INL/EXT-07-12107
Rev. 2

Advanced Fuel Cycle Cost Basis

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The INL is a U.S. Department of Energy National Laboratory
operated by Battelle Energy Alliance

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MODULE REVISION LOG
(based on changes from March 2008 report)

Module(s)	Module Description	New Costs	New Citations	Revision Description
A1	Natural Uranium Mining and Milling	✓	✓	Updated long-term U cost forecast, added analysis contrasting U market behavior to that of other minerals and the fossil fuels. Incorporated most recent (2007) Red Book and (2009) EIA projections, including figures, tables and analysis of current versus historical Red Book data. Added discussion of energy intensity of U extraction and overview of U recovery from coal ash. Updated market data and current industry news.
A2	Natural Thorium Mining and Milling	✓	✓	New module.
B	Conversion		✓	Updated market data and current industry news.
C1	Enrichment (Isotopic Separation)	✓	✓	Added description of SILEX process with figures, current status and performance comparison *vis a vis* other technologies. Discussed US plans for post-2013 SWU transactions with Russia. Incorporated WNA projections of SWU demand through 2030. Updated market data and current industry news; provided analysis of recent elevated SWU prices and prognosis.
C2	Highly Enriched Uranium Blend-Down		✓	Blend-down of U.S. surplus HEU from military programs now discussed
D1	Fabrication of Contact–Handled Fuels	✓	✓	New SRS data on MOX fuel added. Small changes in other fuel fabrication costs
E1	Wet Storage of SNF			No changes
E2	Dry Storage of SNF		✓	New data added from the Follow-on Engineering Alternative Studies

Module(s)	Module Description	New Costs	New Citations	Revision Description
E3	Storage of Combined Recycled Product of Mixed Plutonium, Minor Actinides, and Uranium Product	✓	✓	New data added from the Follow-on Engineering Alternative Studies
E4	Managed Decay Storage	✓	✓	New module
F1	SNF Aqueous Reprocessing Facility	✓	✓	New data added from the Follow-on Engineering Alternative Studies
F2/D2	Electrochemical Reprocessing and Remote Fuel Fabrication	✓	✓	New data added from the Follow-on Engineering Alternative Studies
G	Waste Conditioning, Storage, and Packaging	✓	✓	New data added from the Follow-on Engineering Alternative Studies
I	Long-Term Monitored Retrievable Storage,			No changes
J	Near Surface Disposal			No changes
K1	Depleted Uranium Conversion and Disposition	✓	✓	New cost data on UDS tails conversion plants. Discussion of regulatory uncertainties associated with tails disposal. Slight upward changes in unit cost.
K2	Reprocessed Uranium Disposition-Aqueous	✓	✓	Added discussion of how REPU materials from U.S. military fuel cycles are handled. LOW Unit costs are adjusted slightly upward.
K3	Reprocessed Uranium Disposition-Electrochemical			No changes
L	Geologic Repository	✓	✓	Updated with the latest cost estimates from the Yucca Mtn. Project and added new international data

Module(s)	Module Description	New Costs	New Citations	Revision Description
M	Alternative Disposal Concepts			No changes
O	Transportation of Radioactive Materials			No changes
R1	Thermal Reactors	✓	✓	Recent escalation in costs reflected. Much new data on plants undergoing COL process. Many new references added: both pro and anti nuclear.
R2	Fast Reactors	✓	✓	A small amount of new cost data has been added
R3	Gas Cooled Reactors	✓	✓	New module
R4	Small-Medium Reactors	✓	✓	New module

ABSTRACT

This report, commissioned by the U.S. Department of Energy (DOE), provides a comprehensive set of cost data supporting a cost analysis for the relative economic comparison of options for use in the Advanced Fuel Cycle Initiative (AFCI) Program. The report describes the AFCI cost basis development process, reference information on AFCI cost modules, a procedure for estimating fuel cycle costs, economic evaluation guidelines, and a discussion on the integration of cost data into economic computer models. This report contains reference cost data for 25 cost modules—21 fuel cycle cost modules and 4 reactor modules. The cost modules were developed in the areas of natural uranium mining and milling, thorium mining and milling, conversion, enrichment, depleted uranium disposition, fuel fabrication, interim spent fuel storage, reprocessing, waste conditioning, spent nuclear fuel (SNF) packaging, long-term monitored retrievable storage, managed decay storage, recycled product storage, near surface disposal of low-level waste (LLW), geologic repository and other disposal concepts, and transportation processes for nuclear fuel, LLW, SNF, transuranic, and high-level waste.

SUMMARY

This report, commissioned by the U.S. Department of Energy (DOE), provides a comprehensive set of cost data supporting an ongoing, credible, technical cost analysis basis for use in the Advanced Fuel Cycle Initiative (AFCI) Program. System analysts will use this report to evaluate the impacts and benefits of a wide range of AFCI and Generation IV deployment options. The objectives underlying this report are to (1) understand the issues and opportunities for keeping nuclear power an economically competitive option, (2) evaluate the elements dominating nuclear fuel cycle costs, and (3) develop the tools to evaluate the economics of creative solutions to make the nuclear fuel cycle even more cost competitive.

The intended use of the cost data is for the relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. Each element of cost has a probabilistic range of accuracy, and when the costs are coupled together into a total fuel cycle system estimate, the uncertainty range is additive. This information is being used in studies to evaluate costs of fuel cycle options. Fuel cycle costs are an important part of the comprehensive evaluation, which also includes measures of sustainability, proliferation resistance, adaptability to different energy futures, and waste management impacts (e.g., heat load impacts on the repository). These evaluations will result in the identification of cost drivers within the fuel cycle where development may be focused to reduce the costs within the system.

This report describes the AFCI cost basis development process, reference information on AFCI cost modules, a procedure for estimating fuel cycle costs, economic evaluation guidelines, and a discussion on the integration of cost data into economic computer models. This report contains reference cost data for 25 cost modules—21 fuel cycle cost modules and four reactor modules. The cost modules were developed in the areas of natural uranium mining and milling, thorium mining and milling, conversion, enrichment, depleted uranium disposition, fuel fabrication, interim spent fuel storage, reprocessing, waste conditioning, spent nuclear fuel (SNF) packaging, long-term monitored retrievable storage, managed decay storage, recycled product storage, near surface disposal of low-level waste (LLW), geologic repository and other disposal concepts, and transportation processes for nuclear fuel, LLW, SNF, transuranic, and high-level waste. The AFCI cost developers are closely coordinating with the Generation IV Economic Modeling Working Group (EMWG) and have adopted many of the EMWG estimating structures, assumptions, and estimating processes.

This report is based on data collected from historical reports and expert knowledge of past and current fuel cycle facilities and processing requirements. The reference data have been placed into a cost collection database, screened, normalized for U.S. facilities, and summarized for this report. The fuel cycle requirements for future generation nuclear reactors are also being assessed and will be included in the cost basis as the technology matures. The cost basis information will be updated annually to keep pace with advances in the technology development studies.

ACKNOWLEDGMENTS

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PREFACE

The December 2009 release of the AFC Cost Basis report contains a number of important updates and improvements since the previous report published in March 2008. Module content and cost data have been further improved through use the use of new resources and information derived from new references. The What-It-Takes (WIT) tables have been updated with additional cost breakdowns and details reflecting the cost analyst's current expectations. Module cost frequency distributions have been expanded to further illustrate the most likely cost bounds and probabilities. The most significant module changes in this revision include the addition of the thorium mining and milling module (A-2), updates to the uranium mining (A-1) and milling and enrichment (C) modules, new cost data for aqueous reprocessing (F) and electrochemical modules (F2/Ds), a relook at the estimating bases for geologic disposal, and the addition of new modules for gas-cooled reactors (R3), and Small Medium Reactors (R4). A revision change log has been added to the very beginning of this report summarizes which modules received cost updates, where new reference sources have been identified, and a brief summary of the changes.

The University of Texas-Austin provided the new thorium module in addition to updates to the fuel cycle front-end modules. Uranium and enrichment costs were updated by taking a fresh look at the historical trends as well as recent run-up in uranium and enrichment prices. In the reprocessing (F1, F2/D2) and waste conditioning (G) modules, many important updates were provided by the Savannah River Site based on the Engineering Alternative Study (EAS) and the follow-on EAS. Burns & Roe provided cost details for the recycled product storage (E3) and the new managed decay storage module (E4). Oak Ridge National Laboratory provided updates to the thermal and fast reactor costs and developed the estimating bases for the new reactor modules including gas-cooled reactors (R3) and Small Medium Reactors (R4). Also, Idaho National Laboratory provided updates to the geologic repository module (L) and coordinated the overall report preparation.

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ACRONYMS

ac	alternating current
ACP	American Centrifuge Plant
ADU	ammonium diuranate
AEC	Atomic Energy Commission
AFC	advanced fuel cycle
AFCI	Advanced Fuel Cycle Initiative
AFM	Ateliers Vitrification Marcoule
AGNS	Allied-General Nuclear Services
AHWR	advanced heavy water reactor
AIROX	Atomics International Reduction Oxidation
ALMR	advanced liquid metal reactor
ANL	Argonne National Laboratory
ANL-W	Argonne National Laboratory-West
ANS	American Nuclear Society
APSF	Actinide Packaging and Storage Facility
ASTM	American Society for Testing and Materials
AVH	Ateliers Vitrification La Hague
AVLIS	Atomic Vapor Laser Isotopic Separation
AVM	Ateliers Vitrification Marcoule
AVR	Atom Versuchs Reaktor
BCM	Boston Consulting Group
BLEU	Blended Low Enriched Uranium
BNFL	British Nuclear Fuels plc
BSG	borosilicate glass
BWR	boiling water reactor
CANDU	Canada deuterium uranium
CARBOX	CARBothermic-reduction Oxidation
CBFO	Carlsbad Field Office
CEA	Atomic Energy Commission

CEFR	Chinese Experimental Fast Reactor
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFRP	Consolidated Fuel Reprocessing Program
CFTC	Consolidated Fuel Treatment Center
CHEMEX	chemical exchange
CLS	Canadian Light Source
CNNC	China National Nuclear Corporation
COA	code of accounts
Co-Ex	co-extraction
CPP	Central Processing Plant
CRBR	Clinch River Breeder Reactor Project
CSF	Consolidated Storage Facility
CST	crystalline silicotitanate
CWCCIS	Civil Works Construction Cost Index System
CY	calendar year
D&D	decontamination and decommissioning
DF	dispersion free
DOD	Department of Defense
DOE	U.S. Department of Energy
DYMOND	Dynamic Model of Nuclear Development
DOE-NE	DOE Office of Nuclear Energy
DR	digital radiography
DU	Depleted Uranium
DWPF	Defense Waste Processing Facility
EAR-I	Estimated Additional Resources Category I
EAR-II	Estimated Additional Resources Category II
EAS	Engineering Alternative Studies
EBR-II	Experimental Breeder Reactor-II
EDF	Electricite de France
EDRP	European Demonstration Fast Reactor Reprocessing Plant

EFR	European Fast Reactor
EIA	Energy Information Administration
EM	Office of Environmental Management
EMWG	Economic Modeling Working Group
EPA	Environmental Protection Agency
EPR	European Pressurized-water Reactor
EPR&S	Early Fuel Receipt and Storage
ERI	Energy Resources International
EU	enriched uranium
EURODIF	European Gaseous Diffusion Uranium Enrichment Consortium
F&OR	Functional and Operational Requirements
FBTR	fast breeder test reactor
FCF	Fuel Conditioning Facility
FCRD	Fuel Cycle Research and Development
FF	fuel refabrication
FFTF	Fast Flux Test Facility
FOAK	First-of-a-Kind
FOEAS	Follow-on EAS
FP	fission product
FR	fast reactor
FRC	reprocessing range
FY	Fiscal Year
GAO	General Accounting Office
GBP	Great Britain Pounds
GDP	gaseous diffusion plant
GE	General Electric
GTCC	Greater-than-Class-C (low-level waste)
HEF	Hot Experimental Facility
HEPA	high-efficiency particulate air
HEU	highly enriched uranium

HF	hydrogen fluoride
HIPing	hot isostatic pressing
HLW	high-level waste
HM	heavy metal
HTB	Hexagonal Tungsten Oxide Bronze
HTGR	High-Temperature Gas-Cooled Reactor
HTO	hydrous titanium oxide
HVAC	heating, ventilating, and air conditioning
HWR	heavy water reactor
IAEA	International Atomic Energy Agency
IBR	International Business Relations
IDC	Interest during construction
IDM	Integrated Decision Management
ILW	intermediate level waste
INB	Institute of Neurosciences and Biophysics
INEEL	Idaho National Engineering and Environmental Laboratory
INFCE	International Nuclear Fuel Cycle Evaluation
INIS	International Isotopes
INL	Idaho National Laboratory
IREL	Indian Rare Earths Limited
ISL	In Situ Leach
IWMS	Integrated Waste Management Strategy
IX	ion exchange
JNC	Japan Nuclear Cycle Development Institute
JNFL	Japan Nuclear Fuel, Ltd.
JSFR	Japanese Sodium-cooled Fast Reactor
kgHM	kilogram of heavy metal
LCC	Life Cycle Cost
LDR	Land Disposal Restriction
LES	Louisiana Energy Services, LLC

LEU	low-enriched uranium
LLW	low-level waste
LUEC	Levelized Unit of Electricity Cost
LWR	light water reactor
MTHM	metric ton of heavy metal
MA	minor actinides
MC&A	material control and accountancy
MFC	Materials and Fuels Complex
MFDS	Modular Vault Dry Store
MFFF	Mixed-Oxide Fuel Fabrication Facility
MFRP	Midwest Fuel Recovery Plant
MIT	Massachusetts Institute of Technology
MK	Manavalakurichi
MLLW	mixed low-level waste
MOX	mixed oxide
MPC	multipurpose canister
MSRE	Molten Salt Reactor Experiment
MT	metric tons
NAS	National Academy of Sciences
NATU	natural uranium
NDA	non-destructive assay
NDA	Nuclear Decommissioning Authority
NEA	Nuclear Energy Agency
NECDB	Nuclear Energy Cost Data Base
NEF	National Enrichment Facility
NEI	Nuclear Engineering International
NETL	National Energy Technology Laboratory
NFAL	Nuclear Fuel Australia Ltd.
NFS	Nuclear Fuel Services
NNSA	National Nuclear Security Administration

NOAK	Nth-of-a-Kind
NRC	Nuclear Regulatory Commission
NPP	Nuclear Power Plant
NRC	Nuclear Regulatory Commission
NTI	Nuclear Threat Initiative
NTS	Nevada Test Site
NTWMP	National TRU Waste Management Plan
NU	natural uranium
NURE	National Uranium Resource Evaluation
O&M	Operations and Maintenance
OCC	overnight capital cost
OCRWM	Office of Civilian Radioactive Waste Management
OCW	outer can welder
OECD	Organization for Economic Cooperation and Development
ORGDP	Oak Ridge Gaseous Diffusion Plant
ORNL	Oak Ridge National Laboratory
OSCOM	Orissa Sands Complex
P&RS	Product & Residue Store
PEcoS	Pacific EcoSolutions Inc.
PHWR	pressurized heavy water reactor
ppm	parts per million
PRISM	Power Reactor Inherently Safe Module
PUREX	Plutonium-Uranium Extraction
PWR	pressurized water reactor
R&D	research and development
RD&D	research, development, and demonstration
RAR	Reasonably Assured Resources
RE	rare earth element
REPU	reprocessed uranium
RF	Russian Federation

RH	remote-handled
ROM	rough order of magnitude
RRP	Rokkasho recycling plant
RTPI	Radkowsky Thorium-Plutonium Incinerator
RU	reprocessed uranium
SA5	Sensitivity Analysis 5
SFTF	Spent Fuel Treatment Facility
SI	Systeme Internationale
SNF	spent nuclear fuel
SNL	Sandia National Laboratories
S-PRISM	Super-Power Reactor Inherently Safe Module
SR	Speculative resources
SRP	Salt River Project
SRS	Savannah River Site
SS	stainless steel
SSL	Smith and Storm van Leeuwan
SWU	separative work units
TBP	tributyl phosphate
TCC	total capital cost
TCIC	Total Capital Investment Cost
TCOE	Total Cost of Electricity
TENEX	Techsnabexport
THORP	Thermal Oxide Reprocessing Plant
THTR	Thorium High Temperature Reactor
TIG	Tungsten Inert Gas
TOC	Total Overnight Cost
TPC	Total Project Cost
TRL	technology readiness level
TRU	transuranic
TRUPACT-II	Transuranic Package Transporter Model-II

TVA	Tennessee Valley Authority
TWRS	Tank Waste Remediation System
UDS	Uranium Disposition Services, LLC
UNH	uranyl nitrate hexahydrate
URENCO	URanium-ENrichment-COmpany
UREX	uranium extraction
USEC	United States Enrichment Corporation
UXC	Ux Consulting Company
VHTR	Very High Temperature Reactor
VIPAC	vibropacked
VISION	Verifiable Fuel Cycle Simulation
VOA	Voluntary Offer Agreement
VPS	vitrified product store
VVER	Vod-Vodyanoi Energetichesky Reaktor
VWISF	Vitrified Waste Interim Storage Facility
WBS	work breakdown structure
WFP	Waste Vitrification Plant
WIPP	Waste Isolation Pilot Plant
WIT	What-It-Takes
WNA	World Nuclear Association
WTF	Waste Treatment Plant
WVP	Waste Vitrification Plant

NOMENCLATURE

The following definitions established the common terminology used to develop fuel cycle cost estimates. These terms were developed by the Generation IV Economic Modeling Working Group and, in some cases, have been modified to describe fuel cycle costs. It is understood that some of these terms will not be used or become applicable until much later in the system development and deployment cycle.

Base cost. The base construction cost is the most likely plant construction cost based on the direct and indirect costs only. This cost is lower than the total capital cost because cost elements such as contingency and interest are not included. The direct costs are those costs directly associated on an item-by-item basis with the equipment and structures that comprise the complete production plant, fuel cycle facility, equipment fabrication factory, or end-use plant. The indirect costs are expenses for services applicable to all portions of the physical plant. These include field indirect costs, design services, engineering services, architectural engineer home office engineering and design services, field office engineering and services, and construction management services. Process equipment manufacturer home office engineering and services are included in separate accounts. Owner’s costs, such as commissioning, are added to the base costs prior to the application of the contingency allowance.

Common plant facilities. Common plant facilities are those systems, structures, and components that provide common support to the operation at a new plant site. They include such facilities as administration buildings, general warehouse, water supply, general fire systems, energy distribution, cooling water intakes, cooling towers, and civil and engineering offices. These common plant facilities can be sized to share with other production units added subsequently.

Constant money. Constant money cost is the cost of an item, measured in money that has a general purchasing power as of some reference date, (e.g., January 1, 2001). Because inflation is associated with the erosion of the purchasing power of money, constant money analysis factors out inflation. In the Advanced Fuel Cycle Initiative (AFCI) economic analyses carried out using the present guidelines, only constant money costs will be considered.

Construction module. A construction module is a free standing, transportable preassembly of a major portion of the plant, or a system or sub-system of the unit. A construction module may be a preassembly of a single system or portion thereof, or may contain elements of all the systems that exist in a given location in the plant. A construction module may contain parts of the building structure. A construction module might be assembled in a factory, shipped to the plant site, and installed in the plant (perhaps after minor assembly and/or linking). The direct costs for modules should contain their share of the manufacturing costs, including the fair burden of the cost of operating the factory where they are manufactured. If not, the factory-related costs must be accounted for elsewhere. An example would be groups of gas centrifuges for uranium enrichment shipped as production units from a centrifuge machine manufacturing facility.

Contingency. Contingency is an adder to account for uncertainty in the cost estimate Contingency includes an Allowance For Indeterminates and should be related to the level of design, degree of technological advance, and the quality/reliability level of given components. Contingency does not include any allowance for potential changes from external factors, such as changing government regulations, major design changes or project scope changes, catastrophic events (*force majeure*), labor strikes, extreme weather conditions, varying site conditions, or project funding (financial) limitations. Contingencies can be also applied to the interest during construction (IDC) and the capacity factor to account for uncertainty in the reactor design/construction schedule and reactor performance, respectively.

Deployment costs. Costs of developing a standard facility design and licensing it. These are considered part of First-of-a-Kind (FOAK) costs and are distinct from research and development costs.

Direct cost. All costs that are traceable to construction of permanent plant, but excluding support services such as field indirect costs, construction supervision, and other indirect costs (see also Base cost).

Discount rate. In the context of the present guidelines, discount rate will be taken as equal to the real cost of money. This cost will, in turn, depend on the market risk, deployment risk, financing scheme, and other external factors.

Economic life. The number of years of commercial operation over which capital costs are recovered. This value is needed to calculate a fixed charge rate or capital recovery factor. The economic life is usually fixed at the number of years of commercial operation allowed by the regulator.

Escalation rate. The rate of cost change. This rate can be greater than or less than the general inflation rate, as measured by the Gross Domestic Product Implicit Price Deflator. For Advanced Fuel Cycle Initiative cost estimation, it will be assumed to be zero, unless otherwise justified.

Equipment. Equipment for production facilities includes all manufactured items ordered and delivered to a site, and used in construction. Such items may be procured on a design and build contract from qualified vendors, wherein design responsibility belongs to the seller (vendor) or is maintained by the buyer or purchasing agent on a “build-to-print” basis. To facilitate bottom-down estimating techniques, only major process related equipment costs will be categorized as equipment cost. Nonprocess related equipment such as heating, ventilating, and air conditioning (HVAC), plumbing, lifting or maintenance equipment, or large pipe and valves is to be classified as material costs.

Equipment module. An equipment module is a prepackaged and site delivered (skid-mounted, factory-assembled) package that includes (but is not limited to) equipment, piping, instrumentation, controls, structural components, and electrical items. Module types include Box Modules, Equipment Modules, Structural Modules, Connection Modules, Electrical Modules, Control System Modules, and Dressed Equipment Modules. These Modules are applicable to both the Main Process and Balance of Plant, including support buildings.

Factory (manufacturing facility) first-of-a-kind costs. These First-of-a-Kind (FOAK) costs include the development of manufacturing specifications, factory equipment, facilities, startup, tooling, and setup of factories that are used for manufacturing specific equipment for the fuel cycle system. These costs can be minimized if existing facilities are used for module production. These facilities might not be dedicated to, or even principally used for this application (e.g., a shipyard or any other factory that already builds modules for other industries or units). For a new modular production facility, the new equipment module fabrication factory might be considered a FOAK cost and included in module prices. If these costs are to be spread over a production run (or total Number of Plants), then the cost should be estimated on that basis, and the number of plants or production needed to recover the factory costs defined. The module prices are in the unit/plant costs and, as such, the price should be amortized into the unit product cost over some number of modular facilities produced over its projected lifetime. The capital cost of the modules must amortize the module factory capital costs plus the normal annual production (operating) costs for the factory. For a preexisting factory, it is assumed that the price of the modules includes a fair share of any factory operating and capital recovery costs (overheads).

First commercial plant costs. The first commercial plant is the first standard plant of a particular type that is sold to an entity for the purpose of commercial production of fuel and/or other fuel cycle related products or services. The costs include all engineering, equipment, construction, testing, tooling, and project management costs, as well as any other costs that are repetitive in nature. Any costs unique to the first commercial plant, which will not be incurred for subsequent plants of the identical design, will be identified and broken out separately as FOAK plant costs. The “learning” process for this first plant will reflect its first commercial plant status and not be the average over a larger number of later plants.

First-of-a-kind plant costs. The First-of-a-Kind (FOAK) costs are those necessary to put a first commercial plant in place that will not be incurred for subsequent plants. Design and design certification costs are examples of such costs. Refer to the figure on temporal relationship of research, development, and demonstration (RD&D); deployment; and standard plant costs at the end of nomenclature section.

Force account. Construction Labor Force account involves the direct hiring and supervision of craft labor to perform a construction activity by a prime contractor, as opposed to the prime contractor hiring a subcontractor to perform these functions.

Indirect cost. All costs that are not directly identifiable with a specific permanent plant, such as field indirect, construction supervision, design services, and PM/CM services (see Base cost).

Industrial grade construction. Industrial grade construction means construction practices that conform to generally accepted commercial requirements such as those required for fossil-fired plant or general chemical plant construction. Industrial grade construction could be used for nonnuclear parts of fuel cycle facilities, such as a zirconium tube factory in a light water reactor fuel fabrication facility. A module factory could also use industrial grade construction for the production of some modules. See also definition of nuclear grade construction.

Inflation rate. The rate of change in the general price level as measured by the Gross Domestic Product Implicit Price Deflator. The inflation rate is assumed to be zero in constant money based studies.

Interest during construction. Interest during construction (IDC) is the interest accrued for up-front cost financing (i.e., it is accrued to the end of construction and plant startup). This report assumes that once the plant is in commercial operation, the IDC plus the total overnight costs are “rolled-over” to a long-term loan or financing structure.

Levelized unit of electricity (LUEC) cost. The levelized cost of electricity generation, expressed in U.S.$/MWh or mills per net kWh. For the standard plant, it includes costs associated with nongeneric licensing, capital investment, operation and maintenance of the energy plant, owner’s costs, ongoing refurbishment, fuel, waste disposal, and decommissioning the plant at the end of life, and may include revenue offsets due to by-product production. Typically, the four components of levelized unit of electricity cost (LUEC) reported are: the capital component (recovery of capital cost over economic life), the production or nonfuel operating and maintenance component, the fuel component, and the decontamination and decommissioning component. Normally, this cost does not have research and development or demonstration (prototype) cost embedded in it. If the FOAK plant were a commercial plant, it would have some FOAK costs, such as generic design and design certification, recovered in the LUEC. The remaining recoverable costs would be standard plant costs. When multiple reactors (and types) are evaluated in a fuel cycle scenario, then the composite unit cost is referred to as the total cost of electricity (TCOE).

Materials. Materials include field-purchased (site material) and/or bulk commodity items, such as lumber, concrete, structural steel, and plumbing items. All piping is a materials item, as are all wire, cable, and raceways, including those in building service power systems. Also included is nonprocess related equipment such as HVAC, cranes, hoists, doors, plumbing, sewage treatment, etc. To facilitate bottom-down estimating techniques, only process-related equipment is categorized as equipment cost.

Module. See Construction Module and Equipment Module.

Multi-unit plant. A plant consisting of more than one production unit.

Nominal dollars. Nominal dollar cost is the cost for an item measured in as-spent dollars and includes inflation. Nominal dollars are sometimes referred to as “current” dollars, “year of expenditure” dollars, or “as spent” dollars.

Nominal cost of money. The nominal cost of money is the percentage rate used in calculations involving the time value of money containing an inflation component. It explicitly provides for part of the return on an investment to keep up with inflation.

Nth-of-a-kind plant cost. The nth-of-a-kind (NOAK) plant cost is the cost of the nth-of-a-kind or equilibrium commercial plant of identical design to the FOAK plant. NOAK plant cost includes all engineering, equipment, construction, testing, tooling, and project management, as well as any other costs that are repetitive in nature and would be incurred if an identical plant was built. The NOAK plant cost reflects the beneficial cost experience of prior plants. This currently defines the NOAK plant as the next plant after 8.0 GWe of capacity have been built (Chandler and Shropshire 2005). However, some U.S. nuclear analysts suggest that the NOAK plant may be achieved earlier (e.g., closer to four power plants). Refer to the figure on temporal relationship of RD&D, deployment, and standard plant costs at the end of nomenclature section.

Nuclear-safety grade. Nuclear-safety grade construction means construction practices that satisfy the Quality Assurance and other requirements of national licensing. Both reactor and fuel cycle facilities will require some nuclear-grade construction.

Overnight cost. The (total) overnight cost is the base construction cost plus applicable owner's, contingency, and first core costs. It is referred to as an overnight cost in the sense that time value costs (IDC) are not included (i.e., the cost is as if the plant were constructed "overnight" with no accrual of interest). Total overnight cost is expressed as a constant dollar amount in reference year dollars (overnight cost = total capital investment cost – IDC). Commissioning costs are included in the overnight cost for this study, which is not usually the case for conventional facility estimates. This expanded definition is used to reflect the fact that an owner is likely to need to finance the start-up cost in addition to the design and construction costs. Allowing all "up-front" costs to be combined into one lump sum term prior to calculation of the IDC simplifies the algorithms used to calculate the LUEC.

Prototype-of-a-kind. Costs specific to any prototype plant. These include prototype-specific design, development, licensing, construction, and testing, as well as operation of the prototype to support the demonstration of the system or concept (this prototype may assist, but does not meet or satisfy standard plant design certification). These costs are separate from FOAK and are not amortized within the LUEC.

Research, development, and demonstration costs. Costs associated with material, component, system, process, and possibly even fuel development and testing performed specifically for the particular advanced concept. These costs are often borne by governments or by industry consortia, and may be recovered depending on national norms and practices. In the present guidelines, RD&D costs are not distributed into the LUEC; however, their sum for each system is an important figure of merit for AFCI decision makers.

Real cost of money. The real cost of money (r) is the percentage rate used in calculations involving the time value of money when the inflation component has been removed (constant money calculations). Calculations using the real cost of money assume that the money maintains a constant value in terms of purchasing power, and, thus, no return on investment is needed to cover inflation.

Reference plant costs. These costs are the basis for estimating costs in the absence of a fully worked up or proven cost for a commercial unit (i.e., a surrogate basis for estimating total plant cost and cost differences). The reference plant is not part of the overall project, but rather a benchmark from which to begin costing the real planned facilities. Obtaining this information may incur some costs. See Chapter 4 of the Generation IV Cost Estimating Guidelines for information on the process for top-down cost estimation using reference plant costs.

Single-unit plant. A stand-alone commercial production plant consisting of a single unit and all necessary common plant facilities is referred to as a single-unit plant or unit. This is the smallest unit of production capacity normally sold to a customer, such as a uranium enricher or fabricator.

Specific cost. Total cost divided by the net capacity (such as net MTHM) of the plant.

Standard plant design costs. Costs associated with the engineering and engineering support functions for the design of the standard plant. These are a FOAK cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Standard production plant licensing costs. Costs associated with licensing-related activities performed to establish that the design of the standard plant is adequate for obtaining a license. In the United States, it includes the design and analysis of prototype tests necessary for certification, coordination with the Nuclear Regulatory Commission, and preparation of documents required for certification of the standard plant design. These are a FOAK cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Technology development costs. See research, development, and demonstration costs.

Total Cost of Electricity. The total cost of electricity (TCOE) is represented by the composite costs from an alternative consisting of multiple reactors (and potentially types of reactors), expressed in U.S.$/MWh or mills per net kWh. These costs include the individual reactor LUEC and fuel cycle costs. The TCOE can be decomposed into composite contributions from the reactor (thermal and fast) capital component (recovery of capital cost over economic life), operating and maintenance component, fuel component, and the decontamination and decommissioning component. This cost does not represent life-cycle costs which would also include research and development and demonstration (prototype) costs.

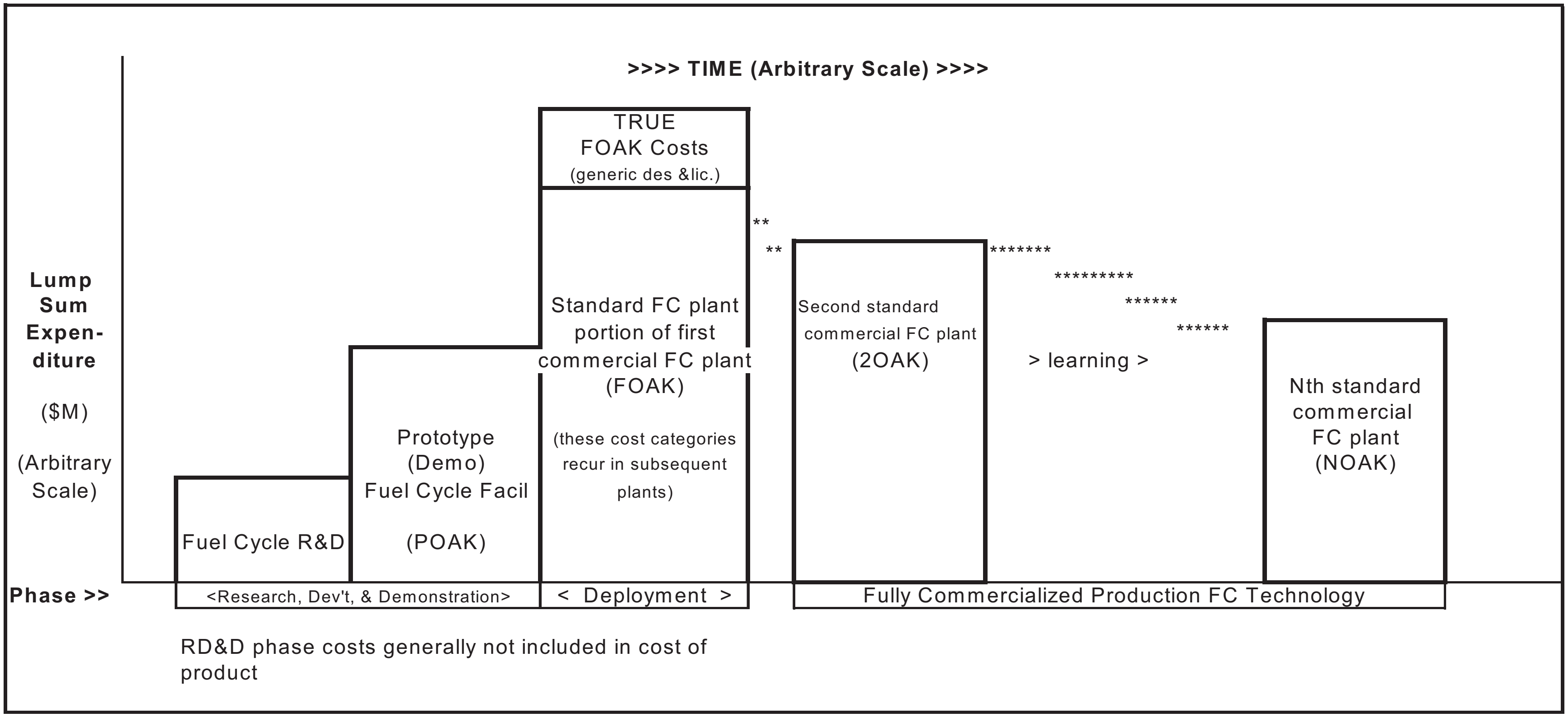
Transition period. The period from the start of the construction of the FOAK to the start of construction of the NOAK plant.

Transition period plant-specific capital costs. The capital costs for the transition plants (such as the second and third of a kind). These costs exclude any FOAK costs and include costs for manufacturing of factory equipment, site construction, site-specific engineering, and home office construction support. The transition in costs from FOAK to NOAK and the beneficial cost effects of serial manufacturing and construction should be documented.

Unit. See single-unit plant.

Total Capital Investment Cost. The total capital investment cost is an all-inclusive plant capital cost (or lump-sum up-front cost) developed for the purpose of calculating the plant LUEC ($/production unit), or that of a factory-fabricated module or equipment item (such as $/module). This cost is the base construction cost plus contingency, escalation (zero for these studies, unless justified), IDC, owner's cost (including owner's start-up cost), and commissioning (nonowner startup cost, such as that spent by process equipment manufacturer or architectural engineer). Because constant dollar costing will be used in these studies, escalation and inflation are not included.

The following figure shows the relationship in time between some of the cost categories defined above as well as which costs are included in the cost of product. It should be noted that the horizontal and vertical scales of the graph are illustrative only and not scaled to real time and expenditures.



Temporal relationship of RD&D, deployment, and standard plant costs.

Advanced Fuel Cycle Cost Basis

1. INTRODUCTION

This report builds on work performed over the past 6 years by the Advanced Fuel Cycle Initiative (AFCI) Program to develop cost-estimating processes and establish a uniform structure for the collection of fuel cycle cost data. This report describes the advanced fuel cycle (AFC) cost basis development process, and provides reference information for AFC cost modules, a fuel cycle strategy costing procedure, economic evaluation guidelines, and integration of the cost data into economic computer models, and finally conclusions and recommendations. The report does not include an evaluation of the future costs of or technical challenges for other potential future (non-nuclear) electricity generation alternatives. It also does not deal with non-cost (e.g., sustainability, societal, environmental, non-proliferation) issues. However, these important factors should be considered when evaluating the competitiveness and benefits of nuclear energy.

A significant body of cost data has been collected and organized; however, the report is a continuous "work in progress" where some elements of the overall life-cycle cost for a given fuel cycle step may be incomplete, but new cost data is constantly being added to the database from new sources. Some of the cost and technology information derived from older reference sources are dated, but are included for completeness and will be updated as new data becomes available. This external release of the AFC Cost Basis report is intended to allow a wider distribution of the cost information, help identify new cost data sources, and facilitate closer collaboration, both domestically and internationally, with industry and universities. These costs are being reviewed by international experts from the International Generation IV Reactor Systems Economic Modeling Working Group (EMWG) and the Organization for Economic Cooperation and Development/Nuclear Energy Agency (OECD/NEA) that have prepared similar studies. The reconciliation of any differences will be reported in a future report update.

There are some general assumptions and caveats of which users of the AFC cost data should be aware. The costs are presented in current-year (2009) dollars, but are assumed to represent longer-term (10–20 year) market conditions, long-term contracts, and mature commercial technologies. The authors recognize that uranium and enrichment spot prices have recently exceeded the high-cost range provided in this cost basis. These price trends continue to be evaluated and the cost ranges in the report may continue to be revised as appropriate in future updates. The projected costs for recycling facilities and fast reactor projected costs are based on Nth-of-a-kind facilities. Special attention should be directed towards including the costs for recycled product storage, conditioning, and disposition of all waste streams.

The cost data, especially the unit cost data such as the cost per kilogram of heavy metal, may be readily input to cost models to perform engineering cost studies on both open and closed fuel cycles. Users are cautioned that their models may provide different answers and resulting conclusions due to different assumptions on the fuel cycle configuration, mass flows, time delays, cost escalation, technology performance, learning effects, market growth, and other user-defined parameters. Assumptions should be clearly documented and sensitivity analyses performed to evaluate the impacts resulting from the various assumptions.

Any comments are welcomed on the data or text in this study, especially any new data that has not been publicly available or is the result of recent new analyses outside of the Department of Energy. Comments may be provided to David Shropshire at David.Shropshire@inl.gov or by calling (208) 526-6800.

1.1 Background

The AFCI's definition of fuel cycle costs is consistent with the Generation IV EMWG's definition of nuclear fuel cycle costs, stated as "the costs of uranium supply, conversion, and enrichment; fuel fabrication; transport; intermediate storage and final disposal of spent fuel (for the direct disposal option). For the reprocessing option, the costs also include those for spent nuclear fuel (SNF) reprocessing associated with waste management, along with storage and final disposal of high-level radioactive waste, as well as any credits realized through the sale and use of uranium, plutonium, heavy water, or other materials" (EMWG 2005). The AFCI definition also extends into advanced or innovative fuel cycles that may require additional cost elements related to fuel recycling (e.g., recycled product storage, reprocessing variations) and alternative disposal concepts (e.g., deep bore hole).

Current AFCI cost analysis includes an extensive evaluation of the fuel cycle costs and also includes reactor costs to fully understand the interdependency relationships between the fuel cycle and the reactor technology. The EMWG describes the total costs as the levelized unit of electricity cost (LUEC), which is the unit of most interest to utility decision makers. The LUEC "is composed of four main contributors to its total: a capital component (which includes up-front cost of financing and amortization over the economic life); an Operations and Maintenance component; fuel cycle component (fuel reloads); and a decontamination and decommissioning (D&D) component. The component costs and the total are generally expressed in constant money per unit of electricity/energy produced (e.g., $/kWh)" (EMWG 2005).

Several weaknesses of past fuel cycle economic analysis are identified and addressed in this report:

1. A fundamental weakness was the lack of a consistent and comprehensive documented source of fuel cycle cost data. With this report, we have established a documented reference cost basis with a structure and processes for continued improvement of the cost data.
2. Current design bases and requirements for critical AFCI operations (e.g., separations, fuel refabrication, waste forms) are lacking. Improving the design cost basis will shadow the development of fuel cycle technology and facility designs prepared by the AFCI Program. Cost information consistent with the cost structure and processes identified in this report will be obtained through economic integration with the fuels and separation working groups, engineering alternative studies, and through industry engagement.
3. Verified estimating models to support fuel cycle cost analysis are lacking. In FY 2005, the requirements for a verifiable fuel cycle cost model were established. The selection of a modeling platform and development of an initial dynamic model to support systems economic analyses were completed in FY 2006. In FY 2008/2009, the dynamic model was used to perform dynamic analysis on a range of fuel cycle cases and the results were compared to static (equilibrium) modeling results.
4. Previous cost studies failed to provide a complete economic accounting of all the fuel cycle costs (e.g., D&D costs, refurbishment, and waste forms were omitted) in the overall life-cycle costs of a facility. Such "partial" studies can result in misleading conclusions. This work will continue to be expanded to encompass all relevant aspects of the nuclear fuel cycle and related cost elements. Internal AFCI review of the module cost data, external reviewers of this report, and input from report users will be used to help identify areas of omission or discontinuity in our estimate basis.

1.2 Related Program Interfaces and Related Key Evaluations

The economic benefits of the AFCI accrue in-part from cost savings in high-level waste (HLW) disposal. Therefore, AFCI economic analysis has coordinated with the U.S. Department of Energy (DOE) Office of Civilian Radioactive Waste Management (OCRWM). The OCRWM program has an ongoing effort that annually updates the Total System Life-cycle Cost estimate for the repository program. AFCI economic analysis draw from the Total System Life-cycle Cost analysis. In FY 2005, the AFCI Program began working with the OCRWM Program to develop a joint understanding of the impact of advanced fuel cycles on both the need for and cost of future repository capacity in the United States.

The AFCI Economic Analysis activity has developed a close working relationship with the Generation IV EMWG. For this report, we defined a consistent fuel cycle code of accounts (COA) structure, a cost basis development process, and a set of cost estimating terminology. The AFCI Economic Analysis activity has received feedback from the EMWG on key AFCI economic deliverables. Some reactor cost data has been received from the EMWG and from studies sponsored by the International Atomic Energy Agency (IAEA) to support total nuclear system cost calculations.

The AFCI Systems Analysis Working Group coordinates with the AFCI Separations/Waste Form and Fuel Fabrication Campaigns. The AFCI Systems Analysis Campaign supports technical working group reviews and analysis, and identifies ways to reduce the costs and uncertainty of recycle processes. Through this involvement we gain access the latest design and cost data for input to the cost database and use in AFCI system studies.

1.3 Annual AFCI Cost Basis

As stated previously, the AFCI Program has established the foundation for cost estimates with a greater level of confidence and completeness, and provided the framework for incremental process improvements. The AFCI Program has been collecting cost references and has expanded the fuel cycle cost data for over 6 years. The intended use of the cost data is relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. As technology development progresses and detailed engineering designs are completed, cost estimate accuracy will be further improved. The cost report will be periodically updated to include the latest technology and design information and to support the improvement of processes and tools used to perform fuel cycle cost analysis.

The report is updated with cost data based on U.S. information as well as experience gained in developed and developing nuclear countries. The analysis may be extended to foreign applications as an evolution in the cost development activity.

1.4 Cost Module Description

Each type of fuel cycle facility or activity is referred to as a cost module. A cost module provides a specific fuel cycle function that is separate from but dependent on other fuel cycle activities (e.g., the enrichment module is influenced by the enrichment required by the fuel manufactured in the fuel fabrication module). The cost modules are assembled in various ways to create different fuel cycle scenarios, as illustrated in the AFCI Cost Flow Sheet in Figure 1-1.

The flow sheet includes 21 fuel cycle modules with interface lines that show the flow paths through the fuel cycle from the initial Module A, Mining and Milling, through various open and closed fuel cycle paths that terminate with Modules J, L, and M that provide the function of waste disposition. The interfaces between the functional Modules A through M (associated with facilities) are provided by the transportation process, Module O.

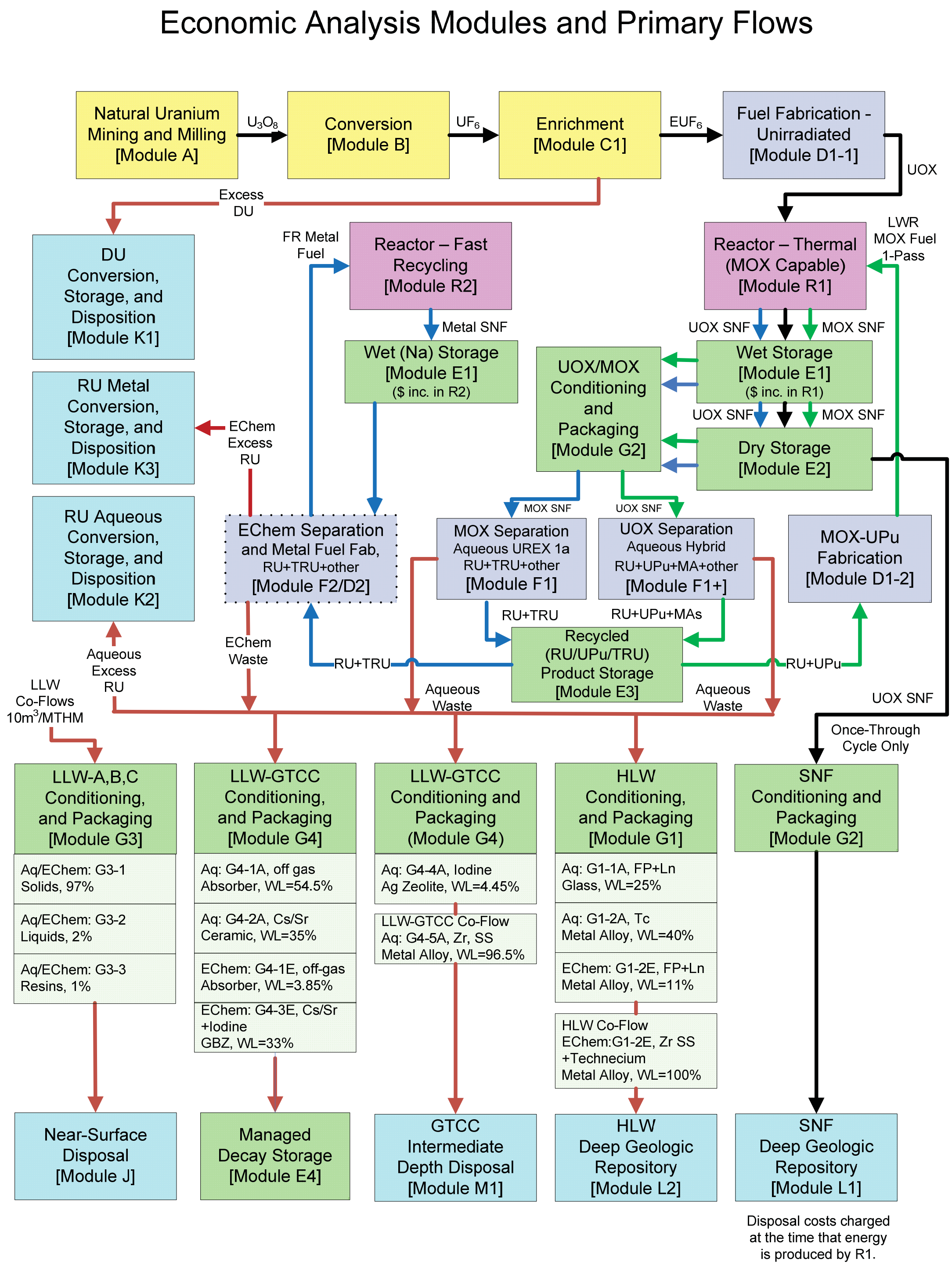


Figure 1-1. AFCI cost flow sheet.

1.5 Structure of the Report

A list of definitions that provide a common set of terminology for describing fuel cycle costing activities is included in the nomenclature section at the beginning of the report.

Section 1 of this report contains the background, program interfaces, description of the annual report cost activities, description of cost modules and example of fuel cycle paths.

Section 2 describes the cost development process used to develop the fuel cycle costs. The process includes data collection methodology, cost data normalization, verification, data gap analysis, and cost data documentation, and a description of the AFCI cost database. A COA dictionary for estimating costs of fuel cycle facilities is provided in Appendix A. A common cost table that summarizes the module cost data, called the AFCI What-It-Takes (WIT), is described.

Section 3 describes the organization of the reference cost modules into front-end, back-end, and recycle groups. A general description of the twenty cost modules is provided.

Section 4 provides a procedure for costing fuel cycle options using the cost modules in this report.

Section 5 includes guidelines for comparing alternatives using qualitative and quantitative techniques.

Section 6 describes the use and integration of the cost data into cost models. A description of fuel cycle models that could be used for cost analysis is provided.

Section 7 summarizes the conclusions and recommendations resulting from the development of the report.

Section 8 provides general (nonmodule specific) report references.

The appendix provides additional fuel cycle cost details on the code-of-accounts.

Attachment 1 is broken into separate tabbed sections for 25 cost modules. Fuel cycle modules are included in tabs A through O, as listed in Section 3. Baseline cost information for different types of reactors/transmutation options are included under tab R. Each of the module sections contains cost documentation based on the module outline described in Section 2. The AFCI WIT table is used to summarize the module fuel cycle cost data in a consistent manner.

2. AFCI COST BASIS DEVELOPMENT PROCESS

The goal of the AFCI Cost Basis Development Process shown in Figure 2-1 is to establish a credible cost basis and to create a reference source for fuel cycle unit costs. Cost data will be evaluated on discrete fuel cycle activities, called cost modules, which represent the various front-end fuel cycle, back-end fuel cycle, waste disposition, and transportation functions. This task does not include the “bottoms up” development of cost estimates from a design basis. Instead, the cost basis for each module is derived from existing cost reference sources and studies.

2.1 Process Description

The AFCI cost basis development includes cost data collection, cost normalization, data verification, and gap analysis. Data gaps are recommended to DOE as the subjects for future engineering cost studies. For example, specific recommendations were made on additional cost study needs based on the review of the AFCI Engineering Alternative Study in FY 2008/2009. The data from the engineering studies are used to improve the cost basis. The synthesized data developed are being input to the VISION (Verifiable Fuel Cycle Simulation) model for use in quantitative analysis (such as the calculation of the Total Cost of Electricity), or may be used as qualified static input data for scenario evaluations and development of fuel cycle strategies.

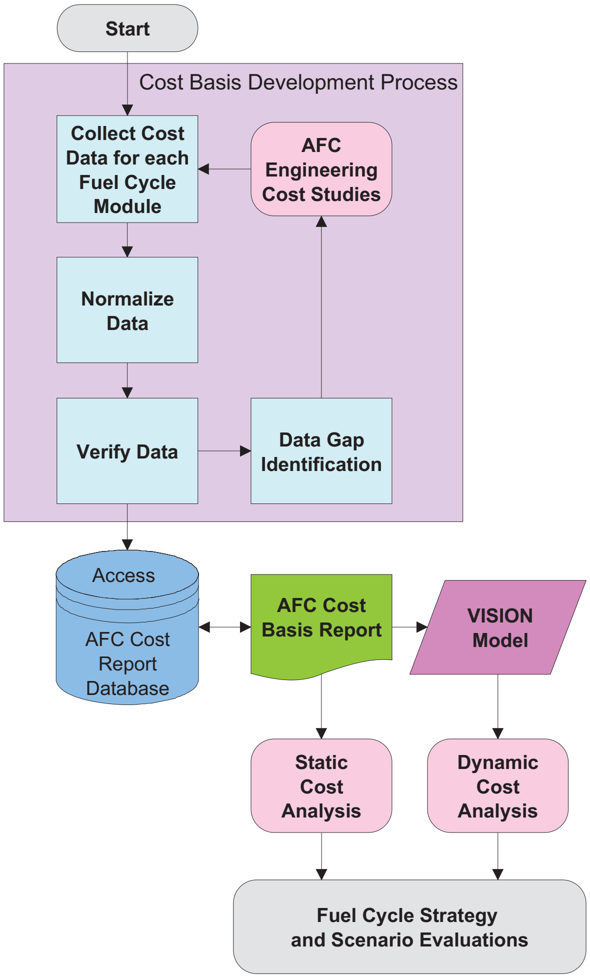


Figure 2-1. AFCI cost basis development process.

2.2 Fuel Cycle Data Collection

Data were collected for 21 fuel cycle modules and 4 reactor modules. The cost data were analyzed and evaluated on a common basis. The complete list of modules is included in Section 3.

The data collection methodology identifies the data sources and selection for use. The source of the cost information is identified, including data generated and maintained/updated by the AFCI program, and those taken from data gathering and modeling efforts of other organizations (e.g., OECD/International Atomic Energy Agency "Red Book").

2.3 Cost Data Normalization

Fuel cycle cost data were normalized to establish uniform baseline costs and assumptions. The characteristic attributes of the cost data were identified for each module. The following sections describe the unique characteristics that are important to understanding the costs.

2.3.1 Government versus Private Facility Ownership

Ownership affects the methodology by which unit costs are calculated and also affects the categorization of costs. The treatment of risk, especially as it is represented in the assumed discount rate, is also different for government projects as opposed to private commercial projects. Some aspects of the fuel cycle, such as geologic disposal, are typically considered to occur in government facilities while others, such as enrichment, are typically considered to occur in private facilities. To provide both consistency and flexibility, the differences due to ownership are made explicit so that the fuel cycle module (e.g., separations facility) can be estimated for either type of ownership. The reference cost data for each module will identify the ownership basis of the cost estimate. Further discussion on the economics of private sector versus regulated nuclear fuel cycle facilities is included in Chandler and Shropshire's 2006 ICONE conference paper.

2.3.2 Technology Readiness Level (Program/Project R&D Status)

The technology readiness level often affects the detail level of the information needed for cost estimating and also the extent to which contingency must be applied to cover risk in project costs. For this cost basis, the technology readiness is categorized into three classes: Research & Development (R&D) — possible, Pilot — feasible, Commercial — viable. Subsequent to the development of the initial classification, a basis will be developed for relating technology readiness to contingency for purposes of developing cost estimates and associated confidence ranges. The EMWG has evaluated approaches for handling contingency in nuclear energy system cost estimation (EMWG 2007). Guidelines for contingency cost assessments were developed for various stages of a project.

2.3.3 Code of Accounts/Work Breakdown Structure

The COA and associated dictionary provide a means for consistently placing cost information in explicitly defined "bins" or categories that are common to most projects and their life cycles. Having uniformity in the definition of the COA allows useful comparison of process alternatives or competing technologies and provides some insight at the subsystem level. The work breakdown structure that eventually evolves from the COA structure can be used for management of the project, such as in subcontracting work packages and tracking costs.

The front-end modules (i.e., natural uranium mining and milling, conversion, enrichment, and fuel fabrication) are typically commercial operations where COA and work breakdown structure cost information is typically not available due to sensitivity over the competitive nature of the information.

The life-cycle costs can basically be divided into costs that are recovered in the price of a product and those which are not. These (nonrecovered) costs may be paid by the government or through public/private consortia. This would be consistent with what has been done for the Generation IV Reactor Systems program in their draft guidelines. The following level "0" account provides a structure for these costs. The cost categories in bold typeface are the "single digit" COA titles. The "two digit" accounts "roll up" by summing to the "one-digit" value.

0 – Early Life-Cycle Costs Not Normally Recovered in the Price of the Plant Product or Service Sold

0.1 – Planning Costs

0.2 – Research and Development Costs

0.3 – Prototype or Pilot Plant Costs

0.4 – Generic Licensing Costs

The recoverable life-cycle costs can be placed in a more familiar and structured COA typical of nuclear production facilities. The COA structure has been derived by modifying the COA proposed for Generation IV Reactor Systems, and also described in detail in that set of draft guidelines (EMWG 2005). "Capitalized" costs are those "up-front" (time wise) costs that must be financed, and for which costs are recovered in the price charged for facility product over the amortization life of the project. Annualized costs can be represented as the recurring cash sums needed to sustain a constant level of annual production exclusive of the "mortgage." The following summarizes the proposed COA for recoverable fuel cycle facility costs. If all cost data obtained can be placed in such appropriate "bins," useful comparisons of cost data and technological economic potential can be greatly enhanced.

1 – Capitalized Preconstruction Costs

11 – Land and Land Rights
12 – Site Permits
13 – Plant Licensing (including National Environmental Policy Act)
14 – Plant Permits
15 – Plant Studies (e.g., preliminary safety studies and hazards analysis)
16 – Plant Reports (formal documents)
17 – Other Preconstruction Costs
18 – Other Preconstruction Costs
19 – Contingency: Preconstruction Costs

2 – Capitalized Direct Costs

21 – Structures and Improvements
22 – Process Equipment
23 – Equipment
24 – Electrical Equipment
25 – Heat Addition/Rejection System
26 – Miscellaneous Equipment
27 – Special Materials (such as high unit cost nuclear materials)
28 – Simulator
29 – Contingency: Direct Costs

Total Directs = 1 + 2

3 – Capitalized Support Services

31 – Field Indirect Costs
32 – Construction Supervision
33 – Commissioning and Start-up Costs
34 – Demonstration Test Run Field Cost
35 – Design Services Offsite (offsite might be "home-office" of architectural engineer designer)
36 – PM/CM Services Offsite (Project manager/construction manager)
37 – Design Services Onsite
38 – PM/CM Services Onsite
39 – Contingency: Support Services

Base Construction Cost = 1 + 2 + 3

4 – Capitalized Operations (Mostly plant owner costs prior to commercial operation)

41 – Staff Recruitment and Training
42 – Staff Housing
43 – Staff Salary Related Costs
44 – Other Owner Capitalized Costs
49 – Contingency: Operations Costs

5 – Capitalized Supplementary Costs

51 – Shipping and Transportation Costs
52 – Spare Parts
53 – Taxes
54 – Insurance =
58 – Decommissioning Costs (if not covered by escrow fund)
59 – Contingency: Supplementary Costs

Total Overnight Cost (TOC) = 1 + 2 + 3 + 4 + 5

6 – Capitalized Financial Costs

61 – Escalation (not used for constant dollar analysis)
62 – Fees (noninterest fees paid to financial institutions)
63 – Interest during Construction (IDC)
69 – Contingency: Financial Costs

Total Capital Investment Cost (TCIC) = 1 + 2 + 3 + 4 + 5 + 6

7 – Annualized Operations and Maintenance (O&M) Cost

71 – Operations and Maintenance Staff
72 – Management Staff
73 – Salary Related Costs (benefits, Federal Insurance Contribution Act, etc.)
74 – Operations Chemicals (feedstock) and Lubricants.
75 – Spare Parts
76 – Utilities, Supplies, Miscellaneous Consumables
77 – Capital Plant Upgrades (not including financing costs)
78 – Taxes, Insurance, Regulation (Nuclear Regulatory Commission [NRC] inspections)
79 – Contingency: Annualized O&M Costs

9 – Annualized Financial Costs

- 91 – Escalation (not used for constant dollar analysis)
- 92 – Fees (noninterest financial costs during operations)
- 93 – Cost of Money (financing of large replacement capital items or upgrades: interest)
- 94 – Annual contribution to the D&D Escrow Fund
- 99 – Contingency: Annualized Financial Costs

Total Project Life-Cycle Cost = Nonrecovered costs (R&D, etc.) + TCIC + Yr of Plant Ops * (7 + 9)

The COA dictionary for estimating costs of fuel cycle facilities in Appendix A provides additional explanations of the content for each of these cost elements. Throughout this cost structure, the government or private enterprise may fund some costs. The ownership definition must be explicitly defined for each module.

2.3.4 Common Currency (U.S.$)

The U.S. dollar is the most common monetary standard for nuclear facility cost estimating and is easily convertible into other currencies. Consideration should be given to the years in which the project costs were incurred (e.g., 1970 versus 2000). The equivalent monetary exchange rates applicable at that point in time may be significantly different than present day exchange rates. In some cases the base currency unit has also changed, for example the French franc is now converted to the European Monetary Union (Euro). Many Web-based calculators are available to perform the conversion calculations.[a]

2.3.5 Common Year (Current Year Basis)

A reference year for constant dollar costing and use of discount/escalation factors was chosen. The AFCI Program has chosen to use 2009 dollars and 3%/year escalation for cost estimate updates from 2007 and 2009. Escalation factors can be obtained from the Defense and General Construction Escalation indices for construction costs (ENR 2009), the U.S. Dept. of Labor (U.S. Department of Labor 1970–2004) for escalation of operations costs, and the Civil Works Construction Cost Index (U.S. Army Corps of Engineers 2009).

2.3.6 Differences in Cost Estimating Methodologies (Top Down vs. Bottom Up)

Both “top-down” and “bottom-up” methodologies can be used for cost estimating. The former is usually used for systems that are not well defined, but for which scaling data from other projects can be used. Bottom-up cost estimating is used for well-defined projects for which material balances, flow sheets, process floor layouts, and detailed drawings are available for “engineering take-off” type cost estimating. Cost estimating groups in Architect Engineer firms usually use the latter technique. There are also differing techniques for calculating cost estimating figures of merit such as unit cost of product and discounted life-cycle cost. The techniques used also depend on the level of cost estimating and project schedule data available. Reference cost information will be evaluated to determine which method was used to develop the costs.

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[a] Web-based currency conversion calculator is available at http://www.x-rates.com/calculator.html; http://www.france-pub.com/currency.html provides a calculator to convert from older French currency bank notes franc(s) to other currency.

2.4 Cost Data Verification

Cost data verification will consist of performing the following three assessments:

- Definition of data quality based on credibility measures
- Identification of cost estimate limitations and applicability (often technology driven)
- Evaluation of cost data sensitivity, technical cost discriminators (cost drivers), and uncertainty bounds.

The data quality will be defined and categorized based on credibility measures. The measures used to evaluate each data source are based on the degree of detail and rigor of the analysis, use of a consistent basis and approach, and whether data were independently reviewed. Each source will be categorized into one of the following five quality levels.

1. Independently-reviewed detailed assessments using a common basis and consistent approach
2. Detailed assessments using a common basis and consistent approach
3. Scoping assessments using a common basis and consistent approach
4. Engineering judgment of program specialists
5. Potentially biased or conflicting assessments collected from independent sources that do not use a common basis or consistent approach.

Cost estimate limitations and applicability will be determined for each data source/study. The data will be analyzed to determine on what restrictions and assumptions that the estimate was based, omissions from the estimate, unique circumstances, etc. An estimate of the range of applicability of the data will also be developed, indicating bounds in scaling or other parameters beyond which the estimate is not deemed credible.

The cost estimates will be analyzed to understand their sensitivity and uncertainty bounds within the range of applicability. If sufficient cost details are available, then sensitivity modeling may be performed with spreadsheets to determine the sensitivity of the estimates to different estimating assumptions. High sensitivity items that make a sufficient contribution to the overall module cost will be identified and assigned sufficiently wide uncertainty bounds to be a major contributor to the uncertainty of the full module cost estimate.

2.5 Data Gap Analysis

A set of criteria is used to determine when additional engineering cost trade-off studies are needed. The criteria highlight those cost areas with large data gaps, potential for high costs, restrictive assumptions, etc. Pareto analysis is used to identify the largest cost drivers, and to evaluate the limitations of the cost data (technology readiness, data quality). Emphasis is placed on improving the consistency of high sensitivity cost uncertainties within the range of applicability, as well as expanding the range of applicability as needed to fully support AFCI program objectives.

Through the previous analysis, data gaps were identified for aqueous reprocessing, electrochemical reprocessing, hot fuel fabrication, and waste conditioning. In FY 2008, we recognized gaps in understanding the uncertainties associated with fuel separation and waste conditioning processes and fuel cycle market competition. In FY 2009, additional analysis was performed to help fill gaps associated with (1) bottoms-up estimates for aqueous separation and electrochemical separation; and (2) understanding the current status on market competition in the international nuclear industry (NEA 2008).

2.6 Cost Data Documentation

Each cost module is documented with specific information derived from the data collection, normalization, verification, and gap analysis activities. The report structure for this report includes some, or all, of the following data sections, as applicable, for each module.

1. Module (see Section 3 for listing of modules)

    1.1 Basic Information—includes the overall narrative descriptive information (e.g., the facility purpose, design requirements, history).

    1.2 Define Functional & Operational Description—describes the primary functions and flows of the facility as well as provides a functional block diagram that describes the inflows/outflows.

    1.3 Pictures/Schematics—describes layout of the facility, includes pictures, schematics, etc.

    1.4 Module Interface Definition—describes interdependencies such as with site infrastructure services, dependencies on other modules (e.g., packaging and transportation), secondary waste flows.

    1.5 Module Scaling Factors—describes special attributes and/or associated scaling factors, including appropriate constraints. This section will also detail the manner in which to apply the associated modifying factors to adjust the cost estimate.

    1.6 Cost Bases, Assumptions, and Data Sources—includes the specific bases for design estimates, data sources for key technical reports, and reviews performed by secondary parties.

        1.6.1 The reference cost data for each module will identify the ownership basis as government, private facility, or some combination of the two.

        1.6.2 The reference cost data will be identified as generated from top down, bottom up, or “actuals.”

    1.7 Limitations of Cost Data—addresses the credibility and limitations of the cost data. Information may include reported and observed data gaps, estimate details (planning level vs. detailed), safety/environmental/regulatory conditions unique to country of origin, site-specific cost factors due to labor unions, and other limitations.

        1.7.1 The technology readiness will be categorized as R&D – possible, Pilot – feasible, or Commercial – viable.

        1.7.2 The data quality will be categorized as one of the five quality levels listed in Section 2.4 (i.e., independently reviewed & detailed with consistent approach, detailed assessment with common basis, scoping assessments with common basis/approach, engineering judgment, independent sources without a common basis).

    1.8 Cost Summaries—compiles the cost data that have been placed in the module sections. These data are normalized (CY 2006) and in the standard COA breakdown for comparison purposes. Data may be presented as graphical cost projections based on parametric scaling analysis of cost vs. capacity or other cost measures.

        1.8.1 The cost breakdowns of reported life-cycle costs and unit costs with their associated operating and financial assumptions are presented. Major cost discriminators are identified and separately reported (e.g., contact-handled and remote-handled costs).

1.8.2 The most relevant cost references are used to provide a facility cost breakdown at the one digit level (e.g., 0, 1, 2, 3) using AFCI standard COA (see Appendix A).

1.8.3 The reference costs are escalated to CY 2009 U.S. dollars.

1.8.4 A reference capacity (e.g., throughput rate, package size, storage capacity) is defined for each module.

1.8.5 The cost summary information is placed in a WIT table (see example Table 2-1) that shows reference cost basis (constant year U.S.$); the reference cost basis contingency (if known); the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of the cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis.

1.8.6 The WIT results are further projected into an estimated cost frequency distribution that represents the uncertainty of the data for modeling purposes. The module probability distributions are primarily triangular, with the exception of modules B and C, which use a uniform distribution. Explanations for the choice of distribution are included in the cost summaries.

Table 2-1. Example of a WIT table.

What-It-Takes (WIT) Table				
Reference Cost(s) based on reference capacity (normalized costs in CY$ and U.S.$)	Reference cost contingency	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$100/MTHM based on capacity of 2,000 ton/yr	+/- 10%	$90/MTHM	$150/MTHM	$120/MTHM
(Further breakdowns and assessments of costs may be provided by code of account element or by listing those items that have the highest costs impacts)	(Based on the stated reference contingency percentage)	Rationale (Explanations such as technology improvements, improved economies of scale, changes in estimating assumptions that are more cost favorable)	Rationale (Explanations such as increased regulatory requirements, worst-case economic conditions, estimate limitations)	Rationale (Cost analyst's overall assessment of the most likely cost based on current conditions)

1.9 Sensitivity and Uncertainty Analysis—describes the analysis performed and explains conclusions. The results of these analyses will be summarized in the cost module documentation, and references to more detailed uncertainty analysis reports will be provided.

1.9.1 Evaluations to consider the potential cost implications on variations to the functional design requirements of the reference facility. For example, a separations facility is designed to separate three main product streams. An analysis may be performed to determine the costs for separation of only two product streams.

1.9.2 Evaluations to determine the impacts on costs due to advances in technologies, changing economies of scale and economies of production due to increasing nuclear energy demands, and changes in facility ownership (private vs. government).

1.10 References—lists the most relevant references that form the primary basis for the module costs. Additional (more general) data sources may also be listed in a bibliography section.

2.7 AFCI Cost Database

The AFCI cost collection database, illustrated in Figure 2-2, stores raw cost data, reference reports, and citations (i.e., cost derivations from the reference documents) resulting from the cost review process. The raw cost data undergo the steps defined in the cost bases development process discussed in Section 2. Cited module reference cost data identified in this report are stored on an Access database file. The Access database contains hot links to the associated reports, which reside on AFCI Web portal.

Cost analysts can use the database to perform queries to find references, download specific reports available in the open literature, and review cost data for a specific reference. The cost data user is not allowed to add or modify records in the AFCI Cost Citation Collection database. Open (publicly available) reports may be provided upon written request to David Shropshire at David.Shropshire@inl.gov.

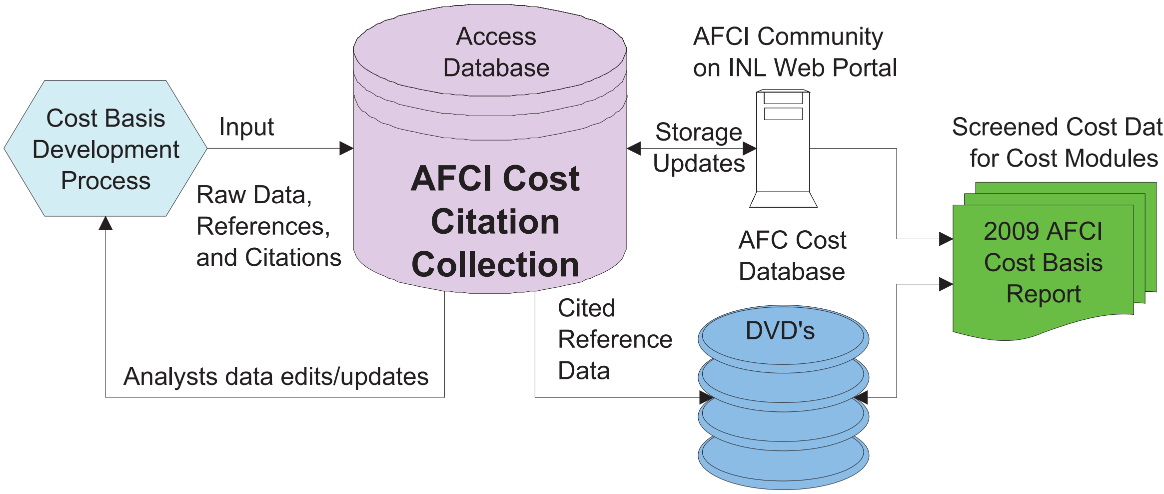

Figure 2-2. AFCI cost database.

3. FUEL CYCLE REFERENCE COST MODULES

The fuel cycle has been broken down into functional elements called cost modules as described in Section 1.5. This section provides a general description and categorization of these cost modules—details on each of the modules are provided in the tabbed sections in Attachment 1. Table 3-1 summarizes information on the 30[b] fuel cycle cost modules. The following paragraphs describe some discriminating characteristics of these modules that impact the type (and quantity) of cost data available for this report.

1. The front-end fuel cycle modules (A1, B, C1, and K1) are generally related to commodity types of services provided by commercial sources. The costs for these types of operations are often market driven and may be obtained from many sources both domestically and internationally. These modules will not be detailed with facility COA breakdown information, but are based on market related unit

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[b] Of the 34 modules, some have been combined or deleted netting 25 currently used modules.

costs (e.g., U.S.$/kg UF_6). Module C2, which deals with light water reactor (LWR) fuel derived from the blend-down of highly enriched uranium from military sources, was added because such blended material (and continuing to 2013 under arrangements with Russia) is currently providing a significant portion of U.S. LWR fuel. UF_6 received from blend-down operations substitutes for fuel cycle operations in Modules A1, B, C1, and K1. Module D1, Fuel Fabrication-Unirradiated, is available from a limited number of sources and some detailed cost data are available at a facility level.

2. Reactor/transmutation baseline cost data are provided in Modules R1, R2, R3, and R4 (including thermal reactors and fast reactors). The SNF wet and dry storage (Modules E1 and E2) is generally located at reactor sites. Wet storage costs (E1) are generally assumed to be a portion of the reactor capital and operations costs and are not typically added on top of reactor costs. The storage costs are based on commercial cost data associated with the reactor construction and operation. Incremental dry storage pads may be added at a reactor site to support extended fuel storage requirements. The reactor operator may have added dry storage pads some time after reactor construction.
3. The back-end fuel cycle modules (I and L) are the responsibility of the government as provided by the Nuclear Waste Policy Act.[c] The government funds these functions and the services would be provided by government contractors.[d] Only a limited number of these types of facilities would be built due to their high cost and political sensitivity.
4. The recycle modules (F1, F2/D2, E3, E4, K2, K3, G, J, and M) are associated with fuel reprocessing and may be provided by some combination of government and private sources. Cost data are generally derived from international and domestic sources with various ownership arrangements. Wastes designated for low-level waste (LLW) disposal in Module J may be associated with depleted uranium, recycled LLW from reprocessing, or from fuel cycle and reactor facility maintenance and operations.
5. The transportation modules (O1 and O2) support the costs for transport of new fuel, recycled fuel, and shipment of SNF, HLW, and LLW. Transportation of raw fuel to the reactor is a commercial cost to the reactor owner/utility. SNF transportation from the reactor to interim storage and the repository is the responsibility of the government. HLW and LLW transportation resulting from recycling could be provided by some combination of government and private sources.

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[c] Information on the Nuclear Waste Policy Act can be found at http://www.ocrwm.doe.gov/ymp/about/nwpa.shtml.

[d] Long-term retrievable storage could potentially be funded through a private venture (e.g., Skull Valley).

Table 3-1. Fuel cycle cost module general descriptions.

Cost Module	Module Name	General Description
A1	Natural Uranium Mining and Milling	Includes the factors involved in extraction of uranium from the earth through production of uranium concentrate in the form of U_3O_8, commonly known as “yellow cake.”
A2	Natural Thorium Mining and Milling	Includes the factors involved in extraction of thorium from the earth through production of thorium concentrate in one of three forms in which it is stored: oxide, oxalate, and nitrate.
B	Conversion	Takes the mined U_3O_8 concentrate, further purifies it, and converts it to a UF_6 solid in cylinders for feed to a uranium enrichment plant.
C1	Enrichment (Isotopic Separation)	Uses the UF_6 solid in cylinders to enrich the % of U-235 from 0.711 mass% to the 3–5% typical of the enrichment used for LWR fuel fabrication, or higher for typical VHTR fuels.
C2	Highly Enriched Uranium Blend-Down	U.S. and Russian government-owned highly enriched uranium (blended down as a secondary supply to meet demand for low-enriched uranium.
D1 (D1-1 through D1-9 submodules)	Fabrication of Contact–Handled Fuels	Uses chemical, ceramic/metallurgical, and mechanical steps to take enriched UF_6 and convert it to finished fuel assemblies.
D2	Fuel Fabrication of Remote-handled (Metal) Fuels and Targets	This module has been combined with Module F2 to create Module F2/D2.
E1	Wet Storage of SNF	Pool storage (at reactor) of SNF from existing commercial reactor operations.
E2	Dry Storage of SNF	Dry storage (at reactor) of SNF coming from reactor wet storage; includes handling costs involved with transfer from wet to dry storage.
E3	Storage of Combined Recycled Product of Mixed Plutonium, Minor Actinides, and Uranium Product	Storage of the actinide by-products produced from the reprocessing of thermal reactor and fast reactor fuels. Would typically be required to support blending needs.
E4	Managed Decay Storage	Storage of immobilized, heat generating, mixed cesium-strontium waste arising from advanced fuel cycles.
F1	SNF Aqueous Reprocessing Facility	Separation of SNF elemental components using aqueous process to support recycling of fissile materials. Includes cost of receipt of SNF through end-product production.
F2	Reprocessing—Electrochemical	This module has been combined with Module D2 to create Module F2/D2.

Table 3-1. (continued).

Cost Module	Module Name	General Description
F2/D2	Electrochemical Reprocessing and Remote Fuel Fabrication	Separation of SNF elemental components using an electrochemical process to support recycling of fissile materials. Includes cost of receipt of SNF through end-product production. Uses chemical, ceramic/metallurgical, and mechanical steps to convert fissile material from the back-end fuel cycle to finished fuel assemblies.
G1	HLW Conditioning, Storage, and Packaging	Stabilizes the waste, provides interim storage of the treated waste, and packages the HLW in preparation for transport to a HLW repository.
G2	SNF Conditioning, Storage, and Packaging	Removes the fuel from wet or dry storage, performs inspection as required, dry, package, seal, leak-check, and prepare the SNF package for shipping to a HLW repository.
G3	LLW Conditioning, Storage, and Packaging	Conditions and packages miscellaneous LLW for disposal in a NRC-licensed near surface landfill.
G4	GTCC Conditioning, Storage, and Packaging	Conditions and packages GTCC LLW for long-term storage for qualification for near surface disposal or direct to GTCC disposal.
G5	TRU Conditioning, Storage, and Packaging	Conditions the waste, certification, interim storage, and packaging of transuranic wastes in preparation for transport to an acceptable disposal facility/repository.
H (no longer used)	SNF Packaging for Transport and Disposal	[Cost data transferred entirely to Module O1]
I	Long-Term Monitored Retrievable Storage	Long-term storage of SNF/HLW until shipped to a geologic repository.
J	Near Surface Disposal	Engineered or trench disposal of LLW, including waste and fill placement and monitoring.
K1	Depleted Uranium Conversion and Disposition	Conversion and disposal of depleted UF_6. In some scenarios, this material is later withdrawn to use in breeder fast reactors.
K2	Reprocessed Uranium Disposition-Aqueous	Conversion of burned uranium resulting from aqueous reprocessing such as PUREX or UREX (LWR spent fuels)
K3	Reprocessed Uranium Disposition-Electrochemical	Conversion and purification of burned uranium resulting from electrochemical reprocessing of LWR spent fuels. Uranium-metal will contain multiple contaminants, including transuranics.
L	Geologic Repository	Cost from inception through closure for repository operations. Based on OCRWM data and projected cost estimates.
M	Alternative Disposal Concepts	Speculative costs for SNF/HLW disposal alternatives to a deep geologic repository, such as deep bore hole, and others.
N (no longer used)	Nuclear Fuel Transportation (Contact and remote handled)	[Cost data transferred to Module O1 and O2]

Table 3-1. (continued).

Cost Module	Module Name	General Description
O1	Transportation of Radioactive Materials	Transportation cost of recycled irradiated fuel and SNF/HLW per relative unit includes handling costs not already included in interim storage costs. Includes cost of required operations to condition and package the SNF for shipment to the repository, interim storage, or to a reprocessing facility.
O2	Transport of Nuclear Fuel and Low-Level Radioactive Materials	Transportation cost for new fuel, unirradiated materials, and LLW per relative unit, includes handling costs not already included in interim storage costs.
R1	Thermal Reactors	Capital, operations and maintenance, and D&D costs for generic thermal reactors in the U.S.
R2	Fast Reactors	Capital, operations and maintenance, and D&D costs for fast reactors in the U.S.
R3	Gas Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic gas-cooled reactors in the U.S.
R4	Small-Medium Reactors	Capital, operations and maintenance, and D&D costs for generic small-medium reactors in the U.S.

Additional cost modules have been defined to distinguish cost differences between modules with different technologies, radioactive environments, and regulatory requirements. Over the past two releases of this report, the following modules have been split to accommodate these differences and provide additional cost distinction:

- Module A, Mining and Milling was divided into a sub-module for uranium (Module A1) and a sub-module for thorium (Module A2).
- Module C, Enrichment, was divided into traditional enrichment (Module C1) produced by gaseous diffusion or centrifuge and highly enriched uranium blend down (Module C2).
- Module D1, Fabrication of Contact-Handled Fuel, includes unirradiated fuel. Fabrication of recycled (remote-handled) fuel is discussed in Module F2/D2. There are ten types of fuel that were evaluated for this report. Fuel fabrication submodules were developed to support both different fabrication technologies and fuel applications (i.e., fuels for fast reactors, heavy water reactors, and gas-cooled reactors).
- Module D2, Fuel Fabrication of Remote-handled Fuel/Targets, was combined with Module F2.
- Module E, Interim SNF Storage, was divided into costs for reactor wet storage (Module E1), reactor dry storage (Module E2), and a special module (Module E3) for recycled product storage of actinide products produced from the reprocessing of thermal reactor and fast reactor fuels, and E4 was added for managed decay storage.
- Module F, Reprocessing, was divided into modules for aqueous reprocessing (Module F1) and electrochemical reprocessing (Module F2). Module F2 has been combined with Module D2 to create a new Module F2/D2. Modules F2 and D2 were combined into this module because they are considered to be one integrated facility, making it difficult to separate the costs.
- Module G, Waste Conditioning, was divided into modules for HLW conditioning, storage, and packaging; SNF packaging (G2); LLW conditioning (G3); Greater-than-Class-C (GTCC)-LLW conditioning (G4); and transuranic waste conditioning (G5).
- Module K, Uranium Conversion, Storage, and Disposition, was further divided into depleted uranium derived from enrichment (K1) and burned uranium (BU) resulting from reprocessing. The burned uranium was further designed based on the type of reprocessing, where BU from aqueous reprocessing (K2) was evaluated separate from BU from electrochemical processing (K3).
- Module O, Transportation, costs were segregated primarily on the type of transport package. Transportation of low radioactive materials in O1 uses a Type-A package to support unirradiated fuel, LLW, and contact handled transuranic wastes. Transportation in Type-B package materials (O2) supports SNF/HLW and remote-handled transuranic wastes.
- Module R, Reactors, costs were developed for gas-cooled reactors (R3) and SMRs (R4).

The cost modules were developed using a consistent structure to provide consistency in data collection, normalization, verification, and documentation. However, the content for each of the modules may vary due to characteristics described above and the availability of the data in the public domain. Attachment 1 contains sections for each of the currently used AFC cost modules listed in Table 3-1.

4. STRATEGY COSTING PROCEDURE

The goal of the AFCI strategy costing procedure, shown in Figure 4-1, is to use the data from the AFCI cost database to support AFCI economic analyses of fuel cycle strategies (Shropshire 2009).

4.1 Process Description

The AFCI strategy costing procedure includes defining the scenario and key parameters, selectively linking and scaling the cost modules, and selecting data from the AFCI Cost Basis to develop complete fuel cycle costs. The fuel cycle costs may be combined with selected reference reactor cost data (Module R or other data sources) to develop total nuclear system costs (or converted into TCOE). The fuel cycle/total nuclear system costs can additionally consider facility ownership options (e.g., regulated, private-sector, government owned, or government/private). The fuel cycle costs and total nuclear system costs can be used to support quantitative cost analysis for fuel cycle and scenario analysis. These processes may be performed manually or through the assistance of a computer model.

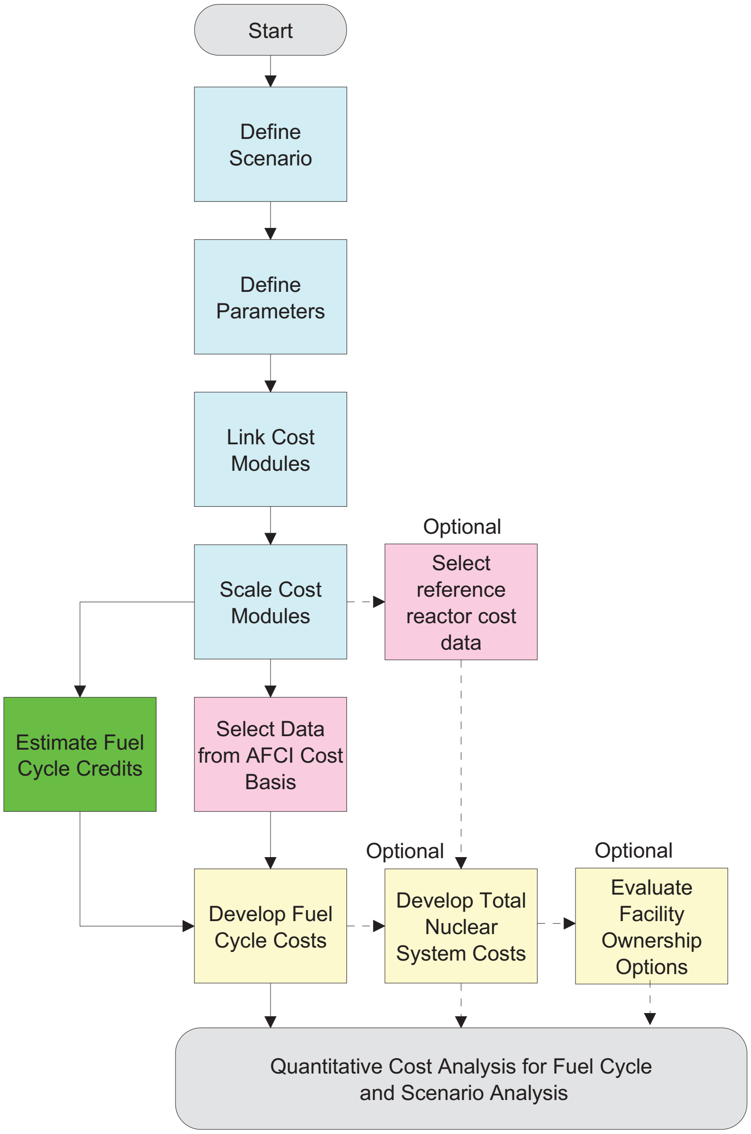

Figure 4-1. AFCI strategy costing procedure.

4.2 Define Scenarios

General strategies (once-through, thermal recycle, thermal/fast recycle, etc.) lead to scenarios that include various options for transmutation, separation, and HLW disposition. An example would be the selection of a once-through fuel cycle with ceramic UO_2 fuel, in an existing light water reactor, with separation of U, Pu/Np/Am/Cm/Sr/Cs, where Tc/I/residuals go to geologic disposal. The selection of a scenario is needed to identify the applicable cost modules. The front-end modules (mining and milling, conversion, enrichment, and fabrication) for most once-through options may be the same. However, the specific parameters may differ depending on the objectives of the scenario (e.g., analysis of high burn-up fuels, percent loading, and enrichment).

Scenarios can focus on a specific part of the fuel cycle, such as used fuel recycling options. Potential scenarios include: fuel cycles to optimize repository space, various reprocessing deployment schedules, selective/total retrieval of fuel for recycle, use of long-term storage, or combinations of these options.

4.3 Define Parameters

After a scenario is developed, additional module parameters are chosen; for example: facility start-up dates, enrichment percent, mass flow rates, storage durations, HLW packaging details, transportation distances, private/government financing arrangements, etc. Integrated functional flow models (mass balance simulations, etc.) may be used to assist in the identification of some parameters and to ensure consistency. The definition of the parameters allows the user to select the most appropriate module data to fit the scenario. The available parameter choices will differ for each module, so the user will need to refer to the specific module section (e.g., Table D1-4 of Module D1-1, WIT costs for pressurized and boiling water reactors) in this report. The nomenclature section at the beginning of this report provides standard definitions for cost estimating terms and parameters that are commonly used in economic analysis.

4.4 Cost Module Coupling

Modules are chosen by linking the front-end modules and the back-end modules to a reactor. Additionally, transportation modules are selected to provide the linkage between the fuel cycle facility modules. There are numerous options for combining the modules to build an integrated fuel cycle system. Figure 4-2 shows a simple example of linked cost modules for a once-through fuel cycle scenario. Further refinement of the module parameters may be necessary based on the specific module interface requirements. The interface requirements are provided for each module in this report. More complex fuel cycle systems may also be developed that include recycle modules. In the case of recycled materials, particular attention must be paid to the recycle material flows to ensure that the facility capacities are sized to adequately support the new and recycled flows. In these cases, a computer model may be required to evaluate the dynamic flows between the modules (refer to Section 6).

4.5 Cost Module Scaling

Modules may have cost data that can be scaled to a range of capacities. The user may adjust the size/throughput rate of the reference modules, and then determine the associated scaling of costs versus size for their scenario using parametric methods. Data on module scaling are provided (as available) in Section 5 of each of the modules in the cost basis report. The user is advised that scaling is limited to a range of applicability around the reference module capacity; extension of the scaling beyond these bounds may be invalid and is not advised. Because of the large uncertainties involved in scaling costs, this task can become highly detailed and complex.

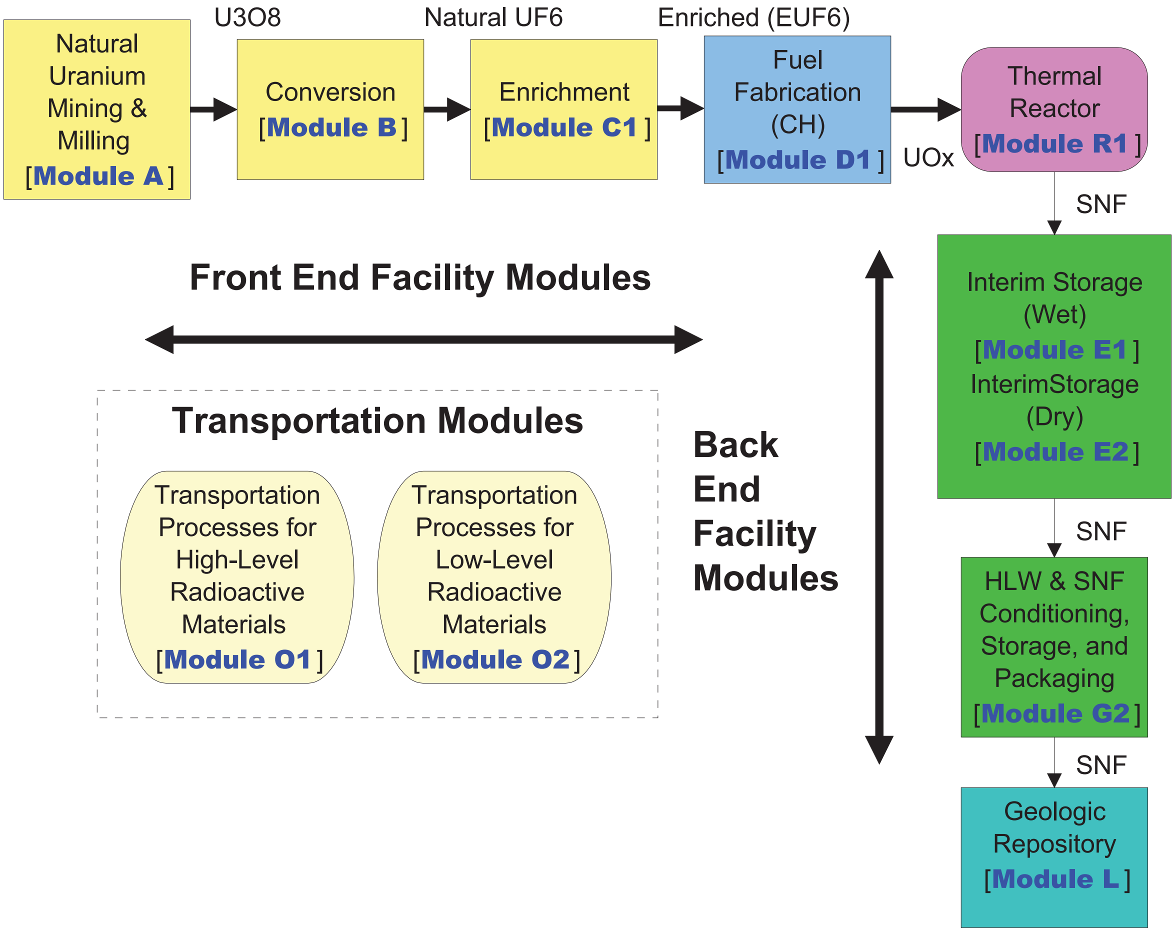

Figure 4-2. Example of linked cost modules.

4.6 Handling of Credits for U, Pu, and Other Materials

In some recycle scenarios, recovered fuel may be sent back to a reactor for reuse. There may be an implied value for this fuel that can be counted as a credit in the fuel cycle cost calculations. This value may be accounted for simply by requiring less new fuel during refueling. In other cases, the materials may take on a commodity value, based on the equivalent cost of the fuels that they are replacing. The user is referred to the applicable front-end cost modules to determine the value of recycled materials.

4.7 Develop Total Fuel Cycle Costs

After the scenario has been defined, applicable modules selected and scaled, and modules linked then a total fuel cycle cost may be derived. The cost estimate is composed of a compilation of cost data that have been normalized, scaled for mass flows, extended based on quantities of production and years of operation. An economic analysis has been performed that provides a cost comparison of three fuel cycles that represent applications of the once through fuel cycle, fast reactor recycling (1 Tier), and thermal/fast recycling (2 Tier) (Shropshire 2009). The module cost data was selected from the March 2008 AFC Cost Basis report and additional sources that were available at the time of the assessment.

4.8 Develop Total Cost of Electricity Costs

The total cost of electricity (TCOE) can be developed for a fuel cycle scenario by adding the total fuel cycle contribution or component (in \$/MWh) to the other cost components (reactor capital, reactor operating and maintenance, reactor D&D). Baseline cost data for different reactor types is necessary to support development of TCOE. The baseline cost data for current generation light water reactors and fast reactors are provided in Modules R1 and R2. The reader may also seek additional reactor cost data sources (e.g., EMWG). These data are provided for estimate completeness and to account for the interdependencies between the reactor technology and the fuel cycle. The user is advised to use a range of reactor costs to evaluate the sensitivity of the total TCOE to the reactor/fuel cycle concept.

4.9 Economics of Private Sector vs. Regulated Nuclear Fuel Cycle Facilities

With the expected high costs and significant risks involved in constructing new nuclear facilities, including nuclear reactors and fuel recycle facilities (i.e., reprocessing, refabrication, and HLW form), consideration should be given to the economics of various facility ownership options. These options include government funding, regulated funding, private funding, and combinations of public and private funding options. These different funding approaches may significantly impact the costs of fuel cycle services. As part of the overall quantitative analysis of the fuel cycle, the assessment of the economics based on the ownership of the fuel cycle facilities was conducted. A sensitivity analysis of the fuel cycle facility ownership options was also prepared, evaluating a range of options from fully government owned to fully private owned were evaluated using DPL (Decision Programming Language 6.0), which can systematically optimize outcomes based on user-defined criteria (e.g., lowest life-cycle cost, lowest unit cost). The analysis was presented at ICONE14 in December 2006 in Miami, Florida (Chandler and Shropshire 2005).

5.

ECONOMIC EVALUATION GUIDELINES

This section provides guidelines for comparing alternatives on a consistent basis. There are two approaches, qualitative analysis and quantitative analysis. Qualitative analysis has been used in analyses such as the DOE AFCI Comparison Report (DOE 2006). Quantitative analysis will be used in the broad system studies to evaluate system scenarios to identify economic drivers and refine scenario evaluations. Because of the large uncertainties in the designs and costs for many of the fuel cycle cost elements, the qualitative method is being used to provide economic analysis data external to the DOE. Quantitative analysis is the primary application internal to the AFCI Program for system assessment.

Qualitative analysis is used when system cost information is unavailable (no current or relevant cost basis, or uncertainties so large that differences derived from system comparisons are unsupportable). The evaluations use factual system data with economic consequences. The cost comparisons consider sources of additional costs and potential areas for cost savings as compared to the current demonstrated technology (e.g., reduced uranium consumption, fewer waste packages required, reduced transportation, increased amount of waste to be dispositioned).

For example, the economics of separation has implications in many areas across the fuel cycle; however, we can expect that separation costs will be driven by the type of spent fuel, number of recycles, type of operation, separation process and facility requirements, recycled elements, and in-process waste storage. Each of these qualitative parameters is evaluated in order to derive a relative comparison for the separation economics across the various systems. As design information becomes available, the qualitative comparisons will be replaced with actual cost estimates and their associated assumptions.

Quantitative analysis numerically evaluates and compares various fuel cycle systems. The fuel cycle cost data contain a high degree of uncertainty. Understanding the range of cost uncertainty associated with each of the concepts is important for determining if a significant cost difference exists between systems. When the process described in this report is used, the data can be used to understand the relative cost differences between systems. There are two types of quantitative analysis that can be performed, which are described as follows:

- Scenario optimization—hold most factors (modules) constant while varying the parameters of a limited number of interrelated modules to determine the most cost-effective technology combination for a particular fuel cycle strategy.
- Strategy/scenario comparison—compare two different integrated concepts for purposes of determining an economic “score” as part of metric application for program down-selects.

6. ECONOMIC COMPUTER MODELS

6.1 Integration of Cost Modules into Cost Models

The cost information included in this report may be used in conjunction with computer models to provide quantitative analysis of fuel cycle options. The costing procedure described in Section 4 is directly relevant to the use of cost data in the cost models. It is strongly recommended that the user become experienced with manually using the cost data in scenario studies before incorporating the data in a cost model. Manual checks on modeling results are recommended for verification.

Cost models can be wonderful time saving analysis tools, but may also provide misleading answers. Wrong conclusions will result from a number of sources:

1. Cost data were not intended for use in the type of scenario.
2. Bounding capacities of the reference facility were exceeded.
3. Module capacities and mass flows were not properly calculated to account for recycling, blending, maximum versus operating capacities, etc.
4. Cost module uncertainties bounds were not considered.
5. Misunderstanding of ownership (private versus government) and associated treatment of interest charges for capital, taxes, etc.
6. Inadequate account taken of the technology maturity and R&D funds needed.
7. Hidden/implicit assumptions
8. Impacts on processing efficiency resulting from future technologies.

6.2 Computer Software and Simulations

Several fuel cycle models have been developed that produce mass flows through the fuel cycle based on various fuel cycle scenarios. Some of the fuel cycle models that could be adapted for use with the AFCI cost data are described in the following sections.

6.2.1 NFCSim

NFCSim Version 3.0 is a JAVA-based model developed by Los Alamos National Laboratory that tracks the flow of nuclear materials at charge level (isotopic level) throughout the nuclear fuel cycle. The object-oriented model reenacts the history (i.e., simulates the operation with the historical variation in burnup and availability) of the U.S. reactor fleet, which includes 104 operating and 14 decommissioned reactors, to obtain an estimate of the associated SNF generated by these reactors. The class structure of the model includes facility classes for the complete fuel cycle, including reactor and accelerator driven systems. The model is coupled to ORIGEN and can produce detailed isotopic flows resulting from irradiation in a reactor or decay while in storage. NFCSim includes a costing model using input unit cost data. The calculation of annual costs is assessed for the year in which the service is rendered. Pre and postoperational costs (e.g., initial core loading) are included in the mortgage and D&D escrow account, respectively. Costs for storage can be assessed on a \$/kg/yr or \$/kg basis. Costs and revenues with a time component (e.g., O&M and electrical production) are apportioned according to the fraction of a year for which they apply (Bathke et al. 2002).

6.2.2 Dynamic Model of Nuclear Development (DYMOND)

DYMOND Version 1.0 and DANESS (not reviewed) are system dynamics models developed by Argonne National Laboratory to perform 100-year global nuclear energy scenarios. The DYMOND model was further developed in FY 2005 by modelers at Argonne and the Idaho National Laboratory to perform fuel cycle systems analysis. The Stella/iThink models provide a summary level simulation of SNF for the U.S. reactor fleet. These types of models support continuous, nonlinear feedback systems. The modeling environment is adaptable to various reactor systems but is less sophisticated than object-oriented tools. The model handles radioactive decay at a summary level, parametrically estimating rates for key isotopes. Unit cost data may be incorporated into the model to determine the total costs resulting from mining, conversion, enrichment, storage, fuel fabrication, recycling, disposal, and power production.

6.2.3 Harvard Spreadsheets

The economic models used in the 2003 Harvard economic study, *The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel* (Bunn 2007), are available as spreadsheets (http://www.puaf.umd.edu/Fettr/programs/COE-LWR.xls). The spreadsheet models are self-documenting. There are two spreadsheets, one for LWR and one for fast reactors. Either can be used to estimate the LUEC (in $/MWh) based on key user-input parameters such as U ore price ($/kg), mixed-oxide (MOX) or fast reactor fuel fabrication cost ($/kg), geological disposal cost ($/kg), separation cost ($/kg).

6.2.4 Generation IV Economic Modeling Working Group Levelized Cost of Electricity Model

The International Generation IV EMWG has an EXCEL-based model called G4 ECONS that considers open fuel cycles and equilibrium closed fuel cycles. The intent of the model is to allow comparison of all six Generation IV concepts and their variants. The financial model is very simple, since the intent is comparison of technologies and not financing or deployment options. The fuel cycle portion of the model inputs unit costs in much the same form that they are given in this report. The fuel cycle component cost for all of the major parts of the fuel cycle is then calculated in mills/kWh ($/MWh), $/kg heavy metal (HM), and $/yr. In order to keep the model—which must also consider capital, O&M, and decommissioning costs—simple, fuel cycle lag and lead times and losses are ignored. So far, the EMWG model has been used for a range of nuclear system analysis, including Japanese Sodium Fast Reactors under study by the Generation IV technology groups.

The first purpose of the highly-transparent and simple G4-ECONS formulation for fuel cycle modeling is to allow comparison of vastly different reactor and fuel cycle technologies being developed by many international partners; secondly, not enough information on the timing of technology deployment and financing is available to allow the use of more sophisticated models. No allowance is made for interest charges due to lag time or lead time in purchase of services, as is done in more sophisticated business models used by utilities.

6.2.5 Total System Model

Bechtel SAIC has developed a model for the Yucca Mountain Project. The objective of the Total System Model is to evaluate alternative approaches for OCRWM disposal. The model encompasses the back-end of the fuel cycle and provides discrete event simulation of waste packages from the 104 U.S. reactors to final disposition at the HLW repository. The model was developed in SimCad and is designed to evaluate life-cycle costs, total project cost, and funding requirements. The model was developed based on a once-through fuel cycle and does not currently support recycling alternatives (Shropshire 2003).

6.2.6 VISION.ECON

The existing fuel cycle models, previously discussed in this section, were not developed specifically to support comprehensive dynamic analysis of fuel cycle costs. A verifiable fuel cycle simulation (VISION) model is being developed to support the requirements defined in Section 6.3. This model was used to perform fuel cycle analysis in support of the AFCI Systems Analysis in 2008 (AFCI 2008). An economic submodel has been developed in conjunction with VISION called VISION.ECON. This model will use the cost data from this report to analyze various fuel cycle alternatives. Results from the dynamic VISON.ECON are compared to the G4 ECONS model for verification purposes and to help in understand the impacts from modeling under dynamic conditions.

VISION is the AFCI nuclear fuel cycle systems code (DOE 2005). The VISION model is the successor to the DYMOND model, the Dynamic Model of Nuclear Development (Yacout et al. 2004). VISION, which is run on the commercial software PowerSim STUDIO (www.powersim.com), is a dynamic stock and flow model that tracks the mass of materials through the entire nuclear fuel cycle. VISION tracks the isotopic mass-flows of uranium, plutonium, minor actinides, and fission products throughout the fuel cycle and accounts for the decay of those isotopes. The current VISION model focuses on the U.S. reactor fleet, with planned expansion to handle the international power fleet in the future.

VISION.ECON was created as a submodel of VISION to provide economic analysis of nuclear fuel cycle cases. The submodel produces cost distributions for relative economic comparisons rather than absolute value cost estimates. VISION.ECON extends the modeling capability beyond static equilibrium analysis tools by providing insight to dynamic modeling impacts to cost over time. The tool currently includes the functionality to evaluate cost and system uncertainties. Model output showing the total cost uncertainties of a case are generated within VISION.ECON in a post processing mode using a modified Monte Carlo method. Cost and system uncertainties can be used to identify the variables within the model that have the largest impact on the cost for each case.

6.3 Model Performance Evaluation and Verification Activities

The objective of VISION is to serve as a broad systems analysis and study tool applicable to AFCI and Generation IV reactor development studies. The model simulates the fuel cycle from cradle to grave, from mining of raw materials to disposition of waste after electricity generation. A software requirements specification (AFCI 2005) was developed to define the objective, scope, and key assumptions of VISION. In addition, expectations and requirements were developed for model variables (flow model, cost model), analysis of estimates or measures, general model architecture elements, hardware/software, constraints, and use cases. Software quality will be ensured through design requirements (e.g., code transparency), quality documentation (e.g., user manuals), and performance testing (e.g., independent verification and review). The model uses nonproprietary, off-the-shelf commercial software; has an open architecture; and is readily usable by fuel cycle practitioners and technical experts; and supports communication of analysis and results to less technical audiences. The graphical user interface provides an intuitive understanding of the model functionality and the capability to trace though the causes of system behavior to identify the key variables driving the behavior within the system. The cost submodule under development in VISION will support simulations using probabilistic algorithms to account for module cost uncertainties.

The model and/or its documentation will explicitly state key assumptions, including what is and is not included in each sector of the model. Good examples include how inflation, escalation, and interest charges on capital are treated—especially given that some parts of the fuel cycle are commercial (power plants), some are government, and some might be either/or. Another key issue is how geological disposal costs are treated (i.e., as a single government-set fee [mills/kWh] or projected repository capital + operating costs amortized over an amount of disposed HLW).

The AFCI Systems Analysis Working Group has integrated cost data into the AFCI VISION.ECON dynamic cost model, while continuing to use the Generation IV ECONS reactor economics code for static analysis and for cost verification purposes. AFCI systems cost analysis is performed using both models as a check on estimating assumptions, modeling algorithms, and data integrity. In the AFC Economic Analysis (Shropshire 2009) a comparison of the results from G4 ECONS and VISION.ECON results was performed in order to calibrate and verify results between the models, and to better understand why dynamic analysis may provide somewhat different answers. As an example, Figure 6-1 provides a comparison between the overall cost distributions for three fuel cycle strategies showing the comparable cost of electricity and fuel cycle costs. Shown in this analysis, it is possible to get very good agreement between the spreadsheet and dynamic modeling analysis.

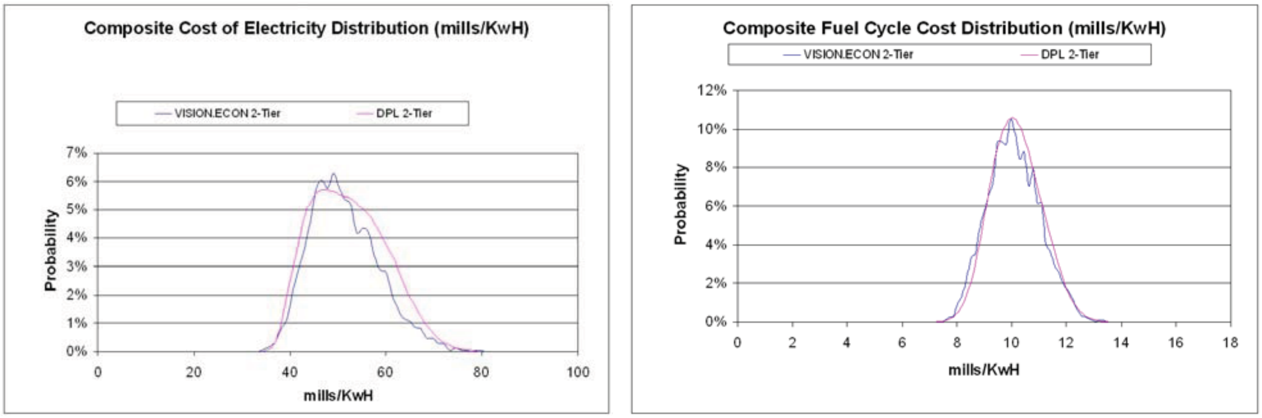

Figure 6-1. Cost comparison between spreadsheet and dynamic analysis.

7. CONCLUSIONS AND RECOMMENDATIONS

The AFCI Economic Analysis team has established the processes and structure to support the collection of fuel cycle cost data. The cost data were drawn from over 200 reference reports, reviewed and summarized, normalized for consistency, verified through cost sensitivity analysis, input to models for evaluation of various fuel cycle scenarios, and applied toward new approaches for communicating fuel cycle economics.

7.1 Creation of a Credible Reference AFCI Cost Basis

The Advanced Fuel Cycle Cost Basis report, commissioned by DOE, provides a comprehensive set of cost data supporting an on-going, credible, technical cost basis for use on the AFCI Program. System analysts will use this report to evaluate the impacts and benefits of a wide range of AFCI and Generation IV deployment options. The report is meant to aid analysts in (1) understanding the issues and opportunities for keeping nuclear power an economically competitive option, (2) evaluating the elements dominating nuclear fuel cycle costs, and (3) developing the tools to evaluate the economics of creative solutions to make the nuclear fuel cycle even more cost competitive.

The intended use of the cost data is for the relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. Each element of cost has a probabilistic range of accuracy and, when the costs are coupled together into a total fuel cycle system estimate, the uncertainty range is additive. The cost data are being used in studies to evaluate costs of fuel cycle options. Fuel cycle costs are an important part of the comprehensive evaluation that also includes measures of sustainability, proliferation resistance, adaptability to different energy futures, and waste management impacts (e.g., heat load impacts on the repository). These evaluations will result in the identification of cost drivers within the fuel cycle where development may be focused to reduce the costs within the system.

This report describes the AFCI cost basis development process, reference information on AFCI cost modules, a procedure for estimating fuel cycle costs, economic evaluation guidelines, and a discussion on the integration of cost data into economic computer models. This report contains reference cost data for 25 cost modules—21 fuel cycle cost modules and four reactor modules. The cost modules were developed in the areas of natural uranium mining and milling, thorium mining and milling, conversion, enrichment, depleted uranium disposition, fuel fabrication, interim spent fuel storage, reprocessing, waste conditioning, SNF packaging, long-term monitored retrievable storage, managed decay storage, recycled product storage, near surface disposal of LLW, geologic repository and other disposal concepts, and transportation processes for nuclear fuel, LLW, SNF, transuranic, and high-level waste. The AFCI cost developers are closely coordinating with the Generation IV EMWG and have adopted many of the EMWG estimating structures, assumptions, and estimating processes.

This report is based on data collected from historical reports and expert knowledge of past and current fuel cycle facilities and processing requirements. The reference data have been placed into a cost collection database, screened, normalized for U.S. facilities, and summarized for this report. The fuel cycle requirements for future generation nuclear reactors are also being assessed and will be included in the cost basis as the technology matures. The cost basis information will be updated periodically with advancements in the knowledge gained in the technology development studies.

This report establishes fuel cycle modules with “What it takes” values and a plausible cost distribution for a particular service, operation, or material. In most cases a cost or prices is given and does not include any taxes, carrying charges, or other overheads sometimes applied to such items by utility accounting systems. For example, some utilities may add refueling service overheads or significant carrying charges to the front end costs for UO_2 fuel. This may result in open cycle fuel cycle front-end costs of 10 mills/kWh or higher. The constituent unit costs given are intended to be used in a simple, but highly transparent, "value added" model such as the Generation IV G4-ECONS reactor economics code. This model moves through the steps of the fuel cycle, multiplying all of the annual flows times the unit costs for each module or "box" and summing the annual costs. The grand total annual cost is then divided by the annual electricity production in kilowatt hours per year to obtain the fuel cycle contribution to the overall levelized unit electricity cost (LUEC). (Reactor-related components of the LUEC are discussed in Modules R-1, R-2, R-3, and R-4.)

7.2 Path Forward

This report will continue to be updated in future years based on the input from technical reviews; updated cost information; advances in the knowledge gained in the technology development studies; information collected through integration with AFCI and Generation IV studies. Additional cost sensitivity and uncertainty analysis will be performed to expand the knowledge base. Additional studies are underway to understand the cost implications from system losses, different reprocessing partitioning schemes, hybrid fuel cycles (e.g., U/Th), better understand the costs for small nuclear power reactors, improved utilization of the geologic repository, and studies identified by the AFCI Systems Option Study in FY-09.

All reference fuel cycle cost data and source documentation will continue to be placed in the AFCI Cost Collection database. The fuel cycle requirements for future generation nuclear reactors will also be assessed with the help of the EMWG and included in the cost basis as this technology matures.

AFCI systems cost analysis will continue to be performed using both static and dynamic models as a check on estimating assumptions, modeling algorithms, and data integrity.

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Module A1

Uranium Mining and Milling

Module A1

Uranium Mining and Milling

A1-1. BASIC INFORMATION

The authors recognize that uranium and enrichment spot prices have recently exceeded the high-cost range provided in this cost basis. Although prices have declined from peak values seen in 2007, price trends continue to be evaluated and the cost ranges in the report may continue to be revised as appropriate in future updates. The cost basis reflects reasonable expectations about uranium and enrichment long-term contract prices applicable to reactors with long operating lives, rather than reflecting market spikes as experienced in the 1970s and observed in the spot market U_3O_8 prices circa 2007.

This module covers the factors involving extraction of uranium from the earth through production of uranium concentrate in the form of U_3O_8, commonly known as "yellow cake." Supply of uranium for use in the commercial nuclear industry in the United States is obtained from both domestic and foreign supplies. Uranium is somewhat unique among fuel resources in that nontraditional or secondary supply currently provides a significant portion of uranium requirements. The sources of uranium for any given year's demand are classified as originating from primary supplies representing newly extracted and processed uranium from the earth's surface or from secondary supplies such as existing inventories of natural or low-enriched uranium (LEU), highly enriched uranium (HEU), mixed oxide fuel (MOX), reprocessed uranium (RepU), and reenrichment of depleted uranium (tails). In general, the difference between the demand for uranium to produce new fuel and that supplied by secondary sources results in the market demand for newly extracted uranium from mining of the earth's surface.

Availability of supply is evaluated using the accepted systematic convention of reporting reserves as established by a joint Organization for Economic Cooperation and Development/Nuclear Energy Agency-International Atomic Energy Agency (OECD/NEA-IAEA) expert group and as adapted by U.S. Department of Energy-Energy Information Administration (DOE-EIA). The various categories of reserves indicate both the confidence level that given amounts of reserves will exist as well as the difficulty in making that uranium available for use. These indications are expressed in an estimated cost to reclaim and utilize the reserves with reasonably established methods. Adequacy of the market to supply uranium and appropriateness of pricing are influenced by many factors including overall demand, secondary supplies, primary supplies, lead time for discovery and production, cost of extraction, and such factors as captured markets. Extensive analyses of such factors are performed regularly and published in a biennial report by OECD/NEA-IAEA known as the *Red Book* (OECD 2008a) and annually by DOE-EIA in the *Uranium Industry Annual* (DOE EIA 2008). IAEA has published an *Analysis of Uranium Supply to 2050* (IAEA 2001) evaluating uranium supply to three distinct uranium demand cases. These ranged from a "Low" uranium demand case, reflecting a low energy demand growth and a phase out of nuclear power by 2100, to a "High" demand case, reflecting high economic growth with significant development of nuclear power. A "Middle" demand case, which was also defined, is mainly driven by sustained development of nuclear power worldwide, including the demand in developing countries. Such analysis permits the estimated reserves to be evaluated relative to adequacy of supply, expectations of relative pricing, and projections of ability to make the resources available for utilization in a timely manner.

Two unit systems for quantifying uranium masses are in widespread use in literature. These are pounds of U_3O_8 (lb U_3O_8) and kilograms of U (kg U), where 1 kg U = 2.60 lb U_3O_8. In the figures and tables accompanying this module, the units used by individual source documents are generally preserved.

A1-1. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTION

A1-1.1 Mining and Milling

Uranium is widely distributed throughout the crust of the earth. The ability to extract the uranium in a practical and cost-effective manner depends on the relative grade of the ore to be mined (i.e., the percentage of uranium in the ore body), the type of formation in which it resides, and the location. Uranium, on average, is more prevalent in the earth's crust than such economically important metals as silver and tungsten (Table A-1); it is a constituent of most rocks and even of the sea. Table A-2 shows some typical concentrations in ppm (parts per million).

Table A1-1. Crustal abundance (grams/tonne) of selected elements.

Element	Grams/tonne
Gold	0.004
Silver	0.07
Tungsten	1.5
Molybdenum	1.5
Uranium	2.8
Thorium	7
Lead	13
Copper	55
Zinc	70
Iron	50,000

Table A1-2. Typical concentrations (uranium parts per million).

Substance	Uranium Concentration (ppm)
High-grade ore—2% U	20,000
Low-grade ore—0.1% U	1,000
Granite	4
Sedimentary rock	2
Earth's continental crust (av)	2.8
Seawater	0.003

An ore body is, by definition, an occurrence of mineralization from which the metal is economically recoverable. It is therefore relative to both costs of extraction and market prices. At present, neither the oceans nor any granites are ore bodies, but conceivably either could become so if prices were to rise sufficiently (UIC 2005).

The cost of meeting environmental requirements is also a major factor in the attractiveness of the ore body. Although there are varied means of extracting the uranium to "yellow cake," only two basic approaches will be discussed here, conventional mining (surface pit or deep) and in situ leaching, as depicted in Figure A-1. The quantity of ore required to produce a tonne of uranium will depend on the average grade of the ore. Typically amounts from 10–1000 tonnes of ore are processed to produce a single tonne of uranium (e.g., ore grade 10% to 0.1% U); although, in certain circumstances lower-grade ore bodies are being tapped. The Olympic Dam mine in Southern Australia, for instance, holds the largest-currently known ore body in the world—greater than 1 million tonnes of yellow cake. The average grade of Olympic Dam ore is only 0.04% U, but the ore is rich in copper (1.1%) and gold (Global InfoMine, Inc. 2005). The presence of iron, copper, and gold in this and other breccia complex deposits allow profitable U mining at lower market prices than would otherwise be the case.

Mining techniques, as depicted below, will thus be impacted by the difficulty in reaching the ore, the grade, and the amount of secondary waste to be generated.

A1-1.2 In situ Leaching

With the in situ leaching technology (Figure A-2), a leaching liquid (e.g., ammonium-carbonate or sulfuric acid) is pumped through drill-holes into underground uranium deposits. The solution dissolves and mobilizes the deposit, and the uranium bearing liquid is pumped out from below. The solution is further processed through a series of ion exchange resins or solvent extraction processes and eventually precipitated, dewatered, and yellow cake is produced. The yellow cake is packaged in 55-gallon steel drums for shipment to the conversion plant. The process recovers the leachate, which is adjusted and recycled back into the injection wells. Very little secondary waste is formed. This technology can only be used for uranium deposits located in an aquifer in permeable rock, confined between nonpermeable rocks.

The advantages of in situ leaching are (a) elimination of stockpiling and hauling of ore; (b) elimination of the crushing, grinding, and other milling operation; (c) elimination of large-scale excavations; (d) reduction of risks to miners because they do not have to work underground; and (e) a very small portion of the radioactivity (~5%) of the ore reaches the surface. Disadvantages include (a) risk of leaching liquid excursions beyond the uranium deposit and subsequent contamination of ground water, (b) production of some amounts of waste sludge and waste water when recovering the leaching liquid, (c) impossibility of restoring natural conditions in the leaching zone after finishing the leaching operation, and (d) a low recovery rate of approximately 50% is considered optimum (Diehl and Schwedenteich 2005; Cochran and Tsoulfanidis 1999).

A1-1.3 Open Pit and Underground Mining

Historically most uranium ore has been mined in open pit or underground mines. The uranium content of the ore is often between only 0.1% and 0.2%. Therefore, large amounts of ore have to be mined to acquire uranium. Waste rock is produced during open pit mining when overburden is removed and during underground mining when driving tunnels through non-ore zones. Piles of so-called waste rock often contain elevated concentrations of radioisotopes compared to normal rock. They are typically returned to the pit and covered with overburden. Other waste piles consist of ore with too low of a grade for processing. The transition between waste rock and ore depends on technical and economic feasibility.

The uranium bearing ore must be stockpiled and subsequently hauled to the uranium mill (Figure A-3) where it is processed and concentrated into yellow cake. A uranium mill is a chemical plant designed to extract uranium from ore. It is usually located near the mines to limit transportation. The ore has to be crushed and ground into a fine powder and then roasted to remove most of the organic matter. In most cases, sulfuric acid is used as the leaching agent, but alkaline leaching is also used. As the leaching agent not only extracts uranium from the ore, but also several other constituents like molybdenum, vanadium, selenium, iron, lead, and arsenic, the uranium must be separated out of the leaching solution. This procedure may be an ion exchange or solvent extraction type of process. The uranium is eventually precipitated out and washed, centrifuged, and dried; and the yellow cake is placed in 55-gallon steel drums for shipment to the conversion plant. In some cases, uranium has been removed from low-grade ore by heap leaching. This may be done if the uranium content is too low for the ore to be economically processed in a uranium mill. The leaching liquid (often sulfuric acid) is introduced on the top of the pile and percolates down until it reaches a liner below the pile, where it is caught and pumped to a processing plant.

Waste from the uranium mill is released to a tailings pond where it forms sludge. The tailing ponds receive nearly all the radium and other decay products of the original ore. The amount of sludge produced is nearly the same as that of the ore milled. At a grade of 0.1% uranium, 99.9% of the material is left over. Apart from the portion of the uranium removed, the sludge contains all the constituents of the ore including heavy metals and other contaminants, such as arsenic, as well as chemical reagents used during the milling process. As a result, such tailings require control to safeguard the surrounding environment from radioactive contamination or unwanted radiation exposure. Control of the tailings falls under the Uranium Mill Tailings Radiation Control Act and U.S. Environmental Protection Agency standards.

Advantages of open pit or deep mining are usually centered on a higher recovery of the uranium ore, or, in the case of underground mining, very little surface disturbance. Obvious disadvantages include the large amount of secondary waste that is generated—the 60 million tonne Olympic Dam tailings pile, for example, presently covers over 500 hectares—as well as a much larger exposure of operating personnel to radiation and potential contamination. Deep mining has the added risk of cave-ins, subsidence, and hazards of radon gas generation during mining operations.

A1-2. PICTURES/SCHEMATICS

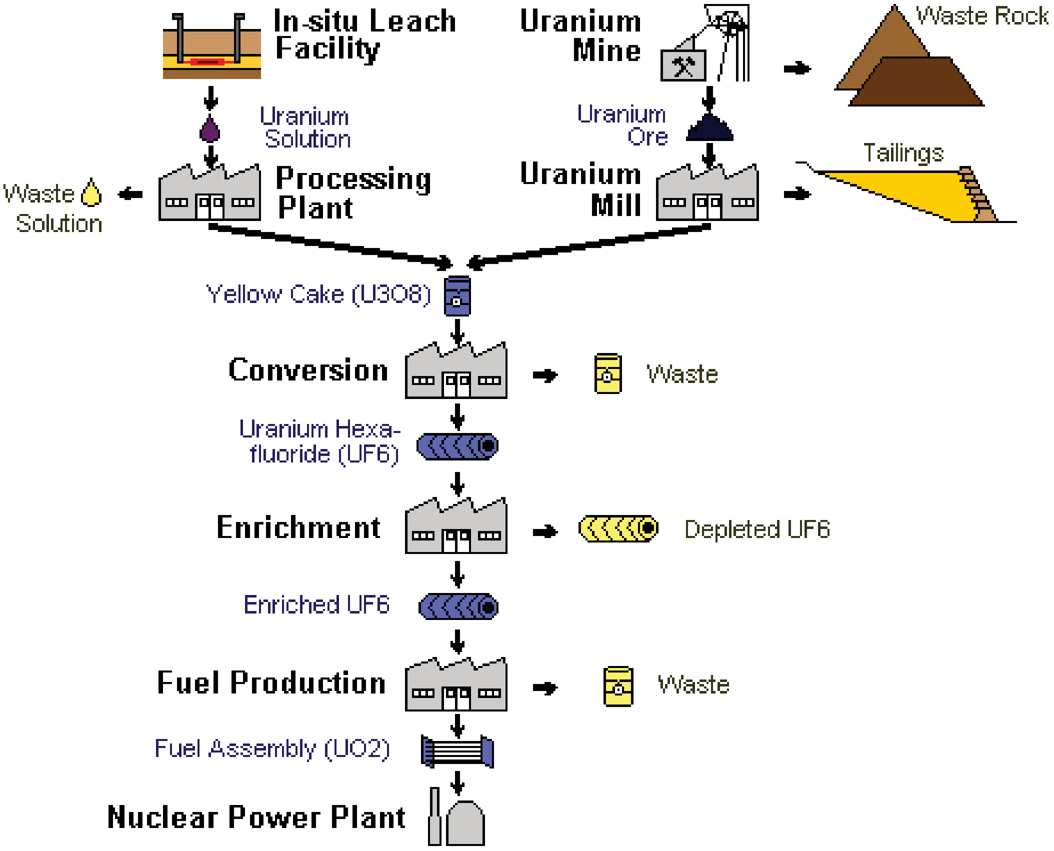


Figure A1-1. Nuclear fuel production chain for light water reactors (Diehl and Schwedenteich 2005).

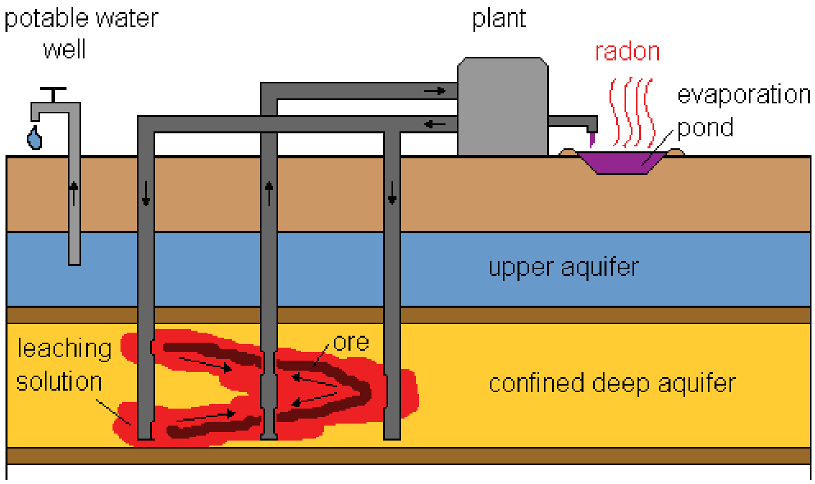


Figure A1-2. Typical in situ leaching operation (Diehl and Schwedenteich 2005).

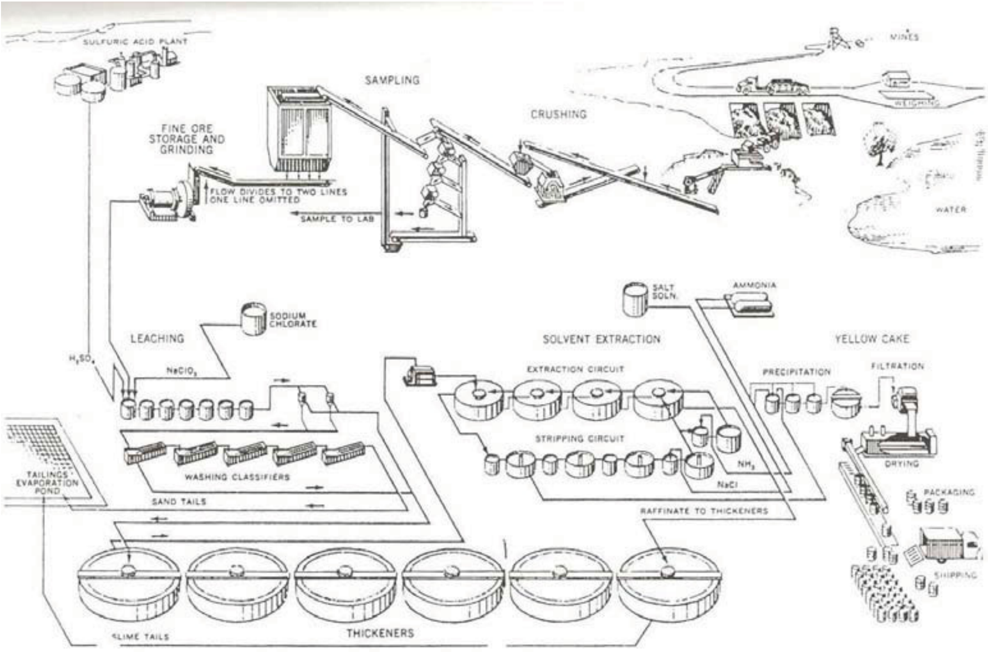


Figure A1-3. Typical uranium mill (EPA 1995).

A1-3. MODULE INTERFACE DEFINITION

The product of Module A is greatly influenced by the requirements for Module D1, Fabrication of Contact-handled Fuels, which defines overall demand. However, relative to specific demand, there are other factors outside of the defined modules that have influence on this module. The requirements for Module D1 can be made up from uranium originating from mining with subsequent conversion and enrichment, or from a number of secondary sources including but not limited to inventory reduction, HEU blend down to LEU and RepU. Module A should, therefore, be directly linked to Modules B and C with the potential for planned inventory buildup by the suppliers.

A1-3.1 Module Scaling Factors

Scaling factors are not specifically applicable. Size and cost of establishing a new mine will depend on many factors and are not generally scalable unless conditions would be nearly identical to another mining opportunity including type of mining method, location, and type of ore body, thickness of seam, etc.

A1-3.2 Cost Bases, Assumptions, and Data Sources

The cost basis for uranium depends on a number of factors impacting supply and demand. Availability, at a given cost, drives the specific supply to meet demand for new product. This demand is also impacted by secondary sources of uranium already existing in many forms in the overall fuel cycle. The following discussions highlight the key factors relative to the actual supply and demand for newly produced uranium.

A1-3.3 Definition of Uranium Reserves

The definitions of the conventional resource categories as established by the IAEA are as follows:

Reasonably Assured Resources (RAR) refer to uranium that occurs in known mineral deposits of delineated size, grade, and configuration such that the quantities that could be recovered within the given production cost ranges with currently proven mining and processing technology can be specified. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of deposit characteristics. RAR have a high assurance of existence.

Inferred Resources (before 2008 Estimated Additional Resources Category I (EAR-I)) refer to uranium in addition to RAR that is inferred to occur, mostly on the basis of direct geological evidence, in extensions of well explored deposits or in deposits in which geological continuity has been established but where specific data, including measurements of the deposits and knowledge of the deposits' characteristics, are considered to be inadequate to classify the resource as RAR. Estimates of tonnage, grade, and cost of further delineation and recovery are based on such sampling as is available and on knowledge of the deposit characteristics as determined in the best known parts of the deposit or in similar deposits. Less reliance can be placed on the estimates in this category than on those for RAR.

Prognosticated Resources (before 2008 Estimated Additional Resources Category II [EAR-II]) refers to uranium in addition to inferred resources that is expected to occur in deposits for which the evidence is mainly indirect and which are believed to exist in well defined geological trends or areas of mineralization with known deposits. Estimates of tonnage, grade, and cost of discovery, delineation, and recovery are based primarily on knowledge of deposit characteristics in known deposits within the respective trends or areas and on such sampling, geological, geophysical, or geochemical evidence as may be available. Less reliance can be placed on the estimates in this category than on those for inferred resources.

Speculative Resources refer to uranium, in addition to Prognosticated Resources, that is thought to exist, mostly on the basis of indirect evidence and geological extrapolations, in deposits discoverable with existing exploration techniques. The location of deposits envisaged in this category could generally be specified only as being somewhere within a given region or geological trend. As the term implies, the existence and size of such resources are speculative.

Unconventional Resources are considered very low-grade resources, which are now not economic or from which uranium is only recoverable as a minor by-product (phosphates, monazite, coal, lignite, and black shale).

The IAEA in its biennial *Red Book* (OECD 2008) also uses the convention of Identified Resources (before 2008 Known Conventional Resources) that consist of RAR and Inferred Resources, recoverable at a cost of less than \$130/kgU (<\$50/lb U_3O_8) USD. Undiscovered Resources consists of Prognosticated and Speculative Resources (SR).

Special note on U.S. reserves: The U.S. does not report EAR-I and EAR-II (Inferred and Prognosticated) quantities separately, but rather combines and reports them as EAR-II only. IAEA also uses the following cost categories for uranium resources.

<\$40/kgU (<\$15.38/lb U_3O_8)
<\$80/kgU (<\$30.77/lb U_3O_8)
<\$130/kgU (<\$50.00/lb U_3O_8)

Thus the combination of implied resource availability and cost defines the expectations for recovered reserves within a given price expectation.

A1-3.4 World Reserves of Uranium

The IAEA *Red Book 2007* estimated world reserves are as shown in Table A-3. Changes from *Red Book 2005* values are noted in italics (OECD 2006a, OECD 2008). This data is displayed graphically in Figure A1-4. The right-hand scale in the figure maps the resource amount to the years of supply it represents were annual demand to remain at late-2000s consumption levels of about 67,000 tU/year. If one assumes that all uranium sources are captured in the *Red Book* estimates, then, Identified Resources at less than \$80/kgU will suffice for 70 years and the resource base represents approximately 240 years of supply.

Table A1-3. *Red Book 2007* Known World Uranium Resources and changes from *Red Book 2005 (italics)* (1000 tU).

	Cost Category				
Resource Category	\$0–40/kgU	\$40–80/kgU	\$0–80/kgU	\$80–130/kgU	\$0–130/kgU
Reasonably Assured Resources	1,766 *(-181)*	832 *(+136)*	2,598 *(-45)*	740 *(+86)*	3,338 *(+41)*
Inferred Resources	1,204 *(+405)*	654 *(+292)*	1,858 (+697)	272 *(-13)*	2,130 *(+684)*
Total Identified Resources	2,970 *(+224)*	1,486 *(+428)*	4,406 *(+652)*	1,012 *(+74)*	5,469 *(+726)*
Prognosticated Resources	—	—	1,946 *(+246)*	823 *(+4)*	2,769 *(+250)*
Speculative Resources (SR)	—	—	—	—	4,797 *(+240)* *2,973 *(-6)*
Total Undiscovered Resources	—	—	1,946 *(+246)*	—	7,770 *(+234)*
All Conventional Resources	2,970 *(+224)*	—	6,349 *(+898)*	—	13,035 *(+1,216)*
^{a}Unconventional Resources**	—	—	—	—	
- From Phosphates					22,000
- Seawater					4,000,000

"t" is metric tonne.
* Cost range unassigned
** Phosphate recovery has been estimated at USD 60–100/kgU including capital investment, and seawater extraction has been estimated in the order of USD 300/kgU
a. 2005 data.
Not all countries report separate figures for the two lowest cost categories.
The figures are adjusted to account for mining and milling losses.

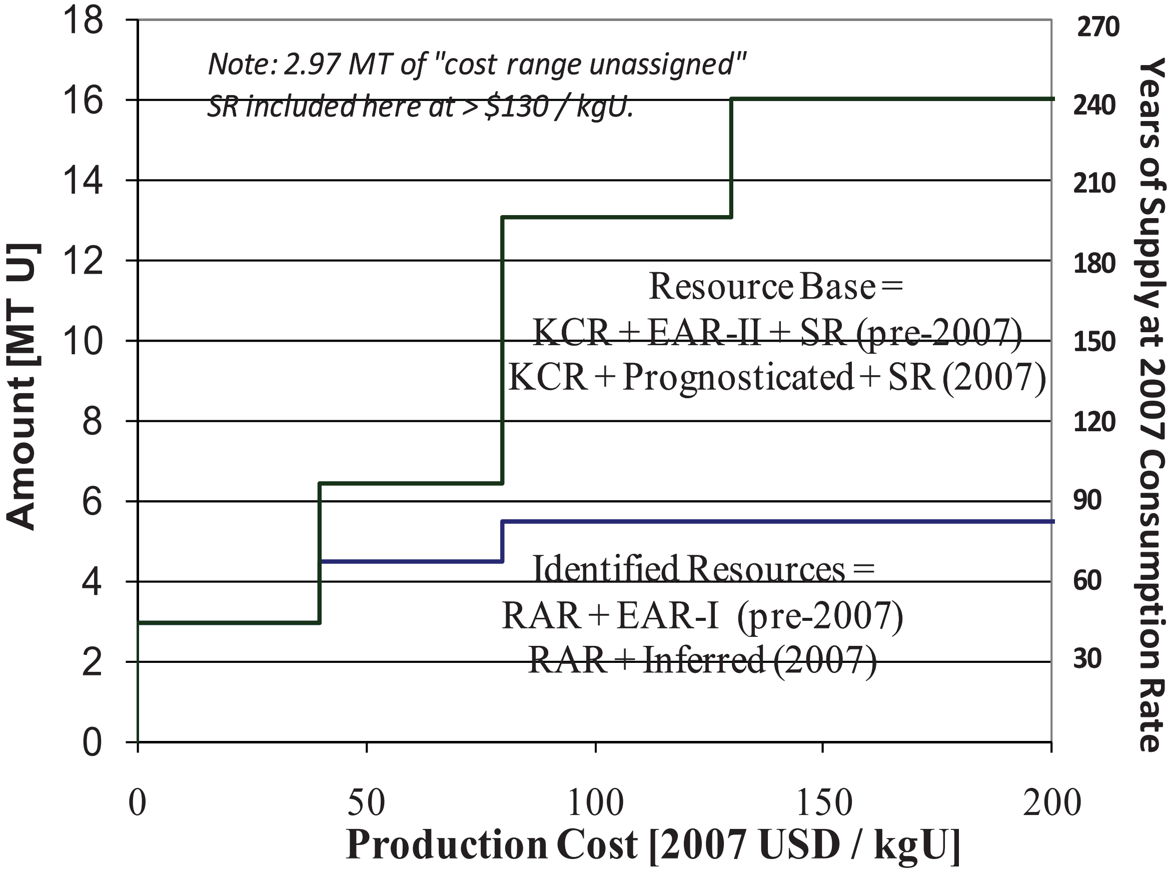


Figure A1-4. Graphical depiction of Red Book supply estimates.

Table A1-4 shows that the world reserves of uranium are dominated by foreign supply.

Table A1-4. Known recoverable resources of uranium.[a]

Country	Tonnes U	Percentage of World
Australia	1,216,000	27%
Kazakhstan	751,600	17%
Russian Fed.	495,400	11%
Canada	423,200	9%
South Africa	343,200	8%
Brazil	231,000	5%
Namibia	230,300	5%
USA	99,000	2%
Uzbekistan	86,200	2%
World Total	4,456,000	

[a] Reasonably Assured Resources plus Inferred Resources to U.S.$80/kgU, from OECD NEA & IAEA, *Uranium 2007: Resources, Production and Demand.*

The World Nuclear Association (WNA) (WNA 2009) interprets these data to imply that "the world's present measured resources of uranium (5.5 Mt) in the cost category somewhat below present spot prices and used only in conventional reactors, are enough to last for over 80 years. This represents a higher level of assured resources than is normal for most minerals. Further exploration and higher prices will certainly, on the basis of present geological knowledge, yield further resources as present ones are used up." The *Red Book* authors reinforce this point, noting that "[t]he uranium resource figures presented here are a 'snapshot'… and are not an inventory of [the] total amount of mineable uranium contained in the Earth's crust. Should favourable market conditions continue to stimulate exploration additional discoveries can be expected…" (OECD 2008). *Red Book* supply estimates are fluid, with new discoveries that increase the resource base offsetting extraction activities that reduce it. Figure A1-5 shows that from 1965 to 2007, *Red Book* Identified Resources increased by approximately 2 million tU, even as 2 million tU were extracted. Therefore, about 4 million tU was added to the Identified Resource base during this time period.

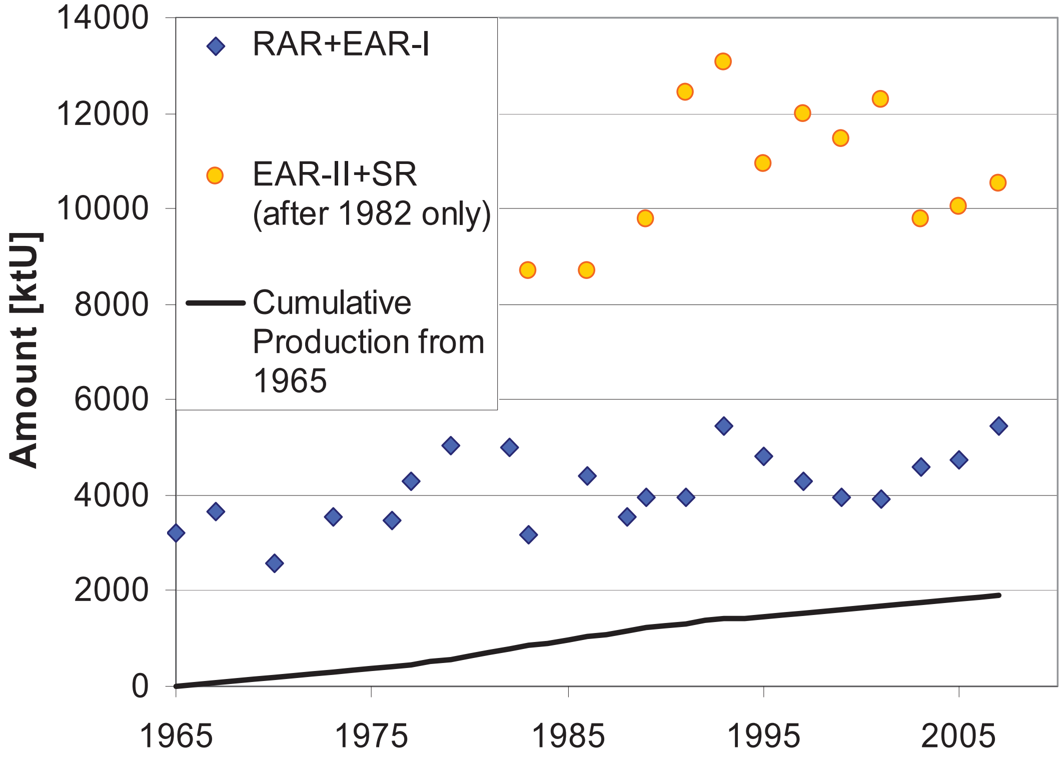


Figure A1-5. Cumulative uranium production, *Red Book* Identified (RAR+EAR-I) Resources and Resource Base, 1965-present.

Much of what is known about the existence of uranium reserves is the result of a single cycle of exploration-discovery-production that was driven in large part by peak prices for uranium in the late 1970s. Little exploration has occurred from the early 1980s to the mid 2000s. As has been seen, that initial cycle provided enough uranium to last for over 3 decades (see Figure A1-7). The uranium price boom of the mid to late-2000s has fostered a second wave of intensive exploration. A strong increase in world uranium exploration expenditures (Figure A1-6 [OECD 2008]) has contributed to the 1.2 million tonne increase in the uranium resource base of the 2007 *Red Book* as compared to 2005. Exploration expenditures may be placed in perspective if it is noted that the historical average cost of resource discovery has been \$2/kgU (OECD 2008). Then the 2005–2006 exploration expenditures, which totaled around US \$1.5B, show that prospecting is continuing to yield discoveries that match or even surpass historical norms.

Domestically, the U.S. Energy Information Administration reports that domestic uranium exploration and development expenditures increased from an average of \$5M/year during the 1999–2001 time period to \$18.1M in 2005, \$40.1M in 2006, \$67.5M in 2007, and \$81.9M in 2008. Large exploration expenditure increases are also being seen in Canada and Kazakhstan; the *Red Book* indicates worldwide exploration expenditures of about \$400M in 2005. Given that, historically each \$3 of exploration expenditures has led to the production of 1-pound U_3O_8 (Pool 2006), the current supply tightness may be expected to ease.

It is important to note that it takes some time for a successful prospecting claim to become an operational mine. For mines that opened in 1999–2001, the elapsed time between discovery and commencement of mining was 20 years (OECD 2006b). On the other hand, the corresponding time interval for mines that opened between 1970 and 1980 was under 10 years. While an increased regulatory burden and local public opposition may account for a component of this increase, it is likely that the unfavorable economics—from a seller's perspective—of the uranium business accounted for many discoveries remaining untapped through the 1990s. Therefore, it is reasonable to claim 10–15 years as a realistic prospecting-to-production time delay.

Discoveries and mine openings in the U.S. will be addressed later in this section.

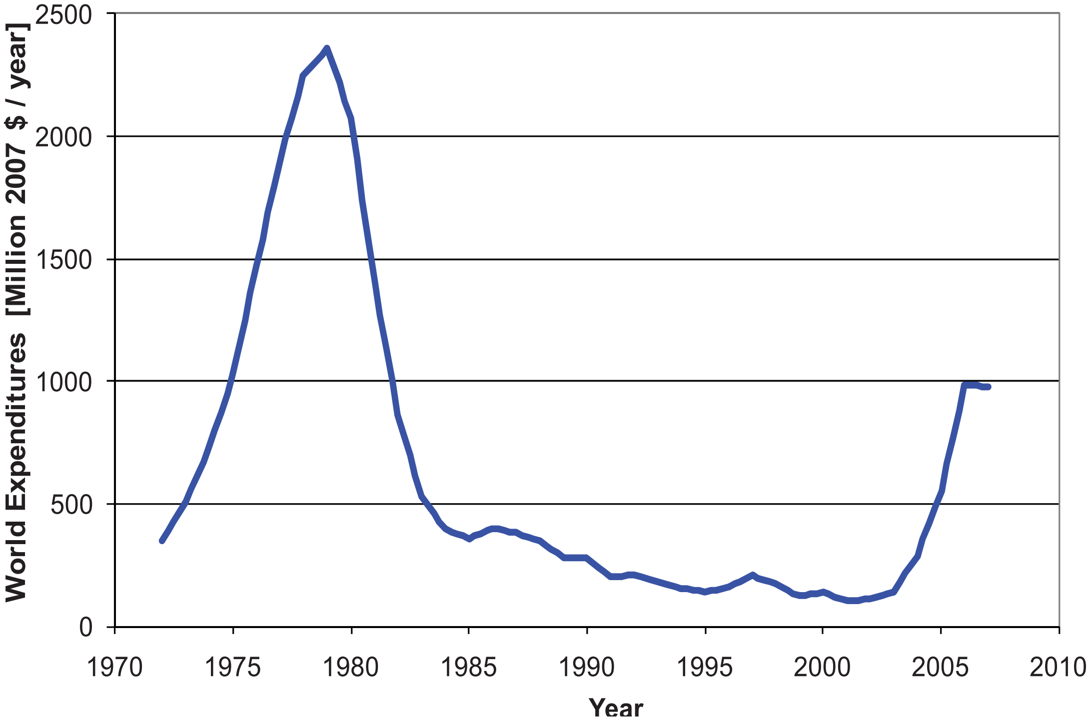
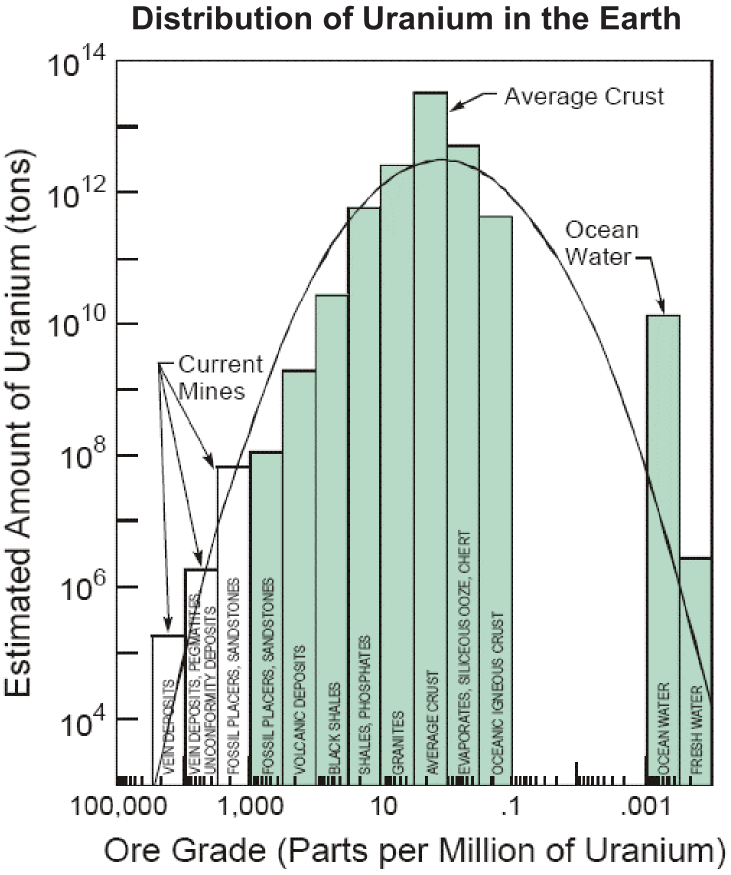


Figure A1-6. Worldwide annual uranium exploration expenditures, 1972-present.

Figure A1-7 depicts an evaluation of the abundance of uranium in the earth's crust by K. S. Deffeyes and I. D. MacGregor. The Figure A1-7 shows many of the recognized source materials from which uranium can be recovered. As with other metals and energy-related commodities, such as oil and gas, focused exploration could be expected to expand known resources. WNA further states that "a doubling of price from present levels could be expected to create about a tenfold increase in measured resources, over time" (EPA 1995).

This WNA statement may be inferred from Figure A1-7 with the aid of a simplifying assumption. If one assumes that, to first order, the cost of extracting and purifying a unit mass of ore is independent of grade, then the cost of producing a kilogram of uranium would be inversely proportional to the ore grade. Looking at the region of Figure A1-7 labeled "Current Mines," one sees that a reduction of an order of magnitude in ore grade would lead to a three order of magnitude increase in the availability of uranium at that lower ore grade. For example, referring to Figure A1-7 one sees that 10^5 tonnes of uranium are estimated to exist in deposits having grade 10,000 ppm or higher. Moving to ores one order of magnitude less rich, 1,000 ppm, the estimated availability increases by three orders of magnitude to 10^8 tonnes. Hence, if the production cost is indeed inversely proportional to grade, and no other factors affecting the price are considered, the ore grade distribution of uranium deposits does indeed imply that a doubling of price would increase the economically extractable amount of uranium by about a factor of 10. Other forecasters have applied somewhat different assumptions and interpretations of Figure A1-7 to arrive at slightly different conclusions (Schneider 2005). It must be noted that these estimates do not take into account that factors discussed below that have seen most mineral prices decline over the past century.



Deffeyes 1978, 1980

Figure A1-7. Distribution of uranium in the earth (Deffeyes and MacGregor 1980).

Without constraint by cost, the total resource base reported by IAEA-NEA (Known Conservative Resources with Undiscovered Conventional Resources) represent 16.0 million tonnes, which is almost a 300-year supply at today's rate of consumption by light water reactors. If unconventional resources, such as phosphate deposits (22 MT) and seawater (up to 4000 MT), which would cost two to six times the present market price to extract, are considered, the supply becomes essentially unbounded. Uranium extraction as a by-product of phosphate mining, where tailings contain 50–200 ppm U, has historically been achieved with costs ranging from \$22–54 per lb U_3O_8 (Wise Uranium Project 2008). Higher prices for supply will drive further exploration. As exploration expands, more geologic knowledge is gained of existing or new deposits and typically new technologies developed to cost effectively utilize the resource. The recent history of the Athabasca Basin in Canada suggests that the largest proportion of future resources will be as deposits discovered in the advanced phases of exploration. It is clear that a combination of mineral exploration and development of technology advances will need to generate economical resources at least as fast as they are being consumed.

Granted that a large supply of crustal uranium is theoretically available, the issue of the economic viability of lower-grade deposits that might be mined in the future remains controversial and unresolved. In the absence of industrial experience or detailed bottom-up studies of such operations, a surrogate measure of their cost has been devised. This is the concept of the cutoff ore grade. Extending beyond uranium to other minerals, it postulates that there exists an ore grade below which the energy input to the mining process alone makes the extraction cost prohibitive.

For uranium, the cutoff grade is typically defined as the grade at which the energy consumed in mining exceeds some threshold fraction of the energy produced by the nuclear power cycle. Chapman (1975) pioneered the investigation of the uranium cutoff grade. He calculated the ore grade at which the nuclear power cycle becomes endothermic to be around 20ppmU (Prasser et al. 2008). Extraction energy and production cost are closely coupled, and there is no doubt that (due primarily to overburden haulage) an inverse relationship exists between ore grade and energy requirements per unit uranium produced. Chapman and successors estimate this cutoff grade by summing the energy inputs associated with each step shown in Figure A1-8. Note that in-situ leaching, a new technique that was in its infancy when Chapman wrote, bypasses waste rock haulage.

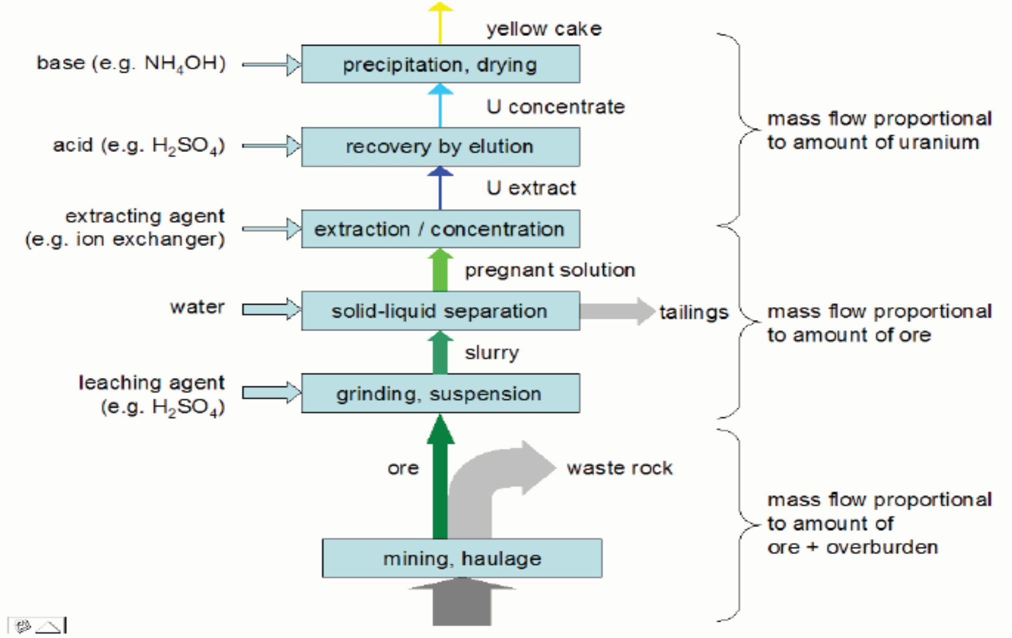


Figure A1-8. Mass flow through the uranium mining and milling process (from Prasser et al. 2008).

Chapman and others derived cutoff grade estimates by extrapolating energy consumption data trends from existing mines to low ore grades. A great deal of additional data, some for mines operating with low grade ore, has accumulated since Chapman's pioneering work. Smith and Storm van Leeuwen (SSL) used extensive data relating ore grade to energy consumption collected in the 1970s and 1980s to refine Chapman's analysis. Assuming a reciprocal relationship between ore grade and energy requirements and including energy inputs elsewhere in the fuel cycle (e.g. decommissioning), they predicted a much higher breakeven grade—between 100 and 200 ppm—implying exhaustion of viable uranium by 2050 if nuclear power grows at 2.5% per year from 2008 (Storm van Leeuwen and Smith 2005). This result implies that even some of the reserves identified in the *Red Book* will prove prohibitively expensive (as measured by mining energy consumption, or equivalently monetary cost) to extract.

Prasser et al. used newer data for mines operating at lower grade (e.g., Rossing, 250 ppm) and/or using in-situ leaching (ISL) to create another estimate of the cutoff grade. Prasser discarded the assumed reciprocal ore grade, energy relationship of SSL, and instead used the newer data to fit a more general functional relationship. Prasser's work therefore also extends to ISL facilities with low stripping ratios. The stripping ratio, S, is defined as (ore mass + waste mass)/(ore mass) (i.e., no overburden or ore haulage). His results, along with those of SSL, are shown in Figure A1-9.

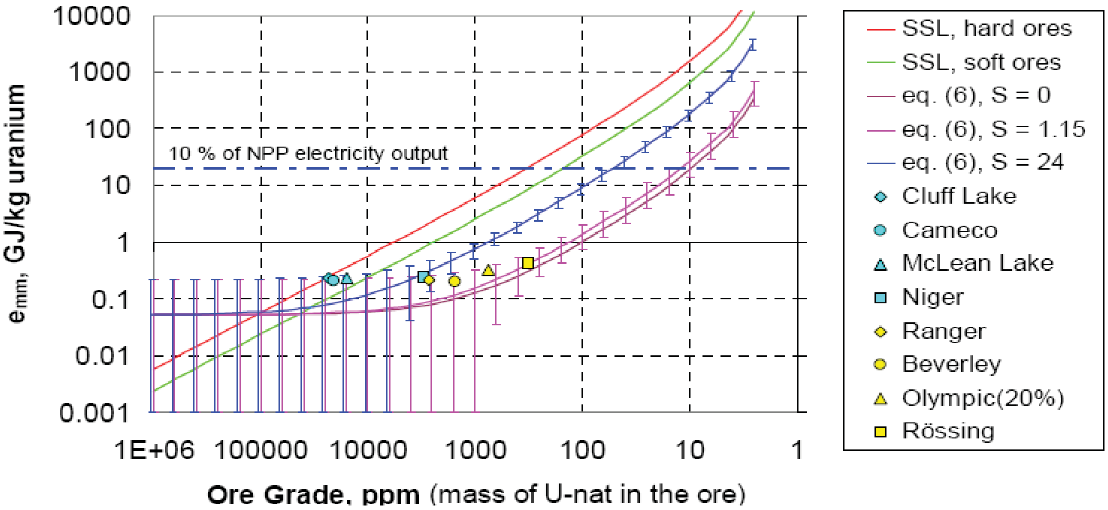


Figure A1-9. Ore Grade versus mining energy input estimates of Smith and Storm van Leewen (SSL) and Prasser. Figure source: Prasser 2008.

Data points from existing mines are superimposed upon the forecasts of SSL and Prasser. Prasser's three sets of results correspond to underground mining of high-grade sandstone deposits (S = 24), lower-grade open-pit projects such as Rossing (S = 1.15) and ISL or surface leaching of existing tails piles (S = 0). Using a practical variant of the cutoff grade definition (i.e., extraction would be impractical if the energy input exceeded 10% of eventual power output) the cutoff grade is seen to range from 200 to 300 ppm (SSL), to 50 ppm (Prasser, high overburden mines), to 10 ppm (Prasser, low overburden mines).

These forecasts correspond to a vast range of economically attractive uranium reserves: from less than the *Red Book* currently estimates (SSL) to orders of magnitude more (Prasser). Prasser's model evidently provides a much better fit to existing data for low-grade mines, but estimates based upon extrapolation from existing data—all *a priori* forecasts of the cutoff grade rely upon this technique—must be used with caution.

Hubbert peak theory has been used to support the claim that scarcity of uranium supply is imminent. The theory states that all nonrenewable resources will obey a trajectory in which a peak global extraction rate is reached, followed by a terminal decline. Therefore, cumulative temporal mineral extraction histories plotted versus time will obey a logistic or S-shaped function. It is difficult to observe this peak or prove its existence statistically until after it has passed. Some evidence may be interpreted to imply that this peak may indeed have passed for uranium. One study claims that some early leaders in uranium extraction have passed the peak production that can be supported by their own resource base. In France and the United States, uranium production began in the 1950s, peaked in the 1980s (at 3 ktU/year and 20 ktU/year respectively), and has since declined drastically (in the U.S. by over 90%; in France production has ceased altogether). Proponents of an imminent or already-passed uranium Hubbert peak assert that attractive deposits having been depleted in these nations, the same phenomenon can be expected to occur elsewhere in the near-term (Energy Watch Group 2006). Others claim that declining demand following the late-1970s boom and discovery of inexpensive resources elsewhere simply pushed the marginal French and U.S. operations into obsolescence.

A1-3.5 U.S. Reserves of Uranium

Details on the U.S. uranium reserves by state are provided in Table A1-5 with geographical locations shown in Figures A1-10 and A1-11. The U.S. potential uranium resources by forward-cost category and resource region are included in Table A1-6. The U.S. uranium mine production and number of mines and sources for the period of 1995–2008 is provided in Table A1-7.

Table A1-5. U.S. reserves of forward-cost uranium by state (December 31, 2003) (DOE EIA 2005).

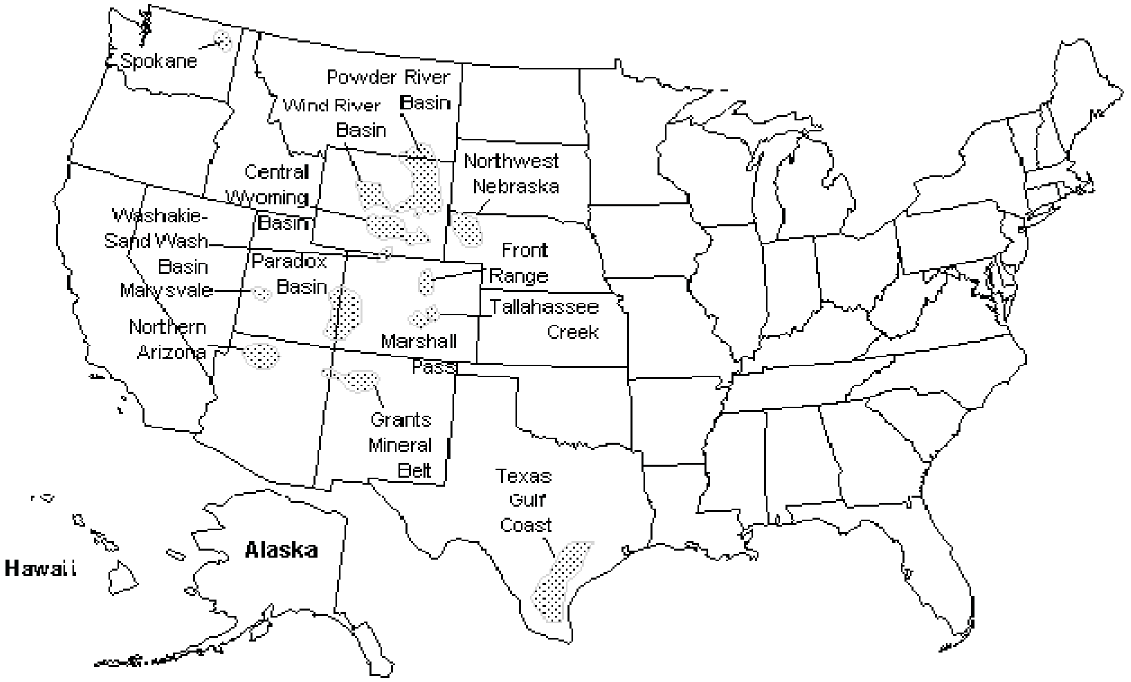
	\$30 per pound			\$50 per pound		
State(s)	Ore (million tons)	Grade[a] (percent U_3O_8)	U_3O_8 (million pounds)	Ore (million tons)	Grade[a] (percent U_3O_8)	U_3O_8 (million pounds)
Wyoming	41	0.129	106	238	0.076	363
New Mexico	15	0.280	84	102	0.167	341
Arizona, Colorado, Utah	8	0.281	45	45	0.138	123
Texas	4	0.077	6	18	0.063	23
Other[b]	6	0.199	24	21	0.094	40
Total	74	0.178	265	424	0.105	890

a. Weighted average percent U_3O_8 per tonne of ore.

b. Includes California, Idaho, Nebraska, Nevada, North Dakota, Oregon, South Dakota, and Washington.

Notes: Uranium reserves that could be recovered as a by-product of phosphate and copper mining are not included in this table. Reserves values in forward-cost categories are cumulative; that is, the quantity at each level of forward cost includes all reserves at the lower costs. Totals may not equal sum of components because of independent rounding.

Sources: Estimated by Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, based on industry conferences; U.S. Department of Energy, Grand Junction Office, files; and Energy Information Administration, Form EIA-858, “Uranium Industry Annual Survey,” Schedule A, Uranium Raw Material Activities (1984–2002) and Form EIA-851A, “Domestic Uranium Production Report,” (2003).



Sources: Based on U.S. Department of Energy, Grand Junction Project Office (GJPO), National Uranium Resourc Evaluation, Interim Report (June 1979) Figure 3.2; and GJPO data files.

Figure A1-10. Major U.S. uranium reserve areas.

Figure A1-11. Uranium resource regions of the U.S.

Table A1-6. U.S. potential uranium resources by forward-cost category and resource region (million pounds U_3O_8).

Resource Region	Forward-Cost Category					
	$30 per pound		$50 per pound		$100 per pound	
	EAR[a]	SR[b]	EAR[a]	SR[b]	EAR[a]	SR[b]
Colorado Plateau	1,330	480	1,900	770	2,540	1,210
Wyoming Basins	160	80	340	160	660	250
Coastal Plain	370	130	490	180	600	230
Northern Rockies	30	110	60	200	170	300
Colorado and Southern Rockies	140	90	180	140	220	190
Basin and Range	50	90	160	170	390	320
Other Regions[c]	110	330	180	610	270	990
Total	2,190	1,310	3,310	2,230	4,850	3,490

a. EAR = Estimated Additional Resources.

b. SR = Speculative Resources.

c. Includes Appalachian Highlands, Great Plains, Pacific Coast and Sierra Nevada, Central Lowlands, and Columbia Plateau regions, and Alaska.

Notes: Values shown are the mean values for the distribution of estimates for each forward-cost category, rounded to the nearest 10 million pounds U_3O_8. Estimates of uranium that could be recovered as a by-product of other commodities are not included. Resource values in forward-cost categories are cumulative; that is, the quantity at each level of forward cost includes all resources at the lower cost in that category.

Sources: Prepared by the Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, based on uranium resources data developed under DOE National Uranium Resource Evaluation (NURE) program and the USGS Uranium Resource Assessment project, using methodology described in Uranium Resource Assessment by the Geological Survey: Methodology and *Plan to Update the National Resource Base*, U.S. Geological Survey Circular 994 (1987).

Table A1-7. U.S. uranium mine production and number of mines and sources, 1995–2008.

Mining Method	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Underground														
(metric tonnes U)	0	W	W	W	W	W	0	0	W	W	W	W	W	W
Open Pit														
(metric tonnes U)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
In situ Leaching														
(metric tonnes U)	1,297	1,684	1,571	1,431	1,473	1,152	W	W	W	W	1,031	1,638	W	W
Other[a]														
(metric tonnes U)	60	125	241	408	276	49	W	W	W	W	W	W	W	W
Total Mine Production														
(metric tonnes U)	1,357	1,810	1,812	1,840	1,750	1,201	1,018	925	^{E}846	961	1,171	1,804	1,747	1,492
Number of Mines Operated														
Underground	0	1	1	4	3	1	0	0	1	2	4	5	6	10
Open Pit	0	0	0	0	0	0	0	0	0	0	0	0	0	0
In situ Leaching	5	6	7	6	6	4	3	3	2	3	4	5	5	6
Other Sources[b]	7	6	6	5	5	5	4	3	1	1	2	1	1	1
Total Mines and Sources	12	13	14	15	14	10	7	6	4	6	10	11	12	17

a. For 1995, "Other" includes production from uranium-bearing water from mine workings and restoration. For 1996–2000, "Other" includes production from underground mines and uranium-bearing water from mine workings and restoration.

b. "Other Sources" includes, in various years, heap leach, mine water, mill site cleanup and mill tailings, well field restoration, and low-grade stockpiles as sources of uranium.

W=Data withheld to avoid disclosure. The data are included in the total for "Other" through 2000.

E=Estimate to avoid disclosure of individual company data.

Notes: Totals may not equal sum of components because of independent rounding. Table does not include by-product production and sources.

Sources: Energy Information Administration: 1993–2001-Uranium Industry Annual 2001 (May 2002). 2002-Form EIA-858, "Uranium Industry Annual Survey;" Schedule A: Uranium Raw Material Activities; Energy Information Administration: Form EIA-851A, "Domestic Uranium Production Report" (2003–2008).

A1-3.6 Market Price for Uranium

Because the supply of newly generated uranium is controlled by the world market and dominated by foreign supply, the future price for U.S. supply would expect to meet that world market price. IAEA-NEA in its analysis of uranium supply evaluated cumulative supply and demand for uranium to 2050 (IAEA 2001). The study considered the reality of reducing existing inventories, the infusion of prior weapons HEU into the market, as well as other significant secondary supply market impacts. Three demand cases were evaluated (low, middle, high) and covered scenarios from phase out of nuclear power in 2100 in the low case to high economic growth and significant development of nuclear power in the high case. The middle was simply the mid-point of the two cases. Cumulative uranium requirements ranged from 3,390 to 7,577 MTU. Production from high confidence RAR was projected to be adequate in the low demand case. Deficits arise when considering use of low cost supplies to meet the middle and high cases. The study, therefore, estimated the year in which uranium from higher cost production could be justified. Table A1-8 is a summary of the IAEA-NEA projections.

Table A1-8. Year when higher cost uranium production is justified (U.S. dollars) (IAEA 2001).

	\$20–30/lb U_3O_8 \$52–78/kgU	\$30–50/lb U_3O_8 \$78–130/kgU	>\$50/lb U_3O_8 >\$130/kgU
Middle-Demand Case			
RAR	2019	2024	2028
RAR + EAR-I	2021	2027	2034
RAR + EAR-II	2021	2029	2041
High-Demand Case			
RAR	2013	2019	2023
RAR + EAR-I	2015	2022	2026
RAR + EAR-II	2015	2023	2031

The years highlighted above (2034 and 2026) for the middle demand and high demand cases respectively, indicate the first year in which a deficit is projected to exist between the lower-cost (<\$130/kgU) "known resources (RAR + EAR-I)" and market-based production requirements. The timing of the deficit corresponds with a significant increase in the price of uranium. However, IAEA-NEA has speculated that if significant and timely exploration is conducted, and sufficient resources are discovered, there could be an adequate supply of lower-cost uranium to satisfy demand. If not, the demand can be met by both very high-cost conventional resources and unconventional resources, or by new lower-cost conventional resource discoveries made from speculative resources. This would require use of very high-cost conventional and unconventional resources to meet both the middle and high-demand cases.

The U.S. does not own any currently producing uranium mines, but DOE does have inventories of secondary supplies as shown in Table A1-9. The DOE inventory reported in the table—134.9 million lbs. of natural U_3O_8 equivalent—represents uranium of all forms declared surplus by DOE as of May 2006 (DOE 2006a) (DOE 2008a). Of this excess uranium, 55.8 million pounds is HEU to be blended to LEU; most of the rest is NUF_6 or DUF_6 "of economic value." To avoid distorting effects that would accompany large-scale dumping, DOE proposes to place on the market no more than 10% of the annual fuel requirements of the domestic reactor fleet, or about 5 million tons per year.

Table A1-9. Inventories of natural and enriched uranium as of end of year, 1998–2007 (thousand pounds natural U_3O_8 equivalent).

Type of Uranium Inventory	Inventories at the End of the Year									
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Owners and Operators of U.S. Civilian Nuclear Power Reactors	65,758	58,250	54,804	55,636	53,461	45,639	57,665	64,729	77,484	81,227
Of which: Natural Uranium	42,051	44,761	35,952	34,433	31,029	22,674	27,889	45,339	54,251	55,927
Of which: Enriched Uranium [a,d]	23,708	13,488	18,851	21,204	22,432	22,965	29,766	19,390	23,233	25,301
U.S. Supplier Inventories [b]	70,732	68,848	56,455	48,147	48,653	39,850	37,544	29,068	29,107	31,156
Of which: Natural Uranium	35,030	29,468	12,616	9,192	W	W	W	W		
Of which: Enriched Uranium [a,d]	35,702	39,380	43,839	38,955	W	W	W	W		
Total Commercial Inventories	136,491	127,097	111,258	103,783	102,114	85,489	95,209	93,796	106,591	112,384
Excess DOE-owned Inventory [c]	24,454	53,054	N/A	N/A	51,789	N/A	N/A	134,900	N/A	153,200

a. Includes amounts reported as inventories of enriched UF_6 at enrichment suppliers (1998–2001).

b. Includes inventories owned by the 1998 privatized USEC, Inc. (United States Enrichment Corporation).

c. DOE-owned excess inventories reported by the U.S. Department of Energy. Variations during this period largely reflect changes in DOE classification of excess materials, rather than disbursement or acquisition of uranium. See text and (DOE 2008a).

d. Enriched UF_6 and fabricated fuel not inserted into a reactor (2002–2008).

W = Data withheld to avoid disclosure.

Note: Totals may not equal sum of components because of independent rounding.

Source unless otherwise noted: Energy Information Administration, Form EIA-858, "Uranium Industry Annual Survey;" Energy Information Administration, Form EIA-858 "Uranium Marketing Annual Survey" (2003–2008).

The market price (and essentially the effective cost to the utilities) is driven by a number of key factors as follows:

Uranium Demand. Demand must consider the amount of nuclear fuel to be delivered over a given period. Relative to the nuclear market, demand is driven by the projections for economic growth driving need for power as well as the role of nuclear power in meeting the demand. Such demand can be driven by other than electricity such as a significant growth in hydrogen demand or major desalination programs. Of course, the most significant factor is the projected growth in developing nations, which will greatly influence the worldwide demand for energy. Because of such a broad range of uncertainties, demand is normally considered over a wide range of demand scenarios. Current worldwide demand requires about 68,000 MT of uranium from mines or the equivalent from stockpiles.

Supply Factors. Supply can be considered in terms of primary and secondary supplies. In the next several decades, supply will continue to be strongly influenced by the use of secondary supplies. At the beginning of this century, 42% of the worldwide demand was met by use of secondary supplies creating a buyers market and reducing the economic attractiveness of exploring for and developing new primary supplies. However, such supplies are being reduced and are under a scenario of growth of nuclear power, the gap between overall demand and that provided by secondary supply will grow, creating a stronger demand for primary supplies in the longer term.

A1-3.7 Secondary Supplies

Existing Inventories. Inventories of natural uranium and LEU are currently owned by uranium suppliers, United States Enrichment Corporation (USEC), utilities, and DOE. Other nations, especially Russia, also have significant inventories. Depending on short-term needs and opportunity for profit, such inventories are released into the market place (at or near market price).

Highly Enriched Uranium. Following the cold war, the United States and Russia declared large quantities of HEU and plutonium as surplus for national defense purposes (see Module C2 for details and implementation of the agreement). While other nations such as China, France, and the United Kingdom have similar materials, the market impact is basically dominated and controlled by agreement between the U.S. and Russia, who are believed to hold over 95% of the HEU stocks dedicated to nuclear weapons. In 1993, an agreement was made with Russia that 500 tonnes of Russian HEU would be converted to roughly 150,000 tonnes of LEU over a 20-year period to be used in the U.S. market. Such an amount represents roughly 50% of the U.S. utilities requirements during this period. Basically, USEC exchanges natural uranium for down-blended LEU, effectively contracting Russia (Tenex) for the cost of enrichment. The LEU is sold through USEC and a consortium of three Western companies (Cameco, Cogema, and RWE Nukem). The equivalent natural uranium feed is returned to the Russians, who can sell it or return it to Russia. In the U.S., DOE programs plan to down-blend an additional 145 tonnes of HEU for commercialization.

MOX Use. Although not currently used by the U.S. market, the world demand for uranium is influenced by the amount of plutonium/uranium MOX fuel that is to be used as the energy content of the plutonium replaces the demand for natural uranium. Use of MOX represents less than 4% of the overall equivalent uranium demand. Should U.S. policy be revised to encourage MOX use in the U.S., there would be a small but significant impact as MOX use is increased. The agreement between the U.S. and Russia to disposition surplus plutonium from the weapons programs at this point is not large enough to produce any significant impact in the overall demand.

RepU. Reprocessed uranium can be used as a direct substitution for newly generated uranium in fuel fabrication. As with MOX, the acceptance of RepU will be driven by cost with RepU use increasing as the market price for natural uranium increases. Should MOX use be initiated in the U.S., a potential large source of RepU could be available to meet supply. As an example, approximately 0.94 kg of RepU having about 0.9 w/o ^{235}U content could be recovered from reprocessing one kilogram of current U.S. irradiated fuel. If this RepU were enriched—compensating for ^{236}U by enriching to say 5% versus about 4.2% for present-day PWR LEU fuel—with tails taken to 0.2 w/o ^{235}U, it could produce 0.15 kg of fuel worth approximately equivalent to that of PWR LEU fuel. Such a U.S. source has not been considered in any supply or cost projections to this point because reprocessing is not within current U.S. policy, and the U.S. is decades away from implementation. Reactor operation will also impact the economics as deeper burn fuels have less value relative to remaining fissile uranium content. Nonetheless, if nuclear fuel reprocessing does become a reality, primary uranium prices remain high, and suitable enrichment capacity is available, a policy of sustained single recycle of RepU could reduce domestic primary uranium demand by 15% or more.

Depleted Uranium (DU). In the enrichment process for nuclear fuel for each kilogram of enriched uranium produced, an average of 8 kg of depleted uranium (enrichment tails) is also produced. Some reenrichment of tails is being used in Russia to recover fissile uranium because a surplus of low cost enrichment capacity currently exists, but it is not a significant factor versus total world demand. In general, the existence of low cost uranium, as well as the added cost for reenrichment, results in DU not being considered to have value as a uranium supply at this time. Because stable storage of the tails is possible, emergence of lower-cost enrichment technologies could result in DU becoming a valuable energy source in the future. However, most projections take no credit for such entry into the market place. Other uses to be considered are for HEU or MOX dilution and future fast reactor core blankets. Again, such use is not expected to have any impact on market price. Most studies also assume that tails will remain at 0.3% throughout the demand period, but evolution of technology and uranium pricing could result in driving the tails to lower value trading off the additional cost of separative work units versus the cost of newly mined uranium.

Stockpiles of DU, in the form of uranium hexafluoride (UF_6), have been accumulating since the beginning of the nuclear age and the U.S. currently holds 708,189 tonnes of UF_6 in storage sites at Peducah, Kentucky and Portsmouth, Ohio. These inventories are far from homogenous and the conditions under which they would become attractive alternatives to mined natural uranium depend on many factors.

The decision of whether to mine fresh uranium, or exploit alternative sources, is largely a matter of which offers the cheaper supply. Depleted uranium stockpiles have a highly variable ^{235}U composition (Table A1-10) and will often require additional enrichment beyond what is needed for manufacturing LWR fuel from natural uranium. Because of this, the price of using DU will depend on the costs of enrichment, DU cylinder transport from storage to the enrichment plant, UF_6 tails storage, deconversion of UF_6 tails to U_3O_8, and its subsequent disposal.

The table shows the amount of depleted uranium in UF_6 from in the US as a function of ^{235}U assay. The UF_6 is stored in 58890 cylinders at Paducah, Kentucky and Portsmouth, Ohio. In total there are 708,189 million tonnes of UF_6 in the U.S. One MT = 10^9 kg.

The U.S. Department of Energy currently plans to deconvert stockpiled UF_6 to U_3O_8 for stable storage until final disposal at a cost of \$2.80/kg UF_6.[a] A limited number of uses for DU exist beyond reenrichment. Depleted uranium can make an ideal matrix for down blending highly enriched uranium from dismantled nuclear weapons and its use for fast reactor blanket material has also been explored (Diehl 2004; Hertzler and Nishimoto 1994). However, with the exception of shielding applications for spent fuel storage casks, the amount of material required to meet potential needs is small compared to the current supply. This disparity is likely to grow with time, especially if demand for nuclear power increases. Alternatives for DU disposition are discussed in greater detail in Module K.

Table A1-10. Assay distribution of U.S. depleted uranium (DOE 2006b).

Assay Range (% ^{235}U)	No. Cylinders	MT UF_6
0.1250–0.1649	20	149
0.1650–0.2149	16,036	174,137
0.2150–0.2649	15,290	192,883
0.2650–0.3149	10,749	135,056
0.3150–0.3649	12,165	151,952
0.3650–0.4149	1,939	23,989
0.4150–0.4649	861	10,535
0.4650–0.5149	47	425

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[a] Cost estimate based on communication with Uranium Disposition Services, LLC.

0.5150–0.5649	97	1,163
0.5650–0.6149	20	94
0.6150–0.6649	31	227
0.6650–0.7149	1,634	17,580

Reduction of Tails Assay. Although not a supply source, the DU tails assay bears mentioning as it is the sole short-term method of introducing demand elasticity available to utilities. Prior to 2000, the prevailing DU tails assay was 0.3 w/o ^{235}U. As the price of uranium has increased, the front-end cost-minimizing tails assay has decreased to perhaps 0.2 w/o ^{235}U. To place this into context, for production of 4.2% enriched fuel the reduction of tails assay from 0.3 to 0.2 w/o would decrease natural uranium requirements by 18%. Hence, its market-driven adjustment can lead to economies of primary uranium consumption similar to those listed above for the various secondary supply sources.

Recovery from Coal Ash. Coal ash, particularly ash from brown coal, can be sufficiently rich in uranium to make ash-pile stripping economically viable. This practice is not new, over three million lb U_3O_8 was recovered from ash in the U.S. through the 1970s, and uranium recovery from ash is ongoing in China. Ash piles being mined there have uranium content ranging from 20 ppm upward to 315 ppm. At 2008 prices and assuming 160 ppm uranium content, the annual ash from one medium-sized coal-fired power station would contain 100,000 pounds of U_3O_8—roughly one-eighth of the annual requirement of a 1 GWe PWR—and be worth over $5M. With production costs estimated at $20–35 per lb U_3O_8, it would therefore be profitable to harvest ash having U content of approximately 100 ppm or more. The size of this resource pool is unknown as a comprehensive assay of ash piles has not been conducted, but perhaps its greatest value is the speed with which it can be brought online if supply shock conditions were to arise. Ten to 15 years are needed for a conventional mine site to advance from discovery to production, whereas production from ash could commence in a quarter of this time (NEI 2009).

A1-3.8 Primary Supplies

Newly mined and processed uranium has been divided into four categories for purposes of world uranium supply projection by the IAEA-NEA:

1. Commonwealth of Independent States, the former Soviet Union
2. National programs
3. Chinese production
4. Market-based production.

The first three are generally perceived as captured production for "in-house" utilization and, therefore, do not have a significant impact on the world market except as avoiding import of world market-based supplies. As any of the first three categories develop cost-effective production capacity exceeding demand, they could begin to impact the market price.

Market-based production is simply the difference between the overall demand minus the secondary supplies and the first three primary supplies. As can been seen in Table A1-11, the primary producers of uranium are Canada, Australia, Niger, Namibia, Russia and Kazakhstan. The reference data have been collected from actual bottoms-up feedback from industry along with specific country reporting of supply and demand. More recently, data have begun to be withheld as a more competitive market emerges.

Kazakhstan, a minor player in the market as recently as 2001 when it was the sixth-largest producer, is poised to overtake Australia and Canada as the world's largest yellowcake producer in 2009 or 2010. Kazakh production, mostly ISL, is expected to exceed 15,000 tU/year in 2010 and could reach 23,000 tU/year by 2015. Capacity is also set to increase in other producer nations. In Canada, where mine floods have plagued operations, production could reach 19,000 tU/year by the mid-2010s. The capacity of the Olympic Dam open pit mine in Australia, which houses the largest known uranium deposit in the world, is set to expand, but other projects there— the Jabiluka deposit, for example—are being held up by local governmental and activist resistance. Projects in the U.S. and Canada are facing similar hurdles, but new projects are moving forward in major supplier states Namibia and Russia (Steyn 2008).

Developments on the demand side have spurred growth in domestic supply with several uranium mines being reopened in the U.S. for the first time in nearly a decade. Other mine openings are being resisted by local groups; Native American tribal opposition to proposed re-openings in Arizona and New Mexico and intense local debate surrounding prospecting activities in Virginia are two examples. Regardless, U.S. mines are expected to remain a relatively minor source of uranium through the next decade.

Table A1-11. Uranium production, tones U, 1997–2007.

Country/ Area	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007[e]
Argentina	30	7	4	0	0	0	0	0	0	0	0
Australia	5,488	4,894	5,984	7,579	7,720	6,854	7,573	8,982	9,512	7,593	7,600
Belgium	27	15	0	0	0	0	0	0	0	0	0
Brazil	0	0	0	11	56	272	230	300	110	200	340
Bulgaria	0	0	0	0	0	0	0	0	0	0	0
Canada	12,031	10,922	8,214	10,683	12,522	11,607	10,455	11,597	11,628	9,862	9,850
China	570	590	700	700	700	730	730	730	750	750	750
Czech Rep	603	610	612	507	456	465	452	412	409	375	309
France	572	452	416	296	184	18	9	6	4	3	2
Gabon	470	725	0	0	0	0	0	0	0	0	0
Germany	28	30	29	28	27	221	150	77	94	65	45
Hungary	200	10	10	10	10	10	4	4	3	2	3
India	207	207	207	207	230	230	230	230	230	230	270
Kazakhstan	1090	1270	1560	1870	2114	2822	3327	3719	4346	5281	7245
Namibia	2905	2780	2690	2715	2239	2333	2037	3039	3146	3067	3800
Niger	3487	3714	2907	2914	2919	3080	3157	3245	3322	3443	3633
Pakistan	23	23	23	23	46	38	40	40	40	40	40
Portugal	17	19	10	14	4	0	0			0	0
Romania	107	132	89	86	85	90	90	90	90	90	90
Russia	2580	2530	2610	2760	3090	2850	3073	3280	3275	3190	3381
South Africa	1100	965	927	798	878	824	763	747	673	534	750
Spain	255	255	255	255	30	37	0	0	0	0	0
Ukraine	1000	1000	1000	1005	750	800	800	855	830	808	900
United States	2170	1810	1773	1522	1015	902	769	878	1171	1805	2000
Uzbekistan	1764	1926	2159	2028	1945	1859	1603	2087	2300	2260	2300
Total	36724	34886	32179	36011	37020	36042	35492	40263	41943	39603	43328

NA = not applicable

e = expected

Source: Redbooks, 1997–2007

A1-4. LIMITATIONS OF COST DATA

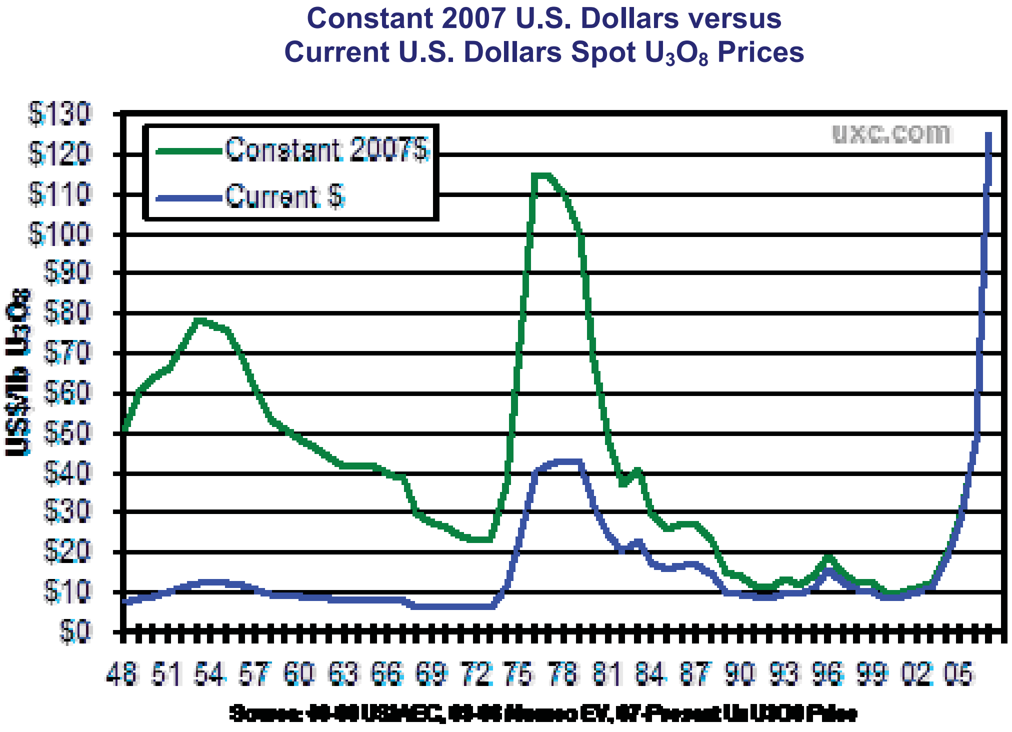
Much of the data is based on speculation and intuitive evaluation of geologic data and speculation relative to the movement of future power markets versus demand. Many factors including actual cost of recovery, market timing versus production of newly mined uranium, and future regulatory impacts (both positive and negative) will affect the credibility of the information. The data best represent a “speculative supply” to an uncertain demand.

The mining industry is relatively mature but will expand and utilize new techniques as dictated by ability to make profit versus a competitive market.

Most of the data used for analyses have received detailed evaluation and are as good as any speculative approach can be applying engineering judgment.

A1-5. COST SUMMARIES

The actual price paid for uranium is a combination of long-term contract prices and “spot market” procurements. While spot market prices are tracked and published and in general the indicators are very close to one another, they do not necessarily indicate the appropriate price to reflect the average uranium sale on the longer-term contracts. Any slight variation of demand or supply has a significant effect on the spot price. Spot prices represent a snapshot of market conditions at the publication date when quantities traded are fairly low; inventory sales on the spot market may not reflect production cost at all. In terms of quantity, the spot market procurements only represent roughly one-tenth of the demand. The spot market can be viewed as speculative in nature and is driven by short-term impacts rather than real supply/demand interaction. Following the trends of the spot market does provide some insight into market factors as can be seen in Figure A1-12.


Constant 2007 U.S. Dollars versus
Current U.S. Dollars Spot U_3O_8 Prices

Source: 48-68 USAEC, 69-86 Nuexco EV, 87-Present Ux U3O8 Price

Figure A1-12. U_3O_8 spot prices (UXC 2009).

The pricing in the 1990s was dominated by the influx of LEU from down-blend of Russian HEU and reduction of commercial uranium inventories. As part of the privatization of USEC in 1997, the U.S. government provided them with ~70 million pounds of yellow cake, which USEC used to ensure some return for investors. The combination of these three factors reduced the need for newly mined uranium and drove the spot market down. A flood in the largest mine in Canada, McArthur river, sparked a sharp upturn in spot market prices in 2003. The mine is now back in production, but a 2006 flood at Cigar Lake is expected to keep that Canadian mine offline until 2011–2012. Other unforeseeable events have also curtailed primary supply: a 2001 fire at Australia's Olympic Dam mine reduced production through 2003, weather events substantially curtailed production at mines in Australia and Canada in 2006, and lower than expected ore grades affected production at McClean Lake in Canada in 2006.

Developments on the secondary side of the supply picture also contributed to the upward pressure on prices. In November of 2003, Tenex, citing unfavorable agreement terms, announced that beginning in 2004 that natural uranium from the HEU to LEU arrangement would be returned to Russia and thus would not be available for the Western market. Although this impasse was resolved and LEU deliveries were not interrupted, in 2006 the Russian government indicated that a second HEU deal would not be pursued once the current arrangement expires in 2013. This future loss of up to 9000 tU/year of supply sparked a concern about the longer-term supply of newly mined uranium to replace this important source. It is also anticipated that the significant utility and producer inventory drawdowns are complete and the market price will once again begin to respond in relation to a more stable demand including growth scenarios.

The uranium price increased more than five-fold from January 2005 to July 2007 (Figure A1-13). Market factors combined with the supply-side effects discussed above contribute to the price increase. The relative weakness of the U.S. dollar has also affected local prices in the import-driven domestic market. Hedge funds and speculative investors since 2004 have added substantially—at least 12 million lb of U_3O_8—to the demand side of the uranium market (Steyn 2006). In addition, long-term contract volume has increased significantly from its historical average as utilities have hastened to secure supplies as hedges against further price increases. In a further hedging measure that parallels behavior during the 1970s-early 1980s price boom, utilities have also taken measures to expand their uranium stockpiles (Table A1-9).

As of August 2009 the price of uranium has fallen to \$48/lb U_3O_8 (\$125/kgU), less than 40% of 2007 its peak. Although the price paid by utilities under long-term contractual agreements continues to increase, it is evident that the late price boom will be of much shorter duration than was the case in the 1970s. Moreover, a convergence of spot and contract prices is to be expected as utility shifts toward long-term contracts relieve pressure from the spot market (see discussion and data below). Figure A1-14 compares uranium price trajectories through the two boom cycles. The greater maturity and transparency of a more mature uranium market is contributing to the present rapid stabilization in prices.

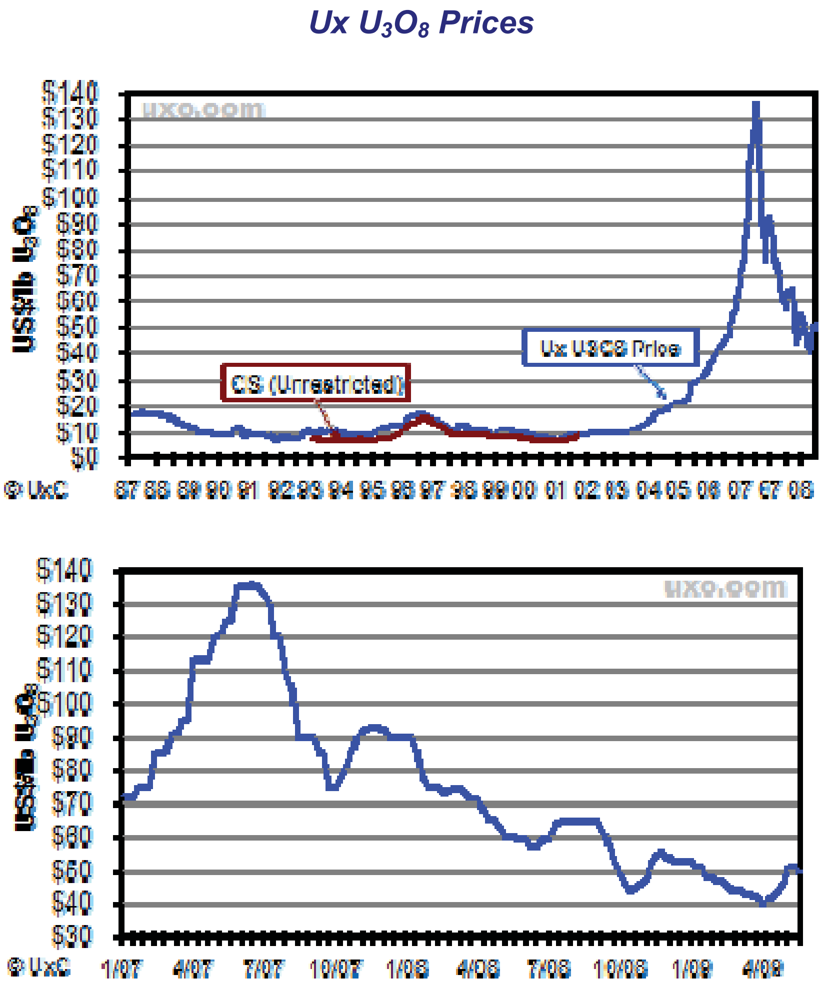


Figure A1-13. U_3O_8 spot prices in current dollars, 1987–2009 (top) and January 2007–July 2009 (UXC 2009).

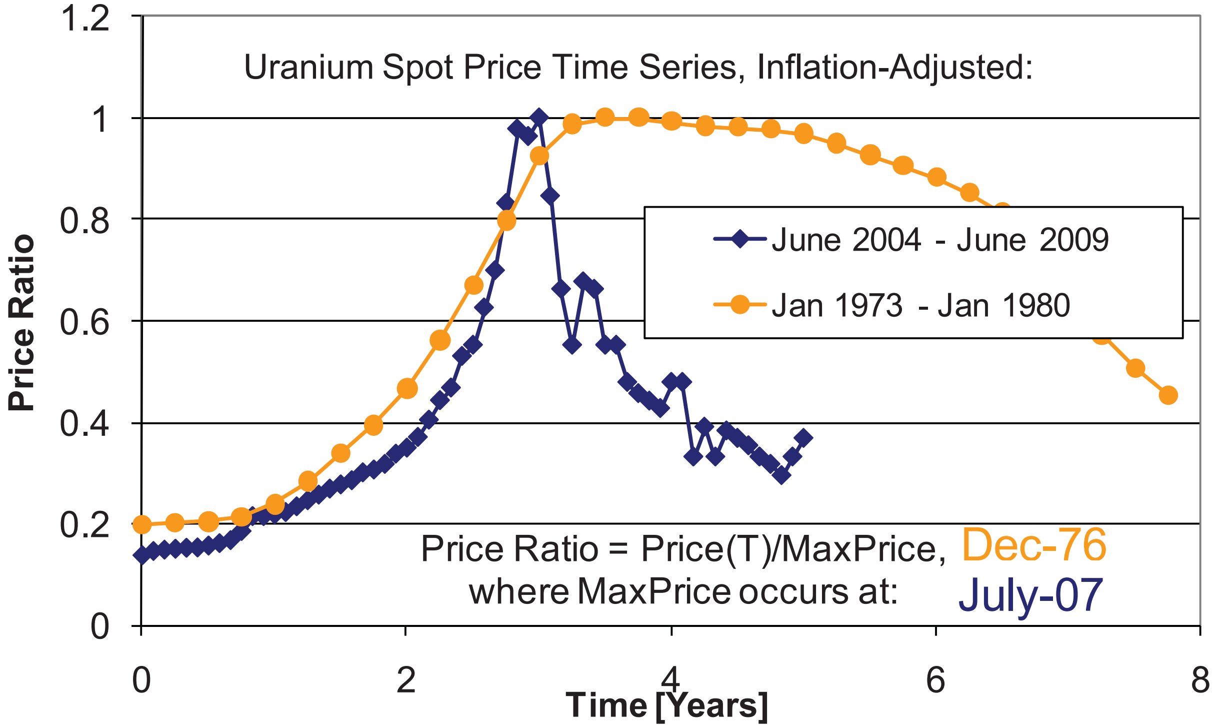


Figure A1-14. Comparison of price histories during the late-1970s and mid-2000s booms.

Volumes of uranium contracted by utilities continued to be heavy into 2007. Table A1-12 shows that the volume of new contracts secured by reactor owners and operators increased as the price of uranium rose and peaked. However, it is important to note that market prices, especially the spot price, do not always reflect the actual cost of uranium to utilities. While the details of contract terms are confidential, EIA data makes clear that utilities are paying considerably less for uranium than spot market prices would imply.

Table A1-12. U.S. reactor owner and operator multi-year contract volume (thousand lb U_3O_8) by date of contract initiation.

Year of Contract Initiation	Minimum Volume Contracted for Delivery	Maximum Volume Contracted for Delivery
2001	49,245	76,158
2002	20,004	29,231
2003	>33,141[a]	>36,072[a]
2004	>52,038[a]	>58,207[a]
2005	>47,259[a]	>48,821[a]
2006	81,466	90,422
2007	69,565	71,078
2008	35,973	36,180

a. Some data was withheld by EIA to avoid disclosure of sensitive contractual information.

Source: US Energy Information Administration, "Uranium Industry Annual," 2001–2002, and "Uranium Marketing Annual Report," 2003–2008.

Table A1-13 reveals that spot market volume decreased considerably in the years following 2005 as utilities exercised their rights to purchase the maximum amount of uranium they were entitled to under existing contracts. Pricing mechanisms play a role here, but even so spot market prices do affect a significant portion of uranium that is delivered under contract. For instance, Cameco reveals some information on its Web site[b] regarding pricing mechanisms utilized by its contractual agreements. Of Cameco's contracts, 60% are at least partially tied to the spot market price at delivery time, while 40% are fixed, base-escalated or negotiated annually. This figure may be changing with time, though; Table A1-13 shows that utilities have responded to higher prices by moving away from contracts that are tied to spot market prices.

Table A1-13. US utility annual spot and contract-specified price (dollars per lb U_3O_8 unadjusted for inflation) and volume (thousand lb U_3O_8) of delivered uranium.

	Spot Market Pricing[A]		Contract Specified Pricing	
	Volume	Price	Volume	Price
2000	16,740	8.73	28,563	12.65
2001	17,742	8.42	28,453	11.61
2002	18,591	9.57	25,063	11.15
2003	20,098	10.54	26,755	11.00
2004	14,923	13.77	37,691	12.13
2005	13,615	14.65	42,114	14.42
2006	9,523	18.04	41,164	18.18
2007	10,322	50.89	28,142	25.19
2008	10,260	64.01	31,706	37.27

a. Spot-market pricing includes contracts with pricing mechanisms tied to spot market prices at time of delivery.

Source: US Energy Information Administration, "Uranium Industry Annual," 2001–2002, and "Uranium Marketing Annual Report," 2003–2008.

It is important to differentiate short-term pressures from the longer-term picture with which this review is chiefly concerned. More recent trends anticipating a renaissance in nuclear energy have not only spurred new interests in uranium supply, but also introduced new factors into the market not seen in the recent past.

A1-5.1 Natural Uranium Production Cost and Price

The pricing market is far from disciplined or mature; companies and countries have chosen not to share any long-term contract pricing information. As a result, many of the indices stopped reporting uranium prices in 2002, and some have even withdrawn previously published data. Using published data such as spot market prices to form conclusions for the future does not appear to have a solid basis.

Estimates of future pricing often ignore uranium resource replacement via new exploration. As a result, long-term supply-demand analyses tend to have a pessimistic bias (i.e., toward scarcity and higher prices) that typically will not reflect reality. New exploration cycles may drive up uranium prices in the short term. However, this exploration should be expected to add uranium resources to the world inventory. To the extent that some of these resources may be of higher quality and involve lower operating cost than resources previously identified, this will tend to mitigate price increases. This is precisely what has happened in Canada, as the low-cost discoveries in the Athabasca Basin have displaced higher-cost production from many other regions, lowering the cost curve and contributing to

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[b] http://www.cameco.com/

lower prices. Secondary uranium supplies, to the extent that they can be considered as a very low-cost mine, have simply extended this price trend. Likewise, existing estimates generally neglect advances in extraction technologies and other factors affecting productivity per mineworker. For instance, in 1980 combined employment in the U.S., Canadian, and Australian uranium extraction industries was 26,520 persons; in 2005 employment stood at 1824 individuals (OECD 2006b). The corresponding annual production figures are 25,511 tU in 1980 and 21,615 tU in 2005. Hence, to a first approximation, productivity stood at 0.96 tU/person/year in 1980 and 11.85 tU/person/year in 2005 (Figure A1-14). Evidently, labor inputs to uranium mining have decreased significantly.

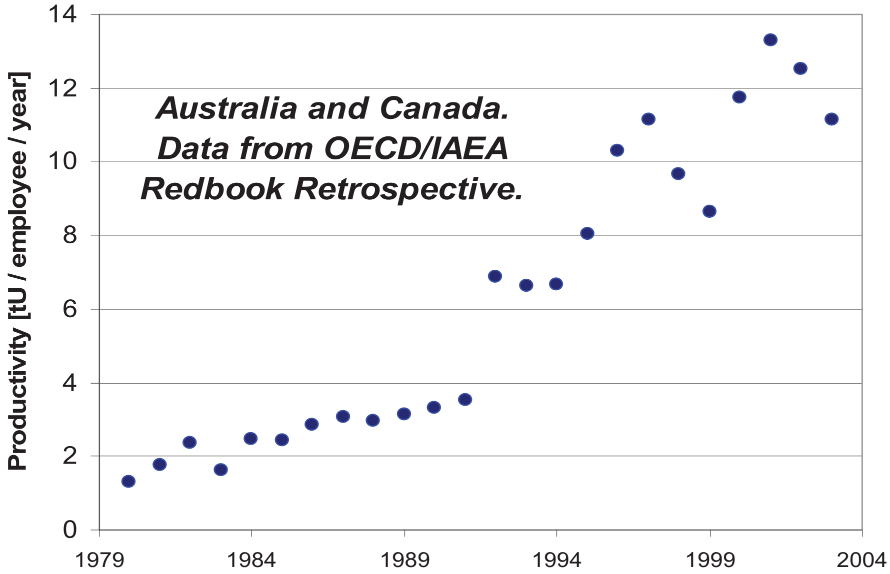

Figure A1-14. Labor productivity, Australian and Canadian uranium mines.

