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Advanced Fuel Cycle Cost Basis – 2017 Edition

Nuclear Technology Research and Development

Prepared for
U.S. Department of Energy
Fuel Cycle Options Campaign

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ABSTRACT

This report, commissioned by the U.S. Department of Energy (DOE) Office of Nuclear Energy (NE), provides a comprehensive set of cost data supporting a cost analysis for the relative economic comparison of options for use in the DOE Nuclear Technology Research and Development (NTRD) Program (previously the Fuel Cycle Research and Development (FCRD) and the Advanced Fuel Cycle Initiative (AFCI)). The report describes the NTRD cost basis development process, reference information on NTRD 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 numerous fuel cycle cost modules (modules A-O) as well as cost modules for a number of reactor types (R modules). The fuel cycle 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.

Since its inception, this report has been periodically updated. The last such internal document was published in August 2015 while the last external edition was published in December of 2009 as INL/EXT-07-12107 and is available on the Web at URL: www.inl.gov/technicalpublications/Documents/4536700.pdf.

This current report (Sept 2017) is planned to be reviewed for external release, at which time it will replace the 2009 report as an external publication. This information is used in the ongoing evaluation of nuclear fuel cycles by the NE NTRD program.

PREFACE

In 2003 the U.S. Department of Energy-Nuclear Energy (DOE-NE) Advanced Fuel Cycle Initiative (AFCI) program established an Economics Working Group for the purpose of assessing the projected life cycle costs of new fuel cycles being examined as part of the ongoing fuels-related DOE-NE research and development (R&D) program. The group was formed of several individuals from multiple DOE National Laboratories and NNSA Facility Sites. Being that complete fuel cycles, including the nuclear reactors or other transmutation systems, consist of multiple process or service steps, there is a need to understand the life cycle costs associated with each. As an example today's "once-through" light water reactor (LWR) fuel cycle consists of mining & milling, conversion, uranium enrichment, fuel fabrication, fuel irradiation (reactor), spent fuel storage, and geologic repository steps. Fuel cycles for advanced reactors may consist of considerably different and/or additional steps for which there is little or no operational experience or cost data. This is especially true of those systems for which spent fuel is "recycled" and useful products recovered along with the production of separated wastes for disposal.

It was decided that the AFCI Economic Working group would begin the preparation and occasional updating of an economic data base for all of the steps of the nuclear fuel cycle. Emphasis would be on the unit cost ($/unit of mass or service) for each step. Acquisition of the data would be from public reports, the trade press, other fuel cycle studies, discussion with private industry, and for many steps life cycle cost calculations made by this group for hypothetical new facilities. Each possible step was assigned a "module designator" and a "tab" or chapter in the AFC Cost Basis Report (AFC-CBR). In addition to suggested unit cost ranges for each module, there is a comprehensive description of the step, including process diagrams, historical information, module interface consideration, existing facility data, and discussion of data limitations. By providing "what-it-takes", "low", "mode" (most likely), "mean" (average) and "high" values (or a low to high range), for each unit cost, along with suggested probability distribution types, a useful self-consistent set of data is provided for those who wish to assess the economics of entire fuel cycles. How such overall fuel cycle assessment is conducted is discussed in the AFCI document *Advanced Fuel Cycle Economic Tools, Algorithms, and Methodology*; May 2009; INL/EXT-09-15483. The body of the AFC_CBR also discusses a number of related cost analysis topics.

AFC-CBR documents were prepared nearly every year 2004 through 2009 and grew from around 250 pages to over 600 in the 2009 version. As the size of the document grew, so too did the effort involved with the updates. A decision was made move to less frequent updates and a 370 page addendum to the 2009 report was issued in 2012 (FCRD 2012). This 2017 edition is the second full update since 2009, following a 2015 edition that incorporates the 2012 addendum. This edition also incorporates material from a 2016 status report.

As successive new AFC-CBR documents have been prepared, each has maintained much of the original text from the first time a fuel cycle module was introduced. The following also appear in any newer volume:

- New cost analysis topics in the main report

- New data and the references supporting it in the cost modules
- Additional reactor types (R-modules)
- Additional sub-modules that address different topics within the main module (e.g. fabrication of different types of fuels)
- Placeholders for any modules or submodules which have been superseded or rearranged in subsequent updates.

This edition follows the same format as preceding editions. Front material in each module summarizes the main changes since the last full report. At the front of this report there is also a Table which lists all the module unit cost ranges.

