NOT USE	REDUCE A LOT	REDUCE SOMEWHAT	KEEP SAME	INCREASE SOMEWHAT	INCREASE A LOT
Coal	4.8%	23.3	29.9	25.0	10.7	6.0
Dams	1.4	3.8	11.2	31.1	34.2	18.0
Gas	1.3	6.3	24.1	37.2	22.7	8.1
Nuclear	9.2	19.2	18.6	24.6	18.3	9.8
Oil	3.4	19.7	33.6	30.2	9.5	3.2
Solar	1.4	2.3	4.9	13.6	27.0	50.4
Wind	1.6	2.5	4.7	13.9	24.4	52.6

Question 8. How expensive do you think it is to produce electricity from each of the following fuels?

1. Very Expensive;
2. Somewhat Expensive;
3. Moderately Priced;
4. Somewhat Cheap;
5 Very Cheap

DISTRIBUTION OF RESPONSES (all groups):

	EXPENSIVE		MODERATELY	INEXPENSIVE		
FUEL	Very (1)	Somewhat (2)	Priced (3)	Somewhat (4)	Very (5)	AVERAGE
Coal	13.4%	24.5%	35.1%	21.4%	5.6%	2.8
Nuclear	38.8	33.0	19.3	7.4	2.0	2.0
Natural Gas	11.8	32.8	42.5	11.5	1.3	2.6
Oil	25.2	42.1	26.7	5.3	0.7	2.1
Hydroelectric	9.9	24.5	34.7	22.4	8.9	3.0
Solar	9.9	19.4	22.7	28.1	19.9	3.3
Wind	4.5	11.6	19.3	31.1	33.5	3.8

Question 7. Some ways of generating electricity may be harmful to the environment we live in because they produce air pollution, water pollution, or toxic wastes. How harmful do you think each of these power sources is? (Higher values are less harmful)

DISTRIBUTION OF RESPONSES:

	VERY	MODERATELY	SOMEWHAT	SLIGHTLY	NOT	AVERAGE
Coal	32.9%	31.7%	24.2%	9.0%	2.3%	2.2
Nuclear	45.1	22.5	17.3	10.4	4.7	2.1
Natural Gas	6.9	18.0	35.0	29.4	10.8	3.2
Oil	23.4	37.1	28.0	8.6	2.8	2.3
Hydroelectric	6.0	12.0	19.0	29.2	33.8	3.7
Solar	2.7	3.1	8.9	14.0	71.2	4.5
Wind	1.7	2.9	6.9	12.8	75.8	4.6

Question 9. There are approximately 100 nuclear power plants in the United States. How likely do you think it is that in the next 10 years there will be a serious accident at a nuclear power plant?

Almost Certain	18.9%
Very Likely	23.0
Somewhat Likely	31.9
Not Very Likely	23.6
Not At All	2.3

Question 10. Do you agree or disagree with the following: Nuclear waste can be stored safely for many years.

Strongly Agree	5.9%
Agree	30.3
Disagree	39.7
Strongly Disagree	23.9

REGRESSION ANALYSIS EXPLAINING FUTURE USE

For each fuel, Question 11 is the dependent variable. For all fuels, responses to Questions 7 and 8 are used to measure perceived harms.

Table A-9.2 Relationship between Perceived Harm and Perceived Cost and Future Use, Holding Constant Other Factors

	IN FUTURE INCREASE/]REDUCE USE OF …						
	Coal	Hydro	Gas	Nuclear	Oil	Sun	Wind
Perceived (Lower) Harm:							
Coal	+.38**	–.03	–.09	–.06	+.07	–.13**	–.13**
Dams	–.09	+.32**	–.13**	–.04	–.05	–.02	+.01
Gas	+.03	–.13**	+.30**	–.08*	–.00	–.06	–.05
Nuclear	–.07	–.05	–.09**	+.35**	–.14**	–.02	–.00
Oil	_.06	–.16**	+.06	–.00	+.29**	–.13**	–.12**
Sun	–.10*	+.02	–.10*	–.01	–.22**	+.30**	+.12**
Wind	–.10*	–.01	–.03	–.11*	–.14**	+.10*	+.27**
Perceived (Lower) Cost:							
Coal	+.09**	–.04	–.01	+.06	+.01	–.04	–.06*
Dams	–.05	+.15**	–.10**	–.06	–.12**	+.07**	+.11**
Gas	–.07	+.02	+.15**	–.12**	+.00	.01	+.01
Nuclear	+.03	–.05	+.01	+.14**	–.01	–.06*	–.08**
Oil	–.05	+.04	–.01	–.00	+.06*	–.02	–.01
Sun	–.02	–.10**	+.02	+.01	–.03	+.10**	+.02
Wind	+.05	+.06	–.01	+.00	+.08*	–.12**	–.05
Nuke Accident	+.01	+.03	+.05**	–.22**	–.00	+.08**	+.05
Nuke Waste Safe	–.01	–.05*	+.00	+.18**	+.01	–.06**	–.08**
Global Warming	–.03	–.02	+.00	–.02	+.05	+.00	+.01
R-squared	.49	.53	.57	.55	.47	.49	.46

(% of y explained)
* Statistically significant at p<.05.
** Statistically significant at p <.01.

In summary, the results of our survey find

- The public correctly perceives the relative costs and benefits of nuclear power compared to other power sources.
- The public has yet to connect the way we generate power to carbon emissions and global warming.
- Additional information may not be enough to change public attitudes toward nuclear power.

NOTE

1. For a discussion of the roots of French opinions toward nuclear power see: http://www.pbs.org/wgbh/pages/frontline/shows/reaction/readings/french.htmlattributes