The following summary reflects current information that appears valid for use in economic modeling for Advanced Fuel Cycle Initiative fuel cycle analyses.

Specific Exploration, Mining, and Milling Cost Data. The huge uranium reserves of Canada's Athabasca Basin were discovered for about U.S. $0.70/kg (2003 dollars, including unsuccessful exploration). It has been suggested that finding costs for uranium can be estimated as low as 2% of the spot price. On the high side, extrapolation of past exploration costs suggests costs as high as $1.80/kg (2005 U.S. dollars), a figure mentioned earlier in this Module. In any case, it is small fraction of the cost to produce the yellow cake product.

Supply and Demand Data. The data available through the DOE-EIA, the IAEA, and OECD/NEA have a reasonable degree of consistency relative to reserves, supply, and demand data. Most other references use that data.

Uranium Price Data. Ux Consulting and NUEXCO have Web sites that maintain "real-time" published values for spot market pricing.

Future Price Evaluation. No published sources were discovered with specific predictions of uranium prices beyond 2025. A mine-opening cycle requires around 15 years to complete; this sets the time horizon for which information available now can be used to develop production cost (and then price) estimates. Energy Resources International in 2009 forecast that the long-term (i.e., contract) uranium price would decline to less than $50/lb U_3O_8 ($130/kgU) in 2015, but rise to $67/lb U_3O_8 ($170/kgU) by 2025 (NuclearFuel 2009).

The IAEA-NEA study, *Uranium Supply to 2050,* provides the best source of speculative data relative to likely price ranges for newly produced uranium versus a broad range of demand scenarios (IEA 2007). Such data could be plotted and assumed to have linear growth to provide a speculative cost value for a dynamic model. Based on the reserves listed and the influence of secondary supplies, it would appear that uranium prices would fall well within the projections of the IAEA.

The excitement over potential growth sparked a short-term growth in the price of uranium with the spot pricing peaking at \$350/kgU (\$135/lb U_3O_8) in June 2007. An energetic growth in nuclear power could create a temporary lag in supply driving prices up, but that would spark more interest in supply, again bringing high prices to a reasonable market level. The reasonable market level will be influenced by policy, actual growth in nuclear power capacity, and both the timing as well as the relative cost of producing new supplies.

It is necessary to choose a distribution that can reasonably be expected to depict the likely average uranium price over the next century. Forecasts are rarely attempted over such extended periods for any mineral, and market-driven uranium price data itself has only a 40-year history. Indeed, many of the concerns discussed in preceding subsections of this report are applicable to short and medium-term prices and will have little if any bearing on long-term price trends. Nonetheless, given that uranium is a mineral with ore deposit phenomenology similar to that of other minerals and that the abundance of uranium in the earth's crust is not exceptionally low or very high as compared to other minerals of economic importance, it is reasonable to draw an analogy between the price evolutions of uranium and other minerals.

The United States Geological Survey (USGS) maintains a database (Kelly et al. 2007) of commodity prices tabulated in constant year 2005 dollars. For many minerals the data extends back to the year 1900. Many of the price histories show a gradual decline in price—regardless of the level of mining—punctuated by occasional upward and downward excursions. Some of the minerals show an upward price trend over the past century.

It is assumed that the price of uranium over the next century will continue to evolve in a manner that is not exceptional when compared to that of the USGS-tracked minerals over the past century. Therefore, to create a distribution that describes the probable average uranium price over the 21st century, the following procedure was developed.

Thirty-five minerals were selected. Those commodities in the USGS database that were omitted (peat, wood, helium, and cement) were clearly not analogous to uranium and other minerals. For each mineral, the time series data was regressed onto the function:

$P = C * e^{Mt}$

where

P = price (2005 dollars per tonne)

t = year

C and M = regression coefficients.

The data series and regression results for four minerals are depicted in Figure A1-15. A similar analysis of historical USGS data has recently been published (Schneider and Sailor 2006).

The coefficient *M* is interpreted as a price growth rate with respect to time. Minerals with negative *M*-values have experienced declining prices; for those with positive *M*-values, the price has increased over the past century. Table A1-14 gives the *M*-values obtained for all 35 minerals. The *M*-coefficients for six of the minerals were positive, while 29 were negative.

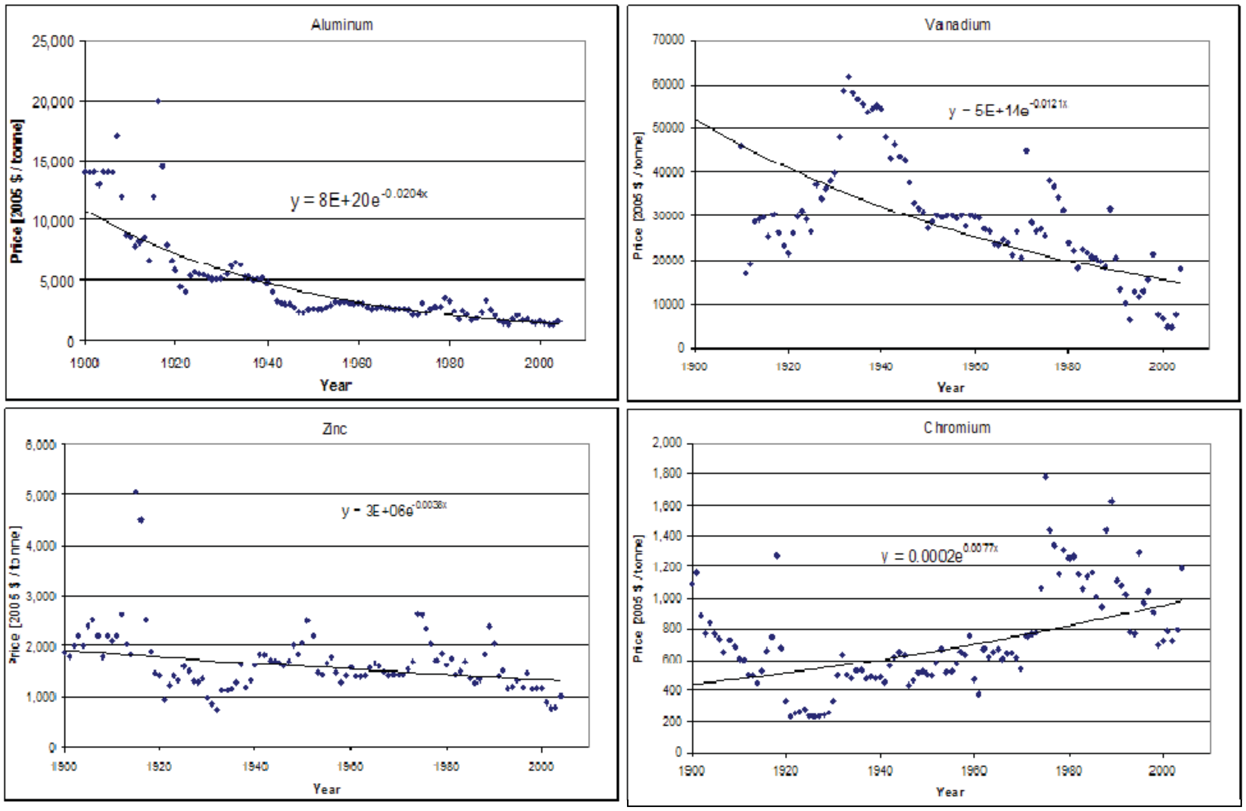

Figure A1-15. 100-year price trends for four minerals.

Table A1-14. Regression *M*-coefficients for 35 minerals.

Aluminum	**Antimony**	**Arsenic**	**Bauxite**	**Beryllium**	**Bismuth**	**Boron**	**Bromine**
-0.0204	**0.0014**	**-0.0087**	**-0.0074**	**-0.0186**	**-0.0210**	**-0.0015**	**-0.0283**
Cadmium	**Chromium**	**Cobalt**	**Copper**	**Germanium**	**Gypsum**	**Indium**	**Iodine**
-0.0243	**0.0077**	**-0.0049**	**-0.0064**	**-0.0212**	**0.0041**	**-0.0407**	**-0.0153**
Iron Ore	**Lead**	**Lithium**	**Magnesium**	**Manganese**	**Mercury**	**Molybdenum**	**Nickel**
0.0029	**-0.0052**	**-0.0254**	**-0.0232**	**0.0033**	**-0.0124**	**-0.0075**	**-0.0043**
Platinum	**Pumice**	**Rhenium**	**Silver**	**Tantalum**	**Thorium**	**Tin**	**Titanium**
-0.0046	**-0.0139**	**-0.0499**	**-0.0013**	**-0.0059**	**-0.0046**	**0.0013**	**-0.0395**
Tungsten	**Vanadium**	**Zinc**					
-0.0019	**-0.0121**	**-0.0038**					

The distribution of *M*-values was then itself subjected to statistical analysis. A normal distribution was assumed and the mean and standard deviation of the distribution were calculated. Table A1-15 shows that the mean value was negative: -0.0118. This implies a decrease in average mineral prices with time.[c] The standard deviation was computed to be 0.0136, which implies about a 20% probability that the *M*-value for any given mineral will in fact be positive. The 95% confidence interval for *M*—computed by calculating the interval falling within 2 standard deviations of the mean—is thus found to be (-0.0390, +0.0153).

Table A1-15. Statistical distribution of the 35 *M*-coefficients.

Most Negative	Rhenium, -0.0499
Most Positive	Chromium, 0.0077
Mean	-0.0118
Standard Deviation	0.0136
Two Standard Deviation Confidence Interval	(-0.0390, +0.0153)

Accepting that future uranium price trends should not diverge from the experience of the past century, the mean *M*-value and its confidence interval can be used to make a very approximate projection of uranium price evolution over this century. To do so, one must first select a starting point for the uranium price that roughly corresponds to a long-term average value. This was chosen to be \$120/kgU (\$46/lb U_3O_8) which corresponds closely to the historical average uranium price over the past 50 years (*viz.* Figure A1-12). Although contract prices at the time of delivery have historically averaged somewhat less than \$100/kgU, Table A1-13 indicates that a convergence between prices paid by utilities under a variety of pricing mechanisms is taking place. Likewise, recent estimates (Lehman Brothers, Inc. 2007; UIC 2007)[d] of marginal production costs and prices indicate that \$40/lb U_3O_8 is a reasonable estimate of the equilibrium price in the medium term. Beginning from this price in 2005, then, price evolutions corresponding to the mean and upper and lower confidence interval boundary *M*-values were computed and plotted. A time-averaged uranium price for this century was computed for each of the three evolutions. The results are shown in Figure A1-16.

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[c] This phenomenon is well-known: witness the famous 1980 wager between the economist Julian Simon and Stanford biologist Paul Ehrlich. Simon and Ehrlich wagered \$1000 against the price of a basket of five commodities chosen by Ehrlich, an early proponent of scarcity theory. Ehrlich ‘bought’ the basket in 1980, and Simon agreed to purchase the basket from Ehrlich in 1990 regardless of its price. The price of the basket fell considerably and Simon made a profit of \$570.07 from the wager.

[d] This discussion, based upon a study of mine production costs conducted by International Nuclear, Inc., indicates that at production levels corresponding to expected demand in 2015, marginal production costs should be around \$20/lbU3O8.

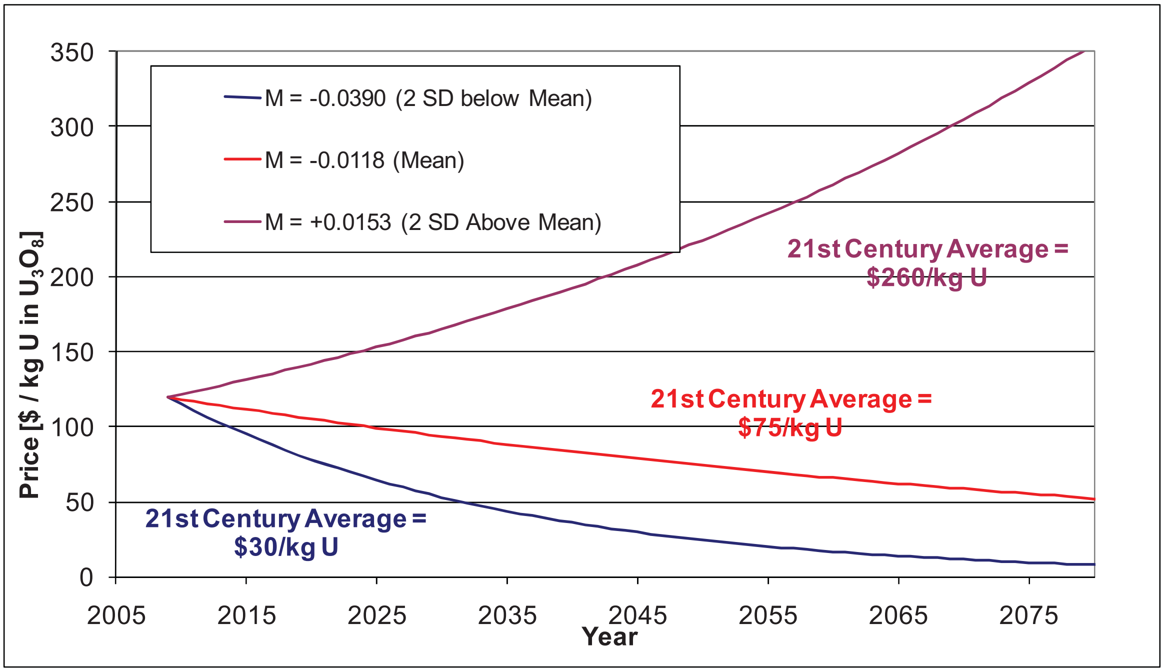

Figure A1-16. Upper bound, most probable, and lower bound uranium price forecasts obtained from USGS data.

Therefore, a price distribution having lower, most likely, and upper values of $25, $60, and $240/kgU was obtained. A logical alternate upper bound would be set by the cost of uranium extraction from seawater; however, since that cost has not been credibly estimated at less than $300/kgU (DOE 2002), the upper bound of $260/kgU was allowed to stand. Although the true shape of the distribution derived here is lognormal, for reasons of simplicity a triangular distribution with vertices at $30, $75, and $260 is recommended.[e] The analysis described above accounted only indirectly for temporal variations in mining intensity. Another approach to describing mineral price behavior considers cumulative mining activity as an independent variable. The objective of this approach is to quantify the effect of resource depletion upon mineral prices, and applying its results to uranium price forecasting, to investigate whether the resource base can sustain a future of aggressive nuclear growth.

A rapid increase in mining activity would be expected to lead to price increases, and minerals with accelerating mining rates would tend to rise in price when compared to minerals with stagnant or declining mining rates. One approach to addressing these questions would be to compare a time period in which mining activity increased rapidly to one that is less active. The USGS data (Kelly 2007) shows that across the full spectrum of minerals mining activity accelerated rapidly between 1947 and 1974, less rapidly after 1974. Mineral prices fell over both time periods, but not as rapidly between 1947 and 1974 as after 1974.

Table A1-16 shows the effect of resource depletion rate on price gleaned from analysis of the USGS time series data. Over the 1974–2004 period, the minerals were extracted at an average rate 1.65 times larger than in 1974. Regression analysis showed that the M-coefficent for this time period was larger in absolute value than for the full data series presented above. Therefore, prices declined more rapidly

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e. It is recognized that this methodology for projecting uranium price trends differs from the approach taken in for other Modules of this document where existing literature was sufficient to formulate an estimate. To confirm that our approach is reasonable, we have undertaken a peer review process that includes a consultation with fuel cycle experts at the Nuclear Energy Institute and publication and presentation in professional society venues. Regardless, given a system as complex as the uranium market we recognize the impossibility of true high-fidelity forecasting of long-term behavior.

between 1974 and 2004 than was the case for the full century-long period studied earlier. If the period of analysis is 1947–1977, Table A1-16 shows that extraction rates increased rapidly in the post-1947 period. Therefore mineral prices would be expected to decline less rapidly and this is indeed the case: the price of the basket of minerals was almost unchanged over the 1947–1977 period (Schneider and Shah 2008).

To place the M-coefficients of Table A1-16 into context, they may be employed as described above to project average uranium prices over this century. If uranium consumption followed the low-growth trajectory represented by the 1974–2004 data (M = -0.0335), its price would average about $40/kg, while if it were extracted much more rapidly (following the 1947–1977 trend with M = -0.0002 its price would remain near the present-day assumed marginal production cost value of $120/kg.

Table A1-16. M-coefficients for USGS minerals, 1974–2004 and 1947–1977.

Time Period	1974–2004	1947–1977
Number of Minerals in Sample	34	27
Mining Rate Acceleration Metric[a]	1.65	3.16
Average M-value	-0.0335	-0.0002
a. Defined as the average annual mining rate over the full time period divided by the amount mined in the first year of the time period. Thus, it is a measure of the average rate at which the mineral is being extracted.		

Similarities and differences between uranium and many other minerals may be briefly summarized. Uranium is uncommon in the Earth’s crust, its ores must be reasonably well-concentrated to be economically viable, at current consumption rates, the earth hold a few decades of confirmed-plus-estimated uranium reserves, it has no natural substitutes, and demand for it is not diversified. These factors may make uranium an “exceptional” mineral, one that would not be expected to obey the trends presented so far. If that is the case, some minerals offer better analogies to uranium than others, or the listed explanatory variables may not even be significant drivers of price trends.

As mentioned above, the overall abundance of uranium is middling in comparison to that of other minerals. Certain types of uranium are also abundant in minerals like silver, copper, gold, and iron, making co-extraction of these minerals worthwhile. Examples include hematite-granite complex deposits such as Olympic Dam, uranium-vanadium deposits such as found on the Colorado Plateau, and solution breccia pipe-type deposits, which can additionally contain economically viable zinc and lead sulfides. The in-situ leaching technique, predominantly used for the extraction of uranium from sandstone roll-front deposits, has thus far played a considerably more significant role in the uranium extraction industry than for most other minerals. It has grown to account for about 20% of world uranium production and 80% in the U.S. but is not used at all for the vast majority of minerals depicted in Table A1-14. Most uranium mining is still carried out using open-pit and underground approaches; however, so advances in these areas would continue to benefit the uranium industry as well as the broader mining sector.

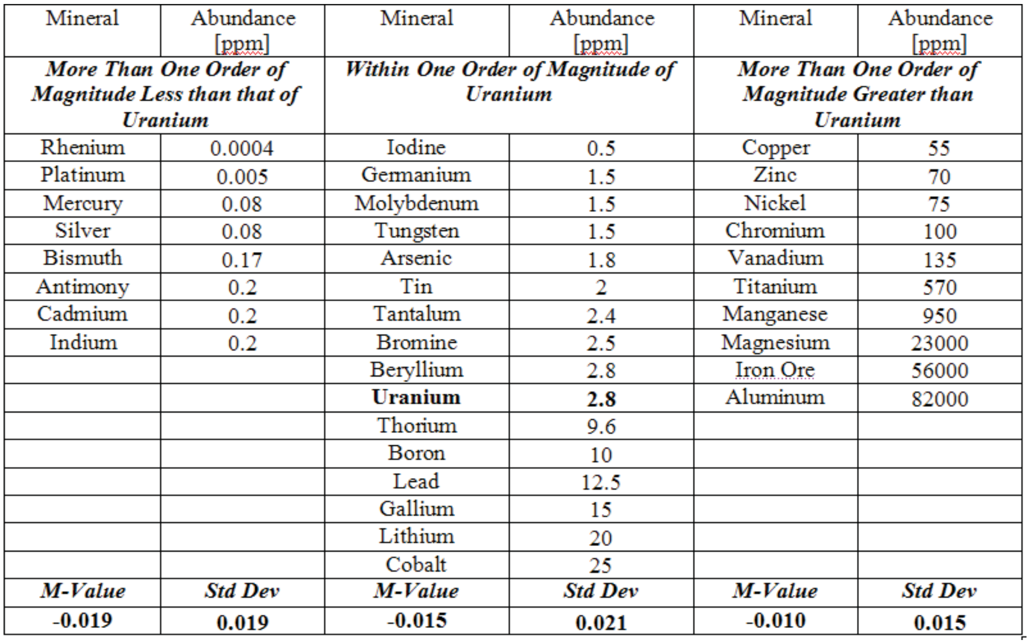
Laving in-situ leaching aside, the concentration factor at which uranium extraction is economically feasible is consistent with that of other minerals. The concentration factor is defined as the ore grade of an economically viable deposit divided by the average grade in the earth’s crust. For uranium, taking 1000 ppm to be a viable concentration, the concentration factor is (1000/2.8) = 180. Other common minerals have concentration factor thresholds bracketing this value: gold, 2,500; iron, 10; mercury, 10,000; lead, 2,500; copper, 100 (Griffits 1973).

(Schneider, Shah 2008) collected data for each USGS mineral for five explanatory variables:

- Crustal abundances
- Concentration factors
- Years of known reserves
- Demand diversification
- Existence of substitutes.

To explore the dependence of price upon variations in these supply and demand side drivers, the minerals were binned into categories according to their properties in each category relative to uranium and the M-value distributions of the minerals in each bin were calculated. The distributions were subjected to statistical analyses to explore their significance as explanatory variables with results shown in Table A1-17 through Table A1-21.

Table A1-17. Mineral crustal abundance relative to uranium and its effect on price trends.



Mineral	Abundance [ppm]	Mineral	Abundance [ppm]	Mineral	Abundance [ppm]
More Than One Order of Magnitude Less than that of Uranium		***Within One Order of Magnitude of Uranium***		***More Than One Order of Magnitude Greater than Uranium***	
Rhenium	0.0004	Iodine	0.5	Copper	55
Platinum	0.005	Germanium	1.5	Zinc	70
Mercury	0.08	Molybdenum	1.5	Nickel	75
Silver	0.08	Tungsten	1.5	Chromium	100
Bismuth	0.17	Arsenic	1.8	Vanadium	135
Antimony	0.2	Tin	2	Titanium	570
Cadmium	0.2	Tantalum	2.4	Manganese	950
Indium	0.2	Bromine	2.5	Magnesium	23000
		Beryllium	2.8	Iron Ore	56000
		Uranium	**2.8**	Aluminum	82000
		Thorium	9.6		
		Boron	10		
		Lead	12.5		
		Gallium	15		
		Lithium	20		
		Cobalt	25		
M-Value	***Std Dev***	***M-Value***	***Std Dev***	***M-Value***	***Std Dev***
-0.019	**0.019**	**-0.015**	**0.021**	**-0.010**	**0.015**

Table A1-18. Mineral concentration factor relative to uranium and its effect on price trends.

Mineral	Concentration Factor	Mineral	Concentration Factor	Mineral	Concentration Factor
More Than One Order of Magnitude Less than that of Uranium		***Within One Order of Magnitude of Uranium***		***More Than One Order of Magnitude Greater than Uranium***	
Bismuth	1.5	Titanium	62	Silver	3750
Aluminum	4	Cobalt	80	Tungsten	4000
Antimony	5	Copper	150	Beryllium	4000
Iron Ore	9	Nickel	175	Chromium	4500
		Manganese	190	Mercury	100000
		Lithium	240		
		Uranium	**350**		
		Zinc	370		
		Molybdenum	770		
		Platinum	1000		
		Tin	2500		
		Lead	3300		
M-Value	***Std Dev***	***M-Value***	***Std Dev***	***M-Value***	***Std Dev***
-0.009	**0.013**	**-0.009**	**0.013**	**-0.005**	**0.010**

Table A1-19. Years of reserves relative to uranium and its effect on price trends.

Mineral	Reserves / Annual Production	Mineral	Reserves / Annual Production	Mineral	Reserves / Annual Production
At Least 50% Less than that of Uranium		***Within +/- 50% of Uranium***		***At Least 50% Greater than Uranium***	
Indium	6	Thallium	38	Cobalt	122
Antimony	13	Tungsten	40	Titanium	122
Silver	14	Manganese	40	Bauxite	141
Lead	20	Nickel	41	Lithium	195
Arsenic	20	Iron Ore	47	Vanadium	208
Zinc	22	Rhenium	56	Platinum	318
Tin	22	Bismuth	57	Molybdenum	480
Cadmium	26	**Uranium**	**76**	Iodine	593
Copper	31			Beryllium	630
Mercury	33			Bromine	Large
Tantalum	33			Gypsum	Large
Boron	36				
M-Value	***Std Dev***	***M-Value***	***Std Dev***	***M-Value***	***Std Dev***
-0.009	**0.012**	**-0.006**	**0.025**	**-0.015**	**0.013**

Table A1-20. Demand diversification and its effect on price trends.

	Diversified (No industry accounts for more than 75% of consumption)		**Not Diversified** (One industry accounts for more than 75% of consumption)	
Number of Minerals	**15**		**10 (+ uranium)**	
	M-Value	Std. Dev.	M-Value	Std. Dev.
	-0.010	0.010	-0.021	0.025

Table A1-21. Existence of substitutes and its effect on price trends.

	One or more substitutes evident		**No substitutes, or substitutes listed as inferior**	
Number of Minerals	**20**		**11 (+ uranium)**	
	M-Value	Std. Dev.	M-Value	Std. Dev.
	-0.013	0.013	-0.005	0.020

The M-value distributions of the mineral populations in each category for every explanatory variable were tested for statistically significant differences in their variances and means. It was found that with 90% confidence the means of all distributions were indistinguishable. Therefore, the study concluded that variations in Crustal Abundance, Concentration Factor, Years of Known Reserves, Demand Diversification and Existence of Substitutes do not lead to demonstrably dissimilar mineral price trajectories, although differences in variances were in some cases significant (Schneider, Shah 2008).

The discussion has thus far focused upon uranium in analogy to other minerals. It is useful to close with a comparison of uranium price trends to those of fossil fuels. While uranium is geologically dissimilar from these commodities, they share the role of producing a singular end-use product. Uranium and fossil fuel prices have to an extent moved in sympathy (Figure A1-17), experiencing booms in the 1970s to early1980s and again more recently (note that many mineral commodities also went through price booms in the 1970s–1980s; see Figure A1-14). Inelastic demand has caused upward pressure on oil and gas prices. Uranium demand is also inelastic: with short of alterations in the fuel cycle that require decades to achieve, only limited steps can be taken in the short run to reduce uranium requirements. This landscape tight supply and inflexible demand would give rise to the downside (high cost) uranium price scenario presented in this module, where the mid-century average production cost (and hence equilibrium price) of the resource has more than doubled from 2009 values.

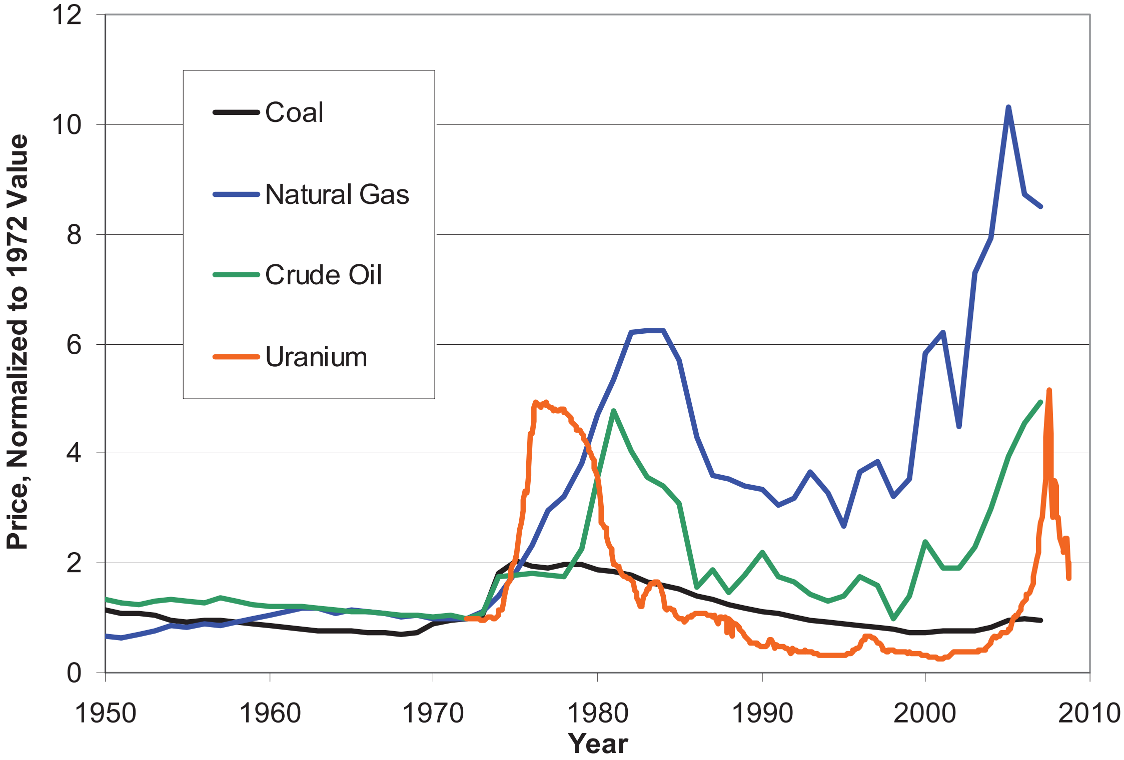


Figure A1-17. Inflation-adjusted uranium and fossil fuel prices, 1972–2008. 1972 price = 1.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table A1-22. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distribution based on the costs in the WIT table is shown in Figure A1-18. Note that the mean cost associated with this skewed distribution is $122/kgU. See Section A-6.1 for explanation.

Table A1-22. Cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
\$50–300/kgU	NA	\$30/kgU	\$260/kgU[f]	\$75/kgU
Reflects near-term (next 10–15 years)				

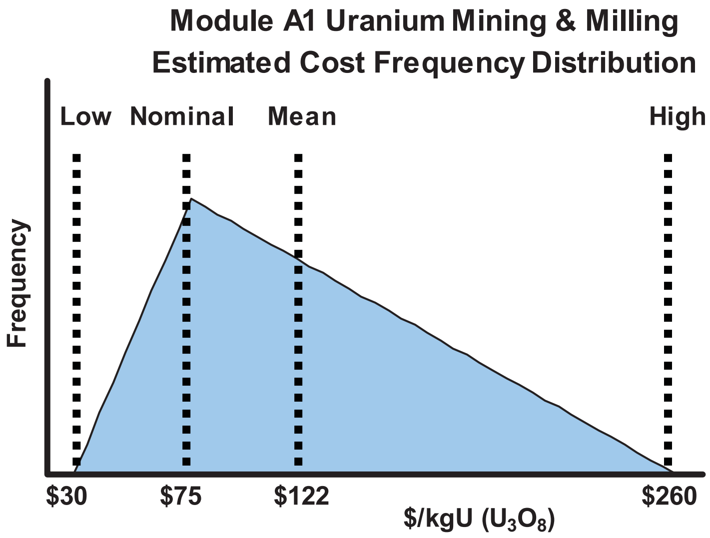


Figure A1-18. Uranium mining & milling estimated cost frequency distribution.

A1-6. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Uranium Cost Sensitivity. The cost of uranium represents about 20% of the cost of fuel. A doubling of the ore price has little sensitivity in terms of the total fuel cycle cost. The sensitivity from a \$150/kgU increase in price is in the range of ~1 mil/kWh relative to the cost of electricity.

Implication of expanding use of secondary sources of uranium and growth in price of natural uranium can become the driver for enhancements and capacity growth for new enrichment technologies and consideration for expanded use of existing tails and reprocessed uranium. With laser enrichment, or if the present high prices are sustained, even depleted uranium could be considered for cost-effective supply.

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[f] The authors recognize that uranium and enrichment spot prices have recently exceeded the high-cost range provided in this cost basis. These price trends continue to be evaluated and the cost ranges in the report may continue to be revised as appropriate in future updates. The cost basis reflects reasonable expectations about uranium and enrichment long-term contract prices applicable to reactors with long operating lives, rather than reflecting market spikes as experienced in the 1970s and observed in the spot market U_3O_8 prices circa 2007.

A1-7. REFERENCES

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Module A2

Thorium Mining and Milling

Module A2

Thorium Mining and Milling

A2-1. BASIC INFORMATION

This module covers the factors involving extraction of thorium from the earth through production of thorium concentrate in one of the three forms in which it is stored: oxide, oxalate, and nitrate. It also provides a brief review of the past and present applications of thorium for nuclear power production. Apart from trace quantities of alpha-emitting Th-228 ($T_{1/2}$=1.91 yr), thorium found in nature consists of only one isotope, Th-232. This species has a half-life of over 14 billion years and is not fissile by thermal neutrons. Its fission threshold is rather high (ca. 700 keV) and its fission cross section does not exceed 0.1 barn over most of the range of neutron kinetic energies relevant to even fast-spectrum critical reactors. Instead, thorium is of interest because it breeds the attractive thermal fissile species U-233 via a neutron capture reaction followed by two beta decays:

$${}^{232}_{90}Th(n,\gamma){}^{233}_{90}Th \xrightarrow[T_{1/2}=22\ \min]{\beta^-} {}^{233}_{91}Pa \xrightarrow[T_{1/2}=27\ d]{\beta^-} {}^{233}_{92}U.$$

Thorium fuel cycles have attracted interest for their potential to ameliorate resource sustainability and mitigate waste management concerns, as compared to the once-through uranium cycle. The potential of the thorium cycle to benefit long-term waste management arises from the relatively benign actinide content of thorium fuel at discharge. Plutonium and transuranic production in particular is greatly reduced as the activation products of Th-232 must undergo several neutron captures to form even the lightest long-lived transuranic, Np-237. As an example, one proposal for employing thorium in light-water reactors (LWRs) reduces plutonium production by a factor of 6–7 compared to an energy equivalent of U-235/U-238 fuel in the same reactor (Galperin, Radkowsky, Todosow 1999; also see Section A2-7).

All designs that utilize thorium in critical reactors must rely upon a more readily fissionable “seed” or “driver” fuel to provide the surplus neutrons needed to initiate U-233 breeding. To maximize U-233 production, thorium is often employed as a matrix material in driver fuel elements to promote in-situ breeding as well as in a breeding blanket. Historically U-235-enriched fuel has been used as the driver, although plutonium with other transuranics could also serve; in a mature closed thorium fuel cycle, sufficient excess U-233 is bred to serve as seed material for startup of new reactors. Indeed, in several respects (per-fission neutron yield, capture-to-fission ratio) U-233 is superior to U-235, both as a reactor fuel and as a candidate for weaponization. Some fuel cycle proposals blend U-238 with thorium to reduce the enrichment levels in order to gain a non-proliferation benefit. The resultant improvement in the intrinsic proliferation resistance comes at the expense of increased production of Pu-239 and other activation products derived from U-238.

Thorium use has been demonstrated in all major types of power producing reactors. Table A2-1 highlights noteworthy operational campaigns; several of which involved commercial power production. At present, India maintains the most aggressive thorium fuel cycle research and development (R&D) program, continue to load thorium in both commercial and research reactors. The Indian program has also demonstrated a substantially complete thorium fuel cycle by loading U-233 recovered from a breeder (the Fast Breeder Test Reactor (FBTR) as the primary driver fuel in another reactor (KAMINI and other research reactors). Table A2-1 shows that outside of India, large-scale utilization of thorium in power and test reactors ceased in the 1980s. The decline in interest in the thorium fuel cycle during this decade proceeded in tandem with a sharp and sustained drop in uranium prices and global slowdown in the construction of new nuclear power plants (NPPs).

Table A2-1. Commercial and experimental reactors loading thorium or U-233 fuel (WNA 2009).

Reactor	Location/Period of Operation	Comments
Shippingport, 100 MWe	USA, 1977–1982	Pressurized water reacorit (PWR) in operation from 1957; Th loaded 1977–1982 in seed-blanket array (ThO_2 – $^{233}UO_2$); successful demonstration of breeding in an LWR
Atom Versuchs Reaktor (AVR), 15 MWe	Germany, 1967–1988	He cooled, graphite moderated pebble bed, HEU-Th fuel (1,360 kg Th used over reactor lifetime, some fuel reached 150 MWd/kg burnup)
Dragon, 20 MWt	UK, 1964–1973	Utilized 10:1 Th:HEU converter fuel elements designed for 6-year residence time
Peach Bottom 1, 40 MWe	USA, 1967–1974	Helium-cooled graphite moderated oxide/dicarbide fuel
Thorium High Temperature Reactor (THTR), 300 MWe	Germany, 1983–1989	Helium-cooled, graphite moderated pebble bed, HEU-Th fuel
Fort St. Vrain, 330 MWe	USA, 1976–1989	Helium-cooled, graphite moderated, prismatic HEU-Th fuel
Kakrapar pressurized heavy water reactors (PHWRs), 220 MWe	India	Thorium used for power profile flattening in initial cores
Lingen boiling water reactor (BWR), 60 MWe	Germany	Limited in-core testing of Th/Pu fuel elements
KAMINI, 30 kWt	India, 1996–Present	Loaded with Al-^{233}U driver and Th blanket fuel; Other research reactors in India have also loaded Th-bearing fuel
Fast Breeder Test Reactor, 40 MWt	India, 1985–Present	Liquid metal fast breeder based on French “Rapsodie” design: Pu/UC driver, ThO_2 blanket
Molten Salt Reactor Experiment (MSRE), 7.4 MWt	USA, 1965–1969	Operated with $^{233}UF_4$-FLiBe fuel; MSRE was an investigation of the “driver” portion of a thorium-based molten salt fueled breeder

A2-2. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTION

A2-2.1 General

Thorium is widely distributed throughout the crust of the earth. Table A2-2 shows some typical concentrations; roughly three times more abundant than uranium, thorium is the 39-most common of the 78 crustal elements (Herring 2004). The ability to extract the thorium in a practical and cost-effective manner depends on the relative grade of the ore to be mined (i.e., the percentage of thorium in the ore body), the type of formation in which it resides, and the location. An ore body is, by definition, an occurrence of mineralization from which the metal is economically recoverable. It is therefore relative to both costs of extraction and market prices.

Table A2-2. Crustal abundance (grams/tonne) of selected elements.

Element	Grams/tonne
Gold	0.004
Silver	0.07
Tungsten	1.5
Molybdenum	1.5
Uranium	2.8
Thorium	7.2
Lead	13
Copper	55
Zinc	70
Iron	50,000

Phosphates, silicates, carbonates, and oxides of thorium are all found in nature. As it often associates with alkaline igneous rocks, thorium is commonly concentrated together with rare earth elements (REs), titanium, niobium, zirconium and uranium that exhibit similar behavior. Hence, ore bodies will often contain both thorium and uranium, although it is usually the case that only one of the two is present in economically viable concentrations.[a] As will be discussed later, the geographic distribution of known thorium resources does not align strongly with that of uranium resources.

Most of the thorium in ore bodies suitable for large-scale near-term extraction is found as $ThPO_4$ in the phosphate mineral monazite. The ThO_2 content of monazite concentrate ranges from 3% to 15%. Rare earth oxides constitute about 50% of typical monazite, with the dominant rare earth constituents being cerium, lanthanum, and yttrium. In most cases, monazite also contains a few tenths of 1% uranium, but zirconium and titanium are more often present at economically attractive concentrations. Monazite can be a notable constituent of alluvial formations, in particular beach sands: beach and inland placers of monazite account for around 30% of reported thorium reserves. Beach deposits containing economically attractive monazite concentrations are relatively common because offshore wave action will transport light minerals more readily than monazite. If the geographic configuration of a coastline and offshore currents are favorable, local wave, and tidal phenomena can concentrate monazite and other heavy minerals. Favorable beach sand concentrate in India may contain 0.5–2.0 weight percent (w/o) monazite. Sand concentrate from Florida in the U.S. has been found to yield 0.05 w/o monazite, a concentration that is still considered sufficiently favorable to warrant inclusion in the domestic thorium resource base (Schapira 1999).

Resource estimates of this type are affected by the value of other minerals that may be co-extracted from the same deposit. In fact, much historical thorium production was derived from milling of monazite for its rare earth content. At present, however, monazite is not being milled in the United States; even at mine sites where it is present in the ore body (Hedrick 2007 and 2009).

Other formations may also give rise to suitable thorium deposits. For instance, thorium is produced, but in large it is not refined as an undesired by-product of carbonate ore mining. The thorium resource base in carbonates is large, but grades tend to be low: typically 0.5% versus 3–15% in monazite or higher in some vein-type deposits. The United States is unusual in that its most appealing deposits are vein-type silicate formations harboring thorite, $ThSiO_4$. Section A2-4 will expand upon the domestic resource

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[a] There are exceptions: for example, monazite containing 11.3 w/o thorium and 15.6 w/o uranium concentrates has been found in Italy (Schapira 1999).

picture, but monazite extraction will likely continue to dominate the short-term world supply picture. Mining techniques such as the monazite technique depicted below will be impacted by the difficulty in reaching the ore, the grade, and the amount of secondary waste to be generated.

A2-2.2 Extraction Techniques

Commercial scale monazite production began in the 1950s. Its mining process is of the open pit type: dredging is employed for shallow offshore or riverine collection of monazite sands, while bulldozers and other earth-moving equipment suffice for onshore formations such as dunes. Separation of monazite from overburden is simplified by differences in density, electrical conductivity, and magnetic properties of monazite as compared to other constituents. (See Figure A2-1 for a flowchart depicting the steps taken to isolate monazite.)

An aqueous process is employed to mill thorium from monazite. In India, where most of the world's monazite is currently processed, the mineral slurry is first dissolved in a basic (NaOH) medium. The resultant solution monazite is subjected to a series of extraction processes, as shown in Figure A2-2. At present, the final product of the Indian process is thorium oxalate, $Th(C_2O_4)_2{\cdot}2H_2O$, at 99% purity. This compound is sufficiently stable to be suitable for long-term storage in concrete silos. The oxalate decomposes to ThO_2 when heated (calcined) to 300–400°C. A portion of the Indian production is converted to "mantle grade" thorium nitrate. At the Indian plants, around 1,000–10,000 tons of feed yields 1 tonne of thorium metal. Recovery efficiencies are presently approximately 90% (Schapira 1999).

Overburden haulage in this process is less than that of standard—underground or open-pit—uranium extraction techniques and radioactive waste by-product production is estimated to be two orders of magnitude less than is the case for production of analogous amount of uranium (IAEA 2005). Effluents from tailings and milling remain a concern. The thorium decay chain also has a gaseous member, Rn-220 (half life ($T_{1/2}$) = 56 s), although its content in secular equilibrium in the decay chain is several orders of magnitude smaller than that of the U-238 daughter Rn-222 ($T_{1/2}$ = 3.82 d). In addition longest-lived daughter of the Th-232 decay chain, Ra-228 ($T_{1/2}$=5.7 year), must be compared to $T_{1/2}$=77,000-year Th-230 from the U-238 chain. Hence tailings pile management and public health protection from milling operations is simplified in some respects, though in practice sufficient uranium might be present in the ore body for no practical gain to be observed. While inhalation of Rn-220 would lead to a higher radiological impact, its decay during the atmospheric dispersion process implies that its concentration at a postulated mill site boundary would be lower than for a uranium mill of equivalent capacity (Schapira 1999)

The volume of radioactive wastes requiring long-term storage has been estimated at 0.4 m^3/tTh (i.e., one 75-cm-diameter × 90-cm-high barrel (Schapira 1999). This waste arises because radium is extracted with other waste products during rare earth purification steps. Since Ra-228 has a half-life of 5.7 years and its descendants are all shorter-lived, in principle the solid waste would be suitable for permanent disposal within a few decades. In practice, the presence of small amounts of longer-lived Ra-226 ($T_{1/2}$=1600 yr), a U-238 decay product, might preclude this option. Additional byproducts include about 1 tonne per tonne Th of low-level and 3–6 tonnes per tonne Th of medium-level solid wastes suitable for shallow land burial. Table A2-3 summarizes the major radioactive wastes arising from extraction from a typical Indian deposit and processing of monazite ore to yield 1 tonne Th.

Table A2-3. Major radiologically active wastes arising from production of 1 tTh from monazite (Data from Schapira 1999).

Waste form	Mass [tonne / tonne Th metal]	Storage/disposal strategy
Solid, Ra-228-bearing waste arising from rare earth purification	0.47 (0.4 m^3/tonneTh)	Reinforced cement concrete barrels; long-term storage in underground trenches
Medium-level liquid and acid-leached solid from solid-liquid separation of thorium concentrate	~3–6 depending on desired Th purity	Suitable for ground disposal
Low-level solid from other steps in process	~1	Suitable for shallow ground disposal.

A2-3. Pictures/Schematics

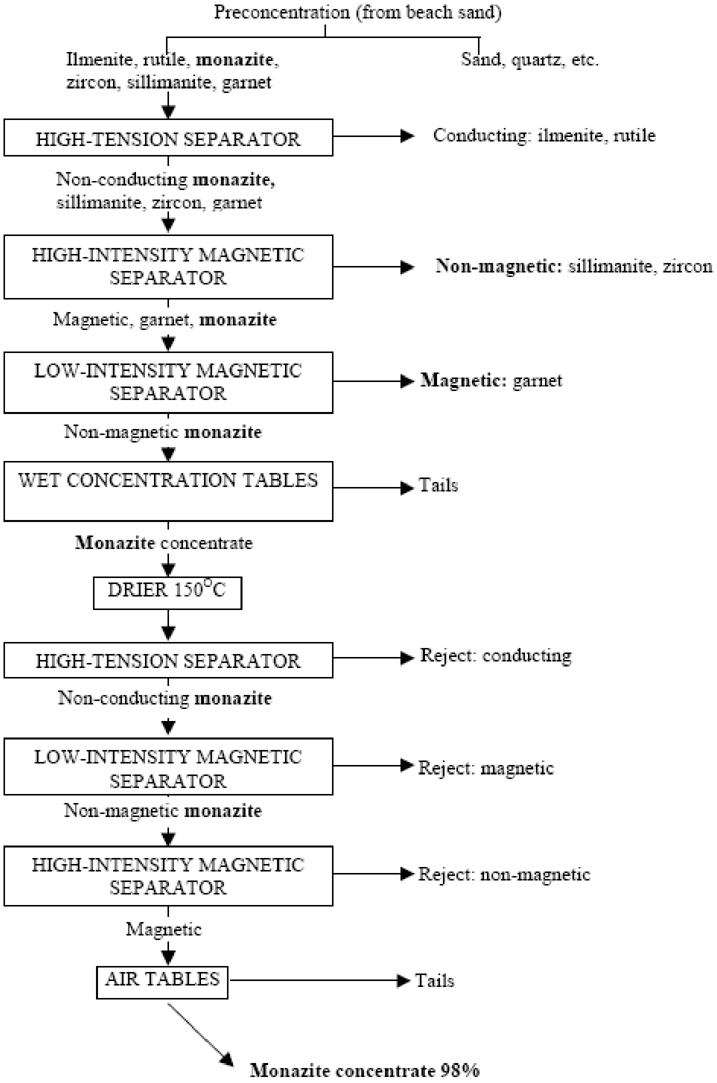

Figure A2-1. Flowsheet for monazite isolation (IAEA 2005).

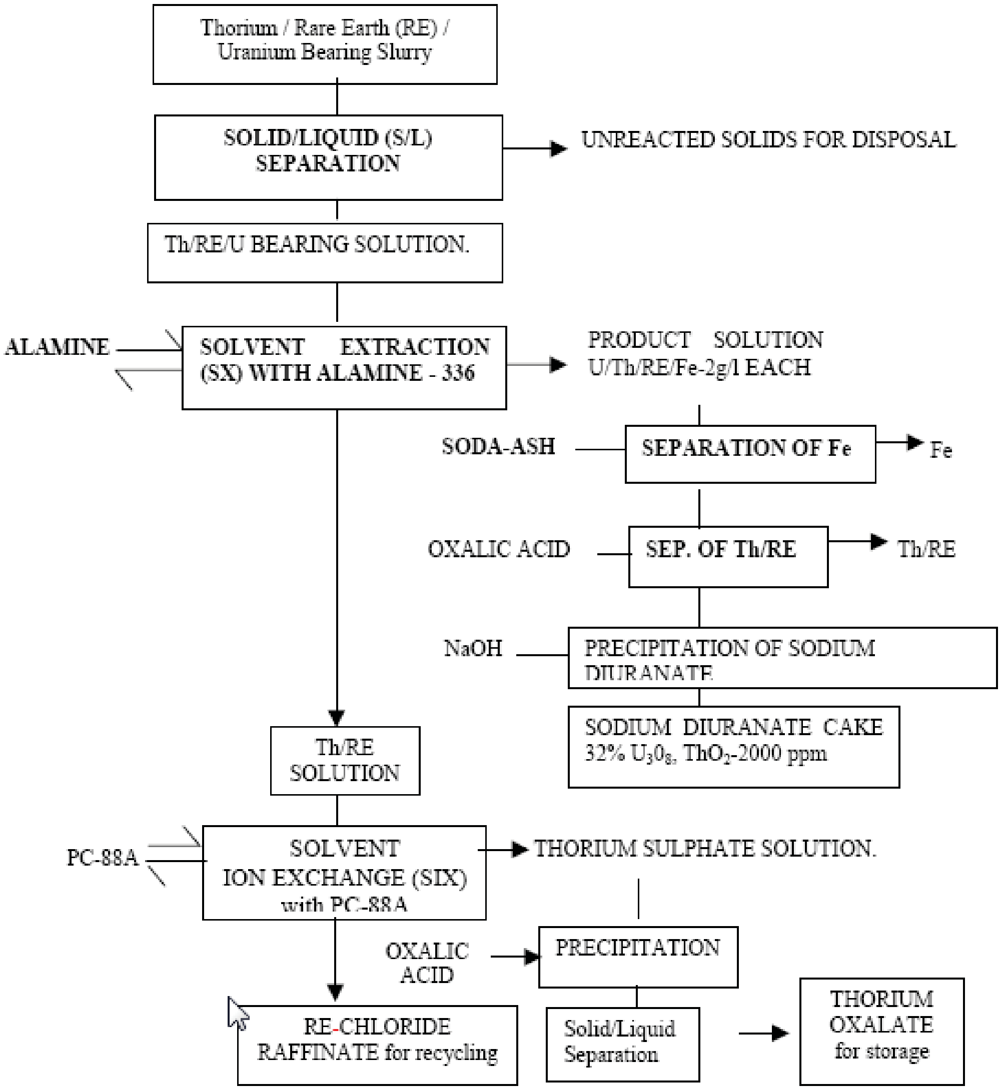

Figure A2-2. Flowsheet for thorium oxalate production from monazite (IAEA 2005).

A2-4. MODULE INTERFACE DEFINITION

The product of Module A2 is greatly influenced by the requirements for Module D1, Fabrication of Contact-handled Fuels, which defines overall demand. However, relative to specific demand, there are other factors outside of the defined modules that have influence on this module. In particular, the requirements for Module D1 can be affected by the driver or seed fuel providing the fissile support for the thorium-bearing fuel. Note that there is no enrichment in thorium-based fuel cycles unless low-enriched uranium (LEU) is in use as a driver fuel. Therefore, Module A2 interfaces with Modules B and C1 in this context only.

A2-4.1 Module Scaling Factors

Scaling factors are not specifically applicable. Size and cost of establishing a new mine will depend on many factors and are not generally scalable unless conditions would be nearly identical to another mining opportunity including type of mining method, location, and type of ore body, thickness of seam, etc.

A2-4.2 Cost Bases, Assumptions, and Data Sources

The cost basis for thorium depends on a number of factors impacting supply and demand. Availability, at a given cost, drives the specific supply to meet demand for new product. This demand may be heavily impacted by the cost of uranium, which is addressed in Module A1. The following discussions highlight the key factors relative to the actual supply and demand for newly produced thorium.

A2-4.3 Definition of Thorium Reserves

Availability of supply is evaluated using the accepted systematic convention of reporting reserves as established by a joint Organization for Economic Cooperation and Development/Nuclear Energy Agency-International Atomic Energy Agency (OECD/NEA-IAEA) expert group and as adapted by U.S. Department of Energy-Energy Information Administration (DOE-EIA). The various categories of reserves indicate both the confidence level that given amounts of reserves will exist as well as the difficulty in making that thorium available for use. These indications are expressed in an estimated cost to reclaim and utilize the reserves with reasonably established methods. Extensive analyses of factors affecting the uranium market are performed regularly and published in a biennial report by OECD/NEA-IAEA known as the *Red Book* (OECD 2008). Until 1982, the *Red Book* offered a similar depth of analysis for thorium; subsequently, however, all but the summary information was dropped. The de-emphasis of thorium in the *Red Book* paralleled a general decline in interest in thorium as a commodity, but nonetheless the *Red Book* continues to provide limited estimates of thorium reserves.

The definitions of the conventional resource categories, as established by the OECD/NEA-IAEA, are the same as those adopted for uranium, with two exceptions: Speculative and Unconventional Resources are not tabulated for thorium. The resource categories are listed below, in order of decreasing confidence in the deposit size and extraction cost.

Reasonably Assured Resources (RAR) refer to thorium that occurs in known mineral deposits of delineated size, grade, and configuration such that the quantities that could be recovered within the given production cost ranges with currently proven mining and processing technology can be specified. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of deposit characteristics. RAR have a high assurance of existence.

Estimated Additional Resources Category I (EAR-I) refers to thorium in addition to RAR that is inferred to occur, mostly on the basis of direct geological evidence, in extensions of well-explored deposits or in deposits in which geological continuity has been established, and where specific data, including measurements of the deposits and knowledge of the deposits' characteristics, are considered to be inadequate to classify the resource as RAR. Estimates of tonnage, grade, and cost of further delineation and recovery are based on such sampling as is available and on knowledge of the deposit characteristics as determined in the best known parts of the deposit or in similar deposits. Less reliance can be placed on the estimates in this category than on those for RAR.

Estimated Additional Resources Category II (EAR-II) refers to thorium in addition to EAR-I that is expected to occur in deposits for which the evidence is mainly indirect and which are believed to exist in well-defined geological trends or areas of mineralization with known deposits. Estimates of tonnage, grade, and cost of discovery, delineation, and recovery are based primarily on knowledge of deposit characteristics in known deposits within the respective trends or areas and on such sampling, geological, geophysical, or geochemical evidence as may be available. Less reliance can be placed on the estimates in this category than on those for EAR-I.

A2-4.4 World Reserves of Thorium

The IAEA *Red Book 2007* estimates world thorium resources to be 6.08 million metric tons. Table A2-4 provides the distribution of resources by deposit type. Monazite-bearing placer deposits can have thorium grades of 10% or more and are likely to be among the first resources exploited if thorium production expands.

Table A2-4. Known world thorium resources by deposit type.

Deposit Type	Amount (1000 tTh)
Carbonatite	1,900
Placer (alluvial)	1,500
Vein-type	1,300
Alkaline Rocks	1,120
Other	258
Total	**6,078**

"t" is metric tonne.

In contravention to the practice followed in its uranium estimate, wherein the resource is classified into four extraction cost categories as well as the confidence levels described above, the *Red Book* provides only two cost categories for thorium. These are: extractable at a cost of $80/kgTh or less (4.36 million metric tons) and extractable at greater than $80/kgTh (1.72 million metric tons). Table A2-5 shows the distribution by confidence level of resources extractable at $80/kgTh or less (OECD 2008).

Table A2-5. Known world thorium resources recoverable at less than $80/kgTh.

Resource Category	Amount (1000 tTh)
Reasonably Assured Resources	1,173
Inferred Resources	1,400
Prognosticated Resources	1,787–1,887*
Total	**4,360**

"t" is metric tonne.

* The OECD estimate of Prognosticated Resources in Turkey is 400–500 tTh, accounting for the range seen above.

Table A2-6 shows the geographic distribution of thorium reserves as derived from OECD/NEA-IAEA data. The distribution of uranium is provided for comparison; the distinct geological characteristics of minerals bearing the two elements give rise to wide variance in locations where the elements are sufficiently concentrated to be economically viable for extraction. Note that the thorium reserves of India are six times larger than its uranium reserves; supply-security has been instrumental in fostering the emphasis on thorium in the Indian fuel cycle R&D program.

Table A2-6. Distribution of identified resources of uranium and thorium.

Country	Percentage of World Thorium[a]	Percentage of World Uranium[a]
Australia	18%	28%
USA	16%	3%
Turkey	13%	<2%
Brazil	12%	6%
India	12%	<2%
Venezuela	12%	<2%
Norway	5%	<2%
Egypt	4%	<2%
Russian Fed.	3%	5%
Canada	2%	12%
Others	~3%	~36%

a. Reasonably Assured Resources plus Inferred Resources to $80/kgTh.

It is interesting to note that, although thorium is considerably more abundant than uranium, the *Red Book* identified thorium resources, 4,360 thousand tTh, are less than the identified uranium resources, 5,469 thousand tU. This should not be taken to imply that the potential supply of economically viable thorium is smaller than that of uranium. The figures reported in the *Red Book* are supplied to the OECD/NEA-IAEA by member countries and are tied to the thoroughness of prospecting activities in the individual nations. Since demand for thorium is low, it is only lightly prospected and the identified resource base would assuredly increase if demand were revived. As an example, the identified uranium resource base reported in the *Red Book* increased from 3,400 thousand tU in the original 1965 *Red Book* to its current value of 5,469 thousand tU even, as about 2,000 thousand tU were extracted from the ground.

Limited thorium prospecting activities continue in several countries. Prospecting is most intensive in India where a mature thorium production chain already exists. Exploration has also been reported in Canada and the United States; in the U.S., Thorium Energy, Inc., contracted Idaho Engineering and Geology, Inc., to further quantify the extent of its thorium holdings in the Lemhi Pass area of Idaho and Montana. In a report submitted to the U.S. Geological Survey (USGS), the investigators indicated that the Th deposits in the Lemhi Pass area may be considerably larger than the USGS values cited below (Gillerman 2008).

A2-4.5 Domestic Resources

The identified thorium resource base of the United States is the second largest in the world, after that of Australia. Table A2-7 shows the reserves associated with the largest known domestic deposits and Figure A2-3 maps the location of these deposits. Much of the identified thorium is contained in vein deposits; the Lemhi Pass mining district in Montana and Idaho is the largest of these with over 56,000 tTh of reserves and additional undiscovered resources estimated at over 100,000 tTh. Silicate (thorite) and phosphate (monazite) veins dominate in this region. Samples taken from the ten largest veins in the district indicated an average ore grade of 0.43 w/o ThO_2. The USGS estimates that the Wet Mountains region, in which thorite veins predominate, may also contain undiscovered resources of greater than 100,000 tTh. The thorium ore grade at Wet Mountains is similar to that of Lemhi Pass: the average ore grade of 201 samples taken from Wet Mountains was found to be 0.46 w/o ThO_2. (Van Gosen et al., 2009)

Domestic carbonate resources are also extensive. Thorium concentrations in carbonate deposits are typically low; the formations at Iron Hill, for instance, bear only 30–40 ppm Th. Yet this and other carbonatite formations are enriched in rare earth elements, as well as Ti, V, and Nb, so that Th production as a co-product may become economically appealing. Domestic placer deposits of monazite similar to those already being tapped in India also represent a considerable share of U.S. reserves. These alluvial monazite deposits are located in beach sands (Florida) as well as riparian environments in Idaho and the Carolina Piedmont. (Van Gosen et al. 2009)

There is currently no production of thorium in the United Sates. The limited domestic industrial demand for Th, averaging less than 10 t/yr from 1995 to the present, has been satisfied by imports or consumption of stockpiled material.

Table A2-7. Estimated reserves in selected major thorium deposits in the United States (data source: Van Gosen et al. 2009).

Name, location *(deposit type)*	Amount (tTh)
Lemhi Pass, Montana-Idaho *(vein)*	56,200
Wet Mountains, Colorado *(vein)*	51,100
Iron Hill, Colorado *(carbonate, vein)*	26,900
Florida beach placers *(placer)*	12,900
Idaho stream placers *(placer)*	8,000
Mountain Pass, California *(carbonate)*	7,800
North and South Carolina stream placers *(placer)*	4,200
Hall Mountain, Idaho *(vein)*	3,600

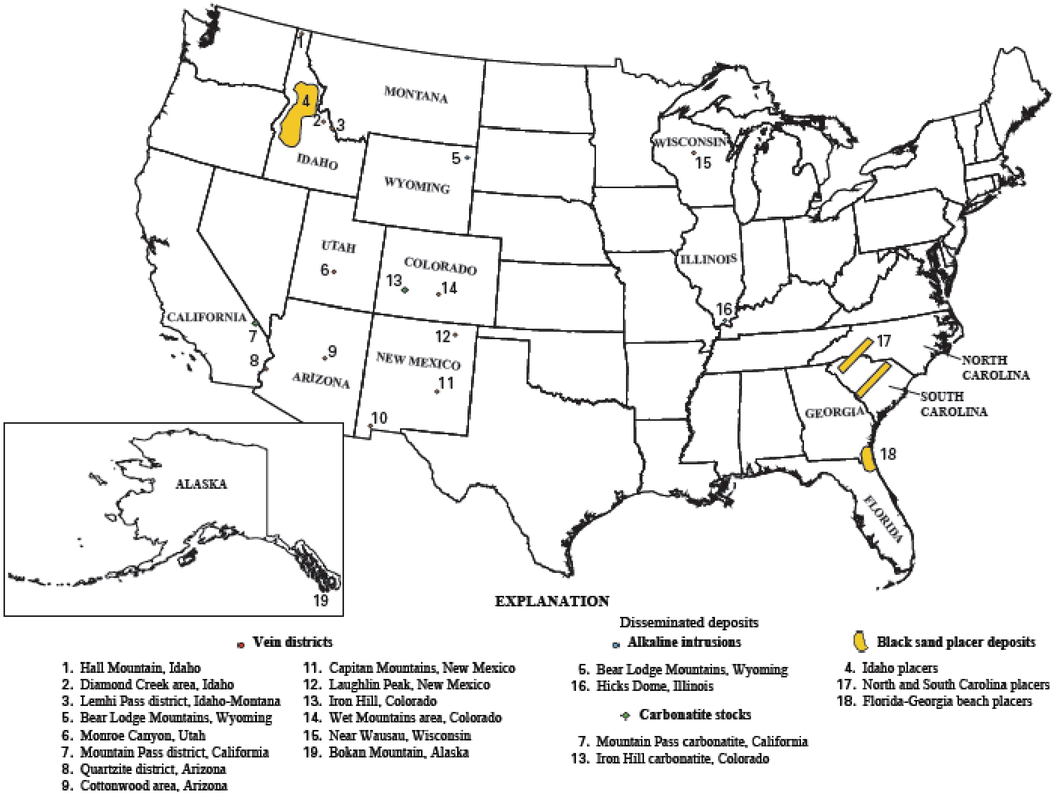

Figure A2-3. Location of prospected thorium deposits in the United States (USGS 2009).

A2-4.6 Market Price for Thorium

Due to its small size, the thorium industry is not associated with a well-developed commodity market of the type that has matured around the uranium resource. Therefore, such data as exists on recent thorium prices derived from individual transactions and evinces a great deal of variability. Table A2-8 shows that prices are highly dependent on product purity. This price disparity with product grade would be expected to decline if the industry expanded in scope and the demand for high-purity products increased.

Table A2-8. Average domestic thorium compound prices as reported by the U.S. Geological Survey.

	Mid 1990s prices (1996 USD, Hedrick 1997)	Mid 2000s prices (2008 USD, Hedrick 2009)
Nitrate, welding grade	\$5.46/kg $Th(NO_3)_4$	\$5.46/kg $Th(NO_3)_4$
Nitrate, mantle grade	\$22.10/kg $Th(NO_3)_4$	\$27.00/kg $Th(NO_3)_4$
Oxide, 99.0% purity	\$64.20/kg ThO_2	Not reported
Oxide, 99.9% purity	\$89.25/kg ThO_2	\$113.33/kg ThO_2
Oxide, 99.99% purity	\$107.15/kg ThO_2	\$164.35/kg ThO_2

The USGS also reports an imputed thorium price index, the so-called "unit value" index. This may be most relevant to nuclear energy applications of thorium as it is tied to the economic value of consumption of high-purity thorium oxide (97% purity before 1977, 99% between 1978 and 1994, and 99.9% from 1995 to the present). The data series is plotted in Figure A2-4; its volatility should be interpreted as a consequence of the small number of annual transactions rather than the action of market forces.

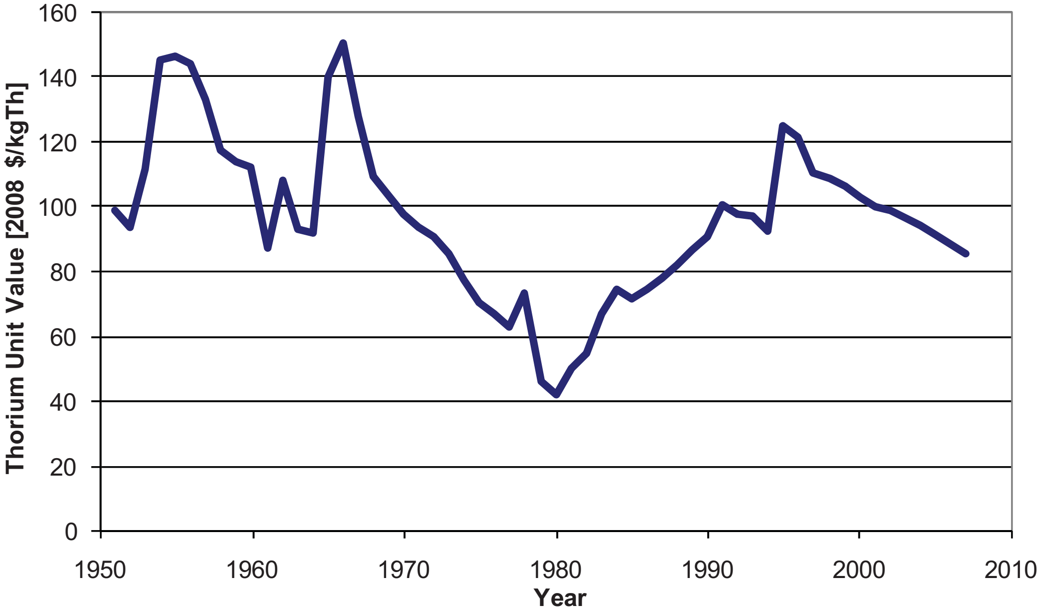

Figure A2-4. Thorium unit value, world mass-weighted average, 1952 to present, data in 1998 U.S. dollars (USGS 2008).

A noteworthy difference between a potential upper limit on thorium and uranium extraction costs arises from the relative concentrations of the two elements in seawater. Uranium is moderately soluble in water (3 ppb), so that its recovery from that host may ultimately become viable. The solubility of thorium is very low (0.05 ppb), so its extraction from seawater is not at all feasible.

A2-4.7 Secondary Supplies

By far the largest potential reservoir of easily accessible secondary thorium is tailings associated with milling operations where thorium was not taken up as a product. Approximately 25,000 $tThO_2$ are contained in residues resulting from the processing of monazite for rare earths recovery (Schapira 1999).

The U.S. Atomic Energy committee obtained several thousand metric tons of thorium nitrate in the 1950s and 1960s. The unused portion of this material was stored at the Defense National Stockpile Center depots in Maryland and Indiana. In the early 2000s, following a study that compared the costs of continuing to store the thorium, either as nitrate or in a more stable form, to the cost of disposal, the U.S. government decision to permanently dispose 3,200 metric tons of thorium by burying it at the Nevada Test Site. This operation, in which over 21,000 drums thorium nitrate were buried in pits sealed with over 20 feet of top cover, was completed in 2005 (Hermes and Terry 2007). This material is potentially retrievable.

A2-4.8 Consumption and Primary Supplies

Commercial use of thorium for incandescent lighting applications began as early as 1884. Thorium has since found limited application in selected non-energy uses tied to its electron density and the very high melting point of its ceramic oxide compounds. Employment of thorium as a chemical catalyst, as well as in welding electrodes (where it improves arc stability as compared to tungsten-only electrodes) and high-temperature ceramics, has declined as non-radioactive substitutes have come into widespread use. Thorium nitrate has historically been employed as a thermoluminescent material in camping lantern mantles but has largely been supplanted in this role by yttrium oxide. The USGS cites liability concerns, environmental monitoring regulations and disposal costs as forces driving industrial consumers toward acceptable non-radioactive substitutes to thorium (Kelly 2007).

Worldwide industrial consumption of thorium is therefore small and continues to decline. Apparent consumption, having averaged 50 t/yr from the mid 1970s through the early 1990s, dropped to around 10t/yr thereafter (Figure A2-5). These figures may do fully reflect thorium consumption in India where a small portion of primary thorium is converted to nitrate form for industrial use, but the remainder is added to a government-controlled stockpile. This stockpile—30,000 t of thorium concentrate—is being retained for use in its planned thorium-based fuel cycle (Kelly 2007).

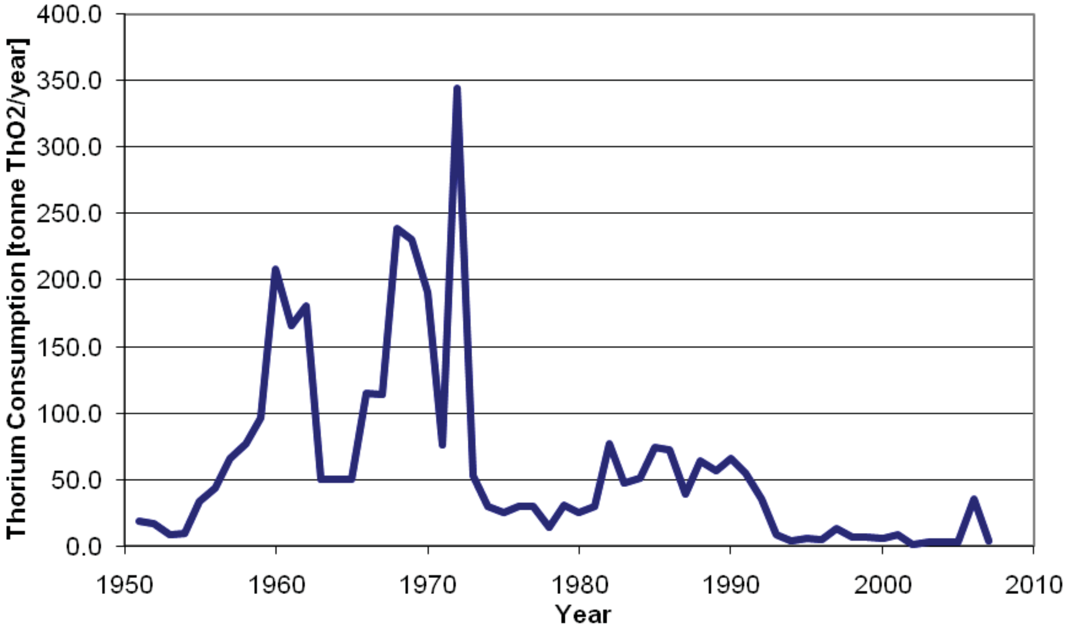

Figure A2-5. World thorium consumption, 1952 to present (USGS 2008).

No unified data set of world thorium production was produced after 1977 although it is known that thorium production declined sharply from the late 1970s. Indian Rare Earths Limited (IREL) is presently the largest producer of thorium through its rare earths production operations from beach sands at Chavara and Manavalakurichi (MK). MK produces around 3000 t/yr of monazite with a thorium content of approximately 200 t/yr. Indian output accounts for around 90% of world monazite production of around 6000 t/yr (IAEA 2006). The largest IREL thorium refinement facility, the Orissa Sands Complex (OSCOM), has a capacity of 240 t/yr $Th(NO_3)_4$ or 116 tTh/yr (IREL 2009). Outside of India, small amounts of thorium are produced only as by-product from monazite milling operations.

Figure A2-6 shows the primary thorium production data that is available. Note that production just between 1960 and 1977 substantially exceeded consumption from 1960 to the present. Production continues at the current time, notably in India; however, numerical data are not available. Instead, the dashed line illustrates a theoretical maximum thorium production rate of 450 t/yr. This figure was obtained by surmising that the full 6000 t/yr of monazite extracted annually (an average rate for 2005–2008, with an average thorium concentrate content of 7.5 w/o) were milled for thorium recovery. The true annual production is likely somewhat lower.

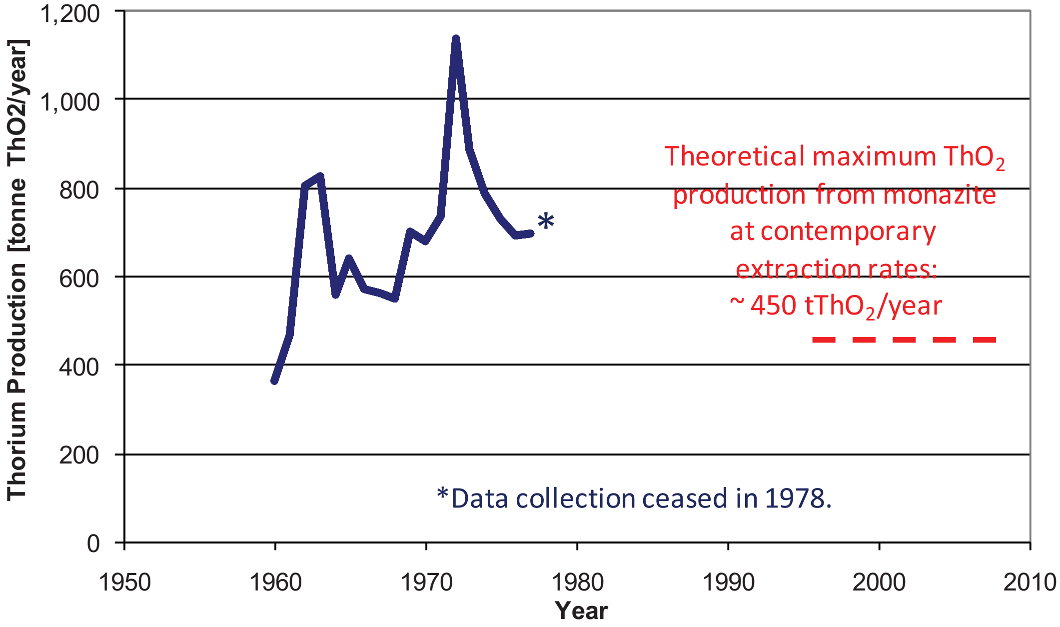

Figure A2-6. World primary thorium production (USGS 2008).

A2-5. LIMITATIONS OF COST DATA

Much of the data is based on speculation and intuitive evaluation of geologic data and speculation relative to the movement of future power markets versus demand. Many factors including actual cost of recovery, future regulatory impacts (both positive and negative), and especially the ultimate level of interest in thorium fuel cycles will affect the reliability of the information. The data best represent a “speculative supply” to an uncertain demand. As is the case with uranium and other minerals resources, it should be expected that a thorium industry will be susceptible to boom-bust cycles, shocks and other events that introduce both cyclical behavior and volatility in the market price. Yet the price of thorium in a mature industry would fluctuate in the vicinity of the long-run marginal cost of its production. The estimate presented in this module is intended to reflect that cost.

A2-6. COST SUMMARIES

Since there is no true market for thorium, investigators who have studied the economics of thorium-using fuel cycles have limited themselves ad hoc estimates of future thorium prices. No formal estimates of future thorium price dynamics or market behavior have been undertaken. Table A2-9 shows the thorium cost used in four system-level studies of thorium-based fuel cycles. These estimates all lie at or near the ceiling production cost for identified thorium resources quoted by the OECD/NEA-IAEA ($80/kgTh) and the prices quoted by the USGS for thorium of 99% or higher purity ($64–$164).

Table A2-9. Thorium cost used in previous thorium fuel cycle studies.

Source	Cost (U.S. $/kgTh)	Basis Year
(IAEA 2005)	50	2005
(Herring et al. 2001)	88.5	2000
(Bae, Kim 2005)	85	1994
(Wang 2003)	50	2003

It seems reasonable to postulate that $80/kgTh, the upper boundary of the OECD/NEA-IAEA production cost category for identified thorium resources, represents a reasonable near-term marginal production (mining plus milling) cost for Th as ThO_2. This may be thought of as a consensus estimate as it is in reasonable alignment with estimates from fuel cycle system analyses and USGS prices: the USGS-quoted prices for high-purity thorium are in fact somewhat higher than $80/kgTh, but this may be ascribed to the very small scale of the milling operations that support transactions on the order of less than 10 t/yr.

In Module A1, the marginal cost model presented in Section A1-6 was applied to provide a forecast of the evolution of the uranium resource production cost. Namely, it was proposed that future uranium price trends should not be expected to diverge from the experience of many other minerals over the past century. Using a statistical model derived from those mineral price histories, a very approximate projection of uranium price evolution over this century was presented. To do so, a starting point for the uranium price that roughly corresponds to a present-day marginal production cost was chosen. Beginning from that price in 2005, price evolutions corresponding to the mean and upper and lower confidence interval boundary values derived from 105 years of price data for other minerals were computed.

The thorium forecast depicted in Figure A2-7 follows this procedure for thorium but starts (in 2009) from a marginal cost of $80/kgTh. A time-averaged thorium price for this century, rounded to the nearest $5/kgTh, was computed for each of the three evolutions. These constitute the lower, nominal, and upper costs given in the What-It-Takes table in Section A2-6.1.

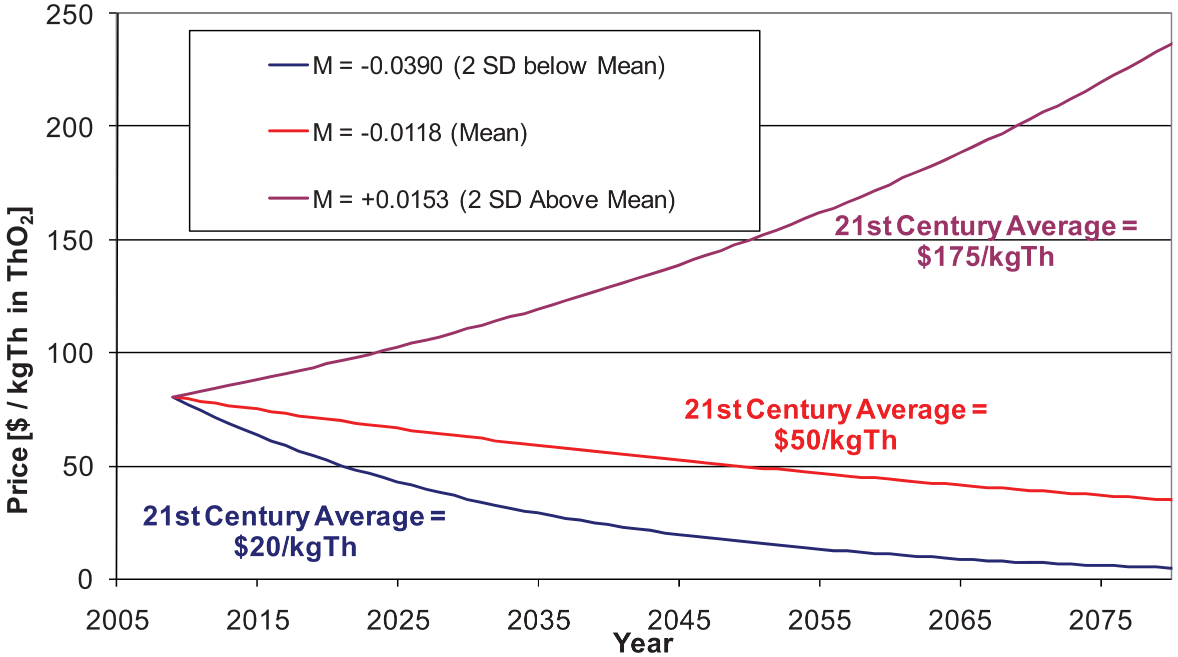

Figure A2-7. Upper bound (purple), most probable (red), and lower bound (blue) uranium price forecasts obtained from USGS mineral price model data.

A2-7. Thorium Production Cost and Price

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table A-10. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distribution based on the costs in the WIT table is shown in Figure A2-8. Note that the mean cost associated with this skewed distribution is $82/kgTh.

Table A-10. Cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$80/kgTh	NA	$20/kgTh	$175/kgTh	$50/kgTh
For Th as ThO_2 (99.9% purity)				

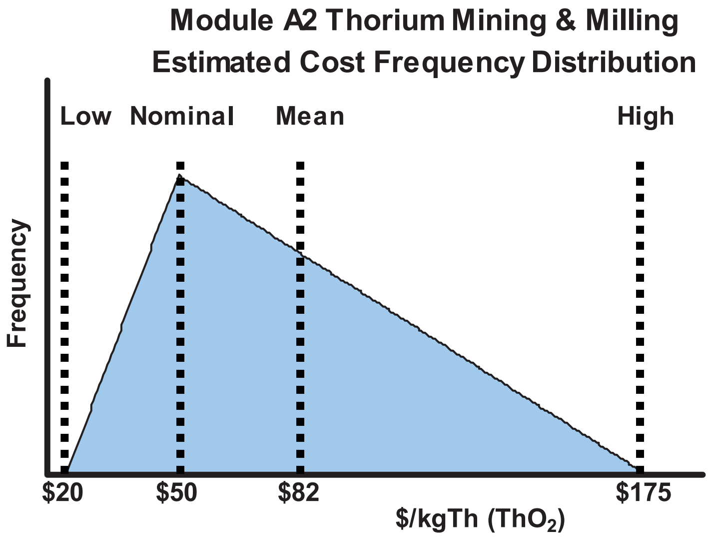

Figure A2-8. Thorium mining and milling estimated cost frequency distribution.

A2-8. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Thorium Cost Sensitivity. Thorium-based fuel cycles are expected to be less sensitive to the cost of their resource than is the case for present-day uranium cycles. While the unit cost of both metals is of the same order, since natural thorium contains no fissile species thorium cycles invariably feature multiple recycle or at least extensive in-situ U-233 breeding. The once-through uranium cycle currently fissions less than 1% of mined uranium; a fully-closed breeding-based thorium cycle, like the analogous uranium cycle, would eventually offer complete utilization of the resource. Even thorium cycles suitable for once-through, for instance those featuring direct disposal of heterogeneous seed-blanket fuel assemblies, would be insensitive to the cost of the thorium resource. Radkowsky Thorium Fuel and similar concepts, for example, would result in the fission of 8–10% of the thorium blanket fuel (Galperin, Radkowsky, Todosow 1999). It must be noted that these cycles rely on the presence of an enriched uranium or plutonium (as Pu/U/ThO_2 MOX) seed, although overall resource utilization efficiency (MWd/kg(NU+Th)) is comparable to current practice. Figure A2-9 shows annualized mass flows for a 3400 MWt PWR operating under the Radkowsky concept. The plutonium discharge is reduced by a factor of approximately six as compared to an energy equivalent quantity of conventional LEU fuel. Similarly, large reductions are seen in trans-plutonium species, and the bred-in LEU is mixed in-situ with the existing blanket uranium so that the discharged uranium mixture falls below IAEA limits.

It is important to note that this once-through cycle does not offer a marked uranium resource sustainability benefit; its separative work requirement is in fact somewhat higher than for an energy-equivalent LEU-only cycle. A fully-closed, breeding-based thorium cycle is quite feasible if U-233 is recovered. The three-stage Indian strategy for transitioning to such a cycle is shown in Figure A2-10. Stage 1, which is ongoing, involves conventional LWRs and HWRs. Some thorium oxide fuel is loaded and serves to flatten power profiles, but the predominant fuel is uranium. In Stage 2, sodium-cooled fast breeder reactors with thorium blankets utilize plutonium recovered from the LWRs and HWRs as driver fuel. U-233 from the fast reactors starts up the advanced heavy water reactors (AHWRs) of Stage 3. These operate with a breeding ratio of greater than unity, so that the fast reactors can eventually be phased out once sufficient U-233 inventory is attained. Therefore, this cycle ultimately draws upon only the thorium resource.

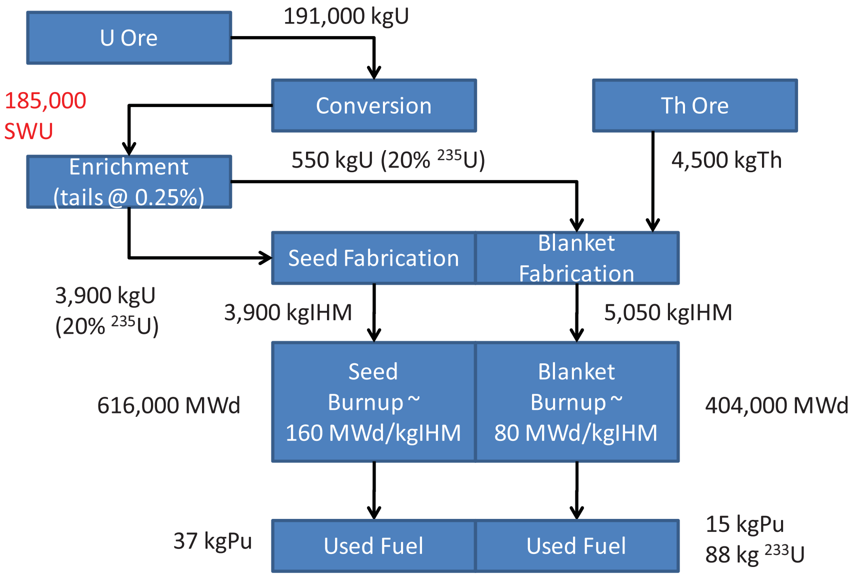

Figure A2-9. Annual mass flow chart for the once-through (Galperin, Radkowsky, Todosow 1999) concept in a 3400 MWt PWR.

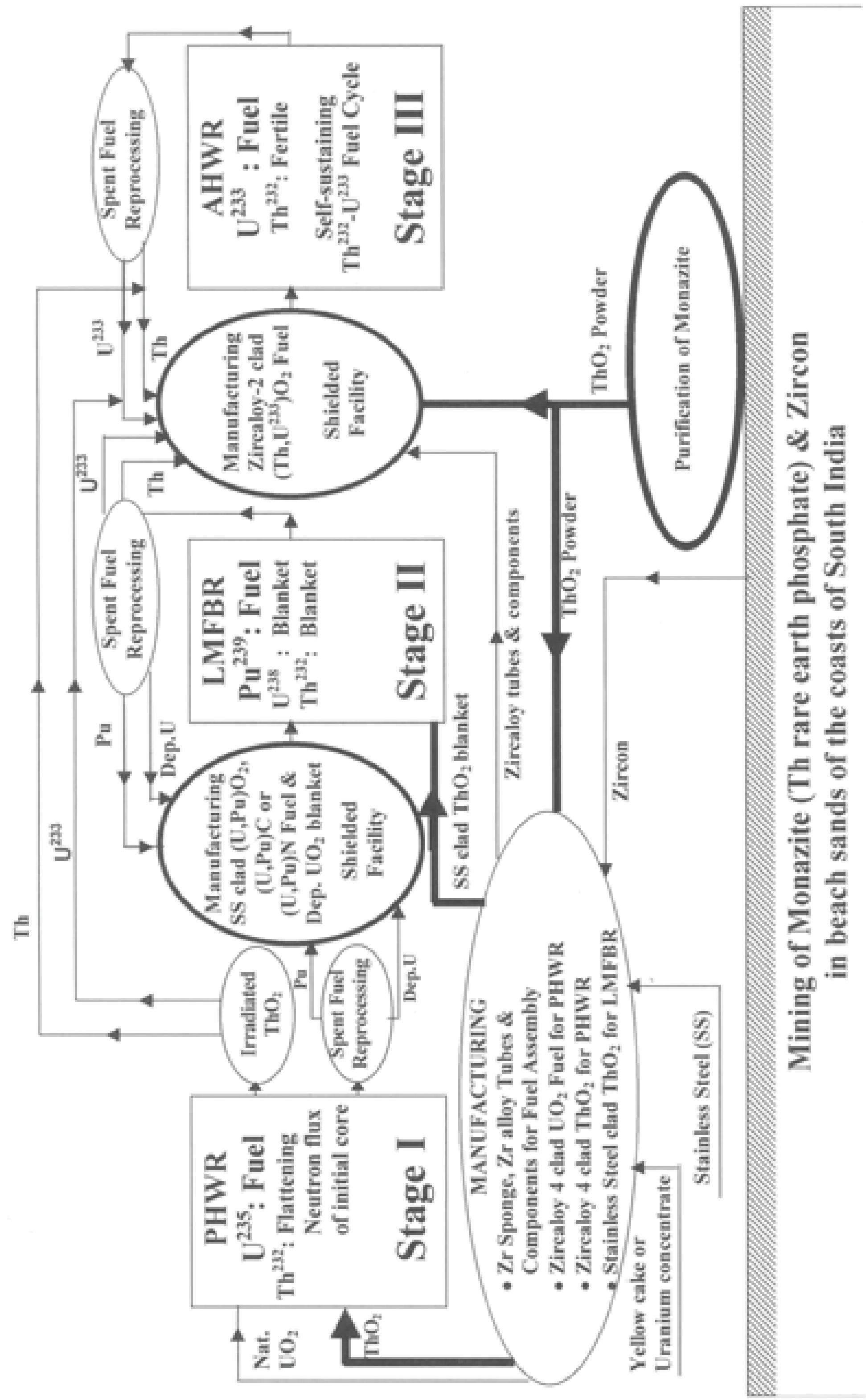

Figure A2-10. India’s three-stage path to a closed, breeding thorium cycle (IAEA 2005).

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Module B

Conversion

Module B

Conversion

B-1. BASIC INFORMATION

Module B discusses the step in the nuclear fuel cycle where the mined U_3O_8 concentrate is further purified and converted to a uranium hexafluoride (UF_6) solid in cylinders for feed to a uranium enrichment plant (Canaux 1997). It involves receipt of feed stock, chemical operations, and shipment of cylinders.

Conversion of the U_3O_8 yellow cake to UF_6 is driven basically by the need for purified uranium to enrich for fuel fabrication. The current U.S. annual demand for conversion is approximately 22,000 MTU. Worldwide, the demand for conversion is approximately 64,500 MTU per year, excluding Pakistan, India, and China. The major suppliers of conversion capability are BNFL/Cameco (United Kingdom), Cameco (Canada), Areva (France), ConverDyn (U.S.), and Rosatom (Russia). The Russian capacity is utilized internally and not available for export at this time.

The U.S. capacity resides in only one facility, Honeywell Specialty Chemicals, located in Metropolis, Illinois. The nominal 14,000 MTU/yr capacity is marketed by ConverDyn, a joint venture of Honeywell International and General Atomics. Because the U.S. demand of approximately 22,000 MTU/yr exceeds supply, the U.S. uses both domestic and foreign sources of conversion services. This facility has been in service since 1959 and ConverDyn plans to expand its capacity to 18000 MTU/yr by around 2013 (Steyn, Danilov 2008). A second conversion facility, the Sequoyah Fuels Corporation plant, was operated by General Atomics and located in Gore, Oklahoma. However, following numerous safety and environmental challenges, it was shut down in 1992 and is now undergoing decommissioning.

The cost of conversion represents only approximately 4% of the overall cost of fuel manufacture and is representative of a competitive market relative to cost of operations. Conversion cost is typically reported in U.S. dollars/kgU in the UF_6 product and includes related transportation costs to the enrichment plant.

B-2. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTION

Following formation of the U_3O_8 "yellow cake" at the mill, the uranium must be further purified and enriched as necessary for use as a reactor fuel. The chemical and physical form of the conversion product depends on the subsequent use of the product. If enrichment is not required, the yellow cake can be processed directly to UO_2 for fuel fabrication. In the more common case, enrichment of the ^{235}U is desired, and the yellow cake is converted to a purified UF_6 gas suitable for subsequent enrichment operations. The "conversion" to UF_6 is achieved using either a wet or dry chemical process.

The basic steps of a dry process are as follows. The yellow cake is ground into a fine powder and fed into a fluidized bed reactor at 1,000–1,200°F where it is reduced by hydrogen and emerges as uranium dioxide (UO_2). The crude UO_2 is passed through two successive hydrofluorination fluidized bed reactors, where interaction occurs with anhydrous hydrogen fluoride (HF) at a temperature of 900–1,000°F. Uranium tetrafluoride (UF_4), a green salt, is formed which is a nonvolatile solid with a very high melting point. The UF_4 is treated at high temperatures with fluorine gas to form UF_6 gas. Volatile impurities are removed at several steps in this process, leaving a uranium product that is at least 99.95% pure (see Figure B-1).

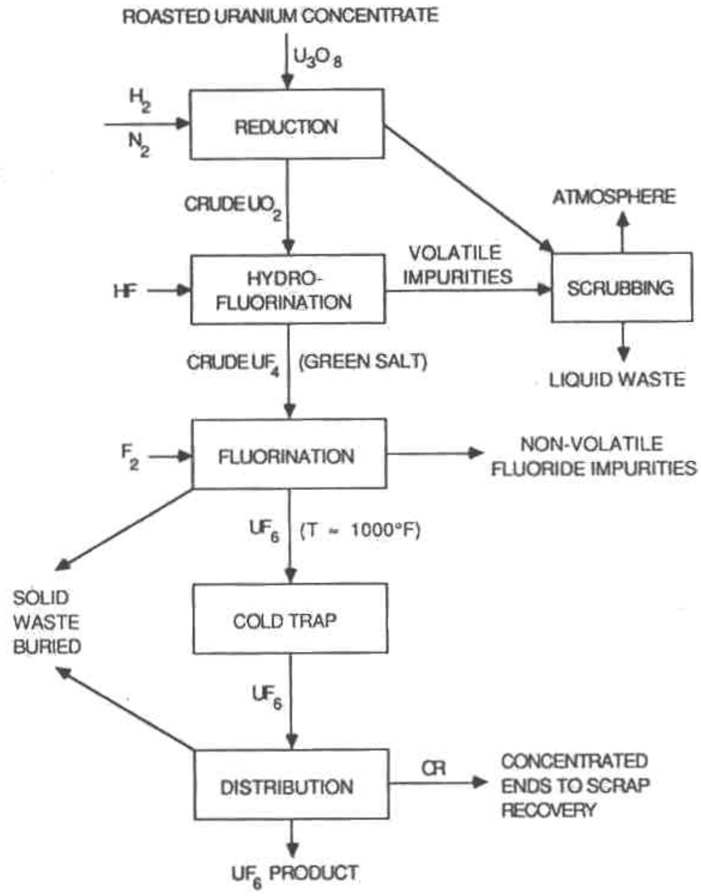

Figure B-1. Simplified flow chart of the dry hydrofluorination process to convert U_3O_8 to UF_6.

The basic steps of a wet process are similar to the dry process, but the yellow cake is initially dissolved in nitric acid and goes through a solvent extraction process to remove impurities. The extraction is followed by the hydrogen-reducing furnace as well as the hydrofluorination and the fluorination steps to again produce a very pure UF_6 gas (see Figure B-2).

With both processes, the UF_6 gas is distilled to remove the light fraction gases, pressurized, and cooled into a liquid. In the liquid state, it is drained into 14-ton mild steel cylinders where it solidifies after cooling for approximately 5 days. The UF_6 is a solid at room temperatures, which makes it easy to handle and ship. At a slightly elevated temperature above the triple point (~147°F), it becomes a gas, which makes it ideal for current enrichment technologies. As future enrichment technologies develop, the needed chemical and physical form of the conversion product could change (Varley 1997). Physical losses are small (<0.5%).

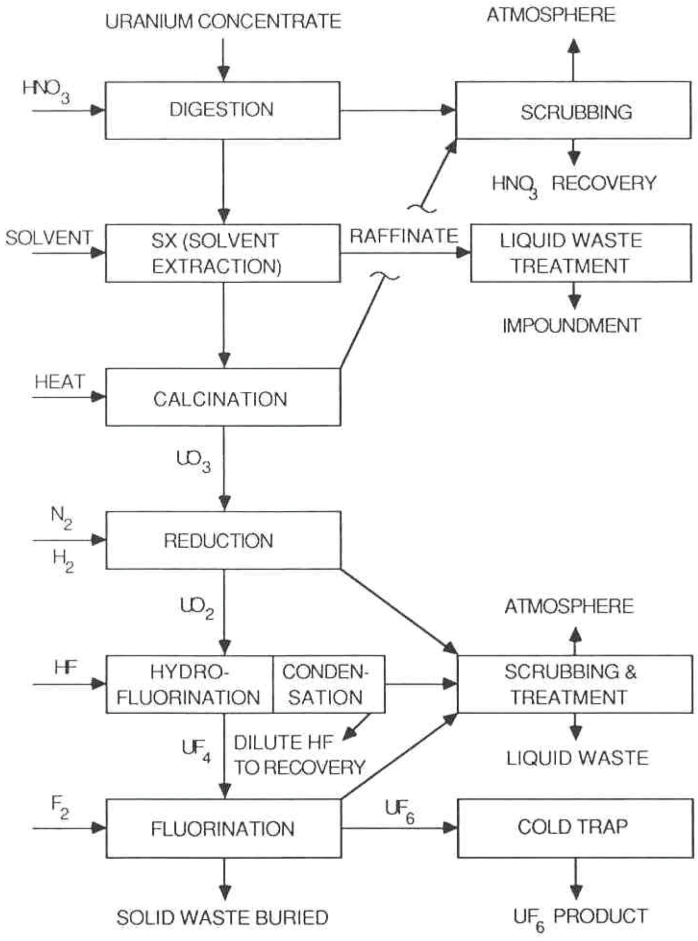

Figure B-2. Flow chart of the wet solvent extraction-fluorination process to convert U_3O_8 to UF_6.

B-3. PICTURES/SCHEMATICS

Cameco is an integrated uranium fuel supplier with fuel services facilities (conversion and fuel fabrication) at Port Hope, located in Ontario, Canada. (The company's Port Hope conversion services plants chemically change the form of the [UO_3] to either uranium hexafluoride [UF_6] or uranium dioxide [UO_2]). During 2006, Cameco became a nuclear fuel manufacturer by acquiring Zircatec Precision Industries, Inc. (Zircatec) in Port Hope. Zircatec manufactures fuel bundles for use in Canada deuterium uranium (CANDU) reactors. Pictures of the conversion facility are shown in Figures B-3 and B-4. A loaded UF_6 cylinder is shown in Figure B-5.

Figure B-3. Port Hope Conversion and Fuel Fabrication Plant (Cameco) in Ontario, Canada.

Figure B-4. Port Hope conversion facility.

Figure B-5. Loaded UF_6 cylinder at Port Hope.

B-4. MODULE INTERFACE DEFINITION

The need for conversion services is highly dependent on Modules A, C1, C2, D1, F2/D2, and K, which essentially define the supply and demand relationship. Raw uranium pricing impacts the source uranium cost of conversion. The availability of mixed oxide, reprocessed uranium, and/or blend down of highly enriched uranium (HEU) impacts demand for enrichment services from UF_6. Timing of fuel fabrication also impacts the need for conversion services. In addition to real-time feed and product needs, decisions relative to inventory levels along the front-end of the fuel cycle will have impact on this conversion module.

The key dependencies on supply and demand as impact costs are discussed in the following subsections.

B-4.1 Supply and Demand

The United States has only one operating plant for uranium conversion services. The plant, Honeywell Specialty Chemicals is located in Metropolis, Illinois, across the Ohio River from the Paducah, Kentucky, enrichment plant. It is owned by Honeywell International Corporation, based in Minneapolis, Minnesota. ConverDyn, a general partnership created by affiliates of Honeywell and General Atomics, markets the UF_6 conversion services, a key step in the nuclear fuel cycle, to the worldwide electric utility industry (UXC 2005). An upgrade completed in 2001 increased the nominal capacity of the facility from 12,700 MTU per year to its present level of 14,000 MTU per year. It uses the dry fluoride volatility process described above. On May 15, 2007, ConverDyn received a license from the U.S. Nuclear Regulatory Commission to continue operating the Metropolis Works through 2017.

Table B-1 shows the worldwide commercial-scale capacity as reported by the World Nuclear Association for UF_6 product (WNA 2009) ConverDyn appears to be considering adding capacity at Metropolis Works; Jim Graham, ConverDyn's president and CEO was quoted in 2004 as saying that the company was considering adding 5,000 MTU/year of capacity around 2010 (Nuclear Energy Institute 2004). However, given that the company has issued no official statements to this effect, it must be assumed that such a move, at most, is still in the planning stages.

Table B-1. World conversion nameplate capacity.[a]

Company (Country)	Nameplate Capacity, 2007 Million kgU
BNFL/Cameco (UK)	5.0*
Cameco (Canada)	14.26
CNNC (China)	1.0
Areva (France)	16.5
ConverDyn (USA)	14.0
Atomenergoprom (Russia)	17.76
Total	68.52

Cameco has purchased all capacity at the BNFL Springfields plant. Springfields is slated for shutdown in 2015.

The Russian conversion plants are tightly integrated to their enrichment plants and do not export their product on the Western market. On February 9, 2001, BNFL announced their intent to halt UF_6 production in 2006 and had ceased marketing of UF_6 conversion services. However, in March 2005, a 10-year agreement was reached between Cameco and BNFL to acquire uranium conversion services at a base quantity of 5 million kg of uranium (UO_3) to UF_6 per year for the duration of the contract. Discounting Russia, the world demand is essentially filled by the U.S., French, and Canadian plants. While the capacity of these Western suppliers is adequate in the short term, there is obviously uncertainty about future adequacy when the primary uranium supply begins to increase as is suggested by projected growth in nuclear power (Varley 1997).

Obviously new conversion capability will be required although there has not been a new commercial facility for UF_6 production built since 1984. That has been because the availability of secondary supplies of uranium, such as HEU blend-down and mixed oxide, has filled the difference between supply and demand for uranium to produce reactor fuel. Unlike facilities in Russia, the U.S. conversion facilities did not have the capability to convert HEU metal or oxide into UF_6. The U.S. converts the HEU into uranyl nitrate hexahydrate (UNH) with the blended UNH going to fuel fabricators where it is converted to uranium oxide powder. Whether there will be new capacity built or expansion of existing capacities will be driven by market analysis. However, there does not appear to be a new technology in the horizon that will have a significant impact on the cost of conversion, and thus, new capacity is a matter of providing supply to meet the market demand.

Plans for new conversion plants in France, Kazakhstan, and Australia have been announced. In May 2007, Areva declared the launch of a 15,000 MTU facility, Comurhex II, to be built at Malvesi, the site of its existing 14,500 MTU plant. Comurhex II, slated to open in 2012 at a cost of $820M, could be increased in capacity to up to 21,000 MTU/year if demand increases (World Nuclear News 2007a). It is unclear if or when Areva's existing facility would be retired. Also in May 2007, Cameco and the Kazakh state-owned nuclear fuel corporation, Kazatomprom, signed a memorandum of understanding to study the feasibility of constructing a conversion plant at or near the site of the Inkai mine. This proposed facility, like the Inkai mine itself, would be a joint venture between the two firms (Mining Weekly 2007). In June 2008 the joint venture announced that the Ulba plant would have a capacity of 12,000 MTU/year and may start up in the 2014 time frame (Steyn, Danilov 2008). Discussions in Australia regarding construction of conversion as well as enrichment capacity have not, as of July 2007, moved past the study phase. A report prepared by the firm Nuclear Fuel Australia Ltd. (NFAL) envisaged a conversion facility supplying UF_6 to a collocated 3 million separative work units (SWU)/year enrichment plant. Construction was proposed to begin in 2010 with the plants becoming operational in 2015. NFAL estimated the costs of these facilities at $420M (U.S.) for the conversion plant and $1.68B for the enrichment facility (World Nuclear News 2007b).

Figure B-6 indicates the relationship of the various types of equivalent UF_6 supply relative to the projected source. The graph implies growth in capacity in those areas of the world where demand is expected to grow the most. Note that Figure B-6 does not reflect the very recent developments described above; if all of these came to fruition and no existing capacity were retired, a considerable oversupply of conversion services could exist over the medium term.

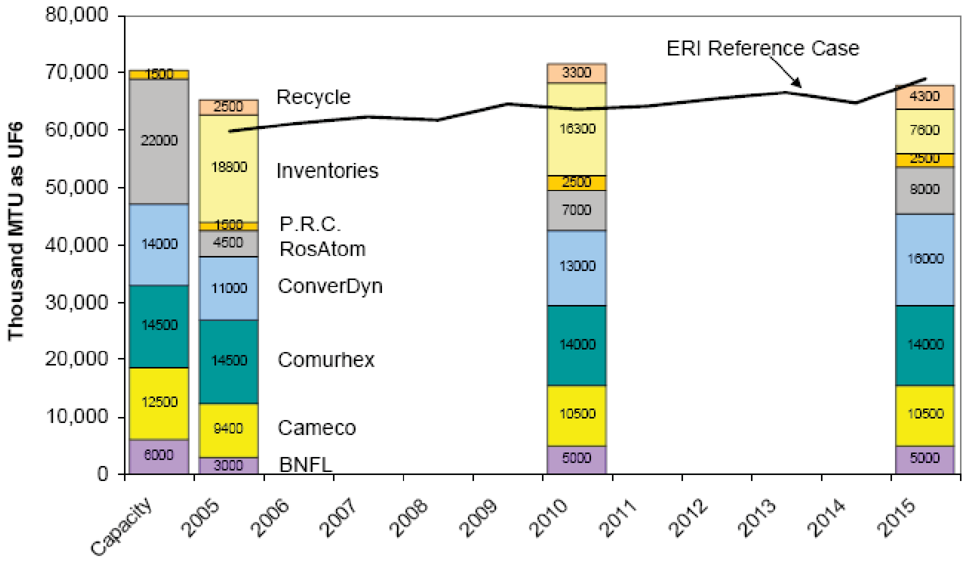

Figure B-6. Conversion capacities and production forecasts as projected by Energy Resources International (Energy Resources International 2006).

B-5. MODULE SCALING FACTORS

Scale-up is not an issue for application of mature technology. Additional capacity can be added via expansion of existing facilities or new capacity. Location relative to enrichers within a continent is of importance because shipping UF_6 overseas adds cost, requires additional time, and thus more in-pipeline inventory.

B-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

B-6.1 Conversion Pricing and Forecasts

Over the past 15 years, the long-term, U.S. spot, and European spot prices for conversion services (UF_6) have converged as the market has been dominated by excess primary supply. Reductions in inventories, introduction of HEU, as well as use of mixed oxide fuels and reprocessed uranium reduced the need for conversion services and created a very competitive market. Utility buyers took advantage of the opportunity and prices were driven well below the historical trends. The current well-publicized spot market provides some indication of the relative stability of the conversion pricing. Presently, the spot and term prices are close and are expected to again return to values in the \$6–8/kgU range as was experienced up to the mid-1990s (see Figures B-7 and B-8). It should be noted that, in contrast to natural uranium and SWU, most conversion price indices, including that depicted in Figure B-7, reflect both spot and base-escalated long-term contract prices.

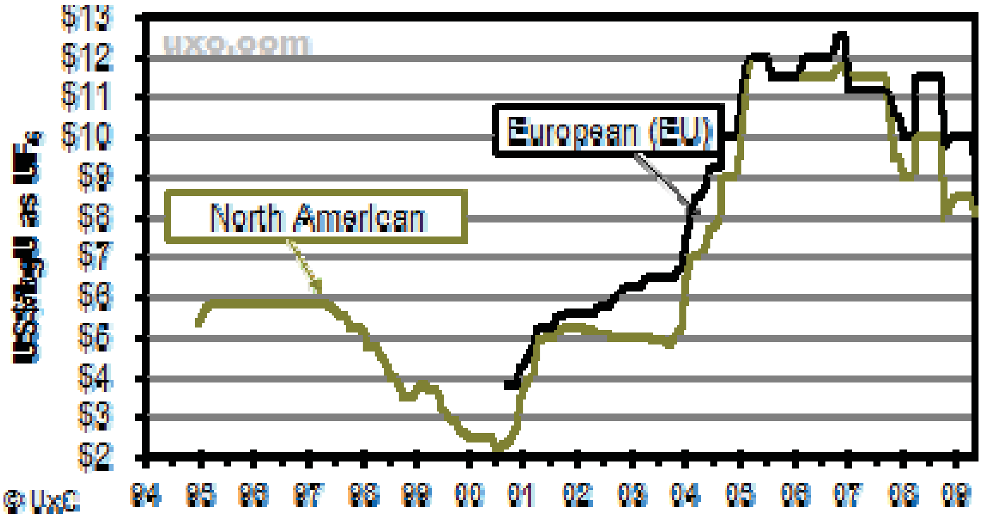

Figure B-7. Ux conversion spot prices (UXC 2009).

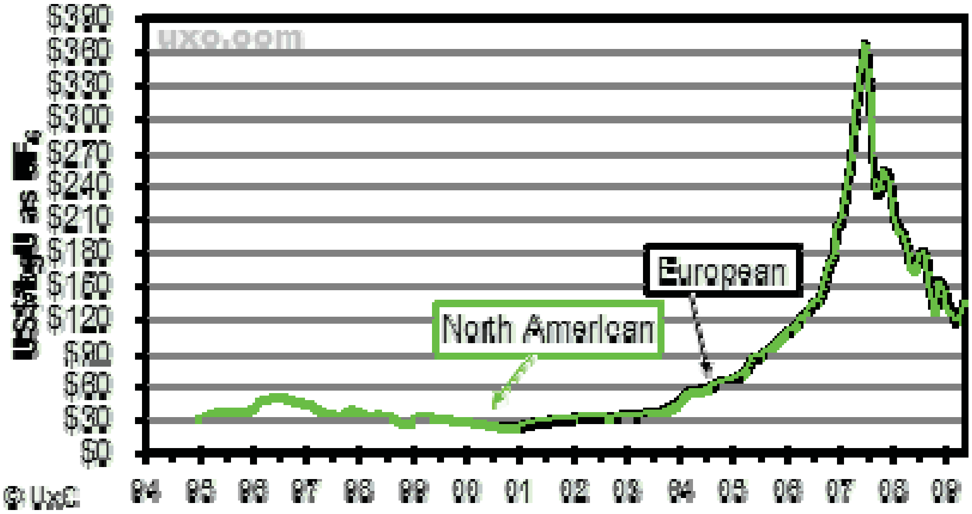

Figure B-8. Ux UF_6 spot values (UXC 2009).

The strong drop from 1997 through 2000 reflected the influx of Russian HEU into the Western market through USEC, creating an oversupply of UF_6. The increase beginning in 2003 reflects a number of factors, chiefly the need to increase supply from natural uranium as utility and producer UF_6 stockpiles have been largely drawn down. In addition, a significant supply interruption took place at the Metropolis Works. This facility was forced offline by process leaks and was offline for most of the period September 2003–April 2004. More than a year followed before the plant was again operating at nearly full capacity. Also in November 2003, Techsnabexport (Tenex) announced that it would no longer sell its excess UF_6 resulting from the U.S.-Russian agreement to down blend HEU to LEU. Beginning in 2008, the excess will be returned to Russia to meet internal demand. This will create a need to replace that availability from additional conversion services, which in turn will likely help to maintain current elevated conversion prices until the market supply and demand become more closely matched. Alternatively, a substantial portion of the DOE-held surplus uranium inventory—46,000 of 58,000 MTU— is already in hexafluoride form. If DOE moves forward on releasing this inventory to the market at a rate of about 2 MTU/year as is planned, some of the pressure on suppliers may be relieved. In any case, the conversion services market today reflects substantially lower prices than was the case 25 years ago, only about 1/2 of the mid-1970s prices in real terms.

Recent studies by Harvard University, Massachusetts Institute of Technology, and Atomic Energy Commission-Nuclear Energy Agency (CEA-NEA) suggest a range of $4–8/kgU is reasonable for evaluation of conversion services (Nuclear Energy Agency 1994; Bunn et al. 2007; Deutch et al. 2003). This is based on the adequacy of secondary supplies for uranium and an expected leveling of inventory management. Figure B-8 shows the pot market price for UF_6, which reflects the average U_3O_8 price plus a spread of $4–15 for conversion. At present, secondary supplies ensure that primary uranium requirements (tU as U_3O_8/yr) are not equal to UF_6 conversion requirements (tU as UF_6/yr). HEU downblend by the U.S. and Russia is one such source. This and the release of DOE-held UF_6 will play a role in UF_6 price evolution. Agreements between the countries control and limit the amount to be placed in to the supply chain. DOE has stated that it will not release UF_6 in amounts greater than 10% of annual domestic demand, so the dramatic drop in price experienced in the late 1990s should be avoided. The recent upturn in U as UF_6 price reflects mainly the increase in uranium pricing versus a significant impact from conversion services.

B-6.2 Assumptions

Should the demand for natural uranium begin to grow quickly, in the short term the price for conversion could increase. However, as uranium and UF_6 prices go up, the use of more separative work units to drive to a lower enrichment tail becomes a check and balance on longer-term price growth. Also as the uranium price goes up, the attractiveness of reprocessed uranium for reenrichment increases—again, a check on conversion prices.

B-7. LIMITATIONS OF COST DATA

Real time costs are not reported for Russia and the other Commonwealth of Independent States countries. Most countries are beginning to take a proprietary view of long-term contract costs with reporting becoming less prevalent. Modelers and forecasters must view the total uranium supply picture and use the spot market trends as the feedback tool. Real time costs are relatively low initially, which represents typically less than 4% of the fuel cost. Short-term fluctuations should have little to no impact on the overall fuel cycle costs.

B-7.1 Cost Summaries

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table B-2. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table. The triangular distribution based on the costs in the WIT table is shown in Figure B-9.

This distribution is uniform, with every price between the lower and upper limits being forecast as equally likely to occur (see Figure B-9). See Section B-8 for discussion.

Table B-2. Cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
\$8/kgU as UF_6	+/- \$2	\$5/kgU as UF_6	\$15/kgU as UF_6	\$10/kgU as UF_6
Reflects a competitive and mature market at a world capacity of ~58,000 MTU/yr		Upside potential exists only when capacity exceeds supply. This is not expected in the long term.	A rapid growth in nuclear reactors would spawn growth for additional conversion capacity. The extent to which capacity growth lags demand could drive interim pricing for conversion much higher.	Selected value is judgment vs. current pricing during a time of much market excitement, but no maturity.

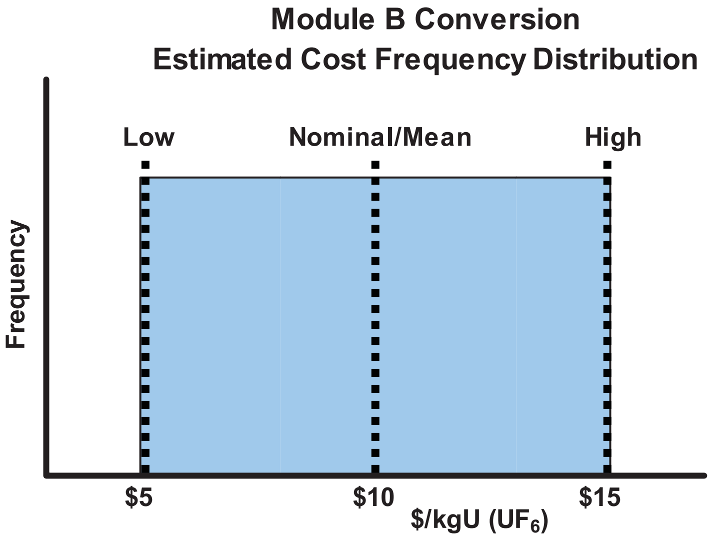

Figure B-8. Conversion estimated cost frequency distribution.

B-8. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Prior studies have highlighted the relative insensitivity of conversion cost to the overall fuel cycle as the conversion cost represents generally less than 4% of the fuel cost. The impact of doubling the price impacts the cost by only a few percent.

Figure B-10 is a histogram of monthly conversion prices on the spot market as reported by Ux Consulting, LLC. This data has been adjusted for inflation using the CPI and extends back to January 1981. It shows that prices have varied considerably, from a low of around $2.50/kgU in 1983 and again in 2000 to a high of nearly $13/kgU in 2005. This trend of variability, with prices varying by a factor of three or more over the time period for which data is available, is not atypical of market-driven prices for front-end services. Given the historically wide variation in conversion prices, then, a rectangular rather than triangular distribution is chosen for the cost distribution proposed in this module.

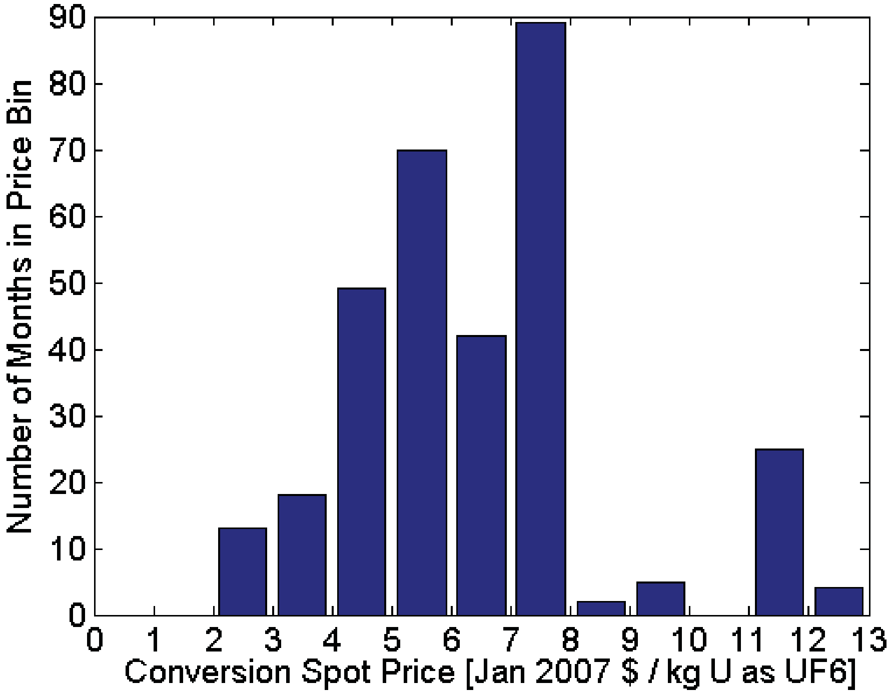

Figure B-10. Histogram of monthly conversion spot price.

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Module C1

Enrichment

Module C1

Enrichment

C1-1. BASIC INFORMATION

The authors recognize that uranium and enrichment spot prices have recently exceeded the high-cost range provided in this cost basis. These price trends are being evaluated and the cost ranges in the report will be revised as appropriate in future updates. The cost basis reflects reasonable expectations about uranium and enrichment long-term contract prices applicable to reactors with long operating lives, rather than reflecting market spikes as experienced in the 1970s and observed in the spot market U_3O_8 prices circa 2005.

Module C1 discusses the step in the nuclear fuel cycle where the UF_6 solid in cylinders from the conversion plant is processed to enrich the percentage of U-235 from 0.711% to the 3–5% typical of the enrichment used for light-water reactor nuclear fuel fabrication. It involves receipt of UF_6 feed stock in 12.5-ton cylinders, enrichment operations, formation of enriched UF_6 solid, and shipment of 2.3-ton cylinders to fuel fabricators.

The degree of enrichment is driven by the specific reactor requirements (pressurized or boiling water reactors) to meet desired burnup as well as other factors such as use of mixed oxide fuel or reprocessed uranium. The product from the enrichment plant is called low-enriched uranium (LEU) if the enrichment is less than or equal to 20% U-235. At present, licensing constraints restrict the enrichment of LEU for civilian reactors to 5%. The product is highly enriched uranium (HEU) if the enrichment is greater than 20%. HEU was produced in support of nuclear weapons programs and is currently used in some research reactors. During the enrichment process, the U-235 in the UF_6 is enriched from its natural state of 0.711% to the desired end state (3–5%). The by-product of the enrichment process is a large quantity of depleted uranium whose U-235 content is less than 0.711%. This material is known as the enrichment “tails” and typically has an assay in the range of 0.25 to 0.35% U-235. Such material is stable and is currently stored at the enrichment sites for future use because it does have a significant fissile material loading.

The basic enrichment market deals with supply of LEU. LEU can be supplied to the fuel manufacturer as a product of an enrichment process or by virtue of “down-blending” HEU with natural uranium or LEU. The overall demand can be satisfied by either or both of these methods. See Module C2 for details of HEU supply from military stockpile reductions.

The current U.S. annual demand for LEU is approximately 21,500 tU. Worldwide, the demand for LEU is approximately 66,700 tU per year. The capacity of enrichment plants is measured in terms of “separative work units” (SWU or kg SWU). A SWU represents a quantity of separative work performed to enrich a given amount of uranium by a certain amount. It is a function of the amount of uranium processed, the degree to which it is enriched, as well as the level of depletion of the remaining tails. It is proportional to the amount of work required to move the gaseous uranium through the separation cascade. As an example, 3.8 SWUs are required to produce 1 kg of uranium enriched to 3% U-235 if the plant is operated to a tails assay of 0.25% or 5.0 SWUs are required if the plant is operated to a tails assay of 0.15%. With the lower tails assay, more SWUs are required; however, only 5.1 kg of natural uranium feedstock are required versus 6.0 kg for the higher assay. Therefore, SWU demand is established by the utilities looking at all aspects of the fuel cycle to determine how to best meet the reactor burn requirements. About 100–120 thousand SWUs are required to enrich the annual fuel loading for a typical 1,000 MWe light-water reactor.

The current worldwide enrichment requirements are about 39,000 million SWUs of which the U.S. demand is approximately 11,800 million SWUs. Although there are 21 enrichment facilities in operation, the world supply is dominated by four companies:

1. Eurodiff (France)
2. Minatom (Russia)
3. URENCO (Germany, Netherlands, United Kingdom)
4. United States Enrichment Corporation (USEC) in the U.S.

The current world enrichment nameplate capacity is about 49.25 million SWUs. Thus an overcapacity exists. The current U.S. capacity of 11.3 million SWUs exists in one facility at Paducah, Kentucky. A second unit located in Portsmouth, Ohio, with an additional capacity of 7.4 million SWUs was placed in cold standby in March 2001.

The cost of enrichment represents ~30–40% of the overall cost of fuel manufacture. Enrichment services are highly competitive due to overcapacity and availability of LEU from blend-down of HEU (see Module C2). Enrichment cost is typically reported in U.S.$/SWU and includes related transportation costs to the fuel fabrication plant.

C1-2. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTION

Globally, uranium is enriched on a commercial scale by one of two methods: gaseous diffusion and gas centrifugation. All operating uranium enrichment plants use UF_6 as feed (historically, uranium tetrachloride was used in some electromagnetic separation processes). The processes depend on the physical properties of the molecules, specifically the 1% difference in mass, to separate the isotopes of U-235 and U-238. The use of UF_6 is preferred because fluorine has only one stable isotope, and thus, the difference in processing is entirely due to the properties of the uranium isotopes. There are other methods such as laser isotopic enrichment and aerodynamic enrichment using separation nozzles and/or vortex tubes, but these are not commercially viable at this time. Worldwide gaseous diffusion (mainly in the U.S. and France) currently represents about 40% of capacity, with more recent facilities using the more cost-effective gas centrifuge process. The gaseous diffusion plants have been durable and reliable, but are nearing the end of their design life with the focus on advanced centrifuge technology to replace this aging capacity. Table C1-1 shows that, with the retirement of diffusion-based facilities in France and the United States over the next decade, gas centrifuge plants will dominate the next generation of enrichment capacity.

Table C1-1. SWU or SWU equivalent market share by supply source (WNA 2009).

Supply Source	2007	2017
Diffusion	25%	0
Centrifuge	65%	93%
Laser	0%	3%
HEU Downblend[a]	10%	4%

a. SWU equivalent: derived from amount and enrichment of LEU produced via HEU downblending.

Both gaseous diffusion and gas centrifugation begin with receipt of 12.5-t cylinders of solid UF_6 under a slight vacuum. The UF_6, when heated above 135°F, becomes a gas and is the ideal feed for the two main commercial scale processes, which are described below.

Gaseous Diffusion. The gaseous diffusion process has been highly developed and used to produce both HEU and commercial reactor-grade LEU. The U.S. first employed gaseous diffusion during World War II and expanded its capacity after the war to produce HEU. Since the late 1960s, the U.S. facilities have been used primarily to produce commercial LEU, with the last remaining HEU capacity being shut down in 1992. China and France currently have operating diffusion plants. Russia's enrichment facilities have been converted from diffusion to centrifuge technology. Britain's diffusion facility was shut down and dismantled (Federation of American Scientists 2000).

The gaseous-diffusion process depends on the separation effect arising from the difference in rate of molecular effusion of the UF_6 isotopes through a thin barrier (i.e., the flow of gas through small holes). The frequency at which the different species pass through the tiny hole in the barrier is proportional to the speed of the molecule and inversely proportional to the square root of the molecular weight. On the average, lighter gas molecules travel faster than heavier gas molecules and, consequently, tend to collide more often with the porous barrier material. Therefore, lighter molecules are more likely to enter the barrier pores than are heavier molecules. For UF_6, the difference in velocities between molecules containing U-235 and U-238 is small (0.4%). Consequently, the amount of separation achieved by a single stage of gaseous diffusion is small. Therefore, this process must be repeated in approximately 1,400 stages in a single cascade to achieve even LEU assays of 2.5 to 5%. The higher the desired enrichment, the more stages and recycle are required to get the desired product.

UF_6 is a solid at room temperature but becomes a gas when heated above 135°F. The solid UF_6 is heated to form a gas, and the gaseous diffusion enrichment process begins. The process separates the lighter U-235 isotopes from the heavier U-238. The gas is forced by a compressor through a diffusion cell consisting of a porous membrane with microscopic openings. Because the U-235 atoms are lighter, they have a slightly higher probability of reaching and passing through the membrane. As the gas moves, the two isotopes are separated, increasing the U-235 concentration and decreasing the concentration of U-238. Approximately 50% of the feed material passes through the membrane and is pumped off as lightly enriched product. The remaining material flows past the membrane, containing less U-235 and thus is slightly depleted. Passing through the membrane causes a pressure drop. After each stage, the gas must be depressurized, and the heat of compression must be removed (see Figures C1-1 and C1-2).

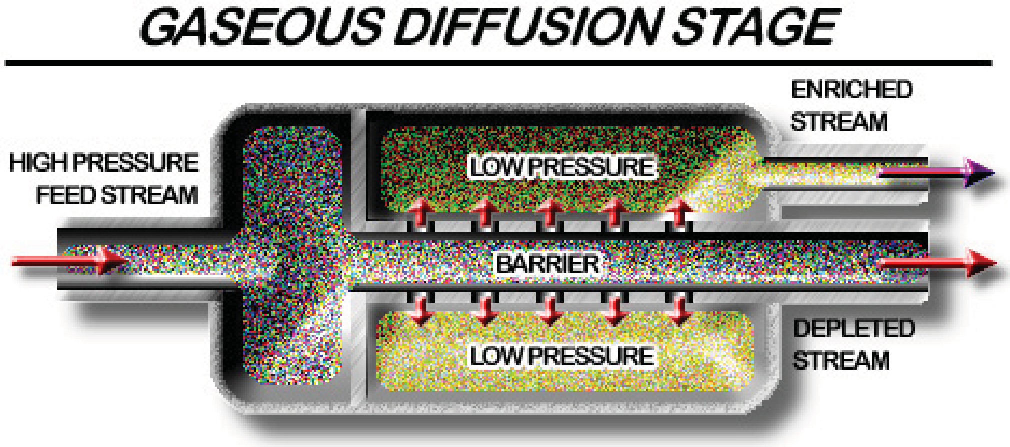

Figure C1-1. Gaseous diffusion stage (Federation of American Scientists 2009).

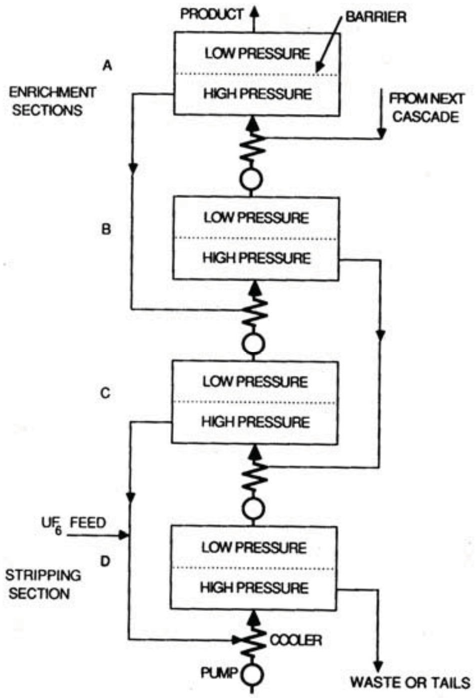

Figure C1-2. Gas must be depressurized, and the heat of compression must be removed.

Figure C1-3 shows a typical gaseous diffusion cascade for enriching and stripping.

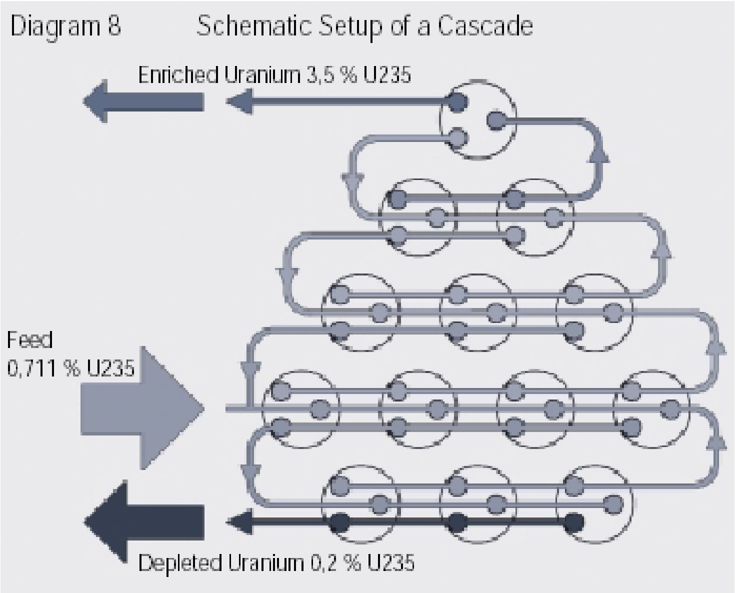

Figure C1-3. Gaseous diffusion cascade for enriching and stripping.

Diffusion equipment tends to be large and consumes significant amounts of energy. The main components of a single gaseous-diffusion stage are (1) a large cylindrical vessel, called a diffuser or converter, that contains the barrier; (2) a compressor used to compress the gas to the pressures needed for flow through the barrier; (3) an electric motor to drive the compressor; (4) a heat exchanger to remove the heat of compression; and (5) piping and valves for stage and interstage connections and process control.

The entire system must be essentially leak free, and the compressors require special seals to prevent both out-leakage of UF_6 and in-leakage of air. In addition to the stage equipment, auxiliary facilities for a gaseous-diffusion plant include a large electrical power distribution system, cooling towers to dissipate the waste process heat, a fluorination facility, a steam plant, a barrier production plant, and a plant to produce dry air and nitrogen. The process is energy intensive requiring over 2,500 kWh/SWU. A gas diffusion plant uses approximately 4% of the energy that can be generated with its enriched uranium.

At the end of the process, the enriched UF_6 gas is withdrawn from the pipelines and condensed back into a liquid that is poured into containers. The UF_6 is then allowed to cool and solidify in 2.3-t cylinders before it is transported to fuel fabrication facilities where it is turned into fuel assemblies for nuclear power reactors.

Gas Centrifuge. The gas centrifuge uranium enrichment process uses a large number of rotating cylinders in a sequence. These sequences of centrifuge machines, called trains, are interconnected to form cascades. Gaseous UF_6 is fed into a cylindrical rotor that spins at high speed inside an evacuated casing. Because the rotor spins very rapidly, centrifugal force results in the gas occupying only a thin layer next to the rotor wall, with the gas moving at approximately the speed of the wall. The centripetal forces induced by the circular motion of the gases (about a million times the gravitational force on the gas) also causes the heavier $^{238}UF_6$ molecules to tend to move closer to the outer wall than the lighter $^{235}UF_6$ molecules, thus partially separating the uranium isotopes. This separation is increased by a relatively slow axial countercurrent flow of gas within the centrifuge that concentrates enriched gas at one end and depleted gas at the other. UF_6 depleted of U-235 flows upward adjacent to the rotor wall, while the UF_6 enriched in U-235 flows downward closer to the axis. The two gas streams are continuously removed through small pipes. The separative capacity of a single centrifuge increases with the length and radius of the rotor and the rotor wall speed. Consequently, centrifuges containing long, high-speed rotors are the goal of centrifuge development programs.

The primary constraint upon further enhancement of the separation factor achievable in a single centrifuge unit is imposed by the rotor material. Specifically, the maximum tangential velocity of the rotor is limited by the square root of its yield strength to density ratio. Therefore, strong lightweight materials such as aluminum and titanium are favored. The length of a centrifuge unit is often constrained by the need to avoid exciting a destructive resonant oscillation.

Although the capacity of a single centrifuge is much smaller than that of a single diffusion stage, its capability to separate isotopes is much greater. Centrifuge stages normally consist of a large number of centrifuges in parallel. Such stages are then arranged in cascade similarly to those for diffusion. Although the separation factors obtainable from a centrifuge are large compared to gaseous diffusion, several cascade stages are still required to produce even LEU material. In the centrifuge process, however, the number of stages in a series may only be 10 to 20, instead of a thousand or more for diffusion. As was the case for the diffusion cascade, the stream that is slightly enriched in U-235 is withdrawn and fed into the next higher stage, while the slightly depleted stream is recycled back into the next lower stage. Eventually, enriched and depleted uranium are drawn from the cascade at the desired assay. Significantly more U-235 enrichment can be obtained from a single unit gas centrifuge than from a single unit gaseous diffusion barrier. Each cascade is capable of producing the desired separation. Many cascades must be run in parallel to gain the desired throughput. However, this lends flexibility to the operation and supports ease of modular growth. This is in stark contrast to a diffusion plant where the many stages must run in one cascade to obtain the final product (WNA 2009).

The end of the process is basically the same as the gaseous diffusion process; the enriched UF_6 gas condensed into a liquid that is poured into containers before being transported to fuel fabrication facilities.

Figures C1-4 and C1-5 show schematics of typical gas centrifuges used for U-235 enrichment.

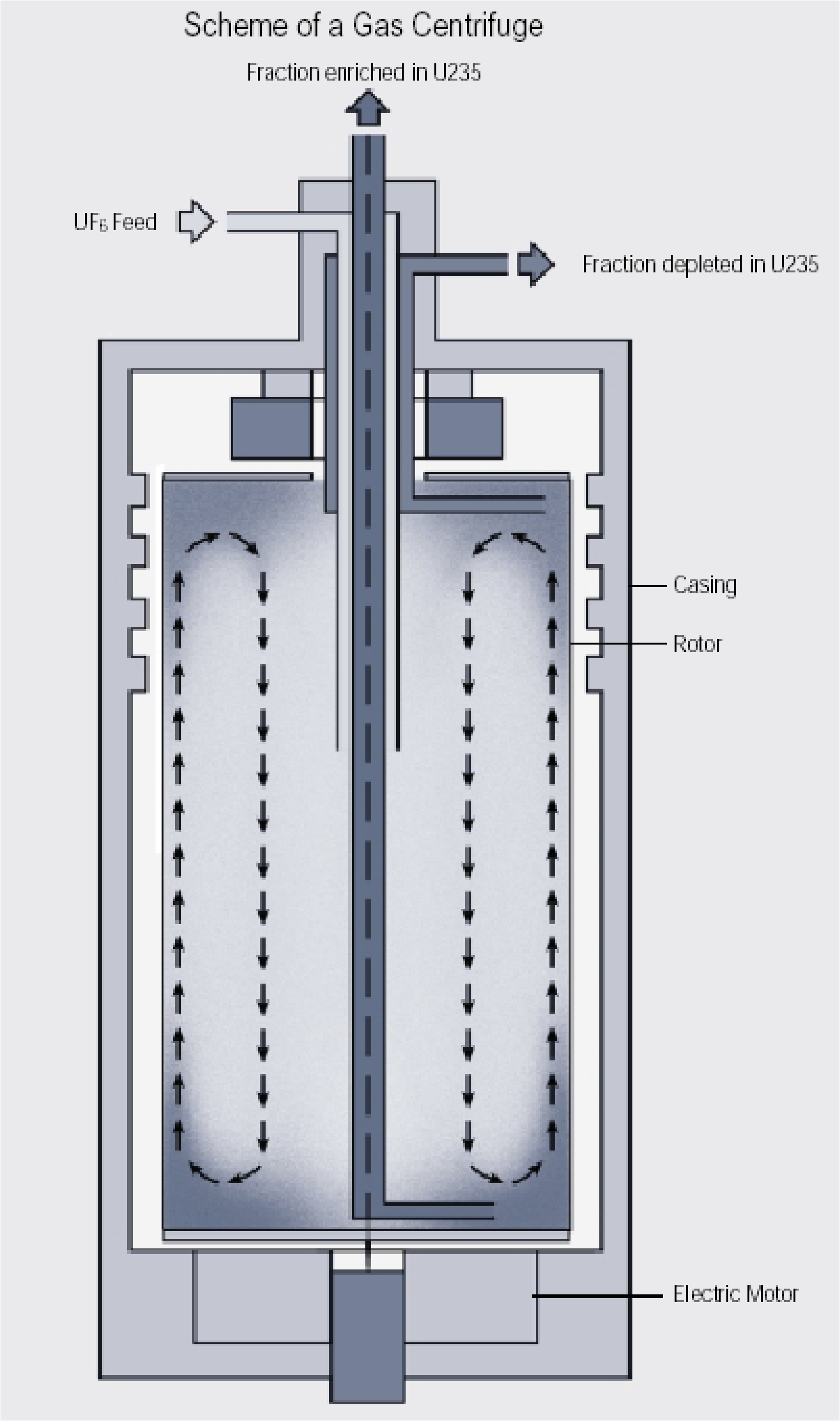

Figure C1-4. Gas centrifuge.

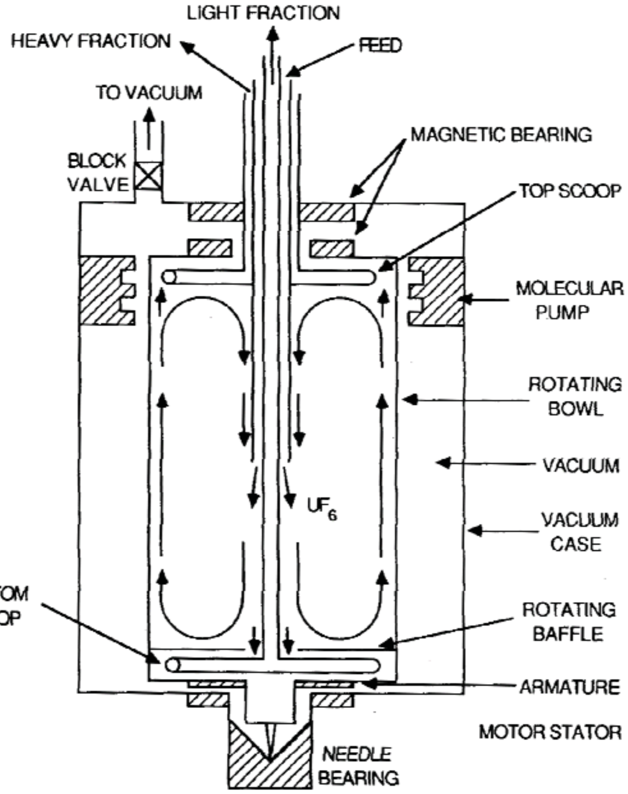

Figure C1-5. A schematic showing the Zippe centrifuge.

One of the key components of a gas centrifuge enrichment plant is the power supply (frequency converter) for the gas centrifuge machines. The power supply must accept alternating current (ac) input at the 50 or 60-Hz line frequency available from the electric power grid and provide an ac output at a much higher frequency (typically 600 Hz or more). The high-frequency output is fed to the high-speed gas centrifuge drive motors (the speed of an ac motor is proportional to the frequency of the supplied current). The centrifuge power supplies must operate at high efficiency, provide low harmonic distortion, and provide precise control of the output frequency.

The casing not only maintains a vacuum, but must also contain the rapidly spinning components in the event of a failure. If the shrapnel from a single centrifuge failure is not contained, a “domino effect” may result and destroy adjacent centrifuges. A single casing may enclose one or several rotors.

A notable feature of the gas centrifuge process is that the plant capacity can be expanded on a modular basis. Capacity can be increased according to market demand. This leads to substantial economic advantages and allows advanced technology to be installed in each increment of capacity. Because of the development of almost friction-free bearings, the electrical consumption of a modern gas centrifuge facility is much less than that of a gaseous diffusion plant requiring as little as 50 kWh/kg SWU (roughly 2% of the diffusion requirement).

Laser Isotopic Separation. The Atomic Vapor Laser Isotopic Separation process (AVLIS) and the similar French process SILVA were extensively studied in the 1990s by the U.S., France, and Japan. These processes have not proven to be commercially viable in the short term, and the U.S. and France have stopped development efforts.

SILEX Process. USEC secured exclusive worldwide rights to the commercial use of the SILEX laser-based technology for enriching uranium in 1997, working in partnership with SILEX Systems LTD., in Australia. After funding it for 6 years, USEC announced its withdrawl from the SILEX project in 2003, despite continuing positive results. SILEX and General Electric Company (GE) signed an exclusive Commercialization and License Agreement for the SILEX Uranium Enrichment Technology in 2006 (SILEX Systems, LTD 2006). If successfully deployed, SILEX, a molecular laser separation process using UF_6, would selectively separate U-235 in a manner that requires lower power consumption, lower capital cost, and lower tails assay. Similar to gas centrifuges, SILEX could be implemented in a modular manner. GE-Hitachi is currently evaluating the SILEX process in a significant scale engineering prototype facility.

The SILEX process is illustrated schematically in Figure C1-6. The physical principle on which the process is based is the isotopic shift between $^{235}UF_6$ and $^{238}UF_6$ for certain vibrational infrared light absorption bands. In particular, the isotopic shift between the absorption peaks for the 16 micron absorption line is on the order of 0.5 cm^{-1}. Therefore, laser light may be used to selectively excite $^{235}UF_6$, provided that the gas is cooled to around 50 K to reduce the width of the absorption lines. Light from 10.8 µm pulsed CO_2 lasers is subjected to a series of optical processes, emerging at the desired 16 µm wavelength. This enters a tank containing cold UF_6 and carrier gases. The product stream, enriched in the excited $^{235}UF_6$, is collected and may be subjected to additional enrichment stages if necessary.

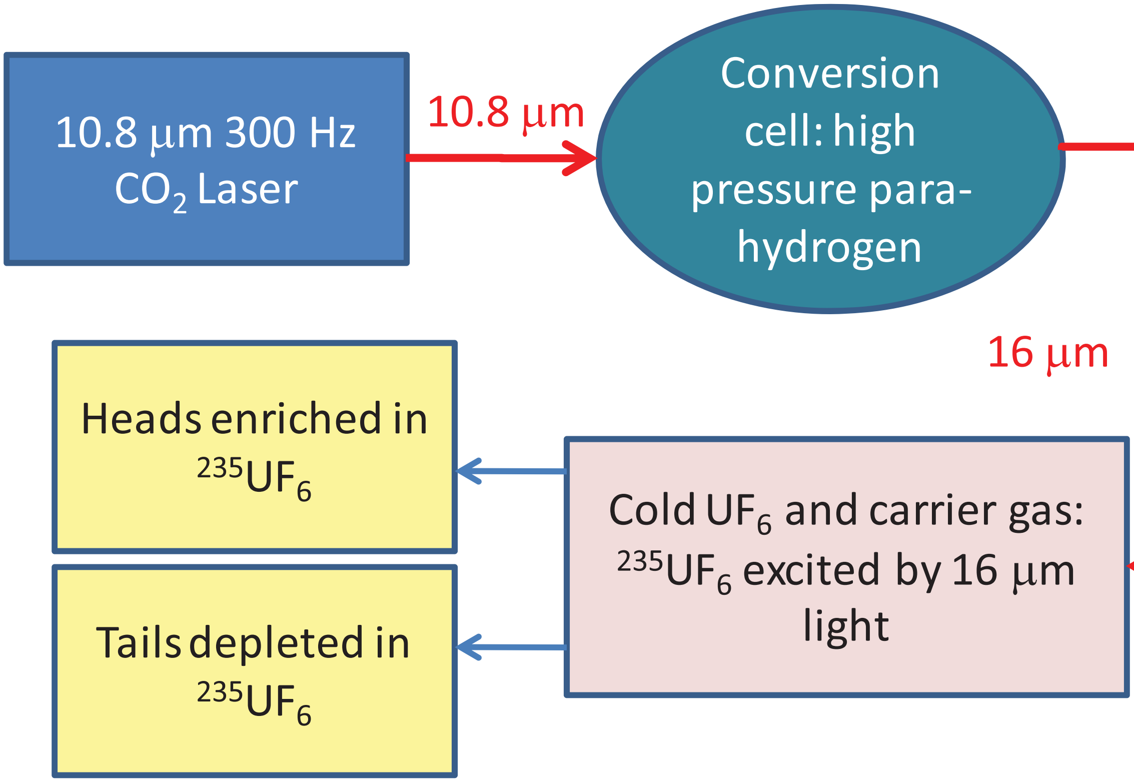

Figure C1-6. Schematic of SILEX process.

Although SILEX engineering and performance details are proprietary, the technical considerations that have hampered laser-driven enrichment in the past are known. These include the repetition rate of the CO_2 laser, which must reach several hundred cycles per second for the process to be commercially viable. Low repetition rates harm throughput and separation efficiency because only a small fraction of the material in the target tank is exposed to the light during a given time interval. Second, the UF_6 must be maintained at low temperature to limit molecular kinetic energy so that the absorption lines are resolved.

But UF_6 is solid at low temperatures and atmospheric pressure, so its molecular density must be quite low to preclude condensation. (Lyman 2005) estimates that densities higher than 10^{15} molecules/cc may be difficult to achieve, with consequent implications for throughput.

If these obstacles are overcome, the technology could offer exceptionally high stage separation factors (Table C1-2). This could in turn render further enrichment of existing enrichment tails much more attractive than is presently the case. The technology may also be especially useful if applied to reprocessed uranium, as ^{236}U need not be concentrated along with ^{235}U in the product stream as is the case for existing technologies that rely upon mass differences. On May 22, 2006 GE and SILEX Systems announced plans to move forward on a test loop at the GE Global Nuclear Fuel—Americas site in Wilmington, North Carolina. This test loop is now operational; subsequent developments are described in Section C1-4.1.1, Supply.

Table C1-2 summarizes key performance metrics of the three most prominent enrichment technologies.

Table C1-2. Performance metrics of enrichment technologies.

Technology	Energy Consumption [kWh/SWU]	Stage Separation Factor[b]
Diffusion	2000–2500	1.004
Centrifuge	50–100	1.2–1.6
Laser (SILEX)[a]	15–150	2–20

a. SILEX values are estimates; exact figures are considered trade secrets. The quoted range for the stage separation factor was taken from (SILEX 2008). The upper bound for energy consumption was taken from (Whittaker 2005).

b. The stage separation factor is defined as the U-235:U-238 ratio in the heads (i.e., the product stream_ of a single stage) divided by the U-235:U-238 ratio in the tails. For example, consider a single machine whose feed is natural uranium at 0.72% U-235. If it is operated in a manner typical of commercial enrichment cascades, the U-235:U-238 ratio in the heads divided by the U-235:U-238 ratio in the feed will be the square root of the stage separation factor. Thus for diffusion, the product from that single machine would have a U-235 enrichment of 0.7214%. Taking a stage separation factor of 1.4, the midpoint of the range given in Table C1-2, the product from a single centrifuge would be enriched to 0.851%. For SILEX with a stage separation factor of 10, the product enrichment would be 2.24%.

Other Separation Technologies. Numerous chemical, ion exchange, electromagnetic, aerodynamic and plasma separations processes have been investigated, but none are being seriously considered at this time for large-scale commercial enrichment applications.

C1-3. PICTURES/SCHEMATICS

Large commercial enrichment plants are in operation in France, Germany, Netherlands, United Kingdom, U.S., and Russia with smaller plants elsewhere. The following picture shown in Figure C1-7 is the European Gaseous Diffusion Uranium Enrichment Consortium's (EURODIF's) Tricastin gaseous diffusion enrichment plant in France. Note the four reactors in the foreground that supply 3000 MWe of power to the enrichment facility and the large production facilities beyond the cooling towers.

Figure C1-8 shows the USEC Gaseous Diffusion Building in Paducah, Kentucky.

Figures C1-9, C1-10, and C1-11 show the URENCO gas centrifuge enrichment plant at Gronau, Germany.

Figure C1-7. EURODIF's George Besse Gaseous Diffusion Enrichment Plant.

Figure C1-8. United States Enrichment Corporation Gaseous Diffusion Production Building.

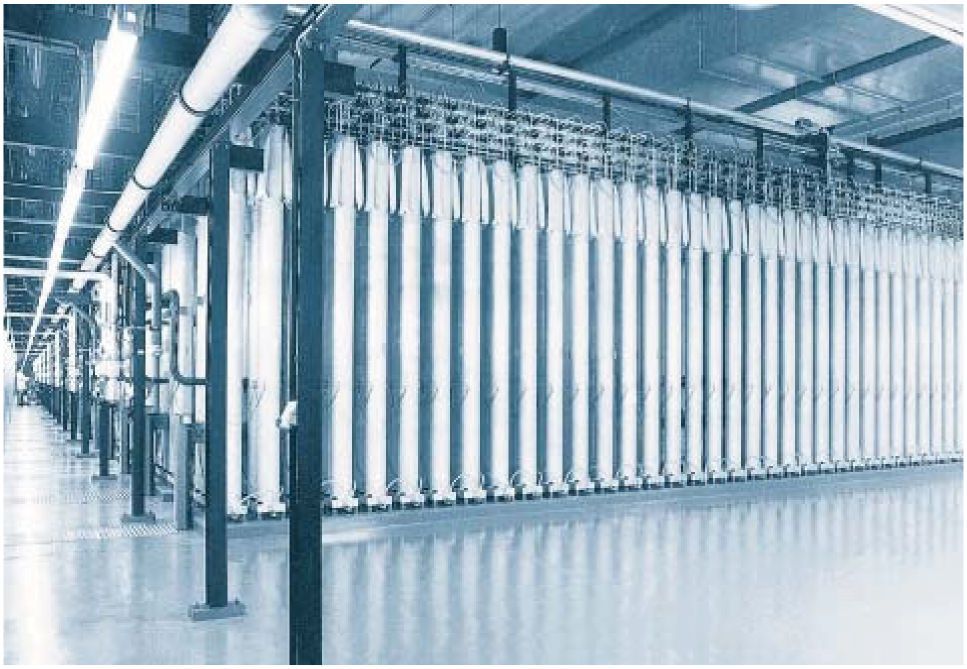

Figure C1-9. Separation Hall with centrifuges at the Gronau Enrichment Plant, Germany.

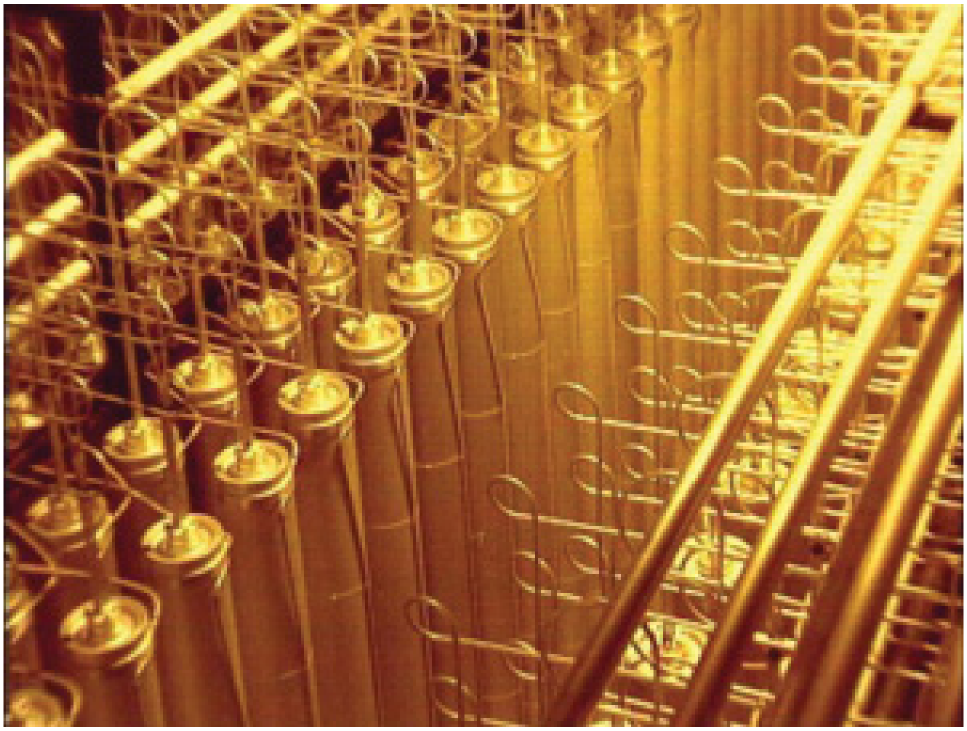

Figure C1-10. Top view of a bank of centrifuges at a URENCO gas centrifuge plant.

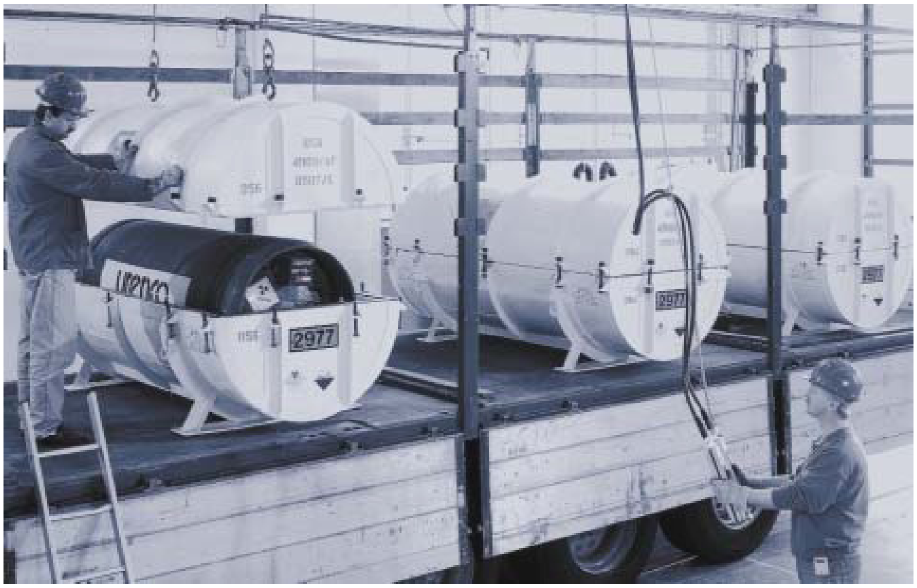

Figure C1-11. Enriched UF_6 product container being loaded into an overpack for shipment.

C1-4. MODULE INTERFACE DEFINITION

The need for enrichment services is highly dependent on Modules A, C2, D1, D2, and K. Raw uranium pricing impacts the source uranium cost of conversion. The availability of mixed oxide, reprocessed uranium, and/or blend down of highly enriched uranium impacts the demand for enrichment services from UF_6. Timing of fuel fabrication also impacts the need for conversion services. In addition to real-time feed and product needs, decisions relative to inventory levels along the front-end of the fuel cycle will have impact on this enrichment module.

The key cost dependencies on supply and demand are discussed in the following section.

C1-4.1 Supply and Demand

C1-4.1.1 Supply

Although there are 21 enrichment facilities in operation, four companies dominate the world enrichment supply: EURODIF (France), Minatom (Russia), URENCO (Germany, Netherlands, United Kingdom) and USEC (U.S.). The current world enrichment nameplate capacity is about 49 million SWU. Actual production capability is estimated to be closer to 40 million SWU/yr. The world supply is dominated by Russia with approximately 40% of the world capacity.

Table C1-3 implies a worldwide capacity of ~49 million SWU, most sources evaluate the reasonable and reliable capacity to be closer to 40 million SWU/yr.

The U.S. presently has only one operating plant for uranium enrichment, although that state of affairs is poised to change as soon as the last quarter of 2009. USEC, Inc. is the only producer of enrichment services in the U.S. USEC leases production facilities from the United States Department of Energy at Paducah, Kentucky, and Portsmouth, Ohio, (also referred to as Piketon, Ohio). The current capacity at Paducah is 11.3 thousand SWU with a license to enrich uranium up to 5.5% U-235. The second unit located in Portsmouth, Ohio, with an additional capacity of 7.4 million SWU per year was placed in cold standby in March 2001 and cold shutdown in September 2005. A date for the initiation of final decontamination and decommissioning (D&D) activities at Portsmouth has not yet been identified.

Table C1-3. World enrichment nameplate capacity (Wise Uranium Project, 2009 except where noted).

Company (Country)	Nameplate Capacity Million SWU (as of May 2009)		Planned and Under Construction, Million SWU, centrifuge unless otherwise noted
	Diffusion	Centrifuge	
Industrias Nucleares do Brasil (INB) (Brazil)		0.1	0.15 (by 2012)[a]
China National Nuclear Corporation (CNNC) (China)	0.9	1.0	0.5 (planned)[a]
Eurodif (France)	10.8[b]		7.5 by 2016, additional 3.5 possible (Georges Besse II)
Japan Nuclear Cycle Development Institute (JNC), Japan Nuclear Fuel Ltd. (JNFL) (Japan)		1.25	0.25 (at Rokkasho by 2020)[a]
Minatom (Russia)		23.0	4.0 (by 2015; upgrades at existing facilities)[a]
URENCO:			
(Germany)		2.2	--
(Netherlands)		4.0	0.5 (expansion of Dutch Almelo site)
(UK)		5.0	--
(USA)			6.4 (at National Enrichment Facility in New Mexico; 3.2 online by end of 2009, 3.2 planned thereafter)
USEC (USA)	11.3[b]		3.8 (by 2012 but project is doubtful; see text)
Areva (USA)			3.3–6.6 (Eagle Rock Enrichment Facility in Idaho; 0.5 by 2014, 3.3 by 2019, additional 3.3 provided for in license application)
GE-Hitachi/SILEX (USA)			3.5–6.0 (laser [SILEX] facility at Wilmington, North Carolina; after 2013/2014)
Total	23.0	36.55	15.2 (under construction) Up to 21.4 (planned)
Grand Total	59.55		Up to 36.7

a. Source: Neely, et al. 2008

b. These facilities are to be decommissioned in 2012 (USEC Paducah facility) and 2012–2014 (Eurodif Georges Besse)

Gaseous diffusion plants cost much more than gas centrifuges to operate with costs near $100/SWU versus close to $70/SWU for centrifuges. To remain competitive, by 2013 ERODIF plans to phase out their gaseous diffusion plant at Tricastin by replacing it with the gas centrifuge plant, George Besse II, initially capable of 7.5 million SWU with tentative plans to expand to 11 million SWU. The first centrifuge cascade at Georges Besse II was inaugurated on May 18, 2009. Commercial operation is expected to commence in late 2009. Under the aegis of its Russian Centrifuge Project, Russia is upgrading centrifuges at its existing plants. It is estimated that these refitting activities, in which older (so-called Generation V and VI machines) are being replaced with higher speed and throughput Generation-VIII centrifuges, will result in additional capacity of 3–4 million SWU by 2015 (Neely et al. 2008).

Incremental capacity enhancements are planned at several other international sites as well (Table C1-3), but the most substantial developments in the industry are taking place in the United States. Louisiana Energy Services, USEC, GE-Hitachi, and Areva have all submitted license applications to the Nuclear Regulatory Commission (NRC) for enrichment plants. If all of these plants were to come online, their combined SWU capacity would be at least 13.8 million SWU and could reach as high as 22.8 million SWU if all proposed expansions are carried out. Therefore, they would match or exceed current U.S. annual SWU demand, around 12–14 million SWU depending on market conditions.

In 2005, Louisiana Energy Services (LES) announced plans to begin construction of a National Enrichment Facility (NEF) in Eunice, New Mexico with a capacity of 3.2 million SWU. This facility received a construction license from the NRC in June 2006, and ground was broken in October of that year. LES, a subsidiary of URENCO, is nearing completion of the first 1.6 million SWU block of NEF. This first block is expected to begin commercial operation in late 2009; a second 1.6 million SWU block will follow shortly thereafter. In November 2008, LES announced that it was moving forward with plans to open an additional two blocks that would double the capacity of the facility to 6.4 million SWU in the next decade.

USEC planned to begin construction in 2007 on the American Centrifuge Plant (ACP) in Portsmouth, Ohio with an initial capacity of 3.5 million SWU expandable to 7.0 million SWU. A Lead Cascade facility at Portsmouth will pilot the USEC centrifuges without producing product. Originally billed at $1.7B the ACP's cost has recently been updated to $2.3B; USEC has already invested more than $1B in the facility. The increase comes as a result of higher commodity prices for construction materials (both facility and cascade) and because of a 1-year construction delay resulting from poor test results on cascade equipment. Future cost increases are possible as the current estimate of $2.3B is based on an aggressive construction schedule. Because of the increased cost, USEC does not currently have sufficient funds for ACP and has been seeking investors or some other cash stream.[a]

Therefore, the fate of the ACP appears doubtful. USEC has requested loan guarantees from DOE to support the financing of the ACP. In July 2009, DOE requested that USEC withdraw its application for the guarantee, citing the immaturity of the American Centrifuge technology. Appealing the DOE decision, USEC cited 235,000 machine hours of operation experience with the new centrifuges along with advance customer commitments to purchase a portion of the plant output. As of August 2009, this issue is still pending, but in the absence of at least a partial reversal of the DOE decision, USEC will, by its own admission, be forced to begin demobilizing the ACP project (The Wall Street Journal 2009).

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[a] USEC's 2006 SEC K-10 filing.

In May 2008, Areva announced that it had selected a site near Idaho Falls, Idaho for a new 3.3 million SWU plant using centrifuge technology. The construction cost was estimated at $2B. Areva filed a combined construction and operating license application with the NRC on December 30, 2008. In May 2009, AREVA modified its license application to cover a maximum nameplate capacity at the site of 6.6 million SWU (Wise Uranium, 2009). Areva envisions commercial operations beginning in 2013, with 3.3 million SWU of capacity option being reached from 2018 and the 6.6 million SWU, if exercised, being attained in 2022.

On October 11, 2006 GE informed the NRC of its plans to file an operating license application for a SILEX facility in the U.S. The partnership has since expanded to include Hitachi (25% stake) and Cameco (24%) with GE retaining a majority share of 51%. In May 2008 the NRC granted GE Hitachi permission to construct a test loop at Wilmington. GE Hitachi subsequently filed a combined construction/operation license application with the NRC (June 30, 2009). Test loop began operation shortly thereafter (July 30, 2009). Therefore, GE Hitachi is poised to bring online the first-ever large scale laser enrichment facility; an ultimate capacity of 3.5–6 million SWU is planned with commercial operations envisioned for 2013–2014. Exelon and Entergy, two major operators of commercial nuclear power plants, have signed nonbinding letters of commitment to purchase enrichment services from GE Hitachi.

Presently, the U.S. imports most of its SWU; the remainder is accounted for by the soon-to-retire USEC Paducah gaseous diffusion plant (see Section C1-4.1.2 below). A majority of today's SWU imports were in fact employed decades ago to produce HEU in Russia. These SWU are imported as LEU from Russian surplus HEU, in accordance with the USA-Russia HEU Agreement; the LEU is marketed domestically by USEC (Module C-2). At present, U.S. trade policy forbids importation of Russian SWU under any mechanism other than the agreement. As the agreement is set to expire in 2013 and the Paducah facility will go offline at the same time, well over half of domestic supply would abruptly cease to exist. The new plants are certainly responses to this business opportunity, but the U.S. government has also made an effort to mitigate the shock of an abrupt termination of Russian SWU imports.

This effort resulted in the bilateral (U.S.-Russia) "Suspension Agreement" amendment of February 2008. This amendment to a 1992 antidumping agreement will provide Russia limited access to the U.S. enrichment market. The import quotas shown in Table C1-4 have been established for 2011–2020. Note the jump from 2013–2014 that is intended to act as partial compensation for the termination of supplies from the HEU Agreement (Neely 2008). Since Russian SWU are comparatively cheap to produce (see Section C1-8) and Russian capacity is underutilized it is reasonable to expect these quotas to be fully met. Moreover, Russian SWU may play an even larger role after 2020 when the "Suspension Agreement" amendment stipulates the termination of limits on Russian SWU exports to the U.S. (Rothwell 2009). It is important to note that the amendment decreases the uncertainty surrounding SWU availability after 2013 and should exert a stabilizing influence on prices.

Table C1-4. Importation quotas (millions of SWU) for Russian enrichment services under the Suspension Agreement amendment.

Year	Import Limit	Year	Import Limit
2011	0.10	2016	2.90
2012	0.15	2017	2.96
2013	0.25	2018	2.98
2014	2.93	2019	3.07
2015	2.75	2020	3.11

See Module C2 for further discussion concerning supply from downblend of HEU.

C1-4.1.2 Demand

The current U.S. demand for SWUs is approximately 13 million SWU per year, up from less than 12 million per year prior to 2006. This increase in enrichment service demand is partially a consequence of uranium price increases. In 2008, roughly 15% of the U.S. demand for SWU was provided by USEC with 85% originating from foreign enrichment plants—largely Russian LEU from blend-down (see Figure C1-12).

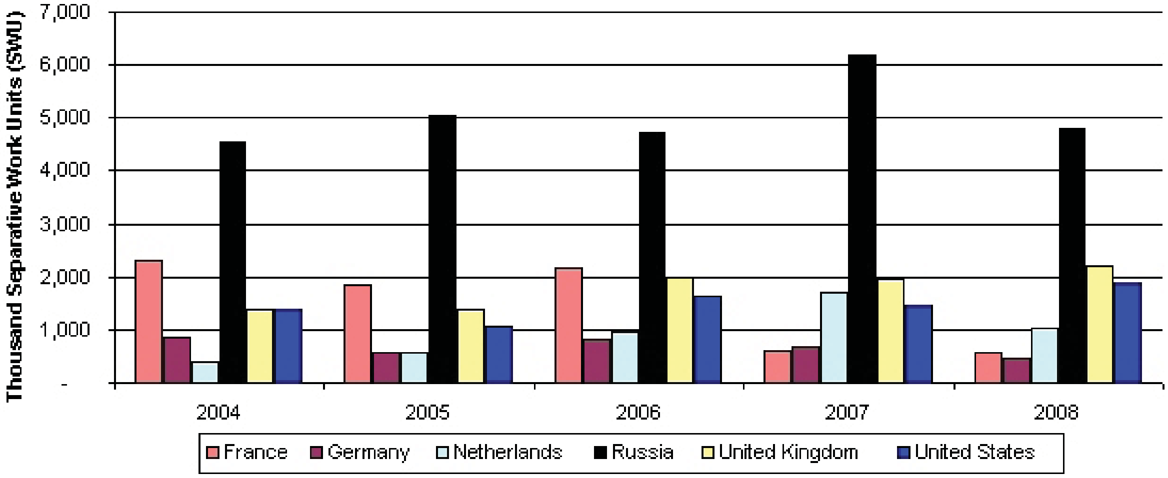
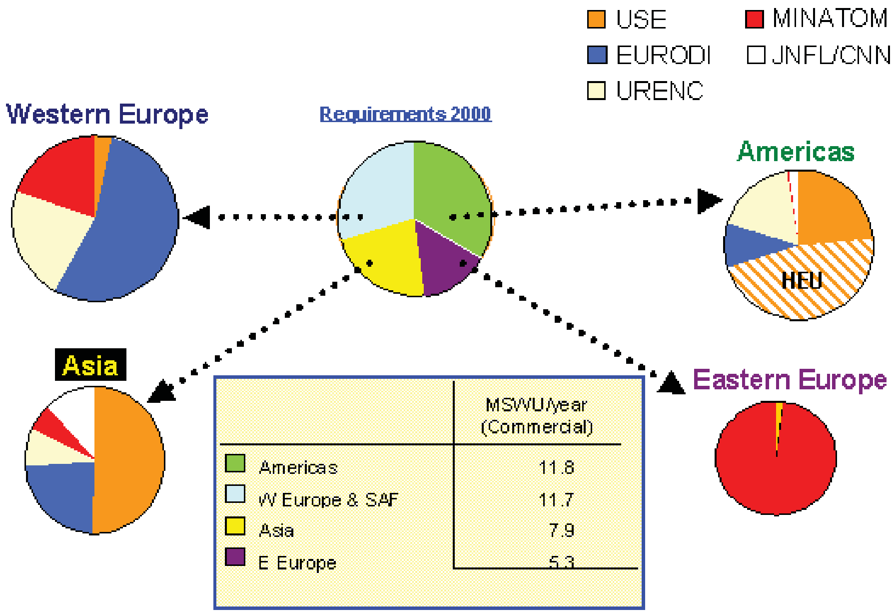


Figure C1-12. Purchases of enrichment services by owners and operators of U.S. civilian nuclear power reactors by origin country and delivery year, 2004–2008 (EIA 2009).

Jean-Jacques Gautrot, Areva's director for international operations and marketing, shows the supply breakdown by region and supplier in Figure C1-13 (Gautrot 2002).



	MSWU/year (Commercial)
🟩 Americas	11.8
☐ W Europe & SAF	11.7
🟨 Asia	7.9
🟪 E Europe	5.3

Figure C1-13. Supply breakdown of the market in 2000.

This figure implies that the Americas, dominated by the U.S., require about 30% of the total demand. Russia’s three plants at Seversk, Zelenogorsk, and Novouralsk satisfy nearly 45% of the U.S. demand and almost 30% of the world demand. Thus from a supply standpoint, Russia has a major impact on the world market. It is also interesting to note that USEC is filling nearly 50% of the growing Asia market.

C1-4.1.3 World Nuclear Association 2001 Enrichment Requirements Forecasts

The World Nuclear Association has projected annual SWU demand through 2030 for three nuclear growth scenarios, low (which assumes a phaseout ensues in the U.S.), reference, and high. Figure C1-14 shows that demand in 2030 is quite uncertain, ranging from 40 million to as high as 120 million SWU per year (Elliott 2009). Recalling the existing, planned and projected capacities of Table C1-2, even if all capacity projected for 2020 comes online, once the diffusion plants retire only 74 million SWU of nameplate capacity could be available. This capacity easily handles the lower case. The middle case would fall within the 2020 nameplate worldwide capacity, but additional capacity would be required thereafter. Clearly the high scenario requires even more additional new SWU capacity.

There is a very key interaction between Cost Modules A and C1. Figure C1-15 depicts the relationship between raw uranium requirements and the enrichment tails assay. Simply stated, if more U-235 is separated (i.e., lower tails assay) per unit of feed, then less feed (i.e., natural uranium) is needed.

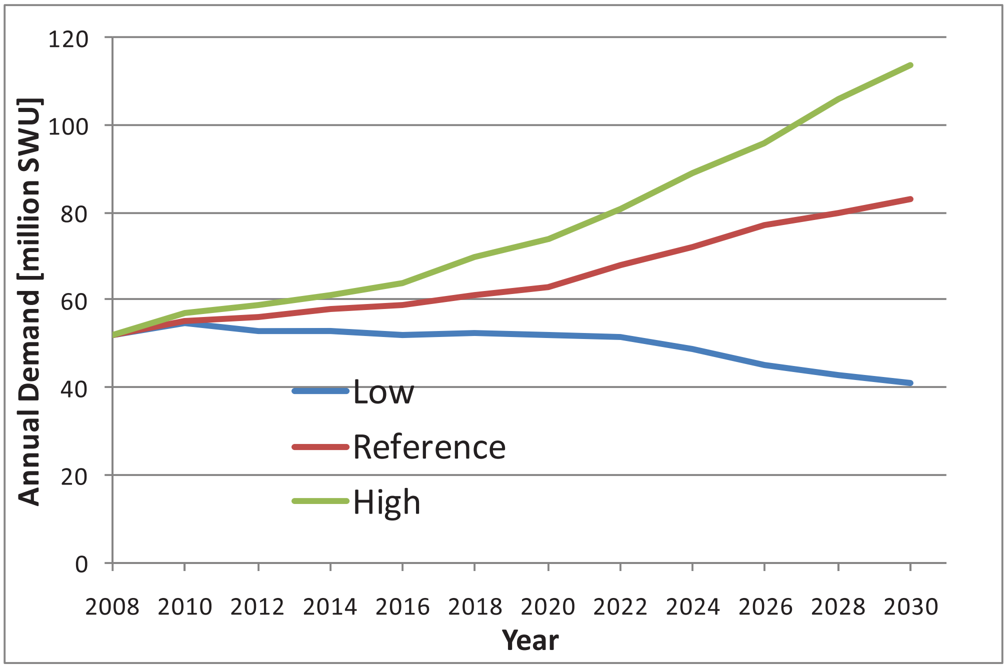


Figure C1-14. World Nuclear Association projections of annual global SWU demand through 2030.

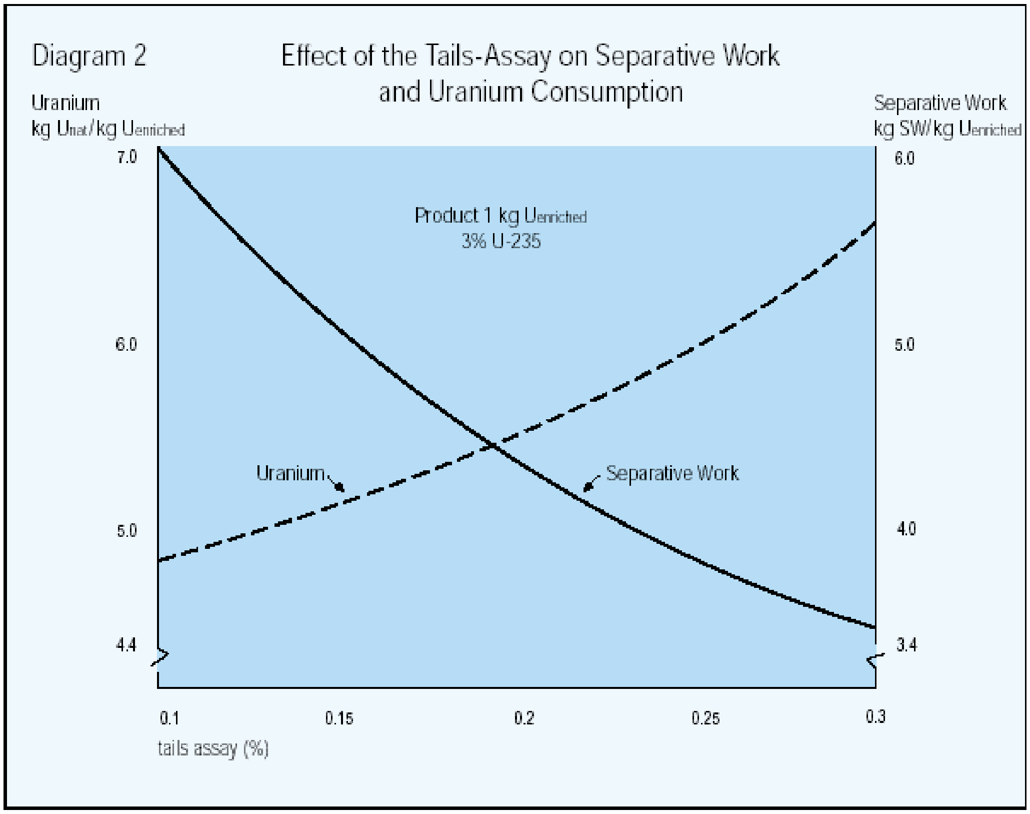


Figure C1-15. Relationship between raw uranium requirements and the enrichment tails assay.

As an example of this coupling, the optimal tails enrichment as a function of uranium-to-SWU price ratio ($/kgU as UF_6 per $/SWU) has been calculated by Thomas Neff of Massachusetts Institute of Technology (MIT) (Neff 2006). His results are shown in Figure C1-16. From 2002 through late 2006, as uranium prices increased at a greater rate than SWU prices, the optimal tails enrichment dropped from about 0.35% to 0.22%. Utilities' shift to lower tails fractions should, over time, serve to reduce primary uranium prices, with attendant upward pressure on SWU prices that would accompany higher demand. This effect is evidently too small to stem the rise in uranium prices. At the time Neff prepared his figure, the U in UF_6:SWU price ratio was about 1.0; as of May 2007 it reached 2.2 as the U in UF_6 price rose from $134 (August 2006) to $305 (May 18, 2007), while the SWU price rose only slightly, from $130/SWU to $138/SWU.

At a UF_6:SWU price ratio of 2.2, the optimal tails enrichment would be 0.15%. Information regarding recent enrichment contracts and volumes is difficult to obtain; however, inherent lead times ensure that tails enrichments are not yet this low. Nonetheless, over the medium term and subject to SWU supply constraints, this elasticity of demand ensures that:

1. Uranium and SWU prices will have a positive correlation
2. Upward (or downward) price pressure within one of these industries will be mitigated to an extent.

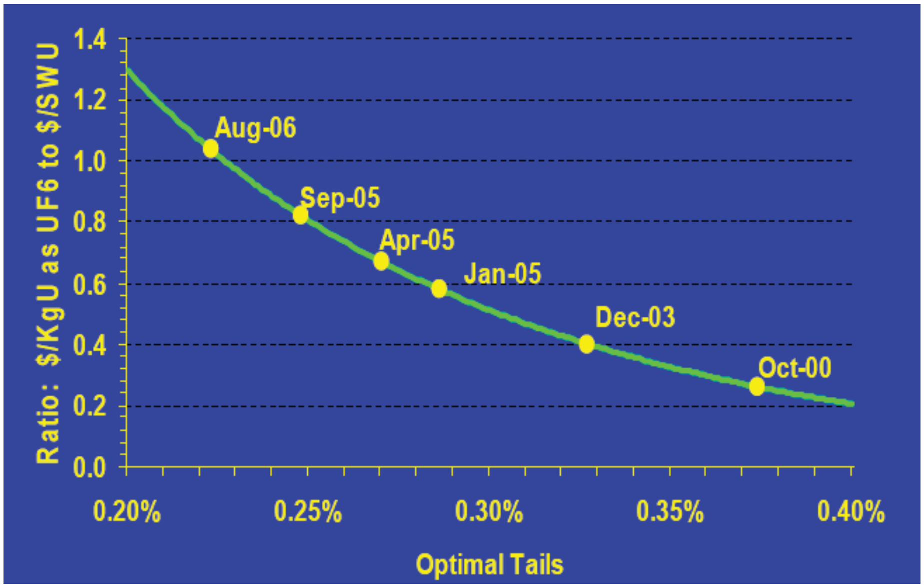


Figure C1-16. Optimal tails as a function of ratio of uranium to SWU price.

In summary, if the price of UF_6 increases, while the price per SWU remains stable, there is a point where it is more cost effective to pay for more separation (i.e., more SWU) and reduce the natural uranium demand. The impact of this relationship provides for other cost optimization scenarios in addition to tails assay adjustment. These scenarios are as follows:

1. In the case that the price of uranium goes up and excess SWU capacity exists, enrichers (especially more cost effective processors) could use the unused SWU to enrich the existing richer tails and thus provide a new source of uranium.
2. If laser isotope enrichment becomes a commercial reality, then the door is open for utilization of reprocessed uranium as feedstock for enrichment in addition to the existing tails.

The reality of the supply-demand discussion is that is it a very dynamic and extremely competitive market. Key interactive factors include:

- Tails assay versus natural uranium price and supply.
- Commercialized HEU to LEU availability (both Russian and U.S.) and timing (blend-down can occur with natural uranium, LEU, enrichment tails, and/or reprocessed uranium) (see Module C2).
- Further reductions in nuclear stockpiles and government inventories of uranium in all forms (see Module C2).
- Openness of emerging enrichment suppliers especially from currently restricted markets. Because of past dumping practices, several countries and the Commonwealth of Independent States are not permitted to enter the competitive market or are currently heavily taxed to do so. Under the amendment to the Russia/U.S. “Suspension Agreement,” this restriction on Russian SWU will be partially, and after 2020 perhaps fully, lifted. Protections extend beyond Russian SWU: in a January 26, 2009 reversal of a circuit court ruling, the U.S. Supreme Court ruled in favor of USEC in an anti-dumping case it filed against Eurodif. Therefore, a 20% tariff on Eurodif SWU levied by the Commerce Department in 2000 was reinstated. This decision set an important precedent: the Supreme Court in effect ruled that SWU should be considered a “good” rather than a “service.” Therefore, enrichment services may continue to be subject to tariffs under anti-dumping laws (NTI 2009).
- Cost versus reliability and flexibility (reliability is critically important).

- Demand for higher enrichment because of deeper burn reactor operations or to support use of mixed oxide fuel (and to address the higher enrichment needs of very high temperature gas reactors).
- Continued integration of fuel cycle companies to integrate all aspects of the fuel cycle up through fuel fabrication.
- Enriched uranium product procurement versus utility procurement of natural uranium, conversion, and enrichment services (changes price structure due to avoidance of carrying costs from uranium purchase to fuel delivery).
- Much of the existing infrastructure is getting quite old. New facilities, while capital intensive, will be more cost effective, reliable, capable of modular expansion, and have more flexibility in products.

These factors should all work to keep the price of SWU fairly stable with moderate price increases to support new supply balanced by an overall production cost decrease as electricity-hungry diffusion plants are retired in favor of centrifuge facilities.

C1-5. MODULE SCALING FACTORS

New additions to supply are planned. In cases like the U.S. and France, the new facilities will permit the more costly gaseous diffusion plants to be replaced by the more efficient gas centrifuge plants. The gas centrifuge technology is relatively mature with ongoing work to improve efficiency even further. Costs are reasonably well understood and capacity can easily be added in a cost-effective modular basis. Therefore, scale-up is not a process or cost concern for this technology. A general cost per SWU can be expected to apply over the range anticipated for future growth.

C1-5.1 Cost Bases, Assumptions, and Data Sources

C1-5.1.1 Enrichment Pricing and Forecasts

Although spot market pricing is published, most enrichment services are tied to longer contracts where reliability is more important than price. However, the pricing of Russian SWU was driven by the HEU agreement between the U.S. and Russia, and agreement was made to follow market pricing (see Module C2). The restricted market jumped to about $108/SWU as a result of the decision by USEC to place the capacity of the Portsmouth Gaseous Diffusion plant in cold standby in March 2001. The spot market price for SWU is shown in Figure C1-17.

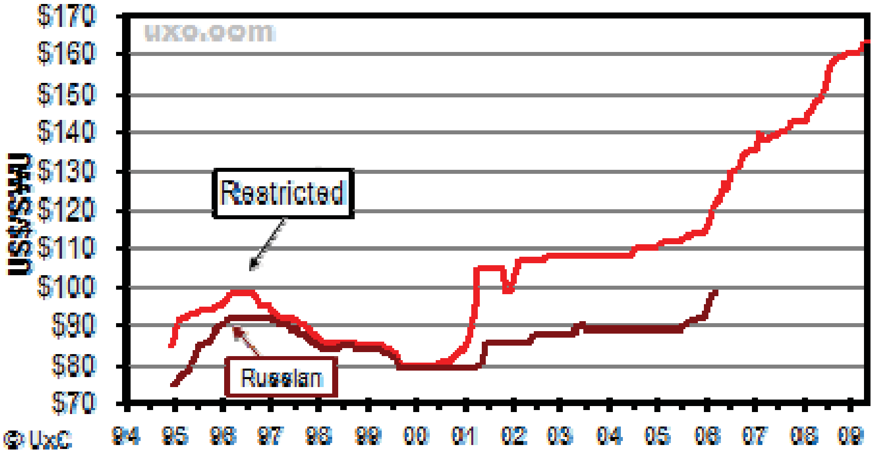


Figure C1-17. Spot market price for SWU unadjusted for inflation (UxC 2009).

SWU prices have reached record levels in 2009. Spot market prices peaked at $162/SWU in April 2009 and have since fallen slightly, standing at $155/SWU in August 2009. Therefore, prices remain quite high by historical standards. Ux Consulting Company analysts ascribe the elevated prices to a combination of factors (Neely 2008):

- Elevated uranium prices have increased demand for enrichment services. This tradeoff between uranium and SWU, as described in Section C1-4, favors greater SWU consumption when uranium prices are high. In fact, the annual U.S. SWU consumption rate from 2006 to 2008 averaged 1.5 million SWU higher than the 2004 to 2005 rate (EIA 2009).
- There is evidence of an uptick in long-term contract agreements as utilities work to secure additional SWU supply. As is the case for the uranium market, a large majority of SWU transactions are settled via forward contracts with at least a 12-month lead time. In 2008, 96% of domestic SWU were delivered under such contracts (EIA 2009).
- Given that there is a measure of international trade in enrichment services, the decline in the value of the U.S. dollar has also played a role in the escalation of SWU prices in dollar terms.
- Electric power is a major driver of SWU production costs, especially for diffusion plants playing the role of price-setter in the current seller's market. Power prices have risen. According to the Energy Information Administration, the average price paid by a domestic industrial customer has increased from 5.11 cents/kWh in 2003 to 7.15 cents/kWh in the 12-month period ending in April 2009 (EIA 2009).
- Diffusion plants act as price-setters in part because the market is presently tight; there is little slack between capacity and annual demand.

The UxC analysts forecast that SWU prices will remain high in the short term but decline in the medium-term (after 2012–2013). The largest single factor that will exert downward pressure on SWU prices is the substantial increment in lower-cost centrifuge enrichment capacity coming online at that time (Table C1-2). As this study focuses on medium to long-term price trends, the post-2013 landscape in which essentially all capacity is supplied by centrifuges is considered.

Recent studies by Harvard University, MIT, and Atomic Energy Commission (CEA)-Nuclear Energy Agency suggest a range of $80–130/SWU is reasonable for evaluation of future enrichment services, and most economic comparisons use a value of ~$105–110/SWU. Although Figure C1-17 shows the spot market price for SWU, very little SWU is purchased on the spot market reflecting a stronger need for reliable longer term committed supply. The most significant factor is the impact of weapons reduction by the U.S. and Russia, making HEU (effectively the Russian SWU) available for commercial use (see Module C2). Longer term contract prices are not published. However, roughly 50% of the U.S. SWU demand is being filled via Russian SWU through 2013. Further reductions are expected in the nuclear stockpiles making additional HEU and plutonium available for the market. It is, therefore, reasonable to assume that some convergence of the markets could occur, but the range suggested above is reasonable for SWU service.

Russian SWUs have also had a significant effect upon European markets. Since the mid-1990s, Russia has been making available between 2.5 million and 4.0 million SWU per year to AREVA, URENCO, and others. As shown in Figure C1-17, these SWUs have consistently changed hands at lower than world market prices. Under the AREVA and URENCO contracts, over 100,000 tonnes of depleted uranium tails have been upgraded to natural uranium assay (Neely and Combs 2006). In late 2006, Minatom announced that contracts for this work would not be renewed once the current program is complete. It is likely that Russia perceives greater economic advantage in making this capacity available on the unrestricted world market. In fact, Russia has been using its excess SWU to enrich its own depleted uranium (DU) stockpiles. The 1.5% enriched blendstock used by Minatom to dilute HEU is in fact stripped from stored Russian tails. Russia uses almost as many SWU to produce this blendstock as would be needed to produce the LEU product from virgin uranium (Bunn 2008).

It is possible that some of the SWU capacity liberated by the lapsing of the Russian-European tails re-enrichment contracts may be deployed to enrich reprocessed uranium that was recovered from Japanese spent nuclear fuel (SNF) but still located in France and the UK. These uranium stocks, amounting to 6,400 tonnes, would be enriched in Russia as part of a larger deal involving natural uranium extraction and enrichment from mines in Kazakhstan in which Japanese companies hold a stake. The Japanese newspaper Yomiuri Shimbun reported that the negotiations are in their “final stage,” (World Nuclear News 2007), but no particulars regarding the terms of the deal are yet available.

At this point, sufficient evaluation has been completed to address ongoing research and development expenses and new capital cost. They can assume to be unimportant to a cost model because the market will drive the price; companies with large research and development efforts must plan to recover those expenses without obtaining a premium for their services.

Prices for reenrichment of depleted uranium hexafluoride would be the same as prices for identical services involving natural uranium. The situation for reprocessed uranium (RU) is more complex. Although commercial RU enrichment is not presently taking place (subject to change in the near term in view of the Russian-Japanese negotiations), the U.S., Russia, and France have enriched RU within their facilities. Russia and France’s supplies are in significant quantities. The U.S. does not presently hold large stocks of RU.

The most recent major study of RU enrichment in the U.S. took place in 1993 (Michaels and Welch 1993). Given the availability of RU stocks, the option has received more frequent attention in Europe (a Russian study [International Business Relations Corporation 2006] was issued in 2006). Given that the latter report is proprietary, the conclusions presented below are drawn from the earlier U.S. study. The Department of Energy (DOE) is presently obligated to accept RU for enrichment, provided the source uranium was originally enriched in a DOE facility and it meets certain purity standards. DOE reserves the right to apply an additional “service charge,” which has historically been nominal—up to $10 per kilogram of RU feed or about a 10% surcharge per SWU when the separative work is computed according to the traditional two-component formula. The service charge is in fact based upon the additional separative work requirements to enrich RU feed to a specified U-235 content given the presence of U-236. Indeed, to ensure that the tails from the RU enrichment process can be stored and disposed in the same manner as traditional DU, it is advantageous to pursue one of the following:

- Blending of RU feedstock with natural uranium (NU) to decrease the U-232 and U-236 concentrations. This strategy offers the further advantage of reducing the level of over-enrichment required to compensate for the negative effect of U-236 on the neutron economy of a reactor.
- Blending of RU with HEU or alternatively LEU having greater than 5% enrichment. This option would obviate the need to pass any RU through an enrichment cascade, but like RU use as a diluent in mixed oxide or fast reactor fuel, it may not be sufficient to balance the rate at which RU is recycled with the rate at which it is produced.
- Employment of a secondary cascade to produce a second tails stream that is highly concentrated in U-232. This small amount of material would require some decades of storage before becoming disposable in the same fashion as traditional DU.

In any case, since there is no indication that Russia imposes more than a nominal surcharge for enrichment services involving RU and since the DOE charge is also nominal, the SWU price estimates given in this section would also be valid for RU, *given that the RU meets purity standards* and that the separative work for the multicomponent stream is calculated according to the methodology given in the 1993 ORNL report (Michaels and Welch 1993). If the simpler two-component (U-235 and U-238) equation is used to calculate the SWU, a 10% surcharge should be assessed to the SWU cost as a first approximation.

Decontamination and Decommissioning (D&D) is the area in which enrichment of RU would be expected to most impact costs. A great deal of uncertainty surrounds the correlation between RU enrichment and D&D costs for the three U.S. enrichment facilities. The Uranium Enrichment Decontamination and Decommissioning Fund was established by the 1992 Energy Policy Act. This fund was to be paid into between 1992 and 2007 by government appropriations and utilities, with the utility portion reflecting previous purchase of SWU from government-owned facilities. In addition to D&D costs, the fund is also intended to defray remedial cleanup activities, waste management, plant surveillance and maintenance, and reimbursement to active uranium and thorium processing facilities to defray their own decontamination and cleanup costs. Therefore, it is difficult to identify from the fund balance that portion of the costs that are organic to RU enrichment.

The most substantial additional expenses that adhere to RU enrichment are therefore purification and tails disposal (see Module K). Effective removal of fission products, especially Tc-99, is necessary prior to enrichment or disposal. Both of these issues are also complicated by the presence of the isotope U-232. Although U-232 ($T_{1/2} = 68.9$ yr) is present in RU at levels of a few parts per 10^7 atoms, Th-228, and other daughters in its chain that undergo particularly energetic decays lead this parent isotope to be the dominant contributor to the RU dose field. Given that these daughters are removed from the uranium stream at the time of separation, it is advantageous to enrich RU as quickly as possible to avoid a costly secondary purification step. Indeed, the dose rate from RU immediately following its separation is nearly the same as that of NU. One year after separation, the RU dose rate increases to almost ten times that of NU and its decay power exhibits an even more substantial increase; the radiation field from RU peaks about 10 years after separation. Therefore, it seems essential to enrich the RU within a few months of its separation.

If quick re-enrichment is not possible, or if the original separation process does not sufficiently extract certain fission products and actinides, additional “polishing” of the RU would be required. A number of polishing processes have been proposed. While PUREX or a similar aqueous process could be employed, given the low contaminant concentrations, other methods offering considerably less complexity and expense can be pursued. One of these is fluoride volatility purification (high-purity separation of uranium fluorides from fluorides of many fission products and actinides). Uranium fluorides become volatile at significantly lower temperatures than other fluoride compounds; none of the noble metal fluorides become gaseous at a temperature within 30 K of the UF_6 boiling point. Indeed, this purification process is already employed at the Metropolis Works and other U fluorination facilities, and the cost of purifying RU in this fashion would be similar to the cost of conversion. See Module K2 for further discussion of RU polishing and its cost.

C1-5.2 Assumptions

Should the demand for natural uranium begin to grow quickly, the price for enrichment could increase in the short term as capacity is added. The price of enrichment services will also be responsive to short-term relatively rapid increases in uranium pricing as has been the case since 2004. As uranium prices increase, the desire to reduce the tails concentration also increases, thus creating a more rapid change in the demand for SWUs. While this is self-correcting in the longer term, it has demonstrated an increase in the volatility of SWU pricing. However, there is no apparent driver other than a rapid increase in demand that should drive up the relatively stable price of SWU, and shortfall can be accommodated with the release of more HEU to produce enriched uranium product without enrichment. The addition of new capacity from gas centrifuges in the U.S. should also have a stabilizing effect on future cost as more than 75% of the current U.S. need is being met through foreign support. The new SWU capacity in the U.S. will be replacing the gaseous diffusion technology with the more cost-effective centrifuge technology. However, the U.S. industry will need to recoup the large capital expenses to obtain the newer and more cost-effective technology.

C1-6. LIMITATIONS OF COST DATA

There are obviously many factors with impact on the enrichment demand. See Section C1-4 for details. Real time costs are not reported because of the highly competitive nature of the tight supply-demand scenario, which at this point is nearly balanced.

Modelers and forecasters must view the total uranium supply picture and consider the closer relationship between the price of natural uranium and enrichment as utilities try to optimize the total front-end of the fuel cycle. While enrichment currently represents between 30 and 40% of the cost of fuel, short-term fluctuations should have only a moderate impact on the overall fuel cycle costs. When a closed fuel cycle is considered, its impact will be dwarfed by the reprocessing and fuel fabrication expenses.

As centrifuge technology replaces diffusion, assuming long-term supply-demand equilibrium with open markets, its lower production costs should translate into lower SWU prices. A dramatic drop in SWU prices is not expected for two reasons. First, since centrifuge plants are modular, producers can expand capacity incrementally and relatively quickly, avoiding creation of a persistent supply glut. Second, the SWU market is not fully competitive in the sense that enrichers do not offer fully flexible contract terms. For example, the cost-minimizing process of tails enrichment optimization, while easy to carry out in paper, is not generally an option in present-day contracts which stipulate a fixed tails assay for their duration.

C1-7. COST SUMMARIES

The module cost information is summarized in the WIT cost summary in Table C1-5. The summary shows the reference cost basis (constant U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT. Note that the reference costs have been adjusted from 2006 to 2009 dollars and rounded to the nearest $5.

The uniform distribution based on the costs in the WIT table is shown in Figure C1-18.

Table C1-5. Cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$110/SWU	+/- $25	$85/SWU	$135/SWU[b]	$110/SWU
Reflects a competitive and mature market where current world demand and supply are nearly matched		Upside potential exists only when capacity exceeds supply. This is not expected in the medium term. In the long term, this reflects the lower production costs for centrifuge technology.	Should demand for uranium increase rapidly, capacity would also have to increase driving some short-term increases in price.	Reflects the relatively stable price for the 1990–2005 time period.

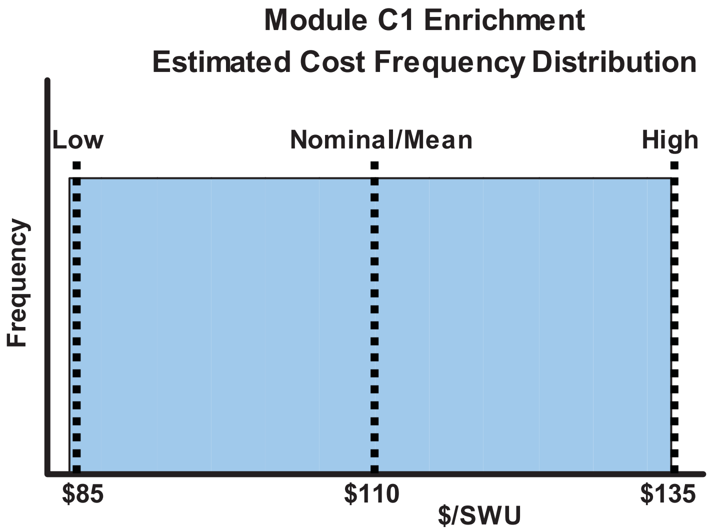


Figure C1-18. Enrichment estimated cost frequency distribution.

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[b] The authors recognize that uranium and enrichment spot prices have in recent years exceeded the high-cost range provided in this cost basis. These price trends are being evaluated and the cost ranges in the report will be revised as appropriate in future updates. The cost basis reflects reasonable expectations about uranium and enrichment long-term contract prices applicable to reactors with long operating lives, rather than reflecting market spikes as experienced in the 1970s and observed in the spot market U_3O_8 prices circa 2005.

C1-8. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

SWU is a service and as such is subject to volatility not seen in largely noncompetitive back end processes such as reprocessing and repository disposal. It is important to reflect this volatility in the proposed long-term price distribution, so that uncertainties in future SWU prices are properly captured. Figure C1-19 is a histogram of the inflation-adjusted quarterly average SWU price shown in Figure C1-20.

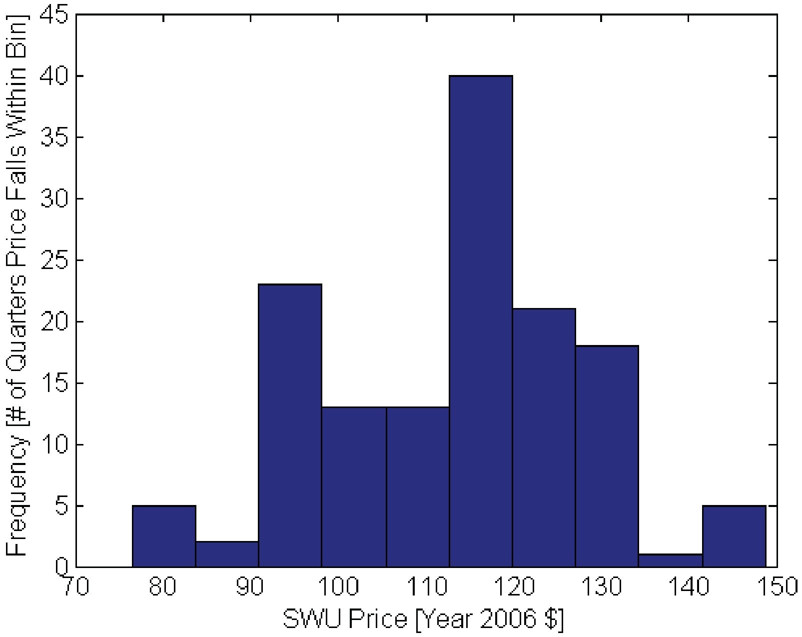

Figure C1-19. Histogram of quarterly SWU prices, 1972–2006.

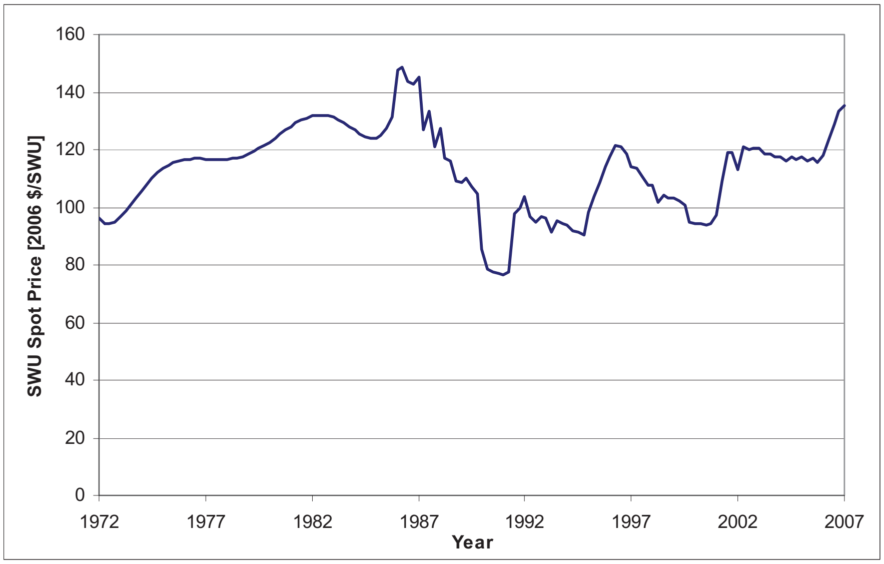

Figure C1-20. Historical SWU price (UxC spot post-1986), adjusted for inflation.

Table C1-6 summarizes the statistical parameters of the historical SWU price along with those of two proposed future price distributions. Both of these have lower and upper bounds of $80 and $130 per SWU. One proposed distribution is triangular, like those employed to describe costs associated with many other modules; it is also symmetric, with the likeliest price chosen to be $105 per SWU. The second option is a uniform distribution, with all prices between $80 and $130 being equally likely. The triangular distribution shows a smaller variance than does the historical SWU price data; the uniform distribution matches well in this area.

Therefore, the uniform distribution, with its implication that low and elevated SWU prices are equally likely even over the long term, appears more able to replicate uncertainties in this price. It is adopted as the reference distribution for this module.

Table C1-6. Statistics of historical quarterly SWU price distribution versus proposed distribution (2006 dollars).

	Historical ($/SWU)	$80–130 ($/SWU) Triangular Symmetric	Proposed: $80–130 ($/SWU) Uniform
Mean	113	105	105
Median	116	105	105
Standard Deviation	14.9	9.8	14.9

A lower price limit of $80/SWU is forecasted over the medium to long-term. This projection is supported by Rothwell's (Rothwell 2007) formulation of the 2015 SWU spot market supply curve. Figure C1-21 depicts an estimate of the situation in 2015, with the heavy black line representing the supply curve. The thin blue box represents the contribution of electricity purchase to the production cost; the areas of the pink and orange boxes represent the profits forecast for the Russian and URENCO facilities, respectively. Steps in the curve represent individual facilities; all facilities planned to be operational by 2015 are included and minimal demand growth prior to 2015 is assumed. By 2015, all world capacity will utilize centrifuges, so that plants in Russia as well as new capacity in the U.S. and France each appear as steps in the supply curve.