The "body" of the report includes a number of new cross-cutting topics. Some of these topics present both the current state of development in the AFC-CBR as well as the likely direction of future evolution.

The report modules (the majority of the report) is contained in separate files within the AFC-CBR folder and include multiple new reactor types and major revisions of several other modules since the 2009 report.

SUMMARY

The following Table S-1 summarizes the projected FY 2017 constant dollar unit costs (or prices where indicated) for all of the fuel cycle modules. Monetary units were escalated and, unless otherwise noted, rounded to the nearest whole unit. Where possible a range and/or distribution is indicated for each category. The inclusion of more than just a "mode" or "most likely" single-point value allows fuel cycle system modelers and analysts to assess the economic uncertainty associated with complete fuel cycles. This Summary Table is a compilation of the "What-It-Takes" (WIT) tables appearing in subsequent pages of this report. In Note that the following qualitative changes have been made since 2009:

- The addition of five new reactor or transmuter modules ["R" Modules: Pressurized Heavy Water Reactors (R5), Accelerator-Driven Systems (R6), Liquid-fueled Molten-salt Reactors (R7), Solid-fueled Molten-salt Reactors (R8), and Fission/Fusion Hybrids (R9)].
- The inclusion of new data and references for nearly all of the front-end fuel cycle modules (Module Series A, B, C, and D: source materials, conversion, uranium enrichment, and fuel fabrication respectively).
- Updates to the background information on spent fuel storage (Modules E1eliminated and E2 moved to Module I), and the addition of a new module G5 for secondary Greater-than-Class C (GTCC) waste conditioning, storage, and packaging.
- Module L (Geologic Disposal) is now divided into two parts: Module L1 for spent fuel and high level waste (HLW) disposal, and L2 for GTCC disposal.

The following Figure S-1 shows the material flow order of and relationships between the various fuel cycle modules. This order applies to most commonly analyzed fuel cycles.

Figures S-2 and S-3 show pictorial representations of both the triangular and uniform distributions, respectively, suggested for the data in Table S-1. The uniform distribution is defined by two parameters (low and high values) and the triangular by three parameters (low, nominal, and high). The mean or average value is also calculated for each set of WIT values.

New Introductory Material has also been added to the report to cover generic issues such as "cost versus price," historical escalation, the use of discounting, cost analysis for modular reactor systems, and the treatment of uncertainty.