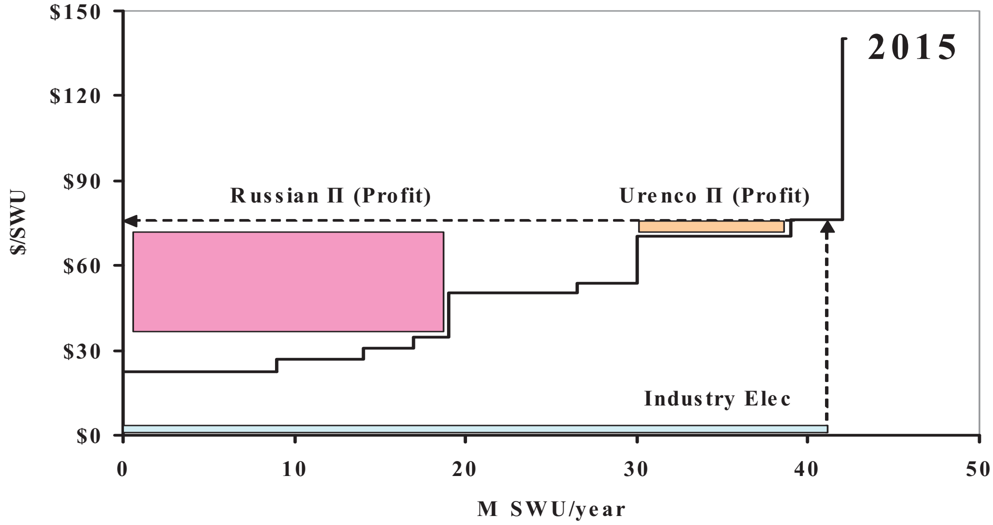

Figure C1-21. Supply Curve for the SWU Spot Market, 2015 Projection (Rothwell 2007).

The plateaus in the curve represent production costs for each facility. At a demand of ca. 42 MSWU/year, the production cost for the marginal plant—the cost of producing one additional SWU at the most expensive plant to operate—is about $75/kgU. Making the assumption of equilibrium, so that price equals marginal production cost, one arrives at a SWU price very close to the lower estimate presented here. It is important to note that the SWU market will evidently be very tight in 2015, so that a supply disruption or unexpected increase in demand could easily push prices significantly higher.

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Module C2

Highly Enriched Uranium Blend-down

Module C2
Highly Enriched Uranium Blend-down

C2-1. BASIC INFORMATION

Module C2 discusses the use of U.S. and Russian government-owned highly enriched uranium (HEU) blended down as a secondary supply to meet demand for low-enriched uranium (LEU). The introduction of such government weapons-origin LEU has a direct impact on the uranium supply chain by reducing the need for newly mined uranium, conversion capability, and enrichment services. This impact was anticipated, and the two governments agreed to control such addition into the LEU supply so as to have minimal impact on the front end fuel cycle industries.

After the end of the Cold War, nonproliferation considerations made it imperative that safe and economical means be found to disposition stockpiles of surplus HEU (and other nuclear materials) from the U.S. and Russian weapons complexes. Because of the quick dissolution of the Soviet Union, the security of HEU in Russia became the paramount issue. In the mid-1990s, a program was initiated under which the west would receive and purchase $LEUF_6$ from Russia. $LEUF_6$ is made by blending converted Russian HEU with Russian slightly enriched uranium. This bilateral U.S.-Russian "Megatons to Megawatts" program agreed to the blend-down of 500 MTU of Russian HEU with Russia receiving market value for the separative work units (SWUs) and natural uranium feed content for the LEU produced by blending.

The U.S. private corporation United States Enrichment Corporation (USEC) acts as the U.S. agent for enrichment sales to U.S. utility customers, and Techsnabexport (known as TENEX) acts as Russia's executive agent for sales to USEC. The U.S. agreed to purchase over a 20-year period (1994–2013), 500 metric tons (MT) of HEU (~90% U-235) from Russian weapons down blended to LEU_6 (4.5% U-235). The HEU is down blended in facilities at Seversk, Zelenogorsk, and Novouralsk. USEC receives the equivalent of about 30 MT/yr of HEU in the form of LEU_6 (~5% U-235) derived from blend-down of Russian HEU for sale and distribution to the U.S. utility market. In return for the LEU procured from Russia at an agreed upon market price, USEC returns to TENEX natural uranium as uranium hexafluoride (UF_6). This is equivalent to the natural uranium and conversion service that was incorporated into the down-blended HEU, effectively only procuring the enrichment services SWUs contained in the LEU. USEC uses the UF_6 to supply utility customers in the U.S. This secondary supply of LEU, therefore, effectively represents about 5.5 million SWU annually to the U.S. market. In most years of this decade, the 870 MT of LEU delivered annually to the U.S. from this program supplied approximately 40% to 50% of the nuclear power used in the U.S. and approximately 10% of overall U.S. electricity production. As of June 30, 2009, 367 metric tons of bomb-grade HEU have been recycled into 10,621 metric tons of LEU, equivalent to 14,686 nuclear warheads eliminated.

The natural assay UF_6 that is received by TENEX is marketed through an HEU Feed Deal Agreement to a consortium of Cameco, COGEMA (AREVA), and RWE NUKEM. The remaining UF_6 that is not purchased can be returned to Russia and placed in an inventory monitored by the U.S. Department of Energy (DOE). Each year TENEX is permitted to withdraw 7,000 lb from the approximately 44 MT of monitored inventory for use in further downblending or delivery into existing contracts in Russia and the former Soviet-bloc states.

In July 2006, the Russian Federal Atomic Energy Agency announced that Megatons to Megawatts would not be renewed past its 2013 expiration date. While it is possible that Russian downblending activities will continue, it appears that Russia views direct control over the marketing of the LEU product to be advantageous. It is known that they still have hundreds of metric tons of HEU in surplus for their military needs. Although this development was not unexpected, it is now certain that domestic utilities will need to look elsewhere to secure the 40–50% of their annual requirements that are currently being served by Megatons to Megawatts.

Likely, the 1992 USEC-TENEX agreement will be amended such that Russia (Tenex) can directly compete for up to 25% of the U.S. enrichment market after 2013. The SWUs produced may not necessarily come from blend-down in Russia. Russia has plenty of gas centrifuge enrichment capacity available for direct production of LEU from either tails or natural uranium feedstocks. This agreement is to stay in force until 2020, at which point Russia will no longer have a marketing cap imposed. These constraints are required to protect the U.S. front-end fuel cycle industries (mining, milling conversion, and enrichment) from SWU "dumping" because of Russia's ability to undercut the pricing of all competitors. This issue of international SWU marketing is discussed in a comprehensive paper by Matthew Bunn (Bunn 2008).

Figure C2-1 is a schematic of the U.S.-Russian Megatons to Megawatts program.

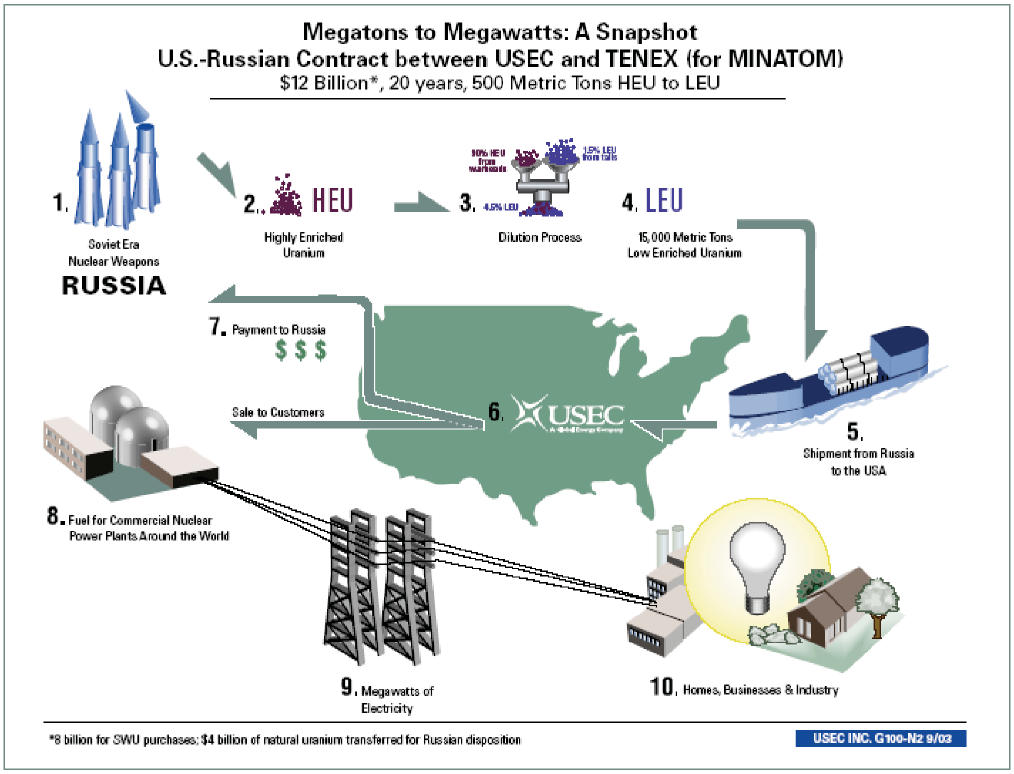

Figure C2-1. Megatons to Megawatts program (USEC 2006).

The U.S. has its own version of the Megatons to Megawatts program declaring an excess of 174.3 tons of HEU from the weapons program. This HEU has a U-235 content from 50 to 90+% with various amounts of impurities. Some of this material was of sufficient quality to be down blended at USEC's Portsmouth Plant (14.2 MT HEU) with additional downblending in progress at BWX Technologies Inc. in Lynchburg, Virginia (46.6 MT HEU). These two down-blending campaigns were completed in July 1998 and September 2006, respectively. Some of the U.S. Government "off-spec" HEU (reprocessed HEU with U-236 and slight fission product/transuranic contamination) has been processed and blended down under the BLEU (Blended Low Enriched Uranium) program. The material (~39 MT HEU) is decontaminated at the Savannah River Site (SRS) in Aiken, South Carolina, and shipped to

Nuclear Fuel Services in Ervin, Tennessee, for blend-down to LEU and refabrication by AREVA for use in Tennessee Valley Authority reactors. (The blending and refabrication of this material for use in LWRs is discussed in Module D1-1.) Approximately 120 MT HEU remaining in DOE inventory represents a reserve of about 21,000 MT of natural uranium equivalent, roughly 1 year's supply for the domestic reactor fleet at current consumption rates.

Up until very recently, the down-blended LEU has purposely not been made available for sale in the U.S. to avoid a significant negative impact on the uranium supply and conversion vendors (see Section C2-9). The U.S. DOE has recently procured a contractor to expedite the blend-down of surplus Defense program HEU to LEU. The contractor will be allowed to keep an agreed amount of the blended material as compensation for their effort and which can be sold to nuclear utilities. Nuclear Fuel Services of Erwin, Tennessee, a recently purchased subsidiary of Babcock and Wilcox, is the selected contractor to DOE/NNSA for this program (NFS 2009). DOE will continue to control the entry of the HEU to LEU into the market. In fact, the probable DOE strategy calls for its sales from all sources to not exceed 10% of the annual domestic requirements (i.e., about 2000 MT natural uranium equivalent per year). While the bulk of DOE sales over the next decade are expected to come from downblended HEU, off-spec and otherwise, the HEU represents only a minority of DOE's total reserve of about 52,000 MT natural uranium equivalent. The remainder of the DOE inventory is in the form of UF_6; while most of this is unenriched natural uranium, part (9000 MT natural uranium equivalent) is termed "depleted uranium of economic value." The assays in this stockpile are variable but never less than 0.4% U-235. The U.S. DOE recently issued a "Management Plan" for the disposition of this material. (DOE 2008)

C2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Russian HEU to LEU. The product received by USEC is EUF_6 in small UF_6 cylinders of 4–5% U-235 content shipped from St. Petersburg, Russia, to a U.S. port and eventually DOE's Portsmouth site, which is leased by USEC. At Portsmouth, it can be further blended from 5.0% U-235 to the light-water reactor utility's exact U-235 assays before shipment to a fuel fabricator. Under USEC's arrangement it is receiving only SWU from Russia, not uranium. USEC is obliged to return the uranium content of the EUF_6 to Russia. Typically the USEC sells Russian LEU to their customers and returns to the Russians natural uranium that those customers gave USEC to enrich.[a]

The conversion of Russian nuclear weapons takes place at several locations. It begins with the removal of the warheads and their HEU metal components from strategic and tactical nuclear missiles**.** The HEU warhead components are machined into metal shavings. The shavings are then heated and converted to an HEU oxide, and any contaminants are chemically removed. The HEU oxide is converted to highly enriched UF_6, a compound that becomes a gas when heated. The highly enriched UF_6 is introduced into a gaseous process stream. There, it mixes with other material and is diluted to less than 5% concentration of the fissionable U-235 isotope. The now low-enriched UF_6 fuel is checked to ensure the product meets commercial specifications and is then transferred to 2.5-ton steel cylinders. The uranium fuel is enclosed in shipping containers and sent to a collection point in St. Petersburg. USEC takes possession of the fuel containers in St. Petersburg and they are shipped to USEC's facilities in the U.S. (originally the Portsmouth plant but now the Paducah plant). The LEU is tested again to ensure that it meets appropriate commercial and customer specifications. If necessary, the enrichment level of the uranium fuel can be further adjusted at Paducah to meet utility customers' needs. Based on customer instructions, USEC ships the LEU fuel to fabricators (Global Nuclear Fuel, Framatome, or Westinghouse), who convert the LEU into uranium oxide pellets and fabricate them into fuel assemblies. The assemblies are then shipped to USEC utility customers as a source of fuel for their nuclear reactors.

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[a] USECs 2006 K-10 SEC filing.

U.S. HEU to LEU. Unlike conversion facilities in the Russian Federation, U.S. facilities must convert HEU metal into uranyl nitrate hexahydrate (UNH). For project BLEU, which uses previously irradiated SRS uranium the blended UNH product is delivered to fuel fabricators where it can be further converted to uranium oxide powder and pelletized for use in fuel rods. At the SRS, off-specification material from weapons production was dissolved and processed through H Canyon (a large chemical fuel reprocessing plant) to remove impurities, blended with natural uranium supplied by industry, and shipped as a UNH solution to Nuclear Fuel Services in Erwin, Tennessee. Nuclear Fuel Services will also eventually convert HEU metal and unirradiated uranium-aluminum alloy into uranyl nitrate solutions as well. The UNH solutions from SRS and Nuclear Fuel Services (NFS) will be converted by NFS/AREVA to LEU oxide powder. The oxide will be shipped to Richland, Washington, where it will be prepared and pressed into fuel pellets and built into fuel assemblies by Framatome Advanced Nuclear Products to be used in Tennessee Valley Authority reactors. The new blend-down program being undertaken by NFS will utilize “virgin” or unirradiated HEU surplus to defense programs. The uranium processing methodologies will be similar, with the difference that the feedstock should have fewer impurities.

C2-3. SCHEMATIC OF PROCESS

Figures C2-2 and C2-3 show simplified flow diagrams for the Russian and U.S. processes “currently” being deployed to blend down excess weapons HEU material to LEU for use in commercial reactors.

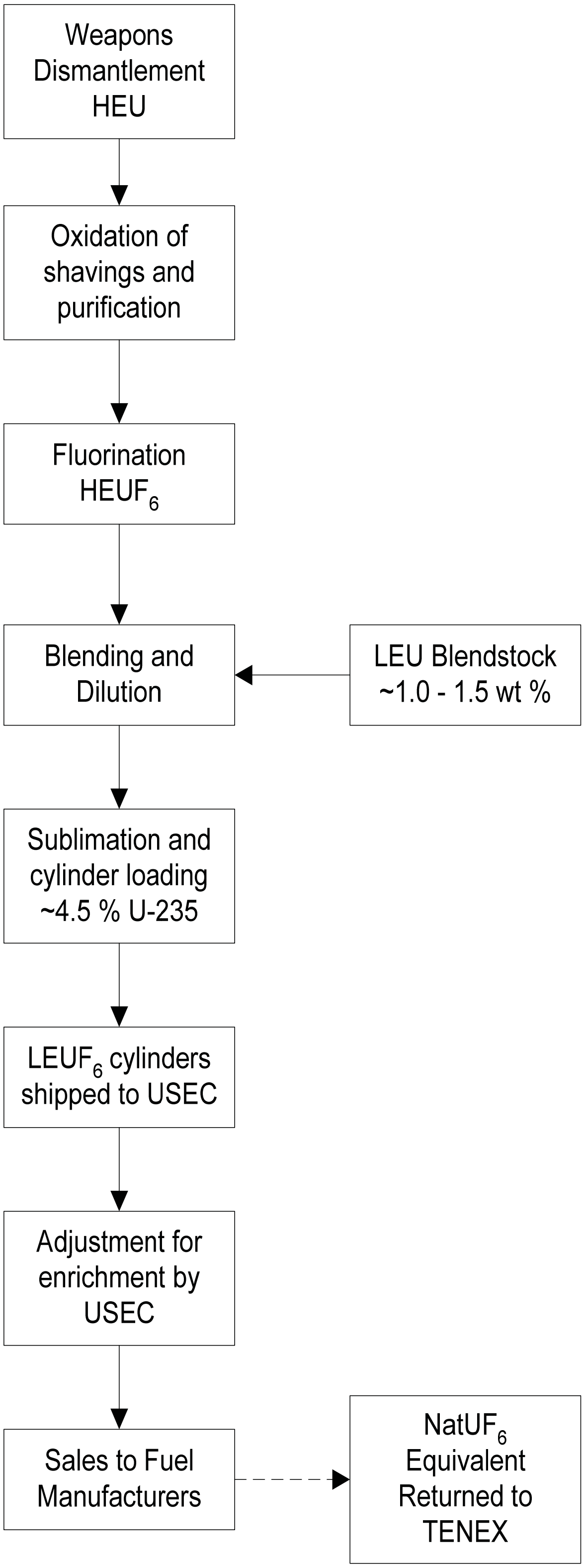

Figure C2-2. Russian HEU to LEU blend process.

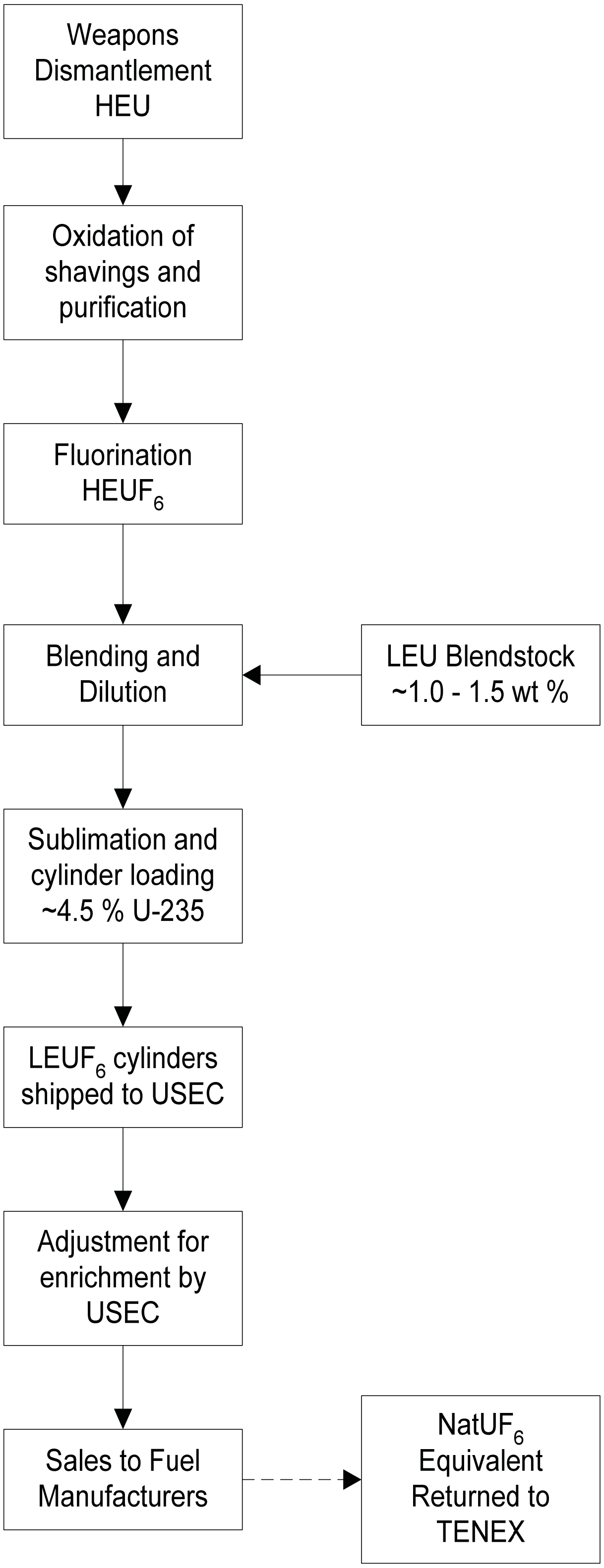

Figure C2-3. Generic U.S. off-specification HEU to LEU blend process. (Selected DOE contractor may modify this generic process.)

C2-4. MODULE INTERFACE DEFINITIONS

HEU blending essentially is an alternative to the steps of mining and milling, U_3O_8 to UF_6 conversion, and uranium enrichment. The EUF_6 product is provided directly to the fuel fabricator (basically the same product as from Module C1).

C2-5. MODULE SCALING FACTORS

Scaling factors do not apply to this model. Twenty-five to 30 MTU of HEU are blended annually.

C2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Cost and Pricing. USEC and TENEX are actually paid as they are supplying commercial enrichment and natural feed services. The Russians charge an enrichment price in the low range of commercial enrichment prices. The buyer must provide the natural uranium content and value associated with the LEU. This can be done by a payment or actually providing Russia with U_3O_8 or $NatUF_6$. “Flag Swaps” on uranium possession between nations can also be used to avoid transportation costs.

The actual cost of the blending operations is not known. The western value of EUF_6 at commercial ore, conversion, and enrichment sources is around \$800 to 1,500/kgU. The costs of enrichment to HEU are sunk costs to Russia, which were realized decades ago. Ninety percent of U-235 HEU is worth \$35,000/kgU at western commercial ore and SWU prices, but there is no legitimate market for this today. It is estimated that the cost of conversion and blending in Russia is a small fraction of what they realize from their sales. All operations, including tails enrichment (which does use a considerable amount of SWU), HEU oxidation and fluorination, and blending, probably cost Russia less than \$100 per kg of LEU sold. For purposes of modeling the impacts of HEU blend-down, the impact is only one of supply. The actual market price will be kept reasonably close to (and slightly below) the market price for EUF_6, which originated from natural uranium.

C2-7. LIMITATIONS OF COST DATA

No actual Russian or U.S. cost data are available. Modelers and forecasters can make the assumption that the cost impact from current or future HEU to LEU blend-down will follow the general market trends with the effective cost of Russian SWUs being close to the open market SWU cost. Neither market penetration nor HEU/LEU cost contracts are expected to do anything to make a dramatic impact on the basic supply demand chain.

C2-8. COST SUMMARIES

Because the basis for this program is government driven, the politics of HEU reduction becomes a more important factor than economics. See Section C1-8 in Module C1 for cost summaries relative to market driven SWUs and assume this program will have some parity to those assumptions.

It can be assumed that the equivalent of 30 MT of HEU will continue to enter the market through the end of the current agreement (2013). The U.S. entry into the LEU market will be gradual and controlled so as to have minimal impact on the uranium supply market. It can be further suggested that because the U.S. and Russia have considerably more HEU in the stockpiles, the Russian agreement for HEU purchase and accompanying U.S. reduction as well could continue for at least another decade. The impact is only to minimize the squeeze on producing newly mined uranium over the next 2 decades should growth in nuclear power become more prevalent.

C2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

Figure C2-4 is a conceptual illustration of the effect of sales of blended-down HEU, or any other government-held uranium inventory, on the market. The blue curve shows the price-supply relationship for primary uranium from mines. The dark red curve is the demand curve; some elasticity is afforded by the ability of utilities, over the medium term, to adjust the enrichment of tails, so the curve is not vertical. If no secondary supply sources exist, Point 1 is the market clearing point.

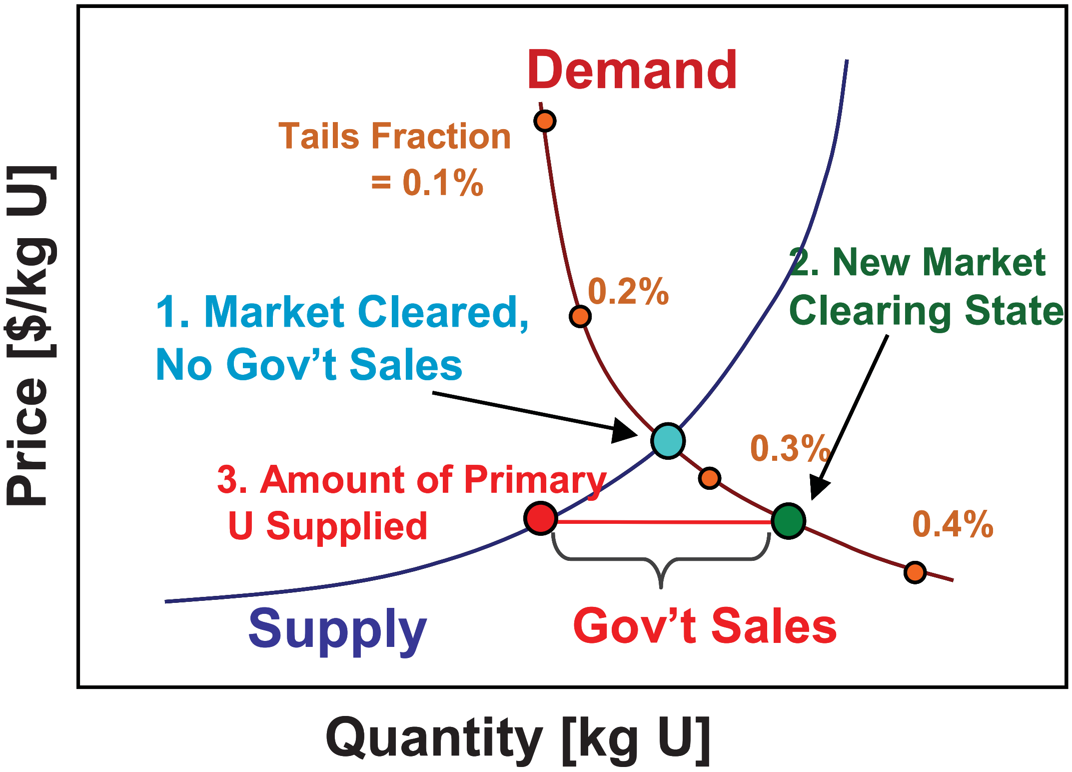

Figure C2-4. Effect of down blended HEU sales on the uranium market.

If government decides to place some uranium on the market, both the price and quantity supplied will change. This secondary uranium may come from government stockpiles as well as HEU blend-down; in fact, the secondary source of uranium could be in private hands, for example utility or producer inventories. Regardless of the source, the secondary uranium has the dual effect of reducing the amount of primary uranium supplied and reducing the market price. In the figure, the quantity of secondary uranium placed on the market is represented by the line connecting Points 2 and 3. The secondary uranium essentially shifts the supply curve to the right by this amount, so that Point 2 becomes the new market clearing state and Point 3 is the amount of uranium supplied by mines. Since the uranium price has decreased, utilities choose to consume less SWU in exchange for more uranium so that the optimal tails enrichment increases.

A situation like the one shown in the figure existed through the 1990s as utilities consumed uranium from stockpiles while down-blended HEU and other varieties of secondary uranium appeared on the market as well. This situation is somewhat analogous to dumping situations that occur from time to time in commodity markets, and its effect of suppressing primary supply over time is well known. Indeed, it is for this reason that DOE has constrained itself to sell only limited quantities of its surplus uranium over the next decade.

C2-10. Other U Blending Programs

The U.S. government's defense and reactor nuclear programs have a legacy of around 2 metric tons of blended HEU and U-233 stored mostly at Oak Ridge (ORNL Building 3019) and at Idaho National Laboratory (INL). This material is over 80% fissile and also contains daughters that make it highly radioactive and difficult to handle. This material originated from defense work and work on thorium fuel cycles. (See ORNL [1999] for complete information on this fissile material, which could someday be used for fuel cycles involving thorium.) This blended material is to be blended with depleted U (from SRS) at Oak Ridge, and the packaged waste shipped to the Nevada Test Site for geologic burial. The cost of this program is estimated to be \$384M. Over 400 metric tons of blendstock DU are required. From these numbers it can be seen that a cost of over \$850/kgU of blended material is calculated. It should be noted that considerable processing, repackaging, transportation, and disposal costs are associated with this hazardous material. U-232 and its decay daughters account for much of the radiological hazard. Isotek Services, a consortium of Energy Solutions, Burns and Roe, and Nuclear Fuel Services, is the contractor for this blend-down task (Knoxnews 2009). It should be noted that U-233 is a potential nuclear fuel; however, its radioactivity (specific activity) is closer to that of Pu-239 than U-235. For this reason today's uranium fuel fabricators are reluctant to handle it. Its use would also require a significant fuel qualification program.

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Module Series D1

Fabrication of Contact-handled Fuels (Summary for Modules D1-1 through D1-9)

Module Series D1

Fabrication of Contact-handled Fuels

D-1. INTRODUCTION

Fuel fabrication represents the set of chemical, ceramic/metallurgical, and mechanical steps that take a basic chemical form of the fissile material (such as enriched UF_6 product from an enrichment plant or other fissile chemical forms from a spent fuel reprocessing plant) and convert it to finished fuel assemblies and associated hardware ready for insertion into the reactor as either first cores or reloads. This category would also apply to blanket or target materials that are irradiated in a reactor along with the driver fuel (i.e., a heterogeneous reactor system). The nature of these facilities and operations is affected by the following factors:

1. **Type of reactor system** (Module R) into which the fuel will be charged and its associated peak temperatures, fuel heat transfer considerations, reactor moderator/coolant chemistry, fuel fissile enrichment (% U-235, fissile plutonium and other actinide isotopes, or U-233 in the diluent fuel materials), and desired fuel burnup. Fissile isotope enrichment level is important because it defines the batch sizes and equipment sizes that can be accommodated in a fuel fabrication plant that is safe from a nuclear criticality standpoint. The choice of the fuel fissile material also affects the facility design from a safety and environmental standpoint, because some elements, such as plutonium and other higher actinides, present a significant radiotoxicity hazard. As noted below, the nature of the radioactivity of the elements within the fuel will determine whether fuel is "contact-handled" and will be covered in this D1-series of modules or is "remote-handled" and will be covered in the F2/D2 module. The nature of the fuel-handling environment has a very strong effect on fuel fabrication design and ultimately fuel fabrication unit costs. Nonproliferation is another factor that is also becoming increasingly important in assessment of fuel types. The "attractiveness level" to a potential proliferator will depend on the fuel's radiological and isotopic properties and its physical form. As closed fuel cycles are considered, the compatibility of the fuel form with the associated spent fuel reprocessing scheme (Modules F1 and F2/D2) must also be considered. The fact that new fuel might be refabricated from reprocessing plant "products" is another economic consideration, since "avoided costs" for other fuel cycle steps come into play.

   Fabricated fuel assemblies take many different physical forms. Every September, Nuclear Engineering International (Nuclear Engineering International 2006) publishes diagrams and design data for fuel assemblies required by most of the world's commercial reactors (i.e., pressurized water reactors [PWRs], Voda-Vodyanoi Energetichesky Reaktors [VVERs; Russian pressurized water reactors], boiling water reactors [BWRs], and heavy water reactors [HWRs]).

2. **The regulatory and quality assurance requirements for the fuel as stated in the fuel specification** (i.e., American Society for Testing and Materials [ASTM] International "specs" for enriched uranium oxide [EUO_2] and light-water reactor [LWR] mixed oxide [MOX] fuel). These specifications define the morphology, mechanical properties, and allowed impurity levels in the fuel. The intent is to minimize the probability of fuel failure or leakage of fission products into the reactor coolant/moderator. Whatever matrix or containment in which the base fuel form resides, such as a pellet or particle, must be able to confine fission product noble gases and other volatile radionuclides over the duration of irradiation exposure. This means that any fuel types used by electrical utilities must have undergone a rigorous fuel qualification process, which is likely to include the irradiation and postirradiation examination of test fuel ampoules and lead test assemblies.

1. **The fuel form must be capable of safe and secure transport and storage** both as unirradiated fuel before reactor insertion and as spent fuel after discharge. The integrity of the cladding or fuel matrix must be maintained at all times.

   The following assumptions are made for the cost analysis for Module D1:

2. Nine types of fuel will be considered: (1) ceramic UO_2 LWR fuel in the form of clad pellets (Section D1-1), (2) ceramic MOX (UO_2/PuO_2) LWR fuel in the form of clad pellets (Section D1 2), (3) gas-cooled reactor fuel in the form of coated particles in a graphite matrix (Section D1-3), (4) ceramic pellet fuel (and possible pellet blankets) for use in sodium-cooled fast reactors (Section D1-4), (5) ceramic vibrocompacted fuel for use in sodium-cooled fast reactors (Section D1-5), (6) metallic and alloyed fuels for use in sodium-cooled fast reactors (Section D1-6), (7) natural or slightly enriched clad pellet fuels for use in heavy-water moderated Canadian deuterium-uranium (CANDU)-type reactors (Section D1-7), (8) fuels involving the use of thorium as a fertile material, including “seed-blanket” concepts (Section D1-8), and (9) “advanced fuels,” which will include dispersion and inert matrix fuels (Section D1-9). Each of these fuels will be treated in the subsequent writeups as if it were a separate module. The subsection numbering for D1 will subdivide each fuel’s section into the same 10 topics (N.1 through N.10; N=1 through 9 depending on fuel type) as if it were a stand-alone module.
3. For this Module D1, all nine fuel types are assumed to be contact-handled. This means that the radioactivity level of the fresh, unirradiated driver fuel or blanket/target fuel is low enough that the rods and fuel assemblies can be safely handled outside of hot cells. (Gloveboxes may be required, however.) This would mean that the fuel handled is likely to be uranium, plutonium, or plutonium with small amounts of neptunium. This is in contrast with the transmutation fuels discussed in Module F2/D2 that originate from a non-PUREX recycling (reprocessing) process and are not separated to the extent that they can be contact handled. These fuels are likely to contain significant amounts of higher actinides, such as americium and curium, and may also include some unseparated fission products such as elements from the lanthanide series. Some of these remote-handled fuels will need to be refabricated in a hot-cell immediately adjacent to an electrochemical reprocessing step and involve inherently simple metallurgical operations such as direct injection-casting of fuel rods. These Module F2/D2 fuels are likely to be metal alloy fuels such as those envisioned for the General Electric/Materials and Fuels Complex[a] Integrated Fuel Recycle fuel cycle. Fuel materials, such as oxides, arising from an aqueous reprocessing process, such as UREX 1-a, where higher actinides and small amounts of lanthanides are not separated out (i.e., transmutation fuels) also would require remote refabrication. Because of the integral nature of reprocessing and refabrication for this technology, the F2 and D2 modules are combined.
4. Transportation costs from the fuel fabricator to the reactor are included as part of the fabrication cost. For fuels that can be contact-handled, these costs are generally quite small compared to the manufacturing costs.
5. For enriched uranium fuels, the feed material to the fabrication plant is assumed to be either virgin (never irradiated) or aqueously reprocessed UF_6 from enrichment plants or blending facilities. For natural uranium-fueled or thorium-fueled reactors, the feed material is assumed to be a clean “nuclear-grade” oxide from a mill or processor. No fluorine-related steps are required, since there is no enrichment step requiring UF_6. For MOX fuels (both LWR and foreign reactor) the feed material is assumed to be clean PuO_2 or $(Pu, Np)O_2$ powder from an aqueous reprocessing plant or from a facility capable of preparing clean PuO_2 from weapons program feedstocks. “Virgin” uranium or

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[a] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL). Argonne National Laboratory-West (ANL-W) was renamed the Materials and Fuels Complex (MFC).

thorium fuel materials are those that are not derived from previous irradiation and reprocessing. Enriched uranium prepared from natural (ore-derived) uranium feed is one such material.

6. The level of technical readiness or deployment varies tremendously by the type of fuel considered. The production of LWR fuels is a highly mature private industry, while other fuel types are still in the bench scale or pilot plant development stage of an overall fuel process qualification program.

A cost summary is provided below for each of the nine types of fuel (see Table D1-1). Note that no single reference had up-to-date and "apples-to-apples" comparisons for the costs of fabricating different fuel types. The only documents (Olsen et al. 1979; Judkins and Olsen 1979) found that presented a uniform costing methodology for all fuel types were prepared nearly 30 years ago by ORNL for the International Nuclear Fuel Cycle Evaluation (INFCE) effort. The data therein may be useful to consider on a comparative basis; merely updating the costs therein for general inflation from 1979 to 2008 would not cover all the cost-affecting changes in the regulatory, security, and financial environment surrounding new nuclear projects in the U.S.

Table D1-1. Cost summary table.

What-It-Takes (WIT) Table (updated to 2007 constant $)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
D1-1 LWR UO$_2$ Fuel Fab				
Only unit fuel costs available: $240/kgU for PWR $290/kgU for BWR	Not available	$200/kgU for PWR $250/kgU for BWR $220/kgU for PWR REPU $275/kgU for BWR REPU	20% or less increase if higher enrichment (>5% U-235), higher burnup fuels produced $300 for PWR $350 for BWR $400/kgU for PWR REPU $450/kgU for BWR REPU	$250/kgU for PWR $300/kgU for BWR, for today's LWR fuel designs $300/kgU for PWR REPU, and $350/kgU for BWR REPU
D1-2 LWR MOX Fuel Fabrication				
"Overnight" capital cost for 94 MTHM/yr plant: $4,500 M Unit cost from private plant of above capacity with guaranteed market and guaranteed loan: $4,000/kgHM	10% to 40% Not available	Larger plant size (additional lines) or multishift operation should bring down unit cost. Unit Cost=$3000/kgHM	Use of "dirty" MOX with oxides of higher actinides (curium, neptunium, etc.) will drive up capital, operating, and unit costs and perhaps, depending on concentrations, require remote handling. Unit Cost = $5000/kgHM	Stay with reference cost for "normal" MOX: Cap = $4.5B for 94 MT/yr; $4000/kgHM for first-of-a-kind (FOAK) Unit=$3,200/kgHM for mature nth-of-a-kind (NOAK) technology in US

Table D1-1. (continued).

What-It-Takes (WIT) Table (updated to 2007 constant $)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
D1-3 Gas-Cooled Reactor particle Fuels				
No good data on plant capital costs; Today's 8–19.9% U-235 unit fab cost probably $25,000/kgU	Not available	Assumes complexity of fab process is at best comparable to LWR MOX $5000/kgU	Quality or process development difficulties. Use of PuO_2 kernels $30,000/kgU	If automated process is successful: $10,000/kgU
D1-4 Ceramic Pelletized Fast Reactor Fuel				
No good data on plant capital costs: Reference unit cost: $2,300/kgHM from centralized, private 50 MT/yr facility with loan and market guarantee	Not available	$3,200/kgHM Blanket: $350/kgU	Many of same factors affecting SRS-MFFF would affect this cost. (see Module D1-1) $6,000/kgHM Blanket: $700/kgU	Core (driver fuel): $4,000/kgHM Blanket: $500/kgU
D1-5 Ceramic Vibrocompacted Fast Reactor Fuel				
No data available	No data available	Could be cheaper process than pelletization (fewer steps)	Difficulties in development/automation	$3,600/kgHM if VIPAC assumed 10% cheaper than pellet fast reactor MOX
D1-6 Metallic or Alloyed Fast Reactor Fuel				
See Section D.2 for remote handled. No data available on fab part of recycle process only.	No data available	No data	No data	See Module F2/D2
D1-7 CANDU Fuel				
No fab plant capital cost data available. Unit cost = $135/kgU	No data available	None identified $115/kgU	Use of enrichments over 1% U-235 $155/kgU	Use reference value of $135/kgU
D1-8 Thorium-based Fuels				
$(U,Th)O_2$ pellet fuel	No data	$800/kgHM in Russia (HM is U+Th). Includes SWU component in uranium cost. Longer fuel life than for $LEUO_2$	$3,000/kgHM Higher fuel production costs due to need for 19.95% EU and HVAC modifications	$1,600/kgHM in West (U component includes SWU cost) (HM is U,Th)

Table D1-1. (continued).

What-It-Takes (WIT) Table (updated to 2007 constant $)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Pu-Zr metal fuel for RTPI Pu-disposition application (in tandem with (U,Th)O_2 blanket)	No data	High annual consumption of surplus plutonium in LWR	Having both metal seed and pellet oxide blankets make very complicated and expensive fuel. Long and expensive fuel qualification program needed	$27,000/kg metal (U.S. or Russia) for Pu-Zr driver [seed] fuel
D1-9 "Advanced" Fuels (No cost data available)				

BWR = boiling water reactor
EU = enriched uranium
HVAC = heating, ventilation, and air conditioning
LEU = low-enriched uranium
LWR = light-water reactor
MOX = mixed oxide
PWR = pressurized water reactor
REPU = reprocessed uranium
RTPI = Radkowsky Thorium-Plutonium Incinerator

Module D1-1

LWR UO_2 Fuel Fabrication

Module D1-1

LWR UO_2 Fuel Fabrication

D1-1. BASIC INFORMATION

Fuel Form. Low-enriched uranium (LEU) light water reactor (LWR) fuel for both pressurized water reactors (PWRs) and boiling water reactors (BWRs) is in the form of ceramic enriched UO_2 (EUO_2) sintered pellets stacked inside long (up to 14 ft, depending on the reactor size and manufacturer), sealed Zircalloy (or other Zirconium-based alloys such as Zirlo, E-110, M-5, etc.) tubes. A Western fuel assembly consists of a square (n × n) array of these tubes separated by spacers and held in place via clips and springs. Most of the hardware holding the tubes is also made of Zircalloy or a similar zirconium alloy. The upward flowing water (pressurized water reactor [PWR]) or steam/water mixture (boiling water reactor [BWR]) removes the nuclear-generated heat by contacting the outside surface of the Zircalloy tubes enclosing the pellets. Before sealing, the tubes are pressurized to counteract the reactor coolant's external pressure on the cladding. The tubes are also designed to handle the pressure of any fission product gases generated during fuel irradiation.

D1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Status of the Industry. Production of such LWR fuel assemblies is a highly mature industry and is totally privatized in the U.S. Because of the need to specifically tailor the fuel to the reactor, most of the companies' manufacturing LWR assemblies are also affiliated with the ones that design the nuclear steam supply system for the reactor using the fuel. Table D1-1-1 lists the LWR fuel fabricators in the U.S. and the capacities in terms of MTU/yr for their facilities. This is a highly competitive nuclear business, and because of recent worldwide oversupply (Varley 2002) and general consolidation (Kidd 2005) of the nuclear business, the number of plants in the U.S. has dropped to four. This over-supply situation, however, is ending, with the onset of the "Nuclear Renaissance." LWR fuel fabrication business is highly international, and there are at least eight countries outside of the U.S. that have LWR fuel fabrication plants. Some of these foreign companies are considering significant expansion of their business (Siebert 2006; Gizitdinov 2007; Rothwell and Braun 2007). Some of these foreign companies sell fuel to U.S. utility customers; however, this requires that the fuel production process and the fuel itself be certified by the U.S. Nuclear Regulatory Commission (NRC) just as it would be for a domestic fabricator.
Figure D1-1-1 shows a BWR and a PWR fuel assembly manufactured by Global Nuclear Fuel Americas and AREVA NP, respectively.

Table D1-1-1. LWR fuel fabrication capacity in the U.S.

Plant Owner	Location	Capacity in MTU/yr	Fuel Type
AREVA NP	Lynchburg, Virginia	600	PWR (fuel assembly only, no pellet production)
AREVA NP (formerly Siemens)	Richland, Washington	900	Mainly BWR, some PWR
AREVA NP (ref Energy-Business-review.com 2008)	Erwin, Tennessee	small	$LEUO_2$ powder is produced from blended HEU/NATU nitrate solutions provided by NFS and after conversion to oxide is sent to Richland for pelletization
Global Nuclear Fuel Americas, LLC (GE Energy, Toshiba, Hitachi)	Wilmington, North Carolina	1,100	Mainly BWR
Westinghouse Nuclear Fuel	West Columbia, South Carolina	1,150	PWR, some Vod-Vodyanoi Energetichesky Reaktor (VVER)

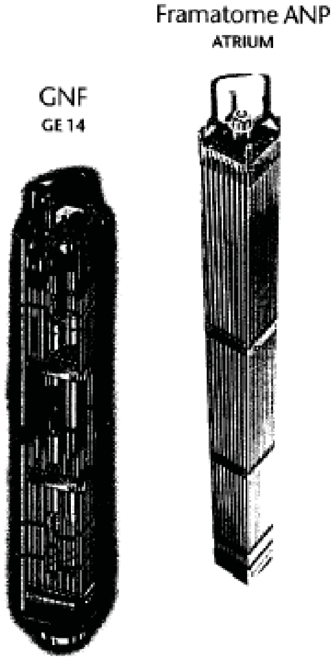


Figure D1-1-1. BWR and PWR fuel assemblies.

Fuel fabrication is a highly "campaigned" business (i.e., the production of the UO_2 powder and subsequent steps are designed to meet the utility customer's enrichment needs and the utility's reload schedule). Each campaign may take several weeks, with time required between campaigns to retool for the next utility's requirements.

D1-3. PICTURES AND SCHEMATICS

Fuel Fabrication Process. Figure D1-1-2 shows the basic steps in the generic LWR fuel fabrication process. The process shown is an environmentally preferable and predominant "dry" process in which there are no aqueous steps in the main process. (There may be some aqueous or "wet" steps in the scrap recycle/recovery lines for such plants, however). Most U.S. manufacturers have migrated toward the dry process and have already qualified $LEUO_2$ fuel prepared in this way.

The first step in the process is a chemical one, "EUF_6 to EUO_2 conversion." Despite the oxide stoichiometry difference it is basically the same as the DUF_6 to DU_3O_8 process described in Module K1, except in this case the fuel is enriched in U-235, and the typical plant EU throughput quantities (400 to 1,500 MTU/yr) are three to four orders-of-magnitude smaller than those in the proposed plants for converting enrichment plant waste or "tails" UF_6 depleted in U-235. Because the enrichment levels for EUO_2 are typically from 2 to 5% U-235, there are some criticality considerations in processing LWR fuel, and batch sizes must be limited. Quality assurance considerations are also important at every step. The EUO_2 powder from the first step must meet a very high purity and morphology specification (ASTM fuel specification) to be used in LWR fuel. The specified low impurity levels and particle size/flowability requirements ensure that the UO_2 will not attack the fuel cladding in the reactor and that the EUO_2 powder will sinter into a strong and stable pellet. For this reason, the cost per kgU for this first EUF_6 to enriched oxide conversion step is at least an order of magnitude higher than the $5+/kgU required to convert depleted UF_6 as discussed in Module K1. This conversion or “powder preparation” cost is eventually rolled into the overall fabrication $/kgU cost/price of the fuel assembly. The second step involves adjustment of the powder U-235 enrichment to meet the customer’s requirement. This is done by blending it with small amount of preexisting enriched blendstock. A binder and flowability enhancer may also be blended with the EUO_2 powder to assist the pellet production steps, which are pressing the “green” pellet; sintering it to a homogeneous, hard ceramic structure; and grinding and finishing it such that it meets dimensional specifications; and loads easily into the Zircalloy tubes. Pellet inspection and loading into tubes is an automated process requiring limited human interaction. Once the tubes are loaded, they are pressurized and welded shut. The washed tubes are then transported to the fuel bundle assembly room where the structural or “skeleton” hardware is added. This operation is semi-automated and requires careful inspection and handling so that the tubes are not damaged and are inserted in the correct array positions. Among the major operations costs involved in the above steps are manufacturing and support personnel and the purchase or onsite manufacturing of Zircalloy tubes and assembly parts. As NRC-licensed fuel cycle facilities under 10 CFR 70, LWR fuel fabrication facilities are also subject to regulatory costs such as inspections. The above recurring operations costs, however, can be partially offset by the sale of hydrogen fluoride (HF) from the UF_6 to UO_2 conversion step if a buyer of very slightly uranium-contaminated HF can be found. Finished fuel assemblies are hung vertically for storage prior to shipping to light-water nuclear power plants (Module R1).

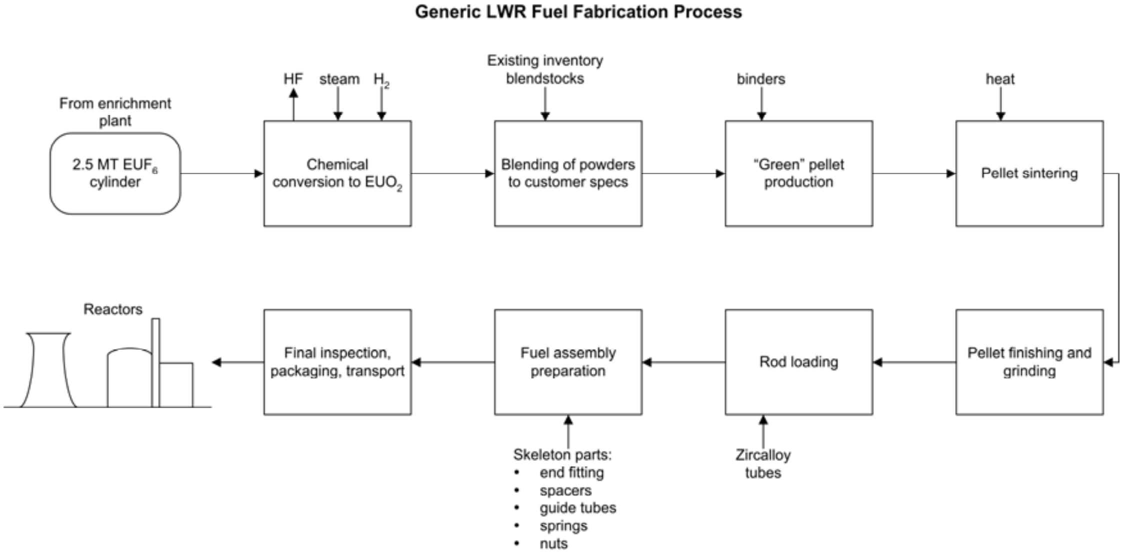


Figure D1-1-2. Generic LWR fuel fabrication process.

D1-4. MODULE INTERFACE DEFINITION

Front-end interface. The EUF_6 is received from the enrichment plant in 2.5 MTU “30B” type cylinders. These criticality-safe cylinders must be “overpacked” during transportation from the enricher or blender in a certified container. The chemical toxicity hazard associated with fluorine product (gaseous HF) release in a transportation accident is far more serious than the small radioactivity level associated with the uranium product UO_2F_2 (solid particles). (Released UF_6 reacts with the moisture in the air to form HF and UO_2F_2.)

Back-end interface. When ready for transportation, the finished fuel is loaded in special shock-absorbing packages, which are then enclosed in wooden crates. Commercial carriers usually transport these packages on flat bed trucks to the LWR plant sites. The ceramic UO_2 form in sealed tubes is a very safe form for transportation, and the external radiation hazard is very low.

D1-5. MODULE SCALING FACTORS

Scaling factors are not relevant for this step. Additional LWR fuel fabrication capacity could be added by reopening existing shutdown lines, constructing new additional lines, or by operating existing lines on more than one shift. New capacity would probably be added at an existing site. A recent American Nuclear Society (ANS) paper by Rothwell (Rothwell and Braun 2007) discusses the scaling issue.

D1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Unlike uranium ore, natural U_3O_8 to UF_6 conversion, and enrichment prices, LEU fabrication prices (and costs) are unpublished and considered proprietary information. This is partly because each fuel fabrication batch is custom-suited to the utility's core design, and its price is separately negotiated. There are some nuclear consulting firms like NAC International and TradeTech that legally obtain data on such matters from users, which is then made available in "sanitized" report form (NAC Worldwide Consulting 2004) to utilities and other parties at a price too high for this project to use. Its publication in a public document such as this would also be prohibited by non-disclosure agreements. However, it has been possible to calculate approximate LEU fabrication pricing over many initial and reload fuel batches. Table D1-1-2 shows ranges and reference values for four data sources for LWR fuel fabrication.

Table D1-1-2. LEU fuel fabrication prices in \$/kgHM (\$/kgU).

Study/Year	Low Value	Medium or Reference Value	High Value
Energy Resources International (ERI)/2007		207 (PWR in U.S.) 276 (BWR in U.S.)	
Nuclear Energy Cost Data Base (Delene, et al./1988	170	200[a]	280
OECD NEA/1994	200	275	350
J. James & K. Williams/1999		180 (PWR)	
Harvard (Bunn et al.)/2003	150	250[b]	350
MIT (Deutch et al.)/2003		275	
MIT (DeRoo & Parsons)/2009		250 (PWR)	
Delene, Williams, et al./2000	200	270	300

a. Higher burnup fuel would add \$20/kgU to this cost.

b. Bunn suggests that the cost (as opposed to price) is on the order of \$200/kgU based on 1999 data of Varley and Collier. Bunn also suggests low, medium, and high penalties of \$5, \$15, and \$25 per kgU, respectively, for handling reprocessed LEU in the fabrication plant.
OECD NEA = Organization for Economic Cooperation and Development-Nuclear Energy Agency
MIT = Massachusetts Institute of Technology
OECD NEA 2001, OECD NEA 2005; and Tolley and Jones 2004 present similar ranges to above (i.e., \$200 to \$300/kgU)

c. ERI reports European prices to be 30% higher than U.S.; East Asian prices 60% higher than U.S.

The price is expressed in \$/kg heavy metal or \$/kgHM and normally includes the cost of converting the EUF_6 to EUO_2. Because the only fissile material is uranium, \$/kgHM is the same as \$/kgU in this case. These prices are for unirradiated or "virgin" LEU, and not LEU that arises as product from spent fuel reprocessing. (A price penalty of 5 to 10% of the unirradiated LEU fuel cost is assessed to cover the additional safety and radiation-related costs of handling reprocessed uranium and its trace fission products and higher actinides. This has been done mainly in Europe where reprocessing of spent LWR fuel is commonplace. The use and handling of reprocessed uranium (REPU) is discussed in more detail in Module K2 and at the end of this section). The real prices for LEU fabrication have been decreasing slightly over the last 15 years. This has been due mainly to overcapacity, higher fuel burnup, increased automation, a highly competitive international market, and the use of now fully amortized plants. Because the nuclear fuel market is now beginning to tighten, fuel fabrication costs are likely to rise as proposed NPPs become real construction projects. Other factors that may drive fuel fabrication prices up are:

1. As longer fuel cycles and extended burnup of LEU fuels are required for economic reasons (OECD NEA 1994), the performance requirements for cladding and fuel integrity will become more stringent. The fabricator's research and development and other costs to allow high burnup will be passed along to the fuel buyer. Perspectives on LWR fuel development are presented in a 1998 article by Gunnar and Junkrans.
2. Higher burnups may require LEU fuels of enrichments greater than the 5% maximum U-235 assay now used as the NRC-licensing basis for LEU fuel fabrication facilities. Retrofitting and relicensing costs will have to be passed along to utility customers. The intent is that higher burnups will eventually result in a lower "mills/kWh" fuel component for the overall electricity generation cost. This reduction will be the result of the fact that less low-enriched uranium (LEU) fuel will be required per kWh generated. Gregg and Worrall (2005) discuss the effect of higher burnup on overall "front-end" UO_2 costs and nuclear design parameters. Gingold and Goldstein (2002) discuss how the choice of higher burnup fuel would affect the fuel steps (modules) downstream of the reactor.

In general, BWR fuel fabrication prices are somewhat higher than PWR prices because of the greater hardware complexity of the former fuel assemblies. Foreign fuel fabrication prices are higher than in the U.S. In 1994, the Organization for Economic Cooperation and Development price range, which in addition to U.S. data contains foreign data, was higher than any of the other ranges in Table D1-1-3. For future U.S. studies and non-reprocessed fuel enrichments less than 5% U-235, the following reference values are suggested by the author: \$220/kgU for PWR assemblies and \$270/kgU for BWR assemblies. For reprocessed LWR UO_2, a penalty of at least \$20/kgU should be added to the price. It will be seen below, and that reprocessed uranium from higher burnup UO_2 spent fuel is more difficult to recycle, re-enrich, and refabricate.

Table D1-1-3. Cost summary table for contact-handled fuel fabrication.

What-It-Takes (WIT) Table (2007 constant $)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$240/kgU for PWR $290/kgU for BWR	N/A	$200/kgU for PWR $250/kgU for BWR	$300 for PWR $350 for BWR	$250/kgU for PWR $300/kgU for BWR
		$220/kgU for PWR REPU $275/kgU for BWR REPU	$400/kgU for PWR REPU $450/kgU for BWR REPU	$300/kgU for PWR REPU $350/kgU for BWR REPU
Only unit fuel costs available, no published capital costs.	Not available	None likely, this mature industry already very competitive	20% or less increase in unit cost if higher enrichment (>5% U-235), higher burnup fuels produced	Based on today's LWR fuel designs

D1-7. LIMITATIONS OF COST DATA

Identification of Gaps in Cost Information. The data above are for today's LWR fuel market. Some changes are envisioned for the future, however. It is likely that fuel enrichments over 5% associated with higher burnups will eventually become commonplace. In order to understand how the LEU fabrication price will be affected, the following cost studies should be made.

1. The determinable costs of advanced higher burnup fuel research and development must be calculated and amortized over some number of reloads. This includes the ongoing research on new alloys, improved cladding, better process automation, etc.
2. The cost of modifying and relicensing existing fuel fabrication plants to handle the higher enrichments must be determined. These costs must also be recovered in the new, higher price. New enrichment plants will be needed in the U.S. to produce these higher LEU U-235 assays. At least two such new enrichment plants are planned for the U.S., and both are likely to request the production of U-235 assays greater than 5% as part of their licensing basis.
3. No information was available on the costs of constructing or operating new LEU fabrication plants. Such historical information would be proprietary in a highly competitive industry. It is likely that if new U.S. production capacity is needed, it will be added by reopening existing lines, constructing additional process lines, or going to additional shift operations at existing facilities. An educated guess is that a new fabrication line of 200 to 300 MTHM/yr capacity would cost over $100 million in an existing building. This value is based on analysis of data in reports that consider the use of LEU fabrication plants for the production of thorium oxide fuel (Hermes et al. 2001a; Hermes et al. 2001b; Lahoda 2004).

Technical Readiness. LWR pelletized fuel fabrication falls in the technical readiness category of "viable and fully commercial." Two variations on pellet LWR fuel that are in the R&D stages are annular fuel (USEC Inc. 2007) and ceramic-clad fuel (Platts 2007b).

D1-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-1-3. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distribution based on the costs in the WIT Table is shown in Figures D1-1-3 and D1-1-4.

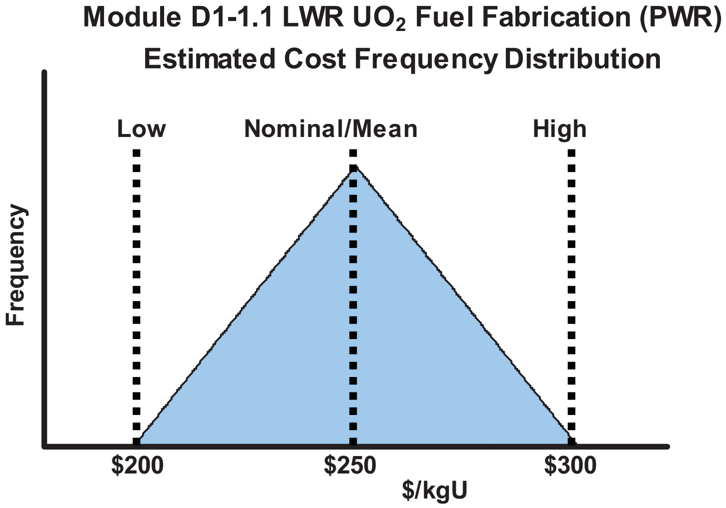


Figure D1-1-3. LWR UO_2 fuel fabrication (PWR) estimated cost frequency distribution.

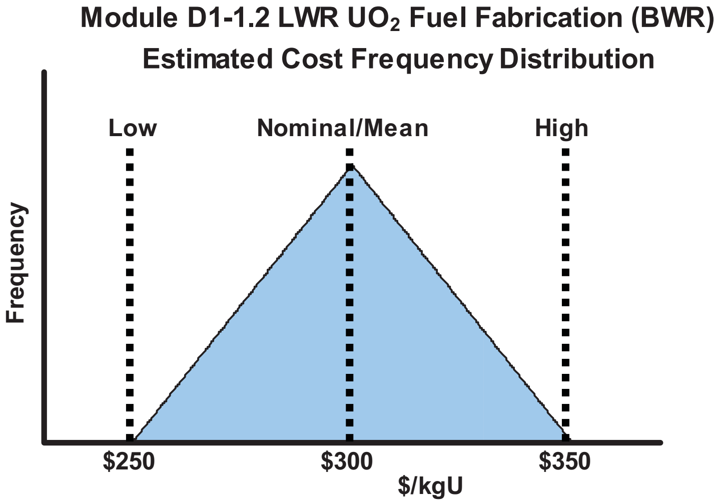


Figure D1-1-4. LWR UO_2 fuel fabrication (BWR) estimated cost frequency distribution.

D1-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

Because of the high readiness level of this fuel fabrication technology, no studies were performed. Fuel fabricators have likely done such studies; however, they are likely to be proprietary.

D1-10. SPECIAL TOPIC: LEUO$_2$ FABRICATED FROM REPROCESSED URANIUM

LEU in the form of uranyl nitrate hexahydrate (UNH) is one of the by-products of PUREX or UREX reprocessing of LWR fuels (Module F1) in addition to high-level waste, TRU waste, low-level waste, and separated higher actinides such as plutonium. (It is also possible that UO$_3$ product could be produced.) Like plutonium, the uranium has some value if it can be reused as reprocessed uranium fuel or REPU. (94%+ of the mass of spent LWR fuel is still in the form of uranium for which the U-235 isotopic content is significantly reduced from that prior to irradiation. Over 50,000 MTU of uranium already exist in U.S. legacy spent fuel.) If this reprocessed uranium is not reenriched and refabricated, it must be safely stored and dispositioned. Storage and disposition options for reprocessed uranium are covered in Modules K2 and K3, depending whether aqueous or electrochemical technology is used in the reprocessing step. Also like plutonium solution to MOX fuel preparation, there are cost-incurring process steps that must be taken on the route from reprocessing plant uranium by-product (UNH) to LWR reprocessed/reenriched/refabricated UO$_2$ fuel. (The costs of these steps must be assessed against any monetary “credits” for the virgin LEUO$_2$ assemblies displaced by reprocessed uranium, just as MOX preparation costs are assessed against “credits” for the virgin LEUO$_2$ assemblies displaced by plutonium-derived MOX.)

The uranium is essentially what is left when the 2–5% U-235 “virgin” unirradiated LEUO$_2$ pellet fuel has burned down to unfissioned uranium enrichment levels of 0.5–1.2 % U-235. This unburned uranium constitutes about 94+% of the heavy metal mass of a spent fuel assembly. (The remaining heavy metal (HM)-derived masses are fission products and minor actinides such as plutonium, neptunium, americium, and curium.) Unfortunately undesirable uranium isotopes, such as U-236, a neutron absorber, and U-232, an isotope with a very strong gamma-emitting daughter, have been generated in the reprocessed uranium by irradiation, and their percentages increase with reactor fuel burnup. U-232 has the undesirable aspect of producing radioactivity that increases with time. Its decay chain includes the radioisotopes lead-212, bismuth-212, and thallium-208; the latter is especially notable for its 2.615 MeV hard gamma emission. Gamma activity of the freshly separated reprocessed uranium increases for about a decade because of the accumulation of these decay products and then slowly decreases. The associated radiation increases the risks of (and costs of) handling reprocessed uranium vis-à-vis “virgin” uranium in the conversion, reenrichment, and refabrication steps. The natural nonfissile isotope U-234 is also enhanced in reprocessed uranium above its level in virgin LEU fuel by the fact that it does not fission, whereas its adjacent U-235 isotopic species does. U-234 has a short enough half-life (245,000 years) that it becomes a problem for long-term waste disposal somewhat like other actinides. These and other issues are treated in greater detail in Michaels and Welch’s ORNL 1993 report and in a more recent ORNL report (Del Cul 2009).

PUREX-derived reprocessed uranium has been successfully used in commercial reactors; however, steps are needed to prepare it for reactor use. First, the UNH or other stored product form, such as U$_3$O$_8$ or UO$_3$, must be converted to UF$_6$. This is usually done at the reprocessing or enrichment plant site and is anticipated to cost significantly more than the \$5–8/kgU for natural U$_3$O$_8$ to UF$_6$ conversion. The presence of radiotoxic minor isotopes and criticality issues associated with possible higher than natural enrichments probably means that the conversion cost is more on the order of \$11 to \$20/kgU. The second step is reenrichment to a U-235 level capable of use in the same reactor that burns the “virgin” LEUO$_2$. Because of the U-236 and U-234 content, a higher U-235 level than for virgin LEU is needed to compensate for the U-236 “poisoning” effect. Because of the difficulty of handling the more radioactive reprocessed UF_6, the enrichment cost is anticipated to be higher than for virgin EUF_6 enrichment plant feed. A 20–30% penalty on the price of separative work unit (SWU) is probably warranted. The last step is fuel fabrication from the $LEUF_6$ enrichment plant product. If not blended with other $LEUF_6$ or passed through an additional enrichment step, the U-232 and U-236 content of this material will be even higher than for the enrichment plant reprocessed UF_6 feed. This is because the gaseous diffusion and centrifuge enrichment processes tend to push these undesirable isotopes into the product. The fabrication plant must now minimize personnel radiation exposures and use more automated handling of the process steps. Additional shielding may be required. For these reasons, the cost of reprocessed UO_2 fuel fabrication is expected to be at least several percent higher than for virgin $LEUO_2$ fuel. In Bunn’s report (2003), penalties of up to $20/kgU are suggested. Michaels and Welch (1993) indicates that as reactor burnups for LWR fuel increase, the reprocessed uranium derived from reprocessing thereof will have increasingly undesirable isotopic content, thus refabrication costs could go even higher.

Michaels and Welch (1993) also considers storage and disposal options for the reprocessed uranium. UNH or any oxides produced may not qualify as low-level waste because of the minor isotopes and any residual fission products therein. Costs for uranium storage are also covered in Michaels and Welch (1993) and Spencer et al. (2005) and are discussed in Modules K2 and K3.

Reprocessed uranium reconversion, reenrichment, and refabrication for the production of reprocessed UO_2 fuel are now under way in Europe and with the high price of U_3O_8 today, expansion of this REPU capability is planned (Platts 2007c and 2007d). Figure D1-1-5 shows the scheme used in Russia at the Siberian Chemical Combine (Seversk/Tomsk) to take stored French reprocessed uranium (produced at LaHague and stored at Pierrelatte), remove the undesirable daughter products, convert the oxides to UF_6, and reenrich this clean material to low U-232 enhanced U-235 product in two centrifuge cascades for ultimate refabrication. The processes and economics are described in IBR 2006 and IBR 2008. Russian cost estimates in this reference indicate that this scheme should produce finished reprocessed UO_2 fuel at prices competitive with virgin $LEUO_2$ fuel, especially as uranium ore (U_3O_8) prices continue to rise.

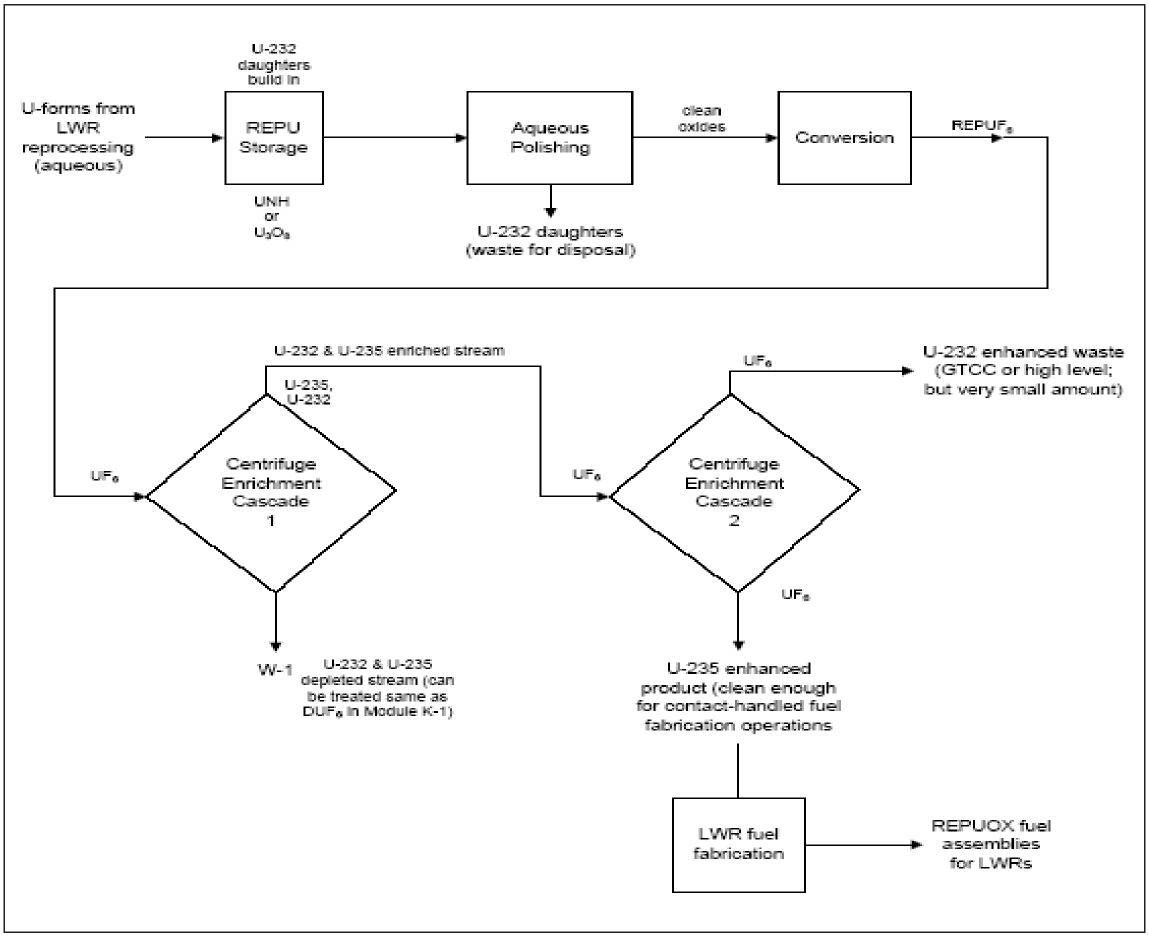


Figure D1-1-5. French-Russian scheme for reprocessed uranium recycle.

AREVA has recently announced plans (Platts 2006) to build their own 1,000-MTU/yr reprocessed uranium oxide to reprocessed UF_6 conversion plant next to their proposed centrifuge plant at Pierrelatte. This announcement seems to indicate that rising uranium ore costs and large quantities of stored reprocessed U_3O_8 are making deployment of this scheme in France economically attractive.

As the U.S. deploys the more versatile centrifuge enrichment technology and reconsiders LWR fuel reprocessing, such a scheme may ultimately prove economical for the even larger amounts of unburned uranium now remaining in the U.S. The U.S. is presently gaining some experience in the use of reprocessed-material fuels via Project BLEU (Tousley 2005). In this program, Tennessee Valley Authority is burning LWR fuels produced by the blending of reprocessed production reactor highly enriched uranium with lower assay blendstocks. The Nuclear Fuel Services Inc. press release on May 30, 2006 described this U.S. Department of Energy (DOE)-National Nuclear Security Administration (NNSA) supported program in more detail.

Module D1-2

LWR MOX Fuel Fabrication

Module D1-2

LWR MOX Fuel Fabrication

D1-2.1 BASIC INFORMATION

Fuel Form. An LWR MOX fuel assembly and its array of pellet-loaded rods appear identical to a LEUO_2 thermal LWR fuel assembly. In fact in the European reactors that burn MOX fuel, the two types of assemblies reside together in the reactor, with 1/3 MOX: 2/3 LEUO_2 being a typical fuel assembly loading ratio. Even the ceramic MOX pellets within the rods appear nearly identical to their ceramic LEUO_2 counterparts. It is because of the radiotoxicity of plutonium; however, that vastly different types of plants are needed to fabricate MOX fuel. This is true even though 95+% of the MOX material flowing through the fabrication plant is the depleted, natural, or slightly enriched U-235 assay UO_2 diluent that is blended with the 10% or less (by mass) of PuO_2 powder to form the MOX pellet process feed. Most of the world's MOX fuel is presently fed to PWRs.

Status of Industry. European industries, such as Cogema, Belgonucleaire, and Siemens, have been successfully fabricating MOX, and European utilities in France, Switzerland, and Belgium have been successfully burning it for over a decade. The PuO_2 in all of this European MOX arises from the reprocessing of spent LEUO_2 thermal reactor fuel at facilities such as LaHague in France and THORP in the United Kingdom. The Japanese will soon begin use of MOX in their reactors as part of their "Pluthermal Fuels" program, and are constructing a MOX facility at Rokkasho-Mura. The British are also now producing limited MOX (Platts 2007e) at their SMP (Sellafield MOX Plant) located near their THORP reprocessing plant.

Up to 1978, the U.S. was on the verge of using MOX as part of a closed LWR fuel cycle. A MOX fabrication plant design had already been prepared for a MOX plant at Anderson, South Carolina, with PuO_2 to come from a nearly completed fuel reprocessing plant at Barnwell, South Carolina. All this was halted by the Presidential edict of Jimmy Carter putting an end to plutonium recycle because of nonproliferation concerns with spent fuel recycling. In 1993, after the end of the Cold War, the U.S. began to start investigating the use of MOX fuel derived from surplus weapons-grade plutonium. Reports by the National Academy of Sciences (National Academy of Sciences 1995) and others (ORNL 1996; Williams 1999) documented the technical and economic feasibility of utilizing existing U.S. utility LWRs to burn partial cores of weapons-derived MOX fuel. In 1996, a Record of Decision was issued by DOE to pursue the MOX reactor option as one of two methods to disposition plutonium. In 1997, a procurement action was started to find a corporate entity willing to design, construct, and operate a government-owned MOX Fuel Fabrication Facility (MFFF) at the Savannah River Site (SRS). In early 1999, the consortium Duke, Cogema, Stone, and Webster (DCS – now Shaw AREVA MOX Services) was chosen for this purpose and was chosen to also burn the MOX fuel at Duke Energy's two reactor sites, McGuire and Catawba, just north and south, respectively, of Charlotte, North Carolina. (These MOX use contracts have now expired and MOX Services is negotiating with Duke and other potential customers for fuel contracts.) The design of this plant is now complete, NRC construction approval has been received and construction is well underway. The plant will process 70 to 100 MTHM per year for over 10 years. The intent is to disposition 34 MT of weapons-grade plutonium over this campaign and possibly some other less-pure government plutonium scrap. (Prior to 2007 a similar "build-to-print" LWR-MOX plant, also based on French MELOX technology, was being designed for a parallel Russian program at Tomsk [Seversk] in Siberia. The MOX was to be burned in VVER-type reactors. Liability, funding and technology transfer concerns have prevented this project from moving at the speed of the U.S. MOX project. It now appears that the Russian Pu-disposition program may utilize weapons-derived fast reactor

MOX in BN-type fast reactors for their Pu-disposition program [Platts 2007f].) Figure D1-2-1 shows a flowsheet for the generic reactor-based plutonium disposition programs.

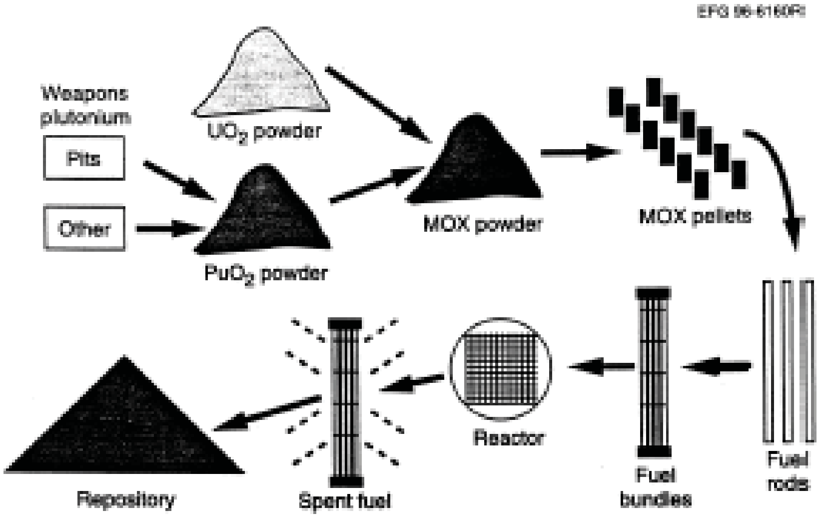


Figure D1-2-1. Generic reactor-based option for weapons plutonium-disposition (ORNL 1999).

Present DOE/National Nuclear Security Administration plans are to limit the U.S. plant (SRS-MFFF) to weapons plutonium-disposition activities only, even if the plant life is limited to 10 to 12 years of operations. Up until recently, U.S. policy has been to discourage plutonium recycle and the construction of commercial facilities, such as MOX or reprocessing plants.

D1-2.1 FUNCTIONAL AND OPERATIONAL DESCRIPTION

MOX Fuel Fabrication Process. The steps involved in the fabrication of MOX fuel are basically the same as those for LEU fuel assembly production except that most of the front and middle steps must be enclosed in gloveboxes to protect the workers from exposure to radiotoxic plutonium compounds. The radioactivity level in a MOX plant is also somewhat higher than for UO_2 because of the spontaneous neutrons, beta, and gamma radiation emanating from plutonium isotopes and their daughter radionuclides. Some radiation also comes from (alpha, n) reactions where PuO_2 is in contact with low atomic weight materials. Fire protection considerations are also important with pyrophoric plutonium compounds, and process areas within the process building must be capable of isolation. There is also a security consideration arising from the fact that MOX has a proliferation or terrorist attractiveness level much higher than for $LEUO_2$. This is because plutonium could be readily chemically separated from the uranium in the MOX and has great value as a fissile material for a nuclear weapon. This fact requires that the stringent Materials, Protection, Control, and Accounting (MPC&A) and safeguards be implemented and that the process building itself be extremely robust and resistant to attack or intrusion. The avoidance of nuclear criticality is also more of a consideration for MOX due to the smaller critical mass of Pu-239 as compared to U-235. All these considerations contribute to the very high capital and operating costs for MOX as compared to LEU. However, economics must be evaluated on the whole nuclear fuel cycle, where for commercial MOX use, reduced ore, conversion, and SWU costs and waste disposal cost savings due to reprocessing in tandem with MOX use become evident. For weapons MOX use, the cost savings arise from not requiring perpetual government storage and guarding of plutonium and the fact that other plutonium-disposition methods, such as immobilization, are likely to increase costs and encounter technical difficulties. MOX is essentially made available to the utility at a unit cost somewhat below that for $LEUO_2$ fuel assemblies in order to provide an incentive to electric utility participation.

D1-2.2 PICTURES/SCHEMATICS

Figure D1-2-2 shows the generic MOX production process for either commercial (Pu-239 isotopic content less than 94%) or weapons-derived (Pu-239 content 94% or greater) MOX. The feedstocks PuO_2 and DUO_2 are blended into a 20 to 30% plutonium “master-mix,” which is then later blended with more DUO_2 to the desired fissile content of 4 to 9% plutonium in heavy metal. Because of criticality concerns, all early processing operations are in small batches of a few kilograms Pu each. Final blended MOX batches may be 100 kg MOX or more. The pellet pressing, sintering, grinding/finishing, and inspection operations are nearly identical to their LEU counterparts except for the difficulty of handling somewhat smaller batches and the need for glovebox operations. Once the pellets are loaded into the Zircalloy tubes and the tubes are welded and cleaned, the decontaminated rods can be contact handled.

The bundle assembly area is very similar to that of the LEU plant. Because of the higher radiation field arising from decay of the americium-241 plutonium decay daughter, it is necessary to limit worker exposure times to MOX fuel assemblies.

D1-2.3 MODULE INTERFACE DEFINITION

Front-end Interfaces. For commercial MOX as done in Europe, the starting materials are reactor grade PuO_2 powder arising from aqueous PUREX-type reprocessing such as is done at LaHague or THORP. The reactor-qualified powder so produced is stored in special cans in protected areas at the reprocessing plant. (Costs related to MOX are assumed to start with shipping of this powder in special double-walled cans and special “safe and secure” trucks to the MOX fabrication plant). The diluent natural, depleted, or slightly enriched UO_2 powder, which is part of the MOX mix, must also be reactor-spec grade and is usually purchased from or manufactured by uranium converters or fuel fabricators with aqueous processing equipment, although some dry-process UO_2 powder is being qualified for MOX use. (Slightly enriched [$0.0071 <$ U-235 assay (mass fraction) <0.015] uranium diluent would be likely to be reprocessed uranium oxide, most likely recovered in the same facility as the plutonium oxide. Module K2 discusses issues associated with reprocessed uranium.) This UO_2 material can be shipped by normal commercial trucks in sealed drums. The front end steps for the U.S. and Russian plutonium-disposition projects are more complex. The metal plutonium pits and any other weapons-grade legacy plutonium forms from the DOE complex must be converted to clean reactor spec PuO_2. For the U.S. program, a Pit Disassembly and Conversion Facility (PDCF) is planned at SRS to oxidize the impure plutonium metal to impure PuO_2. This “pit-derived” impure PuO_2 plus other legacy impure PuO_2 is then stripped of its gallium, americium, uranium, halide, and other impurities in an aqueous-polishing front end step: i.e., an MFFF- aqueous polish (AP building) addition to the overall SRS-MFFF MP (MOX Process building). From this AP point onward, the commercial and disposition flowsheets are basically the same, with the back-end of the SRS-MFFF (called the MFFF-MP) being very similar to the French MELOX fuel fabrication plant at Marcoule. The SRS-MFFF plans to use DUO_2 as the diluent, thus reducing the U-235 content and maximizing the Pu-239 content of the fissile part of the MOX fuel. This reactor grade DUO_2 must be manufactured by a conversion plant starting with clean legacy DUF_6 in cylinders located at one of the U.S. gaseous diffusion enrichment plant sites. Shaw-AREVA MOX Services, the new DOE/National Nuclear Security Administration plutonium disposition contractor, is responsible for implementing this conversion step and subcontracted Framatome-ANP to use a specially modified (for DU use) wet conversion line at their Richland, Washington LEU fuel fabrication plant to test the basic process. Shaw-Areva and the DOE Savannah River are developing a procurement process to obtain the ~1000 MTU of depleted material needed for MFFF operations. The cost of this uranium conversion step will be included in the SRS-MFFF operations costs and is likely to cost in the tens of dollars per kgU, the actual unit cost depending on the batch sizes and quality of the UO_2 powder required. Framatome has already prepared cost proposals to Shaw-Areva MOX Services for this operation; however, DOE’s ultimate choice of the DUO_2 provider will depend heavily on economics and the response to the procurement request for proposals (RFP).

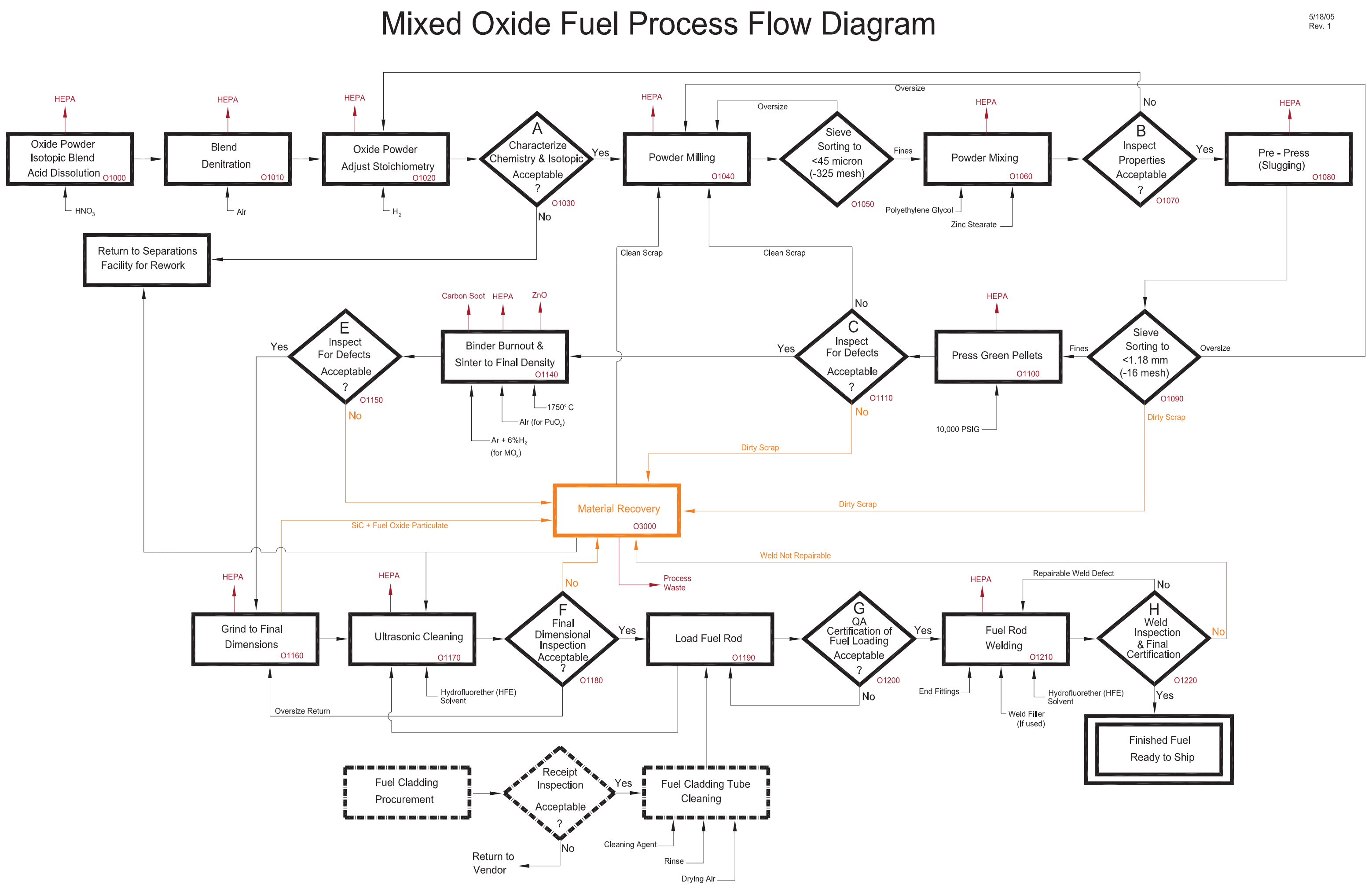


Figure D1-2-2. Generic MOX fuel process flow diagram (DOE-AFCI Fuels Working Group, 2007).

Back-end Interfaces. Storage and shipping of the MOX assemblies to the reactor is included in the cost. Special safe and secure transport vehicles are needed for this purpose. For the U.S., plutonium-disposition program the DOE/National Nuclear Security Administration will provide this service.

Transuranic and low-level waste from the MOX fabrication plant must also be handled. For the U.S. disposition program, waste will be processed and packaged by modified existing SRS waste facilities plus a new facility, the Waste Solidification Building. Because the plutonium arises from the weapons program, transuranic waste containers can be sent to the DOE/National Nuclear Security Administration's Waste Isolation Pilot Plant (WIPP) geologic disposal site near Carlsbad, New Mexico. For future commercial MOX facilities in the U.S., use of the Waste Isolation Pilot Plant may not be possible. MOX production wastes would have to be jointly considered along with reprocessing wastes and a viable disposal option studied and implemented. Modules J, L, M, and I discuss some possible disposal methods.

D1-2.4 MODULE SCALING FACTORS

Scaling rules are similar to those for LWR fuel production, since the fuel manufacturing is performed in parallel process lines. The line size is limited by the fact that many of the process steps are batch operations with batch size limited by criticality concerns. Capacity additions to a plant would likely be realized by adding shifts or adding a new line in an existing building. As will be seen in the cost discussion, very high fixed costs are associated with any plutonium-handling facility, regardless of size. The ratio of these fixed costs to total life-cycle cost, however, falls as more capacity is added; thus, economies of scale are possible. Rothwell discusses economy-of-scale issues in a recent ANS presentation (Rothwell and Braun 2007).

D1-2.5 COST BASES, ASSUMPTIONS, AND DATA SOURCES

Cost and Pricing of LWR MOX Fuel Fabrication. Most of the MOX fuel fabrication cost data available are for existing facilities in Europe. In the Harvard report, Bunn, et al. 2003 performed a very complete survey of life-cycle cost information. Table D1-2-1 summarizes this information along with the Section D1 author's analysis of the U.S. SRS-MFFF projected life-cycle costs.

No data were available for the French MELOX or the Belgonuclaire facilities. Data for the U.S. plant had to be partitioned by the author to remove the aqueous polishing costs. Capital (sunk design costs plus projected construction) costs of $4.8B (FY 2007$) now include the additional design/construction scopes of strengthening the building to meet post-September 11, 2001 security and structure hardening requirements, the aqueous front-end processing facility, technology transfer costs, numerous HVAC and fire protection design improvements, commodity escalation, and anticipated facility startup. The U.S. MOX facility has also suffered schedule delays due to attempts to allow the Russian MOX plutonium-disposition to "catch-up" so that schedule parallelism can be established. (The Russian LWR MOX facility of similar capacity was to be located at the Siberian Chemical Combine near Seversk [Tomsk]. Its capital cost was estimated at least $2.8B before it was canceled by the Russian government.)

The CFTC studies did not develop an estimate for the fuel fabrication facility for commercial reprocessing-derived MOX. The team determined a TPC estimate by using the Savannah River MOX Fuel Fabrication Facility (MFFF) estimate at completion (EAC) and performing the following adjustments:

- An adjusted MFFF TPC was determined by removing $100M of duplicated scope for administration and other support buildings which have been included the overall CFTC reprocessing (Module F1) estimates, and removing $704M of contingency. The Adjusted MFFF TPC is $3,996M. The unit construction cost of the MFFF is determined by dividing the adjusted TPC by the total area of the MFFF (395,000 ft^2) See Table D1-2-1.

- The scope of the MFFF is adjusted to the scope MOX fuel fabrication facility that uses all of the product produced by an 800MT/yr LWR reprocessing center by the following:
  - The fuel fabrication area of the MFFF (208,050 ft^2) is adjusted based on the MOX fuel production capacity. Three factors determine this capacity, the reference fuel burn-up (50 GWd/MT), the separations facility capacity (800 MT SNF/yr), and the higher Pu content of the commercial reprocessing-derived MOX fuel product (10%) as compared to the weapons-derived MOX fuel product (4–5%). Using these assumptions, the capacity of the MOX fuel facility is 94 MT/yr compared to the MFFF capacity of 70 MT/yr (1.34X).
  - The process area associated with MFFF aqueous processing (AP) is eliminated.
  - The shipping and receiving area of the MFFF is assumed to be constant (59,400 ft^2) and is not increased for the increase in capacity.
  - The laboratory area of the MFF is assumed to constant (22,800 ft^2) and is not increased for the increase in capacity.
- The resulting point estimate is $3,662M and after applying low (10%) and high (40%) contingency, the TPC range is $4,028M to $5,127M respectively.

Table D1-2-1 CFTC MOX Fuel Fabrication TPC Estimate

Parameter				**SRS MFFF**		**TPC Estimate for 800MT/yr Reprocessing Heavy Metal Output**		
Capacity of Recycling Facility (MT SNF/yr)						800		
Burn-up (GWd/MT)						50		
Capacity (kg Pu/yr)				3,360		9,430		
Fuel Pu%				4.8%		10%		
Capacity (MT MOX fuel/yr)				70		94		
	MFFF Building size							
	Length	Width	Floors	Sq Ft		Sq Ft		
Shipping and Receiving	120	165	3	59,400		59,400		
Laboratory	80	285	1	22,800		22,800		
Fuel Fabrication Area	270	285	2	153,900		280,273		
	190	285	1	54,150				
Aqueous Processing	175	120	5	105,000		-		
Total Sq Footage				**395,250**		**362,473**		
				MFFF		**Point**	**Low**	**High**
TPC ($M)				$ 4,800		**$ 3,662**	**$ 4,028**	**$ 5,127**
Administration and Other Support Buildings				$ 100				
Contingency				$ 704				
Adjusted TPC ($M)				$ 3,996				
Cost per Sq Ft				$ 10,116				

MFFF operating costs are estimated using a staff of 1,000 times $125,000/yr average labor rate, assuming 15% miscellaneous materials, 20% for utilities, 3% for insurance and other miscellaneous small projects and $100M for the specialized fuel fabrication hardware costs. This yields a point estimate of $275M/yr. Without aqueous polishing, the staffing is expected to be reduced to about 700 and the annual operating costs drop to $220/yr. Using an uncertainty of ±20% the O&M 40-year life cycle ranges from $7.5B to $11.3B.

Unit costs are determined in Table D1-2-2 taking the D&D costs as 15% of the TPC.

Table D1-2-1. CFTC MOX fuel fabrication LCC unit costs.

Millions of 2007 Dollars	MOX Fuel Fabrication 94 MT/yr	
	Low	High
Annual Operations Cost (nominal Year) Labor	70	105
Utilities	11	16
Materials	14	21
Misc. Projects	2	3
Fuel Fabrication Hardware	80	120
Total Annual Operations Cost	**177**	**265**
40 Year LCC		
Labor	3150	4725
Materials	472	709
Utilities	630	945
Misc. Projects	95	142
Fuel Fabrication Hardware	3200	4800
Subtotal: 40-Year Operations	**7,547**	**11,321**
Future Capital Projects	0	0
D&D	600	770
Subtotal LCC O&M & D&D	**8,147**	**12,091**
Early Life Cycle	200	300
TPC	4,028	5,127
Total LCC	**12,375**	**17,518**
LCC Unit Cost ($/kg HM) [no interest is included in this unit cost]	**3,390**	**4,660**

From Table D1-2-3, it is difficult to notice any capital cost scaling relationship. According to Stoll (2002), however, there is such a relationship for unit costs, which include capital and operating components, as shown in Figure D1-2-3. Because the fixed safety, security, and other infrastructure costs associated with both the capital and operating costs are so high, the unit costs climb rapidly as throughput decreases. Therefore in order for MOX to be more competitive, large throughput plants should be built.

Table D1-2-3. Available data on MOX fuel fabrication plants.

Plant	Owner	Location	Capacity (MTHM/yr)	Financing	Capital Cost (2003$)	Operating Costs (2003$)	Ref
SMP	BNFL	Sellafield UK	120	Private & Gov't	750M	50M	Bunn et al., 2003
Hanau-2	Siemens	Hanau, Germany	120	Private	750M	Not avail	Bunn et al., 2003
Rokkasho (under constr)	JNC	Rokkasho-mura, Japan	130	Private & Gov't	1,000M	Not avail	Bunn et al., 2003
SRS-MFFF (under constr)	DOE/NNSA	Aiken, So Carolina U.S.	70	Gov't	3.9B not incl aqueous polish (AP)	220M/yr not incl AP	trade press staffing and TPC scaled for capacity and function
SRS-MFFF (under constr)	DOE/NNSA	Aiken, So. Carolina U.S.	70	Gov't	4,800 incl AP	$275M/yr	trade press staffing and TPC

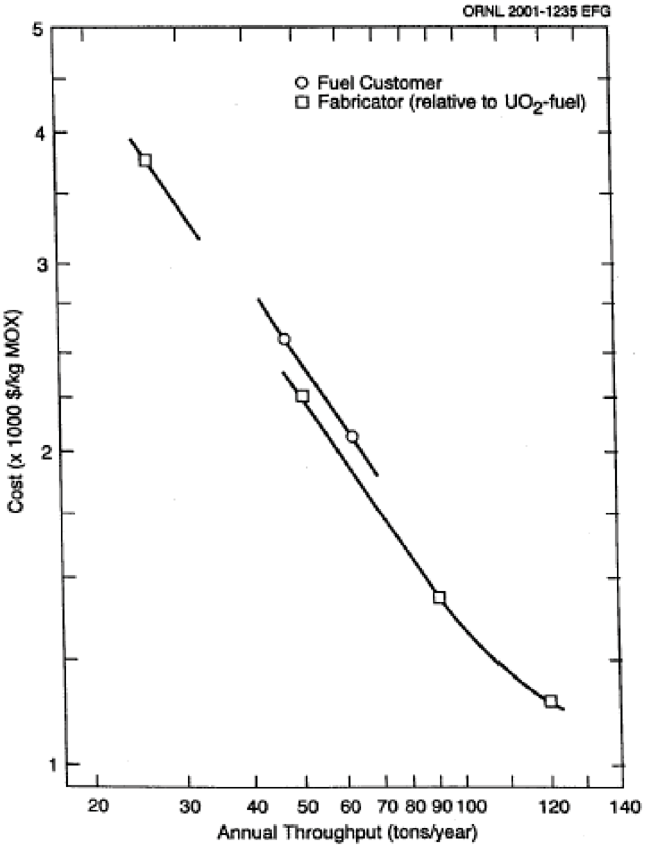


Figure D1-2-3. MOX unit cost as a function of throughput (Stoll 2002).

Table D1-2-4 shows the range of unit production costs for LWR MOX fuel gleaned from the literature. The range is very large and is influenced by market and political factors in addition to pure engineering economics. Nearly all the numbers shown are for European experience. As with LEU fabrication, there is no price list for MOX fabrication. A major variable in the calculation of unit cost is the method of financing and ownership of the MOX facility. Bunn et al. (2003) performed financing calculations for a 100-MTHM/yr MOX plant with a 30-year operating life, a $750M overnight capital cost, and a $56M/yr operating cost. Under government financing, at a low discount rate, a unit cost (or price since return on investment is included) of $1,010/kgHM results (not including transportation) from his calculation. For private ownership and financing with a guaranteed market and rate of return, a unit cost of $1,460/kgU results. For the highest discount rate associated with high-risk financing and private ownership, a unit cost of $2,140/kgHM results. In a document prepared at the onset of the plutonium-disposition program for DOE-MD, Williams (1999) found basically the same result: that government financing of MOX is much less expensive than private financing. Most of this difference is attributable to the very large carrying charges or interest associated with construction financing and plant amortization.

Table D1-2-4. Unit fabrication costs for LWR MOX fuels.

Reference/Date	Fabrication Cost in $/kgHM ("then year $") L=Low; M=Medium or Reference; H=High
Bunn et al., 2003	(L/M/H) 700/1,500/2,300
OECD NEA, 1994	(L/M/H) 800/1,100/1,400
Delene et al., 2000	(L/M/H) 2,000/3,200/4,000
CFTC analysis of SRS MOX FFF publicly available data	(L/H) 3,400/ 4,700 (aqueous polish of weapons-derived feed excluded)
NEA 2001	(L/M/H) 1,000/1,250/1,500
MIT 2003	(M) 1500
MIT 2009	(M) 2400
Red Impact 2006	(M) 1800

In summary, MOX fabrication costs and pricing are very assumption-driven, and have a high degree of uncertainty due to the very limited set of firm data on actual plants. In all cases, MOX is more expensive than LEU, a point constantly mentioned by all plutonium fuel cycle opponents. One must remember, however, that use of MOX is economically advantageous to other parts of the fuel cycle, and that the socioeconomic benefits, such as reduced repository space per kWh of electricity generated, of fuel recycling are not fully reflected. The plutonium-disposition program has been also criticized for "subsidizing" Duke Energy or any other possible future utility participants in the form of selling MOX fuel to them at a discount relative to LEU. One must also remember, though, that the reactor-based disposition program is really a waste disposal program in addition to its function of providing an incremental power production cost benefit to a particular utility. Any extra costs that the government pays are lower than the alternative methods of plutonium disposition such as perpetual plutonium storage/surveillance (at a few $/gram plutonium/yr) or immobilization with its highly uncertain performance and cost uncertainties. Unlike reactor burning, immobilization also does not change the isotopics of the Pu, thus leaving in a "weapons-usable" U-239 isotopic concentration (USDOE NNSA 2007).

D1-2.6 LIMITATIONS OF COST DATA

Technical Readiness. In Europe, LWR MOX is a mature technology, and costs can be readily calculated or derived. In Japan and the U.S., LWR MOX is a new technology experiencing first-of-a-kind plant cost growth due to regulatory and international political delays, litigation, scope changes, and special requirements (in the U.S.) for weapons program-derived feeds. Once hot startup problems, which are nearly always encountered in a process of this type, are resolved, the costs should be more representative of a mature commercial technology.

Identification of Gaps in Cost Information for future fuel cycles. Some of the fuel cycles to be studied in Advanced Fuel Cycle Initiative program assume the use of MOX fuel with higher actinides in the fuel, i.e., actinides such as neptunium, curium, and americium in addition to the plutonium. (Such fuels would be the result of new proliferation-resistant reprocessing schemes such as UREX.) These additional constituents and their associated higher radioactivity will impose significant safety and operational burdens on a MOX plant (hence the name "dirty" MOX is sometimes applied). The cost effects of these new requirements, such as a requirement for remote-handling, need to be studied, and the effects of additional automation of the MOX fuel fabrication process need to be considered (to reduce worker exposures). The cost effects of multiple thermal MOX recycle also need to be considered as well as benefits to the back end of the fuel cycle. The December 2006 *AFC Economic Sensitivity Analysis Report* (INL/EXT-06-11947) provides an initial analysis of the thermal actinide recycle.

D1-2.7 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-2-3. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table D1-2-3. Cost summary table for commercial LWR MOX fuel.

What-It-Takes (WIT) Table (2007 constant $)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$3,200/kgHM as reference cost for "normal" MOX based on European experience.	10% to 40%	Unit=$3,000/kgHM	Unit=$5,000/kgHM	Unit=$3,200/kgHM
Alternative cost based on SFFF. Cap=$4.5B for 94 MT/yr; Unit=$4,000/kgHM (private facility with full cost recovery and all operations and D&D costs.)		Collocation with LWR spent fuel reprocessing plant could reduce cost. Larger plant size (additional lines) or multishift operation should bring down unit cost.	Use of "dirty" or multiply-recycled MOX with oxides of higher actinides (Cm, Np, etc.) will drive up capital, operating, and unit costs even if remote handling is not required.	Mature MOX technology in the U.S. for new facilities.

The triangular distribution based on the costs in the WIT Table is shown in Figure D1-2-4.

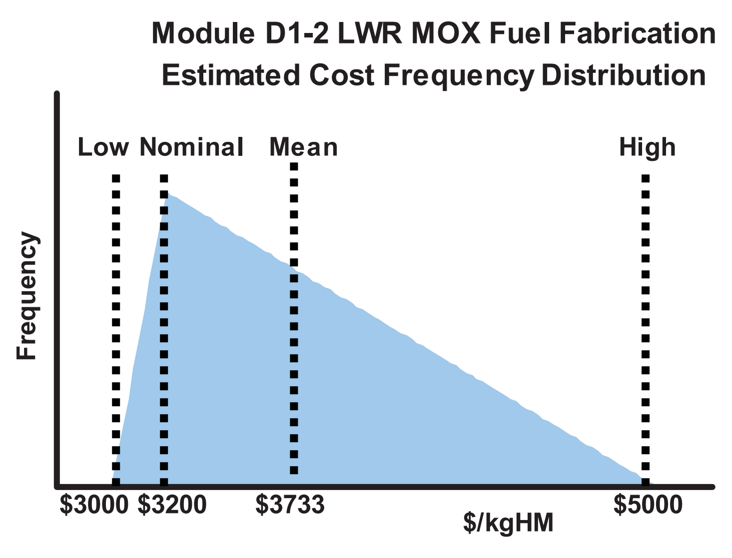


Figure D1-2-4. LWR MOX fuel fabrication estimated cost frequency distribution.

Module D1-3

Gas-Cooled Reactor Fuels

Module D1-3

Gas-Cooled Reactor Fuels

D1-3.1 BASIC INFORMATION

Fuel Form. The high temperatures envisioned for today's gas-cooled reactor (GCR) designs offer the cost advantages of higher thermodynamic efficiency; however, they also put very stringent demands on the fuel. The fact that the moderator, carbon in the form of graphite, is a solid, and the coolant is a gas, helium, also affects the design of the fuel. The fuel form for GCRs is also supposed to be the first line of "defense in depth" as far as safety is concerned, with the fuel form itself actually described as part of the over all "containment" philosophy. The volatile fission products are contained by the fuel particle design, and the possibility of a "meltdown" in the classical sense is eliminated through inherent safety features.

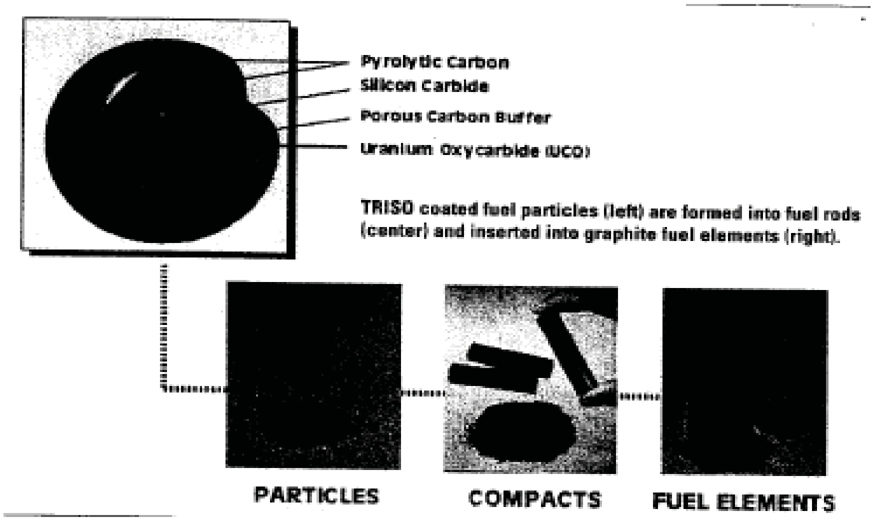
There are two major fuel forms now envisioned for GCRs:

1. The prismatic concept in which a fuel assembly or "block" is in the shape of a hexagonal cylinder with holes drilled for flow of the gas coolant. These hexagonal blocks are stacked and arrayed inside of a machined graphite core. Each prismatic block has smaller graphite right circular cylinders or "compacts" imbedded in other vertical holes in the block. These compacts contain the fuel particles. This is the concept that has been developed over many years by General Atomics (GA) as the Modular High-Temperature Gas-cooled Reactor (MHTGR) and more recently the direct cycle Gas Turbine-Modular Helium Reactor (GT-MHR).
2. The other fuel "assembly" form is that of a billiard-ball sized graphite sphere or "pebble" with the fuel particles imbedded within. This concept was developed and demonstrated in Germany and is now being vigorously pursued in China, Japan, and South Africa. The latter nation plans to build a demonstration plant called the Pebble Bed Modular Reactor (PBMR). If successful, this plant concept will be marketed worldwide by South Africa. (ESKOM is the South African utility that ordered the PBMR demo module.) China recently announced plans to deploy the PBMR concept.

D1-3.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

Two GCR Fuel Concepts. Both GCR fuel concepts, however, have a common fuel production technology. The fissile material, enriched uranium or plutonium, in the form of an oxide (UO_2 or PuO_2) or other ceramic forms (e.g., UCO), exists as tiny 200 to >500 micron spheres or "kernels," which are coated with layers of mechanically tough and highly refractory coatings of porous carbon, silicon carbide, and electrochemical carbon. The resulting sphere, which measures less than 1 mm in diameter, is called a TRISO coated fuel particle and is in essence a tiny pressure vessel. Thousands of these particles are then imbedded in a graphite matrix that forms the "pebble" or the cylindrical "compacts." The latter are inserted in a prismatic hexagonal block. For both concepts, the fuel enrichments (U-235) are considerably above the 3 to 5% U-235 for today's LWRs. In fact, early MHTGR designs utilized highly enriched uranium at >90% U-235. For nonproliferation reasons, all GCR designs have backed off to LEU enrichments in the range 8 to 19.9% U-235. The fuel for these two concepts is often referred to as "particle fuel" as opposed to pellet, vipac, or cast fuel for other reactor concepts. GA includes some "fertile" natural uranium TRISO particles in their design and in the past has incorporated thorium in the form of thoria (ThO_2) fertile particles.

Figure D1-3-1 shows the basic fuel concept for the GA GT-MHR concept. Figure D1-3-2 shows a similar diagram for the "pebble bed" concept. Figure D1-3-3 shows the makeup of the basic TRISO particle. All GCR concepts discussed for future deployment have some variant of the particle fuel concept.



TRISO coated fuel particles (left) are formed into fuel rods (center) and inserted into graphite fuel elements (right).

Figure D1-3-1. Prismatic concept utilizing particle fuel (General Atomics, 1998).

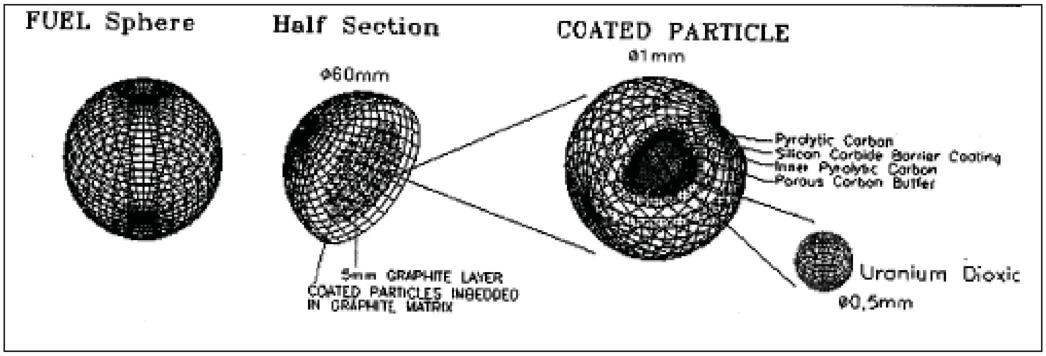
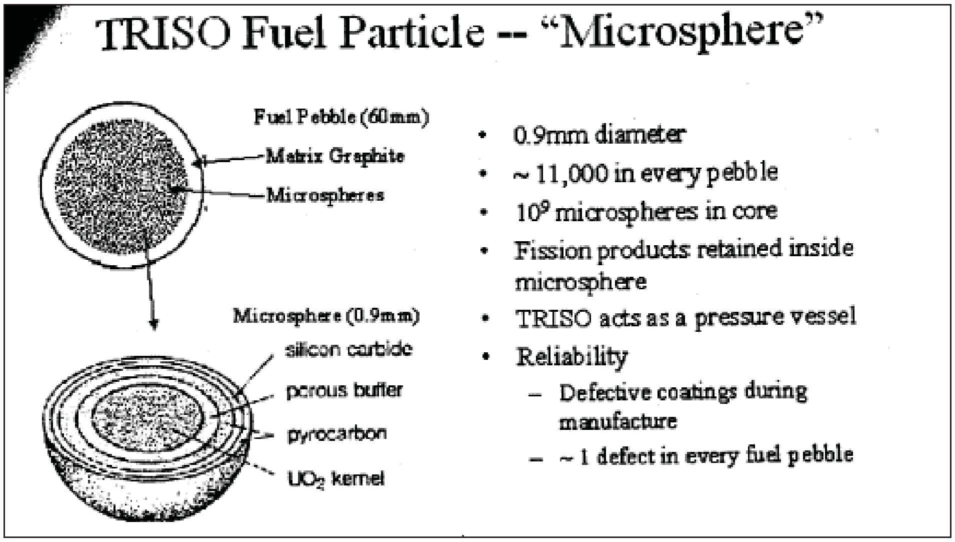


Figure D1-3-2. Pebble concept utilizing particle fuel (UC and OSU 1998).



TRISO Fuel Particle -- “Microsphere”

- 0.9mm diameter
- ~ 11,000 in every pebble
- 10^9 microspheres in core
- Fission products retained inside microsphere
- TRISO acts as a pressure vessel
- Reliability
  - Defective coatings during manufacture
  - ~ 1 defect in every fuel pebble

Figure D1-3-3. Illustration of a TRISO fuel particle concept (UC and OSU 1998).

Status of Industry. Unlike for LWR fuel, no large-scale GCR fuel manufacturing capability exists in the U.S. (or in the world for that matter). Because there is no fleet of electricity producing GCRs of a current design, this fact is not surprising. (The United Kingdom has an aging fleet of lower-temperature CO_2-cooled advanced GCRs that are not candidates for further deployment.) All the world's existing high-temperature GCR projects had their fuel produced in pilot scale facilities. A commercial MHTGR was operated for several years at Fort St. Vrain, Colorado. Its fuel was produced in a pilot scale facility operated by GA at Sorrento Valley, California. Pebble bed fuel pilot lines in China and proposed for South Africa at Pelindaba are based on German PBMR technology, which was formerly located at Karlsruhe. Nuclear Fuel Industries in Japan has a 0.4 MTU/yr coated-particle fuel line at Tokai-Mura, which was completed in 1992. NUKEM/HOBEG of Germany had a line at Hanau from 1960–1968 that was capable of manufacturing 200,000 fuel blocks per year. It is now being decommissioned. Cost information on these pilot facilities is either not available or is considered proprietary.

If GCR technology is to be deployed for large-scale electricity generation, a large-scale particle fuel production facility will need to be built to support the fleet of modular reactors. No company has yet initiated such a project and will not until the proposed demonstration GCR modules utilizing pilot-plant-produced fuel prove to be technically and economically viable. (To support a prototype high-temperature GCR, such as the proposed U.S. Next Generation Nuclear Plant [NGNP], a pilot-scale fuel fabrication line will be required.) The U.S. companies Nuclear Fuel Services of Erwin, Tennessee, and BWXT Technologies and AREVA-NP of Lynchburg, Virginia, have all shown some interest in pursuing this technology. GA Technologies of San Diego, California, has decided to pursue only the reactor part of this fuel cycle.

In terms of heavy metal or uranium throughput, commercial particle fuel production facilities are likely to be smaller than LWR facilities, but this is partially because the U-235 enrichment of this fuel is at least twice that of LWR fuel and less "heavy metal" (combined fertile and fissile) is required per kilowatt of electricity produced. In an LWR fuel assembly, most of the "weight" is UO_2 in the form of pellets. However, for GCR fuel, much of the fuel assembly weight will be machined or formed graphite. The fissile mass is dispersed within defined locations within the graphite.

From 1988–1992, DOE embarked on a program to design and construct tritium production reactors for military purposes. The original Record of Decision was to build eight 350 MWth modules at the Idaho National Laboratory (INL).[b] These steam cycle MHTGR modules were to use 93.5% U-235 weapons-grade highly enriched uranium in its fuel. The fuel design was the TRISO/prismatic block concept. To support this operation, a 3 MTU/yr onsite fuel fabrication plant was proposed, and a preconceptual design was prepared in 1990 by Fluor-Daniel Corporation based on GA process concepts. This plant was to be government (DOE Defense Programs)-owned and financed and operated by the INL prime government contractor. Cost information from this report will be discussed in a section below.

GA has proposed the GT-MHR as a plutonium-dispositioning reactor both in the U.S. and Russia. (The same particle fuel concept can be used with PuO_2 or other plutonium compound ceramic kernels.) GA is engaged in a joint program to eventually construct a plutonium GT-MHR in Russia; however, very limited information on the fuel fabrication facility that would be needed has been presented. The GT-MHR uranium burner is also being NRC-certified for future U.S. deployment; however, no plans or cost information for a supporting fuel fabrication facility have come forth. Some GA cost information can be gleaned from conference papers, and some of this is discussed below.

The South African utility ESKOM plans a small (maximum 13 MTU/yr) fuel production facility to support their first-of-a-kind demonstration module. This is likely to be an expansion of the 2.4 MTU/yr

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[b] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

pilot plant now being design and licensed by NECSAs (Nuclear Energy Corporation of South Africa) German contractor Uhde, A division of Thyssen-Krupp. Again, very limited cost information on this proposed facility is available.

There is, however, considerable developmental work taking place in the area of TRISO fuels. Two of the International Generation IV reactor concepts involve high temperatures (required for nuclear hydrogen production) and gas-coolants as well as some space reactor concepts. DOE is also considering the construction of a NGNP at INL that will be a demonstration GCR for hydrogen production. AREVA-NP, BWXT, GA, Nexia (formerly BNFL), and national laboratories such as INL and Oak Ridge National Laboratory all have research and development interests in this type of fuel. Any economic analyses performed on GCR fuel manufacturing, however, have not been made public.

GCR Fuel Fabrication Process. There is no single process for all particle fuels, and many of the processes are proprietary. They all have some basic similar element; however, and these will be briefly mentioned. Figure D1-3-4 shows a generic TRISO fuel fabrication process being considered by the Advanced Fuel Cycle Initiative (AFCI) Fuels Working Group. Production of the ceramic UO_2 or UCO kernel is a crucial step in the process. In order to get uniform spheres, a sol-gel or similar fluidization process must be used to render liquid spheres into hard solid spheres. This means that a liquid solution such a uranyl nitrate hexahydrate (UNH) must be produced from the UF_6. This is a relatively simple step, since many of the older LWR fuel “wet” or aqueous fuel fabrication processes required the same step on their front end. Uniform UNH solution drops of the desired size are formed and then contacted with ammonia to form gel-spheres (gel-precipitation process). These gel-spheres are washed with water, dried to a low-density form, calcined to a medium-density form, and then sintered to a high-density microsphere “kernel.” Fission-product-retentive ceramic coatings are applied to the kernel by chemical vapor deposition in a fluidized-bed furnace. The coated particles are mixed with various carbonaceous materials and formed into either cylindrical compacts or spherical pebbles. For the GT-MHR, the compacts are inserted into predrilled hexagonal blocks of graphite. Each pebble or compact will have thousands of such TRISO particles imbedded within. The requirement for quality control and TRISO particles in a reactor core, the defective particle fraction must be kept very low, especially for modern vented confinement reactor designs in order to meet the licensing requirements for low onsite and offsite doses/releases.

Bench and pilot scale work is under way in several nations on variants of this process. The problems of scaleup and automation are just now being seriously considered. The economic viability of this reactor/fuel system will depend heavily on how successful these efforts are.

D1-3.3 PROCESS DESCRIPTION

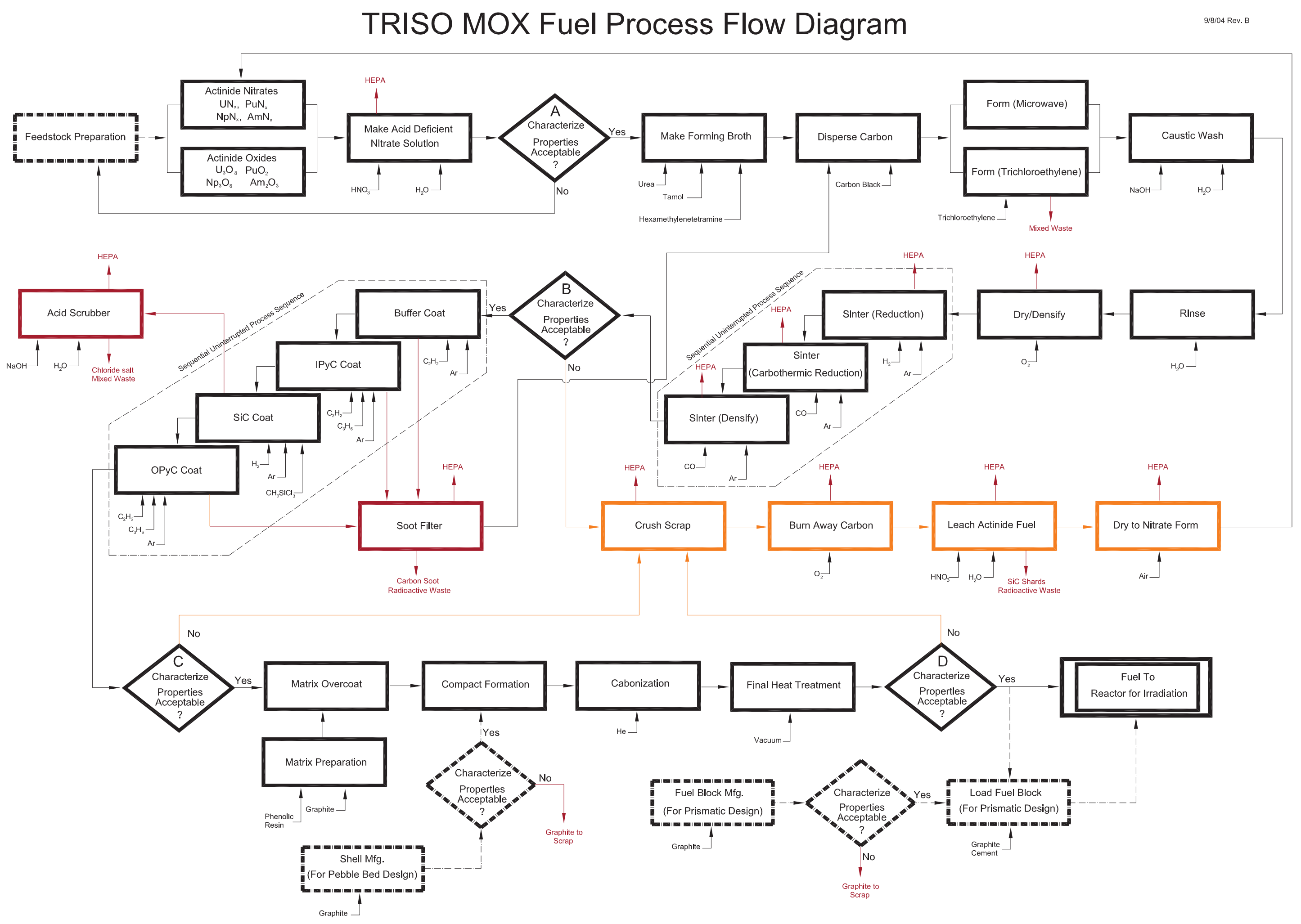


Figure D1-3-4. TRISO MOX fuel process flow diagram (DOE-AFCI Fuels Working Group, 2007).

D1-3.4 MODULE INTERFACE DEFINITION

Front-end interface. Because the fuel enrichment level is 8 to 19.9% U-235, the likely feed material to a fabrication facility will be EUF_6 coming from a new centrifuge enrichment plant or from blended U.S. or Russian EUF_6 derived from surplus HEU.

Back-end interface. Irradiated blocks and pebbles are the fuel forms that exit a GCR fuel fabrication facility. Special transport packages will need to be designed to safely move and protect this type of fuel. The spent fuel handling and disposal steps are technically different than for LWR fuels. The bibliography includes three publications dealing with waste characterization and repository issues associated with this fuel type. Most MHR reactor and fuel concepts are designed for open cycles. Reprocessing of this type of fuel presents many processing and waste-related difficulties compared to that for LWR or fast reactor fuels, especially in head-end operations. The Generation IV Roadmap (see Bibliography for reference) for gas-cooled systems discusses research and development issues with reprocessing and other aspects of this technology.

D1-3.5 MODULE SCALING FACTORS

No scaling factors or other scaling information was found in the literature. Because batch sizes are limited by criticality concerns, any capacity additions to an already-existing production scale facility (none exists now) will be accomplished by adding new process lines or the use of multiple shifts. The size of an optimal automated TRISO particle fabrication line is still to be determined.

D1-3.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

Cost and Pricing of GCR Fuel Fabrication. The fabrication cost of GCR fuel is most useful if it can be expressed in \$/kgU or \$/kgHM and not include the ore, natural U_3O_8 to UF_6, and enrichment components. In the literature, it is hardly ever expressed in this fab-only way, so in the cases below the fab-only unit cost had to be calculated by the author. Four different literature sources are analyzed below.

Proposed New Production Reactor Fuel Fabrication Facility (DOE/NP-24 and ORNL 1991) In FY 2003 dollars, this 3 MTU/yr fuel fabrication plant, based on a Fluor-Daniel study, would have cost \$355M and have annual operating costs of \$22.6M/yr. This operations cost does not include the ore, conversion, SWU, or UF_6 to UO_3 or UNH conversion needed to supply feed material (UO_2 or UCO) to the plant. If this New Production Reactor-support plant is amortized over 30 yr at a 4% real discount rate, a unit fabrication cost of nearly \$40,000 per kgU or \$49,000/hexagonal fuel block results. The fabrication of fuel at this price would account for 11 mills/kWh for a steam cycle 135-MWe MHTGR operating on a 1-year cycle at an 80% capacity factor. The proliferation, security, and criticality issues associating with dealing with weapons-grade (> 90% U-235) highly enriched uranium contribute significantly to these high costs. In later commercial designs, such as the GT-MHR, GA designers have reduced the fuel enrichment to below 20% U-235 and increased the fuel burnup, thermodynamic efficiency, and electrical capacity of the reactor, which will drive down the per kWh unit cost.

GA Study on production of Spherical Targets for Fusion Energy (Goodin et al. 2002). This report attempts to predict the cost of producing tiny spherical D-T targets for inertial confinement fusion based on past and projected costs of producing TRISO microspheres for GCRs. A graph in this document demonstrates how the cost per particle (fabrication only) for TRISO fuel has decreased from 20 cents/particle for 1960s bench scale fuel to a projected cost of less than 0.001 cents per TRISO particle for future fuel in an automated plant.

Each MHTGR or GT-MHR block (fuel assembly) has over 10 million of these particles. For the more current direct cycle 300 MWe GT-MHR reactor, both 19.8% U-235 and natural uranium particles will be used. Using the above costs per particle (midrange values) the fuel costs are calculated in Table D1-3-1 as follows, (Note: ore, SWU, graphite, conversion from UF_6, etc., add $5,900/kgU to the stand-alone particle fabrication cost):

Table D1-3-1. Fabrication costs as a function of TRISO particle cost.

Reference: **Particle Cost (U.S. cents)**	Fab Cost per Block (particle fab only)	Fab Cost ($/kgU) (particle fab only)	Fab Cost per Block (incl ore, SWU, conv)	Fab Cost ($/kgU) (incl ore, SWU, etc.)
20	$2,540,000	$573,000	$2,560,000	$579,000
1	127,000	28,700	147,000	34,700
0.1	12,700	2,870	33,000	8,850
0.003	382	860	20,700	6,070

Today's cost is likely between the $33,000 and $147,000 per block. GA would like to force fabrication costs down to around $12,000/block (particle preparation and graphite steps, but no ore or SWU cost are in this goal). A block contains around 4 kg of uranium, with over 75% of particles consisting of 19% U-235, and <25% of particles containing natural uranium.

1993 Gas-Cooled Reactor Associates Commercialization Study (DOE 1993). This report deals mostly with MHTGR construction costs. However, it does have some fuel cycle information. It states that the goal of the fuel development/qualification program is to get the cost of an MHTGR fuel assembly or "block" down to ~$12,000 in 1993 dollars. This would be ~$16,000 per block in today's dollars. It did not state if this includes only fabrication or includes all materials/services such as ore, SWUs, etc. If each block contains ~4 kg of uranium, the goal cost per kgU is therefore around $4,000/kgU. This means that the Gas-Cooled Reactor Associates goal cost probably does not include ore or SWU, because these combined items alone would likely contribute nearly $6,000/kgU to the overall fuel cost. If GA can drive the overall cost ($6,000 + $4,000) to $10,000/kg of enriched uranium for a finished fuel assembly, they will meet the target. Realization of the target fuel cost above would result in a fuel cycle component of the power generation cost of around 9 mills/kWh.

University Design Project Study for Pebble Bed Reactor (UC and OSU 1998). The concept described is called the Modular Pebble Bed Reactor (MPBR) as opposed to the Eskom/BNFL PBMR. The plant designed and evaluated is a 10-reactor module facility totaling 1,100 MWe. It was developed jointly in 1998 by Massachusetts Institute of Technology (Andy Kadak and students) and INL. It was also part of a University of Cincinnati/Ohio State Design Course for which the documentation was made available on the Internet. The capital cost data are at the two-digit energy economic database code-of-accounts level only. All the costs are in 1992 constant dollars. The data from this study were input by this section's author to the Power Generation Cost model, G4-ECONS, being developed by the Generation IV Economics Working Group. In this model, the costs were all increased by a factor of 1.275 to take them to today's constant dollars using a construction index similar to the Handy-Whitman Utility Construction Index.

The reactor core for each PMBR module consists of 360,000 round pebbles with 7 g (expressed as uranium) of 8% U-235 enriched UO_2 in each. The UO_2 is encapsulated in 11,000 TRISO-coated microspheres within each billiard-ball-sized pebble. For the Generation IV Economics Working Group model, each pebble is assumed to be a “fuel assembly.” An annual reload consists of 120,000 pebbles per module. The design project authors assume each pebble costs $22 in 1992 dollars including all front-end fuel cycle steps. The author of this section assumes that this has risen to $28 in today’s dollars. This yields a fabrication cost of ~$1,700/kgHM or per kgU if all other front-end fuel cycle costs (ore, SWUs, etc.) are set at today’s values. This cost, in the opinion of the analyst for this report, is unrealistically low given the complexity of GCR fuel fabrication.

Facility Cost Projections. The author of this report located some fuel fabrication facility cost projections for both the South African PBMR (IAEA 2001; National Engineering International 2005; Platts 2005) and GA GT-MHR (1994) concepts. Both of these costs were for fuel fab facilities to be located outside the U.S., either in South Africa or Russia. The GT-MHR data were for a plant producing PuO_2 TRISO fuel for use in the joint U.S.-RF Plutonium Disposition Program. Table D1-3-2 shows the fissile loading, throughput, and cost projections for each of these facilities. Based on experience in the U.S. with other nuclear facilities, these cost projections would likely be considerably higher for similar facilities to be located in the U.S.

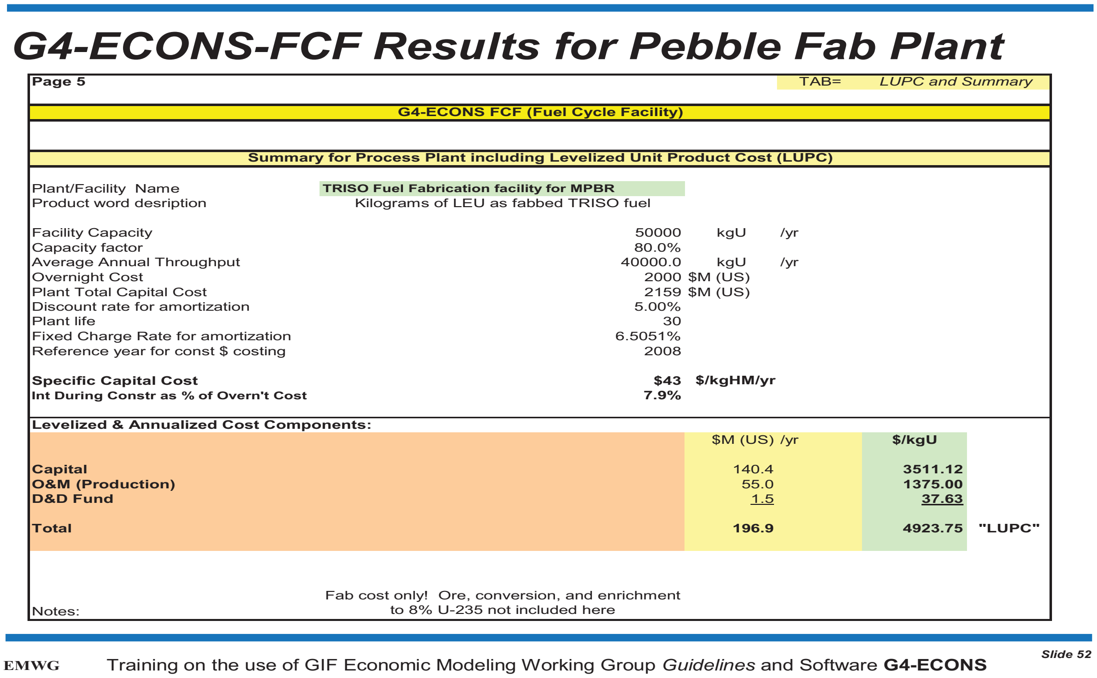
ESKOM of South Africa recently (May 2005) announced the award of a $20 million design and construction contract for a 270,000 sphere (pebble fuel assembly) per year pilot plant to support their PBMR project. If this ~2.4 MTU/yr plant operated for 10 years and the capital cost is distributed over the uranium processed (9 g U per pebble), the capital component of the unit cost comes to ~$825/year. The operating cost anticipated for this pilot plant was not given, but it is anticipated that a staff of 50 will be required. At an $80,000/yr loaded average staffing cost about $4M/yr would be required. Spread over the 2 MTU/yr, this is an additional $2000/kgU. As PBMR orders come in, South Africa will add additional production capacity to this pilot facility. This staffing O&M component cost is felt to be much more realistic that the $20M capital cost for what will be a very complex process facility.

Because of the need for gloveboxes and more nuclear safety controls for plutonium fuels, the costs associated with the use of plutonium TRISO fuels are likely to be an order of magnitude higher than for 19.8% U-235 LEU TRISO on a per kilogram (heavy metal) basis.

Table D1-3-2. Data for projected ESKOM and GA TRISO fuel fabrication facilities.

ESKOM Pebble-Bed Modular Reactor (PBMR)	for Uranium Fuel:	**GA Modular Helium Reactor (GT-MHR) U or Pu burner**	for Uranium or Plutonium fuel as noted:
		TRISO Particles per Cylindrical compact	4230
TRISO Particles per Sphere (Pebble)	~15000	Compacts in Full Core of one 286MWe GT-MHR module	3102120
Spheres in Full Core of one 117MWe module	~360000	Average enrichment of U in initial core	10.31%
New Spheres introduced annually per module	~122000	Total U mass of initial core for one GT-MHR module (MTU)	4681
Grams of U in one sphere	9	Average 235 enrichment of U in annual GT-MHR reload	15.46%
Ave U-235 Enrichment of TRISO fuel	8.0%	Total U mass of annual MHTGR reload for 1 module (MTU)	2262
		Total Pu mass of initial core for one GT-MHR module (MTPu)	634
Uranium loading of full core (MTU) for 1 module	3.24	Total Pu mass of annual reload for one GT-MHR module (MTPu)	262
Make-up Uranium required per year to fuel one module (MTU)	1.10	Projected Yr 2000 US$ cost in Russia (Seversk) for Pu-TRISO FFF supporting 4 GT-MHR modules (Nth of kind plant) [$M]	126
		Annual throughput of Pu-TRISO FFF [kg Pu/yr]	1048
Proposed prod'n capacity of initial ESKOM fuel fab plant based on 1.4 million spheres/yr (MTU/yr)	12.6	Annual operations cost for Pu-TRISO FFF in Russia ($M/yr)	28.4
		Capital cost per unit of capacity ($/kgPu/yr)	120229
Estimated capital cost of ESKOM fuel plant based on nth-of-kind cost of $2M/reactor supported ($M)	23	Operations cost per kgPu processed [$/kgPu]	27099
		Unit cost using 10 year amortization at 4% annual discount rate (in $/kgPu) [in Russia]	41922
Capital cost per unit of capacity ($/kgU/yr)	1825		
ESKOM Projected Fuel cycle contribution to 16.7 mills/kwh electricity cost (South African conditions; nth of a kind)	4.0	Projected Fuel cycle contribution to electricity cost (mills/kwh) from nth of a kind Pu-burning plant	13
[Information from IAEA-TECDOC-1198 (Feb 2001)]		**[Information from General Atomics Reports]**	

Because of the high process complexity (and not radiological considerations) it is likely that the lowest unit cost for LEU TRISO fuel will be on the order of that (the HIGH unit cost) for commercial MOX fuel (i.e., around $5000/kgHM or U in this case). Using some data from the MIT study cited previously and the G4-ECONS Fuel Cycle Facility economics model (G4-ECONS 2008), one can deduce what the capital cost of TRISO plant might be for a given production capacity. Figure D1-3-5 below shows the breakdown of the unit cost and a capital cost for a TRISO facility of capacity 50 MTU/yr. This fabrication cost would be about $35 per pebble for spheres containing 7 grams of 8% U-235 UO_2. The overnight cost for the facility would be around $2B. This plant could supply fuel for ~6500 MWe of HTR capacity.



G4-ECONS-FCF Results for Pebble Fab Plant

Page 5 TAB= *LUPC and Summary*

G4-ECONS FCF (Fuel Cycle Facility)

Summary for Process Plant including Levelized Unit Product Cost (LUPC)

Plant/Facility Name	**TRISO Fuel Fabrication facility for MPBR**		
Product word desription	Kilograms of LEU as fabbed TRISO fuel		
Facility Capacity	50000	kgU	/yr
Capacity factor	80.0%		
Average Annual Throughput	40000.0	kgU	/yr
Overnight Cost	2000	$M (US)	
Plant Total Capital Cost	2159	$M (US)	
Discount rate for amortization	5.00%		
Plant life	30		
Fixed Charge Rate for amortization	6.5051%		
Reference year for const $ costing	2008		
Specific Capital Cost	**$43**	**$/kgHM/yr**	
Int During Constr as % of Overn't Cost	**7.9%**		

Levelized & Annualized Cost Components:

	$M (US) /yr	$/kgU	
Capital	140.4	**3511.12**	
O&M (Production)	55.0	**1375.00**	
D&D Fund	1.5	**37.63**	
Total	**196.9**	**4923.75**	**"LUPC"**

Notes: Fab cost only! Ore, conversion, and enrichment to 8% U-235 not included here

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Figure D1-3-5. Breakdown of unit and capital cost for a TRISO facility.

D1-3.7 LIMITATIONS OF COST DATA

Identification of Gaps in Cost Information for Future Fuel Cycles. The gaps in the economic information for this type of fuel are very wide and deep, especially given the fact that PBMRs and GT-MHRs are being seriously considered for deployment as electricity producers and even hydrogen producers. It may be that the private developers of these concepts are keeping such information proprietary. In any case, it would be in DOE's best interest to initiate a study that would at least consider the economic and cost issues associated with scaleup and automation of at least some of the various TRISO particle fuel flowsheets now under development. It would also be useful to understand the cost issues associated with the radiochemical and radiotoxicity amelioration design fixes required to adapt TRISO fuel production flowsheets to plutonium particle fuel production or actinide burning. The joint U.S./Russian GT-MHR program could also greatly benefit from such an analysis.

Readiness level. This fuel fabrication technology reached the pilot plant level of deployment in the U.S. for the production of Fort St. Vrain MHTGR fuel at Sorrento Valley near San Diego, California. Presently, that facility has been shuttered, and any U.S. work in progress is now at the "bench scale."

D1-3.8 COST SUMMARY

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-3-3. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distribution based on the costs in the WIT Table is shown in Figure D1-3-5. The distribution is skewed toward the low cost because the nominal cost reflects past experience with making TRISO fuel; however, the outlying high cost reflects a very high uncertainty in deploying a large-scale, automated facility for manufacturing of TRISO particle fuel.

Table D1-3-3. Cost summary table for GCR TRISO fuel.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Today's 8–19.9% U-235 unit fab cost probably ~$25,000/kgU	N/A	$5,000/kgU Low cost assumes that complexity of this fab process is at best comparable to glovebox-handled LWR MOX	$30,000/kgU	$10,000/kgU
No highly reliable data on plant capital costs;	Not available	Development of a reliable, highly automated TRISO process in a central large facility	Quality or process development difficulties. Use of PuO_2 kernels	If automated process is successful:

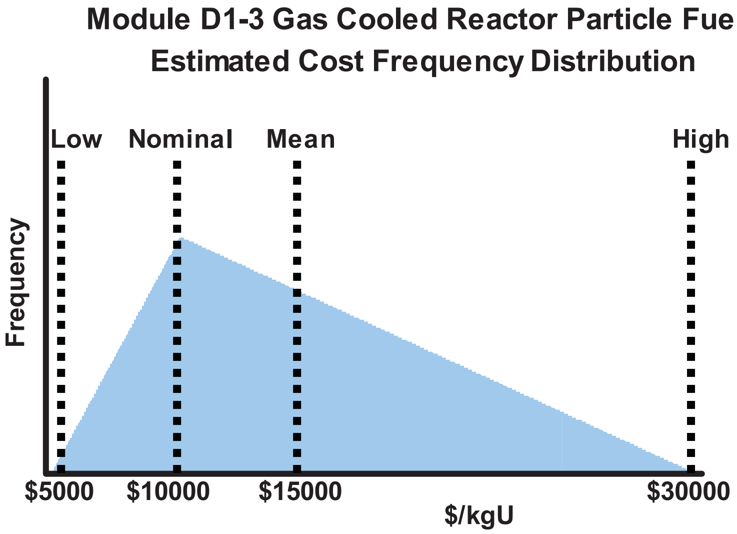

Figure D1-3-5. Gas cooled reactor particle fuels estimated cost frequency distribution.

D1-3.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

Insufficient base process cost data exist for such studies to begin. Goodin et al. (2002) and DOE (1993) have some limited sensitivity study data.

D1-3.10 BIBLIOGRAPHY

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Owen, Paul E., 1999, *Waste Characteristics of Spent Nuclear Fuel from a Pebble Bed Reacto*r, MS Thesis in Nuclear Engineering, Massachusetts Institute of Technology, June 1999.

Module D1-4

Ceramic Pelletized Fast Reactor Fuel

Module D1-4

Ceramic Pelletized Fast Reactor Fuel

D1-4.1 BASIC INFORMATION

Fuel Form. Ceramic fueled fast reactors can operate on either highly enriched uranium fuel (such as the BN-600 in Russia) or plutonium-based MOX fuels (such as the French Phenix reactors and the cancelled U.S. Clinch River Breeder Reactor). For electricity production "breeder" fast reactors, the ceramic material of choice has been either enriched UO_2 or MOX $(Pu,U)O_2$, which can be contact-handled during fabrication if the minor actinide (neptunium, americium, curium) content is sufficiently low. For "burner" fast reactors, where significant amounts of the minor actinides arising from LWR reprocessing or from the fast reactor's own fuel cycle are to be recycled within the driver fuel, remote-handling during fabrication will be required because of the radiation level associated with mainly americium and curium and any trace fission products carried over from fast reactor fuel reprocessing. These fuel types will be addressed in Module F2/D2, where reprocessing and remote refabrication are considered as integral processes. Because of the use of higher fissile content, typically 15% or higher U-235 or plutonium in heavy metal, the amount of fissile material per unit volume in the driver fuel is a factor of four or more higher than for LWR fuels.[c]

For a given power level the fuel assemblies and the reactor core are smaller in mass and volume than for an equivalent power LWR. Ceramic fast reactor fuel assemblies are typically less than 3 m long including axial blankets and end pieces, hexagonal in shape, and with much thinner fuel rods. The cladding is stainless steel instead of Zircalloy for reasons of better chemical resistance to the liquid sodium coolant. Table D1-4-1 compares example LWR (thermal) and fast reactor fuel assemblies:

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[c] Fast reactors may have as many as three types of fuel rods within the core: drivers, blankets, and targets. Drivers constitute the fissile materials that account for most of the energy production and in which the fissile content falls with continuing irradiation ("burning"). Blanket fuel consists of fertile material, such as DUO_2 or ThO_2, which will be partially converted via neutron absorption to new fissile material ("breeding"), such as Pu-239 or U-233, which can be recovered by reprocessing and refabricated into new fuel. Targets contain radionuclides, such as higher actinides or fission products, which are converted by neutron irradiation to other nuclides with shorter lives; this "burning" process is sometimes called burnout, transmutation, or destruction. These spent targets can subsequently be more efficiently and safely emplaced in a geologic repository.

Table D1-4-1. Comparison of fast and thermal pellet fuel.

	Thermal Reactor	Fast Reactor
Fuel	UO_2	$(U,Pu)O_{1.96}$
Fuel Pellet Density (% of theoretical)	92	90
Max. fuel centerline temperature (overpower condition)°C	2450	2800
Cladding	Zircaloy-4	316 Stainless Steel
Max. cladding mid-wall temperature °C	380	660
Coolant temperature, °C	H_2O, 280-320	Na, 470-650
Maximum rod linear power, W/cm	620	550
Fuel wrapper assembly	Square, 30x30	Hexagonal, 13 cm across flats
# of pins in assembly	200	220
Fuel-rod outside diameter, mm	10.7	6.3
Cladding thickness, mm	0.6	0.4
Initial fuel-cladding radial gap, mm	0.08	0.07
Length of fueled portion, cm	365	90

Figure D1-4-1 shows a French ceramic fast reactor fuel assembly from their Superphenix fast reactor, which is typical of this type of fuel assembly.

Ceramic fuels other than oxides have also been considered, with uranium or plutonium nitrides and carbides receiving the most research and development attention in the U.S.

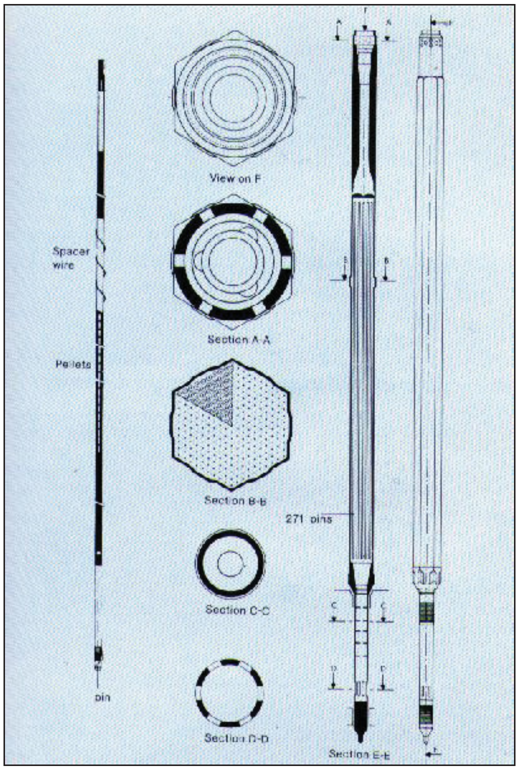


Figure D1-4-1. Superphenix fuel assembly diagram (CEA, 1985).

D1-4.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

Similarity to LWR MOX. The functions and operations in a fast reactor fuel plant based on pellet technology are similar to those in an LWR MOX plant. The higher fissile content (typically >15%) of fast reactor fuel, however, requires more stringent security and criticality avoidance measures. The previous existence of a developing fast reactor industry in Europe, Japan, and Russia shows that such facilities are technologically viable.

Status of Industry. Slowdowns or cancellations of fast reactor programs have put production of ceramic fast reactor fuel worldwide at a near standstill. Belgium, the UK, France, Germany, and Japan all have fabrication plants that are now shutdown or inactive. Russia still produces mostly highly enriched uranium (HEU) and some $(U,Pu)O_2$ MOX fuel for their BN-600 Reactor located at Beloyarsk. When the U.S. was about to construct the Clinch River Breeder Reactor, plans were being drawn up to construct a U.S.fast fuel fabrication facility. The ceramic fast reactor fuel production that has taken place in the U.S. has been on a small scale in national laboratory or reactor vendor development facilities, and most of this was in the 1960s and 1970s. Unless interest is revived in closed fuel cycles and particularly one that uses ceramic rather than metallic fast reactor fuel (Module F2/D2), near-term prospects are dim for the deployment of such fast reactor fabrication capacity in the U.S. As the Generation IV and AFCI programs progress, however, interest may be revived. (AFCI "burner" fast reactor concepts are more likely to require the types of remote-handled, higher-actinide laden fuels discussed in Module F2/D2; however, the first cores are likely to be U,Pu only.)

Russia, China, India, and Japan plan to keep the fast reactor option open, with electricity generation and "breeding" being the predominant missions rather than actinide burning. Japan is about to restart their experimental MONJU sodium-cooled reactor. India and China are constructing a 500 MWe and 25 MWe prototype fast reactors, respectively. The Russian Federation plans to construct an 800-MWe unit at Beloyarsk near its existing BN-600 unit and has even proposed a 1,800-MWe design. The Russian Federation has also indicated interest in using BN-type reactors to disposition surplus plutonium from their military programs. A small fuel fabrication facility at Mayak named "Paket" could be restarted to provide early pellet-based fuel assemblies; however, the vibrocompaction process (Module D1-5) seems to be the presently-preferred technology. The Japanese also have limited capability to produce pellet MOX fuel at their Tokai Works. Costs for production at these facilities are not known. India is constructing a fast reactor; however, no information on the fuel source is available.

D1-4.3 SCHEMATIC OF PROCESS

For fast reactor-MOX pellet fuel, the schematic would be very similar to the process diagram shown in Subsection D1-4.2 on LWR MOX fuels, except there would be one less blending step. Figure D1-4-2 shows the fabrication process for the ceramic nitride fuel being examined by the AFCI Fuels Working Group for Generation IV fast reactor applications. Most of the steps are similar to those for oxide fuel.

Fast Reactor Pellet Fuel Fabrication Process. For medium enriched uranium (>10% U-235 or <20% U-235 or highly enriched uranium), ceramic fuel the process would be much the same as for LEU fuel production. Because of the security and criticality concerns, batch sizes would be very limited in size. For MOX ceramic fast reactor fuel, the process is much the same as for thermal MOX (Section D1-2). Again, the batch sizes handled would have to be much smaller. Both plants would likely have to purchase or fabricate their own stainless steel fuel assembly hardware such as grids and spacers.

D1-4.4 MODULE INTERFACE DEFINITIONS

For the fast reactor MOX plant the starting material for driver fuel would likely be clean, reactor-grade PuO_2 powder from the reprocessing plant or PuO_2 storage. (For contact handling some neptunium and/or very small amounts of americium can be present with the plutonium.) For the EUO_2 driver fabrication plant, the starting material is likely to be EUF_6. Blanket UO_2 fuel could be produced in a conventional industrial facility with very low security and radiation protection requirements, i.e., no gloveboxes or criticality alarms. Transportation of finished fast reactor MOX driver fuel will, of course, need special casks for added security and radiochemical safety reasons. Other interfaces are similar to those for LWR MOX.

MOX driver fuel and DUO_2 blanket fuel are best matched to aqueous reprocessing at the back end of the fast reactor closed fuel cycle. The Japanese have already begun planning such a plant to reprocess spent fuel and blankets from their Japanese Sodium-cooled Fast Reactor (1,500 MWe; JSFR) concept. Note that spent fast reactor fuel is likely to require development of a new type of storage/shipping cask.

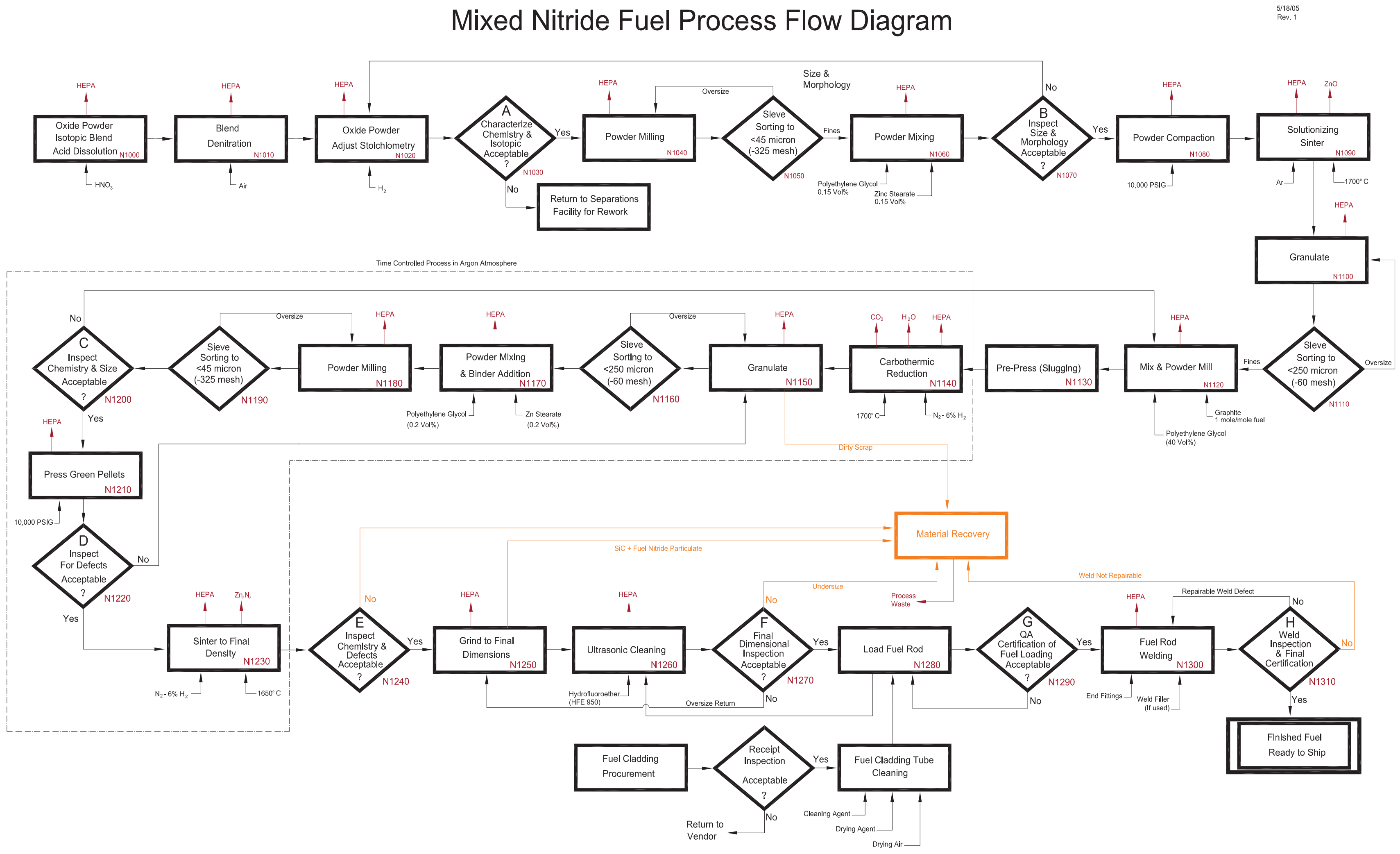


Figure D1-4-2. Fabrication process for mixed nitride fuels (DOE-AFCI Fuels Working Group, 2007).

D1-4.5 MODULE SCALING FACTORS

The same considerations apply in this area as for LWR MOX fuel (see Subsection D1-2.4). In terms of heavy metal throughput, the reference fast reactor MOX plant will be much smaller for the same amount of fissile nuclide (plutonium) processed.

D1-4.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

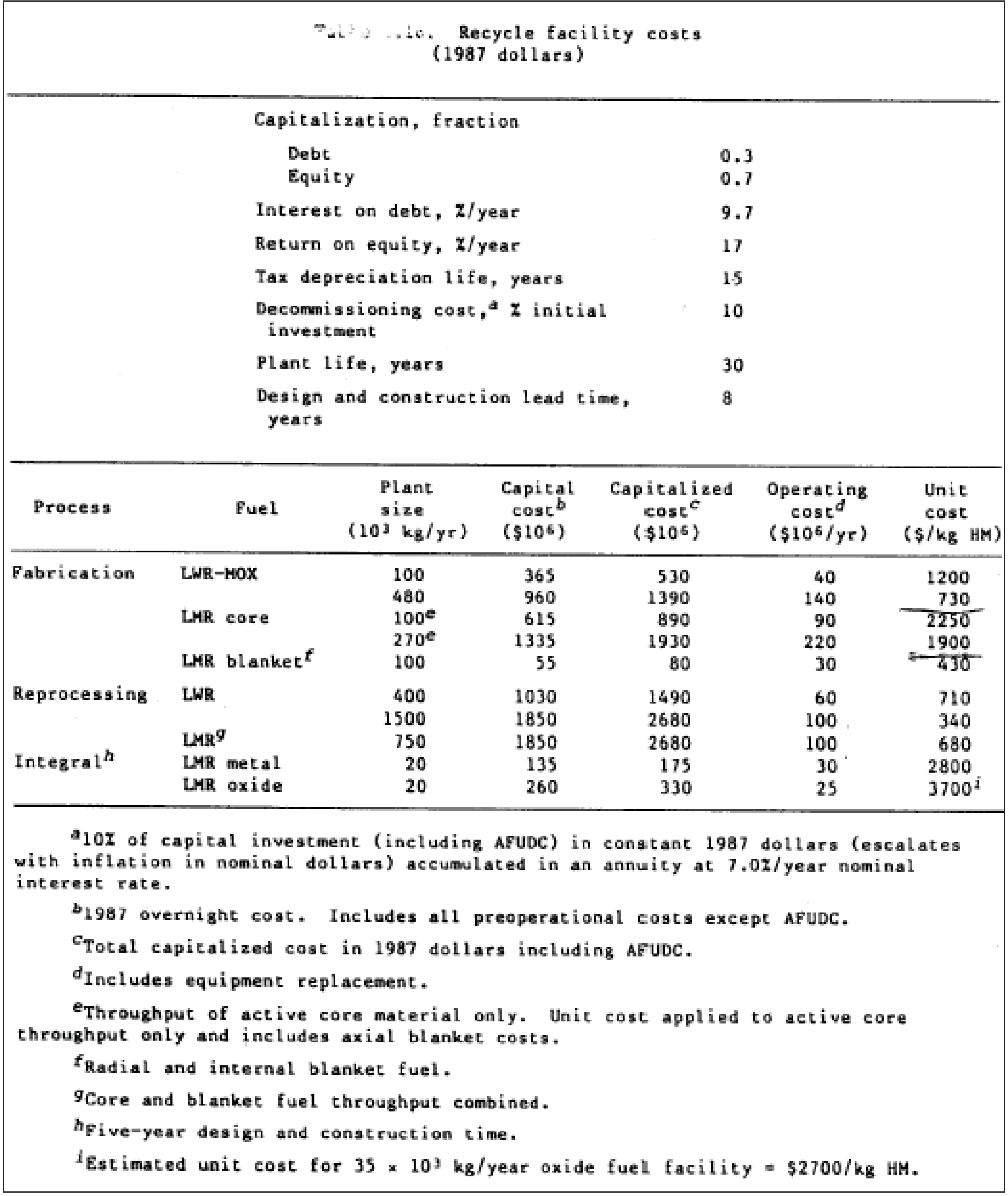
Cost and Pricing of Fast Reactor Fuel Fabrication. Fixed costs for a fast reactor ceramic fuel fabrication plant are likely to be similar to those for an LWR MOX fabrication facility. These costs are distributed over a smaller heavy metal throughput, however, because less of the heavy metal is diluent and more is fissile. One would expect that the cost per kgHM for ceramic fast reactor fuel would be higher than for LWR MOX and that the plant heavy metal throughputs would be smaller. Table D1-4-2 shows projected costs for fast reactor (sodium-cooled LMR) ceramic MOX [$(U,Pu)O_2$] fuel from various sources. Some of the cases below have fabrication costs for MOX fuel that contain minor actinides such as neptunium, americium, and curium, which make the radioactivity hazard associated with fabricating fuel somewhat more serious. Remote-handling facilities of the type discussed in Module F2/D2 would be required for these facilities. “Heterogeneous” fast reactors have two types of fuel in their cores: the fissile “driver” core with high fissile content, and the fertile blanket, with natural or depleted uranium oxide or other ceramic forms. Fabricating blanket fuel should cost no more than fabricating LEU fuel, because criticality and radiotoxicity are minor or nonexistent concerns. “Homogeneous” fast reactors do not have a separate blanket or set of targets.

The sizing of ceramic fast reactor fuel fabrication plants is uncertain, because it is not known how many fast reactors utilizing pellet fuel might eventually be used. The only scaling data found were from the 1988 Oak Ridge National Laboratory Nuclear Energy Cost Data Base, which references data from the late 1970s Nonproliferation Alternative Systems Assessment Program (NASAP) that looked at many fuel cycles. A table from the Nuclear Energy Cost Data Base is reproduced here (Table D1-4-3) to show some plant capacity and capital cost data. All costs are in 1987 dollars. A multiplication factor of 1.9 would bring them to 2009 dollars.

Table D1-4-2. Unit fabrication costs for various fast reactor fuels.

Reference/Date	Fuel (Contact-handled unless otherwise noted)	Fab Cost in $/kgHM (“then year $”)
DOE/2002	MOX with minor actinides (ceramic pellet)	Core [driver] (M) 2,600
Bunn/2003	MOX (ceramic pellet)	Core (L/M/H) 700/1,500/2,300 Blanket 150/250/350
OECD NEA/1994	MOX with minor actinides (ceramic pellet. Reference did not specify whether facility was totally remote-handling.)	Core (L/M/H) 1,400/2,600/5,000
NECDB/1988	MOX (ceramic pellet)	Core (L/H) 1,900/2,250 Blanket (M) 430
Delene/2000	ALMR metal fuel (for comparison, remote handling assumed)	Core (L/M/H) 4,600/5,150/7,700
G4-EMWG/2005	MOX from equilibrium breeding cycle (JSFR data)	Core (M) 1537 revised in 2006 to 1,675
OECD/2005	Fast Reactor MOX	Core (L/M/H) 1,000/1,500/2,000
OECD/2006	Fast Reactor MOX	Core (L/M/H) 1,100/1,650/2,200
MIT/2009	Fast Reactor MOX	Core (M) 2400
Red Impact/2006	Fast Reactor MOX	Core (M) 2832

Table D1-4-3. Fast Reactor (LMR) recycle costs from 1988 Oak Ridge National Laboratory NECDB study.



[illegible] Recycle facility costs
(1987 dollars)

Capitalization, fraction	
Debt	0.3
Equity	0.7
Interest on debt, %/year	9.7
Return on equity, %/year	17
Tax depreciation life, years	15
Decommissioning cost,[a] % initial investment	10
Plant life, years	30
Design and construction lead time, years	8

Process	Fuel	Plant size (10^3 kg/yr)	Capital cost[b] ($\$10^6$)	Capitalized cost[c] ($\$10^6$)	Operating cost[d] ($\$10^6$/yr)	Unit cost ($/kg HM)
Fabrication	LWR-MOX	100	365	530	40	1200
		480	960	1390	140	730
	LMR core	100[e]	615	890	90	2250
		270[e]	1335	1930	220	1900
	LMR blanket[f]	100	55	80	30	430
Reprocessing	LWR	400	1030	1490	60	710
		1500	1850	2680	100	340
	LMR[g]	750	1850	2680	100	680
Integral[h]	LMR metal	20	135	175	30	2800
	LMR oxide	20	260	330	25	3700[i]

[a] 10% of capital investment (including AFUDC) in constant 1987 dollars (escalates with inflation in nominal dollars) accumulated in an annuity at 7.0%/year nominal interest rate.

[b] 1987 overnight cost. Includes all preoperational costs except AFUDC.

[c] Total capitalized cost in 1987 dollars including AFUDC.

[d] Includes equipment replacement.

[e] Throughput of active core material only. Unit cost applied to active core throughput only and includes axial blanket costs.

[f] Radial and internal blanket fuel.

[g] Core and blanket fuel throughput combined.

[h] Five-year design and construction time.

[i] Estimated unit cost for 35 × 10^3 kg/year oxide fuel facility = $2700/kg HM.

The Japan Atomic Energy Agency (JAEA) (G4-EMWG 2006) has projected a capital cost of approximately $750 million for a 200-MTHM/yr pellet MOX fabrication facility needed to support JSFRs. The updated unit cost of $1,675/kgHM in G4-EMWG 2005 data of Table D1-4-3 is calculated based on amortization of this capital cost and the addition of operations and maintenance and decommissioning levelized costs.

D1-4.7 LIMITATIONS OF COST DATA

Technology Readiness Level. Fast reactor MOX or enriched uranium pellet fuel production technology in the U.S. could reasonably progress quickly to the pilot plant stage; however, changing requirements would link FR MOX progress to that for LWR MOX. Considerable fuel qualification would be required before industrial scale implementation in the U.S.

Identification of Gaps in Cost Information. If the benefits and risks of closed fuel cycles vis-à-vis open cycles are to be well understood, the fabrication costs for fuels arising from closed cycles must be better understood. Unfortunately, there is little U.S. experience in operating large-scale facilities, and what work has been done to date is mostly on LWR or thermal MOX. The most recent U.S. fast reactor cost studies have been for plants preparing metal fuel, with the feeds coming from an adjacent dedicated fuel reprocessing facility on the reactor site (i.e., the GE/MFC[d] Integral Fast Reactor cycle associated with the GE PRISM metal-fueled concept [discussed in Module F2/D2]). Therefore, they add little to the database for ceramic fast reactor fuels. It is also difficult to separate fabrication costs from reprocessing costs for such studies involving collocated integrated facilities.

It is likely that fast reactor ceramic (such as liquid metal reactor MOX) fuel fabrication plants will need to be tied in closely or be part of a reprocessing complex for fabrication unit costs to decrease. This collocation allows fixed costs for considerations, such as security and radiochemical hazard protection, to be distributed over more fuel cycle operations and also greatly decreases spent fuel transportation requirements and costs. Some preconceptual designs for collocated facilities need to be prepared by an architect-engineering firm in order for this assumption to be validated. The only other studies that might have very limited use are Russian design/cost studies on small fast reactor pelletized fuel facilities to support the burning of 17–25% fissile MOX fuels in the BN-600 reactor to support the joint U.S./Russian Federation weapons plutonium disposition program.

To increase the proliferation resistance of closed fuel cycles, the idea of not separating plutonium from other transuranic actinides ("grouped" actinides) in the aqueous reprocessing plant has been advanced. The UREX 1a reprocessing concept is one such process. This means that the fast reactor fuel that would be refabricated from this material would contain neptunium, americium, and perhaps other actinide (curium and trace californium) oxides in the MOX. Sometimes referred to as "dirty" MOX, this material would impose special and more stringent requirements on the fuel fabrication facility from the standpoints of personnel radiation exposure, heat management, criticality, and materials accountability. The resulting plants would more appropriately fall under Module F2/D2 (remote handling). These additional costs of more automated or remote handling are not known; however, if a "dirty MOX" economic study is done for thermal reactor fuel, such as $(Pu,Np)O_2$ or for higher actinide LWR targets, the results will have similar impacts on fast reactor MOX plants.

D1-4.8 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-4-4. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and

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[d] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL). Argonne National Laboratory-West was renamed the Materials and Fuels Complex (MFC).

evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table D1-4-4. Cost summary table for Fast Reactor Pelletized Ceramic fuels.

What-It-Takes (WIT) Table (2007 constant $)			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$2,400/kgHM from centralized, private 50-MT/yr facility with loan and market guarantee	$3,200/kgHM Blanket: $350/kgU	$6,000/kgHM Many of same factors affecting SRS-MFFF would affect this cost. (see Module D1-1) Blanket: $700/kgU	Core: $4,000/kgHM Blanket: $500/kgU
No reliable and validated data on plant capital costs	Same as for LWR MOX; use of enriched uranium in 15 to 25% U-235 range would be cheaper (fabrication cost) than plutonium use.	25% higher than for LWR MOX nominal cost	20% higher than for LWR MOX nominal cost

The triangular distribution based on the costs in the WIT Table is shown in Figure D1-4-3. The distribution is skewed toward the low cost because there is European and Japanese industrial experience, although at a small scale, with this type of fuel.

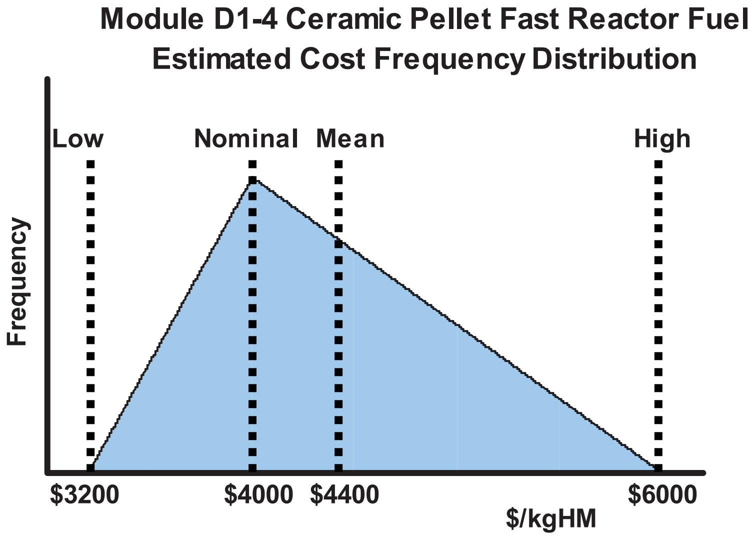

Figure D1-4-3. Ceramic pellet fast reactor fuel estimated cost frequency distribution.

D1-4.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY STUDIES

No such studies were found in the literature or were performed by the author for this fuel type.

Module D1-5

Ceramic Vibrocompacted Fast Reactor Fuel

Module D1-5

Ceramic Vibrocompacted Fast Reactor Fuel

D1-5.1 BASIC INFORMATION

Current Status. A vibrocompacted or VIPAC fast reactor fuel assembly appears identical to a pelletized ceramic fuel assembly on the outside. The fuel rods, however, initially contain vibrationally compacted, dense ceramic granulate instead of stacked pellets. (Some metallic powder may be added to the oxide mix to improve the fuel performance characteristics.) As the VIPAC fuel is irradiated, the reactor heat sinters the granulate into what is essentially a long pellet. The technical and cost advantage of this type of fuel is elimination of the costly pressing, sintering, and pellet grinding/finishing steps in the usual MOX fuel fabrication process. This process was investigated on a bench scale in the U.S. several decades ago, and some fuel was irradiated in the Saxton (Pennsylvania) test reactor. There is still considerable interest in this process for fast reactor MOX in Russia and in Japan. The Japanese have funded some Russian MOX vibro-fabrication work at RIAR (or NIIAR) in Dimitrovgrad, and some test rods have been irradiated in the BN-600 at Beloyarsk (Mayorshin, Skiba, et al. 2000). Figure D1-5-1 describes the purported advantages of vibropack technology as presented by RIAR. This technology is presently slated to play a role in the joint U.S./R.F. plutonium disposition program.

There are several variations of VIPAC technology. Early techniques focused on granulate produced by crushing sintered ceramic pellets. More recent work outside Russia has focused on use of sintered gel-spheres, and the associated technology is known as Sphere-Pac in reference to the resulting spherical feed. The East German–Russian variant promoted vigorously by NIIAR uses a crushed glassy granulate resulting from electrochemical deposition of UO_2 or $(U,Pu)O_2$ out of the molten salt solution.

VIPAC fuel fabrication is often paired with electrochemical fuel reprocessing (Module F2/D2 type process, but with ceramic rather than cast-metal fuel) in proposed fuel cycles because of the nature of the processes as explained below. One such fuel cycle is for the STAR-H2 reactor (The Secure Transportable Autonomous Reactor for Hydrogen [Electricity and Potable Water] Production). This is one of the metal-cooled reactor concepts being studied under the Generation IV program by Argonne National Laboratory and would use a U,Pu-nitride fuel.

D1-5.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

Vibrocompaction equipment (sieve-sizing, feeding, shaking) replaces pellet fabrication equipment for this type fuel. Feed powder preparation, however, may be somewhat more complex for vibrocompaction than for pelletization. The feed powder is usually in the form of tiny irregular shards rather than round or nearly-round particles. The oxide powder would actually be produced from an electrochemical process where oxide crystals are interspersed with other salts on an electrode. These other salts must be separated or washed away before the irregularly-shaped shard-powder is sieved and prepared for vibrational compacting into fuel rods.

D1-5.3 PICTURES/SCHEMATICS

Figure D1-5-2 shows a conceptualized view of the VIPAC process. In the diagram, three particle sizes are chosen. Some processes, such as the Russian RIAR one, have five particle sizes. The particles are not actually round, however, and exist as irregular shards that can be sized by sieving.

Figure D1-5-3 shows the overall VIPAC process as practiced at RIAR and how it meshes with their electrochemical reprocessing technology.

Fuel rods containing granulated fuel are fabricated using a standard vibropacking procedure (in glove-boxes or hot cells) have been used at RIAR for about 20 years.

The main advantages of the vibropack technology and fuel rods with vibropack fuel are as follows:

- Simplicity and reliability of the production process due to a smaller amount of process and control operations facilitating automation and remote control
- Granulate of homogeneous composition can be used as well as in the form of mechanical mixture
- Lower (as compared with a pellet stack) thermal-mechanical impact of vibropack fuel on the cladding
- Weakened requirements to the inner diameter of fuel rod claddings.

Fuel column is a mechanical mixture of (U, Pu)O_2 granulate and uranium powder, having a function of getter and is added to a fuel weighted portion at the stage of agitation before pouring. Getter addition for regulation of the fuel oxygen potential and elimination of process impurities effect allowed for complete solution of the problem of chemical interaction of vibropack oxide fuel and cladding. The process provides for a 100% fuel column quality control including distribution of plutonium and density along the fuel column length. The uniform getter distribution is ensured by the technology.

A number of studies were performed to verify the performance of fuel rods with vibropack oxide fuel including the optimization of the fabrication and control technology as well as the performance of all required reactor tests (SM, BOR-60, BN-350, BN-600) and post-irradiation material science examinations. Based on the testing results performed in the SM, BOR-60 and BN-350 reactors the basic parameters of fuel rod design for the BOR-60 and BN-600 reactors were optimized as well as the technological processes for production and control with consideration of remotely controlled operation.

Due to the fuel rod design optimization the world record burnup of 30% was achieved in the BOR-60 reactor.

Figure D1-5-1. RIAR (Federal State Unitary Enterprise "State Scientific Center of Russian Federation–Research Institute of Atomic Reactors." Vibropacking technology description and advantages).

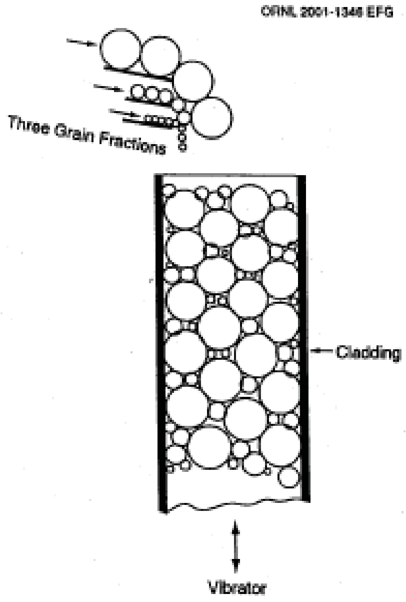

Figure D1-5-2. Conceptualized view of VIPAC (ORNL, 1965).

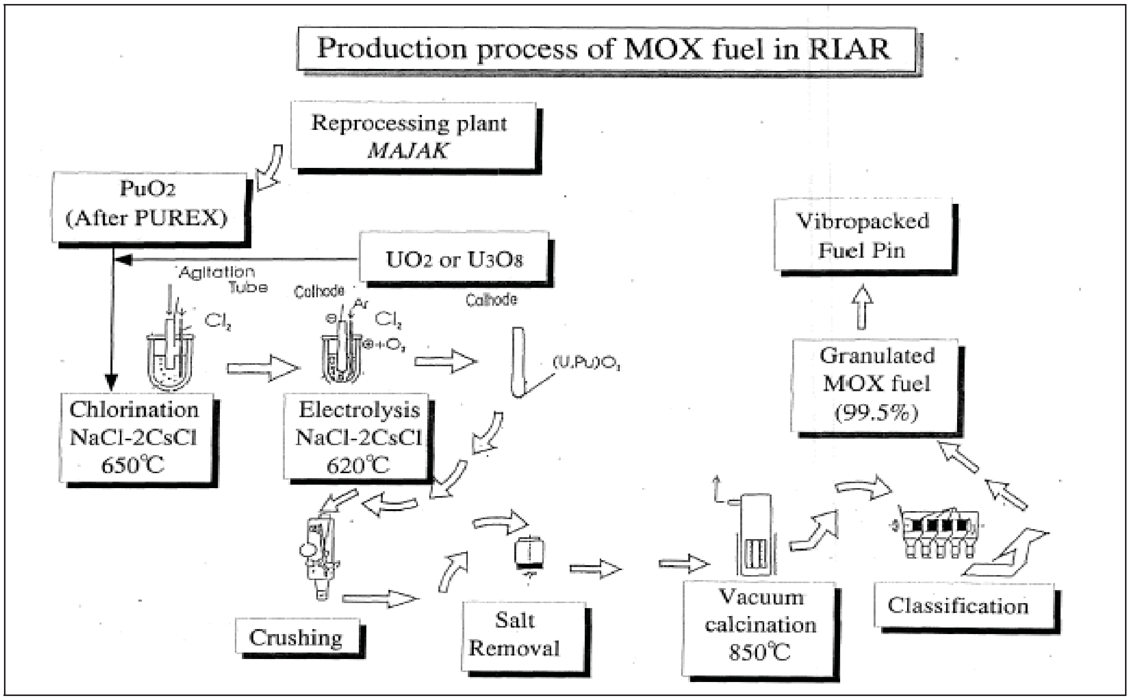

Figure D1-5-3. The VIPAC process and its relation to pyrochemical reprocessing technology (RIAR, 1965).

D1-5.4 MODULE INTERFACE

The feed MOX mixture fed to the vibrator/tube-filler must have a very well-defined particle size distribution (enabled by sieving) and particle shape characteristics (small shards or crystals). The powder characteristics of material coming from electrochemical reprocessing techniques are better suited for VIPAC; however, it is still quite possible to fix the morphology of aqueous precipitation-derived MOX powders.

VIPAC feasibility has been examined for LWR fuels including UO_2. A DOE-NERI report suggests that spheroidal powder could be vibropacked into annular cladding as one of several fuel options, which would allow higher power density and extended burnup with their beneficial economic consequences (Kazimi 2002). The higher fabrication costs for annular fuel are predicted to be overcome by the lower mills/kWh fuel cycle cost component of the cost of electricity resulting from the use of less fuel. No detailed cases with cost numbers were presented in the report.

D1-5.5 MODULE SCALING FACTORS

No data were available. Any scaling would be similar to fast reactor pelletized fuel facilities.

D1-5.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

No direct unit cost information was found for Western or Japanese vibropacked fast reactor fuels; however, it is known that the Japanese considered VIPAC in their feasibility study (JAEA 2006) for commercialization of fast reactor fuel cycle systems. All that can be said is that proponents have roughly estimated that VIPAC unit costs should be 20% lower than for pelletized fuel unit costs. This estimate probably does not include all the additional research and development, fuel qualification, and process qualification costs that would be involved with this type of fuel, and which might need to be amortized into the price of the fuel.

In 1998, Russian engineers prepared a cost estimate for converting and operating the BN-600 Fast Reactor to a partial MOX core of vibropacked fuel as part of the joint U.S./RF Plutonium Disposition Program (State of Scientific Center of Russian Federation–IPPE 1998). Their estimate concluded that a BN-600 VIPAC fuel assembly could be produced for less than $100,000 per unit. Because each fuel assembly contains approximately 28.7 kg of heavy metal (MOX with >20% PuO_2), a unit cost of ~$3,500/kgHM could be calculated for production from the pilot-plant sized facility that would need to be operated to supply these assemblies. Because this is a pilot scale facility number, it would be expected that a large fuel fabrication plant of this type could produce fuel at a lower cost. Converting the above Russian number to the U.S. wage rate and industrial conditions, however, would elevate the cost. Regulatory costs in the U.S. would also be higher.

An OECD report (NEA/OECD 2005) gives unit cost projections for advanced fast reactor fabrication and reprocessing steps in an integrated (one building) facility. For the fabrication step, which involved gelation[e] and vibrocompaction, the following unit costs are given:

Present (2001):	$4,900/kgHM
Future:	$1,600/kgHM

These data are based on Japanese sources such as ICONE 8 papers.

D1-5.7 LIMITATIONS OF COST DATA

The Russian Federation is likely to have some limited cost data. However, it may be difficult to convert it to U.S. dollar equivalents for deployment in the West. The Russian VIPAC process is still at the bench scale level of development. Yet, funding from and cooperative work with Japan may allow for some larger scale fabrication. Via the Generation IV Economic Modeling Working Group (EMWG) JAEA may make available in the near future some cost projections on VIPAC fuel fabrication, which was part of one of the four fuel-cycle scenarios studied as part of their fast reactor analysis (JAEA 2006).

D1-5.8 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-5-1. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

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[e] Gelation rather than electrochemistry produces "rounder" particles which can be vibrationally compacted. Such a process is sometimes called "spherepak."

Table D1-5-1. WIT cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Plant capital cost: No data available	N/A			N/A
Unit production cost: no validated data available	No data available	Could be cheaper process than pelletization (fewer steps)	Difficulties in development/ automation	$3,600/kgHM if VIPAC assumed 10% cheaper than nominal pellet fast reactor MOX

D1-5.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

None available.

Module D1-6

Metallic or Alloyed Fast Reactor Fuel

Module D1-6

Metallic or Alloyed Fast Reactor Fuel

D1-6.1 BASIC INFORMATION

Current Status. Metallic fast reactor fuel, such as is produced by casting operations, is generally part of refabrication schemes associated with on reactor-site closed fuel cycles where the reprocessed and refabricated fuel must be handled in hot cells, with the higher actinides allowed to remain in the fuel for partial destruction in the next irradiation cycle. No cost information was found on metallic fuels not arising from a reprocessing plant or a transmutation/separation facility; although that does not mean that such schemes do not exist. (Some Pu-based metallic fuel for the now-closed Hanford FFTF (Fast Fuel Test Facility) was prepared without high concentrations of higher actinides [Np,Am,Cm].) Generally the higher actinide metals are alloyed with uranium and another heat-resistant metal such as zirconium. The INL MFC Integral Fast Reactor fuel cycle is one such cycle. The processes and costs associated with these remotely refabricated fuels are discussed in Module F2/D2. Unfortunately no data on separated reprocessing and refabrication costs were found. As noted above small amounts (a few hundred kilograms) of sodium-bonded metal fuel were fabricated for the now-deactivated FFTF reactor at Hanford (Westinghouse 2004). Government-owned plutonium was used for this fuel. No costs for its manufacture have been found by the author.

Metallic or alloyed fuels have been extensively used in (nonelectricity) production and research reactor applications where high temperature is not needed, but high fast or thermal neutron fluxes exist. Much of this fuel, which is mostly uranium alloyed or mixed with aluminum or molybdenum, or even silicides, is produced by pressing or extrusion type metallurgical operations. Because this fuel is usually 19% or greater in fissile content and is made in relatively small quantities, the unit costs for fabrication are usually high (i.e., a few thousand dollars to tens of 1,000s of $ per kgHM). Dispersion type fuels, such as those proposed by the AFCI Fuels Working Group, for the Generation IV Gas-cooled Fast Reactors, are discussed in Section D1-9.

D1-6.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

See Modules D1-9, F2/D2.

D1-6.3 PICTURES AND SCHEMATICS

See Modules D1-9, F2/D2.

D1-6.4 MODULE INTERFACE DEFINITION

See Modules D1-9, F2/D2.

D1-6.5 MODULE SCALING FACTORS

No data available.

D1-6.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

See Modules D1-9, F2/D2.

D1-6.7 LIMITATIONS OF COST DATA

See Modules D1-9, F2/D2.

D1-6.8 COST SUMMARIES

See Modules D1-9, F2/D2.

D1-6.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

Module D1-7

CANDU Fuel

Module D1-7

CANDU Fuel

D1-7.1 BASIC INFORMATION

Current Status. Because the advanced CANDU ACR-700 heavy-water reactor design at one time started Nuclear Regulatory Commission (NRC) certification in the U.S. and is being offered for sale on the international market, it is useful to briefly consider the projected manufacturing cost for its fuel and that of its other CANDU cousins. CANDU fuel is fabricated in Canada by two firms: GEH Canada and as Zircatec Ltd (a division of Cameco). Present generation CANDU fuel is not made from enriched uranium, hence no UF_6/enrichment steps are needed in the front-end fuel cycle. The "spec-powder" oxide feed required by the fabricator for pelletization can be prepared in a facility adjacent to the mill (natural UO_2 can be used for fuel in a water reactor with a heavy water moderator/coolant). The newer-type ACR-700 fuel, however, will be slightly enriched uranium at around 2% U-235. Its fuel assembly and the older $NATUO_2$ fuel assemblies, however, do not at all look like an LEU LWR fuel assembly. The fuel assemblies are much shorter but still use stacked UO_2 pellets.

D1-7.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

Basic Plant Configuration. A CANDU fuel bundle (assembly) still uses pelletized ceramic UO_2 fuel; so, most of the pellet and rod loading manufacturing process steps are the same as for LWR fuel. Because the fuel bundle is an order of magnitude shorter and lighter than LWR fuel, the steps at the end of the manufacturing process are somewhat simpler. However, one should note that the quality control costs are higher per kilogram of heavy metal because each closure weld applies to much less heavy metal than for LWR fuel. Batch size control and criticality concerns are minimal to nonexistent in CANDU fuel fabrication plants as compared to LEU PWR and BWR fuel fabrication plants.

CANDU reactors can also be operated on plutonium-bearing MOX fuel. Atomic Energy of Canada Limited has irradiated some weapons-derived MOX fuel in their experimental heavy-water reactor at Chalk River, Ontario. This PARALLEX MOX project with Russia and the U.S. was part of the joint U.S./Russian Federation Plutonium Disposition Program. A plant that would produce production quantities of CANDU MOX fuel would be nearly identical to fuel fabrication plants producing PWR or BWR MOX fuel, except that the resulting final fuel assembly form would be much smaller and would appear the same as UO_2 CANDU fuel.

D1-7.3 PICTURES/SCHEMATICS

Figure D1-7-1 shows the ACR-700 assembly, which resides in the reactor horizontally rather than vertically. Each of the parallel tubes is filled with ceramic oxide pellets. The assemblies are fed continuously to the pressure-tube type reactor while it is running rather than in reload batches during shutdowns (per the LWR). Figure D1-7-2 from ACR data submitted to the USNRC (AECL 2006) shows this operation.

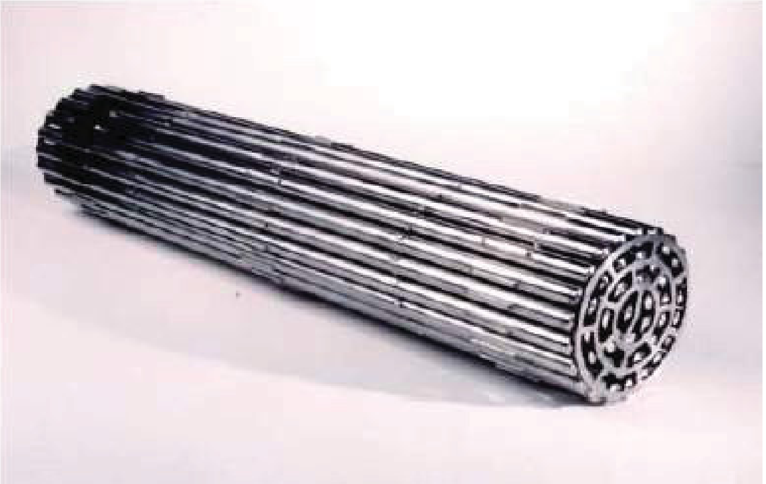


Figure D1-7-1. The ACR-700 CANDU fuel assembly (AECL, 2005).

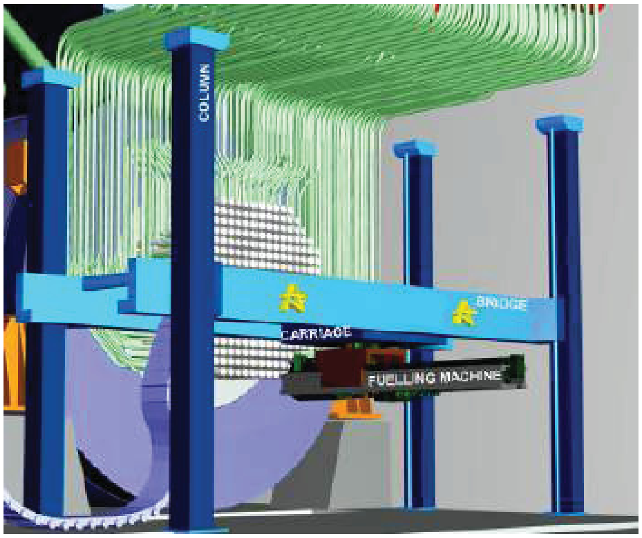


Figure D1-7-2. Horizontal on-line refueling for the ACR-700 CANDU reactor (AECL, 2005).

D1-7.4 MODULE INTERFACE DEFINITION

Front end Interfaces. A CANDU fuel fabrication plant preparing slightly enriched UO_2 ACR-700 fuel will require enriched UF_6 conversion (UF_6 to UO_2) before the pellet preparation steps. For present generation CANDU reactor fuel, which is natural uranium (NATU), reactor grade sinterable UO_2 powder can be prepared as a final milling step rather than as a front-end step in the fuel fabrication plant. $NATUO_2$ CANDU fuel bundles are shipped in conventional cartons to the reactor sites. Criticality safety is not a concern. The ACR-700 EUO_2 fuel may require a certified shipping package as does LWR fuel in the U.S.

Back-end Interfaces. CANDU reactors have larger cores than LWRs for the same power capacity. Volume-wise, there will be more spent fuel that needs to be stored and ultimately disposed by geologic repository emplacement.

D1-7.5 MODULE SCALING FACTORS

The same observations on fabrication plant scaling apply for this type fuel as for LWR fuel (Subsection D1-1).

D1-7.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

Assuming that the manufacturing/fabrication process for this slightly enriched uranium fuel assembly is the same as for past CANDU NATU assemblies, the unit cost should be similar. If the 1991 NATU value from the NEA/OECD fuel cycle study (OECD NEA and IAEA 2005) is escalated to 2009 constant dollars, a fabrication cost of $~105/kgU results. To this should be added a conversion cost for slightly enriched EUF_6 to ceramic-grade UO_2 powder, a step that is not needed for natural uranium CANDU fuels. The author of this report assumes that $30/kgU cost would be appropriate, for a total cost of $135/kgU. This is smaller than for LWR fuel; however, the CANDU fuel assembly/bundle is simpler by design.

Fabrication costs for CANDU MOX fuels would be expected to be in the lower end of the ranges for LWR MOX fuel as presented in Section D1-3.

D1-7.7 LIMITATIONS OF COST DATA

The reliability of the cost data is good, since CANDU fuel production is a fully commercialized operation.

D1-7.8 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-7-1. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table D1-7-1. Cost summary table for CANDU ACR-700 fuel.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Unit cost=$135/kgU	$115/kgHM	$155/kgHM	$135/kgHM
No fab plant capital cost data available.	None identified	Use of enrichments over 1% U-235	Use reference value

The triangular distribution based on the costs in the WIT Table is shown in Figure D1-7-3. The distribution is not heavily skewed since there is considerable industrial cost experience with CANDU fuel.

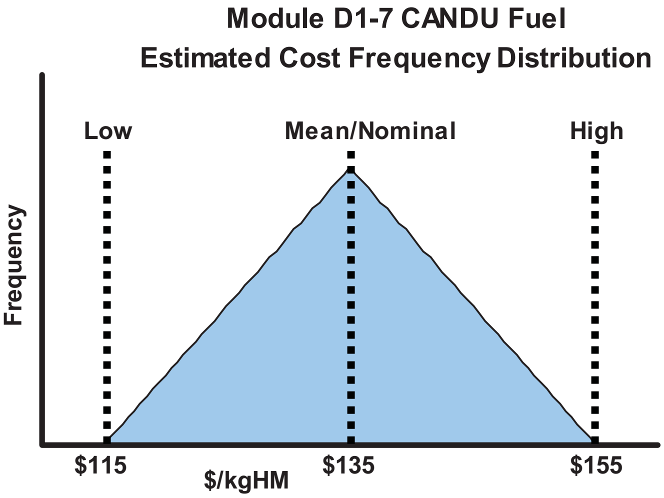


Figure D1-7-3. CANDU fuel estimated cost frequency distribution.

D1-7.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

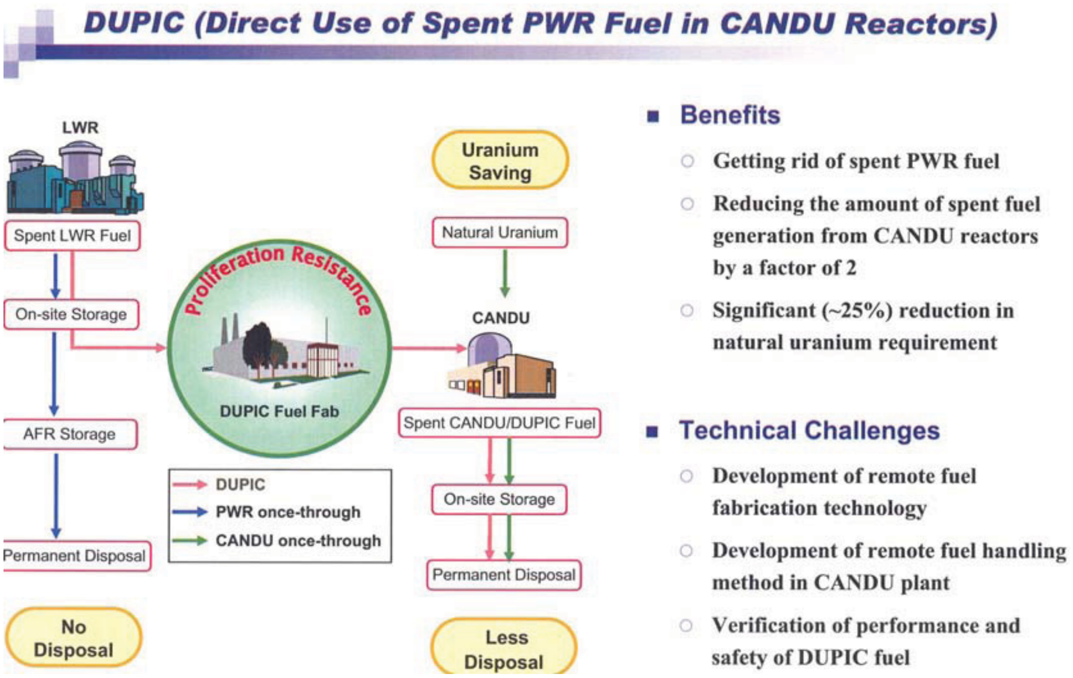
No data were found or generated.

D1-7.10 SPECIAL TOPIC: DUPIC: THE DIRECT USE OF SPENT PWR FUEL IN CANDU REACTORS

After irradiation, PWR fuel still has a high enough fissile content that it could be further irradiated in CANDU reactors. The problem is that the fuel forms are different. South Korea has both PWRs and CANDUs and has been part of a cooperative program with the U.S. and Canada to see if irradiated PWR fuel could be declad, crushed, volatiles removed, reoxidized, and remade into CANDU pellets without separation of the nonvolatile transuranic or fission-product components. Doing so would solve the PWR spent fuel problem for Korea and allow use of a tandem PWR/CANDU fuel cycle. Figure D1-7-4 shows the benefits and challenges of this scheme as envisioned by the Korean Atomic Energy Research Institute (KAERI).

This type of fuel would have to be remotely handled all the way through its production process (see Figure D1-7-5) and through its insertion in the CANDU reactor. With continuous fuel loading machines, however, such shielded and automated loading may be feasible. Choi, et al. (Choi 2001) of KAERI have performed a conceptual design and cost study for a CANDU DUPIC fuel plant capable of manufacturing 400 MT/yr of fuel. For a 40-year plant and a 5% discount rate, the unit cost of CANDU DUPIC fuel production is calculated to be $616/kgHM. Although much higher than for UO_2 CANDU fuel, this cost is counteracted by the much lower back-end fuel cycle costs for the PWRs. There are also greatly reduced uranium costs for the CANDU reactors.

Using relatively pure uranium oxide recovered from LWR reprocessing is also an option. Such REPU could have 0.7 to 1.2 % U-235 and could be obtained from future U.S. reprocessing operations. Use of this material would avoid expenditure for the purchase of new uranium ore. Basically the costs involved would be conversion of the reprocessing product (UNH or an oxide) into a sinterable UO_2 powder grade and fabrication into pellets and assemblies. Initial indications for high natural uranium prices (~$100/lb U_3O_8) are that the upfront cost for the CANDU open cycle could be cut in half (Del Cul et al. 2009).



DUPIC (Direct Use of Spent PWR Fuel in CANDU Reactors)

- **Benefits**
  - ○ Getting rid of spent PWR fuel
  - ○ Reducing the amount of spent fuel generation from CANDU reactors by a factor of 2
  - ○ Significant (~25%) reduction in natural uranium requirement
- **Technical Challenges**
  - ○ Development of remote fuel fabrication technology
  - ○ Development of remote fuel handling method in CANDU plant
  - ○ Verification of performance and safety of DUPIC fuel

Figure D1-7-4. Benefits and challenges of turning PWR fuel into CANDU fuel (KAERI, 2005).

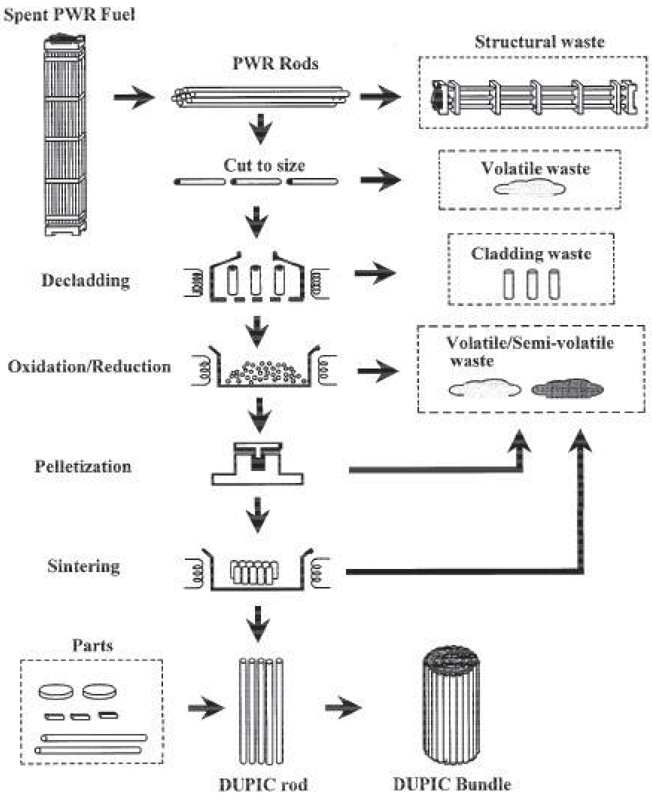


Figure D1-7-5. Process steps for DUPIC CANDU fuel fabrication (KAERI, 2005).

Module D1-8

Thorium-based Fuels

Module D1-8

Thorium-based Fuels

D1-8.1 BASIC INFORMATION

Current Status. For sustainability (U-conservation) and nonproliferation reasons the use of thorium/U-233 LWR fuels has recently received considerable attention (Kazimi 2003; Greneche 2006; Reuters 2007; Lifton 2007; Filippov 2007; India's Atomic Energy Agency 2006, Norway Thorium Report Committee 2008) and some DOE research and development funding (as part of NERI, and the Russian plutonium disposition programs). A U.S. company, Thorium Power (now part of Novastar), is working on one such concept, called the Radkowsky Thorium-Plutonium Incinerator (RTPI) with the Kurchatov Institute in Moscow, Russia. The intent is to develop a two-part hybrid [ceramic (U,Th)O_2 blanket, metal Pu-Zr alloy seed driver] LWR fuel assembly that could deeply burn enriched uranium or plutonium without producing additional higher actinides. The use of a plutonium driver is not necessary if the mission is to only produce electricity and not to disposition plutonium. Pelletized UO_2/ThO_2 MOX fuel can be used in lieu of low-enriched UO_2. The UO_2 mixed with the ThO_2 must be at a U-235 content (19.95% U-235 to still qualify as LEU) considerably above that of typical LWR LEU fuel (2 to 5% U-235). The U-233 that is formed or "bred" by neutron irradiation of thorium helps to sustain the life of the nuclear fuel such that residence times of as long as 9 years are deemed possible (if cladding can be developed with such a long life). Such long residence times mean higher fuel burnup or utilization and less consumption of nuclear fuel. Thus there is the potential for a reduction in the fuel cycle component of the busbar levelized cost of electricity from a reactor. Most thorium-related fuel development work to date in the U.S. has been on LWR and gas-cooled reactor fuels. This section will deal mainly with possible LWR applications, mainly U.S. and Russian PWRs (VVERs).

World thorium resources are estimated to be three times those of uranium, and several nations, such as Brazil, Australia, Norway, and India, and even the U.S. have significant indigenous thorium sources. India has the largest thorium program, and is actually including its future use in it energy planning activities. China is also showing increasing interest in thorium cycles (Platts 2009). In the U.S. Thorium Power is the major advocate for this fuel cycle; they base their arguments mainly on the fact that the major waste products have shorter decay times and that fewer long-term heat-producing radioisotopes are generated (Washington Post 2009)

D1-8.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

For a reactor using only UO_2-ThO_2 (U-Th MOX) pellets, the fuel fabrication facility would be very similar to a low-enriched UO_2 facility such as that at West Columbia, South Carolina (BNFL/Westinghouse). Figure D1-8-1 shows the major process steps. The major differences would be at the front end of the plant, where a UO_2/THO_2 blending step would be needed. Prior to this, some purification/conversion of the original thorium feed form, such as a nitrate [Th(NO3)4], would be required. The uranium conversion step (UF_6 to UO_2) would have a major difference from that in an LEU plant, however. The higher U-235 enrichment (19.95% U-235) would require special criticality control and smaller batch sizes prior to blending with ThO_2. Pellets of this type have been successfully produced on a small scale and irradiated in commercial reactors.

For a reactor using the RTPI concept, such as for plutonium disposition, essentially two fuel plants are needed. The plant described in the paragraph above would provide the "blanket" fuel in which a high conversion of Th-232 to U-233 would take place, and the fission of bred U-233 would augment the fission of U-235 from the uranium component. Within each fuel assembly there would also be a driver fuel that would consist of long, thin, trefoil rods of plutonium metal alloyed with zirconium. Most of the neutrons for fission would be produced in the driver. Figure D1-8-2 shows how each RTPI fuel assembly would have driver rods surrounded by rods containing blanket $(U,Th)O_2$ pellets. The driver fuel plant would contain complex chemical and metallurgical operations that must be performed in a glovebox environment, such as exists for production of $(U,Pu)O_2$ MOX fuel. None of the proposed operations, which include conversion, reduction, pressing, and extrusion of plutonium compounds or alloys, have been performed in a large-scale commercial facility. Figure D1-8-1 shows the steps required for the driver fuel production for a plant envisioned to support possible Russian VVER-PWR disposition of 38 MT of Russian Federation plutonium over ~16 years. Compared to a proposed similar weapons plutonium-disposition scheme using French MOX (U,Pu) technology (Module D1-2) in Russia, the RTPI scheme appears considerably more complex and is likely to also be much more expensive.

D1-8.3 PICTURES AND SCHEMATICS

The top part of Figure D1-8-2 shows an RTPI mockup hexagonal fuel assembly for a Russian VVER-1000 PWR. The two-part assembly (blanket and driver separable) has the metal-alloy, twisted, trefoil drivers in the middle surrounded by tubes of blanket pelletized ceramic fuel. A cross section of a driver rod is shown bottom left. A cross section of an annular blanket pellet is shown bottom right.

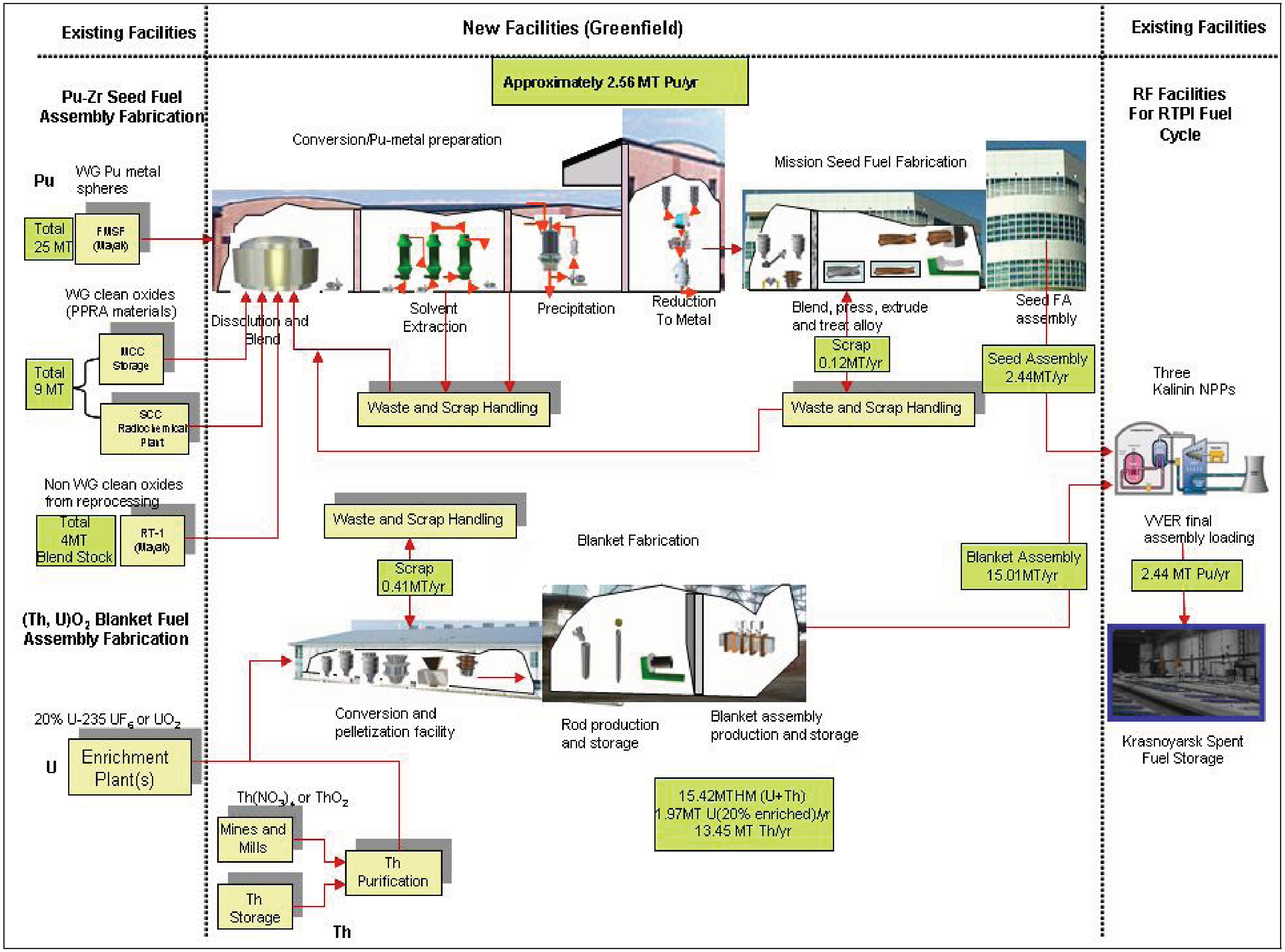


Figure D1-8-1. Fuel fabrication facility process schematics for a thorium concept utilizing both a blanket (U, ThO$_2$) pelletized fuel and a metallic Pu-Zr driver fuel (RTPI concept proposed for Russian Pu-disposition) (ORNL, 2005).

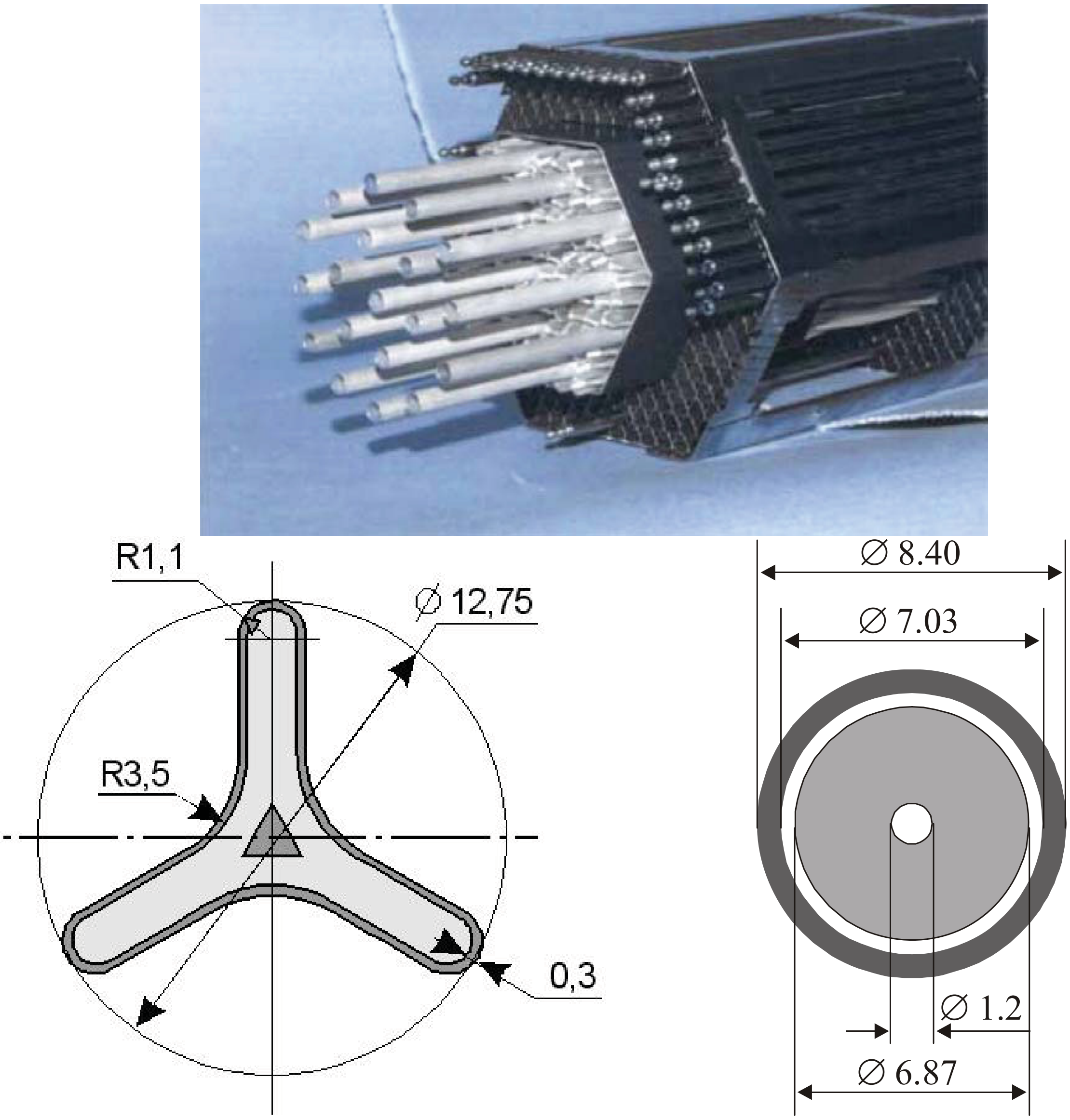


Figure D1-8-2. RTPI blanket/driver fuel envisioned for plutonium-disposition (dimensions are in millimeters) (ORNL, 2005).

D1-8.4 MODULE INTERFACE DEFINITION

Front-end interfaces. Thorium is three times as abundant in the earth's crust as uranium (see Module A20 ; hence there is plenty of thorium ore available for use. Like uranium, the thorium ore must be mined and milled. The thorium compound produced at the mill, such as an oxide or a nitrate, must be chemically purified to produce a reactor-grade thoria powder. The accompanying uranium is likely to be received as enriched UO_2 produced from a new enrichment facility or blended from weapons-highly enriched uranium stockpiles. For the RTPI plutonium-disposition concept, the plutonium is envisioned to come from nuclear weapons as impure metal or as impure PuO_2 from other military facilities. This plutonium must be chemically purified before it is reduced to metal and alloyed with zirconium. Front-end process conversion steps involving aqueous chemistry are required. Over 10 years of fuel qualification would likely be required for the RTPI concept before it could be commercially implemented.

Back-end interfaces. These thorium fuel cycles are envisioned to achieve high burnups and be operated on a once-through basis. The spent fuel is likely to be more radiotoxic than normal low-enriched UO_2 spent fuel. The driver and blanket spent fuel for the RTPI application will be separable. Casks for transportation and final geologic disposal would need to be developed.

Thorium-based spent fuels present special problems if they are reprocessed for recovery of U-233 and minimization of wastes. Along with U-233, small amounts of the isotope U-232 are produced. This relatively short-lived uranium radioisotope has decay daughters, such as thallium-208, which produce very potent gamma radiation. If the U-233 fuel refabrication operations are not performed quickly after reprocessing (which strips out the U-232 daughters but not the U-232 itself), U-232 daughters will build back up and present a significant radiological hazard in the fuel fabrication facility. The required shielding and handling procedures, perhaps even totally remote fabrication, will very significantly increase the unit cost of U-233 fuel refabrication. Thorium compounds are also harder to dissolve in aqueous processes, which also complicates reprocessing.

D1-8.5 MODULE SCALING FACTORS

No documented data were available. For $(U,Th)O_2$ blanket ceramic pellet fuel the plant scaling laws would be similar to those for LWR UO_2. The Pu-Zr driver fuel would probably scale similarly to metal fast reactor fuel facilities.

D1-8.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

The Kurchatov Institute and Thorium Power Corporation have produced analyses claiming that their thorium fuel cycles are at least 20% cheaper than the conventional UO_2 fuel cycle on a mills/kWh basis (fuel component of the cost of electricity). The favorable economics are based on the high burnup and long residence time of the fuel assembly, with U-233 being continually produced and burned. Residence times up to 9 years are projected. Unfortunately, a fuel rod cladding that lasts this long has not been developed. If it were, it would benefit not only $(U,Th)O_2$ fuel but also any UO_2 fuel, thus the cost advantage over UO_2 may be illusory. As far as unit production (fabrication only) costs for $(U,Th)O_2$, a detailed analysis by Lahoda (2004) indicates that they would be no more than 50% greater than those for low-enriched UO_2 LWR fuel (Section D1). Such fuel could be produced in a low-enriched UO_2 fuel line with some heating, ventilating, and air-conditioning (HVAC) and front-end modifications. A license amendment and significant building and procedure modifications would be needed to handle the 19.95% U-235 UO_2 component. Because of higher U-235 content, the total front-end fuel cycle cost (ores, conversion, enrichment, and fabrication) of the $(U,Th)O_2$ assembly, which is 13% uranium and 87% thorium, would be at least 60% higher than for low-enriched UO_2 fuel ($784/kgHM versus $476/kgHM). Lower Russian unit costs for these front-end fuel cycle steps are assumed (Cowell et al. 2005). The SWU component alone for 19.95% U-235 is $5,000 to 6,000/kgU or kgHM in the west.

The unit fabrication costs for the twisted, trefoil Pu-Zr alloy driver (Cowell et al. 2005) fuel are projected by Oak Ridge National Laboratory to be much higher than those projected by Kurchatov Institute. In terms of unit cost per unit of metal (plutonium + zirconium for fuel which is 15% plutonium) a value of $27,000/kg metal was calculated by Oak Ridge National Laboratory. This is several times higher than unit costs for either fast reactor MOX or cast metallic fuel. The high cost is based on the Oak Ridge National Laboratory analysis of the various chemical and metallurgical operations involved in extruded trefoil rod production under glovebox conditions. These high plutonium-handling costs are validated by U.S. cost experience with plutonium and its compounds and alloys in its weapons complex.

D1-8.7 LIMITATIONS OF COST DATA

Technical Readiness Status: Planning for bench scale development is under way in Russia. A pilot plant for RTPI fuel would be at least 5 years away, and a large scale fabrication plant at least 12 years distant. If only $(U,Th)O_2$ or $(Pu,Th)O_2$ pellet fuel were to be used, these deployment times would be considerably shorter. India, in fact, has shown interest in using such fuel because of the large amount of indigenous thorium and has performed some successful irradiation experiments.

A report by the Thorium Report Committee (Norway Thorium Report Committee 2008) discusses the problem of lack of economic data on thorium fuel cycles. It suggests that just the R&D required for such cycles will cost over $1 billion. The report compares its level of development to that of Accelerator Driven Systems (ADS) for nuclear power.

D1-8.8 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-8-1. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table D1-8-1. Cost summary table for LWR thorium-based RTPI fuel now under development in Russia.

What-It-Takes (WIT) Table (2007 constant $)			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$(U,Th)O_2$ pellet fuel	$800/kgHM in Russia (HM is U+Th). Includes SWU component in uranium cost. Longer fuel life than for $LEUO_2$	$3,000/kgHM Higher fuel production costs due to need for 19.95% EU and HVAC modifications	$1,600/kgHM in West (U component includes SWU cost) [HM is U,Th]
Pu-Zr metal fuel for RTPI Pu-disposition application [in tandem with $(U,Th)O_2$ blanket]	High annual consumption of surplus Pu in LWR	Having both metal seed and oxide blankets makes very complicated and expensive fuel. Very long, expensive fuel qual program needed.	$27,000/kg metal (U.S. or Russia)

If ThO_2 only pellets and rods were to be produced in the U.S. for "blankets" in LWRs, the fabrication-only cost would be on the order of $400/kgHM or Th. However, reprocessing the blanket pellets to obtain fissile U-233 and its refabrication into U-233/U-238 LEU fuel assemblies would incur very significant costs and is not being seriously considered in the U.S.

D1-8.9 RESULTS FROM UNCERTAINTY ANALYSES

None available.

D1-8.10 OTHER THORIUM UTILIZATION NOTES

Thorium can also be used as a fertile material in fuel cycles other than those in water reactors. It has actually been used in TRISO-type fuels for gas-cooled reactors in both the U.S. (Fort St. Vrain) and Germany (THTR). The durability and long life of TRISO fuels makes the thorium to U-233 conversion feature beneficial for high fissile burnup. The additional economic impact of using thorium dioxide in addition to 8 to 20% U-235 UO_2 in TRISO fuel production is relatively low. HTGR applications are also discussed in IAEA's 2005 report. Thorium oxide blankets on fast reactors (such as liquid metal fast breeder reactors) are also of interest, and fast reactors in India may in fact use plutonium driver fuel and some ThO_2 blankets. Thorium could also be burned in liquid molten salt-based reactor systems with online reprocessing. This concept was the basis of the Molten Salt Reactor Experiment (MSRE) at Oak Ridge in the 1960s–1970s. The fuel cycle can also be operated in a breeder or actinide burner mode (Pickard and Forsberg 2002).

Module D1-9

Inert Matrix and Other Advanced Fuels

Module D1-9

Inert Matrix and Other Advanced Fuels

D1-9.1 BASIC INFORMATION

Background and Current Status. Inert Matrix Fuels (IMFs) are those in which there are no or minimal fertile radioisotopes, such as U-238 or Th-232, that are transmuted to higher actinides. The advantages of such fuel are as follows:

- The generation of long-lived higher actinides which contribute to repository heat-loading is minimized.
- High fissile destruction fractions are attainable because no new fissile material is generated from fertile constituents. This can be an advantage for some open cycle concepts.
- Because the initial fissile fraction or percentage of the overall fuel mass must be high, the reactor volume and fuel mass per kilowatt thermal can be reduced. This is advantageous for small modular reactor and space reactor concepts. The associated high neutron fluxes can also effectively burn out any actinides introduced in the core, such as in fast reactor burner concepts.

The inert (diluent) materials in such fuels may be oxides of metals with low neutron absorption cross sections or metallic alloying constituents such as zirconium. Some suggested (Tulenko 2009) inerting materials are silicon carbide and magnesium oxide-pyrochlore ceramic-ceramic (cercers). Other rare earth ceramic oxides are also under investigation as IMF diluents.

Advanced Fuels are those special fuel types envisioned for some of the Generation IV Reactor Systems concepts such as the Gas-cooled Fast Reactor (GFR) and not included in Modules D1-1 through D1-8. Dispersion fuel, where ceramic fuel particles are dispersed in a metal or ceramic matrix, is one such example of an advanced fuel.

It is too early to know definitively whether these two types of fuel would be fabricated in contact-handling (D1) or remote handling (D2) facilities. If significant higher actinides are to be included in a homogeneous IMF, the latter facility will be required. The reactor concepts and fuel cycle are still being defined as part of the Generation IV Program. Fuels of these two types have been produced as “specialty fuels” for use in research reactors or other special reactor applications. The manufacturing of these fuels is a batch operation with considerable human contact handling. Some such fuels have been used in (nonelectricity) production and research applications where high temperature is not needed, but high fast or thermal neutron fluxes exist. Much of this “specialty-type” fuel is produced by pressing or extrusion type metallurgical operations. Because this fuel is usually 19% or greater in fissile content and is made in relatively small quantities, the unit costs for fabrication are usually high (i.e., a several thousand to tens of 1,000s of dollars per kgHM).

D1-9.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

No data were available on processes for the large scale production of such fuels. As Generation IV research and development continues, such manufacturing processes will be further defined.

D1-9.3 PICTURES AND SCHEMATICS

Figure D1-9-1 shows two types of IMF fuel pellets produced by a fuels research and development program (LANL 2002).

The two IMF pellets (solid solution and macro-dispersed) are shown at the beginning of life before irradiation in the frame of the OTTO project. The pellet on the left is a representative pellet made of $Er_xY_yPu_zZr_{1-x-y-z}O_{2-(x+y)/2}$ material. The pellet on the right is a composite material pellet. Visible microspheres made of $Er_xY_yPu_zZr_{1-x-y-z}O_{2-(x+y)/2}$ are partially popping out of the pellet's white surface, which is made of $MgAl_2O_4$ spinel.

Figure D1-9-2 shows the types of dispersion fuel being considered by the Generation IV Gas-cooled Fast Reactor Program.

D1-9.4 MODULE INTERFACE DEFINITION

There is not yet enough fuel cycle definition to describe these interfaces.

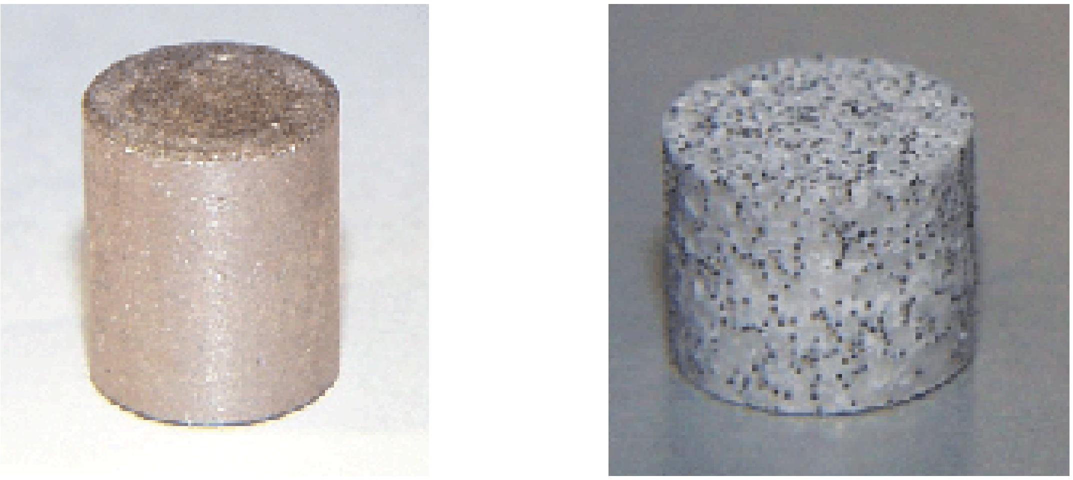


Figure D1-9-1. Solid solution and macro-dispersed inert matrix fuel pellets.

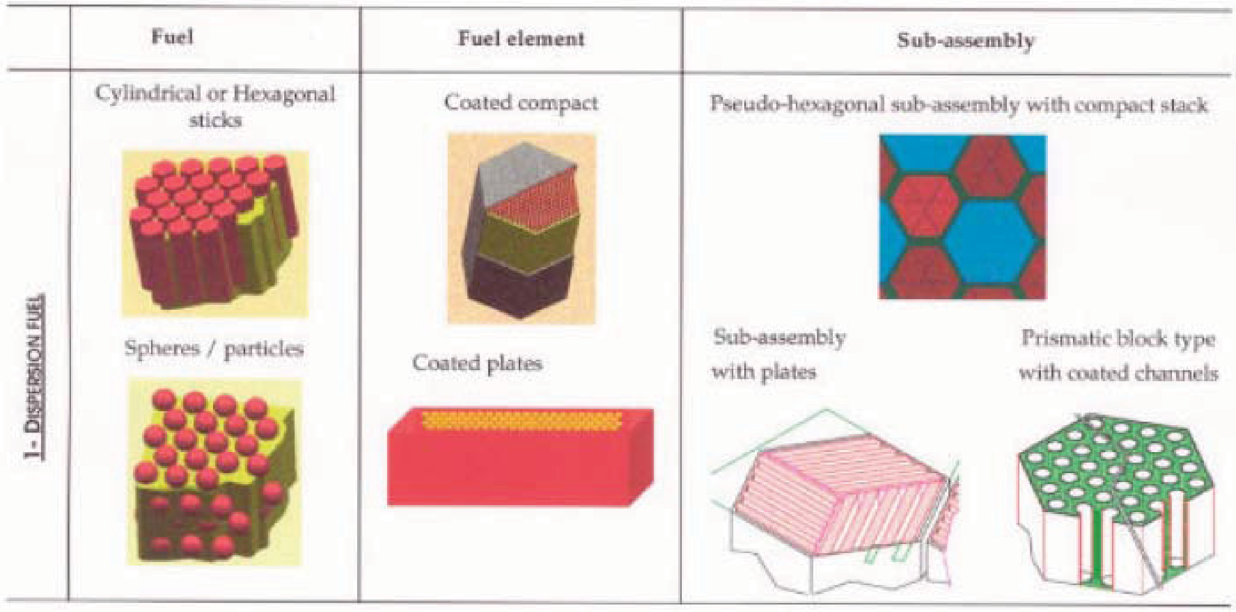


Figure D1-9-2. Dispersion fuel concepts.

D1-9.5 MODULE SCALING FACTORS

No data available.

D1-9.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

No cost data on these fuel types were found. For contact-handled IMF or Advanced Fuel, the cost data in Sections D1-3 (Gas-cooled Reactors) and Section D1-6 (Metallic and Alloyed Fuels) might provide some idea of unit costs for production quantities. For remote-handled IMF or Advanced Fuels, the comments in Section F2/D2 should apply.

D1-9.7 LIMITATIONS OF COST DATA

There is not enough cost data available to define cost limitations

D1-9.8 COST SUMMARIES

For these fuels a considerable fraction of the fuel mass (not including clad or assembly hardware) will not be a diluent heavy metal (HM) such as uranium. The figure of merit used should be $/kg base fuel metal. Because of the high fissile content of such fuels, the cost is expected to range from several thousand to tens of thousands $/kg, depending on quantities produced and the manufacturing environment. As is the case with other fuel types, the unit fabrication cost of IMF could easily rise exponentially with the amount of higher actinide (Pu, Am, Np, and Cm) present. A “step” in this cost function is likely where the high actinide content forces the transition from contact-handling to remote-handling.

D1-9.9 RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

D1-9.10 REFERENCES (For all D1 Modules)

References for all of the D1 Modules appear in this section. The boxed headings group them by fuel type in the same manner as the text. Note that some references are proprietary, copyrighted trade press newsletters, official government documents marked “official use only” or “applied technology,” or reports prepared by consulting firms with limitations on their release.

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Module D2 was combined with Module F2

(Go to Tab F2/D2 for this information)

Module E1

Wet Storage of Spent Nuclear Fuel

Module E1

Wet Storage of Spent Nuclear Fuel

E1-1. BASIC INFORMATION

Module E1 discusses the cost involved with wet storage of commercial spent nuclear fuel. This covers the spent fuel from the time it is removed from the reactor and it is placed in the pool until it is either placed into dry storage or packaged for shipment. In nearly all cases, this spent fuel storage was installed as a portion of the initial investment and was meant to hold just a few core changes before the waste would be sent to disposal. New reactors will certainly consider the economics of installing a pool capable of holding the spent fuel generated during the life of the facility.

All currently operating nuclear power reactors use water pools to store their spent fuel when it is first discharged from the reactor to allow the fuel to cool. There are 103 commercial nuclear reactors operating in the U.S. at 65 sites in 31 states. Of these, 69 are pressurized-water reactors (PWRs) and 34 are boiling-water reactors (BWRs). In addition there are 14 previously operating light-water-cooled power reactors in various stages of decommissioning. Some of these reactors share spent fuel pools, so that there is a total of 65 PWR and 34 BWR pools. There is also one independent site (prior commercial reprocessing site in Morris, Illinois) that is used for wet storage of spent fuel.

In any case, spent fuel is kept in wet storage for a minimum of 5 years to permit adequate decay of the shorter lived isotopes and meet criteria for packaging and transport from both a shielding and heat management basis.

As disposal options became elusive, utilities began efforts to increase their use of spent fuel storage space. This was accomplished by several means. In some cases, material was moved out of wet storage into dry storage at the reactor site or a site owned by the utility. In other cases, the fuel was restacked and use was made of neutron absorbing material to permit much closer “dense-packed” or “high density” storage spacing. Approximately 90 to 95% of spent fuel currently resides in wet storage. Most pools are densely packed so they can contain as much as 3.5 times more spent fuel than the original design. Tables E1-1 and E1-2 provide a 1998 snapshot of how such wet storage is distributed among the world nuclear power producers.

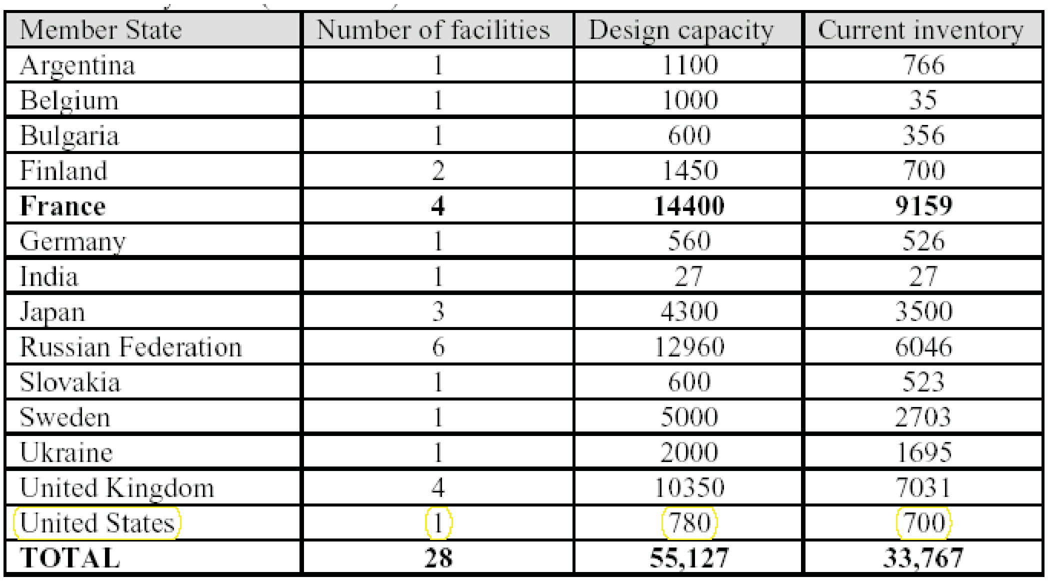
E1-2. FUNCTIONAL AND OPERATING DESCRIPTION

In the United States, spent fuel storage pools are regulated by the Nuclear Regulatory Commission (NRC). Figure E1-1 shows the locations of the reactors and storage pools in the U.S. The pools are typically 30 to 60 feet long, 20 to 40 feet wide, and 40 feet deep. Pools could nearly hold three semi-truck tractor-trailers parked side-by-side and stacked three deep. The pool is contained by a structure consisting of a 1/8-inch to 1/4-inch stainless steel liner, and 4 to 6-foot-thick walls of steel-reinforced concrete. The location of the pool is dependent on the type of reactor. Figures E1-2a and E1-2b show diagrams of “generic” PWR and BWR spent fuel pools. The water in the pool is constantly cooled and circulated to remove impurities. The fuel assemblies, stored vertically in racks, must be immersed at least 20 feet below the surface of the water in order to keep the fuel cool and to provide a sufficient radiation barrier.

Table E1-1. At reactor wet storage.

COUNTRY	REACTOR TYPE	No of Pools	Capacity tonnes HM	Inventory tonnes HM
Argentina	PHWR	2	1450	120
Bulgaria	WWER-440	4	480	121
	WWER-1000	2	520	266
Canada	CANDU	10	31407	22555
China	PWR	3	177	0
Czech Rep.	WWER	4	480	306
Finland	BWR/WWER	4	666	251
France	**900 MW PWR**	**34**	**5870**	**4187**
	1300 MW PWR	**20**	**5420**	**1608**
Germany	operating PWR	13	3176	2011
	operating BWR	6	1385	821
	Shut down	8	526	0
Hungary	WWER	4	480	350
Italy	LWR	3	253	253
Japan	PWR	20	6460	2070
	BWR	23	8410	3050
	Others	2	280	120
Korea, Rep.	PWR/PHWR	12	5875	3072
Lithuania	RBMK	2	209	1380
Mexico	BWR	2	984	80
Romania	CANDU	1	940	100
Russian Fed	WWER-440	6	480	320
	WWER-1000	7	1200	460
	RBMK	11	3560	2700
Slovakia	WWER	4	480	150
Slovenia	PWR	1	410	205
South Africa	PWR	2	670	392
Spain	PWR/BWR	9	3820	2000
Sweden	PWR/BWR	12	1500	730
Switzerland	PWRIBWR	5	705	150
Ukraine	WWER-440	2	240	92
	WWER-1000	11	2170	1156
	RBMK	3	600	380
UK	Magnox	20	1500	330
	AGR	14	230	154
	PWR	1	936	30
USA	operating LWR	110	59000	38343
	shutdown LWR	8	1700	957
TOTALS		405	154,649	91,270

Table E1-2. Summary of away-from-reactor wet spent fuel storage (tonnes heavy metal as of 1997).



Member State	Number of facilities	Design capacity	Current inventory
Argentina	1	1100	766
Belgium	1	1000	35
Bulgaria	1	600	356
Finland	2	1450	700
France	**4**	**14400**	**9159**
Germany	1	560	526
India	1	27	27
Japan	3	4300	3500
Russian Federation	6	12960	6046
Slovakia	1	600	523
Sweden	1	5000	2703
Ukraine	1	2000	1695
United Kingdom	4	10350	7031
United States	1	780	700
TOTAL	**28**	**55,127**	**33,767**

Spent fuel pool designs must meet specific performance criteria before NRC can issue a license for construction or operation. The requirements focus on ensuring that the safety features of the pool survive certain natural phenomena or accidents to ensure that, among other things, the pool will retain water and keep the stored fuel sufficiently cool. Spent fuel in wet storage is also protected by the physical security measures in place at the storage site. As part of the licensing process prior to construction and operation, utilities must submit reports that analyze the likelihood of certain natural phenomena, such as earthquakes, hurricanes, floods, and tidal waves. Using probability analyses, historical information, and current information on seismology, geology, meteorology, and hydrology, the utilities must determine the risks of certain types of natural phenomena. Then the utilities must show that the proposed pool designs would survive the most severe natural phenomena or combinations of less severe phenomena expected for that particular area.

The utilities must also perform the same exercise for the likelihood and severity of certain accidents, including airplane crashes. For example, pools constructed near airports may have to be designed to withstand certain types of accidental airplane crashes.

Consequently, although the specific designs of wet storage pools vary from site to site, they are massive, robust structures. Generally, the pools are contained in other buildings. The roofs of some of these buildings may be made from industrial-type corrugated steel. Spent fuel pools are also protected by the physical security measures in place at the facilities where they are located. About 95% of the spent fuel inventory is stored in pools, most of which are located at operating nuclear reactors. The perimeters of these reactor sites are secured by fences topped with barbed wire, vehicle barriers, and intrusion detection systems—including perimeter cameras and motion detection technology—that are monitored 24 hours per day. Access to the building containing the wet storage pools is impeded by locked steel doors capable of surviving armed assault and security checkpoints where a person’s identity must be verified and where security searches take place. Finally, these facilities are manned by a force of armed guards.

Storage pools not only store the spent fuel prior to packaging for transport and disposal but also play a very important role in supporting reactor outages and refueling. All reactors are connected to the spent fuel pools via fuel-transfer canals or tubes. These transfer channels are used to reduce shutdown durations as reactor operators often transfer the entire core to the pool in order to facilitate and expedite inspection of the reactor pressure vessel internals as well as inspecting fuel for leaks.

U.S. nuclear power plant operators have dealt with the lack of an offsite destination for their accumulating spent fuel by packing as many fuel assemblies as possible into their storage pools and then, when the pools are full, acquiring dry storage casks for the excess. The original design density of spent fuel in the pools associated with PWRs had the fuel assemblies spaced out in a loose square array. The standard spacing for new dense-pack racks today is 23 cm—barely above the 21.4 cm spacing in reactor cores. This "dense-packed" fuel is kept subcritical by enclosing each fuel assembly in a metal box whose walls contain neutron-absorbing boron-51 (see Figures E1-3 and E1-4). This dense-pack approach has been extremely important to the U.S. nuclear power industry as the delay in providing final disposal has resulted in the spent fuel pools reaching near capacity (see Figures E1-5 and E1-6).

E1-3. PICTURES/SCHEMATICS

Figure 1: Locations for Wet and Dry Storage Sites for Commercial Spent Nuclear Fuel and Yucca Mountain, as of April 2003

Sources: DOE and NRC (data); GAO (presentation).

Figure E1-1. Locations of the reactors and storage pools in the U.S.

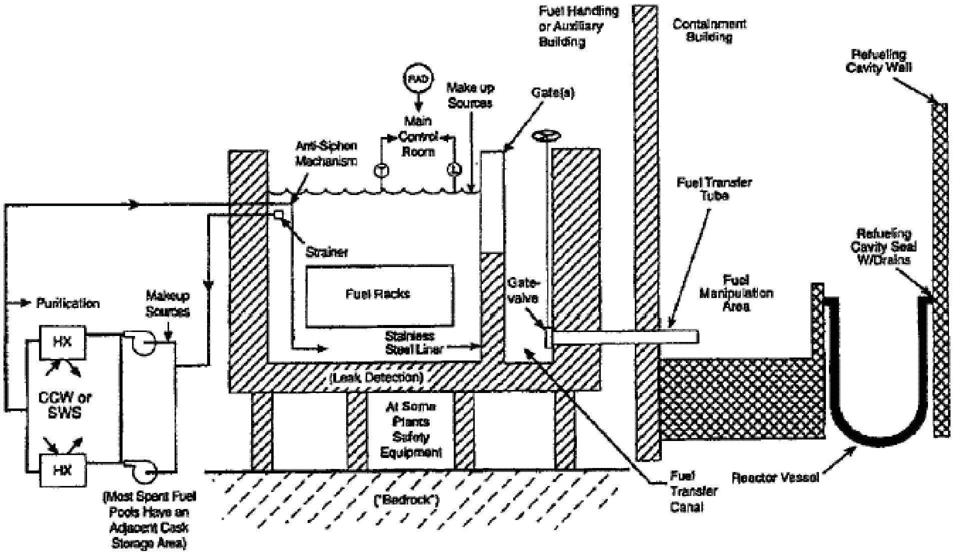


Figure E1-2a. Layout of spent fuel pool and transfer system for pressurized water reactors (Alvarez et al. 2003).

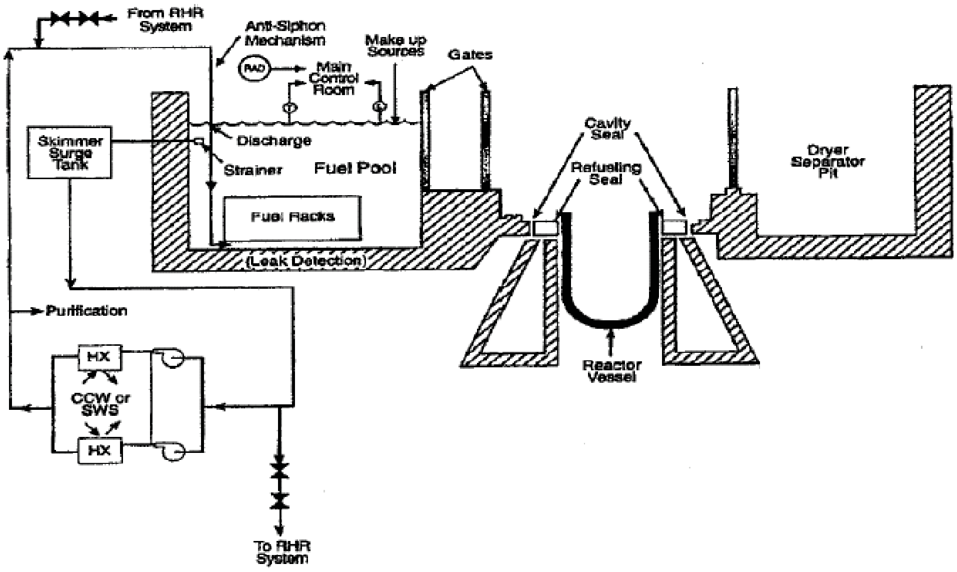


Figure E1-2b. Layout of spent fuel pool and transfer system for boiling-water-reactors (Alvarez et al. 2003).

Source: Nuclear Energy Institute.

Figure E1-3. Wet storage pool showing densely packed spent fuel.

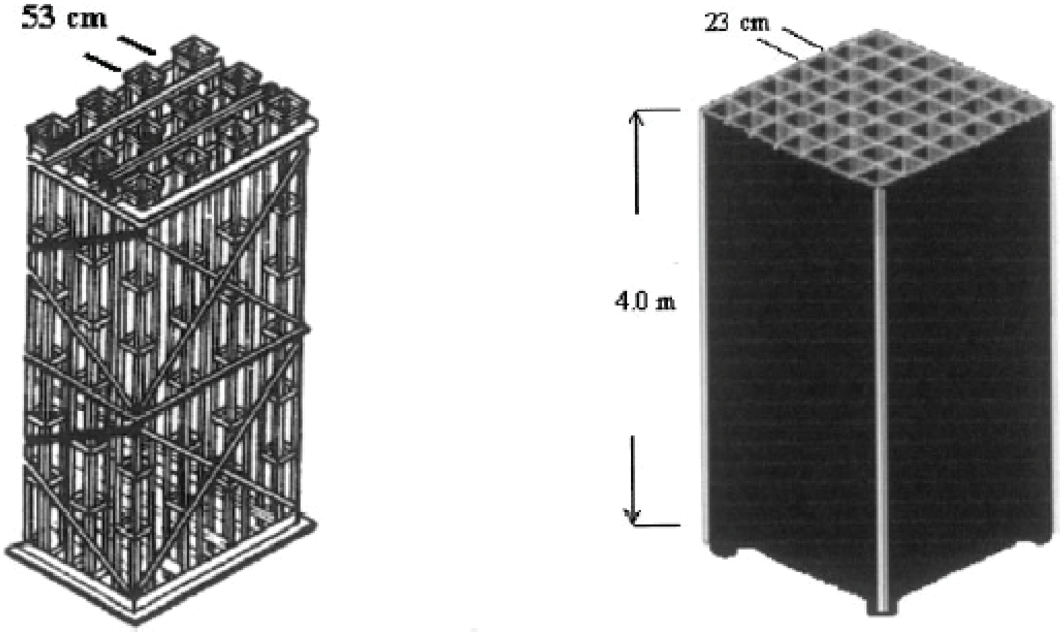
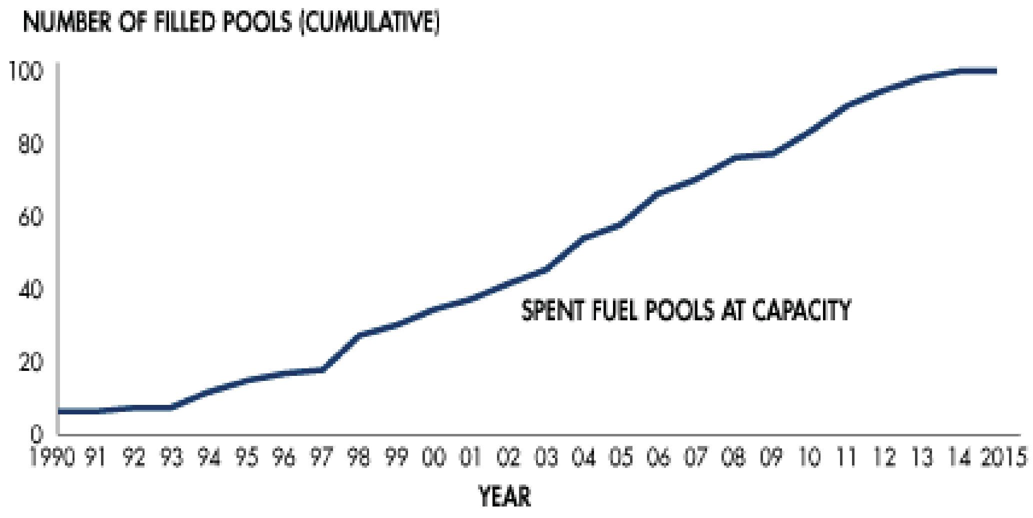


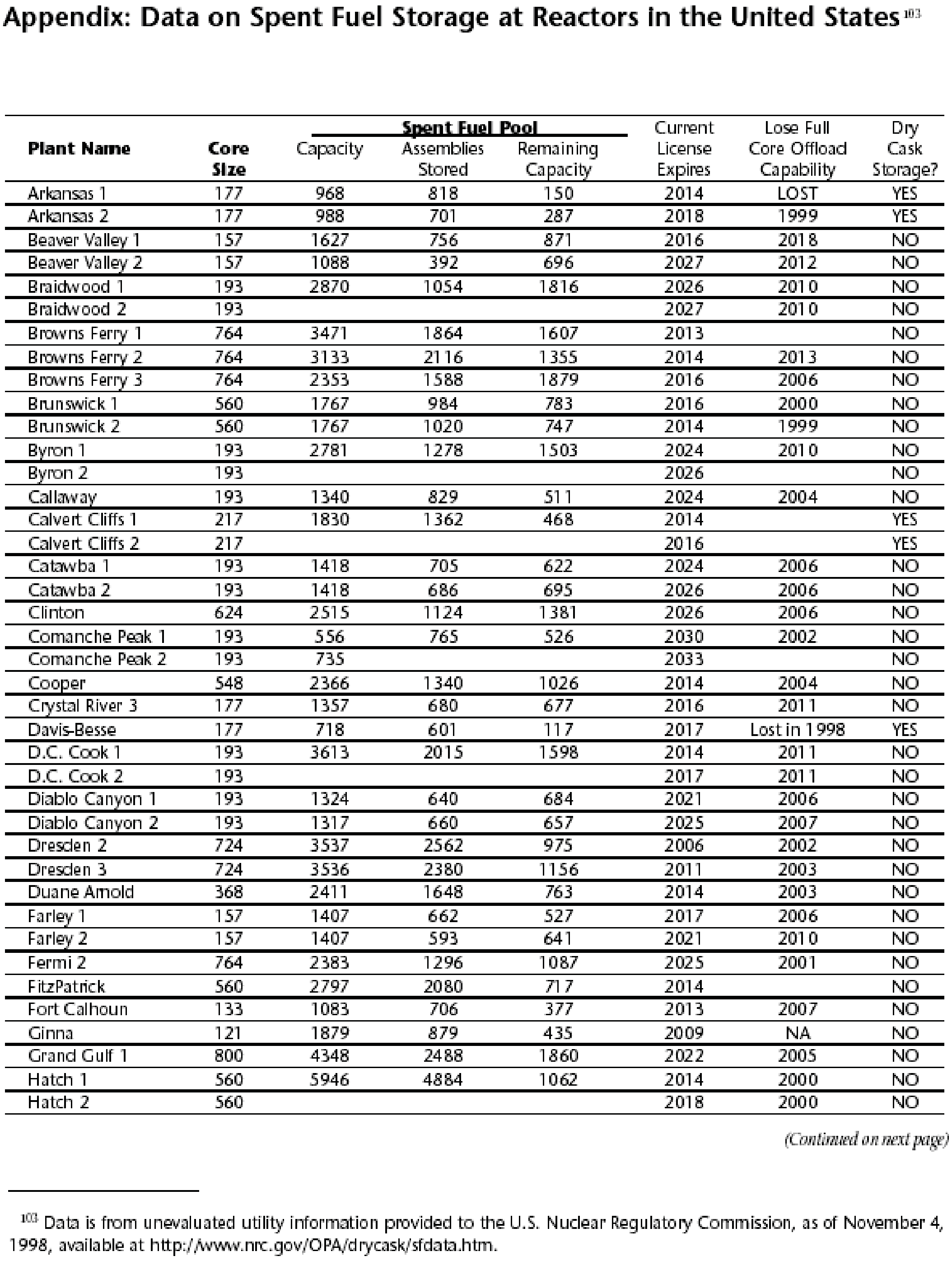
Figure E1-4. Example of open versus dense-packed spent fuel rack.



Note: All operating nuclear power reactors are storing used fuel under NRC license in spent fuel pools. Some operating nuclear reactors are using dry cask storage. Information is based on loss of full-core reserve in the spent fuel pools.

Source: Energy Resources International and DOE/RW-0431 – Revision 1

Figure E1-5. Spent fuel pools at capacity in the U.S.



Appendix: Data on Spent Fuel Storage at Reactors in the United States[103]

Plant Name	Core Size	Spent Fuel Pool Capacity	Spent Fuel Pool Assemblies Stored	Spent Fuel Pool Remaining Capacity	Current License Expires	Lose Full Core Offload Capability	Dry Cask Storage?
Arkansas 1	177	968	818	150	2014	LOST	YES
Arkansas 2	177	988	701	287	2018	1999	YES
Beaver Valley 1	157	1627	756	871	2016	2018	NO
Beaver Valley 2	157	1088	392	696	2027	2012	NO
Braidwood 1	193	2870	1054	1816	2026	2010	NO
Braidwood 2	193				2027	2010	NO
Browns Ferry 1	764	3471	1864	1607	2013		NO
Browns Ferry 2	764	3133	2116	1355	2014	2013	NO
Browns Ferry 3	764	2353	1588	1879	2016	2006	NO
Brunswick 1	560	1767	984	783	2016	2000	NO
Brunswick 2	560	1767	1020	747	2014	1999	NO
Byron 1	193	2781	1278	1503	2024	2010	NO
Byron 2	193				2026		NO
Callaway	193	1340	829	511	2024	2004	NO
Calvert Cliffs 1	217	1830	1362	468	2014		YES
Calvert Cliffs 2	217				2016		YES
Catawba 1	193	1418	705	622	2024	2006	NO
Catawba 2	193	1418	686	695	2026	2006	NO
Clinton	624	2515	1124	1381	2026	2006	NO
Comanche Peak 1	193	556	765	526	2030	2002	NO
Comanche Peak 2	193	735			2033		NO
Cooper	548	2366	1340	1026	2014	2004	NO
Crystal River 3	177	1357	680	677	2016	2011	NO
Davis-Besse	177	718	601	117	2017	Lost in 1998	YES
D.C. Cook 1	193	3613	2015	1598	2014	2011	NO
D.C. Cook 2	193				2017	2011	NO
Diablo Canyon 1	193	1324	640	684	2021	2006	NO
Diablo Canyon 2	193	1317	660	657	2025	2007	NO
Dresden 2	724	3537	2562	975	2006	2002	NO
Dresden 3	724	3536	2380	1156	2011	2003	NO
Duane Arnold	368	2411	1648	763	2014	2003	NO
Farley 1	157	1407	662	527	2017	2006	NO
Farley 2	157	1407	593	641	2021	2010	NO
Fermi 2	764	2383	1296	1087	2025	2001	NO
FitzPatrick	560	2797	2080	717	2014		NO
Fort Calhoun	133	1083	706	377	2013	2007	NO
Ginna	121	1879	879	435	2009	NA	NO
Grand Gulf 1	800	4348	2488	1860	2022	2005	NO
Hatch 1	560	5946	4884	1062	2014	2000	NO
Hatch 2	560				2018	2000	NO

(Continued on next page)

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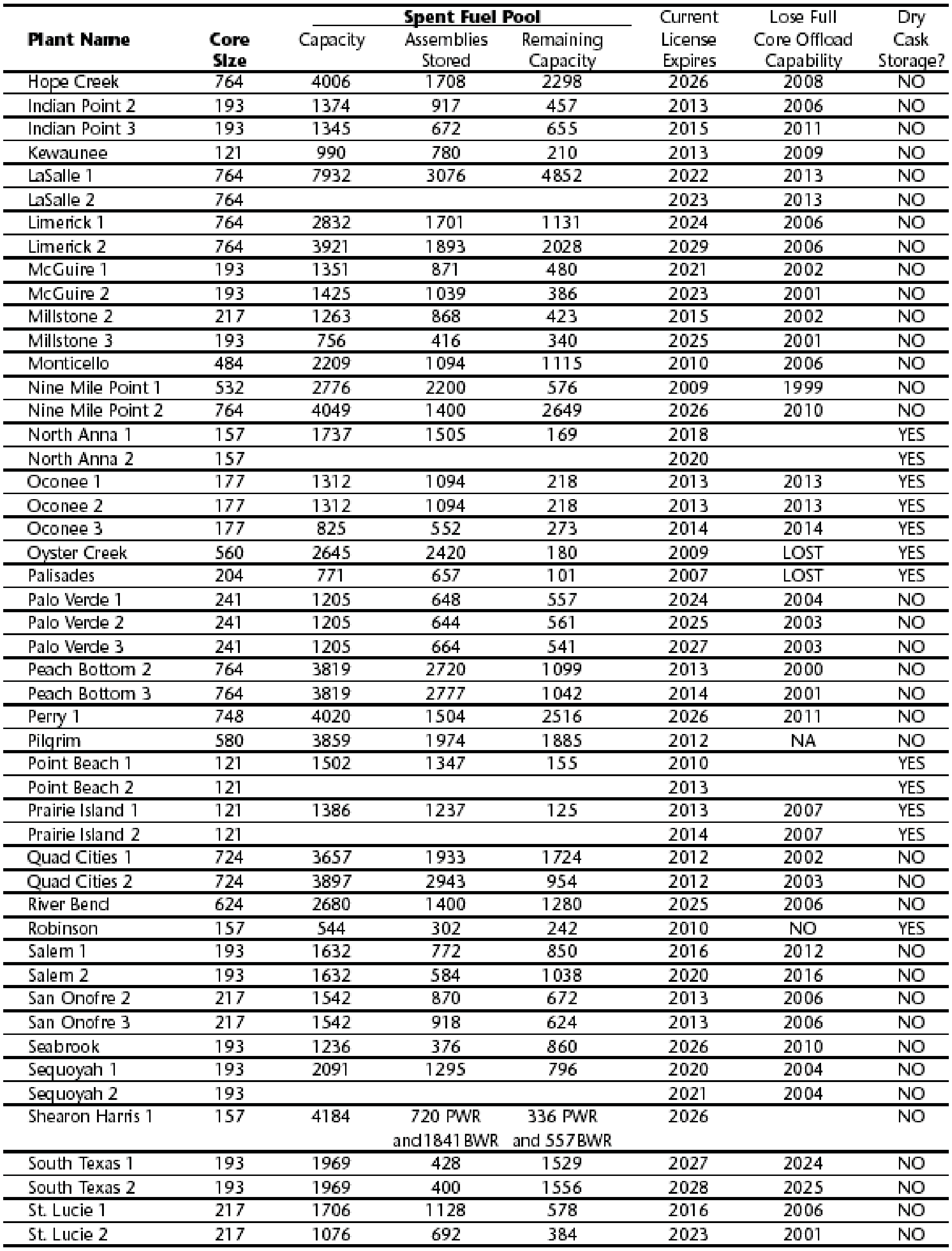
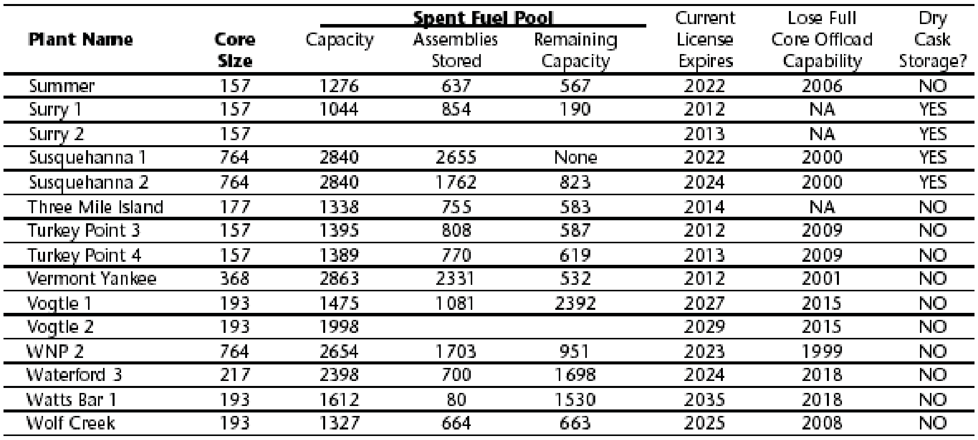
[103] Data is from unevaluated utility information provided to the U.S. Nuclear Regulatory Commission, as of November 4, 1998, available at http://www.nrc.gov/OPA/drycask/sfdata.htm.

Figure E1-6. Data on spent fuel storage at reactors in the United States.



Plant Name	**Core Size**	Spent Fuel Pool Capacity	Spent Fuel Pool Assemblies Stored	Spent Fuel Pool Remaining Capacity	Current License Expires	Lose Full Core Offload Capability	Dry Cask Storage?
Hope Creek	764	4006	1708	2298	2026	2008	NO
Indian Point 2	193	1374	917	457	2013	2006	NO
Indian Point 3	193	1345	672	655	2015	2011	NO
Kewaunee	121	990	780	210	2013	2009	NO
LaSalle 1	764	7932	3076	4852	2022	2013	NO
LaSalle 2	764				2023	2013	NO
Limerick 1	764	2832	1701	1131	2024	2006	NO
Limerick 2	764	3921	1893	2028	2029	2006	NO
McGuire 1	193	1351	871	480	2021	2002	NO
McGuire 2	193	1425	1039	386	2023	2001	NO
Millstone 2	217	1263	868	423	2015	2002	NO
Millstone 3	193	756	416	340	2025	2001	NO
Monticello	484	2209	1094	1115	2010	2006	NO
Nine Mile Point 1	532	2776	2200	576	2009	1999	NO
Nine Mile Point 2	764	4049	1400	2649	2026	2010	NO
North Anna 1	157	1737	1505	169	2018		YES
North Anna 2	157				2020		YES
Oconee 1	177	1312	1094	218	2013	2013	YES
Oconee 2	177	1312	1094	218	2013	2013	YES
Oconee 3	177	825	552	273	2014	2014	YES
Oyster Creek	560	2645	2420	180	2009	LOST	YES
Palisades	204	771	657	101	2007	LOST	YES
Palo Verde 1	241	1205	648	557	2024	2004	NO
Palo Verde 2	241	1205	644	561	2025	2003	NO
Palo Verde 3	241	1205	664	541	2027	2003	NO
Peach Bottom 2	764	3819	2720	1099	2013	2000	NO
Peach Bottom 3	764	3819	2777	1042	2014	2001	NO
Perry 1	748	4020	1504	2516	2026	2011	NO
Pilgrim	580	3859	1974	1885	2012	NA	NO
Point Beach 1	121	1502	1347	155	2010		YES
Point Beach 2	121				2013		YES
Prairie Island 1	121	1386	1237	125	2013	2007	YES
Prairie Island 2	121				2014	2007	YES
Quad Cities 1	724	3657	1933	1724	2012	2002	NO
Quad Cities 2	724	3897	2943	954	2012	2003	NO
River Bend	624	2680	1400	1280	2025	2006	NO
Robinson	157	544	302	242	2010	NO	YES
Salem 1	193	1632	772	850	2016	2012	NO
Salem 2	193	1632	584	1038	2020	2016	NO
San Onofre 2	217	1542	870	672	2013	2006	NO
San Onofre 3	217	1542	918	624	2013	2006	NO
Seabrook	193	1236	376	860	2026	2010	NO
Sequoyah 1	193	2091	1295	796	2020	2004	NO
Sequoyah 2	193				2021	2004	NO
Shearon Harris 1	157	4184	720 PWR and1841 BWR	336 PWR and 557BWR	2026		NO
South Texas 1	193	1969	428	1529	2027	2024	NO
South Texas 2	193	1969	400	1556	2028	2025	NO
St. Lucie 1	217	1706	1128	578	2016	2006	NO
St. Lucie 2	217	1076	692	384	2023	2001	NO

Figure E1-6. Data on spent fuel storage at reactors in the United States (continued).



Plant Name	Core Size	Spent Fuel Pool Capacity	Assemblies Stored	Remaining Capacity	Current License Expires	Lose Full Core Offload Capability	Dry Cask Storage?
Summer	157	1276	637	567	2022	2006	NO
Surry 1	157	1044	854	190	2012	NA	YES
Surry 2	157				2013	NA	YES
Susquehanna 1	764	2840	2655	None	2022	2000	YES
Susquehanna 2	764	2840	1762	823	2024	2000	YES
Three Mile Island	177	1338	755	583	2014	NA	NO
Turkey Point 3	157	1395	808	587	2012	2009	NO
Turkey Point 4	157	1389	770	619	2013	2009	NO
Vermont Yankee	368	2863	2331	532	2012	2001	NO
Vogtle 1	193	1475	1081	2392	2027	2015	NO
Vogtle 2	193	1998			2029	2015	NO
WNP 2	764	2654	1703	951	2023	1999	NO
Waterford 3	217	2398	700	1698	2024	2018	NO
Watts Bar 1	193	1612	80	1530	2035	2018	NO
Wolf Creek	193	1327	664	663	2025	2008	NO

Figure E1-6. Data on spent fuel storage at reactors in the United States (continued).

E1-4. MODULE INTERFACE DEFINITION

Module E1 has direct interface with Module E2 as cost is involved with moving spent fuel from the pools into dry storage and with Module H for ultimate packaging for transportation and disposal. While these costs are not significant in the overall cost, modeling must avoid doubling the expense as these costs are not always broken out separately. The same would be true when considering interface with reprocessing Modules F1 and F2/D2.

Wet storage requires continuous operation of cooling, filtration, cleaning, and sampling systems, which depend on mechanical components such as pumps, valves, and filters. The chemical and temperature control of cooling water requires continuous monitoring and sampling. These operations result in appreciable quantities of radioactive low-level wastes. Such operational requirements increase with the amount of fuel in the pond and are particularly high when pools are near to capacity. Thus a link to Module J exists, albeit not well documented and of low order cost importance.

For purpose of modeling interim storage cost, it is reasonable to consider such cost independent of scale.

E1-5. MODULE SCALING FACTORS

There are no direct scaling factors to be considered for this module. Design of pools is fairly straightforward; however, the module can be enhanced by more clearly understanding the cost impacts from dense packing versus open packing. There is an advantage to the unit cost for a larger storage pool (see Section E1-1.6). Relative to new light water reactor projects, most utilities are expected to provide wet storage adequate for the projected life of the facility. This would avoid the need for any additional interim storage cost to remove the spent fuel from the pool to a dry storage form.

E1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The cost bases for this module have been gleaned from numerous studies by the U.S. Department of Energy, International Atomic Energy Agency, Organization for Economic Cooperation and Development/Nuclear Energy Agency, General Accounting Office, NRC, and independent studies such as by Bunn et al. (OECD 1994, NRC 2005, Bunn et al. 2001)

It is basically assumed that capital expenses for wet storage pools are captured in the original cost of reactor design and construction, and amortized with the rest of the reactor. It is further assumed that the ongoing surveillance and operations and maintenance expenses are included in the basic reactor facility staffing and represent partial staff responsibilities, not a separate significant expense. In general, ongoing Operations and Maintenance (O&M) cost for wet storage is much greater than dry storage on an annual basis since all the cooling and purification systems must be kept in service and generate a modest amount of low-level radioactive waste.

"Bowser et al. (1994) estimated that the annual running costs of wet ponds to store fuel from the closed Rancho Seco reactor in California to be $10.6 million per year and for dry stores $2.6 million per year, a saving of about $8 million per year." (Fairlie 2000)

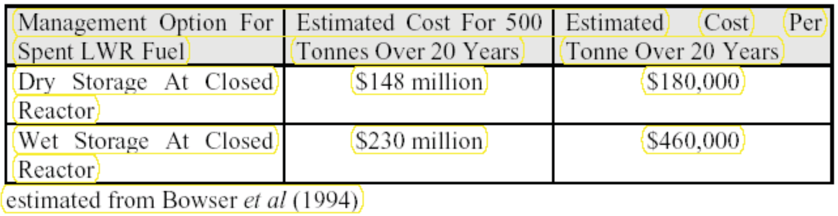
Because most pool costs have been paid for and dry stores have yet to be constructed, a useful comparison is the amortized cost of constructing a dry store plus annual operating costs, compared with the annual operating costs of an existing pool. In a 1994 study by Bowser et al., of the Rancho Seco reactor shutdown, the costs of constructing a transportation plus dry storage system to store spent fuel were estimated at $12.4 million. The study amortized this figure over a 10-year depreciation period using a 5% interest rate. This, plus annual running costs, resulted in an estimated total annual cost of $4.2 million for dry storage compared with annual operating costs of $10.6 million for wet storage. In other words, considerable savings accrued from constructing dry stores and transferring fuel from pools to them. Table E1-3 compares estimated costs of wet and dry storage systems in more detail. It reveals that the cost of dry storing fuel can be as much as 2.5 times lower than wet storing it (Fairlie 2000).

Bunn et al., report on a 1998 Japanese study comparing costs (albeit generally much higher than the U.S. would expect) between wet and dry storage over a 54-year timeframe for 5,000 tonnes of heavy metal in a centralized facility and applying a 5% discount rate (Bunn et al. 2001). The unit costs per this approach were as follows and were estimated for comparison only and obviously do not represent actual experience:

- Pool Storage $396/kgHM (roughly 1.15 mills/kWh)
- Cask Storage $238/kgHM (roughly 0.70 mills/kWh).

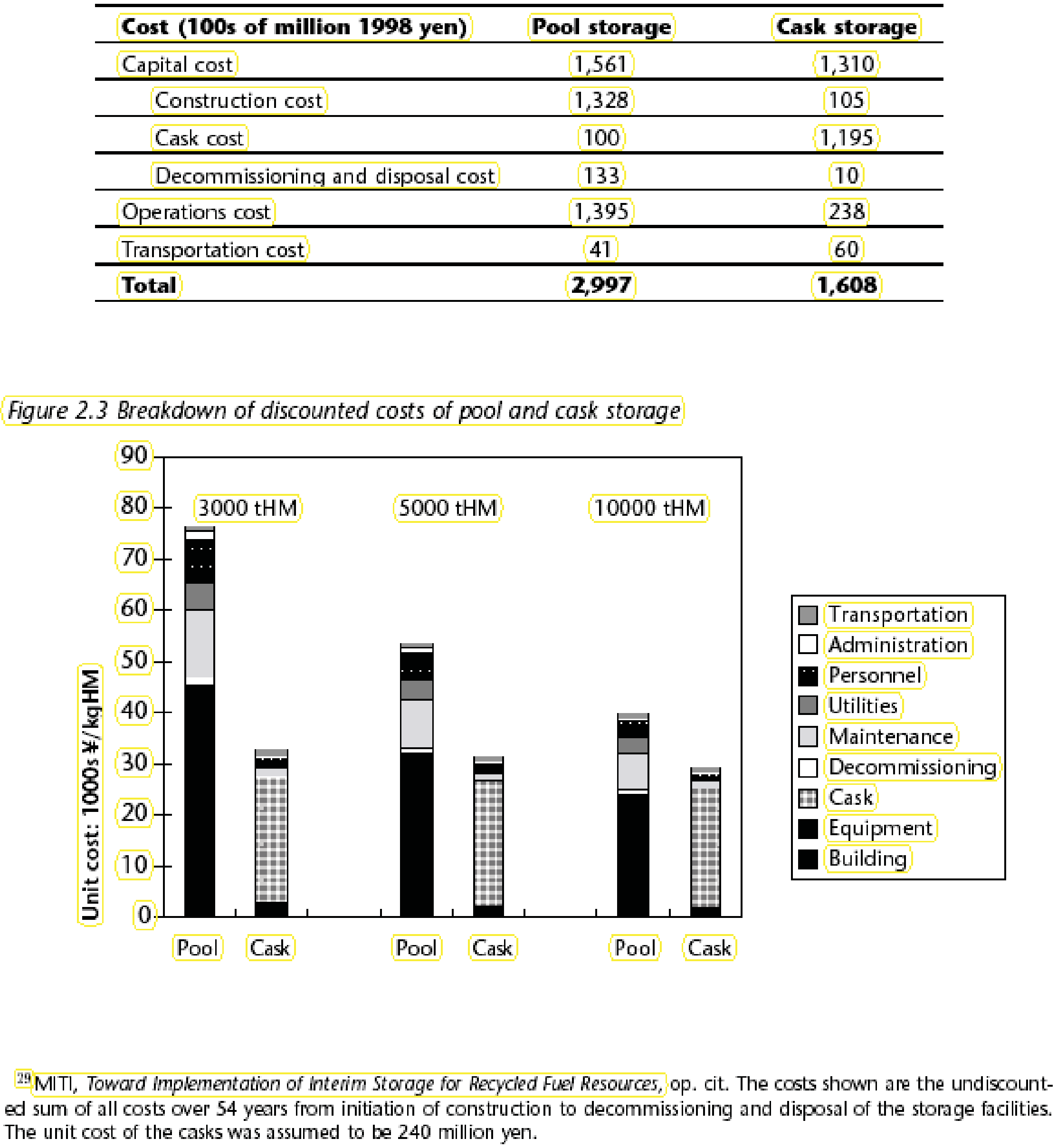
The report also analyzed costs at different scales (3,000 ton and 10,000 ton). Pool costs on a unit basis dropped considerably at the larger scale (see Figure E1-7). Please note that costs in Figure E1-7 are in yen.

Table E1-3. Cost of wet and dry storage options.



Management Option For Spent LWR Fuel	Estimated Cost For 500 Tonnes Over 20 Years	Estimated Cost Per Tonne Over 20 Years
Dry Storage At Closed Reactor	$148 million	$180,000
Wet Storage At Closed Reactor	$230 million	$460,000

estimated from Bowser *et al* (1994)



Cost (100s of million 1998 yen)	Pool storage	Cask storage
Capital cost	1,561	1,310
Construction cost	1,328	105
Cask cost	100	1,195
Decommissioning and disposal cost	133	10
Operations cost	1,395	238
Transportation cost	41	60
Total	**2,997**	**1,608**

Figure 2.3 Breakdown of discounted costs of pool and cask storage

[29] MITI, *Toward Implementation of Interim Storage for Recycled Fuel Resources,* op. cit. The costs shown are the undiscounted sum of all costs over 54 years from initiation of construction to decommissioning and disposal of the storage facilities. The unit cost of the casks was assumed to be 240 million yen.

Figure E1-7. Life-cycle costs for wet storage of spent nuclear fuel.

Initial fixed cost (licensing, design, construct and startup—includes interest) is normally considered part of the overall capital cost of building the reactor and would likely be depreciated over the same period as the reactor.

Annual O&M is certified manpower which is a very small part of the basic operating staff, utilities (electricity and cooling water), consumables for water purification, and a small amount of low-level waste for disposal.

Variable cost would be incurred should pool expansion be needed. This would include the capital cost of neutron absorbing, seismically qualified inserts to permit reracking of pool contents to a dense-packed arrangement with closer spacing. Existing fuel handling equipment and personnel would be expected to be adequate to support such a task although no such data were found.

E1-6.1 Other Considerations

Spent fuel pool operation and related personnel would be required for at least 5 years following shutdown of reactor to permit cooling before loading spent fuel for shipment.

It is assumed that use of higher burnup or mixed oxide fuel will have no significant impact on interim storage cost.

Cost data for this module should be considered as a private enterprise expense, even when considering use of spent mixed oxide fuel.

Reference data should be viewed as a top-down speculative cost or estimate because well-defined data specific to this task were not found.

E1-7. LIMITS OF COST DATA

Because it is a minor portion of the reactor capital cost and has relatively minor annual operating cost, limited data are readily available for the unit costs of wet storage for spent fuel. Capital costs are buried in the overall capital and operating cost absorbed in the basic O&M cost.

When building a model, it is important that such costs not be included twice. Some foreign data are available but not considered of any real value because NRC standards do not necessarily apply.

Cost data are not considered to be of high quality because there has been no common basis or consistent approach.

Technology application is one of a fully mature commercial process.

E1-8. COST SUMMARIES

To get a levelized unit cost for wet storage, the initial capital, annual operating expenses over the life of the spent fuel pool (until emptied), the total amount of electricity produced by the reactor, and the total tons of spent fuel consumed and cooled must be considered.

At this point nearly all, if not all, nuclear plants in the U.S. have been amortized. So, cost reflects only the ongoing O&M costs (neglecting final decontamination and decommissioning costs), encompassing Code of Accounts 71–77. For purposes of this initial module input, related O&M costs are assumed to be in the range of $2M to $10M annually with an arbitrary selection of $6M for a typical 1,000 MWe reactor with a 90% capacity. The most relevant code of accounts are 71 and 74; although, we have not been able to collect data to this level.

The reference cost to be used is 0.76 mils/kWh with a range of 0.25 to 1.27 mils/kWh. Assuming a reference case for a 1,000 MWe plant discharging ~20 tonnes of heavy metal per year, an annual O&M expense of $6 million relates to $300/kgHM

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table E1-4. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table. The triangular distribution based on the costs in the WIT Table is shown in Figure E1-8. The distribution indicates an equal chance that the costs will be on the low end as on the high end.

Table E1-4. Cost summary table.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
0.76 mil/kWh (undiscounted)	0.25 mil/kWh ($100/kgHM)	1.27 mil/kWh ($500/kgHM)	0.76 mil/kWh ($300/kgHM)
Or average 1000 MWe Rx discharging ~20 tHM/yr → $300/kgHM	Low side cost reflects a case of well planned capacity that may be anticipated for new reactors where-in significant reracking is not required. Basic costs would reflect cooling and purification costs only	The high side cost reflects a condition where a significant amount of spent fuel management is required over the duration of the facility, such as reracking for dense-packed storage. It should (again judgment) also be adequate to cover capital cost of initial installation of the pool, containment building and related systems.	(same as the reference case)

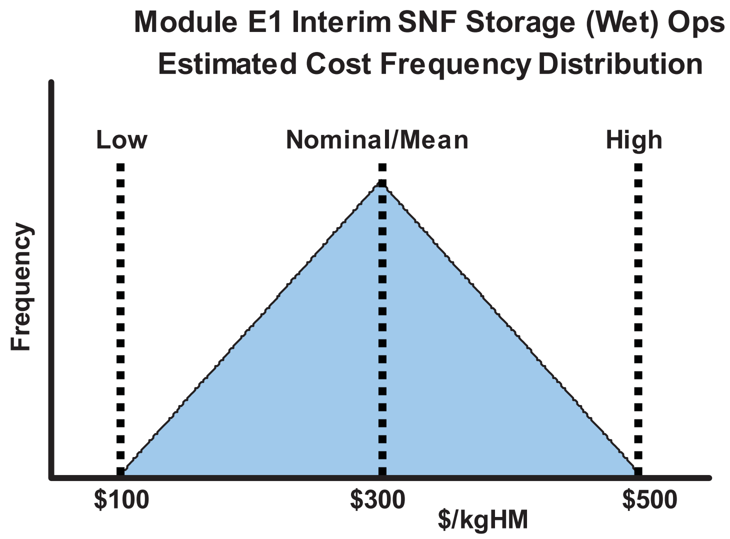


Figure E1-8. Module E1 interim SNF storage (wet) ops estimated cost frequency distribution.

E1-9. SENSITIVITY AND UNCERTAINTY ANALYSES

There have been no significant sensitivity analyses applied to this cost module as the influence of this module cost is so very low relative to the total fuel cycle cost. To improve these data, it will be necessary to perform more detailed investigation of cost parameters with emphasis on pursuing actual O&M cost data from operating U.S. utilities.

New reactor facilities would consider a tradeoff of size of spent fuel pool versus cost to stage spent fuel into dry storage. To be attractive, the much lower cost of dry storage over a period of time must be considered versus the added expense to license such storage, procure casks and related O&M, to load, and to survey as well as provide safeguards and security.

This cost evaluation would be changed should the U.S. government decide to implement a centralized Monitored Retrievable Storage because strategy for length of wet storage could be impacted.

E1-10. BIBLIOGRAPHY

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E1-11. REFERENCES

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Fairlie, I., 2000, "Dry Storage of Spent Nuclear Fuel: The Safer Alternative to Reprocessing," Report to Greenpeace International in Response to Cogema Dossiers to the La Hague Public Inquiry, May 2000, http://scholar.google.com/scholar?hl=en&lr=&q=cache:ZVJt2rZ0S.

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Module E2

Dry Storage of Spent Nuclear Fuel

Module E2

Dry Storage of Spent Nuclear Fuel

E2-1. BASIC INFORMATION

Module E2 discusses the cost involved with dry storage of commercial spent nuclear fuel. This includes the cost of licensing and construction of a dry storage area (assumed at the reactor site); procurement, loading and placement of casks and/or storage containers; and routine Operations and Maintenance expenses. Spent fuel is assumed to have cooled for a minimum of 5 years before being placed in dry storage. Worldwide inventory of spent fuel in dry storage was only 5,300 metric tonnes of heavy metal (MTHM) in 1998, but is expected to grow significantly (see Table E2-1).

Dry storage of spent fuel differs from wet storage by making use of gas or air instead of water as the coolant (often an inert gas such as helium or an only modestly reactive gas, such as nitrogen, to limit oxidation of the fuel while in storage) and metal or concrete instead of water as the radiation barrier. The casks are typically steel cylinders that are either welded or bolted closed. The steel cylinder provides a leak-tight containment of the spent fuel. Each cylinder is surrounded by additional steel, concrete, or other material to provide radiation shielding to workers and members of the public. Some of the cask designs can be used for both storage and transportation.

Spent fuel is currently stored in dry cask systems at a growing number of independent spent fuel storage installations located at 24 power plant sites, one decommissioned power plant site (Fort St. Vrain), two plants in the process of decommissioning (Rancho Seco and Trojan), and at an interim storage facility operated by the U.S. Department of Energy (DOE) located at Idaho National Laboratory near Idaho Falls, Idaho. One additional independent spent fuel storage installation, the General Electric-Morris Operation in Illinois, is licensed for wet storage of spent fuel. Figures E2-1 and E2-2 in Section E2-3 contains maps showing the location of existing independent spent fuel storage installations.

Cask designs approved for use under the general license are listed in the Nuclear Regulatory Commission (NRC) regulations in Title 10 of the Code of Federal Regulations under Part 72.214 and in Table E2-2.

The casks used in the dry storage systems are designed to resist floods, tornadoes, projectiles, temperature extremes, and other unusual scenarios. The NRC requires the spent fuel to be cooled in the spent fuel pool for several years before being transferred to dry casks. Typically, the maximum heat generated from 24 fuel assemblies stored in a cask is less than that given off by a typical home heating system in 1 hour. As the fuel cools further, the heat generated will decrease over time.

There are various dry storage cask system designs. Casks typically consist of a sealed metal cylinder that contains the spent fuel enclosed within a metal or concrete outer shell. With some designs, the steel cylinders that contain the fuel are placed vertically in a concrete vault; other designs orient the cylinders horizontally. The concrete vaults provide the radiation shielding. Other cask designs orient the steel cylinder vertically on a concrete pad at a dry cask storage site and use both metal and concrete outer cylinders for radiation shielding. See the picture of a typical dry cask storage systems in Section E2-3.

Reactor operators have a large range of choice of dry storage systems. For those seeking economies of scale in storing large quantities of spent fuel for a prolonged period, vaults and silos are attractive; while for those seeking the flexibility of a modular, piece-by-piece storage system, dry casks are preferred.

The NRC currently licenses storage casks for 20 years although the NRC has stated in the Federal Register that “dry storage in particular is safe and environmentally sound for a period of 100 years.” Some U.S. dry-cask storage facilities will reach the 20-year mark in a few years. The NRC is, therefore, currently deciding what analysis will be required to provide a basis for license extensions. With reactor operators increasing fuel burnup, casks will also eventually have to be licensed for the storage of high-burnup fuel. Current licenses allow burnups of up to 45,000 MWd/MT. However, the CASTOR V/19 cask is already licensed in Germany to store 19 high-burnup Biblis-type fuel assemblies, which are slightly bigger and heavier than U.S. pressurized water reactor fuel assemblies. The license allows 15 5-year-cooled fuel assemblies with burnups of 55 MWd/kgU plus four with burnups of up to 65 MWd/kgU. U.S. storage casks have been tested with fuels with burnups of 60 MWd/kgU.

Operating costs are very modest. Once loaded, the operating costs principally relate to providing safeguards and security as necessary to meet the licensing requirements. Most U.S. operations use concrete pad storage for simplicity of operation and compatibility with transport.

E2-2. FUNCTIONAL AND OPERATING DESCRIPTION

The dry storage process begins with the same process as loading of spent fuel for transport. Removal and transfer operations are scheduled to take place when no other operations are required or are underway in the storage pool. An approved cask (generally a multipurpose canister [MPC]) is brought into the reactor spent pool area and placed into the pool. The spent fuel is removed by loading it into the storage cask under water inside the pool. The cask is made of stainless steel alloy and also contains aluminum heat conduction elements and neutron absorbing materials. The MPC looks like a welded cylinder with flat ends. It consists of a honeycombed fuel basket, base plate, canister shell, lid, and a closure ring. After assemblies have been loaded, the MPC is vacuum-dried to remove all water and filled with helium after the used fuel rods are inserted and then sealed. The helium helps maintain the used nuclear fuel assemblies in an inert or passive environment as well as improving heat transfer. These inner containers are never opened after being sealed.

The pool crane is used to lift the loaded storage cask from the pool, and transfer the cask to an appropriate overpack container used for the dry-storage facilities. The overpack is a heavy-walled steel and concrete vessel also shaped as a cylinder. Its sidewalls consist of concrete enclosed between inner and outer steel shells. The overpack is designed to provide protection for the interior MPC while allowing air to circulate around the surface of this sealed canister. The overpack typically has inlets at the bottom and outlets at the top to allow air to circulate naturally through the cavity to help cool the MPC inside. A special transporter is used to place the overpacks on the storage pads (see Figures E2-3–E2-9 for pictures of these functions).

E2-3. PICTURES/SCHEMATICS

Table E2-1. Summary of worldwide dry spent fuel storage (tonnes heavy metal as of 1998).

State	Number of facilities	Design capacity	Current inventory
Argentina	1	200	64
Belgium	1	800	142
Canada			
Operating	7	8567	1930
Under Construction	1	14500	0
Czech Republic	1	600	232
France	**1**	**180**	**180**
Germany			
Operating	3	7768	58
Under Construction	1	585	0
Hungary	1	162	54
Japan	1	73	73
Republic Of Korea			
Operating	1	609	609
Under Construction	1	812	0
Lithuania	1	419	0
Ukraine	1	50	0
United Kingdom	1	958	680
USA			
Operating	10	4,700	1,270
Under Construction	6	2,155	0
Total	**39**	**43,138**	**5,292**

Table E2-2. Dry spent fuel storage designs: NRC approved for general use.

Vendor	Storage Design Model	Certificate of Compliance Issue Date	Docket	Amendment (A) ADAMS Accession Number
General Nuclear Systems, Inc.	CASTOR V/21	August 17, 1990	72-1000	A0—ML033020117
NAC International, Inc.	NAC S/T	August 17, 1990	72-1002	A0—ML033020120
NAC International, Inc.	NAC-C28 S/T	August 17, 1990	72-1003	A0—ML033020125
Transnuclear, Inc.	TN-24	November 04, 1993	72-1005	A0—ML033020128
BNFL Fuel Solutions Corp.	VSC-24	May 07,1993	72-1007	A0—ML003728434 A1—ML003719688 A2—ML003764775 A3—ML011340049 A4—ML030230287
Transnuclear, Inc.	NUHOMS-24P NUHOMS-52B NUHOMS-61BT	January 23, 1995	72-1004	A0—ML033020053 A1—ML003704754 A2—ML003730072 A3—ML012620111 A4—ML020640202 A5—ML040150834 A6—ML040120831 A7—ML040640919
Holtec International	HI-STAR 100	October 04, 1999	72-1008	A0—ML033020058 A1—ML003780760 A2—ML011500503
Holtec International	HI-STORM 100	June 01, 2000	72-1014	A0—ML003711779 A1—ML022000176
Transnuclear, Inc.	TN-32	April 19, 2000	72-1021	A0—ML003696930 A1—ML010460291
NAC International, Inc.	NAC-UMS	November 20, 2000	72-1015	A0—ML003762577 A1—ML010230249 A2—ML020250546
NAC International, Inc.	NAC-MPC	April 10, 2000	72-1025	A0—ML003704081 A1—ML020250491 A2—ML021420129 A3—ML032820197
BNFL Fuel Solutions Corp.	FuelSolutions	February 15, 2001	72-1026	A0—ML010300147 A1—ML011210377 A2—ML020250512 A3—ML031320795
Transnuclear, Inc.	TN-68	May 28, 2000	72-1027	A0—ML003711273
Transnuclear, Inc.	Advanced NUHOMS-24PT1	February 05, 2003	72-1029	A0—ML030100419
Disclaimer: This replaces NUREG-1419, Directory of Certificates of Compliance for Dry Spent Fuel Storage Casks, which is no longer available.				

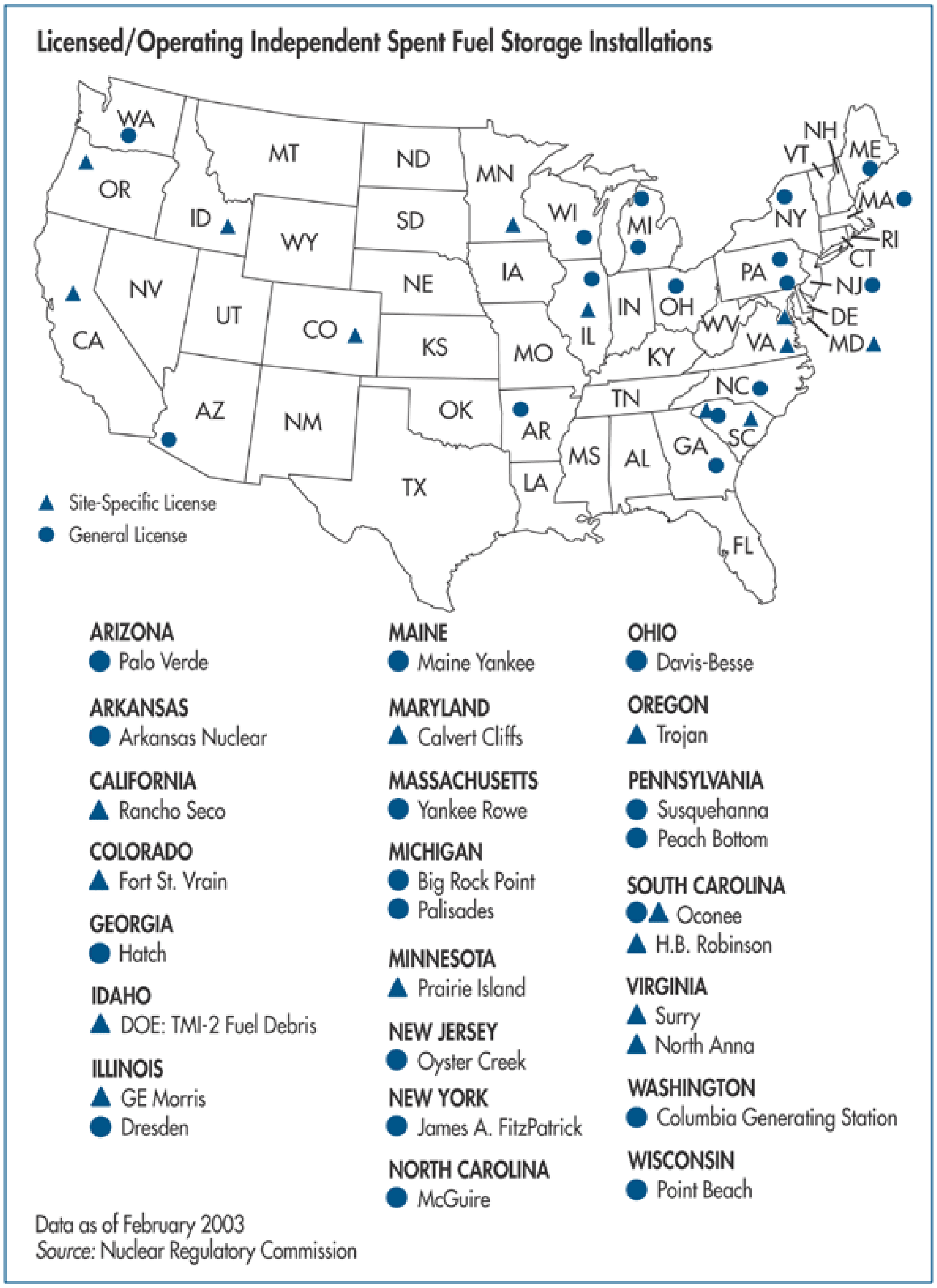

Figure E2-1. Licensed/operating independent spent fuel storage installations (NRC 2005).

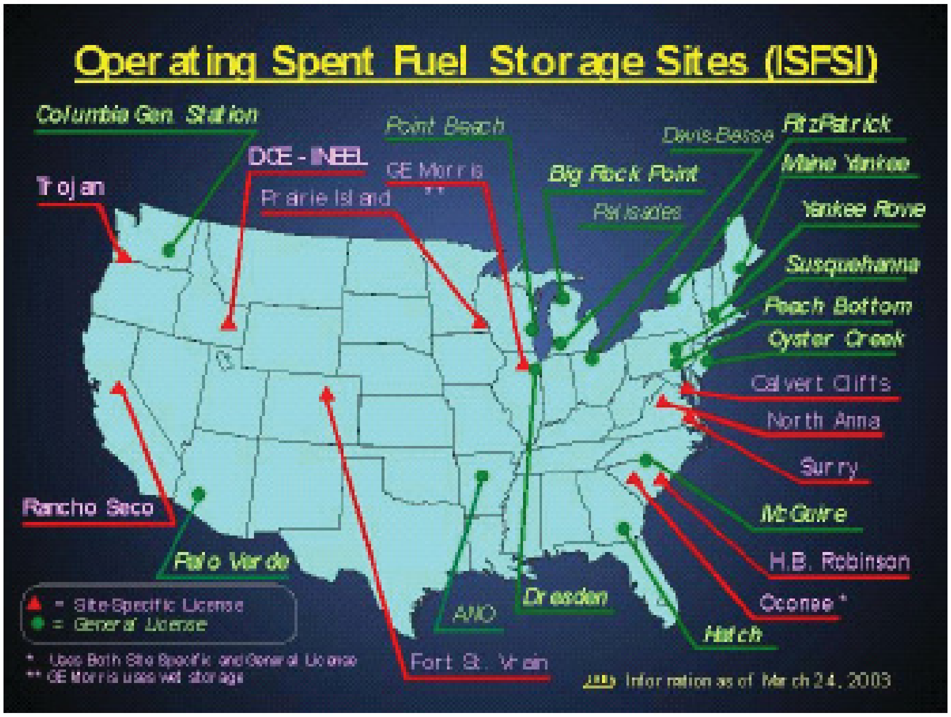

Figure E2-2. Location of independent spent fuel storage sites.

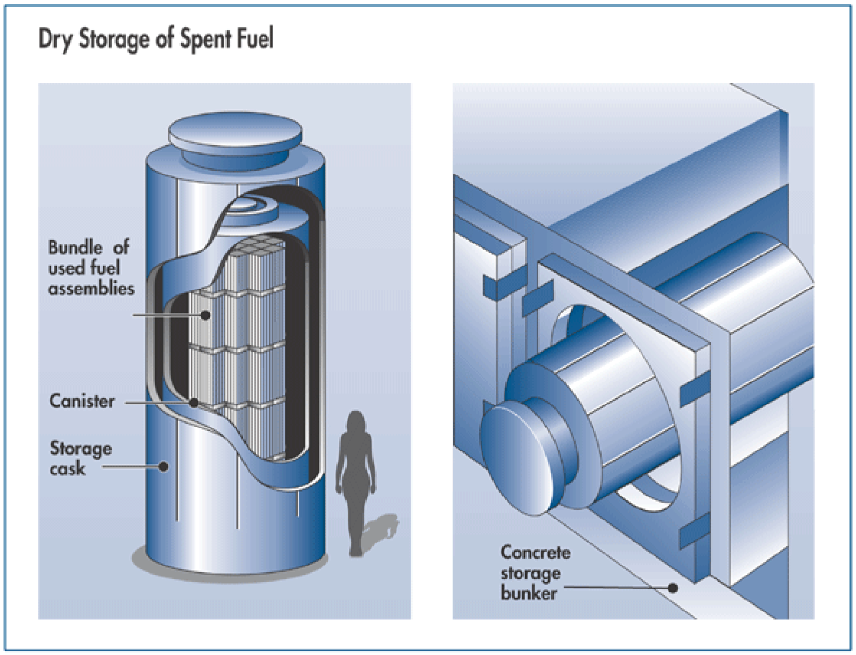

Figure E2-3. Dry storage of spent fuel.

Figure E2-4. Left: Receiving the MPC at J. A. FitzPatrick Nuclear Plant. Right: Fit up of the MPC and MPC lid at J. A. FitzPatrick Nuclear Plant.

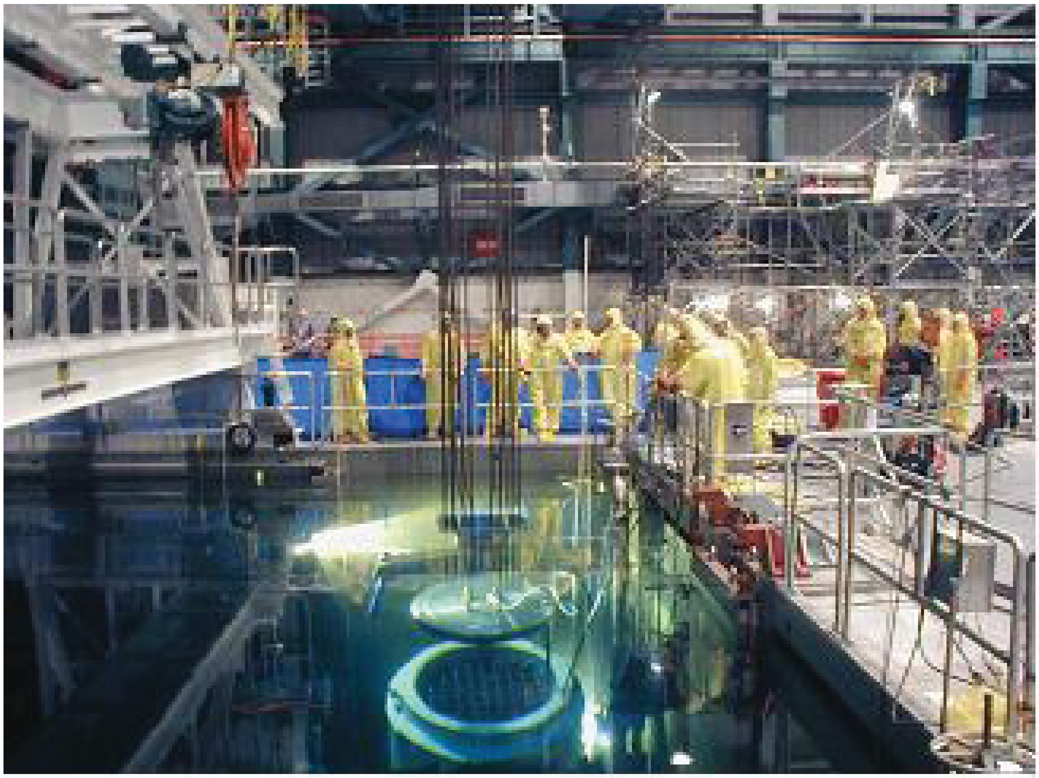

Figure E2-5. Cask for dry fuel storage being closed under water for shielding protection.

Figure E2-6. Cask being placed on dry storage pad.

Figure E2-7. Dry storage cask transporter.

Figure E2-8. Typical dry storage casks.

Figure E2-9. Overview of typical dry storage pad.

E2-4. MODULE INTERFACE DEFINITION

Module E2 has direct interface with Module E1 as cost is involved with moving spent fuel from the pools into dry storage and with Module G for ultimate packaging for transportation and disposal. While these costs are not significant in the overall cost, modeling must avoid doubling the expense because these costs are not always broken out separately. The same would be true when considering interface with reprocessing Modules F1 and F2/D2.

For the purpose of modeling interim storage cost, it is reasonable to consider such cost independent of scale.

E2-5. MODULE SCALING FACTORS

There are no direct scaling factors to be considered for this module. Specific cost is more influenced by choice of dry storage container and number of procurements for storage casks (i.e., the cask market).

E2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The cost bases for this module have been gleaned from numerous studies by DOE, IAEA, OECD/NEA, GAO, NRC and independent studies such as by Bunn et al. (2001).

Specific costs for dry storage will vary by the type of system used, the modifications required at the facility that will receive the dry storage, the licensing requirements, the type of containers to be used, and the capacity of the dry storage unit to be acquired.

Bunn et al. did a thorough review of dry storage costs in the 2001 report, "Interim Storage of Spent Nuclear Fuel" published by Harvard University and the University of Tokyo (Bunn 2001). Their findings are summarized as follows. Capital costs for dry storage at reactors involve (1) upfront costs, which include costs for design, engineering, NRC licensing, equipment, construction of initial storage pads, security systems, and startup testing; and (2) storage system and loading costs, which include the price of the casks themselves, additional pads, labor, decommissioning, and consumables.

In the United States, total upfront costs to establish a new dry storage facility at a reactor site (which are largely fixed, regardless of the amount of spent fuel to be stored) are estimated by different sources at $9M or $8M–$12M, regardless of the specific amount of fuel to be stored. Costs to purchase and load the dry casks, including labor, consumables, and decommissioning, are estimated to be in the range of $60–80 per kilogram of heavy metal (kgHM) in the spent fuel. Operating costs are very modest, because virtually nothing needs to be done to the casks each year once they are loaded. The principal operating costs relate to providing the security and safety monitoring needed to maintain the NRC license for the facility. For storage sites collocated with operating reactors, many of these costs can be charged to the reactor operation, and the net additional operating costs are estimated to be only $750,000 per year (largely independent of the amount of spent fuel to be stored).

For independent storage sites or storage sites at reactors that have been shut down, these costs must be attributed to the storage site itself, and so the net additional operational cost is substantially higher. For shutdown reactors with all their spent fuel in dry storage, operating costs are estimated to be $3M–$4M per year.

Total undiscounted lifecycle costs for 40 years of dry cask storage for the roughly 1,000 tonnes of spent fuel generated in a typical reactor lifetime, if incurred while the reactor is still operating, would be roughly $120M or $120/kgHM. For 40 years of storage after the reactor was shut down, total undiscounted costs would be $250M or $250/kgHM. The discounted present value of this 40-year life-cycle cost is only modestly less, because nearly all the cost is up-front expenditure. At a 5% rate, the net present cost would be $100/kgHM for the case in which the reactor was operating during the storage period, and $160/kgHM for 40 years of post-shut-down storage. Per-kilogram estimates for a large centralized facility are similar to these at-reactor costs.

Bunn et al. also reported on a 1998 Japanese study (Figure E2-10) comparing costs (albeit generally much higher than the U.S. would expect) between wet and dry storage over a 54-year time frame for 5,000 tHM in a centralized facility and applying a 5% discount rate. The unit costs per this approach were as follows and were estimated for comparison only and do not represent actual experience:

Pool Storage	$396/kgHM (roughly 1.15 mills/kWh)
Cask Storage	$238/kgHM (roughly 0.70 mills/kWh).

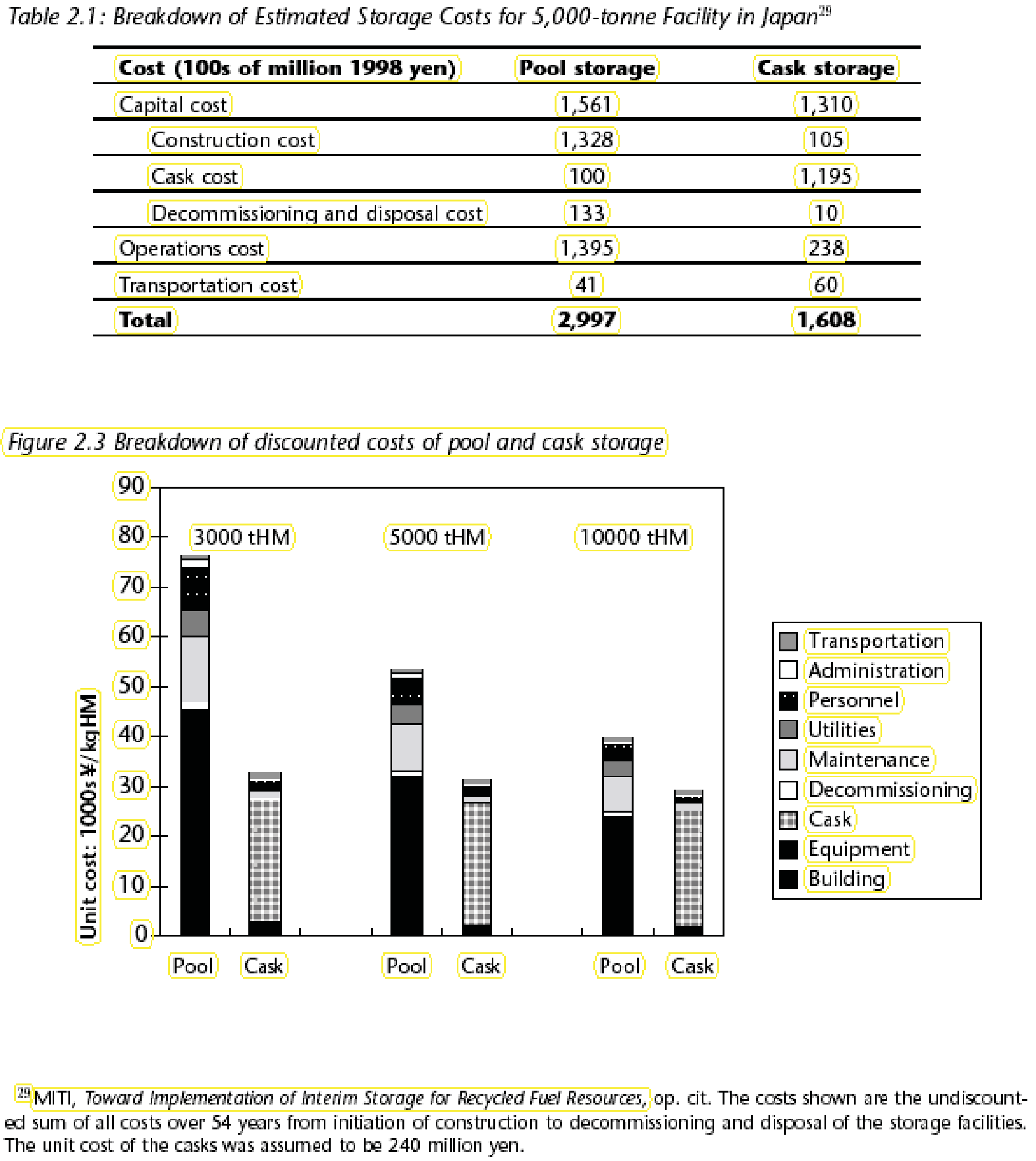

Table 2.1: Breakdown of Estimated Storage Costs for 5,000-tonne Facility in Japan[29]

Cost (100s of million 1998 yen)	**Pool storage**	**Cask storage**
Capital cost	1,561	1,310
Construction cost	1,328	105
Cask cost	100	1,195
Decommissioning and disposal cost	133	10
Operations cost	1,395	238
Transportation cost	41	60
Total	**2,997**	**1,608**

Figure 2.3 Breakdown of discounted costs of pool and cask storage

[29] MITI, *Toward Implementation of Interim Storage for Recycled Fuel Resources*, op. cit. The costs shown are the undiscounted sum of all costs over 54 years from initiation of construction to decommissioning and disposal of the storage facilities. The unit cost of the casks was assumed to be 240 million yen.

Figure E2-10. Storage costs (note that costs are in yen).

Dr. Ian Fairlie looked at advantages of dry storage (Fairlie 2000). In a 1994 study by Bowser et al. of the Rancho Seco reactor shutdown, the costs of constructing a transportation plus dry storage system to store spent fuel were estimated at $12.4M. The study amortized this figure over a 10-year depreciation period using a 5% interest rate. This, plus annual running costs, resulted in an estimated total annual cost of $4.2M for dry storage compared with annual operating costs of $10.6M for wet storage. This implied that considerable savings could be accrued from constructing dry stores and transferring fuel from pools to them. Table E2-3 compares estimated costs of wet and dry storage systems in more detail. It reveals that the cost of dry storing fuel is 2.5 times lower than wet storing it.

Table E2-3. Estimated costs of wet and dry storage systems.

Management Option For Spent LWR Fuel	Estimated Cost For 500 Tonnes Over 20 Years	Estimated Cost Per Tonne Over 20 Years
Dry Storage At Closed Reactor	$148 million	$180,000
Wet Storage At Closed Reactor	$230 million	$460,000

estimated from Bowser *et al* (1994)

Fairlie also presented the following summary of dry storage estimates. Cost estimates of dry storage from various studies are listed in Table E2-4. The data in this table are not directly comparable because different assumptions, financial conventions, years for currencies, and exchange rates are used in their calculation. Also, estimates of storage costs that are expressed simply in $ per tonne should be treated as approximate, because costs will depend on the length of time that fuel is expected to be retained. This is often not stated in industry estimates or is indeterminate, as in the SN-BNFL 1995 agreement. A more precise indication of estimated costs would be expressed in costs per tonne per year, but this is rarely stated. Nevertheless, the data in the table report the figures from a number of studies that can be used to give an approximate indication of estimated dry store costs in various situations.

Table E2-4. Cost estimates of dry storage.

STUDY	LWR FUEL $,000/tonne
KfK-PAE (NuclearFuel (1993b)*	220
OECD-NEA (1994)++	225
IAEA (1990)	82-165
Supko (1995)+	50-100
Wisconsin PSC (1994)#	35-68
Ontario Hydro (Stevens-Guille, 1994; Nash, 1997)	15-20

+representative life cycle costs
++levelised fuel cycle costs
#constant $ analysis
* undiscounted

Alvarez reports that the cost of onsite dry-cask storage for an additional 35,000 tons of older spent fuel has been estimated at $3.5B to $7B ($100 to 300/kgHM) (Alvarez et al. 2003). Storage cask capacity costs U.S. utilities from $90 to 210/kgU. Additional capital investments for new onsite dry storage facilities would include NRC licensing, storage pads, security systems, cask welding systems, transfer casks, slings, tractor-trailers, and startup testing. These costs are estimated to range from $9M to $18M per site. However, at most sites, they will be incurred in any case, because even dense-packed pools are filling up. The capital cost of moving 35,000 tons of spent fuel into dry casks would, therefore, be dominated by the cost of the casks and would range from about $3.5B to $7B ($100 to 200/kgU). Per GWe of nuclear capacity, the cost would be $35M to $70M.

The additional cost per kWh would be about 0.03 to 0.06 cents/kWh. The values reported by Alvarez compare favorably with the values suggested by the Bunn report (Bunn 2001; Alvarez et al. 2003).

The extra cost of dry storage would be reduced significantly if the casks could be used for transport and ultimate disposal as well. For MPCs with stationary concrete overpacks, the extra cost would then be associated primarily with the overpack (about 20% of the total cost) and with the need to buy the canisters earlier than if the spent fuel stayed in dense-packed pools until it was transported to the geological repository. However, the U.S. DOE currently plans to have spent fuel unpacked from transport canisters and then repacked in special canisters for disposal.

Costs would be increased by the construction of buildings, berms, or other structures needed to surround the casks to provide buffering against possible attack by antitank missiles or crashing aircraft. The building at Gorleben (Germany), which is licensed to hold 420 casks that contain about 4,200 tons of uranium in spent fuel, would cost an estimated \$20M to \$25M to build in the United States or about \$6/kgU. Assuming conservatively that the building cost scales with the square root of the capacity (i.e., according to the length of its walls), the building would cost about \$12/kgU to store 100 casks containing 1,000 tons of uranium in spent fuel. This would correspond to an inventory of a typical two-reactor site. Berms for a middle-sized storage area might cost about \$1.5 to \$3/kgU. The berms for the 300-cask site at the Palo Verde, Arizona nuclear power plant were reported to cost \$5M to \$10M.

The Consolidated Fuel Treatment Center (CFTC) Follow-on Engineering Alternative Studies (EAS) included an evaluation of “Early Fuel Receipt and Storage” (EPR&S) concept that stored 8,000 MT of spent nuclear fuel (SNF) at a reprocessing site. The cask and fuel canister handling and storage concepts described are based closely on the facility that the U.S. NRC licensed as Private Fuel Storage L.L.C., to be constructed in Toole County, near Low, Utah (WSRC 2007).

Following loading into fuel canisters, at the source reactor sites, the spent fuel will be sealed in canisters that are seal-welded closed. These will provide high-integrity closure/containment seals on the fuel package, which is recognized, by the NRC, and credited in the transportation, storage and safety cases for the fuel packages and facility. The canisters are shipped in transportation casks that measure approximately 7 feet in diameter and 17 feet long. Each cask may weigh as much as 175 tons, gross container weight, including fuel.

When received at the EFR&S facility, the licensed transportation cask will be opened and unloaded by removal of its sealed fuel canister. The sealed canister is placed directly into a licensed storage cask, and the storage cask transferred to and placed on an outdoor storage pad. The storage casks discussed in this document are typically vertical, cylindrical, concrete and steel structures that provide radiological shielding. The study assumed 800 MT/yr of receipt capacity or a 10-year reprocessing quantity (the reprocessing facility was assumed to be in operation after 10 years).

For cost estimating the initial facilities were included in the Total Project Cost (TPC) and the remainder included in the life-cycle costs (LLCs). On a basis of approximately 11 MTHM per cask (26 PWR assemblies at approximately 426 Kg HM/assembly), 30 pads (2,400 MT SNF) and 220 casks would be initially constructed. To reach the full 8,000 MT of storage, 70 additional pads and 500 additional casks would be constructed over 7 years. The facility is assumed to be in operation (receiving 800 MT/yr from off-site and transferring 800 MT/yr to the reprocessing fuel pool) for 40 years to support the reprocessing center.

In addition to the storage pads, the receipt facility would consist of five principal buildings: a two bay Canister Transfer Building, a solid and liquid low-level waste handling building, an Operations/Maintenance/Radiological Protection building (to include shops for both electrical and mechanical maintenance, Radiological Protection laboratories, and offices), a Security building, and an Administration building.

The TPC was estimated (WSRC 2008) to range from \$438M to \$564M and the 40-year LCC was estimated to range from \$2.4B to \$3B for 40 years of operation. The unit cost is therefore \$76 to \$95/kgHM. This unit cost amortizes the TPC over 40 years consistent with the life of the CFTC reprocessing center.

E2-6.1 Other Consideration in Determining Life Cycle Costs for Dry Storage of Spent Nuclear Fuel

1. DOE could decide to use a MPC that does not require over packing.
2. DOE could decide to use a centralized Monitored Retrievable Storage approach for interim storage, relieving much of this cost from the utility.
3. Changes in safeguards and security standards could force additional design measures.
4. Use of deep burn fuels and mixed oxide could force some development of more expensive containers unless allowed to cool longer in a pool.
5. A new dynamic will arise should DOE initiate a program to take ownership of spent fuel as well as consider significant interim storage. Such storage has been suggested for DOE sites. Private Fuel Storage in Utah has recently been licensed by the NRC for spent fuel storage. Such operations would either be competitive in the case of Private Fuel Storage or use government funding. In any case, the impact comes from the additional transportation cost and not likely to greatly impact the cost of dry storage itself. It could bring more competition into the cask business and thus work to control cost growth.

   Cost data for this module should be considered as a private enterprise expense.

Reference data should be viewed as top-down estimates but founded on several broad and independent studies that appear to be consistent in approach.

E2-7. LIMITS OF COST DATA

Dry storage represents a rather minor capital and operating cost relative to the total fuel cycle.

When building a model, it is important that cost for specific dry storage be separated from wet storage such that costs for spent fuel storage are not included twice.

Technology application is one of a relatively mature commercial application that utilizes NRC licensing requirements.

E2-8. COST SUMMARIES

To estimate the levelized unit cost for dry storage, several factors need to be considered. The factors include the initial capital, the annual operating expenses over the duration of the interim storage (until shipped for disposal or reprocessing), the total amount of electricity produced by the reactor, and the total tons of spent fuel consumed and cooled.

At this point nearly all current operating nuclear plants in the U.S. are either using or considering the need for dry storage. It is assumed that new requirements for dry storage casks will not result in any significant growth in cost and that prior studies provide a sound basis for estimating costs.

Nearly all the code of accounts could be applied by treating new storage capacity as a project as most utilities would. However, that degree of detail has not been found at this time. The most relevant code of accounts are 71 and 74 (from Appendix A), considering initial startup to be a one-time expense and new casks being considered as a consumable.

The reference cost to be used has been arbitrarily selected at \$120/kgHM with a range of \$100 to \$300/kgHM.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table E2-5. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table. The triangular distribution based on the costs in the WIT Table is shown in Figure E2-11. The distribution is skewed toward the low cost because the cost analyst judged that the lower costs would be most similar to the reference costs, and a low likelihood for significant changes to the dry storage regulations.

Table E2-5. Cost summary table.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	(Low Cost) Upsides	(High Cost) Downsides	(Nominal Cost) Selected Values
$120/kgHM (undiscounted)		$100/kgHM	$300/kgHM	$120/kgHM
Or considering an average 1,000 MWe Rx discharging ~20 tHM/yr	TBD	Low-side cost reflects a case of well-planned capacity where several reactors can share the cost of the dry storage operation.	The high-side cost reflects a condition where dry storage regulations undergo significant change, increasing design and construction cost as well as stronger canisters.	(Same as the reference case)

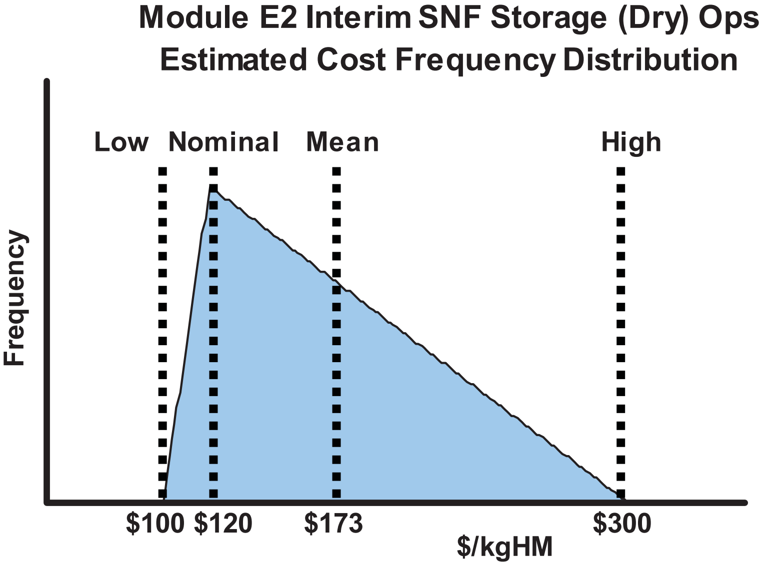

Figure E2-11. Interim SNF storage (dry) ops estimated cost frequency distribution.

E2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

There have been no significant sensitivity analyses applied to this cost module because the influence of this module cost is so low relative to the total fuel cycle cost. To improve these data, it will be necessary to perform more detailed investigation of cost parameters with emphasis on pursuing actual Operations and Maintenance cost data from operating U.S. utilities and numerous cask vendors.

The owners of new reactor facilities would need to consider the trade-off of increasing the size of their spent fuel pool versus the cost to develop dry fuel storage. For dry storage to be attractive, the much lower cost of dry storage must be traded-off against the added expenses to license the storage, procure storage casks, provide operators and maintenance staff to load and survey the casks, and provide additional guards for safeguards and security.

This cost evaluation would be changed should the U.S. government decide to implement a centralized Monitored Retrievable Storage because strategy for length of any interim dry storage could be impacted, including the addition of significant transportation costs.

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Module E3

Storage of Combined Recycled Product of Mixed Plutonium, Minor Actinides, and Uranium Product

Module E3

Storage of Mixed Recycled Plutonium, Minor Actinides, and Uranium Product

E3-1. BASIC INFORMATION

Recycled product storage facilities would safely store the pure or mixed transuranic actinide products or by-products produced from the reprocessing of thermal reactor and/or fast reactor fuels. The particular aim of this module is to provide best estimates of the cost of storage for mixed plutonium and other transuranic minor actinides as proposed for advanced fuel cycles with higher actinide incineration. These costs estimates are extrapolated from existing facility experience and design studies for storage plants for plutonium oxide and metal. The cost estimates are provided in two forms: a fixed quantity based on a nominal storage period suited to an established advanced fuel cycle and a time-dependent quantity for use where the advanced fuel cycle system is far from steady state.

Several operating facilities and/or design studies were found that represent plutonium storage: the Mayak fissile material storage facility in Russia, the Actinide Packaging and Storage Facility (APSF) at the Savannah River Site (SRS), the Unirradiated Fuel Storage Facility – Central Processing Plant (CPP) 651 at Idaho National Laboratory (INL)[a], the Sellafield Product and Residues Store (P&RS) in the U.K., and the Pu product store at AREVA Cap La Hague in France The Savannah River Site provided information for a U.S. consolidated storage facility (an unpublished study) and information from the Engineering Alternative and Follow-on Engineering Alternative Studies conducted for the Consolidated Fuel Treatment Center (CFTC) . Generalized cost information was also obtained from a nuclear fuel cycle economics study reported by the Organization for Economic Cooperation and Development (OECD)-Nuclear Energy Agency (NEA).

There are two main storage approaches that must be accommodated. For the eventual well-developed and deployed nuclear fuel cycle with full plutonium recycle and possibly also the partial/full recycle of minor actinides, short (several year, storage of plutonium, etc.) is required to act as buffer storage between facilities and to accommodate the logistics of the overall fuel cycle, which may be in a transient phase of growth. Given the delay in deployment of fast reactors compared to earlier plans, the current general approach being adopted for excess fissile materials by both commercial and defense sectors is that of stabilization (if needed), packaging and placement into stores with the capability of 50-year secure storage life, possibly extendable to 100 years. Nuclear materials can be withdrawn at any time consistent with the facility material handling rate, but the time period and costs are sufficient to deter unnecessary movements.

Module E3 examines cost estimates for material handling and short-term storage as well as material stabilization, handling, and long-term storage. Approximate costs are determined for the case of plutonium: both commercial oxide storage and defense oxide and metal storage. The costs of storage of other transuranic products and blends, which may arise from advanced fuel cycles, are estimated by extrapolation from plutonium storage costs by consideration of decay heat levels, criticality safety, and dose levels.

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[a] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

Recycled actinide products, actual and proposed, for potential storage include the following cases:

1. Recycled uranium oxide
2. Plutonium oxide
3. Blended uranium and plutonium oxides
4. **Mixed plutonium, transuranic minor actinides and uranium (1)** – Near pure uranium and blended uranium, plutonium, and/or minor actinide (Np, Am, and Cm) metals or oxides from various electrochemical processing ("pyro") flowsheets
5. **Mixed plutonium, transuranic minor actinides and uranium (2)** – Selected pure or mixed streams of U, Pu, Np, Am, and Cm oxides as delivered as by-products from various proposed UREX+ flowsheets
6. Mixed americium and curium oxide from aqueous reprocessing.

From recycling of thermal oxide fuel, the first two cases, UO_3 and PuO_2 storage, have been routinely performed by commercial industry for decades although the technical demands of plutonium oxide storage have increased with increasing fuel burnup, especially in light-water reactors (LWRs). The third case has recently started at the Rokkasho recycling plant (RRP) in Japan where deliberate mixing of U and Pu products has been practiced to improve safeguards. In the last decade, increased attention has been paid to long-term storage of metallic and oxide plutonium within the defense sector.

Regarding Case 1, the recycled uranium from LWR fuels is often low enriched, ~1% U-235, and has higher U-232 concentration than natural uranium. In LWR recycled uranium, the β-γ dose increases by several orders of magnitude after several years' storage. This is due to daughters of Th-228 created by α decay of U-232. Commercial recycling plants use mainly automated remote equipment for uranium finishing (formation of dry solid oxide product), sampling, metering to drums, closure, decontamination, transport, and storage. This equipment is normally maintained, following inventory removal, using contact maintenance. This modern approach is consistent with conventional industrial automation, and dose and toxic inhalation/ingestion minimization. The heat generation rate of a filled drum is low. Drum capacity varies between around 180 kg for ~1% enriched reprocessed uranium (UO_3) from LWR fuel to around 800 kg for ~0.2% enriched uranium from first generation, natural uranium fuelled, gas reactors. The overall storage cost of once reprocessed uranium is low and is included in Module K-2. The cost values in this module concern the higher costs of storage of transuranic material, which may also be mixed with uranium.

The first three cases, 1–3, were generally planned for buffer storage purposes, but the delayed introduction of fuel recycling has increased the need for planned long term storage (e.g., up to 50 years and with potential for extension to 100 years). Plant capital and operating costs for Cases 2 and 3 are known in principle, but may be commercially restricted information. The perceived excess of fissile materials for defense purposes and the need to treat and/or recover fissile materials from process wastes has also created the need to provide capabilities for stabilization of mixed fissile materials (e.g., plutonium bearing metals and oxides with ≥30 wt% plutonium plus uranium).

Plutonium separated from LWR fuels in commercial oxide reprocessing plants is separated by solvent extraction in pulse columns or centrifugal contactors in cells, further purified by additional polishing trains in gloveboxes, and finished to solids using remotely equipment in gloveboxes with contact maintenance. It is sampled, metered (~4–8 kg Pu) to stainless steel canisters, and the canister seals are remotely welded and contaminated ends cut off (by laser for Sellafield). Again, gloveboxes are used with contact maintenance. The higher burnups of LWR fuel give higher decay heats and penetrating doses from Pu products with isotopic spectrum of increased higher radionuclide atomic masses. These necessitate an all metal storage canister and an automated loading system for the Pu store. Criticality safety and package cooling require engineered features.

Mixed U and Pu product (MOX blend) (i.e., Category III) as used by Rokkasho, can be stored under similar conditions to Pu oxide storage. Costs per kg(Pu) may be greater due to the U diluent essentially increasing the number of canisters and storage positions needed. A conservative approach to design would be to retain the same size canisters for U-Pu oxide product as for PuO_2 product as a form of geometric limitation (take no safety credit for U dilution). The CFTC studies adopted an approach of limiting the Pu content to the same quantity (4.4 kg Pu) as allowed by the DOE 3013 package standard (Jones 2007) but allowing an increased canister length to accommodate the additional U diluent. This "elongated" 3013 canister was accommodated in an APSF style vault with very little increase in building height/size.

Cases 4–6, especially Case 5, are the particular focus of this module and cost estimates. The needs for buffer, medium or long storage of the latter three products, by-products and/or wastes, Cases 4–6, are not yet established and will depend on the requirements, processes, and properties of the projected advanced fuel cycles. These cases are being studied under the DOE, Office of Nuclear Energy, Fuel Cycle Research and Development (R&D) (FCRD) program for potential future industrial deployment and have much higher penetrating dose rates and decay heats than Pu. The whole of the UREX+ flowsheet operation is likely to be deployed within fully remote-maintained hot-cells. Finishing of the actinide product, sampling, metering, canister welding, checking, and swabbing will be performed remotely with full remote maintenance of equipment. The actinide products (e.g., separated streams or blends of U, Pu, Np, Am, and Cm oxides) generally have higher decay heat, penetrating radiation, and still with high-fissile content. A proposed U content is 67 wt% and the higher actinide content 33% by weight. Again there will be an increased number of canisters for storage relative to pure PuO_2 product. This may stem from dilution with UO_3 and either criticality safety or heat rating limitation. There is little cost data for storage of products and wastes for Case 4 and so no strong reasons to consider these separately from Case 5.

For Cases 4 and 5, the CFTC studies adopted an approach of limiting the TRU content to the same quantity (4.4 kg) of Pu allowed by the DOE 3013 standard (Jones 2007). This "elongated" 3013 canister was accommodated in an APSF style vault with very little increase in building height/size. The increased heat and radiation dose was determined to be acceptable for an air cooled vault when the TRU content did not exceed 35% (Jones 2007).

For Case 6, the specific heat (watts/gram) of the Am/Cm oxide is much greater than the U/TRU product due to the loss of the diluent such that the CFTC studies adopted an approach of using a high-heat source type package as allowed by DOE standard 5320. The EP-60 product container associated with this standard is much smaller (1.7-inch ID × 14.4-inch length) and the capacity is limited to 0.25 kg Am/Cm. The CFTC studies envisioned a separate vault for the cases in which high decay heat materials were stored.

Although actual cost data is not readily available for large-scale mixed transuranic storage, the design development, operational, and cost data from existing plutonium storage is considered adequate for extrapolation to the higher decay heat, criticality hazards, and radiation levels posed by the higher actinide mixtures of Cases 4–6.

E3-2. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTIONS

E3-2.1 General Transuranic Storage Requirements

Storage facilities containing fissile transuranic material shall provide safe, secure storage while satisfying national safeguards, and if commercial in use, may need to satisfy international (International

Atomic Energy Agency [IAEA]) safeguards. The facilities are fabricated with massive secure structures, which maintain geometric integrity to avoid criticality accidents and minimize damage to canisters from external hazards such as aircraft impact, seismic events, extreme weather, and terrorist actions while containing radionuclides and supplying gamma and neutron shielding. They have multiple systems of containment, material control and accountancy (MC&A), and surveillance to provide an effective safeguards system.

In principle, there are three main storage options for actinides: storage in vented canisters, sealed canisters, or in an immobilization medium such as glass or ceramic. Air-cooled and water-cooled concepts have been proposed. For plutonium, either as metal or as oxide, the approach usually adopted is to stabilize the material, package within multiple nested canisters, and store within an air-cooled store. This may be a secure vault separated into bays by concrete walls where unshielded canisters are hung on walls in a horizontal array and an automated guided vehicle moves canisters to or from storage locations. Alternatively, it may be modules of air-cooled arrays of horizontal (or vertical) sleeves with shield plugs extending through the concrete wall (or floor) of the vault bay. A remotely operated stacker retriever moves canisters to or from storage locations. Facility design should support documented surveillance of all packages for integrity, safety, safeguards, and storage conditions. There may be a trade off between ease of inspection, potential for widespread contamination of canisters, and store. Natural convection may be possible for some vault geometries and has the advantage of passive cooling, but safety analysis may require the use of active ventilation systems with high air flow, treatment by filtration, etc. High reliability of ventilation systems is required and the ability of the canisters and store to survive ventilation failure is often part of the licensing process. Typically, a long-term store (design life of 50–100 years) is likely to accept ~10,000 storage canisters (approx. 40 t of fissile material) or more.

Technical issues concerning safe storage include: criticality safety of each canister and all arrays of canisters, limitation of heat generation (depends on isotopic composition, and mass, and may be limited to 19–30 with a canister depending on store design), drop testing of nested canisters, restriction of moisture and other volatiles content, loss on ignition testing (etc.), specific area limitation on metals (avoidance of thin section metals with pyrophoric hazard), removal of thick oxide coating from metals, pressure rise tolerance of canister, immobilization process (plutonium oxide stabilization in oxidizing atmosphere [e.g., 950°C for ≥2 hours] where significant non-actinide materials are present), use of inert filler gas and avoidance of water adsorption after stabilization, free volume of canister to minimize pressure rise, and potential explosive hazard on re-opening canisters with hydrogen enriched atmospheres (Rothman and Liu 1998).

Significant industrial factors include: operational efficiency, maintenance and repair, environmental impact, radiation and criticality safety, safeguards and security, heat removal, waste minimization, national and international inspection, and construction and operational costs.

Plant activities include: receipt and shipping, material handling, monitoring, system engineering (e.g., potentially radioactive ventilation), and physical security. Remote and/or automated handling of canisters is needed to minimize radiation dose to operators and provide geometric controls for criticality safety.

Heat generation (self-heating) from radioactive decay during storage and handling is a serious issue for design and operation. The decay energies for various grades (isotopic compositions) of plutonium and other transuranic isotopes differ markedly. The principal ones relevant to storage of uranium and plutonium products and storage of pure or mixed transuranic by-products are shown in Table E3-1. Reprocessing of thermal oxide fuel (e.g., LWR type) is assumed to take place after 5–10 years or more of cooling so that short-lived isotopes are assumed to have decayed. These values are approximate since in some cases they incorporate increases due to decay of short-lived daughters and are time dependent (DOE 2004).

Table E3-1. Specific heat generation rates for actinide products and by-products of reprocessing.

Nuclide or Mixture	Grade	Half Life/ Composition	Heat Generation Rate, W/kg
U-235	-	710×10^6 yr	60×10^{-6}
U-238	-	4.51×10^9 yr	8×10^{-6}
Pu	Weapon Grade	0.05%, 93.5%, 6.0%, 0.40%, 0.05% wt. for Pu isotopes 238 to 242.	2.8
Pu	Fuel Grade	0.1%, 86.1%, 12.0%, 1.6%, 0.2% wt. for Pu isotopes 238 to 242.	4.5
Pu	Power Grade (≥19% Pu-240)	1.0%, 63.0%, 22.0%, 12.0%, 3.0% wt. for Pu isotopes 238 to 242.	19
Pu-238	-	86 yr	570
Pu-239	-	24.4×10^3 yr	1.9
Pu-240	-	6.58×10^3 yr	7.1
Pu-241	-	13.2 yr	13
Am-241	-	458 yr	110
Cm-242	-	163 days	120×10^3
Cm-244	-	17.6 yr	2.8×10^3

For fuels, a high content of Pu-239, the high specific thermal output of Pu-238, together with in-growth of Am-241 from Pu-241 dominates overall self-heating. The thermal outputs of civil plutonium derived from 30 and 60 Gw.d/MT(U) burnup fuels are approximately 10 and 30 W/kg, respectively. The Pu-238 content increases with increasing fuel irradiation and exceeds 2% wt for burnup levels of 40 GW.d/MT(U) in LWRs. Canister wall temperatures may exceed 100°C and possibly reach twice this value at the center of the nuclear material. To provide defense-in-depth and aid handling, multiple nested metallic canisters, normally 300 series stainless steel, are used that must retain high conductivity for heat rejection, often by close fit. Canisters are frequently rated for an internal pressure rise of around 20 bar. Criticality safety limits and allowances are examined to store design and process operation (including mal-operation) to accommodate flooding, composition ranges, heterogeneity, batch doubling, analysis accuracy, etc. In some cases, a critical dimension method is used. The need for free volume in storage canisters is in competition with the use of the canister to provide geometric control.

For decay storage of curium, Case 6, the heat generation is dominated by Cm-244 and Cm-242 (depending on cooling period), which gives an overall decay power of about 2 kW/kg and is about two orders of magnitude higher on a mass basis than that for LWR plutonium. The quantity of plutonium from reprocessing of LWR uranium fuel is about two orders of magnitude greater than that of curium. Also, selected isotopes of the higher actinides have lower criticality safety mass limits than Pu-239. Commonly, engineered glasses are used for the storage and transport of separated curium and americium. Engineered glasses are designed to minimize the rate of dissolution in groundwater, provide dilution and reduced storage temperatures, and enable actinide recovery by glass dissolution in, for example, strong acid. (The CFTC studies assumed an Am/Cm oxide product). In broad terms, the number of packages to store curium from a given amount of LWR fuel may be quite similar to the number to package plutonium from the same fuel. This would make curium storage some 100 times more expensive per kg of actinide than plutonium storage. An alternative waste form and store design may be cost effective for long-term storage of curium.

E3-2.2 Examples of Plutonium and Higher Actinide Storage Facilities

These facilities are not chemical or manufacturing process plants. Defense stores may accommodate stabilized high Pu-bearing materials whereas Pu product oxide from commercial reprocessing has exceptional chemical purity. In the commercial nuclear fuel cycle, material stabilization and packaging in canisters is often performed in the reprocessing plant, which reduces the complexity of the store. Although improbable, any breached canisters are likely to be over-packed and returned to the reprocessing plant. In the defense sector, plants for storage of excess plutonium and components may include process stages for inspection, material analysis, monitoring, material stabilization and/or testing prior to canister filling, and closure. Material from any breached canisters is likely to be repackaged within the storage facility. The main technology considerations to note for storage aspects are the security, remote handling, maintenance, inspection, and material control and accountability aspects. Commercial stores are likely to provide international safeguards arrangements. Descriptions of the Mayak Storage Facility, Actinide Packaging and Storage Facility, CFTC storage facilities, Idaho Central Processing Plant-651, Consolidated Storage Facility, and Sellafield Product & Residues Store are now given.

E3-2.2.1 Mayak Storage Facility at Ozersk, Russian Federation

The Mayak facility, completed around 2003, is a central storage facility to provide safe and secure storage of nuclear materials from disassembled Russian nuclear weapons and is operating at Mayak (Chelyabinsk-65). Originally, the storage site was planned as a two-wing facility, which was expected to provide secure, centralized storage for fissile material from approximately 12,500 dismantled nuclear warheads with a service life of 100 years. Using two wings, it was designed to store 50,000 canisters capable of holding 50 metric tons (MT) of plutonium (Pu) and 200 MT of highly enriched uranium. After the 1999 GAO evaluation of the project, the United States decided to bear most of the costs, which had increased from $275M to $413M. Design, construction, and specialized equipment for the storage facility were funded, mainly, by the U.S.A., and the design and construction contract was won by Bechtel, a U.S. company. Up until 2004 at least, the construction of the facility was limited to a single wing to store 25,000 canisters. The facility is surrounded by a concrete wall and rows of barbed wire and has three guardhouses. The walls of the facility itself are said to be 8 m thick, and the roof is covered with 4 m of concrete, tar, and gravel. The facility was designed to withstand an earthquake measuring 8 on the Richter scale, and to survive a flood or the impact of a jet plane crash. It is not designed to withstand the effects of a nuclear bomb. The facility area, degree of remote operation, etc., is not available, but the store was described in 2003 as having state-of-the-art security and dose protection (NTI 2009).

E3-2.2.2 Actinide Packaging and Storage Facility (APSF) – Design Study

Department of Energy (DOE) proposed and designed a semi-automated state-of-the-art facility, called the Actinide Packaging and Storage Facility (APSF) to safely store and monitor all excess plutonium for an indefinite (long) period at the Savannah River Site (ReFalo and Wong 1998). Also proposed was a plutonium stabilization facility to provide a near-term disposition pathway for excess plutonium not designated for mixed-oxide (MOX) fuel. Plutonium oxide and metal were the primary materials stabilized and stored in the APSF. Plutonium to be stored in the facility was intended to be placed under international safeguards under the Voluntary Offer Agreement (VOA) with IAEA.

This project, which was suspended in 1999 (Richardson 1999) prior to start of construction, consisted of a hardened, underground material access area totaling 49,300 ft^2 and a 20,000-ft^2 surface concrete utility building. It was sized for 2,000 storage positions with a potential to hold 5,000. Each position would hold a “3013” canister with a loading of 4.5 to 4.8 kg plutonium (or HM). The 3013 designation referred to the DOE Standard (DOE-STD-3013-96), “Criteria for Preparing and Packing of Plutonium Metals and Oxides for Long Term Storage,” which required the packaging of stabilized plutonium in two welded canisters (an inner and an outer canister) for safe storage up to 50 years. DOE-STD-3013-96 is now superseded by DOE-STD-3013-2004, April 2004.

This report assumes the 2,000-canister capacity, which equates to approximately 9.5 MTHM. Although a portion of the facility is used for plutonium oxide calcining and packaging, it is classified as a storage facility.

E3-2.2.3 Consolidated Storage Facility – SRS Design Study

After cancellation of the APSF, DOE conducted a systems engineering evaluation of plutonium material management to determine the benefits of integrating plutonium storage/disposition facilities. The SRS team evaluated the design and construction of a consolidated storage facility (CSF) for DOE surplus non-pit plutonium. This APSF-style, enlarged facility with surveillance capability was the subject of an unpublished study by SRS in 2001 (Boore 2004). The storage capacity was 10,000 storage positions with declared capacity of 45 MT(Pu). Each storage spot was to hold a “3013” canister (DOE 2004) with a similar quantity of HM/canister as APSF (4.5–4.8 kg). Due to variations between the canister capacities of defense and commercial stores, CSF may be taken as a nominal 50 MT(Pu) capacity store for commercial product purposes.

E3-2.2.4 Consolidated Fuel Treatment Center (CFTC) U/TRU Storage Concepts– Design Study

The CFTC U/TRU storage concepts built upon the state of the art APSF and consolidated storage facility designs. The basic design has a below-ground concrete storage vault, which includes storage racks and shield plugs, air inlet, and exhaust shafts, and an above-grade operating area and building support systems, including structures and services required for the building and equipment operations. The vault portion of the building is an underground (~11 ft) reinforced concrete construction structure. The roof slab is nominally 5 feet thick and the walls and floor 3 feet thick. The vault capacities varied with the specific CFTC alternative.

The 3,000 MT/yr Engineering Alternative Study (EAS) for a UREX +1 application had a requirement for 10 years of U/TRU product storage. The design proposed 3 storage vaults with each vault providing storage for nearly 38,000 “elongated” 3013 cans or nearly 170 MT TRU.

The 800 MT/yr Follow-on Engineering Alternative Study (FOEAS) for a UREX + 1 application reduced the storage requirement to 3 years capacity and proposed a 10,000 canister vault similar to the Consolidated Storage Facility.

The 800 MT/yr FOEAS for a Co-Ex application in which only U/Pu is recovered proposed a 3 year capacity with a 10,000 canister vault. The overall dimensions were slightly smaller to reflect the smaller storage container.

The 800 MT/yr FOEAS for a UREX+3 application requires the storage of both a U/Pu/Np oxide and an Am/Cm oxide. The same U/Pu storage described above is required as is an additional storage vault with enhanced decay heat removal systems for the Am/Cm oxide storage.

E3-2.2.5 Unirradiated Fuel Storage Facility at INL[b] (CPP-651) – Concept for Upgrading Existing Facility

The CPP-651 was constructed in 1984 and is used to store un-irradiated fuel. It is an entirely hands-on operation with heightened security capabilities. The hardened area for this facility is 4,960 ft^2. DOE considered the store in 2000 for upgrading to a capability for storage of cans containing 6 kg of Np-237 as NpO_2 for possible future conversion by irradiation of Np to Pu-238. In the event, CPP-651 was not selected for this purpose.

E3-2.2.6 Sellafield Product & Residues Store (P&RS) – U.K.

This robust store for plutonium oxide product and plutonium wastes is nearing completion of construction in 2009. It is a stand-alone facility that will provide storage for cans of products and residues from Magnox and Thermal Oxide Reprocessing Plant (THORP) reprocessing plants, and the Sellafield MOX plant as well as replacement for older Pu stores at Sellafield, U.K. P&RS possesses no facilities for immobilization or other treatment of plutonium material as this is performed in other facilities on the Sellafield site. Historically, Magnox-derived plutonium oxide was stored in aluminum cans each holding about 5.5 kg Pu. THORP-derived plutonium oxide is stored in stainless steel, nested triple canisters, each holding 7.5 kg Pu. The cost of P&RS is quoted as £220M for construction only (Cabinet Office 2009). The Pu inventory on the Sellafield Site is around 100 MT(Pu) and may increase to 130 MT(Pu) as reprocessing continues and depending on the rate of shipment to utility customers.

The new store has a design capacity of 9,600 plutonium canisters and comprises 128 storage modules [each containing 75 canisters ≡ 560 kg(Pu)]. The design lifetime for storage is 50 years extendable to 100 years. The nominal maximum capacity of the store is estimated as about 72 MT(Pu). So far, no cost data has been obtainable for this facility although it should continue to be sought as this store probably represents the newest generation facility constructed in a western nation following a decade of increased international security concerns. Besides the new plutonium store, Sellafield has spent an additional $100M in the period of 2003–2009 on enhanced physical security, contingency planning, and consolidation of nuclear material for transfer to the Sellafield P&RS (Hansard 2009; Cabinet Office 2009).

E3-3. PICTURES/SCHEMATICS

Figure E3-1 shows a schematic of the design concept of modules of air-cooled arrays of horizontal storage sleeves with shield plugs extending through the concrete wall of the vault bay. A remotely operated stacker retriever moves canisters to or from storage locations (Forsberg 1995).

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[b] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

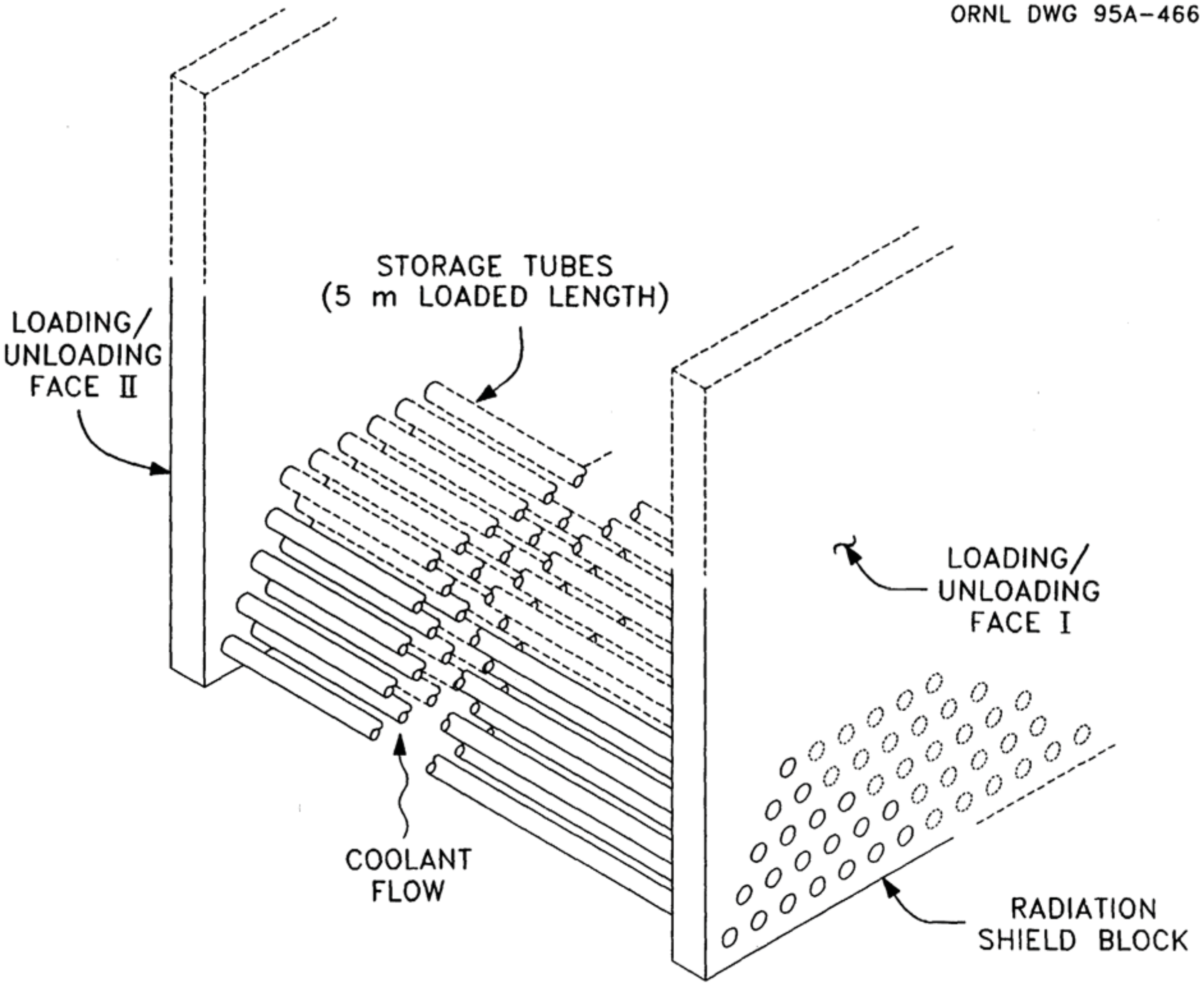

Figure E3-1. Storage module concept using horizontal sleeve geometry within plutonium storage vault.

A buffer plutonium oxide store, see Figure E3-2, is attached to the THORP reprocessing plant at Sellafield in the U.K. It was first operated in 1994. The Pu canister loading/unloading system uses a trolley propelled by chain along a rail with lifting action for package deposition or retrieval. A second trolley provides equipment for in situ inspections of packages. The degree of automation appears quite basic, but is part of the criticality safety case. A cable is used, as necessary, for retrieval of a failed trolley.

Figure E3-2. Remotely operated store for pure PuO_2 in welded stainless steel canisters in the THORP facility at Sellafield, U.K.

Information on the British Nuclear Fuels plc (BNFL) canister design is given in Table E3-2 (DOE 2004). This canister type is used by the U.S. DOE. A welded closure is preferred because it is believed to provide the best combination of features such as design qualification test performance, ease of assembly under production conditions in a glove box, canister (package) payload capacity, and achievement of a 50-year lifetime. The material canister (convenience canister) is the inner canister that is used to transfer plutonium-bearing material. A material canister is not required in packaging and is not considered an isolation barrier by the DOE Standard (DOE-STD-3013-96). Use of a material canister can reduce the potential for contamination during loading and closure of the "middle" canister, facilitate packaging, and provide an additional material barrier. The specified design pressure of 4,927 kPa (699 psig) for the welded outer canister is sufficient to contain the pressure generated by the mass of oxide specified in Section 6.3.2 under DOE "worst case" conditions of 0.5 wt% moisture, 19 w heat generation, and 211°C (412°F) gas temperature (DOE 2004). Use of low-carbon stainless steels, such as 304 L and 316 L, is recommended with 316 L being preferable to 304 L because of its greater corrosion resistance.

Table E3-2. BNFL canister volumes.

Component	Interior Volume in liters	Mass in grams	Material Volume in liters	Free Volume in liters
Convenience Can	1.839	1580	$v_{cc} = 0.198$	$V_c = 1.839$
Inner Can	2.266	1600	$v_i = 0.200$	2.068
Outer Can	$V_o = 2.602$	4026		2.204

Pictures of nested BNFL MOX canisters are shown in Figure E3-3.

Figure E3-3. Nested Stainless Steel BNFL Canisters with Welded Closure for Storage of Pure PuO_2 at Sellafield, U.K. (similar used for DOE at SRS).

For the APSF, the handling of the Pu loaded 316 SST canister with laser-etched bar code in the material accountancy stage was designed to be fully remote. The design for the top of the canister, see Figure E3-4, gave challenges for item handling over a large area and insertion and removal from the measurement instrumentation. The latter did not allow canister gripping from the side and had to be gripped from the top with all tooling, etc., sufficiently small for insertion into the instrumentation channel. Two and three-finger grippers were designed, fabricated, and tested. The design goal of the gripper tooling was to maximize positioning tolerance while maintaining handling capability for the 25–30 lb (11.4–13.6 kg) canister (ReFalo and Wong 1998).

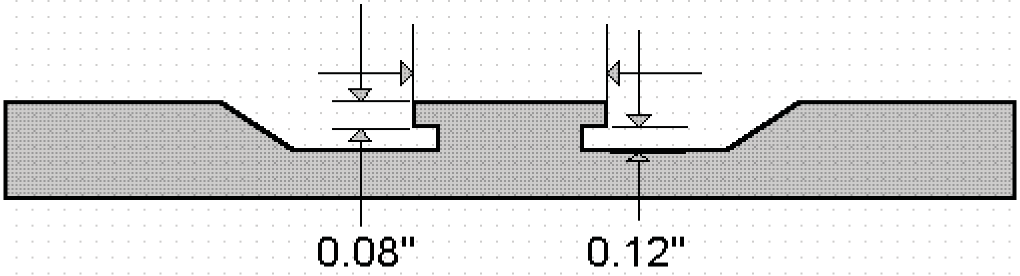

Figure E3-4. Canister top for remote handling of "1330 Canister."

In design and development for the APSF, emphasis was placed on shared use material accountancy as material is loaded. In addition to DOE-STD-3013-96 storage requirements, the facility design met the most recent radiation exposure limits of 500 mrem (5 mSv)/year/employee. A balanced approach in terms of automation, exposure control, processing rates, storage requirements, accountability requirements, general nuclear facility design requirements, manual operation, and cost control was adopted. New concepts are in development, including non-destructive assay (NDA) equipment/software development, automated handling of the canisters, development for new IAEA equipment/software, and testing of the IAEA conceptual safeguard's approach. These features needed mock-up and testing to provide key details for facility design, see Figure E3.5.

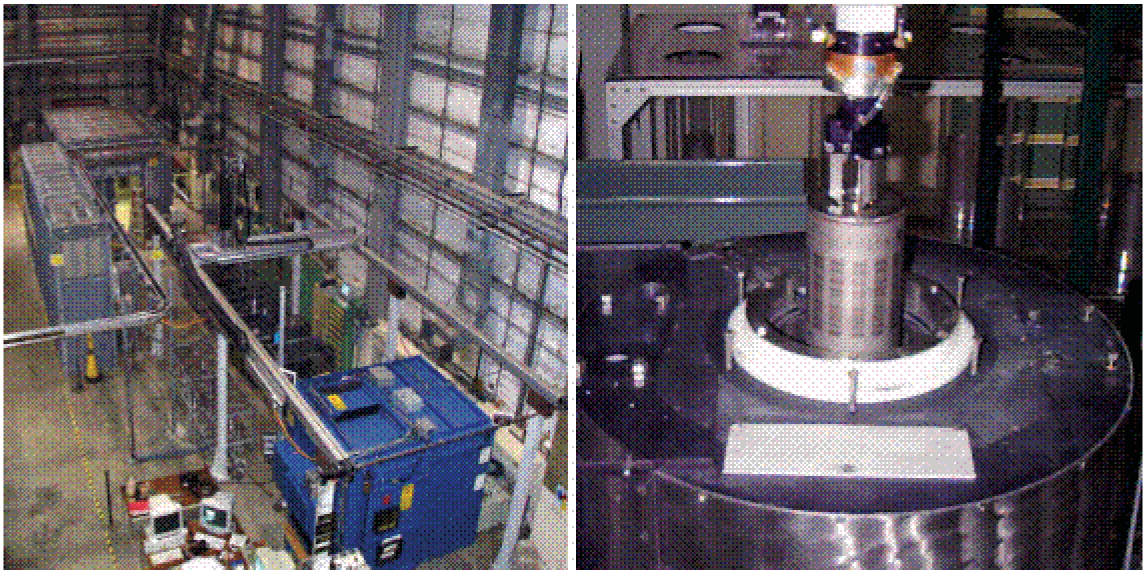

Figure 1. APSF Mockup **Figure 2. Crane Loading ITSC into Neutron Counter**

Figure E3-5. Mockups at SRS for Actinide Packaging and Storage Facility (ReFalo and Wong 1998).

Plutonium metal and oxide have been stored at SRS for several years. In order to be compliant with the DOE 3013 standard, the FB-Line Facility at SRS is packaging plutonium metal and stabilized plutonium oxide into outer canisters using the outer can welder (OCW) system. After welding the weld parameters are reviewed. Next, the outer canisters undergo a helium leak test, see Figure 3-6.

Figure E3-6. Test of leak detector installed in FB-Line Facility at SRS (Hudlow 2004).

Then, the outer canisters undergo a visual examination by an ASME qualified visual examiner. Last, the outer canisters undergo screening by the digital radiography (DR) system for weld porosity (see Figure E3-7) (Hudlow 2004).

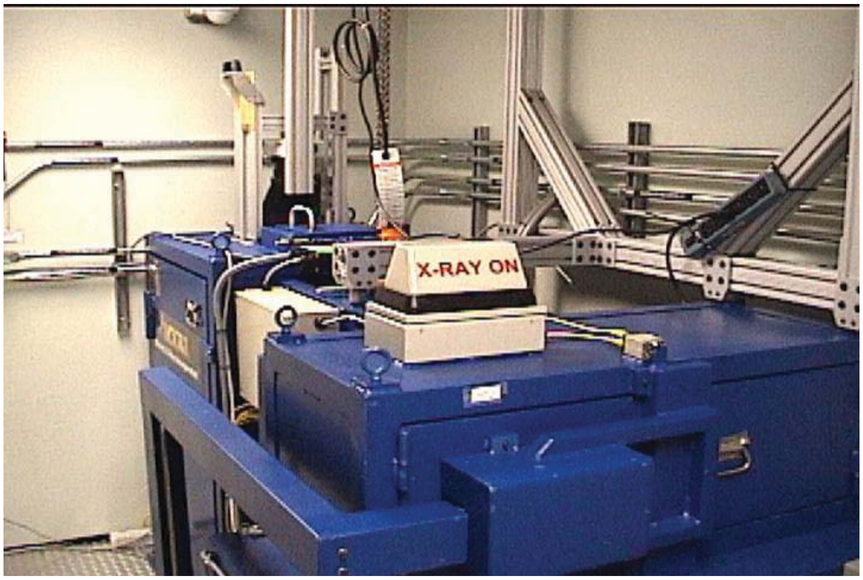

Figure E3-7. Test of digital radiography system installed in FB-Line Facility at SRS (Hudlow, 2004).

E3-4. Module Interface Description

The actinides that would be stored in these facilities would be received from "Aqueous Reprocessing," Module F1, or "Electrochemical Reprocessing," Module F2/D2. One path out of this module is Module O1, "Shipment of Materials to a Mixed Oxide Fuel Fabrication Facility," (if fuel fabrication is not integrated at the reprocessing facility). Depending on the fuel cycle eventually adopted, further path options include waste management, such as Modules G, I, F2/D2, L, M, and O Series.

E3-5. MODULE SCALING FACTORS

To report the costs in near present day (2005) dollars, the Engineering News Record Construction Cost Index and Building Cost Index were used to escalate the Work Breakdown Structure Level 2 costs to 2005. Work Breakdown Structure 1 and 3–7, where available, were escalated to 2005 using the U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index—All Urban Consumers. Escalation to 2007 for all Work Breakdown Structure levels was also based on this index. Further escalation was performed using the U.S. Army Corps of Engineers, 2007, Civil Works Construction Cost Index System (CWCCIS), using CWBS Feature Code – 07 Power Plant (Corps of Engineers 2009). Table E3-3 summarizes information for five selected facilities; also see the cost data from Section E3-6.

Table E3-3. Recycled product storage summary.

Store	Mayak, R.F.	APSF	CPP-651	CSF	P&RS, UK
Status	Operated 2004	Design, 1995	Not used	Design, 2001	Construction
Hardened Area	Unknown	49,300 ft^2	4,960 ft^2	Unknown	Unknown
No. of Canisters	25,000	2,000	-	10,000	9,600
Storage Capacity	100 MT(Pu)	9 MT(Pu)	1 MT(Pu)[a]	45 MT(Pu)	72 MT(Pu)
Total of WBS Levels 1–6 in 2005 $K	$570,600	$319,300	$9,320	$634,000	~$400,000 (capital)
Capital Cost/Unit of Material	$5,700/kg	$35,500/kg	$9,320/kg	$14,100/kg	$5,500/kg[b] ($9,200/kg)
Store	CFTC EAS UREX+1	CFTC FOEAS UREX+1	CFTC FOEAS U/Pu	CFTC FOEAS UREX+3	
Status	Design Study	Design Study	Design Study	Design Study	
Hardened Area	475,000	28,000	24,000	52,000	
No. of Canisters	114,000	10,000	10,000	20,000	
Storage Capacity	500 MT TRU	44 MT TRU	44 MT Pu	44 MT TRU	
Total of WBS Levels 1–6 in 2007 $[c]	$6.5B–9.0B	$0.7B–1.0B	$0.65B–0.9B	$1.5B–2.1B[d]	
Capital Cost/Unit of Material	$13,000–$18,100/kgTRU	$17,800–$24,700/kg TRU	$16,100–$21,700/kg TRU	$37,000–$51,400/kg TRU	

a. Capacity estimated from the APSF on the basis of hardened area.

b. This figure is based on 7.5 kg/canister, which becomes $9,200/kg based on 4.5 kg/canister as used by APSF and CSF. P&RS does not include plutonium immobilization as do APSF and CSF. P&RS has eight-fold greater capacity than APSF and 60% greater capacity than CSF.

c. Figure includes a distributed share of the infrastructure and balance of plant cost associated with the reference reports WSRC 2007 and WSRC 2008.

d. Includes the cost of two vaults one for the U/Pu oxide and a second for the Am/Cm oxide.

E3-6. COST BASIS, ASSUMPTIONS, AND DATA SOURCES

E3-6.1 Basis and Assumptions

The facilities, other than the CFTC design studies, referenced here are "stand-alone" operations, not dependent on other facilities for shared services, except utilities including transport. It is not known how these estimated costs were developed; "top-down" or "bottoms-up," except the capital costs for Mayak and CPP-651, are reported as the actual costs. The latter is likely to have needed substantial upgrading expenditure for remote handling, improved cooling, modern dose standards, enhanced material controls, and accountancy for the proposed new storage mission. Furthermore, the designs of the facilities are different and include other functions, especially some with remote material stabilization and canister welding and inspection.

The CFTC design study estimates are "bottoms-up" estimates. The facility is assumed to be collocated on the reprocessing site (within the security PIDAS) and a portion of the site infrastructure and balance of plant costs have been allocated to this facility segment. No functions other than storage are conducted in this building.

Since this module may receive for storage a mixed U-TRU product, the relative cost difference due to storage of a product high in U content versus a pure TRU product is needed. The relative cost factor evaluation shown in Table E3-4 is generally based on the commercial store receiving intact and sealed canisters, returning defective ones, and eventually exporting intact cans to downstream plants. For uranium, the heat emission is negligible and realistic changes hardly affect store cost. The relative cost per kilogram for storage of reprocessed LWR 1% ^{235}U uranium product, although low, is judged to be several times greater on a mass basis than for reprocessed 0.2% ^{235}U product (e.g., Gen I gas reactors). This is due to the greater number of drums, the increased shielding required, the greater number of storage positions, the need for outrigger spacers ("bird cage") for geometric safety, and the greater degree of remote handling. The unit costs of storage for pure uranium trioxide are judged to be orders of magnitude lower than for materials with high transuranic contents. For this module, the effects of uranium storage are mainly important when contributing to mass/canister increases to mixed actinide storage.

The OECD-NEA estimated unit charges for commercial plutonium storage, which have the following broad technical context (OECD-NEA 1994). A representative commercial PUREX plant with LWR oxide spent nuclear fuel (SNF) throughput of 800 MT(HM)/year has a plutonium arising rate of about 1% of initial heavy metal input to reactor, which equates to 8,000 kg(Pu)/year or 1,100–1,500 PuO_2 canisters/year [~5 canisters/working day with ~6 kg(Pu)/canister]. For a steady-state buffer store of ~8,000 canister [~50 MT(Pu) capacity servicing a typical PUREX oxide recycling plant, this then gives a mean residence time of 6 years, which would be greater than the expected buffer period for a well-developed closed nuclear fuel cycle near steady state, but not excessive for present conditions where thermal MOX fuel for use in LWRs remains the exception for utilities. [Note that the CSF (defense store) assumes 4.5 kg(Pu)/canister, whereas commercial fuel cycle stores with different Pu feed may use values of 5.5–7.5 kg(Pu)/canister]. For recycling plutonium oxide to current designs of thermal or fast reactors, without the presence of the minor (higher) actinides, a period of about 2-years storage (preferably ≤1 year) post reprocessing may be the upper limit prior to fuel fabrication using hands-on techniques in gloveboxes and the commencement of irradiation in reactor. This is because fuel/power grade plutonium materials have Pu-241 contents of 1.6%/12% that decay by β-decay to Am-241 with a half-life of 13.2 years and increase dose levels. OECD-NEA quotes the possible requirement for purification of long-stored plutonium due to americium in-growth. The need depends on the source of Pu, period of storage, and design of MOX fuel fabrication plant. The cost range is given as \$10–28/g(Pu) with a value of \$18/g(Pu) for a 2,000 kg(Pu)/year plant (OECD-NEA 1994).

For advanced fuel cycles with burning of minor actinides, the recycle fuel is likely to need to be fabricated remotely and remotely handled during reactor refueling. The period of storage of plutonium, and possibly uranium, mixed with minor actinides (MA) is less significant although clearly, due to cost, all storage for recycle should be minimized unless it contributes to optimization of waste management. The nominal value assumed here for storage of Pu-MA-U is 4 years.

It is seen that commercial Pu or Pu-MA-U stores in a developed fuel cycle may have continuous loading and unloading of fissile material, which implies a higher level of operations than for defense stores, which may load for a period (e.g., 5 years) and maintain storage for a long period (e.g., 40 years and then unload), for example, over the next 5 years.

The relative storage unit capital cost (cost per kg) for high fissile material such as pure plutonium and high plutonium blends with transuranic (TRU) minor actinide and uranium elements are judged in Table E3-4 as based on the two multiplying factors relative to the base case of storage of pure PuO_2 in canisters as was widely used for the plutonium product of commercial PUREX reprocessing of electric utility fuels. The extrapolating factors are based first on the likely increased numbers of canisters and storage positions, and second on the increased radioactivity, dose, ventilation, handling, and criticality safety requirements.

Table E3-4. Judged storage cost increase factors relative to depleted UO_3 and PuO_2.

Stored Material	Relative Factor-Drums/Canisters Needed	Relative Factor—Heat, Activity, Dose, Handling	Store Cost Factor— c. f. kg(U) or kg(Pu)	Nominal Period of Storage,Years
UO_3 drums (0.2% 235U)	1 (800 kg Magnox GCR)	1	1	-
UO_3 drums (1% 235U)	3 (180 kg THORP LWR)	2	5	-
PuO_2 canisters	1 (4.4 kg)c	1	1	2
UO_3-PuO_2 (50%)	1.2d	1	1.2	2
$TRUO_2$ (33%)-UO_3	1.5d	1.3	2e	4
CmO_2 (100%)	10f	2	20g	~100

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c. DOE-STD-3013-2004, p. 9, "The total mass of plutonium and other fissile species within either metal or oxide contents shall not exceed 4.40 kg (9.70 lb.). The total mass of the package contents, whether metal or oxide, shall not exceed 5.00 kg (11.02 lb.)." Commercial reprocessors may use higher values (5.5–7.5 kg of plutonium depending on fuel burnup, etc.).

d. EAS studies assumed the 4.4 kg TRU per container will apply and the total mass could be increased so this factor is 1.0

e. EAS studies used a factor of about 1.2 based on the ratio of the hardened facility area from Table E3-3

f. EAS studies used a factor of 4.4/0.25 or 17 for Am/Cm oxide

g. EAS studies used a factor of about 1.2 based on the cost per unit area

E3-6.2 Storage Facility Costs

E3-6.2.1 Mayak Fissile Material Storage Facility

The facility was reported to have cost $458M U.S. ($413M provided by the U.S. Department of Defense [DOD] and $45M provided by Russia), with a cost of $223M (≡ 12% of capital/year) to load the facility with the actinide product. This covered the construction of the first wing only. Loading the facility began in July 2006 and is anticipated to take 4 years to complete. Annual operating costs thereafter were estimated by a U.S. contractor to be $13M. The operating cost during storage is judged to be low and perhaps represents staff costs, which are much lower than U.S. costs. These costs are in 1999 dollars. As of May 1999, the Fissile Material Storage Facility Budget through 2001 stood at $397.6M. That amount is broken down in Table E3-5 (NTI 2009):

Table E3-5. Mayak store cost breakdown ($M).

Design	$9.1
Construction	$175.0
Equipment Purchases & Installation	$171.5
Transportation	$6.5
Cooperative Threat Reduction Logistics Support	$2.1
Project Support	$33.3

An additional $15M was spent on the early design of the facility.

Taking the unloading cost to be the same as loading and taking 42 years of operation at $13M/year (~3% of capital per year), and adding 20% for decommissioning and contingencies, the lifecycle cost (LCC) is found to be ~$1.45B, which is approximately 3.2 times the total project cost (TPC), which broadly equates to capital cost. The total cost for work breakdown structure (WBS) Levels 1–6 is given in Table E3-3 as $570.6M in 2005 dollars.

Actinide Packaging and Storage Facility (APSF)

The reported capital cost is $330M in 2000 dollars.

Unirradiated Fuel Storage Facility (CPP-651)

Its reported capital cost in 1984 was $5.16M. Significant costs for upgrading are judged likely to achieve modern standards for plutonium and greater for Pu-MA-U storage.

Consolidated Storage Facility (CSF)

The SRS CSF design study derived a rough order of magnitude (ROM) cost estimate in 2005 U.S. dollars of $600M in capital and $75M/yr for operating expense (≡12.5% of capital/year) throughout the period of operation.

CFTC U/TRU Storage Facilities

The SRS EAS derived four estimate ranges for various product storage vaults and capacities including:

- $6.5B–9.0B for a U/TRU oxide product vault with a capacity 500 MT of TRU
- $0.7B–1.0B for a U/TRU oxide product vault with a capacity of 44 MT of TRU
- $0.65B–0.86B for a U/Pu oxide product vault with a capacity of 44 MT of Pu or Pu/Np
- $0.68B–0.90B for an Am/Cm oxide product vault with a capacity of 2.4MT of TRU.

In addition the EAS determined the steady-state operations cost (continuous loading and unloading) operations as:

- \$26M–39M/yr for a U/TRU oxide product vault with a capacity 500 MT of TRU
- \$7M–10M/yr for a U/TRU oxide product vault with a capacity of 44 MT of TRU
- \$7M–10M/yr for a U/Pu oxide product vault with a capacity of 44 MT of Pu or Pu/Np
- \$7M–11M/yr for an Am/Cm oxide product vault with a capacity of 2.4MT of TRU.

Sellafield Product & Residues Store (P&RS)

The cost of Sellafield P&RS has been quoted as £220M (pounds sterling) (Cabinet Office 2009). This is for construction only and does not include operation, decommissioning, or interest during construction. The money value year was not given, but much of the construction has been completed and was performed during the past 5 years when the average pound sterling exchange rate was about 1.00£:US\$1.80. A broad capital cost value of \$400M (2007 dollars) is estimated. The P&RS specific capital cost is lower than APSF or CSF, due partly, it is judged, to the larger canister inventory used by P&RS, the greater economy of scale of P&RS (60% greater capacity than CSF), and the smaller scope with no plutonium immobilization plant. The anticipated operating costs of P&RS have not been disclosed. After adjustments, the P&RS capital cost is considered to be broadly consistent with that for CSF (see Table E3-3).

E3-6.3 Cost Correlations

Figure E3-8 shows the capital costs of four facilities in Table E3-3. A power trend line to these data was determined to be:

Capital cost (millions of 2007 dollars) = 16.123 (Pu Capacity in MT)$^{0.912}$

This is based on a very small data sample, but indicates that some benefits of scale may accrue to this type of facility. A somewhat smaller exponent showing greater economies of scale might be expected. The low cost of CPP-651, its age, and the lack of adjustment of the capital cost to represent a totally remote-operated facility is considered to unrealistically skew the correlation downwards near the origin.

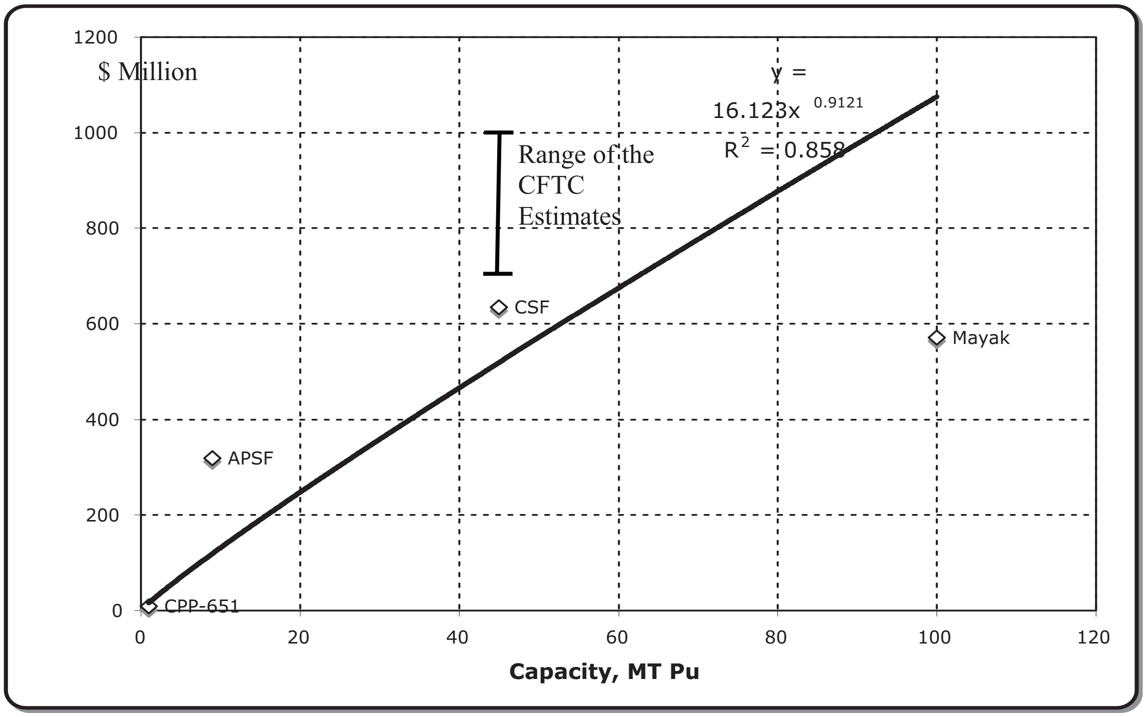

Figure E3-8. Costs of various sizes of plutonium storage facilities.

Using just the data for APSF and the CSF as relevant to the U.S. and DOE environment (both design studies performed by SRS), a linear equation can be derived:

Capital cost (millions of 2007 dollars) = 241 + 8.74 × (Pu Capacity in MT)

It is not unreasonable that the line intersects the cost axis at several hundred million dollars as the storage capacity tends toward zero, since the facility would still comprises a wide range of capabilities and operations including receipt, handling, MC&A, security, ventilation, health physics, maintenance, inspection, etc., systems while omitting storage modules.

From the reasonable consistency of these data, use of the CSF case and its cost data is selected for further analysis and comparison with the overall unit cost information provided by OECD-NEA.

Using data from the CFTC studies the cost was fitted using the logarithmic relationship:

$$CostofA = CostofB\left(\frac{CapacityofA}{CapacityofB}\right)^{n}$$

Where, capacity is expressed as instantaneous design capacity (MT/yr), and the exponential factor is typically in the range of about 0.6. However, due to the inherently high structural costs associated with highly shielded and remotely operated nuclear facilities not found in commercial operations, the power law exponent is expected to be less than 0.6. The preceding equation indicates that a log-log plot of the capacity versus cost should be a straight line with the slope equal to the exponent. Therefore, the CFTC U/TRU vault estimates for different capacities shown in Table E3-3 were used to determine the power law factor was equal to about 0.41 over the range of storage capacities from 44 to 500MT.

E3-6.4 Representative U.S. Plutonium Storage Unit Cost Estimate

Based on the above subsections of E3-6, cost estimates given here use CFTC CO-EX case as the representative U.S. Pu Store Design. The TPC, broadly capital cost, of the CFTC U/Pu oxide storage value was given as $650M to $875M with annual operating cost of $7M to $11M (1% of capital/year) with store capacity of 10,000 canisters [45 MT(Pu) defense], Costs were reported in 2007 dollars. The EAS Studies also reported a 40 year operational Operations and Maintenance (O&M) cost of $360M to $540M when combined with the D&D and TPC gives a total LCC of $1.1B to $1.5B or a levelized cost of $25,000 to $35,000 per kg of Pu for 40 years or $0.62 to $0.90/g(Pu)-year

This is about half the OECD-NEA unit values for commercial plutonium storage charges of $1.5–2.9/g(Pu)·yr in 2007 dollars. The difference may be due to the assumptions of the storage vault being collocated with the reprocessing center. It should be noted that the O&M costs were considerably higher (75M/yr) for the stand alone CSF. If this O&M value is used then the LCC becomes $3.7B to $4.0B or $84,000 to $91,000/kg Pu or $2.10 to $2.30 g(Pu)-year within the range of the OECD-NEA estimate.

E3-6.5 OECD-NEA Unit Charge Estimates for Plutonium Storage

The OECD-NEA report, “The Economics of the Nuclear Fuel Cycle,” Section 4.3.2.6, Plutonium Storage, p. 40, 1994, states that the costs for Pu storage varies widely between countries due to store size and other factors and are usually taken to be in the region of $1 to $2 per gram (1994 dollars) of total Pu per year.

Adjusted to 2007 dollars, the unit plutonium storage charge values are $1.5–$2.9/g(Pu)·yr. This forms an essentially linear capacity versus cost correlation. OECD-NEA also states, “Both BNFL (now NMP) and COGEMA (now AREVA) include the cost of short-term storage as a minor component of the overall recycling price, but some countries requiring longer-term storage are incurring additional prices of this order.” As a price, this includes the reprocessor’s profit element for the service provided.

It was anticipated that operational and maintenance costs for loading/unloading would be appreciably higher from those for long-term storage of essentially undisturbed material. Estimates of operational costs of 10–12% of capital per year during buffer storage with steady filling/emptying and significantly <10% of capital per year during long-term storage, where Pu inventories are retained in full stores pending potential future recycling, seemed reasonable. However, the SRS cost estimates and the OECD-NEA report do not justify this. The low operating cost value for steady long-term storage at Mayak may be due to low wages in the Russian Federation (R.F.) as compared to the higher capital cost of a U.S. designed and equipped plant.

E3-6.6 Converting OECD-NEA Unit Charge to Capital and Operational Costs

In this subsection, OECD-NEA unit plutonium storage charges are broken down into corresponding capital and operational elements. For example, taking the midrange OECD-NEA overall estimate (1994 dollars) of $1,500/kg(Pu).year cost as based on a 50 MT(Pu) store operated for 50 years and carrying out a broad consistency check.

Overall charge of $1,500 × 50,000 kg (Pu) × 50 year = $3.75B (1994 dollars) ≡ $5.4B (2007 dollars), where 50,000 kg (Pu) at 5 kg (Pu)/container = 10,000 containers.

The period of steady loading/unloading and buffer storage is taken as 50 years at 10% of capital/year ≡ 500% total. The capital cost is then \$5.4B × 10/60 = \$900M (2007 dollars). The unit capital cost is \$900M/50,000 kg (Pu) = \$18,000/kg (2007 dollars).

In undiscounted terms, this gives total operating and capital costs of 600% of capital only (i.e., Annual operating cost = \$5.4B/60 ≡ \$90M [2007 dollars]). This equates to ~450 overall staffing (day/back shifts, radiation workers, physical protection, management, etc.) as based on \$200K/staff, which includes all other elements of operation such as utilities, materials, contracts, projects, etc.

E3-6.7 Comparing OECD-NEA and SRS Cost Estimates

The cost comparisons for the two 50 MT(Pu) stores, each operating for 50 years, are shown in Table E3-6.

Table E3-6. Capital, operational, and lifecycle costs (2007 dollars).[a]

Pu Store Cost Basis	Capital Cost Unit Capital Cost	Operational Cost Unit Operational Cost	Lifecycle Cost Averaged Unit Cost[e]
OECD-NEA, 1994[c] Mid cost range; 50 MT	900 \$M \$18,000 \$/kg(Pu)	90 \$M/yr \$1,800 \$/kg(Pu)·yr	5.4 \$B 2,200 \$/kg(Pu)·yr
CSF Cost Basis[d] CSF scaled to 50 MT	750 \$M \$15,000 \$/kg(Pu)	94 \$M \$1,900 \$/kg(Pu)·yr	5.4 \$B 2,200 \$/kg(Pu)·yr
CFTC U/Pu Vault Cost Basis scaled to 50MT[f]	\$712M–960M \$14,300–\$19,200/kg Pu	\$9M–14M/yr \$180–\$280/kg (Pu)-Yr	\$1.25B–1.7B \$500–\$680/kg (Pu)-Yr

a. Cost escalation derived using: U.S. Army Corps of Engineers, CWCCIS, Using CWBS Feature Code – 07 Power plant, Appendix A, EM 1110-2-1304, Appendix Revised September 30, 2007. Values used: \$1 (1994 dollars) ≡ \$1.31 (2005 dollars) ≡ \$1.38 (2006) ≡ \$1.47 (2007) ≡ \$1.54 (2008) ≡ \$1.56 (2009).

b. Capital and operational expenditure (decommissioning not explicitly included).

c. OECD-NEA, "The Economics of the Nuclear Fuel Cycle," Section 4.3.2.6, Plutonium Storage, 1994, using mid-range overall cost value of \$1.5 (1994 dollars)/g(Pu).year.

d. Capital cost of U.S. SRS design for CSF of \$600M with annual operating cost of \$75M with store capacity of 45 MT(Pu). Costs in 2005 dollars (Boore 2004).

e. Undiscounted sum of costs divided by storage capacity times facility lifetime.

f. capital cost determined using the logarithmic equation using the 0.41 power factor

For a 50 MT(Pu) capacity store, the unit storage charge range given by OECD-NEA of \$1–2 g(Pu)/year (1994 dollars) ≡ \$1.5–2.9 g(Pu)/year (2007 dollars) implies a store capital and operating cost range of \$3.7B–7.4B (2007 dollars) with reasonable assumptions for operating costs over 50 years. At the same capacity, the SRS design for the U.S. CSF for plutonium oxide has a store capital and operating cost estimate of \$5.4B (2007 dollars) over the same period while the CFTC design has a lower operating cost and LCC of \$1.7B. The unit capital costs for the OECD-NEA and SRS cases are similar in the range of \$14,000 to \$19,000 per kg(Pu) The unit operational costs for the OECD-NEA and CSF cases are also similar at \$1,800 and \$1,900 per kg(Pu).year, respectively while the CFTC O&M costs are an order of magnitude lower. The CSF cost estimate is seen to be in the middle of the OECD-NEA cost range. OECD-NEA is using commercial industry data, which may be more broadly based from worldwide nuclear operators. Also, OECD-NEA does comment on the wide spread of costs. However, design requirements, particularly relating to safeguards, physical security, and non-proliferation aspects for storage of fissile material, have increased since the early 2000s and may further increase. The lower operational costs in the CFTC studies indicate the magnitude of the stand-alone versus collocated assumption.

E3-6.8 Selected Values for Pu and Pu-U Storage Unit Costs

There is good consistency of the OECD-NEA cost range of \$1.5–2.9/g(Pu)·yr in 2007 dollars for plutonium oxide storage and the \$2.2/g(Pu)·yr in 2007 dollars for plutonium/plutonium oxide storage of the SRS Consolidated Storage Facility design study. The CSF costs are consistent with those for the APSF and reasons have been given that account for the lower cost values shown by Mayak and CPP-651.

Accordingly, a cost value of \$2,200/kg(Pu)·yr in 2007 dollars for commercial storage of pure plutonium oxide is adopted. A 1-year period is taken as the minimum for cost purposes, and costs for longer periods are estimated using the product of the storage time and yearly rate. For stored Pu-U oxide and using the factor 1.2 from Table E3-4, the nominal storage cost for a Rokkasho-type mixed oxide (Pu-U oxide) product for is estimated as \$2,600/kg(Pu)·yr. The nominal storage period is taken as 2 years, which gives a storage cost of \$5,200/kg(Pu) for MOX (Pu-U mixed oxide). Note that the unit cost is based on the plutonium mass rather than the combined Pu and U mass.

E3-6.9 Selected Values for Pu-Minor Actinide-Uranium Costs

Using a factor 2 multiplier derived from Table E3-4, a value of \$4,400/kg(Pu-MA)·yr in 2007 dollars for storage of mixed plutonium, transuranic minor actinides, and uranium is adopted. A 1-year period is taken as the minimum for cost purposes, and costs for longer periods are estimated using the product of the storage time and yearly rate. The nominal storage period is taken as 4 years, which gives a nominal storage cost of \$17,600/kg(Pu-MA) for MOX (Pu-MA-U mixed oxide). Note that the unit cost is based on the sum of the plutonium and minor actinide mass rather than the combined Pu, MA, and U mass.

The reference costs are approximately 5 times those used in the CFTC U/TRU vault studies, which ranged from \$700 to \$1000/kg(TRU)·yr. The primary difference between the estimates is that the CFTC assumes an integrated storage facility versus the reference cost is based on a stand-alone storage facility. Estimates for an integrated storage facility are estimated at one fifth of the reference costs.

E3-7. LIMITATIONS OF COST DATA

The information obtained for these facilities is at a very high level. Details were considered proprietary and not available as of this writing. The technology readiness level (TRL) was considered to be “viable” or “commercial” for the facilities APSF and CSF because of the existence of operating facilities. Mayak, NDA Sellafield, and AREVA Cap La Hague are existing operating facilities.

OECD-NEA is using commercial industry data, which may be more broadly based from worldwide nuclear operators. Also, OECD-NEA does comment on the wide spread of costs. But design requirements, particularly relating to safeguards, physical security, and non-proliferation aspects for storage of fissile material, have increased since the early 2000s and are likely to continue. The nominal cost value for storage of PuO_2 is therefore judged to lie above the minimum value established by OECD-NEA in 1994 for stores constructed and operating in the 1980–1990s period. It is equated to the undiscounted unit storage cost from CSF data developed by SRS and is less than the OECD-NEA upper range value.

Mayak

Russian craft wages are considerably less than in the U.S.A., although productivity is historically much lower than in the U.S.A.

APSF

The overall technology incorporated into this facility is not considered “new technology”; some specially engineered equipment is included. Although a portion of the facility is used for plutonium oxide firing and packaging, it is classified as a storage facility. The relatively small storage capacity of this concept would tend to drive up the per-MTHM-cost.

CFTC Studies

The CFTC study technology incorporated into this facility is not considered “new technology”; some specially engineered equipment is included. The facility is dedicated to the storage mission. The O&M costs appear low compared to other studies and most likely reflects the difference between a stand alone facility and one co-located with a reprocessing facility.

CPP-651

Because of its hands-on operation, it does not compare well with the above two examples. The secure nature of this facility limits the amount of information available on storage capacity and operating costs. No attempt was made to adjust the capital cost to represent a totally remote-operated facility.

CSF

This “APSF-style” facility was the subject of an unpublished study by SRS in 2001. The estimate was considered rough order of magnitude.

P&RS

The construction cost value does not include money value year and the facility has smaller scope than the SRS studies. P&RS stores pure commercial product in contrast with SRS studies for defense fissile materials.

E3-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table E3-7. The summary shows the reference capital cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The following cost values are proposed, which are summarized in Table E3-7:

1. The reference cost for plutonium oxide storage is derived as \$2,200/(kg(Pu)·yr) in 2007 dollars for buffer storage using a 50 MT(Pu) capacity store of recycled pure plutonium oxide product based on U.S. security requirements. For cost purposes, a minimum 1-year storage is assumed. The cost of storage is estimated as the product of storage time and unit storage cost. The latter covers both capital and operating costs. A nominal period of 2 years storage is expected for a well-developed conventional PUREX fuel cycle.
2. The reference cost for plutonium-uranium mixed oxide storage is estimated as \$2,600/(kg(Pu)·yr) in 2007 dollars for buffer storage using a 50 MT(Pu) capacity store of recycled mixed plutonium-uranium oxide product based on U.S. security requirements. For cost purposes, a minimum 1-year storage is assumed. The cost of storage is estimated as the product of storage time and unit storage

cost. The latter covers both capital and operating costs. A nominal period of 2 years storage is expected for a well-developed fuel cycle. Storage of plutonium as the mixed oxide with uranium is the expected approach for most recent and near future PUREX reprocessing plants.

3. A nominal cost value of \$4,400/(kg(Pu-MA)·yr) is estimated corresponding to buffer storage of the proposed PuMAOx(33%wt.)-UO_3 advanced fuel cycle fissile product material using a 50 MT(Pu+MA) capacity store based on U.S. security requirements. For cost purposes, a minimum 1-year storage is assumed. The cost of storage is estimated as the product of storage time and unit storage cost. The latter covers both capital and operating costs. A nominal period of 4 years storage is expected for a well-developed fuel cycle. This corresponds to a doubled storage cost per transuranic actinide mass and a doubled storage period compared to the reference pure plutonium oxide commercial buffer storage. Storage of plutonium as the mixed oxide containing minor actinides and uranium is one of the main approaches [homogeneous recycle of PuMAOx(33%wt.)-UO_3 material proposed under the AFCI/FCRD programs] for the advanced fuel cycle.
4. The high-range estimate of \$6,000/(kg(Pu–MA)·yr), corresponding to buffer storage of proposed PuMAOx (33%)-UO_3 material, reflects a greater number of canisters due to lower material loadings and higher decay heat and radiation levels, over the nominal cost estimate. The low range cost value is assessed as \$3,300/(kg(Pu-MA)·yr). It might correspond to the cost value for long (e.g., 50–100 years) storage of Pu-MAO_2-UO_3 inventories where operating costs might possibly be reduced as loading/unloading operations become a less-significant part of overall costs.
5. Higher cost values/(kg(Cm)·yr) for curium storage due to exceptionally high decay heat and need for dilution in engineered glass and/or very small canisters.

Table E3-7. Cost summary table of selected values for storage of mixed recycled plutonium, minor actinides, and uranium.

What-It-Takes (WIT) Table				
Reference Unit Capital Cost based on 50 MT(TRU) Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$30,000/kg(Pu-MA) For storage of PuO_2-MAO_2-UO_3 in remote handling facility (see Table E3.4; Store cost factor = 2). 50-year facility life.	(± 25%)	$3,300/(kg(Pu-MA)·year)	$6,000/(kg(Pu-MA)·year)	$4,400/(kg(Pu-MA)·year)
Collocated facility based on 1/5 the costs of stand-alone.		$660/(kg(Pu-MA)·year)	$1200/(kg(Pu-MA)·year)	$880/(kg(Pu-MA)·year)
$18,000/kg(Pu) For storage of mixed PuO_2-UO_3 in remote handling facility (see Table E3.4; Store cost factor = 1.2). 50-year facility life.		$2,000/(kg(Pu)·year)	$3,300/(kg(Pu)·year)	$2,600/(kg(Pu)·year)
Collocated facility based on 1/5 the costs of stand-alone.		$400/(kg(Pu)·year)	$660/(kg(Pu)·year)	$520/(kg(Pu)·year)
		Economy-of-scale for larger capacity facility, increased Pu/MA loading of canisters, or shared safeguards and security functions	Increased regulatory/safety requirements, ROM estimate as partial basis	For other periods use product of unit storage cost and storage time; minimum period of 1 year.

The triangular distributions based on the costs in the WIT table E3-7 are shown in Figures E3-9 and E3-10. Figure E3-9 gives the estimated cost frequency distribution for the advanced fuel cycle product from, for example, UREX+ processing (i.e., mixed plutonium, minor actinide, and uranium oxide material). The costs for the similar component metallic product from molten salt electrochemical processing are less well known, and until further work is performed may be taken as similar to the UREX+ oxide product.

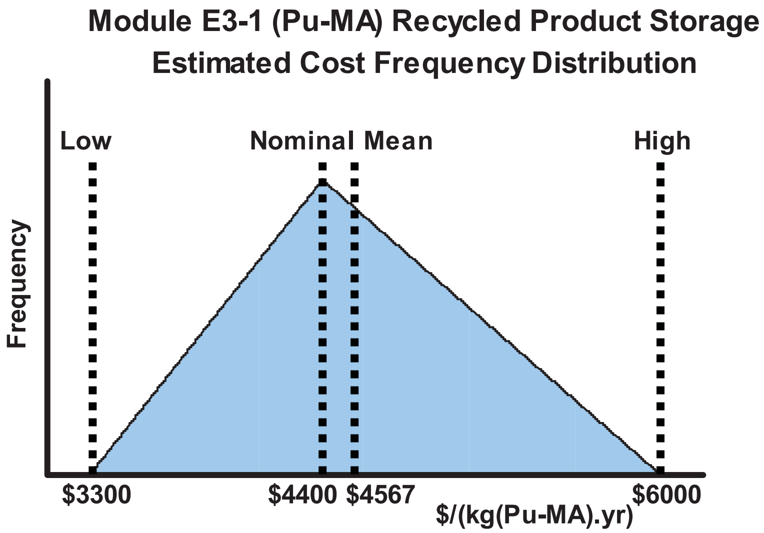

Figure E3-9. Module E3-1 recycled product storage (Pu-MA-U) estimated cost frequency distribution.

Figure E3-10 gives the estimated cost frequency distribution for the latest generation PUREX product from, for example, reprocessing at Rokkasho, Japan (i.e., mixed plutonium) and uranium oxide material.

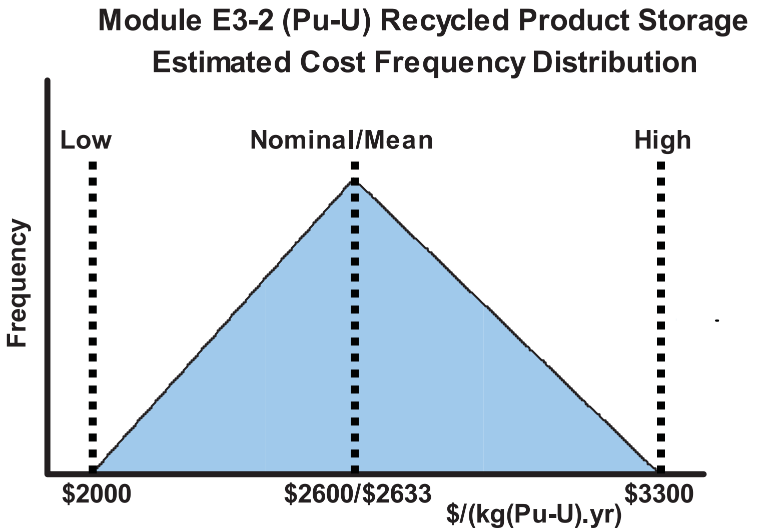

Figure E3-10. Module E3 recycled product storage (Pu-U) estimated cost frequency distribution.

E3-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

None performed to date.

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Module E4

Managed Decay Storage

Module E4

Managed Decay Storage

E4-1. BASIC INFORMATION

Module E4 provides the cost for decayed storage of immobilized, heat generating, mixed cesium-strontium-barium-rubidium (CsSr-BaRb) waste arising from advanced fuel cycles. The removal of these short and medium-term heat emitters from used fuel enables a substantial (1–2 orders of magnitude) increase in repository loading compared to direct disposal of spent nuclear fuel (SNF) (Wigeland et al. 2006). The period of decay storage has a nominal value of 300 years and may allow subsequent shallow disposal as low-level waste (LLW). After 100 years of storage, 3 half-lives for CsSr, the decay heat reduces to several hundred watts per canister and actinide decay power starts to predominate.

Advanced fuel processing flowsheets (e.g., UREX+) may separate a near pure aqueous CsSr-Rb-Ba nitrate or carboxylate (salt-free) stream and use electroreduction /refining using molten chloride salts to extract CsSr halides using zeolite ion exchange/occlusion. The often lower selectivity of molten salt processing may decrease CsSr loadings, decrease specific decay power, and increase waste quantities as well as decay periods for compliance with Class C waste criteria, and affect subsequent waste management. CsSr heat generating streams may be immobilized using a wide variety of waste forms and processes including vitrification and ceramic sintering. Depending on design, many repositories have good capacities for vitrified high-level waste (HLW) at this stage though further decay, increasingly effective removal of actinides and CsSr and/or disposal in heat dissipating salt repositories may significantly increase repository capacity. However, this study is restricted to performing sensitivity analysis for technology and cost of decay storage of immobilized CsSr waste form arising from advanced fuel cycles. Unit costs of CsSr waste storage are estimated based on storage technology, waste form properties, and canister size.

This module includes an evaluation of immobilization processes and corresponding waste form properties for storage of the separated CsSr fission product waste fraction derived from advanced fuel separation processes for treatment of light-water reactor (LWR) SNF. Waste form properties determine acceptable canister dimensions, features, numbers, and store design, which enable prediction of capital and operational costs. Various storage designs (e.g., ponds, standalone casks, housing arrays, dry vault storage [passively or forced convection cooled], and modification of existing facilities) to provide dry storage are available for storage of solid heat generating wastes such as spent fuel and vitrified HLW. Cost data from existing heat-generating waste storage studies is used to determine unit costs for 300-year CsSr storage. Three centuries provide 10 half-lives of decay and is the nominal value for the CsSr waste to comply with Class C waste criteria for proposed shallow disposal as low-level waste (LLW). Data is taken from a variety of sources including U.S., UK, French, and Japanese vitrified HLW, SNF, and Advanced Fuel Cycle Initiative (AFCI) studies. These provide various costs and waste forms (e.g., aluminosilicate, bentonite, borosilicate glass, synroc, and SNF) for a variety of specific decay powers (W/L) and store designs, so that it is important to reconcile scope and consistency of data.

E4-2. DEFINE FUNCTIONAL AND OPERATIONAL DESCRIPTIONS

E4-2.1 Waste Forms, Canister Sizes, and Storage of Heat Generating Wastes

Solidification of HLW, the main existing heat generating waste, serves the two main purposes of immobilization of waste for storage, transport, and emplacement in the repository and long-term fixation of radionuclides after repository closure and permanent disposal. Interim storage is normally required to allow further decay of the major heat emitting nuclides, and therefore reduce the early thermal loading of the repository. Thermal, mechanical and chemical stability of the waste form is required including effects of irradiation and leaching. For separated CsSr wastes, the main objective is that of immobilization while a secondary one is longer-term stability (e.g., to prevent the leaching of long-lived isotopes such as Cs-135 and stable toxic species such as Ba [Alvarez 2007]).

Various waste forms and corresponding waste immobilization processes are known for HLW. Calcines are products or intermediates obtained by partial or complete removal of volatile components of the waste, such as water and nitrates, at temperatures of 400–900°C. This creates a mixture of oxides in particulate form and with a specific surface of 0.1–5 m^2/g. Calcine powders may not be very stable because of the chemical properties of some constituents, large surface area, low thermal conductivity, and friable nature of the solids creating fine dust. Depending on calcination temperature, calcines may have residual water and nitrate content. Calcine powder may be pressed or solidified within cements or concentrated solutions grouted. If waste temperatures, radiation, or canister corrosion effects are sufficient to release water, NOx or hydrogen, then canister venting, inspection, and off-gas treatment may be needed (Streatfield et al. 2006).

For passive long-term decay storage, higher process temperature, refractory, near-inert waste forms, such as glasses and ceramics are preferred. For heat generating wastes, waste form dimensions may need optimization to limit center line temperatures to acceptable values. The more important immobilization alternatives for HLW are calcine, ceramics, glass, glass ceramics, and cement (Benedict et al. 1981), see Table E4-1.

Table E4-1. Immobilization waste form options.

Alternative	Calcine	Glass	Ceramic
Basic	Fluidized bed (particulates) Pot (cake)	Borosilicate (cylinder) Phosphate (cylinder)	Aluminosilicate Bentonite
Advanced	Supercalcine (additives, high T)	Borosilicate glass ceramic (cylinder)	Synroc (multi-phase ceramic) – Hi T, HIP
Composite	Multibarrier (e.g., pyroC, SiC in metal matrix)	Vitromet (glass/ glass ceramic in metal matrix)	Glass ceramic (e.g., puck crystallized glasses and sodalite in glass matrix)
Cement-vented Canister	Low T encapsulation of concentrated solution or calcined particles.		Higher temperature specialized cements (e.g., supercalcines).

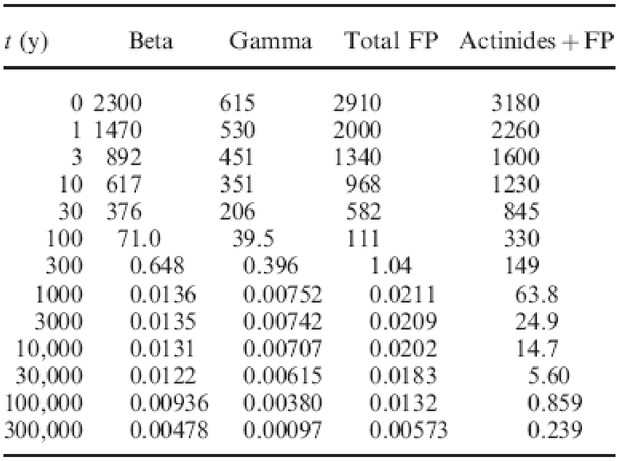
There is generally an increased processing cost for refractory, inert waste forms. This may take place through need for high-temperature operation, corrosive conditions limiting equipment lifetimes, volatilization of selected fission products requiring complex off-gas systems and waste recycle. Synrocs often require small batch operations using hot isostatic pressing (HIPing) at high temperature and with relatively long process cycles.

Waste forms may incorporate differing waste concentrations to meet waste performance and economic goals. Waste packaging and transportation costs are significant so that reduction of package number is desirable. However, thermal limitations apply to transportation, disposal and the waste form itself, and excessive fission product (FP) concentrations reduce the chemical performance of waste and may cause excessive internal temperatures. Composition limitations are typical for glasses where either phase separation or lack of glass forming occurs. For borosilicate glasses, for example, the FP oxide limit is normally considered to be around 20–25% by weight (plus process additives) using existing hot-wall melters. Higher concentration may create a distinct yellow crystalline phase formed of alkaline and alkaline earth molybdates. This readily soluble phase contains Cs-137 and Sr-90. Glasses can be formulated to incorporate most fission product and actinide oxides with good stability. Devitrification occurs above the glass transition temperature, for example at elevated temperatures of ~500°C for phosphate and ~600°C for present borosilicate glasses. Some processes employ controlled crystallization to glass ceramics to create known waste form properties. Other waste form composition/temperature limitations may arise from a wide variety of limits such as melting, volatization, and recrystallization into new phases, chemical reaction, canister pressurization, etc. Composition is not a direct limitation for calcines, which are amorphous, but high-heat load may cause further chemical decomposition, canister corrosion, and pressurization. Grouts are normally used to immobilize mineral ion exchange (IX) materials used for treatment of LLW and (in Europe) for intermediate level wastes (ILW) liquid wastes, but have also been used for encapsulation of low specific decay power raffinates from specialized recycling operations.

Industrial practice for HLW vitrification tends to use large canisters for low specific decay heat defense wastes (e.g., 0.61 m o.d., 3 m height and 2.1 t filled mass) for Savannah River Defense Waste Processing Facility (DWPF), and small canisters for high-specific decay power LWR wastes (e.g., 0.43 m o.d., 1.3 m height and 0.5 t filled mass) for Ateliers Vitrification La Hague (AVH) (IAEA 1992). Even smaller diameter canisters, o.d. 0.3 m, have also been used at PAMELA (Germany) and WIP (India). In general terms, canisters with diameters less than 0.2–0.15 m diameter are not favored industrially due to difficulties of filling with molten glass due to bridging, potentially more thimble tubes due to retention of moderate l/d ratios for canister cooling, increased pressure drops with high-air velocities, and possible limited cost reduction of storage with decreasing thimble tube diameter. KfK Germany developed a process where HLW phosphate glass beads were cast and then embedded in molten metal in a canister. Such an approach or other internal features for heat conduction may be especially useful for CsSr vitrification of short-cooled, high-loaded fission products.

For LWR fuel of typical burn-up of 40 GW(t).d/t(iHM), the decay powers are given in the Table E4-2, (Bergelson et al. 2005).

Table E4-2. Decay heat power of FPs and transuranics (Pu, Am, Cm) during long-term storage, W/t(iHM).



t (y)	Beta	Gamma	Total FP	Actinides + FP
0	2300	615	2910	3180
1	1470	530	2000	2260
3	892	451	1340	1600
10	617	351	968	1230
30	376	206	582	845
100	71.0	39.5	111	330
300	0.648	0.396	1.04	149
1000	0.0136	0.00752	0.0211	63.8
3000	0.0135	0.00742	0.0209	24.9
10,000	0.0131	0.00707	0.0202	14.7
30,000	0.0122	0.00615	0.0183	5.60
100,000	0.00936	0.00380	0.0132	0.859
300,000	0.00478	0.00097	0.00573	0.239

Data in Table E4-2 shows both total FP and total FP with transuranic (Pu, Am, Cm) contributions to decay power. Often the Pu contribution is omitted as vitrified HLW includes minor actinides, but not Pu. The total FP decay power reduces by 40% in the period 10-year cooled to 30-year cooled, which indicates the major contributions of Cs-137 ($t_{½}$ = 30y) and Sr-90 ($t_{½}$ = 28y) to decay power in this period.

Heat generation in immobilized HLW and CsSr waste causes the waste form to be at elevated temperature for more than 100 years. With some simplifications, the maximum temperature difference between the centerline and surface of a long cylindrical waste form is given by:

$$\Delta T_{max} = q\, r^2 / 4\, \kappa$$

Where q is the power density, W/m^3, r is the radius of the cylinder, and κ is the waste form thermal conductivity, W/(m°C). The surface temperature is given by the storage conditions including canister wall and waste surface/canister interfacial properties. This enables scaling of canister radius against heat loadings from existing commercial practice (IAEA 1992). Representative values for conductivity of waste forms are given in Table E4-3 (Benedict et al. 1981).

Table E4-3. Thermal conductivity ranges for various HLW forms in temperature range 100–500°C.

Waste Form	Thermal Conductivity, κ W/(m°C)
Particulate calcine	0.2–0.3
Phosphate glass	0.8–1.2
Borosilicate glass	0.9–1.3
Borosilicate glass ceramic	1.5–2.0
Particulate calcine or glass beads in metal matrix (e.g., vitromet)	~10

Waste form conductivity clearly has a major influence on centerline (peak) temperature and corresponding canister dimension (radius), see Figure E4-1, (Benedict et al. 1981).

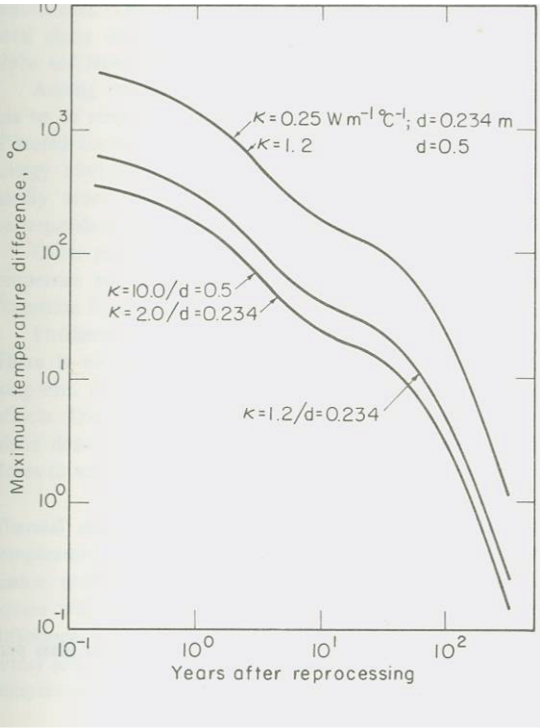


Figure E4-1. Calculated maximum temperature difference in a cylinder of solidified waste for different diameters and thermal conductivities as a function of time (years) after recycling.

The heat generation rate is based on fission products and minor actinides incorporated into a waste form specific volume of 70 L/t(iHM). The originating SNF burnup is 30 GW(t).d/t(iHM) and recycling taking place at 150 days SNF decay.

Figure E4-1. Maximum centerline temperature difference of waste form as a function of decay time.

At the assumed waste loading, Figure E4-1 indicates maximum temperature differences for glass ceramic waste with canister diameter of about 0.5 m of between the waste center line and surface of >1,000°C (≡ 100 W/L) and >100°C (≡ 10 W/L) for 1 year and 10 years decay after recycling, respectively.

In the present study, borosilicate glass is considered the reference HLW form. This is conservative since it is somewhat more restrictive thermally than some synrocs and other ceramics. For civil design, it is generally preferable to restrict natural convection cooling air discharge temperatures to around 150–200°C as concrete structural components are damaged by long-term contact with air at temperatures approaching 100°C. However, higher values can be engineered. Air cooling in forced convection stores would be less limiting, but for a long-term decay store, there is likely to be conservatism concerning highly rated systems and effects of cooling failure. This suggests that a maximum temperature difference, ΔT, between waste centerline and surface of around 300°C may be appropriate assuming a centerline maximum design temperature of ~500°C. For a canister with diameter 0.5 m containing borosilicate glass HLW, a maximum specific thermal power in the range 10–30 W/L appears suitable. Raising the glass transition temperature by ~200°C increases the maximum thermal power by about 60%.