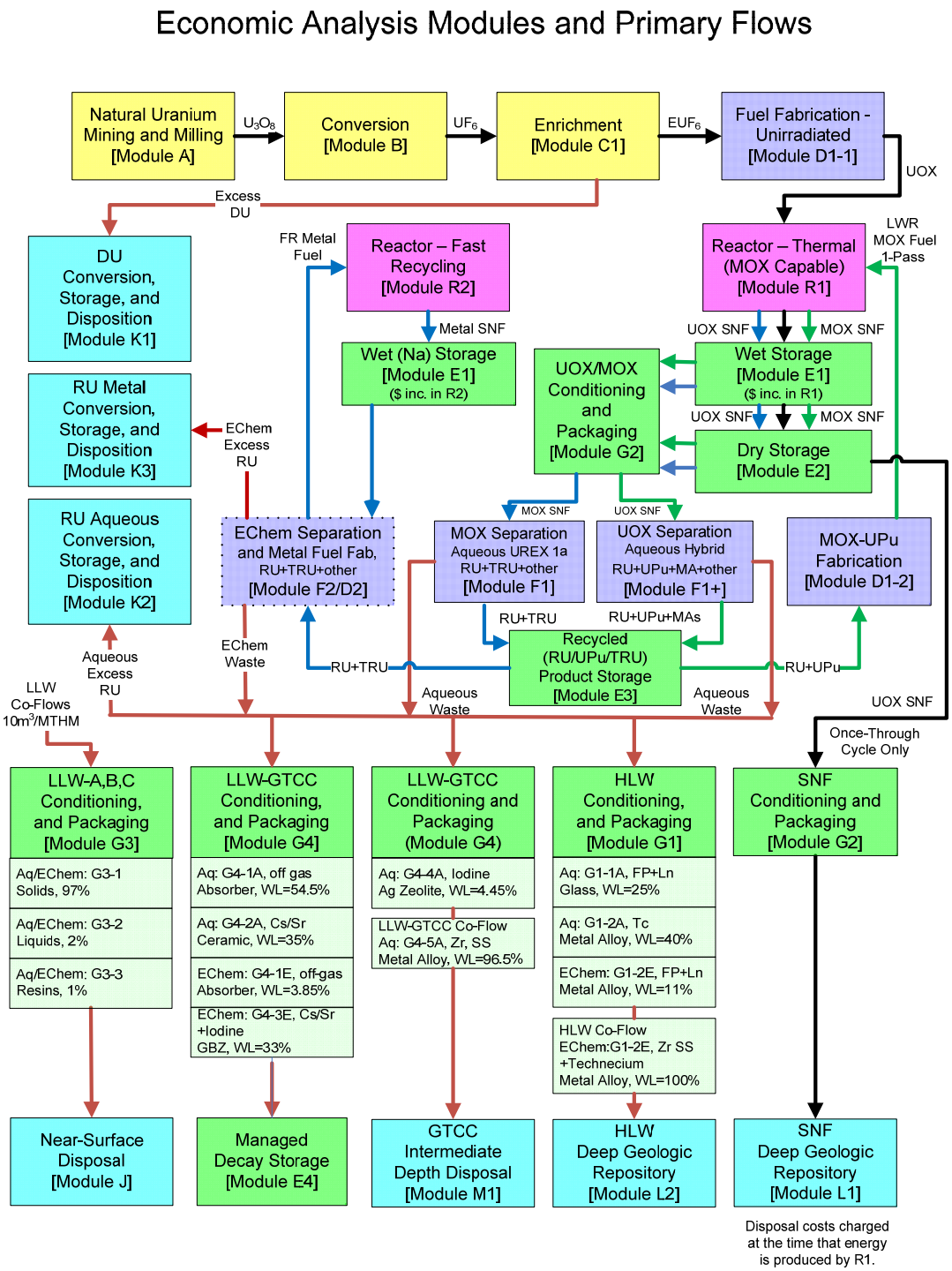

Figure S-1. General Flow of Fuel Cycle Modules.

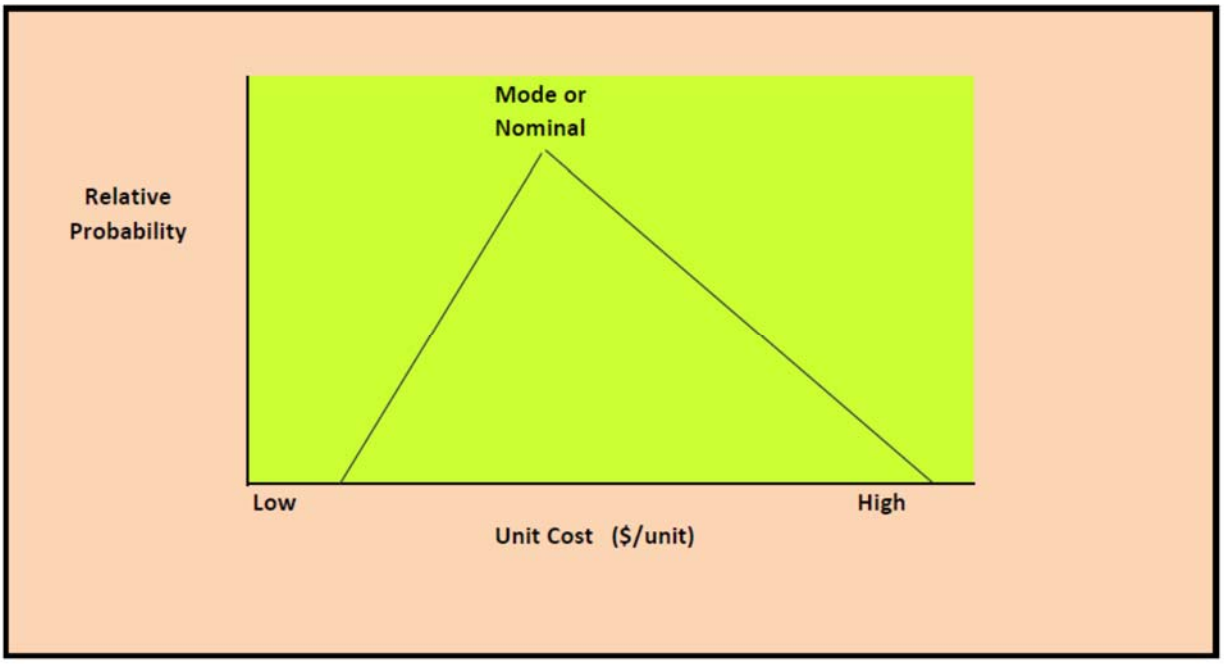

Figure S-2. Triangular Distribution Defined by Three Values.