E4-2.2 Potential Waste Forms for Immobilization of Short Lived Fission Products

Of the fission products, the most troublesome Cs and Sr isotopes are Cs-137 ($t_{1/2}$=30.07 y: 0.66 MeV γ and 0.514 MeVmax β-) and Sr-90 ($t_{1/2}$=28.78 y: 0.546 MeVmax β-), so their activities remain a concern for ~300 years (i.e., ~10 half-lives). These two isotopes generate a major portion of the decay heat in spent nuclear fuel over the first 100 years of storage, but then are essentially stable. Removing Cs and Sr for decay storage will reduce the short-term heat load on a repository waste form.

Fission product oxide mass, excluding noble gases, is ~1 kg(FPOx)/GW(t).d, and so for a metric ton, t, of SNF at 40 GW(t).d/t(iHM), the mass of FP oxides is about 40 kg. Cs and Sr form about 10 atom % of the FPs, of which around half are the major heat emitting isotopes—Cs-137 and Sr-90. Total CsSr also form around 10% by weight of the FP oxides, that is 4 kg/t(iHM) of spent fuel. Total CsSr-Rb-Ba form around 15% by weight of the FP oxides, that is 6 kg/t(iHM) of spent fuel. From Table E4-2, where Cs-137 and Sr-90 are the only major FP isotopes with half lives between 10–50 years, the decay power of CsSr is seen as about 1 kWt(iHM) at 10 years ex-reactor. Alternatively the CsSr decay power can be expressed as ~¼ kW/kg(CsSr) at 10-years cooling. In engineering terms, the specific decay power of CsSrOx is about 10 times that of overall FPOx at 3–20 years cooling.

Recently, interest in separation of Cs and/or Sr during remediation of long-stored HLWs and for advanced fuel cycles has stimulated developments in waste forms tailored to CsSr immobilization. These include variants of waste forms for HLW and several new matrices (see Table E4-4), which is representative rather than complete. The various minerals formed have differing capacities for Cs and Sr.

Table E4-4. Representative CsSr-Rb-Ba waste forms.

Matrix	CsSr Composition	Composition Matrix, (% wt)	Process	Reference
Cement	4% Zeolite A, 5mEq/g	PFA, Ordinary Portland Cement	Grouting ambient T Maintain ≤95°C	El-Kamash et al. 2006
Alumino-silicate (Steam reform)	27%Cs / 8%Sr $SrCO_3$ $CsAlSi_2O_4$	Pollucite/hydroceramic Slawsonite	Steam reform CsSr-Ba with carbon & alumino-silicate clay at ~700°C	Ortega and McDeavitt, 2007 Law et al. 2007
Bentonite (alumino-silicate) Dry sinter	≤40% Cs loading	Celsian Pollucite Hydroxyl-apophyllite	Dry sintering bentonite clay containing Cs, Sr, Rb, Ba to 600–1,000°C	Kaminski and Merz, ANL.
Crystalline Silicotitanate, CST and niobate IX	Cs_2O ~ 20% wt	$Cs_2TiSi_6O_{15} \bullet 3H_2O$ $Cs_3TiSi_3O_{95} \bullet 3H_2O$ and Ti analogue of Pollucite $CsTiSi_2O_6 \bullet 3H_2O$	Calcining CsSr soaked UOP CST IE-911 in air at 900–1,000°C	Balmer et al. 2000. Luca et al. 2006
Borosilicate Glass High mp glass	Cs_2O 13% wt and SrO 7% wt PNNL ~40%wt	Na_2O 10-20 B_2O_3 10-17 SiO_2 45-50 Al_2O_3 2-5 Ba,Pb,TiOx 4-6	Calcination and Melting High-melting glass	Aloy et al. 2007
Hexagonal Tungsten oxide Bronze (HTB)	Cs_2O ~12% wt or SrO ~5% wt	$Cs_{0.13}Mo_{0.03}W_{0.97}O_3$ $Sr_{0.05}Mo_{0.03}W_{0.97}O_3$	CsSr adsorbed hexagonal tungsten oxide bronze, Calcine 500–1,000°C in air.	Luca et al. 2006
Synroc-C Hydrous titanium oxide (HTO)	CsSr-Rb-Ba 12 %wt	Hollandite Rutile Titanates	Calcination 750°C & HIP 1,275°C, 30MPa, 1h	Carter et al. 2007
Cs/Sr Oxides	Cs_2O/SrO	Pure	Calcination	-
CsCl	100% Cs salt in capsule in pool	CsCl, 35kCi 190W	IX separation and Evap	Nat Acad Sci, 2003
SrF_2	Sr salt in capsule in pool	CsF_2, 33kCi 260W	IX separation and Evap	Nat Acad Sci, 2003

These potential CsSr waste storage forms evolved from upstream processing needs. Bentonite (including commercial UOP IE-911), and hydrous titanium oxide (HTO) are examples of IX materials used to selectively adsorb Cs, Sr, etc., from stored, complex chemistry salt HLWs to provide partitioning of waste for optimized waste management. These IX materials bearing low-medium Cs, Sr concentrations are heat treated by sintering, generally in the temperature range 500–1,000°C. This causes removal of water, recrystallization, denitration and additional phases, and ultimately removal of hydroxyl groups. By contrast, the advanced fuel cycle processes (e.g., UREX+ [Vandegrift et al. 2004]) create salt-free product streams of CsSr (e.g., nitrate and carboxylic acid based). These are not constrained by feed of mineral IX materials and can be used to form the complete range of waste forms from pure CsSr oxides/chlorides to glasses to freely tailored ceramics. The uses of zeolites (i.e., micro-porous crystalline solids with well-defined structures) generally contain silicon, aluminum, and oxygen in their framework and cations, and/or other molecules within their pores. For CsSr recovery in molten salt, electrochemical waste forms are more likely to be aluminosilicate ceramics or aluminosilicate glass ceramics.

High-level waste vitrification is well known as a complex technology with significant cost impact on existing PUREX commercial and defense recycling waste management. Advanced fuel processes generally partition FP and actinide species into more streams (e.g., seven for UREX+4). Some of these, (CsSr), have medium radioactive lifetimes and means have been sought to optimize the waste immobilization process to the waste lifetime, including storage requirements. For substantial masses, CsSr wastes need cooling for periods of 100–200 years. AFCI has examined use of a steam reforming process to fabricate alumino-silicate waste forms for CsSr storage (Law et al. 2006).

The UREX+ suite of processes has a separation segment, CCD-PEG in UREX+1a (Law et al. 2004) or FPEX in UREX+1b (Law et al. 2007), for recovery of CsSr-Rb-Ba from the raffinate of the UREX segment. Both of these technologies provide simultaneous solvent extraction of Cs and Sr together with the majority of Rb and Ba. With CCD-PEG, the CsSr by-product is stripped using an organic amine and carboxylic acid mixture whilst FPEX uses dilute nitric acid as strip. Steam reforming has been developed for stabilization of streams because it can produce a solid waste form while retaining the Cs and Sr in the solid, destroy the nitrates and organics present in these aqueous solutions, and convert the Cs and Sr into leach resistant aluminosilicate minerals. The waste form is intended to meet a 300 year, 10 half-life periods of storage prior to projected LLW disposal complying with Class C waste criteria.

A bench-scale steam reforming pilot plant has been operated at Idaho National Laboratory (INL) with several potential CsSr feed compositions and steam reformed product has been generated and analyzed (Law et al. 2006). A small, but representative fluidized-bed was used to conduct steam-reforming tests to produce mineralized granular product. Operating conditions of 700°C, ~3% H_2, ~4% CO, 70% CO_2, and 20% steam were used to decompose nitrates and organics. A starting bed of 100–300 micron aluminum oxide particles was used and Sagger clay slurried with the feed to produce pollucite and other alumino-silicate minerals. Excess clay was used to mineralize the cationic feed constituents. The clay particles are less than 10 μm to achieve a high-surface area for reaction. The final bed material in each run was generally a granular material much like the initial aluminum oxide starting bed with some additional smaller diameter solids. The bench-scale steam reformer tests successfully converted cesium/strontium strip products to a solid form without volatilizing the Cs. Results also indicate that with optimization of the steam reforming operating parameters, 100% mineralization is possible (Law et al. 2006). The bed waste product material may be compacted, for example, within canisters to form pucks, which may be loaded into an over-pack.

A collection of scoping studies, entitled Engineering Alternative Studies (EAS), related to a commercial scale UREX+ separations plant were commissioned by Department of Energy (DOE) and carried out by a multi-national laboratory team in 2006–2008. EAS investigated features of a canyon approach for a commercial plant, with expected throughput of ~3,000 t(HM)/year, with three solvent extraction lines. The Follow-on EAS (FOEAS) evaluation assumed a smaller plant throughput (~800 t(HM)/year UREX+) with re-examination of facility layout options, requirements, alternate flowsheets, etc. (Hebditch et al. 2007).

In the EAS, an engineering proposal and costing of the proposed storage of the UREX+ cesium-strontium (CsSr) waste stream was presented. The study was based on the UREX+1a process, throughput of 3,000 t(iHM)/year mixed LWR fuel of 60 GW(t).d/t and formed a variety of products and wastes, including an aluminosilicate mineral powder CsSr waste intended for a 300-year period of storage prior to projected LLW disposal. This study demonstrated reasonable feasibility, but was not an economic optimization and further studies were performed.

The FOEAS was based on the UREX+1b process, throughput of 800 t(iHM)/year mixed LWR fuel of 60 GW(t).d/t and formed a variety of products and wastes. For CsSr, three waste forms were examined conceptually (i.e., a sintered bentonite and two vitrified CsSr options with differing CsSr loadings). As for EAS, these would need nominal 300-years storage for compliance with Class C waste disposal. Other geological disposal scenarios may be feasible, but are not well defined yet and so are not considered here. This was a top-down assessment based on the above 3,000 t(HM)/year study with some variations to account for process changes and scale, etc. The use of sintered bentonite or vitrified CsSr wastes may possibly increase waste immobilization costs, but is expected to decrease overall waste storage costs life cycle costs (LCC) by increasing CsSr loading and canister diameter and by reducing waste volumes, total canisters, and required storage capacity. However, depending on design these may need periods of forced convection cooling and delayed potential for using passively cooled storage. If AFCI does call for CsSr separation, a vitrified CsSr waste form option is presently favored with a range of increased loading values being examined and this makes good use of state-of-the-art vitrification and waste storage technologies.

There was a third conceptual design, which was based on a high temperature, molten salt electrochemical process. This design was based on oxide fuel electrochemical reduction, uranium electrorefining, and transuranic product recovery by electrowinning. The design throughput is 300 t(HM)/year mixed LWR fuel of 60 GW(t).d/t and the process formed a variety of products and wastes including a glass-ceramic CsSr waste formed with zeolite used as an ion exchange material to recover CsSr from salt. The specific activity of this waste form is expected to be similar to or lower than the aluminosilicate waste and so costs for this case can be considered equivalent to EAS costs using a per kg(CsSr) basis. However, the electrometallurgical CsSr waste may have higher radioactive impurity levels (e.g., TRU), and require longer decay storage to comply with Class C limits or need disposal as GTCC.

In summary, the CsSr-Rb-Ba separated waste stream from UREX+ aqueous separations is salt free and can be decomposed thermally to the oxides and converted into a wide variety of waste forms and chemistries including particulate ceramics, cements, sintered ceramics, glass ceramic composites, and cast vitrified waste. The waste stream has few process additives so the CsSr waste form may be made as concentrated in CsSr as desired consistent with chemical, physical, and thermal waste-form properties. The Integrated Waste Management Strategy (IWMS) presently favors the CsSr vitrified waste option using existing waste storage and state-of-the-art vitrification technologies. Incorporation of 20% wt CsSrOx in borosilicate glass has been reported and fully active samples made (Aloy 2007). Pacific Northwest National Laboratory is understood to be investigating higher incorporations, ≥40% wt. CsSr-Rb-BaOx, which equates to ≥27% wt CsSrOx. CsSr concentrations in commercial LWR vitrified waste are around an order-of-magnitude lower than the latter number so that borosilicate glass (BSG) waste container diameters may be need to be reduced from 0.4 m to 0.13 m (i.e., by factor √10), or SNF decayed stored for >3 CsSr half-lives (i.e., ~100 years). Additionally, increasing the glass transition temperature by several hundred degrees centigrade may allow the canister diameter to be increased back to around 0.2 m with the same high CsSr incorporation. Glass formulations with higher devitrification temperatures generally require formulations with higher melting point as may be achieved by a cold crucible melter.

E4-2.3 Vitrification and Storage of LWR Oxide HLW

For LWR fuels, the main operating commercial separations plants in the world are UP2-800 and UP-3 at Cap La Hague and THORP at Sellafield (Rokkasho is believed to start full operation in 2008 and uses Japanese JCM vitrification technology). These French and UK plants have used French AVH vitrification technology for nearly 2 decades. Calcined fission product waste is mixed with glass frit in the ratio of around 1:3 by weight. The PUREX raffinate has low processing inerts and after calcination is mainly FP and minor actinide (MA) oxides with very low U, Pu content, and moderate corrosion product concentrations.

Vitrification of commercial and/or defense HLW has taken place at Cap La Hague and Marcoule in France, Sellafield in the UK, Tokai in Japan, Karlsruhe in Germany, Savannah River and West Valley in U.S., Tarapur in India, Russian Federation, etc. Almost all of these facilities use air-cooled vault storage systems where waste canisters are stored in cooled thimble tubes. Most use forced air convection, at least initially, whereas one uses natural convection with forced convection as standby during early operation (IAEA 1992).

France first performed vitrification operations in the 1970s in the Ateliers Vitrification Marcoule facility (known as the AVM) and then in the late 1980s in the R7 and T7 facilities of the La Hague plant (referred to as the AVH). French vitrification technology uses a rotary calciner feeding a metallic inductively heated melter vessel, which siphons batches of vitrified waste into HLW canisters. The Marcoule vitrified waste store used HLW canisters of dimensions, 0.5 m diameter and 1 m height, for lower burnup, lower decay power gas-cooled reactor wastes. For AVM, three casts of glass (120 kg each) totaling about 140 L are made into a single stainless steel canister. The vitrified waste store used thimble tubes (steel sleeves with base set into concrete) and stacked canisters, 10 high. The sleeves are 0.6 m diameter and 10 m height. The maximum output of the 10 canisters in a sleeve is 8 kW (i.e., 0.8 kW/canister) on average, but 1 kW peak value. Forced convection cooling air normally flows between sleeves and canisters at velocities of 10–15 m/s with filtration at outlet but can revert to natural convection without filtration for power failure conditions or after long storage, etc. Two vaults were built initially at Marcoule, one with 80 storage sleeves and the other with 60 storage sleeves. The maximum heat load of the whole store is 1 MW. One AVM single line plant was constructed in the 1970s at Marcoule, to provide vitrification of low burnup gas reactor fuel with vitrified waste power densities of ≤8 W/L.

The AVH stainless steel canisters are cylindrical with overall dimensions of around 0.42 m diameter (17 inches) and height 1.3 m (52 inches). The canisters have a top flange of reduced diameter with welded closure following filling with two pours from the melter. After pouring, the canisters contain about 400 kg (150 L) vitrified HLW and are around three-fourths filled. (In France, the residual space is filled with pucks of compacted leached fuel hulls.) Two AVH plants, designated R7 and T7 and each of three vitrification lines, were constructed in the late 1980s at La Hague, to provide vitrification of standard LWR fuel (33 GW(t).d/t) HLW after 4 years of cooling. Preliminary evaluations foresaw glass center line temperatures ≤650°C and power densities of ≤60 W/L, which implied a maximum canister heat load of 9 kW. Eventual design values were specified as 20 W/L and 3 kW, respectively.

The Sellafield waste vitrification plant was constructed with two AVH process lines, and first operated in the early 1990s. Its vitrified product store (VPS) accommodates up to 8,000 AVH canisters stacked 10 high (about 13 m). Each canister (400 kg waste) typically contains vitrified waste from the recycling of 8 t Magnox fuel or 2 t oxide fuel (Dobson and Phillips 2006). There are 800 stainless steel storage thimble tubes into which the canisters are stacked through top plugs and seals. Each storage tube is within a rectangular compartment to guide cooling air. Decay heat is removed by natural convection cooling of the exterior of the sealed storage tubes, and due to multiple barriers and compliance with glass centerline limits and civil structural limits, no filtration of the cooling air is required. The Sellafield borosilicate glass formulations have waste oxide incorporations in the range 20–30 wt% with glass transformation temperature of around 550°C; 500°C is taken as the glass center line temperature limit. VPS has capacity for vitrified HLW from 2 decades of THORP design throughput of 800 t(oxide SNF)/year, that is 16,000 t(oxide SNF) equivalent.

British Nuclear Fuels plc (BNFL) commenced active commissioning of the third line at Sellafield's WVP in January 2002. The start of operation of the 320M UK pound (~2000 m.v.) ≡ U.S. $485M (2000 dollars) line enables BNFL to meet its commitment to speed up the conversion of liquid HLW to borosilicate glass blocks for longer term storage. The UK regulator requires year-on-year reductions in highly active liquid waste down to buffer stocks of 200 m^3 by 2015.

The operation of WVP has led to the production of over 4,000 containers of vitrified waste to-date, which are currently stored within the VPS at Sellafield. The VPS is deemed suitable for this interim storage requirement, subject to regular maintenance and refurbishment, for at least 100 years. A proportion of the vitrified HLW will be returned to overseas customers at the appropriate time as set out in the recycling contracts. The canisters of vitrified HLW are kept in a purpose-built store (VPS), which has passive cooling and a back-up forced cooling system.

The design and operation of HLW vitrification facilities has been well described for the major national nuclear programs (IAEA 1992). Following filling of stainless steel, cylindrical waste canisters with vitrified waste, various operations are used to prepare canisters for storage and ultimate disposal. Thermal conditioning of canisters to reduce heat shock and decrease glass cooling rate and fracture may be used. Tungsten Inert Gas (TIG), plasma torch, or upset-resistance welding is used to seal the canisters with lids. Canister welds are normally inspected optically or by helium leak testing. Canister dimensions, weight temperature and dose rate may be determined. The exteriors of canisters are often decontaminated using high-pressure water, sand slurries, dry blasting, or electrochemical decontamination. Waste canisters must be cooled in storage to minimize devitrification and maintain store integrity.

Currently, operating and planned interim stores use air cooling of canisters. Air cooling can be achieved by conduction, or natural or forced convection. For some high-specific decay power glasses, forced cooling is combined with natural convection cooling. Canister, waste, and store characteristics for various national facilities are given in Table E4-5.

Table E4-5. Canister and waste parameters for operating vitrified HLW stores.

Facility Cooling	Canister I.D./Height m/m	Glass Mass/ Volume, kg/L	Max Activity GBq α/β	Maximum Canister Power, W	Maximum Power W/kg
AVM France Forced/Natural	0.49 1.0	360 135	3.0×10^7 1.4×10^7	1,000	2.8
R7/T7 France Forced/Natural	0.42 1.34	400 150	1.4×10^5 2.8×10^7	2,980 peak 2,100 average	7.5
WVP–VPS UK Natural	0.42 1.34	400 150	-	*Estimated 2,000*	-
DWPF–U.S. Forced	0.59 3.0	670	-	-	-
TVF–Japan Forced	0.42 1.0	300 110	1.5×10^7 Combined	1,400	4.7

BNFL WVP with Lines 1 and 2 and VPS has dimensions 64 m long × 38 m wide × 40 m high, which gives footprint of 2,430m^2 (IAEA 1992). The capital cost is estimated as 250M Great Britain Pounds (GBP) (1990 dollars) ≡ \$446M (U.S. 1990 dollars[a]) ≡ 730M (U.S. 2008 dollars[b]). The two stores and access corridor have a footprint of around 25 m × 40 m = 1,000 m^2 (10^4 ft^2) or 40% of WVP footprint. A pro rata capital cost for the VPS is then \$292M (U.S. 2008 dollars) ≡ 146M GBP with a capacity corresponding to 16,000 t (LWR SNF). This corresponds to a facility square foot capital cost of \$29K. Commonly process areas have costs that are several times greater than waste storage areas. So, a value of \$150M (\$15K/ft^2) for the store may be appropriate here, and this is regarded as high although passive cooling favors lower long-term operational costs.

E4-3. PICTURES/SCHEMATICS

Figure E4-2 shows a cross-section of vitrified waste storage, showing how decay heat is removed by natural convection cooling of the exterior of the sealed storage tubes.

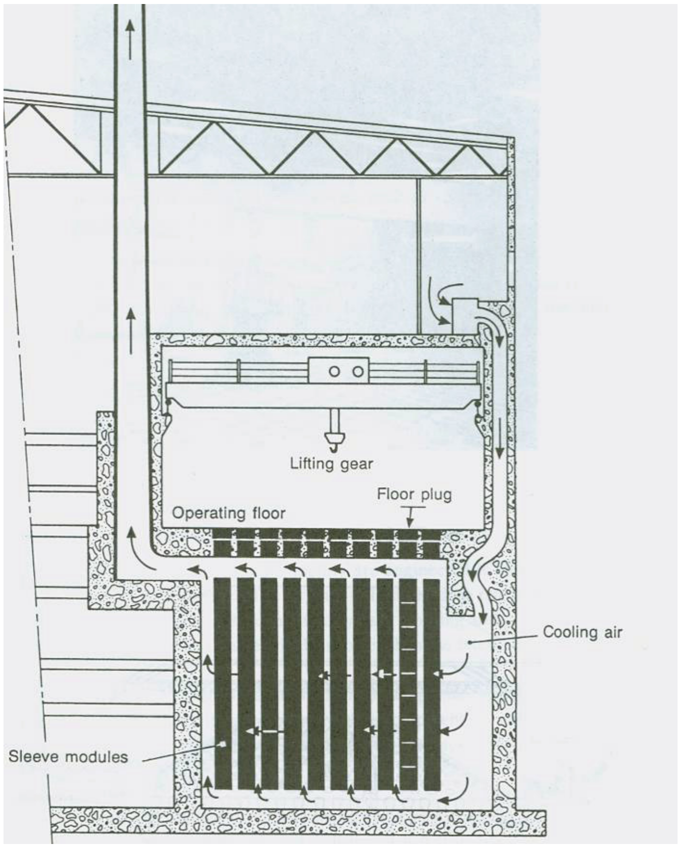


Figure E4-2. WVP VPS natural convection air-cooled storage system.

The canisters of vitrified HLW are kept in a purpose-built store (VPS) shown in Figure E4-3 has passive cooling and a back-up forced cooling system.

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[a] Measuring Worth - Exchange Rates Between the United States Dollar and Forty-one Currencies, http://www.measuringworth.com/datasets/exchangeglobal/result.php

[b] Money values derived using: U.S. Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), Using CWBS Feature Code – 07 Power plant, Appendix A, EM 1110-2-1304, Appendix Revised September 30, 2007.

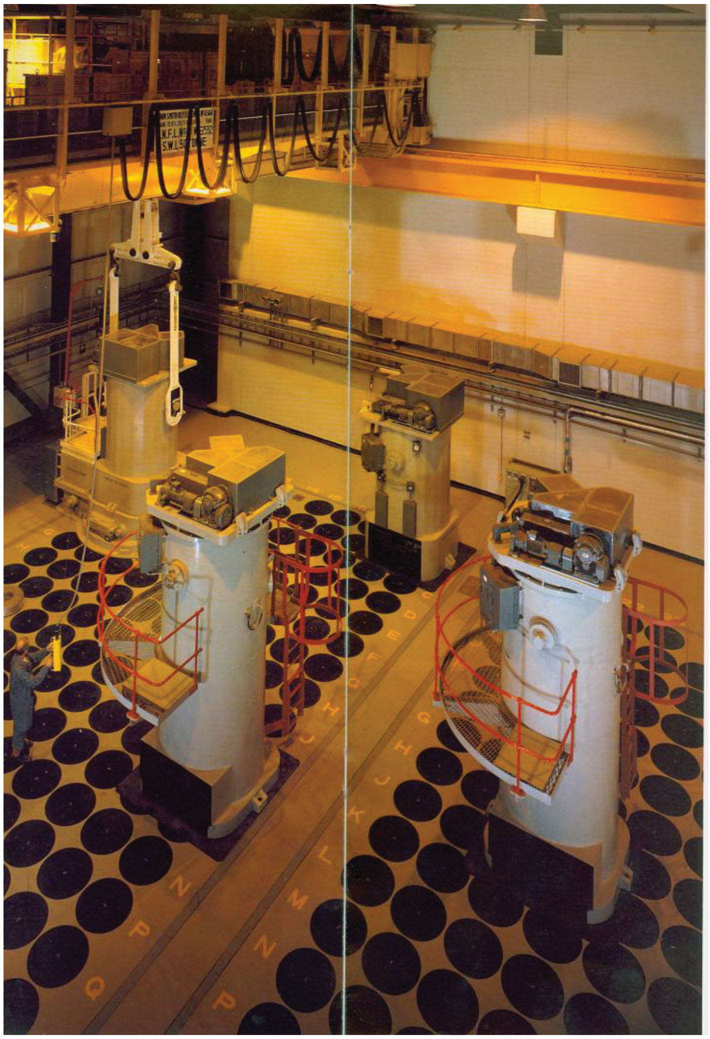


Figure E4-3. WVP VPS charge face showing waste product flasks over storage channels (BNFL 1991).

E4-4. MODULE INTERFACE DESCRIPTION

The wastes that would be stored in these facilities would be received from LLW-Greater-than-Class-C (GTCC) Conditioning and Packaging modules (Module G4). After the wastes have been decayed (e.g., 300 years) they would sent to Near Surface Disposal (Module J).

E4-5. MODULE SCALING FACTORS

No scaling analysis has been completed for this module.

E4-6. COST BASIS, ASSUMPTIONS, AND DATA SOURCES

E4-6.1 Basis and Assumptions

Sound cost estimates require the examination of relevant design parameters, existing industrial practice, and the definition of a reference design concept for immobilization and storage of CsSr waste. The reference process need not be fully optimal, but should be broadly representative to provide a conservative basis for costing. The reference process adopted here for CsSr immobilization and storage is that of vitrification to form borosilicate glass of CsSr loading in the range 2–10% by weight depending on decay time before separation and immobilization. The shortest decay period is likely to be around 4 years and this requires use of canisters of diameter ~0.4 m, (e.g., AVH type), and low CsSr loadings. A modular vault dry storage system is selected consistent with worldwide practice for long storage of heat generating wastes. CsSr waste storage costs are then taken to be the same as HLW vitrified waste storage costs on a capital cost and yearly operational expense basis. Vitrified waste is planned to be stored 50–100 years before disposal whereas CsSr waste is planned to be stored 300 years prior disposal.

The current use of commercial MVDS facilities for storage of vitrified HLW and spent fuels for planned periods of ≤100 years gives confidence in this approach. However, the project and operational costs of these are often commercially protected. Estimates have been gathered where possible and values also taken from cost studies for planned facilities, which may not be constructed. Table E4-8 summarizes cost data given above.

Table E4-8. Summary cost data for managed decay storage.

Facility	Est. Capital Cost,[a] $M	Est. Operating Cost,[1] $M/yr	Comments
Vitrified Waste, MVDS			
WVP–VPS (1990)	150	4[b]	8,000 AVH canisters ≡ 16,000 t(SNF[c])
Hanford TWRS (1996)	106	4[b]	8,000 AVH canisters ≡ 16,000 t(SNF[c])
INEEL VWISF (2001)	126	4[b]	8,000 AVH canisters ≡ 16,000 t(SNF[c])
Oxide SNF, MVDS	Est. Life Cycle Cost		
Bunn et al. (2001)	$250M	3–4	1,000 t(SNF[c]) stored, LWR operation +40 years
Fairlie (2000)	~$200K/t(SNF[c])	-	

a. 2008 money values – Derived using US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), Using CWBS Feature Code – 07 Power plant, Appendix A, EM 1110-2-1304, Appendix Revised September 30, 2007.

b. Operating cost based on team of 20 for 24-hour coverage at fully loaded cost of $200K/staff.

c. LWR oxide spent nuclear fuel.

The estimated capital costs of the vitrified waste stores are seen to be similar with possibly U.S. practice lower cost than UK.

Two sources provide similar values for annual operating costs for dry storage of vitrified waste and spent fuel. Due to the unusually long period of storage (300 years), the undiscounted total operating costs outweigh capital cost by around a factor of ~10.

Taking the operational expenses of a single module of vitrified CsSr waste air-cooled store, capacity of 64,000 kg(CsSr elemental) ≡ 16,000 t (oxide SNF), as $4M/year and the operational period as 300 years gives an operational expense of $1.2B. The capital cost of the store is estimated as $150M. The cost of decommissioning of the store is taken as 10% of capital cost plus 5 years operational cost.

CsSr Waste Storage Life Cycle Cost
= $4M × 300 + $150M + (5 × $4M + $15M) = $1,385M
CsSr Storage Unit Cost = 1,385M/64,000 = $21,600/kg(CsSr elemental)

The nominal cost of storage of CsSr is judged to be ~$22.5K/kg(CsSr elemental).

The low range cost is judged by halving the capital cost, discounting (starting at 100 years) the second and third centuries of operation to about 30% of their nominal value and halving decommissioning costs. This gives an unit value of around $10K/kg(CsSr elemental). Other opportunities include alternative glass formulations with high-temperature limits that enable increased CsSr concentrations and decreased numbers of waste canisters. Cold crucible induction melters are under development for HLW vitrification, which may supersede the two main industrial types, joule ceramic and hot wall induction, and provide higher temperature operation giving access to higher melting glass formulations with higher glass transition temperatures.

Risks for higher unit storage costs include requirements to increase operational team size, decrease the module storage capacity for each team, and/or increase of the required storage period to account for minor radionuclide decay. The high range cost is estimated as 60% higher than nominal (i.e., $35K/kg([s-Sr elemental]).

E4-6.2 Cost Correlations

Storage costs were correlated with the storage of spent oxide fuel and interim storage of vitrified waste.

E4-6.2.1 Storage of Spent Oxide Fuel Facility Costs

Further cost confirmation can be derived from data on storage of spent fuel. Storage of vitrified HLW is expected to not be dissimilar in cost to that of SNF since the thermal power and radiation level is similar though the mass of vitrified waste is about 80% less. Of the main alternatives of vault storage, casks, and housing arrays, the preferred option for long-term storage of large quantities of spent fuel and other heat generating wastes is dry vault storage. This concept for spent fuel was originated by Alstec (now Babcock International Group PLC) and deployed in the U.S. by Foster Wheeler (BNS 2009). There is considerable similarity between vault storage of vitrified waste and spent fuel.

Costs of dry cask interim storage of fuel are reported as about $250M for storage of 1,000 t (LWR SNF) during 40 years generation and for 40 years following this (Bunn et al. 2001). Casks are licensed by the Nuclear Regulatory Commission (NRC) for 20 year operational periods. Research and development (R&D) is underway to assess NRC's judgment is that storing fuel in dry casks would be safe for 100 years. This averages to $250K/t(iHM). Costs for dry vault storage were said to be similar. For shutdown reactors with all spent fuel in dry storage the annual costs were estimated as $3–4M, while for pool storage after reactor shutdown the annual costs were estimated as $9M (Bunn et al. 2001). Japanese and European SNF storage costs are in general higher than these costs.

The Modular Vault Dry Store (MVDS) system is used at the PAKS, Hungary (Figure E4-4) and at Fort St. Vrain (Figure E4-5) in the U.S. It is a passive system employing natural convection cooling. The Paks MVDS handles thermal power of up to 17 kWt of fuel when fully loaded compared with about 1.4 to 2 kWt for concrete casks. The PAKS MVDS uses a natural convection cooling system, as shown in Figure E4-6. Vaults have sufficient heat removal capacity to keep fuel-cladding temperatures of 5-year-cooled PWR assemblies below 200°C. The Fort St. Vrain MVDS was designed for a 40-year lifetime.

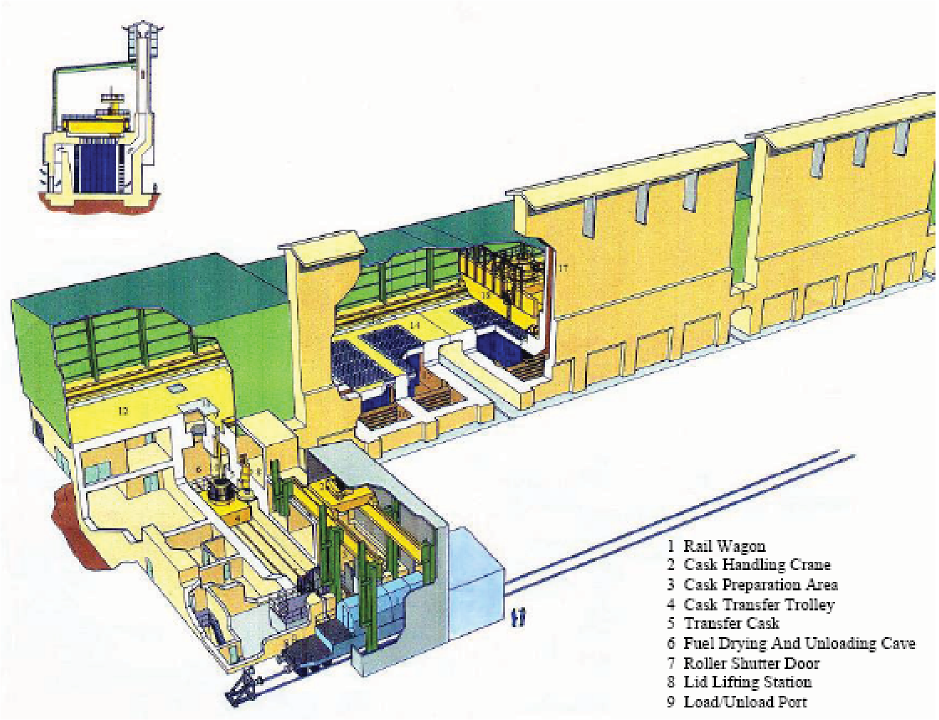
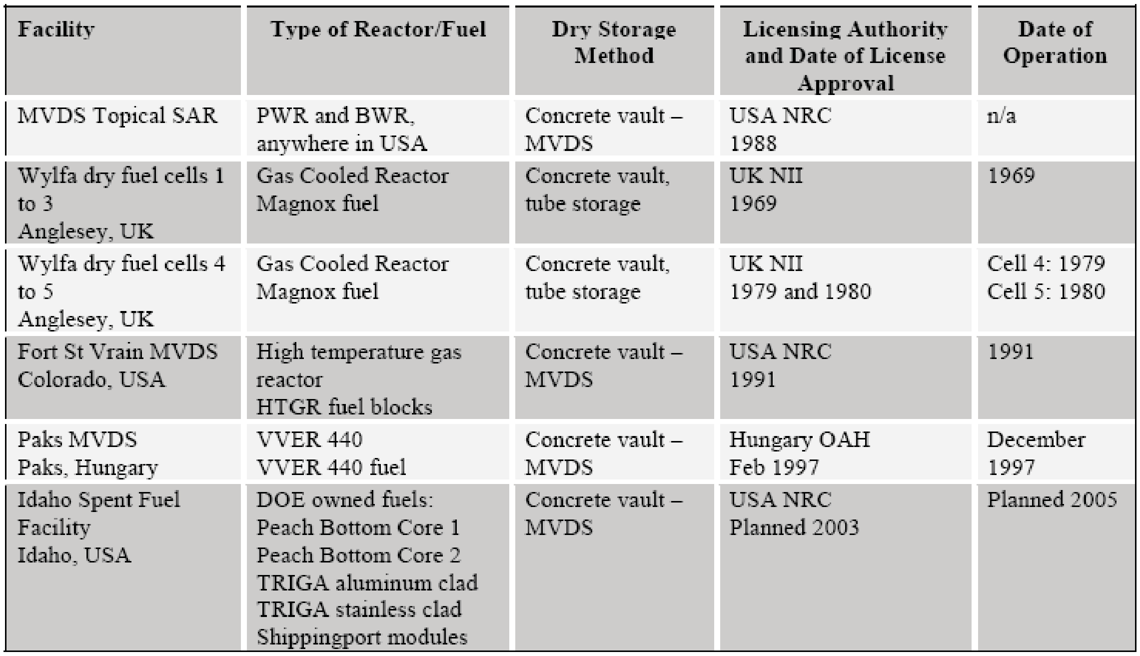


Figure E4-4. Schematic of modular vault dry storage of spent fuel at PAKS, Hungary (Ordogh et al. 2004).

Figure E4-5. Fort St. Vrain modular vault dry store (MVDS) showing charge face.

The status of MVDS facilities designed by Foster Wheeler and ALSTEC are shown in Table E4-6, below:

Table E4-6. Status of MVDS facilities by Foster Wheeler and ALSTEC (Roberts et al. 2003).



Facility	**Type of Reactor/Fuel**	**Dry Storage Method**	**Licensing Authority and Date of License Approval**	**Date of Operation**
MVDS Topical SAR	PWR and BWR, anywhere in USA	Concrete vault – MVDS	USA NRC 1988	n/a
Wylfa dry fuel cells 1 to 3 Anglesey, UK	Gas Cooled Reactor Magnox fuel	Concrete vault, tube storage	UK NII 1969	1969
Wylfa dry fuel cells 4 to 5 Anglesey, UK	Gas Cooled Reactor Magnox fuel	Concrete vault, tube storage	UK NII 1979 and 1980	Cell 4: 1979 Cell 5: 1980
Fort St Vrain MVDS Colorado, USA	High temperature gas reactor HTGR fuel blocks	Concrete vault – MVDS	USA NRC 1991	1991
Paks MVDS Paks, Hungary	VVER 440 VVER 440 fuel	Concrete vault – MVDS	Hungary OAH Feb 1997	December 1997
Idaho Spent Fuel Facility Idaho, USA	DOE owned fuels: Peach Bottom Core 1 Peach Bottom Core 2 TRIGA aluminum clad TRIGA stainless clad Shippingport modules	Concrete vault – MVDS	USA NRC Planned 2003	Planned 2005

Estimated dry storage costs from a variety of sources are given, see Table E4-7 (Fairlie 2000), that provide discussion of wide differences observed. A reasonable value of \$200K/t(iHM) is adopted with 2008 money value.

Table E4-7. Estimated dry storage costs for oxide spent fuels (Fairlie 2000).

STUDY	LWR FUEL, $K/t(iHM)
PAE-KfK (NuclearFuel 1993)	220[a]
OECD-NEA (1994)	225[b]
IAEA (1990)	82–165
Supko (1995)	50–100[c]
Wisconsin PS C (1994)	35–68[d]
Ontario Hydro, (Stevens-Guille, 1994; Nash, 1997)	15–20[e]

a. Undiscounted
b. Levelised fuel cycle costs
c. Representative life cycle costs
d. Constant $ analysis
e. Low burnup fuel. References given in Fairlie 2000.

Figure E4-6. Paks MVDS in 2000 showing natural convection cooling exhaust outlets (Ordogh et al. 2004).

German institutions give undiscounted estimates of about $225,000 per tonne of LWR fuel over indeterminate periods. Relatively expensive CASTOR spent fuel casks were used in these calculations. Estimated costs of U.S. and Canadian dry storage systems are significantly lower than European systems.

E4-6.2.2 Comparison with U.S. DOE HLW Vitrification and Interim Storage Costs

A valuable review and evaluation of interim storage facilities for application to Hanford Tank Waste Remediation System (TWRS) vitrified waste and Cs dry IX waste canisters was performed by Calmus (1996). He examined the four options of Standalone casks, Housing arrays, Vault storage, and Modification of existing major facilities to provide vault storage. The canister dimensions were vitrified waste: 0.61 m diameter × 3.0 m height (max 1 kW) or 0.61 m diameter × 4.57 m height (max 1 kW); and Cs IX waste: 0.33 m diameter × 1.37 m height (max 1.5 kW). The design requirements included air cooling. It was concluded that forced convection with high-efficiency particulate air (HEPA) filtration would generally be needed for reuse of existing facilities but natural convection with use of indirect cooling by means of loading waste canisters into storage sleeves (thimbles) was preferred for new facilities. Standalone casks and Housing arrays were found to be substantially more expensive.

Using passive above-ground air-cooled MVDS for vitrified waste canisters, Hanford TWRS estimated overall facility capital costs based on $37,000 (1996 mv) per storage tube of ~5 m tube height (Calmus 1996). A total of 2,000 tubes of ~5 m height then are required for 8,000 AVH type HLW canisters. This gives a capital cost of $74M (1996 dollars), which equates to around $106M (2008 dollars).

Idaho National Environmental and Engineering Laboratory (INEEL) reported a study of the Idaho Waste Vitrification Facilities Project—Vitrified Waste Interim Storage Facility (VWISF) (Aitken et al. 2001). Two scenarios were evaluated during this study. The first scenario includes individual storage tubes for the vitrified waste canisters (two canisters per tube) and a passive ventilation system. This option is called the “Hanford Option,” because it is modeled after the Hanford vitrified waste storage design. The second scenario includes racks for holding the vitrified waste canisters and a mechanical ventilation system. The second option is labeled the “Savannah River Option,” since it is modeled after the Savannah River Site’s vitrified waste storage facility. The second option has lower total project cost, but higher life cycle cost. The costs interpolated here are for the first option. The major waste product resulting from the treatment process will be a vitrified waste glass. The glass will be placed in canisters approximately 15 ft (4.5 m) long × 2 ft (0.6 m) in diameter referred to as “Hanford Canisters.” Under a “high” waste loading scenario in the IWVF melter, this will result in approximately 436 canisters of the treated SBW and 4,600 canisters of the treated calcine. Two canisters are stored in each Hanford thimble tube, which is equivalent to around 10 AVH type HLW canisters. This gives a capital cost of ~$95M (2001 dollars), which equates to around $126M (2008 dollars).

E4-7. LIMITATIONS OF COST DATA

The information obtained for these facilities is at a very high level. Additional details are not currently available.

E4-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table E3-7. The summary shows the reference capital cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The following cost values are proposed, which are summarized in Table E3-7:

1. This module determined a cost range for 300-year decay storage of immobilized, heat-generating, mixed cesium-strontium (CsSr-BaRb) waste such as generated by the AFCI UREX+ based fuel cycle and a reference waste immobilization and storage process defined here. The period of storage may allow subsequent shallow disposal as LLW.
2. The life cycle cost estimates for storage of CsSr waste are $22.5K/kg (CsSr) nominal, $10K/kg (CsSr) low range, and $35K/kg (CsSr) high range. The estimates use 2008 money values and are based on mass of cesium and strontium in elemental form (i.e., do not include Rb, Ba, oxide, or other glass or ceramic forming elements).
3. Due to the uniquely long lifecycle period, ~350 years for construction through decommissioning, of the CsSr storage facility (normally nuclear facilities have a lifecycle of <100) the summed operational costs significantly exceed the initial capital cost (e.g., by one order of magnitude). Under these circumstances, discounting of all costs following 100 years of operation may be more appropriate for decision analysis and the low range value includes this effect to some degree.
4. The operational expenditure cost estimates are based on facility design that is operationally conservative (i.e., assumes full 24 hour, 365 day per year) manning for the full period of storage even when decay power has reduced substantially, and are technically conservative, appropriate to the long period of storage, through adoption of modular vault dry stores, passive cooling, multiple containment barriers, and refractory waste form (borosilicate glass) of relatively low specific decay power. New melter types and higher transition temperature glasses may enable higher CsSr-Rb-Ba loadings, which can reduce container numbers and storage requirements.
5. Due to the unusual cost structure, optimization of facility design in relation to progressive reduction of staffing consistent with decreasing hazards with eventual remote monitoring and control and periodic inspection may yield significant reduction in undiscounted cost. This is analogous to “Safestor” designs for radioactive decay of nuclear reactor structures prior to decommissioning. Further cost and design studies are needed to substantiate potential cost reductions. Table E3-7 is the cost summary table of selected values for managed decay storage.

Table E3-7. Cost summary table of selected values for managed decay storage.

What-It-Takes (WIT) Table				
Reference Unit Capital Cost based on xx MT(TRU) Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
\$/kg(kg(Cs/Sr) For storage of Cs/Sr in remote handling facility	(± 25%)	\$10,000/(kg(Cs/Sr)	\$35,000/(kg(Cs/Sr))	\$22,500/(kg(Cs/Sr)

The triangular distributions based on the costs in the WIT Table E3-7 are shown in Figures E3-9 and E3-10. Figure E3-9 gives the estimated cost frequency distribution for the advanced fuel cycle product from, for example, UREX+ processing, (i.e., mixed plutonium, minor actinide, and uranium oxide material). The costs for the similar component metallic product from molten salt electrochemical processing are less well known, and until further work is performed may be taken as similar to the UREX+ oxide product.

E4-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

None performed to date.

E4-10. REFERENCES

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Module F1

Spent Nuclear Fuel Aqueous Reprocessing Facility

Module F1

Spent Nuclear Fuel Aqueous Reprocessing Facility

F1-1. BASIC INFORMATION

The spent nuclear fuel aqueous reprocessing facility is used for separations of spent nuclear fuel elemental components to support recycling of fissile materials, transmutation, decay management of selected actinides and fission products, and segregated immobilization, storage, and disposal of remaining materials as different classes of wastes. The generic facility consists of a spent nuclear fuel receiving area, processing buildings (chemical separation area), interim storage facilities for both spent nuclear fuel and separated products, and support buildings for utilities, offices, and laboratories. The plant may also include collocated waste solidification, special nuclear material secured storage, reprocessed uranium conversion facilities, and mixed oxide (MOX) fuel fabrication facilities.

A major feature of the reprocessing facility is the need for massive processing buildings. Multistory, below-grade, heavily shielded operating cells are typical. These building areas may be completely buried or bermed for parts of the process involving separated minor actinides. These large spaces are maintained at negative pressure to manage airborne particulate contamination, generally requiring large banks of high-efficiency particulate air (HEPA) filters.

Several approaches to aqueous separations exist or are under consideration, ranging from "conventional" Plutonium-Uranium Extraction (PUREX)-based, oxide fuel separation facilities with pure uranium and plutonium oxide products, such as THORP and La Hague, to multistep UREX+ process concepts that separate many actinides and fission products for tailored recycling or disposal. The latter, more complex separations possibly make better use of geologic repository space (Laidler 2003; Vandegrift et al. 2004).

F1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Front End. Spent nuclear fuel arrives at the facility by truck or rail. Cranes lift the shipping casks and move them inside to unload the spent nuclear fuel into a temporary storage area (wet or dry storage). Head-end processing begins either with use of a massive shear to cut the fuel assemblies without dismantling or with mechanical separation of the fuel rods from the balance of the fuel assembly hardware followed typically by cropping the fuel rods into short segments. The fuel is acid-leached from the chopped fuel rod, and the cladding hulls are washed and prepared for disposal as Greater-Than-Category-C (GTCC), low-level waste (LLW)—depending on their radioactivity level—or for possible recycling and reuse.

Aqueous Separations. The dissolved fuel is generally passed through a series of aqueous-organic solvent extraction processes to achieve chemical separations. The number and order of steps is dependent on the number of product streams. These separate liquid streams, typically nitrate solutions, are then subject to further processing to obtain the desired products or prepare them for waste handling. The PUREX process results in two primary product streams: a converted uranium form (uranium nitrate hexahydrate [UNH], salt, a uranium oxide, or UF_6) and PuO_2, and a primary high-level waste (HLW) stream that contains the fission products and minor actinides. The UREX+ process has more product or by-product streams, including purified uranium suitable for disposal or recycle. Cesium/strontium and technetium streams can be separated from the other fission product streams, and a suite of minor actinide by-products can be separated and tailored to meet specific fuel cycle by-product objectives (such as Pu/Np/Am/Cm, Pu/Np, Am/Cm, or americium separated from curium).

Back End. The back end process includes product storage and shipping facilities, and waste processing, storage, and shipping facilities. The most valuable products are fissile materials or special nuclear materials requiring secured storage and shipping. Collocation of fuel fabrication facilities, such as a MOX facility, can eliminate secured shipping requirements of separated materials as well as provide for synergy of meeting security requirements. Waste processing is necessary to stabilize and solidify liquid waste streams. Streams containing volatile products such as iodine, tritium, and noble gases must also be processed and packaged in appropriate disposal media and containers.

Figure F1-1 shows an example of a UREX+ aqueous reprocessing process flow. The front-end process consists of the dissolver (chop-leach process) with the cladding hulls going to recycling or disposal. The primary aqueous separations are completed in the UREX+ steps, which consist of chemical processes that separate uranium, Cs/Sr, Pu/Np, and Am/Cm. Another alternative is to produce a uranium/group-transuranic oxide product that can be used as actinide burning fuel in fast reactors. This fuel material has the additional qualities of proliferation resistance due to the presence of a much higher radiation field. The back-end processes include denitration, immobilization, storage and decay-storage, uranium LLW disposal or storage, and fission product treatment, packaging, and shipment to the HLW repository.

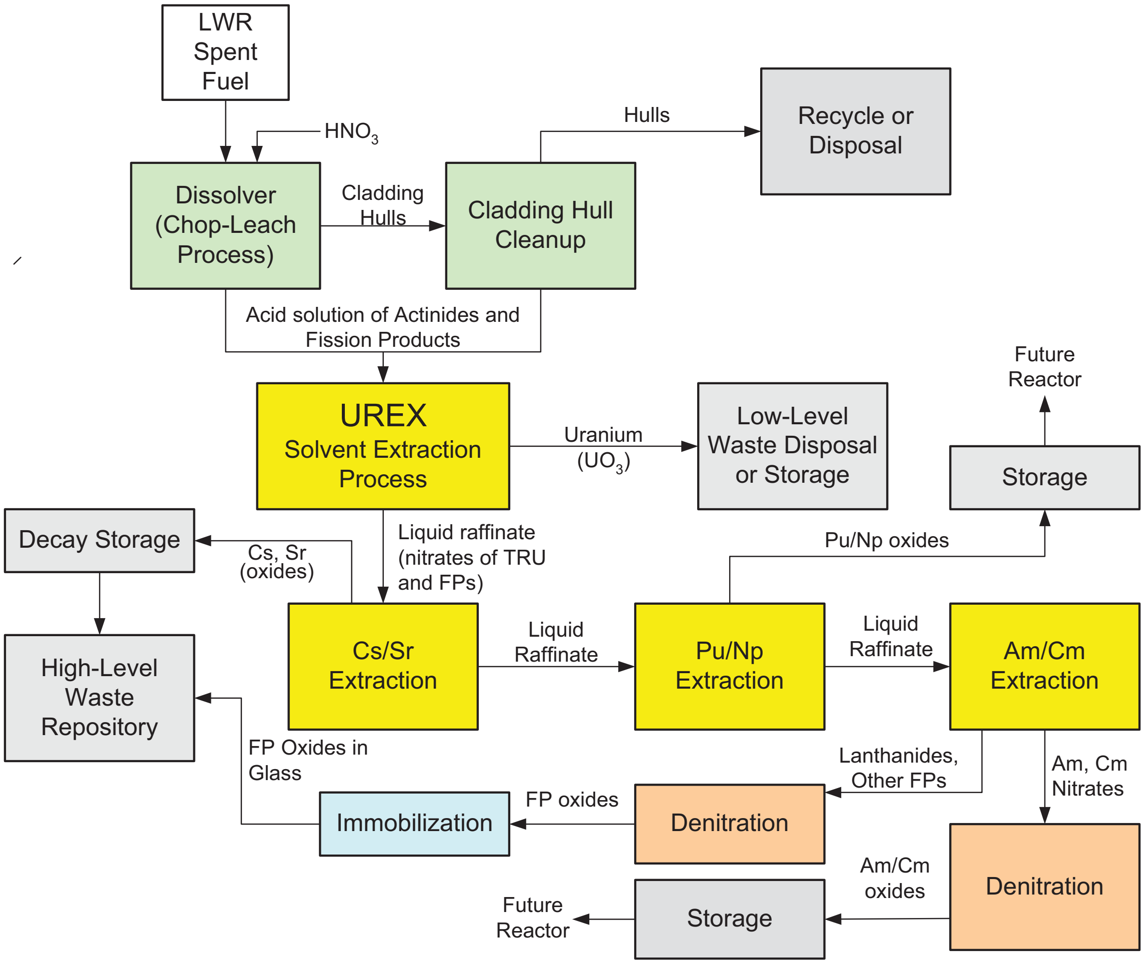

Figure F1-1. Example of UREX+ aqueous reprocessing process flow (Laidler 2003).

F1-3. PICTURES/SCHEMATICS

The following pictures, Figures F1-2–F1-4, show reprocessing sites with currently operating PUREX facilities in France and the U.K., and another site in Japan with a PUREX plant now in the commissioning phase. Some of the buildings shown are not directly part of the reprocessing capability, but support other collocated functions.

Figure F1-2. La Hague site, France, with reprocessing plants, UP2-800 and UP-3 (AREVA).

Figure F1-3. Sellafield site, U.K., with THORP and B205 reprocessing plants (BNFL, plc).

Figure F1-4. Rokkasho-Mura site, Japan, with Rokkasho Reprocessing Plant (JNFL).

F1-4. MODULE INTERFACE DEFINITION

This module interfaces with upstream reactor (Modules R1 and R2) and spent nuclear fuel storage modules (E1 and E2) that supply the spent nuclear fuel, downstream recycled product storage (Module E3 for higher actinides and Module K2 for separated uranium), fuel fabrication (Module F2/D2 for MOX), HLW conditioning/storage/packaging (Module G), waste storage (Module I), and disposal modules (L and M). As noted previously, it is advantageous to collocate the separations and recycled fuel fabrication facilities to share the costs of security and storage as well as minimizing the need for dedicated secure transport for the separated fuel fabrication feed materials.

F1-5. MODULE SCALING FACTORS

There are many aspects that impact the scaling of reprocessing plants. A schematic of drivers relating to UREX+ conceptual design is provided in Figure F1-5 as an example. One important factor is appropriate equipment selection in conjunction with the engineering approach used to achieve operational functions of availability and maintainability. Others are flow-sheet adopted; maximum line size for particular separations equipment that can be made criticality safe; the need for fuel receipt, head-end (and fuel fabrication if included) equipment to meet full-scale reactor fuel assembly size regardless of how low the fuel throughput may be; the criticality safety approach adopted (extremes are administrative control versus inherently safe [e.g., geometric control]); margins to accommodate extreme burn-up (low and high) fuels; fuel decay time; overall decontamination factors; recovery factors; and close coupling or de-coupling of process steps, waste management, reagent recycle, etc.

M. Jonathan Haire assessed several plant designs developed in the 1970s and early 1980s and noted that availability improves with designs that include redundancy, although this redundancy comes at a cost of duplicate equipment, additional facility size, and increased operational complexity (Haire 2003). As facilities scale up, parallel process trains may provide increased operational availability, though at reduced throughput, without further equipment duplication. Since the capital cost of small to medium capacity PUREX plants is insensitive to scale (see below), construction of two “small” plants to ensure near constant reprocessing availability has an economic disadvantage.

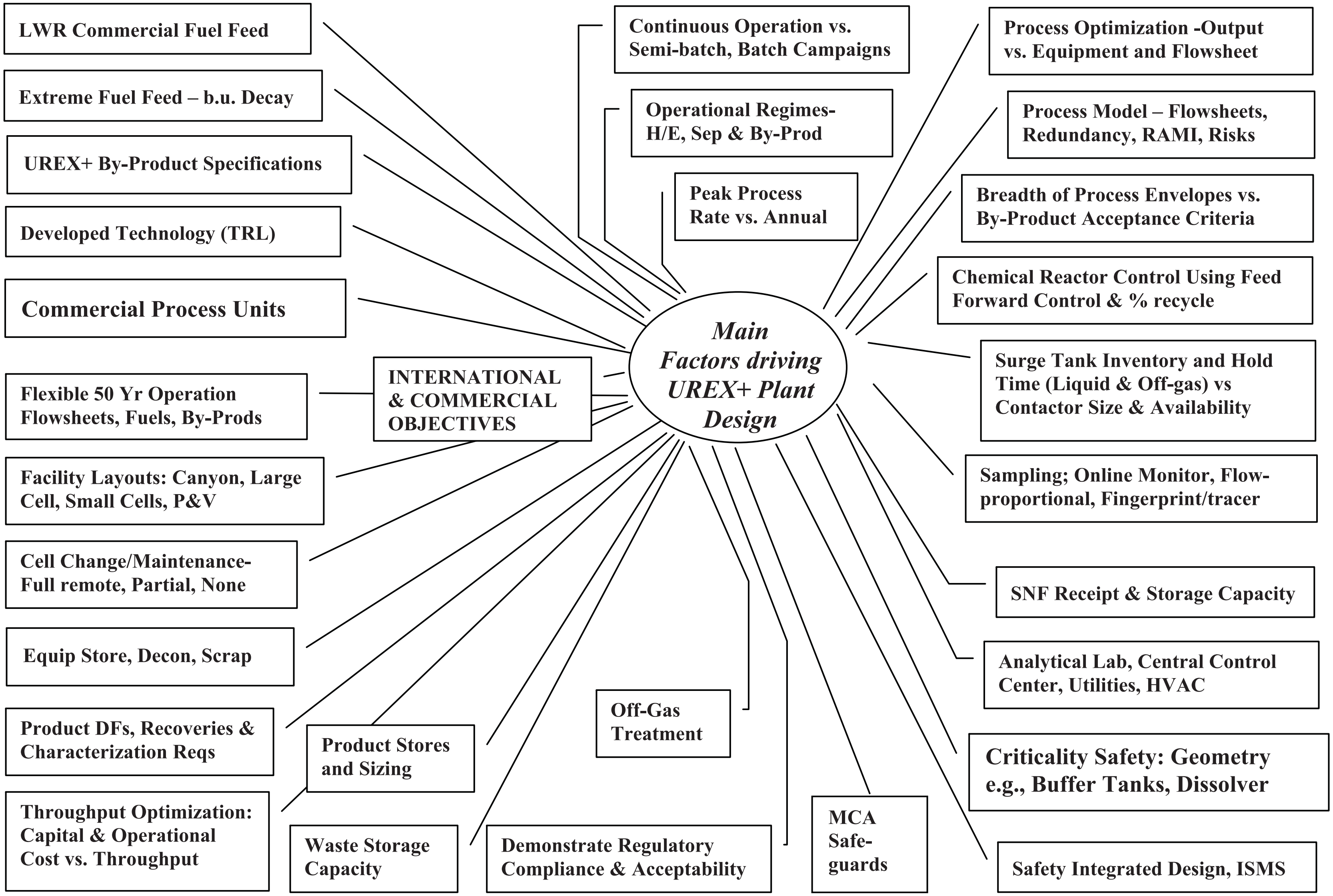

Figure F1-5. Schematic of drivers for UREX+ Plant Concept Design.

Haire also noted two maintenance approaches. The first approach involved a "canyon-type" facility allowing for remote equipment replacement via overhead cranes. The second approach, which was to be used in the Barnwell, South Carolina, reprocessing plant, is to place failure-prone equipment in shielded alcoves for easier access in a primarily contact handling-based maintenance mode. While the fully remote maintenance approach involves larger facilities, and therefore higher costs, the canyon design for small throughput plants may require fewer changes with scale-up and provides flexibility to adapt to process evolution, changing fuel or product specifications, or other requirements. However, the progressive reduction in permissible dose levels and the application of "as low as reasonably achievable" now further restricts the use of this second approach.

An additional third approach, which has been used in Europe for chemical separations in particular, is to use "dark cells," which require no planned maintenance for several decades, but may require tailored remote intervention afterward if initial design and operation is unsuccessful. THORP designed in the 1980s generally favored this approach by adopting remote maintenance of the massive shear/shear pack and full-life-of-plant "zero-maintenance" chemical separation equipment using airlifts, vacuum-operated slug lifts, reverse flow diverters, steam ejectors, vacuum lifts and through-wall drives for CVFs, and non-wetted flow actuators using compressed air. Valveless maintenance-free diverters and distributors are used. There is limited hot-cell access for maintenance work. Overall commercial facility design is often a hybrid of these. However, it should be noted that a fully remote canyon facility has never been constructed for the commercial nuclear fuel sector, but only for defense applications, which may be less cost sensitive.

The final factor noted by Haire is a difference in the scaling of facilities that process thermal and fast reactor fuel. The lower total heavy metal content and higher fissile content (fraction) of fast reactor fuels results in relatively larger front-end processes and the need for more criticality control features. This added complexity may result in additional unit cost for both capital and operations, though Haire added that this effect becomes insignificant at lower design throughputs (e.g., 300 MTHM/year), which is substantial for a FR processing plant [e.g., supports about 15 commercial scale fast reactors, each of ~1 GW(e)].

For the above and additional reasons, Haire differs with several other authors in avoiding the use of a constant 0.6 scaling factor as is commonly used in non-nuclear industry sectors (e.g., chemical and oil) (NAS 2000; Bunn et al. 2003). Instead he notes, "In the familiar rule of thumb scaling law, capital costs are proportional to the *n*th powers of capacity; however, *n* is not a constant. The value of *n* approaches 0.1 for very small-capacity plants and 0.9 for very large plants" (Haire 2003). This results in diminishing returns for scale-up. Haire recommended an optimal size for a reprocessing plant of ~2,500 MT/yr. Spencer et al. (2003) extended Haire's work to include several additional plant designs, supporting the development of a scaling curve, showing the difference in plant cost versus design throughput (Haire 2003). This curve is provided in Figure F1-6. While the bottom of the curve is at ~7,000 MT/yr, they noted very little unit cost difference between 2,000 and 10,000 MT/yr. A throughput of 7,000 MTHM/yr may require four to seven solvent extraction lines. Data for capacities beyond 10,000 MT/yr are questionable or suggest a capacity point where multiple plant locations become the only practical siting means, thus the unit cost increases.

However, the influence of line throughput and solvent exchange contactor types was not explicitly recognized. For a low burn-up fuel and use of mixer-settlers, where criticality safety restrictions from the relatively low Pu level are less significant, the actual throughput may be 1,500 MTHM/yr using a single line of contactors, for example the British Nuclear Fuels plc (BNFL) Magnox B205 plant at Sellafield. Cap La Hague, Thermal Oxide Reprocessing Plant (THORP), and now Rokkasho show that throughputs of 800–1,000 MTHM/yr are achievable with LWR oxide fuels using pulse columns of diameters in the range 300–500 mm. Beyond this, criticality safety restrictions become dominant and multiple-line plants or multiple single-line plants seem to be required. Given the complexity of reprocessing technology and relative lack of design standardization and operating experience, at least compared to LWR technology, the tendency has been to minimize risk to capital by constructing independent reprocessing plants. It is arguable that with current practice the minimum of the cost curve shown in Figure F1-6 should appear near the single line value, probably in the range 1,000 to 2,000 MTHM/yr. The latest generation U.S. designs appear to build on Savannah River Site (SRS) DuPont philosophy by extensive use of centrifugal contactors with their operational benefits of high availability and rapid re-start of processing, but concomitant requirement for fully remote operation and maintenance. While SRS has used designs of centrifugal contactor banks that appear to support single line throughputs of 1,000 MTHM/yr, the safety limit of centrifugal contactor diameter and associated throughput does not appear to have been established. Optimization, concerning process remote equipment versus capital cost and throughput, needs further development and appears critical to future plant design.

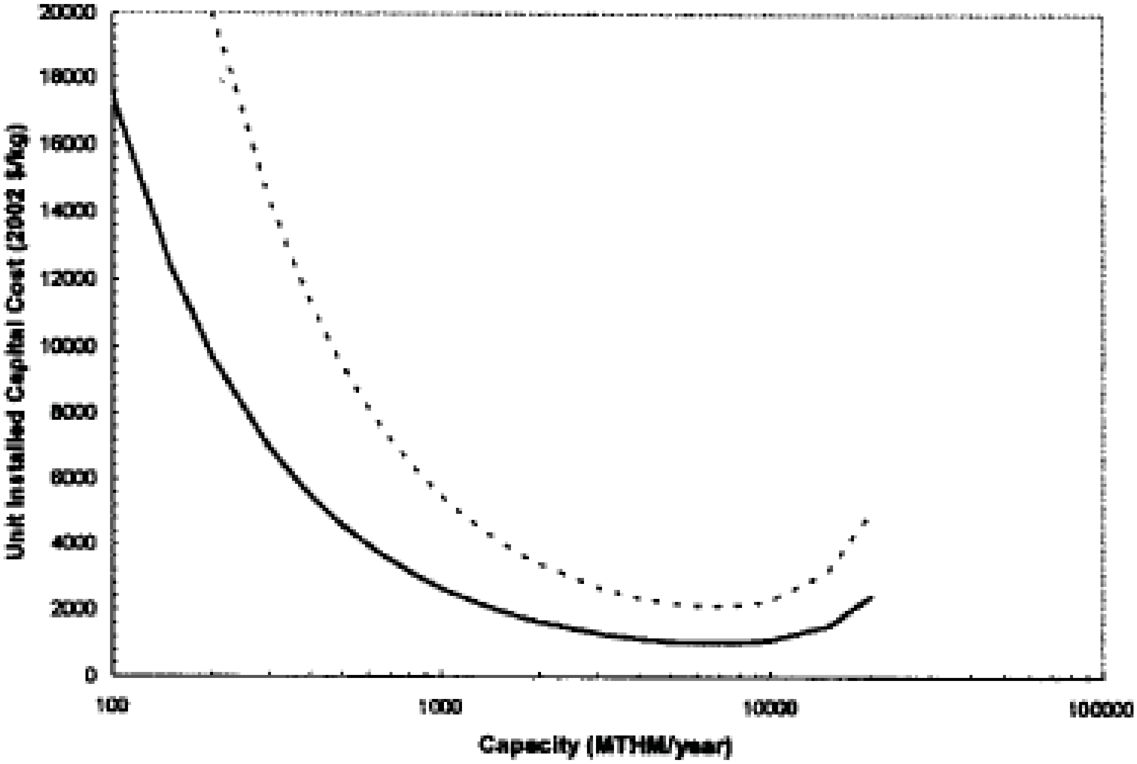

Figure F1-6. Reprocessing unit installed capital cost versus capacity (Haire 2003).

The four Cap La Hague and Sellafield operating PUREX reprocessing plants are at coastal sites and use sea discharges of low-level liquid wastes. The processing plant for these at Sellafield is significant in cost. (Alpha discharges decreased by 100-fold over past 10–20 years due to pressure from Eire and Scandinavia.) This cost should be included in reprocessing since it is affected by reprocessing plant design (e.g., salt-free flowsheet and degree of recycle to high-level liquid waste). If, as expected, UREX+ were to be a zero liquid discharge plant with inland siting, this may well increase costs. Rokkasho is also at a coastal site and may have liquid discharges.

It may be worth noting that PUREX and UREX+ processes were developed in different historic time periods with different aims and design requirements. There are also potential processes intermediate in complexity to PUREX and UREX+ that use tributyl phosphate (TBP) and complexants to form uranium and mixed TRU products together with HLW. AREVA and British Nuclear Group (formerly BNFL) already store vitrified HLW in passive air-cooled vaults for decay of high heat, intermediate half-life emitters such as cesium and strontium.

A factor further affecting scaling is the number of separations to be handled by the design. In a small plant, each additional separation stage adds an increment of complexity, including the separation equipment, process control, additional in-process holdup, and product storage. However, since the latter separations typically involve small volumes (once the uranium, which is over 92% of the heavy-metal mass, is removed), considerable scale-up can be accommodated without substantial additional complexity provided that close coupling of process steps can be tolerated, flexible process envelopes are available, criticality safety and mal-operation scenarios, and process analytical requirements can be met. For UREX+, where there are a larger number of specified products (each by-product or "waste" stream has a specification rather than being a residual). The early removal of uranium is helpful in reducing chemical process mass, but it may be more valuable to remove Pu with some U/MA (for non-proliferation reasons), and then the buffer tanks presently needed between separation areas would be much less expensive (presently a significant contributor to overall capital cost) as they may not need to be safe regarding criticality. Also removing U does not necessarily substantially reduce the liquor volumes and equipment/cell sizing since these may now be governed by Pu concentrations and flowsheet chemistry to achieve desired decontamination factors (DFs).

Using data from the Consolidated Fuel Treatment Center (CFTC) studies the cost was fitted using the logarithmic relationship:

$$CostofA = CostofB\left(\frac{CapacityofA}{CapacityofB}\right)^{n}$$

Where, capacity is expressed as instantaneous design capacity (MT/yr), and the exponential factor is typically in the range of about 0.6. However, due to the inherently high structural costs associated with highly shielded and remotely operated nuclear facilities not found in typical industrial operations, the power law exponent is expected to be less than 0.6. The preceding equation indicates that a log-log plot of the capacity versus cost should be a straight line with the slope equal to the exponent. Therefore, the CFTC reprocessing Total Project Cost (TPC) estimates for different UREX+1 capacities shown below were used to determine the power law factor was equal to about 0.42 over the range of capacities from 800 to 3000MT/yr.

F1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

F1-6.1 Historical Cost of Existing Facilities

The cost basis for aqueous reprocessing should be straightforward because several facilities have been built and run in the last 50 years, and there are current contracts for reprocessing services. However, most of these facilities were related to military programs, and little information is available for them. The two existing commercial reprocessing sites have published only rather limited cost data because the information is considered proprietary.

Current prices charged for spent nuclear fuel reprocessing services at La Hague are ~$900/kgHM (NAS 2000). This should provide a base cost from which to work. However, the above price includes other services such as transportation, storage, and some waste disposal. Thus the reprocessing service alone is a lesser scope than this. The term "reprocessing service" is used to distinguish from the actual cost of reprocessing. Bunn notes the prices of reprocessing services at existing facilities in Europe were initially artificially high to cover capital costs, and prices have come down as the capital costs have been recovered and demand has reduced (Bunn et al. 2003). But these may now be coming below long-term economic cost, for example leading to the planned closure of THORP in 2010. A number of European countries have removed the legal duty on their electric utilities to contract for reprocessing of their spent fuels. The fact that one of these services is being offered at a particular price does *not* in itself demonstrate that its full cost must be at that price or below.

The UREX+ suite of processes are much different from the traditional PUREX. The UREX+ processes use multiple solvents and complexants increasing the number of separations stages required to meet the objectives of the program, which are quite different from the traditional reprocessing in Europe and Japan. The main transuranic product of the UREX+ process is also a significant heat generator that adds complexity. Therefore, there is no direct comparison that would seemingly match. Even the proposed initial front-end shearing, voloxidation, and dissolution is more complex in UREX+ due to higher TRU recovery requirements.

While direct construction and operating cost information on the THORP and La Hague plants are limited, there are a large number of independent cost studies of reprocessing facilities with various functional and operational requirements. There are also a number of studies of designs that were not built or operated. Rather than assess each of these studies, the work of others is referenced in integrating these different sources (Spencer 2003; AREVA 2004). Also, the 2004 scoping study is referenced for a UREX+ Spent Fuel Treatment Facility (SFTF) conducted for the Advanced Fuel Cycle Initiative (AFCI) program. And, the more detailed information available is used from this source to establish the code of accounts relative cost splits (WGI 2004).

The scaling studies sited previously recommended the optimal size of a reprocessing facility to be approximately 2,500 MT/yr. The design life of an aqueous processing facility has not been well established. The cost studies referenced above are based on a range of operating lives from 15 to 30 years. A longer life stretches out repayment of capital, reducing per unit cost, but it increases the risk of substantial equipment replacement and changed regulatory and commercial requirements. Given the large amounts of commercial spent nuclear fuel projected, any new reprocessing facility developed in the U.S. should be designed for a long life. The most economical would be a plant size of at least 2,500 MT/yr and an operating life of at least 40 years, resulting in a total processing throughput of 100,000 MTHM (or more).

However, an operating lifetime of 40 years may not always be desirable given that parts of the plant see aggressive conditions and that plants are normally designed to be economic for particular flowsheets and not easily converted to new standards such as much higher fissile contents/burnups. It may be reasonable and conservative to assume a 20-year economic lifetime since this period is likely to be met, and then further operation involving replacement of equipment to continue processing or meet a new flowsheet can be considered. At commercial interest rates, any operation after 20 years has lower impact, but it does reduce unit costs for near-zero interest rates.

F1-6.2 Studies of Advanced Reprocessing Facilities

DOE has conducted two pre-conceptual design studies for reprocessing. The Engineering Alternative Study (EAS) developed Life Cycle Cost (LCC) estimates for a 3,000MT/yr UREX+1 based reprocessing center. The facility included segments to receive and manage SNF, dissolve the fuel core from inside the cladding material, and use the UREX+1a process to separate the various components of the SNF. In addition, the facility treated all product and waste streams to acceptable forms either for further processing into a proliferation-resistant fast reactor fuel, or for disposal. The design concept included a fully remote canyon-type operation. LCC estimates were developed assuming a 40-year life. The LCC included extended product and waste storage facilities to allow, for example, the HLW and Cs/Sr waste to decay prior to disposal.

The second study or Follow-on EAS (FOEAS) modified a number of programmatic and engineering assumptions used in the EAS. This included the waste and product disposition paths, which were assumed to be available so that storage facilities were limited to those required for buffer storage, the canyon concept was optimized to allow better utilization of the shielded space, the ventilation system sand filters were replaced with HEPA filters, and the Cs/Sr treatment process was revised to reduce the waste storage requirements.

The FOEAS also developed LCC estimates for a number of alternative processes, including a UREX+3 in which U/Pu/Np and Am/Cm are separate products, and a simpler processing scheme in which only the U/Pu are recovered and the minor actinides are combined into a single HLW borosilicate glass. An electrochemical alternative was also developed (see Module F2/D2).

F1-7. LIMITATIONS OF COST DATA

Direct construction and operating costs of commercial facilities are not available from the construction and operating companies. Even if direct costs were available, they would provide only around four data points for one technical approach (PUREX) under one financing scheme for one facility size (though near optimal scale using pulse column technology with “dark cells”).

The number of cost estimates for the UREX + technology is more limited. There are also a number of options of technologies for waste processing, including collection and stabilization of key fission products (e.g., cesium, iodine, strontium, and technetium) and stabilization of the HLW component. Many of the newer technologies have high technical uncertainty that equates to high uncertainty in the limited cost data.

Technical improvements are possible and even probable after a facility is completed. One study estimated process improvements, and improved operating experience at La Hague would result in an 85% reduction in waste volume per unit processed over a 10-year period (NEA 1994). Such dynamics can result in changes in operating costs over time for the same facility, making comparisons between facilities even more difficult, though these changes may be more for environmental and acceptability reasons and could possibly lead to increased costs.

Given the size of reprocessing facilities and the long construction time, financing is the major cost. The difference in financing costs alone of a government-financed facility and a for-profit private facility of the same size can result in a factor of approximately 2.5 increase in the total facility cost (Bunn et al. 2003; WGI 2004). The existing commercial facilities in France and the U.K. were developed under unique customer financing arrangements. New facilities are likely to also be developed with special financing, including heavy government involvement.

While the costs for this module are based on 2005 dollars, this adjustment provides an incomplete picture. The prevailing interest rates at the time and place of the cost estimate are potentially a larger impact than changes due to inflation. Most of the studies referenced here used a 5% discount rate, but some other earlier studies assumed interest rates as high as 12%. Given construction periods of 6 to 10 years or longer, this difference from 5 to 12% was estimated to increase unit costs by 70% (WGI 2004).

The method used to adjust costs to current year dollars can also impact cost estimates. For example, Bunn’s use of a gross domestic product deflator approach (Bunn et al. 2003) results in ~20% higher adjusted costs from the Nuclear Energy Agency, Organization for Economic Cooperation and Development study (WGI 2004) than is developed by using the Engineering New Record’s “Construction Cost Index History” (ENR 2009).

F1-8. COST SUMMARIES

A number of capital cost estimates have been included as part of the studies in the referenced analyses. For example, Haire includes reference capital costs for facilities ranging in capacity from very small (15 MTHM/yr) to large facilities (3,000 MTHM/yr) (Haire 2003). The National Academy of Sciences study on "Nuclear Wastes: Technologies for Separations and Transmutation" also has numerous tables with cost data in its Appendix J (NAS 2000). This study along with that of Bunn et al. are the most comprehensive studies to date in the area of reprocessing costs (Bunn et al. 2003). Table F1-1 provides the reference capital costs along with the inflator factor and the equivalent costs for 2005.

Significantly larger escalated capital costs (from $5B to $7B) for some of the facilities above are reported in the National Academy of Sciences 2000 article. These values may include some costs for onsite facilities covered in other modules, such as vitrification of high-level reprocessing wastes (G Module). The estimated actual costs for the La Hague (France) and the Rokkasho-mura (Japan) plants are reported (1996) in this range in a report from The National Academy of Sciences (NAS 2000). However, more recent capital costs for Rokkasho-mura are estimated at over $20B.

Data from the EAS and FOEAS have been adjusted from those provided in the references reports (WSRC 2007, 2008a). These costs have been distributed within the various modules in this report. The data presented in Table F1-1 for the 3000 MT/yr reprocessing alternative have also been adjusted from that presented in the reference document (WSRC 2007). Adjustments were made to ensure the assumptions and design attributes were consistent with the 800 MT/yr cases. These adjustment include the elimination of sand filters and inclusion of additional footprint for HEPA filters, a reduction in the hardened footprint to reflect an optimized canyon equipment arrangement developed as a part of the FOEAS, and elimination of future project cost from the LCC to reflect a consistent assumption that waste disposal facilities were available such that multiple waste glass storage buildings were not required.

The most recently constructed reprocessing facility is the 800 MT/yr Rokkasho-mura facility with a stated capital cost of $20B including MOX fuel fabrication and other associated reprocessing facilities. Using values for support modules from the EAS studies (MOX fuel fabrication [$4B to $5.1B], the HLW vitrification [$3B to $4.4B], the U/Pu vault [$0.75B to $1.0B] and U solidification and storage costs [$0.25B to $0.33B]) provides a Rokkasho reprocessing core plant cost of $9.2B to $12.0B. This compares to about 15% of the core FOEAS Co-Extraction (Co-Ex) reprocessing plant with an estimate range of $10.2B to $14.2B.

The FOEAS estimates have also been compared to the estimates developed under federal grants. The FOEAS Co-Ex and industry estimates were found to agree within 15% after adjustments were made to align the scope of the pre-conceptual designs and estimate bases (WSRC 2008b).

Based on the agreement of the FOEAS estimates with industry and the most recently deployed commercial reprocessing facility, the FOEAS is used as the basis for selected values for reprocessing.

Table F1-1. Capital cost and throughput estimates for various reprocessing plants design studies and actual facilities.

Plant or Design Study (Complete construct/ operate/design study)[24]	Design Rate MT/day (days/yr)	Planned Throughput MTHM/yr	Actual Throughput MTHM/yr	100% Capacity MTHM/yr	Ref. Capital Cost ($B)	m.v. Basis Year	Inflator Factor	Capital Cost 2005 ($B)
Windscale B205(1964-)[1]	**7 (214)**	**1,500**	**~500-1,500**	**2,555**	**-**	**-**	**-**	**-**
West Valley (1966-72)[2]	**1 (300)**	**300**	**~110 (640 – 6y)**	**-**	**-**	**-**	**-**	**-**
HTGR Ref. RP (1969)[3]	-	260	Design/cost	-	0.060	1969	~4	0.24
GE Morris (1974)[4]	**3**	**(900)**	**Inoperable**	**1,095**	**0.064**	**-**	**~4**	**0.26**
AGNS Barnwell (1974) [5]	**5 (300)**	**1,500**	**Not operated**	**1,825**	**1.50**	**1983**	**1.8**	**2.7**
Exxon (1976)[6]	Est. 1.7 (300)	500	Design/cost		0.99	1978	2.6713	2.64
Exxon (1976)[6]	Est. 5 (300)	1,500	Cost estimate	-	1.5	1983	1.8	2.7
IAEA (1976)[7]	-	300	Cost estimate	-	0.48	1976	3.0786	1.48
IAEA (1976) [7]	-	750	Cost estimate	-	0.70	1976	3.0786	2.16
IAEA (1976) [7]	-	1500	Cost estimate	-	1.05	1976	3.0786	3.23
IAEA (1976) [7]	-	3000	Cost estimate	-	1.72	1976	3.0786	5.30
Tokai RP (1977-)[8]	**0.7 (143)**	**100**	**40 (1,123 -28 y)**	**255**	**-**	**-**	**-**	**-**
RT-1 Mayak (1977-)[9]	**1 (200)**	**200**	**146 (3,500 -24y)**	**400**	**-**	**-**	**-**	**-**
DuPont (1978)[10]	5 (300)	1,500	Design/cost	1,825	2.4	1983	1.8	4.3
DuPont (1978)[10]inc. fab	10 (300)	3,000	Design/cost	3,650	3.7 inc fuel fab	1978	2.6713	9.0
CFRP FR Dem (1979)[11]	0.1 (150)	15	Design/cost	30	0.80 ± 0.2	1982	1.8808	1.50
CFRP Hot Exp (1979)[12]	0.5	-	Design/cost	183	1.0 ± 0.25	1982	1.8808	1.88
EDRP FR UK (1984)[13]	0.3 (250)	75	Design/cost	110	0.42 (£0.24B)	1982	1.8808	0.79
GE ALMR (1990)[14] fab	-	2,700	Design/cost	-	5	1990	1.4	7
EPRI Study (1990) [15]	-	1,500	Cost study	-	3.0	1990	1.4	4.2
UP-3 (1990-)[16]	**5 (160-200)**	**800 (1,000)**	**800+**	**1,825**	**6.2 (28BFF'92)**	**2003**	**1.1**	**6.8**
OECD study (1994) [17]	~5 (180)	900	Cost study	1,825	4.1B (£2.7B)	~1993	1.3623	5.5
THORP (1994-)[18]	**5 (120)**	**600**	**600**	**1,825**	**4.1 (£2.3B)**	**1992**	**1.37**	**5.6**
UP2-800 (1994-)[19]	**5 (160-200)**	**800 (1,000)**	**800+**	**1,500**	**5.8 (37BFF'00)**	**1990**	**1.4**	**8.1**
SFTF – UREX+ (2004)[20]	7.4 (270)	2,000	Design/cost	2,700	3.0	2004	1.05	3.2
Rokkasho (2007-8) [21]	**5 (160)**	**800**	**Commission**	**1,500**	**5.2-6.5**	**1992**	**1.37**	**(~20)**
COEX^{TM}–AREVA (2006)[22]	8.3 (300)	2,500	COEX^{TM} design	3,030	16.2 inc fuel fab	2005	1	(~13)
EAS – UREX+1a	12.5(240)	3,000	Design Study	4,500	$26.6 to $39.2B	2007	1	
FOEAS - UREX+1b	3.34(240)	800	Design Study	1,200	$14.5 to $21.2B	2007	1	
FOEAS – UREX+3	3.34(240)	800	Design Study	1,200	$17.2 to $25.6B	2007	1	
FOEAS – Co-Ex	3.34(240)	800	Design Study	1,200	$10.2 to $14.2B	2007	1	
NOTE: See Section F1-12 for additional notes to this table.								

Table F1-2 provides the LCC estimates for the principle EAS and FOEAS alternatives.

Table F1-2 CFTC TPC and LCC Estimates for Reprocessing Module

Millions of 2007 Dollars	Benchmark 2 800 MT/yr UREX+1		SA4 800 MT/yr UREX+3		SA5 800 MT/yr Co-Ex	
	Low	High	Low	High	Low	High
Annual Operations Cost (nominal year) Labor	194	288	214	322	195	293
Utilities	17	28	17	28	20	33
Materials	22	33	23	34	20	26
Misc contracts	6	6	6	6	7	7
Misc Projects	17	22	17	23	13	20
Total Annual Operations Cost	**254**	**376**	**277**	**412**	**254**	**377**
40-year LCC						
Labor	9822	14734	10852	16278	9805	14707
Materials	1048	1573	1223	1835	938	1406
Utilities	956	1434	967	1450	1107	1660
Contracts	180	270	182	273	208	313
Misc. Projects	531	796	576	864	547	820
Subtotal: 40-year Operations	**12,538**	**18,807**	**13,800**	**20,700**	**12,604**	**18,906**
Future Capital Projects	0	0	0	0	0	0
D&D	1690	2545	2032	3079	1156	1714
Subtotal LCC O&M & D&D	**14,228**	**21,352**	**15,832**	**23,779**	**13,760**	**20,620**
Early Life Cycle	201	300	262	407	187	270
TPC	14453	21202	17193	25656	10211	14186
Total LCC	**28,882**	**42,853**	**33,287**	**49,842**	**24,158**	**35,076**
LCC Unit Cost ($/kg HM)	903	1,339	1,040	1,558	755	1,096

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table F1-3. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table F1-3. Cost summary table.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Co-Ex 800 MT/yr	$755/kg HM	$1,096/kg HM	$925/kg HM
UREX+1a 800 MT/yr	$903/kg HM	$1,339/kg HM	$1,120/kg HM
UREX +3a 800 MT/yr	$1040/kg HM	$1,558/kg HM	$1,300/kg HM
Facility scales are based on 800 MT/yr. Capacity scaling is limited to a single train due to criticality.			

Facility costs for such things as waste disposition and fabrication would be additional costs as provided by other cost modules. The triangular distribution used for modeling purposes is shown in Figure F1-7.

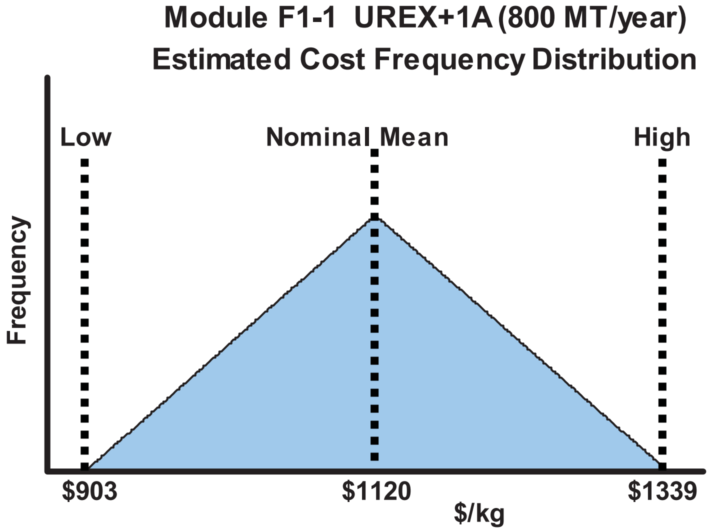

Figure F1-7. UREX+1A aqueous separation estimated cost frequency distribution.

The extensive analyses, in Appendix J of the 2000 NAS report, warn that cost experience with existing facilities, rather than estimates for new facilities, should be the basis for realistic estimates. It also warns that only government financing (in the U.S.) will keep the costs low enough to be competitive with the once-through fuel cycle. The 2000 NAS report suggests that aqueous reprocessing of UOX fuel will cost well over $1,000/kgHM and that reprocessing of light-water reactor or fast reactor MOX fuel will cost even more because of the more complex flowsheets. If costs for Rokkasho-mura were recovered in the manner of a private facility in the U.S., over $2,000/kgHM would be required.

The unit costs for all required modules are combined in Table F1-4. These costs do not include MOX fuel fabrication or extended waste storage for decay, but do include the cost for all product and waste processing to a final form and buffer storage. (See Modules G1, G3, G5, K2 and E3 for additional details.) The total cost of reprocessing is similar to the values in the National Academy of Science study with more complex processing adding additional cost.

Table F1-4. Total reprocessing, waste conditioning, and storage unit costs.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Co-Ex 800 MT/yr	$1,108/kg HM	$1,619/kg HM	$1,370/kg HM
UREX+1a 800 MT/yr	$1,494/kg HM	$2,214/kg HM	$1,850/kg HM
UREX +3a 800 MT/yr	$1,670/kg HM	$2,488/kg HM	$2,080/kg HM

F1-9. RESULTS FOR SENSITIVITY AND UNCERTAINTY ANALYSIS

A sensitivity analysis was provided in previous releases of this report based on the SFTF cost data. Since more current and detailed information is now being used in this module, this earlier analysis is no longer provided.

F1-10. NOTES FOR TABLE F1-1

1. The UK Windscale B205 reprocessing plant for Magnox, ≤8 GW(t).d/t burnup, gas-cooled, natural uranium metal-fuelled (Gen I) reactors originally operated at over 1,000 t/yr throughput and is still operating at around 500 t(HM)/yr (one of two head-end decanning lines closed down as reactor fleet decreased) and planned for closure in 2012, when all reactor-lifetime fuel arising has been reprocessed. Plant is described in the Nuclear Power Technology article (Marshall 1983).[23]
2. Nuclear Fuel Services (NFS) West Valley, New York reprocessing plant is the only plant in the U.S. to have reprocessed commercial reactors fuels. During its 6-year period of operation it separated 1,926 kg of plutonium from a mixture of Atomic Energy Commission and commercial utility fuels. Process losses, discharges, and exposures became higher than planned and final product sometimes did not meet expected quality levels. The plant was permanently shut down in 1976 after it was determined that stricter regulatory requirements could not be met (DOE 1996).
3. Conceptual design and capital cost estimate for High-Temperature Gas-Cooled Reactor (HTGR) Reference Fuel Reprocessing Plant, prepared for Idaho Nuclear Corporation by Bechtel, August 1969, INEEL Report No. IN-1451. The plant design includes a crush-burn head-end process for removing the bulk of graphite: fuel particles are separated by screening, crushed to break SiC coatings, again burned and Th, U and FP are separated using an acid-thorex solvent extraction process.
4. Midwest Fuel Recovery Plant (MFRP) hybrid aqueous/electrochemical nuclear fuel reprocessing plant constructed at Morris, Illinois, near the Dresden Nuclear Power Station. When in final cold testing in 1974, General Electric (GE) determined that its performance would not be acceptable without extensive modifications. The combination of complex processing equipment with higher expected failure rates and close coupling of process steps, which required much longer time to resume operation after shutdown, would permit only a low throughput. The request for a reprocessing plant operating license was withdrawn and the plant was licensed only to store spent fuel (700 t) DOE 1996.
5. Allied-General Nuclear Services (AGNS) Barnwell Plant was due to begin operation in 1974. But by 1977 was not completed or licensed when the U.S. decided to defer indefinitely all reprocessing of commercial irradiated fuel. It was technically unproven since it never operated with spent fuel and has since been decommissioned. A technical description is given in Nuclear Chemical Engineering, pp. 491–501, M. Benedict, T. Pigford, H. Levi, 2nd Ed, McGraw-Hill, 1981. The flow-sheet gives a

chemical separations feed of 5 t(HM)/d and the plant is described by Haire (2003) as having an annual capacity of 1,500 t(HM). It should be noted that to achieve this annual throughput, the availability would need to be nearly twice that of the French and UK plants, THORP, UP-2, and UP-3.

6. Exxon undertook conceptual design and capital cost estimates for oxide reprocessing plants with a period of 7 years of design effort including 200 man-years of architect engineering (Exxon Nuclear Company 1976). Also see Exxon nuclear fuel recovery and recycling center process description (Ritter 1979). Capital cost for 1,500 t/yr plant is quoted by Haire (2003).
7. IAEA PUREX-based reprocessing plant cost studies to scope against plant scale (Meckoni et al. 1977). Approximate capital costs may be derived from unit and levelized costs, but it is not clear whether costs were derived from bottoms up estimates or expert judgment.
8. Tokai Reprocessing Plant–PUREX thermal oxide uranium reprocessing pilot plant, no longer operating commercially for Japanese electric utilities, but is reserved for test runs, mainly with MOX fuels.
9. Mayak RT-1 at Ozersk, R. F. was commissioned in 1977 to reprocess spent fuel from VVER-440, BN-350, BN-600, research, and naval propulsion reactors. Most of the feed is from VVER-440 reactors and this is the only Russian facility that reprocesses spent power reactor fuel. The plant's nominal reprocessing capacity (based on spent fuel from the VVER-440 reactors) is 400 tons of spent fuel per year, The RT-1 facility is made up of a spent fuel storage pool, three chopping-dissolution process lines, and a modified PUREX process. High-level liquid radioactive waste from the reprocessing is vitrified (NTI 2009).
10. Dupont design studies completed around 1978. These used canyon design with rapid equipment replacement, selective centrifugal contactor placement and rapid startup compared to other plants. Haire (2003) quotes the capital cost of the smaller plant. Bastin (2000) quotes the capital cost for the larger plant that also includes MOX fuel fabrication. This cost was reduced by 10% ($0.9B) in Table F1-1 to account for removal of MOX fabrication scope. The plant is described in DuPont de Nemours 1979 article. Detailed flow-sheets were prepared by Savannah River Laboratory for a conceptual 10 MT/day reprocessing facility. These plants were considered conservative and designed with stronger engineering emphasis on availability and capacity factor, design value of 80%, than the AGNS Barnwell and Exxon Nuclear Company designs. Haire (2003) quotes the Dupont 1,500 t/yr plant as being 60% higher capital cost than the AGNS Barnwell and Exxon Nuclear Company designs, both also of nominal 1,500 t/yr throughput.
11. Oak Ridge National Laboratory (ORNL) studies performed under the Consolidated Fuel Reprocessing Program (CFRP) during the late 1970s and early 1980s as quoted by Haire (2003). The cost of a small-scale fast reactor reprocessing plant to support one or two demonstration fast reactors was scoped. Calculations showed almost no difference in capital cost of reprocessing plant for thermal and fast reactor fuels at throughputs <300 t(HM)/yr. FR reprocessing then becomes more costly than thermal oxide fuel when expressed as per t(HM), but may be less expensive per kW(e)hr.
12. ORNL studies performed under the CFRP during the late 1970s and early 1980s as quoted by Haire M. J. (2003). Except in throughput, the design basis of Hot Experimental Facility (HEF) is similar to that of the 1,500 t(HM)/yr LWR oxide fuel PUREX reprocessing plant and design was performed to obtain a direct comparison of capital costs.
13. Outline Planning Application for a European Demonstration Fast Reactor Reprocessing Plant (EDRP) at Dounreay at Caithness, Scotland, UK was prepared in May 1985, by United Kingdom Atomic Energy Authority (UKAEA), to treat fuel from four commercial fast reactors, but plant construction did not take place. The design used batch dissolvers, sulphate flowsheet for U-Pu partitioning, and liquid waste treatment by flocculation prior to sea discharge.

14. GE advanced liquid metal reactor (ALMR) reprocessing plant. The NRC (1996) provides an estimate of $6.1B (1990) capital cost for PUREX-TRUEX reprocessing plant (2,700 t/yr throughput) for high recovery of transuranic actinides for transmutation in the ALMR and includes plant for fabrication of TRU MOX fuel. An earlier separate estimate for the same throughput and believed without MOX fuel fabrication was lower at a quoted value of $4.25B (Salerno et al. 1989).

15. The Electric Power Research Institute (EPRI) 1990 study for a generic U.S. site estimated reprocessing plant capital costs ranging from $2.73B (government-owned plant) to $3.00B (privately-owned plant) with a planned annual throughput of 1,500 t/yr (Gingold 1991).

16. AREVA (formerly Compagnie générale des matières nucléaires [COGEMA]) thermal oxide reprocessing plant constructed in France for foreign customers. The capital cost value for UP-3 is quoted in a 2003 article) Bunn et al. The capital costs provided for UP-3 and THORP plants do not include interest during construction, which were borne by reprocessing customers. In 1998, Cogéma submitted dossiers seeking authorization to reprocess up to 1,000 metric tons of heavy metal per year in UP2-800 and up to 1,000 in UP-3 (previously 800 t/yr each). COGEMA committed not to reprocess a total of more than 1,700 t per year. In 2003, permission was given, subject to the overall limit, for up to 1,000 t(HM)/yr for each plant.

17. OECD-NEA 1994, "The Economics of the Nuclear Fuel Cycle"; Cost data supplied by BNFL, capital cost includes reprocessing, fuel receipt and storage, intermediate level waste encapsulation and associated research and development (R&D), but excludes vitrification and HLW management (likely higher cost in pounds sterling than THORP due to need for design modification and additional facilities for increased throughput as compared to THORP). The 1993 Great Britain Pound exchange rate was approximately $1.50 USD—markedly weaker pound than 1992.

18. THORP is part of the UK Sellafield site, 988 acres. Capital Cost - THORP-only GBP £1.85B (1992 m.v.), THORP and associated waste facilities £2.85B. BNFL (1993) states that the "construction cost of THORP, spread over the ten years 1983–1992, equates to around £1.9B. However, taking account of other projects which are directly related to THORP, the overall capital cost of the programme was around £2.85 B." Part of the stated £1B for associated waste facilities covers items (excluding vitrification of HLW) that are needed for a standalone reprocessing plant (e.g., receipt pond, liquid waste treatment, degraded solvent treatment, ILW encapsulation). The judgment is that a capital cost for THORP "reprocessing and excluding high level waste treatment" of £2.3B (1992 m.v.) would be reasonable (low rather than high). Using a mean historic exchange rate for 1992 of 1.77 and an inflator factor of 1.37 (approximately Engineering New Record's "Construction Cost Index History") gives a capital cost for THORP of $5.7B (1992 mv). Like Bunn, it is judged that use of a Construction Cost Index may underestimate costs of unique facilities such as a reprocessing plant. Originally THORP was planned to have a throughput of 6,000 MTHM in 10 years. This figure was later revised to 7,000 MTHM in 10 years, but the higher throughput was not achieved. Of current generation, operating PUREX plants, THORP has published the most detailed economic data. The figure provided here is consistent with the OECD-NEA hypothetical for which BNFL provided cost input and COGEMA input on basic design and future improvements. Also similar to value given by Bunn et al. (2003).

19. AREVA (formerly COGEMA) thermal oxide reprocessing plant constructed at Cap La Hague site (717 acres) in France for Electricite de France (EDF). UP-2 commenced operation in 1966 as a reprocessing plant for Gaz-Graphite (Gen I reactor) metallic fuels, was converted in around 1976 to UP2-400 plant (400 t/yr) for oxide reprocessing (addition of UP2-HAO) and later still (1994) to UP2-800 (800 t/yr) LWR oxide fuel deriving from EDF French national electric utility. It seems unlikely that a definitive capital cost value can be given for this plant that evolved over many years. However, Bunn et al. quote a capital cost for UP-2. They also quote a combined capital cost for UP-2 and UP-3 facilities at Cap La Hague as FF90B (equated to $16B in 2003 m.v.). It is not clear whether this

includes vitrification and other supporting requirements to oxide reprocessing or not (Bunn et al. 2003). The report "Economic assessment of Used Nuclear Fuel Management in the United States," by Boston Consulting Group (BCM) for AREVA, July 2006, quotes a capital cost of $17.8B (2005 money value and assuming 1€ ≡ 1$[USD]) for oxide fuel reprocessing, HLW vitrification and MOX fuel fabrication (essentially Cap La Hague [UP-3, UP-2, etc.] and Melox). On this basis, a capital cost of UP-3 (new, as-built plant rather than modified) would be $6B– $7B (2005 m.v.).

20. The UREX+ process design, which is more complex than PUREX, provides for five distinct solvent extraction processes that yield the separation of uranium, technetium, cesium with strontium, plutonium with neptunium, and americium with curium (WGI 2004). Some volatile fission products are also separated and residual fission products including rare earths are immobilized. The cost is described as rough order of magnitude (ROM) value.

21. Rokkasho reprocessing plant (RRP), part of the 939-acre fuel cycle center, was originally planned to operate in 2000, but it is likely to be about 8 years late. Capital costs are reputed to have trebled from ¥7.6B to around ¥21B, but no official estimates were obtained. RRP uses the PUREX process as exemplified by French reprocessing technology, but will mix U and Pu streams to avoid separation of a pure PuO_2 solid product.

22. The report "Economic assessment of Used Nuclear Fuel Management in the United States," by BCG (2006) for AREVA, quotes a capital cost of $16.2B (2005 money value and assuming 1€ ≡ 1$[USD]) for an integrated facility for fuel reprocessing, HLW vitrification and MOX fuel fabrication (essentially Cap La Hague [UP-3, UP-2, etc.] and Melox). A capital cost of $13B (2005 m.v.) for reprocessing alone (removal of remote fuel fabrication, vitrification and interim storage components) was quoted. But, it is noted that the days/yr of full-effective operation for reprocessing has been raised from 200 (UP-3 recent increased value, formerly 160) to 300. Also a long period of operation, 50 years, is assumed. In the Co-Ex flowsheet, irradiated fuel is separated into three main streams: plutonium-uranium oxide, which is then fabricated into fuel on site in the MOX fuel fabrication unit; recycled uranium oxide, which is purified, converted, and re-enriched outside the integrated recycling plant and fabricated into conventional uranium-based fuel; and mixed fission products and minor actinides, which are considered HLW and vitrified. Subsequent updates to the costs in 2008 indicate the potential for cost growth (WSRC 2008b).

23. The Systeme Internationale (SI) symbol for metric ton is t (i.e., t ≡ MTHM).

24. In the first column of Table F1-1, the names of plants actually constructed are shown in bold; some of these operated and some were never operated. The names of cost and design studies that were not used to construct actual plant are shown in normal font.

25. The EAS and FOEAS studies represent the cost associated with this module only, U/transuranic (TRU) storage costs have been reported in Module E-3; U/Tc Separations and Tc Solidification, HLW vitrification and storage, Cs/Sr Solidification and Storage costs have been reported in Module G-1; GTCC secondary waste treatment costs have been reported in Module G-5; LLW treatment and packaging costs have been reported in Module G-3.

F1-11. REFERENCES

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Combined Module F2/D2

Electrochemical Reprocessing and Remote Fuel Fabrication

Module F2/D2

Electrochemical Reprocessing and Remote Fuel Fabrication

F2/D2-1. BASIC INFORMATION

A Combined Module. This module discusses predominantly electrochemical reprocessing of spent nuclear fuel. Since remote fuel fabrication is an integral part of the overall recycle system and would be housed in the same facility, the associated remote fuel refabrication step is also included in this module. The technical reasons for such integration are considered below. (Another reason they are combined in this report is that very little cost data is available for which the electrochemical reprocessing steps are separated from the fuel refabrication steps. Although the Consolidated Fuel Treatment Center [CFTC] included a study for a centralized electrochemical reprocessing concept.) Refabrication is usually the last process step in an integrated electrochemical recycle system usually proposed for fast reactor systems.

The Reprocessing Step. Sometimes the variants of this generic step are called pyrochemical, pyroprocessing, pyrometallurgical, pyrolytic, or molten salt methods. In this document, the term electrochemical is used to encompass all of these terms. Their distinguishing characteristic is that they do not employ aqueous solution chemistry; therefore, they fall into the class of what are called “dry” processes. All processes of this type involve molten salt chemistry at elevated temperatures. While this type of process has never been applied on a commercial scale, it has been demonstrated for research reactor fuel.

In early research, spent nuclear fuel (oxide and carbide) was treated in gaseous reducing and oxidizing environments. The resulting chemical and physical changes in the fuel structure breaks it down to release many of the fission products. Remaining material was subjected to a final reduction step to create the necessary composition for use in recycled fuel. Neither of these gaseous electrochemical processes (sometimes called “volatility” processes) was applied on a large scale, and no production facility was built. A good history on such processes was prepared by Benedict, Pigford, and Levi (1981). Note that electrochemical processes were seriously considered in the UK for the reprocessing of magnox and AGR fuels.

More recent references to electrochemical processing relate to molten salt electrolytic treatment of fast reactor metal and oxide fuels, such as that developed at Argonne National Laboratory (ANL).[a] Fuel is separated electrochemically into waste and product streams via a molten salt electrolyte. Various types of separation are possible, depending on the fuel cycle needs and potential for chemical separations. Interim storage, waste stabilization, and recycle fuel refabrication may also occur in the same plant, and for nonproliferation, radiation safety, and cost minimization purposes, such consolidated operations are the recommended deployment path. This process has been successfully demonstrated on a small scale through treatment of the sodium-bonded metal fuel from Experimental Breeder Reactor-II (EBR-II). Current research and design efforts at the Materials and Fuels Complex (MFC) will result in a preconceptual design and preliminary costing for a molten salt electrochemical processing facility to treat current commercial spent nuclear fuel.

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[a] Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL). Argonne National Laboratory-West was renamed the Materials and Fuels Complex (MFC).

Costing of several conceptual designs for first-of-a-kind molten salt electrochemical processing facilities are discussed in this module. These designs are based largely on the early work by ANL with EBR-II fuel. The costed facilities are designed for collocation with one or more power plants on a given site or can be centrally located to serve more than one power plant in a given region. Stated capacities of the facilities range from a minimum of 20 MTHM/yr to 200 MTHM/yr for a 30-year life span. Plant concepts handling as much as 2,500 MTHM (metric tons heavy metal) have also been investigated.

The Fuel Fabrication or Refabrication Step. As defined in the introduction to Module D1, fuel fabrication represents the set of chemical, ceramic/metallurgical, and mechanical steps that take a basic chemical form of the fissile material and convert it to finished fuel assemblies and associated hardware ready for insertion into the reactor. In F2/D2, however, the fissile material is assumed to arise from back-end fuel cycle steps (i.e., reprocessing or transmutation/separation: Modules F1 or F2/D2) rather than from front-end fuel cycle steps such as mining, conversion, and enrichment (Modules A, B, and C). In fact, the fuel refabrication step is likely to be totally integral to the reprocessing technology. The nature of these fuel fabrication operations and the associated facility is affected by the following factors:

1. If a fuel comes from front-end fuel cycle steps or has its uranium and/or plutonium separated out in a PUREX or Co-Ex-type aqueous reprocessing step, it is likely to have such low radioactivity that it can be contact-handled. Low-enriched uranium (LEU) and thermal and fast mixed oxide (Pu, U, Np mixed oxide [MOX]) fuel fall in this category and are described in the Module D1 series. Fuels that are refabricated from reprocessing steps can contain grouped higher actinides, including Cm (curium) and Am (americium), or even some fission products, which are recycled into a reactor for destruction. Such grouped actinides and some fission products can originate from an aqueous spent LWR fuel reprocessing scheme such as uranium extraction (UREX) 1a from which highly radioactive mixed actinide oxide powder would be a product. (Such fuel cycles can have nonproliferation advantages because no weapons-useable fissile materials, such as plutonium, are separated out, and the refabricated fuel rods are self protecting from theft or tampering because of their high radiation fields.) Any stand-alone fuel fabrication plant that fabricates such higher actinide-laden (or fission product-laden) material, whether derived from spent light-water reactor (LWR) or fast-reactor fuel, into drivers or targets for either reactor type will need to incorporate a remote-handling process in a very robust building. Since the building radiation safety and security requirements for such a remote-handling fabrication facility are much like a reprocessing plant, economics drives one to integrate fabrication and reprocessing into one building. These types of fuels, when used in tandem with fast reactor (FR) systems, also allow for destruction of selected long-lived fission products by transmutation and long-lived actinides by transmutation or fission. Because of the high gamma/neutron-radiation fields associated with the fuel material, the refabrication process must be contained in a highly shielded hot cell and must be highly automated, yet, at the same time be simple enough for cost-effective robotics to be used.
2. The regulatory and quality assurance requirements for such refabricated fuel are not yet available in the form of a fuel specification, such as that available for enriched UO_2 and LWR-MOX fuel. Considerable research and development (R&D) and fuel qualification demonstration will be needed before these types of fuels reach this stage, but the reasons for quality assurance remain the same (i.e., fuel reliability, meaning prevention of fission–product) and actinide releases from the fuel form.
3. The fuel form must be capable of safe transport and storage both before and after each irradiation cycle. The integrity of the cladding or fuel matrix must be maintained at all times. If the reprocessing and refabrication facility is collocated with the reactors, such as in a multireactor park, transport concerns are obviated or minimized.

Some reactors and fuel cycles will have fuel components in the reactor simultaneously, some of which are contact-handled (Module D-1) such as driver fuel or blankets, and some of which are remote-handled (this Module F2/D2) such as grouped-actinide driver fuel or targets for long-lived radionuclide destruction. This will depend on whether the reactor core or a given fuel assembly is homogeneous or heterogeneous. A heterogeneous-core fast reactor, which burns actinides and also breeds some new plutonium, may have depleted-uranium blankets. The blankets can be produced in a relatively inexpensive contact-handling facility. A driver fuel, which contains significant amounts of recycled higher actinides and makeup uranium and/or plutonium, must be produced in an expensive remote-handling facility. There is even the option of putting all the minor actinides (Am and Cm) and long-lived fission products in separate rods called "targets." Fabrication of these highly radioactive rods would require a robust remote-handling facility. A homogeneous core for a "burner" fast reactor would have the driver fissile material (recycled and make-up) and higher actinides together in the same fuel rods, and would not include blanket fuel, since the intent is to destroy actinides (burn) and not to produce new ones (breed).

It can be seen that the fuel type (D Modules) and reprocessing scheme (F Modules) are intimately linked. Definition of the fueling scheme for the reactor will determine which components must be separated in the reprocessing plant and sent to the appropriate refabrication facilities or processed in integral refabrication facilities. Even thermal reactors can be configured to burn minor actinides by use of specially fabricated target rods that are interspersed among the more conventional UOX and/or U, Pu MOX rods in a given LWR fuel assembly. Unlike the UOX and U Pu MOX rods, the target rods would require remote refabrication, unless the concentrations of Am, Cm, and carried over fission products are very low.

Integrated Approach. In any case, it is worthwhile to integrate reprocessing and refabrication plants at a single site. Such collocation can eliminate the expensive and time-consuming packaging and transportation steps that would be required if sited separately. Life-cycle cost savings could be considerable. Careful design and operational measures must be taken to prevent cross-contamination of radionuclides from one facility to the other.

F2/D2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Reprocessing Steps. At an electrochemical processing facility, spent nuclear fuel would be received, unloaded, and temporarily stored until treatment (see sample flow sheet in Figure F2/D2-1). The general treatment involves spent fuel element disassembly and/or shearing followed by steps in preparation for electrorefining. Metal fuel, such as that which is processed at MFC, is chopped into small segments before immersion in LiCl-KCl salt within an electrorefiner vessel. In order to be compatible with electrorefining, spent oxide fuel would first undergo chemical or direct electrolytic reduction to the metallic form. This means that for spent LWR fuels most of the fuel mass that would require reduction to metal would be irradiated UO_2. The large plant size and cost that would be required to reduce and electrochemically process such LWR-spent fuel may make this option less viable than aqueous reprocessing for LWR fuels. General Electric (GE) is considering a "dry" process for LWR spent fuel processing that would provide makeup actinides to the fast-reactor system for destruction (Chicago Tribune 2007).

Uranium, fission products, transuranics, and unreactive metals can be separated from each other in the electrorefiner. In a separate process, the uranium may be removed from the electrorefiner and processed into a metal product to be stored as waste (likely to be Greater-Than-Class-C) or recycled into new fast reactor fuel (see Module K-3 for a detailed description of these options). Unreactive metals, including cladding and fuel components, may be removed from the electrorefiner and processed with other waste metals for creation of a metal, high-level waste form. Cleanup (refining) of this metal is another option that prevents the need to deal with high-level waste. Fission products, which largely remain in the electrorefiner and are dissolved in the salt electrolyte solution, may be extracted from the salt and immobilized in a ceramic high-level waste form. Short-term (in terms of geologic time) storage (many decades) of the ceramic high-level waste form would allow for decay of fission products cesium and strontium, which are heat- load concerns for a geologic repository. The salt can then be recycled for reuse in the electrorefiner. Transuranics may be treated as a high-level waste, sent for decay storage, or returned to a reactor in the form of refabricated fuel. The nature of this treatment is dependent on the chemical and radioactive characteristics of the specific transuranic mix and the type of reactors available for fuel recycle (fast versus thermal).

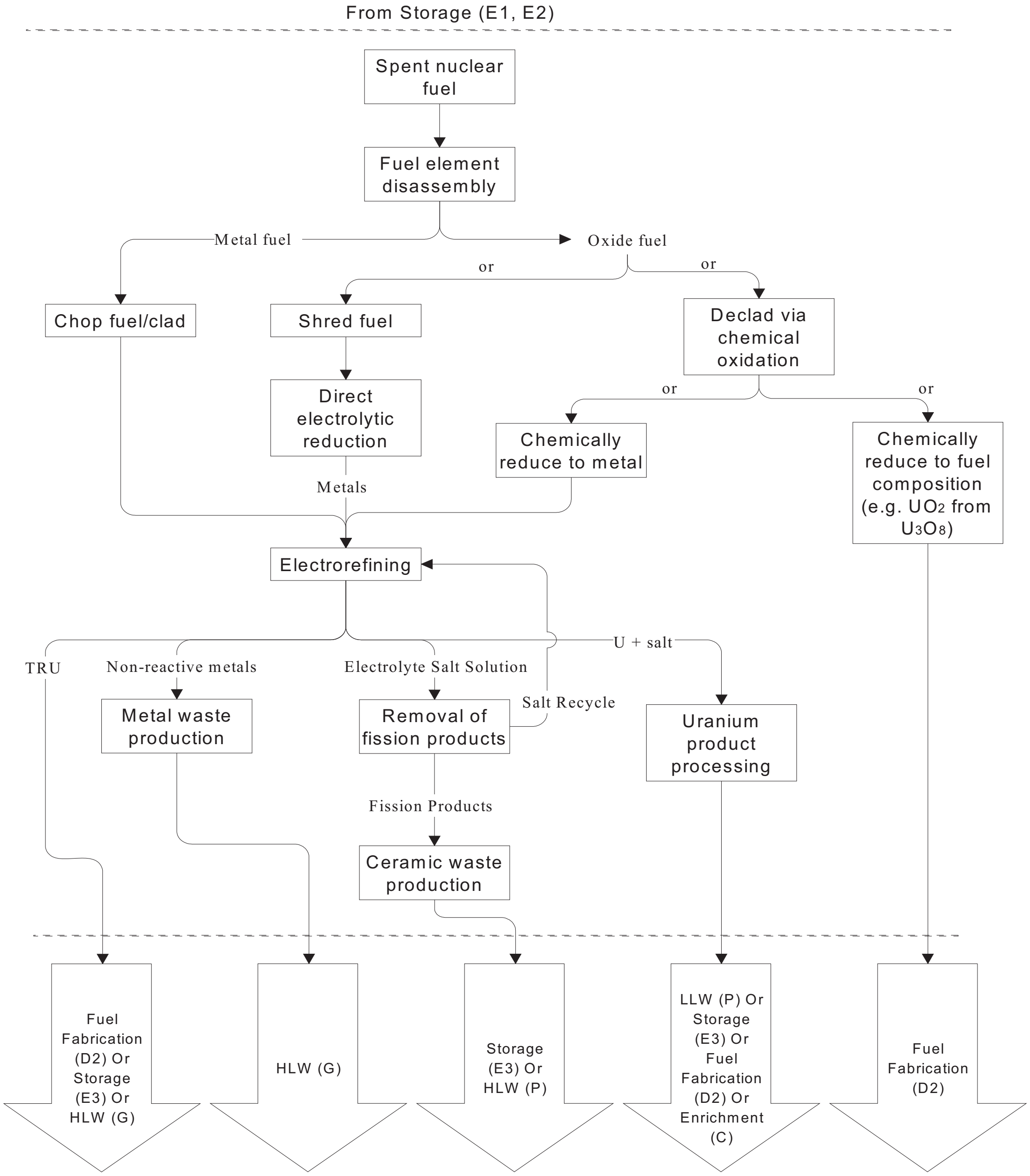


Figure F2/D2-1. Example of electrochemical processing flow sheet for spent nuclear fuel. (Note: HLW metal waste might be diluted with DU to form Class C low-level waste or might be re-refined.)

Fuel Form. The fuel form most commonly envisioned today consists of thin, cylindrical, cast rods consisting of a uranium and plutonium (with some minor actinides and trace fission products) metal alloyed with a metal such as zirconium. The fuel material originates most likely from an electrochemical reprocessing scheme with the possible addition of some makeup plutonium (with possible other actinides) from storage and/or makeup uranium. These thin rods are then clad in stainless steel and inserted into a fast-reactor fuel assembly, which appears from the outside much like the fast-reactor oxide pellet (Module D1-4) or vibropacked (VIPAC; Module D1-5) fuel assembly. This is the fuel type envisioned for liquid metal reactor concepts such as the GE Super-Power Reactor Inherently Safe Module (S-PRISM) and the ANL Fast Burner Reactors. Ceramic remote-handled fuel (such as [U, Pu, MA] oxide) feed materials could originate from either an integral electrochemical or stand-alone aqueous reprocessing scheme. UREX 1-a is an example of the latter. (Note: a ceramic fuel refabrication plant could be located within the same building as an aqueous reprocessing plant; however, the two processes are not “integral” in the same process-chemistry sense as pyroreprocessing and pyro-refabrication.)

Status of the Industry. Reprocessing and production of remote-handled metal fast reactor fuels is not yet done on an industrial scale; however, a large central plant may not be needed. Proponents suggest that it will be best to keep this operation on a small scale, where refabrication is collocated with the electrochemical reprocessing step dedicated only to the onsite reactors. ANL-West successfully demonstrated such technology at their Idaho Integral Fast Reactor facility adjacent to EBR-II. (Nearly all of this work was discontinued in the mid-1990s as a result of policy decisions made by the U.S. government to discourage plutonium recycle and fast reactors in general.) Work on fast reactor fuel cycles continues mainly in Russia, France, India, and Japan. The Generation IV program is also considering the Sodium-cooled Fast Reactor and its fuel cycle as one of the six concepts to be studied. K. Abney et al. (1997), provides a good assessment of the technology status of electrochemical processing and the International Atomic Energy Agency (IAEA) provides a good country-by-country assessment of reprocessing in general, including R&D on electrochemical processing (IAEA 2005).

F2/D2-3. PICTURES/SCHEMATICS

Process Diagrams. For the metal remote-fabricated fuel option, the refabrication and electrochemical spent fuel reprocessing steps are part of one synergistic process (see Figure F2/D2-2). The metal-fuel fast reactor option is the best known in the U.S., since it is supported by GE in the PRISM reactor program. By adding steps at each end, oxide fuels can also be accommodated by pyrochemistry; and considerable R&D has been performed for the electrochemically compatible oxide fuel type in Russia. It also turns out that VIPAC fuels fit in well with electrochemical reprocessing schemes, since the powder morphology required for VIPAC fuel is well-accommodated by electrolytic electrochemical processing steps. For purposes of unit costing, it is very difficult to separate the reprocessing from the refabrication steps. Nearly of the unit costs reported in sections below are assumed to have some reprocessing steps included, hence the combining of Modules F2 and D2.

Figures F2/D2-3 and F2/D2-4 provide a conceptual drawing of a proposed molten salt electrochemical processing facility for treating commercial spent nuclear fuel. This concept is the subject of a preconceptual design effort underway at MFC. Results from this study (Frigo et al. 2003) provide some preliminary cost estimates for inclusion in the Advanced Fuel Cycle Initiative (AFCI) cost database.

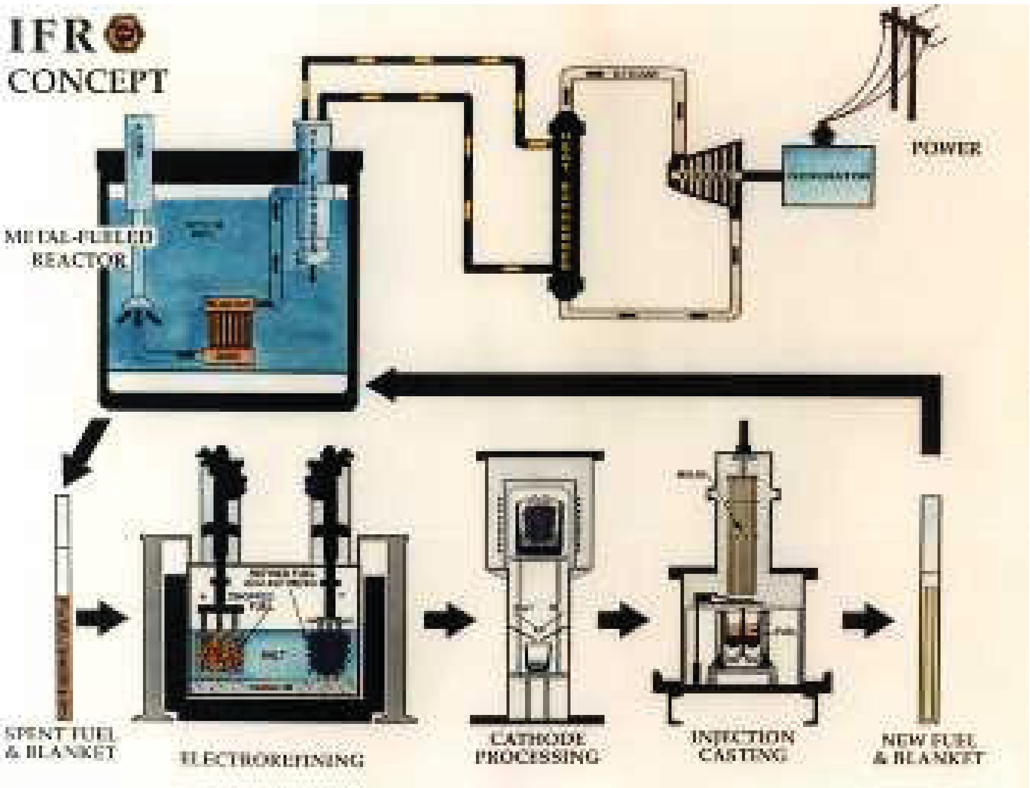


Figure F2/D2-2. ANL Integral Fast Reactor concept showing last three refabrication steps.

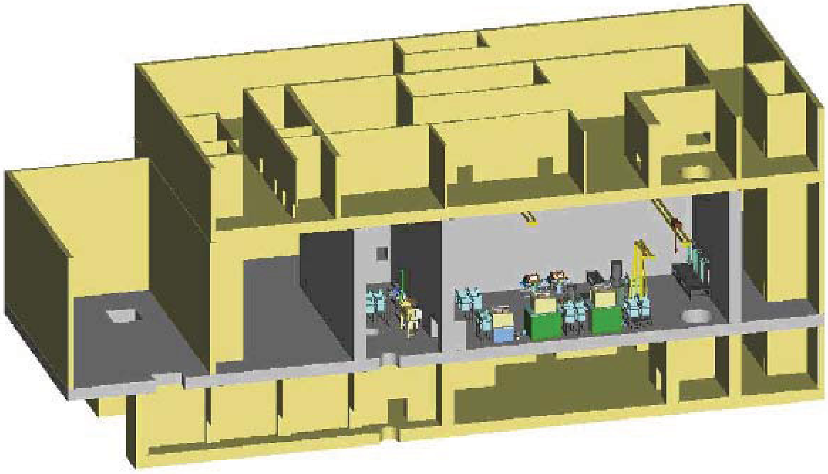


Figure F2/D2-3. Three-dimensional conceptual rendering of the Advanced Pyroprocess Recycle Facility (Frigo et al. 2003).

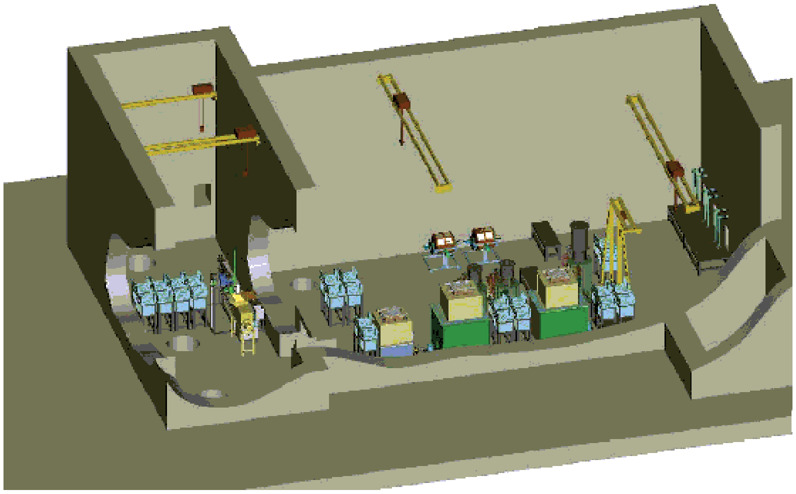


Figure F2/D2-4. Three-dimensional conceptual rendering of the air and process cells (Frigo et al. 2003).

F2/D2-4. MODULE INTERFACE DEFINITION

This F2/D2 module interfaces with upstream reactor (R1 for irradiated targets in thermal reactors and R2 for irradiated fast-reactor driver fuel and/or targets) and possible upstream makeup actinide storage modules (E modules), and waste disposal modules (Module G). The fast reactor (R2) is also the downstream recipient of the integrated facility's refabricated fuel product. In practice, a small throughput electrochemical processing facility may be immediately collocated with a fast reactor (or multiple modular fast reactors) as an integrated recycle function along with the fuel fabrication facility. Alternatively, a higher throughput centralized electrochemical processing facility might be integral to a larger group of fast reactors.

When considering costs for such facilities, care must be taken to differentiate between separation and waste management functions. This must be done to avoid double counting costs for waste management (Module G) that might already be in the integral reprocessing/refabrication facility Module F2/D2 cost breakdown.

Metal Fuel Considered. Nearly all the remotely handled fuels addressed in this section will be metal fuels for sodium-cooled fast reactors (such as the PRISM Advanced Liquid Metal Reactor [ALMR]) arising from electrochemical reprocessing. Early fuels are likely to have higher actinides blended with uranium and plutonium and small amounts of carried-over fission products such as lanthanides. Later, fuels may have some fabricated long-life fission product target rods slated for fission product destruction by transmutation. These rods would be produced in the same highly-shielded refabrication facility. Accommodation for the production of fast reactor first cores is also an interface issue, since a separate larger fabrication facility may be required, and the initial fuel may contain fewer actinides.

Dirty MOX Considered Elsewhere. The use of thermal or fast-reactor MOX containing plutonium, neptunium, and very small amounts of the highest actinides, Am, and Cm, (sometimes called dirty MOX) is considered in Modules D1-2 and D1-4. It is possible that such MOX fuel could be handled in special shielded gloveboxes designed for maximum personnel protection, however, a full-fledged, hot-cell-type, remote-handling facility will be needed if Am and Cm concentrations are sufficiently high. If higher concentrations of Am and Cm (and/or fission products) require destruction, LWR or FR target rods would definitely have to be fabricated in a remote-fabrication, hot cell environment. This is the type of facility envisioned for LWR-derived, grouped actinide (Pu, Np, Am, Cm) oxides arising from a UREX-1a reprocessing facility.

F2/D2-5. MODULE SCALING FACTORS

Equipment Size Limited by Throughput. No scaling relations were found in the literature. The first processing line in a new facility fixed costs will predominate; the capital cost will not vary much with capacity. Any capacity additions to an existing line would likely be accomplished by adding more parallel process lines, especially since criticality concerns limit equipment sizes in a batch process of this type.

Some Cost Data on Different-sized Facilities. Four sets of unscaled reference costs are organized according to the AFC standard code of accounts in Table F2/D2-1. The table provides bottom-up cost estimates based on conceptual designs for the three main facilities discussed: the MFC Fuel Conditioning Facility (FCF), the ALMR, and the S-PRISM reactor system. All costs were adjusted to 2004 dollars from the year of the cost estimate. Construction costs were adjusted according to the Defense and General Construction Escalation Indices. All other costs were adjusted according to the Consumer Price Index.

Table F2/D2-1. Code-of-accounts life cycle cost estimate summary for spent nuclear fuel electrochemical process facilities of differing capacities and fuel types.

Code of Accounts	MFC FCF (metal fuel) (>20 MTHM/yr) (2004$ × 10^6)	ALMR (metal fuel) (200 MTHM/yr) (2004$ × 10^6)	S-PRISM (metal fuel) (100 MTHM/yr) (2004$ × 10^6)	S-PRISM (oxide fuel) (1,000 MTHM/yr) (2004$ × 10^6)
0-Early Life Cycle Costs		1812		
1-Capitalized Preconstruction Costs				
2-Capitalized Direct Costs	69		233	260
3-Capitalized Support Services	14		61	61
4-Capitalized Operations				
5-Capitalized Supplementary Costs		126		
6-Capitalized Financial Costs				
7-Annualized Operations and Maintenance Costs	21	145	62	109
9-Annualized Financial Costs		6		

Scaled reference summary costs are listed in Tables F2/D2-5 (metal fuel facility) and F2/D2-6 (oxide fuel facility) found below in Section F2/D2-8, "Cost Summaries." A reference capacity of 100 MTHM/yr was chosen for the metal facility cost summaries. Because electrochemical processing is a batch process, as opposed to continuous or semicontinuous in aqueous processing, traditional chemical plant cost-scaling factors do not apply. A pyro-batch line would consist of the largest demonstrated equipment run in a serial batch mode. The number of parallel lines would produce the desired throughput. For this cost data collection activity, it is assumed that additional electrochemical process batch lines, for example, would simply be a multiple of the cost of the first line.

S-PRISM metal fuel facility costs (already designated for 100 MTHM/yr capacity) were chosen as the reference values given in Table F2/D2-2. ALMR costs were not included in the average, because the nature of initial investment costs was ill-defined in the available reference and, therefore, not easily compared to defined construction and equipment costs from the other facility cost references. The MFC FCF cost numbers were not used in the summary table based on the age of the study and the ill-defined heavy metal throughput for the facility.

Table F2/D2-2. Cost data on two ALMR-Integral Fast Reactor recycle plant concepts: central and collocated.

Pyrochemical ALMR Reprocessing (central plant)		
Plant annual capacity	200	MTHM/yr
Economic life	20	yrs
Total base capital cost including contingency (FOAK)	518.0	$M
Imputed interest during construction (2 yrs to construct)	25.9	$M
Total capital cost (2002$)	**543.9**	$M
Annual ops cost breakdown:		
Manpower	32.8	$M/yr
Consumables	143.0	$M/yr
Total annual operations cost	175.8	$M/yr
Operations contribution to levelized cost of product/service	879.00	$/kgU
Discount rate for government project (real)	3.80%	
Capital recovery factor (fraction per yr of ops)	0.0723	
Annual payments to recover capital cost of plant over life	39.32	$M
Capital portion of unit product cost	196.58	$/kgU
Total levelized product cost (1991$)	**1075.58**	**$/kgU**
In 2004$:	**1590.0**	**$/kgU**

Pyrochemical ALMR Reprocessing (collocated with reactor plant)		
Plant annual capacity	20	MTHM/yr
Economic life	20	yrs
Total base capital cost including contingency (FOAK)	105.0	$M
Imputed interest during construction (2 yrs to construct)	5.3	$M
Total capital cost (1991$)	**110.3**	$M
Annual ops cost breakdown:		
Manpower	10.4	$M/yr
Consumables	17.4	$M/yr
Total annual operations cost	27.8	$M/yr
Operations contribution to levelized cost of product/service	1390.00	$/kgU
Discount rate for government project (real)	3.80%	
Capital recovery factor (fraction per yr of ops)	0.0723	
Annual payments to recover capital cost of plant over life	7.97	$M
Capital portion of unit product cost	398.47	$/kgU
Total levelized product cost (1991$)	**1788.47**	**$/kgU**
In 2004$:	**2650.0**	**$/kgU**

The CFTC FOEAS included an electrochemical reprocessing alternative. The pre-conceptual design reprocessed 300MT/yr of LWR fuel in a centralized facility concept. The alternative did not include fast reactor fuel recycling or fuel manufacturing. The pre-conceptual design included uranium recovery to a metal ingot, U/TRU recovery to metal suitable for fast reactor fuel manufacturing, a metal wasteform, which included the hulls, hardware, and fission products that do not convert to chloride salts including Tc, a zeolite-glass bonded ceramic which includes the cesium, strontium, and excess salts. The lanthanides were recovered separately and converted to a lanthanide glass wasteform.

The annual operations cost, life cycle costs are provided in Table F2/D2-3 (WSRC 2008). The resulting unit cost are on a basis of $/MT of SNF being reprocessed. The later value must be added (including others such as LLW packaging and treatment and uranium solidification and packaging) to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

Table F2/D2-3 CFTC TPC and LCC estimates for reprocessing module.

Millions of 2007 Dollars	Benchmark 3 300 MT/yr Electrochemical	
	Low	High
40 Year LCC O&M		
Labor	6123	9184
Materials	692	1038
Utilities	891	1337
Contracts	121	182
Misc. Projects	338	508
Subtotal: 40-Year O&M	8,165	12,249
Future Capital Projects (FCP)	0	0
D&D	1468	2203
Subtotal LCC (O&M, FCP, and D&D)	9,633	14,452
Early Life Cycle (ELC)	452	659
Total Project Cost (TPC)	10757	15564
Total LCC (O&M, FCP, D&D, ELC, and TPC)	20,842	30,675
LCC Unit Cost ($/kg HM)	**1,737**	**2,556**

F2/D2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Costs of Some Early Electrochemical Processes. The Atomics International Reduction OXidation (AIROX) process was developed for treatment of UO_2 fuel. Heat is applied in an oxidizing atmosphere to create U_3O_8, which results in breaking open the cladding and pulverizing the fuel due to material volume increase. Chemical reduction by reaction with hydrogen returns the uranium to UO_2. Most fission products are removed during a series of these oxidation-reduction reactions, and the final UO_2 product can be reformed into fuel pellets for recycle. Similarly, the CARBothermic-reduction OXidation (CARBOX) process was developed for UC fuel. Again, a series of oxidation and reduction reactions are performed, resulting in lower fission product concentrations. Costing for these two pioneer electrochemical processes was estimated in 1963 and 1965 government reports (Colby, et al. 1963, 1965). Given the age of the estimates and the significant changes in technology and regulation, not to mention cost escalation during the intervening 40 years, values given in the reports are not considered useful for the purpose of AFCI system studies.

ANL-GE Estimates. More recent electrochemical processing facility cost estimates are based on the fundamental technology developed at ANL. A detailed conceptual design study was performed for a commercial-scale electrochemical processing facility to serve a collocated 1,400 MWe fast breeder reactor. Annual processing of at least 25% of the full core metal fuel (reload minimum of 20 MTHM/yr) is necessary for reactor refueling. Recycled fuel is also fabricated in this facility. One-year decay storage of the fuel is assumed, and reactor plant services are shared. Bottom-up cost estimates for this facility are provided in a 1985 publication by ANL (Lineberry et al. 1985). While the estimate was performed by a government entity and based on government experience, no assumption was made on whether government or private funding/operation of the proposed facility is assumed.

Based on the ANL technology, GE's ALMR more recently prepared a conceptual design and conducted a cost study for a more advanced electrochemical processing facility (Delene et al. 1993; Taylor et al. 1991; ORNL 1992). This is a bottom-up cost estimate assuming private/utility ownership and operation, 30-year plant life, 200-MTHM/yr spent metal-fuel treatment, recycle fuel production, and a 15-month fuel cycle time. A report by the National Academy of Sciences uses this conceptual design and cost study in a 1996 economic assessment of fuel reprocessing technologies (NAS 1996).

A later generation ALMR system, the S-PRISM, incorporated a hybrid recycle scheme with facilities that processed oxide and metal fuel in parallel. The S-PRISM fast reactor would begin operation with metal fuel fabricated from LWR oxide fuel reprocessed material. Metal fuel would subsequently be reprocessed for use in the reactor, and the usage of LWR fuel material would decrease. Utility ownership, multireactor feed, metal fuel production, and minor actinide recycle are assumptions for design of both oxide and metal fuel facilities. A bottom-up cost estimate was performed for a 100-MTHM/yr metal fuel recycle facility. The LWR oxide fuel facility was cost estimated with a top-down approach for 1,000-MTHM/yr throughput. For the purpose of calculating the unit cost summaries given in Tables F2/D2-6 and F2/D2-7, a 30-year lifetime for both oxide and metal fuel facilities was assumed. These two plants are similar in design and function but significantly differ in heavy metal throughput rates. However, the fissile mass throughput for each facility is about the same because of the difference between metal and oxide fuel fissile enrichment (a throughput factor of 10).

The French and Japanese nuclear industries have also pursued development of molten salt electrochemical process technology from the ANL basis, but have not published cost estimates on their designs. The Russian institute RIAR at Dimitrovgrad is also active in this area and has linked their vibrocompaction method (Module D1-6) for fast reactor fuel fabrication to electrochemical fuel reprocessing.

The U.S. Department of Energy (DOE) has a multiyear program to debond and partially reprocess some of the sodium-bonded irradiated EBR-II fuel in the adjacent FCF using electrochemical techniques. A DOE report describes the anticipated cost and schedule for this activity (DOE 2003). A section below will show the calculated unit costs for this activity.

Cost and Pricing of Remote-handled Fuel Fabrication. All this discussion deals with projected costs, because there is no industry from which commercial pricing is available. Most of the cost data available are from GE or ANL reports prepared in the early 1990s. Table F2/D2-2 (above) shows the projected capital and life-cycle costs for both a central facility and collocated (at reactor) fuel recycle facility. The highlighted numbers come from a conceptual design report prepared by Oak Ridge National Laboratory (ORNL) in 1981 and 1991 GE assessment data (Jones 1981; Taylor et al. 1991). The other plant life, discount rate, etc., data were added so that a unit cost of refabricated fuel in \$/kgHM could be calculated. It is not surprising that the fabrication cost is higher than for thermal MOX fuel in light of the fact that reprocessing steps are included and a hot cell building is required. It can also be seen that a larger centralized facility has a lower unit cost; hence, one might surmise that scaling laws do appear to apply. The two facilities, however, would be very different in design and function, so scaling may not really apply. Economic benefits of the centralized plant are likely to be counteracted by spent fuel and freshly refabricated fuel packaging, safeguarding, and transportation difficulties.

Table F2/D2-4 shows projected unit costs from other literature sources for this type of fuel. Important underlying assumptions are noted where possible.

Table F2/D2-4. Projected unit costs for remote-handled fuel recycle/refabrication (from various literature sources).

Reference/Year	Unit cost in \$/kgHM (\$ in same yr as Ref unless otherwise noted)	Assumptions
Taylor et al./1991	2,650 (2004\$)	Collocated 20 MTHM/yr recycle (FRC+FF)[a] plant
Westlén et al./2001	1,540 (2004\$)	Central recycle plant 200 MTHM/yr (FRC+FF)
Westlén et al./2001	5,000–17,500	Accelerator–driven subcritical reactor fuel (transmutation) fabrication (FF) only
OIA/1995	3,000–4,600	GE/ANL ALMR oxide fuel from electrochemical processing (FRC+FF)
Delene et al. /2000	4,600–7,700	ALMR-IFR metal fuel (FRC+FF) from electrochemical processing
Taylor et al./1991	5,810–7,210	Acceleration transmutation of waste target pyro-processing
Platt[22]/2007	1,600–4,900	Remote handled VIPAC MOX from low DF aqueous reprocessing plant (FF). Reprocessing range [FRC] is \$2,700–\$7,800/kgHM

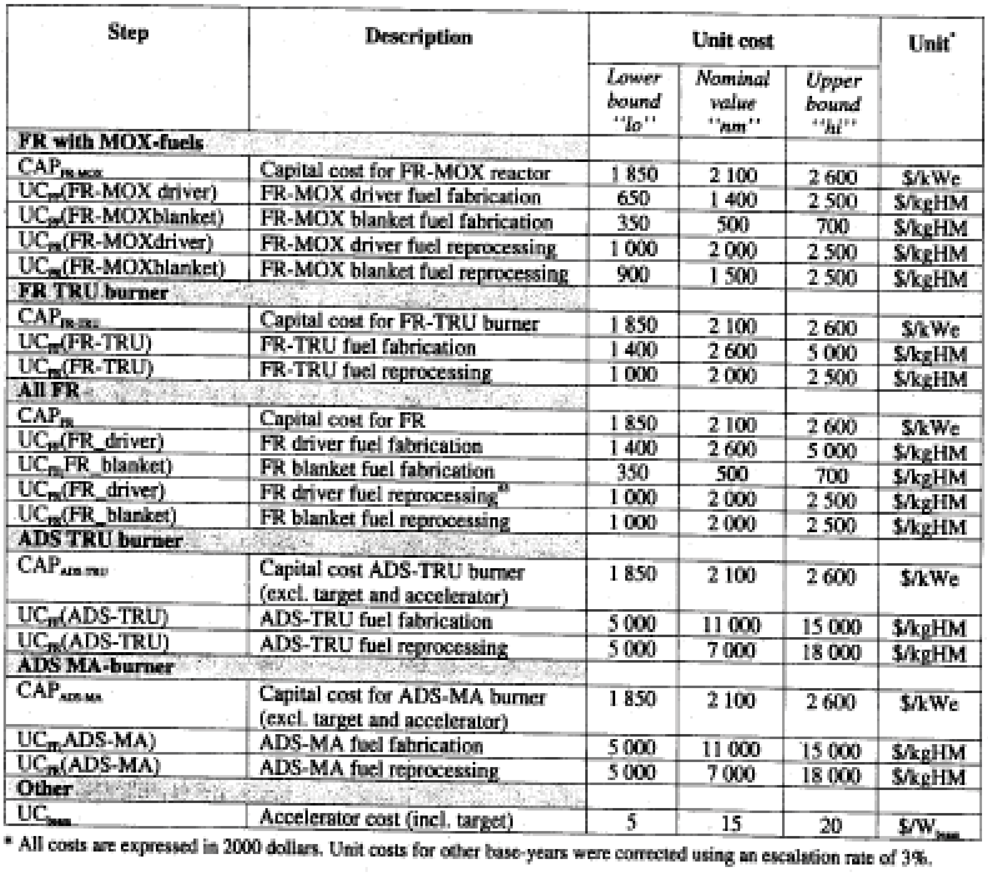
a. FRC = reprocessing range, FF = fuel refabrication (costs have both unless otherwise noted)

The newer the reference, the higher the unit cost for basically the same process, which is not unexpected because unit cost projections usually increase as the R&D program proceeds (Williams 1984). It can be seen that the inclusion of fission products and/or higher actinides for transmutation also increases the fuel recycle cost considerably. Another factor likely to influence such costs in the U.S. is the need to construct a very thick-walled robust concrete building to contain the hot cells and their processes. These costs are driven by seismic and terrorism mitigation requirements that are in turn driven by seismic event scenario and design basis threat scenarios, which include direct plane crashes for the latter. This kind of structure is estimated to cost $10,000 to $20,000 per square foot for construction. If a refabrication facility has a small throughput, amortization of the fixed building cost becomes a significant part of the unit fuel fabrication cost. Recent cost escalation experience with U.S. Department of Energy/National Nuclear Security Administration heavily fortified facilities, such as the Savannah River Site-Mixed Oxide Fuel Fabrication Facility (MFFF) and the Y-12 Highly Enriched Uranium Storage facility, is indicative of this trend. The magnitude of the cost impact however, will not be known until the first facility of this type is designed and estimated.

Electrochemical technology and metal fuels (drivers and targets) are envisioned for accelerator driven systems and fission-product transmutation schemes, such as Acceleration Transmutation of Waste. Cost trends for these cycles, discussed in NEA/OECD YEAR; Zerriffi and Makhijani 2000; Lauferts et al. 2007; and Platt 2007, might be representative of the higher-end refabrication and reprocessing costs for fast reactor systems using metal fuel and electrochemical processing. (The latter two of these references discuss just-published initial economic results of the European Union's "Red Impact" study, which is considering the best ways to manage nuclear wastes in Europe.) Only four reports (Delene et al. 2000, NEA/OECD 2006, NEA/OECD 2001, and WSRC 2008) were found where fabrication and reprocessing costs were separated. The table from Delene et al. 2000 is reproduced from the NEA/OECD report as Table F2/D2-5.

It can be seen that nominal values for some fuels, which in some cases are mostly target materials to be destroyed or transmuted, go as high as $11,000 per kgHM in year 2000, which would be around $12,000/kgHM in today's dollars. Useful fast reactor capital cost data also appear in the table.

Table F2/D2-5. Fabrication and reprocessing unit costs for various fast reactor and transmutation systems (NEA/OECD 2006).



Step	Description	Unit cost			Unit*
		Lower bound "lo"	*Nominal value "nm"*	*Upper bound "hi"*	
FR with MOX-fuels					
CAP_{FR-MOX}	Capital cost for FR-MOX reactor	1 850	2 100	2 600	$/kWe
UC_{ff}(FR-MOX driver)	FR-MOX driver fuel fabrication	650	1 400	2 500	$/kgHM
UC_{ff}(FR-MOXblanket)	FR-MOX blanket fuel fabrication	350	500	700	$/kgHM
UC_{rp}(FR-MOXdriver)	FR-MOX driver fuel reprocessing	1 000	2 000	2 500	$/kgHM
UC_{rp}(FR-MOXblanket)	FR-MOX blanket fuel reprocessing	900	1 500	2 500	$/kgHM
FR TRU burner					
CAP_{FR-TRU}	Capital cost for FR-TRU burner	1 850	2 100	2 600	$/kWe
UC_{ff}(FR-TRU)	FR-TRU fuel fabrication	1 400	2 600	5 000	$/kgHM
UC_{rp}(FR-TRU)	FR-TRU fuel reprocessing	1 000	2 000	2 500	$/kgHM
All FR					
CAP_{FR}	Capital cost for FR	1 850	2 100	2 600	$/kWe
UC_{ff}(FR_driver)	FR driver fuel fabrication	1 400	2 600	5 000	$/kgHM
UC_{ff}FR_blanket)	FR blanket fuel fabrication	350	500	700	$/kgHM
UC_{rp}(FR_driver)	FR driver fuel reprocessing[a)]	1 000	2 000	2 500	$/kgHM
UC_{rp}(FR_blanket)	FR blanket fuel reprocessing	1 000	2 000	2 500	$/kgHM
ADS TRU burner					
$CAP_{ADS-TRU}$	Capital cost ADS-TRU burner (excl. target and accelerator)	1 850	2 100	2 600	$/kWe
UC_{ff}(ADS-TRU)	ADS-TRU fuel fabrication	5 000	11 000	15 000	$/kgHM
UC_{rp}(ADS-TRU)	ADS-TRU fuel reprocessing	5 000	7 000	18 000	$/kgHM
ADS MA-burner					
CAP_{ADS-MA}	Capital cost for ADS-MA burner (excl. target and accelerator)	1 850	2 100	2 600	$/kWe
UC_{ff}ADS-MA)	ADS-MA fuel fabrication	5 000	11 000	15 000	$/kgHM
UC_{rp}(ADS-MA)	ADS-MA fuel reprocessing	5 000	7 000	18 000	$/kgHM
Other					
UC_{beam}	Accelerator cost (incl. target)	5	15	20	$/W_{beam}$

* All costs are expressed in 2000 dollars. Unit costs for other base-years were corrected using an escalation rate of 3%.

F2/D2-7. LIMITATIONS OF COST DATA

Cost estimates for commercial-scale electrochemical processing facilities are of limited value as a whole (Quality Level 5—Potentially biased or conflicting assessments collected from independent sources that do not use a common basis or consistent approach). No commercial-scale facility has been built and only one engineering-scale facility has operated. The FCF at MFC processed and fabricated metal fuel for the EBR-II and is now demonstrating electrochemical reprocessing (Williams 1984). While significant, detailed cost estimates have been performed for commercial-scale facilities based on the FCF experience, this information is not easily modified to the necessary process and throughput changes for treatment of oxide fuel. The main reason for this is the batch process nature of electrochemical processing. Based on current technology, batch size is limited by the efficiency of electrorefining at large volumes and by criticality concerns for the postrefining process steps.

Technical Readiness Level. The technical readiness level for a metal fuel facility may be classified as pilot/feasible based on work to date. However, an oxide electrochemical processing facility is clearly at the R&D level, bringing the overall electrochemical processing facility concept to a R&D level.

The total challenge and cost impacts for electrochemical processing have yet to be established as the fast reactors of the future have not been defined. Even if the reactor coolant is specified as liquid sodium, the choice of metal or oxide fuel still remains. Following the choice of fuels is the mode of reactor operation. If used as an actinide burner, the lower conversion ratio and intended burnup will impact the electrochemical processing requirements. A breeder operation with its high conversion ratio and use of blankets presents an entire new set of criteria.

Clearly, a more detailed, current cost estimate is needed for a new generation electrochemical processing facility. For the purposes of AFCI, both oxide and metal fuel capability should be considered. Technology advancements for treatment of each fuel type must be incorporated into a new set of functional and operational requirements for the conceptual design and estimation efforts.

The level of technical readiness or deployment for this type of fuel is low compared with thermal LEU and MOX fuel. The production of thermal fuels is a highly mature private industry, while refabricated liquid-metal reactor fuel types are still in the bench scale or pilot plant development stage. Of all the concepts that considered the GE ALMR fuel cycle, MFC integrated fuel recycle has enjoyed the most R&D effort and success. Most of the well-documented cost data also come from estimates prepared for this concept.

Cost Data Gaps. It would be useful to study GE and ANL detailed cost data to determine the separation of unit cost between the reprocessing and refabrication parts of the Integral Fast Reactor recycle process. Data on electrochemical refabrication of oxide fuel would also be useful, especially to see if vibropacked fuel would have any cost advantage. Some data on Russian work at NIIAR might be available (see Module D1-5).

F2/D2-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summaries in Tables F2/D2-6 (spent LWR oxide fuel) and F2/D2-7 (metal fast reactor fuel). The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated and as a result of sensitivity and uncertainty analysis. Refer to introductory paragraphs in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Comparison of electrochemical processing costs for metal and oxide fuels is problematic. While both sets of numbers in Tables F2/D2-6 and F2/D2-7 are listed in terms of dollars per metric ton of heavy metal, the relative worth of the heavy metals from each fuel type are not the same. This is because fast reactor metal fuel has historically been (and presumably in any future designs) enriched in fissile isotopes to a significantly higher level (~20% U-235 or plutonium) than LWR oxide fuel (~4% U-235 or plutonium). In other words, the energy content per kilogram of FR metal fuel is higher than for LWR fuel. For this reason it may be more useful for future comparisons to look at cost-per-unit of fissile material.

Upsides and downsides affecting reference costs are mentioned qualitatively in Tables F2/D2-6 and F2/D2-7, and predicted dominant cost factors are stated; based on the nature of the data, it was not possible to quantify these affects. Of the three studies referenced in Table F2/D2-1, only one is an original cost estimate report (Lineberry et al. 1985). The two other references, a conference proceeding (Boardman et al. 2000) and a national laboratory report (Delene 1993), provide summarized data based on an original cost study that is not publicly available. Simply stated, the level of detail given in the available references and the age of the one available detailed report did not allow a very sound estimate of a facility cost or the ability to assess effects of changing various cost factors. This assessment is strongly reiterated in Appendix J of the 1996 NAS report on nuclear wastes (NAS 1996). They state that significant space must be given for cost growth in electrochemical processing vis-à-vis aqueous reprocessing due to the fact that electrochemical processing is a pioneer technology and aqueous reprocessing is an industrially demonstrated technology.

Table F2/D2-6. WIT cost summary table for spent LWR oxide fuel-based electrochemical processing facility. (Head-end and separations costs only; costs do not include fuel fabrication, waste product packaging, storage, or disposal).

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	(Low Cost) Upsides	(High Cost) Downsides	(Nominal Cost) Selected Values
CFTC costs ($2,150 nominal in 2007) for a 300 MT/yr electrochemical reprocessing facility, 40 years facility life.	$1,800/kgHM	$2,700/kgHM	$2,300/kgHM
(see Table F2/D2-3)	Scale to larger throughput, increase facility life >40 years	Decreased facility life <40 years, FOAK plant	300 MTHM/yr, 40 year facility life

The high and selected unit costs for LWR reprocessing are primarily based on the Follow-on Engineering Alternative Studies (FOEAS) for a 300 MT/yr capacity. The high estimate unit cost was $2,550/kg HM and the average of the estimate range was $2,150/kg HM (Table F2/D2-3). These costs assumed a 40-year operating life; shorter operating periods will significantly increase the unit cost.

Table F2/D2-7. Cost summary table for integral electrochemical processing of fast reactor metal fuel. (Head end, separations, and fast-reactor fuel refabrication only, table does not include waste product packaging, storage, or disposal.)

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	(Low Cost) Upsides	(High Cost) Downsides	(Nominal Cost) Selected Values
Sum of "nominal value FR-TRU", $4,600/kgHM (2000 dollars) based on NEA/OECD studies	3,000/kgHM	$9,000/kgHM	$6,000/kgHM for metal fuel refabrication (homogeneous fuel with significant higher actinides; no blankets/targets included).
—	—	—	$500/kgU for DU blankets $10,000/kgHM for LWR targets containing significant higher actinides (Np,Am,Cm)
See Table R2/D2-5	50% less, scale to larger throughput and increased facility life >40 years	50% more, to account for FOAK, more stringent safety, seismic, and design basis threat mitigation requirements for larger facility	Costs escalated to 2009 dollars

History suggests that the uncertainty and cost growth associated with a first-of-a-kind electrochemical processing facility would be the dominant cost factor and, therefore, the cost per MTHM processed would increase, in practice, from the reference value. Both the first-of-a-kind status of the facility and lack of technology scale-up experience would be expected to dominate upward cost changes from the reference value.

The three unit costs (low, high, and WIT) have been increased over historical estimates for the following reasons:

- All operations would need to take place in a hardened, highly secure building that houses several hot cells for remote handling. Such facilities cost on the order of $15,000/ft^2. The building cost alone for a electrochemical processing plant is likely to be over $100M regardless of size.
- Projected costs (DOE 2003) for the ongoing processing of EBR-II driver fuel are $94,000/kgHM ($282M to process 3,000 kgHM). Blanket fuel processing will cost $13,000/kgHM ($260M for 20,000 kgHM). It is unlikely that such unit costs will come down two orders of magnitude in a larger industrial facility.

Significant R&D will be necessary before any fuel electrochemical processing facility could be available on industrial scale, but even more R&D would be needed for the oxide fuel compared to the metal fuel. Even with a tried and tested technology, first-of-a-kind issues would likely be a dominant cost factor. New technology and first-of-a-kind plant factors are expected to dominate costs.Current studies at ANL include continued development of an electrochemical process for treating LWR oxide fuel and an electrorefiner design that eases materials handling requirements (which is important in a remotely operated facility), facilitates scaling to achieve fuel throughput goals, and provides a means for electrorefining to transition from a batch process to a continuous process. These design and development efforts include establishing the technical and functional operational requirements for a fuel processing facility. Some preliminary cost estimates for this oxide pyro facility may eventually be made available. GE reports cited above incorporate the ANL metal fuel pyroprocess.

This Argonne work is a step toward a very necessary goal, specifically, to perform a cost estimate study on electrochemical processing facilities commensurate with the recent study (WGI 2004) on aqueous processing so that the two technologies can be more directly, fairly, and efficiently compared on a level playing field basis.

The triangular distribution shown in Figure F2/D2-5 is based on the costs in the WIT tables.

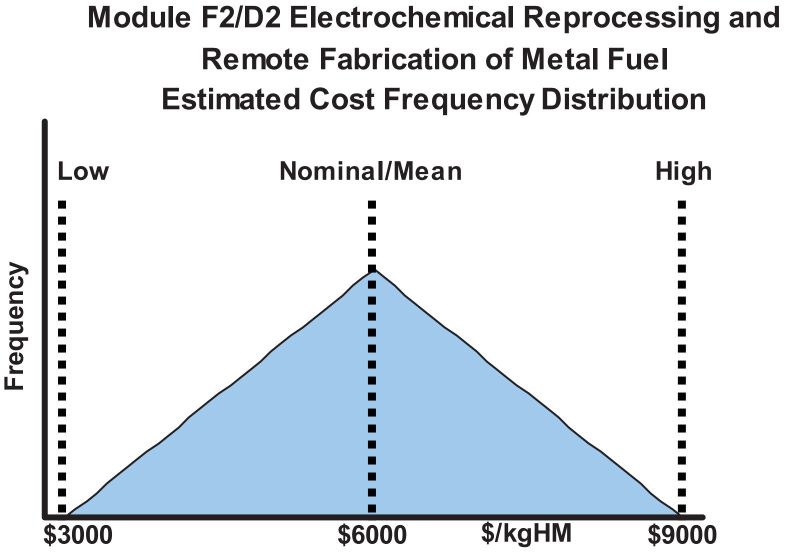


Figure F2/D2-5. Module F2/D2 distribution of combined unit cost for electrochemical reprocessing and remote fabrication of fast reactor metal fuel.

F2/D2-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Once a current, detailed cost estimate for a spent nuclear fuel electrochemical processing facility is complete, cost sensitivity and uncertainty analyses may be performed. Cost driving factors that should be addressed in these analyses include:

- Batch versus continuous operation of the electrochemical process electrorefiner
- Capacity of the electrorefiner (throughput of the facility, scale-up possibility)
- Equipment reliability and related availability/utility versus design and throughput basis
- Number and type of fuel component separations
- Fuel type (oxide, metal, or other)
- Ability to meet product and waste form specifications and acceptance criteria without additional secondary processes
- Waste type, volume, and processing techniques.

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Module G Series

Waste Conditioning, Storage, and Packaging (Summary and Modules G1 through G5)

Module G Series

Waste Conditioning, Storage, and Packaging

G-1. INTRODUCTION

This module includes all conditioning operations to prepare wastes for disposal or long-term storage in compliance with relevant Nuclear Regulatory Commission (NRC), U.S. Department of Energy (DOE), and Environmental Protection Agency (EPA) regulations. Wastes include high-level waste (HLW) according to 10 CFR 60.2 highly radioactive reprocessing wastes, spent nuclear fuel (SNF), low-level waste: Classes A, B, C, and Greater-than-Class-C (GTCC) waste (10 CFR 61.55), and transuranic (TRU) waste (40 CFR 191). Other than HLW conditioning, all other wastes are considered handled by disposal service contracts and do include dedicated facilities. Though not explicitly stated in each section, all waste operations will be handled considering ALARA principles and will maintain personnel dose and potential exposure of the public at or below regulatory limits. Also, where appropriate, all operations will maintain criticality control and incorporate intrinsically safe design with multiple layers of defense via engineering and administrative controls in that order of priority.

G-1.1 Module Series G Cost Summary

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table G-1. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Costs for SNF, low-level waste (LLW), GTCC, and TRU are for services only and do not include dedicated facilities, which are assumed to be separate commercial ventures or independently funded federal facilities similar to current LLW/mixed LLW (MLLW) landfills, and the Waste Isolation Pilot Plant (WIPP) repository.

Table G-1. WIT cost summary table for waste conditioning selected values.

Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
G1–HLW			
HLW Borosilicate Glass	\$2,200/kg FP	\$6,600/kg FP	\$5,000/kg FP
Electrochemical HLW Treatment CFTC EAS	\$12,015/kg FP	\$18,122/kg FP	\$15,100/kg FP
U/Tc Separation and Solidification CFTC EAS	\$161,836 /kg Tc	\$231,496 /Kg Tc	\$200,000/kg Tc
Cs/Sr Solidification and Packaging CFTC EAS	\$30,700/kg Cs/Sr	\$47,600/kg Cs/Sr	\$40,000/kg Cs/Sr
G2—SNF			
\$80–100K/MTHM SNF	\$50K/MTHM	\$130K/MTHM	\$100K/MTHM
G3—LLW			
CFTC EAS (debris)	\$1,000/m^3 LLW debris	\$4,200/m^3 LLW debris	\$1,500/m^3 LLW debris
\$11,000/m^3 LLW Liquid	\$3,300/m^3 LLW liquid	\$22,000/m^3 LLW liquid	\$11,000/m^3 LLW liquid
\$90,000/m^3 Resins	\$81,000/m^3 resins	\$99,000/m^3 resins	\$90,000/m^3 resins
G4—GTCC			
G4-1A Aqueous LLW-GTCC Offgas Absorber (H3, Kr, Xe)	\$8,000/m^3 gas	\$15,000/m^3 gas	\$11,200/m^3 gas
G4-1E EChem LLW-GTCC Offgas Absorber (H3, Kr, Xe)	\$8,000/m^3 gas	\$15,000/m^3 gas	\$11,200/m^3 gas
G5—GTCC Secondary			
INL Cost of Processing Defense TRU Waste and CFTC EAS	\$19,000/m^3 GTCC	\$37,000/m^3 GTCC	\$27,000/m^3 GTCC

CH = contact-handled
CFTC = Consolidated Fuel Treatment Center
EAS = Engineering Alternative Studies
FP = fission product
GTCC = Greater-than-Class-C
HLW = high-level waste
LLW = low-level waste
MTHM = metric ton heavy metal
SNF = spent nuclear fuel
TRU = transuranic

Module G1

High-Level Waste Conditioning, Storage, and Packaging

Module G1

HLW Conditioning, Storage, and Packaging

G1-1. BASIC INFORMATION

Module G1 receives high-level waste (HLW) from a reprocessing facility, stabilizes the waste, provides interim storage of the treated waste, and packages the waste in preparation for transport to a disposal site. According to the Nuclear Waste Policy Act, HLW includes:

"The highly radioactive material resulting from the reprocessing of spent nuclear fuel, including liquid waste produced directly in reprocessing, and any solid material derived from such liquid waste that contains fission products in sufficient concentrations; and…

Other highly radioactive material that the Commission, consistent with existing law, determines by rule requires permanent isolation (DOE 2004)."

Several examples of existing and planned HLW facilities exist, including two examples in the United States, the Defense Waste Processing Facility (DWPF) and the West Valley Demonstration Project. These facilities represent completed HLW conditioning facilities. The Waste Treatment Plant (WTP) at Hanford is under construction with a current forecast operational date of 2017. All these facilities are designed to vitrify the wastes into a glassy form in compliance with 40 CFR 268, "Land Disposal Restrictions, Subpart D Treatment Standards."

Though other stabilization techniques and waste forms could be cost-effective for HLW, the current baseline in the United States is defined by DOE in the *Waste Acceptance System Requirements Document* and the DOE-Office of Environmental Management *Waste Acceptance Product Specification for Vitrified High Level Waste Forms* as borosilicate glass. This baseline is similar to operations in France and Japan, but other types of glass and crystalline waste forms are being considered as part of the evaluation of used fuel processing for fissile material recycle. The electrochemical processing fuel recycling flowsheet under development by Idaho National Laboratory includes production of metallic and glass-bonded ceramic waste forms. A ceramic waste form is planned for disposal of plutonium though these waste forms have not yet been adopted in the baseline.

In the uranium extraction (UREX)+ aqueous reprocessing system envisioned, light-water reactor oxide fuel is dissolved in nitric acid and low-enriched uranium is recovered for reuse or disposal as low-level waste (LLW) if sufficiently decontaminated. Transuranic (TRU) elements would be recovered in one or two partitions and either recycled in metal fuel to be consumed in a fast spectrum reactor or disposed of in a geologic repository. Zirconium fuel cladding hulls and other hardware components are decontaminated and packaged for disposal. Gaseous fission products are captured separately and packaged for disposal. Cesium and strontium may be segregated for interim "decay-storage" for ~300 years and not sent to a geologic repository. Presuming the chemical separation efficiency goals are met, after decay of the cesium and strontium to near-surface LLW disposal standards, these wastes would be disposed accordingly as Greater-than-Class-C (GTCC) not HLW. This assumes the stream does not contain significant amounts of long-lived fission products or TRU, and a long-term (>300 years) storage facility is licensed to store the cesium and strontium pending decay. Technetium is captured and treated separately to enhance the wasteform and allow increased repository loading of this HLW. The remaining fission products are HLW and stabilized in a waste form for the repository. Different conceptual designs for treatment of the HLW streams incorporate calcination, steam reforming, precipitation with filtration and drying, or the baseline glass melters. Regardless of which design is used for estimating purposes, it is important that the costs used for reprocessing and the costs used for preparing HLW for disposal in a geologic repository do not double-count the waste treatment costs.

In the electrochemical processing system, metal fuel from fast reactors is dissolved electrolytically in an electrorefiner, with the chopped fuel submerged in a molten lithium/potassium chloride salt bath. Uranium and TRU are to be captured for recycle at a cathode, while zirconium from the fuel matrix and noble metal fission products including technetium remain with the stainless steel fuel hulls at the anode. The cladding/Tc/Zr/fission product (FP) stream is to be melted into ingots for disposal as a metal HLW form in a geologic repository. Waste salts containing the balance of FP including the cesium, strontium and iodine are to be absorbed into zeolites and bonded using borosilicate glass to make a ceramic HLW form for disposal in a geologic repository.

All the streams from reprocessing could be considered HLW under current regulations. If the developed separations are assumed to be adequate to meet disposal and recycling specifications and that the decay storage strategy is licensed and a repository for commercial TRU wastes is created, the steams from fuel processing may have more cost-effective disposition pathways available. A summary of the potential streams from aqueous UREX and high-temperature electrochemical processing and their planned and possible alternate disposition pathways is shown in Table G1-1. Some entries in the table are undefined because testing has not yet been done, or data are unavailable.

Whether the HLW ends up in baseline glass or in a different form will be dictated by the reprocessing design and government policy. For the purposes of this document, cost bases for the treatment of aqueous waste are vitrification facilities similar to defense HLW vitrification facilities (DWPF and WTP), since this technology is expected to remain the baseline for at least the next 20–30 years. Shipping and disposal costs are all based on canisters of glass. The costs reported here are based on the DWPF actual costs and Consolidated Fuel Treatment Center (CFTC) Engineering Alternative Studies (EAS) estimates. None of these estimates include the cost for transportation or disposal of glass canisters. However, potentially higher waste loading and waste forms with greater density are considered in assigning the range of values in the cost tables.

Electrochemical waste processing costs reported here are those developed as a part of the CFTC Follow-on EAS (FOEAS). The study includes cost associated with the zeolite/borosilicate glass-bonded process to make a ceramic HLW form and the production of a lanthanide glass for disposal in a geologic repository.

Table G1-1. Fuel reprocessing streams.

Aqueous UREX processing of LWR fuel	Planned Disposition			Example Alternative Disposition		
	Disposition	**Potential Waste Form**	**Range of Waste Loading**	**Disposition**	**Potential Waste Form**	**Range of Waste Loading**
U	LLW	Oxide powder or grout	30–100%			
				TRU waste	Oxide powder or grout	30–100%
				HLW	Glass or glass-like, Synroc, or iron-phosphate	20–40%
				Recycle via reenrichment	Fuel raw material	Not waste
				Recycle as DU metal	Metal	Not waste
TRU	Fuel	Metal FR fuel	Not Waste			
				Burn in LWR	MOX or inert matrix fuel	Not waste
				TRU waste	Oxide powder or grout	30–100%
Cs/Sr	HLW	Ceramic formed from bentonite clay	10%			
				HLW	Glass or glass-like, Synroc or iron-phosphate	10–20%
				GTCC	Ceramic or grout	10–20%
Tc	HLW	Metal	0–5%			
				HLW	Codisposed with other FP in glass	<1%
				HLW	Low-temp ceramic	10–30%
				GTCC	Low-temp ceramic	10–30%
I	HLW	Ag-zeolite in grout	5–10%			
				HLW	Anionic	5–10%
Balance of FP	HLW	Glass	20–50%			
				HLW	Synroc, iron-phosphate	30–70%
				HLW	Crystalline, low-temp	10–30%
				GTCC	Grout	20–50%

Table G1-2. (continued).

Aqueous UREX processing of LWR fuel	Planned Disposition			Example Alternative Disposition		
	Disposition	**Potential Waste Form**	**Range of Waste Loading**	**Disposition**	**Potential Waste Form**	**Range of Waste Loading**
Zr Cladding Hulls	GTCC	Compacted Metal	100%			
				Re-use in FR metal fuel alloy	No waste	No waste
				HLW	Compacted metal	100%
Electrochemical						
U/TRU	Reuse in burner FR	Not waste	Not waste			
				U only as LLW near surface disposal	Metal or macroencapsulated	60–100%
				TRU waste	Metal or macroencapsulated	60–100%
				HLW	Glass or glass-like, Synroc, or iron-phosphate	20–40%
SS Cladding, Zr, Tc, noble FP	HLW	Metal waste form with Tc and matrix Zr	100%			
				TRU waste	Compacted metal	100%
				HLW	Compacted metal	100%
Cs/Sr/I Excess Salts and other FP except lanthanides	HLW	Glass-bonded salt in zeolite	10%			
				HLW	Glass or glass-like, Synroc, or iron-phosphate	10–20%
				GTCC	Grout	10–20%
Lanthanides	HLW	Lanthanide glass	50%			
				HLW	Glass or glass-like, Synroc, iron-phosphate	20–40%

FP=Fission Product
MOX=Mixed Oxide
FR= Fast Reactor
SS=Stainless Steel

G1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

All HLW will be handled remotely, in specially equipped hot cells, designed with 2 to 4-feet-thick concrete walls, oil-filled windows, and manipulators. Waste will be received from tank farm or solid storage operations and held in interim storage that can be mixed sufficiently to allow representative sampling. Samples will be acquired remotely and analyzed to characterize wastes, including a full suite of α, β, and γ emitting radionuclides, toxic metals, and organic constituents likely to be present based on the selected process. In addition to establishing the basic chemistry of the waste to develop a recipe for a waste form, the analytical data will be reviewed as required to determine if the waste is hazardous according to the Resource Conservation and Recovery Act and if the waste contains any listed organic constituents. Once characterized, laboratory support facilities will develop a reliable chemical recipe for converting the waste to a borosilicate glass meeting disposal requirements.

The main process area of the facility will be equipped with reliable melter technology to convert the waste with additives into the desired glassy waste form, or parallel technology to produce a nonglass acceptable waste form. This area will be remotely operated as well, and all maintenance will be conducted remotely or constrained by very limited access preceded by decontamination. Equipment will be designed for reliable operation and remote disassembly where possible. The facility must have the capability to conduct routine maintenance as well as nonroutine activities, such as change out of damaged or worn out large equipment including the melter itself.

Facilities will also be equipped with postprocess remote sampling and analytical capabilities to characterize waste form products including durability in standard tests such as the Product Consistency Test (ASTM 2008) and the Toxic Characteristic Leach Procedure (EPA 1992) if deemed necessary. The facility will be equipped with an offgas treatment system designed such that when operated in coordination with the melter system retention of materials in the waste form is maximized and gaseous effluents meet Maximum Achievable Control Standards, as designated in the facility permit. This will probably require recycle of filter catch materials to the main process equipment (melter), include specialized operation such as specific RedOx chemistry control in the melter, and require operation with a cold-cap (layer of liquid feed covering most of the molten glass surface). The offgas system for a thermal process for highly radioactive materials may make up 60% or more of process space, and the hot-cell area will likely drive facility capital cost.

The facility will likely recycle water with the evaporator bottoms being recycled to maximize waste incorporation in the glass and the condensates collected for nitric acid recovery, and additional decontamination. The purified water will then be recycled and any excess water will likely be stabilized in concrete or a similar stabilizer and disposed of as LLW. The cost of acid recovery and effluent treatment is not included in this module.

Offgas filters, clothing, tools, and miscellaneous hardware will also generally be disposed of as LLW. There is a potential for generating GTCC and TRU wastes, but a properly designed waste management and decontamination system should minimize this occurrence.

This module generally does not include additional separations that could produce several streams from the HLW. Fractionation of the reprocessing wastes is contained within Modules F1 and F2/D2 dedicated to reprocessing.

In the following sections, the Functional and Operational Requirements (F&ORs) for HLW (with potential to reclassify to either LLW or GTCC) are examined in terms of waste conditioning and waste forms, canister sizes, and storage.

G1-2.1 Waste Forms, Canister Sizes, and Storage of Heat Generating Wastes

Solidification of the waste serves the two main purposes of immobilization of waste for storage, transport, and emplacement in a permanent disposal facility. Interim storage is normally required to allow further decay of the major heat emitting nuclides, and therefore reduce the early thermal loading of the disposal facility. Thermal, mechanical, and chemical stability of the waste form is required including effects of irradiation and leaching.

Various waste forms and corresponding waste immobilization processes are known for HLW. Calcines are products or intermediates obtained by partial or complete removal of volatile components of the waste, such as water and nitrates, at temperatures of 400–900°C. This creates a mixture of oxides in particulate form and with a specific surface of 0.1–5 m^2/g. Calcine powders may not be very stable because of the chemical properties of some constituents, large surface area, low thermal conductivity, and friable nature of the solids creating fine dust. Depending on calcination temperature, calcines may have residual water and nitrate content. Calcine powder may be pressed or solidified within cements or concentrated solutions grouted. If waste temperatures, radiation, or canister corrosion effects are sufficient to release water, NOx or hydrogen, then canister venting, inspection, and offgas treatment may be needed (Streatfield et al. 2006).

For passive long-term decay storage, higher process temperature, refractory, near-inert waste forms, such as glasses and ceramics are preferred. For heat generating wastes, waste form dimensions may need optimization to limit center line temperatures to acceptable values. The more important immobilization alternatives are calcine, ceramics, glass, glass ceramics, and cement (Benedict et al. 1981) (see Table G1-2).

Table G1-2. Immobilization waste form options.

Alternative	Calcine	Glass	Ceramic
Basic	Fluidized bed (particulates) Pot (cake)	Borosilicate (cylinder) Phosphate (cylinder)	Aluminosilicate Bentonite
Advanced	Supercalcine (additives, high T)	Borosilicate glass ceramic (cylinder)	Synroc (multi-phase ceramic) – Hi T, HIP
Composite	Multibarrier (e.g., pyroC, SiC in metal matrix)	Vitromet (glass/glass ceramic in metal matrix)	Glass ceramic (e.g., puck crystallized glasses and sodalite in glass matrix)
Cement-vented Canister	Low T encapsulation of concentrated solution or calcined particles		Higher temperature specialized cements (e.g., supercalcines)

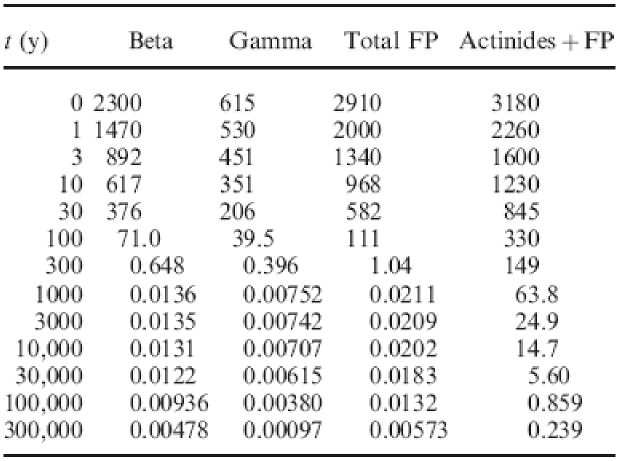
There is generally an increased processing cost for refractory, inert waste forms. This may take place through need for high-temperature operation, corrosive conditions limiting equipment lifetimes, volatilization of selected fission products requiring complex off-gas systems and waste recycle. Synrocs often require small batch operations using hot isostatic pressing (HIPing) at high temperature and with relatively long process cycles.

Waste forms may incorporate differing waste concentrations to meet waste performance and economic goals. Waste packaging and transportation costs are significant so that reduction of package number is desirable. However, thermal limitations apply to transportation, disposal and the waste form itself, and excessive fission product (FP) concentrations reduce the chemical performance of waste and may cause excessive internal temperatures. Composition limitations are typical for glasses where either phase separation or lack of glass forming occurs. For borosilicate glasses, for example, the FP oxide limit is normally considered to be around 20–25% by weight (plus process additives) using existing hot-wall melters. Higher concentration may create a distinct yellow crystalline phase formed of alkaline and alkaline earth molybdates. This readily soluble phase contains Cs-137 and Sr-90. Glasses can be formulated to incorporate most fission product and actinide oxides with good stability. Devitrification occurs above the glass transition temperature, for example at elevated temperatures of ~500°C for phosphate and ~600°C for present borosilicate glasses. Some processes employ controlled crystallization to glass ceramics to create known waste form properties. Other waste form composition/temperature limitations may arise from a wide variety of limits such as melting, volatization, and recrystallization into new phases, chemical reaction, canister pressurization, etc. Composition is not a direct limitation for calcines, which are amorphous, but high-heat load may cause further chemical decomposition, canister corrosion, and pressurization. Grouts are normally used to immobilize mineral ion exchange (IX) materials used for treatment of LLW and (in Europe) for intermediate level wastes (ILW) liquid wastes, but have also been used for encapsulation of low specific decay power raffinates from specialized recycling operations.

Industrial practice for HLW vitrification tends to use large canisters for low specific decay heat defense wastes (e.g., 0.61 m o.d., 3 m height and 2.1 t filled mass) for Savannah River DWPF, and small canisters for high-specific decay power LWR wastes (e.g., 0.43 m o.d., 1.3 m height and 0.5 t filled mass) for Ateliers Vitrification La Hague (AVH) (IAEA 1992). Even smaller diameter canisters, o.d. 0.3 m, have also been used at PAMELA (Germany) and WIP (India). In general terms, canisters with diameters less than 0.2–0.15 m diameter are not favored industrially due to difficulties of filling with molten glass due to bridging, potentially more thimble tubes due to retention of moderate l/d ratios for canister cooling, increased pressure drops with high-air velocities, and possible limited cost reduction of storage with decreasing thimble tube diameter. KfK Germany developed a process where HLW phosphate glass beads were cast and then embedded in molten metal in a canister. Such an approach or other internal features for heat conduction may be especially useful for CsSr vitrification of short-cooled, high-loaded fission products.

For LWR fuel of typical burn-up of 40 GW(t).d/t(iHM), the decay powers are given in the Table G1-3, (Bergelson et al. 2005).

Table G1-3. Decay heat power of FPs and transuranics (Pu, Am, Cm) during long-term storage, W/t(iHM).



t (y)	Beta	Gamma	Total FP	Actinides + FP
0	2300	615	2910	3180
1	1470	530	2000	2260
3	892	451	1340	1600
10	617	351	968	1230
30	376	206	582	845
100	71.0	39.5	111	330
300	0.648	0.396	1.04	149
1000	0.0136	0.00752	0.0211	63.8
3000	0.0135	0.00742	0.0209	24.9
10,000	0.0131	0.00707	0.0202	14.7
30,000	0.0122	0.00615	0.0183	5.60
100,000	0.00936	0.00380	0.0132	0.859
300,000	0.00478	0.00097	0.00573	0.239

Data in Table G1-3 shows both total FP and total FP with transuranic (Pu, Am, Cm) contributions to decay power. Often the Pu contribution is omitted as vitrified HLW includes minor actinides, but not Pu. The total FP decay power reduces by 40% in the period 10-year cooled to 30-year cooled, which indicates the major contributions of Cs-137 ($t_{½}$ = 30y) and Sr-90 ($t_{½}$ = 28y) to decay power in this period.

Heat generation in immobilized HLW and CsSr waste causes the waste form to be at elevated temperatures for more than 100 years. With some simplifications, the maximum temperature difference between the centerline and surface of a long cylindrical waste form is given by:

$$\Delta T_{max} = q\, r^2 / 4\, \kappa$$

Where

q = power density, W/m^3

r = radius of the cylinder

κ = waste form thermal conductivity, W/(m.°C).

The surface temperature is given by the storage conditions including canister wall and waste surface/canister interfacial properties. This enables scaling of canister radius against heat loadings from existing commercial practice (IAEA 1992). Representative values for conductivity of waste forms are given in Table G1-4 (Benedict et al. 1981).

Table G1-4. Thermal conductivity ranges for various HLW forms in temperature range 100–500°C.

Waste Form	Thermal Conductivity, κ W/(m.°C)
Particulate calcine	0.2–0.3
Phosphate glass	0.8–1.2
Borosilicate glass	0.9–1.3
Borosilicate glass ceramic	1.5–2.0
Particulate calcine or glass beads in metal matrix (e.g., vitromet)	~10

Waste form conductivity clearly has a major influence on centerline (peak) temperature and corresponding canister dimension (radius), see Figure G1-1, (Benedict et al. 1981).

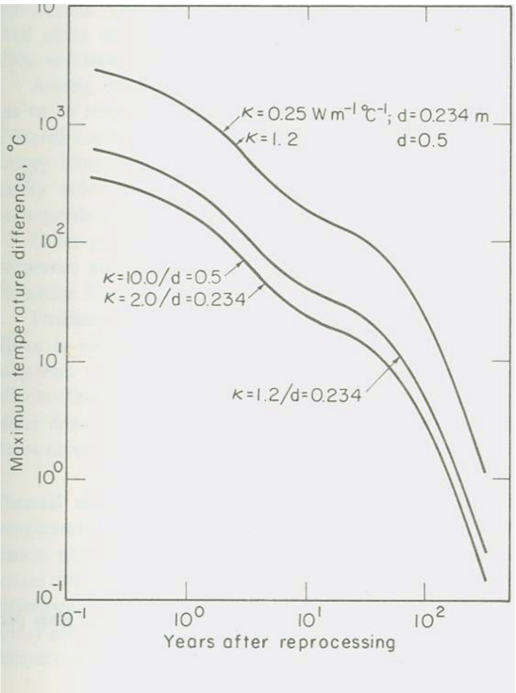


Figure G1-1. Calculated maximum temperature difference in a cylinder of solidified waste for different diameters and thermal conductivities as a function of time (years) after recycling.

The heat generation rate is based on fission products and minor actinides incorporated into a waste form specific volume of 70 L/t(iHM). The originating SNF burnup is 30 GW(t).d/t(iHM) and recycling taking place at 150 days SNF decay.

Figure G1-1. Maximum centerline temperature difference of waste form as a function of decay time.

At the assumed waste loading, Figure G1-1 indicates maximum temperature differences for glass ceramic waste with canister diameter of about 0.5 m of between the waste center line and surface of >1,000°C (≡ 100 W/L) and >100°C (≡ 10 W/L) for 1 year and 10 years decay after recycling respectively.

In the present study, borosilicate glass is considered the reference HLW form. This is conservative since it is somewhat more thermally restrictive than some synrocs and other ceramics. For civil design, it is generally preferable to restrict natural convection cooling air discharge temperatures to around 150–200°C as concrete structural components are damaged by long-term contact with air at temperatures approaching 100°C. However, higher values can be engineered. Air cooling in forced convection stores would be less limiting, but for a long-term decay store, there is likely to be conservatism concerning highly rated systems and effects of cooling failure. This suggests that a maximum temperature difference, ΔT, between waste centerline and surface of around 300°C may be appropriate assuming a centerline maximum design temperature of ~500°C. For a canister with diameter 0.5 m containing borosilicate glass HLW, a maximum specific thermal power in the range 10–30 W/L appears suitable. Raising the glass transition temperature by ~200°C increases the maximum thermal power by about 60%.

G1-2.2 Potential Waste Forms for Immobilization of Cesium and Strontium

The most troublesome Cs and Sr isotopes are Cs-137 ($t_{1/2}$=30.07 y: 0.66 MeV γ and 0.514 MeVmax β-) and Sr-90 ($t_{1/2}$=28.78 y: 0.546 MeVmax β-), so their activities remain a concern for ~300 years (i.e., ~10 half-lives). These two isotopes generate a major portion of the decay heat in spent nuclear fuel over the first 100 years of storage, but then are essentially stable. Removing Cs and Sr for decay storage will reduce the short-term heat load on a repository waste form.

Fission product oxide mass, excluding noble gases, is ~1 kg(FPOx)/GW(t).d, and so for a metric ton, t, of SNF at 40 GW(t).d/t(iHM), the mass of FP oxides is about 40 kg. Cs and Sr form about 10 atom % of the FPs, of which around half are the major heat emitting isotopes (Cs-137 and Sr-90). Total CsSr also form around 10% by weight of the FP oxides, that is 4 kg/t(iHM) of spent fuel. Total CsSr-Rb-Ba form around 15% by weight of the FP oxides, that is 6 kg/t(iHM) of spent fuel. From Table E4-2, where Cs-137 and Sr-90 are the only major FP isotopes with half lives between 10–50 years, the decay power of CsSr is seen as about 1 kWt(iHM) at 10 years ex-reactor. Alternatively the CsSr decay power can be expressed as ~¼ kW/kg(CsSr) at 10-years cooling. In engineering terms, the specific decay power of CsSrOx is about 10 times that of overall FPOx at 3–20 years cooling.

Recently, interest in separation of Cs and/or Sr during remediation of long-stored HLWs and for advanced fuel cycles has stimulated developments in waste forms tailored to CsSr immobilization. These include variants of waste forms for HLW and several new matrices (see Table G1-5), which is representative rather than complete. The various minerals formed have differing capacities for Cs and Sr.

Table G1-5. Representative CsSr-Rb-Ba waste forms.

Matrix	CsSr Composition	Composition Matrix, (% wt)	Process	Reference
Cement	4% Zeolite A, 5mEq/g	Pulverized Fuel Ash, Ordinary Portland Cement	Grouting ambient T Maintain ≤95°C	El-Kamash et al. 2006
Alumino-silicate (Steam reform)	27%Cs / 8%Sr $SrCO_3$ $CsAlSi_2O_4$	Pollucite/hydroceramic Slawsonite	Steam reform CsSr-Ba with carbon & alumino-silicate clay at ~700°C	Ortega and McDeavitt, 2007 Law et al. 2007
Bentonite (alumino-silicate) Dry Sinter	≤40% Cs loading	Celsian Pollucite Hydroxyl-apophyllite	Dry sintering bentonite clay containing Cs, Sr, Rb, Ba to 600–1,000°C	Kaminski and Merz, ANL.
Crystalline Silicotitanate (CST) and Niobate IX	Cs_2O ~ 20% wt	$Cs_2TiSi_6O_{15}$ $Cs_3TiSi_3O_{9.5}$ and Ti analogue of Pollucite $CsTiSi_2O_6$	Calcining CsSr soaked UOP CST IE-911 in air at 900–1,000°C	Balmer et al. 2000. Luca et al. 2006
Borosilicate Glass High mp glass	Cs_2O 13% wt and SrO 7% wt PNNL ~40%wt	Na_2O 10-20 B_2O_3 10-17 SiO_2 45-50 Al_2O_3 2-5 Ba,Pb,TiOx 4-6	Calcination and Melting High-melting glass	Aloy et al. 2007
Hexagonal Tungsten Oxide Bronze (HTB)	Cs_2O ~12% wt or SrO ~5% wt	$Cs_{0.13}Mo_{0.03}W_{0.97}O_3$ $Sr_{0.05}Mo_{0.03}W_{0.97}O_3$	CsSr adsorbed HTB, Calcine 500–1,000°C in air.	Luca et al. 2006
Synroc-C Hydrous Titanium Oxide (HTO)	CsSr-Rb-Ba 12 %wt	Hollandite Rutile Titanates	Calcination 750°C & HIP 1,275°C, 30MPa, 1h	Carter et al. 2007
Cs/Sr Oxides	Cs_2O/SrO	Pure	Calcination	-
CsCl	100% Cs salt in capsule in pool	CsCl, 35kCi 190W	IX separation and Evap	Nat Acad Sci, 2003
SrF_2	Sr salt in capsule in pool	CsF_2, 33kCi 260W	IX separation and Evap	Nat Acad Sci, 2003

These potential CsSr waste storage forms evolved from upstream processing needs. Bentonite (including commercial UOP IE-911), and hydrous titanium oxide (HTO) are examples of IX materials used to selectively adsorb Cs, Sr, etc., from stored, complex chemistry salt HLWs to provide partitioning of waste for optimized waste management. These IX materials bearing low-medium Cs, Sr concentrations are heat treated by sintering, generally in the temperature range 500–1,000°C. This causes removal of water, recrystallization, denitration, and additional phases, and ultimately removal of hydroxyl groups. By contrast, the advanced fuel cycle processes (e.g., UREX+ [Vandegrift et al. 2004]) create salt-free product streams of CsSr (e.g., nitrate and carboxylic acid based). These are not constrained by feed of mineral IX materials and can be used to form the complete range of waste forms from pure CsSr oxides/chlorides to glasses to freely tailored ceramics. The uses of zeolites (i.e., micro-porous crystalline solids with well-defined structures) generally contain silicon, aluminum, and oxygen in their framework and cations, and/or other molecules within their pores. For CsSr recovery in molten salt, electrochemical waste forms are more likely to be aluminosilicate ceramics or aluminosilicate glass ceramics.

High-level waste vitrification is well known as a complex technology with significant cost impact on existing plutonium-uranium extraction (PUREX) commercial and defense recycling waste management. Advanced fuel processes generally partition FP and actinide species into more streams (e.g., seven for UREX+4). Some of these, (CsSr), have medium radioactive lifetimes and means have been sought to optimize the waste immobilization process to the waste lifetime, including storage requirements. For substantial masses, CsSr wastes need cooling for periods of 100–200 years. AFCI has examined use of a steam reforming process to fabricate alumino-silicate waste forms for CsSr storage (Law et al. 2006).

The UREX+ suite of processes has a separation segment, CCD-PEG in UREX+1a (Law et al. 2004) or FPEX in UREX+1b (Law et al. 2007), for recovery of CsSr-Rb-Ba from the raffinate of the UREX segment. Both of these technologies provide simultaneous solvent extraction of Cs and Sr together with the majority of Rb and Ba. With CCD-PEG, the CsSr by-product is stripped using an organic amine and carboxylic acid mixture while FPEX uses dilute nitric acid as strip. Steam reforming has been developed for stabilization of streams because it can produce a solid waste form while retaining the Cs and Sr in the solid, destroy the nitrates and organics present in these aqueous solutions, and convert the Cs and Sr into leach resistant aluminosilicate minerals. The waste form is intended to meet a 300 year, 10 half-life period of storage prior to projected LLW disposal complying with Class C waste criteria.

A bench-scale steam reforming pilot plant has been operated at Idaho National Laboratory (INL) with several potential CsSr feed compositions and steam reformed product has been generated and analyzed (Law et al. 2006). A small, but representative fluidized-bed was used to conduct steam-reforming tests to produce mineralized granular product. Operating conditions of 700°C, ~3% H_2, ~4% CO, 70% CO_2, and 20% steam were used to decompose nitrates and organics. A starting bed of 100–300 micron aluminum oxide particles was used and Sagger clay slurried with the feed to produce pollucite and other alumino-silicate minerals. Excess clay was used to mineralize the cationic feed constituents. The clay particles are less than 10 μm to achieve a high-surface area for reaction. The final bed material in each run was generally a granular material much like the initial aluminum oxide starting bed with some additional smaller diameter solids. The bench-scale steam reformer tests successfully converted cesium/strontium strip products to a solid form without volatilizing the Cs. Results also indicate that with optimization of the steam reforming operating parameters, 100% mineralization is possible (Law et al. 2006). The bed waste product material may be compacted, for example, within canisters to form pucks, which may be loaded into an over-pack.

A collection of EAS related to a commercial scale UREX+ separations plant were commissioned by DOE and carried out by a multi-national laboratory team in 2006–2008. EAS investigated features of a canyon approach for a commercial plant, with expected throughput of ~3,000 t(HM)/year, with three solvent extraction lines. The FOEAS evaluation assumed a smaller plant throughput (~800 t(HM)/year

UREX+) with re-examination of facility layout options, requirements, alternate flowsheets, etc. (WSRC 2007, 2008).

In the EAS, an engineering proposal and costing of the proposed storage of the UREX+ cesium-strontium (CsSr) waste stream was presented. The study was based on the UREX+1a process, throughput of 3,000 t(iHM)/year mixed LWR fuel of 60 GW(t).d/t, and formed a variety of products and wastes, including an aluminosilicate mineral powder CsSr waste intended for a 300-year period of storage prior to projected LLW disposal. This study demonstrated reasonable feasibility, but was not an economic optimization and further studies were performed.

The FOEAS was based on the UREX+1b process throughput of 800 t(iHM)/year mixed LWR fuel of 60 GW(t).d/t and formed a variety of products and wastes. For CsSr, three waste forms were examined conceptually: a sintered bentonite and two vitrified CsSr options with differing CsSr loadings. As for EAS, these would need nominal 300-years storage for compliance with Class C waste disposal. Other geological disposal scenarios may be feasible, but are not well defined yet and so are not considered here. This was a top-down assessment based on the above 3,000 t(HM)/year study with some variations to account for process changes and scale, etc. The use of sintered bentonite or vitrified CsSr wastes may possibly increase waste immobilization costs, but is expected to decrease overall waste storage costs life cycle costs (LCC) by increasing CsSr loading and canister diameter and by reducing waste volumes, total canisters, and required storage capacity. However, depending on design these may need periods of forced convection cooling and delayed potential for using passively cooled storage. If Advanced Fuel Cycle Initiative (AFCI) does call for CsSr separation, a vitrified CsSr waste form option is presently favored with a range of increased loading values being examined and this makes good use of state-of-the-art vitrification and waste storage technologies.

There was a third conceptual design, which was based on a high temperature, molten salt electrochemical process. This design was based on oxide fuel electrochemical reduction, uranium electrorefining, and transuranic product recovery by electrowinning. The design throughput is 300 t(HM)/year mixed LWR fuel of 60 GW(t).d/t and the process formed a variety of products and wastes including a glass-ceramic CsSr waste formed with zeolite used as an ion exchange material to recover CsSr from salt. The specific activity of this waste form is expected to be similar to or lower than the aluminosilicate. However, the electrometallurgical CsSr waste may have higher radioactive impurity levels (e.g., TRU).

In summary, the CsSr-Rb-Ba separated waste stream from UREX+ aqueous separations is salt free and can be decomposed thermally to the oxides and converted into a wide variety of waste forms and chemistries including particulate ceramics, cements, sintered ceramics, glass ceramic composites, and cast vitrified waste. The waste stream has few process additives so the CsSr waste form may be made as concentrated in CsSr as desired consistent with chemical, physical, and thermal waste-form properties. The Integrated Waste Management Strategy (IWMS) presently favors the CsSr vitrified waste option using existing waste storage and state-of-the-art vitrification technologies. Incorporation of 20% wt CsSrOx in borosilicate glass has been reported and fully active samples made (Aloy 2007). Pacific Northwest National Laboratory is understood to be investigating higher incorporations, ≥40% wt. CsSr-Rb-BaOx, which equates to ≥27% wt CsSrOx. CsSr concentrations in commercial LWR vitrified waste are around an order-of-magnitude lower than the latter number so that borosilicate glass (BSG) waste container diameters may be need to be reduced from 0.4 m to 0.13 m (i.e., by factor $\sqrt{10}$), or SNF decayed stored for >3 CsSr half-lives (i.e., ~100 years). Additionally, increasing the glass transition temperature by several hundred degrees centigrade may allow the canister diameter to be increased back to around 0.2 m with the same high CsSr incorporation. Glass formulations with higher devitrification temperatures generally require formulations with higher melting point as may be achieved by a cold crucible melter.

G1-2.3 Vitrification and Storage of LWR Oxide HLW

For LWR fuels, the main operating commercial separations plants in the world are UP2-800 and UP-3 at Cap La Hague and THORP at Sellafield (Rokkasho is believed to start full operation in 2008 and uses Japanese joule –heated ceramic melter vitrification technology). These French and UK plants have used French AVH vitrification technology for nearly 2 decades. Calcined fission product waste is mixed with glass frit in the ratio of around 1:3 by weight. The PUREX raffinate has low processing inerts and after calcination is mainly FP and minor actinide (MA) oxides with very low U, Pu content, and moderate corrosion product concentrations.

Vitrification of commercial and/or defense HLW has taken place at Cap La Hague and Marcoule in France, Sellafield in the UK, Tokai in Japan, Karlsruhe in Germany, Savannah River, and West Valley in U.S., Tarapur in India, Russian Federation, etc. Almost all of these facilities use air-cooled vault storage systems where waste canisters are stored in cooled thimble tubes. Most use forced air convection, at least initially, whereas one uses natural convection with forced convection as standby during early operation (IAEA 1992).

France first performed vitrification operations in the 1970s in the Ateliers Vitrification Marcoule facility (known as the AVM) and then in the late 1980s in the R7 and T7 facilities of the La Hague plant (referred to as the AVH). French vitrification technology uses a rotary calciner feeding a metallic inductively heated melter vessel, which siphons batches of vitrified waste into HLW canisters. The Marcoule vitrified waste store used HLW canisters of dimensions, 0.5 m diameter and 1 m height, for lower burnup, lower decay power gas-cooled reactor wastes. For AVM, three casts of glass (120 kg each) totaling about 140 L are made into a single stainless steel canister. The vitrified waste store used thimble tubes (steel sleeves with base set into concrete) and stacked canisters, 10 high. The sleeves are 0.6 m diameter and 10 m height. The maximum output of the ten canisters in a sleeve is 8 kW (i.e., 0.8 kW/canister) on average, but 1 kW peak value. Forced convection cooling air normally flows between sleeves and canisters at velocities of 10–15 m/s with filtration at outlet but can revert to natural convection without filtration for power failure conditions or after long storage, etc. Two vaults were built initially at Marcoule, one with 80 storage sleeves and the other with 60 storage sleeves. The maximum heat load of the whole store is 1 MW. One AVM single line plant was constructed in the 1970s at Marcoule, to provide vitrification of low burnup gas reactor fuel with vitrified waste power densities of ≤8 W/L.

The AVH stainless steel canisters are cylindrical with overall dimensions of around 0.42 m diameter (17 inches) and height 1.3 m (52 inches). The canisters have a top flange of reduced diameter with welded closure following filling with two pours from the melter. After pouring, the canisters contain about 400 kg (150 L) vitrified HLW and are around three-fourths filled. (In France, the residual space is filled with pucks of compacted leached fuel hulls.) Two AVH plants, designated R7 and T7 and each of three vitrification lines, were constructed in the late 1980s at La Hague, to provide vitrification of standard LWR fuel (33 GW(t).d/t) HLW after 4 years of cooling. Preliminary evaluations foresaw glass center line temperatures ≤650°C and power densities of ≤60 W/L, which implied a maximum canister heat load of 9 kW. Eventual design values were specified as 20 W/L and 3 kW, respectively.

The Sellafield waste vitrification plant was constructed with two AVH process lines, and first operated in the early 1990s. Its VPS accommodates up to 8,000 AVH canisters stacked 10 high (about 13 m). Each canister (400 kg waste) typically contains vitrified waste from the recycling of 8 t Magnox fuel or 2 t oxide fuel (Dobson and Phillips 2006). There are 800 stainless steel storage thimble tubes into which the canisters are stacked through top plugs and seals. Each storage tube is within a rectangular compartment to guide cooling air. Decay heat is removed by natural convection cooling of the exterior of the sealed storage tubes, and due to multiple barriers and compliance with glass centerline limits and civil structural limits, no filtration of the cooling air is required. The Sellafield borosilicate glass formulations have waste oxide incorporations in the range 20–30 wt% with glass transformation temperature of around 550°C; 500°C is taken as the glass center line temperature limit. VPS has capacity for vitrified HLW from two decades of THORP design throughput of 800 t(oxide SNF)/year, that is 16,000 t(oxide SNF) equivalent.

British Nuclear Fuels plc (BNFL) commenced active commissioning of the third line at its Waste Vitrification Plant (WVP) at Sellafield in January 2002. The start of operation of the 320M UK pound (~2000 m.v.) ≡ U.S. \$485M (2000 dollars) line enables BNFL to meet its commitment to speed up the conversion of liquid HLW to borosilicate glass blocks for longer term storage. The UK regulator requires year-on-year reductions in highly active liquid waste down to buffer stocks of 200 m^3 by 2015.

The operation of WVP has led to the production of over 4,000 containers of vitrified waste to-date, which are currently stored within the VPS at Sellafield. The VPS is deemed suitable for this interim storage requirement, subject to regular maintenance and refurbishment, for at least 100 years. A proportion of the vitrified HLW will be returned to overseas customers at the appropriate time as set out in the recycling contracts. The canisters of vitrified HLW are kept in a purpose-built store (VPS), which has passive cooling and a back-up forced cooling system.

The design and operation of HLW vitrification facilities has been well described for the major national nuclear programs (IAEA 1992). Following filling of stainless steel, cylindrical waste canisters with vitrified waste, various operations are used to prepare canisters for storage and ultimate disposal. Thermal conditioning of canisters to reduce heat shock and decrease glass cooling rate and fracture may be used. Tungsten Inert Gas (TIG), plasma torch, or upset-resistance welding is used to seal the canisters with lids. Canister welds are normally inspected optically or by helium leak testing. Canister dimensions, weight temperature and dose rate may be determined. The exteriors of canisters are often decontaminated using high-pressure water, sand slurries, dry blasting, or electrochemical decontamination. Waste canisters must be cooled in storage to minimize devitrification and maintain store integrity.

Currently, operating and planned interim stores use air cooling of canisters. Air cooling can be achieved by conduction, or natural or forced convection. For some high-specific decay power glasses, forced cooling is combined with natural convection cooling. Canister, waste, and store characteristics for various national facilities are given in Table G1-6.

Table G1-6. Canister and waste parameters for operating vitrified HLW stores.

Facility Cooling	Canister I.D./Height m/m	Glass Mass/ Volume, kg/L	Max Activity GBq α/β	Maximum Canister Power, W	Maximum Power W/kg
AVM France	0.49	360	3.0×10^7		
Forced/Natural	1.0	135	1.4×10^7	1,000	2.8
R7/T7 France	0.42	400	1.4×10^5	2,980 peak	
Forced/Natural	1.34	150	2.8×10^7	2,100 average	7.5
WVP–VPS UK	0.42	400		*Estimated*	
Natural	1.34	150	-	*2,000*	-
DWPF–U.S.	0.59				
Forced/Natural	3.0	670	-	<1,000	<0.25
TVF–Japan	0.42	300	1.5×10^7		
Forced	1.0	110	Combined	1,400	4.7

BNFL WVP with Lines 1 and 2 and VPS has dimensions 64 m long × 38 m wide × 40 m high, which gives footprint of 2,430m^2 (IAEA 1992). The capital cost is estimated as 250M Great Britain Pounds (1990 basis) ≡ \$446M (U.S. 1990 dollars[a]) ≡ 730M (U.S. 2008 dollars[b]). The two stores and access corridor have a footprint of around 25 m × 40 m = 1,000 m^2 (10^4 ft^2) or 40% of WVP footprint. A pro rata capital cost for the VPS is then \$292M (U.S. 2008 dollars) ≡ 146M GBP with a capacity corresponding to 16,000 t (LWR SNF). This corresponds to a facility square foot capital cost of \$29K. Commonly process areas have costs that are several times greater than waste storage areas. So, a value of \$150M (\$15K/ft^2) for the store may be appropriate here, and this is regarded as high although passive cooling favors lower long-term operational costs.

G1-2.4 Defense Waste Processing Facility

The DWPF, located on the Savannah River Site (Figure G1-1), uses vitrification to process waste into a stable glass medium. The project began in 1983 and testing began in 1989. Evolving nuclear safety standards and testing difficulties delayed the start of chemical trials until 1993 and radioactive operations did not begin until March of 1996. This protracted start-up period added significantly to the operations component of the capitalized cost. For the purpose of this report, 1986 was chosen as the activity midpoint. The DWPF is a stand-alone process facility. The technology incorporated at the time of construction was considered new technology. It was built as a government-owned facility; therefore, the cost of money is not applicable. The hardened area of the facility is reported as 150,000 ft^2. The square footage does not include the associated interim storage facility. The facility produces about 250 canisters of glass waste per year.

G1 2.2 CFTC Engineering Alternative Studies

The CFTC Engineering Alternative Studies (EAS and Follow-on Engineering Alternative Studies (FOEAS) used the proven DWPF technology concepts used to develop HLW treatment alternatives for various alternatives. These alternative included concepts for the disposal of HLW from:

- 3000MT/yr UREX+1 reprocessing facility (Cs and Sr not incorporated in the borosilicate glass)
- 800MT/yr UREX+1 reprocessing facility (Cs and Sr not incorporated in the borosilicate glass)
- 800MT/yr co-extraction (Co-Ex) reprocessing facility (Cs and Sr are included in the borosilicate glass)
- 300MT Electrochemical reprocessing facility in which the Cs/Sr/I and excess chloride salt are incorporated into a glass bonded zeolite and the lanthanides are incorporated into a lanthanide glass.

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[a] Measuring Worth - Exchange Rates Between the United States Dollar and Forty-one Currencies, http://www.measuringworth.com/datasets/exchangeglobal/result.php

[b] Money values derived using: U.S. Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), Using CWBS Feature Code – 07 Power plant, Appendix A, EM 1110-2-1304, Appendix Revised September 30, 2007.

G1-3. PICTURES AND SCHEMATICS

Figure G1-1. Defense waste processing plant at the Savannah River Site.

G1-4. MODULE INTERFACE DEFINITION

Module G1 receives HLW from Aqueous Reprocessing (Module F1) or Electrochemical Reprocessing (Module F2/D2), conditions the waste (stabilizes to form a durable product such as glass), provides interim storage of the treated waste, and packages the waste in a canister for transport to a Geologic Repository (Module L), Long-term Monitored Retrievable Storage (Module I), or an Other Disposal Concept (Module M) by means of Module O1, SNF/HLW Transportation. Management of HLW in wet or dry bulk interim storage between reprocessing and the conditioning described in this module (e.g., a tank farm) is not included in this module. No transportation or disposal costs are included in this module.

As stated above, all streams from processing used fuel could be potentially classified as HLW under current regulations. In the United States, this is a functional rather than characteristic designation. Also in the United States, wastes from defense related nuclear activities that are not HLW that contain ≥100 nCi/g TRU are "TRU wastes," and the WIPP repository for these wastes is restricted to receiving waste derived from defense materials. These same waste characteristics from commercial nuclear operations would be considered GTCC LLW. Commercial wastes not designated as HLW are LLW, and the numerical limits designating disposition requirements for Classes A, B, and C, and GTCC are defined in 10 CFR 61 and described in detail in Submodule G3 on LLW. Though these wastes are relatively well defined based on characteristics, the disposition pathway for GTCC waste, a geologic repository, has not yet been designed or designated. Thus, for the purposes of this report, it is assumed that the regulations will be reevaluated and changes will allow some of the disposition options shown in Table G1-2. In summary, these changes may include:

1. Consideration of useful radionuclides for recycling, including limits on allowable contaminants.

2. Expansion of the technical bases for the HLW repository license to include additional HLW forms other than borosilicate glass based on performance of the material in standardized tests.
3. Expansion of the WIPP repository capacity and license, or development of a new WIPP like repository for commercially derived GTCC wastes, including reevaluation of the 100 nCi/g limit, and disposition of wastes contaminated to greater than background levels but less than 100 nCi/g TRU.
4. Designation of a repository or other routine disposal pathway for GTCC not requiring a case-by-case performance assessment.
5. Consideration of the concept of “decay storage”: secure storage facilities to allow problematic radionuclides such as cesium, strontium, tritium, and noble gases to decay to LLW limits. These materials must be stored for several hundred years isolated from the biosphere and protected against unregulated use.

Costs for each of the major classes of waste are estimated in their respective sections of the report. The criteria for assigning waste classifications are assumed to be consistent with current regulations with no distinction between defense and commercial origin.

Vitrification is used as the HLW baseline because it is the most well-characterized. However, conversion of waste chloride salts to a glass-bonded ceramic, and metalliferous wastes to a metal ingot have been demonstrated on small scales for the electrochemical processing program, and preliminary data packages have been submitted to DOE-Office of Civilian Radioactive Waste Management. Iron-phosphate glasses could be produced using technology similar to current vitrification technology, and Synroc can be made using a hot-isostatic press or a cold-crucible melter, all of which have been published in the literature (Begg et al. 2005; Day et al. 2003; Kim and Hrma 1996; Nicaise et al. 1999). Less well characterized are durable low-temperature ceramics, anionic waste forms for iodine and technetium, crystalline waste forms for noble gases, and steam reforming. Steam reforming is a mid-range high-temperature technology that can destroy organic contaminants and nitrates and convert the inorganic residuals to a mineral form. This type of approach could be particularly useful for some of the streams from aqueous processing that are produced in an organic form such as cesium and strontium. Conversion of this type of material to a durable crystalline form using steam reforming with clay and carbon additives is believed to be possible, but has not been verified at an engineering scale.

G1-5. MODULE SCALING FACTORS

Using data from the CFTC studies (see G1-6) the cost was fitted using the logarithmic relationship:

$$CostofA = CostofB\left(\frac{CapacityofA}{CapacityofB}\right)^n$$

Where, capacity is expressed as instantaneous design capacity (MT/yr), and the exponential factor is typically in the range of about 0.6. However due to the inherently high structural costs associated with highly shielded and remotely operated nuclear facilities not found in commercial operations, the power law exponent is expected to be less than 0.6. The preceding equation indicates that a log-log plot of the capacity versus cost should be a straight line with the slope equal to the exponent. The CFTC HLW vitrification estimates were used to determine the power law factor was equal to about 0.43 over the range of reprocessing facility capacity of 3000MT/yr to 800 MT/yr.

G1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

G1-6.1 Defense HLW Solidification and Packaging

The total project cost for DWPF including the first two melter replacements is estimated to be about \$2.6B in 2006 dollars,[c] (capitalized cost of the facility was \$1.5B in 1986 dollars). The current year operating budget is \$140M and planned operation is for 25 years.[d] Initially, the facility was designed to produce about 7,000 canisters, but is now planned to produce 6,000 canisters. This increase in efficiency drives the cost per canister up because capital costs are fixed. A simple life-cycle analysis reduces the calculation to:

- Cost per canister = (\$2.6B + \$140M/yr × 25 yr + D&D)/(6,000 cans) = \$1.02M/canister + D&D
- Rounding up to \$1.1M/canister would allow \$500M for two more melters and decontamination and decommissioning (D&D).
- Per canister cost can be converted to a fission product basis with certain assumptions. As described above, the future reprocessing design has not yet been specified, but a conservative estimate can probably be assumed to be the PUREX baseline. Presumably a new reprocessing design would not be adopted if it generated more waste.

Assuming:

HLW from processing defense fuels is predominantly reprocessing chemicals contaminated with <1 wt% FPs.

FPs include a broad range of elements, but for simplicity assume 50% each Cs-137/Sr-90.

Glass product contains 33.3% HLW oxides.

Canister contains 1800 kg of HLW glass.

Therefore,

1 kg FP = 1.118 kg FP-oxides (Cs_2O and SrO)

1 kg FP = 1.118 kg FP-oxides/(0.01 kg FP-oxides/kg HLW-oxides)/(0.333 kg HLW-oxide/kg glass)

1 kg FP = 339 kg glass = 339 kg glass/(1,800 kg glass/canister) = 0.188 canister

1 kg FP = 0.188 canister × \$1.1M/canister = \$207K/kg FP.

Thus \$207K/kg FP is the reference case. However, the DWPF was designed for a particular mission, to vitrify Savannah River HLW in a 25-year life. If the DWPF lifetime is extended to process new HLW, these costs drop, and the incremental costs for more canisters result in the following: annual operating cost/canister production = \$140M/250 canisters = \$560K, or \$105K/kg FP roughly half the baseline cost using the limited DWPF programmatic design life. Recalculating the entire basis, amortizing using a 50-year design life, producing 250 canisters per year yields:

Cost per canister = (\$2.6B + \$140M/yr × 50 yr + 8 melters × \$80M/melter changeout + \$500M D&D)/(50 × 250 cans) = \$860K/canister, or \$162K/kg FP.

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[c] This \$2.6B figure includes the full cost of the facility operations staffing during the protracted start-up. Using today's accounting practices for the OPC component, the TPC would have been \$1.3B in 1993 dollars.

[d] Telecon and email with Brent Boore and David McGuire, Savannah River Site, January 2006.

The total project cost (TPC) and annual operations cost cited above present an extremely conservative estimate. The TPC of \$2.6B includes the total cost of the operations staffing during the protracted testing and start-up period. Using assumptions similar to today's estimating guidelines the TPC for DWPF would have been \$1.3B in 1993. Annual operations cost have continued to drop after start-up and are currently about \$90M/yr in 2007 dollars. Using these figures a more reasonable unit cost for 50 years of operation is (\$1.3B + \$90M/yr × 50 yr + 8 melters × \$40M/melter changeout + \$500M D&D/(50 × 250 cans) = \$530K/canister or \$100K/kg of fission products.

Assuming (a) commercialization of new technology for processing used nuclear fuels, (b) many of the problematic radionuclides are partitioned, and (c) the regulatory changes described above, it is likely that scale-up and market forces will drive these costs down. Further, assuming a glass waste form with the same nominal density, but a glass technology that would allow melting at a higher temperature to enable higher waste loading, a glass containing 50 wt% HLW oxides could be possible (Day et al. 2003 and Hrma et al. 1999). If the waste contained 50 to 100% radionuclide oxides as envisioned in the UREX flowsheet, the processed waste form would contain 50% × (50 to 100%) = 25 to 50% radionuclides, versus 1% ×33.3% = 0.33% used above in the baseline or 75 to 150 times more radionuclides per unit of glass. Thus, with \$530K/canister operating cost, on the low end the HLW stabilization costs could be:

0.188 canister × \$530K/canister/(75 to 150) = \$670 to 1,330/kg FP.

More conservatively, it could be assumed that maximum radionuclide loading is limited to about 5%, but the facility costs remain at \$530K/canister of the resulting unit cost is:

0.188 canister × \$530K/canister/(5/.33) = \$6,600/kg FP.

G1-6.2 CFTC Fission Product Solidification and Storage Estimates

The CFTC EAS and FOEAS developed HLW treatment alternatives for various alternatives. These alternative included concepts for the disposal of HLW from:

- 3000MT/yr UREX+1 reprocessing facility (Cs and Sr not incorporated in the borosilicate glass)
- 800MT/yr UREX+1 reprocessing facility (Cs and Sr not incorporated in the borosilicate glass)
- 800MT/yr Co-Ex reprocessing facility (Cs, Sr, Am and Cm are included in the borosilicate glass)
- 300MT Electrochemical reprocessing facility in which the Cs/Sr/I and excess chloride salt are incorporated into a glass bonded zeolite and the lanthanides are incorporated into a lanthanide glass.

The cost estimates for these alternatives are provided in Table G1-3. These cost estimates are for the HLW vitrification segment of the CFTC, they do not include the costs of volatile off-gas capture and treatment, cesium/strontium solidification and packaging, or technetium conversion to metal and packaging in cases where those processes are applicable. See below for cost estimates of the Cs/Sr and Tc solidification.

The data presented in Table G1-3 for the 3000MT/yr reprocessing alternative has been adjusted from that presented in the reference documents (WSRC 2007). Adjustments were made to ensure the assumptions and design attributes were consistent with the 800MT/yr cases. These adjustments include the elimination of sand filters and inclusion of additional footprint for HEPA filters, a reduction in the hardened footprint to reflect an optimized canyon equipment arrangement developed as a part of the FOEAS, and elimination of future project cost from the LCC to reflect a consistent assumption that waste disposal facilities were available such that multiple waste glass storage buildings were not required.

The Sensitivity Analysis 5 (SA5) or Co-Ex case is slightly higher than the UREX+1 due to the inclusion of both Cs/Sr and Tc in the glass waste form. The overall reprocessing cost of the Co-Ex process is less than the cost of the more complex UREX+1 processes, which offer potential advantages in waste disposal costs.

Table G1-3 also provides the resulting unit cost on a basis of $/kg of fission products and $/MT of SNF being reprocessed. The later value must be added (including others such as LLW packaging and treatment and uranium solidification and packaging) to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

The 3000 MT/yr case is somewhat less on a unit cost basis reflecting the economy of scale expected for these treatment processes.

An initial 5-year waste storage capacity is provided in the estimates. Long-term decay storage may be planned for some case studies. A storage vault with a 1,400 storage locations is required every 5 years during recycling operations and has an estimated TPC range of $60M to $85M and an annual Operations and Maintenance (O&M) cost of $9M to $14M/yr. Assuming a 40-year operation, seven additional vaults will be required. If the glass is allowed to cool for 100 years before shipment then the total additional LCC is approximately $1B to $1.4B or an additional $800 to $1,200/kg FP.

Table G1-3. CFTC TPC and LCC estimates for HLW vitrification.

Millions of 2007 Dollars	Benchmark 1 3000 MT/yr UREX+1		Benchmark 2 800 MT/yr UREX+1		SA5 800 MT/yr Co-Ex		Benchmark 3 300 MT/yr Electrochemical	
	Low	High	Low	High	Low	High	Low	High
Annual Operations Cost (Nominal Year) Labor	41	62	34	50	40	60	33	49
Utilities	9	13	3	5	4	7	5	7
Materials	4	6	4	6	4	5	3	5
Misc. Contracts	1	1	1	1	1	1	0	2
Misc. Projects	3	4	3	4	3	4	3	3
Total Annual Operations Cost	58	86	45	66	52	77	44	65
40 Year LCC								
Labor	2,175	3,259	1,722	2,583	2,008	3,012	1686	2528
Materials	213	319	184	276	192	288	191	286
Utilities	452	678	168	251	227	340	245	368
Contracts	40	67	32	47	43	64	33	50
Misc. Projects	113	166	93	140	112	168	93	140
Subtotal: 40-Year Operations	2,993	4,489	2,198	3,297	2,581	3,872	2,248	3,372
Future Capital Projects	0	0	0	0	0	0	0	0
D&D	582	825	303	431	343	541	20	34
Subtotal LCC O&M & D&D	3,575	5,314	2,502	3,729	2,924	4,414	2,268	3,406
Early Life Cycle	46	54	36	51	55	85	6	10
TPC	4,434	6,175	2,594	3,593	3,030	4,482	148	237
Total LCC	8,055	11,544	5,132	7,373	6,009	8,981	2,422	3,653
Unit LCC Cost ($/kg FP)	1,804	2,586	4,277	6,144	3,964	5,921	12,015	18,122
LCC Unit Cost ($/MT SNF)	67	96	160	230	188	281	202	304
Values may not add due to rounding								

G1-6.3 CFTC Tc Separation and Solidification Estimates

The CFTC EAS developed estimates for the separation of the Tc from the uranium nitrate solution using an ion exchange process. The resin was loaded and pyrolyzed to reduce the Tc to a metallic form. The cost estimates shown in Table G1-4 do not include the cost of combining the Tc with a portion of the Zr hulls and production of the metal alloy. These later functions were conducted in the fuel receipt and dissolution building and their cost are an integrated part of the reprocessing module (F-1) costs.

The data presented in Table G1-4 for the 3000MT/yr reprocessing alternative has been adjusted from that presented in the reference documents (WSRC 2007). Adjustments were made to ensure the assumptions and design attributes were consistent with the 800MT/yr cases. Table G1-4 also provides the resulting unit cost on a basis of $/kg of Tc and $/MT of SNF being reprocessed. The later value must be added to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

The 3000 MT/yr case is somewhat less on a unit cost basis reflecting the economy of scale expected for these treatment processes.

Table G1-4. CFTC TPC and LCC estimates for Tc separation and solidification.

Millions of 2007 Dollars	Benchmark 1 3000 MT/yr UREX+1		Benchmark 2 800 MT/yr UREX+1		SA5 800 MT/yr Co-Ex		Benchmark 3 300 MT/yr Electrochemical	
	Low	High	Low	High	Low	High	Low	High
Annual Operations Cost (Nominal Year) Labor	37	56	24	35	Not Applicable		Not Applicable	
Utilities	8	12	2	3				
Materials	4	5	3	4				
Misc. Contracts	1	1	1	1				
Misc. Projects	3	4	2	3				
Total Annual Operations Cost	**52**	**78**	**31**	**46**				
40 Year LCC								
Labor	1973	2956	1209	1813				
Materials	193	290	129	193				
Utilities	410	615	118	176				
Contracts	36	60	22	33				
Misc. Projects	103	151	65	98				
Subtotal: 40-Year Operations	**2,715**	**4,072**	**1,543**	**2,314**				
Future Capital Projects	0	0	0	0				
D&D	247	344	162	225				
Subtotal LCC O&M & D&D	**2,962**	**4,416**	**1,704**	**2,539**				
Early Life Cycle	19	23	19	27				
TPC	1,884	2,571	1,384	1,879				
Total LCC	**4,866**	**7,009**	**3,107**	**4,445**				
Unit LCC Cost ($/kg FP)	32,491	46,805	161,836	231,496				
LCC Unit Cost ($/MT SNF)	41	58	97	139				
Values may not add due to rounding								

G1-6.4 CFTC Cs/Sr Solidification, Packaging and Storage Estimates

The CFTC EAS developed estimates for the solidification and packaging of the cesium and strontium (rubidium and barium is also included). Benchmark 1 used the sodium aluminosilicate process to form a ceramic, while Benchmark 2 used the bentonite clay process to form a ceramic wasteform. The use of two different processes at two different capacities makes comparison of the data difficult.

The data presented in Table G1-5 include the cost to solidify, package, and store the waste for 3 years. Additional storage is required if the waste is to be decayed at the reprocessing site.

Table G1-5 also provides the resulting unit cost on a basis of \$/kg of Cs/Sr and \$/MT of SNF being reprocessed. The later value must be added to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

Table G1-5. CFTC TPC and LCC estimates for Cs/Sr solidification, packaging and storage.

Millions of 2007 Dollars	Benchmark 1 3000 MT/yr UREX+1		Benchmark 2 800 MT/yr UREX+1		SA5 800 MT/yr Co-Ex		Benchmark 3 300 MT/yr Electrochemical	
	Low	High	Low	High	Low	High	Low	High
Annual Operations Cost (Nominal Year) Labor	59	88	38	56	Not Applicable		Not Applicable	
Utilities	12	18	3	5				
Materials	6	9	4	6				
Misc. Contracts	1	2	1	1				
Misc. Projects	4	6	3	4				
Total Annual Operations Cost	**83**	**124**	**49**	**73**				
40 Year LCC								
Labor	3114	4666	1907	2861				
Materials	305	457	204	305				
Utilities	648	971	186	279				
Contracts	57	95	35	52				
Misc. Projects	162	238	103	155				
Subtotal: 40-Year Operations	**4,285**	**6,428**	**2,435**	**3,652**				
Future Capital Projects	0	0	0	0				
D&D	480	775	328	533				
Subtotal LCC O&M & D&D	**4,766**	**7,203**	**2,763**	**4,185**				
Early Life Cycle	38	51	39	63				
TPC	3,659	5,802	2,804	4,441				
Total LCC	**8,462**	**13,056**	**5,606**	**8,689**				
Unit LCC Cost (\$/kg Cs/Sr)	12,329	19,021	30,700	47,600				
LCC Unit Cost (\$/MT SNF)	71	109	175	272				

Values may not add due to rounding

An initial 4-year waste storage capacity is provided in the estimates. Long-term decay storage may be planned for some case studies. Due to the different wasteform properties the storage costs for the two processing options varied significantly. The wasteform produced by the sodium aluminosilicate process is a finely divided powder and a relatively high (10%) Cs/Sr waste loading. The heat transfer properties of the power combined with the high decay heat resulted in 3-inch-diameter storage containers. For this case a storage vault with a 30,000 storage locations is required every 2 years during recycling operations and has an estimated TPC of $390M to $620M and an annual O&M cost of $15M to $23M/yr. Assuming a 40 year operation 18 additional vaults will be required. If the ceramic is allowed to cool for 300 years before shipment then the total additional LCC is approximately $11.0B to $17.2B or an additional $15,900 to $25,000/kg FP.

The wasteform produced by the bentonite clay process is pucks that are then stacked into approximately 9-inch-diameter canisters. For this case a storage vault with a 1,400 storage locations is required every 5 years during recycling operations and has an estimated TPC of $170M to $275M and an annual O&M cost of $11M to $17M/yr. Assuming a 40 year operation seven additional vaults will be required. If the ceramic is allowed to cool for 300 years before shipment then the total additional LCC is approximately $4.0B to $6.3B or an additional $22,200 to $34,800/kg FP.

G1-7. LIMITATIONS OF COST DATA

The DWPF reported costs are gross numbers based on a one-of-a-kind facility for processing defense HLW. The CFTC studies for the treatment of aqueous waste are based on a borosilicate waste form (the worldwide standard for HLW) and currently understood technological limits. The CFTC study for the electrochemical HLW treatment is a ROM estimate as many of the processes required have not been demonstrated at a commercial scale. Future reprocessing concepts for commercial fuels may generate entirely different waste forms including glass-ceramics, metal ingots, and pressed ceramic pucks. It can probably be assumed that a transition to a new waste form would be driven by efficiency in terms of greater fission product loading (10 to 100 times or more), which could drive costs down (for stabilization and the repository, but not necessarily for the entire life-cycle). If multiple waste forms are produced then additional capital and operating costs will be incurred. Assuming that all the separations are successful, the HLW form would only be limited by durability and not heat loading or criticality. Further, waste-form manufacture may be integrated with the reprocessing plant rather than in a dedicated facility, which should also drive cost down. Lastly, future processing scenarios envisioned include many different product streams with a significantly reduced HLW volume, as described above. This may drive the unit costs for HLW forms up due to fixed facility costs, but the ratio of HLW to metric ton of heavy metal (MTHM) processed should be reduced enough to more than compensate, reducing overall waste management costs.

G1-8. COST SUMMARIES

The module cost information is summarized in the WIT cost summary in Table G1-6. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

New fuel processing flowsheets are being developed to generate far less waste volume, and to segregate problematic radionuclides. It is also widely recognized that many waste forms are as durable or better than single-phase BSG in containing radionuclides for extended times in exposure to the environment. Based on this and knowing that much higher waste loading is attainable in other materials significant reduction in cost (10–100X) may be attainable for HLW stabilization by cutting operation costs and using much more efficient waste forms and stabilization technology. However, the costs of the vitrification facility at Hanford are currently under review, and little is known about large-scale production of some of the proposed waste forms such as glass-ceramics and metal ingots, so the potential reduction in costs may be nearer the low end of this range. The selected value is based on the value from the CFTC study for a vitrification facility integrated into a reprocessing facility with a nominal capacity of 800 MT/yr using a reasonably aggressive waste loading of 15%.

Table G1-6. Cost summary table for HLW conditioning selected values.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
HLW Borosilicate Glass			
	$2,200/kg FP	$6,600/kg FP	$5,000/kg FP
The low and selected values are based on the CFTC EAS studies for a 3000MT/yr and 800MT/yr facility, respectively	15% FP loading	5% loading	15% loading
	Unit cost for a large capacity reprocessing integrated complex	The high Cost is based on the DWPF facility with a lower waste loading	Unit cost for a reasonable capacity (800 MT/yr) reprocessing center with a reasonably aggressive waste loading
Electrochemical HLW Treatment CFTC EAS	$12,015/kg FP	$18,122/kg FP	$15,100/kg FP average of the CFTC high/low values
U/Tc Separation and Solidification CFTC EAS	$161,836 /kg Tc	$231,496 /Kg Tc	$200,000/kg Tc average of the CFTC high/low values
Cs/Sr Solidification and Packaging CFTC EAS	$30,700/kg Cs/Sr Low unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center	$47,600/kg Cs/Sr High unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center	$40,000/kg Cs/Sr Average unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center

The triangular distribution based on the WIT Table is shown in Figure G1-2. The distribution is skewed toward the high cost due to the difficulty in achieving fission product loading greater than 10% in the waste form.

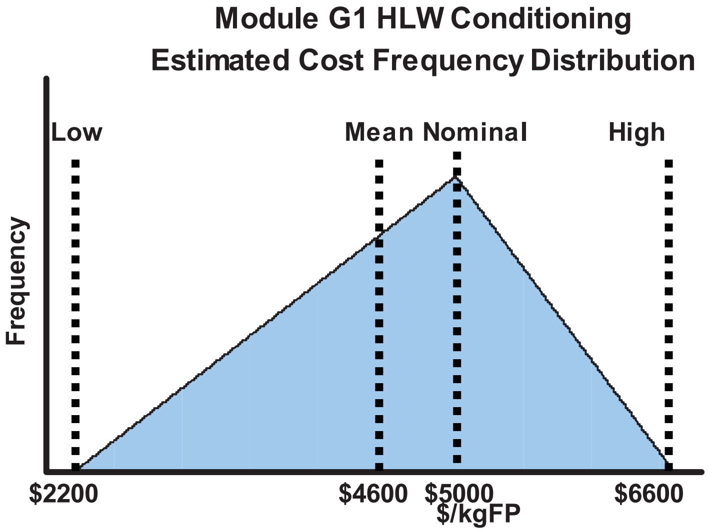

Figure G1-2. HLW conditioning, storage, and packaging estimated cost frequency distribution.

G1-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

Module G2

SNF Conditioning and Packaging

Module G2

SNF Conditioning and Packaging

G2-1. BASIC INFORMATION

The SNF packaging module includes capabilities to safely remove SNF from wet or dry storage; perform inspection as required; and dry, package, seal, leak-check, and prepare the SNF package for shipping to reprocessing, storage, or disposal. Fuel is assumed to be in wet or dry interim storage at a nuclear facility, and a contractor is hired to provide packaging services. The contractor will interface with site personnel to receive fuel from interim storage and conduct all operations necessary to leave the fuel in stable dry storage at an onsite storage pad. Transportation offsite is covered in Module O.

In the future, these costs are envisioned to be routine, and could be part of the general maintenance and fueling of a commercial reactor. The costs are delineated here to estimate the burden on current nominal operating costs. Whether the actual costs are born by the reactor operator as part of operating costs, or are a part of the fee paid to the Nuclear Waste Fund is not defined.

G2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Fuel will be removed from wet or dry interim storage, conditioned for indeterminate storage, packaged, and left in a protective cask at the storage site. All fuel movement procedures and equipment will be designed to ensure criticality-safe conditions at all times. Facility procedures will ensure verification and visual inspection of all lifting equipment and heavy load handling procedures. Fuel assemblies selection will be verified to ensure only fuel assemblies approved for loading in a fuel storage container are loaded. Inspection will include verification of the condition of the fuel to ensure it is acceptable for packaging, including integrity of fuel rods and replacement of any removed rods to ensure configuration control.

Drying procedures will meet or exceed the methodology described in NUREG 1536 and be in compliance with the facility Safety Analysis Report. Moisture will be removed from the cask and container until vacuum can be maintained for the prescribed test period. Seal welding will of the multipurpose canister will meet all prescribed nondestructive examination tests. Transportation and storage casks and multipurpose canisters will be licensed by the NRC.

In general, the contractor will:

1. Bring a fuel container (container, basket) and a shielded transfer cask to the fuel pool
2. Place the container into the transfer cask, forming concentric cylinders
3. Fill the assembly with water and lower into the fuel loading pool
4. Place preselected fuel elements into the container compartments
5. Place a shielded plug in the top of the container
6. Move the loaded assembly to a draining area, then drain and decontaminate
7. Weld the container shut by an automated machine
8. Apply a vacuum to the container while it is filled with an inert gas (helium)

9. Continue the vacuum procedure until a vacuum can be maintained, indicating negligible free water remaining
10. Weld the container ports, apply another cap, and weld cap shut
11. Move the loaded transfer cask assembly to the fuel storage pad
12. Lower the sealed fuel container vertically or push horizontally (depending on design) directly from the transport cask into the storage cask, maintaining continuous shielding
13. Place the storage cask lid and bolt shut
14. Store fuel dry indefinitely pending disposition.

G2-3. PICTURES AND SCHEMATICS

Several configurations are available for SNF packaging, shipment, and interim to long-term dry storage. Examples are shown in Figures G2-1 through G2-5.

Receiving the MPC at J.A. FitzPatrick Nuclear Plant

Fit up of the MPC and MPC Lid at J.A. FitzPatrick Nuclear Plant

Figure G2-1. Holtec International fuel storage canister to be loaded with fuel assemblies. Figure taken from Holtec International Web site.

Figure G2-2. Holtec International cask in fuel storage pool). Figure taken from Holtec International Web site.

Figure G2-3. Holtec International HI-STORM Dry Storage Casks on storage pad (note vertical storage). Figure taken from Holtec International Web site.

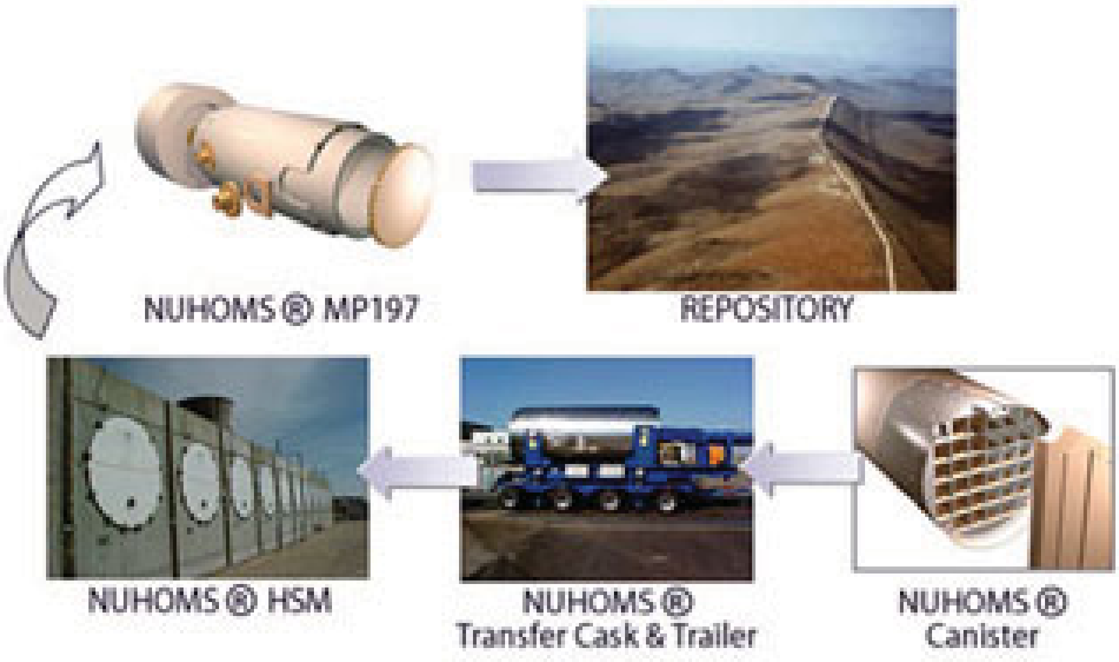

Figure G2-4. Transnuclear NUHOMS design (Note horizontal storage allowing stacking) (AREVA 2007).

Figure G2-5. BNG Fuel Solutions vertical cask lift. Figure taken from BNG Web site.

G2-4. MODULE INTERFACE DEFINITION

Module G2 SNF Packaging removes SNF from wet or dry interim storage and prepares it for indeterminate dry Long-term Monitored Retrievable Storage (Module I), and shipping to reprocessing via Aqueous or Electrochemical Separations (Modules F1 and F2/D2), or a Geologic Repository (Module L) or Alternative Disposal Concepts (Module M). Module G2 can be considered more of an activity or service more than a facility. Conditioning and packaging of fuel can be done as a contracted service or an in-house capability, depending on the nature of the facility and whatever strategy is cost-effective. This module does not include shipment of SNF to an offsite facility even if the facility is owned by the utility. Transportation onsite is considered within the estimating error of the conditioning and packaging costs.

This module includes the costs of a multipurpose canister to move the fuel to a storage cask or a shipping cask, but not the cost of the cask itself. Transportation Module O1 includes the cost of the transportation cask (overpack) and impact limiters. The Fuel Storage Modules E1 and E2 include a dry-storage cask where necessary, but do not include the multipurpose canister.

G2-5. MODULE SCALING FACTORS

Fuel is removed from the cooling pool and placed in dry storage by a contractor as described above. The dry storage pad may be in an onsite or offsite leased Independent Spent Fuel Storage Installation. The reactor operator will buy the fuel movement and conditioning services and the necessary materials including the fuel container and the storage cask. The only scaling factor is a storage cask, which generally holds 11 to 15 MTHM, depending on the type and design of the fuel (pressurized versus boiling water reactor).

G2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Commercial services and their costs are generally proprietary, but the following estimates are based on informal vendor communications:

- Service contract labor costs for implementing the procedures above start at $200K/cask
- Capital costs for storage container and dry storage overpack (cask) start at $1M
- Cost per MTHM=($200K/cask loading + $1,000K/container and overpack capital)/(11−15 MTHM)
- Total cost to implement dry storage = $80K–110K/MTHM.

These costs do not reflect the capital or operating costs of the Independent Spent Fuel Storage Installation itself because this module only includes SNF conditioning and packaging.

G2-7. LIMITATIONS OF COST DATA

The cost data reported here are a snapshot in time and reflect the input from one helpful vendor. The estimates are based on a utility having a contract for recurring services, but no economies of scale are considered for operators negotiating for services to multiple sites or multiple reactors. Also, no transportation costs are considered to support an offsite Independent Spent Fuel Storage Installation.

G2-8. COST SUMMARIES

The module cost information is summarized in the WIT cost summary in Table G2-1. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Cost data reflect starting prices for services and materials that imply costs can be higher, reflected in the downsides of about 33%. However, many utilities operate plural reactors and plural reactor sites, which may allow for some economies of scale and reduced negotiated contract prices, reflected in the upsides of about 17%. The selected value is the high end of the reference range because of the limited data available.

The triangular distribution based on the costs in the WIT Table is shown in Figure G2-6.

Table G2-1. Cost summary table for SNF conditioning selected values.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$80K–100K/MTHM SNF	$50K/MTHM	$130K/MTHM	$100K/MTHM

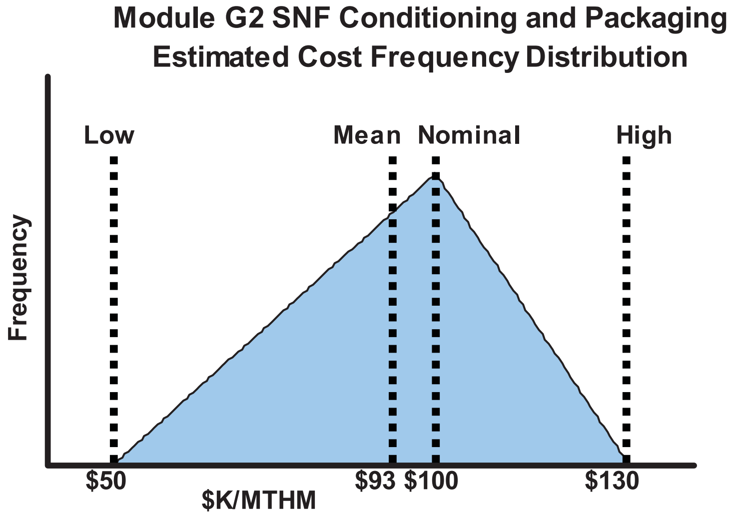

Figure G2-6. SNF conditioning and packaging estimated cost frequency distribution.

G2-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

Module G3

LLW Conditioning, Storage, and Packaging

Module G3

LLW Conditioning, Storage, and Packaging

G3-1. BASIC INFORMATION

Module G3 conditions and packages miscellaneous LLW (10 CFR 61) for disposal in an NRC-licensed near surface landfill. If the wastes are both hazardous (40 CFR 261.3) and radioactive, treatment must consider EPA Land Disposal Restrictions (LDRs; 40 CFR 268), and the receiving landfill may be required to have a permit from the EPA and/or state. Mixed-waste treatment and disposal generally cost 2 to 5 times more than LLW because facilities are limited. Currently, mixed-waste treatment/disposal is a seller's market, but this could change in the future, resulting in more consistent pricing based on waste volume.

Wastes are received by truck or rail and must be characterized to ensure that they are within the facility specific permit limits. For example, EnergySolutions in Utah is currently limited to Class A wastes, while Permafix can receive and treat some Class B and C wastes as long as after treatment the treated wastes meet Class A limits and can be sent to EnergySolutions. The regulations, particularly the mixed waste regulations issued independently by the DOE/NRC and EPA can conflict and produce so-called "orphan" wastes for which there are no permitted disposal facilities at this time. Innovation by commercial entities such as the synergy described between Permafix and EnergySolutions have allowed treatment/disposal of many of the orphan wastes, but generally at a cost premium. This is an area that should be considered carefully in support of an expanded nuclear industry. Fortunately, the commercial nuclear industry has carefully evaluated many of their ongoing activities and has all but eliminated production of mixed wastes. Until facilities are decommissioned, production of mixed wastes will be minimal and should not be significant in future commercial nuclear facilities.

G3-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The LLW Conditioning, Storage, and Packaging Facility will likely be a part of future nuclear facilities, but may also be contiguous with the disposal landfill such as the case with EnergySolutions (see Figures G3-1 through G3-4), or may be a separate contracted facility such as the Duratek facility in Tennessee; Pacific EcoSolutions Inc., (PEcoS) in Washington; or Permafix in Florida, that all ship the conditioned wastes to landfills such as Barnwell (see Figure G3-5) in South Carolina or EnergySolutions. External facilities must be capable of receiving wastes by truck and rail, and must have sufficient analytical facilities or access to such facilities to ensure that the materials they receive are within the limits imposed by their permits. At a minimum, the facilities must be able to inspect and repackage to meet the waste acceptance criteria for the landfill. Other conditioning and treatment services offered will likely be based on return on investment and local expertise. Some of the more common services include:

- Supercompaction to reduce volume of compressible materials
- Size reduction to reduce volume of oversized materials such as construction debris
- Stabilization using sorbents to immobilize free liquids
- Stabilization using a cement and/or a pozzolonic material to reduce leachability of metals
- Macroencapsulation of debris including lead bricks
- Chemical oxidation for reactive metals and some organics

- Thermal desorption to separate organic constituents from waste matrices
- Incineration to minimize ultimate volume of combustibles or destroy solvents and other organic materials
- Specialized treatability studies and treatment for unique wastes.

G3-3. PICTURES AND SCHEMATICS

Figure G3-1. Aerial view of EnergySolutions Facility in Utah (EnergySolutions 2009).

Figure G3-2. Filling voids around drums at EnergySolutions Facility in Utah. Figure taken from EnergySolutions Web site.

Figure G3-3. EnergySolutions microencapsulation and macroencapsulation of waste in plastic polymer. Figure taken from EnergySolutions Web site.

Figure G3-4. Landfill disposal cell at EnergySolutions (Note line and leachate collection piping). Figure taken from EnergySolutions Web site.

Figure G3-5. Waste placement in landfill at Chem-Nuclear Systems Barnwell site (Chem-Nuclear Systems, LLC 1997).

G3-4. MODULE INTERFACE DEFINITION

Module G3 receives miscellaneous low activity waste streams from throughout the fuel cycle. These wastes can be solid or liquid and may result from treatment of gaseous effluents, but the gases themselves are not considered in this module. Specific links are shown from Aqueous and Electrochemical Separations (Modules F1 and F2/D2), but wastes including decontamination solutions, clothing, resins, and so-called combustible rags, bags, and tags wastes may come from any module. All LLW leaving Module G3 is transported (Module O2) to Near Surface Disposal (Module J) once conditioned to meet the facility waste acceptance criteria. Mixed wastes have essentially been eliminated from the commercial nuclear industry by careful selection of materials and waste management. However, mixed wastes are more likely to occur with fuel reprocessing activities generating process and decontamination solutions and spent solvents.

G3-5. MODULE SCALING FACTORS

Little or no reliable cost data are available for construction of facilities, and scaling based on throughput is unreliable because of the variable nature of the wastes, site-specific waste acceptance criteria, and conflicting regulations. In general, this type of work can be assumed to be contracted, but for the purposes of this document two reference studies were used, one by the DOE Office of Environmental Management (EM) (Yuracko et al. 2002) and one by the General Accounting Office (GAO) (GAO 2000).

G3-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

G3-6.1 Idaho National Laboratory

Idaho National Laboratory (INL) has contracts with several waste treatment and disposal service companies, and these values have been generalized to develop Table G3-1. The costs shown are in 2005 dollars and are subject to change, but provide reasonable factors for estimating the impacts for LLW generated in the fuel cycle. These costs are charges for treatment and disposal at disposal facilities. A rough estimate to include the generator costs for characterization, packaging and shipping would double these costs. The costs shown in Table G3-1 are bracketed by those reported by EM and the GAO. The EM study is an attempt to gather life-cycle costs including both generator and disposal facility costs. The GAO study is limited by the fact that disposal facilities are not consistent in billing practices and do not include full life cycle even for the disposal facilities themselves.

Table G3-1. Treatment/disposal cost estimating factors for LLW.

Waste Type—These wastes can be derived from any module	Media	Characterization/ Pack $/m^3	Treatment $/m^3	Total $/m^3
General LLW Combustible debris	Paper, plastic, cloth, wood	440	N/A	440
General LLW Noncombustible Debris	Metal, construction debris, labware	520	N/A	520
General LLW Liquids	Primarily aqueous solutions requiring stabilization prior to disposal	5,800	5,000	10,800
LLW Water Purification resins	Spent ionic exchange resins – Cs/Sr	5,800	84,000	90,000
General MLLW Combustible Debris	Paper, plastic, cloth, wood	4,000	3,400	7,400
General MLLW Noncombustible Debris	Metal, construction debris, labware	5,500	4,700	10,200
General MLLW Liquids	Typically combustible organic solvents, but may contain significant aqueous fraction	14,000	14,000	28,000
LLW/MLLW	Premium cost per curie of H-3 or C-14	19,000	N/A	19,000

Yuracko, et al.'s 2002 report breaks down costs into disposal facility and predisposal (generator) costs with cost ranges of \$70–2000/m^3 and \$130–4,100/m^3 respectively or \$200–6,000/m^3 total. Disposal costs include charges by the disposal facility itself, which should include management, operations, closure, long-term stewardship, and profit. Predisposal costs include characterization, treatment, packaging, and transportation. Disposal of bulk contaminated soils from Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) cleanup at DOE CERCLA disposal units may bias these values to the low end, and special case wastes of very small volume with unique characteristics are at the high end, with an order-of-magnitude or more between the unit costs for various waste streams. This type of rangeability can also be seen in Table G3-1 with \$500–600/m^3 for general LLW disposal requiring no special treatment up to \$95,000 for volume reduction and disposal of spent ion-exchange resins, a nearly 200 times multiplier.

The U.S. General Accounting Office's 2000 report is somewhat dated in that the Nevada Test Site facility is now accepting mixed wastes and does not include full life-cycle costs for the generator or the disposal facilities, so in general the GAO study shows LLW disposal costs toward the low end of the spectrum at \$60–400/m^3. This may also be due to the weighted average emphasis on CERCLA wastes going to onsite CERCLA disposal facilities that limits characterization, treatment, and transportation costs. Some wastes at INL are also sent to an onsite CERCLA disposal landfill, but the costs shown in Table G3-1 are for wastes sent offsite. Offsite disposal is more likely representative of the true costs for Module G.

The scope of Module G covers only the costs prior to shipping; for LLW, this is generally characterization and packaging. At the treatment, storage, and disposal facility, wastes are treated as necessary for disposal in a landfill. Treatment is only mandated for mixed wastes, but absorption, size reduction, and compaction may also be done for nonhazardous LLW, depending on the waste and the waste acceptance criteria for the facility. Thus, it is difficult to allocate particular costs to before or after transportation. Table G3-1 includes estimated values for characterization and packaging, and treatment. These costs can be allocated as necessary, depending on how the operations are modeled.

G3-6.2 CFTC LLW Treatment Estimates

The CFTC FOEAS estimated the TPC and LCC costs for a treatment and packaging of LLW expected to be generated by an integrated reprocessing center. Waste volumes were generated based on a task analysis using current work practices (to minimize the volume generated) and treatment practices (such as compaction) to minimize the volume disposed.

Table G3-2 provides the resulting unit cost on a basis of \$/m^3 of LLW waste and \$/MT of SNF being reprocessed. The later value must be added (including others such as HLW packaging and treatment and uranium solidification and packaging) to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

The unit costs in Table G3-2 are consistent with those values reported by Yuracko for pre-disposal operator costs. The LCC cost for solid LLW treatment and packaging is equal for either the aqueous reprocess or electrochemical reprocessing waste. However, the unit cost for the electrochemical waste are nearly 3 times the aqueous reprocessing waste reflecting the increase in unit cost based on the lower waste generation from a plant with 40% of the processing capacity.

Table G3-2. CFTC Cost Estimate for Solid LLW Treatment and packaging.

Millions of 2007 Dollars	Benchmark 2 800 MT/yr UREX+1		Benchmark 3 300 MT/yr Electrochemical	
Annual Operations Cost (Nominal Year)	Low	High	Low	High
Labor	15	22	15	22
Utilities	1	2	2	3
Materials	2	3	1	2
Misc. Contracts	0	0	0	1
Misc. Projects	1	2	1	1
Total Annual Operations Cost	20	29	20	29
40 Year LCC				
Labor	761	1142	753	1130
Materials	81	122	85	128
Utilities	74	111	110	164
Contracts	14	21	15	22
Misc. Projects	41	62	42	62
Subtotal: 40-Year Operations	972	1,458	1,005	1,507
Future Capital Projects	0	0	0	0
D&D	1	1	1	1
Subtotal LCC O&M & D&D	972	1,459	1,005	1,508
Early Life Cycle	0	0	0	0
TPC	5	6	5	7
Total LCC	978	1,465	1,011	1,515
Unit LCC Cost ($/m^3)	980	1,469	2,828	4,236
LCC Unit Cost ($/MT SNF)	31	46	84	126
Values may not add due to rounding				

G3-7. LIMITATIONS OF COST DATA

Cost data shown represent 2005 (or in the FOEAS case 2007) dollar unit costs for typical waste characterization, packaging, and treatment. These numbers are subject to change at any time, and can be significantly impacted by specific combinations of contaminants and radionuclides.

G3-8. COST SUMMARIES

In general, whether the operations are done by the generator or the treatment, storage, and disposal facility, the costs for characterization, packaging and treatment for LLW debris are estimated at approximately $1500/m^3 and liquids at $11,000/m^3. Most commercial nuclear facilities have essentially eliminated MLLW, but debris is estimated at $9,000/m^3 and liquids at $28,000/m^3. Special case waste streams, such as ion-exchange resins, should be estimated at $90,000/m^3.

The module cost information is summarized in the WIT cost summary in Table G3-3. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table G3-3. Cost summary table for LLW conditioning selected values.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
CFTC EAS	\$1,000/m^3 LLW Debris Based on 800MT/yr Aqueous Process	\$4,200/m^3 LLW Debris Based on 300MT/yr E-chem Process	\$1,500/m^3 LLW Debris Based on 800MT/yr High Range
\$11,000/m^3 LLW Liquid	\$3,300/m^3 LLW Liquid	\$22,000/m^3 LLW Liquid	\$11,000/m^3 LLW Liquid
\$90,000/m^3 Resins	\$81,000/m^3 Resins	\$99,000/m^3 Resins	\$90,000/m^3 Resins

Cost data has been rounded to two significant digits. Values are sensitive to market, specific waste characteristics, and regulatory changes. Waste disposal at EnergySolutions has been essentially monopolistic, but waste control specialists are still trying to establish themselves as a fully permitted facility. Similarly, waste disposal at Hanford and Barnwell has been limited to regional state pacts, but the National Test Site now accepts wastes, and the equilibrium on costs is expected to change. Costs for LLW/MLLW are +100%, -30%, based on experience of the author and recognition of the wide range over which the market may evolve.

The triangular distributions based on the costs in the WIT table are shown in Figures G3-6, G3-7, and G3-8.

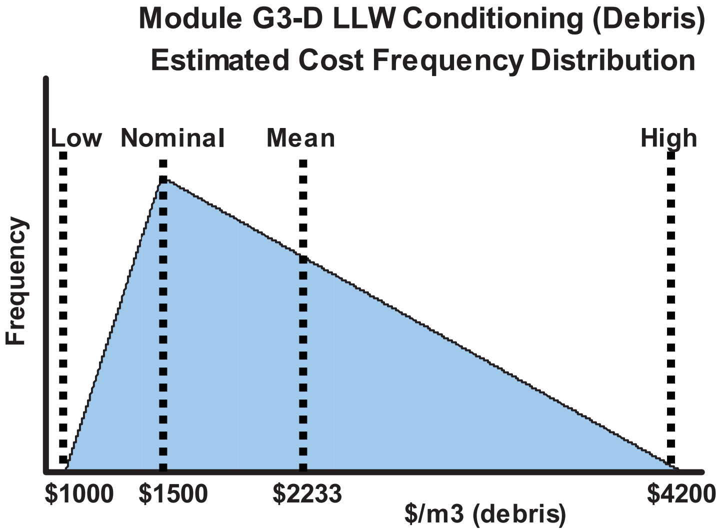

Figure G3-6. Module G3-D LLW conditioning estimated cost frequency distribution.

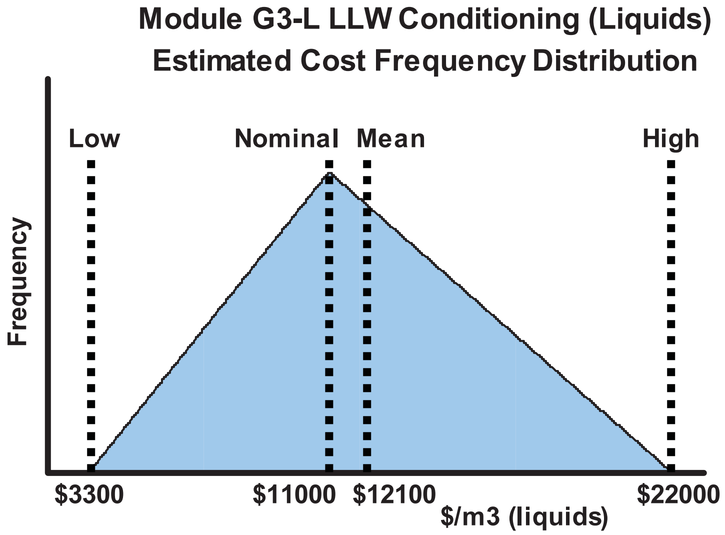

Figure G3-7. Module G3-L LLW conditioning estimated cost frequency distribution.

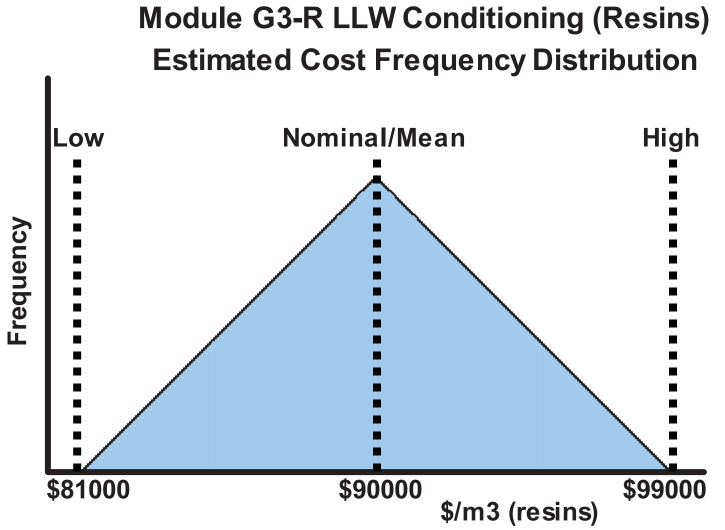

Figure G3-8. Module G3-R LLW conditioning estimated cost frequency distribution.

G3-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

Module G4

GTCC Process Waste Conditioning, Storage, and Packaging

Module G4

GTCC Process Waste Conditioning, Storage, and Packaging

G4-1. BASIC INFORMATION

All of the process waste generated by reprocessing would be currently classified as high-level waste (HLW) except for the compacted hulls and hardware. Waste from the captured and treated volatile radionuclides (C-14, I-129, Kr-85, and H-3) and solidified and packaged Cs/Sr can potentially be reclassified as Greater-than-Class-C (GTCC) (or even low-level waste [LLW]) waste. Module G-1 includes the cost of solidifying and packaging the Cs/Sr using a number of different processes and will not be repeated in this module since the cost of treatment is the same regardless of the waste classification. The disposal cost may vary under differing waste classification assumptions.

This module is dedicated to those wastes that contain sufficient long or short-lived radionuclides to be classified GTCC and are:

"Waste that is not generally acceptable for near-surface disposal is waste for which form and disposal methods must be different, and in general more stringent, than those specified for Class C waste. In the absence of specific requirements in this part, such waste must be disposed of in a geologic repository as defined in part 60 or 63 of this chapter unless proposals for disposal of such waste in a disposal site licensed pursuant to this part are approved by the Commission." (40 CFR 61)

G4-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

GTCC wastes may require specialized containment/shielding/waste forms/storage canisters/storage that may be a hybrid of low-level, transuranic, and HLW, depending on the alpha or beta/gamma radiation prevalence. In general, the beta/gamma radiation from these wastes will require some shielding or special handling that may not be necessary for Class A/B/C wastes. Also, depending on the nature of the waste matrix and the treatment technology, wastes that are not transuranic (TRU) (>100 nCi/g), but that contain appreciable TRU contamination, may also require alpha containment similar to TRU wastes. Refer to LLW and TRU waste modules for more detail.

G4-3. PICTURES AND SCHEMATICS

These wastes may require packaging and handling similar to HLW, such as prepared in the Defense Waste Processing Facility (DWPF) in Figure G4-1.

Figure G1-1. Defense waste processing plant at the Savannah River Site.

G4-4. MODULE INTERFACE DEFINITION

Module G4 receives GTCC wastes from reprocessing, including all streams not regulated as HLW, containing <100 nCi/g TRU, and exceeding the limits established in 10 CFR 61 for Classes A, B, or C LLW. Wastes exit potentially to Near Surface Disposal (Module J) if considered LLW, Geologic Repository (Module L2) if treated as HLW/TRU, or Alternative Disposal Concepts (Module M).

In terms of the fuel processing flowsheets under development and the new streams to be produced such as the iodine, cesium/strontium, tritium, and technetium wastes, any of these could be considered GTCC if not regulated as HLW and more concentrated than the limits defined in 10 CFR 60.

As stated above, all streams from processing used fuel could be potentially classified as HLW (except for the hulls and hardware) under current regulations. In the United States, this is a functional rather than characteristic designation. Also in the United States, defense wastes that are not HLW that contain $\geq$100 nCi/g TRU are "TRU wastes," and the WIPP repository for these wastes is restricted to receiving waste derived from defense materials. Commercial wastes other than HLW are designated LLW, and the numerical limits designating disposition requirements for Classes A, B, and C, and GTCC are defined in 10 CFR 61 and described in detail in Submodule G3 on LLW. Though these wastes are relatively well-defined based on characteristics, the disposition pathway for GTCC waste, a geologic repository, has not yet been designed or designated. Thus, for the purposes of this report, it is assumed that the regulations will be reevaluated and changes will allow some of the disposition options shown in Table G1-1. In summary, these changes may include consideration of the concept of "decay storage": secure storage facilities to allow problematic radionuclides such as cesium, strontium, tritium, and noble gases to decay to LLW limits. These materials must be stored for several hundred years isolated from the biosphere and protected against unregulated use.

G4-5. MODULE SCALING FACTORS

These facilities are unique and designs are not readily extrapolated. It is not expected that future facilities will emulate current facilities and unit costs may be significantly different. Therefore, scaling is not considered practical.

G4-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Costs for G4 modules were further detailed in order to support current assumptions on the aqueous and EChem separated HLW streams, waste forms, and waste loading. These wastes consist of gases (H3, Kr, Xe), metals (ZrSS) and Iodine. Costs were developed for each type of waste.

Gas wastes: Modules G4-1A (Aqueous) and G4-1E (EChem) provide waste conditioning for the gaseous wastes (H3, Kr, Xe). Cost basis was derived from study on Krypton encapsulation preconceptual design (Knecht 1994). Off-gas conditioning costs range from \$8,000/m^3 gas to \$15,000/m^3 gas, with a nominal cost of \$11,200/m^3 gas. Aqueous and EChem off gases are conditioned and packaged then placed in long-term managed decay storage.

The Knecht study was based on 233 m^3/yr of off-gas (99% krypton) produced from a 2,000 MTHM/yr reprocessing plant. This rate corresponds to 873 kg Kr/yr for the zeolite encapsulation part of the reprocessing complex. Table 7-7 from the Knecht report gives a discounted life cycle cost of \$21.9M in 1994 dollars or \$32.4M if converted to today's dollars. Since unit costs (\$/unit) can be calculated by dividing discounted life cycle costs by discounted annual production, the discounted production of 233 m^3 gas per year for 30 years at a 7% discount rate gives an overall discounted production of 2891 m^3. Dividing \$32.4M by 2891 gives a unit cost of \$11,200/m^3 of off-gas. This was designated as the nominal value. The high and low values were selected to give approximately a plus or minus 30% variation from the nominal value.

The CFTC EAS included cost estimates for similar volatile off-gas capture (H-3 capture and grouting, C-14 capture as carbonate and grouting, cryogenic capture and separation of Kr, iodine adsorption on mordenite and grouting), compaction of Zr hulls and stainless steel hardware. All these operations were to be conducted in the fuels receipt and dissolution building and are therefore inherently included in the cost of reprocessing (see module F1).

The CFTC FOEAS did examine the cost of eliminating the Kr-85 and C-14 capture and treatment and determined the TPC cost ranged from \$112M to \$156M.

Iodine. Module G4-4A (Aqueous derived) conditions iodine for placement in GTCC intermediate depth disposal. The nominal cost of \$67,000/m^3 iodine is based on an engineering estimate of \$25M capital and \$2M/year O&M for a 50 m^3/year iodine throughput. The costs range from \$50,000/m^3 to \$80,000/m^3 iodine.

Zr/SS. Module G4-5A (Aqueous) is estimated the same as G1-2E (EChem metal alloy conditioning of ZrSS). This waste is dispositioned to GTCC intermediate depth disposal.

G4-7. LIMITATIONS OF COST DATA

Advanced commercial fuel processing flowsheets that generate waste streams such as concentrated cesium and strontium, iodine, and technetium streams for which disposal options are not currently specified and glass may be inappropriate.

G4-8. COST SUMMARIES

The module cost information is summarized in the WIT cost summary in Table G4-2. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides).

Table G4-2. Cost summary table for GTCC waste conditioning selected values.[a]

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
G4-1A Aqueous LLW-GTCC Offgas Absorber (H3, Kr, Xe)	$8,000/m^3 gas	$15,000/m^3 gas	$11,200/m^3 gas
G4-1E EChem LLW-GTCC Offgas Absorber (H3, Kr, Xe)	$8,000/m^3 gas	$15,000/m^3 gas	$11,200/m^3 gas

[a] GTCC may be remote handled and generally not allowed in commercial surface landfills, but this has occurred on DOE reservations. Premium charges based on curie content of specific radionuclides are extremely variable due to the limited capacity for these materials per disposal site permits. Developing a repository specifically for GTCC wastes or codisposal with TRU waste is an unknown at this time.

These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distributions based on the costs in the WIT Table are shown in Figure G4-2 and G4-3.

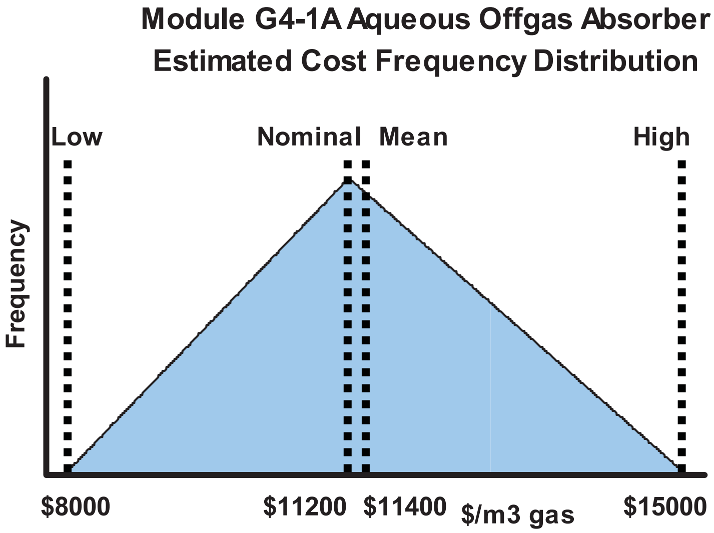

Figure G4-2. Module G4-1A aqueous offgas absorber.

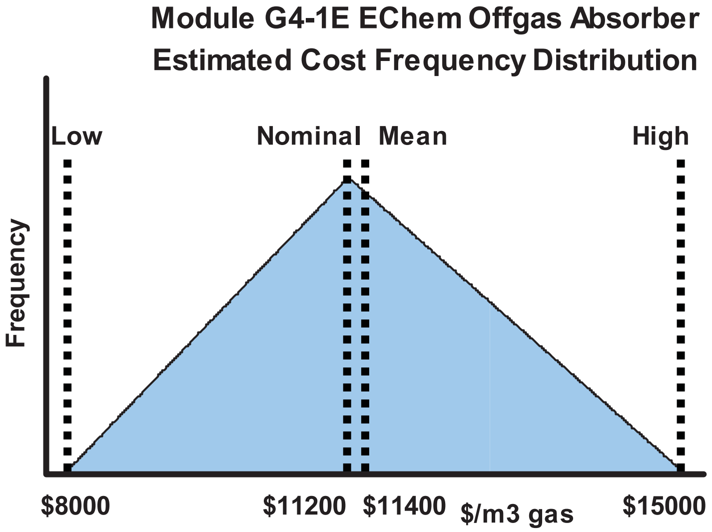

Figure G4-3. Module G4-1E EChem offgas absorber.

G4-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

Module G5

GTCC Secondary Waste Conditioning, Storage, and Packaging

Module G5

GTCC Secondary Waste Conditioning, Storage, and Packaging

G5-1. BASIC INFORMATION

Future fuel cycles are planned to include transuranic (TRU) recovery for recycle as fuel for fast reactors to destroy TRU and to generate additional energy. Goals for recovery of TRU are very aggressive with an overall recovery of approximately 99.9%. This includes leaching and rework of off-specification products, scraps, and process residuals to further reduce losses. Keeping losses less than 0.1% could allow expanding the capacity of a geologic repository for high-level waste (HLW) by two orders-of-magnitude. However, there will still be losses that contaminate consumable items and equipment, and some of these wastes will likely be classified as Greater-than-Class-C (GTCC) low-level waste (LLW) containing TRU contamination.

GTCC waste is defined as:

"Waste that is not generally acceptable for near-surface disposal is waste for which form and disposal methods must be different, and in general more stringent, than those specified for Class C waste. In the absence of specific requirements in this part, such waste must be disposed of in a geologic repository as defined in part 60 or 63 of this chapter unless proposals for disposal of such waste in a disposal site licensed pursuant to this part are approved by the Commission." (40 CFR 61)

In general, however, these wastes will be disposed of in a geologic repository. The similarities of commercial GTCC and defense TRU waste allow direct comparison of the treatment and disposal concepts (e.g. Waste Isolation Pilot Plant [WIPP] in the U.S.).

This module includes waste conditioning, certification, interim storage, and packaging of GTCC secondary generated from reprocessing spent nuclear fuel (SNF) using either aqueous or electrochemical processing. The closest analogues are the activities underway at several Department of Energy (DOE) sites that are shipping TRU waste to WIPP. Assuming that a future TRU waste repository would be similar to WIPP in design and operation, the costs can be estimated from current activities.

G5-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The GTCC Conditioning, Storage, and Packaging Facility will likely be a part of future nuclear facilities, but may also be operated similar to LLW disposal operation in which the treatment process is contiguous with the disposal such as the case with EnergySolutions, or may be a separate contracted facility such as the Duratek facility in Tennessee; Pacific EcoSolutions Inc., (PEcoS) in Washington; or Permafix headquartered in Florida that all ship the conditioned wastes for disposal such as Barnwell in South Carolina or EnergySolutions. External facilities must be capable of receiving wastes by truck and rail and must have sufficient analytical facilities or access to such facilities to ensure that the materials they receive are within the limits imposed by their permits. At a minimum, the facilities must be able to inspect and repackage to meet the waste acceptance criteria for the landfill. Other conditioning and treatment services offered will likely be based on return on investment and local expertise. Some of the more common services include:

- Supercompaction to reduce volume of compressible materials

- Size reduction to reduce volume of oversized materials such as construction debris
- Stabilization using sorbents to immobilize free liquids
- Stabilization using a cement and/or a pozzolonic material to reduce leachability of metals
- Macroencapsulation of debris including lead bricks
- Chemical oxidation for reactive metals and some organics
- Thermal desorption to separate organic constituents from waste matrices
- Incineration to minimize ultimate volume of combustibles or destroy solvents and other organic materials
- Specialized treatability studies and treatment for unique wastes.

Disposal criteria are likely to be similar to WIPP. WIPP waste acceptance criteria does not allow receipt of:

- Free liquids in excess of 1% of the container volume or 1 inch, whichever is less
- Sealed containers over 4 L
- Electrochemical radioactive materials over 1% by weight
- Ignitable, corrosive, or reactive wastes according to 40 CFR 261
- Explosives, corrosives, or compressed gases
- Flammable headspace gases >500 ppm.

Though this module does not include the repository itself (Module L), these requirements do imply the characterization capabilities to identify any of these characteristics and rectify them if found. Thus, some combination of verifiable information on how the waste was generated and analytical techniques for all these characteristics must be available.

Costs have been gathered and reported by the National Energy Technology Laboratory (NETL) (GAO 2000) including the following:

- Compilation of acceptable knowledge on the history of the waste
- Nondestructive assay
- Radiography and visual examination
- Gas generation testing
- Head space gas sampling and analysis.

At a minimum, it is likely that drums of TRU waste generated in the future will be subject to manual sorting and packaging and possibly radiography to verify packaging records. In the event that there are discrepancies identified, sampling and analytical capabilities designed for alpha containment and/or manual resorting and repackaging will be needed.

In addition to packaging waste drums and boxes to meet the waste acceptance criteria, receipt, inspection, decontamination, loading, and shipping of casks will also be necessary.

G5-3. PICTURES AND SCHEMATICS

Future generation of GTCC wastes will probably be better characterized than legacy wastes, because disposal in a repository will likely be planned, rather than assuming the waste can be buried in a surface landfill, as was the practice prior to 1970. Future wastes will probably be primarily stabilized waste forms, including ion-exchange media and precipitates encapsulated/mixed in a relatively inert matrix. Some wastes may still be generated that are debris. Figure G5-1 shows examples of legacy waste packaging that will hopefully serve as examples of what should be avoided.

Figure G5-1. Legacy TRU wastes packaged in 55-gallon drums with and without liners, bags, and stabilizing sorbent media.

Much has been learned from expensive retrieval and characterization activities for legacy wastes, and it is likely that future waste disposal will be more streamlined and cost effective. Figures G5-2 and G5-3 are photographs from Idaho National Laboratory (INL) showing waste drum tomographic and headspace sampling equipment. Figure G5-4 is a collage of pictures from a Sandia Web site showing one potential design for a manual GTCC waste sorting system. Handling and sampling GTCC wastes is very expensive, and hopefully better record keeping will allow handling these materials one time in the future to stabilize and prepare them for disposal.

Figure G5-5 shows a cutaway of the TRUPACT-II cask that is used for overland transport of packaged TRU wastes. Note the sophisticated design of the cask to ensure containment of the wastes even in the event of foreseeable accident scenarios. Figure G5-6 shows a typical truck shipment of three casks, each capable of holding 14 drums of waste.

Figure G5-2. X-ray tomographic equipment for imaging drummed waste without opening the drum.

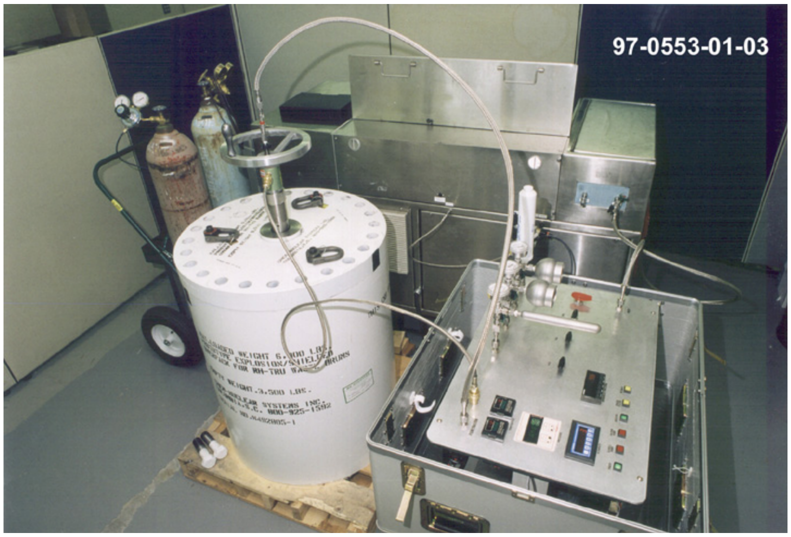

Figure G5-3. Headspace gas sampling of heated drum using Fourier transform infrared.

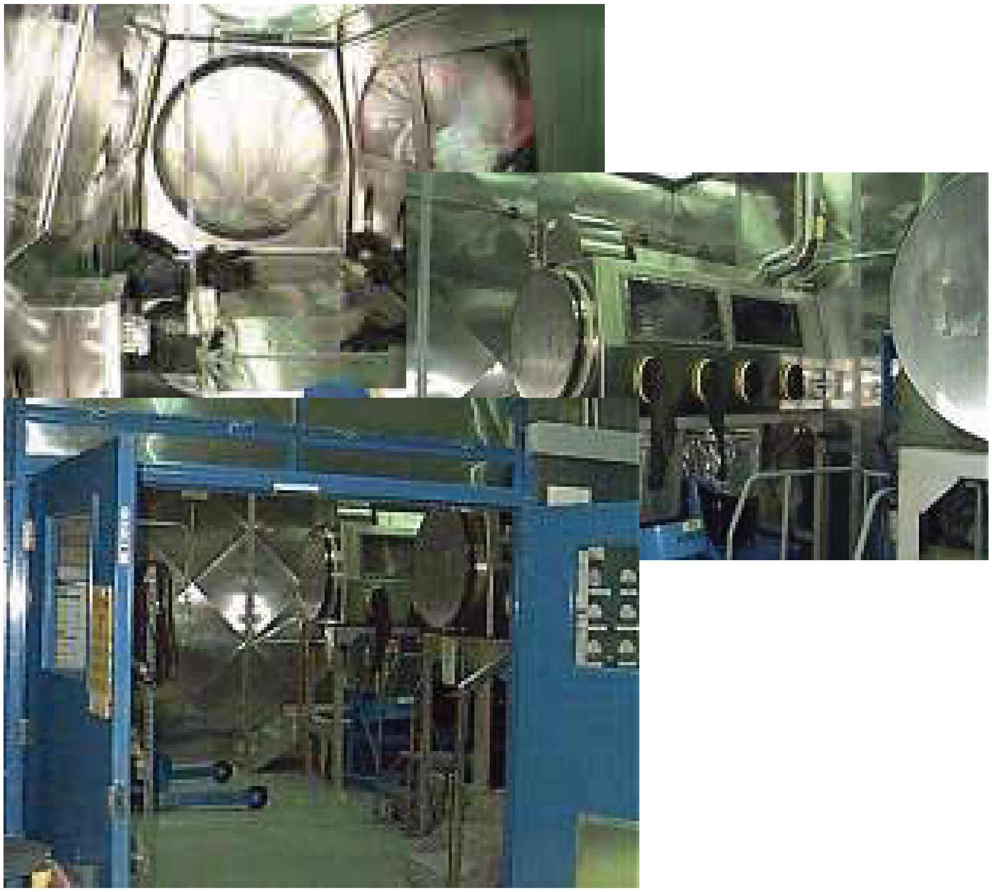

Figure G5-4. Collage of pictures showing a TRU waste sorting system.

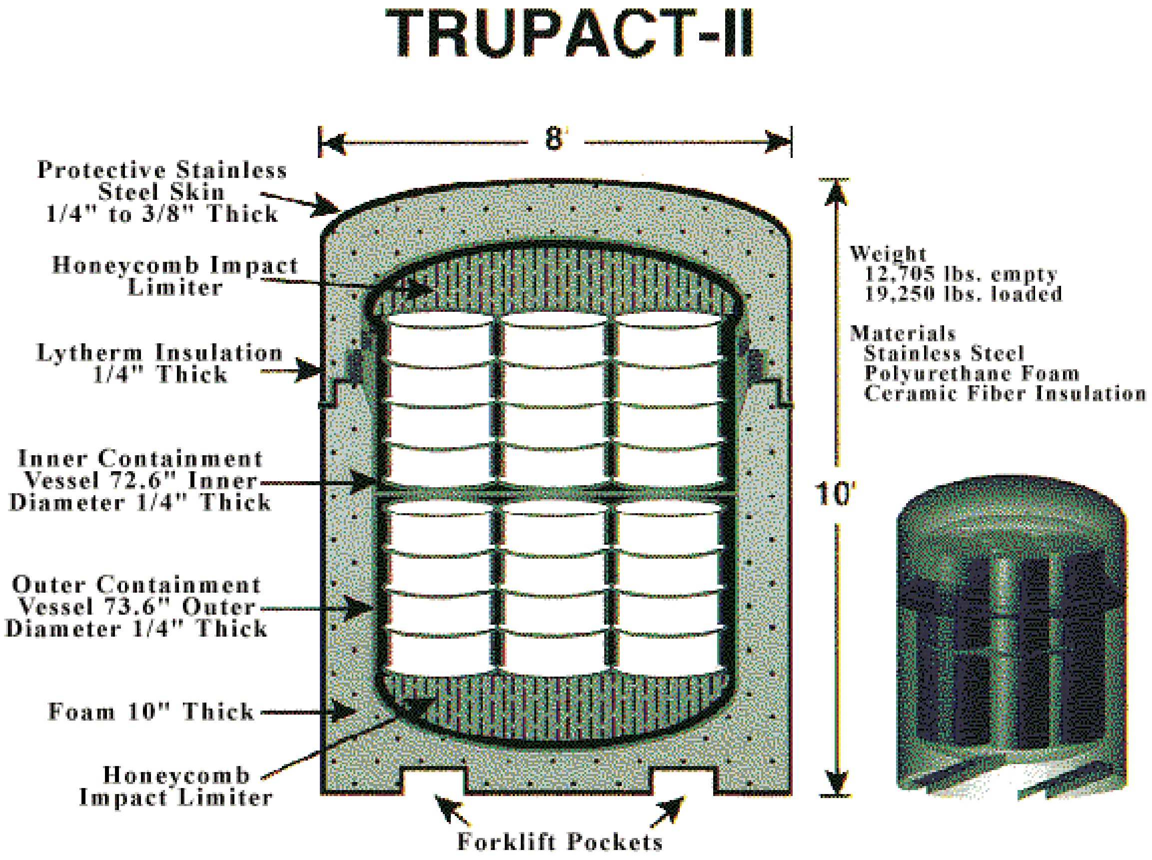

Figure G5-5. Schematic of TRUPACT-II shipping cask for TRU wastes.

Figure G5-6. Truck shipment of three TRUPACT-II casks.

G5-4. MODULE INTERFACE DEFINITION

Module G5 includes waste conditioning, certification, and interim storage of GTCC secondary wastes that include TRU. These wastes could be shipped (Module O1) to a Geologic Repository (Module L) or an Other Disposal Concept (Module M) that is yet to be determined. Most TRU wastes are expected to come from Modules F1 and F2/D2, the fuel separations modules. In fuel fabrication, there is expected to be a significant effort made to leach or reprocess off-specification materials to recover TRU. Materials may also be recycled to separations to purify TRU. However, it is still expected that in addition to consumables such as protective clothing, filters, and analytical solutions, there will also be contaminated equipment such as gloveboxes, grinding machines, and molds that may contain over 100 nCi/g TRU.

G5-5. MODULE SCALING FACTORS

This module does not represent a “facility” and cannot be scaled as such.

G5-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

G5-6.1 Defense TRU Waste Analogies

The closest analogous costs are remote-handled TRU (RH-TRU). Costs are derived from estimates made for WIPP. The information is from a study of TRU waste characterization and certification costs conducted by the NETL for WIPP (GAO 2000). The study was based on a combination of actual 2002 costs from INL and Rocky Flats Environmental Technology Site, and on estimated 2003 costs from Savannah River Site. Capital costs were not included.

Based on a typical drum of contact-handled TRU waste, the average life-cycle cost of characterization is \$3,850 per drum (in 2002 dollars). Using 208 L per drum, this translates to \$18,500/m^3.

These costs were developed based on the sum of the average cost for a set of 15 individual waste certification activities (e.g., real-time radiography, nondestructive assay, and head space gas sampling). Furthermore, the data were based on the certification of 17,900 drums from a stored waste population of 24,600 drums, plus the visual examination of 14,200 drums. The cost of each activity was prorated by the percentage of drums for which the activity was applicable.

Table G5-1 shows the cost of three particularly high-cost activities to illustrate how dependent the cost of characterization is on specific activities. For example, if the waste requires solids coring and sampling, then the total cost of certification would jump to about \$115,000/m^3 (2001 dollars). To bring the cost back down to the average, solids coring and sampling would have to be restricted to approximately 1% of the waste drums (specific numbers can be obtained from the WIPP TRU characterization cost analysis [GAO 2000]). The actual cost for an individual certification program then depends on the waste type, the certification activities required, and the number of containers available for averaging. The \$18,500/m^3 represents a good current estimate for a large number of drums of waste of various types.

Table G5-1. Examples of high-cost characterization activities.

Activity	Average Cost (per drum and m^3) Cost per Drum	Cost/m^3
Visual examination and retrievably store	$22,500	$108,000
Solids coring and sampling (FY 2001)	$24,000	$115,000
Solids analysis (FY 2001)	$63,000	$303,000

The method of computing the values in Table G5-2 is shown below with an example.

Table G5-2. Estimated characterization and certification costs for TRU wastes.[a]

Waste Type	Characterization $/$m^3$
CH-TRU	18,500

a. Costs do not include capital facility costs, waste treatment, or transportation.

From Table 4.3-1 of the National TRU Waste Management Plan (NTWMP), “Baseline Cost Data,” (NETL 2003) the quoted dollar value for INL in Fiscal Year (FY) 2002 was $72,937,000. The DOE Carlsbad Field Office (CBFO) estimates that 75% of this value is used in waste characterization, certification, and preparing waste for shipment. Therefore, INL cost for TRU waste characterization and certification during FY 2002 is shown in Equation (1).

$$\$72{,}937{,}000 \times 0.75 = \$54{,}702{,}750. \tag{1}$$

The method of estimating the volume characterized and certified is shown below. The number of planned shipments to WIPP is given in Table 3.2.1-1 of the NTWMP; however, the volume of waste is not given. The following conservative assumptions were used to determine a best-case estimate of the volume disposed:

- Each shipment consists of three Transuranic Package Transporter Model-IIs (TRUPACT-II)
- Each TRUPACT-II is full (i.e., 14 drums/TRUPACT-II or 42 drums/shipment)
- Each drum has a volume of 0.208 m^3.

Again, using an FY 2002 INL reported value of 437 shipments and the assumptions above, the volume of waste is as shown in Equation (2).

$$437 \text{ shipments} \times 42 \text{ drums/shipment} \times 0.208 \text{ m}^3\text{/drum} = 3{,}817 \text{ m}^3. \tag{2}$$

This volume, divided into the cost above, gives the characterization and certification cost of $14,327/$m^3$.

In most cases, the number of drums shipped is less than 42 because of transportation issues such as weight or wattage. Based on the INL shipping rate during the 3,100 m^3 project, the above estimate gives a volume estimate approximately 25% too high, or a cost estimate 25% too low in FY 2002. As such, the value calculated here should be considered a practical minimum. If the estimate of $14,327/$m^3$ is increased by 25%, it becomes $17,900/$m^3$, which is within 3% of the NETL estimate of $18,500/$m^3$ for characterization and certification of contact-handled TRU. Thus, the same approximate cost can be estimated from two approaches, and this is believed to be a good baseline.

G5-6.2 CFTC GTCC Treatment Estimates

The Consolidated Fuel Treatment Center (CFTC)Follow-on Engineering Alternative Studies (FOEAS) estimated the total project cost (TPC) and life cycle cost (LCC) for a treatment and packaging of GTCC waste expected to be generated by an integrated reprocessing center. Waste volumes were generated based on a task analysis using current work practices (to minimize the volume generated) and treatment practices (such as compaction) to minimize the volume disposed.

Table G5-2 provides the resulting unit cost on a basis of $\$/m^3$ of GTCC waste and \$/MT of SNF being reprocessed. The later value must be added (including others such as HLW packaging and treatment and uranium solidification and packaging) to the unit cost of reprocessing to obtain a comparable number to those often sited in the literature and other studies for the total unit cost of reprocessing.

The unit costs in Table G5-2 are consistent with those values reported for defense TRU pre-disposal operator costs. The LCC cost for solid GTCC treatment and packaging is somewhat less electrochemical reprocessing waste than for the aqueous reprocessing waste. However, the unit cost for the electrochemical waste is slightly higher than the aqueous reprocessing waste reflecting the increase in unit cost based on the lower waste generation from a plant with 40% of the processing capacity.

Table G5-2. CFTC cost estimate for solid GTCC treatment and packaging.

Millions of 2007 Dollars	Benchmark 2 800 MT/yr UREX+1		Benchmark 3 300 MT/yr Electrochemical	
Annual Operations Cost (Nominal Year)	Low	High	Low	High
Labor	15	23	12	18
Utilities	1	2	2	2
Materials	2	3	1	2
Misc. Contracts	0	0	0	1
Misc. Projects	1	2	1	1
Total Annual Operations Cost	**20**	**29**	**16**	**24**
40 Year LCC				
Labor	769	1154	619	928
Materials	82	123	70	105
Utilities	75	112	90	135
Contracts	14	21	12	18
Misc. Projects	42	62	34	51
Subtotal: 40-Year Operations	**982**	**1,473**	**825**	**1,238**
Future Capital Projects	0	0	0	0
D&D	4	5	2	3
Subtotal LCC O&M & D&D	**986**	**1,478**	**828**	**1,241**
Early Life Cycle	0	1	1	1
TPC	31	43	16	23
Total LCC	**1,017**	**1,522**	**845**	**1,265**
TPC Unit Cost, 40 yr amortization ($/m^3)	**758**	**1,052**	**554**	**766**
Unit LCC Cost ($/m^3)	**25,047**	**37,480**	**28,615**	**42,849**
LCC Unit Cost ($/MT SNF)	**32**	**48**	**70**	**105**
Values may not add due to rounding				

G5-7. LIMITATIONS OF COST DATA

The quoted values from defense TRU operations are baseline estimates based on operational costs; they do not include capital costs for the equipment or facilities used for characterization and certification. Characterization and certification costs can be dominated by sampling and analysis, which can be from 6 to 30 times the average cost of characterization and certification. Characterization costs reported here should be considered bounding. Much of the characterization is necessitated by a lack of acceptable knowledge due to the poor data quality describing legacy wastes. In the future, it is expected that TRU wastes generated by commercial facilities and future reprocessing will be well characterized, and most characterization will not be necessary. Also, a significant fraction of the characterization cost is related to container handling between characterization activities, and this should be greatly reduced for future wastes.

However, the CFTC studies made similar assumptions as regards the reduced characterization requirements for non-legacy waste and obtained somewhat higher unit costs including capital.

Costs for RH-TRU were not estimated separately from contact-handled TRU costs in the defense waste report. Costs estimated based on the NTWMP are simple averages; therefore, the costs are reasonably applicable to contact-handled TRU waste because the current plan is to fill WIPP repository with 95% contact-handled TRU waste. If waste characterization and treatment must be done remotely, the costs could be 3 to 10 times greater.

The CFTC study captures the cost of remote handled GTCC (expected to be the activated hulls and hardware, which have a high Co-60 neutron source) packaging in the reprocessing module since this operation is conducted inside the Fuel Receipt and Dissolution Building. The costs reported here are for the contact-handled GTCC waste only.

G5-8. COST SUMMARIES

The module cost information is summarized in the WIT cost summary in Table G5-3. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT Table.

Costs for TRU wastes are driven almost entirely by regulations. If it can be assumed that future commercial wastes will be produced by well-characterized processes, characterization costs will diminish, and treatment costs should be minimal and will be covered under operation of the recycling/separations facility.

The triangular distribution based on the costs in the WIT Table is shown in Figures G5-7. The distribution is skewed toward the low cost (the nominal was selected to be the low cost) because it is based on experience from WIPP. The distributions for RH-TRU are judged to be skewed toward low cost, but have potential to increase due to potential regulation of commercial facilities.

Table G5-3. Cost summary table for GTCC secondary waste conditioning selected values.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
INL actual cost of processing defense TRU waste and CFTC EAS EAS	\$19,000/m^3 GTCC	\$37,000/m^3 GTCC	\$27,000/m^3 GTCC
	Average of Defense TRU Waste Processing from INL Actual Costs	CFTC high range for 800MT/yr aqueous reprocessing	Average of the high and low
CH=Contact-handled RH=Remote-handled			

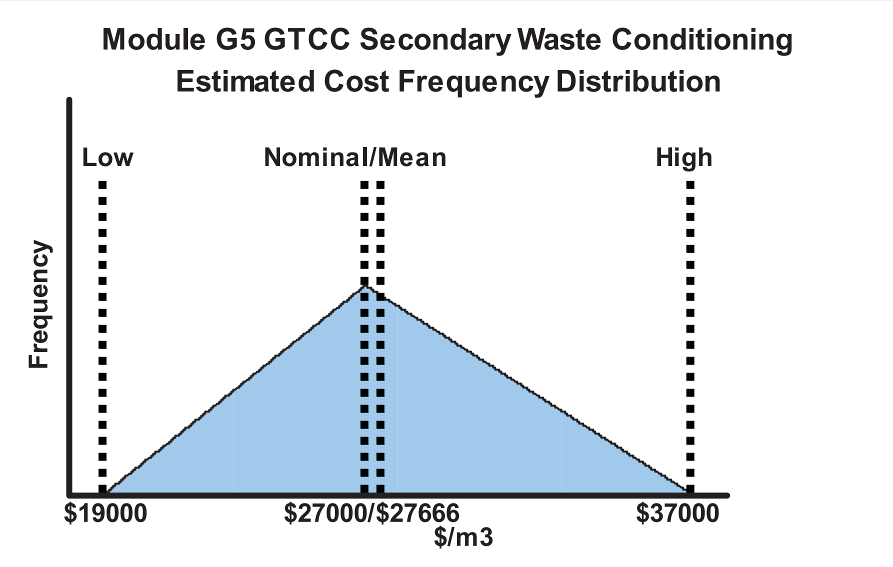

Figure G5-7. Module G5 GTCC secondary waste conditioning estimated cost frequency distribution.

G5-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

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Module I

Long-term Monitored Retrievable Storage

Module I

Long-Term Monitored Retrievable Storage

I-1. BASIC INFORMATION

Title 10, Code of Federal Regulations, Part 72 (10 CFR 72), contains the Nuclear Regulatory Commission regulations pertaining to the licensing requirements for the independent storage of spent nuclear fuel and high-level radioactive waste. Licenses issued under the part are limited to the receipt, transfer, packaging, and possession of either:

1. Power reactor spent fuel to be stored in a complex that is designed and constructed specifically for storage of power reactor spent fuel aged for at least 1 year, other radioactive materials associated with spent fuel storage, and power reactor-related Greater-than-Class-C (GTCC) waste in a solid form in an independent spent fuel storage installation.
2. Power reactor spent fuel to be stored in a monitored retrievable storage installation owned by the U.S. Department of Energy (DOE) that is designed and constructed specifically for the storage of spent fuel aged for at least 1 year, high-level radioactive waste that is in a solid form, other radioactive materials associated with storage of these materials, and power reactor-related GTCC waste that is in a solid form.

The term Monitored Retrievable Storage Installation, as defined in 10 CFR 72.3, is derived from the Nuclear Waste Policy Act of 1982 and includes any installation that meets this definition:

> A Monitored Retrievable Storage installation or MRS*,* means a complex designed, constructed, and operated by DOE for the receipt, transfer, handling, packaging, possession, safeguarding, and storage of spent nuclear fuel aged for at least 1 year, solidified high-level radioactive waste resulting from civilian nuclear activities, and solid reactor-related GTCC waste, pending shipment to a HLW repository or other disposal.

Although DOE has performed systems studies on various monitored retrievable storage installation designs, no detailed cost estimations have been produced to date. However, the Skull Valley Band of Goshute Indians have proposed and developed a detailed conceptual design of the nongovernmental adjunct, a privately owned and operated Independent Spent Fuel Storage Installation (ISFSI) to be located in Tooele County, Utah. Indeed, on February 21, 2006, the Nuclear Regulatory Commission issued a license to Private Fuel Storage, LLC (PFS) to build and operate its proposed temporary storage facility for spent nuclear fuel on the Skull Valley Goshute reservation in Skull Valley, Utah—the first nuclear facility to receive a license in more than 20 years.

Preliminary cost estimates for the Skull Valley ISFSI have been developed by PFS based on the detailed conceptual design depicted in Figure I-1 and having the layout as illustrated in Figure I-2. The detailed information is contained in the Skull Valley Environmental Impact Statement (EIS) (NRC 2001), which is prepared and submitted to the Environmental Protection Agency but also constitutes the basis of the formal license application to the Nuclear Regulatory Commission. The concept of the facility consists of a remotely located open area on which casks are stored in an upright position, having a maximum facility capacity of 4,000 casks, which is equivalent to approximately 40,000 MTHM.

Figure I-1. Artist rendition of Skull Valley Independent Spent Fuel Storage Facility.

I-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The following description was extracted with slight modifications from the Skull Valley EIS (NRC 2001). The basic site plan for the proposed private fuel storage facility is illustrated in Figure I-2. A fence would mark the boundaries of the 330-hectare (820-acres) general area. Within the general area, a 40-hectare (99-acre) restricted-access area would contain the storage pads and some of the support facilities. The entire 330-hectare site would be enclosed by a typical four-strand barbed wire range fence. Fencing around the restricted-access area would consist of two 2.4-m (8-ft) chain link security fences topped with barbed wire. The inner fence would be separated from the outer chain link nuisance fence by a 6-m (20-ft) isolation area. A new 4-km (2.5-mile) access road would lie within an 82-hectare (202-acre) right-of-way. The road would be built east of the site and would connect the site to the existing public roads. No fence would be constructed to enclose the new access road. Buildings and storage areas would primarily be located within the restricted-access area, with the exception of the administration building, concrete batch plant, and operations and maintenance building, which would be located on the site outside the security fences.

The facility would contain 4,000 modular concrete storage pads that would be 20 × 9 × 1 m (67 × 30 × 3 ft). Each storage pad would be constructed flush with grade level and would hold up to eight storage casks in a 2 × 4 array. Areas between the storage pads would be surfaced with compacted crushed rock 20 cm (8 in.) thick and sloped toward the north to facilitate drainage.

In addition to the storage pads described above, there would be four buildings:

1. The Canister Transfer Building, a massive, reinforced-concrete, high-bay structure approximately 60 m (200 ft) wide, 80 m (260 ft) long, and 27 m (90 ft) high. The Canister Transfer Building would facilitate the transfer of the spent nuclear fuel canister from its shipping cask into the storage cask and would be equipped with a 180-metric-ton (200-ton) overhead bridge crane for moving the shipping casks, a 135-metric-ton (150-ton) semigantry crane for canister transfer operations, and three canister transfer cells to provide a radiation-shielded work space for transferring the spent nuclear fuel canisters from the shipping casks to the storage casks. Shipping casks would be moved into the high bay portion of the building either on railcars or heavy/haul trailers, depending on the transportation option.

2. The Security and Health Physics Building, the entrance point for the 40-hectare (99-acre) restricted-access area, would be located adjacent to the Canister Transfer Building and consists of a single-story, concrete masonry structure approximately 23 m (76 ft) wide, 37 m (120 ft) long, and 5.5 m (18 ft) high. This building would provide office and laboratory space for security and health physics staff and would house security, communication, and electrical equipment needed by personnel.
3. The Administration Building consists of a single-story, steel-frame building approximately 24 m (80 ft) wide, 46 m (150 ft) long, and 5 m (17 ft) high that would include office and records management space, an emergency response center, meeting rooms, and a cafeteria.
4. The Operations and Maintenance Building consists of a single-story, steel-frame building approximately 24 m (80 ft) wide, 61 m (200 ft) long, and 8 m (26 ft) high, which would house maintenance shops and storage areas for spare parts and equipment to service vehicles and equipment at the facility.

Paved parking areas would be constructed adjacent to the Administration Building, the Operations and Maintenance Building, and the Security and Health Physics Building.

The storage pad emplacement area has a soil-cement subgrade to support the cask storage pads.

An 82-hectare (202-acre) right-of-way between the site and public roads would contain an asphalt paved access road to the proposed facility and overhead power and telephone lines. The road would consist of two 4.5-m (15-ft) lanes.

Onsite drainage at the storage pad area would be conveyed by a surface flow system to a 3-hectare (8-acre) storm water collection and detention basin to be located at the northern boundary of the restricted-access area (Figure I-3).

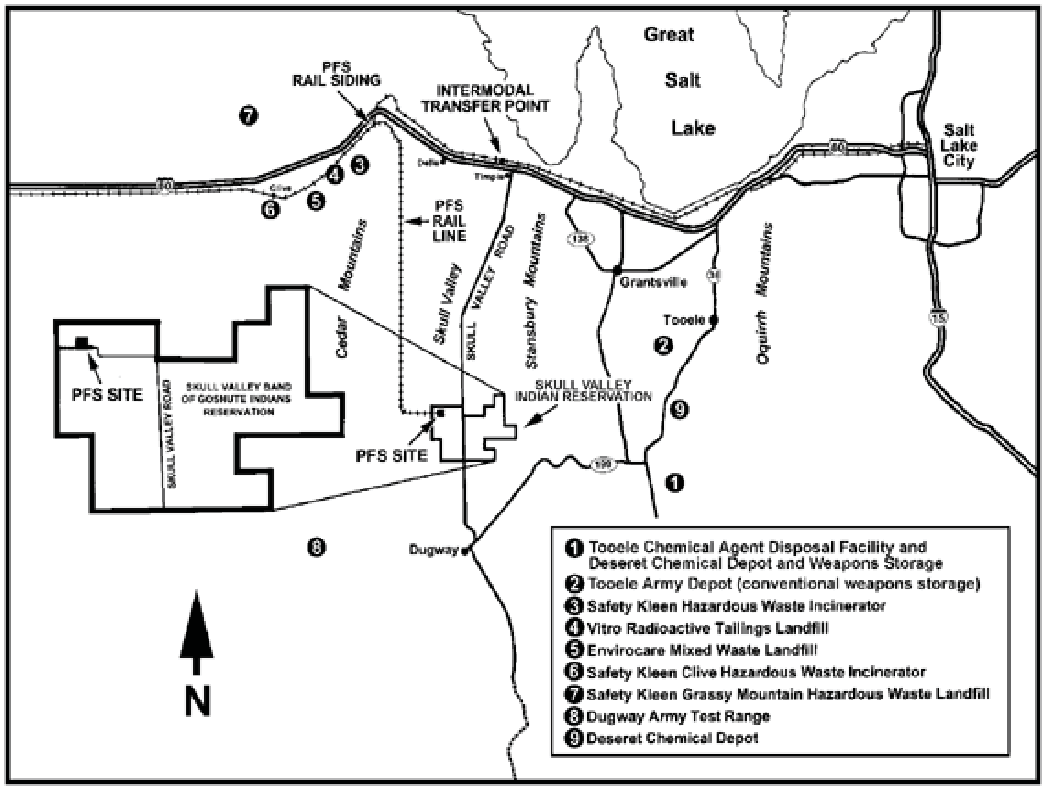
Electrical power for lighting, the security system, equipment operation, and other general purposes would be obtained from a new transformer to be connected with new lines on standard poles to existing 12.5 kV commercial power systems. Backup power for the security system, emergency lighting, and the site public address system would be provided by a diesel generator located in the Security and Health Physics Building. The communication system would consist of telephones, a public address system, and short-wave radio equipment. All buildings would be heated by propane due to the remoteness of the facility. Four propane tanks are located at a minimum distance of 550 m (1,800 ft) from the Canister Transfer Building and the cask storage area, and each propane tank would hold up to 19 m^3 (5,000 gal). A potable water supply system would be provided for the facility, taking water from either a groundwater well on the site or from offsite sources. Aboveground storage tanks would provide adequate water for potable water for extinguishing fires and for the concrete batch plant. A fire suppression system in the Canister Transfer Building would be fed by fire pumps and both a primary and backup water tank, each with a capacity of 380 m^3 (100,000 gal).

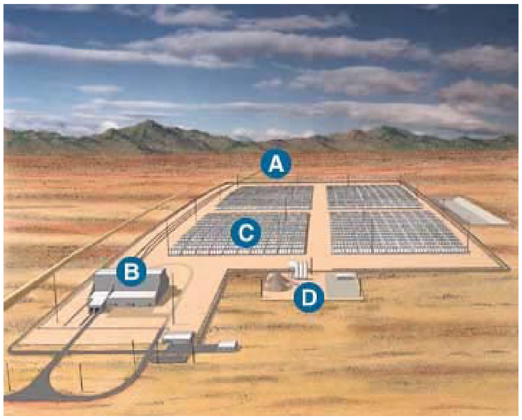
Other infrastructure includes a rail siding to connect to the existing trunk lines. The proposed right-of-way for the rail line would be approximately 51 km (32 miles) long and 60 m (200 ft) wide.

Figure I-4 shows the functional flow for the facility. Spent nuclear fuel is received in shipping casks, transferred to storage casks, and stored on a pad. At some later time, the spent nuclear fuel is transferred back to a shipping cask and shipped out (via Module O) for reprocessing (Modules F1 and F2/D2) or disposal (Modules L and M).

I-3. PICTURES/SCHEMATICS

Figures I-2, I-3, and I-4 describe the Skull Valley site plan and layout.





This illustration shows the rail line **(A)** that will enter the PFS facility from the west and run to the cask transfer building **(B)**. There, the shipping casks will be removed from the rail cars. Then the storage canisters will be removed from the shipping casks and placed into steel and concrete storage casks. The storage casks will then be placed on three-foot thick reinforced concrete pads **(C).** The concrete for the robust storage casks will be made on site at the batch plant **(D)**.

http://www.privatefuelstorage.com/project/facility.html

Figure I-2. Basic site plan for the proposed private fuel storage facility.

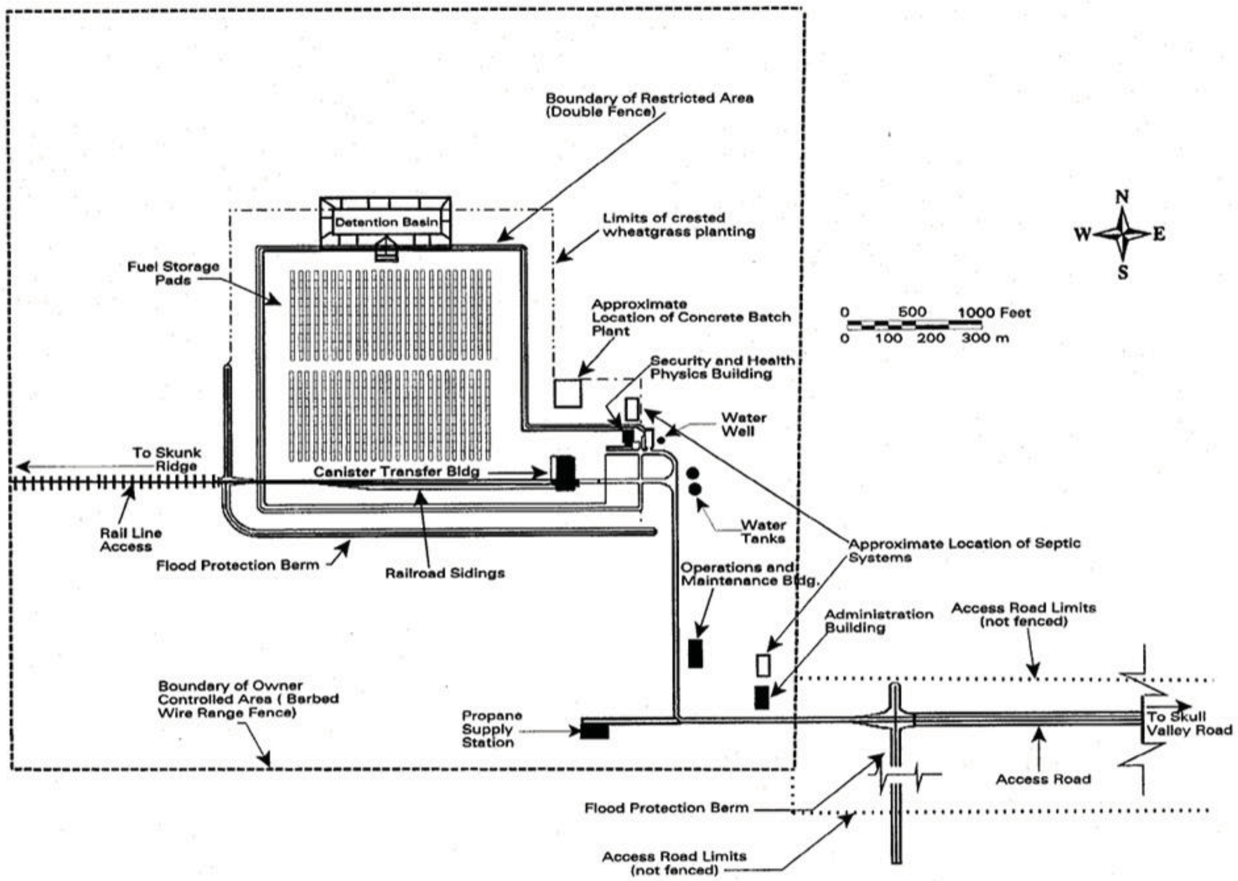


Figure I-3. Skull Valley facility layout and major components (NRC 2001).

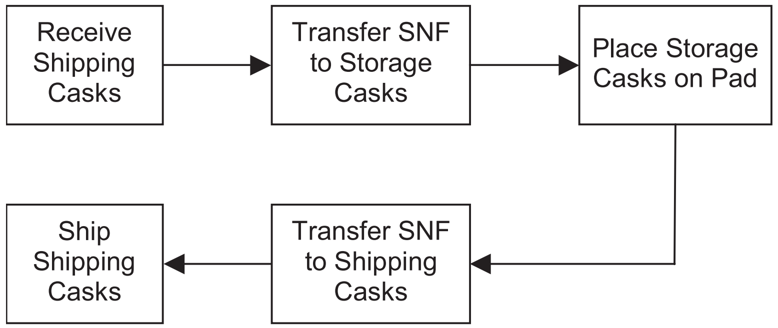


Figure I-4. Facility functional block diagram.

I-4. MODULE INTERFACE DEFINITION

The module will accept spent nuclear fuel casks transported (Module O) from wet (Module E1) or dry storage (Module E2) at nuclear power plants. On arrival, sealed canisters containing the spent fuel assemblies will be transferred to site-fabricated concrete storage casks and placed in storage. At unspecified future dates, fuel can be removed for ultimate disposition (Modules L or M) or for reprocessing (Modules F1 or F2/D2).

I-5. MODULE SCALING FACTORS

Within a site, facilities can be expanded simply by the addition of more pads, which is an expense of approximately $20,000 per 20 × 9-m pad, provided land is available.

I-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The reference cost basis in 2006 dollars for a private ISFSI is presented in Table I-1, generated from a top-down estimate based on the Skull Valley representative design for a monitored retrievable system. Combining the capital cost of $480M and Operations and Maintenance cost of $2,400M for a 40,000 MTHM facility operating over a 40-year lifetime, yields a Total Life-Cycle Cost of $2,880M ($72/kgHM) before financing, which escalates to $3,780M ($94.53/kgHM) after assessing interest at 16.27% over a 10-year amortization schedule.

The Skull Valley annual operating expenses are estimated by a principal of PFS at $60M per year, as quoted during a recent (2006) interview in an industry trade publication. Division of the annual cost by the maximum number of casks envisioned to be stored at the facility yields a value of $15,000 per year as the amount required for operations on a per cask basis, which is the source of the entry in Table I-1.

I-7. LIMITATIONS OF COST DATA

The cost estimate is based on direct conversations with the chairman and chief executive officer of PFS, accompanied by recent information available from trade publications.

The technology readiness is considered to be commercially viable. While no facilities of this type currently exist, the technology is not substantially different from the dry storage facilities presently operating at multiple reactor sites throughout the country. The data quality is categorized as a top-down scoping assessment with a common basis/approach.

Table I-1. Surface monitored retrievable storage (Skull Valley).

Private Fuel Storage (PFS) Goshute Reservation, Skull Valley, Utah	Value 2006 $	Units	Data Source or Person Making Assumption
Maximum number of casks onsite	4,000	casks	PFS/JD Parkyn, Chairman and Chief Executive Officer (CEO)
MTHM maximum onsite	40,000	MTHM	PFS/JD Parkyn, Chairman and CEO
Average kgHM per cask	10,000	kgHM/cask	PFS/JD Parkyn, Chairman and CEO
Facility capital investment per cask	120,000	$/cask	PFS/JD Parkyn, Chairman and CEO
Total PFS capital investment for land/facility development	480	$10^6$$	Calculated
Assumed number of years for facility to reach full storage capacity	10	years	ORNL/KA Williams
Facility fill rate	400	casks/year	Calculated
	4,000,000	kgHM/year	Calculated
Operations charge	15,000	$/cask/year	*Nuclear Fuel*, March 27, 2006, Operations: $60 M/y

Table I-1. (continued).

Private Fuel Storage (PFS) Goshute Reservation, Skull Valley, Utah	Value 2006 $	Units	Data Source or Person Making Assumption
Operations charge per year per kgHM	1.5	$/kgHM/year	Calculated
Typical storage time	20	years	ORNL/KA Williams
$/kgHM for operations	30	$/kgHM	Calculated
Fixed charge rate interest	10.00%	%	ORNL/KA Williams
Fixed charge rate to amortize capital over 10 years	16.27%	%	Calculated
Annual capital charge for facility	78.12	10^6\$/year	Calculated
Capital investment per kgHM	19.53	$/kgHM	Calculated
Total levelized storage cost	49.53	$/kgHM	Calculated
Total life-cycle cost for PFS facility (without interest)	2.88	10^9\$	Calculated
Total life-cycle cost with interest	3.78	10^9\$	Calculated

I-8. COST SUMMARIES

Table I-2 is a code-of-accounts cost summary.

Table I-2. Code-of-accounts information.

AFCI Code of Accounts No.	Code of Accounts Description	Cost (Million 2007 $)	Comments
0	Early Life Cycle Costs	—	
1	Capitalized Preconstruction Costs	—	
2	Capitalized Direct Costs	489	
	Total Directs	**489**	
3	Capitalized Support Services	—	Included above
	Base Construction Cost (BCC)	489	
4	Capitalized Operations	—	Included above
5	Capitalized Supplementary Costs	—	Included above
	Total Overnight Cost (TOC)	489	
6	Capitalized Financial Costs	306	
	Total Capital Investment Cost (TCIC)	**795**	
7	Annualized O&M Cost	61.5	10-year fill period
9	Annualized Financial Costs	18.3	
	Total Operating Costs	**3,057**	50-year life*
	Total Project Life-Cycle Cost	**3,852**	
* Note: The 50-year life includes 10 years to fill, 30 years at capacity, and 10 years to empty.			

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table I-3. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The cost summary includes potential upsides and downsides. A potential cost upside would be to arrange the storage casks closer together (e.g., for cooler spent fuel), for which a rough estimate of a 10% decrease in construction cost has been applied herein. A potential cost downside would be the stipulated requirement of a perimeter intrusion detection and assessment system (PIDAS) around the restricted area. A typical assessment for the cost of a PIDAS is $3,000 per foot, which is multiplied by an approximate estimate of 8,000 feet for the perimeter length. Such an upgrade in the security might require additional Operating and Maintenance costs as well (e.g., additional security guards), which are not included here. Another large potential cost downside would be associated with storage of the waste in underground bunkers to increase security and protection, for which a very rough estimate would result in a doubling of construction costs.

The triangular distribution based on the costs in the WIT Table is shown in Figure I-5. The distribution is skewed toward the low cost because there are many reactors already performing dry storage which provides the basis for the nominal cost.

Table I-3. Cost summary table.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Capital Costs of $796M Annual costs of $61.5M/year, 50-year life	$3,774M Total Project: Life Cycle Cost	$3,878M to $4,649M Total Project: Life Cycle Cost	$3,853M Total Project: Life Cycle Cost
Unit Cost/kgHM	$94/ kgHM	$116/kg HM	$96/kgHM
Based on a capacity of 40,000 MTHM* or a fill (and empty) rate of 4,000 MTHM/year	Lower cost for greater storage density (10% lower construction cost)	Additional cost for high-security perimeter ($24.5 M); increased cost for storage in buried bunkers (higher construction cost $1,592 M).	

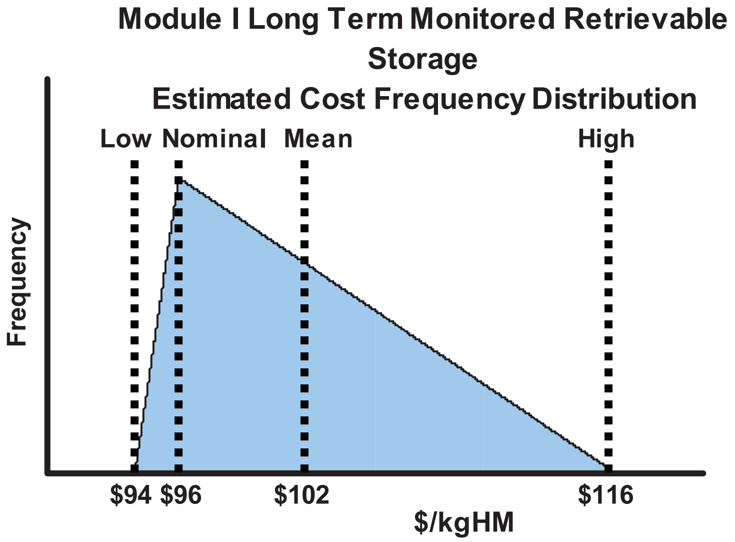


Figure I-5. Module I long term monitored retrievable storage estimated cost frequency distribution.

I-9. RESULTS FOR SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity or uncertainty analyses were performed.

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Module J

Near Surface Disposal

Module J
Near Surface Disposal

J-1. BASIC INFORMATION

Low-level waste (LLW) is disposed in shallow, or “near surface,” disposal trenches. The trenches are lined, accessible by truck, and have an earthen cover. Currently, both U.S. Department of Energy (DOE) and commercial (Nuclear Regulatory Commission or state licensed) LLW disposal sites exist in several locations across the country. However, for the purposes of this module, costs were developed for a new or “greenfield” site, with a comparison to available cost data of existing disposal sites. LLW arrives prepackaged in 1.22 × 1.22 × 2.33-m (4 × 4 × 7-ft) containers and is buried in shallow (8-m) trenches for near surface disposal. Each trench or pit can hold approximately 146,000 m^3 of waste (46,000 containers).

J-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Figure J-1 shows a simple diagram of the functional flow. Waste material arrives in trucks prepackaged in standard waste (4 × 4 × 7-ft) containers. Containers are unloaded in the pit and stacked along the long wall for burial. Figures J-2 and J-3 illustrate typical operations for near surface disposal facilities. Figure J-4 provides an example of a typical near surface disposal layout, for which cost estimates were developed.

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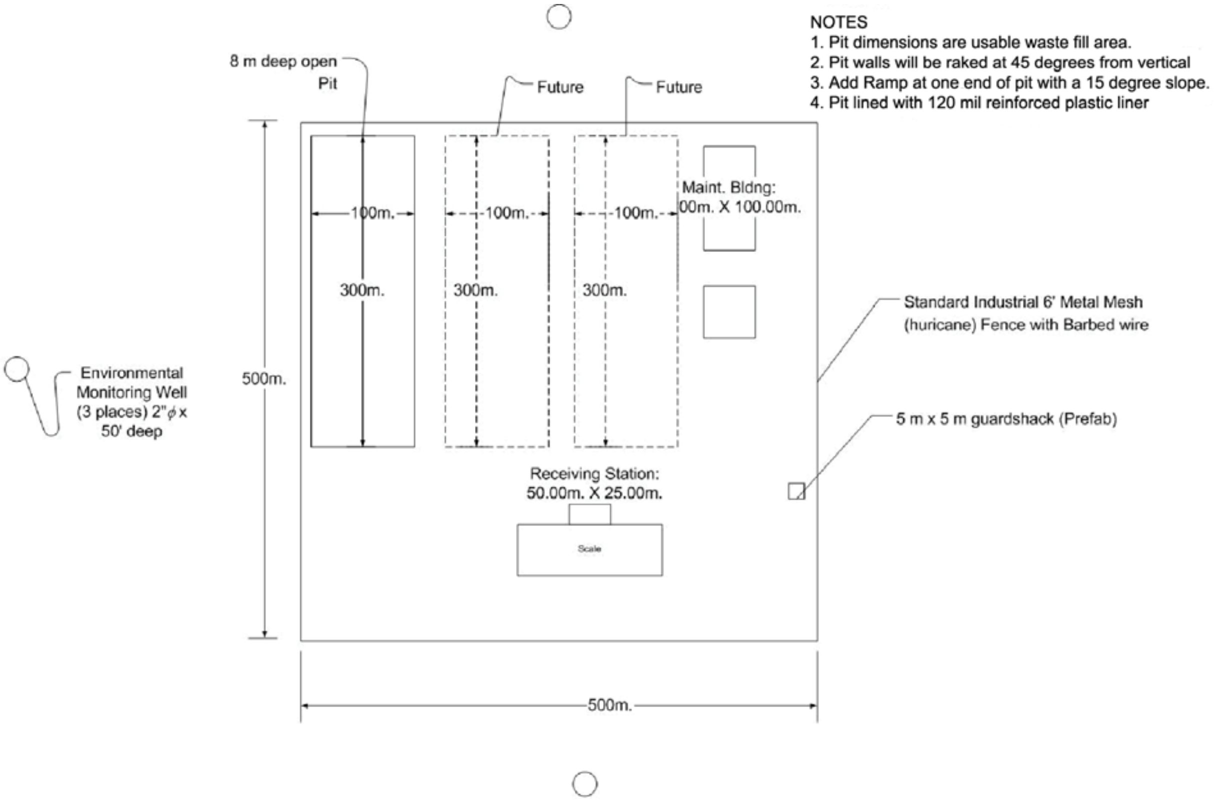
Figure J-1. Functional block diagram for near surface waste disposal.

J-3. PICTURES/SCHEMATICS

Figure J-2. Low-Level Waste operations at Nevada Test Site (State of Nevada 2009).

Figure J-3. Nevada Test Site low-level waste disposal facility aerial view (State of Nevada 2009).



NOTES
1. Pit dimensions are usable waste fill area.
2. Pit walls will be raked at 45 degrees from vertical
3. Add Ramp at one end of pit with a 15 degree slope.
4. Pit lined with 120 mil reinforced plastic liner

Figure J-4. Typical near surface disposal site dimensions.

J-4. MODULE INTERFACE DEFINITION

Low-level waste is material that has been slightly contaminated by radioactive material. It typically consists of clothing worn in contaminated (or potentially contaminated) areas, tools, cleaning supplies, and other contaminated disposable items. It can be generated at any nuclear facility, but the bulk will probably be generated at reprocessing plants (Module F), fuel fabrication plants (Module D), and reactors.

The module covers only the capital and operating expense of the LLW burial site. Transportation (Module O2), LLW containers, and ancillary expenditures are excluded. Depleted uranium from Module K can also be disposed of as LLW, but the expectation is that it will be dispositioned by Module K. Module J is a terminal module in that nothing leaves once it has been accepted.

Module J may also potentially be used to dispose of materials that exceed the general classification of LLW. In the United States, radioactive waste is generally categorized as one of three classes:

1. Spent nuclear fuel or the high-level waste resulting from the processing of spent nuclear fuel.
2. LLW, which is further subdivided into three successively stringent classes (Class A, Class B, and Class C) based on quantities and activities of the constituents.
3. Material that is in excess of the highest category of LLW (Class C), which is generally referred to as Greater Than Class C (GTCC) waste. The Code of Federal Regulations lacks clarity with regard to disposal of GTCC waste, which is commonly interpreted as being material destined for the mined geologic repository (Module L). However, it is possible to safely dispose of GTCC material without using valuable repository space by burying the waste at intermediate depths (~35 m), referred to as Greater Confinement Disposal (GCD). This document does not provide costs for GTCC disposal because such costs remain highly speculative until greater specificity is provided by the regulations or by licensing decisions.

The following historical summary regarding disposal of GTCC waste is provided for informational purposes. From 1984 until 1989, intermediate depth disposal operations were conducted by DOE at the Nevada Test Site. The operations emplaced high specific-activity low-level radioactive waste and limited quantities of transuranic (TRU) waste in GCD boreholes.

The GCD boreholes are about 3 m (10 ft) in diameter and 36 m (120 ft) deep, of which the bottom 15 m (50 ft) were used for waste emplacement and the upper 21 m (70 ft) were backfilled with native alluvium. The boreholes are situated in a thick sequence of arid alluvium of which the bottom is almost 200 m (650 ft) above the water table at the Nevada Test Site—one of the most arid regions of the U.S.

Following emplacement, a performance assessment was completed to determine whether the TRU waste posed a danger to human health, the requirements of which are defined under the U.S. Environmental Protection Agency (EPA) Code of Federal Regulations, Title 40, Part 191 Subpart B promulgated in 1985. The primary conclusions of the performance assessment were that disposal of TRU waste in intermediate depth GCD boreholes in the Nevada Test Site setting easily provides isolation under the 10,000-year Containment Requirement, and potential doses under the Individual Protection Requirements in the 1,000-year regulatory timeframe are almost insignificant.

Although there are currently no dedicated federal or commercially licensed facilities to dispose of GTCC materials, it is anticipated such facilities will become available in the near future, particularly for the eventual very large volumes expected from the decontamination and decommissioning of aged nuclear plants, including conversion, enrichment, reactors, reprocessing, and fuel fabrication facilities.

J-5. MODULE SCALING FACTORS

The traditional exponential scaling factor is not applicable to this type of facility. Capacity increases are generally accomplished by increasing the number of pits, rather than by increasing the size of a single pit. Consequently, the capital cost of the facility is better expressed as a cost for a one-pit facility plus an incremental cost for each pit after the first one. For example, the capital cost for the facility estimated here is \$52.19M + \$29.79M • (N – 1), where N is the number of pits.

J-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Credible partitioned costs for near-surface disposal facilities are not readily available in the literature, so an estimate was developed from the bottom up based on the Nevada Test Site facility diagrammed in Figure J-4. The following assumptions apply:

1. Facilities will be located on existing nuclear facility sites, remote federal lands, or remote private lands. In all cases, land cost is an insignificant factor and is ignored.
2. All waste arrives in 1.22 × 1.22 × 2.33-m (4 × 4 × 7-ft) rectangular standard waste boxes known as "B-25 Crates" (Figure J-2), the cost of which is covered under LLW transportation.
3. All material is transported by truck to the site.
4. The estimate includes groundwater-monitoring wells, which may or may not be required.

Each pit can contain approximately 146,000 m^3 of waste based on standard B-25 boxes stacked four high and covered with a 2.4-m-thick cap.

Table J-1 shows the estimated operating costs for a near surface disposal facility. The estimated operating cost is \$2,500,000 per year in 2006 dollars, with a discounted cost of \$171.5/m^3 for a 460,000 m^3 capacity facility having a life of 30 years. Staffing and cost are based on interviews with Sandia National Laboratories personnel who are involved with storage facilities operations.

Table J-1. Estimated operating costs (2007 dollars/year).

Cost Description	Rate	Units	Quantity	Extension
Direct labor				
Manager	\$86,500	\$/year	2	\$173,000
Waste Acceptance	\$65,200	\$/year	8	\$521,760
Heavy Equipment	\$27.00	\$/hour	4,160	\$112,320
Miscellaneous Support	\$13.50	\$/hour	4,160	\$56,160
Subtotal				\$863,240
Overhead and Support @ 1.25				\$1,079,050
Total Labor				\$1,942,290
Fuel	\$3.00	\$/gallon	25,000	\$75,000
Repair to Operating Equipment				\$25,500
				\$2,042,790
Allowance Unforeseen Expenses @ 25%				\$510,700
				\$2,553,490
Regulatory @ 135%				\$3,447,200
Total (rounded)				\$6,000,000

In addition to the costs shown in Table J-1, it is likely that costs for security, regulatory compliance, etc. will be incurred as part of a "facility charge" imposed by the federal or state site upon which the facility is located. As an example, the Hanford LLBG has annual operating costs of $3.1M and "regulatory" costs of $4.2M, or 135% of the operating cost. When this factor is applied, the annual costs are $6M.

Table J-2, on the next page, provides a cost estimate provided to Sandia by F. Wingate. The basic estimate is for three pits. The estimate was then adjusted, as shown in the last two columns, for just one pit. It was assumed that the surface facilities occupy approximately the same area as one pit. Thus, the area of a one-pit facility will be half that of a three-pit facility. By the same token, the fencing required for a one-pit facility will be 75% that of a three-pit facility. Table J-3 takes the results from Table J-2 and completes the cost estimate to include contingency and some "administrative" items. By taking the difference between the cost for three pits and the cost for one and dividing the result in half, the incremental cost for additional pits can be determined to be approximately $34.2M.

The amount of waste generation per year is an estimate. As described at their Web site (DOE 2005), the Nevada Test Site facility accepts approximately 35,000 m^3 per year (actually, less than 1 million ft^3) with two pit systems operational. Hence, each trench is accepting about 17,000 m^3 per year. This was taken to be a "reasonable" receipt rate and reduced slightly in the present analysis to 14,600 m^3/year to accommodate a 10-year fill time for a single pit.

In addition to the capitalized costs to open the facility, it will be necessary to fund its closure and any long-term stewardship costs that might be imposed. The Hanford LLBG estimated $317,000/acre to close, INL estimated $400,000/acre, and SRS estimated $430,000/acre (DOE 2002). Based on Figure J-3, this facility encompasses 61.75 acres, so its cost to close will be $24.7M at $400,000/acre. Various sites have estimated long-term stewardship costs at $0.5M/acre for 100 year ($50M) while Tennessee imposes a cost of $1M for 10 years ($10M) (DOE 2002). This study uses $50M.

It is now possible to combine the operating costs from Table J-1 and the capital costs from Table J-3 to estimate the life cycle costs presented in Table J-4. Table J-4 contains a present value analysis showing each capital cost outlay and the operations and maintenance (O&M) expenditures per year with inflation, taxes, and discount factors included. Inflation is assumed to be 2% per year and the discount factor used in the analysis is 15%, which should be sufficient to allow a reasonable return on investment and some profit. The unit cost (which also escalates annually) is approximately $1,245/$m^3$. This compares well with Table J-5, providing a sort of "mid-range" estimate as compared to the many examples in the table.

The bottoms-up estimate shown in Table J-3 is accurate for the scope presented to within a range of 30% high or low.

Table J-2. Detailed capital cost estimate in 2003 dollars for near-surface disposal facility.

File Name: Detail Worksheet								
Code	Description	Quantity	Unit	Matl/Equip Unit Cost	Material/ Equipment	Labor	One Only Mat/Equip	One Only Labor
1	Clear Site w/dozer. Medium clearing.	61.82	AC	110.00	$6,800	$3,555	$6,800	$3,555
2	Grade Site, 200-ft haul	299,209.00	SY	0.67	$200,470	$80,786	$100,235	$40,393
3	Excavate 3/ea 100 × 300 × 30-m pits.	4,594,287.00	CY	3.28	$15,057,776	$9,351,671	$5,019,259	$3,117,224
4	Haul Excavated Material (1 mile RT w/12 CY dump truck)	4,594,287.00	CY	2.14	$9,831,774	$5,177,761	$3,277,258	$1,725,920
5	Spread fill, w/dozer 300 HP, 300-ft haul	4,594,287.00	CY	1.88	$8,637,260	$2,756,572	$2,879,087	$918,857
6	Fence, Chain Link, Sch.40, 3 Strands of Barbed wire, 6 ft H	6,500	LF	19.53	$126,926	$26,761	$95,195	$20,070
7	Gates, allowance	2	EA	7,000.00	$14,000	$6,000	$14,000	$6,000
8	Truck scale	1	EA	35,000.00	$35,000	$15,000	$35,000	$15,000
9	Concrete foundation for above	1	EA	4,700.00	$4,700	$8,900	$4,700	$8,900
10	Receiving station, all in cost	13,500	SF	106.00	$1,431,000		$1,431,000	
11	Maintenance building	32,400	SF	83.00	$2,689,200		$2,689,200	
12	Guard shack, all in cost, allowance	1	EA	100,000.00	$100,000		$100,000	
					$38,128,106	$17, 423,452	$15,651,733	$5,852,365
	FREIGHT ALLOWANCE @ 0%							
	DESIGN DEVELOPMENT @ 10%				$3,812,810	$1,742,350	$1,565,173	$585,237
	CONTRACTOR INDIRECT @ 35% LABOR/10% OF MATERIAL				$4,194,092	$6,708,031	$6,025,917	$2,253,161
	TOTAL				**$46,135,008**	**$25,873,833**	**$23,242,823**	**$8,690,762**

Table J-3. Summary capital cost estimate for near-surface disposal facility.

Description	Factor	Labor Hours	Three $ × 1,000s Cost	One Only $ × 1,000s Cost
Equipment			$46,135	$23,243
Material			w/above	w/above
Labor	60.00	431,230/144,850	$25,874	$8,691
Total Field Cost		351,445	$72,009	$31,934
Construction Mgmt/Procurement @ % of Field	3%		$2,160	$958
D.E./P.M. @ % of Field Cost	12%	100,840	$8,641	$3,832
Total Directs			$82,810	$36,724
Owners Field (5% Craft Hours) @ $/hour	80.00	21,561/7,243	$1,725	$0
Owners Home Office (5% Direct Cost)			$4,141	$1,836
Total Owners Cost			$5,866	$2,415
Total Dir. + Owners			$88,676	$39,139
Environmental Permitting@ % of Above	3.00		$2,660	$1,174
Licensing @ % of Above	0.00		$0	$0
Total Allowances			$2,660	$1,174
Total Dir.+Owners+Allow			$91,336	$40,313
Startup & Testing @ % Above	0.00		$0	$0
Total in 2003 Dollars			$91,336	$40,313
Escalation/Rounding	11.6%		$10,595	$4,676
Total in 2007 Dollars			$101,931	$44,989
Contingency	20.0%		$20,386	$8,998
Grand Total			$122,317	$53,987

Table J-4. Present value analysis (escalation at 2%/yr, and a 15% discount factor).

Year	Capital Cost	O&M	Boxes/year	Annual Volume	Revenue	Pretax Income	Depreciation	Tax	Cash Flow	Present Value
0	-$53,987								-$53,987	-$53,987
1		-$6,120	4,600	14,600	$18,615	$12,495	-$5,399	-$2,839	$9,656	$8,397
2		-$6,242	4,600	14,600	$18,987	$12,745	-$5,399	-$2,938	$9,806	$7,415
3		-$6,367	4,600	14,600	$19,367	$13,000	-$5,399	-$3,040	$9,959	$6,548
4		-$6,495	4,600	14,600	$19,754	$13,260	-$5,399	-$3,144	$10,115	$5,783
5		-$6,624	4,600	14,600	$20,149	$13,525	-$5,399	-$3,251	$10,274	$5,108
6		-$6,757	4,600	14,600	$20,552	$13,795	-$5,399	-$3,359	$10,437	$4,512
7		-$6,892	4,600	14,600	$20,964	$14,071	-$5,399	-$3,469	$10,602	$3,986
8		-$7,030	4,,600	14,600	$21,383	$14,353	-$5,399	-$3,582	$10,771	$3,521
9		-$7,171	4,600	14,600	$21,810	$14,640	-$5,399	-$3,696	$10,943	$3,111
10	-$41,647	-$7,314	4,600	14,600	$22,247	$14,933	-$5,399	-$3,814	-$30,528	-$7,546
11		-$7,460	4,600	14,600	$22,692	$15,231	-$4,165	-$4,427	$10,805	$2,322
12		-$7,609	4,600	14,600	$23,145	$15,536	-$4,165	-$4,549	$10,987	$2,054
13		-$7,762	4,600	14,600	$23,608	$15,847	-$4,165	-$4,673	$11,174	$1,816
14		-$7,917	4,600	14,600	$24,080	$16,164	-$4,165	-$4,800	$11,364	$1,606
15		-$8,075	4,600	14,600	$24,562	$16,487	-$4,165	-$4,929	$11,558	$1,420
16		-$8,237	4,600	14,600	$25,053	$16,817	-$4,165	-$5,061	$11,756	$1,256
17		-$8,401	4,600	14,600	$25,554	$17,153	-$4,165	-$5,195	$11,958	$1,111
18		-$8,569	4,600	14,600	$26,065	$17,496	-$4,165	-$5,333	$12,163	$983
19		-$8,741	4,600	14,600	$26,587	$17,846	-$4,165	-$5,472	$12,373	$869
20	-$50,767	-$8,916	4,600	14,600	$27,119	$18,203	-$4,165	-$5,615	-$38,180	-$2,333
21		-$9,094	4,600	14,600	$27,661	$18,567	-$5,077	-$5,396	$13,171	$700
22		-$9,276	4,600	14,600	$28,214	$18,938	-$5,077	-$5,545	$13,394	$619
23		-$9,461	4,600	14,600	$28,778	$19,317	-$5,077	-$5,696	$13,621	$547
24		-$9,651	4,600	14,600	$29,354	$19,703	-$5,077	-$5,851	$13,853	$484
25		-$9,844	4,600	14,600	$29,941	$20,097	-$5,077	-$6,008	$14,089	$428
26		-$10,041	4,600	14,600	$30,540	$20,499	-$5,077	-$6,169	$14,330	$379
27		-$10,241	4,600	14,600	$31,151	$20,909	-$5,077	-$6,333	$14,576	$335
28		-$10,446	4,600	14,600	$31,774	$21,328	-$5,077	-$6,500	$14,827	$296
29		-$10,655	4,600	14,600	$32,409	$21,754	-$5,077	-$6,671	$15,083	$262
30		-$10,868	4,600	14,600	$33,057	$22,189	-$5,077	-$6,845	$15,344	$232
31	-$136,722	-$11,086	0	0					-$147,807	-$1,941
Total				**Rate/m^3**	1.25					
	-$283,123	-$259,362	13,8000	43,8000	$755,175	$506,898	-$146,401	-$144,199	$68,491	$294

Table J-5. Life cycle costs for disposal of DOE low-level waste at various facilities (DOE 2002).

Disposal Site	Life-Cycle Cost ($\$/m^3$)
DOE CERCLA Disposal Facilities	
Hanford ERDF	$29
Oak Ridge EMWMF	$140
INL ICDF	$160
Fernald OSDF	$190
DOE Non-CERCLA Disposal Facilities	
Savannah River Site Trenches	$130
Nevada Test Site	$320
INL RWMC	$700
Hanford LLBG	$2,000
Savannah River Site Vaults	$2,100
Commercial Disposal Facilities	
Envirocare (soil)	$180
Envirocare (debris)	$520
Barnwell	$14,000
U.S. Ecology	$2,500

Notes:

(1) To gain a true cost comparison of disposal sites, generator costs including waste preparation, packaging, and transportation must also be considered, which vary depending on the disposal site.

(2) These costs do not include surcharges for remote handling, shielding, mixed low-level waste, etc.

(3) The values shown for Barnwell and U.S. Ecology are their nominal average prices for low-level waste and do not include curie or dose rate surcharges.

(4) Cost estimates for DOE facilities include all future closure and long-term stewardship costs. Even though for many of the facilities, these are partially sunk costs that DOE must pay regardless of whether any future waste is emplaced in the facility.

J-7. LIMITATIONS OF COST DATA

- Estimate is plus or minus 30% as standard factored cost on scope presented
- Scope is well established based on existing facilities
- Technology is well proven on a large scale commercially.

The technology readiness is commercially viable. Disposal of LLW is existing technology. The data quality is categorized as a scoping assessment with a common basis/approach.

J-8. COST SUMMARIES

Given the variable nature of LLW, it is not possible to estimate the amount of uranium present. Therefore, no attempt was made to relate these costs to uranium consumption based on a 2,000 MTHM/year spent nuclear fuel processing capacity. Instead, costs were normalized to the volume of material delivered to the site, which is based roughly on a volume rate similar to the current Nevada Test Site system and a 30-year life. The waste receipt rate and related volume of delivered material could possibly double. Table J-6 is a code-of-accounts breakdown of disposal cost.

Table J-6. Code-of-accounts information.

AFCI Code of Accounts No.	Code of Accounts Description	Cost (Million 2007 $)	Comments
0	Early Life-Cycle Costs	—	
1	Capitalized Preconstruction Costs	—	
2	Capitalized Direct Costs	122	
	Closure Costs (Sinking Fund)*	24	
	Stewardship Costs (Sinking Fund)*	50	
	Total Directs	196	
3	Capitalized Support Services	—	Included above
	Base Construction Cost (BCC)	196	
4	Capitalized Operations	—	Included above
5	Capitalized Supplementary Costs	—	Included above
	Total Overnight Cost (TOC)	196	
6	Capitalized Financial Costs	—	
	Total Capital Investment Cost (TCIC)	196	
7	Annualized O&M Cost	6.0	
9	Annualized Financial Costs, Taxes & Profit	5.7	
	Total Operating Costs	351	30-year life
	Total Project Life-Cycle Cost	547	Inflation not included

* Note that end-of-life costs for closure and stewardship have been included with capital costs.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table J-7. The summary shows the reference cost basis (constant year U.S. dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated and because of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table. The triangular distribution based on the costs in the WIT Table is shown in Figure J-5.

Table J-7. Cost summary table (2006 dollars/MTU).

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
\$1,250/m^3	(± 30%) \$875–\$1,560/m^3	\$450/m^3 (Comparable to Envirocare)	\$2,500/m^3 (Comparable to US Ecology)	\$1,250/m^3
		Lower capital costs; lower stewardship costs (i.e., Tennessee at \$10M)	More stringent requirements for security, environmental protection and long-term stewardship	

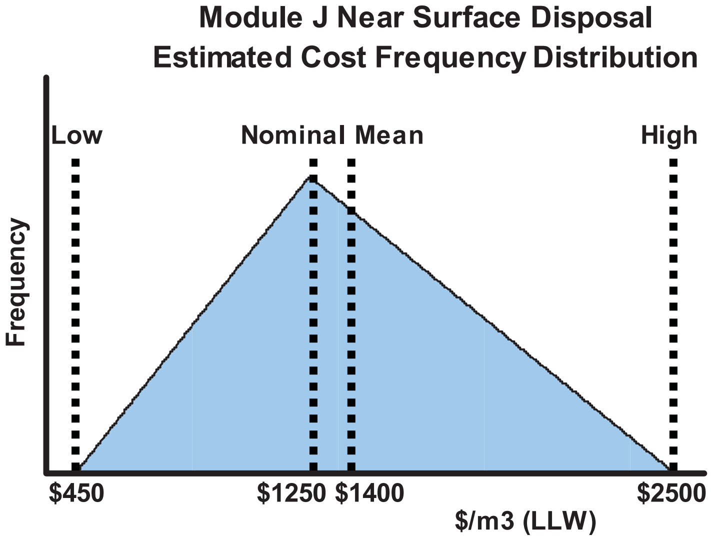


Figure J-5. Module J near surface disposal estimated cost frequency distribution.

J-9. RESULTS FOR SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for this module.

J-10. BIBLIOGRAPHY

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Module K1

Depleted Uranium Conversion and Disposition

Module K1

Depleted Uranium Conversion and Disposition

K1-1. BASIC INFORMATION

Depleted uranium (DU) in the form of uranium hexafluoride (UF_6) is the by-product of the isotope separation processes used to enrich uranium above its natural isotopic abundance of 0.711 wt% U-235 for military and reactor applications (see Figure K1-1). Material balance demands that a stream of uranium of assay less than the natural feed isotopic abundance of 0.711 wt% U-235 also be produced. Because most uranium goes through the enrichment (isotope separation) process (Module C) in the form of UF_6 and is withdrawn from the process in the same form using large cylinders, most depleted uranium still resides in this chemical form. The forms of depleted UF_4 U-metal, and UO_3 also exist in smaller amounts at some U.S. Department of Energy (DOE) sites. The U-235 assay of natural or slightly enriched uranium can also become depleted by virtue of being irradiated in a nuclear reactor (consumption of U-235 by the fission process). This fission-depleted uranium material is often found in the form of nitrate solutions or crystals or stable oxide powders from spent fuel reprocessing or plutonium recovery operations. (Handling of this reprocessed uranium material derived from burned natural uranium [NATU] or enriched uranium [EU] fuel is covered in Module K-2.) In any case, the term "depleted" always indicates a U-235 isotopic assay of less than 0.711 wt% U-235.

In the U.S, most depleted uranium is in the form of DU_6, resulting from 60+ years of uranium enrichment operations conducted by three DOE enrichment (gaseous diffusion enrichment process) plants for military, research, and commercial nuclear plant use. Over 700,000 metric tons of DUF_6 reside at cylinder yards at the Paducah, Kentucky and Portsmouth, Ohio gaseous diffusion plant (GDP) sites; this material constitutes the largest DOE radioactive material legacy inventory (in terms of mass, not Curies) in the U.S. (see Figures K1-2 and K1-4). It should be noted that approximately 6,000 UF_6 legacy cylinders, formerly located at the Oak Ridge Gaseous Diffusion Plant site in Tennessee, were successfully transported to the Portsmouth site by the end of Calendar Year 2006 (Knoxville News Sentinel 2006).

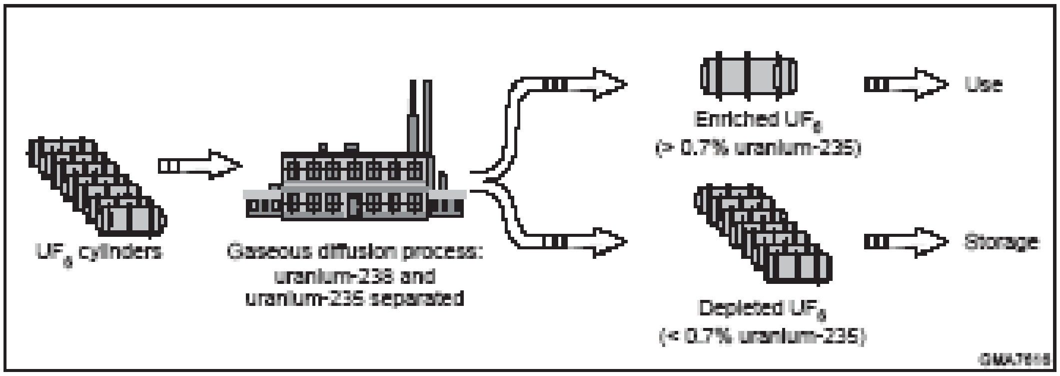
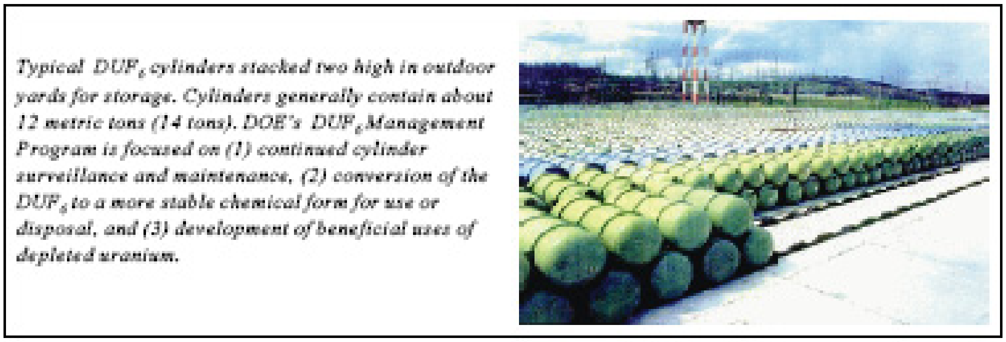


Figure K1-1. DUF_6 is the by-product of uranium enrichment (DOE 2001).



Typical DUF_6 cylinders stacked two high in outdoor yards for storage. Cylinders generally contain about 12 metric tons (14 tons). DOE's DUF_6 Management Program is focused on (1) continued cylinder surveillance and maintenance, (2) conversion of the DUF_6 to a more stable chemical form for use or disposal, and (3) development of beneficial uses of depleted uranium.

Figure K1-2. DUF_6 cylinders stacked for storage at a DOE gaseous diffusion plant site (DOE 2001).

As of January 2007, the following amounts existed at each site as government legacy material:

- Portsmouth Gaseous Diffusion Plant site: 250,517 metric tonnes depleted uranium hexafluoride ($MTDUF_6$)
- Paducah Gaseous Diffusion Plant site: 436,369 $MTDUF_6$.

The United States Enrichment Corporation (USEC) owns over 35,000 $MTDUF_6$ mostly at Portsmouth. The total is over 722,000 $MTDUF_6$. The U-235 isotopic assay of this material varies from 0.15 to 0.55 wt% U-235. (The tails assay for operation of the enrichments plants is determined by balancing feed [ore mining and milling + U_3O_8 to UF_6 conversion] costs against the cost of enrichment [separative work units (SWUs)]). Figure K1-3 shows how the U-235 assay of the depleted UF_6 inventory is distributed.

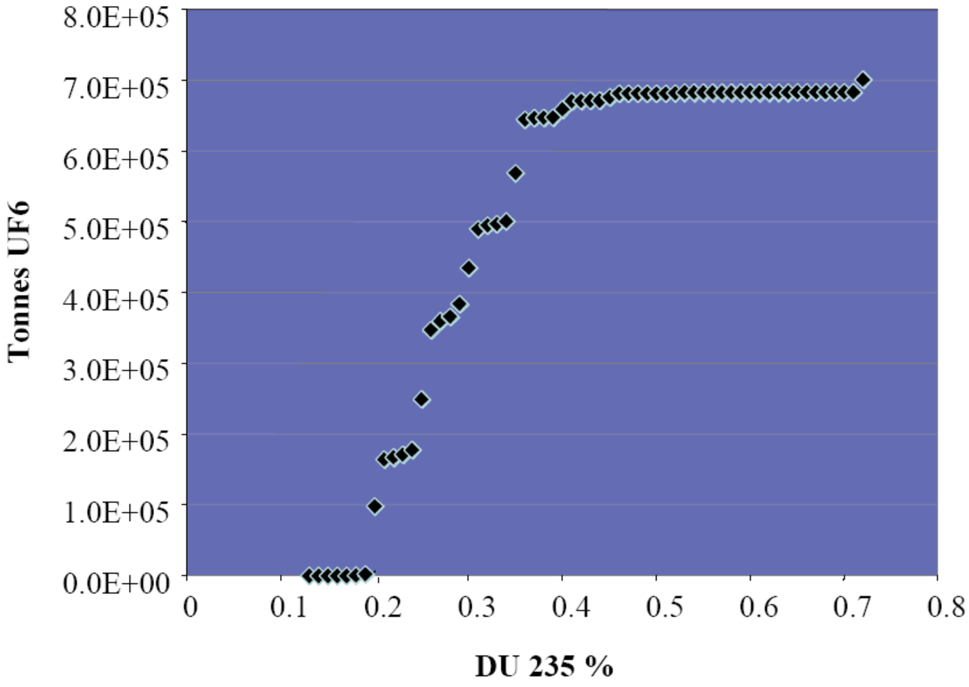


Figure K1-3. Cumulative distribution of DUF_6 metric tonnage versus U-235 assay.

The normal enrichment plant practice is to collect the DUF_6 from the GDP tails withdrawal systems in 14-ton steel-walled cylinders that are stacked and stored on the enrichment plant site. (This is still being done by USEC at the Paducah Gaseous Diffusion Plant, the only U.S. GDP operating today.

USEC's tail cylinders represent nongovernment USEC DUF_6, which is not considered part of the government legacy described above, but will in the future be treated by the same chemical processes as the government material.) In the early 1990s, some of the older legacy DUF_6 cylinders were found to be so degraded and corroded that oxidation compounds formed by the reaction of solid UF_6 with wet air were found on the surface of the cylinders. At this point, Congress and DOE realized that a serious water and air contamination problem could ensue if the DUF_6 storage problem were not fixed. (UF_6 vapor, produced by ambient or elevated temperature sublimation of solid UF_6, and moist air react to form gaseous hydrogen fluoride [HF, a very toxic and corrosive material] and UO_2F_2, a white, slightly radioactive powder that becomes airborne.) In the late 1990s, a program was initiated by the DOE Office of Nuclear Energy (DOE-NE) to begin looking at the options for long-term disposition of this legacy, including consideration of the best and safest chemical forms for future storage/disposal. These studies also included looking at possible beneficial uses of the depleted uranium, such as shielding for accelerator or nuclear facilities, containers for spent fuel or high-level waste, the diluent for mixed oxide fuel, re-enrichment, and semiconductors, with the realization that such uses may only utilize a fraction of the DOE inventory. The official DOE Web site for DUF_6 has links to many DUF_6-related documents of use to the interested researcher (DOE 2001).[a]

It soon became apparent that the best route for permanent disposition of legacy DUF_6 is to convert it to a more stable and less-toxic chemical form, such as an oxide, and to isolate this form from the environment. In 2001, the U.S. nuclear and chemical industries were given the opportunity to propose and bid on the management, conversion, and disposition of the DOE-owned DUF_6 legacy material. Uranium Disposition Services, LLC (UDS), a consortium of three firms (Framatome-ANP, Duratek [now part of Energy Solutions, and Burns and Roe) was selected (DOE 2002) in 2002 to design and construct two DUF_6 to DU_3O_8 plants (one each at Paducah and Portsmouth [see Figure K1-4) and to contract for the disposition of the DU_3O_8 product in the same manner as is done for low-level waste (LLW). (Note that the conversion product is more accurately described as UOx [x~2.4 to 2.6], because there is some variation in stoichiometry.) The likely shallow burial resting place for this DU_3O_8 material, now to be packed in the old but washed-out UF_6 cylinders, was at that time designated to be Envirocare (a private firm now also part of the Energy Solutions consortium) in Clive, Utah, or the Nevada Test Site (NTS, a government site) near Beatty, Nevada. Construction of the two DOE-owned conversion plants commenced on July 31, 2004. More recently, it has been determined that DOE's LLW facility at the Nevada Test Site is the more economical and environmentally acceptable location for disposal of the DOE-legacy derived U_3O_8 (DOE 2004a and DOE 2004b).[b,c]

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[a] Author's note on beneficial uses: Early in the days of atomic energy, it was recognized that U-238, the isotope that constitutes over 99.29% of DU, could be readily converted in a reactor to the fissile isotope Pu-239. In fact, this is exactly what was done with the DU targets inserted into the U.S. plutonium production reactors that were located at Hanford and Savannah River for defense purposes. A fast neutron reactor fueled with plutonium could eventually produce enough new plutonium by irradiation of U-238 blanket assemblies that the fuel cycle would be self-sustaining with no requirement for new fissile material. Alvin Weinberg, former Director of Oak Ridge National Laboratory, once pointed out that the potential energy available from all the uranium in the DUF_6 cylinders in the storage yard of the nearby Oak Ridge Gaseous Diffusion Plant (K-25 or ORGDP) was the same as that available from a significant fraction of the U.S. reserves of coal.

[b] Selection of NTS. Personal communication from Phillip McGinnis, ORNL DUF_6 Program Manager; April 2007.

[c] Technical note: The two UDS facilities under construction will have to handle some DUF_6 that is slightly contaminated with the higher actinides plutonium and neptunium plus some fission product Tc-99. These contaminants were introduced into the GDP tails when the U.S. Atomic Energy Commission fed slightly impure reprocessed uranium into the GDPs. These two UDS plants are incorporating special safety features and procedures at some additional costs. Any new DUF_6 conversion plants supporting new enrichment capacity are not likely to have to deal with this problem, because virgin or unreprocessed uranium will only be fed to the enrichment facilities. Tc-99 and transuranic nuclides are potential problems for only a few cylinders after the DUF_6 is removed. Transferable Tc-99 and transuranic waste offer negligible additional radiological hazard in the proposed Portsmouth and Paducah processing plants and in the uranium oxides produced.

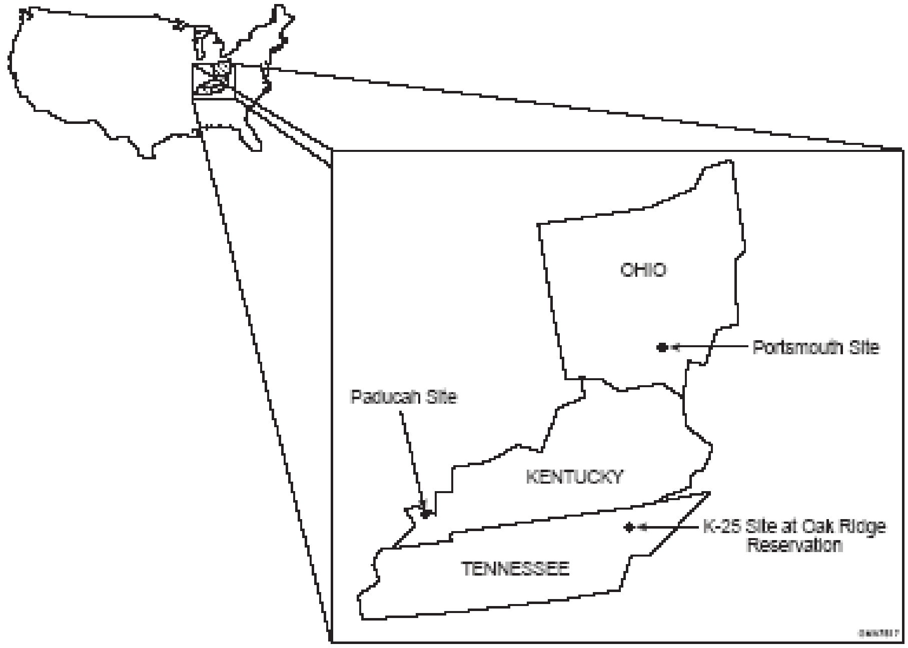

Figure K1-4. Source locations of U.S. DUF_6 stockpile (all DUF_6 now at Paducah and Portsmouth) (DOE 2001).

Currently these two facilities will handle only DOE legacy DUF_6 during most of their operating lives and that the same environmental/safety liability problem remains for the existing USEC DUF_6 stockpile and any future DUF_6 produced in new U.S. enrichment plants using UF_6 as feedstock. Disposition of the future DUF_6 stockpile was the major public licensing issue (NRC 2004) for the National Enrichment Facility, a Nuclear Regulatory Commission (NRC)-licensed (NRC 2003) gas centrifuge enrichment plant under construction in Hobbs, New Mexico, by the private firm Louisiana Energy Services, LLC (LES). Disposition of DUF_6 will also need to be addressed by the proposed NRC-licensed American Centrifuge Plant to be constructed by USEC at DOE's Portsmouth site (NRC 2004) and AREVA's proposed gas-centrifuge Eagle Rock Enrichment Facility to be built near Idaho Falls, Idaho.

Being aware of DOE's problems at the three legacy GDP sites, stakeholders in the southeast New Mexico (location of LES plant) area do not want long-term storage of DUF_6 at the enrichment plant site. Because of such future enrichment commercial activity, it is very likely that new DUF_6 conversion facilities, such as those under construction by UDS at Paducah and Portsmouth, will have to be constructed either at or nearby the new enrichment plant sites, as add-on or schedule-extension capacity at Paducah or Portsmouth, or at new, Greenfield locations. It is very likely that private firms will finance, construct, and operate such plants, as opposed to the government contractor arrangement at Paducah and Portsmouth, which handles mainly government-owned materials. In fact in February of 2005, LES and AREVA signed a memorandum of understanding that could lead to the possible construction of a private deconversion plant in nearby West Texas to support the proposed New Mexico enrichment facility (NEI 2005).

Additionally, International Isotopes of Idaho Falls, Idaho (INIS) has chosen Lea County, New Mexico as the site (640 acres) for the nation's first private depleted uranium deconversion and fluorine extraction facility (Platts 2009). This private facility will process ~7,000 MTU/yr and will be an NRC-licensed facility. Its nearness to the LES Enrichment Facility makes it likely that it will seek the business of handling LES tails. Its Idaho connection also makes it a candidate to handle future Eagle Rock (AREVA) tails. No costs for the project have been given, and the method of financing is still being evaluated by INIS (Earth Times 2009). However, compared to other fuel cycle steps this one has relatively low technical, safety, and environmental risk; hence, total privatization should not be difficult.

A proposed laser-based enrichment process utilizing UF_6 as the feed material, such as the SILEX process being considered for deployment by General Electric near Wilmington, North Carolina will have the same tails disposal issue.

It is also very likely that this step will become mandatory in the front end of any fuel cycle where UF_6-based uranium enrichment is involved. This means that a definite market for this service will exist. To eliminate or minimize transportation costs, the enricher might want to locate such conversion facilities adjacent to or as part of the new enrichment plant. France already does this with their DUF_6 to DU_3O_8 W-Plant located immediately adjacent to Cogema/Eurodif's Pierrelatte "Georges Besse" Gaseous Diffusion Plant. As mentioned earlier, LES is also known to be discussing DUF_6 conversion/disposition possibilities with existing nuclear and chemical firms. USEC, for their existing GDP and future gas centrifuge capacity at Portsmouth (American Centrifuge Plant), is very likely to contract with UDS for new conversion capacity at Portsmouth or queue their cylinders for conversion at the government facility after the legacy DUF_6 campaign is complete. (Note that federal law allows a government DUF_6 conversion plant to process nongovernment DUF_6 on a total cost-recovery basis. In fact, DOE has provided a unit cost estimate to LES for the provision of such services [Platts 2005a].)

K1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The DUF_6 conversion is a dry (nonaqueous) process that involves fluidized bed reaction of UF_6 vapor with steam and hydrogen to produce a flowable UOX powder, which is mostly U_3O_8. The process basically occurs in two steps:

$UF_6\ (v) + H_2O\ (v) \rightarrow UO_2F_2(s) + 4HF\ (v)$

$3UO_2F_2 + H_2 + 2H_2O \rightarrow U_3O_8 + 6HF$

where

(v) = vapor

(s) = solid

The hydrofluoric acid (HF) by-product has some value if it can be sold to an industrial user who is not concerned with the small (<10 ppm) amount of uranium that might be present in the HF. A nuclear user, such as a U_3O_8 (yellowcake) to natural UF_6 converter, might be interested in this HF. According to the 2007 DOE report UDS and Solvay Fluorides signed an HF sales agreement for an undisclosed amount of HF in May 2006. If all the HF cannot be sold, it may be necessary to convert the HF to stable, slightly uranium-contaminated CaF_2, which is relatively nontoxic, but which itself must be dispositioned, most likely by packaging and shallow burial as LLW. This disposal issue is also discussed in the 2007 DOE report (DOE 2007).

K1-3. PROCESS SCHEMATIC

The basic UDS process and material balance, as shown from the Site-Specific Environmental Impact Statement for Paducah (DOE 2004), is shown on Figure K1-5 and described in Table K1-1. The process is very similar to the one used at the Framatome fuel fabrication facility at Richland, Washington, which converts enriched UF_6 to enriched UO_2 for use in light-water reactor (LWR) fuel (see Module D1). However, the throughput of the proposed DUF_6 plant is orders of magnitude higher than that of the Richland EUF_6 to EUO_2 plant.

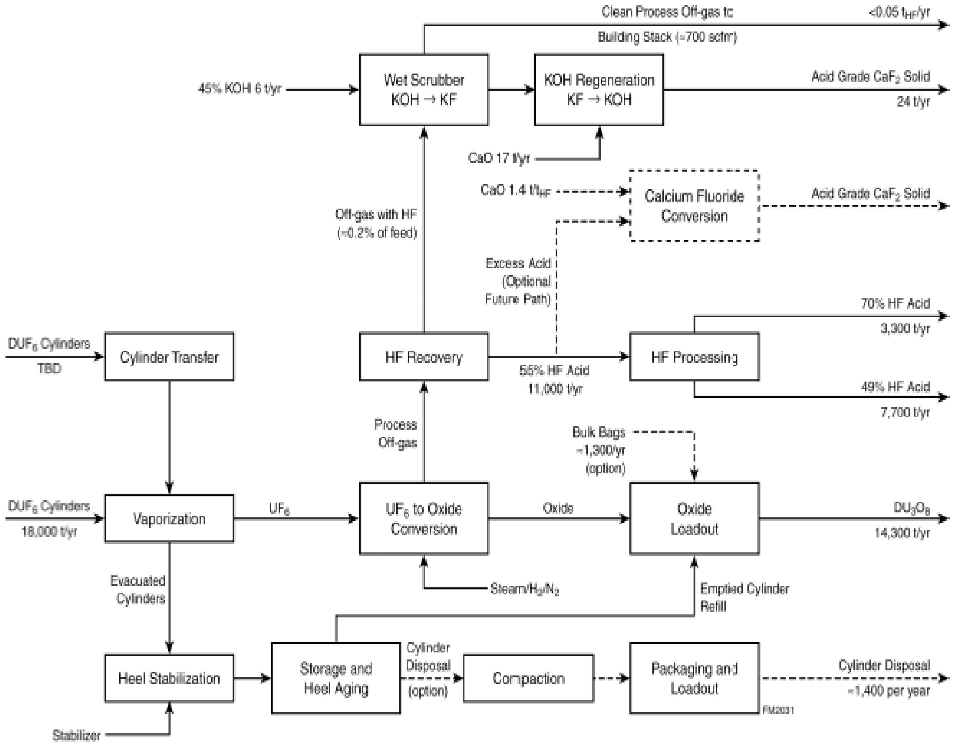

Figure K1-5. DUF_6 to DU_3O_8 conversion process (DOE 2007).

Table K1-1. Technical data for Paducah Uranium Disposition Services conversion facility (DOE 2007).

Parameter/Characteristic	Value
Construction start	2004
Construction period	2 years
Start of operations	2006
Operational period	25 years
Facility footprint	10 acres (4 ha)
Facility throughput	18,000 t/yr (20,000 tons/yr) DUF_6 (≈1,400 cylinders/yr)
Conversion products	
Depleted U_3O_8	14,300 t/yr (15,800 tons/yr)
CaF_2	24 t/yr (26 tons/yr)
70% HF acid	3,300 t/yr (3,600 tons/yr)
49% HF acid	7,700 t/yr (8,500 tons/yr)
Steel (emptied cylinders, if not used as disposal containers)	1,980 t/yr (2,200 tons/yr)
Proposed conversion product disposition (see Table 2.2-2 for details)	
Depleted U_3O_8	Disposal; Envirocare (primary), NTS (secondary)[a]
CaF_2	Disposal; Envirocare (primary), NTS (secondary)
70% HF acid	Sale pending DOE approval
49% HF acid	Sale pending DOE approval
Steel (emptied cylinders, if not used as disposal containers)	Disposal; Envirocare (primary), NTS (secondary)

[a] DOE plans to decide the specific disposal location(s) for the depleted U_3O_8 conversion product after additional appropriate NEPA review. Accordingly, DOE will continue to evaluate its disposal options and will consider any further information or comments relevant to that decision. DOE will give a minimum 45-day notice before making the specific disposal decision and will provide any supplemental NEPA analysis for public review and comment.

K1-4. MODULE INTERFACE DEFINITION

Front-end interface. The cost of storage of DUF_6 at enrichment plant sites should be assigned to the enrichment plant operational costs. If DUF_6 conversion is to be located away from the enrichment plant site, the cost of DUF_6 transportation (in 14-ton cylinders) by rail or truck should be assigned to the DUF_6 to DU_3O_8 conversion facility. Experience shows that these transportation costs are relatively small.

Back-end interface. Disposal of the DU_3O_8 powder resulting from conversion has its own regulatory and procurement issues. UDS or any other conversion plant owner will need to contract with an LLW disposer, such as Envirocare or NTS, for shallow burial disposition. The converter must also appropriately package the powder to minimize water intrusion and allow safe transportation. Both purchased containers (such as supersacks or drums) or emptied, washed, and adapted DUF_6 cylinders were being considered for this purpose. The latter option has been deemed economically superior. The tipping fee for this material is likely to constitute a significant percentage of the unit cost ($/kgU) of the overall conversion/disposition life cycle. Because tipping may be charged on a $/volume basis, the conversion process will need to achieve an as reasonably high as possible bulk powder density that can accommodate transportation and tipping requirements. The volumes of material (DU_3O_8) projected from a likely U.S. uranium enrichment/conversion enterprise will likely require the opening of new or the major expansion of LLW near-surface disposal capacity (Module J). (Note: Costs of our new LLW capacity specifically for DU_3O_8 burial should be assigned to this step [Module K1 and not Module J]). The near surface disposal will allow the eventual recovery of this depleted-uranium material if the breeder reactor plutonium economy ever evolves in the distant future and DU would be needed for target fuel assemblies.

The regulation of the shallow geologic disposal as LLW of large amounts of bulk DU_3O_8 or other uranium forms remains an issue. The very large inventory of this material and its concentration in one area means that in the distant future (thousands of years), after the cylinders enclosing the insoluble DU_3O_8 corrode away, the burial area will be a large producer of radon gas from the uranium decay chain. This gas will easily diffuse through the dry soil cap. In order to prevent this occurrence, a deeper or more robust engineered capped burial site or non-corrodible containers will be needed. The NRC investigated the geologic disposal issue as part of the LES National Enrichment Facility licensing process, and a ruling was recently issued. In a March 2009 ruling (Salt Lake Tribune 2009) the USNRC declared DU-materials from the commercial nuclear industry (NRC-licensees) to be Class-A LLW, thus they could be buried in a commercial LLW facility such as that owned and operated by Energy Solutions in Clive, Tooele County, Utah. To respond to stakeholder concerns, however, the Commission, based on Staff recommendations (NRC 2008) agreed to hold rulemaking hearings on this material (Federal Register 2009). This additional regulatory attention is warranted because of the large quantities of tails that are likely to be generated by NRC-licensed U.S. enrichment plants and the fact that DU's specific activity actually increases with time due to the long-term buildup of radioactive daughter products, including radon. (Figure K1-6 shows how these U-238 daughter products build in with time, just as they did with the original uranium ore.) DU compounds, such as DU_3O_8 are also in a very "dense" or concentrated form compared to most LLW, which is often equipment or substances with surface contamination only. It is possible that the NRC could rule that special packaging and/or burial precautions need to be taken such that radon release and dispersal does not pose a hazard to local populations. Low permeability liners or clays might be required in conjunction with the normal shallow burial process. Others have suggested that disposal in deeper locations, such as old mines, might be appropriate. In any case, some retrievability should be maintained, since this DU material may become the nuclear fuel (U-238 transmuted to Pu-239) of the future when breeder reactors are deployed.

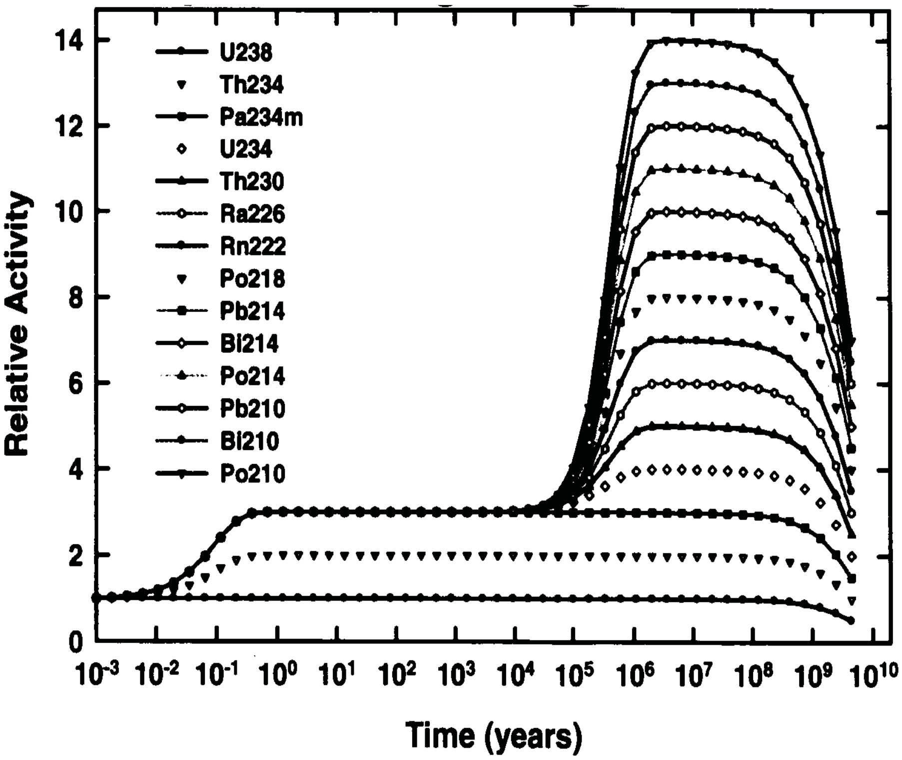

Figure K1-6. Buildup of decay products from depleted uranium as a function of time.

If stringent radon isolation and control is required, the unit disposition cost associated with more robust packaging and geologic disposal would be expected to rise significantly. NUREG/BR-0216 discusses the storage and disposal of LLW (NRC 2003).

K1-5. MODULE SCALING FACTORS

The UDS Paducah facility described above will have four parallel conversion lines in a single building (each line around 5,000 tons DUF_6 per year). It is now anticipated that these four lines will be replicated at Portsmouth. Up to this single-line capacity, a capital cost scaling exponent of 0.6 is probably appropriate. Beyond 5,000 tons per year, a 0.9-capital cost scaling factor can account for multiple lines in a single building. Operational costs are manpower intensive, and a scale factor of 0.9 for large plants should apply.

K1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Publicly available cost information on this new step of the fuel cycle has evolved over the last 8 years. The Paducah GDP formerly made depleted uranium compounds and metal from DUF_6 for defense applications from the mid-1950s until the 1980s; however, the costs and other technical information on this operation are still classified. Among the sources of cost data are initial cost studies for the former DOE-NE DUF_6 program (now a DOE Environmental Management [EM] project), DOE-UDS contract information, and proceedings related to the NRC licensing of the LES National Enrichment Facility. All this cost information is essentially in the form of projections. No such facilities are yet operating on a large scale in the U.S.; hence, no historical data are available. (The first DOE-UDS conversion operation is slated for late 2009.) The cost figure of merit of interest for this step is the unit cost in \$/kg U (as DUF_6) converted and dispositioned for plants of capacities in the several thousands of metric tons of uranium per year (MTU/yr). Table K1-1 shows the throughput and other relevant technical data for the proposed Paducah facility. (The Portsmouth facility will be nearly identical.) Such plants consist of multiple identical process trains or lines of a few thousand MTU/yr each, thus any plant scaling/expansion beyond one line is achieved by line replication. In 2002, capital costs for such plants were expected to be in the $100+ million each range, which is relatively low for nuclear facilities with similar footprints or process areas.

The 1997 Livermore report (Elayat et al. 1977) contains the first economic analysis projection performed for DOE DUF_6 management after the program was formed in DOE-NE. It looked at several end products (such as U, UO_2, U_3O_8, and the sale of by-product HF). Costs were expressed as lump-sum discounted life-cycle costs. The closest option considered by Lawrence Livermore National Laboratory to the one finally selected by DOE in 2002 is that of dry conversion to U_3O_8 followed by burial in shallow trenches. It was assumed that 28,000 MTU/yr be processed for 20 years in a single large privately owned and financed plant. At a discounted (7% real) life-cycle cost, including design, construction, operations, and decommissioning of $758M for the whole conversion/disposal program (not including revenues from by-product sales, which decrease the net unit cost by a few percent), a projected unit cost of $5.38/kgU was calculated by Oak Ridge National Laboratory from the Lawrence Livermore National Laboratory data in August 2004.

As will be seen, this unit cost is higher than the price derived from the life-cycle costs proposed by the winning bidder for the DOE legacy work. However, the latter considered revenues from HF sales, a smaller building and throughput, no financing charges (government funds to construct), and very competitive negotiated disposal fees (for shallow burial of U_3O_8). Therefore, the analyst for Module K1 believes that the calculated $5.58/kgU ($6/kgU in 2007 $) estimate is a reasonable projection in light of the lower Fiscal Year (FY) 2001 unit cost estimates made for the DUF_6 to DU_3O_8 government-owned plants now under construction at Paducah, Kentucky, and Portsmouth, Ohio.

The $5+/kgU projected cost is supported by another fuel cycle study (Bunn et al. 2003). One of the contentions brought up by interveners is the disposition of DUF_6 tails from the proposed LES National Enrichment Facility to be located in southeastern New Mexico. The interveners question the validity of the $5.50/kgU cost of disposal number put forth by LES in the licensing documentation (NRC 2003) submitted to the NRC. (This was one of the admissible contentions brought forth by the interveners). Oak Ridge National Laboratory believes a number around this figure to be a credible projection for a privately owned and financed facility. It is surmised that LES, a private corporation, probably based their calculation of this unit cost on what it would cost for them to do these operations (deconversion of 7,800 $MTDUF_6$/yr) as part of the enrichment step (i.e., as a fully amortized add-on facility to their gas-centrifuge plant). If the $5.5/kgU unit cost was rolled into the price of enrichment, the latter $/SWU price would have to be increased on the order of 10%. Because of the highly competitive enrichment market, LES's reluctance to commit to the additional step of DUF_6 conversion/disposition at this time is not unexpected. In a March 2005 letter (Platts 2005a), DOE indicated that its projected charge to LES to perform this service would be $3.34/$kgDUF_6$ or $4.91/kgU in a government facility based on a pro-rata share of the capital and operating costs of the two UDS facilities under construction. NRC found another LES estimate of $4.68/kgU to be reasonable (Platts 2005b). In a June 2005 agreement with the State of New Mexico, LES is being required to put up a bond of $7.15/kgU (Neary 2005). This unit cost is likely to be closer to the unit cost that will ultimately be realized later in this decade, especially as costs for the UDS facilities surpass the original estimates.

Antinuclear groups such as Institute for Energy and Environmental Research (Makhijani and Smith 2005a) suggest that even this is too low a value, and that values as high as $30/kgU should be used for the bond (Makhijani and Smith 2005b). Such a high value would imply that shallow burial of the DU_3O_8 would not be allowable because of radon considerations and that deep burial in a mine or geologic repository would be required. Hopefully, all nuclear fuel cycle nations with enrichment plants will ultimately agree that DUF_6 conversion/disposition is environmentally necessary and will add the needed DUF_6 conversion/disposal capacity, which will eventually level the playing field for enrichment pricing. A new path for DUF_6 disposition is now being pursued (i.e., re-enrichment of the tails to produce natural assay feed). Rising uranium ore and conversion prices have convinced the Bonneville Power Administration that such a scheme is economic (Platts 2005c). The economics of tails re-enrichment will be discussed in more detail in Module C and is also the subject of ongoing study by DOE, as indicated by recent issuance of a uranium management plan (DOE 2008).

The unit cost from a proposed UDS facility can also be roughly calculated from contract announcement (DOE 2002) information that mentions the \$5.58/kgU value of the contract (2002 dollars), the 700+ thousand metric ton inventory (to be processed over 20 years), and the need to design and construct the two plants in 3 years and operate them for 5 years. (Additional years will be under a new contract.) The following Oak Ridge National Laboratory-generated spreadsheet (see Table K1-2) was used in the early part of this decade to project the unit cost from the proposed Paducah government-owned/contractor-built and operated conversion facility.

The calculation assumes a low (3.8%) government real discount rate and assumes that the 5-year constant dollar operating costs are maintained over the additional 15 years of plant production. The capital cost is assumed to be amortized over the 20 years of operations. Although the government does not amortize in the same sense as a private enterprise, an imputed amortization can be used to calculate the same unit cost that would be derived by discounting government cash flows at the same low discount rate.

As expected, a government financed plant was projected to convert and disposition DUF_6 at a lower unit cost, (i.e., a projected \$3/kgU unit cost as opposed to \$5+/kgU for the private facility). For future fuel cycles, it should be assumed that private industry will finance, own, and operate such facilities. With process improvements and operational learning, a constant dollar price of \$5/kgU for the private facility should certainly be realizable if deployment risks are minimized and shallow U_3O_8 burial is allowed. This cost is in line with Bunn, et al.'s estimate (Bunn et al. 2003) for producing fast reactor blanket feed material, presumably DU metal or DUO_2 feed to the fuel/blanket fabrication plant, of \$6/kgU. The earlier DOE/Lawrence Livermore National Laboratory studies show that producing DU metal or DUO_2 is somewhat more expensive than producing DU_3O_8. This is because batchwise reduction operations are needed as opposed to the continuous process for DU_3O_8 production.

It should be noted that as of summer 2009 the two UDS plants are ending their construction phase and beginning start-up procedures. The actual construction cost has been reported (IPA 2009) to be nearly \$600M for both plants, an amount nearly double that (~\$300M) projected at the time design was initiated. If the government were to amortize this higher capital cost across future plant production, it is likely to add at least \$1/kgDU to the unit production cost.

Another very useful "actual" cost number relevant to DU disposition is that for the packaging, transportation, and disposal of 7 million pounds (1.29 million kg Th) of U.S. government surplus thorium nitrate pentahydrate [$Th(NO_3)_4{*}5H_2O$] powder. This material has radiological and morphological properties very similar to natural or depleted uranium, and was formerly warehoused at the Department of Defense (DOD) depots in Curtis Bay, Maryland and Hammond, Indiana. In the period 2004–2005 this material was repackaged, transported, and disposed by geologic shallow burial at the DOE Nevada Test Site. (The Nevada Test Site is also likely to receive DU_3O_8.) The cost for this entire effort was \$15M in 2003\$ or a unit cost of \$11.6/kgTh. In 2008 dollars this is \$13.5/kgTh. Documentation of this activity can be found in Hermes 2001, Hermes 2003, Hermes 2006, and DOD 2005. The disposition rate (MT/yr) for this material is over an order of magnitude smaller than that projected for DU. Therefore, it is not surprising that a somewhat higher unit cost for disposing of thorium was experienced as compared to the projected unit cost of disposition of DU materials. Further discussion of thorium can be found in Modules A2 and D1-8 of this report.

K1-7. LIMITATIONS OF COST DATA AND OTHER CONSIDERATIONS

The following considerations are relevant to depleted-uranium materials in the fuel cycle:

1. If non-UF_6 based enrichment processes are eventually realized, such as atomic vapor laser isotope separation (AVLIS) or chemical exchange (CHEMEX), the chemical form of DU from the enrichment plant will be different. Conversion costs for metal DU from AVLIS, for example, are likely to be somewhat higher than for conversion of DUF_6. In Table K1-2, all costs are limited to DUF_6-based processes.

2. If reprocessed uranium is ultimately fed back to enrichment plants, a possibility from closed fuel cycles, very small amounts of actinides and fission products might contaminate these “secondary” tails. Dealing with this problem and its safety consequences could cause a unit cost increase for DUF_6 conversion/disposal. Future experience with the UDS (Paducah and Portsmouth) plants should provide better cost data, since some of the U.S. GDPs handled RU in periodic re-enrichment campaigns and some DUF_6 cylinders are likely to contain such minor constituents.

   The 2007 constant dollar unit conversion/disposal cost would be ~\$3.2/kgU.

3. Unit conversion/disposal costs for natural assay or enriched UF_6 up to approximately 0.9% U-235 are likely to be close to those for DUF_6. (It is unlikely one would dispose of these materials unless irradiation or contamination has driven the fission product, transuranic, or U-236 levels up to a level at which recovery of pure uranium products would not be economic.) Up to this 0.9% U-235 assay, nuclear criticality under light-water moderation is not a concern for processing or disposal. A UREX-based reprocessing plant (Module R1) will produce such low enrichment U products as part of its multiple output streams (see Module K2).

4. The disposition of weapons-grade plutonium by use of LWRs burning mixed oxide fuel may use 0.5 to 2% of the government DUF_6 stockpile. DUO_2 is the preferred diluent for the plutonium in LWR mixed oxide (MOX) fuel (i.e., ~96% DUO_2 and 4% PuO_2). A conversion facility will be needed to produce DUO_2 from DUF_6 for the U.S. plutonium disposition program, and Framatome (AREVA) has proposed such a facility for its Richland, Washington facility. The DUO_2 powder produced will have special quality assurance and fuel qualification requirements far exceeding those of dry-processed U_3O_8 or UO_2 powder destined for disposal. A “wet” or “dry” processed DUO_2 powder, such as from the Framatome ammonium diuranate (ADU) wet process, that is capable of meeting the present MOX fuel irradiation specification for the U.S. plutonium disposition program will have a unit cost considerably higher than the \$5/kgU proposed for dry-processed U_3O_8, which will ultimately be buried. The conversion cost for this special MOX-grade powder will likely be in the \$30 to \$70/kgU range. This cost is eventually absorbed in the overall cost of the MOX fuel (Module D1-2). DOE is presently in the process of seeking fuel fabricators who might want to provide this DUO_2 on a contract basis.

5. Another beneficial use that would consume much of the DUF_6 inventory is the use of DUO_2 rough pellets as filler material in the final disposition spent fuel containers for the proposed Yucca Mountain repository. Since over eons, Pu-239 decays to U-235, the depleted uranium material could isotopically dilute any leached U-235 and prevent future repository criticality. In essence, such an application would be rejoining the U-238 with the remaining unfissioned U-235 (in the spent fuel) from which it was originally separated. This concept is discussed in Forsberg 2000 and Forsberg and Doyle 2006, but is not presently part of the baseline Yucca Mountain spent fuel repository program. The author is not aware of any cost studies on this concept. An INL study (Hertzler and Nishimbo 1994) reports that DU use in casks would cost \$22.80/kg UF_6.

Table K1-2. Unit DUF_6 conversion/disposal cost from a government plant.

Proposed Government DUF6 Conversion Facility at Paducah		
Plant annual capacity	12100	MTDU/yr
Economic life	20	yrs
Design and permitting cost	16	$M
Site-related costs	10	$M
Facility construction cost	84	$M
Total base capital cost including contingency	110.0	$M
Imputed interest during construction (2 yrs to construct)	5.5	$M
Total capital cost (2002$)	**115.5**	$M
Annual ops cost breakdown:		
Conversion plant operations	15.6	$M/yr
U3O8 packaging/disposal	10.4	$M/yr
Total annual operations cost	26.0	$M/yr
Operations contribution to levelized cost of product/service	2.15	$/kgU
Discount rate for government project (real)	3.80%	
Capital recovery factor (fraction per yr of ops)	0.0723	
Annual payments to recover capital cost of plant over life	8.35	$M
Capital portion of unit product cost	0.69	$/kgU
Total levelized product cost (2002$)	**2.84**	**$/kgU**
In 2004$:	**3.0**	**$/kgU**
Effect on Enrichment Price:		
W/P ratio for reload PWR enrichment (3.78% U-235)	7.46	
SWU/P ratio for same (P=1)	4.86	
Additional conv/disp $ to produce 4.86 SWU	21.18	$
Addition to SWU price to cover deconversion/disposal:	4.36	$/SWU

6. If uranium ore prices rise significantly and SWUs remain cheap, re-enrichment of DUF_6 makes eminent economic sense. The Russians are already doing this with DUF_6 from Urenco's European Centrifuge Enrichment plants (Diehl 2007). Russian SWUs from fully amortized centrifuge plants are available at a very low cost. USEC has also recently requested that DOE make available its higher assay tails for re-enrichment at their Paducah facility (Nuclear Fuel Cycle Monitor 2008). At 2007 EUF_6 prices, with their high U_3O_8 component, USEC could realize significant profit from the use of

this essentially free tails feed material, since the costs of additional enrichment from ~0.4% U-235 to 0.71% U-235 (natural feed equivalent) are comparable to the purchase today (at over $130/kgU) of converted U_3O_8.

7. An unfavorable ruling from the NRC or an NRC ruling requiring stringent radon mitigation measures on shallow burial of DU_3O_8 at commercial LWR disposal sites, such as Envirocare, could significantly impact the unit cost, because a more expensive burial solution would be needed. Such a ruling might force burial at a non-NRC regulated site such as DOE's Nevada Test Site (Makhijani and Smith 2005b).[d] Even at a government site, such as Nevada Test Site, some radon amelioration measures are likely to be required. As mentioned earlier, NTS is now the preferred disposal option.

In general, the DUF_6 conversion/disposal step of the fuel cycle can be placed in the viable-commercial category of technology readiness.

K1-8. COST SUMMARIES

No DUF_6 disposition life-cycle cost data are publicly available in the Advanced Fuel Cycle standard code-of-accounts format. It is likely that UDS has such data in their conversion facility detailed design in the work breakdown structure or code-of-accounts system. However, it is available only to their DOE-EM customer.

In summary, a commercial (privately financed) conversion/disposal program is projected to disposition DUF_6 at $6.00/kgU in 2008 dollars). And a government program is projected to disposition the same material at $4–$6/kgU, depending on discount rate assumptions. Both of these assume that shallow burial as LLW is permissible and readily available in the near term. For reference purposes, the private plant with technology improvements is the most likely path for non-legacy DUF_6 in future fuel cycles. In determining a "selected value" for Table K1-3, the author has decided to assume that some cost, schedule, and performance risks are real, and that when the plants are completed and disposal contracts signed, the price will be more like $11/kgU. Recent experience with DOE projects, such as the UDS Deconversion Plants, the Savannah River MOX Fuel Fabrication Facility, the Hanford River Protection Project, and the Tritium extraction facility, indicated that "in-construction" projections of or completed facility "actuals" of capital and operating costs usually significantly exceed early preconstruction cost projections. The $11/kgU selected unit cost value should reflect such conversion facility cost escalation and likely prolonged regulatory and contracting difficulties with DU_3O_8 shallow burial. Ultimate project completion and success, however, is still assumed.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table K1-3. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The triangular distribution based on the costs in the WIT Table is shown in Figure K1-7.

K1-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Because of the conventional nature of their technology, no such calculations were performed.

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[d] Personal communication from D. W. Lee, Oak Ridge National Laboratory.

Table K1-3. Cost summary table for DUF_6 conversion/disposal from privately funded plant.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$6/kgU for 12,000–30,000 MTDU/yr Capacity	$6/kgU	$50/kgU	$11/kgU
	Technology improvements, by-product sales revenues. No difficulty with DU_3O_8 burial.	Severe regulatory difficulties with shallow DU_3O_8 burial. Deep mine or repository burial required (Makhijani and Smith 2005). Need to dispose of all by-products such as HF and CaF_2 with no revenues. Diehl (2007) reports a cost as high as $110/kgU. This is felt to be unreasonable, since it is of the same order-of-magnitude as spent nuclear fuel disposal (hundreds of $/kgHM).	Assumes increase from reference cost due to typical nuclear project cost growth and anticipated special requirements for shallow burial, such as use of liners. Represents unit cost actually expected. Supported by recent reported UDS cost overrun data.

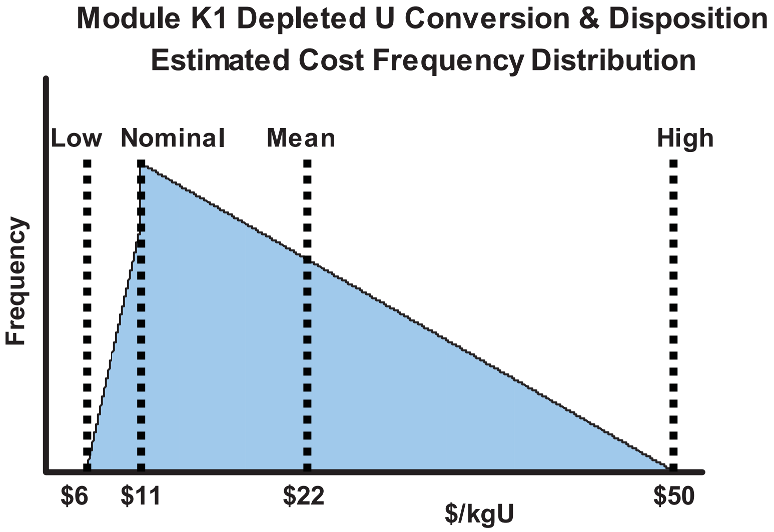

Figure K1-7. Depleted U conversion and disposition estimated unit cost frequency distribution.

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Module K2

Aqueously Reprocessed Uranium Conversion, Disposition, and Possible Recycle

Module K-2
Aqueously Reprocessed Uranium Conversion, Disposition, and Possible Recycle

K2-1. BASIC INFORMATION

For light-water reactor (LWR) fuel cycles and some fast reactor fuel cycles, uranium is the largest resulting constituent of the irradiated spent fuel mass. If it is separated during reprocessing of spent fuel, it is known as “reprocessed uranium” (REPU). For LWR operating on enriched UOX, only a small fraction of the total initial uranium radioisotopes are fissioned or transmuted to other actinides. After discharge from the reactor, typically over 93% of the heavy metal mass (not including zircalloy cladding or fuel assembly structures) is uranium. In the spent fuel pools of U.S. reactors, there is already over 58,000 MTU of this material, which might be ultimately recovered as reprocessed uranium during future reprocessing operations. At first glance it would seem that this reprocessed uranium material could be economically recovered during reprocessing and reused in the fuel cycle. Doing so could reduce requirements for uranium ore and conversion and enrichment services. Realistically, however, there are several factors that affect the “recyclability,” hence the economics, of this uranium and its ultimate path through the fuel cycle. These are:

- The initial U-235 assay of the fuel before irradiation (this is one of the variables that will determine the post-irradiation U-235 assay and the concentrations of other uranium isotopes, such as U-236). Schneider has developed algorithms that allow calculation of the U-235 and U-236 content from the initial U-235 value and the fuel burnup for both PWR and BWR UOX fuel (Schneider et al. 2007). These calculations are based on runs made with neutronics/depletion codes.
- The burnup level of the spent fuel, which also determines the fractions of the various isotopes of uranium in the irradiated fuel. (The higher the burnup, the smaller the ratio of the post irradiation U-235 content to the preirradiation U-235 content.) For example, pressurized water reactor fuel that starts out at 3.5–4.5% U-235 prior to irradiation could end up with 0.5–1.3% U-235 depending on initial assay and burnup. Because of these low postirradiation U-235 assays, any reprocessed uranium would need to be converted to UF_6 and re-enriched before being fabricated into “recycle” LWR UOX fuel for LWRs. (Reprocessed uranium might be more directly used in CANDU reactors. Del Cul et al. discussed this concept in a paper and report and it is presented in a later section below (Del Cul 2007 and 2009). Platt’s 2002 article also discusses some of the technical issues associated with REPU use as LWR fuel burnup increases (Platts 2002).
- The initial U-235 assay and the burnup also determine the amounts of the undesirable isotopes U-232 and U-236 that are formed. Short-lived U-232 has radiologically potent decay daughters such as thallium-208, which complicate reprocessed uranium handling, and U-236 is a neutron poison (absorber), which adversely affects the performance of any new UOX fuel that is produced from reprocessed uranium. The higher the initial U-235 assay and burnup, the more of these undesirable, non-natural radioisotopes are produced.
- The nature and chemistry of the reprocessing scheme (the associated “decontamination factors”) determine the amounts of non-uranium impurities such as fission products (i.e., technicium) and higher actinides, such as plutonium and neptunium, carried over into the reprocessed uranium stream. Aqueous processes, such as uranium extraction (UREX) and plutonium-uranium extraction (PUREX), have higher decontamination factors for separating uranium from fission products and higher actinides. The very low quantities of non-uranium impurities mean that any further handling of the reprocessed uranium stream can be in “contact-handling” facilities, provided that such handling is done quickly before U-232 daughters have a chance to build in. These U-232 daughters peak in

concentration 10 years after irradiation. This module (K2) deals with the options for reprocessed uranium arising from aqueous reprocessing of LWR fuels. It will be seen that costs depend markedly on whether the U-232 daughters must be removed prior to further processing.

Electrochemical molten salt-based processes are possible for the reprocessing of legacy LWR spent fuel; however, the lower decontamination factors for fission products and higher actinides mean that the reprocessed uranium would probably require remote handling during packaging and storage. Module K3 will deal with options for handling the reprocessed uranium arising from the electrochemical reprocessing of LWR and fast reactor oxide or metallic fuels.

- The price of natural uranium, U_3O_8 to UF_6 conversion, and uranium enrichment all affect the economics of reprocessed uranium use. If one or more of these prices are high, as is was the case 2 years ago, the attractiveness of recycling (reconverting, reenriching, and refabricating reprocessed uranium into UOX fuel) versus reprocessed uranium storage or disposal is enhanced. Del Cul et al. describe such sensitivity studies (Del Cul 2007 and 2009).
- Recovery and reuse of REPU in the U.S. and Russia have been part of the military (nuclear weapons) fuel cycle for years. Recovery and reuse of legacy uranium materials are now also part of the U.S. Environmental Management (EM) program designed for remediation of the former U.S. Nuclear Weapons Complex. Some process and cost information from these programs will be discussed later in Section K2-6. Because military programs deal with uranium materials of higher enrichment (>20% U-235) there was very high economic incentive to recover and reuse the reprocessed highly enriched uranium (HEU), which was used originally as naval fuel or production reactor fuel.

An International Atomic Energy Agency (IAEA) technical document (TECDOC) report describes international efforts in the management of reprocessed uranium (IAEA 2007). Based on this document, the nations doing the most in this area are Russia, France, and Japan, which are the nations with the largest LWR fuel reprocessing capability.

K2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Reprocessed uranium in a nitrate solution is separated from fission products and other actinides in an early step in the separations part of the PUREX or UREX aqueous spent fuel reprocessing facility. This large stream can be stored in tanks as a liquid or evaporated to produce dry crystals of uranyl nitrate hexahydrate (UNH). The French LaHague plant already performs such a reprocessed uranium separation on a large scale (Nuclear France 2004 and Trowbridge and Del Cul 2003). The THORP facility, in the U.K. at Sellafield, also has this capability. There are several options for use or disposition of this reprocessed uranium nitrate material:

- **Temporary Storage**. The reprocessed uranium hexahydrate material can be converted to a more stable, solid chemical form and stored until a future decision on its ultimate fate (recycle or geologic disposal) is made. As with depleted uranium (Module K1), the chemical form of dry U_3O_8 powder has been determined to be the most stable and easy-to-handle form for storage. The French convert some of the LaHague reprocessed uranium in this manner and store the U_3O_8 in large (a few cubic meters) steel boxes at a Pierrelatte site warehouse where enrichment tails U_3O_8 are also stored. These reprocessed U_3O_8 boxes are surrounded by enrichment plant tails depleted U_3O_8 boxes, which are less radioactive boxes that act as shielding against the potent gamma radiation building up from U-232 decay daughters.
- **Permanent Geologic Disposal.** The material can be packaged for permanent geological disposal. U_3O_8 is chemically stable; however, robust packaging or grouting of the powder would be needed to reduce fines, prevent leaching of radionuclides, and reduce radon emanation. Near-surface burial of low-level waste-type packages as Class A radioactive waste, such as is proposed for enrichment tails depleted U_3O_8 (Module K1), might not be permissible. The reader should note that even the disposal

[a] A deep or tunneled geologic repository-type environment like Yucca Mountain would be more appropriate, and the heat load associated with this material would be orders of magnitude smaller than for high-level waste or spent fuel. U-234 is the radioisotope that would present the longest range radiotoxicity hazard. U-232 daughters remain a problem for only 300 years. No nation is currently pursuing this permanent reprocessed U permanent disposal option. If such a geologic disposal option is pursued, retrievability of the material would be an advantage, since in the future the fertile uranium content might be needed for breeder reactors. LWR-reprocessing derived DU is just as valuable as enrichment-derived DU for a future breeder fuel resource, and the former adds about 10% more material to the latter in overall resource sustainability terms.

- **Preparation for Recycle as LWR UOX Fuel.** The reprocessing-derived UNH can be converted to a form, such as UO_3, suitable for fluorination/purification (similar to Module B) to reprocessed UF_6 and reenrichment to a U-235 level somewhat above the LEU level required for "virgin" UOX fuel derived from natural uranium (similar to Module C). The extra enrichment is needed to compensate for the neutron absorption by U-236. The reprocessing-derived and re-enriched UF_6 can be refabricated into LWR UOX fuel in a conventional fuel fabrication plant if the small amount of U-232 remaining after purification is isotopically separated in the enrichment process or clean EUF_6 blendstock from elsewhere in the fuel cycle is added. These re-enrichment options are discussed in detail in Module D1-1 (LWR UO_2 Pellet Fuel Fabrication) and in a report by de la Garza (1977). The French (AREVA) sent some of their reprocessed U_3O_8 to Russia (Seversk) for conversion and purification (removal of U-232 daughters), followed by enrichment in a "double cascade" of gas centrifuges, which produce an enriched U-235 product with very low U-232 content. The Russian company, TVEL, fabricates this enriched UF_6 into fuel assemblies, which are burned in reactors in Sweden, Switzerland, Germany, and France (IBR 2006 and 2008). As the prices of enrichment and uranium ore rise, this option becomes increasingly attractive. Only one recycle of reprocessed UOX fuel is presently preferred because of the accumulation of the U-236 "poison" isotope that would occur with multiple recyclings. Note that the U.S. gaseous diffusion enrichment plants in the past have also re-enriched REPU from European customers, as well as re-enriching military REPU from production reactors (Williams 1999 and Diehl 2005).
- **Diluent UO_2 for MOX Fuel.** The reprocessed uranium can be used as the "diluent" for $(Pu,U)O_2$ or $(Pu,Np,U)O_2$ mixed oxide (MOX) fuel for either thermal or fast reactors. This utilization scheme can be accomplished by conversion of the nitrates to oxide and physical blending or by coprecipitation directly from the reprocessing plant nitrate solutions. For Co-Ex reprocessing, this would be the preferred option—only a fraction of the REPU product from LWR fuel reprocessing would be required.

The Consolidated Fuel Treatment Center (CFTC) Engineering Alternative Studies (EAS) utilized a thermal de-nitration process to convert the uranium nitrate solutions from reprocessing to UO_3 powder. The U oxide was packaged in drums containing 400 kg U each. The product could be re-enriched for UOX fuel, used in a MOX fuel or disposed as described above.

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a. Envirocare at Clive, UT has been allowed to accept reprocessing-derived depleted UO_3 from the Savannah River Site (SRS). Since the depleted-U target burnups in the SRS production reactors were extremely low (short irradiation times for Pu-239 production), the amounts of TRU and fission products in this material are low. (Knoxville News-Sentinel 2009)

K2-3. PROCESS SCHEMATIC

Figure K2-1 shows schematically the possible disposition paths for LWR spent fuel reprocessing-derived reprocessed uranium. The paths were described in the subsection above.

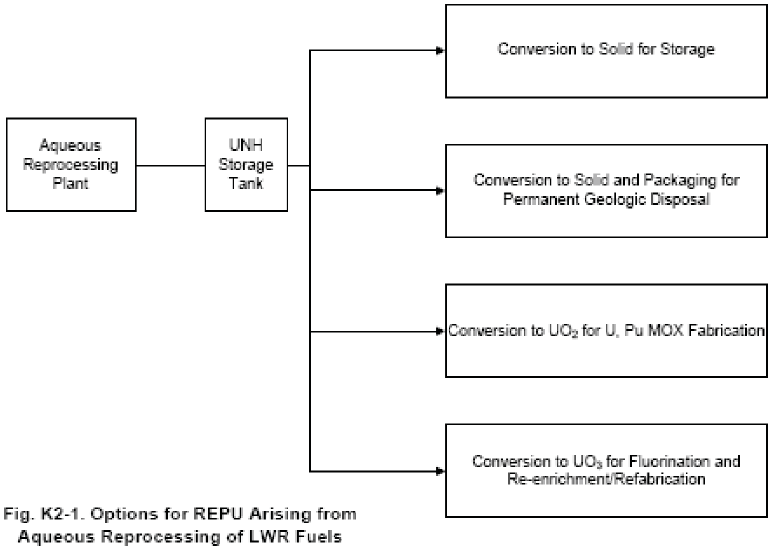

Figure K2-1. Options for reprocessed uranium arising from aqueous reprocessing of light-water reactor fuels.

K2-4. MODULE INTERFACE DEFINITION

Front-end interface. The aqueous spent fuel reprocessing plant (Module F1) represents the front-end interface. The cost analyst should ensure the reprocessed uranium conversions (from stored uranyl nitrate hexahydrate to UO_3, U_3O_8, UF_6, or other form) are not already included in the \$/kgHM cost of the reprocessing steps, since these conversion steps could conceivably be undertaken at the reprocessing complex (as is done in some foreign plants). Transportation of an evaporated solid to an off-reprocessing plant site location for further treatment or storage would likely be in the form of UNH crystals by commercial carrier in lined and sealed drums. This transportation/packaging cost should be assigned to this module and is expected to be very small if these steps are taken soon after reprocessing and the U-232 daughters have not yet had a chance to form in radiologically significant amounts.

Back-end interface. Preparation, storage, or disposal of the reprocessed U_3O_8 powder resulting from conversion of uranyl nitrate hexahydrate, all have their own technical, regulatory, and procurement issues. U_3O_8 would most likely be prepared by ammonium nitrate precipitation of a double uranium salt (ADU) followed by calcination and adjustment of oxygen stoichiometry. UO_3, for later fluorination to UF_6, or UO_2 for preparation of MOX, could both be prepared in the same manner with careful adjustment of oxygen stoichiometry. If the uranyl nitrate hexahydrate feed material has been sitting around long enough for U-232 daughters to build in, it would be advisable to aqueously "polish" a uranyl nitrate hexahydrate solution by using solvent extraction or ion exchange to remove the U-232 daughters. In this manner subsequent processing operations could involve less radiation dose to workers.

As with depleted U_3O_8 derived from enrichment plant tails, the environmental feasibility and regulation of the shallow geologic disposal of large amounts of bulk U_3O_8 or other uranium forms remains highly problematic (i.e., discussion in Module K-1). The U-232 daughters and higher U-234 and U-236 content of this material make the problem much more serious than for "virgin" tails derived U_3O_8.

This material may have to be handled as greater-than-class-C (GTCC) low-level waste; however, no such regulations have been developed for it. As with the tail materials (>100,000 of MTU), the very large inventory of this reprocessed material (>10,000 of MTU) and its possible potential concentration into one geographic area means that in the distant future (thousands of years), after the containers enclosing the insoluble depleted U_3O_8 corrode away, the burial area will be a large producer of radon gas from the uranium decay chain. This gas would easily diffuse through any dry soil cap. In order to prevent this occurrence, a deeper or less-permeable capped burial site or noncorrodible containers will be needed. U-234 would also present a long-term radiotoxicity hazard similar to that from higher actinides, such as neptunium, in a spent fuel repository. For this reason, long-term sequestration of reprocessed U_3O_8 in a deep mine or tunnel-type repository is likely to be required. The lack of high-heat generating radioisotopes; however, means that such material could be efficiently emplaced in a repository without major spacing issues.

An option not yet considered might be to blend enrichment tails U_3O_8 (Module K-1) with reprocessed U_3O_8 for shallow burial. The former much less radioactive material is likely to be available in amounts ten or more times that of the latter. A “blend” might meet the allowable radionuclide limits for the less-expensive shallow burial option.

The reprocessed uranium disposal options above should not be confused with those in Modules G3 (LLW Conditioning, Storage, and Packaging), J (Near Surface Disposal), or L (Geologic Repository). The costs for Module K2 disposal options take the material all the way to final disposal and Modules G3, J, or L costs should not be superimposed.

If recycle is warranted, the costs for this Module K2 step include conversion of the UNH to an oxide and fluorination of this oxide all the way to reprocessed UF_6. If the UNH feed has accumulated U-232 decay daughters, the fluorination process can be designed to remove them, thus reducing the radioactivity level in the enrichment and fuel fabrication facilities. Costs for re-enrichment and fuel refabrication are covered in Modules C1 (Uranium Enrichment) and D1-1 (LWR UO_2 Pellet Fuel Fabrication). The use of REPU as a substitute for natural (virgin) feed is discussed briefly in Module A (Uranium Mining and Milling). Use of reprocessed uranium is anticipated to raise these unit separative work and unit fabrication costs by up to 20% above that for virgin feed materials.

K2-5. MODULE SCALING FACTORS

No data are available. Any reprocessed uranium conversion facilities are likely to be located on the reprocessing plant site; hence, sizing might be similar to that for Module F1.

K2-6. REPU UTILIZATION/DISPOSITION EXPERIENCE IN THE U.S.

Some useful insights can be gained from the disposition of military REPU streams in the U.S. Nuclear Weapons Complex. As mentioned earlier, this government-based REPU utilization/disposition activity is the only one taking place in the U.S. Two programs are underway to utilize and disposition the reprocessed uranium from the Savannah River Site (SRS), which formerly produced weapons-grade plutonium and tritium in production reactors. These reactors had both driver fuel, which provided the neutrons to transmute U-238 to Pu-239 and Li-6 to tritium (H-3) and target fuel, which consisted of mostly depleted-U to be transformed to plutonium by those neutrons. The driver fuel consisted of highly enriched U, which after several cycles still had enough recoverable U-235 present to make reprocessing economically viable. The uranium solution resulting from reprocessing was well over 20% U-235, and could be re-enriched, reconverted, and refabricated into new production reactor fuel. When the production reactors were shutdown in the late 1980s, the HEU solution was saved in tanks for later processing. After the DU targets were processed, and the plutonium and fission products separated out, the remaining depleted uranium nitrate (DUNH) solution was calcined to UO_3, drummed, and warehoused. Figure K2-2 below shows the steps and facilities involved in this process.