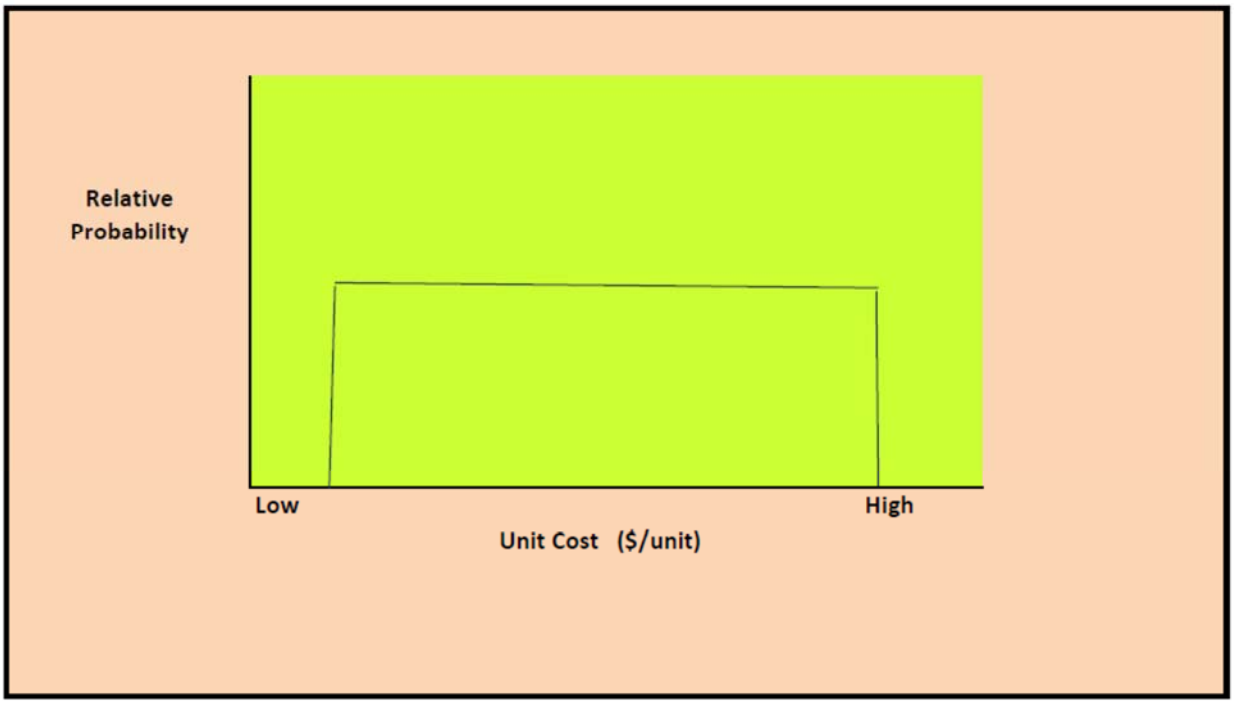

Figure S-3. Uniform Distribution Defined by Two Values.

Table S-1. Projected FY 2017 constant dollar unit costs for all Fuel Cycle Modules.