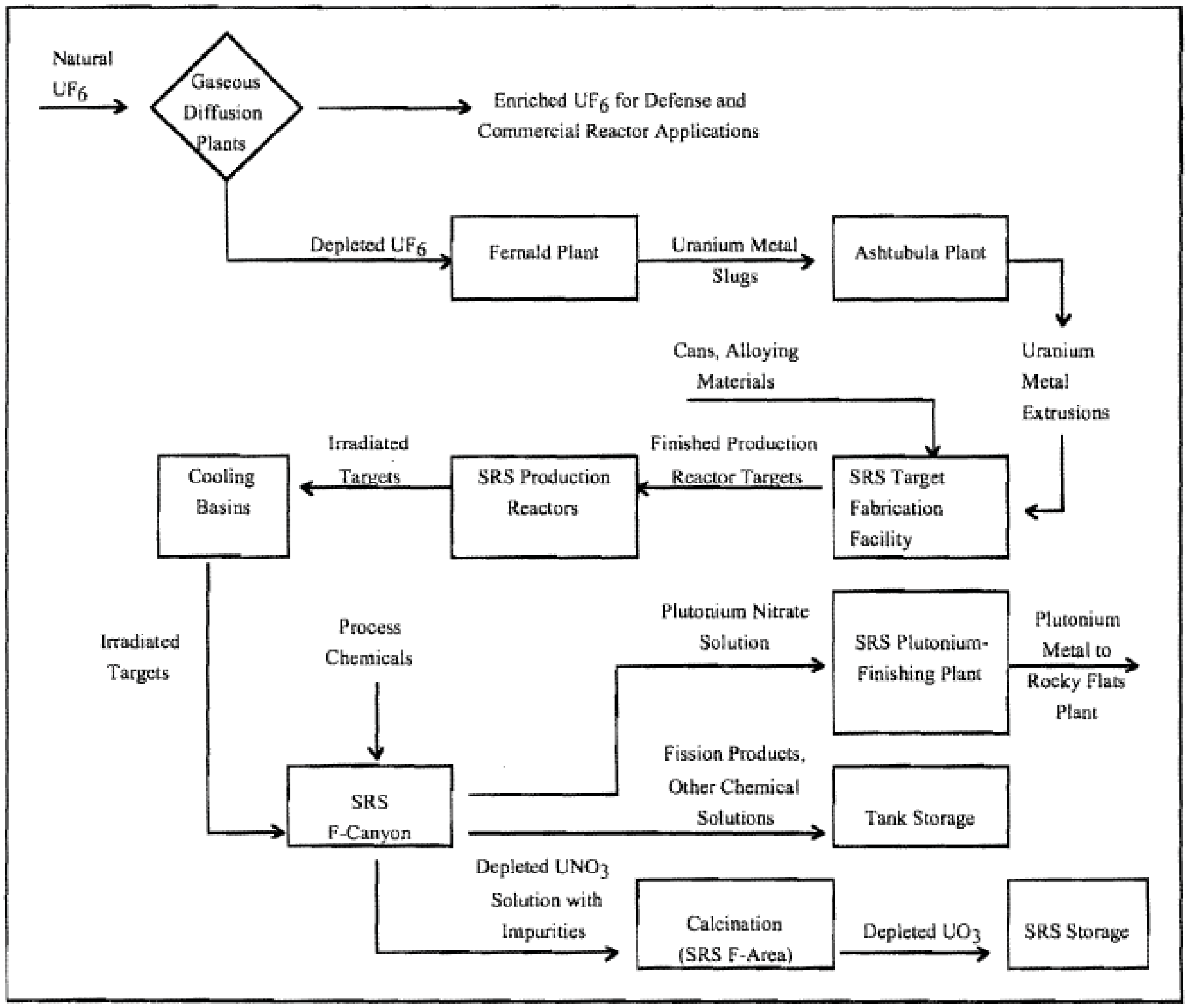

Figure K2-2 Former DU-related steps at Savannah River Site and other Weapons Complex Sites (White 2009).

The HEU solution, after some cleanup at SRS, is now being blended with natural U to prepare LWR enrichment-grade fuel for commercial reactors. A Nuclear Regulatory Commission (NRC)-licensed facility at Erwin, Tennessee (Nuclear Fuel Services) is performing the blend-down with a sister AREVA facility producing fuel for reactors owned and operated by the Tennessee Valley Authority (TVA). After conducting a lead test assembly program, TVA was given permission to burn this “off-spec” uranium as part of Project BLEU (Blended Low-Enriched Uranium). All of this is being done under the auspices of the Department of Energy (DOE) National Nuclear Security Administration (NNSA) Fissile Materials Disposition Program. From an economics standpoint, TVA benefits from very cheap fuel, and DOE-NNSA benefits from disposing of large amounts of legacy materials that were sitting in tanks. It should be noted that reprocessed HEU from Naval Nuclear Programs can also be treated in the same manner.

The drummed reprocessed DUO_3 is also destined to leave the SRS (SRS 2002). According to recent announcements, the material is to be shipped via rail to the Energy Solutions Clive, Utah, LLW “Envirocare” disposal site. Because of the short irradiation time in the production reactors, the amount of U-236, U-232, and fission product left in this material after processing is so small that it can be handled as LLW. However, there is some public concern because of the long-term radon issue. In 2010 over 8000

MTU of this material will be shipped from SRS warehouses to Envirocare for burial (Salt Lake Tribune 2009). From recent contract announcements (U.S. DOE 2009), it appears that the transportation cost for this material must be on the order of 40 cents per kgU.

K2-7. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The unit cost figure of merit of interest (and its value) for this step depends on which of the above options is chosen and the extent to which the material is contaminated with undesirable radionuclides. Each option will be separately discussed below.

Temporary Storage. Temporary storage costs will depend on how long the material is stored. An owner of separated reprocessed U_3O_8, the most likely reprocessed uranium storage form, will save it until the price of natural U_3O_8 rises to the point that recycling of reprocessed uranium as UOX fuel is economically beneficial. An Oak Ridge National Laboratory report (Spencer et al. 2005) describes some engineered product storage forms and options for this material, but does not include cost estimates. An earlier Oak Ridge National Laboratory report (Michaels and Welch) suggests that less-radioactive, contact-handled material, which can be stored in containers with a surface radioactivity of 200 mrem/hr or less, can be bulk-stored in vaults at a capital cost of $3/kgU in today's (2008) dollars.

The CFTC studies (WSRC 2008) indicated that bulk warehouse storage TPC would be in the range of $5.6M to $6.4M for a 5 year capacity (3,700MT). This equates to a capital cost of $1.50 to $1.75/kg U.

In light of other uranium storage capital costs, such as for less-radioactive depleted uranium products, these costs are determined to be low. A value of $6/kgU is appropriate given today's more stringent regulations and building standards (which are still evolving). The ORNL report also suggests that at a storage fill rate of ~2,000 MTU/yr, the facility would incur operational costs of $5M/yr (2008 dollars) during filling and $1.5M/yr (2008 dollars) during surveillance only. The CFTC studies confirm these O&M costs with a range of $5.1M to $6.4M/yr for a storage facility in active operations. (The CFTC studies assumed a single warehouse with constant receipts/shipments since disposition paths were assumed to be available.) These operation costs seem to be reasonable for what is only a logistical/surveillance task. Assuming a 40-year storage time for each kgU before a decision to recycle or dispose, the total storage capacity would need to be 80,000 MTU. The storage facility would operate for 120 years, with 40 years to fill, 40 years of surveillance only, and 40 years to empty. This gives an average operations cost of $6/kgU for each kgU emplaced. The total (capital + operations) unit cost then calculates as $12/kgU, assuming a 40-year storage time. This cost seems reasonable compared to the $5–9/kgU range for handling less-radioactive enrichment plant tails-derived depleted U_3O_8. The reprocessed U_3O_8 unit cost, however, does not include any ultimate disposal costs. As will be seen below, these final disposition unit costs can be more substantial.

A calculated annual unit cost value of $16/kgU/yr was reported by the Generation IV Fuel Cycle Crosscut Group for "separated uranium" (DOE 2002). For 40 years this would represent a cost of $640/kgU. This is more than many national cost estimates (in terms of kgHM) for disposing of spent fuel. Either the "per year" term was mistakenly added, or the value is inordinately high and would be for highly contaminated uranium (i.e., uranium with substantial remaining fission products, very high U-232 content, and/or higher actinides). Note that this module (K-2) is discussing well-known chemical technology for which the radioactivity hazard (and handling costs) can be minimized by "early" treatment (aqueous removal of U-232 daughters) and for which nuclear criticality concerns are non-existent for feedstocks of U-235 content 0.9% or less.

Permanent Geologic Disposal. Michaels and Welch suggests that reprocessed U_3O_8 could be disposed in a deep or tunnel type geologic repository for $72/kgU in 2008 dollars ($53/kgU in 1993 dollars) (Michaels and Welch 1993). This would presumably include the waste package and transportation from the storage location. No mention was made of whether this material could be collocated with spent fuel in a Yucca Mountain type geologic repository. By the time a decision is made whether to store or recycle (tens of years) the U-232 daughters will have built up to the point that a remote handling facility might be needed to empty the U_3O_8 storage containers or vaults, which might be volumetrically large, into volumetrically smaller, more robust packages for repository emplacement.

For comparison, costs of $15/kgU (2007 dollars) ($11/kgU [1993 dollars]) were given for geologic disposal of the less-radioactive depleted U3O8 derived from uranium enrichment operations. (Expensive deep or tunnel disposition of enrichment-derived [tails] depleted U3O8 will hopefully never be necessary. See Module K-1 for discussion of this material and its disposition paths and costs.) Unit costs for disposing the DUO3 reprocessed material from SRS should also be in the low range of possible costs for REPU disposal.

Preparation for Recycle as Light Water Reactor UOX. The cost of the conversion/processing service required before enrichment will depend on how long the material has been stored since reprocessing. Again, the handling difficulty, and hence cost, is driven by the concentration of the U-232 daughters in the uranyl nitrate hexahydrate at the reprocessing plant or the U3O8 at the storage site. According to Michaels and Welch, a "new" recently-separated uranium electrochemical processing product (U-metal) can be converted to U3O8 for $8/kgU (2008 dollars) (Michaels and Welch 1993). This would also represent a reasonable unit cost for converting "new" uranyl nitrate hexahydrate to UF6. If stored "old" U3O8 or UNH needs to be converted to UF6, aqueous polishing will be needed to remove the U-232 daughters. This could drive the unit cost up to $41/kgU (2007 dollars). To calculate the total UOX fuel cost, enrichment, and refabrication costs would need to be added (Modules C1 and D1-1). This option is further discussed in Trowbridge and Del Cul's reports (Del Cul 2007) and Module D1-1 (Trowbridge and Del Cul 2003).

The CFTC studies (WSRC 2008) indicated a thermal de-nitration process for conversion of recently reprocessed U nitrate solutions into UO3 powder and packaged into drums containing 400kg each has a total capital cost between $250M to $330M and an annual O&M cost of between $29M and $43M/yr for a reprocessing plant capacity of 800MT/yr. The total LCC (TPC+ O&M + D&D) ranged from $1.7B to $2.5B for 40 years of operations. This equates to a capital cost component of $8.5 to $11.20/kg U or a total LCC unit cost of $12.4 to $16.9/kg U.

Reprocessed UO2 would make an excellent fuel for CANDU reactors. No additional enrichment would be needed, since the U-235 content of reprocessed uranium fits the requirements of CANDU designs. (This cost is analyzed in Del Cul et al.'s report [2007].) Since there would be no need to enrich LWR REPU for use in CANDUs, the economics of this application are even more attractive than those for REPU recycle in LWRs. In addition, there is no need to deal with enrichment plant tails. The major savings is the avoided cost of purchasing uranium ore. Pursuit of this option by Canada would allow more Canadian ore to be sold on the international market, since domestic use could be cut significantly. Table K2-1 shows that for high ore prices ($233/kgU assumed) the unit cost associated with REPU use is half that for CANDU fuel assemblies derived from virgin (mined) U3O8 (Module D1-7). This is true even if fabrication of REPU incurs a higher unit cost because of the radiation hazard associated with U-232 daughters.

Table K2-1 Comparison of CANDU unit fuel costs from reprocessed and virgin uranium (circa 2008).

Economics of the Use of LWR Reprocessed U in CANDU Reactors		
NATURAL U CANDU FUEL FROM URANIUM ORE:		
Uranium ore price (English)	*89.6*	*$/lb U3O8*
Uranium mine & mill price (Metric) (as if U3O8 produced)	233	$/kgU
Canadian conv of U-mill solutions to pure reactor-grade UO2	10	$/kgU
CANDU fuel fabrication price (from UO2 powder)	100	$/kgU
Total cost	**343**	$/kgU
CANDU FUEL FROM LWR REPROCESSED U*		
Dissolution of REPU3O8, cleanup of sol'n, and conversion to UO2 of right powder morphology	40	$/kgU
CANDU fuel fab price (adj for higher handling risk)	130	$/kgU
Total cost	**170**	$/kU
** No enrichment step assumed. ~0.7%-0.9% U-235 in REPU; some U-236 present*		

Use as a Diluent for Contact-Handled MOX Fuel. As for UOX recycle above, the unit cost to make a material suitable to refabrication into contact-handled fuel would depend on how long it has been since the uranium product was separated during reprocessing. If the time is very short, a fuel grade, "moxable" UO_2 powder could be prepared from uranyl nitrate hexahydrate for around $40/kgU. (Note that this conversion cost is higher than the $7 to $17/kgU [mentioned above] just required to alter the chemical form. It also includes the costs to produce a flowable, sinterable [i.e., "moxable"], UO_2 powder that meets the ASTM fuel specification, thus the > $23/kgU premium.) If old, U-232 daughter-laden feed material is used, another $35/kgU would be required for aqueous polishing prior to powder preparation. If these numbers are used in an analysis, care should be taken to remove the part of the unit MOX fabrication cost (Module D1-2) that comprises the depleted U_3O_8 to "moxable" depleted UO_2 powder step. Around $30 to $70/kgHM of the overall MOX fab cost is attributable to this operation if the MOX plant receives enrichment plant tails derived depleted UF_6 or depleted U_3O_8 as the PuO_2 diluent.

Limitations of Cost Data and Other Considerations

The following considerations are relevant to reprocessed-uranium materials in the fuel cycle:

1. Because of U-236 buildup, it is likely that reprocessed UOX could undergo, at most, two recycles. If a highly selective method for uranium, such as a laser-based process, enrichment became available (one that could selectively remove U-236) more recycles of UOX would become feasible.
2. The reprocessing technology must keep levels of fission products and higher actinides low enough (in the uranium product) to allow contact-handling and favorable economics.

In general, the reprocessed uranium disposition step of the fuel cycle can be placed in the viable-commercial category of technology readiness. Uranium ore and enrichment prices will help dictate when and how reprocessed uranium is dispositioned. The UK Nuclear Decommissioning Authority (NDA) is presently performing such trade-off studies to inform their decision how to deal with the 35,000 MT of REPU arising from reprocessing of Magnox and Advanced Gas Reactor fuel (IDM 2007).

K2-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table K2-2. The summary shows the reference cost basis (constant year U.S.dollars), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low-end of cost range) and downsides (high-end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT Table.

The triangular distribution based on the costs in the WIT Table is shown in Figure K2-3.

K2-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

CFTC studies developed a cost estimate range using contingency as the primary difference between the low and high range. Based upon past nuclear project experiences for nth of a kind, low radiation facilities a contingency of 5% for the TPC low range and 30% for the TPC high range was established. An uncertainty range for the LCC estimate components was established as ±20% of the nominal estimate.

Table K2-2. Cost summary table for reprocessed uranium disposition options (Constant 2008 dollars).

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Conversion of UNH to U_3O_8 storable form: "New" UNH to U_3O_8 "Old" UNH to U_3O_8 including removal of U-232 daughters		 $4/kgU $20/kgU	 $17/kgU $50/kgU	 $12/kgU $40/kgU
Reprocessed U_3O_8 40-year Storage $6/kg U for 80,000 MTU/yr Storage Capacity. Annual costs of $1.5M to $5M/yr	In unit cost, amount unknown, but not felt to cover all risks	$7/kgU if shallow burial allowed	$30/kgU if facility regulation and construction difficulties ensue or very long-term storage is required	$9/kgU
Aqueously–derived reprocessed U_3O_8 Permanent Geologic Repository Disposal	In unit cost, amount is unknown	$61/kgU if above temporary storage package could be emplaced	$93/kgU if regulatory and siting difficulties arise	$72/kgU including repackaging, transportation, emplacement, and perpetual surveillance
Preparation for UOX recycle: "New" product to UF_6 (no aq polish) "Old" product to UF_6 (aq removal of U-232 daughters)	In unit cost, amount is unknown	 $6/kgU $30/kgU	 $20/kgU $60/kgU	 $14/kgU $50/kgU
UOX diluent for MOX fuel: "New" product for immediate contact-handling to "moxable UO_2" "Old" product processing requiring removal of U-232 daughters prior to contact-handling	In unit cost, amount is unknown	Not available	Not available	 $40/kgU $75/kgU

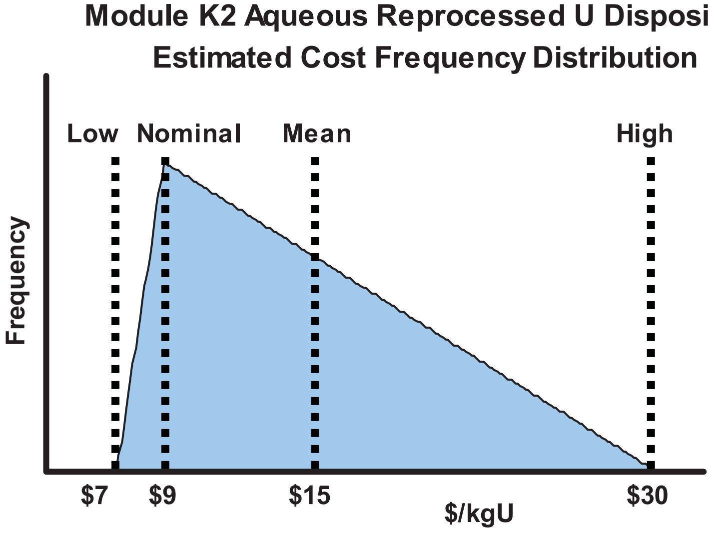

Figure K2-3. Module K2 aqueous reprocessed uranium 40-year storage estimated unit cost frequency distribution.

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Module K3

Electrochemically Reprocessed Uranium Conversion, Disposition, and Possible Recycle

Module K-3
Electrochemically Reprocessed Uranium Conversion, Disposition, and Possible Recycle

K3-1. BASIC INFORMATION

For light-water reactor (LWR) fuel cycles and many fast reactor fuel cycles, uranium is the largest resulting constituent of the irradiated spent fuel heavy metal mass. If it is separated during reprocessing of spent fuel, it is known as "reprocessed uranium" or "REPU." For LWRs operating on enriched uranium oxide (UOX), only a small fraction of the total initial uranium radioisotopes are fissioned or transmuted to other actinides. After discharge from the reactor, typically over 93% of the heavy metal mass (not including zircalloy cladding or fuel assembly structures) is uranium. In the spent fuel pools of U.S. LWRs, there is already over 40,000 MTU of this material that might be ultimately recovered as reprocessed uranium during reprocessing.

For fast reactor cycles operating on uranium, plutonium mixed oxide fuel in the "breeder" mode, the uranium fraction in the driver fuel is typically 50 to 85% of the initial preirradiation heavy metal mass. For lower conversion ratio fast reactors utilizing higher actinide (Pu, Np, Am, Cm) fuels, the uranium content is likely to be smaller than for a "breeder." The blanket fuel starts out as 100% uranium (most likely depleted uranium) and higher actinides, such as Pu-239, are produced by neutron absorption during irradiation. Both fast reactor driver fuel and blanket fuel need to be reprocessed: (1) to get the useful fissile plutonium from the blankets, and (2) to remove fission products and some of the less-desirable, U-232 and U-236 laden uranium from both the drivers and blankets. The remaining fissile mass can be refabricated into new drivers. The "discard" uranium mass can be made up by fabricating new depleted uranium blankets and by adding clean uranium to the refabricated driver fuel. In the U.S., there is very little fast reactor spent fuel, and what there is has limited irradiation exposure. The Experimental Breeder Reactor-II fast reactor was probably the most successful demonstration of U.S. fast reactor technology. The Fast Flux Test Facility (FFTF) also operated well, but was shut down early because of lack of funding. For fast reactors that are to be operated as "burners" rather than "breeders," the actinide fissile content of the fuel is likely to be higher and the initial uranium content lower. This higher fissile content ensures that there are enough neutrons available to destroy (fission or transmute) the undesirable higher actinides and transmute certain long-lived fission products.

For metal-fueled fast reactors, there is likely to be uranium separated out in the aqueous or electrochemical reprocessing step (Module F2/D2). The choice of an electrochemical process depends on whether metal or ceramic fuel is being considered and what other alloying constituents, such as zirconium, are in the fuel mass. Regardless of the reprocessing method, the following factors affect the nature of the reprocessed uranium that can be obtained from reprocessing:

- The initial U-235 assay of the fuel before irradiation (this is one of the variables which will determine the post-irradiation U-235 assay and the concentrations of other uranium isotopes).
- The burnup level of the spent fuel (this also determines the fractions of the various isotopes of uranium in the irradiated uranium). The higher the burnup, the smaller the ratio of the postirradiation U-235 content to the preirradiation U-235 content.
- The initial U-235 assay and the burnup also determine the amounts of the undesirable isotopes U-232 and U-236 that are formed. Short-lived U-232 has radiologically potent decay daughters. such as thallium-208. which complicate reprocessed uranium handling. U-236 is a neutron poison (absorber) that adversely affects the performance of any new UOX or mixed oxide or metal fuel that is produced from reprocessed uranium. The higher the initial U-235 assay and burnup, the more of these undesirable, nonnatural isotopes are produced.

- The nature and chemistry of the reprocessing scheme (the associated "decontamination factors" determine the amounts of nonuranium impurities, such as fission products and higher actinides, such as plutonium and neptunium carried over into the reprocessed uranium stream). Aqueous processes such as UREX and plutonium-uranium extraction (PUREX) have higher decontamination factors for separating uranium from fission products and higher actinides. The very low quantities of nonuranium impurities mean that any further handling of the reprocessed uranium stream can be in "contact-handling" facilities, provided that such handling is done quickly before U-232 daughters have a chance to build in. These daughters peak in concentration approximately 10 years after irradiation.

  Electrochemical processes (Module F2/D2) have been proposed for the reprocessing of legacy LWR spent fuel and the reprocessing of fast reactor blanket (or higher actinide targets) and driver fuel. These dry processes involve molten salt chemistry and electrochemistry and can be used to reprocess oxide or metal fuels. However, they seem to be better suited for the latter type metal fast reactor fuels. Electrochemical processes experience lower decontamination factors for fission products and higher actinides (from uranium). This means that electrochemically-derived reprocessed uranium would contain more residual radionuclides and probably require remote handling during packaging and storage. These lower decontamination factors are not a problem for many fast reactor cycles, because the fuel must be handled remotely from irradiation through refabrication anyhow, and the presence of small fractions of fission products or higher actinides does not pose a safety or personnel exposure problem. Also, some of the uranium can be directly recycled and does not even have to be totally separate from other actinides during the recycle/refab operations. This Module K3 will deal with options for handling the reprocessed uranium arising from the electrochemical reprocessing of LWR and fast reactor oxide or metallic fuels.

  This distinction of whether fast reactor or LWR fuel is being electrochemically reprocessed is very important. Much larger quantities of uranium must be handled from the electrochemical processing of spent LWR fuel. It will likely be a few hundred years before enough fast reactors exist that could readily use the electrochemically-derived reprocessed uranium from LWR spent fuel as make-up material for fast reactor metal fuel refabrication or for fast reactor mixed oxide uranium-diluent. For this scenario, it is likely that thousands of metric tons of highly contaminated uranium-metal would be generated from an electrochemical process that takes UOX spent fuel as the feed form, reduces it to metal, and produces all metal products.

- The price of natural uranium, U_3O_8 to UF_6 conversion, and uranium enrichment all affect the economics of reprocessed uranium use. If these prices are high, as they are now, the attractiveness of recycling (purifying, reconverting, reenriching, and refabricating reprocessed uranium into UOX fuel) versus reprocessed uranium storage or disposal is enhanced.

K3-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

For a typical electrochemical option, reprocessed uranium in the form of a metal is separated from fission products and other actinides in an early step in the separations part of the reprocessing facility. According to Michaels and Welch (1993), the best option for safe storage is to first cast the separated uranium-metal into 180 kgU cylindrical ingots and store them in cans with stainless steel jackets. This jacketing step prevents moist air from oxidizing the uranium metal and producing fines which can become airborne or even burn. Because of the radioactivity from unseparated fission products and higher actinides, this ingoting/canning operation would likely have to take place in the remote handling part of the reprocessing plant. After this step there are several options for use or disposition of this reprocessed uranium product:

- **Long-Term but Temporary Storage**. It is likely that electrochemically-derived reprocessed uranium would not be immediately "thrown away," but saved for the possible future uses, some of which may be many decades away when fast reactor fuel cycles begin to dominate the nuclear enterprise. Among these future uses are the following:
  - If the electrochemically reprocessed uranium is derived from LWR spent fuel, it will be produced in large quantities. It is possible to save it for eventual recycle into new LWR or higher-enrichment fast reactor startup fuel as described below. Tens of years of storage would probably be required.
  - The reprocessed uranium can be saved for makeup uranium for refabrication of metal fuel for a fast reactor fuel cycle. It can also be used to make mixed oxide fuel for oxide-based fast reactor fuel cycles. Since introduction and widespread use of fast reactors could take a few hundred years, any LWR-derived electrochemically reprocessed uranium would have to be stored for that amount of time. Reprocessed uranium from fast reactor spent fuel electrochemical processing could be reintroduced in less time and would require fewer years of storage. The quantities of reprocessed uranium produced by fast reactor electrochemical processing are smaller than for LWR spent fuel electrochemical processing.
- **Recycle**. The reprocessed uranium could be cleaned up, converted to UF_6, and reenriched. The enriched uranium could be used for LWRs or for highly enriched uranium startup of fast reactors. Many tens of years of storage would be required if there is no immediate need for uranium recycle fuel. The nature and cost of the required storage facility will depend on the radiation level at the surface of the U-metal ingots and the amount of worker protection which is needed during their emplacement and long-term surveillance.
- **Permanent Geologic Disposal**. The reprocessed uranium material, which is less radioactive than high-level waste or spent fuel, but a lot more radioactive than aqueously-derived reprocessed uranium, can be packaged for permanent geological disposal in a matter somewhat akin to Greater-Than-Class-C waste. Stainless jacketed metal ingots directly from the electrochemical plant or storage facility are not an ideal permanent disposal form, because the relatively thin stainless steel jacket may corrode away in several decades and expose the uranium-metal to water or moist air in a repository. U_3O_8 is a more chemically stable form, however, robust packaging or grouting of the powder would be needed to reduce the possibility of fines and prevent eventual leaching of radionuclides. A robust waste container would be needed to encase the grouted mass. Near-surface burial of low-level waste-type packages, such as is proposed for enrichment tails DU_3O_8 (Module K1), would not be permissible. A deep or tunneled geologic repository type environment, like Yucca Mountain, would be more appropriate, and the heat load associated with this material would be orders of magnitude smaller than for high-level waste or spent fuel. U-234 and some transuranic isotopes would present the longest range radiotoxicity hazard. U-232 daughters and most fission products remain a problem for only a few dozen years. Preparation of the packages for repository emplacement is likely to be a remote-handling operation.
- **Preparation for Recycle as UOX Fuel for LWRs or Initial Fast Reactor Cores**. The reprocessed uranium ingot can be dejacketed and converted to an oxidized form, such as UO_3, by controlled burning. This powder is suitable for fluorination/purification to reprocessed UF_6. (Fluorination itself can be a dry route to U-purification, because fission product and higher actinide fluorides are less volatile than UF_6.) The reprocessed UF_6 can undergo reenrichment to a U-235 level somewhat above that required for "virgin" LWR UOX fuel derived from natural uranium. The extra enrichment is needed to compensate for the neutron absorption by U-236. The reprocessed UF_6 can be refabricated into LWR reprocessed UOX in a conventional reprocessing plant if the small amount of U-232 remaining after purification is separated out in the enrichment process. This option is discussed in greater detail in a special section of Module D1-1 (LWR UO_2 Fuel Fabrication) and in Module K2. The reprocessed UF_6 can also be taken to higher enrichment levels (>15% U-235) and the enriched

K3-3. PROCESS SCHEMATIC

Figure K3-1 shows schematically the possible disposition paths for reprocessed uranium resulting from electrochemical fuel reprocessing. The paths were described in the subsection above.

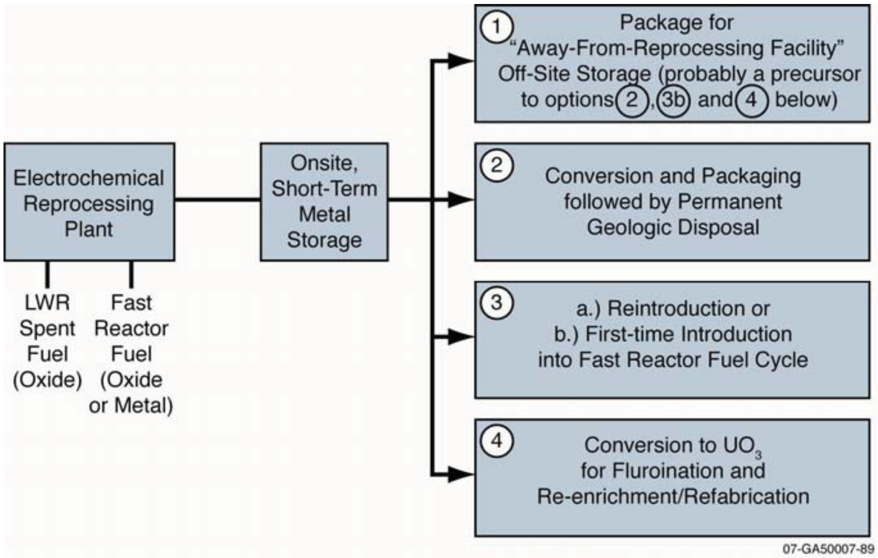

Figure K3-1. Options for reprocessed uranium arising from electrochemical reprocessing of LWR and fast reactor fuels.

K3-4. MODULE INTERFACE DEFINITION

Front-end interface. The electrochemical spent fuel reprocessing plant (Module F2/D2) represents the front end interface. The analyst should make sure the reprocessed uranium ingot casting and jacketing operation is included in the $/kgHM cost of the reprocessing steps, since this remote-handling step must be undertaken at the reprocessing complex. Transportation of the metal ingots to the storage location would likely require special overpacks or containers, but could probably be handled by a commercial carrier. This transportation/packaging cost should be assigned to this module (K3) and is expected to be very small.

Back-end interface. The electrochemically-derived reprocessed uranium disposal options above should not be confused with those in Modules G3 (LLW Conditioning, Storage, and Packaging), J (Near Surface Disposal), or L (Geologic Repository). The costs for the Module K-3 permanent disposal option take the material all the way to final disposal and G3, J, or L costs should not be superimposed upon these.

If recycle is warranted, the costs for this Module K3 step include conversion of the metal to an oxide and fluorination of this oxide all the way to reprocessed UF_6. If the uranium-metal feed has accumulated U-232 decay daughters, the fluorination process can be designed to remove them, thus reducing the radioactivity level in the enrichment and fuel fabrication facilities. Costs for enrichment and fuel refabrication are covered in Modules C1 (Uranium Enrichment), D1-1 (LWR UO_2 Fuel Fabrication), and D1-4 (Ceramic Pelletized Fast Reactor Fuel). Use of even cleaned-up reprocessed uranium is anticipated to raise these separative work unit and fabrication costs by up to 20% above that for virgin feed materials.

K3-5. MODULE SCALING FACTORS

No data are available. Any reprocessed uranium handling/conversion facilities are likely to be located on the reprocessing plant site, hence sizing might be similar to that for Module F2/D2.

K3-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The unit cost figure of merit of interest (and its value) for this step depends on which of the above options is chosen. Each option will be separately discussed below.

Temporary Storage. Temporary storage costs will depend on how long the material is stored. An owner of separated reprocessed uranium metal, the most likely reprocessed uranium storage form, will save it in monitored retrievable storage until the price of natural U_3O_8 rises to the point that recycling of reprocessed uranium as LWR for higher enrichment fast reactor fuel is economically beneficial, or the owner will arrange for its permanent disposal. A 1993 Oak Ridge National Laboratory report (Michaels and Welch 1993), prepared to support the Department of Energy Office of Nuclear Energy, Science, and Technology (DOE/NE) Advanced Liquid Metal Reactor program at that time, suggests that the more radioactive material, requiring remote-handling (a container surface radioactivity of 200 mrem/hr or more), can be bulk stored in vaults at a capital cost of \$13/kgU in today's (2007) dollars (\$9/kgU in 1993 dollars). In light of other radioactive material storage capital costs, such as those for transuranic waste storage and for spent fuel casks, this unit cost is felt to be possible, but optimistic. A value of \$20/kgU is felt to be more appropriate given today's more stringent regulations and building standards (which are still evolving). The report also suggests that at a storage fill rate of ~2,000 MTU/yr, the facility would incur operational cost of \$5 million/yr (2007 dollars) during filling and \$1.5 million/yr (2007 dollars) during surveillance only. These operations costs seem to be reasonable for what is only a logistical/surveillance task, and are the same as those for the less radioactive aqueous reprocessing–derived reprocessed uranium. The problem is that this material may have to be stored for many decades before the reprocessed uranium can be used in fast reactor cycles. Any utility considering recycle in LWRs is likely to want to start with reprocessed uranium from aqueous reprocessing because of its lower radioactivity and lower handling costs, hence, electrochemically-derived reprocessed uranium would be used lastly for this purpose. A vault-type storage facility holding 80,000 MTU would cost \$1.6 billion and if it operated for 300 years would accumulate \$750 million in operations costs. The total unit cost would amount to around \$30/kgU. If multiple centuries of storage are required, unit costs could rise into the hundreds of dollars per kgU (Michaels and Welch 1993).

Permanent Geologic Disposal. A 1993 Oak Ridge National Laboratory report suggest that reprocessed U_3O_8 could be disposed in a deep or tunnel-type geologic repository for \$72/kgU in 2007 dollars (\$53/kgU in 1993 dollars). This would presumably include the waste package and transportation from the storage location. It does not include the cost of converting the uranium-metal ingots to U_3O_8. The 1993 ORNL report suggests a cost of \$7/kgU (2007 dollars) for this conversion; however, this seems low in light of the radioactivity level of the metal feed. A unit cost of \$21/kgU seems more realistic and would include transfer of the U_3O_8 into the new waste container. This would give an overall cost of \$93/kgU for permanent geologic disposal. For comparison, costs of \$15/kgU (2007 dollars) (\$11/kgU in 1993 dollars) were given for geologic disposal of the less radioactive DU_3O_8 derived from uranium enrichment operations and \$72/kgU for aqueous reprocessing-derived reprocessed U_3O_8. (Note: Expensive deep or tunnel disposition of enrichment-derived tails DU_3O_8 will hopefully never be necessary. See Module K-1 for discussion of this material and its disposition paths and costs. Module K-2 discusses reprocessed uranium from aqueous reprocessing.)

Preparation for Recycle as LWR Fuel. The cost of the conversion/processing service required before enrichment will depend on how long the material has been stored since reprocessing and the amounts of fission product and transuranic contaminants in the U-metal starting material. It is likely that a “dry” volatility-type fluorination process can be used to make UF_6 and at the same time separate out the small amounts of fission products, TRUs, and U-232 daughters. According to the 1993 ORNL report, “new” recently-separated uranium metal electrochemical processing product can be converted to U_3O_8 for $7/kgU (2007 dollars). In the subsection above, this number was revised to $21/kgU. This unit cost is probably too low for converting U-metal to UF_6, which is a more complex process. The 1993 ORNL report suggests a unit cost of $42/kgU (2007 dollars). To calculate the total UOX fuel cost, enrichment and refabrication costs would need to be added (Modules C1 and D1-1). This option is further discussed in Modules D1-1 and K2.

Reprocessed UO_2 would make an excellent fuel for CANDU reactors. No additional enrichment would be needed, since the U-235 content of reprocessed uranium fits the requirements of CANDU designs. This cost is discussed in Module K2.

Use as a Diluent for Contact-Handled MOX Fuel. As for UOX recycle above, the unit cost to make a material suitable to refabrication into contact-handled fuel would depend on how long it has been since the uranium product was separated during reprocessing (the U-232 daughter problem) and how bad the feed material is contaminated with fission products. Transuranic contamination would be less important, because glovebox operations can accommodate most plutonium and neptunium isotopes. If the time is very short and fission product concentrations low, a fuel grade, “moxable” UO_2 powder could be prepared from uranium-metal for around $42/kgU. If old, daughter-laden feed material is used or fission product concentrations too high, another $42/kgU would be required for aqueous polishing prior to powder preparation. If these numbers are used in an analysis, care should be taken to remove the part of the unit mixed oxide fabrication cost (Module D1-2) that comprises the depleted U_3O_8 to “moxable” depleted UO_2 powder step. Around $30/kgHM of the overall mixed oxide fabrication cost is attributable to this operation if the mixed oxide plant receives enrichment plant derived depleted UF_6 or depleted U_3O_8 as the PuO_2 diluent.

Limitations of Cost Data and Other Considerations

The following considerations are relevant to reprocessed uranium materials in the fuel cycle:

1. Because of U-236 buildup, it is likely that reprocessed UOX could undergo at most two recycles. If a highly selective method for uranium enrichment became available (one that could selectively remove U-236) more recycles of UOX would become feasible.
2. The problem of large amounts of contaminated reprocessed uranium is one reason that electrochemical processing is better suited for the internal recycle of fast reactor fuel and not the large scale reprocessing of spent LWR fuels.

In general, the reprocessed uranium disposition step of the electrochemical fuel cycle can be placed in the “demonstration required” category of technology readiness. Uranium ore prices will help dictate when and how reprocessed uranium is dispositioned.

K3-7. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table K3-1. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table K3-1. Cost summary table for reprocessed uranium disposition options.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
SS-clad U-metal ingots: 300-year Storage" $20/Kg U for 80,000 MTU/yr Storage Capacity ($1,600M). Annual costs of $1.5M to $5M/yr	In unit cost, amount unknown, but not felt to cover all risks.	$25/kgU for tens of years of storage	$100+/kgU if centuries of temporary retrievable storage required.	$31/kgU for 300-yr storage
Electrochemically-derived reprocessed U_3O_8 Permanent Geologic Repository Disposal	In unit cost, amount is unknown	$75/kgU if contamination level only marginally above that of aqueously-derived reprocessed uranium	$150/kgU if sitting and regulatory difficulties arise	$93/kgU including metal to U_3O_8 conversion, repackaging, transportation, emplacement, and perpetual surveillance
Preparation for UOX recycle: U-Metal product to UF6 (including fluoride volatility removal of fission product, higher actinides, & U-232 daughters)	In unit cost, amount is unknown	$30/kgU	$60/kgU	$42/kgU
Internal reuse in fast reactor electrochemical fuel cycle		Included in fuel fabrication cost Module F2/D2	Included in fuel fabrication cost Module F2/D2	Included in fuel fabrication cost Module F2/D2
UO_2 diluent preparation for contact-handled MOX fuel		$30/kgU	$60/kgU	$42/kgU including aqueous polishing and conversion to fuel grade UO_2 powder

The triangular distribution based on the costs in the WIT Table is shown in Figure K3-2.

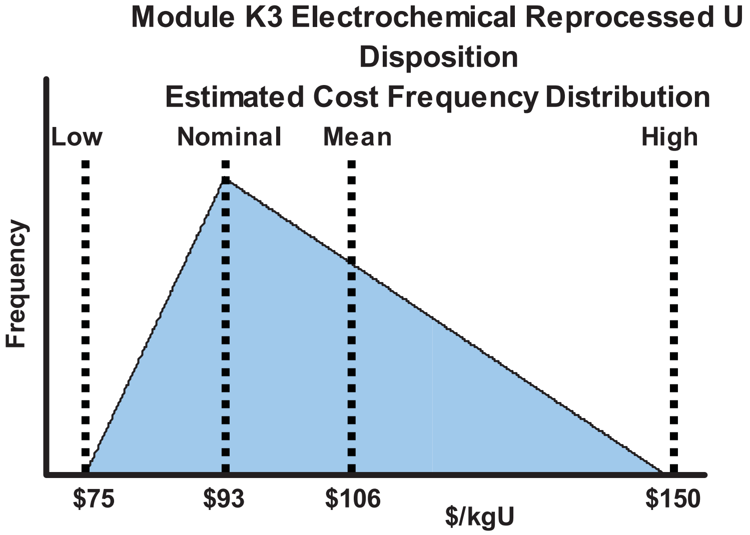

Figure K3-2. Electrochemical reprocessed U disposition estimated cost frequency distribution.

K3-8. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Due to lack of detailed process/cost data no such calculations were performed.

K3-9. REFERENCES

Michaels, G. and T. Welch, 1993, *Evaluation of Disposition Options for Reprocessed Uranium*, ORNL/TM-12326, Oak Ridge National Laboratory, February 1993.

Module L

Geologic Repository

Module L

Geologic Repository

L-1. BASIC INFORMATION

This module has been updated to reflect the most recent cost analysis prepared for the Yucca Mountain Project (YMP) geologic repository by the U.S. Department of Energy (DOE) Office of Civilian Radioactive Waste Management (OCRWM) and data from international studies. Several new references have been added including the *Analysis of the Total System Life-cycle Cost of the Civilian Radioactive Waste Management Program, Fiscal Year 2007* (DOE 2008). Additional information was derived from the Advanced Fuel Cycle Initiative (AFCI) and international studies. There is an emphasis in this update to include international studies as a means to broaden the range of options for geologic disposal to account for different geologies (salt, tuff, clay, granite, etc.) and waste management practices. Increasingly in the future there will be a need for greater cooperation to address key strategic challenges in radioactive waste disposal. Multinational cooperation is valuable in developing siting strategies, approaches to communicating with the public and in preparing and presenting convincing arguments on the safety of repositories (McCombie 2007).

L-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The life cycle costs for geologic disposal typically consist of three major types of activities: (1) the repository itself, (2) transportation, and (3) management and oversight. The function of Module L is to contain the costs for geologic disposal of spent nuclear fuel (SNF) and high-level waste (HLW). Module L does not include waste conditioning and packaging or transportation; however, those costs are relevant to Module G (HLW Conditioning, Storage, and Packaging) and Module O (SNF/HLW Transportation). Transportation costs are specifically excluded as they are dependent on the specifics of the repository location, shipping routes, and SNF and HLW storage locations.

Repository costs can be divided into Capital and Operating categories. The repository may be constructed in a staged fashion, so that some construction continues after operations begin. Repository capital costs include development of the license application and licensing support network; engineering, procurement, and construction of the required surface facilities (e.g., canister receipt and closure, wet handling, initial handling, receipt facility) and subsurface facilities needed for initial operations (e.g., main access tunnels and emplacement drifts); design and procurement of the waste container; physical security systems; and program management. Operating costs may be further divided into three time and activity-based phases of repository operation. These include emplacement during which the waste is received, packaged into the waste containers and emplaced in the repository; monitoring, in which the repository and its contained waste packages are monitored to ensure adequate performance during the period of higher heat generation; and closure. The approximate time spans estimated for YMP were (1) Development and Construction (1983 to 2023); (2) Emplacement (2017 to 2047); (3) Monitoring (2048 to 2112); and (4) Closure (2113 to 2126). This encompasses a total time period of 144 years. Figure L-1 is a simple diagram of the functional flow for Module L.

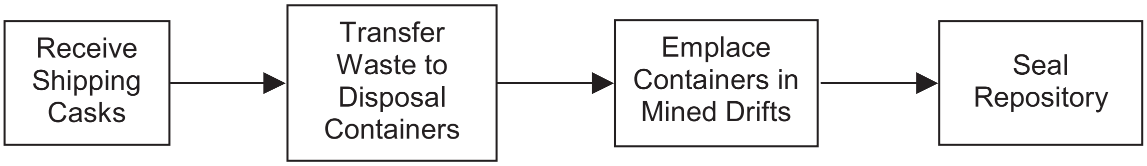

Figure L-1. Functional block diagram for geologic repository waste disposal.

L-3. PICTURES/SCHEMATICS

Figure L-2 is a schematic of the overall radioactive waste management system. Module L includes only the repository, which is enclosed in the black box in the diagram.

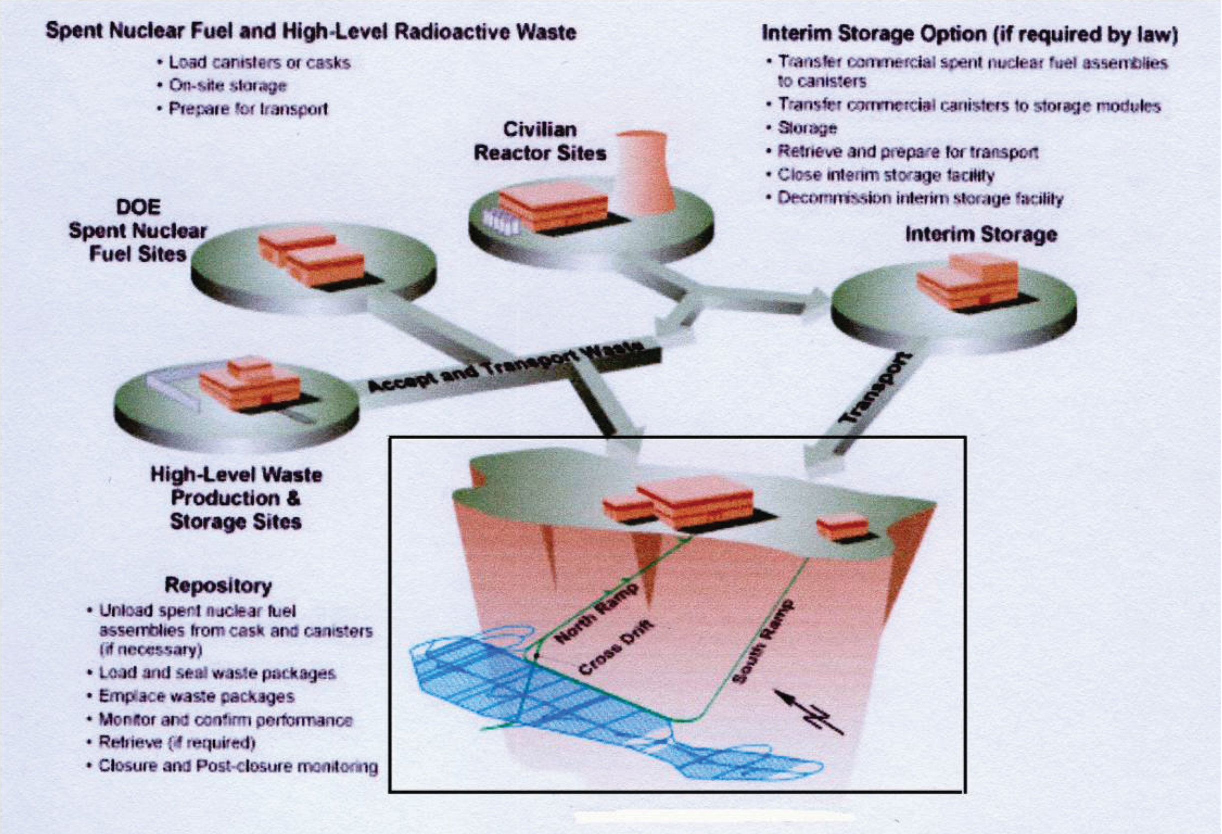

Figure L-2. Concept for the civilian radioactive waste management system (DOE 2001).

Figure L-3 shows the various barriers used in the repository and the waste package accommodating various waste canisters. The figure illustrates how drip shields and waste packages are the primary elements that are designed to complement the natural barriers in isolating waste from the environment.

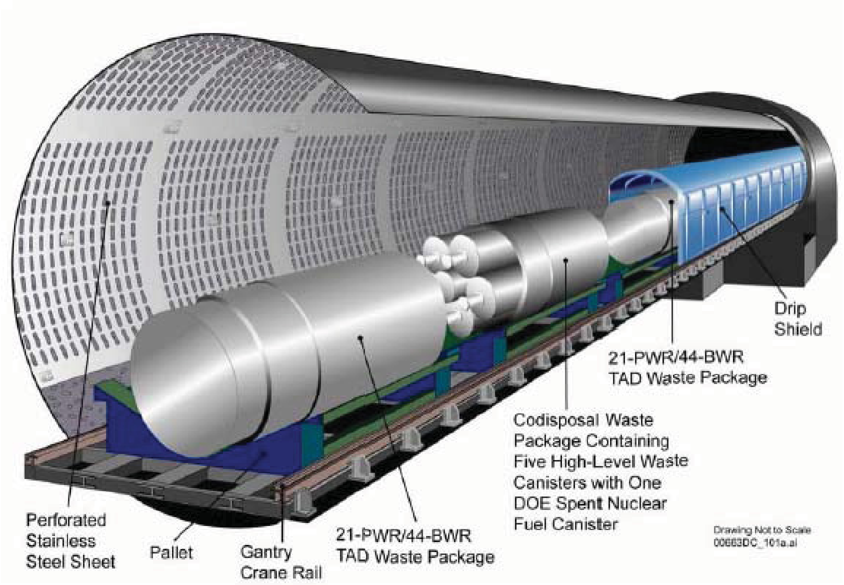

Figure L-3. Waste packages and drip shields (DOE 2008).

L-4. MODULE INTERFACE DEFINITION

This module receives SNF and HLW from Module O (SNF/HLW Transportation) and retains the SNF/HLW in perpetuity. Some waste management schemes include using the geologic repository for interim storage of the SNF until the used fuel is removed for recycling. The additional costs (storage pads, waste handling, repackaging, etc.) to use the repository as an interim storage facility are not included in this module and would need to be separately estimated.

L-5. MODULE SCALING FACTORS

There have been several studies that have tried to define the basic scaling relationships between cost and the size of the repository. Costs have been estimated for repositories of two sizes at Yucca Mountain: 97,000 metric ton of heavy metal (MTHM) (DOE 2001; Gillespie 2001) and most recently 122,100 MTHM (DOE 2008). The primary driver for the 2007 Total System Life Cycle Cost (TSLCC) increase of 38% from the comparable May 2001 TSLCC estimate is the 26% increase in waste quantity. The cost increases were due to multiple factors including an extended waste transportation period and emplacement period, increase in required waste packages, and transportation shipments. Another important factor in the cost increase was the refinement and specificity of the system design. The cost increase for only the repository portion was 25% (excluding transportation and balance of program costs). This cost increase could imply a nearly direct relationship between costs and facility capacity of about 1:1 (25%/26%= ~1.0).

The Electric Power Research Institute (EPRI) performed a study in 2006 that considered possible expansion of Yucca Mountain (from 70,000 MTHM to 260,000 MTHM and 570,000 MTHM) and the estimated costs for the expanded capacities (EPRI 2006). One of the difficulties that EPRI had in this analysis was understanding how much of the YMP costs are fixed costs (not tied to repository capacity) and what percent were variable costs (that is, dependent upon the amount of waste capacity). EPRI was able through a 1998 Viability Assessment (DOE 1998) and additional DOE documentation, to estimate the percentage of fixed costs and variable costs in each cost category. The EPRI results concluded that the waste emplacement phase dominated the costs estimates and increase significantly as a function of repository capacity. Total costs increased from $72B (2007 $) for a 70,000 MTHM repository to $338B (2007 $) for a 570,000 MTHM repository. Figure L-4 provides a comparison of the projected repository costs for three sizes of repositories. The costs rose by 400% for an increase in capacity of more than 800%, or a relationship between costs and capacity size of about 1:2 (400%/800%= 0.5). Assuming a relationship: (Cost/Base Cost) = (Capacity/Base Capacity)^n, the EPRI 70 kT and 570kT data points give a value for the exponent n of 0.737. EPRI states that there are large uncertainties associated with utilizing the unit costs for a repository with a capacity on the order of 100,000 MTHM as a basis for projecting costs for a much larger facility. However, EPRI believes that their estimate can provide a reasonable basis of comparison with scoping-level cost estimates associated with other waste management approaches whose cost are equally uncertain.

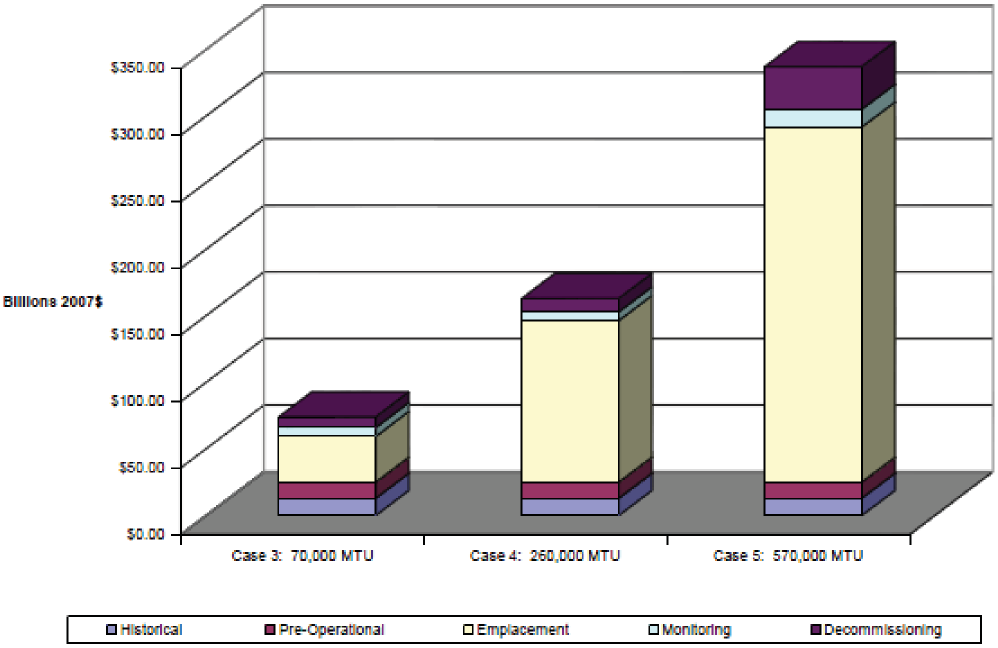

Figure L-4. Comparison of projected repository costs for a 70,000 MTHM, 260,000 MTHM, and 570,000 MTHM repository (EPRI 2007).

The Nuclear Energy Agency (NEA) prepared an international review of cost estimates for disposing of SNF and HLW in deep geologic repositories in 1993 (NEA 1993). The NEA report evaluated the impact of the economy of scale on disposal costs. They concluded that though there is considerable variability in the estimated costs, and there is a general trend that disposing larger quantities of waste result in lower normalized disposal costs. They found that “a substantial investment will be relatively constant,” irrespective of how much waste will be disposed of. This investment is primarily related to constructing facilities that would need to be in place regardless of the size of the repository and includes access shafts/ramps, ventilation systems, lifting equipment, service supply, and communication equipment. The 1993 NEA report points out studies that show cost of increasing repository capacity is smaller than the cost of developing a second repository. This general finding would appear in agreement with the EPRI study.

A disposal cost analysis was also prepared by the AFCI program in 2009 (Nutt 2009). In this analysis, cost data were gathered from NEA, Yucca Mountain Project, generic salt repositories, and international repositories. They came to three basic conclusions: (1) there is considerable uncertainty in estimating SNF/HLW disposal costs, (2) early cost estimates based on preliminary and/or pre-conceptual designs are generally lower than more advanced programs/designs, and (3) there appears to be an economy of scale with respect to disposal costs. This analysis cites an evaluation performed in the UK where data from several international programs were plotted on a log-log scale that showed an approximate straight-line fit where costs increase with the nth power of the waste tonnage, where n is 0.6 (i.e., less than directly proportional).

If a country chose to use multiple, regional disposal facilities rather than centralized disposal then the fixed costs for siting, site characterization, design, and construction of some facilities would have to be repeated at several sites. The advantage of a single repository concept where an existing facility would continue to be used (or expanded as necessary) to dispose of SNF/HLW is that the fixed costs have already been incurred with only variable costs increasing with the size of the facility.

In the author's opinion, there is a minimum facility size of approximately 10,000 MTHM, where up to this capacity there is very little economy of scale. In larger facilities an economy of scale may exist if the site was originally characterized to provide for future expansion, there is no major change to the waste stream (e.g., from SNF to cycled products in HLW) or packaging concepts (transportation and disposal canister repackaging), and the facility receiving throughput remains the same. Under these conditions, a scaling factor of approximately 0.6–0.75 would seem appropriate.

L-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The cost basis for geologic disposal was drawn from domestic and international studies.

L-6.1 Domestic Studies

Currently in the United States, the costs for disposition of commercial spent nuclear fuel is assessed as a one mill ($0.001) per kilowatt-hour fee charged to generators of commercial spent nuclear fuel. Since this estimate is for a system that will operate for over 100 years in to the future, the concept upon which the estimate is based should be viewed as only representative of the system that is ultimately developed. TSLCC studies are performed[a] to determine the adequacy of the 1 mill fee. This fee on a per kilogram heavy metal (kgHM) basis equates to about $400/kgHM based on the average burn-up of the used fuel generated by the utilities to date. Although the TSLCC estimates for the YMP have been increasing over time, the 1 mill fee has not been changed. In the author's opinion the costs for SNF disposition are unlikely to be less than $400/kgHM.

The primary cost bases for the geologic repository are from the YMP, since this is the most mature concept that has been proposed in the U.S. However, the DOE's FY 2010 budget request announces the Administration's intended termination of the Yucca Mountain repository project and includes the funding needed to explore alternatives for nuclear waste disposal and to continue participation in the Nuclear Regulatory Commission license application process. All funding for the development of the Yucca Mountain facility and related infrastructure—such as further land acquisition, transportation access, and additional engineering—has been eliminated. To that end, the Secretary of Energy is convening a Blue-Ribbon Panel of experts to evaluate alternative approaches for meeting the federal government's responsibility (Kouts 2009).

In light of the potential move away from YMP as the repository, it is problematic to estimate from the available cost information what another repository in the U.S. would cost, since many of the costs could be argued to be unique to the Yucca Mountain site. For example, selecting another site with dissimilar hydrological and geochemical conditions might require different waste-package materials, and could have a significant impact on the cost. Some research costs might be lower for a new repository due to the experience gained from YMP, but this experience would only help to a limited extent since the geology is unique for every site. Also, if the legal and regulatory environment were more favorable for a new repository, some of the licensing costs might be reduced. However, more-favorable conditions are not ensured. Cost estimates for European repositories, presented in the next section, may provide some

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[a] The TSLCC is required by Section 302 of the Nuclear Waste Policy Act of 1982 (as amended).

insight. Otherwise, the uncertainties associated with geology, public acceptance, and licensing environment is so large that the YMP cost is likely the best current estimate for geologic disposal.

The most current estimate of the YMP was prepared by DOE-RW in Fiscal Year 2007 (DOE 2008). This estimate was based on the acceptance of YMP for the permanent disposal of all currently projected civilian and defense wastes,[b] estimated to be 122,100 MTHM consisting of 109,300 MTHM of commercial SNF and 12,800 MTHM of DOE HLW. The TSLCC spans the period of 1983 to the assumed closure date of 2133, and totals $96.18B in constant 2007 dollars (or $79.34B in 2000 dollars). The 2007 TSLCC was compared to the costs from the previous estimate prepared in 2001 (escalated to 2007$). The total cost delta is $26,450M (in 2007$). Table L-1 summarizes the 2007 and 2001 TSLCC estimate in terms of 2007 dollars.

Table L-1. Comparison between TSLCC Estimates in 2001 and 2007 (in millions of 2000 dollars) (DOE 2008).

Cost Element	2001 TSLCC Estimate Total Costs (2007 $M)	2007 TSLCC Estimate Total Costs (2007 $M)	Delta Costs from 2001 to 2007 (2007 $M)
Repository	$51,980	$64,730	$12,750
Transportation	$8,680	$20,250	$11,570
Balance of Program	$9,070	$11,200	$2,130
Total	$69,730	$96,180	$26,450

Table L-2 compares the total costs and their associated facility capacities and unit costs per heavy metal. The 2007 TSLCC estimate is higher than the 2001 estimate; however the amount of SNF/HLW is also increased by 25,100 MT. The net increase in unit cost ($719/kgHM to $787/kgHM) is an increase of less than 10% after accounting for inflation.

Table L-2. Comparison of TSLCC Estimates prepared in 2001 and 2007 (DOE 2008).

Cost Element	2001 TSLCC	2007 TSLCC	Delta
Total TSLCC (2007$)	$69,730M	$96,180M	$26,450M
Total SNF/HLW for Commercial + Defense Waste	97,000 MTHM	122,100 MTHM	25,100 MTHM
Unit Cost (2007$)[c]	$719/kgHM	$787/kgHM	$68/kgHM

The costs are broken down into three major categories: (1) Total Repository costs, (2) Transportation, (3) and Balance of Program. All the costs in Table L-4 (including historical costs) are stated in 2000 dollars. The costs ($79.35B) are escalated for inflation at a rate of approximately 3% per year to arrive at a cost equivalent for 2007 ($96.18B). In applying these costs to Module L, the transportation costs are included in this basis but would need to be backed out if the costs for Module O are also estimated. The Project Management and Integration costs would also need to be prorated to eliminate the portion applicable to transportation activities. The repository is assumed to be government-owned, though most of the work would be contracted out. The cost of land is not included as the Yucca Mountain site and surrounding land is already U.S. government property.

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[b] Commercial and defense waste are not equivalent, and a proration scheme (mass, #packages) can be used to back out the costs for only commercial SNF, which according to an AFCI study (Nutt 2009) would be in the range of 75-90% of the cost.

[c] The TSLCC unit costs are not necessarily inconsistent with the ~$400/kg figure equating to the 1 mill/kWh fee, because fees paid by utilities accumulate in the Nuclear Waste Fund and earn interest at 2%-3% per year above inflation. If this weren't the case, the 1 mill/kWh fee would not longer be considered adequate to cover the future costs of the repository.

Table L-4. 2007 TSLCC of the Total Repository, Transportation, and Balance of Program (DOE 2007).

	Cost, $M (in 2000 Dollars)					
	Development and Evaluation	Engineering, Procurement, Construction	Operations	Monitoring	Closure	Totals (2000 $)
Licensing	0	$1,930		0	0	$1,930
Surface & Subsurface Facilities	0	$12,830	$7,900	$850	$800	$22,380
Waste Packages & Drip Shields	0	$200	$10,380	$6,290	0	$16,870
Performance Confirmation	0	0	$1,390	$850	$250	$2,490
Regulatory, Infrastructure, & Management Support	$6,870	0	$2,380	$370	$100	$9,720
Total Repository	$6,870	$14,960	$22,050	$8,360	$1,150	$53,390
Transportation						$16,710
Balance of Program						$9,240
Total (2000 $)						$79,350

In addition to YMP, there has also been substantial experience gained in salt repositories. The Waste Isolation Pilot Plant (WIPP) in Carlsbad, New Mexico, a deep geologic repository for disposal of transuranic waste, has been in operation since 1999. This repository was not designed or licensed for disposal of HLW/SNF, but does provide a basis for similar future facilities (AFCI 2008). Based on the AFCI study (Nutt 2009), the cost of constructing a generic salt repository and operating it over a 100-year period while disposing 263,000 MTHM of spent fuel, was estimated to range from $22.8 to $30.6 billion, not including the costs for site selection, site characterization, and licensing activities.

In evaluation of the domestic cost information for YMP refined over the past 10 years, we have seen the cost estimates increase to reflect higher facility capacities and more mature system designs. The latest design reflects greater certainty in the transportation plans, emplacement schedules, waste packages, and regulatory requirements. The latest 2007 TSLCC estimate of $787/kgHM for a 122,100 MTHM facility (consisting of commercial as well as defense wastes) provides the most current basis yet for fuel cycle economic analysis.[d] This estimate can be further broken down to $600/kgHM (disposal only) and $187/kgHM (transportation only) in 2007$. When the costs are placed into 2009 $, they would increase to about $650/kgHM (disposal only) and $200/kgHM (transportation only) based on a large 122,100 MTHM facility. These costs do not include any waste conditioning or storage.

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[d] The allocated unit costs for commercial fuel disposal only, would be approximately 10% less (~$707/kgHM) than the costs for the combined commercial and defense wastes ($787/kgHM). In terms of utilizing YMP as a proxy for a future HLW repository, the cost analyst has chosen to utilize the higher cost number because the exact composition of waste for any future geologic repository is unknown. In the future, the wastes going to the repository could reasonably consist of commercial SNF, reprocessed commercial fuel as a product of various fuel cycles, and also defense wastes.

L-6.2 International Studies

Various international studies have been performed on potential disposal options and sites including various geologies. Most of the research has been performed in Europe by the European Commission and other international organizations (IAEA, OECD). These organizations are moving forward with research, development, and demonstration programs to develop the technical solutions for deep geological repositories (IGD-TP 2009). Comparisons between the studies are difficult due to differences in country specific waste management regulations, waste treatment strategies (once-through, recycle), vastly different site locations and geologic mediums, various repository design concepts and design maturities, waste disposal volumes, and cost estimates that are based on the indigenous currency under various financial conditions and timeframes. Nonetheless, the data are useful to understand the potential range of options and costs for geologic disposal.

An article (Chapman and McCombie 2006) in *Nuclear Engineering International* discussed costs for a British geologic repository. The costs were based on cost studies for such facilities in Sweden, Switzerland, and Belgium. The studies estimated costs at two capacities: only SNF from “new build” reactors, and SNF (and HLW) from existing reactors. Also, two major cost elements were considered: cost of the repository and cost of encapsulation (cost to place the SNF in an appropriate container and emplace it in the repository). Encapsulation costs were not available for Belgium, so only the data for Sweden and Switzerland are presented in Table L-5. These data were provided without detail, so it is not possible to assess their applicability to the situation in this country. The greatest insight is probably gained from looking at the cost predictor formula, which results in $\$2.56 \times 10^{-4}$B/MTHM for the Swedish model and $\$3.62 \times 10^{-4}$B/MTHM for the Swiss model. This model is not considered applicable to the U.S. repository, due to differences in repository size, geology, and regulatory environment.

Table L-5. Preliminary cost estimates for two geologic repositories (Chapman and McCombie 2006).

	Existing Reactors	New Build Reactors	Total
Projected Spent Nuclear Fuel Inventory			
Sweden	13,498 MTHM	14,030 MTHM	27,528 MTHM
Switzerland	16,433 MTHM	14,030 MTHM	30,463 MTHM
Cost of Geologic Repository (2004 $)			
Sweden	$4,239M	$2,027M	$6,266M
Switzerland	$5,345M	$3,041M	$8,386M
Cost for Encapsulation (2004 $)			
Sweden	$1,659M	$1,290M	$2,949M
Switzerland	$2,119M	$1,659M	$3,778M
Total Disposal Cost (2004 $)			
Sweden	$5,898M	$3,317M	$9,215M
Switzerland	$7,464M	$4,700M	$12,164M
Unit Costs (2007 $)			
Sweden	$472/kgHM	$255/kgHM	$361/kgHM
Switzerland	$490/kgHM	$361/kgHM	$431/kgHM

The NEA completed a study in 2003 that looked at waste disposal of different waste forms arising from the nuclear fuel cycle (NEA 2003). They considered three different waste types: low-level waste, intermediate level waste, and high-level waste, which comprises SNF or vitrified waste from reprocessing. They report does not provide the cost details; however, they do provide an expected lower and upper bound cost for HLW in geologic disposal. The NEA estimates the disposal costs on a kilogram of uranium oxide fuel basis for both direct disposal of spent fuel and the disposal of HLW from the processing of that spent fuel. Disposal costs for the direct disposal of spent fuel range from $300 to $600 per kilogram of uranium oxide fuel and from $80 to $200 for the disposal of HLW per kilogram of uranium oxide fuel processed. The costs are assumed to be in 2003 $ and were converted from the Euro to USD at 1 Euro = 1 U.S. dollar. The report points out that the volume of HLW per unit energy produced is lower than that of spent fuel and that the disposal of HLW would be cheaper on a cost per kWh of electricity produced than the direct disposal of spent nuclear fuel. The NEA also provided a listing of HLW repository sites and laboratories and associated geologic mediums that are listed in Table L-6.

A disposal cost analysis prepared by the AFCI program compiled and normalized the cost estimates for international repositories (Nutt 2009). Preliminary cost estimates were developed for proposed geologic disposal facilities in France, Belgium, Canada, the Czech Republic, Finland, Hungary, Japan, Switzerland, and Sweden. A summary of the normalized cost data (2007 $) are provided in Table L-6. Future details on the estimates can be found in the references listed under each of the countries.

Table L-6. Compiled International cost estimates for geologic disposal (NEA 2003, Nutt 2009).

Country	Geologic Medium	Size (MTHM)	Total Cost (billions 2007 $)	Unit Cost
Belgium (ONDRAF 2001)	Clay	4,900	$1.72	$361/kgHM (SNF) $140/kgHM (HLW)
Canada (IAEA, App. A-3)	unknown	96,000-192,000[e]	$13–$20	$105–$140/kgHM[a] (SNF)
Czech Republic (IAEA, App. A-4)	6 possible locations	3,724	$1.6	$437/kgHM (SNF)
Finland (IAEA, App. A-5)	Granite	5,600	$4.5	$800/kgHM (SNF)
France (ANDRA 2005)	Granite/Clay	45,000	$19.8	$440/kgHM (as HLW)
Hungary (IAEA, App. A-8)	unknown	1,320	$1.3	$984/kgHM (SNF)
Japan (IAEA, App. A-9)	Granite	29,647	$25-26	$851-885/kgHM (SNF)
Sweden (SKB 2003)	Granite	9,741	$3.4	$350/kgHM (SNF)
Switzerland (IAEA, App. A-18)	Granite/Clay	2,000	$3.6	$1,203/kgHM (SNF)

In summary, in comparison of the international cost data we can see that costs for SNF disposal in a geologic repository are estimated (in 2007 $) to range from around $400/kgHM to over $1,000/kgHM based on facility sizes from a small size of about 1,000 MTHM to a large size of 45,000 MTHM. From the details provided in the references we have also seen substantial cost growth between early estimates and later estimates based on further design and planning maturity.

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[e] Note that the CANDU SNF has low burn-up relative to LWR SNF (10,000 MWd/MTU).

L-7. LIMITATIONS OF COST DATA

The Nuclear Waste Policy Act (DOE 2004) places a limit of 70,000 MTHM on the first geologic repository, so scenarios considering higher capacities are contingent on legislation to modify this restriction. The Secretary of Energy has recommended removal of the 70,000 metric tonne limitation (DOE 2009). Note also that lawsuits and delays have already caused substantial expenditures for YMP, and could well incur additional costs in the future. Such costs are included in the existing contingency estimates to some extent, but possibly could be even higher.

The technology readiness could probably be considered pilot-feasible. While no HLW repository has yet been built, portions of the Yucca Mountain repository have been constructed as part of the testing activities, and the WIPP is an operating geologic repository for transuranic waste. The data quality is categorized as a scoping assessment with a common basis/approach.

L-8. COST SUMMARIES

With the high degree of uncertainty of repository plans, concepts, locations and their associated costs, the authors recommend that a broad uncertainty range of costs be used for any fuel cycle economic analysis. Cost summaries are provided bye SNF disposal (Module L1) and HLW disposal of recycled SNF and (Module L2-1) and activated metal (L2-2).

The module cost information is summarized in the Advanced Fuel Cycle (AFC) What-It-Takes (WIT) Tables L-7 and L-8. The summaries shows the normalized reference costs (constant year dollars), reference contingency factors (if known), and the cost analyst's judgment of the potential upsides (reductions to the costs from the reference case), downsides (additions to cost from the reference base), and selected values (i.e., expected costs based on the reference cost, contingency, upsides, and downsides). These values are preliminary and will be updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to report Section 2.6 for additional details on the cost estimation approach used to construct the WIT table. Note that contingency estimates to measure uncertainty are not available. The "project" contingencies have been included in the estimates for the individual line items.

The triangular distribution for the SNF disposal costs (Module L1) from the WIT Table L-7 is shown in Figure L-4. The distribution is skewed toward the high costs due to the current uncertainties in geologic disposal and waste management policies.

Table L-7. Cost summary table for SNF disposal (Module L1) in a geologic repository.

What-It-Takes Table (2009 $)			
Reference Cost and Related Capacity	Upsides (Low Unit Cost)	Downsides (High Unit Cost)	Selected Values (Nominal Cost)
TSLCC $96.18B (122,100 MTHM) (DOE 2007)	$400/kgHM (SNF)	$1,000/kgHM (SNF)	$650/kgHM (SNF) (2007 TSLCC modified for "disposal-only" and escalated to 2009 $.)
	Rationale: 1) Continuation of the 1 mill/kWh fee basis 2) Costs are similar to the average costs of international facilities 3) Based on large facilities with good economies of scale.	Rationale: 1) Costs increase as a result of new regulatory policies, 2) More expensive design due to new geology and site characteristics, 3) Less economical facility size.	Rationale: 1) Future new geologic repository costs will be very similar to YMP.

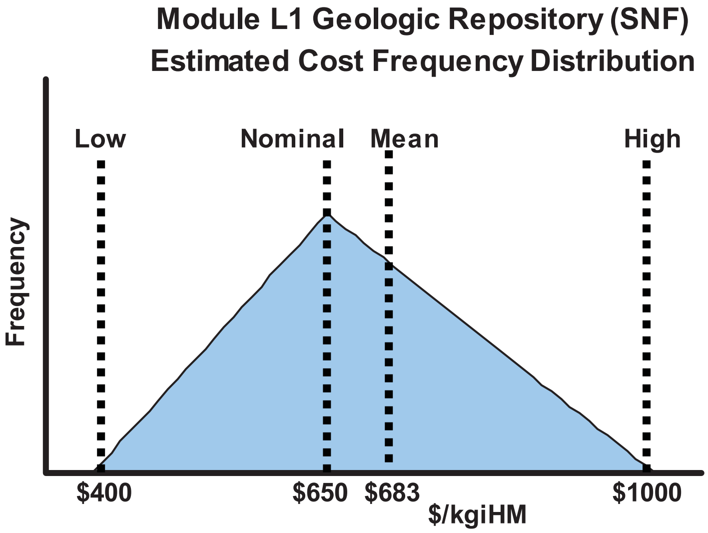

Figure L-4. Geologic repository for SNF estimated cost frequency distribution.

Per unit of energy produced, the cost for disposal of recycled SNF is expected to be less than from unprocessed SNF. By reprocessing the SNF, many of the heat-producing radionuclides are removed, allowing for more efficient disposal. A study by Wigeland & Bauer (Wigeland et al. 2007) determined that uranium, plutonium, americium, and neptunium, along with fission products cesium and strontium were responsible for limiting loading in a repository based on volumetric and thermal constraints. However, when transuranic elements are recycled and short-lived fission products (Cs, Sr) are placed in separate decay storage, then there could be an increased utilization of space as indicated by the allowable linear loading in repository drifts (tunnels). The results further showed that limited recycling in thermal reactors would provide only a fraction of the benefit that could be achieved with repeated processing and recycling, as is possible in fast neutron reactors.

Ultimately, the disposal efficiency will depend on the partitioning efficiency in the separations process and on the "loading" of HLW in the vitrified end product. A simple rule of thumb applicable to all nuclear reactors consuming uranium or plutonium is that energy production of 1 GWd_t consumes 1 kg of fuel and therefore produces 1 kg of fission products. A 1 GWe plant operating with a capacity factor of 0.9 and a thermal efficiency of 33% therefore discharges 20 MT/year of SNF but produces approximately 1 MT of fission products per year. This corresponds to a fuel discharge exposure of approximately 50 GWD/MT. If the fission product waste loading in the vitrified glass is 12%, then the vitrified HLW equivalent to the SNF output will be 8 MT/yr (a waste mass reduction of 60%). If the fission product loading and partitioning efficiency are such that 1 MT of vitrified HLW (with a higher fission product loading) can be emplaced in the same space as 1 MT of SNF, then the cost to emplace 1 MT of vitrified HLW will be the same as the cost to emplace 1 MT of SNF. In terms of the amount of original SNF represented by the fission product content of the HLW, this will increase the disposal efficiency to 250% of that for SNF.

Note that this result applies to light-water reactor fuel with performance characteristics that are a small "stretch" compared to those attainable today. If, for example, the discharge exposure were increased to 100 GWD/MTHM, twice as much vitrified HLW would be generated from each tonne of SNF. Since only half as much of that SNF would be discharged annually, the annual production of HLW would remain the same as would the annual cost. If 1 MTHM of such SNF could be emplaced in the same space as 1 MTiHM of SNF discharged at 50 GWD/MTHM, the disposal costs for SNF would be halved. Consequently, the disposal cost for HLW, in terms of its equivalent SNF, would be doubled. In the case of fast reactor SNF, with discharge exposures possibly exceeding 200 GWD/MTiHM, the disposal efficiency for such material, either as SNF or HLW, is more uncertain and requires further evaluation.

The costs for disposal of recycled SNF (Module L2-1) are derived from Module L1, where the nominal cost for SNF disposition is $650/kg HM (or $16,250/kg fission products [FP] based on an average FP composition of 4% of initial heavy metal). The waste loading of the HLW for L2-1 is estimated to be improved by a factor of 2x to 10x, with a nominal loading of 2.5x. Therefore, the related HLW disposition costs (L1-2) are estimated to range from $1,625/kg FP to $8,125/kg FP, with a nominal cost of $6,500/kg FP. Since these costs are tied to the defined nominal cost of SNF, the costs should be re-calculated if the conditions defined for the upsides or downsides better represent the geologic repository estimating assumptions.

The HLW disposition cost for activated hulls (not the fission products or used fuel) is provided in Module L2-2. These costs are estimated similarly to Module L1, with a low range cost of $400/kg metal, nominal $650/kg metal, and high $1,000/kg metal.

Table L-8. Cost summary table for HLW disposal (Modules L2-1 and L2-2) in a geologic repository.

What-It-Takes Table (2009 $)			
Reference Cost and Related Capacity	Upsides (Low Unit Cost)	Downsides (High Unit Cost)	Selected Values (Nominal Cost)
L2-1: $650/kgHM (SNF) [2007 TSLCC modified for “disposal-only” and escalated to 2009 $.]	$1,625/kg FP (HLW) Nominal SNF cost with a FP waste loading of 10x.	$8,125/kg FP (HLW) Nominal SNF cost with a FP waste loading of 2x.	$6,500/kg FP (HLW) Nominal SNF cost with a FP waste loading of 2.5x.
L2-2: Activated Hulls based on same costs as SNF disposal	$400/kg metal (HLW)	$1,000/kg metal (HLW)	$650/kg metal (HLW) [2007 TSLCC modified for “disposal-only” and escalated to 2009 $.]

The triangular distribution for the HLW disposal costs from the WIT Table L-8 is shown in Figure L-5. The distribution is skewed toward the high costs due to the greater probably of achieving a waste form loading (glass, ceramic, etc.) in the 2x–4x range.

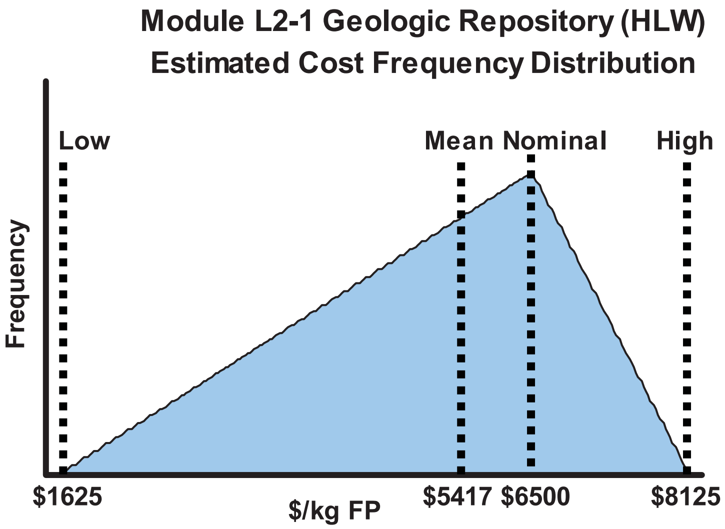

Figure L-5. Geologic repository for HLW (Module L2-1) estimated cost frequency distribution.

L-9. RESULTS FOR SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for this module.

L-10. BIBLIOGRAPHY

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Module M Series

Alternative Disposal Concepts (Modules M1 through M3)

Module M1

Deep Borehole Disposal

Module M1

Deep Borehole Disposal

M1-1. BASIC INFORMATION

Three alternative disposal concepts were briefly investigated: Deep Boreholes (Section M1), Seabed (Section M2), and Extraterrestrial (Section M3). All the alternative disposal options are only at a very preliminary conceptual stage, and therefore, no definitive detailed information or cost estimates are available.

Very deep boreholes, perhaps 4 km deep, have been considered in several countries for the disposal of spent fuel or high-level waste, as well as a proliferation-resistant approach to the disposition of plutonium. In several current concepts, material would be placed in thin-walled canisters in the bottom 2-km portion of a 4-km-deep hole, with clay seals separating each canister and a long column of clay, topped by concrete, on top of the entire assembly of canisters. As a result of the great depth of the boreholes and very low permeability of the granite formations proposed for the concepts, deep boreholes may potentially isolate radioactive materials from the biosphere for much longer periods than even mined geologic repositories. Nevertheless, deep boreholes have not been selected as the preferred disposal method in any country. This is in part because of the greater difficulty of engineering the disposal site, characterizing the physics and chemistry of the surrounding rock, monitoring the material once emplaced, and finally, recovering the material should unforeseen circumstances require retrieval.

The risk of releasing material to the environment from boreholes at such depths requires further study. There are substantial reasons to believe the risk should be very low if the borehole is in an area free of geologic activity that could possibly bring the material to the surface and is also free of vertical faults in the rock that might create pathways for migration toward the surface. The very saline water often found at great depths would make it virtually impossible for material in the borehole to rise to the surface by convection. The saline water is significantly denser than the fresher water above and, therefore, does not rise through even if heated.

Swedish estimates place the cost of deep hole disposal of spent fuel in the range of $100M per hole, although a Russian group advertises it will drill a set of boreholes for much less (Office of International Affairs 1994). A potential lower cost alternative to the generalized approach involves grinding the waste and pumping the slurry into a deep borehole, possibly one developed during the exploration and production of petroleum, resulting in potential savings of approximately $5M if an existing borehole is used. The primary advantage of the slurry method is the stability of the formation. The main disadvantage is the high equipment maintenance associated with pumping slurries, which could result in the approach being prohibitive from either a cost or safety perspective.

M1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

After review of seven disposal concepts, Chapman and Gibb (2003) propose a low temperature disposal conceptual model in which encapsulated wastes are placed in the lower 1,000 m of a borehole 4,000 m in depth, in stable crystalline basement rocks of regions with average geothermal flux. Containment of the waste package within the natural geological barrier is the primary feature of the system.

Key elements of the containment concept follow:

- "The rock in the disposal zone is expected to have no effective movement of pore and fracture fluids under undisturbed conditions." Evidence from very deep boreholes in Russia, Sweden, and Germany indicates fluids in the proposed disposal zone are hydrogeologically stable, with residence times of millions of years.
- The wastes disposed in the deep boreholes are sufficiently cooled such that thermal load imposed on the rock-fluid system does not destabilize the structure by causing fluid convection. The thermal load can be controlled, to some extent, by the proper spacing of the waste containers.
- "A long system of borehole seals isolates the disposal zone from overlying rock formations and groundwater systems." In addition, upper casing sections can be cut and withdrawn, causing the borehole to collapse or backfill, making reentry difficult.

The design described here uses a conceptual borehole diameter of 0.8 m in the disposal zone, which is best suited for small volumes of waste in compact packages. The diameter of the borehole would permit thin-walled metal containers with diameters about 0.5 m and lengths about 1 m. Each of the packages could contain 0.17 m^3 of waste, equivalent to approximately half of a metric tonne. Assuming a nominal emplacement pitch of 2 m and an emplacement zone 100 m in length, a single borehole could accommodate about 250 MT of waste.[a] The disposal method would be best suited to programs with relatively small quantities of high-level waste. A simple diagram of the functional flow is presented in Figure M1-1.

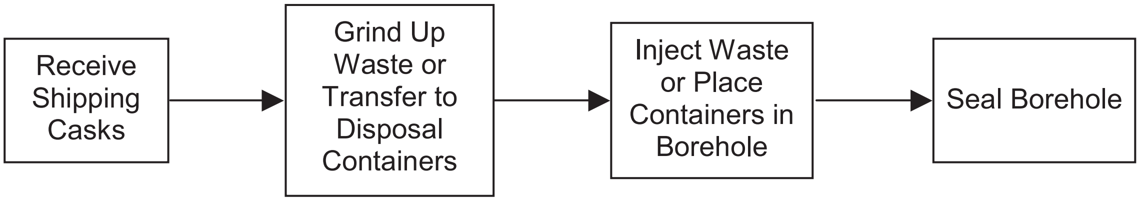

Figure M1-1. Functional block diagram for deep borehole waste disposal.

M1-3. PICTURES/SCHEMATICS

The conceptual model for deep borehole disposal is illustrated in Figures M1-2 and M1-3.

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[a] If the waste is UO_2 spent fuel, 250 MT waste equates to about 220 MTHM. If the waste is high-level waste, the equivalent amount of fuel will depend on the exposure of the fuel. A simple rule of thumb is that fission of 1 g of an actinide yields 1 MWd of energy, and also 1 g of fission products. If the high-level waste form is 50% fission products (and therefore 50% matrix), 250 MT of waste is equivalent to 125 TWd of thermal energy. At an exposure of 50 GWd/MTHM, that is equivalent to 2500 MTHM; at 30 GWd/MTHM, it is 4267 MTHM.

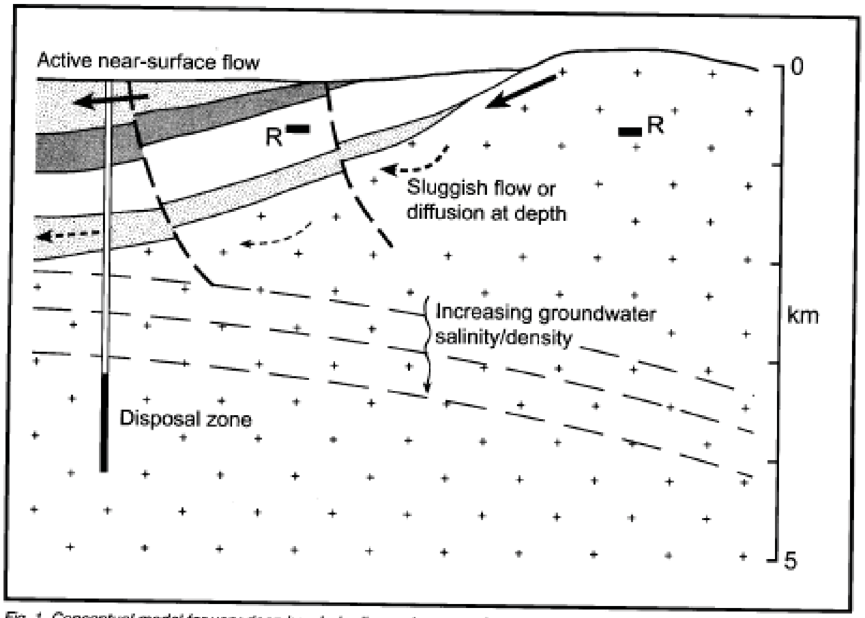

Fig. 1. Conceptual model for very deep borehole disposal. In this scenario, wastes are emplaced in the lower 1000 m of a borehole, deep within crystalline basement rocks in a region that is hydraulically effectively decoupled from more active regions of groundwater flow in the upper part of the crust. At these depths, pore fluids in the rock might be expected to be stagnant, stable, and density stratified, with progressively increasing salinity with depth. "R" denotes typical depths of conventional mined repositories for long-lived wastes.

Figure M1-2. Conceptual model for deep borehole disposal (Chapman and Gibb 2003).

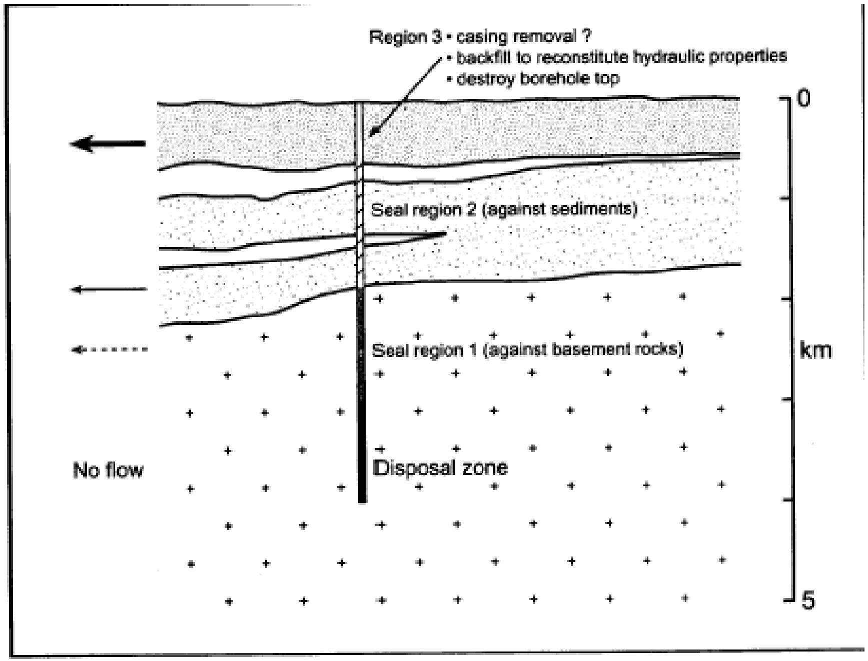

Fig. 2. Sealing concepts for a very deep borehole penetrating deep basement under thick sediments. Different seals are used in each formation, and there is scope for multiple seal types in any single formation. In this concept, the upper part of the borehole casing is cut above one of the casing shoes and is withdrawn with the hole being backfilled, partially to reconstitute formation hydraulic proper ties, leaving a "ghost" of the original hole. For safeguard purposes, the upper part of the borehole is destroyed t hamper future location and reentry (see text for details). Th arrows on the left indicate relative movement of groundwa ters and pore fluids.

Figure M1-3. Sealing concepts for a deep borehole under thick sediments (Chapman and Gibb 2003).

M1-4. MODULE INTERFACE DEFINITION

Module M accepts spent nuclear fuel or high-level waste casks transported by Module O and is a terminal module in that nothing leaves once it has been accepted.

M1-5. MODULE SCALING FACTORS

Not directly applicable.

M1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

An illustration of a project estimate is provided in Table M1-1. The estimate is for a facility to inject waste into a deep borehole. Two other estimates, for boreholes only, were referenced by Chapman and Gibb (2003) from other sources: an estimate of the drilling cost of a large-diameter 4-km-deep borehole at £1M (2000) per km and an estimate of €4.65M (2000) for a 0.8-m-diameter, 4-km-deep borehole. For exchange rates (in 2000) of 0.6609 pounds per dollar and 1.0854 euros per dollar, the former estimate works out to $6.1M for a 4-km-deep hole and the latter works out to $4.3M. If the previous values are multiplied by a factor of 1.13 to convert the estimates from 2000 to 2006 dollars, yields $6.9M and $4.9M for the alternate sources, which are comparable to the 2004 $5M cost ($5.3M 2006) for the disposal well in Table M1-1.

Table M1-1. Estimated cost for deep borehole and injection facility.

			Aug. 19, 2004 Dollars in Millions
Description	Factor	Labor-Hours	Cost
Disposal Well			$5.00
Injection Facility			$10.00
Total Field Cost		0	$15.00
Construction Management/Procurement @ % of Field	0.00		$0.00
D.E/P.M @ % of Field Cost	10.00	0	$1.50
Total Directs			$16.50
Owners Field (10% Craft Labor-Hours) @ $/Labor-Hour	80.00	0	$0.00
Owners Home Office @ 7.73% of Field Cost			$1.16
Total Owners Cost			$1.16
Total Direct + Owners Costs			$17.66
Environmental Permitting @ % of Above	3.00%		$0.53
Licensing @ % of Above	0.00%		$0.00
Total Allowances			$0.53
Total Direct + Owners + Allowances Costs			$18.19
Startup & Testing @ % Above	2.00%		$0.36
Total in 2004 Dollars			$18.55
Escalation / Rounding	0.00%		$0.00
Total in 2004 Dollars			$18.55
Contingency	20.00%		$3.71
Grand Total			$22.26
Grand Total in 2006 Dollars @ 1.06 CPI	106.00%		$23.60

M1-7. LIMITATIONS OF COST DATA

All cost data are extraordinarily preliminary and should be considered only as rough order of magnitude costs. The technology readiness is considered to be research and development–possible. Considerable work and expense would be required to design and license one of these facilities. The data quality is categorized as independent sources without a common basis.

The cost estimates referenced by Chapman and Gibb (2003) are for the borehole drilling alone and do not include surface structures, facilities, and associated maintenance, nor the cost of the land. Although the estimates are from references concerned with nuclear waste disposal, costs due to increased analysis and safety criteria have not been included. Detailed designs and analyses have not been completed and much additional work on the design of the borehole, the effect of borehole fluids on the waste emplacement procedure, and the effect of the mechanical load on a column of packages would be required. In addition, the experience of the Yucca Mountain Project and other nuclear waste disposal projects has demonstrated quality assurance and other regulatory activities, including oversight groups and delays caused by litigation. These activities can—and probably will—add large additional costs, which are not considered here. Indeed, such activities and the required associated responses have already incurred long delays and cost billions of dollars to the Yucca Mountain Project.

M1-8. COST SUMMARIES

The code-of-accounts information for the concept is summarized in Table M1-2. Capital costs are extracted from Table M1-1, where operating and management costs are not estimated. The total cost of $24M is unrealistically much too low and should be considered an extremely optimistic result.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table M-2. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The reference case is the deep borehole injection facility estimated in Table M1-3. The other case presented is the $24,000/MT estimate ($25,500/MT [2006 dollars]) for 280 deep boreholes at $6M each, based on 70,000 metric tonnes of uranium (MTU) of waste and 250 MTU in each borehole, similar to the concept proposed by Chapman and Gibb (2003). The estimate does not include surface facilities or operating, maintenance, and management. The cost of surface facilities is probably small in comparison to drilling the boreholes, but operations and maintenance costs would likely be significant.

The distribution is skewed toward the high cost because this disposal method has not been done before (the technology is at the research stage), so there is a large amount of uncertainty with the cost.

Table M1-2. Code-of-accounts information for deep borehole disposal.

AFCI Code of Accounts Number	Code of Accounts Description	Cost (Million 2006 dollars)	Comments
0	Early Life Cycle Costs	—	—
1	Capitalized pre-construction costs	—	—
2	Capitalized Direct Costs	24	—
	Total Directs	24	—
3	Capitalized support services	—	—
	Base Construction Cost (BCC)	24	—
4	Capitalized operations	—	—
5	Capitalized supplementary costs	—	—
	Total Overnight Cost (TOC)	24	—
6	Capitalized financial costs	—	—
	Total Capital Investment Cost (TCIC)	24	—
7	Annualized O&M cost	—	Not estimated
9	Annualized financial costs	—	Not estimated
	Total Operating Costs	—	—
	Total Project Life-Cycle Cost	24	20% contingency

Table M1-3. Cost summary table for deep borehole disposal.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
\$24 M \$96,000/MT waste \$109,090/MTHM if SNF \$9,600/MTHM if high-level waste from fuel at 50 GWd/MTHM	20%	—	\$1,700 M \$21,600/MT waste \$24,530/MTHM if SNF \$2,160/MTHM if high-level waste from fuel at 50 GWd/MTHM	\$1,700 M
Cost for deep borehole injection (one borehole)	—	—	Cost for 280 deep boreholes	Further analysis required

M1-9. RESULTS OF SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for Module M.

Module M2

Seabed Disposal

Module M2

Seabed Disposal

M2-1. BASIC INFORMATION

Seabed disposal involves emplacing wastes in a subseafloor location in the ocean. The waste can either be emplaced in boreholes or dropped from a ship in a package specially designed to kinetically penetrate into the seabed mud at an appropriate depth.

M2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Disposal of high-level waste by burial in the mud layer on the deep ocean floor, referred as "subseabed disposal," has long been considered the leading alternative to mined geologic repositories. A detailed study by the Nuclear Energy Agency of the Organization for Economic Cooperation and Development in 1988 concluded "sub-seabed burial appears to be a technically feasible method of disposal of high-level radioactive wastes or spent fuel" (NEA 1988) The work was summarized in an eight-volume report of which the most relevant are Volume 1, containing an overview and conclusions, and Volume 4, which discusses engineering aspects and provides some information on cost estimates.

The idea of subseabed disposal is to put the material in metallic canisters that would be emplaced in the "abyssal clay formation" several kilometers beneath the ocean surface. The canisters would be emplaced perhaps 30 m below the deep ocean mud surface, for which core samples demonstrate has been undisturbed in some areas for millions of years. Placement could be accomplished by the following three methods:

1. The use of free-falling "penetrators" dropped from ships that would accelerate falling through the ocean depths and become embedded in the benthic mud
2. A long drill stem from a surface ship
3. Lowering an emplacement package by a cable from the ship.

An alternate approach would be to drill through the sediments into the bedrock below and emplace the canisters in the holes. This in essence combines the deep-borehole and subseabed concepts.

A number of methods for emplacing the waste are illustrated in Figure M2-1. The waste can be emplaced in a trench or drilled borehole or embedded by means of a penetrator. The waste can either be embedded in the soft near-surface seabed sediments or, if drilled, emplaced in deeper rock layers. The disposal site should be away from the edges of tectonic plates, continental margins, potential mineral, or biological resources and have little erosion and active pore water movement. A simple functional-flow diagram is shown in Figure M2-1.

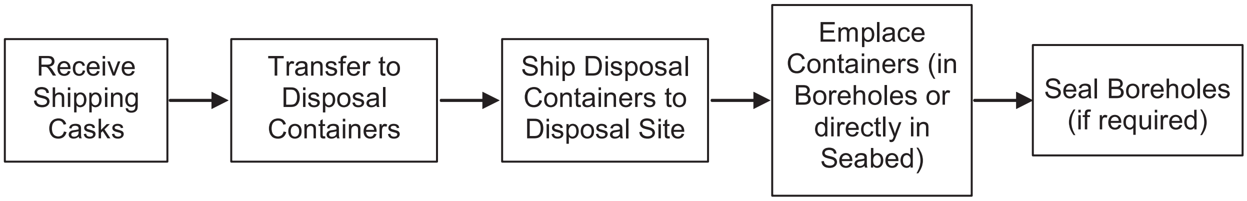

Figure M2-1. Functional block diagram for seabed waste disposal.

The subseabed disposal option in mid-ocean areas considered herein should not be confused with the concept of emplacement in the “subduction zone,” where one tectonic plate is slipping beneath another with the waste being carried deep into the crust of the earth. The difficulty with the subduction disposal approach is even “fast” seafloor motions occur at a rate of approximately 1 cm per year. This means that in all of historic time (~5,000 years) the material would have moved only 50 m. Furthermore, subduction zones are geologically active and unpredictable, prone to volcanoes among other phenomenon, and as a result research into the concept is presently only very preliminary.

M2-3. PICTURES/SCHEMATICS

Concepts for seabed disposal are illustrated in Figures M2-2 and M2-3.

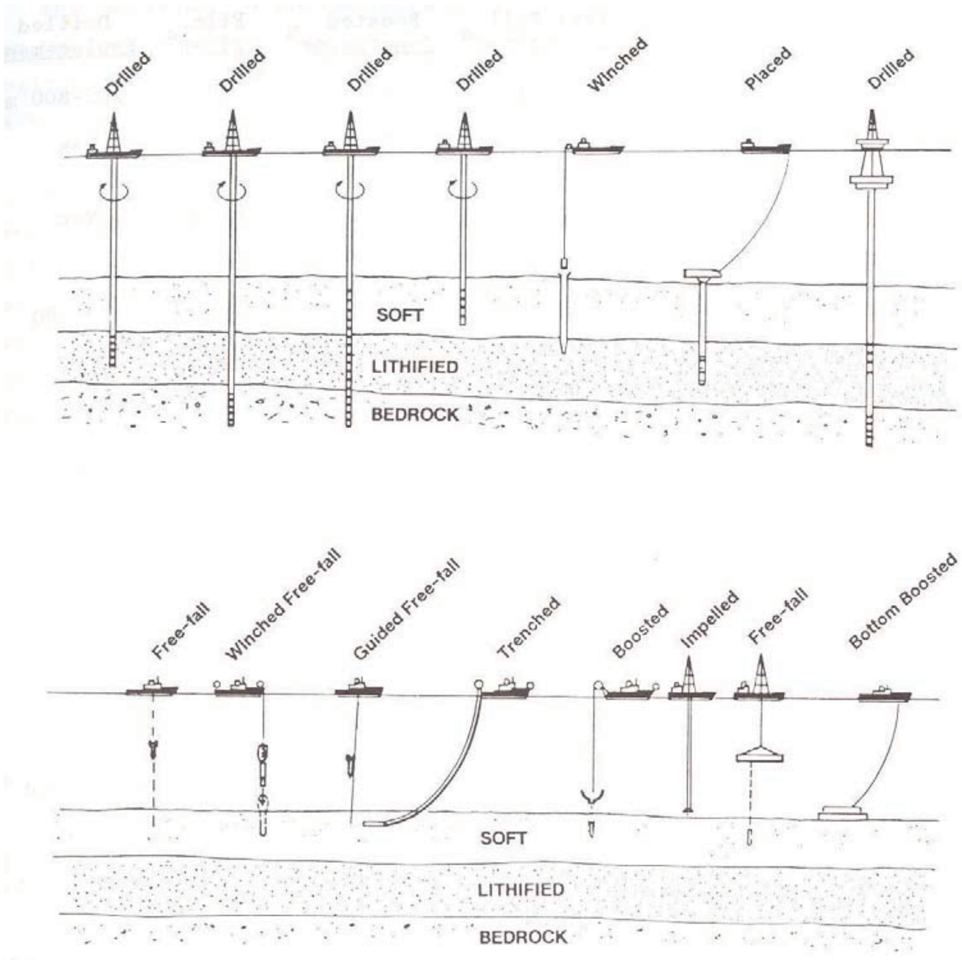

Figure M2-2. Representative emplacement methods for seabed disposal (NEA 1988), Volume 4, p. 27.

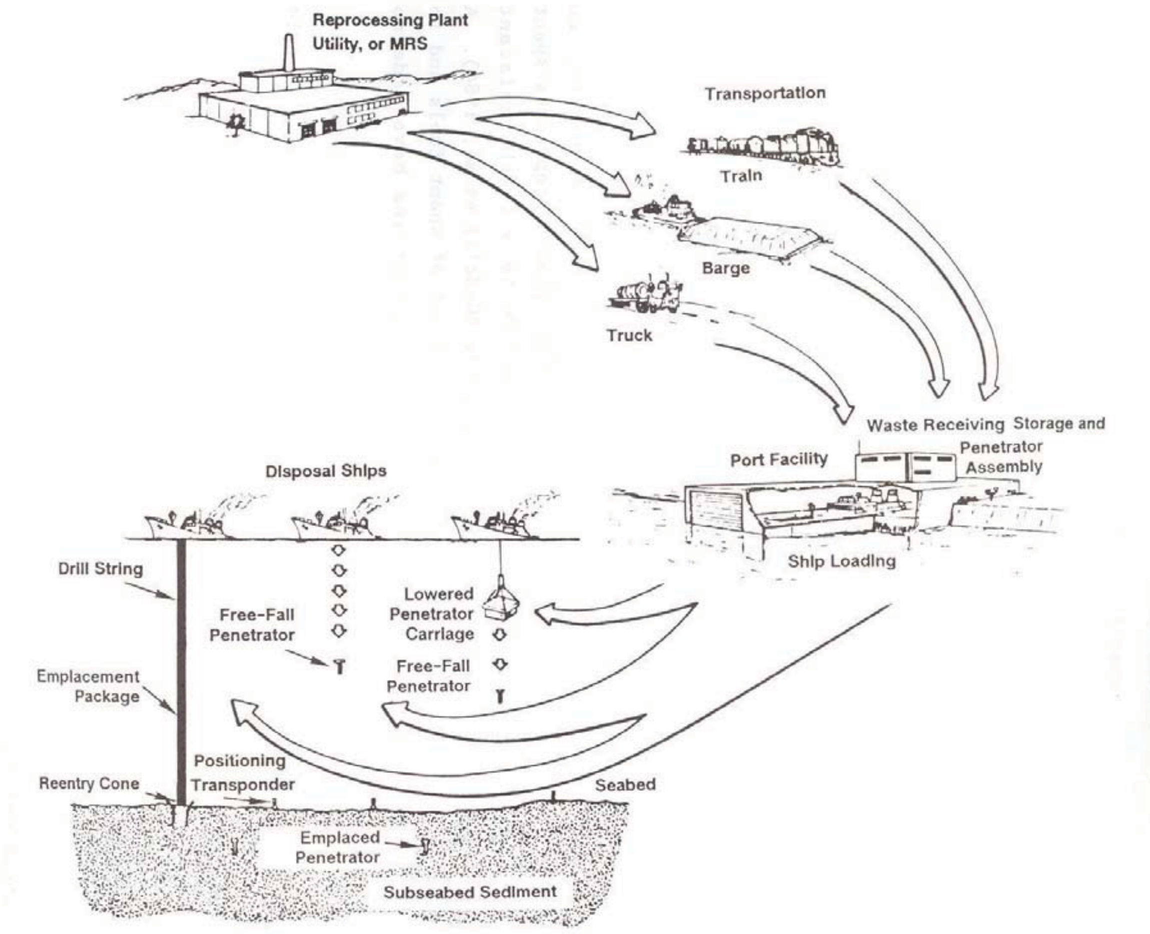

Figure M2-3. A general logistic cycle for seabed disposal (NEA 1988), Volume 4, p. 22.

M2-3.1 Module Interface Definition

The module accepts spent nuclear fuel or high-level waste casks transported by Module O. Module M is a terminal module in that nothing leaves once it has been accepted.

M2-4. MODULE SCALING FACTORS

Not directly applicable.

M2-5. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Although preliminary, past analyses for the case of spent nuclear fuel and high-level waste suggest the costs of subseabed disposal would be competitive with mined geological disposal, with the actual cost of emplacement in the range of a few hundred million dollars. However, the development and demonstration program necessary to meet licensing requirements might well cost billions of dollars, similarly as in the case of land repositories. In addition, subseabed disposal would likely face intense public and political opposition from many quarters, including a complex of both national and international legal barriers and regulation, with the consequence of making any further development of the option difficult, uncertain of success, time-consuming, and expensive.

Two options for seabed disposal discussed in some detail in Volume 4 of the Nuclear Energy Agency report (1988) have been analyzed to derive cost estimates:

1. Emplacement in predrilled boreholes 750 m deep and 1,000 m apart (horizontal spacing). Each borehole would receive a 450-m column of waste packages and would be sealed after waste-package emplacement.
2. Use of free-falling penetrators to embed waste packages about 50 m deep in the seabed, in an array with a nominal horizontal spacing of 180 m.

The spacings were defined to achieve thermal and chemical isolation of each disposal location from neighboring boreholes.

Various parameters for the two cases are listed in Table M2-1. Cost estimates from the Nuclear Energy Agency report are listed in Table M2-2. The cost units are not explicitly stated, but are apparently 1987 British Pound Sterling (UK £) and are based on disposal of vitrified high-level waste. The canisters referred to are European Reference Canisters (ERC), which hold 1.39 MTHM of high-level waste; hence, the 3,750 MTHM per year of Table M2-1 is equivalent to the 2,700 canisters per year of Table M2-2. The conversion rate for pounds per dollar was 1.634 in 1987, and U.S. inflation from 1987 to 2006 was 1.76 based on the Consumer Price Index. Thus, a factor of 2.88 is needed to convert the costs in Table M2-2 to 2006 dollars. The final values presented in the table yield a result of approximately $137,000 (2006 $U.S.)/MTHM for drilled emplacement and $56,000 (2006 $U.S.)/MTHM for penetrator emplacement (following division by a factor of 1.39 MTHM/ERC).

Table M2-1. Utilization parameters for a 100,000 MTHM disposal site receiving waste at a rate of 3,750 MTHM per year (NEA 1988), Volume 4, page 143.

Parameter	Units	Drilled Emplacement	European Reference Penetrators	U.S. Reference Penetrators	
Horizontal Spacing (Square Array)	m	1,000	180	180	
Heavy Metal per Emplacement Location	MTHM	417	6.95	1.97	(RW)
				1.50	(SF)
Total Number of Emplacement Locations	—	240	14,389	50,761	(RW)
				66,667	(SF)
Number of Emplacement Sites Used per Year	—	9	540	1,904	(RW)
				2,500	(SF)
Disposal Site Area	km^2	240	466	1,645	(RW)
				2,165	(SF)
Disposal Site Width (Square Area)	km^2	15.5	21.6	40.6	(RW)
				46.5	(SF)
Transport Ship Capacity	MTHM	423	584	804	(RW)
				524	(SF)
Shipments to Site per Year	—	8.9	6.4	4.7	(RW)
				7.2	(SF)
Emplacement or Transport Ships Required	—	1–2	1–2	1–2	(RW)
				2	(SF)
RW = reprocessed waste, SF = spent fuel (apportioned as 60% pressurized water reactor and 40% boiling water reactor)					

Table M2-2. Costs of drilled versus penetrator emplacement (1987 UK £) (NEA 1988), Volume 4, page 147.

	Drilled Emplacement					Penetrator Emplacement				
	No.	Unit Cost (k£)	Total Cost (k£)	Amorti-zation	Annual Cost (k£)	No.	Unit Cost (k£)	Total Cost (k£)	Amorti-zation	Annual Cost (k£)
Canister land transport:										
Canister flask capital	8	750	6,000	12.5	858	8	750	6,000	12.5	858
Railway wagon capital	8	50	400	12.5	57	8	50	400	12.5	57
Canister transport	24	8	192	0	192	24	8	192	0	192
Flask & canister maintenance	—	—	1,000	0	1,000	—	—	1,000	0	1,000
					2,107					2,107
Ullage filling & overpacking or penetrator assembly plant:										
Assembly buildings capital	1	180,000	180,000	25	19,800	1	180,000	180,000	25	19,800
Assembly equip. capital	1	128,300	180,000	12.5	18,304	1	120,000	120,000	12.5	18,304
Pen/overpack components	2,700	7.5	20,250	0	20,250	540	25	13,500	0	13,500
Assembly materials	included	—	—	0	0	540	5	2,700	0	2,700
Operating costs	included	—	—	0	0	540	3	1,620	0	1,620
Staffing	200	30	6,000	0	6,000	200	30	6,000	0	6,000
Maintenance	—	—	100	0	100	—	—	100	0	100
Insurance (@ 0.25%)	—	—	770	0	770	—	—	770	0	770
					65,224					62,794
Dockside facilities:										
Civil works capital	1	2,000	2,000	25	220	1	10,000	10,000	25	1,100
Dock equipment capital	1	2,000	2,000	12.5	286	1	5,000	5,000	12.5	715
Dock operation	—	—	1,000	0	1,000			1,200	0	1,200
Dock staffing	50	30	1,500	0	1,500	20	30	600	0	600
Maintenance	included	—	—	0	0	included	—	—	0	0
Insurance	—	—	10	0	10	—	—	38	0	38
					1,516					3,653
Penetrator/Canister Sea Transport:										
Ship capital	—	—	N/A	0	0	1	15,000	15,000	12.5	2,145
Flasks	54	750	40,500	12.5	5,792	2	1,000	2,000	12.5	286
Ship operation	included	—	—	0	0	7	70	490	0	490

Table M2-2. (continued).

	Drilled Emplacement					Penetrator Emplacement				
	No.	Unit Cost (k£)	Total Cost (k£)	Amorti-zation	Annual Cost (k£)	No.	Unit Cost (k£)	Total Cost (k£)	Amorti-zation	Annual Cost (k£)
Ship staffing	included	—	—	0	0	20	40	800	0	800
Maintenance	included	—	—	0	0	—	—	200	0	200
Insurance	included	—	—	0	0	—	—	255	0	255
					5,792					4,176
Supply Ships:										
Ship charter	—	—	5,000	0	5,000	—	—	—	0	0
Drilling Ships:										
Ship charter	—	—	34,500	0	34,500					
Hole casings	9	100	900	0	1,900					
Consumables	9	20	180	0	180					
					46,372					0
Semi-submersible:										
Construction site capital	1	45,011	117,977	25	12,977					
Main structure	1	33,269								
Superstructure capital	1	39,697								
Construction site capital	1	45,011								
Equipment capital	1	61,285	61,285	12.5	8,764					
Towing and installation	1	9,682	9,682	12.5	1,385					
Miscellaneous capital	1	18,849	18,849	25	2,073					
Consumables (+ backfilling)	—	3,811	3,811	0	3,811					
Staffing	444	50,000	22,200	0	22,200					
Energy	—	—	5,500	0	5,500					
Maintenance	—	—	3,502	0	3,502					
Insurance (@ 1.5%)	—	—	3,095	0	3,095					
					63,307				0	0
Decommissioning:										
Assembly plants	1	5,800	5,800	–25	64	—	—	—	–25	64
Transport vessels	—	—	—	0	0	—	—	—	0	0
Quayside facilities	—	—	—	0	0	—	—	—	0	0
Emplacement vessel	1	100,000	100,000	–25	1,100	—	—	—	0	
					1,164					64
Total:					179,690					72,794
Cost/European Reference Canister:	179,690,000 2,700			=	66,000	72,794,000 2,700			=	26,960

M2-6. LIMITATIONS OF COST DATA

All cost data are extraordinarily preliminary and should be considered only as rough order of magnitude costs. The technology readiness is considered to be research and development–possible. While subseabed burial appears to be a technically feasible method of disposal of high-level wastes or fuel, the option faces major problems of public and international acceptability as well as major legal restrictions. Moreover, a substantial period of further development would be required prior to implementation. The United States cancelled the program investigating subseabed disposition in 1986, and presently no country in the world is actively pursuing research and development on subseabed disposal. Considerable work and expense would be required to design and license one of these facilities, and as no country is pursuing development, further improved cost estimates are not expected anytime in the near future. The data quality is categorized as independent sources without a common basis.

As discussed in the National Academy of Sciences report, research on seabed disposal has been discontinued as a matter of policy, and any further consideration would require amendments to international treaties involving use of the seabed (NAS 2001). Overcoming such an obstacle would presumably incur additional costs. Further, the experience of the Yucca Mountain Project and other nuclear waste disposal projects has demonstrated quality assurance and other regulatory activities, including oversight organizations and delays due to litigation. These activities can—and probably will—add large additional costs not considered in the presented estimates. Such actions have already cost the Yucca Mountain Project billions of dollars.

M2-7. COST SUMMARIES

Code of accounts information for the concept is summarized in Table M2-3. The presented costs are based on the values in Table M2-2 for penetrator emplacement, which is less expensive than drilled emplacement, normalized to cost per MTHM and converted to 2006 dollars. The unit mass and constant dollar conversion factors, as presently previously, are 1.39 MTHM per canister and 2.88 2006 dollars per 1987£, respectively.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table M2-4. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst’s judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

The costs assume vitrified high-level waste in ERC, and no detailed cost estimates for direct disposal of spent fuel have been found employing the sub-seabed approach.

Table M2-3. Code-of-accounts information for seabed disposal.

AFCI Code of Accounts Number	Code-of-Accounts Description	Cost (Thousand 2006 dollars per MTHM)	Comments
0	Early Life Cycle Costs	—	—
1	Capitalized Preconstruction costs	—	—
2	Capitalized Direct Costs	16	—
	Total Directs	16	—
3	Capitalized Support Services	—	—
	Base Construction Cost (BCC)	16	—
4	Capitalized Operations	—	—
5	Capitalized Supplementary Costs	—	—
	Total Overnight Cost (TOC)	16	—
6	Capitalized Financial Costs	—	—
	Total Capital Investment Cost (TCIC)	16	—
7	Operation and Maintenance Cost	22	—
9	Financial Costs	18	—
	Total Operating Costs	40	—
	Total Project Life-Cycle Cost	56	—

Table M2-4. Cost summary table for seabed disposal.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$56,000/MTHM	—	$137,000/MTHM	$56,000/MTHM
Cost for seabed disposal with penetrator emplacement	—	Cost for seabed disposal with drilled emplacement	Further analysis required

M2-8. RESULTS OF SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for the module.

Module M3

Extraterrestrial Disposal

Module M3

Extraterrestrial Disposal

M3-1. BASIC INFORMATION

Extraterrestrial disposal involves placing the waste into distant earth orbit, a heliocentric orbit between Venus and Earth, or launching into the sun. To maximize payloads and reduce costs would require the spent nuclear fuel to be processed to remove the short half-life (tens to perhaps a 100 years) of radionuclides as well as any useful elements, such as uranium or plutonium.

The usual concept when considering space disposal is to initially launch the material into a circular low-earth orbit of approximately 300 km altitude. This requires a rocket velocity gain of about 8 km/s, followed by an additional burn to move the material onto some desired deep-space path, whether another orbit around the sun, beyond the solar system, or directly into the sun. Staging from low-earth orbit with a subsequent additional burn requires the least amount of energy and is, therefore, likely the lowest cost approach to launching payloads into space.

M3-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

As an alternate low cost approach to expendables, Ehricke (1983) proposes using a space shuttle to transport waste into near-earth orbit, and subsequently release the waste sending it on to a primary candidate disposal “site” between Venus and Earth. The spent fuel is first reprocessed to remove the short half-life and recyclable isotopes, and following 10 years of storage as liquid waste is solidified in 6-inch diameter pots and shipped for final disposal. A single-launch mode is envisioned for early initiation of space disposal but is likely to be more costly than a multilaunch mode.

Depicted below in Figure M3-1 is an associated simplified diagram of the functional flow of the extraterrestrial waste disposal process.

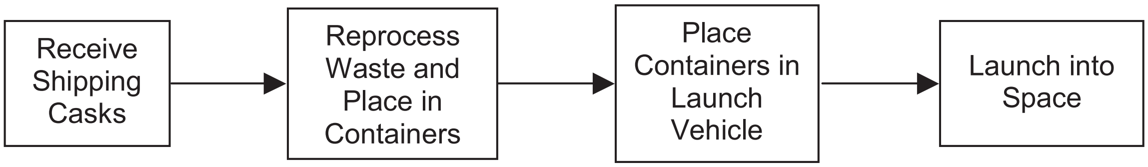

Figure M3-1. Functional block diagram for extraterrestrial waste disposal.

M3-3. PICTURES/SCHEMATICS

Salkeld and Beichel (1980) also examined the possibility of nuclear waste disposal in space. A schematic of one possible nuclear waste cask and shipping container for extraterrestrial disposal to be loaded in an orbit vehicle is shown in Figure M3-2.

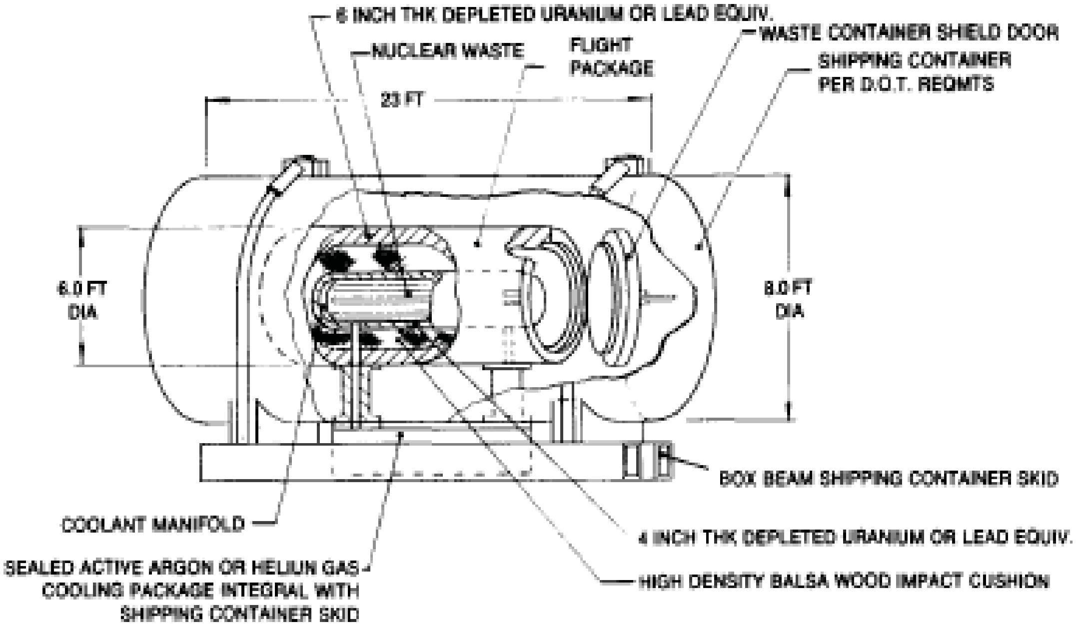

Figure M3-2. Conceptual nuclear waste cask and shipping container for extraterrestrial disposal (Ehricke 1983).

M3-4. MODULE INTERFACE DEFINITION

Module M accepts spent nuclear fuel or high-level waste casks being transported via Module O. The waste will likely have been reprocessed in Module F, conditioned and repackaged in Module G, and subsequently transported via Module O directly bypassing any storage at nuclear power plants or long-term storage facility. Module M is a terminal module with respect that nothing leaves once the spent nuclear fuel or high-level waste has been accepted for disposal.

M3-5. MODULE SCALING FACTORS

Not directly applicable.

M3-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The National Academy of Sciences has evaluated extraterrestrial disposal for the disposition of plutonium, and estimates today large payloads cost approximately $10,000/kg to launch and achieve low-earth orbit (NAS 2001). Achieving low-earth orbit is not sufficient, as the material must still be launched to an orbit unlikely to encounter the earth, put on a path to the sun, or finally escape the solar system to circumvent falling back to the earth. However, just the case of launching the spent nuclear fuel or high-level waste to LEO equates to approximately $10M per MT, which compares very unfavorably with respect to both the earlier deep borehole and subseabed alternatives estimated at $25,500/MT and $56,000/MT, respectively.

An alternative concept proposes using a space shuttle to transport waste into near-earth orbit, and subsequently release and send the material on to a disposal area between Venus and Earth. The ability to reuse the shuttle may be lower in cost as compared to expendables, and a detailed cost estimate analysis has been performed on the concept. Information from Ehricke (1983) is summarized in Tables M3-1 through M3-3.

Table M3-1. Energy characteristics of extraterrestrial disposal of nuclear waste (Ehricke 1983).

From Near-Earth Orbit	Earth Orbit	Geosync Orbit (28°) Venu. S.[4]	Lunar Surface			To Edge of Sun	To 0.01 A.U.	To 0.02 A.U.	To 0.05 A.U.	To 0.1 A.U.	Solar Escape
			Crash Landing	Soft							
				Direct	CLO						
1. Direct Flight (Km/S)	3.3	3.9	3.1	5.7	5.9	22.2	20.2	18.4	15.6	12.4	—
2. Via Venu. S. Gravity Assist (Km/S)1)	—	—	—	—	—	20.2	19.0	17.2	14.2	10.4	—
3. Via Jupiter Gravity Assist (KM/S)2)	—	—	—	—	—	—	—	—	—	—	6.7
From Earth Surface:											
● Disposal Energy Efficiency3) X=	0.97	0.97	0.97	0.985	0.985	0.9999	0.9999	0.9999	0.999	0.999	0.990
1. Direct Flight	0.0063	0.0013	0.008	0.0054	0.0042	0.0007	0.0013	0.0022	0.0011	0.0056	—
2. Via Venu. S. G-assist	—	—	—	—	—	0.0013	0.0019	0.0029	0.0028	0.0095	—
3. Via Jupiter G-assist	—	—	—	—	—	—	—	—	—	—	0.0067
● Ratio of Energy for Space Disposal to Energy Generated 1.	3.2 10-5	2.2 10-4	2.2 10-5	1.1 10-4	1.5 10-4	1.3 10-2	5.8 10-3	2.8 10-3	4.1 10-3	5.1 10-4	—
2.	—	—	—	—	—	5.8 10-3	3.5 10-3	1.9 10-3	1.3 10-3	2.1 10-4	—
3.	—	—	—	—	—	—	—	—	—	—	1.2 10-4

CLO = Circumlunar orbit; ETO = Earth-to-orbit; X = Mass fraction = Ratio of propellant weight to sum of propellant plus structural weight. Above values of X, refer to the number of stages needed to achieve the overall velocity increment from earth surface, based on a mean effective specific impulse of 375 sec. The above values give the mass fraction needed, if a single stage was used for the entire mission.

Launch window recurs every 19.2 months.

Launch window recurs every 13.1 months.

$\Delta V_{ETO} = 8.84$ km/s; plus ΔV in first three lines above.

4. Using Venus G-assist to throw load into heliocentric orbit inside 1 AU; or delivery to Venus surface.
One major powered phase near earth required ($3.7 \leq \Delta V \leq 4.3$ KM/S)

Table M3-2. Characteristic data of single-launch disposal missions (LWR waste; orbiter payload: 14.5 ton, carrying waste and IOV; no jettisonable containers) (Ehricke 1983).

Waste Storage Performance Cost	DEO r=50,000 km	Lunar Surface		Earth Escape	Heliocentric orbit < 1 A.U.		Solar System Escape
		Hi-speed Landing	Soft Landing via CLO		Venus. G-assist	Perihelion Maneuver	
Σ ΔV from NEO (KM/S)	4.4	5.0	5.9	3.3	4.0	4.1	6.7
Number of IOV Stages	2	2	2	1	2	2	2
ΔV, ST. 1 / ST. 2 (KM/S)	2.9/1.5	3.3/1.7	3.3/2.6	3.3	2.5/1.5	3.3/0.8	3.3/3.4
I_{SP}, ST. 1 / ST.2 (SEC)	460/350	470/460	470/460	460	460/420	460/320	470/460
Waste Oxide Weight, $W_{\lambda*}$ (T)	0.360	0.319	0.229	0.590	0.525	0.367	0.24
Gross Weight, Stage 2 (T)	6.4	5.92	5.83		7.96	5.30	5.92
Gross Weight, IOV (T)	14.22	14.45	14.22	14.22	14.46	14.32	14.44
IOV, Liquid H_2 Volume (Fraction of Orbiter PLD. Bay Volume)	0.04	0.06	0.07	0.05	0.05	0.05	0.07
Thermal Energy (Twt-YR) Generated Corresponding to $W_{\lambda*}$	0.00650	0.00575	0.00411	0.0106	0.00943	0.00659	0.00431
Corresponding Electric Energy @ 30% Conversion Efficiency (kWhe)	$1.7\ 10^{10}$	$1.51\ 10^{10}$	$1.08\ 10^{10}$	$2.786\ 10^{10}$	$2.48\ 10^{10}$	$1.73\ 10^{10}$	$1.13\ 10^{10}$
Corresponding Revenue @ 5¢/ kWhe (10^6\$)	850	755.6	540.7	1393	1240	866.5	566.7
Cost of ETO Mission (10^6\$) (1978 \$)	35	35	35	35	35	35	35
Cost of IOV (10^6\$)	15	20	30	10	15	20	30
Other Cost Associated with Launch and Maintenance (10^6\$)	20	20	20	15	25	25	30
Disposal Mission Cost (¢/kWhe)	0.412	0.496	0.786	0.215	0.302	0.462	0.838
Special Waste Processing, Transportation, Pre-launch Storage Loading & Associate Operations (¢/kWhe)	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total space disposal cost, incl. 20% contingency (¢/kWhe)	0.51	0.61	0.96	0.27	0.38	0.57	1.02

DEO = distant earth orbit; CLO = circumlunar orbit; IOV = interorbital vehicle; TWT = terawatt-thermal;
NEO = near-earth orbit; all cost figures in 1978-$

Table M3-3. Characteristic data of multiple-launch disposal missions (LWR waste; NWCO payload: 14.5 MT; orbiter payload for IOV transport: 29.5 MT; no jettisonable containers) (Ehricke 1983).**Error! Bookmark not defined.**

Waste Storage		Lunar Surface			Heliocentric Orbit < 1 A.U.		
Performance Cost	DEO R=50,000 KM	Hi-speed Landing	Soft Landing via CLO	Earth Escape	Venu.s. G-assist	Perihelion Maneuver	Solar System Escape
Number of IOV Stages	2	2	2	1	2	2	2
Weight of IOV Without Payload (T)	28.93	28.98	28.95	28.95	29.44	28.79	28.88
Associated Payload of IOV (T)	8.4	7.1	4.85	17	14.5	8.75	5.0
NWCO Net Payload (T) (Waste Oxides & Glass Matrix)	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Minimum IOV Payload Weights Equal to Multiple NWCO Launchings @ 5 Ton per Mission (T)	25	14.2[1)]	4.85	15	29	35	5
Associated Number of IOVs Needed In NEO	3	2	1	1	2	4	1
Number of NWCO Missions to NEO	5	3	1	3	6	7	1
Total Number of ETO missions	8	5	2	4	8	11	2
Total Weight of Waste Oxides Delivered to NEO (T)	8.25	2.3	1.60	4.95	9.57	11.55	1.65
Corresponding Thermal Energy Generated (TWT-YR)	0.14814	0.0413	0.0287	0.0888	0.1718	0.2074	0.03
Corresponding Electric Energy @ 30% Conversion Efficiency (kWhe)	3.896 10^{10}	1.086 10^{11}	7.56 10^{10}	2.337 10^{11}	4.519 10^{11}	5.454 10^{11}	7.79 10^{10}
Cost of ETO Flights @ \$35 10^6 for NWCO Mission and @ \$30 10^6 for Transport of IOV (10^6 \$)	195	165	65	135	210	245	65
Cost of IOVs (10^6 \$)	60	50	30	18	50	120	30
Cost of All Other Associated Operations (10^6 \$)	100	50	30	40	90	120	40
Disposal Mission Cost (¢/kWhe)	0.091	0.0244	0.0165	0.0826	0.0755	0.0889	0.173
Special Waste Processing, Transportation, Pre-launch Storage Loading & assoc. Operations (¢/kWhe)	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total Space Disposal Cost, incl. 20% Contingency (¢/kWhe)	0.12	0.3	0.21	0.11	0.105	0.12	0.22

DEO = distant earth orbit; CLO = circumlunar orbit; NEO = Near-Earth Orbit; IOV = Interorbital Vehicle;
NWCO = Nuclear Waste Carrying Orbiter; TWT = terawatt-thermal; all cost figures in 1978-\$
[1)] 10 ton IOV payload weights, 4.2 ton impact absorber structure

The figures given in the above tables in ¢/kWhe may be suspect. The energy released per metric tonne of waste appears to be 6,590 GWd/MT. Using the "rule of thumb" that fission of 1 g of fissile material yields 1 MWd of energy and 1 g of fission products, an energy content of 6590 GWd/MT would imply 6,590 kg of fission products per metric tonne of waste. That, in turn, implies significant processing to remove low or non-heat generating nuclides from the waste—likely an extremely expensive option. A better approach is to take the raw costs and determine the cost per metric tonne of waste. Tables M3-4 and M3-5 recast the information from Tables M3-2 and M3-3 into costs per metric tonne of waste.

Total cost estimates for space disposal in heliocentric orbit between Earth and Venus are $44M to $50M/metric tonne waste for multiple-launch disposal missions and $171M to $262M/metric tonne waste for single-launch disposal missions (1978 dollars). Costs increase to $98M/MT waste and $475M/MT waste for solar system escape disposal for multiple- and single-launch missions, respectively (1978 dollars). The multiplier to convert to 2006 dollars is 3.06 based upon the Consumer Price Index.

Table M3-4. Recast costs (in millions of dollars) for single-launch missions.

		Lunar Landing			Heliocentric Orbit		
	DEO	Hi-Speed	Soft	Earth Escape	Venus Assist	Perihelion Maneuver	Solar System Escape
ETO	35	35	35	35	35	35	35
IOV(s)	15	20	30	10	15	20	30
Other	20	20	20	15	25	25	30
Total	70	75	85	60	75	80	95
MT Waste	0.360	0.319	0.229	0.590	0.525	0.367	0.240
$/MT with 20% Cont.	233	282	45	122	171	262	475

Table M3-5. Recast costs (in millions of dollars) for multiple-launch missions.

		Lunar Landing			Heliocentric Orbit		
	DEO	Hi-Speed	Soft	Earth Escape	Venus Assist	Perihelion Maneuver	Solar System Escape
ETO	195	195	65	135	210	245	65
IOV(s)	60	50	30	18	50	120	30
Other	100	50	30	40	90	120	40
Total	355	265	125	193	350	485	135
MT Waste	8.25	2.3	1.6	4.95	9.57	11.55	1.65
$/MT with 20% Cont.	52	138	94	47	44	50	98

M3-7. LIMITATIONS OF COST DATA

All cost data are extraordinarily preliminary and should be considered only as rough order of magnitude estimates. The technology readiness level is considered to be research and development-possible. A significant research and development effort accompanied with considerable expense would be needed to design, construct, license, and operate a high-level waste space disposal facility. The data quality is categorized as independent sources without a common basis.

Although the cost estimates by Ehricke (1983) appear fairly comprehensive and include processing and packaging of the spent fuel waste, the analysis was completed in 1983 and does not reflect the current atmosphere surrounding space shuttle missions following the 1986 Challenger and 2003 Columbia disasters. The cost estimates would very likely rise because of increased analysis and safety requirements. In addition, the experience of the Yucca Mountain Project and other nuclear waste disposal projects has been quality assurance and other regulatory activities, including oversight groups and delays caused by litigation. These activities can—and probably will—add large additional costs. Although not considered here, the litigation, regulatory activities, and license application delays have already cost the Yucca Mountain Project billions of dollars.

M3-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table M3-6. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table M3-6. Code of accounts information for extraterrestrial disposal.

AFCI Code-of-Accounts Number	Code of Accounts Description	Cost (2006 $/MT Waste)	Comments
0	Early Life Cycle Costs	—	—
1	Capitalized pre-construction costs	—	—
2	Capitalized Direct Costs	—	—
	Total Directs	—	—
3	Capitalized Support Services	—	—
	Base Construction Cost (BCC)	—	—
4	Capitalized Operations	—	—
5	Capitalized Supplementary Costs	—	—
	Total Overnight Cost (TOC)	—	—
6	Capitalized Financial Costs	—	—
	Total Capital Investment Cost (TCIC)	—	—
7	Annualized O&M Cost	—	—
9	Annualized Financial Costs	—	—
	Total Operating Costs	—	—
	Total Project Life-Cycle Cost (M of $)	134–154	20% contingency

Table M3-7. Cost summary table for extraterrestrial disposal.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	(Low Cost) Upsides	(High Cost) Downsides	(Nominal Cost) Selected Values
\$134–154 M/MT \$13.4–15.4 M/MTHM at 50 GWd/MTHM	20% (included)	—	\$525–800 M/MT waste (\$52.5–60 M/MTHM) \$300 M/MT waste (\$30 M/MTHM) \$1,454 M/MT waste (\$145.4 M/MTHM)	\$134–154 M/MT \$13.4–15.4 M/MTHM at 50 GWd/MTHM
Cost for multiple launch missions, orbit between Earth and Venus	—	—	Single-launch missions, orbit between Earth and Venus; Multiple-launch missions, solar system escape; Single-launch missions, solar system escape	Further analysis required

M3-9. RESULTS OF SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for the module.

M3-10. BIBLIOGRAPHY

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M3-11. REFERENCES

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Module O Series

Transportation Processes
(Modules 01, 02, and Annex OX)

Module O1

Transportation of Radioactive Materials

Module O1

Transportation of Radioactive Materials

O1-1. BASIC INFORMATION

This module develops cost estimates for the shipment of:

- Spent nuclear fuel (SNF) from nuclear power plants to a monitored retrieval storage facility, to a permanent geologic repository, or to other disposal or processing facilities. SNF is assumed to be intact fuel rods in assemblies or bundles placed into a canister. Damaged fuel will be packed into an additional container in such a manner as to prevent criticality or contamination.
- Mixed oxide fuel (MOX)[a] from MOX fuel fabrication facilities to nuclear power plants. MOX is assumed to be intact fuel rods in assemblies placed into canisters.
- Vitrified high-level waste (HLW) from vitrification plants to a monitored retrieval storage facility, to a permanent geologic repository, or to other disposal facilities. HLW is assumed to be in a glass form (presumably a borosilicate glass) and placed in canisters.
- Fuel from naval reactor cores could be handled in a manner similar to that described herein. However, some details of naval fuel remain classified. Recovery of residual fuel values or disposal is the responsibility of the federal government and is not included in this study.

Spent nuclear fuel and vitrified HLW are shipped in shielded casks that are licensed by the Nuclear Regulatory Commission (NRC) and meet NRC requirements for Type-B packages per 10 CFR 73 (NRC 2009). In this module, it is assumed that MOX will be shipped in Type-B packages.

The Type-B packages[b] that are used to ship SNF, MOX, and vitrified HLW use massive, highly shielded casks that are fitted on their ends with energy absorbing devices called impact limiters, which protect the cask and its bolted closure from damage during high speed impact accidents. The highly radioactive materials that are shipped in Type-B packages may be placed in a metal canister that has a lid that is welded to its body before they are loaded into the Type-B package. Vitrified HLW is always canisterized before it is shipped in a Type-B package. Although some Type-B package systems for SNF and MOX do not use canisters, it is assumed in this module that both SNF and MOX are canisterized when shipped in Type-B packages. Because of the length of the MOX assemblies, the shipping casks will be similar to, if not the same as, the casks used for SNF.

Transportation costs for materials shipped as Type-B packages consist of the cost of the Type-B packaging, loading costs at the shipment origin, shipping costs while in transit, and unloading costs at the shipment destination. The transportation costs developed in this module assume that the Type-B packaging is a HI-STAR cask. The HI-STAR cask system was selected as the basis for packaging costing because of the quantity of detailed information available. Its selection makes no statement regarding the merits of other cask systems. Rudimentary investigation indicates that all modern commercial Type-B cask systems approved by the NRC for the shipment of SNF, MOX, and vitrified HLW are cost competitive based on life-cycle cost estimates.

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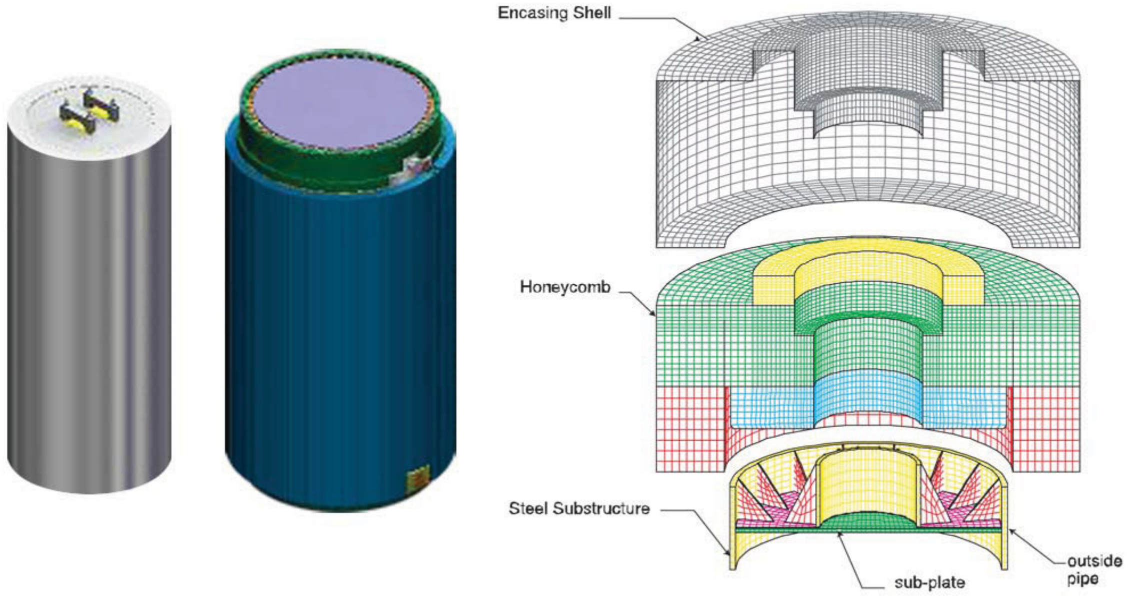
[a] MOX often refers to fuel containing a mix of oxides of uranium and of plutonium that is primarily Pu-239. The term "TRUMOX" is used to describe fuels containing other transuranic nuclides or greater concentrations of the higher plutonium isotopes. In this section, MOX refers to both of these fuels.

[b] In this section, the term "packaging" refers to the devices into which radioactive material is placed for shipment—in other words, the shipping container. The term "package" refers to the container and its contents.

O1-2. PICTURES/SCHEMATICS

Figure O1-1 shows the HI-STAR cask canister and transportation overpack and a schematic of one of the two transportation overpack impact limiters.



Multipurpose Canister **Overpack** **Impact Limiter Schematic**

Figure O1-1. HI-STAR cask components.

O1-3. FUNCTIONAL AND OPERATIONAL DESCRIPTION

The HI-STAR cask system consists of (a) a multipurpose canister equipped with a welded lid that contains the spent fuel assemblies, (b) an overpack in which the canister is housed that provides the required radiation shielding, and (c) two impact limiters, which, when mounted on the ends of the overpack, protect the overpack from the mechanical loads that the cask system might experience during severe collision accidents. Figure O1-1 shows these three principal components of the HI-STAR cask system.

Because the overpack and the two impact limiters can be reused, the cost calculations presented below amortize the costs of these cask system components over the useful life of these components. Because the multipurpose canister is a single use item, its cost is a one-time expense. Since failure of rod cladding due to embrittlement is not a significant concern for average burnup spent fuel, the multipurpose canister may be used to house spent fuel when stored in a geologic repository. If so used, its lifetime should essentially be the same as the lifetime of the geologic repository.

It is possible that the shattering of embrittled high burnup spent fuel cladding might cause a critical pile of spent fuel pellets to form in the bottom of the multipurpose canister before emplacement in a permanent repository. Consequently, transfer of high burnup spent fuel assemblies from the multipurpose canister to single assembly canisters could be required to prevent a criticality event. Such transfer of high burnup assemblies to single assembly canisters is not treated by this module, and the associated cost does not affect the cost estimates developed here.

NRC cask licenses must be renewed every 5 years. In theory, there is no limit on the number of times a cask license can be renewed. However, technological advances tend to render casks obsolete after 20 to 30 years. Moreover, licenses are often revised at less than 5-year intervals because of ongoing changes to the cask design or operational envelope.

Although SNF, MOX, and vitrified HLW can be shipped by truck or by rail, the majority of future shipments of these materials are expected to be by rail. Therefore, only rail casks are considered in this module. Table O1-1 presents SNF capacities for five typical SNF rail casks. The information in Table O1-1 was extracted from the cask Safety Analysis Report for Packaging that the cask manufacturer submitted to the NRC in support of the cask's license application. Because SNF transportation cask systems and in particular the HI-STAR transportation cask system are commercially available technology, the quality of the cost data presented in Table O1-1 is entirely adequate for the scoping analyses performed in this module.

Module G states that the outside diameter of vitrified HLW canisters is 2 ft. Because the inside diameter of the HI-STAR cask cavity is 69-3/4 in., a HI-STAR cask licensed to carry vitrified HLW should be able to carry six vitrified HLW canisters (five canisters placed in a pentagonal array positioned around one central canister) after meeting cask thermal limits by cooling of the vitrified HLW.

Table O1-1 shows that, regardless of fuel type (pressurized water reactor [PWR] or boiling water reactor [BWR]) most SNF Type-B casks can transport about 10 metric tons of initial heavy metal (MTIHM). Thus, for both SNF and for MOX, the shipment packaging cost per kg of initial heavy metal (uranium and plutonium) roughly equals the cask system cost divided by 10^4.

The block diagram in Figure O1-2 presents a flow chart for the operational steps that support the loading of SNF into an SNF cask at a nuclear reactor and shipment of the SNF to a reprocessing plant, a permanent storage facility (e.g., Yucca Mountain Project [YMP]), or an interim storage facility (e.g., PFS, or possibly a spent fuel pool or dry storage facility located at another nuclear reactor).

The diagram shows that the SNF loading sequence consists of three steps. First, the SNF assemblies are loaded into a multipurpose canister; second, the canister is placed in a transportation cask overpack; and finally, the overpack is equipped with impact limiters. After shipment to a reprocessing or storage facility, the multipurpose canister is removed from the cask overpack by reversing the loading sequence, after which the overpack and its impact limiters can be reused.

The functional block diagram for vitrified HLW packaging and transportation would be identical to Figure O1-2 with the topmost block in the diagram that represents storage of SNF at reactor sites replaced by a block that represents storage of vitrified HLW in canisters at the vitrification facility. The functional block diagram for MOX would be very simple, as it would consist of only two blocks, one for the MOX fabrication facility and one for the nuclear power plant to which the MOX fuel is shipped.

Table O1-1. Cask capacities.

Cask	Pressurized Water Reactor Fuel Assembly Design			Boiling Water Reactor Fuel Assembly		
	Ass'y per Cask	Initial U kg/Ass'y	Initial U kg/Cask	Ass'y per Cask	Initial U kg/Ass'y	Initial U kg/Cask
HI-STAR 100	24	440	10,560	68	150	10,200
BFS-TS125	24	440	10,560			
NAC-UMS	24	440	10,560	64	150	9,600
NAC-STC	26	440	11,440	56	180	10,080

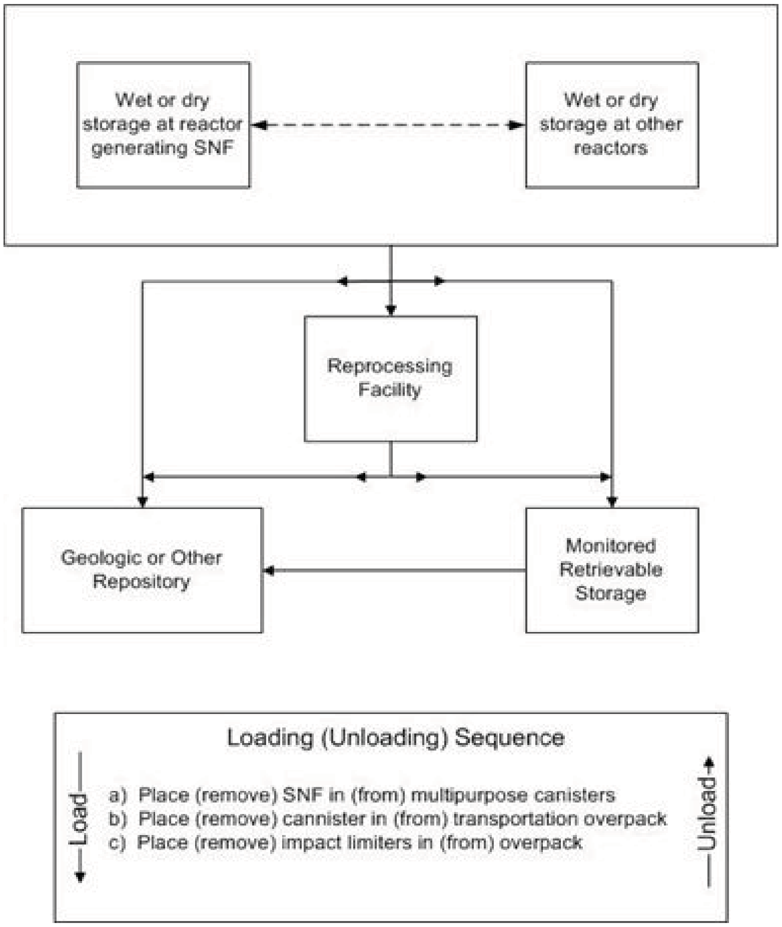


Figure O1-2. Functional block diagram for SNF packaging and transportation.

O1-4. MODULE INTERFACE DEFINITION

Module O receives vitrified HLW from vitrification plants (Module G) and SNF from interim storage in spent fuel pools or dry storage facilities at nuclear power plants (Modules E1 and E2). After packaging, Module O delivers them to interim storage facilities at another nuclear power plant (Modules E1 and E2), to long-term monitored retrieval storage facilities (Module I), to geologic repositories (Module L), or to other permanent disposal sites (Module M). Module O also receives MOX fuel from recycled fuel fabrication plants (Module F2/D2) and delivers this recycled fuel to nuclear power plants.

O1-5. COST BASES, ASSUMPTIONS AND DATA SOURCES

Annex OX to this module derives the algorithm used to estimate transportation costs under consideration for this module and for Module O2 Costs that are not package-specific are provided there, including costs that have been input to a Monte Carlo analysis as distributions.

O1-5.1 Packaging Costs

The costs developed for this module assume that, after placed or poured into a single-use canister, SNF, MOX, and vitrified HLW are shipped in reusable Type-B packagings that are equipped with reusable impact limiters. Although these highly radioactive materials can be shipped in either truck or rail casks, the costs developed in this module assume shipment in rail casks.

In 2001, Sandia National Laboratories solicited informal quotes for several rail cask systems (Ammerman and Sprung 2001) to support the performance of a proposed extra regulatory impact test of a full-scale rail cask. The 2001 quote for the HI-STAR cask system was updated in 2003 (Blessing 2003). Table O1-2 summarizes these cask system cost quotes. All quotes have been escalated to 2007 dollars.[c] The unit costs ($/kg U) shown in the table were calculated using the number of assemblies and total kg of uranium per cask presented in Table O1-1. As Table O1-2 shows, when expressed in 2007 dollars, cask system unit cost estimates range from $368/kgU to $547/kgU (for PWR SNF), and cluster around the escalated November 2003 $456/kgU unit cost quote for the HI-STAR cask system. More detailed cask system descriptions and cost component data are needed if differences in cask system unit costs are to be explained.

A phone conversation with a representative of Holtec International, the firm that manufactures and markets the HI-STAR spent fuel transportation cask system, provided more detailed cost data for this cask system. These data are summarized in Table O1-3, which presents low, modal, and high cost estimates for each costed item.

The range of each of these cost estimates reflects the difference between the 2001 and 2003 cost quotes and the fact that the difference between high end cost estimates and modal cost estimates are often larger than the difference between modal cost estimates and low end cost estimates (Morrow 2004). Table O1-3 shows that the modal value for the total cask system cost is $5.36M. Interestingly, in Appendix E of Feizollahi et al.'s report, gives a cost of approximately $3.75M for an earlier type of SNF shipping cask as of 1993. Conversion of this 1993 cost to 2007 dollars using the Urban Consumer Price Index (CPI) also yields an estimate of $5.36M for the 2007 cost of a spent fuel cask system.

The data in Table O1-3 were used to perform a "1st of a kind/nth of a kind" cost analysis for the HI-STAR cask system. The data were also used to develop cost distributions for the single-use HI-STAR cask canister and for the reusable cask overpack and its two impact limiters by random (Monte Carlo) sampling of the cost distributions for the single-use canister and for the reusable cask system components. A present value analysis was then performed to convert the costs of the reusable items to a daily rental cost. This rental cost is combined with trip lengths (km) and shipment costs per km to estimate total shipment costs for SNF, MOX, and vitrified HLW. Figure O1-3 shows schematically the process through which the raw informal cost quotes were transformed into the information needed to estimate transportation costs for SNF, MOX, and vitrified HLW.

Table O1-2. Summary of Sandia informal quotes (direct costs).

	Direct Cost (Millions of 2007 dollars)				
Cask System	Multipurpose Canister	Transportation Overpack	Impact Limiter (two per overpack)	Complete Cask System	Unit Cost ($/kg U)
HI-STAR 2001 quote 2003 quote	 0.66 0.55	 2.08 2.63	 1.42 0.82	 5.58 4.82	 528/547 456/473
BFS-TS125				5.84	553 (PWR)
NAC-UMS	0.81	2.92	0.30	4.33	410/451
NAC-STC	0.70	2.92	0.29	4.20	368/417

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[c] Cask and container costs have been escalated using the Bureau of Labor Statistics (BLS) Producer Price Index for Construction Machinery and transportation costs have been escalated using the BLS Producer Price Index for Line Haul Railroads. These (and many other) data can be obtained at www.bls.gov.

Table O1-3. HI-STAR cost components.

Component	Cost (Millions of 2007 dollars)			Comments
	Low	Modal	High	
Licensing	8.75	10.94	21.88	High cost reflects additional expenses to obtain a license to transport high burnup SNF. Licensing costs are incorporated into cask system costs by the cask system manufacturer.
Initial fixtures for fabrication	4.38	5.47	10.94	This one time cost is incorporated into cask system costs by the cask system manufacturer.
Single-use multipurpose canister with SNF basket	0.44	0.55	0.77	2001 quote escalated to 2007 dollars is 0.66, which suggests a low end cost uncertainty of $0.1M.
Cask overpack	1.97	2.63	3.50	2001 quote escalated to 2007 dollars is 2.08. Current quote of 2.63 (a 30% increase) is consistent with Holtec's suggestion of a pricing uncertainty of about 33%
Two impact limiters	1.31	1.64	1.97	Reusable
Ancillary equipment for welding and cask loading steps	0.55	0.66	0.88	This is a one-time cost.
Reusable cask components	3.72	4.92	6.35	Sum of Overpack, Impact Limiter, and Ancillary Equipment Costs
Total cask cost	4.27	5.36	7.11	Sum of canister, overpack, impact limiter, and ancillary equipment costs
Annual maintenance costs	Nominal			Because of the design of the single-use multipurpose canister, seals are not an issue. Thus, cask system maintenance will consist of occasional painting and other cosmetic activities
Expected lifetime (years) of the HI-STAR cask overpack and impact limiters	5	25	30	Design life is on the order of 100 years. A license extension every 5 years is initially easy to obtain, but becomes harder to obtain as material and fabrication specifications mature and become obsolete.

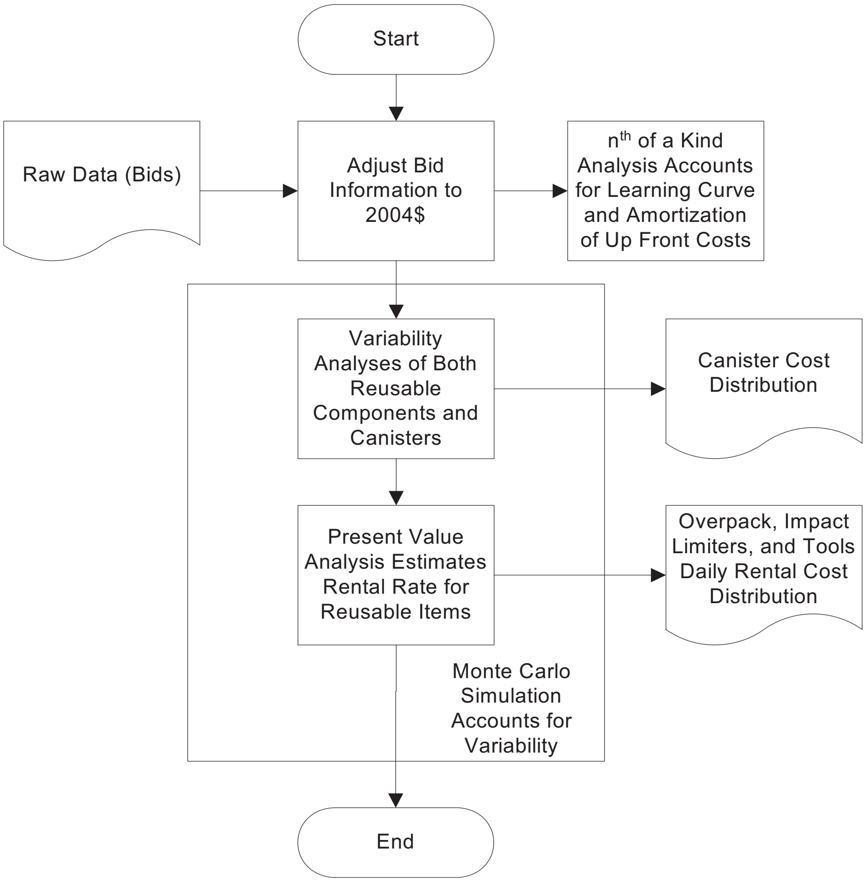

Figure O1-3. Process used to produce consistent cost estimates.

Bids were quoted as n^{th} of a kind costs by Holtec and thus should need no adjustment for the effects of the learning curve on or amortization of up-front costs. Holtec has sold a large number of HI-STORM storage cask systems and is no longer operating as a startup company. Although only a small number of HI-STAR storage/transportation cask systems have been sold to date, Holtec should be able to sell them for an n^{th} of a kind price. Nonetheless, for completeness, a typical "1^{st} of a kind/n^{th} of a kind" cost analysis was performed using the method of analysis presented in the Generation IV economic working group report (G4-EMWG 2003) and the modal HI-STAR cask system costs presented in Table O1-3. For this analysis, the n^{th} of a kind cost was assumed to be reached when the 200^{th} cask system was sold. Figure O1-4 presents the results of this analysis for the reusable cask system components (transportation overpack, impact limiters, and ancillary equipment). Inspection of the figure shows that if Holtec only sells a few HI-STAR cask systems, reusable cask system component costs might be about twice as high as the \$4.8M (escalated) n^{th} of a kind cost quoted by Holtec for reusable cask system components.

Canister Costs. Figure O1-5 presents the cumulative distribution of SNF and MOX canister costs that were developed by Monte Carlo sampling of the triangular distribution of canister costs specified in Table O1-3 for the HI-STAR cask system canister assuming that the procurement costs are about 10% of the canister purchase price (with the 10% procurement costs included, the low, modal, and high values for the triangular cost distribution for the canister become \$0.481M, \$0.602M, and \$0.842M). Figure O1-5 shows that canister costs (canister purchase price + canister procurement costs) might have a median value of about \$675,300 and could range from \$583,700 to \$796,700. Because vitrified HLW is stored at the vitrification plant before being shipped, HLW canister costs are treated as an operational expense in Module G and are not costed in this module.

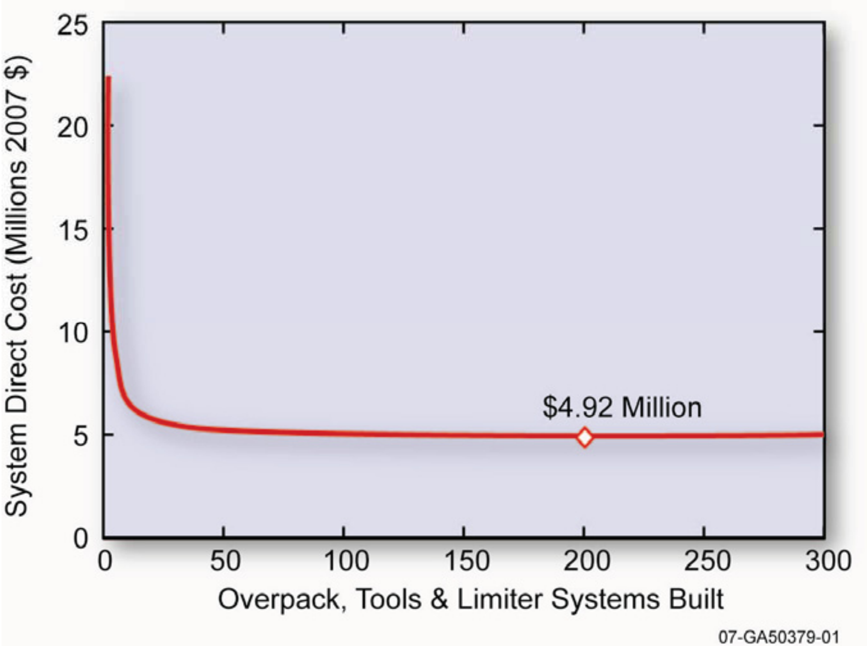

Figure O1-4. N^{th} of a kind curve for reusable items based on modal costs.

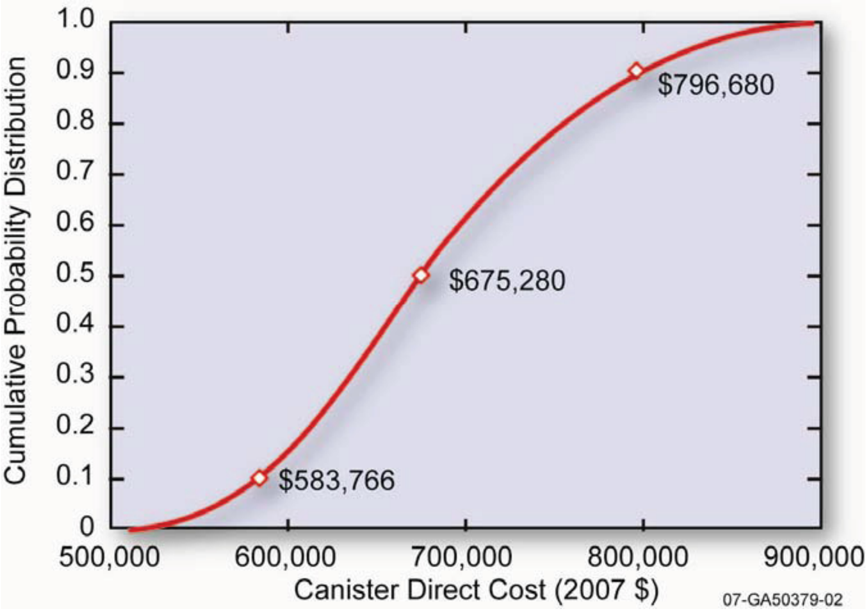

Figure O1-5. Cumulative distribution of multipurpose canister costs resulting from a triangular distribution of canister plus procurement costs.

Rental Costs of Reusable Cask Components. The present value analysis that was performed to develop daily rental costs for reusable cask system components (the cask overpack and its two impact limiters plus the cost of ancillary equipment) used the discounted cash flow methods recommended by Higgins (2001). Price was assumed to match cost at a discount rate of 10%. Table O1-4 presents the parameters that were used in this analysis. The utilization factor represents the fraction of days per year the HI-STAR cask system is assumed to be in use (earning money). Instead of applying an overhead percent to the cask system purchase price, a nominal Operations and Maintenance (O&M) cost

Table O1-4. Present value analysis parameters.

Fixed Parameters		Values		Units
Utilization Factor		0.9		Fraction
Inflation		3%		
Tax Rate		36%		
Discount Rate		10%		
O&M		$117,100		2007 $/year
Sampled Parameters	Low	Modal	High	
Price of Reusable Items	$3.72	$4.92	$6.35	Millions 2007 $
Useful Life	5	25	30	Years

($117,100) was included in the analysis as a fixed cost. The analysis uses straight line depreciation based on the expected life of the cask system. For discounting purposes, year zero was assumed to be 2007. The first five parameters in this table were assumed to be fixed. The final two parameters, the price and useful life of the reusable items, were assumed to vary stochastically. Values for these two parameters were selected by random sampling from the distributions specified for these parameters in Table O1-3.

The present value analysis was run 10,000 times. For each simulation, the calculated cost of the reusable cask components was adjusted to return a zero net present value based on the sum of discounted cash flows for all years of the analysis. Figure O1-6 displays the results of the analysis as a series of rental costs sorted low to high.

Inspection of Figure O1-6 shows that rental costs increase very rapidly once cumulative fractions pass 0.9. Thus, the 90th percentile rental cost is $3,057 per day while the 100th percentile rental cost is over $5,000 per day.

The very rapid increase of daily rental costs at high percentile values is caused by the very asymmetric shape of the triangular distribution assumed for the useful life of the reusable cask system components. This sharp dependence of daily rental cost on useful life is illustrated in Figure O1-7. Figure O1-7 presents a plot of 100 paired values of daily rental cost and the specific value of useful life that generated this daily rental cost. Specifically, the 100 plotted points are the first 100 outputs of the 10,000 calculations that underlie the results presented in Figure O1-6. Because the 10,000 calculations selected their variable input by random Monte Carlo sampling, these 100 results constitute a representative sample of the output of the full set of 10,000 calculations. Also plotted in Figure O1-7 is the best fit regression line through these 100 points. Inspection of Figure O1-7 shows that rental costs for reusable cask components are expected to be about $2,000 per day if the useful life of these components is about 25 years, while daily rental costs increase rapidly as useful life decreases passing $4,000 per day as useful life falls toward 5 years.

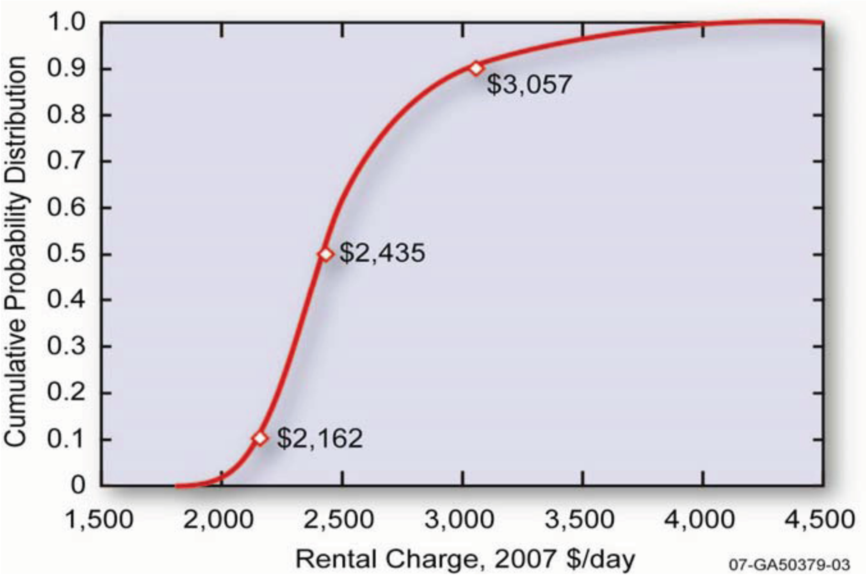

Figure O1-6. Distribution of daily rental cost for reusable cask components. Based on cash flow discounted at 10%.

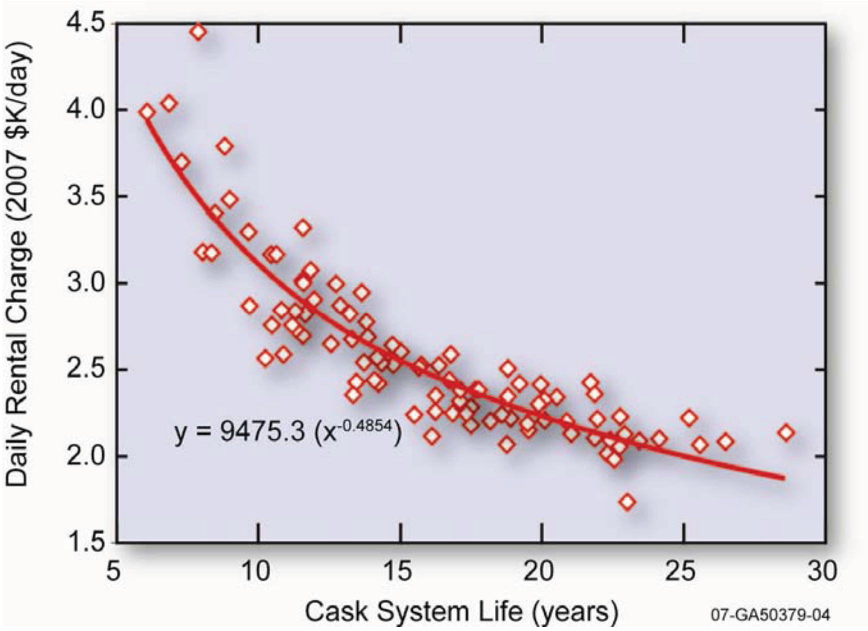

Figure O1-7. Variation of the daily rental rate for cask system reusable components with component useful life.

O1-6. RESULTS

Ten thousand sets of values for the 21 input parameters in the Cost Algorithm, for which distributions were developed, were selected by Monte Carlo sampling. Combination of each set of these values with the values specified for the 11 parameters that had single values generated 10,000 full sets of input for the Cost Algorithm. Running of the Cost Algorithm using these 10,000 sets of input allowed distributions of the five output parameters (fTotalCost, fPackCost, fLCost, fShipCost, fUCost) to be constructed. Output was developed for single shipments in the HI-STAR rail cask of:

- SNF from reactor sites to Yucca Mountain using the reactor sites to Yucca Mountain distribution of trip distances
- SNF from reactor sites to regional reprocessing facilities or interim storage sites using the reactor sites to regional sites distribution of trip distances
- MOX from regional fuel fabrication facilities to reactor sites using the reactor sites to regional sites distribution of trip distances
- Vitrified HLW from regional vitrification plants to regional interim storage sites using the regional sites to regional sites distribution of trip distances.

Monte Carlo sampling of parameters described by normal distributions or any other simple continuous algebraic formula is straightforward. The value of the independent variable in the algebraic formula is selected by Monte Carlo sampling, and then the value of the formula is used to calculate the value of the dependent variable. Selecting values for parameters represented by triangular distributions was done as follows. For any probability, P, the stochastic parameter X is calculated as

$$X = \begin{cases} P \le P_{mode} & X = min + \sqrt{P \cdot (max - min) * (mode - min)} \\ P > P_{mode} & X = min + \sqrt{(1 - P) \cdot (max - min) * (max - mode)} \end{cases} \tag{1}$$

where "X" stands for any of the parameters in Table O1-4 or for any other parameter represented by a triangular distribution,

$$P_{mode} = \frac{mode - min}{max - min} \tag{2}$$

and *max*, *min*, and *mode* are the high, low, and modal values used to specify the triangular distribution (Newendorp 1975).

Table O1-5 presents the input and output for one of the 10,000 calculations that were performed to develop the distribution of trip costs for the shipment of SNF from an operating reactor to Yucca Mountain. Table O1-5 shows that this single calculation predicts a total shipment cost of $831,000, a packaging cost of $733,000 ($725,000 for the single use canister and approximately $6,000 for the rental costs for the reusable cask system components), en route shipping costs of $850, and loading and unloading costs of $8,000 and $10,000, respectively (loading and unloading costs are not the same because different random numbers are used to select loading and unloading parameter values for parameters represented by distributions).

Table O1-5. Input and output for one of the ten thousand trip cost calculations for the shipment of SNF from operating reactor sites to Yucca Mountain (2005 $).

Inputs	Variable Name	Value	Units
SNF Shipped	iTons	20	Tonne U/yr
Weight of Canister Contents		43.27	Tonne Mat'l/yr
Canisters per Year		2	Cans/yr
Shipments per Year		2	Shipments/yr
Number of Packages per Vehicle	iNPackVeh	1	Can/Vehicle
Number of Vehicles per Train	iNPackVeh	1	Veh/Shipment
Number of Buffer Vehicles	iNBufVeh	2	Veh/Vehicle
Weight of Impact Limiters	iWWL	16.56	Tonne
Weight of Overpack	iWtOP	59.87	Tonne
Weight of Canister	iWtCan	18.02	Tonne
Weight of Canister Contents	iWtCanCont	21.64	Tonne
Cost per Shipment	fTotalCost	$830,715	$/Shipment
Cost per Year	fTot/year	$1,661,430	$/year
Annual Cost per Tonne of Heavy Metal	fTotMTiHM	$83.07	$/MTIHM/year
Annual Cost per MTIHM-Km	fTotMTiHM_km	$0.0753	$/MTIHM-km/yr
Cost of Packages	fPackCost	$733,250	$/Shipment
Number of Packages per Shipment	cNPack/Ship	1	Packages/Shipment
Cost of Multiuse Container	sCanCost	$724,955	$/Can
Overpack Rental Daily Cost	sOpCost	$2,155	$/year
Impact Limiter Rental Daily Cost	sILCost		$/year
Cost of Loading	fLCost	$7,844	$/Shipment
Overhead Factor	sLhead	2.02	
Loading Duration per Package	sLdur/Pack	14.02	Hr/Pkg/Person
Loading Duration per Shipment	cLdur/Ship	14.92	Hr/Shipment
Loading Wage Random Number	sLRand	0.1329973992	
Loading Supervisor Hourly Wage	sLS	$23.68	$/hr
Loading Rad Tech Hourly Wage	sLR	$10.68	$/hr
Loading Labor Hourly Wage	sLC	$10.68	$/hr
Number of Loading Oversight	iNLS	1	Person
Number of Loading Rad Technicians	iNLR	4	Persons
Number of Loading Crew Members	iNLC	11	Persons

Table O1-5. (continued).

Inputs	Variable Name	Value	Units
Cost of En-Route Shipment	fShipCost	$79,953	$/Shipment
Distance Scenario		Reactor to Yucca Mountain	
Shipment Duration	cDays	1.92	Days/Shipment
One-Way Trip Distance	strip	1104	Km
Average Speed	sSpeed	573	Km/Day
Convoy Vehicles	cNVeh	3	
Daily Rental Cost for Vehicles	sVehCost		$/day
Tonne Shipped	sTonnekm	139,156	Tonne-km
Shipper Tariff	sTarrif	$0.1064	$/Tonne-km
States Traversed	sStates	2	States
Individual State Fees	sSFee	$2,436	$/State
Dedicated Tran Cost	sDedVeh	$60,273	$/Trip
Cost of Unloading	fUCost	$9,668	$/Shipment
Overhead Factor	sUhead	2.885	
Unloading Duration per Package	sUdur/Pack	10.35	Hr/Pkg/Person
Unloading Duration per Shipment	cUdurShip	14.92	Hr/Shipment
Unloading Wage Random Number	sUS	$32.66	$/hr
Unloading Supervisor Hourly Wage	sUR	$14.68	$/hr
Unloading Rad Tech Hourly Wage	sUC	$14.68	$/hr
Number Pf Unloading Oversight	iNUS	1	Person
Number of Unloading Rad Technicians	iNUR	4	Persons
Number of Unloading Crew Members	iNUC	9	Persons

Figure O1-8 presents the distribution of total shipment costs developed by the Monte Carlo calculations. Because the calculation for SNF shipments from reactor sites to regional sites and for MOX shipments from regional sites to reactor sites yield the same cost distribution, Figure O1-8 only presents three distributions of total shipment costs. Inspection of this figure shows that the total costs in 2006 dollars for a single shipment of SNF or MOX are quite similar, averaging about $0.8M per shipment and ranging from about $0.6 to $1.1M per shipment in 2006 dollars. Total costs for a single shipment of vitrified HLW average about $0.2M and range from about $0.04M to $0.5M. Because the $0.6M cost of the SNF or MOX canister is included in the trip costs for the shipment, while the cost of vitrified HLW canisters is an operational cost for the vitrification facility, the cost distributions for SNF and MOX are shifted toward larger costs by about $0.6M. Thus, this figure indicates that total shipment costs are not strong functions of the differing trip distance distributions used in the three Monte Carlo trip cost calculations.

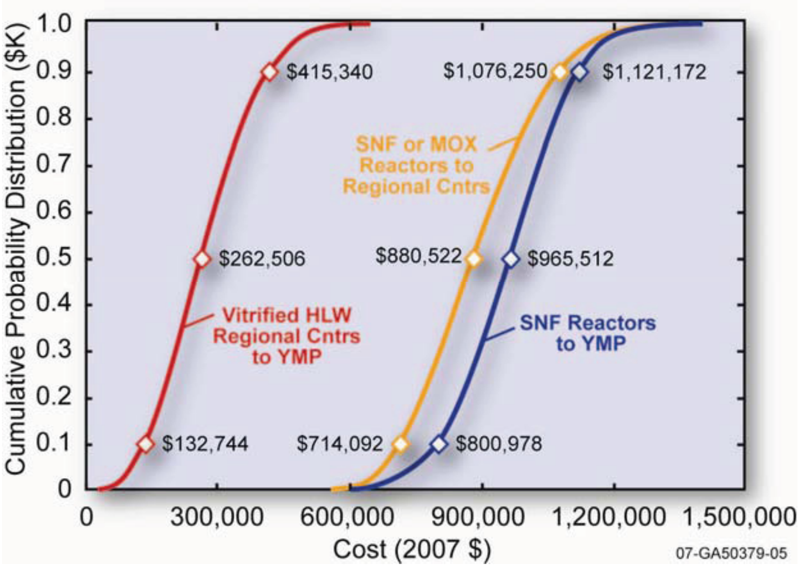

Figure O1-8. Distribution of total shipment costs for shipments of SNF, MOX, and vitrified HLW.

For each of the three Monte Carlo shipment cost calculations for which cost distributions are presented in Figure O1-7, average values for the total shipment costs and for the cask system cost the loading and unloading costs, and the enroute shipping costs that sum to give this total cost are presented in Table O1-6. Also presented in Table O1-6 are the fractional contribution of each cost component to the total cost and the average distance of each shipment and the weight of the material shipped.

Table O1-6 shows that SNF and MOX total trip costs depend mainly on packaging costs, secondarily on en-route shipping costs, and minimally on loading and unloading costs. For vitrified HLW, because canister costs are operational expenses for the vitrification plant, total trip costs depend mainly on en-route shipping costs.

Canister purchase costs, overpack, and impact limiter daily rental costs were developed above. Figures O1-5 and O1-6 present cumulative distributions for these two cost components. Figure O1-9 presents the cumulative distributions of packaging and en-route shipping costs that were calculated for the shipment of SNF or MOX between reactor sites and regional facilities.

Shipping Costs per Tonne per km. Division of the average value for the total trip cost by the product of the average trip distance and weight of the canister contents (the SNF, MOX, or vitrified HLW plus the weight of the canister basket and fuel assembly structures for SNF and MOX) yields the following values for the cost of shipping 1.0 tonne (1,000 kg) of each waste 1.0 km: $18.62 per tonne-km for shipping SNF from reactor sites to Yucca Mountain, $12.61 per tonne-km for shipping SNF or MOX from reactor sites to regional facilities, and $7.92 per tonne-km for shipping vitrified HLW from regional to regional sites.

Finally, an estimate of the annual shipping costs associated with the operation of one typical nuclear power plant for 1 year was developed as follows. First, the mass of the SNF generated by the operation of a typical nuclear power plant for 1 year is estimated. Next, the number of SNF shipments per year of reactor operation was estimated by dividing the mass of SNF generated by a typical reactor during 1 year of operation by the SNF mass carried in one spent fuel cask. Multiplication of the average number of SNF shipments per year of reactor operation times the sum of the average SNF shipment cost per trip and the average MOX shipment cost per trip then developed an estimate of the average annual shipping cost associated with the operation of one typical reactor for 1 year. These calculations are assumed for PWR fuel, whereas the cost for BWR fuel will be slightly higher since loading is slightly lower (Table O1-1)

Table O1-6. Average shipment cost (2007 dollars), trip distance (km), and weight (tonnes) of the contents of the canister for each of the three Monte Carlo shipment cost calculations.

	SNF Reactors to YMP		SNF or MOX Reactor to Regional Centers		Vitrified HLW Regional Centers To YMP	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction	Value (2007 $)	Fraction
Total Cost	962,875	1.000	890,524	1.000	249,982	1.000
Packaging	669,726	0.695	664,645	0.746	18,811[a]	0.072
Shipping	275,276	0.286	208,029	0.234	211,143	0.860
Load & Unload	18,068	0.019	18,115	0.020	8,509	0.067
Trip Length, km	2351		3210		2,746	
Contents Wt, MT	22 10.6[b]	Ass'ys IHM	22 10.6[b]	Ass'ys IHM	12.4 29.8[c]	Glass IHM
Unit Cost	\$18.62/MT-km \$38.78/MTIHM-km		\$12.61/MT-km \$26.27/MTIHM-km		\$7.92/MT-km \$3.30/MTIHM-km	

a. Since the vitrified HLW canister cost does not enter this calculation, the packaging cost is the rental cost of the cask over-pack and its impact limiters

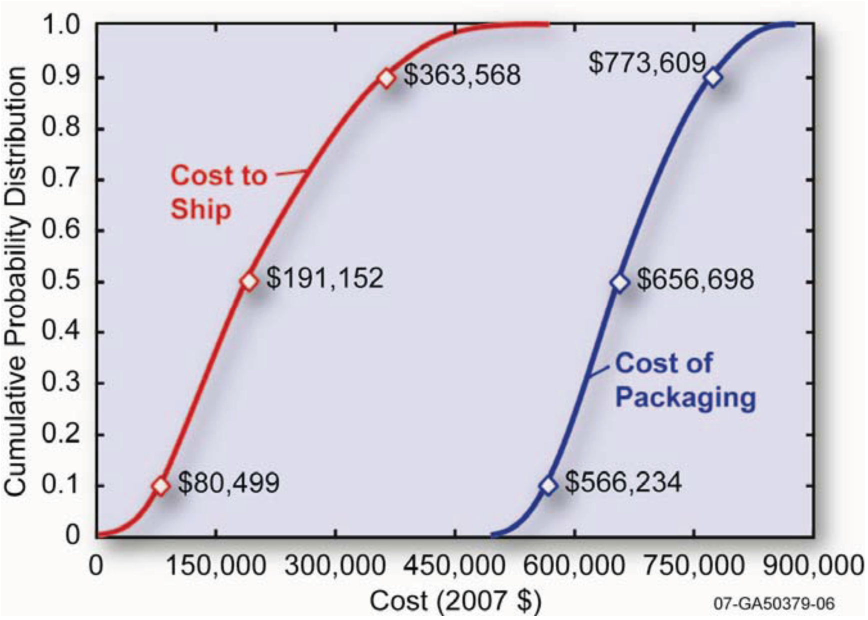

Figure O1-9. Cumulative distributions of packaging and en-route shipping costs for shipment of SNF or MOX between reactor sites and regional facilities.

Glass loading is assumed to be 0.12 MT fission products (FP)/MT glass. SNF contains approximately 0.001E MT FP/MTIHM if discharged at E GWd/MTIHM. Thus 1 MT glass is equivalent to 120/E MTIHM , or 2.4 MTIHM if E is assumed to be 50 GWd/MTIHM. The container holds 12.4 MT glass or 29.8 MTIHM equivalent.

Annual Shipping Costs per Operating Reactor. The amount of vitrified HLW and MOX generated per year by a single operating reactor will depend on the degree to which SNF is reprocessed, which is a scenario-dependent quantity. Consequently, annual shipping costs per operating reactor for vitrified HLW and MOX can not be meaningfully developed in this module. Of course, if all the fresh fuel used in an operating reactor is MOX, then the amount of MOX used per year by that reactor will be the same as the amount of SNF generated by that reactor.

The amount of SNF generated per year by a nuclear power reactor (iTons) depends on the plant's design power rating (GWe), its utilization factor or capacity factor, thermal efficiency, and burnup. Specifically,

MT SNF Produced = {Plant Rating • 365 • Capacity Factor]/[Thermal Efficiency • Burnup]. (3)

Figure O1-10 plots burnup data (GWd/ton) for the last 30 years. Figure O1-10 shows that the data are well fit ($R^2 = 0.9658$) by a straight line with a slope of 0.928. Thus, burnup has historically been increasing linearly with time. Discussions with nuclear power scientists indicate that the projected future increases in burnup, predicted in the figure by extrapolation of the historic data, are both feasible and economically attractive. Because they are economically attractive, it is likely that a technical basis will be developed for increasing the current regulatory burnup limit. Hence, a reasonable range for burnup would be from the current 35 GWd/ton to something like 75 GWd/ton several decades hence.

Reasonable values of these parameters for modern nuclear power reactors are: Plant Rating = 1 GWe; Capacity Factor = 0.9, and Thermal Efficiency = 33%. Use of these parameter values, the preceding expression for SNF produced, and the linear dependence of burnup on time presented in Figure O1-10 now allows the variation with burnup of the annual fuel consumption (MTIHM) of a typical 1 GWe nuclear power reactor to be calculated. Division of the consumption results by 10 tonnes, the fuel capacity in MTIHM of the HI-STAR cask, then allows the number of SNF shipments per year for a typical nuclear power plant to be estimated.

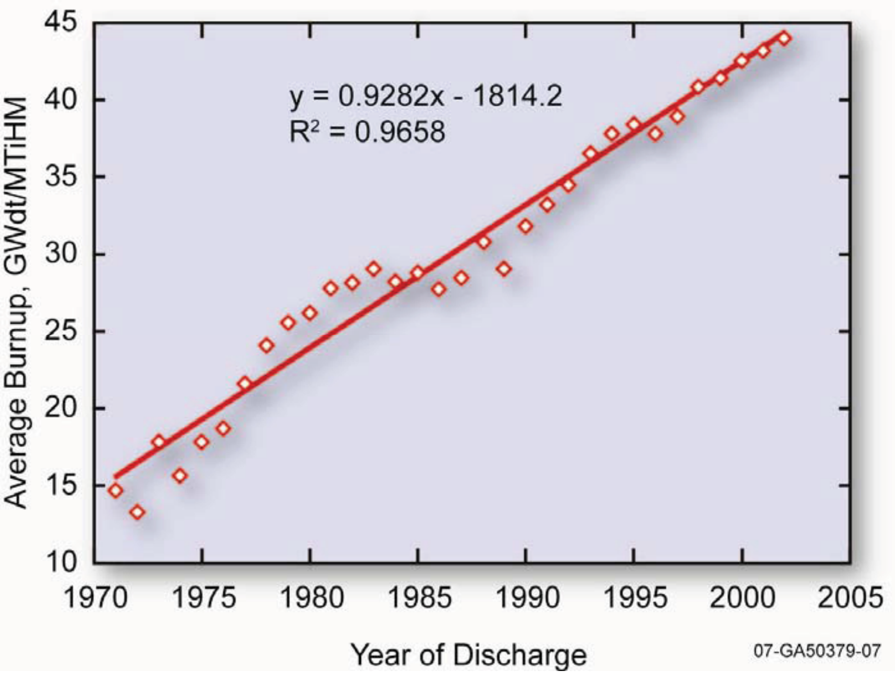

Figure O1-10. Extrapolation of fuel burnup data.

Figure O1-11 presents the results of these calculations. Inspection of Figure O1-11 shows that for a typical 1 GWe nuclear power plant annual fuel consumption and the number of spent fuel shipments per year are respectively about 25 MTIHM and 2.5 shipments/year, if fuel burnup is 40 GWd/ton and about 15 MTIHM and 1.5 shipments/year, if fuel burnup is 70 GWd/ton. Thus, two SNF shipments per year per operating reactor is a reasonable factor to use to convert trip costs into annual SNF shipping costs. Application of this factor to the average trip cost of $0.88M for shipping SNF or MOX yields an annual SNF shipping cost per reactor of about $1.76M. Of course, if a reactor is fueled using only MOX, because the cost per trip for MOX is the same as that for SNF, annual MOX + SNF shipping costs for this reactor will be double, or $3.25M.

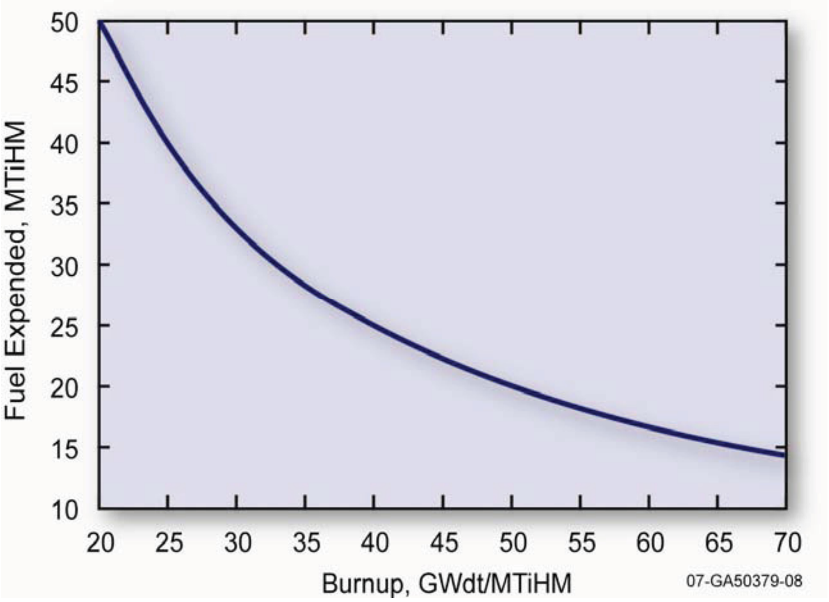

Figure O1-11. Projected SNF production from a typical nuclear power plant.

O1-7. LIMITATIONS OF COST DATA

Because spent fuel pools at commercial reactors are rapidly filling up, substantial quantities of SNF will need to be shipped in transportation casks to interim or permanent storage facilities in the near future. However, at present, there is very little data available on the estimated or actual costs of shipping SNF, MOX, or vitrified HLW. Cost estimates or data for these shipments are sparse because neither a permanent repository for high-level commercial radioactive wastes nor regional monitored retrievable storage facilities for such wastes currently exit. Consequently, shipments of SNF, MOX, or vitrified HLW are rare. A U.S. Department of Energy Report (2001) contains some estimates for the costs of shipping SNF, but they are specific to the current inventory of SNF and to specific shipping campaigns to the proposed Yucca Mountain repository.

Because the cask systems and railroad rolling stock, that would be used to ship SNF, MOX, and vitrified HLW by rail, are already commercially available technologies, the shipping cost estimates developed in this module, though approximate, are not likely to be highly uncertain. Thus, upper bound (downside) estimates of shipping costs should not be substantially larger than the central estimates developed in this module. However, lower bound (upside) estimates could be substantially smaller than the central estimates developed here if the nuclear fuel cycle becomes much larger in the future, whereupon substantial economies of scale might be achievable.

The HI-STAR transportation cask system that is the basis of the cost estimates developed in this module uses a single-use multipurpose canister that has a welded lid, plus a reusable cask overpack and reusable impact limiters to support shipment of SNF. If the HI-STAR multipurpose canister can be used for permanent storage, the cost of transferring SNF from the multipurpose canister to a permanent storage canister will be eliminated and extensive periodic maintenance on the cask system will not be required. Other cask systems that do not use a canister or use a reusable canister will have lower up-front costs but higher maintenance costs. Limited investigation suggests that life-cycle costs for alternative cask systems are similar to those calculated in this module for the HI-STAR cask system. If future model development permits the use of cask system cost data for any cask system, then the suggestion that transportation costs will not vary greatly with cask system should be examined in more detail.

The cost estimates developed in this module contain no costs for any capital facilities needed for the packaging of SNF, MOX, or vitrified HLW. It is assumed that either these costs are incorporated into the capital cost of the power plant, the recycled fuel fabrication plant, or the vitrification facility, or the choice of cask system obviates the need for expensive transfer equipment. Finally, significant cost savings may be obtained if the cask systems used and the equipment at the facilities to which these HLWs are shipped are designed to be mutually compatible. Once a full nuclear fuel cycle economic model has been developed, cask system/storage system costs should be reviewed to identify any significant cost savings that would result from the use of mutually compatible equipment designs.

O1-8. COST ESTIMATE SENSITIVITIES AND UNCERTAINTIES

During the development of shipment cost estimates in Section O1-5, a number of sensitivity calculations were performed. These sensitivity calculations are summarized and discussed in this section. Figure O1-5 shows that the 10th, 50th, and 90th percentile values for the cost of single-use canisters are respectively about \$0.566M, \$0.657M, and \$0.773M. Thus, the cost of an actual canister will probably differ from the best estimate cost by at most about 20%. Figure O1-6 shows that the 10th, 50th, and 90th percentile values for the daily rental cost of the reusable cask components (the overpack and its impact limiters) are respectively about \$2,160; \$2,430; and \$3,060. Thus, the actual daily rental cost for the reusable cask components will probably differ from the best estimate cost by at most about 30%.

Figure O1-4 presents the results of a “1st of a kind/nth of a kind” analysis of the costs of reusable cask system components. This figure indicates that the purchase cost of the reusable cask components is expected to be about \$4.9M so long as the manufacturer of the cask system sells at least 40 cask systems. The figure also shows that the cost of the reusable cask system components will rapidly increase as the number of cask systems sold falls below 40 systems and could approach \$10M if less than 10 systems are sold. Figure O1-7 shows that the daily rental cost for the reusable cask system components depends strongly on the useful life of these components. For example, if these components are used for 25 years, then the rental cost is about \$2,170 per day. However, if component life is only 5 years, then the rental cost can exceed \$4,700 per day. Thus, rapid technological obsolescence could significantly increase the daily rental costs for reusable cask system components. For example, current SNF cask systems are designed to transport 5-year cooled SNF. Therefore, without additional cooldown time, the thermal capacities of current cask systems will not allow them to be completely filled when they are transporting high burnup SNF. Thus, if the nuclear fuel cycle shifts largely to high burnup fuels and if longer cooldown time is uneconomic, then either these casks will have to be replaced, or when shipping high burnup SNF, they will not be able to be fully loaded. Either of these outcomes could increase shipping costs significantly.

Annex OX to this module shows that shipment distances range form 0 to 5,000 km and average about 2,500 km. It also shows that regular freight trains travel about 800 km per day. Because dedicated trains will make fewer stops than regular freight trains, they might cover 1,900 km = (80 km/hr) (24 hr in a day). The Annex further shows that for a 2,500 km trip, the cost per ton-km is about $0.12. Therefore, because a fully loaded SNF cask weighs about 125 tonnes, the weight-based shipping cost of this cask will be about $37,500 = ($0.12 tonne-km)(125 tonnes)(2,500 km). The cost of renting the cask's reusable components will be no more than $6,560 = ($2,100/day)(2,500 km)/(800 km/day) for this trip. Because both of these costs are small compared to the $650,000 cost of an SNF canister, shipments of SNF and MOX will be relatively insensitive to shipment distance or to weight-related shipping costs.

States may try to levy a tariff on each shipment of a highly radioactive material that enters their state. However, even if state tariffs for shipments of highly radioactive materials survive court challenges, because these tariffs are not expected to be much larger than about $2,500 per state traversed, and because the average shipment of SNF, MOX, or vitrified HLW will traverse perhaps eight states, state tariffs should not exceed $20,000. Therefore, the state tariffs will constitute a minor component of total shipping costs. Finally, because shipping costs depend minimally on loading and unloading costs, none of the uncertainties associated with labor rates are important.

O1-9. MODULE SCALING FACTORS

The analysis presented in Section O1-5 shows that the cost of shipping a single SNF or MOX cask by dedicated train will depend principally on the cost of the single-use canister that houses the SNF or the MOX. Thus, for a single shipment of one cask, shipping costs will be relatively invariant. Of course, the cost of a single shipment should scale more-or-less linearly with the number of casks in the shipment. In addition, the annual shipping costs for SNF and MOX should approximately equal the product of the annual cost per operating reactor and the number of operating reactors. For vitrified HLW, since canister costs are an operating expense for the vitrification facility, shipping costs per cask depend principally on en-route shipping costs per cask and thus should also scale with the number of casks per shipment and with the number of operating reactors.

O1-10. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table O1-7. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Table O1-7. What It Takes (WIT) Cost summary table (2007 $).

Reference Cost	Low Cost (Upsides)	High Cost (Downsides)	Selected Value (Nominal Cost)
Canister Purchase	566,000	773,000	657,000
Cask System Rental			
$/day	2,100	3,060	2,430
$/trip	7,600	32,400	17,900
Total Costs			
SNF, Reactors to YMP	804,000	1,122,000	966,000
SNF/MOX Between Reactor & Reg'l Cntr	714,000	1,077,000	881,000
HLW to YMP	133,000	417,000	263,000
Cost/kg IHM			
SNF, Reactors to YMP	75.90	106.30	91.59
SNF/MOX Between Reactor & Reg'l Cntr	67.60	102.00	83.40
HLW to YMP	4.50	14.00	8.80
Cost/ MTIHM-km			
SNF, Reactors to YMP	32.30	45.20	38.90
SNF/MOX Between Reactor & Reg'l Cntr	21.10	31.30	26.00
HLW to YMP	1.60	5.10	3.20

Table O1-8. Code-of-accounts data (median costs per operating reactor, millions 2006 dollars).

AFCI Code of Accounts Number	Code of Accounts Description	Cost Per Operating Reactor ($ Million)	Comments
7	Annualized O&M cost		Once-Through considers only SNF to YMP. Reprocess considers SNF to Regional Center and HLW from there to YMP Recycle considers MOX from Regional Center to Reactor, SNF return and HLW to YMP
	Once-Through	1.93	
	Reprocess	1.95	
	Recycle	3.71	
9	Annualized financial costs		
	Total Annual Operating Costs		
	Once-Through	1.93	
	Reprocess	1.95	
	Recycle	3.71	

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Module O2

Transport of Nuclear Fuel and Low-Level Radioactive Materials

Module O2

Transport of Nuclear Fuel and Low-Level[d] Radioactive Materials

O2-1. BASIC INFORMATION

This module develops cost estimates for the shipment of nuclear fuel and low-level radioactive materials between nuclear fuel cycle facilities. Table O2-1 presents a summary of the 14 facility pairs (an origin facility and a destination facility) between which low-level radioactive materials are shipped. Table O2-1 lists these 14 origin/destination facility pairs and the module that describes each facility. Table O2-1 also specifies for each facility pair the material that is shipped from the origin facility to the destination facility and one or more packages used to ship the material. Although Table O2-1 shows that enriched UF_6 (EUF_6) may be transported in at least three different packages and depleted UO_2 (DUO_2) in at least two different packages, the cost analyses presented in this module examined only one package for each material shipped. For example, the package examined for EUF_6 was the UX-30 package, and for DUO_2 it was the CHT-OP-TU package. Thus, trip costs were developed for nine packages.

Table O2-1. Fourteen pairs of an origin facility and a destination facility, the material shipped between these facilities, and typical shipment packages.

Flow Stream	Modules		Origin Facility to Destination Facility	Material Shipped	Typical Packages
	From	To			
1	A	B	Mill to UO_X Conversion	Yellow Cake, U_3O_8	55-gal drums
2	B	C	UO_X Conversion to Enrichment	UF_6	Paducah Tiger
3	C	D1	Enrichment to Fresh Fuel Fabrication	EUF_6	UX-30 NCI-21PF-1 ESP-30X
4	C	F2/D2	Enrichment to Recycled Fuel Fabrication		
5	C	K	Enrichment to DUF_6 Conversion	DUF_6	Paducah Tiger
6	K	F2/D2	DUF_6 Conversion to Recycled Fuel Fabrication	DUO_2 powder or pellets	CHT-OP-TU (B) ANF-250
7	K	J	DUF_6 Conversion to Surface Disposal	DUO_2	
8	F	B	Reprocessing to UOX Conversion	UOX	
9	F	F2/D2	Reprocessing to Recycled Fuel Fabrication	TRU/TRUOX	9975 (B)
10	F	E3	Reprocessing to Decay Storage	TRU, FP[a]	RH-TRU 72B (B)
11	F	J	Reprocessing to Surface Disposal	LLW, UOX	CHT-OP-TU (B)
12	E3	F2/D2	Decay Storage to Recycled Fuel Fabrication	TRU	RH-TRU 72B (B)
13	E3	J	Decay Storage to LLW Surface Disposal	FP[a]	CNS10-160B (B)
14	D1	R	Fresh Fuel Fabrication to Reactor	Fresh PWR Fuel Assemblies Fresh BWR Fuel Assemblies	MCC-4 SP-1,2,3

a. FP, as used in the table above, means fission products such as cesium, iodine, strontium, & technetium.

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[d] "Low-Level" is a widely used term defined only within the U.S. Department of Energy (DOE). In effect, it means anything other than "high-level." The NRC categorizes "low-level" materials into those that are suitable for land disposal and those that are not. There are three classes of land disposal materials (A, B, & C), with the radioactive content increasing from A through C. The NRC also recognizes a type of "low-level" material that is greater than Class C (GTCC) and which is NOT eligible for land disposal. Some of the materials discussed here may be in the GTCC category.

Low-level radioactive materials can be shipped by truck or rail. Because they are usually shipped by truck, the shipping costs developed in this module assume shipment using 18-wheel tractor/semi-trailer trucks that are fully loaded (i.e., the truck is loaded with the largest number of packages that it is allowed to carry). Moreover, because the vulnerability risks posed by these materials are small, it is assumed that each shipment consists of one truck (i.e., no shipments are made by a convoy of trucks) and also that the truck is not guarded by any escort vehicles.

Many of the packages listed in Table O2-1 are low-specific activity or Type-A[e] packages. Those that are not are indicated by "(B)." Transportation costs for materials shipped in low-specific activity or Type-A packages consist of the cost of the packaging,[f] loading costs at the shipment origin, shipping costs while in transit, and unloading costs at the shipment destination. For Type B packages, it may be necessary to add costs for certification/recertification and for periodic testing and maintenance.

The objective here has been to establish a cost estimate, not to prejudge which packagings might eventually be selected for actual use. In some cases, the certificates currently issued for the packagings assumed may require some amendment to be used for the purposes indicted in Table O2-1. In particular, the 9975 has been certified by DOE under authority granted for weapons-related work and materials. Acceptance by the NRC may be required for "commercial" materials. Such acceptance is considered highly likely.

O2-2. MODULE INTERFACE DEFINITION

Columns two and three of Table O2-1 list the fourteen pairs of modules that describe the origin facility and the destination facility for each material shipped. The table shows that low-level radioactive material fuel cycle shipments originate at the following seven types of facilities: uranium mills (Module A), UO_2 to UF_6 conversion facilities (Module B), UF_6 enrichment facilities (Modules C1 and C2), depleted UF_6 (DUF_6) conversion facilities (Modules K1, K2, and K3), SNF reprocessing facilities (Modules F1 and F2/D2), interim decay/storage facilities (Module E3), and fresh fuel fabrication facilities (Module D1). The table also shows that the low-level radioactive materials produced at these six types of facilities are shipped to one or more of the following seven types of facilities: UO_2 conversion facilities (Module B), UF_6 enrichment facilities (Modules C 1 and C2), fresh fuel fabrication facilities (Module D1), recycled fuel fabrication facilities (Module F2/D2), depleted UF_6 conversion facilities (Modules K1, K2, and K3), interim decay/storage facilities (Module E3), near surface low-level waste disposal facilities (Module J), and nuclear power plants.

O2-3. PICTURES/SCHEMATICS

Figure O2-1 presents photographs of two typical Type-A packagings, a carbon steel 55-gallon open top drum used to ship yellow cake, and a UX-30 packaging used to ship enriched UF_6.

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[e] Transportation packages fall into two categories, depending primarily on radioactive content, with Type A having lower radioactive content than Type B. As long as the enrichment level is less than 5%, virtually all packages containing unirradiated uranium are Type A. However, fairly small amounts of TRU can cause a package to be classified as Type B; the threshold for Pu-239, for example, is only 0.087 g.

[f] In this section, the term "packaging" refers to the devices into which radioactive material is placed for shipment—in other words, the shipping container. The term "package" refers to the container and its contents.

Figure O2-1. Typical Type-A packagings.

O2-4. FUNCTIONAL AND OPERATIONAL DESCRIPTION

At the facility where it is generated, each of the materials listed in Table O2-1 is loaded into a package designed and certified to carry that material. After being loaded onto a truck, the packages are transported from their origin facility to their destination facility where they are unloaded from the truck. At all destination facilities except near surface disposal facilities, the shipped material is removed from the shipping package so that it can be converted to a new material.

O2-5. COST BASES, ASSUMPTIONS, AND DATA SOURCES

O2-5.1 Input Parameter Values

Annex OX to Module O derives the algorithms used to estimate transportation costs and provides values for the parameters that are not packaging-specific. Table O2-2 presents the packaging-specific input parameters. In Table O2-2:

- The values of package loaded weights and package contents weights were extracted from the package Certificates of Compliance
- Package costs were estimated (see Section O2-5.2 for details) from literature data and discussions with two shippers of low-level radioactive materials and a manufacturer of low-level radioactive material packages
- The number of packages carried per truck was based on the package carrying capacity of the floor space of an 18-wheel tractor/semi-trailer truck, reduced where necessary to reflect shielding and criticality limits
- The low, modal, and high values for the triangular distribution used to represent package loading and unloading durations were selected based on the experience of Sandia National Laboratories technical staff.

Although a specific package loading parameter and its analogous unloading parameter could have different triangular distributions (different low, modal, and high values), the calculations presented here assumed that they were the same. Accordingly, as is shown in Table O2-2, the triangular distribution for the overhead factor on wages for loading is the same as for unloading, and the distribution for time required to load a package is the same as to unload.

Table O2-2. Parameter values for packaging-specific parameters.

				Single Value Parameters				Load/Unload Distribution		
Material Carried	Name	Certificate	Packages per Truck	Cost (2007$)	Loaded Wt. (lb)	Contents (kg HM)	Trip Routes	Lo	Mode	Hi
Yellow Cake	55-gal drums	Industrial Package	104	$110	440	139	Mills to Regional	0.167	0.25	0.5
UF_6, DUF_6	Paducah Tiger	6553/AF	1	$211,580	40,000	6,450	Regional to Regional	6	12	24
EUF_6	UX-30	9196/AF-85	4	$24,540	8,270	1,540		1.5	2	3
DUO_2, UOX, LLW	CHT-OP-TU	9288/B(U)F-85	10	$27,890	3,757	643		0.5	1	1.5
TRU/TRUOX	9975	9975/B(M)F-85(DOE)	22	$8,030	404	2		0.167	0.5	0.75
FP	CNS10-160B	9204/B(U)-85	1	$725,000	72,000	2,630		18	24	36
TRU, FP	RH-TRU 72B	9212/B(M)F-85	1	$725,000	45,000	1,475		18	24	36
Fresh Fuel Assemblies	MCC-4	9239/AF	2	$49,080	10,500	2 PWR	Regional to Reactors	4	6	8
	SP-1,2,3	9248/AF	3	$29,000	2,800	2 BWR		4	6	8

As Table O2-2 indicates, the cost calculations performed in this module require a distribution of possible shipment distances. Except for shipments of yellow cake from uranium mills to conversion facilities and of fresh fuel assemblies from fresh fuel fabrication facilities to nuclear power reactors, all the other shipments considered will be between regional facilities. Accordingly, three distance distributions are needed, between uranium mills and conversion facilities located at regional sites (Mills to Regional), between regional conversion, enrichment, reprocessing, fuel fabrication, interim decay/storage, and near surface disposal facilities (Regional to Regional), and between regional fresh fuel fabrication facilities and nuclear power reactors (Regional to Reactors). These are developed in Annex OX.

Before being placed into service, Type-A packages must be certified by the Department of Transportation (DOT) (49 CFR 173.417 2006) and also by NRC (10 CFR 71 2005), if they will carry significant quantities of fissile materials. Because almost all the materials listed in Table O2-1 contain uranium or plutonium, all the packages listed in Table O2-1 should have been certified by both DOT and NRC. Type B packages are certified by the NRC.

Because some Type-A packages used to ship nuclear fuel cycle low-level radioactive materials are likely to be reused, when estimating shipping costs, packaging costs should be amortized over the useful life of the packaging and expressed as a rental cost. This was performed for all the Type B packagings, whereas Type A packagings were considered single use. In retrospect, this is probably appropriate only for the 55-gallon drum. Some cost savings could be achieved by considering the other Type A packagings to be multiple use containers and a rental charge devised to evaluate the cost. Finally, because the packagings examined in this module are all commercially available, the data presented in Table O2-2 are entirely adequate for the scoping cost analyses performed in this module.

O2-5.2 Packaging Costs

The packaging costs developed for this module consider two types of packages. Some materials will be shipped in Type B packages. These packages are used for the more intensely radioactive materials; they are certified by the NRC; and they tend to be complex in design and relatively expensive per unit of payload. Less intensely radioactive materials are shipped in Type A packages, which are generally simpler in design; certified by the DOT, and/or the NRC (NRC certification is required if they carry fissile materials). In Table O2-3, the Type B Packages are indicated by a (B) following the name. The remaining packages are Type A packages. Although these radioactive materials can be shipped by either truck or rail, the costs developed in this module assume shipment by truck.

Table O2-3 again lists the nine packagings considered in this module, presents for each packaging the name of the packaging manufacturer, the approximate cost of the packaging, the number of packages that can be transported by an 18-wheel tractor/semi-trailer truck, and the material carried in the package. All packaging costs have been adjusted to 2007 dollars using the producer price index for hardware. More detailed packaging descriptions and cost component data would be needed if differences in packaging unit costs are to be explained.

Table O2-3. Approximate packaging costs and manufacturers.

Material Carried	Name	Packages per Truck	Cost per Package (2007 $)	Manufacturer
Yellow Cake	55-gal drum	104	$110	LabelMaster, Inc.
UF_6	Paducah Tiger	1	$211,580	US Enrichment Corp.
Enriched UF_6	UX-30	4	$24,540	Columbiana Hi Tech Front End LLC
LLW, DUO_2, UOX	CHT-OP-TU (B)	10	$27,890	Columbiana Hi Tech Front End LLC
TRU/TRUOX	9975 (B)	22	$8,030	DOE - Savannah River Operations Office
FP	CNS10-160B (B)	1	$725,000	Duratek
TRU, FP	RH-TRU 72B (B)	1	$725,000	DOE
Unirradiated PWR Fuel Assemblies	MCC-4	2	$49,080	Westinghouse Electric Company
Unirradiated BWR Fuel Assemblies	SP-1,2,3	3	$29,000	Framatone ANP

Costs to Acquire Packagings. Informal cost quotes for the UX-30, the CHT-OP-TU, and the 9975 packagings were obtained by phone calls to and email exchanges with a representative of the manufacturer of each of these packagings. The cost of the RH-TRU 72B packaging was taken from one of the weekly newsletters published by the Waste Isolation Pilot Plant (TRU TeamWorks 2003). The cost and capacity of the 55 gallon open-head steel drums used to ship yellow cake were obtained from the one manufacturer's 2005 catalog (LabelMaster, Inc. 2005).

When cost data could not be directly obtained for the remaining seven packagings, packaging cost estimates were developed as follows. For the MCC-4, the SP-1, 2, 3, and the CNS10-160B packagings, packaging costs were assumed to be about the same as those of a similar packaging. Thus, after cost data for fresh PWR and fresh BWR fuel packagings manufactured by Columbiana Hi Tech Front End, LLC were obtained by phone calls and email exchanges with a manufacturer's representative, packaging costs for the MCC-4 fresh PWR fuel packaging and for the SP-1, 2, 3 fresh BWR fuel packaging were assumed to be about the same as the costs of the PWR and BWR fresh fuel packagings manufactured by Columbiana Hi Tech Front End LLC. And because the size and design of the CNS10-160B packaging are similar to that of the RH-TRU 72B packaging, it was assumed that the cost of this packaging would be about the same as that of the RH-TRU 72B packaging.

Finally, the cost of one packaging was estimated assuming a cost of about $10.00/lb (in 2004 $) of packaging weight. Since Table O2-2 shows that the Paducah Tiger packaging weighs 21,030 lb, the cost was estimated to be about $210,300 in 2004 $, or $211,600 in 2007 $.

Rental Costs for Packagings Assumed to be Reused Many Times. Because they are more complex and relatively more expensive, all Type B packagings were assumed to be reused many times over the duration of their service lives, which were represented by a triangular distribution with low, modal, and high values of 1, 10, and 30 years. The median life was approximately 20 years. For these packagings, a daily rental cost was developed by performing a present value analysis. This analysis was performed using the discounted cash flow methods recommended by Higgins (2001). The purchase price was assumed to match the manufacturer's cost at a discount rate of 10%. Table O2-4 presents the parameters that were used in this analysis. The utilization factor represents the fraction of the days in a year the packagings are assumed to be in use. Instead of applying an overhead percent to the packaging purchase price, a nominal O&M cost ($10,000 in 2004 $, then escalated using the Consumer Price Index [CPI] for all items) was included in the analysis as a fixed cost. This assumes that the cost to test and maintain a packaging is independent of its size or weight. The analysis uses straight line depreciation based on the expected life of the packaging. For discounting purposes, year zero was assumed to be 2007. The first six parameters in Table O2-4 were assumed to be fixed. The final parameter, the useful life of the packaging, was assumed to vary stochastically. Values for this parameter were selected by random sampling from the triangular distribution for this parameter.

Table O2-4. Present value analysis parameters.

Fixed Parameters	Values			Units
Price of Reusable Items	CNS10-160B $725,000 RH-TRU 72B[a] $613,400 CHT-OP-TU $27,890 9975 $8,030			2007 $
Utilization Factor	0.90			Fraction
Inflation	3.0%			
Tax Rate	36.0%			
Discount Rate	10.0%			
O&M	$11,150			2007 $/year
Sampled Parameter	Low	Modal	High	
Useful Life	1	10	30	Years

a. The RH-TRU 72B packaging consists of a welded canister and an overpack that is fitted with two impact limiters. Based on the costs of these items for SNF casks, the costs of the RH-TRU 72B canister and its overpack and impact limiters were estimated to be $111,600, $362,400, and $251,000 in 2007 $.

The present value analysis was run 10,000 times. For each simulation, the calculated cost was adjusted to return a zero net present value based on the sum of discounted cash flows for all years of the analysis. Figure O2-2 displays the results of the analysis as a series of rental costs sorted low to high. Because some consideration was given to using the interior canister of the RH-TRU 72B as a single use container, the rental costs for that packaging do not include the canister. When it is included, the daily rental cost is exactly the same as the CNS10-160B. The rental costs displayed in Figure O2-2 are for a shipment, not a single package. The CHT-OP-TU results are for 10 packages and the 9,975 results for 22.

Inspection of Figure O2-2 shows that rental costs increase very rapidly once cumulative fractions pass 0.90. This corresponds roughly to lifetimes dropping below about 5 years. Thus, the 90th percentile rental cost is $563/day for the CNS10-160B while the 99th percentile rental cost (corresponding to a 2-year life) is over $1,300/day. Also, the rental cost for 9975 does not vary strongly with the life of the packaging, but is driven instead by the maintenance costs. For an average life of 13 years, the daily rental cost for 22 packagings (a shipment) is $811, of which $731 is for maintenance and $80 is to recover the cost of the packaging. In contrast, of the $360 rental charge for the CNS 10-160B, the vast majority, $327, is for recovery of the packaging cost and only $33 is for maintenance.

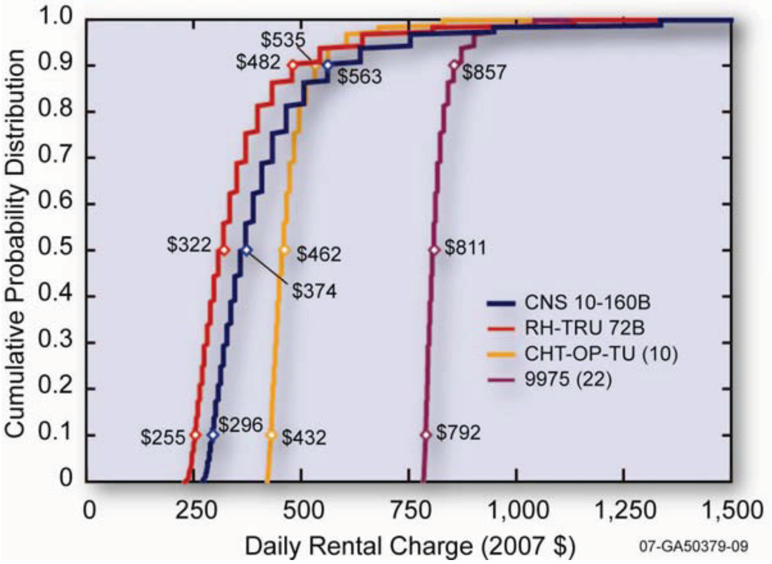

Figure O2-2. Cumulative distribution of daily rental costs for Type B packagings.

O2-6. RESULTS

Ten thousand sets of values for the 17 input parameters in the Cost Algorithm, for which distributions were developed, were selected by Monte Carlo sampling. Combination of each set of these values with the values specified for the 12 parameters that had single values generated 10,000 full sets of input for the Cost Algorithm. Running of the Cost Algorithm using these 10,000 sets of input allowed distributions for the five output parameters (Total Cost, Packaging Cost, Loading Cost, Shipping Cost, and Unloading Cost) to be constructed. Output was developed for single shipments of

- Yellow cake from the mills or ports of entry to regional facilities for conversion using the distribution of trip distances constructed for these shipment routes
- UF_6, enriched UF_6, depleted UF_6, depleted UO_2, UOX, TRU/TRUOX, TRU, FP, and U from regional facilities to regional facilities using the distribution of trip distances constructed for the routes that interconnect regional facilities
- Fresh PWR and BWR fuel assemblies from the regional facilities to the reactor sites using the distribution of trip distances taken from NUREG/CR-6672 for shipments of spent fuel from reactors to these six hypothetical regional facilities.

Monte Carlo sampling of parameters described by normal distributions or any other simple continuous algebraic formula is straightforward. The value of the independent variable in the algebraic formula is selected by Monte Carlo sampling, and then the value of the formula is used to calculate the value of the dependent variable. Selecting values for parameters represented by triangular distributions was done as follows. For any probability, P, the stochastic parameter, X, is calculated as

$$P \leq \text{Pmode:}\quad X = \text{min} + \surd P \bullet (\text{max} - \text{min}) \bullet (\text{mode} - \text{min}) \tag{4a}$$

$$P > \text{Pmode:}\quad X = \text{max} - \surd(1 - P) \bullet (\text{max} - \text{min}) \bullet (\text{max} - \text{mode}) \tag{4b}$$

where “X” stands for any of the parameters in Table O2-4 or for any other parameter represented by a triangular distribution,

$$P_{\text{mode}} = (\text{mode} - \text{min})/(\text{max} - \text{min}). \tag{5}$$

Max, *min*, and *mode* are the high, low, and modal values used to specify the triangular distribution (Newendorp 1975).

To simplify discussion of the results, the nine packagings are divided into two groups: The first group contains the four Type B packagings, for which rental costs were developed. The remaining five packagings, the Type A packagings, constitute the second group.

O2-6.1 Type B Packages

Figures O2-3 through O2-6 present the distribution of shipment costs developed for each Type B package by the Monte Carlo calculations. Figure O2-3 shows that the median total cost for the CNS10-160B package is about \$32,700, and costs range from about \$15,000 to \$60,000 per shipment. Figure O2-4 shows that for the median total cost for the RH-TRU 72B package is about \$140,900, and costs range from about \$125,000 to \$180,000 per shipment. The RH-TRU 72B has an inner canister that was assumed to be used as a single-use container. If that were not done, the cost for the RH-TRU 72B would decrease by about \$110,000—the cost of the inner container. It should be evident that for single use packagings (or packaging systems that have expensive single use components), total trip costs will be largely determined by the cost of the single use items. Figures O2-5 and O2-6 present similar data for the CHT-OP-TU and 9975 packages.

Figures O2-3 through O2-6 also present for the Type B packages the distributions of trip cost without the packaging costs. The distributions of “handling” cost (loading, shipping, and unloading) are quite similar for the CNS10-160B and the RH-TRU 72B because, the loading, en-route, and unloading costs differ significantly only in weight based (i.e., tonne-km based) shipping costs. If the RH-TRU 72B canister is used as a single use container, the difference between the “handling” costs (loading shipping and unloading) for the RH-TRU 72B would decrease by over \$100,000. Figures O2-5 and O2-6 show that the cost for the CHT-OP-TU and 9975 packages are also similar and not dramatically different from the costs of the other two Type B packages.

Table O2-5 presents for the Type B packages median values for the total shipment cost and also for the packaging related costs (loading and unloading costs, and the en-route shipping costs) that sum to give the total cost. Also presented in this table is the fractional distribution of each cost component to the total cost, the average distance of each shipment, and the weight of the package contents. Finally, the cost per kilogram and the cost per tonne-km are provided.

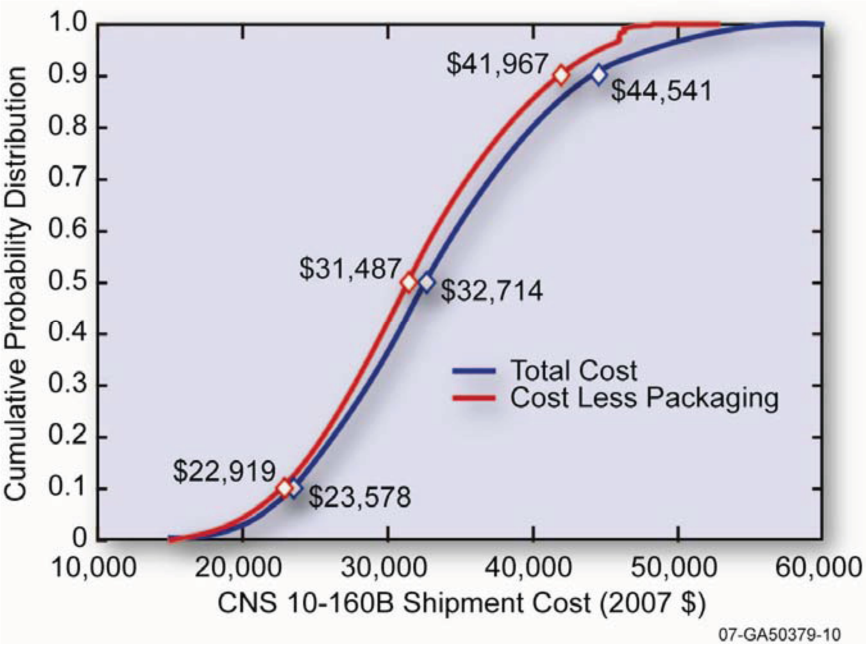

Figure O2-3. Cumulative distribution of shipment costs using a CNS10-160B package.

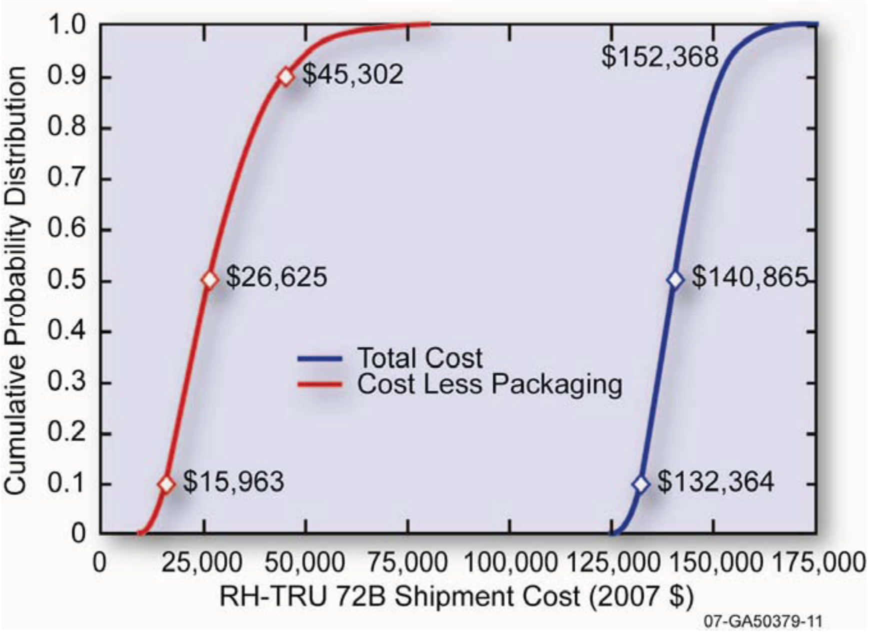

Figure O2-4. Cumulative distribution of shipment costs using a RH-TRU 72B package.

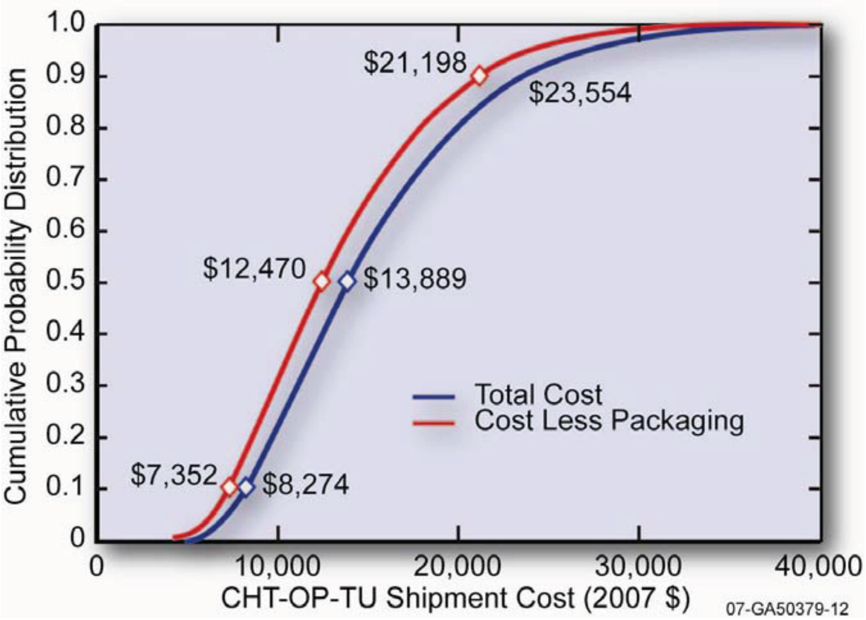

Figure O2-5. Cumulative distribution of shipment costs using a CHT-OP-TU package.

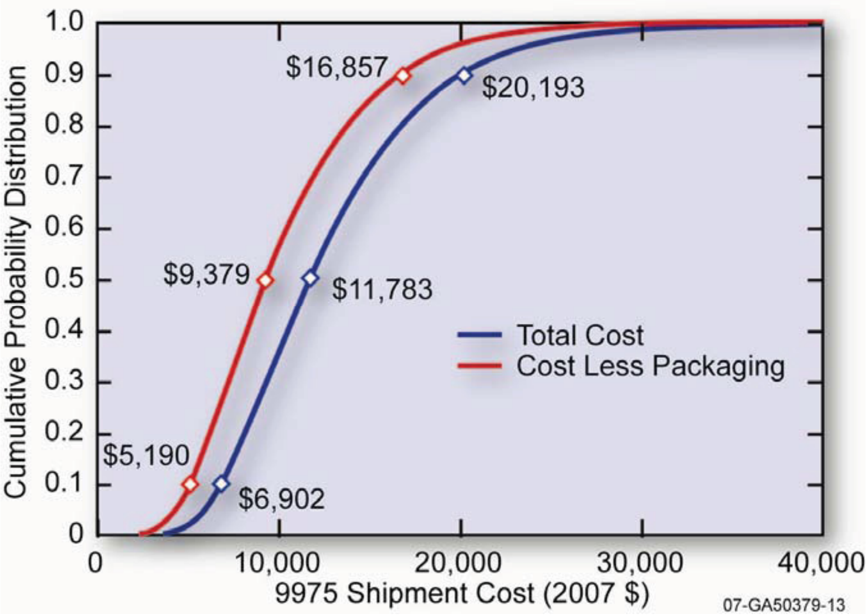

Figure O2-6. Cumulative distribution of shipment costs using a 9975 package.

Table O2-5. Package median shipment cost and other data for Type B packages.[a]

	CNS10-160B Regional Sites to Regional Sites		RH-TRU 72B Regional Sites to Regional Sites	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
Total Cost	$ 32,745	1.00	$ 140,853	1.00
Packaging	$ 1,228	0.04	$ 112,592	0.809
Shipping	$ 8,109	0.264	$5,084	0.037
Load/Unload	$ 21,354	0.696	$ 21,510	0.155
Distance	2,690 km		2,690 km	
Payload	**2.63 MT HM**		**1.475 MT HM**	
Unit Cost	$12.45/kg HM $4.63/MT-km		$95.49/kg HM $35.50/MT-km	
	CHT-OP-TU Regional Sites to Regional Sites		9975 Regional Sites to Regional Sites	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
Total Cost	$3,871	1.00	$11,794	1.00
Packaging	$1,418	0.103	$2,374	0.202
Shipping	$4,212	0.304	$900	0.077
Loading	$8,206	0.593	$8,488	0.722
Distance	2,690		2,690	
Payload	**10 × .643 MTHM**		**22 × 2 kg HM**	
Unit Cost	$2.16/kg HM $0.80/MT-km		$268.05/kg HM $99.65/MT-km	

a. The component values may not sum to the total cost. The actual medial values for the components usually do not exist in the case with the median total cost unless all are distributed similarly.

O2-6.2 Type A Packages

Figures O2-7 through O2-9 present the distribution of shipment costs developed for each Type A package using the Monte Carlo method. In each case, the packaging is treated as being used only once. As a consequence, except for the 55-gallon drum, the total costs including packaging are dramatically different from the "handling" costs, that is, the costs without packaging costs. The cost of the 55-gallon drum is only about $100. The component of the rental costs devoted to O&M costs is about $30 per day. For a three to four-day shipment, the rental component due to O&M roughly equals the purchase price of the container, and a "single-use" approach is very reasonable. For the other packages, the case for single-use treatment is much less persuasive.

With the exception of the 55-gallon drum, the handling costs are quite similar—generally between about $7,000 and $25,000 per shipment. These values are also similar to the handling costs for the Type B packages. The implication is that shipment costs are primarily dependent on the cost of the packaging if it is single-use, as in the case of the Type A packages, but mostly dependent on the handling costs for the multiple-use packages, as in the case of the Type B packages.

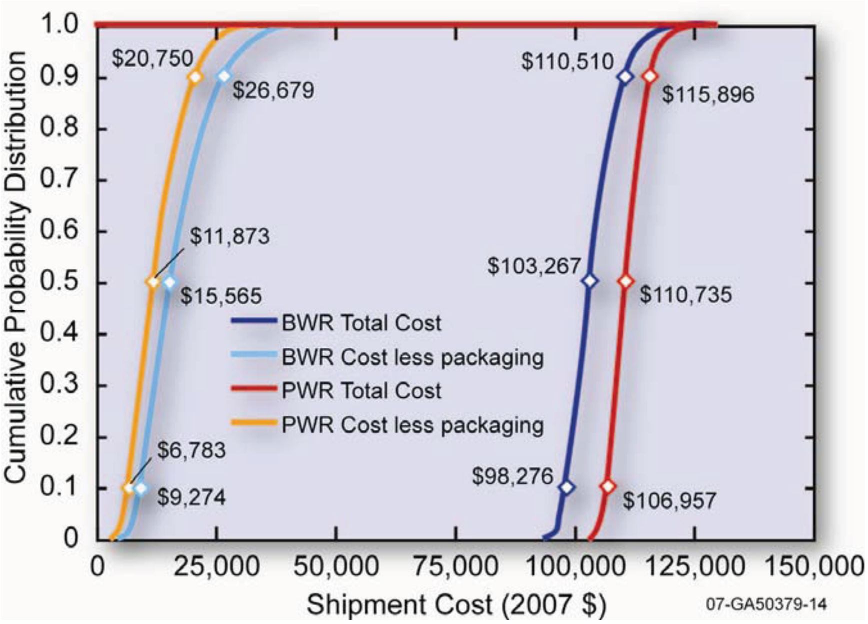

Figure O2-7. Cumulative distribution of shipment costs using an MCC-4 package (PWR fuel) or a SP-1, 2, 3 package (BWR fuel).

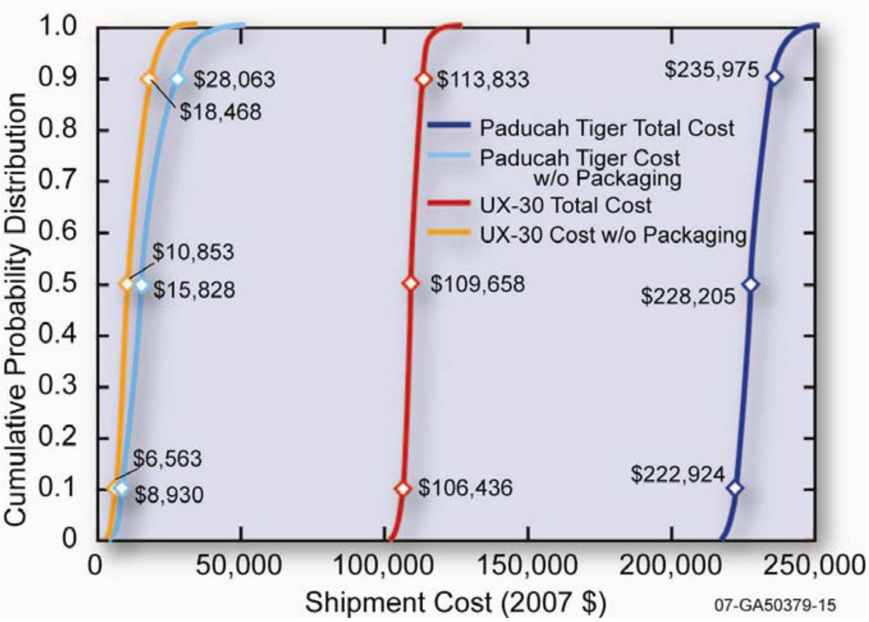

Figure O2-8. Cumulative distribution of shipment costs using a Paducah Tiger or a UX-30 package.

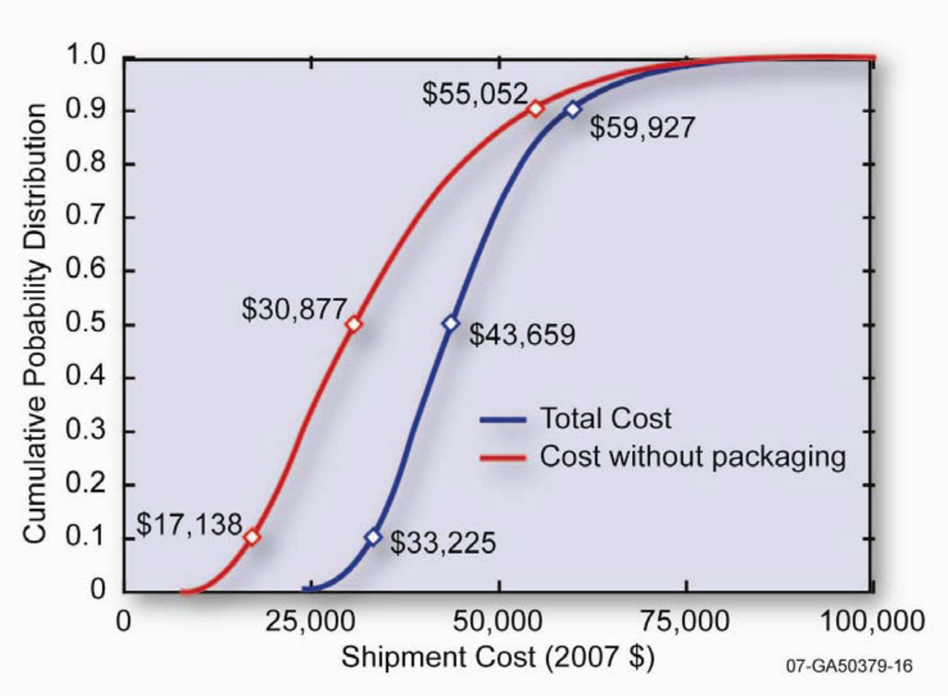

Figure O2-9. Cumulative distribution of shipment costs using a 55-gallon drum.

Table O2-6 presents for the Type A packages, median values for the total shipment cost and also for the packaging related costs, the loading and unloading costs, and the en-route shipping costs that sum to give the total cost. Also presented in this table is the fractional contribution of each cost component to the total cost, the average distance of each shipment, and the weight of the package contents. Finally, the cost per kilogram and the cost per tonne-km are provided.

Table O2-6. Median shipment cost (2007 dollars), and other data for Type A packages.

	SP-1,2,3 Regional Sites to Reactors		MCC-4 Regional Sites to Reactors	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
Total Cost	$103,247	1.0	$105,634	1.0
Packaging	$86,998	0.848	$11,734	0.882
Shipping	$779	0.008	$1,587	0.017
Load/Unload	$14,774	0.144	$4,851	0.090
Distance	2140 km		2140 km	
Payload	3 × 0.636 MTHM		2 × 1.15 MTHM	
Unit Cost	$54.11/kg HM $25.29/MTHM-km		$48.13/kg HM $22.49/MTHM-km	

Table O2-6. (continued).

	SP-1,2,3 Regional Sites to Reactors		MCC-4 Regional Sites to Reactors	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
	Paducah Tiger Regional Sites to Regional Sites		UX-30 Regional Sites to Regional Sites	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
Total Cost	$228,246	1.0	$109,668	1.0
Packaging	$211,583	0.930	$98,151	0.900
Shipping	$4,524	0.0120	$3,690	0.034
Load/Unload	$11,341	0.050	$7,178	0.066
Distance	2690 km		2690 km	
Payload	6.45 MTHM		4 × 1.54 MTHM	
Unit Cost	$22.79/kg HM $8.47/MTHM-km		$17.8/kg HM $6.62/MTHM-km	
	55-Gallon Drum Mills to Regional Sites			
	Value (2007 $)	Fraction		
Total Cost	$43,683	1.0		
Packaging	$11,484	0.271		
Shipping	$5,114	0.121		
Load/Unload	$12,592	0.609		
Distance	2550 km			
Payload	104 × 0.196 MT			
Unit Cost	$3.02/kg HM $1.19/MTHM-km			

O2-6.3 Unit Shipping Costs

Division of the average value for the total trip cost by the product of the average trip distance and weight of the contents of all packages shipped together in one shipment yields the value for the cost of shipping 1.0 tonne (1000 kg) of material 1.0 km. Table O2-7 presents these values for all the packages examined by this module. The table shows that the value of the shipping cost per tonne-km for the 9975 package is two orders of magnitude larger than the values for eight of the other nine packages. This very high cost per tonne per kilometer is caused by the low capacity—only 2 kg/package. Criticality generally limits the capacity to 4.5 kg of contained weapons grade plutonium. Other TRU may allow a higher capacity, but the content is limited to a heat generation rate of 19 Wand for TRU with higher isotopes, this will probably further limit the capacity. The 2 kg value used in this analysis is likely conservative.

O2-7. LIMITATIONS OF COST DATA

At present, there is very little data available on the estimated or actual costs of shipping low-level radioactive materials. Actual or estimated cost data for the shipments considered in this module are sparse because for many of the shipments examined one or both of the facilities between which the shipments would take place (e.g., reprocessing, recycled fuel fabrication, and interim decay storage facilities) do not exist, because reprocessing of SNF is currently not performed in the United States.

Table O2-7. Median package shipping cost.

Package	Cost per Shipment (2007$)	Cost per kilogram (2007 $)	Cost per tonne-km (2006 $)
55-gallon drum	$41,047	$2.013	$0.79
Paducah Tiger	$217,872	$22.79	$8.47
UX-30	$104,551	$11.46	$4.26
CHT-OP-TU	$12,679	$1.73	$0.645
9975	$10,229	$232.47	$86.43
CNS10-160B	$30,401	$4.61	$1.715
RH-TRU 72B	$27,548	$7.57	$2.797
MCC-4	$105,634	$45.86	$21.43
SP-1,2,3	$98,508	$51.63	$24.12

Because the packages and trucking infrastructure that would be used to ship the low-level radioactive materials that are considered by this module are already commercially available technologies, the shipping cost estimates developed in this module, though approximate, are not likely to be highly inaccurate. Thus, upper bound (downside) estimates of shipping costs should not be substantially larger than the central estimates developed in this module. However, lower bound (upside) estimates could be substantially smaller than the central estimates developed here if the nuclear fuel cycle becomes much larger in the future, whereupon substantial economies of scale might be achievable.

The cost estimates for the shipment of yellow cake assume that the cost per tonne of yellow cake at a North American mill is about the same as the cost per tonne when delivered by ship to a port of entry. The cost estimates developed in this module contain no costs for any capital facilities needed to load the low-level radioactive materials of concern into their shipment packages (e.g., for loading of the CNS10-160B or the RH-TRU 72B packages). It is assumed that either these costs are incorporated into the capital cost of the regional facility where these packages would be initially loaded or that these costs are not large enough to be significant. Finally, significant cost savings may be obtained if the packagings utilized and the equipment at the facilities to which these low-level radioactive materials are shipped should be designed to be mutually compatible. Once a full nuclear fuel cycle economic model has been developed, package/storage system costs should be reviewed to identify any significant cost savings that would result from the use of mutually compatible equipment designs.

O2-8. COST ESTIMATE SENSITIVITIES AND UNCERTAINTIES

The analysis results presented in Section O2-6 show that package trip costs depend strongly on the purchase price of single use packagings. For the five packagings that were assumed to be single-use items, the assumption that the packagings would be used only once is the principal determinant of trip costs. Consequently, trip costs would decrease substantially, if these packagings were reused several times. For example, the daily rental cost for the CNS10-160B packaging is about $275 per day if the service life of the packaging is 25 years, while if it is only 5 years then the packaging daily rental cost is about $500 per day. But, in either case, the rental cost for a trip of a few days is at least an order of magnitude less than the purchase price of the packaging.

Some states may try to levy a tariff on each shipment of low-level radioactive material that enters their state. These tariffs are not expected to be much larger than about $2,500 per state traversed, and because the average shipment of low-level radioactive material will traverse perhaps eight states, state tariffs should not exceed $20,000. Therefore, the state tariffs will constitute a minor component of total shipping costs. Finally, because shipping costs depend minimally on loading and unloading costs, none of the uncertainties associated with labor rates are important.

O2-9. MODULE SCALING FACTORS

The analysis presented in Section O2-5 shows that the cost of shipping low-level radioactive material in single use packagings depends principally on the purchase price cost of the packaging or of any expensive single use packaging components. Thus, for a single shipment of one package, shipping costs will be relatively invariant. However, if any of the packagings assumed to be single-use in this module are actually used multiple times, then, very approximately, shipment costs should vary inversely with the number of times that the packaging is reused. In addition, the annual shipping costs for a low-level radioactive material will not equal the product of its annual cost per operating reactor and the number of operating reactors. This is because some of the low-level radioactive materials shipped will be recycled, and thus the amount of fresh fuel needed per operating reactor will depend on the amount SNF that is being reprocessed.

O2-10. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table O2-8. The summary shows the reference cost basis (constant year $U.S.), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.

Because the amounts of each low-level radioactive material generated per operating reactor per year will depend on the degree to which SNF is reprocessed and also on the reprocessing method (aqueous or electrochemical) used, annual shipping costs are highly scenario dependent. Consequently, no annual shipping costs are presented in this table, and no code-of-accounts table is presented. Once nuclear fuel cycle scenarios have been constructed, annualized costs for the shipment of low-level radioactive fuel cycle materials should be entered as an annualized O&M cost in any code-of-accounts table.

Table O2-8. What-It-Takes (WIT) cost summary table.

Package (Packaging and Contents)	Packages/ Shipment	Flow Streams from Table O2-1	Cost per kilogram of material for one fully loaded truck shipment		
			Upside (Low Cost)	Downside (High Cost)	Selected Value (Nominal Cost)
55-gallon drums for yellow cake	104	1	$1.54	$2.76	$2.01
Paducah Tiger for UF_6 or Depleted UF_6	1	2,5	$22.28	$22.79	$23.54
UX-30 for Enriched UF_6	4	3,4	$11.34	$12.09	$11.73
CHT-OP-TU for depleted UO_2, UOX or LLW	10	6,7,8	$1.23	$2.43	$1.73
9975 for TRU or TRUOX	22	9,13	$149.39	$355.41	$232.48
CNS10-160B for FP	1	10	$3.37	$6.26	$4.61
RH-TRU 72B for TRU or FP	1	12	$5.39	$10.53	$7.57
MCC-4 for fresh PWR fuel assemblies	2	14	$32.95	$35.59	$34.08
SP-1,2,3 for fresh BWR fuel assemblies	3	14	$49.18	$55.16	$51.63

O2-11. BIBLIOGRAPHY

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Annex OX to Module O

Transportation Cost Methodology

Annex OX to Module O

Transportation Cost Methodology

OX-1. COST ALGORITHM

This section formulates a general set of equations that specifies the total cost for a single shipment of a radioactive material from a point of origin to a destination. Terms in the set of equations are preceded by letters which indicate whether the value of the term is a single valued input quantity (i), a sampled input quantity (s), a quantity computed from other input (c), or a final output quantity (f). Each of the parameters used below is defined in Table OX-1, along with representative input values.

The total cost *(fTotalCost)* of a single radioactive material shipment is calculated as the sum of four costs:

1. The cost of the packages in which the radioactive material is shipped *(fPackCost)*
2. The costs associated with loading of the filled packages onto the shipment vehicles at the shipment origin (*fLCost*)
3. The en-route shipment costs *(fShipCost)*
4. The costs associated with unloading of the filled packages from the shipment vehicles at the shipment destination (*fUCost*).

Thus,

$$\text{fTotalCost} = \text{fPackCost} + \text{fLCost} + \text{fShipCost} + \text{fUCost}. \quad (6)$$

Packaging costs are calculated as the sum of the costs of the radioactive material container (e.g., an SNF canister), a container overpack, and overpack impact limiters. For single-use items (e.g., the canister), the item cost is the sum of the purchase cost and the procurement cost for the item; for reusable items, the item cost is the product of the daily rental cost of the item and the trip duration in days. Thus,

$$\text{fPackCost} = (\text{cNPack/Ship})[\text{sCanCost} + 2(\text{cDays})(\text{sOPCost} + \text{sILCost})] \quad (7)$$

where

cNPack/Ship = number of radioactive material packages carried by the shipment

2 (cDays) = round trip duration of the trip (the total number of days that the reusable cask components are rented) in days

sCanCost = cost of the single use radioactive material canister

sOPCost = rental costs per day of the canister overpack

sILCost = overpack impact limiters

As formulated, Equation 7 is directly applicable to a Type B package. For shipments in Type-A packages, if the container is reusable, then *sOPCost* is used to enter its rental cost, and if it is single-use, then *sCanCost* is used to enter its purchase cost.

The number of packages (*cNPack/Ship*) carried by the shipment is expressed as the product of the number of packages (*iNPack/Veh*) carried by a single package carrying shipment vehicle (truck or rail car) and the number of vehicles (*iNPackVeh*) in the train or the convoy of trucks that are carrying radioactive material packages. Thus,

$$\text{cNPack/Ship} = (\text{iNPackVeh})(\text{iNPack/Veh}) \tag{8}$$

the one-way duration of the shipment in days (*cDays*) is calculated as the quotient of the trip length in kilometers (*sTrip*) and the average trip speed in kilometers per day (*sSpeed*). Thus,

$$\text{cDays} = \text{sTrip/sSpeed} \tag{9}$$

shipment loading costs (*fLCost*) are calculated as the sum of the wages for the loading crew, radiation technicians, and supervisors increased by an overhead factor (*sLHead*) with wages calculated as the product of the number of workers, an hourly rate, and the time required to load the packages onto the shipment vehicles (*cLDur/Ship*). Thus,

$$\text{fLnCost} = (\text{sLHead})(\text{cLDur/Ship})[(\text{sLS})(\text{iNLS}) + (\text{sLR})(\text{iNLR}) + (\text{sLC})(\text{sNLC})] \tag{10}$$

where

sLS = hourly wages of the supervisors

sLR = hourly wages of the radiation technicians

sLC = hourly wages of the loading crew

iNLS = numbers of supervisors

iNLR = numbers of radiation technicians

iNLC = numbers of crew members.

Similarly, the shipment unloading costs (*fUCost*) are calculated using the following equation.

$$\text{fUCost} = (\text{sUHead})(\text{sUDur/Ship})[(\text{sUS})(\text{iNUS}) + (\text{sUR})(\text{iNUR}) + (\text{sUC})(\text{sNUC})] \tag{11}$$

where all the terms have meanings analogous to those specified for the terms in Equation 10 for loading costs.

The time required to load (*cLDur/Ship*) all the vehicles in the train or the truck convoy that are carrying radioactive material packages is calculated as the product of the total number of radioactive material packages in the shipment (*cNPack/Ship*) and the loading time per package (*sLDur/Pack*). Thus,

$$\text{cLDur/Ship} = (\text{cNPack/Ship})(\text{sLDur/Pack}) \tag{12}$$

similarly, for unloading,

$$\text{cUDur/Ship} = (\text{cNPack/Ship})(\text{sUDur/Pack}). \tag{13}$$

The en-route shipping cost (fShipCost) is calculated as the sum of the vehicle rental costs, the weight-based shipping costs for the radioactive material packages, any charge for transporting the radioactive material by dedicated vehicles, and any fees charged by states for the passage of the radioactive material packages through their states. Thus,

$$\mathrm{fShipCost} = 2(\mathrm{cDays})(\mathrm{cNVeh})(\mathrm{sVehCost})+(\mathrm{iNPackVeh})[(\mathrm{cTonnekm})(\mathrm{sTariff})+\mathrm{sDedVeh}+(\mathrm{sStates})(\mathrm{sSFee})] \tag{14}$$

where

cNVeh and *iNPackVeh* = total number of vehicles (trucks, rail cars) and the number of package carrying vehicles (trucks, rail cars) used to carry out the shipment

VehCost = rental cost per vehicle per day

2 (cDays) = round trip duration of the trip (the total number of days that the shipment vehicles are rented) in days

cTonnekm and sTariff = number of metric tonne-km transported by the radioactive material shipment and the shipping cost per metric tonne-km

sDedVeh = charge for using dedicated vehicles to transport the radioactive material

sStates and sSFee = number of states traversed by the shipment and the average state fee per radioactive material package for trans-shipment of the packages through the state.

The total number of vehicles (trucks or rail cars) used to carry out the shipment (*cNVeh*) is calculated as the sum of the vehicles that carry the radioactive material packages plus any additional vehicles (escort vehicles, buffer cars) in the shipment consist. Thus,

$$\mathrm{cNVeh} = \mathrm{iNPackVeh}+\mathrm{iNBufVeh} \tag{15}$$

where *iNPackVeh* and *iNBufVeh* are the number of package vehicles and the number of buffer plus escort vehicles in the shipment consist.

Finally, the number of metric tonne-km of weight (*cTonnekm*) carried by a single package vehicle is calculated as

$$\mathrm{cTonnekm} = \mathrm{sTrip}(\mathrm{iWtIL} + \mathrm{iWtOP} + \mathrm{iWtCan} + \mathrm{iWtCanCont}) \tag{16}$$

where

sTrip = trip distance

iWtIL, iWtOP, iWtCant, and *iWtCanCont* = weights of the overpack impact limiters, the overpack, the canister, and the canister contents.

Table OX-1. Cost algorithm parameters.

Parameter	Description	Input			Calc'd		Value	Ref
		S	TD	OD	IC	FR		
iCanCost	Purchase cost single use canister ($)	X					Type A: Table O2-2	
sCanCost			X				Type B: $0.44/.55/.77	
cDays	One-way shipment duration (days)				X			
sDedVeh	Charge for shipment by dedicated vehicles ($)		X				Type B: $0/43K/86K	T
sILCost	Rental cost reusable impact limiters ($)			X				
sLC	Loading crew labor rate ($/hr)			X			Figure OX-1	
fLCost	Loading costs ($)					X		
sLDur/Pack	Loading time per package (hr/pkg)	X	X				Type A: Table O2-2 Type B: 6/12/24 hr	S,O
cLDur/Ship	Loading time per shipment (hr)				X			
sLHead	Cost loading overhead factor		X				1.75/2.5/3	O
sLR	Loading radiation technician labor rate ($/hr)			X			Figure OX-1	
sLS	Loading supervisor labor rate ($/hr)			X			Figure OX-2	
iNBufVeh	No. of buffer and/or escort vehicles	X					Type A: 0 Type B: 3	
sNLC	Size loading crew		X				Type A: 4/6/10 Type B: 6/10/12	S,O
iNLR	No. of loading radiation technicians	X					Type A: 1 Type B: 2	STS
iNLS	No. of loading supervisors	X					1	STS
cNPack/ Ship	No. packages/ shipment				X			
iNPackVeh	No. of vehicles that carry packages	X					1	
iNPack/Veh	No. packages/ vehicle	X					Type A: Table O2-2 Type B: 1	
sNUC	Size unloading crew		X				Type A: 4/6/10 Type B: 6/10/12	S,O
iNUR	No. of unloading radiation technicians	X					Type A: 1 Type B: 2	STS
iNUS	No. of unloading supervisors	X					1	STS
cNVeh	Total No. of vehicles used to perform shipment				X			
sOPCost	Rental cost reusable overpack ($/day)			X				
fPackCost	Package cost ($)					X		
sSFee	State fee ($)	X	X				Type A: $0 Type B:0/2500/5000	T
fShipCost	En-route shipping costs ($)					X		
sSpeed	Shipment speed (km/day)			X			1222.6/1800/2113.7	S,O
sStates	No. of states traversed			X				
sTariff	Cost per tonne-km ($/tonne-km)			X			$0.06/0.075/0.10	S,O
cTonnekm	Tonne-km per shipment				X			

Table OX-1. (continued).

Parameter	Description	Input			Calc’d		Value	Ref
		S	TD	OD	IC	FR		
fTotalCost	Total trip cost ($)					X		
sTrip	Shipment distance (km)			X				
sUC	Unloading crew labor rate ($/hr)			X			Figure OX-1	
fUCost	Unloading costs ($)					X		
sUDur/Pack	Unloading time per package (hr/pkg)		X				Type A: Table O2-2 Type B: 6/12/24 hr	S,O
cUDur/Ship	Unloading time per shipment (hr)				X			
sUHead	Cost unloading overhead factor		X				1.75/2.5/3	O
sUR	Unloading radiation technician labor rate ($/hr)			X			Figure OX-1	
sUS	Unloading supervisor labor rate ($/hr)			X			Figure OX-2	
iVehCost sVehCost	Vehicle rental cost ($)	X	X				Type A: in sTariff Type B: 1K/2K/5K	
iWtCan	Weight canister (tonne)	X					Type A: Table O2-2 Type B: 18 MT	
iWtCan Cont	Weight canister contents (tonne)	X					Type A: Table O2-2 Type B: 22 MT	
iWtOP	Weight overpack (tonne)	X					70 MT	
iWtIL	Weight overpack impact limiters (tonne)	X					17 MT	

Parameter Types	S = Single value input TD = Triangular distribution input OD = Other distribution input	IC = Intermediate calculated value FR = Final result
References	S = Sandia Shipping Staff O = Shipping staff at other governmental laboratories	STS = Sandia Technical Staff T = Shipments of materials from TMI

OX-2. LABOR RATES

OX-2.1 Hourly Labor Wage (sLR, sUR, sLC, and sUC)

Figure OX-1 below shows U.S. Bureau of Labor Statistics distributions of hourly take-home wage for representative skilled nonexempt occupations under which loading or unloading labor might fall (Bureau of Labor Statistics 2006). Included in this figure is a line that represents the amalgamation of the U.S. Bureau of Labor Statistics on the premise that all shown categories are equally likely. Because the hourly take-home wage for radiation technicians should be similar to that for operating engineers, this amalgamated labor rate distribution was assumed to apply not only to members of the loading crew but also to radiation technicians

OX-2.2 Hourly Oversight Wage (sLS, sUS)

Figure OX-2 shows U.S. Bureau of Labor Statistics distributions of take-home wage for selected technical occupations under which loading or unloading oversight might fall (Bureau of Labor Statistics 2006). Included in this figure is a line that represents the amalgamation of the U.S. Bureau of Labor Statistics on the premise that all shown categories are equally likely.

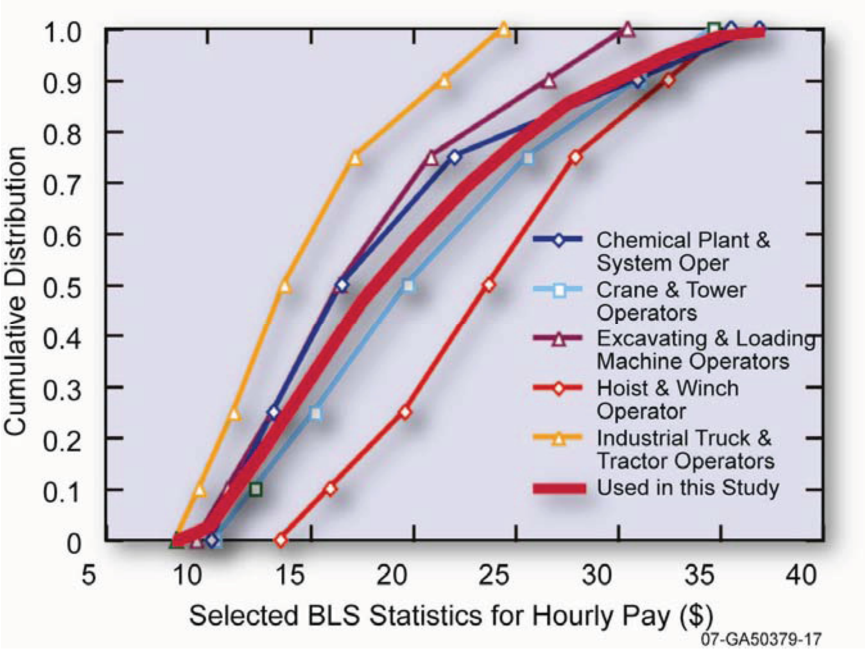


Figure OX-1. Hourly labor wage (Bureau of Labor Statistics 2006).

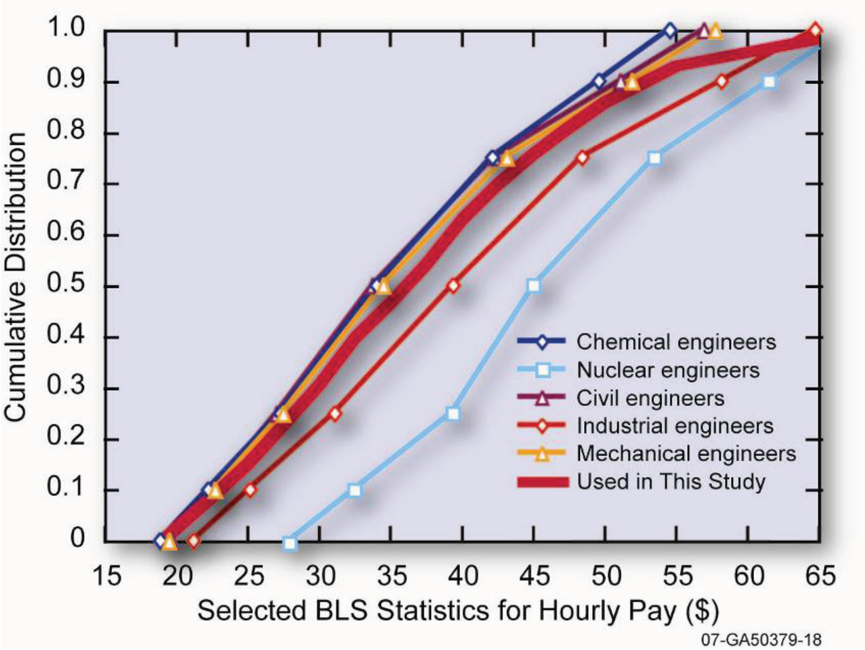


Figure OX-2. Hourly oversight wage (Bureau of Labor Statistics 2006).

OX-3. TRIP ONE-WAY DISTANCES (sTrip)

OX-3.1 Shipments by Rail

Three distributions of shipment distances were used to develop the transportation cost estimates presented in this module. The first distribution assumed that the number of operating reactors in the fuel cycle would not be much increased over the current number of operating reactors. For this scenario, no fuel reprocessing occurs and SNF is shipped directly from operating reactor sites to a permanent repository located at Yucca Mountain. The second and third distributions assumed:

- The number of operating reactors in the fuel cycle would be much larger than the current number
- SNF would be shipped to regional sites for interim storage or reprocessing
- MOX fuel fabricated at regional fuel fabrication facilities would be shipped back to operating reactor sites
- Vitrified HLW generated by reprocessing would be shipped to regional monitored retrievable storage sites.

This scenario uses two trip distance distributions. Both of these distributions assumed that one regional facility would be located in the north western, the north central, the north eastern, the south western, the south central, and the south eastern portions of the continental United States. Table OX-2 presents the hypothetical locations of these six regional sites.

For the first scenario, which covers shipments from operating reactors to Yucca Mountain, distance estimates published in the Yucca Mountain environmental impact statement (DOE 2002) were used to construct the distribution of possible trip distances. The second scenario used the trip distance distribution that was developed in NUREG/CR-6672 (Sprung et al. 2000), assuming SNF shipments from currently operating reactors to the six regional sites listed in Table OX-2. For the third scenario, which covers shipments between regional facilities, the Transportation Routing Analysis Geographic Information System (TRAGIS) routing code (Johnson and Michelhaugh 2003) was used to identify the shortest mainline rail route that connected each of these 15 origin/destination pairs that can be generated from the six hypothetical regional site locations listed in Table OX-2 and to calculate the lengths of these routes. Figure OX-3 depicts the routes identified by these TRAGIS calculations.

Because the six regional site locations listed in Table OX-2 are only hypothetical, the set of 15 distances calculated by TRAGIS was treated as a representative sample drawn from the "true" but presently "unknown" distribution of real distances between the locations of future regional sites. Because a reprocessing and a vitrification facility might both be located at the same regional site, a trip distance of 0 km was also assumed to be possible.

Table OX-2. Hypothetical locations for regional facilities.

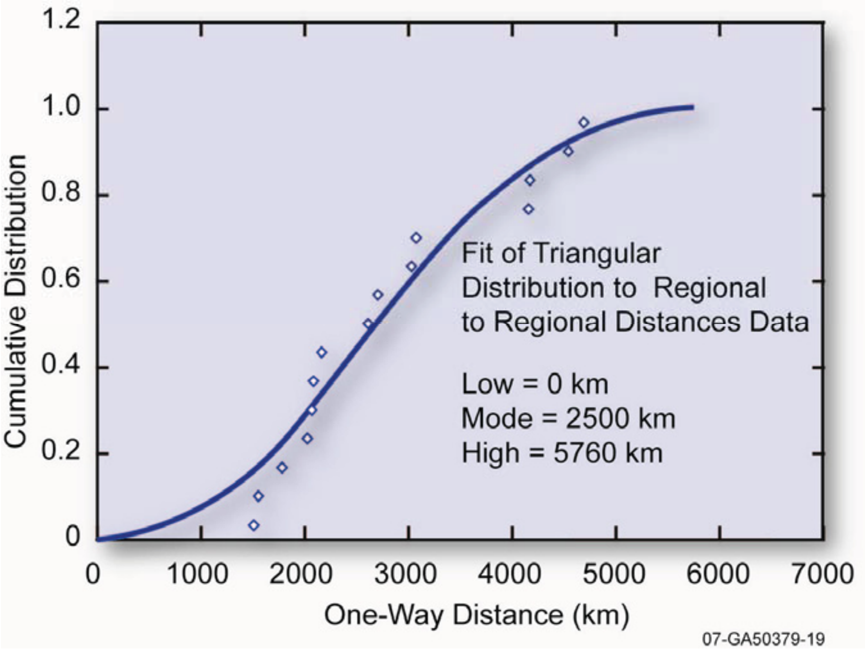
Region	Location
North Western	Hanford, WA
North Central	Prairie Island Indian Reservation, MN
North Eastern	West Valley, NY
South Western	Yucca Mountain, NV
South Central	Kay County, OK
South Eastern	Savannah River, SC

Figure OX-3. Mainline rail routes calculated using TRAGIS that connect the six hypothetical locations for regional facilities.

Low, modal, and high values for a triangular distribution of trip distances between future regional sites were selected as follows. First, the low value of the triangular distribution was set equal to zero to accommodate the possibility that a reprocessing facility and a vitrification plant might both be located at the same regional site. Then, the fifteen trip distances were rank ordered and modal and high values for the triangular distribution were selected that minimized the sum of the squares of the differences between the values of the fifteen representative distances and values of these distances on the cumulative distribution of trip distances generated from the triangular distribution.

Figure OX-4 presents the cumulative distribution that was generated by this minimization method with the restriction that the cumulative distribution passes through the point (0,0). Also plotted in Figure OX-4 are the 15 trip distances that were used to construct the triangular distribution and the low, modal, and high values of the triangular distribution that underlies the cumulative distribution.

Figure OX-5 plots all three of the trip distance distributions. Inspection of Figure OX-5 shows that the three distance distributions are quite similar. Thus, given the somewhat uncertain identities of many of the route origins or destinations, the differences in the three distributions are not very significant.



Source: Cask Shipment RevX.xls

Figure OX-4. Fit of region to region rail distance data to triangular distributions.

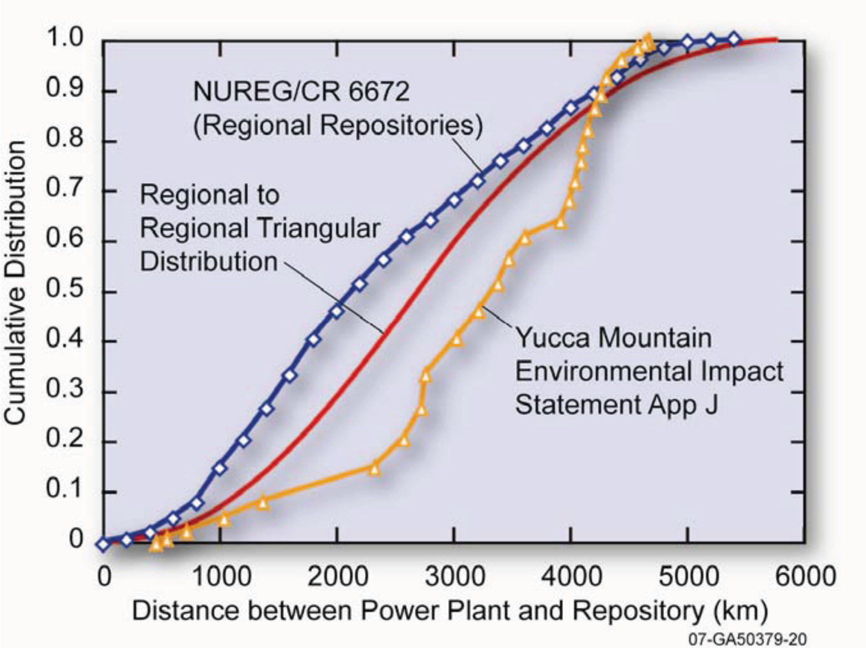


Figure OX-5. Distribution of trip distances (sTrip) for rail shipments from reactors to Yucca Mountain and for shipments to regional storage facilities.

OX-3.2 Shipments by Truck

Three distributions of shipment distances were used to develop the transportation cost estimates presented in this module. The three distributions assume that the number of operating reactors in the fuel cycle will be much larger than the current number and therefore that low-level radioactive material will be shipped to regional facilities for conversion, fabrication, recycling, or interim storage. The first distribution assumes that yellow cake will be shipped to regional conversion facilities from uranium mines located near Moab, Utah or from two representative ports of entry, Long Beach, California, and Norfolk, Virginia, if imported from overseas. The second distribution assumes that shipments between conversion, fabrication, recycling, or interim storage facilities will all be shipments between the regional facilities. Both of these distributions assumed that one regional facility will be located in the north western, north central, north eastern, south western, south central, and south eastern portions of the continental United States. The third distribution assumes that the fresh fuel fabricated at the regional facilities will be shipped to operating reactors.

For shipments of fresh fuel from regional fuel fabrication facilities to reactor sites, the distribution of route lengths used was the distribution developed in NUREG/CR-6672 (Sprung et al. 2000) for the shipment of spent fuel from reactor sites to the six hypothetical regional sites listed in Table OX-2. For yellow cake shipments or for shipments between regional facilities, the TRAGIS routing code (Johnson and Michelhaugh 2003) was used to identify shipping routes and to calculate their route lengths as restricted by the routing rules for Highway Route Controlled Quantities of Radioactive Materials. The 18 shipment routes selected by TRAGIS, which connect the uranium mines near Moab, Utah, and the ports of Long Beach, California, and Norfolk, Virginia, to the six hypothetical regional conversion facilities, are plotted in Figure OX-6. The 15 shipment routes selected by TRAGIS, that interconnect the six hypothetical regional site locations, are plotted in Figure OX-7.

Because the six regional site locations listed in Table OX-2 are only hypothetical, the set of 18 yellow cake shipment distances calculated by TRAGIS was treated as a representative sample drawn from the “true” but presently “unknown” distribution of real distances between uranium mines or port facilities and the locations of the six hypothetical future regional sites. A triangular distribution for the 18 trip distances was constructed as follows. First, the 18 trip distances were rank ordered. Then low, modal, and high values for a triangular distance distribution were selected. These values minimized the sum of the squares of the differences between the values of the 18 representative distances and values of these distances on the cumulative distribution (the integral of the triangular distribution) of trip distances generated from the triangular distribution (Newendorp 1975). Figure OX-8 presents the cumulative distribution of yellow cake shipment distances that was generated by this minimization method. Also plotted in Figure OX-8 are the eighteen trip distances that were used to construct the triangular distribution and the low, modal, and high values of the triangular distribution that underlies the cumulative distribution.

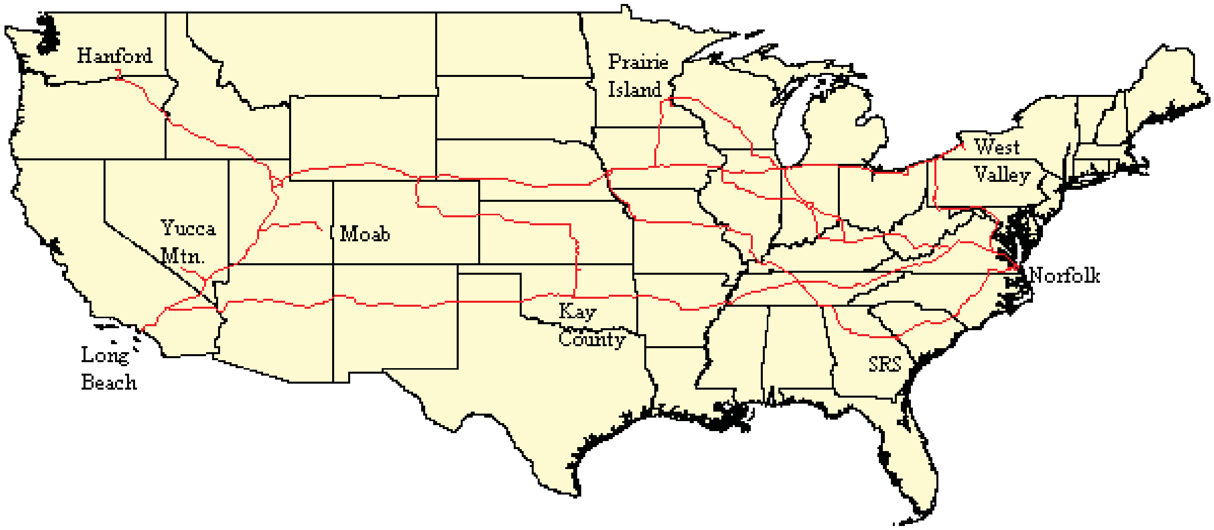


Figure OX-6. Truck routes calculated using TRAGIS that connect the yellow cake shipment sites to the six hypothetical locations for regional facilities.

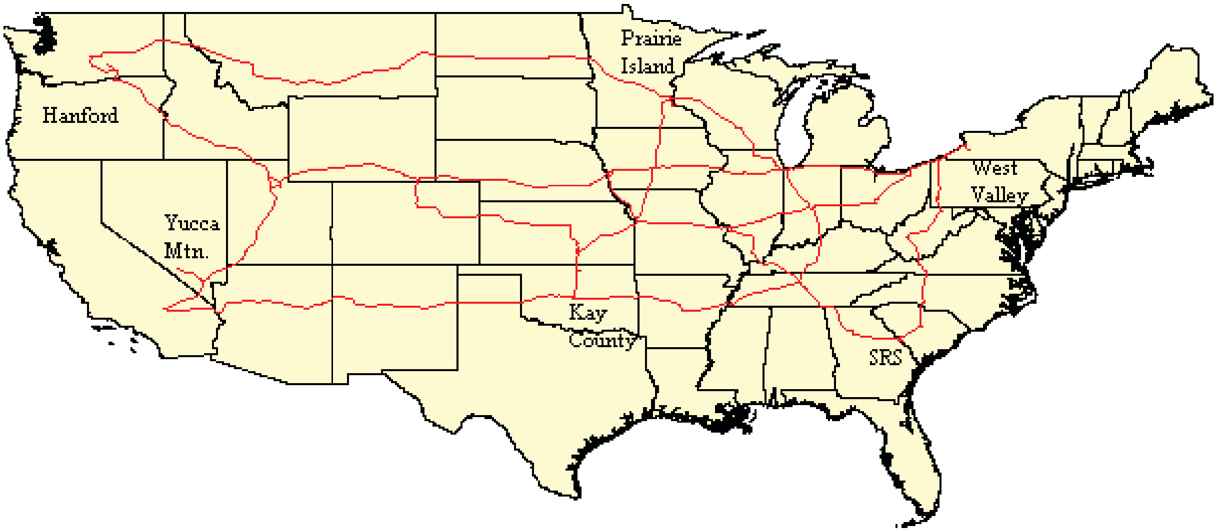


Figure OX-7. Truck routes calculated using TRAGIS that connect the six hypothetical locations for regional facilities.

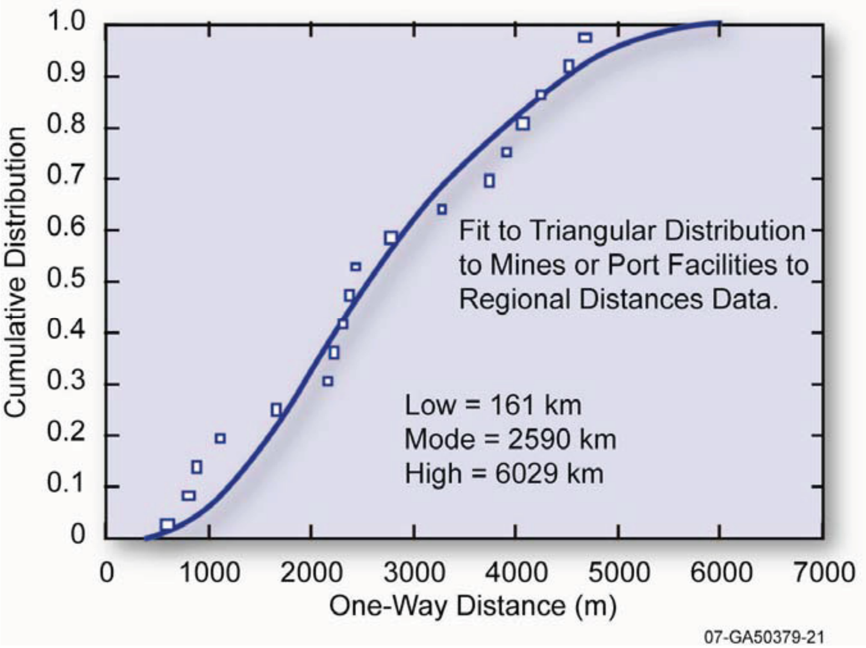


Figure OX-8. Cumulative distribution fit to the 18 route lengths that connect uranium mines in Moab, Utah, or the Long Beach, California, and Norfolk, Virginia, ports of entry to the six hypothetical regional facility sites.

The minimization analysis was also applied to the 15 shipment routes selected by TRAGIS that interconnect the six hypothetical regional site locations. However, because a conversion, fabrication, recycling, or interim storage facility might both be located at the same regional site, a trip distance of 0 km was also assumed to be possible. Therefore, the cumulative distribution generated by the minimization analysis was forced to pass through zero. Figure OX-9 presents the cumulative distribution that was generated by the minimization analysis with the restriction that the cumulative distribution passes through the point (0, 0). Also plotted in Figure OX-9 are the 15 trip distances that were used to construct the triangular distribution and the low, modal, and high values of the triangular distribution that underlies the cumulative distribution.

Figure OX-10 plots all three trip distance distributions. Inspection of Figure OX-10 shows that the three distance distributions are quite similar. Thus, given the somewhat uncertain identities of many of the route origins or destinations, the differences in the three distributions are not very significant.

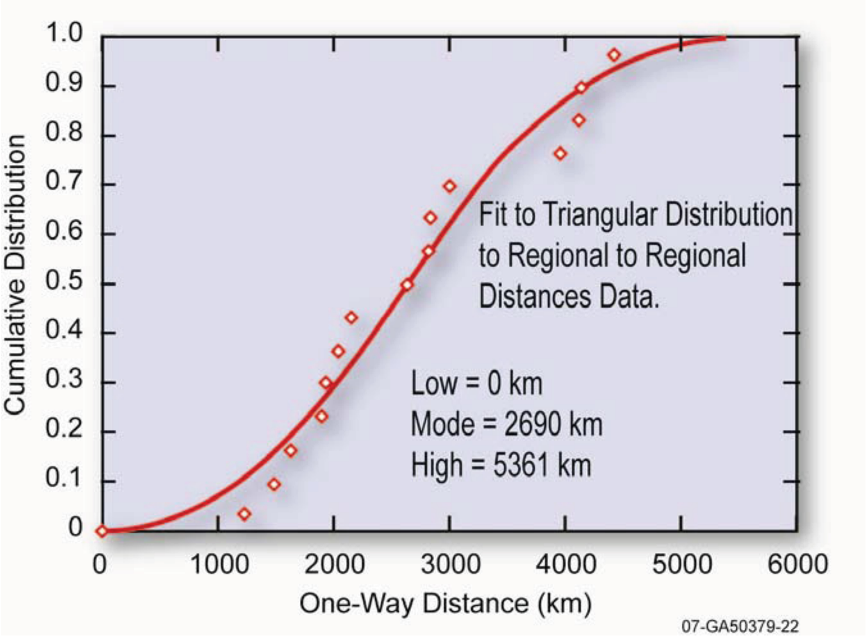


Figure OX-9. Fit of region to region truck distance data to triangular distribution.

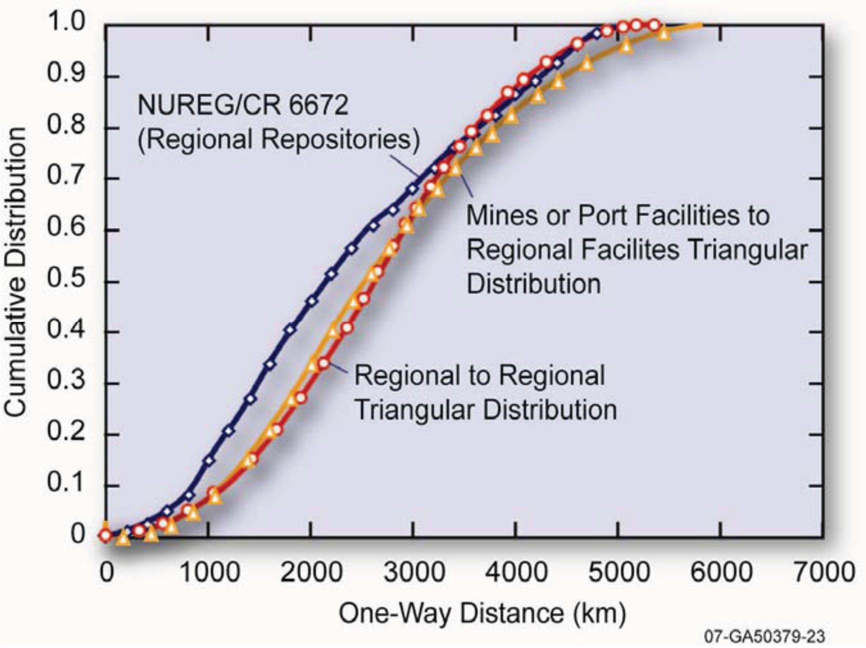


Figure OX-10. Cumulative distribution of trip distances (sTrip) for shipments from regional facilities.

OX-4. STATES TRAVERSED (sStates)

The TRANSCOST database (Michelhaugh 2002) includes a significant amount of information on routes between existing DOE facilities. These data include both route lengths and the states crossed by each route for more than 1,150 routes. Figure OX-11 presents a plot of these data.

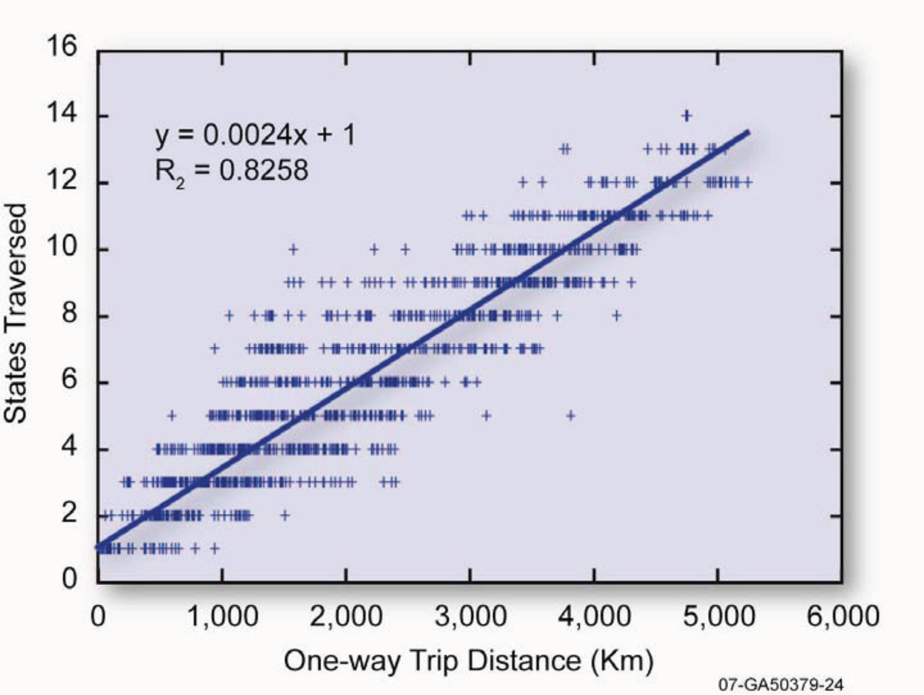


Figure OX-11. States traversed vs. trip distance.

As Figure OX-11 shows, the TRANSCOST data are well represented by the following linear relationship,

$$sStates_{av} = 0.0024\ sTrip + 1.00. \quad (17)$$

Because of the scatter in the data, the standard error (SE_y) of this linear relationship is $SE_y = 1.25$. Nevertheless, despite the scatter in the data, the linear relationship has a surprisingly strong correlation coefficient of $R^2 = 0.8258$.

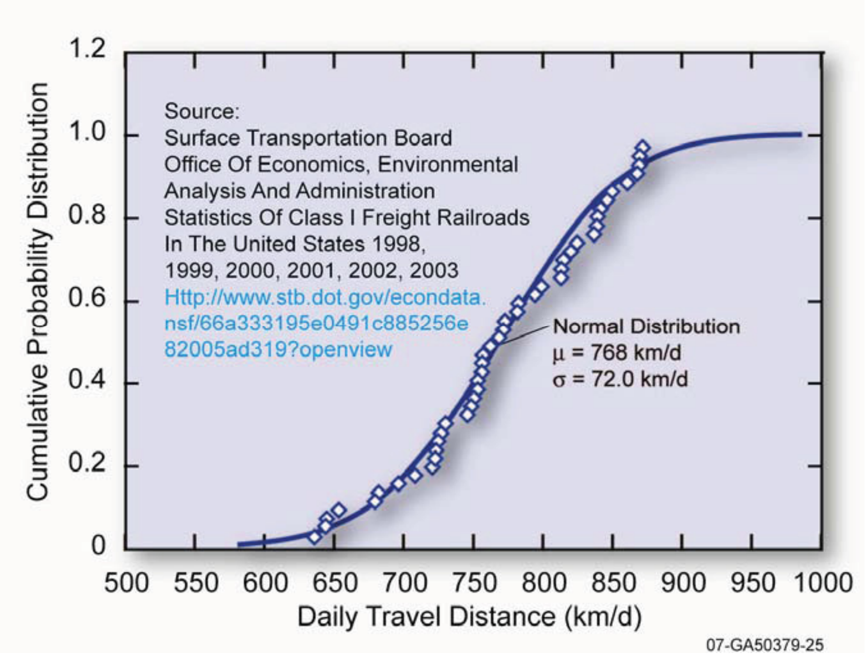
For the Monte Carlo calculation of trip costs, the estimate of sStates was taken as the random variate of a normal distribution using the linear relation for $sStates_{av}$ as a function of distance as the mean value of this distribution and the value of SE_y as its standard deviation. Thus,

$$sStates = (N|\ sState_{av}, SE_y). \quad (18)$$

OX-5. SHIPMENT SPEED (sSpeed)

OX-5.1 Shipments by Rail

Train speeds are based on data collected by the Surface Transportation Board, successor to the Interstate Commerce Commission (U.S. Department of Commerce 1998–2003). The Surface Transportation Board collects total train miles and road service hours, which includes time in switching yards and sidings. The quotient of these two yields an average speed that includes the delays inherent in normal commercial railroad freight traffic. Data were available for 6 years for each different rail freight company operating in the contiguous United States. The number of companies dropped from ten to six over the 5-year period, but averaged eight. The resulting 48 data points are plotted in Figure OX-12. As Figure OX-12 shows, these points are well fit by a normal distribution with a mean of 768 km/day and a standard deviation of 72.0 km/day.



Source: Cask Shipment RevX.xls

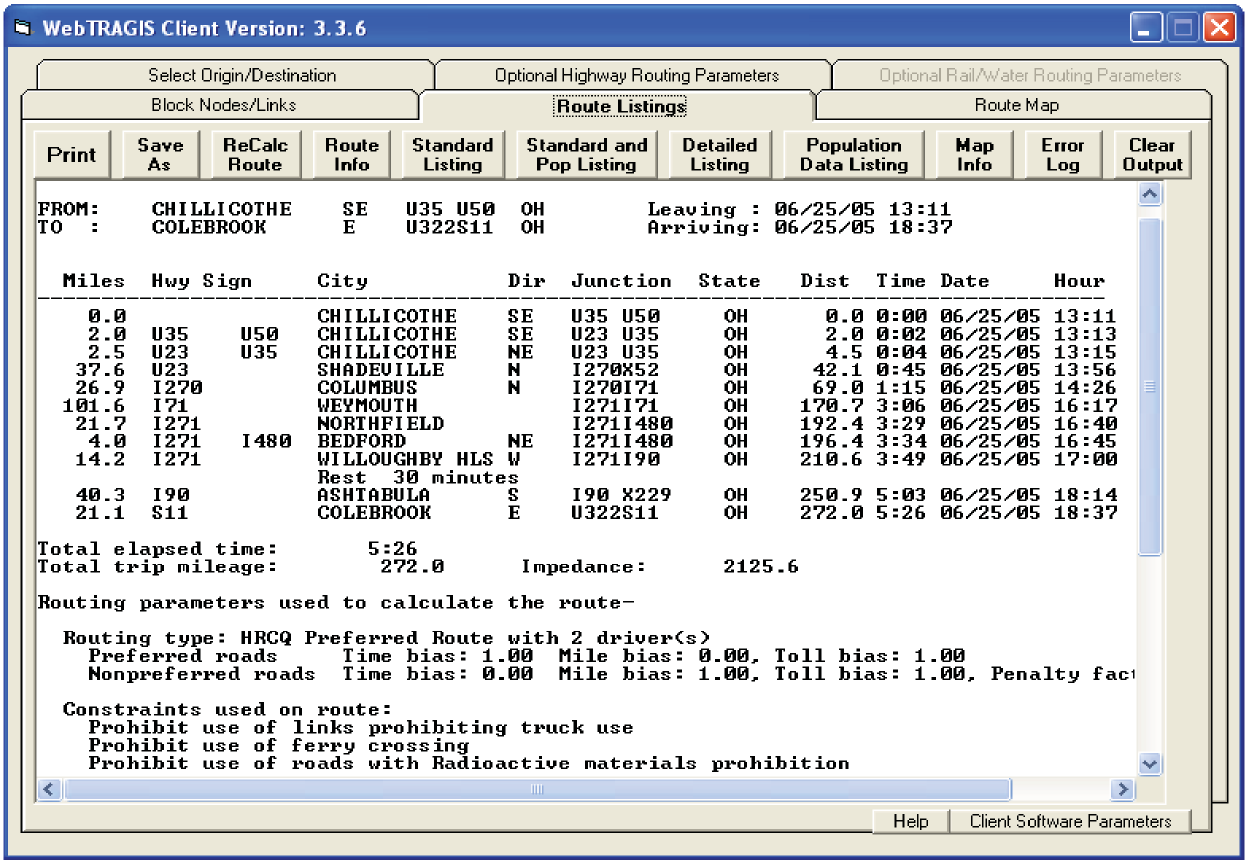
Figure OX-12. Estimating train speeds.

The standard deviation of the sample presented in Figure OX-12 represents the variability of a set of averages. The actual deviation of the full population has been lost. To account for the wider variability of the full population, the estimates of sSpeed used in the Monte Carlo trip cost calculation were calculated using three times the standard deviation of the normal distribution that was fit to the data in Figure OX-12.

$$\text{sSpeed} = (\text{N}|x_{av} = 768,\ s = 216) \qquad (19)$$

OX-5.2 Shipments by Truck

Truck speeds are based on data collected by the TRAGIS routing code (Johnson and Michelhaugh 2003). Figure OX-13 shows an example of the TRAGIS Standard Listing output. The figure shows that TRAGIS provides estimates of driving time and driving distances for each trip route segment.



```
FROM:    CHILLICOTHE    SE   U35 U50  OH        Leaving : 06/25/05 13:11
TO   :   COLEBROOK      E    U322S11  OH        Arriving: 06/25/05 18:37


  Miles  Hwy Sign     City           Dir  Junction  State   Dist  Time Date      Hour
------------------------------------------------------------------------------------
    0.0               CHILLICOTHE    SE   U35 U50     OH      0.0 0:00 06/25/05 13:11
    2.0  U35    U50   CHILLICOTHE    SE   U23 U35     OH      2.0 0:02 06/25/05 13:13
    2.5  U23    U35   CHILLICOTHE    NE   U23 U35     OH      4.5 0:04 06/25/05 13:15
   37.6  U23          SHADEVILLE     N    I270X52     OH     42.1 0:45 06/25/05 13:56
   26.9  I270         COLUMBUS       N    I270I71     OH     69.0 1:15 06/25/05 14:26
  101.6  I71          WEYMOUTH            I271I71     OH    170.7 3:06 06/25/05 16:17
   21.7  I271         NORTHFIELD          I271I480    OH    192.4 3:29 06/25/05 16:40
    4.0  I271   I480  BEDFORD        NE   I271I480    OH    196.4 3:34 06/25/05 16:45
   14.2  I271         WILLOUGHBY HLS W    I271I90     OH    210.6 3:49 06/25/05 17:00
                      Rest  30 minutes
   40.3  I90          ASHTABULA      S    I90 X229    OH    250.9 5:03 06/25/05 18:14
   21.1  S11          COLEBROOK      E    U322S11     OH    272.0 5:26 06/25/05 18:37

Total elapsed time:       5:26
Total trip mileage:        272.0      Impedance:      2125.6

Routing parameters used to calculate the route-

  Routing type: HRCQ Preferred Route with 2 driver(s)
    Preferred roads     Time bias: 1.00  Mile bias: 0.00, Toll bias: 1.00
    Nonpreferred roads  Time bias: 0.00  Mile bias: 1.00, Toll bias: 1.00, Penalty fac

  Constraints used on route:
    Prohibit use of links prohibiting truck use
    Prohibit use of ferry crossing
    Prohibit use of roads with Radioactive materials prohibition
```

Figure OX-13. TRAGIS standard listing output.

TRAGIS has preset biases incorporated into the routing portion of the code. These biases determine the time traveled between each of its nodes. TRAGIS also assumes two drivers per truck for each shipment and 30-minute rest periods at approximately every 250 miles. Because of the required rest periods and also for trips that take significantly less than 24 hours, the trip speed needed is the effective speed that reflects time when the truck isn't moving. At a constant 55 mph, a truck will travel 2,124 km in 24 hr. For the shortest trips considered (822 km for yellow cake shipments and 1,216 km between the closest regional sites), if an effective trip duration of 24 hr is assumed, then the effective speeds for these two trips are 21 mph = 34 km/hr = 822 km/24 hr and 31 mph = 51 km/hr = 1,216 km/24 hr, respectively. So, if the high and low values of the triangular speed distribution are taken to be 55 mph and either 21 or 31 mph, respectively, and the modal values is placed at about two thirds of the range, then the modal value will be about 47 mph = 75 km/hr = 1,800 km/24 hr.

As stated above, this analysis assumes that SNF, MOX, and vitrified HLW will be shipped by dedicated trains, which, when compared to regular freight trains, are likely to make fewer stops in yards and may travel at higher speeds. Nevertheless, although the values of sSpeed calculated using the preceding equation may underestimate dedicated train speeds, the speeds calculated with this equation were used to calculate trip costs without further adjustment.

OX-6. RAILWAY TARIFF (sTariff)

Feizollahi et al. (1995) contains data on railway transportation tariffs. These data are plotted in Figure OX-14. Values in this figure have been escalated to 2006 dollars and converted to metric units. Although the data in Figure OX-14 displays some scatter, it is well fit via regression by the following equation.

$$\mathrm{sTariff}_{av} = 3.27\ \mathrm{sTrip}^{-0.4221}. \quad (20)$$

The standard error of the estimate for this equation was 0.304 \$/tonne-km. If one assumes a normal distribution of data about the regressed line, then sTariff becomes

$$\mathrm{sTariff} = (\mathrm{N}|\mathrm{sTariff}_{av},.304) \quad (21)$$

which is the equation that was used to calculate sSpeed during the Monte Carlo calculation of Trip Costs.

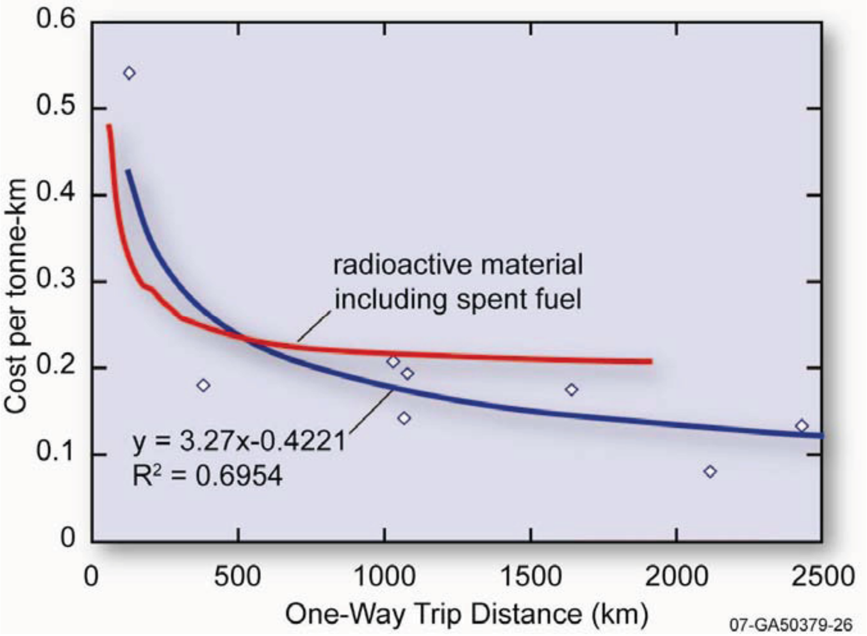


Figure OX-14. Railway tariff as a function of trip distance.

Except for the cost of single-use canisters (sCanCost), low, modal, and high values for triangular distributions were selected (1) by review of the costs associated with the shipment of damaged radioactive Three Mile Island (TMI) reactor components to INL (Fultz et al. 1987), (2) by discussions with staff of the Sandia National Laboratories Shipping and Receiving Department, and (3) based on operational experience of technical staff at Sandia or other government research laboratories.

Although a specific loading parameter and its analogous unloading parameter could have different triangular distributions (different low, modal, and high values), the calculations presented here assumed that they were the same.

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Module R1

Thermal Reactors

Module R1

Thermal Reactors

R1-1. BASIC INFORMATION

The reactor is the central facility of the overall energy system and is supported by the nuclear materials initially processed in the fuel cycle "front end," "burned" in the reactor, and finally dispositioned or recycled in the overall fuel cycle "back end." This section deals with "thermal" reactors; reactors in which the average neutron energies are in the thermal or "slow" range (~0.025-eV) and for which moderators of low atomic number are required. The moderators most commonly used are light water, heavy water, or graphite (carbon). All operating commercial reactors in the U.S. are of this thermal type, all being pressurized water reactors (PWRs) or boiling water reactors (BWRs), approximately two to one in ratio, respectively. As a group, these U.S. plants are called light water reactors (LWRs). Their name distinguishes them from heavy water reactors (HWRs) such as those used predominantly in Canada (CANDU), and gas-cooled reactors such as those used predominantly in the UK, which use a graphite moderator. The predominant product from thermal reactors is electricity. However, the heat generated (in the form of steam) can also be used for industrial applications such as district heat, process heat, or water desalination. Capacities of existing U.S. thermal reactors vary from a few hundred megawatts of electrical power per unit to around 1,400 MWe per unit. A nuclear power plant may actually have more than one unit (reactor) on the same site. The Palo Verde plant in Arizona has three reactors on one site. The fuel cycle cost for a reactor is just one of the four main components of the busbar levelized unit electricity cost (LUEC) from a nuclear power plant. ("Busbar" cost refers to the fact that the electricity cost is measured at the reactor plant boundary connection on the primary side of the switchyard transformer and does not include distribution [transmission] or other utility overhead costs.) The LUEC is usually expressed in mills/kWh or \$/MWh; the value is the same in these two units. (One mill=1/1,000th of a dollar or 0.1 cents). This and other economics-related definitions are described in the *Cost Estimating Guidelines for Generation IV Nuclear Energy Systems* (G4-EMWG 2005). The four components of the LUEC are:

1. Capital component: recovery of reactor capital plus financing costs. The capital component includes all "up-front" costs prior to commercial operation, including: design, licensing, construction, project management, ownership costs, interest during construction, and reactor start-up (commissioning). This component of the LUEC also includes the returns to the investors made during plant operations, such as the interest portion of capital recovery.

2. Operations and maintenance component: annual nonfuel costs including manpower, nonfuel consumables, and overheads. Manpower costs for refueling outages are usually captured in this category. Replacements for major capital items not related to life extension, such as steam generators, can also be placed in this category.

3. Fuel cycle component: the sum of the relevant costs for the needed fuel cycle steps (modules) converted to mills/kWh or \$/MWh unit costs. Models such as G4-ECONS can perform this sometimes complex calculation (G4-EMWG 2006), which involves both unit costs for fuel cycle steps and fuel cycle material balances. Depending on the utility, accounting practices, carrying charges (interest) on stored fuel, and fuel cycle materials undergoing processing are sometimes assessed to this category.

4. Decontamination and decommissioning (D&D) component: usually covered by an escrow or sinking fund accumulated to cover D&D costs for the reactor at its end of life. The calculation of the levelized annual payments to this fund over the operational life of the reactor is described in G4-EMWG 2005.

These four components are ranked from top to bottom with the highest contributors to LUEC at the top. Table R1-1 shows the projected contributors to LUEC for an “Nth-of-a-kind” (NOAK) Generation III PWR design (ABB-CE System 80+). The example table was generated by the G4-ECONS model (2006). All values in the table are in constant (unescalated) 2001 dollars, and fuel cycle costs are based on the lower values of fuel cycle materials and services in that year. The discount (interest) rate is typical of a lower risk, highly-regulated financial environment. Since we are dealing with constant dollars, a “real” or uninflated discount rate is used. This older 2001 example was provided because detailed PWR cost input data was available for G4-ECONS input and it could be benchmarked against other LUEC models. The more current (2009) reactor cost environment (higher construction and fuel costs) is discussed later in this section.

Table R1-1. Projected breakdown (in 2001 $) of electricity cost (LUEC) for a 1,300 MWe Generation III thermal reactor as calculated by G4-ECONS (G4-EMWG 2006).

Summary of Model Results		
Discount Rate =	5.00%	
	Annualized Cost in $M/Year	Mills/kwh or $/MWh
Capital (Including 1st Core and Financing)	158.52	17.40
Operations Cost	78.47	8.61
Fuel Cycle - Front End	29.07	3.19
Fuel Cycle - Back End	9.90	1.09
D&D Sinking Fund	2.48	0.27
TOTAL LUEC	**278.44**	**30.56**

The capital component is always the largest of these costs, which is different than fossil-fuel electricity generation sources, such as oil, natural gas, or coal, where recurring fuel purchase costs can be predominant and also unstable—subject to wide market price fluctuation. The low fuel cycle cost is one of the advantages of nuclear power and is due, in part, to the fact that nuclear fuel (uranium or plutonium) delivers nearly one-million times the energy per unit mass than chemical fuel sources such as fossil fuels (higher energy density). The high capital cost of nuclear power is partly because of the need to safely confine the highly energetic and radioactive reactor core and prevent radioactive materials from escaping to the environment or harming plant workers and the public. Because of the possibly catastrophic consequences of a nuclear accident, nuclear power plants must be constructed to much more stringent safety and quality standards than those for fossil power plants. Massive amounts of steel and concrete with the associated installation labor are required for nuclear power plants.

The most interesting and useful cost figure of merit associated with a reactor project is the “specific” capital cost, which is the cost of planning, licensing, designing, constructing, and starting up the reactor divided by the power capacity. It is usually expressed in $/kilowatt electric ($/kWe.) One must be careful to specify whether the capital cost includes financing (interest) costs and other ownership costs. If not, the capital cost is called the “overnight” cost—the cost if the plant could be built “overnight” and not encounter any interest costs. The total capital cost (TCC) includes interest during construction, which can be a significant percentage of the overnight cost because of the multi-year construction period. (This sensitivity to financing assumptions is examined later in this section.) The following discussion deals mostly with the “overnight” expression of the specific capital cost because it is most dependent on the reactor technology and construction efficiency.

R1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Thermal reactors all use uranium oxide (see Module D1-1) or mixed oxide (see Module D1-2) fuel in some form. LWRs and HWRs use pelletized ceramic fuel clad in zirconium or zirconium alloy rods. The rods are bundled into fuel assemblies that are inserted into the reactor prior to startup. U.S. concept gas-cooled thermal reactors have uranium oxycarbide particle fuel in the form of tiny beads that are coated with heat and diffusion-resistant coatings. Module D1-3 describes this "TRISO" type of fuel, which is embedded in a graphite matrix. The internal heat generated by fission of the U-235 and Pu-239 in the fuel is removed by flowing coolant and transferred by pumps, heat exchangers, and steam generators to a rotating turbine that generates electricity. Because thermodynamic cycles (Rankine cycle for LWRs and Brayton cycle for direct cycle GCRs) are involved, most of the heat energy is rejected to the environment, as is true of all "thermal" (in the thermodynamic rather than neutronic use of this term) power plants using fossil or nuclear fuel. The ratio of electric power generated to total heat generation is the thermodynamic efficiency. Other important reactor performance parameters are:

The capacity factor: the number of effective full power hours divided by the total hours in the year. This factor is lowered by planned or unplanned outages. Outages are planned for refueling and scheduled maintenance, normally during times of lower power demand such as fall or spring. Today's typical U.S. LWR enjoys a capacity factor of over 90%.

The fuel burnup: expressed in (thermal) megawatt-days per metric ton of heavy metal, this figure-of-merit designates the amount of energy that can be extracted from a unit mass of fuel. The accumulation of nuclear poisons (neutron-absorbing nuclides) and fuel materials (cladding, pellet integrity, etc.) limit the lifetime of a fuel assembly in the reactor.

The vintage of reactor technology used is referred to as its "generation." Early prototype and small commercial (a few hundred MWe) units are designated as Generation I. The later and larger units built in the 1960s, 1970s, 1980s, and 1990s are called Generation II. The advanced LWRs and evolutionary design units being built today in the Far East and proposed for construction in the U.S. by 2015 are Generation III or III+ units. These units may incorporate passive safety features. Generation IV reactors are those proposed for deployment after 2020 that may use advanced safety features, incorporate waste minimization, and have additional economics-enhancing and proliferation-resistant features. They are the subject of several extensive international research and development (R&D) programs involving several nations and six technology concepts.

Another reactor category for which interest is growing is that of small to medium reactors (SMRs). (The IAEA defines a small reactor as 300 MWe or less, and a medium-sized reactor as 300 to 700 MWe.) The smaller reactors of this type are sometimes referred to as "grid-appropriate" reactors (GARS) or "deliberately small" reactors (DSRs). The market for such reactors would be for localities or utilities, which cannot afford the high expense of a large reactor, and may not have a power system grid able to accommodate the large reactor. Both fast and thermal neutron type reactors have design candidates in this category. This reactor type and its cost will be discussed in detail in Module R4.

R1-3. PICTURES/SCHEMATICS/DEPLOYMENT STATUS

The "Generations" concept as applied to reactors is explained in Figure R1-1.

To further the advancement of Generation III and III+ reactors in the U.S., the U.S. Department of Energy (DOE) has instituted the NP-2010 program. The NP-2010 program focuses on reducing the technical, regulatory, and institutional barriers to deployment of new nuclear power plants based on expert recommendations documented in *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (DOE-NE 2001).

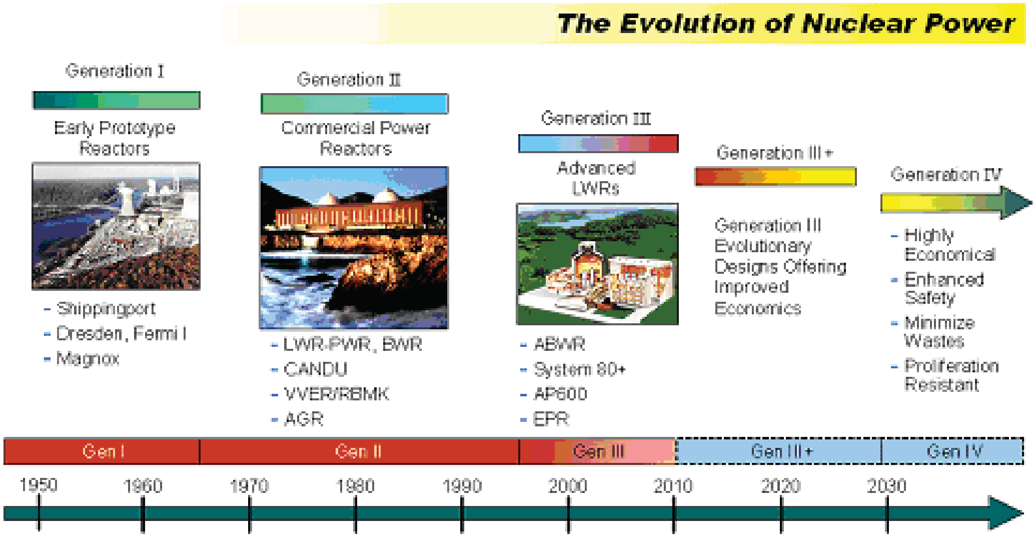


Figure R1-1. Nuclear power evolution by “generations” (DOE 2003).

The technology focus of the Nuclear Power 2010 program is on Generation III+ advanced LWR designs, which offer advancements in safety and economics over the Generation III designs certified by the Nuclear Regulatory Commission (NRC) in the 1990s. To enable the deployment of new Generation III+ nuclear power plants in the United States in the relatively near future, it is essential to completely develop the first-of-a-kind Generation III+ reactor technology and demonstrate the untested federal regulatory and licensing processes for the siting, construction, and operation of new nuclear plants. DOE utilizes competitive procurement processes and conducts program activities in cost-share cooperation with industry. DOE has initiated cooperative projects with industry to develop the business case for new nuclear power plants, to obtain NRC approval of three sites for construction of new nuclear power plants under the Early Site Permit (ESP) process, to support completion of Generation III+ design engineering work, to resolve generic COL regulatory issues, and to support the NRC review of COL applications. The COL process is a “one-step” licensing process by which nuclear plant public health and safety concerns are resolved prior to commencement of construction, and NRC approves and issues a license to build and operate a new nuclear power plant.

The Energy Policy Act of 2005 (EPACT 2005) also includes investment stimuli for new nuclear power plants (NPPs). These include:

- Federal loan guarantees that cover up to 80% of the project cost
- Production tax credits for 8 years of $18/MWh for up to 6,000 MWe of capacity, limited to $750,000,000 per year
- Federal standby support (to cover some of the economic damages from regulatory delays)
    - $2B of risk coverage for first six plants
    - Coverage for delays resulting from licensing or litigation.

The intent of these incentives is to make investors (Wall Street) more likely to finance the high up-front costs required for a reactor project. Utility interest in these incentives has been intense as is evidenced by the number of projects that have announced to the NRC their intent to pursue a COL. Table R1-2 lists the projects announced as of Summer 2009.

Table R1-2. New plant table as compiled by the nuclear regulatory commission (USNRC 2009).

Proposed New Reactor(s)	Design	Applicant
Bell Bend Nuclear Power Plant	U.S. EPR	PPL Bell Bend, LLC
Bellefonte Nuclear Station, Units 3 and 4	AP1000	Tennessee Valley Authority (TVA)
Callaway Plant, Unit 2	U.S. EPR	AmerenUE
Calvert Cliffs, Unit 3	U.S. EPR	Calvert Cliffs 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC
Comanche Peak, Units 3 and 4	US-APWR	Luminant Generation Company, LLC (Luminant)
Fermi, Unit 3	ESBWR	Detroit Edison Company
Grand Gulf, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)
Levy County, Units 1 and 2	AP1000	Progress Energy Florida, Inc. (PEF)
Nine Mile Point, Unit 3	U.S. EPR	Nine Mile Point 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC (UniStar)
North Anna, Unit 3	ESBWR	Dominion Virginia Power (Dominion)
River Bend Station, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)
Shearon Harris, Units 2 and 3	AP1000	Progress Energy Carolinas, Inc. (PEC)
South Texas Project, Units 3 and 4	ABWR	South Texas Project Nuclear Operating Company (STPNOC)
Turkey Point, Units 6 and 7	AP1000	Florida Power and Light Company (FPL)
Virgil C. Summer, Units 2 and 3	AP1000	South Carolina Electric & Gas (SCE&G)
Vogtle, Units 3 and 4	AP1000	Southern Nuclear Operating Company (SNC)
William States Lee III, Units 1 and 2	AP1000	Duke Energy

R1-4. INTERFACES WITH OTHER MODULES

The reactor receives fuel assemblies from the fuel fabrication plant (see Module D1-1) for uranium oxide-fueled thermal reactors, (see Module D1-2) for mixed oxide fueled thermal reactors, or (see Module D1-3) for gas-cooled thermal reactors. Module D1-7 covers the fuel supply for CANDU HWR reactors, and Module D1-8 covers thorium-based fuel in thermal reactors, but mainly for those of Russian design (VVERs).

After irradiation, fuel assemblies are stored in an onsite pool. At some point, the fuel assemblies might be moved to storage casks for onsite or offsite storage (see Modules E1 and E2). Direct transfer to an aqueous reprocessing facility is also possible (see Module F1).

R1-5. MODULE SCALING FACTORS

In general, the cost of electricity and the specific capital cost decrease with higher reactor size (electrical generation capacity). There is likely to be a point where factory production of small reactor modules, as opposed to traditional onsite construction, will allow reduction of unit costs. Studies, such as those being pursued by the Generation IV Economic Modeling Working Group, are investigating this issue. Mycoff and Locatelli's report (2006) is a good summary of such studies to date. The following diagram (Figure R1-2) shows how various concepts for reactor "modularity" affect construction and ultimately the capital costs. It should be kept in mind that any factory that produces modules will need to have its costs amortized over the fleet of NPPs that are supported by it. The costing and general scaling economics of small reactors will be discussed in more detail in Module R4.

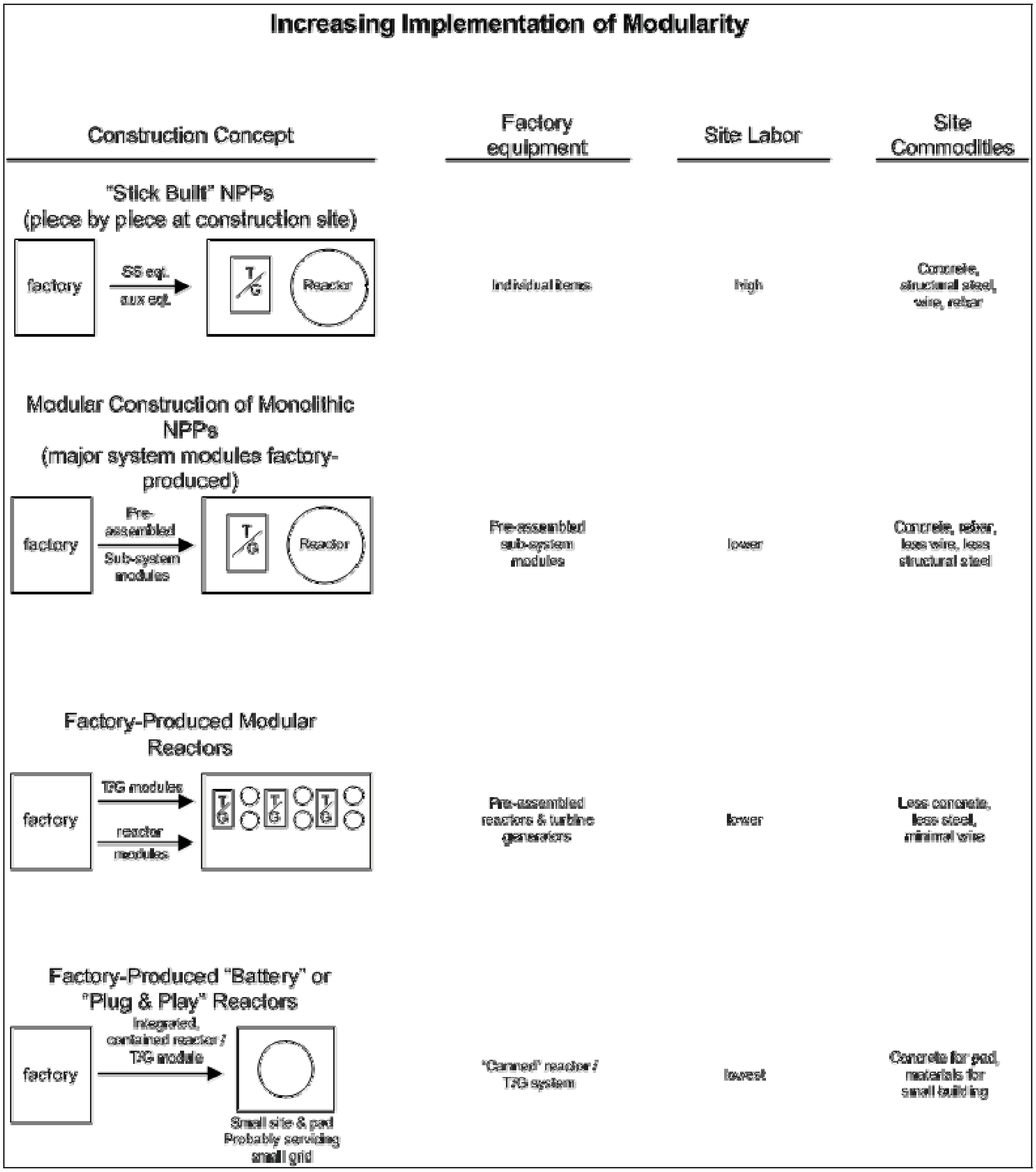
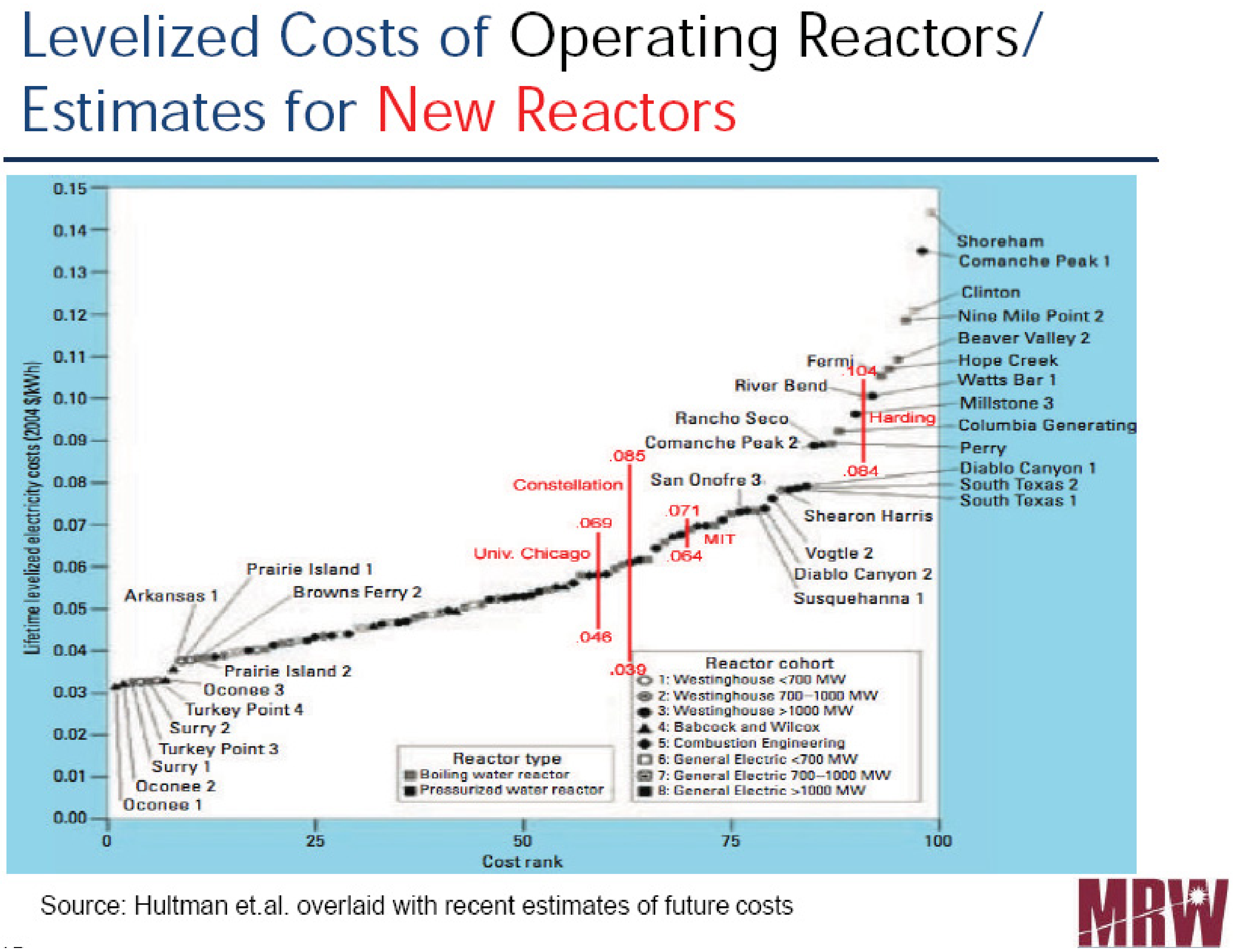


Figure R1-2. How implementation of modularity affects construction.

R1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Before addressing current LWR cost bases, a little cost history is useful. When Generation I reactors were being designed, there was much optimism regarding how the costs of all aspects of nuclear power, including capital costs would eventually decrease. Generation I and early Generation II reactors enjoyed project specific costs ($/kWe) that in today's dollars would be less than $1,000/kWe. In the late 1970s environment, safety, and health (ES&H) considerations and the Three Mile Island accident greatly affected the regulation, public perception, and project execution aspects of nuclear power in a negative fashion, also coming on the heels of the 1973–1974 Arab Oil Embargo, which rapidly reduced the annual growth in electricity demand. The net result was redesign, retrofit, delay, and even abandonment for many proposed LWR projects. During resolution of regulatory issues, some reactors had several years elapse between completion of construction and commercial operation, and some, such as the Shoreham NPP, were never allowed to operate at power levels commensurate with economic commercial operation. These projects were also constructed during a time when interest rates were high. Given the delays, accrued financing (interest) costs, and multiple retrofits, many of these plants experienced specific costs that in today's dollars would be in the $3,000–$6,000/kWe range. Busbar costs for many projects ended up in the range of 60 to 130 mills/kWh. Hultman et al. (2007) and McClary et al. (2007) discuss some of this cost history and Figure R1-3 shows some of the data.


Levelized Costs of Operating Reactors/ Estimates for New Reactors

Source: Hultman et.al. overlaid with recent estimates of future costs

Figure R1-3. Levelized unit cost history (Hultman et al. 2007; McClary et al. 2007).

As time progressed and other forms of electricity production became more competitive, it became apparent that nuclear plants constructed in such an environment could no longer produce competitive electricity; hence, interest in nuclear power waned. Nuclear power would only be saved by (1) safer, more economic, and standardized reactor designs, (2) regulatory reform, (3) improved operations and maintenance procedures (O&M) and lower annual operating costs, (4) higher capacity factors, and (5) shorter construction times. Fortunately, new standardized certified designs have evolved, a new licensing paradigm, the COL, has been established, and today's operating reactors have decreased their O&M costs and increased their capacity factors. All of these factors make nuclear power more attractive for future generations, and the competitiveness of nuclear power has been enhanced by rising fossil fuel costs and the possibility of emission controls or taxes on CO_2 emissions (Nuclear Engineering International 2009). It is also known that shorter construction times are possible as evidenced by experience in the Far East, where schedules have decreased from 60+ months to close to 50 months. Via "coming down the learning curve," Korea has a goal of decreasing construction times to 39 months. Testimony before the U.S. Senate (NEI 2009) discusses Korean experience. Financing and project management are other cost-related issues that have an impact outside of the direct labor and materials construction cost. Articles by Steve Kidd (Nuclear Engineering International 2008-1 and 2008-2) discuss these two areas in detail. Kee (CRA 2009) discusses the important effect of political and state support on project success and cost.

Costs for reactors recently completed or now under construction are considered here. Cost and capacity information sometimes appear in trade press and general press sources. Utilities and architect engineers do not typically publish costs for their projects, especially under today's environment of less economic regulation. Since the March 2008 version of this document, there has been significant increase in estimated capital costs for reactors. Much of the data in the March 2008 report was compiled in 2006–2007 and reflects costs estimated in 2001 through 2006. Table R1-3 shows the cost, capacity, and specific cost data from that 2008 document. Reports by Thomas (2005) and the WEC (2007) summarize other cost studies that were not available to the Economic Analysis Working Group (EAWG) in 2006. Some references may also present the cost results in a manner that reflects the authoring or organization's view on nuclear power (Greenpeace International 2007).

Table R1-3. Specific costs for some actual projects and generic reactors (March 2008 Cost Basis Report).

Reactor and Size	Total Capital Cost (2007 $B)	Specific Capital Cost ($/kWe)
Olkiluoto 3 (Finland) 1,600 MWe EPR (PWR) (Greenpeace 2005)	3.2B Euros=$3.6B fixed price contract	$2,400/kWe incl financing (FOAK)
Lungmen (Taiwan) 2 units: 2,770 MWe total GE ABWRs (South African News Site 2006; Platt 2006)	Old estimate: $5.6B (2,000 $) esc to $6.5B in 2007$ (incl financing). New estimate: $7.1B (2007 $).	$2,370/kWe incl financing (old) $2,560/kWe incl financing (new)
AP-1000 PWR (Generic in U.S.) (Gertner 2006) 1,000 MWe	$1.4B to $1.9B (2006 $) overnight cost	$1,400–$1,900/kWe overnight (NOAK)
System 80+ PWR (Generic in U.S.) 1,300 MWe	$2.65B including financing	$2,040/kWe incl financing (2001 $)
Large LWRs (1,500+MWe) Nth of a Kind (NOAK) 4-module GT-MHR (gas-cooled, direct cycle) (LaBar 2001)		$1,100–$1,700/kWe overnight (NOAK) $1,000/kWe overnight (NOAK) (optimistic)
ABWR or AP1000 in U.S. (DOE-NE 2004; TVA 2004)	Not available	$1,200–$1,600/kWe overnight $2,100/kWe total project for ABWR FOAK in U.S. (Kuhr and Vivenzio 2005)
ESBWR in Europe (General Electric Corp 2006; Nucnet 2007) (factor of 1.3 used to convert Euros to U.S. $)	2007 estimate: $4.4B	$1,430/kWe (total capital project/NOAK) (2006 estimate) $2,750/kW (FOAK incl. Financing: 2007 estimate [1,600 MWe])
AECL CANDU 6 (HWR) (UIC 2006) AECL ACR 700 (HWR) (UIC 2006)	Not available	$2,630/kWe overnight (NOAK) $2,075/kWe overnight (NOAK)

Table R1-3. (continued).

Reactor and Size	Total Capital Cost (2007 $B)	Specific Capital Cost ($/kWe)
Mitsubishi Heavy Industries 1,700 MWe APWR in Texas (Technology Review 2006; Platt 2006) (39% thermal efficiency)	$5.17B for 2 units (2007 $)	$1,520/kWe overnight (2007 $)
New LWR capacity for Constellation Energy (Platt 2007)	Not available	$2,400/kWe overnight (NOAK over 4 units [2007 $])
TVA rehab and restart of Brown's Ferry 1 (1,200 MWe BWR) (Wald 2007)		$1,500/kWe incl financing (predicted actual cost in 2007 $)
Generic LWR in Indonesia (1,000 MWe) (Antara 2007)	$1.5B (2007 $)	$1,500/kWe overnight (2007 $)
Recent MIT estimate for generic LWR (Platt 2006c)	Not available	$2,300/kWe overnight (2007 $)
Completion of 2 partially complete VVER-1000 PWRs in Bulgaria (1,000 MWe/unit) (Sinitsyna 2006)	3.3B Euros ($3.3B)	$1,650/kWe incl financing (2007 $)
Generic LWR (UK Study [Thomas 2005]) OXERA Forecast	Not available	FOAK: 1,625 UK lb/kWe 3,250 $/kWe NOAK 1,150 UK lb/kWe 2,300 $/kWe (all in 2007 $)
Generic LWR (World Energy Council [WEC 2007])	Not available	1,800 Euros/kWe or 2,430 $/kWe (NOAK, overnight, 2007 $)
NOAK= Nth-of-a-kind FOAK= First-of-a-kind		

Table R1-4 shows more recent data from the trade press and other sources gathered in the last year. It can be seen that costs have risen markedly. The reasons for this are as follows:

1. There was very high escalation in the price of commodities, labor, and other procurement-related costs in 2003 through 2008. Figure R1-4 show this graphically. In the last year (Fall 2008 to present), the economic recession has actually caused some negative escalation in power plant costs. (Figure R1-5).
2. Many estimates prepared by regulated utilities for public service commissions are very conservative. These utilities want to make sure that they can recover in the rate base all of the projected front-end costs.
3. More banks and bond-rating agencies have done or commissioned their own studies on the capital costs for proposed reactor projects.

In fact, the issue of cost rather than safety has become the new battleground between the anti-nuclear NGOs and the utilities. A recent newspaper article (Christian Science Monitor 2009) is entitled, "Nuclear Power's New Debate: Cost." The bibliography for this section lists several reports commissioned by anti-nuclear organizations to challenge utility capital and levelized electricity cost estimates. Also listed are some of reports and articles rebutting these reports. (These are not called out as specific references in this report.) With the high level of activity now associated with the "Nuclear Renaissance," a new report appears nearly every month. Even older studies, such as the 2003 MIT Future of Nuclear Report, have been reissued as updates. The new MIT report (MIT 2009) now recommends a specific overnight capital cost of $4000/kWe for new U.S. plants.

Table R1-4 . Specific costs for some actual projects and generic reactors (2009 Cost Basis Report).

Project name	Reactor Type	Reference/Source	Specific Cost in $/kWe
Calvert Cliffs 3	EPR (AREVA PWR)	Platts 2008-1	4500–6000 All-in
South Texas Project	Toshiba BWR	Reuters.com 2009	3700 overnight 4800 all-in
Generic	U.S. LWR	Moody's 2007 Moody's 2008	5000–6000 all in >7000 all in
Ontario, Canada	EPR (AREVA PWR) ACR-1000 (AECL-CANDU)	Platt's 2009-1	6600 all in 9687 all in including outside fence infrastructure
V.C. Summer 2&3	AP-6000 (Westinghouse0	Platt's 2009-2	5680 all-in (was 4400 in 2008)
Levy County (Fla Power & Light)	AP-1000	Nuclear News 2008	7000–8000 all-in includes all infrastructure +some long dist transmission lines+escalation
Turkey Point (Fla Power & Light)	AP-1000	World Nuclear News.org 2009	3108–4540 overnight 5500–8000 all-in
Russian PWRs	VVER-1000 (serial)	Proatom.ru 2008	2900 overnight (previous published value was 2150
Generic U.S. LWRs	LWR	MIT 2009	4000 overnight

Unfortunately, there are not O&M projections, D&D estimates, and fuel cycle data for all of the above cases. Therefore, the overall busbar LUEC cannot be calculated for each of the above cases. Historically U.S. reactors have non-fuel O&M costs in the range of $70M–$120M per unit annually. An example estimate showing O&M subcategories in the Code-of-accounts structure from the Gen IV Guidelines (G4-EMWG 2005) is shown in Table R1-5 below. Over the last 15 years, the average cost has decreased markedly as utilities have learned how to operate their plants more efficiently. Cost escalation has not affected O&M costs nearly as markedly as capital costs. New simpler reactor designs should also experience further decreases. There is some variation of O&M costs with reactor size and energy output. According to Roques et al. (2006), the fixed component of the O&M cost depends on the reactor electrical capacity, which is typically around $60/kW yr. The variable component depends on energy production and is typically around 0.5 mills/kWh. For the Generation III+ reactor in the table below, this formulation would result in an annual cost of $83M/yr; however, it would not include capital replacements. It should be noted that longer life plants (60+ years) would also cause a decrease in the levelized electricity cost, provided that aging issues do not affect safety, plant performance, or recurring costs (Gaertner 2008).

Table R1-5. Typical nonfuel O&M costs for a Gen III+ LWR (from G4-ECONS output).

	G4-ECONS WORKSHEET NAME: Operations & Decommissioning		
	REACTOR O&M COST DATA in Const 2007$		
COA 7	**OPERATIONS COST CATEGORY**		Units
70 series			
71+72	On-site Staffing Cost (71: Non-Management 72: Management)	27.06	$M/Year
73	Pensions and Benefits	7.23	$M/Year
76, 74	Consumables	21.43	$M/Year
75	Repair costs including spare parts	5.24	$M/Year
93	Charges on working capital	0.00	$M/Year
84	Purchased services including refuelling crews	7.33	$M/Year
78	Insurance Premiums & Taxes	8.10	$M/Year
tbd	Regulatory Fees	4.69	$M/Year
tbd	Radioactive Waste Management (non-spent fuel)	2.02	$M/Year
tbd	Other General and Administrative (G&A)	9.16	$M/Year
77	Capital replacements/upgrades (levelized over plant life)	10.00	$M/Year
79	Contingency on O&M (sometimes imbedded in accounts above)	0.00	$M/Year
COA 7	**Total**	**102.26**	**$M/Year**
	Annualized O&M cost per kwh	**#REF!**	**mills/kwh or $/MWh**
	This estimate is for a 1300MWe ABB-CE System 80+ APWR operating at a 90% capacity factor		
	D&D costs are handled by annual sinking fund payments not in this table		

The actual generation costs for nuclear electricity in the U.S. have varied widely. For projects in which high capital costs caused by delays or construction problems are still being amortized, the power cost might be in the range of 60 to 100 mills/kWh. For projects where the capital has already been written off, the production cost (non-fuel O&M + fuel cycle) may be as low as 18 mills/kWh. LUEC projections for new LWRs depend heavily on the interest rates and construction schedule as well as the projected specific capital cost. The regulatory environment will affect all of these factors. Merchant plants with higher risk financing are expected to have considerable higher LUECs than for plants constructed under legislated economic regulation, guaranteed markets, and lower financial risks. LUECs in the range of 30 to 110 mills/kWh would cover most possibilities based on today's models and their inputs. (The low values would be for plants for which the capital has been written off.)

R1-7. LIMITATIONS OF COST DATA

Nearly all the data available on existing or ongoing thermal reactor projects are from outside the U.S. because no new U.S. reactors have been completed since the mid-1990s or ordered since the mid-1970s. Adapting such data to the U.S. is difficult because of currency fluctuations, different wage rates and labor productivity, and different regulatory environments. For example, Far Eastern reactor projects have benefited from short construction times (little regulatory or legal interference), and low interest rates (3% real discount rate or less). It cannot be guaranteed that such beneficial conditions will exist in the U.S. in the near future. Note that constant dollars and real discount rates are used for these reactor analyses, including those in Section R2 on fast reactors.

R1-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table R1-6. The summary shows the reference cost basis (constant year U.S.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range), and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). The financial bases for the upside, reference, downside, and nominal cases may not be the same because the literature sources did not identify these assumptions in any detail (e.g., whether a project is financed by both debt and equity instruments). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. It should be noted that since 2006, a lot of new data have appeared in the trade press and reports, and projected capital cost estimates are rising. This reflects more conservative and realistic estimating for a technology for which new orders in the U.S. are imminent and regulatory work is underway. This accounts for the author's significant increases in the specific data WIT table capital cost entries from those last published in March of 2007, using 2006 data. A recent article and graphic (Figure R1-4) from the New York Times on power plant construction costs validates this fact (Wald 2007). A more recent analysis, based partly on very conservative analyses by investment firms, warns of possible "all-in" specific costs as high as \$5,000–\$8,000/kWe, including escalation (NEI 2007).

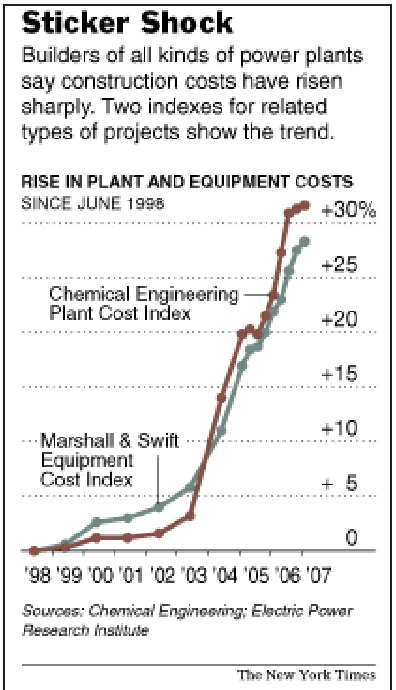
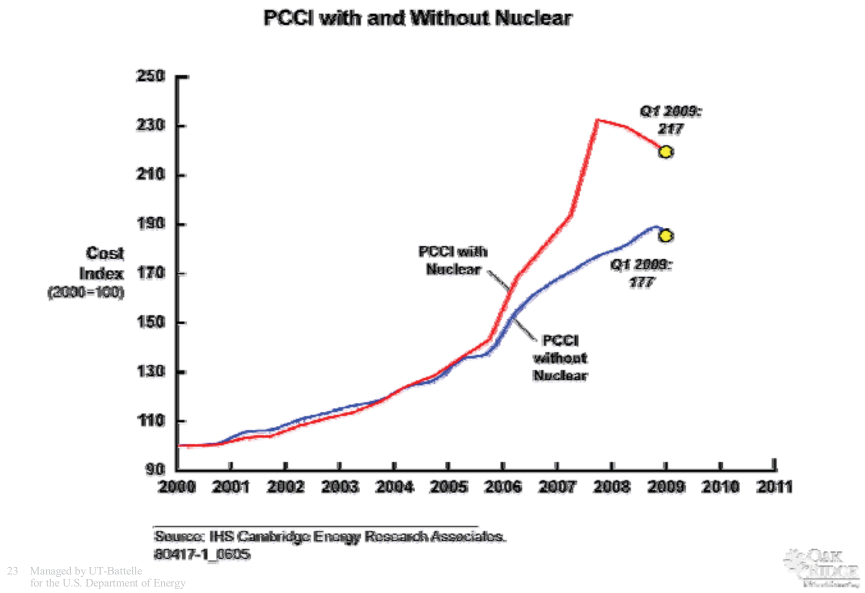


Figure R1-4. Power plant cost escalation (1998–2007).

Table R1-6. Cost summary table (costs in constant \$ unless otherwise noted.).

What-It-Takes (WIT) Table: NOAK LWRs			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Generic LWR in U.S.: (specific overnight cost) NOAK \$3200/kWe	\$2300/kWe	\$5000/kWe	\$3500/kWe
(Specific total capital cost including financing, NOAK) \$3500/kWe (5% DR [discount rate])	\$2600/kWe (low risk financing)	\$6500/kWe (high risk financing)	\$3900/kWe (most likely utility financing at 5% real DR)
Non-fuel O&M including contribution to D&D fund: fixed component 62 \$/kWe-yr (w/o D&D adj) (Roques et al. 2006)	55 \$/kWe-yr including D&D fund	80 \$/kWe-yr including D&D	\$66/kWe-yr including D&D fund
Non-fuel O&M including capital replacements: variable component 0.45 mills/kWh (w/o capital replacements adj) (WEC 2007)[0]	0.8 mills/kWh including capital replacements adj	2.5 mills/kWh including capital replacements adj	1.8 mills/kWh including capital replacements adj

Note that values for nonfuel O&M costs have also been included in Table R1-6. To get the overall O&M cost in millions of dollars per year, the fixed cost component is multiplied times the reactor capacity in kW and this product is added to the product of the variable cost times the annual electrical generation. The O&M components are adjusted to include average lifetime capital replacements for the reactor and contributions to a D&D fund to decommission the reactor at the end of its life. It should be noted that fuel cycle costs are not included in any of these costs, and that this component of the LUEC must be added to the capital and nonfuel O&M costs derived from the table below in order to calculate the total LUEC for the reactor system. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table.



Source: IHS Cambridge Energy Research Associates.
80417-1_0605

Figure R1-5. More recent data on powerplant cost escalation (2000–2009). (Same CERA data source as Figure R1-4.)

R1-9. SENSITIVITY ANALYSES

It is known that the factors that most influence the LUEC are the reactor capacity factor, the total capital cost, and the time it takes to construct it. The overnight cost will be affected strongly by commodity prices for items such as concrete, structural steel, and rebar. Time to construct and the associated interest will affect the total capital cost, which is the sum of the overnight cost plus the financing cost (interest during construction [IDC]). The IDC depends on the discount rate and time required to design, build, and start-up the reactor. Figures R1-5 and R1-6 below show how the discount rate (cost of financing) affects the specific total capital cost and the capital cost component of the LUEC. The overall time to design, construct, and start-up the LWR is assumed to be 5 years for this sensitivity, and the cumulative expenditure pattern over the 5 years is assumed to follow the typical S-curve shape. The G4-ECONS model was used to generate the data below.

The time to design, construct, and start-up a reactor is itself an important cost driver. The most successful reactor projects are those for which this overall time is minimized. It is anticipated that new U.S. projects can be completed in 4 to 6 years. Experience in Asia shows that such project durations are indeed achievable.

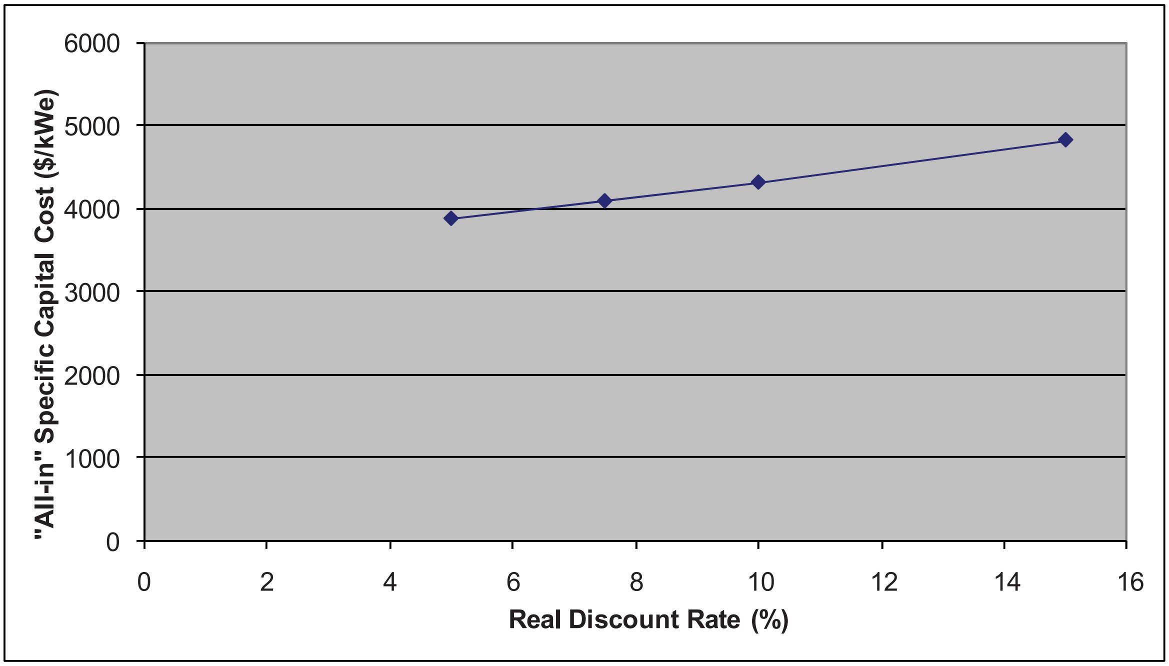


Figure R1-5. Effect of discount rate on the "all-in" specific total capital cost (for a fixed overnight cost of $3500/kWe).

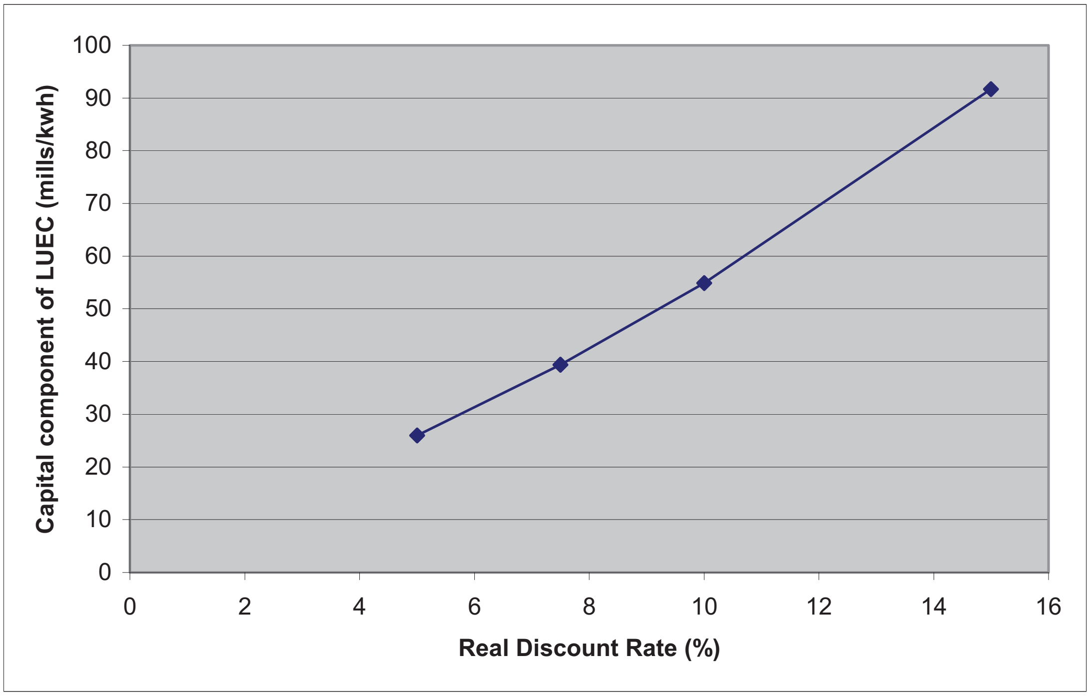


Figure R1-6. Effect of discount rate on the capital component (in mills/kWh) of the LUEC (for a fixed overnight cost of $3500/kWe).

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Module R2

Fast Reactors

Module R2
Fast Reactors

R2-1. BASIC INFORMATION

The reactor is the central facility of the overall energy system and is supported by the overall fuel cycle. This section deals with “fast” reactors, which are those reactors in which the average neutron energies are in the higher energy or “fast” range (>0.1 MeV) for which less or no moderation is required. This allows the use of coolants that are higher in atomic number, including liquid metals such as sodium or lead, or even liquid salts. There are at present no operating commercial reactors in the U.S. of this type. However, small units, such as Fermi-I and Experimental Breeder Reactor (EBR)-II, produced power in the past. A large demonstration project, the Clinch River Breeder Reactor Project (CRBR), existed as a project in the 1970s and 1980s, but it was never completed. Construction work on the CRBR had begun and some large equipment had been procured and fabricated when the project was canceled. The largest projects have been built in Russia (BN-600), France (Superphenix), and Japan (Monju). Russia, India, and China are the only countries presently constructing new fast reactors, the BN-800 (Russia), the 500 MWe Prototype Fast Breeder Reactor (India), and the Chinese Experimental Fast Reactor (CEFR). As with thermal reactors, the predominant product from fast reactors is electricity. However, the heat that is generated can also be used for industrial applications such as hydrogen production (lower-temperature hydrogen production processes), district heat, process heat, or water desalination.

Fast reactors have the advantage over light-water reactors (LWRs) in that the fast spectrum provides sufficient excess neutrons for complete fission of the initial natural uranium, including all transuranic isotopes produced along with additional surplus neutrons that can be used to transmute some fission products, consume transuranics from thermal reactor recycled spent fuel, and/or breed additional fissile material. The thermal spectrum requires additional fissile support, generally in the form of enriched uranium, and can therefore only consume a small fraction (on the order of 1%) of the initial uranium ore. Additionally and possibly more importantly, the fast spectrum is far less sensitive to isotopic variation in the fuel composition, which will vary widely, depending on the source and age of the feed material being recycled.

Closing the fuel cycle is a significant part of the mission projected for the fast neutron reactor. In this case, a waste management mission (transmutation) can be accomplished in addition to electricity production. Fast reactors can also be used to convert fertile U-238 to fissile Pu-239, which makes for a highly-sustainable fuel cycle. This concept is known as “breeding,” and the reactors are known as fast breeder reactors. A fast-neutron nuclear power plant may actually consist of more than one “unit” or reactor on the same site. In fact, there are several concepts for modular sodium-cooled fast reactors that could be located in a reactor park along with dedicated fuel cycle facilities for integrated spent fuel recycle and refabrication.

The fuel cycle cost for a fast reactor (FR) is just one of the main four components of the busbar levelized unit electricity cost. (“Busbar” cost refers to the fact that the cost of electricity is that at the plant electrical boundary connection [busbar] and does not include distribution or other utility overhead costs.) As in Module R-1, the four components of the levelized unit electricity cost are:

1. Capital component (recovery of total project capital plus financing costs).
2. Operations and maintenance (O&M) component (annual nonfuel costs including manpower). Refueling manpower is usually carried in this major account.
3. Fuel cycle component (the sum of the relevant costs for the needed fuel cycle steps [modules] converted to mills/kWh or $/MWh unit costs). For the transmutation fast reactor fuel cycle, this

account would include the pre-FR irradiation costs of processing the actinide products received from an LWR reprocessing facility.

4. Decontamination and decommissioning (D&D) costs, a fund accumulated to cover D&D of the reactor at its end-of-life.

Of these costs, the capital component for the fast reactor will always be the largest (as is the case for thermal reactors). This is different than other electricity generation sources, such as oil, natural gas, or coal, where fuel costs can be predominant and also unstable. The low fuel cycle cost is one of the advantages of nuclear power and is due to the fact that nuclear fuel delivers nearly one-million times the energy per unit mass of chemical fuel sources such as fossil fuels. The high capital cost of nuclear power is in part because of the need to confine radioactive materials originating in the reactor core during design basis accidents. With fast reactors, there is also the fact that the main coolant candidate is liquid sodium, a reactive metal that will burn in air. Nuclear power plants are built to safety and quality control standards that exceed in breadth and scope that of fossil-fueled power plants.

The most useful cost figure of merit here is the specific total capital cost, which is the cost of planning, designing, licensing, constructing, and starting up the reactor (up-front costs) divided by the net power capacity. It is usually expressed in \$/kilowatt electric or \$/kWe. One must be careful to specify whether the capital cost includes financing (interest) and other owner's costs. If the financing (interest) is excluded from the capital cost, this cost figure is called the "overnight" capital cost and is the best measure to compare costs from plant to plant. The total capital cost (TCC) includes interest during construction, which can be a significant percentage of the overnight cost if project construction or regulatory delays are encountered. The discussion below will deal mostly with the "overnight" expression of the specific capital cost, because it is most dependent on the reactor technology and also the one which appears most frequently in the literature.

R2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Fast reactors all require the use of fuel with higher fissile content than LWRs, whether it is U-235 or transuranics. Most international (outside the United States) experience is with MOX or mixed oxide (urania, plutonia) ceramic fuel clad in stainless steel rods (Module D1-4). The fissile content for the MOX driver fuel is generally 17% or more of the heavy metal mass. The rods, thinner than those for thermal reactors, are bundled into fuel assemblies that are inserted into the reactor prior to startup. The United States has extensive experience with metal-based fast reactor fuels (Module D1-6) in EBR-II and Fast Flux Test Facility (testing only). The advantage of metal fuel is heat removal (high thermal conductivity) capability, compatibility with sodium coolant, passive-safety response characteristics during beyond design basis accidents, high breeding capacity, ease in fabricability, and its compatibility with electrochemical spent fuel recycling schemes. The internal heat generated by fission in the fuel is removed by the flowing liquid metal coolant and transferred by heat exchangers to steam generators where water is turned into steam. The steam then flows to turbine generators where electricity is generated. Because thermodynamic cycles are involved, most of the heat energy is rejected to the environment, as is true of all power plants using fossil or nuclear fuel. The ratio of the electric power generated to the total heat generation is the thermodynamic efficiency. Because of the higher liquid sodium temperature, the fast reactor is thermodynamically more efficient than the LWR.

Other reactor performance measures are the capacity factor and the fuel burnup. These have the same definitions as those for thermal reactors in Module R1.

R2-3. PICTURES/SCHEMATICS/DEPLOYMENT STATUS

Figure R2-1 shows the flow concepts within a fast reactor using a liquid sodium coolant.

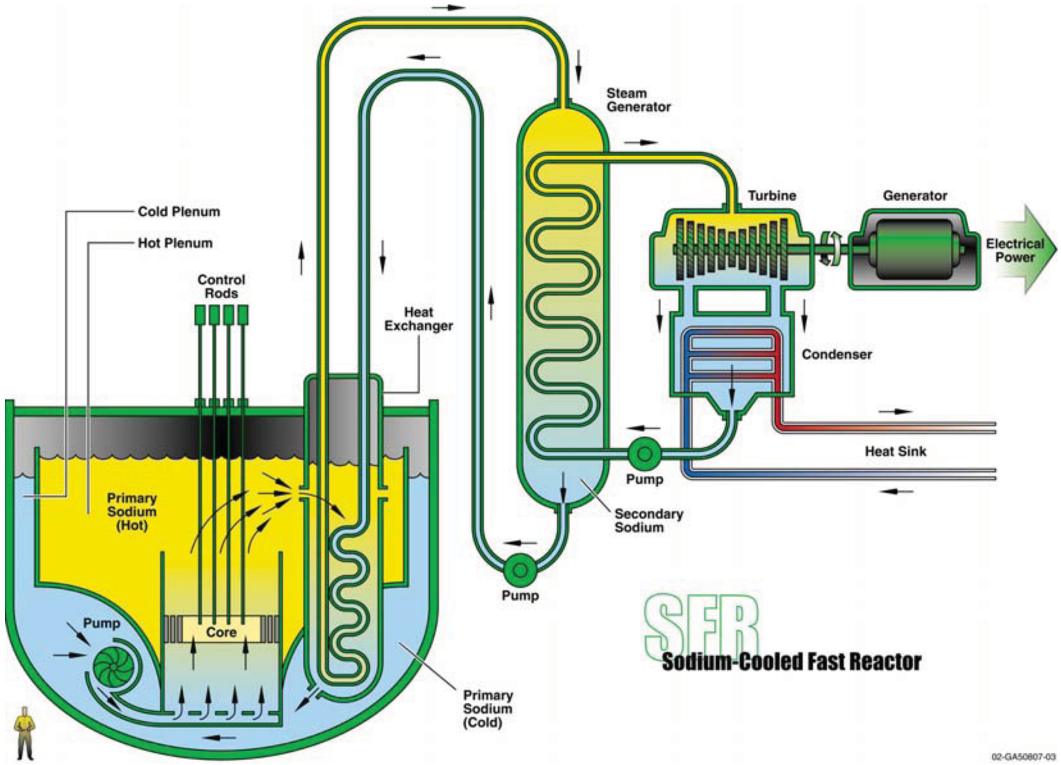

Figure R2-1. Major elements of a liquid-metal cooled fast reactor.

The last fast reactor project actually completed in the U.S. was the Fast Flux Test Facility (FFTF) at Hanford, Washington. This now-defueled and drained Department of Energy (DOE)-owned reactor was not designed to produce electricity; however, the addition of a power generating balance of plant was considered at one time. The next U.S. fast reactor project is projected to comprise a few hundred megawatts of electrical capacity and will also demonstrate actinide burning on a large scale. The decision of whether the reactor will be started up with metal or oxide fuel has yet to be made.

R2-4. INTERFACES WITH OTHER MODULES

The reactor will receive fuel assemblies from the fuel fabrication plant for its startup fast reactor fuel. Initially, this startup fuel is expected to be a more conventional fast reactor fuel, such as U-Pu-Zr metal fuel, mixed oxide fuel, or low enriched uranium metal fuel, as appropriate. As transuranic-based fuels are fabricated and qualified for reactor use, they will be converted over to the transuranic-based fuel.

After irradiation, fuel assemblies are stored in a special area in liquid sodium until they decay to a degree that handling can be accomplished in air. Once the fuel assemblies have decayed, the fuel assemblies might be moved to storage casks for onsite or offsite storage (Modules E1 and E2). Direct transfer to a reprocessing facility (Modules F1 or F2/D2, depending on whether aqueous or electrochemical fuel reprocessing is used) is also possible. With integral fuel cycles, such as the Argonne National Laboratory (ANL) electrochemical recycle scheme based on metal fuel, reprocessing and new fuel fabrication take place in the same hot-cell facility, thus eliminating the need to transport spent FR fuel offsite.

R2-5. MODULE SCALING FACTORS

In general, the cost of electricity and the specific capital cost decrease with higher reactor size (electrical generation capacity). There is likely to be a point where factory production of small reactor modules, as opposed to traditional onsite construction, will allow reduction of unit costs. Studies, such as those being pursued by the Generation IV Economic Modeling Working Group, are investigating this issue. Section R-1 has a more comprehensive discussion and diagram dealing with the modularity issue. It should be noted that the General Electric PRISM FR (aka ALMR or Advanced Liquid Metal Reactor) concept is modular in nature and is the subject of several papers and reports (Ehrman and Boardman 1995; Dubberly et al. 2003a; Dubberly 2003b; Fletcher 2006, GE Hitachi 2008).

R2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The question often arises as to how the specific overnight cost of a fast reactor compares to that for LWRs. From a pure engineering standpoint, one would expect pipe sizes to be larger because of the lower volumetric heat capacity of liquid sodium vis-à-vis liquid water (Forsberg 2007). There are also the additional safety and material considerations associated with the use of liquid sodium, a chemically-reactive metal. The core size, however, for a fast reactor can be smaller, since higher fissile content means less heavy metal content compared to LWRs. Other recent studies (Hoffman 2004) have looked at the issue of capital cost as a function of the conversion ratio. The well-defined Power Reactor Inherently Safe Module (PRISM) reactor was used as the basis for this study. There seems to be a feeling among some utilities and other stakeholders that the specific capital cost for an nth-of–a-kind (NOAK) fast reactor will be 1.0 to 1.6 times that for NOAK LWRs. There are, however, no recent detailed studies to backup this claim. There are several nations pursuing prototype fast reactors (Williams 2009); however, cost information is sketchy, and the prototypes are not the size of the eventual commercial unit that might be deployed. It is known that the Japanese and French are carefully considering the “lessons learned” from past FR projects to reduce this “FR/LWR” specific capital cost factor for their new concepts such as the Japanese Sodium-cooled Fast Reactor (JSFR), the European Fast Reactor (EFR), and the prototypes (Mainichi Daily News 2006; Platt 2006) that will precede them. However, as discussed above, it should be noted that fast reactor are the ultimate solution for closing the nuclear fuel cycle and have capabilities in regards to transmutation and sustainability that cannot be accomplished with LWR technology.

It is now useful to consider capital costs for fast reactors actually built or proposed (paper studies only for the latter). Cost and capacity information sometimes appear in trade press and general press sources. Utilities and architect engineers do not typically publish costs for their projects, especially under today’s environment of less economic regulation. Table R2-1 shows some historical data for FR projects actually completed and projected data for a few that have been recently announced. Table R2-2 shows similar, but more detailed, data for FR projects never completed, are new-proposed, or that are the subject of “paper studies” (cost projections for the latter).

Table R2-1. Historical capital costs for completed fast reactor systems and projected costs for recently announced or currently under construction systems.[a]

Reactor and Size	Total Capital Cost (2006 $)	Specific Capital Cost ($/kWe)
MONJU (Japan) 280 MWe (completed)	$6B (2006 $)	$21,400/kWe (2006 $)
Superphenix (France) 1,240 MWe (completed)	9B Euros = $11B	$8,870/kWe (2006 $)
Proposed Large Japanese Sodium-cooled Fast Reactor 1,500 MWe (announced proto)	$2.3B (all-in costs)	$1,600/kWe (all-in costs)
BN-800 (Russia) (under construction) (2007 estimate) Revised 2008 estimate from (Proatom 2008) reflecting schedule slippage (Platts 2009) and procurement difficulties. Completion date has slipped from 2010 to 2014.	$2B in 2006 $	$2,500/kWe $ >$6000/kWe (2008$)
Future French Prototype (Mainichi Daily News 2006) 800 MWe (announced proto)	1.5B Euros ($2.0B in 2007 $)	$2,500/kWe
Kalpakkam Prototype FBR (India) (Subramanian 2006) (under construction)	$767M	~$1,500/kWe

a. There is not sufficient and publicly-available “lessons learned” information to explain the above historical costs. Historical costs are usually “all-in” or total capital cost and include financing and owner’s costs. Announced and “under construction” projects are generally expressed as overnight costs in constant dollars. U.S. standard GDP deflators were used to escalate historical costs to 2006 $. Most of these costs appear in the references listed at the end of this section.

Table R2-2. Projected capital costs for never-completed, new-proposed, or conceptual fast reactor systems. (Data compiled in 2006, the new and proposed projects have certainly been affected by the increases in commodity and labor pricing from 2006 to 2008. Where available, new data is cited in the text to follow.)

Facility Name	Proposed Location	Size/Capacity (Electric and Thermal)	Units	Proposed Operation dates	Capital overnight cost in millions of local currency units	Currency type (FCU) Foreign Currency Unit	Exchange rate to $ ($/FCU)	Exchange rate date	Capital cost in "then year" $M	Deflator	Capital cost in 2006$M	Electricity Specific Overnight Capital Cost ($/kWe)	Thermal Energy Specific Overnight Capital Cost ($/kWth)
Clinch River Breeder Reactor Project	Oak Ridge, TN USA	1000	MWth	late 1980s	3600	US$	1	1984	3600	1.75	6300	18000	6300
		350	Mwe	(term in 1983)									
BN-800	Beloyarsk, Russia	2300	MWth	2010	2000	US$	1	2006	2000	1	2000	2500	870
		800	Mwe										
Prototype Fast Breeder Reactor (PFBR)	Kalpakkam, India	1400	MWth	2010	3492	crores	0.205	2003	717	1.07	767	1534	548
		500	Mwe										
Japanese Sodium-cooled Fast Reactor (JSFR)	Japan (Conceptual Plant)	3530	MWth	2050	224700	Yen	0.009346	2006	2100	1	2100	1400	595
		1500	MWe										
General Electric S-Prism (modular:2 power blocks/4 Rx modules) Nth of a kind	USA (Conceptual Plant)	4360	MWth	2020	2200	US$	1	1996	2200	1.22	2684	1626	616
		1651	MWe										
Low Conversion ratio variants of PRISM	USA (Conceptual Plant)	1680	Mwe	2020				2004		1.047		1600-1700	
ANL-AFCI-118 Report (Hoffman)		4430	MWth										

R2-7. LIMITATIONS OF COST DATA

All fast reactors constructed to date have been “first-of-a-kind” (FOAK) facilities that have not enjoyed the economic benefits (lower costs) of construction learning and near-design replication (FOAK to NOAK cost improvement) that, to some degree, thermal water reactors enjoy. Instead, the specific capital cost for completed facilities is quite high. The projected specific capital cost given for the reactor cost estimates appearing in planning or “paper studies,” is usually optimistic in that it incorporates some developer optimism, but may not include financing costs.

Newer FR paper studies are incorporating many new innovative features that should lend technical support to what seem to be optimistic claims. An IAEA conference on “Fast Reactor Design with Emphasis on Economics” was held in Vienna in October 2008 (Williams 2009). Ideas for cost improvements were suggested, but no specific cost data was given. It is likely that such data are considered proprietary. The industrial participants (GE-Hitachi 2008) (Energy Solutions 2008) (AREVA 2008) in the former U.S. Global Nuclear Energy Partnership (GNEP) activity produced reports describing their concepts for new fuel cycles in the U.S. Each of these reports suggested some sort of prototype fast reactor to demonstrate transmutation, but again no detailed cost information was available, and none of these companies detailed how the $/kWe cost would decrease in going from the prototype to the FOAK to the NOAK units.

R2-8. COST SUMMARIES

As can be seen above, specific capital costs, both realized and projected, for fast reactors vary widely. Cost experience for actual projects has not been good. These systems have additional piping and components than for LWRs because of the additional intermediate coolant loop (water to sodium) and the larger equipment needed to pump and handle liquid sodium. As part of the Generation IV program, however, new design concepts are being investigated that will hopefully include much enhanced passive safety, simpler systems, and improved economics. The Japanese have worked on such a concept, the JSFR, which they believe for an NOAK system can come in at well below $2,000/kWe including interest during construction (Ono et al. 2007). Recent PRISM studies (Ehrman and Boardman 1995; Dubberly et al. 2003a; Dubberly 2003b; Fletcher 2006; Forsberg 2007) for multiunit modular plants are also calculating specific capital costs in or below this $2000/kWe range. Based on the large projected increases in commodity and labor costs from 2003 onward (discussed in more detail in Module R-1 for thermal reactors), this cost range is no longer considered valid.

As mentioned earlier, many nuclear critics believe that fast reactors will have inherently larger costs than LWRs. A commonly heard “rule-of-thumb” is that the fast reactor will be 20% higher than a LWR on a per kilowatt of capital basis. Russian experience has shown this factor to be more like 60% (VVER cost versus BN cost) (Minkov et al. 1990). At the 2008 IAEA meeting (Williams 2008), the Russian representative suggested that at a unit size of 1800 Mwe or larger, the $/kWe cost of a fast reactor system should be equivalent to or smaller than that of their LWR (VVER) reactor systems. It should also be noted that estimates prepared by designers of the EFR show it to be a 25% cost increase per kilowatt than the European Pressurized-water Reactor (EPR), also estimated by the same team. These cost comparison are currently speculative because neither LWR nor fast reactor have been built in the developed world in the past 2 decades to furnish much actual data for comparison. Again, as mentioned earlier, the fast reactor has benefits that the LWR does not, namely the ability to either breed or burn actinide materials, and in contributing to closing the fuel cycle, while generating electricity on the grid.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table R2-3. These values are larger based on cost analyst’s judgment and are intended to provide a cost distribution that is consistent with LWR (Module R1) values and the sparsely available cost data for commercial-scale NOAK fast reactors. Future versions of this report are anticipated to provide greater detail and better basis and justification for the cost values. The summary shows the reference cost basis (constant year U.S. $), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 2.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table (Table R2-3). It should be noted that the selected nominal value of $4200/kWe (overnight) for the fast reactor compares to the same value of $3500/kWe (overnight) for the LWR (Module R1). This is a 20% difference, and assumes the fast reactor will benefit from some design changes that will reduce the amount of labor and materials needed for construction. It should be noted that escalation in commodity, labor, and procurement costs from 2003 through 2008 have caused the authors to significantly increase the $/kWe costs for all classes of reactors (thermal in Module R-1, fast in this Module R-2, and others in the new Module R-3).

Table R2-3. What-It-Takes cost summary table.

What-It-Takes (WIT) Table			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Overnight Cost for NOAK FR in U.S. $4000/kWe	$3000/kWe	$7000/kWe	$4200/kWe (NOAK)
Total Capital (low risk financing) $2,800/kWe	$3400/kWe	$8500/kWe	$4600/kWe (NOAK)
O&M Fixed Component including D&D fund contribution (no ref. available)	$60/kWe-yr	$85/kWe-yr	$70/kWe-yr
O&M Variable component including Capital Replacement Component (no ref. available)	1.0 mills/kWh	2.7 mills/kWh	2.0 mills/kWh

O&M costs for the reactor have been included in this edition of the Cost Basis Report. They are applied in the same manner as in Module R1—they have a fixed and variable component. The code of accounts structure would also be the same as that described in Module R1. O&M costs are expected to be somewhat larger for FRs as compared to LWRs, mainly because of the more complex systems. The fixed component of the O&M cost has been increased somewhat from the 2008 values to reflect cost escalation.

R2-9. SENSITIVITY ANALYSES

No studies of this type have been undertaken recently. It is known, however, that as with thermal reactors, the factors that will most influence the levelized unit electricity cost are the reactor capacity factor (% of time it is generating electricity), the total capital cost, and the time it takes to construct it.

R2-10. BIBLIOGRAPHY

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Module R3

Gas-Cooled Reactors (High-Temperature Reactors)

Module R3
Gas-Cooled Reactors (High-Temperature Reactors)

R3-1. BASIC INFORMATION

This module is a new addition to the 2009 Advanced Fuel Cycle report cost database. Gas-cooled reactors have been operated, mainly in the UK, for many years. Designs of current interest take advantage of the higher coolant temperatures available with gas-phase (in this case helium) cooling and the associated higher thermodynamic efficiencies. For this reason the moniker “High-Temperature Reactors” (HTR) is more appropriate. It has been added because of increasing interest in this type of reactor for process heat applications, especially where process heat in the range of 700 to 900°C is needed. Nearly all proposed HTR designs for large-scale applications (as opposed to very small space-related applications) are thermal neutron spectrum reactors and use graphite as the moderator. Also, nearly all of today’s HTR designs are modular in nature (i.e., a plant would consist of multiple reactors of 200 MWth to 600 MWth in capacity). Some of the generic economics of smaller reactors will be discussed in Module R4; however, because of the considerable interest in this particular reactor type, a separate module designation and section were dedicated to HTRs in this report. In addition to versatility for process heat applications, proponents of HTRs stress the safety of this design, since the graphite-embedded particle fuel cannot melt, and the reactivity decreases with temperature. The tri-structural isotropic (TRISO) fuel itself is designed such that fission products cannot easily escape outside the fuel particle coatings; hence, the fuel itself is part of the “containment.” The higher temperature variation of the reactor type, the very-high temperature reactor (VHTR), is one of the six concepts being developed under the International Generation IV Reactor Systems Program. The U.S. is developing this reactor type as the Next Generation Nuclear Plant (NGNP), which was selected as first priority of the U.S. Generation IV Program. Currently the commercialization effort for this project is oriented toward high-temperature process heat rather than electricity.

The economics of HTRs is generally expressed with the same types of figures of merit as for the thermal water reactor (R1) and fast (R2) systems, the main exception being that the unit cost of process heat (thermal kilowatts of millions of BTUs) is calculated rather than the unit electrical kilowatt cost. The HTR provides process heat that can be used for a wide variety of applications, only one of which is electricity. The energy supplied to the industrial applications that have been and are being evaluated is in the forms of electricity, steam, and high-temperature gas. For the purposes of analyses, these products are priced in terms of $/MMBtu (million BTU) required to generate them. This metric allows a direct comparison with the costs of the fossil fuel-based (e.g., coal, natural gas) products using conventional processes. (Wholesale natural gas prices have varied from 3 to 13 $/MMBTU over the last 10 years.) This is the target market for the HTR; the pure electricity supply market is a secondary market in which, for reference, the HTR is very competitive in niche applications because of the high net efficiency of the plants when compared with other nuclear technologies and similar net efficiency when compared with coal and natural gas fired plants.

The fuel cycle cost, including preparation of the TRISO fuel, for a HTR is just one of the four main components of the busbar levelized unit electricity cost (LUEC) from a nuclear power plant. (“Busbar” cost refers to the fact that the electricity cost is measured at the reactor plant boundary connection on the primary side of the switchyard transformer and does not include distribution [transmission] or other utility overhead costs.) The LUEC is usually expressed in mills/kWh or $/MWh; the value is the same in these two units. (One mill=1/1,000th of a dollar or 0.1 cents). This and other economics-related definitions are described in the *Cost Estimating Guidelines for Generation IV Nuclear Energy Systems* (G4-EMWG 2007). The four components of the LUEC are:

1. Capital component. Recovery of reactor capital plus financing costs. The capital component includes all "up-front" costs prior to commercial operation, including design, licensing, construction, project management, ownership costs, interest during construction, and reactor start-up (commissioning). This component of the LUEC also includes the returns to the investors made during plant operations, such as the interest portion of capital recovery.
2. Operations and maintenance component. Annual nonfuel costs including manpower, nonfuel consumables, and overheads. Manpower costs for refueling outages are usually captured in this category. Replacements for major capital items not related to life extension, such as steam generators, can also be placed in this category.
3. Fuel cycle component. The sum of the relevant costs for the needed fuel cycle steps (modules) converted to mills/kWh or $/MWh unit costs. Models such as G4-ECONS can perform this sometimes complex calculation (G4-EMWG 2006), which involves both unit costs for fuel cycle steps and fuel cycle material balances. Depending on the utility, accounting practices, carrying charges (interest) on stored fuel, and fuel cycle materials undergoing processing are sometimes assessed to this category.
4. Decontamination and decommissioning (D&D) component. Usually covered by an escrow or sinking fund accumulated to cover D&D costs for the reactor at its end of life. The calculation of the levelized annual payments to this fund over the operational life of the reactor is described in EMWG's 2007 document.

R3-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Most HTR designs intend to use a fuel consisting of TRISO coated particles embedded in a graphite matrix as discussed in Module D1-3 and helium as the primary coolant. For those producing electricity, a direct Brayton cycle is in the current generation designs; however, its demands on materials (suitable for high temperatures) and energy conversion equipment (direct helium drive turbine/generator) are more severe. Older HTR designs were operated on a steam (Rankine) cycle with a helium-to-water heat exchanger/steam generator. In an electric plant more than one reactor module could drive a turbine generator. Each combination of multiple modules and a T/G is called a "power block." Two or more "blocks" constitute a plant.

For the "process heat" plant the primary loop helium coolant will be pumped through a heat exchanger with the secondary side high-temperature coolant transported to the petrochemical, hydrogen, or other process facility. It should also be noted that some HTR concepts do not involve a gas coolant. The Advanced High Temperature Reactor (AHTR) concept involves the use of a molten salt as a coolant. The better heat transfer allows more power to be produced in a given size core as compared to gas coolant.

R3-3. PICTURES/SCHEMATICS/DEPLOYMENT STATUS

Figure R3-1 shows a generic schematic for a Gas-Cooled Reactor System, in this case the VHTR being considered under the Generation IV Reactor program. For this diagram's example concept the heat is being used to drive thermochemical hydrogen production process rather than to drive a turbine/generator. More recently the VHTR mission has been redefined to supply process heat (or high-temperature steam) to more conventional petrochemical facilities and unconventional hydrocarbon recovery operations.

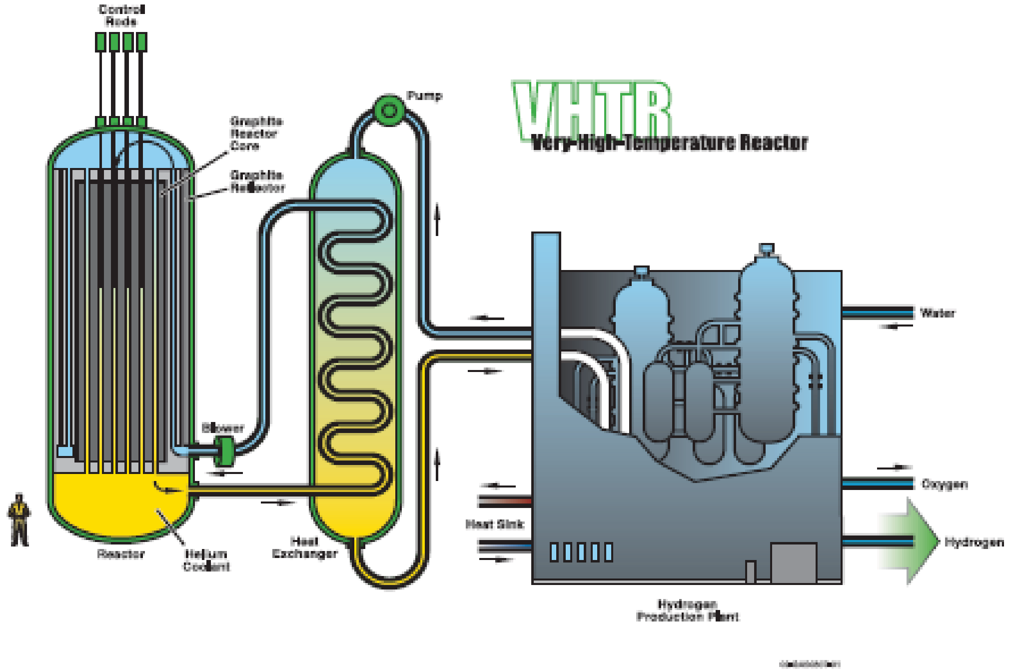

Figure R3-1. VHTR/HTR schematic.

The concept of HTRs is not a new one and has been manifested in many forms over the last 5 decades. The UK has a large, but aging fleet of gas-cooled reactors (MAGNOX and Advanced Gas-Cooled Reactors [AGR]) using CO_2 as the coolant and more conventional (non-particle) fuel. These reactors were built in the 1950s and 1960s, and the construction cost data are not particularly applicable to today's designs. One high-temperature gas-cooled reactor has been constructed and operated for electricity production in the U.S.: the Fort St. Vrain High Temperature Gas-cooled Reactor (HTGR). It was designed by General Atomics (GA) and utilized U and (U,Th) TRISO fuel produced in a small fabrication facility in Sorrento Valley, California. It was constructed in the 1970s and shut down due to operational difficulties in the early 1980s. Again, the construction cost data from that time would not be useful in gauging costs today. GA is still pursuing the HTGR design today; however, the new product is more modular in nature, now called the Modular Helium Reactor (MHR). A direct cycle design has been proposed because of the high thermodynamic efficiency possible (i.e., approaching 50%). This design has also been proposed as a "deep burn" actinide burning reactor, a weapons plutonium destruction reactor, and as a heat source for hydrogen production using high-temperature processes such as the High Temperature Steam Electrolysis (HTE) process. As part of the Generation IV program, the U.S. DOE is proposing a prototype HTGR called the VHTR (Figure R3-1 above). The actual demonstration project is called the Next-Generation Nuclear Plant (NGNP), which was described above. It will be oriented toward process heat applications requiring at least 750°C temperatures. U.S. reactor manufacturer consortia have proposed different VHTR/NGNP designs, and pre-conceptual designs have been prepared. None of the cost data associated with these designs has been made public; however, costs of around $4B are expected for a first-of-a-kind reactor. The quoted range of costs from the FY07 Preliminary Conceptual Design Report (PCDR) was $3.8B to $4.3B (2007$) for reactors between 500 and 565 MWth. The plants covered in that work were high temperature (900 to 950°C), which included intermediate heat exchangers with secondary helium loops supplying steam generators and hydrogen production facilities. As noted above, the focus has shifted to a steam plant supplying steam and electricity in, for example, a co-generation application with an industrial facility or in recovery of unconventional hydrocarbons from oil sands or shale. The project costs for the revision in the focus have not been formalized but are anticipated to be in the upper part of the range cited in FY07.

As mentioned in Module D1-3, the TRISO fuel concept can be either prismatic (compact with embedded TRISO particles), or spherical (billiard-ball sized pebbles with embedded TRISO particles). China is currently pursuing the pebble-bed modular reactor (PBMR) concept. The PBMR concept was also evaluated in South Africa by the utility Eskom, but due to high costs and currency fluctuations the project was put on hold. Eskom cost estimates are highly proprietary; however, early speculation was that LUEC costs of less than 20 mills/kWh (including capital amortization) were considered possible. The current PBMR designs reflect a shift in focus from the high-temperature, higher power annular core and the direct Brayton cycle plant for electricity production to a lower temperature, lower power cylindrical core for production of steam and electricity using a Rankine cycle.

R3-4. INTERFACES WITH OTHER MODULES

Front-end. The fuel for most concepts is the UO_2 or uranium-oxycarbide (UCO) TRISO particle fuel at enrichments of 8 to 19.9% U-235, thus keeping its fissile enrichment in the “LEU” range. Fabrication of this fuel is discussed in Module D1-3. Presently there is no large scale facility for fabrication of this fuel. What would be shipped to the reactors would be critically-safe packages of spherical pebbles or packaged graphite fuel blocks with embedded “prismatic” compacts.

Back-end. The discharged spent particle fuel will still be within its graphite matrices. The pebble-type spent fuel could be packaged in special barrels that because of decay heat would probably require some active cooling, possibly air or gas rather than water. The hexagonal blocks from the prismatic variety can also be packaged and stored. Another option for more compact storage would be to push the compacts out of the hexagonal graphite block and store them in a manner similar to discharged pebbles.

Reprocessing of TRISO spent fuel would be more difficult and less well developed than for light-water reactor (LWR) or fast reactor (FR) fuel because of all the fission product release barriers that were built intentionally into the fuel. To dissolve the fissile material, one must first destroy the graphite and the multiple coatings that constitute the TRISO particles. A few reprocessing schemes, including burning away the graphite and crushing the remaining UO_2 or UCO particles, have been suggested for this type of fuel.

Thorium. It should be noted that thorium-containing TRISO-type particles can be introduced into GCR systems to extend the burn-up. The fertile Th-232 is converted to U-233, which is itself fissile and can extend the life of the overall core. Use of thorium in GCRs has been demonstrated in test reactors in Europe and in the U.S. commercial unit at Fort St. Vrain, Colorado. Fuel fabrication issues associated with thorium are discussed in Module D1-8.

R3-5. MODULE SCALING FACTORS

In general, the cost of electricity and the specific capital cost decrease with larger reactor size (electrical generation capacity). There is likely to be a point where factory production of small reactor modules, as opposed to traditional onsite construction, will allow reduction of unit costs. Studies, such as those being pursued by the Generation IV Economic Modeling Working Group, are investigating this issue. Section R-1 has a more comprehensive discussion and diagram dealing with the construction modularity issue and Section R-4 is a more comprehensive discussion of the cost-size scaling issue.

R3-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The question often arises as to how the specific overnight cost of a HTR compares to that for LWRs or fast reactors. From a pure engineering standpoint, larger structures are required because of the lower power density of the HTR core as compared to water reactor cores and the requirement for high-temperature service. However, the higher thermodynamic efficiency of HTRs vis-à-vis water reactors should help to drive down the $/kWe cost, since more units of electrical capacity are available per unit of heat. Several nations are pursuing prototype HTRs such as China, Japan, and South Africa, but projected cost information is sketchy, and the prototypes for which cost estimates exist are necessarily the size of the eventual commercial unit that might be deployed. Because of recent price volatility in natural gas and the need to reduce "carbon footprints" and concerns with the security of feedstock for foreign sources, many industries are now considering HTRs as a reliable source of non CO_2-emitting process energy and heat with a stable price, (e.g., $/million BTUs) (Nuclear Engineering International 2009). These industries include petro-chemical industries, fertilizer manufacturers, refineries, oil sands and oil shale extraction, and upgrade companies in addition to chemical companies. Even though the early applications of the gas reactor technology focused on production of electricity, because of the interest by the process industries, the current focus is on supplying carbon-free process heat and energy.

Among the applications of the HTGR technology being studied worldwide are tar sands bitumen separation and upgrading, hydrogen production, synfuels production from coal, crude oil beneficiation, ammonia products, ethylene cracking, and steelmaking. These applications use energy in one or more of the forms of electricity, steam, high-temperature gas, hydrogen, and oxygen. The HTR technology can provide energy in all of these forms with stable cost and without emissions of greenhouse gases. The use of nuclear energy to reduce "carbon footprints" in these industries is one of the critical considerations when judging competitiveness of the HTR for these applications. The economics of these applications consider the need for security in the source of energy, the cost and stability of the cost of alternatives, as well as the potential price of carbon emissions. EPRI (2009) estimates for example that a $50/metric ton tax on CO_2 would increase the cost of electricity produced from a conventional coal plant by $43/MWh and from a conventional natural gas fired combustion turbine plant by $19/MWh. Allocation of costs and revenues between process heat and electricity is a complex issue and is discussed in two of the references for this section (Florido 2000 and EMWG 2007).

Consistent with other cost modules in the AFC Cost Basis report, cost data was collected on all types of HTRs, regardless of their timeframes for development. The data on these reactors were collected through various reference sources including the trade press and trade press sources. The cost data represent the costs for HTRs actually completed and proposed (projections made for paper studies). The cost data collection in Table R3-1 includes commercial units (e.g., Fort St. Vrain, Peach Bottom), as well as reactors developed for research purposes. Many of these reactors are first-of-a-kind or demonstration units and are not directly comparable. Further discussions on the limitations of this cost data are included in Section R3-7. All-in costs include financing and owner's costs in addition to the usual "overnight" costs unless otherwise noted.

Table R3-1. Historical capital costs for completed gas-cooled reactor systems and projected costs for recently announced, currently under construction, or hypothetical systems.

Reactor and Size	Total Capital Cost	Specific Capital Cost ($/kWe)
Fort St Vrain (Colorado, USA) One 350 MWe unit (completed in late 1960s) (first-of-a-kind [FOAK])	$200M (1968$) all in $1.4B (2008$) (Costs escalated by historical Handy-Whitman Utility Construction Indices)	$606/kWe (1968$) $4303/kWe (2008$)
Japanese 30MW(th) HTTR at Oarai	$700M (1992$)	$23,000/kWt (1992$)

Table R3-1. (continued).

Reactor and Size	Total Capital Cost	Specific Capital Cost ($/kWe)
Research Center (test reactor: no electricity production) (IAEA 2007) (FOAK) (U.S. Handy-Whitman Index used for escalation)	$1260M (2008$)	$41,000/kWt (2008$)
AVR (Arbeitsgemeinschaft Versuchsreaktor) Pebble-bed; Julich, Germany; 40 MW(th); 15 MW(e) 1966 (FOAK) (Van Heek 2009)	70M Deutschmarks (1966) ~to 17.5M (1966$) $144M in 2008$ (based on 1966 cost estimate and H-W escalation)	$1166/kWe in 1966$ $9600/kWe in 2008$
THTR (Thorium High Temperature Reactor); Germany 300MW(e) (FOAK) (Saunders 2006)	Original estimate $411M $825M in 2008$ Actual cost $2530M (1988$) $5000M in 2008$	$1370/kWe (1988$) $2750/kWe (2008$) $8430/kWe (1988$) $17,000/kWe (2008$)
10 MW(e) Chinese HTR-10 Pebble Bed; Tsinghua University (test reactor) (FOAK)	Not given in IAEA database	–
U.S. Peach Bottom-1; 40 MW(e); 1967–1974 (utility owned, GA designed) (FOAK)	Not given in Komanoff (1981) database of U.S. power reactor actual costs (Komanoff 1981)	–
Japanese conceptual design for 4 module plant of total capacity 1148 MWe (Shintaro 2001)	315B yen (2001 yen) $3.1B (2001$)	$2750/kWe (2001$) $3500/kWe (2008$)
GA (USA) pre-conceptual design for 4 module (1152 MWe total) MHR (GNEP 2008) (NOAK)	$1.57B (overnight cost in 2006$)	$1,639/kWe (overnight) (consistent with other GA studies on hydrogen, etc.)
10 module MIT PBMR design project (1100 MWe total), K. Williams reviewing author (Williams-G4ECONS 2009) (NOAK)	$2.3B (1992$) (all-in) $4.2B (2008$)	$1860/kWe (all in) $3990/kWe (all in)
MIT Study on Integration with Oil Sands projects (Bersak 2007)	–	$4000/kWe overnight for one 172 MWe module (2008$) $3333/kWe overnight for four modules (USA)
Indonesian PBMR study (Nasrullah 2008)	–	$2515/kWe (all-in)
4 and 8 module GA-design MHTGR production reactors with co-production of electricity (135 MWe per module raised to 175 MWe per module to account for technology improvement (NPR1991) (FOAK)	$3.56B incl dev't & contingency for 4 modules (1990$) $6.23B (2008$) $4.85B incl dev't & contingency for 8 modules (1990$) $8.49B (2008$)	$8900/kWe (all-in) $6060/kWe (all-in)

Table R3-1. (continued).

Reactor and Size	Total Capital Cost	Specific Capital Cost ($/kWe)
South African PBMR module (80MWe) (Creamer Media 2009) (FOAK)	$7B Rand including development costs to date. ($875M)	$10,900/kWe (all-in plus some development)
Proposed Kazakhstan 50MWe Gen IV HTGR Project (Nuclear Engineering International 2009)	$500M for Prototype	$10,000/kWe
4 × 173 MWe Rankine steam cycle modular HTGR (MIT/UNLV NERI 2005) (Costs for the Gas-cooled fast reactor [GFR] in this study are scaled from data for a thermal Rankine cycle MHTGR.)	$1.45B in 1992$ $ 2.96B in 2008$ (NOAK overnight costs)	$2100/kWe in 1992$ $4500/kWe in 2008$

R3-7. LIMITATIONS OF COST DATA

All helium gas-cooled reactors constructed to date have been first-of-a-kind (FOAK) facilities that have not enjoyed the economic benefits (lower costs) of construction learning and near-design replication (FOAK to NOAK cost improvement) that, to some degree, thermal water reactors enjoy. Instead, the specific capital ($/kWe) costs for completed facilities, which have been prototype units, have been quite high. The projected specific capital cost given for the reactor cost estimates appearing in planning or "paper studies" is usually optimistic in that it incorporates some developer optimism, but it may not include financing costs. Prototype and development costs are often left out of electricity-related costs, such as the typical "recoverable" $/kWe or LUEC, since the government rather than the utility may pay for these.

Newer HTR paper studies discuss the incorporation of many new innovative features that should lend technical support to the development of lower cost estimates. An International Atomic Energy Agency (IAEA) Technical Meeting on "HTGR Economic Analysis" was held in Washington, DC in October 2008 (Williams 2008). Ideas for cost improvements were suggested, but very little specific cost data were given. It is likely that a great deal of such data is considered proprietary. Most of the meeting dealt with economic modeling issues and the use of G4-ECONS and other models to calculate the LUEC. One industrial consortium participant (GA, CH2M-Hill, KAERI, Hamilton Sunstrand, LISTO, and Potomac Communications) in the former U.S. Global Nuclear Energy Partnership (GNEP) activity recently produced a report (GNEP 2008) describing its concepts for new fuel cycles in the U.S. using LWRs, FRs, and HTRs in a symbiotic fashion. The emphasis was on actinide burning (transmutation), but again no detailed cost information was available, and the consortium did not describe how the $/kWe cost would decrease in going from the prototype to the FOAK to the NOAK ($1639/kWe) HTR "burner" units.

In September 2009 the DOE issued DE-FOA-0000149 for completion of design activities for high temperature gas reactor (HTGR) plants under Phase 1 of the NGNP Project.[a] This work should be completed by the end of FY10. An outcome of this work will be updates and improved confidence in the estimates of cost for deployment of the HTGR technology.

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[a] FINANCIAL ASSISTANCE FUNDING OPPORTUNITY ANNOUNCEMENT, U. S. Department of Energy Idaho Operations Office, Next Generation Nuclear Plant Program – Gas Cooled Reactor Design and Demonstration Projects, Funding Opportunity Number: DE-FOA-0000149, Announcement Type: Initial, CFDA Number: 81.121, Issue Date: 09/18/2009.

R3-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table R3-2. These values are largely based on cost analyst's judgment and are intended to provide a cost distribution that is consistent with LWR (Module R1) and FR (Module R2) values and the very sparse available cost data for commercial-scale NOAK fast and gas-cooled reactors. Future versions of this report are anticipated to provide greater detail and better basis and justification for the cost values. The summary shows the reference cost basis (constant year U.S. \$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. Refer to Section 3.6 in the main section of this report for additional details on the cost estimation approach used to construct the WIT table (Table R3-2). It should be noted that the selected nominal value of \$4500/kWe (overnight) for the HTR compares to the same value of \$3500/kWe (overnight) for the LWR (Module R1). It should be noted that escalation in commodity, labor, and procurement costs from 2003 through 2008 have caused the estimates \$/kWe to be significantly increased for two classes of reactors (thermal in Module R-1, fast in Module R-2, and would presumably affect other reactor types in new Modules R-3 and R-4). A cost of \$2000/kWt has been used in recent evaluations[b] for the overnight costs for an HTGR—at a nominal net efficiency of 42% (Rankine cycle) this is slightly more than \$4,500/kWe. Interest during construction (IDC) and owners costs can add ~34% to this to a little over \$6,300/kWe all-in cost. Table R3-2 lists these costs in this range.

Table R3-2. What-It-Takes cost summary table.

What-It-Takes (WIT) Table			
Reference Cost(s)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Overnight Cost for NOAK HTR in U.S. \$4500/kWe based on composite of various studies	\$3000/kWe	\$7500/kWe	\$4500/kWe (NOAK)
Total Capital (all-in)	\$3400/kWe	\$9000/kWe	\$4900/kWe (NOAK)

Operation and Maintenance costs for the reactor have not been included in this edition of the Cost Basis Report, since very little data is available.

R3-9. SENSITIVITY ANALYSES

No studies of this type have been recently undertaken. However, it is known that as with thermal reactors the factors that will most influence the LUEC are the reactor capacity factor (% of time it is generating electricity), the total capital cost, and the time it takes to construct it. A recent Entergy study cited on a Power Technology Web site (www.Power-technology 2009) indicates that heat from HTRs can be competitive with heat from natural gas if the natural gas price climbs above \$8/MMBTU[c]. No data on electricity costs were found from this summary of the Entergy study.

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[b] Based on personal communications with the NGNP Project.

[c] Note that this price includes no carbon tax on emissions from combustion of natural gas.

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Module R4

Small to Medium-sized Reactors

Module R4

Small to Medium-sized Reactors

R4-1. BASIC INFORMATION

This module is a new addition to the 2009 Advanced Fuel Cycle Cost report database. It has been added because of increasing interest in this type of reactor both in domestic and foreign markets and within the U.S. Department of Energy's nuclear program. The class of reactors, called "small to medium," generally is described by the International Atomic Energy Agency (IAEA) as the following electrical capacities: Small: <300 MWe, Medium: 300–700 MWe, and Large: >700 MWe. In the "small" end of this range, the following terms are also applied:

- Low-Capacity Nuclear Power Plants (LCNP)
- Small Modular Reactors (SMR)
- Deliberately Small Reactors (DSR)
- Grid Appropriate Reactors (GARS)

The reactors in this module can be thermal, fast, or epithermal and also be cooled by several possible substances, including water, sodium, lead, etc. Many nations are conducting research and development (R&D) in the area of SMRs, and some have reactors that are essentially market-ready, such as the Russian barge-mounted KLT reactors. Table R4-1 lists some of these reactors and the countries working on them.

Table R4-1. Examples of SMRs and their nations of origin.

SMRs	Nation of Origin
Integral PWR	CAREM (Argentina), IMR (Japan), IRIS (U.S.), NuScale (U.S.), mPower (U.S.), SCOR (France), SMART (Republic of Korea)
Marine Derivative PWR	ABV (Russian Federation), KLT-40S (Russian Federation), NP-300 (France), VBER-300 (Russian Federation)
BWR/PHWR	AHWR (India), CCR (Japan), MARS (Italy)
Gas-cooled	GT-HTR-300 (Japan), GT-MHR (US), HTR-PM (China), PBMR (South Africa)
Sodium-cooled	4S (Japan), BN-GT-300 (Russian Federation), KALIMER (Rep of Korea), PRISM (U.S.), RAPID (Japan)
Lead/Pb-Bi-cooled	BREST (Russian Federation), ENHS (U.S.), LSPR (Japan), STAR/SSTAR (U.S.), SVBR-75/100 (Russian Federation)
Non-conventional	AHTR (U.S.), CHTR (India), Hyperion (U.S.), MARS (Russian Federation), MSR-FUJI (Japan), TWR (U.S.)

The next section describes why this category has been getting more attention in the last few years. This is evidenced by many news items in the trade press, several which are cited in this Module's bibliography.

R4-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

SMRs behave functionally and operationally the same as their larger counterparts. These physical descriptions are in Module R1 for the water reactors, R2 for fast reactors, and R3 for gas-cooled reactors. It is of interest here to instead describe the rationale for the smaller size. Table R4-2 below lists the beneficial attributes of SMRs and particular applications.

Table R4-2. SMR benefits and applications.

Benefits	Applications
Cheaper (capital outlay)	Smaller utilities
Improved fabrication and construction logistics (especially domestic)	Countries with financing or infrastructure constraints
Enhanced safety (robustness)	Distributed power needs (e.g. military base islanding)
Operational flexibilities (broader applications)	Non-electrical (process heat) customers

Benefits. The lower total capital investment or "all-in" cost (but not necessarily $/kWe cost) is of advantage to small utilities and nations that cannot afford the $3B to $6B required to design, construct, and start-up a large nuclear power plant (NPP). For many utilities the expense for a large NPP would constitute a very large fraction of their capitalization, thus the financial health of the company would be at risk if problems such as cost overruns or delays are encountered.

Procurement and fabrication of the major subsystems for SMRs will also be easier because of a better "supply chain" situation, especially in the U.S. where the industrial infrastructure for large plants has decayed over the last 3 decades. The smaller plants largest components can be fabricated in existing U.S. factories, many of which are up and running or can be readily reactivated. For large plants (PWRs in the U.S.), large parts such as the pressure vessel forgings, must be fabricated overseas. An NPP project has to "get in line" to schedule such heavy manufacturing work, and the potential for delays is significant.

The smaller size of SMRs means lower source terms and smaller amounts of stored energy from a safety standpoint. For many reactor types the engineered safety systems can be eliminated or downsized. Passive safety is easier to implement (Nuclear Engineering International 2008). These considerations should ease the licensing process and lessen the chance of schedule delays.

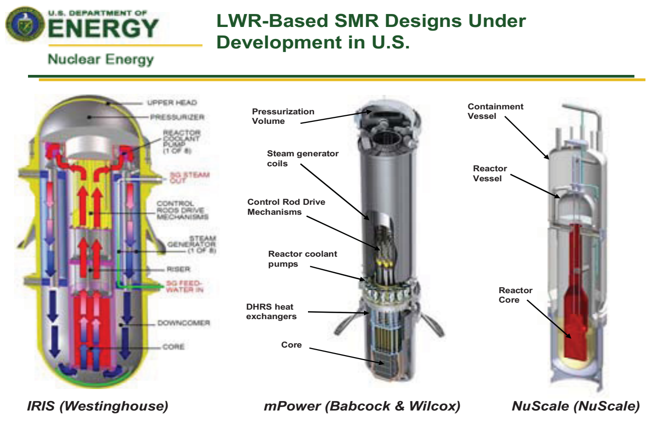
SMRs may also find non-utility applications where the smaller size is an advantage. There may be applications such as process plants, desalination plants, small hydrogen plants, etc., where "carbon-free" electricity or process heat is required.

Applications. Some utilities, such as municipal or rural cooperatives, may find the SMR size much more suitable to their grid size and construction budgets. The small size also is an advantage to growing service areas where SMRs are better-sized to accommodate grid additions without creating the large amount of excess capacity that might come with large NPPs (Sanders 2009). This is also true of countries with smaller grids and lower GDPs. Many of these countries generate electricity with diesel fuel (petroleum-based), which is very expensive in terms of the levelized unit electricity cost (LUEC) ($/Mwh cost). Good examples would be the nations of the Caribbean, such as Jamaica (Jamaica Observer 2008), which is now showing interest in nuclear power. A small town in Alaska (Galena) has shown interest in the very small Toshiba-4S concept, which would require refueling only every 30 years (Christian Science Monitor 2008). This town also relies on petroleum-based fuels which are difficult to transport in winter months.

Other possible applications are military bases where reliable power is needed. This may include temporary bases where it is difficult to supply fossil fuels to remote or dangerous locations, such as in the Middle East.

R4-3. PICTURES/SCHEMATICS/DEPLOYMENT STATUS

Figure R4-1 below shows schematics for three different types of small reactors: LWR-based, Gas-cooled, and Liquid Metal-cooled SMRs . Most of these have been extracted from presentations and an encyclopedic SMR article by Ingersoll (Ingersoll 2009)



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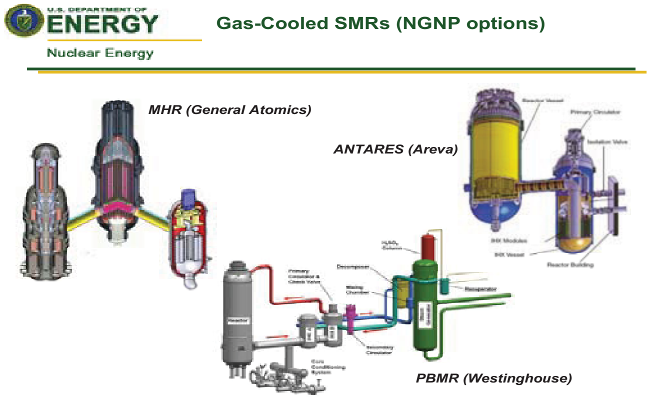
LWR-Based SMR Designs Under Development in U.S.

IRIS (Westinghouse) mPower (Babcock & Wilcox) NuScale (NuScale)



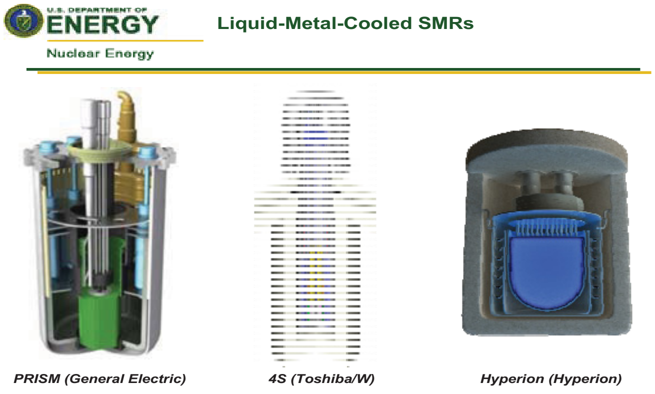
U.S. DEPARTMENT OF ENERGY Nuclear Energy

Gas-Cooled SMRs (NGNP options)

MHR (General Atomics)

ANTARES (Areva)

PBMR (Westinghouse)



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Liquid-Metal-Cooled SMRs

PRISM (General Electric) 4S (Toshiba/W) Hyperion (Hyperion)

Figure R4-1. Schematic of SMRs for three different reactor types.

R4-4. INTERFACES WITH OTHER MODULES

The interfaces with other modules depend on the reactor type as defined by its fuel type and fuel cycle. For some SMR concepts the entire core might be removed and replaced with a refueling interval of several years. This is sometimes called the “battery concept” for SMRs.

R4-5. MODULE SCALING FACTORS

The big question is whether SMRs can compete with their larger NPP counterparts. Economies of scale suggest that as one increases the size (electrical capacity) of an NPP, the specific ($/kWe) cost should decreases, which is shown by the bold black curve in the Figure R4-2 (Mycoff, et al. 2009). This relationship holds for plants that are basically constructed the same way nearly all existing plants have been built in the U.S. (i.e. with a significant amount of onsite labor [mostly “stick-built,” similar design concepts for all sizes, only one or two units on a site, long construction schedules, and no revenues realized until start-up and construction at the site are complete]). The figure describes new ways that can break this conventional scaling assumption. Each of the six suggested factors has the potential to contribute to a decrease in the specific capital cost.

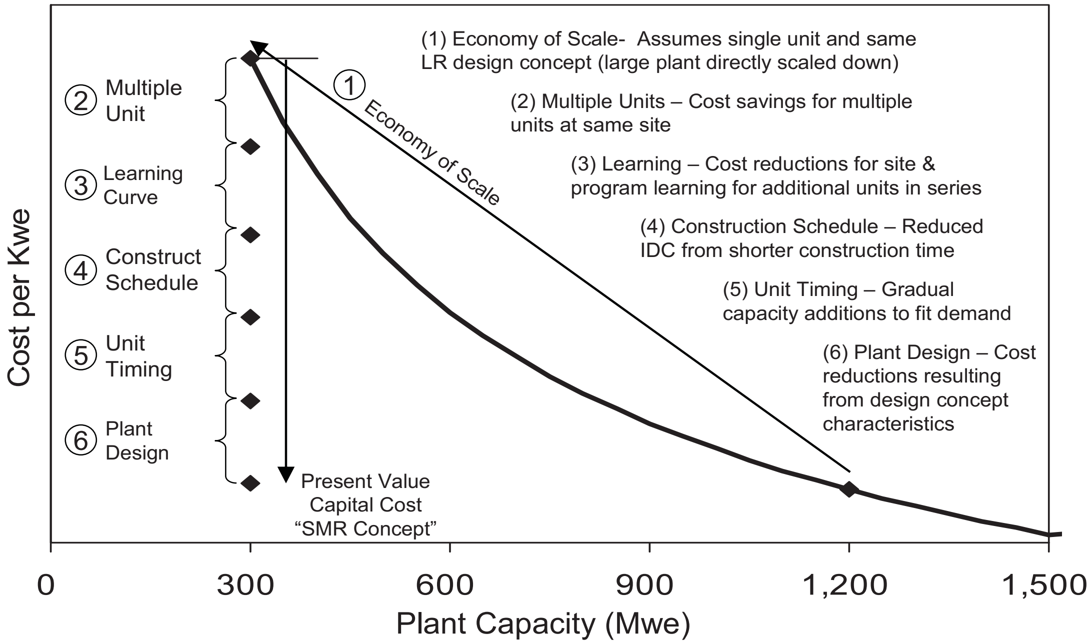

Figure R4-2. Potential SMR cost factor advantages.

Figure R4-3 shows how the cash flow from an NPP benefits from the build of several small units instead of one large unit on a given site (Mycoff, et al. 2009). By the use of sequential build, revenues from the first completed units can offset the expenditures for the subsequent SMR units. The annual outlays in the early years are also lower, which lowers the risk profile and financing costs for the utility.

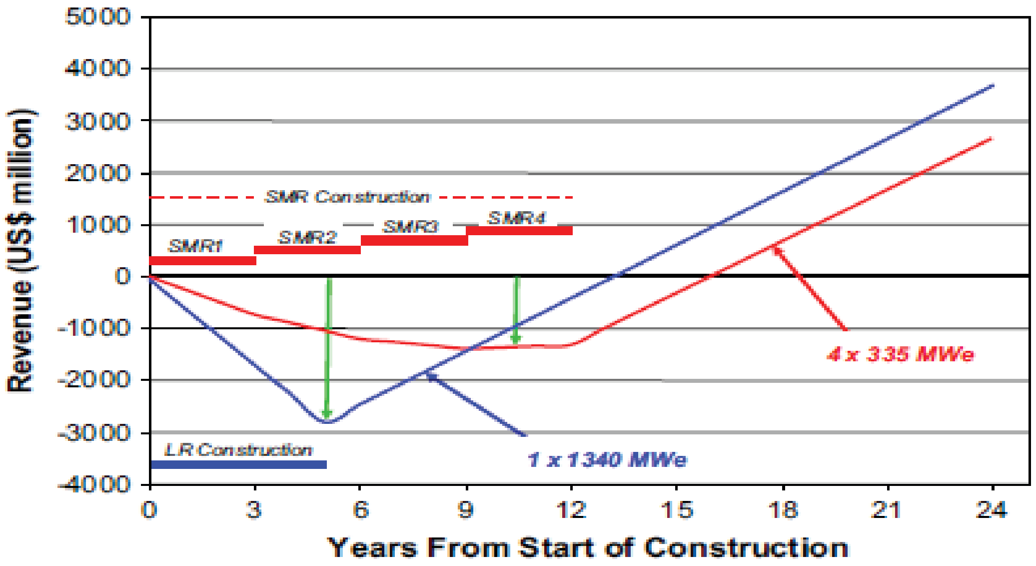

Figure R4-3. Cash outflow profile for staggered build of four small unit plants compared to a single large plant.

R4-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

Considering some cost projections made by proponents of selected SMR concepts, most of these are for LWR concepts for which the design concepts are more mature and the fuel type and design similar to that of existing plants. (Note that some SMRs require more exotic fuels for which significant fuel qualification would be required, such as the Hyperion concept which used uranium hydride fuel [Peterson 2008]). Table R4-3 shows some cost projections from the recent trade and general press. Some SMRs are advertised to have cost goals as low as $1500/kWe (Sanders 2009).

Table R4-3. Projected costs for selected SMR concepts.

Reactor Description	Reference	Capital Cost ($M)	Specific Capital Cost ($/kWe)
Oregon State "NuScale" 40 MWe PWR	(Greentech Media 2009)		$3500 to $4500/kWe
Babcock and Wilcox "mPower" 125 Mwe PWR	(New York Times 2009)		< $5000/kWe
Sandia small Na-cooled LMR (33 to 100 MWe)	(Platts 2009)	$250M per unit	$2500 to 7500/kWe

R4-7. LIMITATIONS OF COST DATA

Since none of these reactor types have been built recently, and no firm orders exist, there is no "actual" cost data that can guide future estimates. Some of the LWR SMR concepts in the U.S. are now in the conceptual design phase; hence, the existing estimates for these reactors are probably more realistic than those for more advanced reactor types like LMRs or gas-cooled reactors (GCRs). It is also not known whether the "trade press" $/kWe figures are for overnight or all-in costs.

R4-8. COST SUMMARIES

Since the only recent data that was found was predominantly for LWRs, only the category of SMR is included in Table R4-4 below. It should be noted that the nominal value for LWRs is somewhat above that for FRs and GCRs in Modules R2 and R3, and $1500/kWe above that for large LWRs in Module R1. The LUECs from SMRs are likely to be higher than for large reactors, and non-fuel operations and maintenance (O&M) costs per kWh generated would be expected to be higher. However, as more modules are deployed on a given site, and expenses shared, these should fall significantly. The higher LUECs should not be a great concern in many applications. This is because the existing electricity market is already high-priced because of the need to burn expensive fossil fuels, such as diesel fuel. As with larger reactors, the imposition of carbon costs on fossil fuels should make nuclear power from SMR more competitive.

Table R4-4. What-It-Takes cost summary table.

What-It-Takes (WIT) Table			
Description	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Overnight Cost for Nth-of a-Kind (NOAK) LWR SMR in U.S.	$2000/kWe (assumes revolutionary advances in factory production of modules and much faster builds)	$10000/kWe (assumes that schedules for SMRs are not much better than for large units and that many benefits are not realized)	$5000/kWe (NOAK) (assumes most factory manufacturing benefits and schedule shortening benefits overcome conventional size/scaling cost performance)

R4-9. SENSITIVITY ANALYSES

No studies of this type have been recently undertaken. However, it is known that as with thermal reactors, the factors that will most influence the LUEC are the reactor capacity factor (% of time it is generating electricity), the total capital cost, and the time it takes to construct it.

R4-10. BIBLIOGRAPHY

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