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
SOURCE MATERIALS						
A1 - Natural Uranium Mining and Milling	$/KgU	34	86	296	TRI	139
	equiv $/lb U3O8	13.1	33.1	114	TRI	53.5
A2- Thorium Mining and Milling	$/kgTh	28	59	200	TRI	93
CONVERSION/ENRICHMENT PROCESSES						
B - Conversion Processes	$/KgU	6.5	13	19	UNI	13
C1-Enrichment	$/SWU	97	125	154	UNI	125
C2- HEU Downblending	$/SWU	N/A	N/A	N/A	—	
FUEL FABRICATION (CONTACT-HANDLED) [CH]						
D1-1 - LWR UO2 Fuel Fab (PWR: Virgin LEU)	$/KgU or $/KgHM	230	400	575	TRI	401
D1-1 - LWR UO2 Fuel Fab (PWR: Reprocessed and re-enriched LEU)	$/KgU or $/KgHM	250	435	635	TRI	435
D1-1 - LWR UO2 Fuel Fab (BWR: Virgin LEU)	$/KgU or $/KgHM	285	400	575	TRI	420
D1-1 - LWR UO2 Fuel Fab (BWR: Reprocessed and re-enriched LEU)	$/KgU or $/KgHM	315	435	635	TRI	440
D1-2 - LWR Pellet MOX Fuel Fab	$/KgHM	800	1,000	1,600	TRI	1,133
D1-3 - Gas-Cooled Reactor Particle Fuel	$/kgU or $/kgHM	3,300	10,900	29,400	TRI	14,500
D1-4 - Ceramic Pelletized FR Driver Fuel such as U/Pu MOX (Contact-handled)	$/kgHM	2,700	4,900	7,600	TRI	5,060
D1-4 - Ceramic Pelletized FR Blanket Fuel: UO2	$/kgU	270	500	690	TRI	487
D1-4 - Ceramic Pelletized FR Enriched Uranium Fuel (MEU)	$/kgU	500	870	1,240	TRI	870
D1-5 - Ceramic Vibrocompacted Fast Reactor Fuel	$/kgHM	720	900	1,440	—	1,020
D1-6 - Metal alloy contact-handled Fast Reactor Fuel	$/kgHM	N/A	N/A	N/A	—	N/A
D1-7 - Ceramic CANDU Reactor fuel (Natural UOX)	$/kgHM	125	218	327	TRI	224
D1-7 - Ceramic CANDU Reactor fuel (Reprocessed or SEU UOX)	$/kgU	164	284	425	TRI	291
D1-8 - Thorium-based contact-handled fuels (U,Th)O2 pelletized	$/kgHM	327	573	818	TRI	573
D1-8 - Thorium-based contact-handled fuels(ThO2 blanket pellets only)	$/kgTh	273	490	687	TRI	483
D1-9 - Inert matrix and other advanced contact-handled (CH) fuels	$/kgHM	N/A	N/A	N/A	—	N/A
FUEL FABRICATION (REMOTE-HANDLED)[RH]						
D2/F2 - Fuel Fabrication of remote handled (RH) Transmutation Fuels (INEL reproc.): Refabrication Portion only	$/KgHM	1,000	1,400	1,800	TRI	1,400
STORAGE OF ACTINIDES, SPENT FUEL, and FISSION PROD						
E3-1a - Recycled Combined Actinide Product Storage (Stand-alone Facility)	$/Kg TRUs	3,762	5,016	6,840	TRI	5,206
E3-1b - Recycled Combined Actinide Product Storage (Co-Located Facility)	$/Kg TRUs	712	950	1,300	TRI	991
E3-2a - Recycled PuO2 Product Storage before MOX fabrication (Stand-alone)	$/kgPu	2,280	2,964	3,762	TRI	3,000
E3-2B - Recycled PuO2 Product Storage before MOX fabrication (Co-Located Facility)	$/kgPu	433	562	712	TRI	570
E4 - Managed Decay Storage of selected separated FPs	$/KgCsSr	11,400	25,650	39,900	TRI	26,500
AQUEOUS REPROCESSING HEAD-END & SEPARATIONS						
F1- UREX+1a Aqueous Separation only for UOX UNF	$/KgHM	1,030	1,277	1,526	TRI	1,277

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		**Low**	**Mode**	**High**	**Dist Type**	**Mean**
F1- UREX+3 Aqueous Separation only for UOX UNF	$/KgHM	1,186	1,482	1,776	TRI	1,482
F1- COEX Aqueous Separations only for UOX UNF	$/KgHM	861	1,055	1,250	TRI	1,055
F1- UREX+1a Total Aqueous Reprocessing of UOX UNF	$/KgHM	1,703	2,109	2,523	TRI	2,112
F1- UREX+3 Total Aqueous Reprocessing of UOX UNF	$/KgHM	1,904	2,371	2,836	TRI	2,371
F1- COEX Total Aqueous Reprocessing of UOX UNF	$KgHM	1,263	1,562	1,846	TRI	1,557
F1- COEX for Thorium-bearing fuels (Aqueous separations)	$/KgHM	904	1,161	1,375	TRI	1,147
F1- UREX+1a for Thorium-bearing fuels (Aqueous separations)	$/KgHM	1,080	1,405	1,680	TRI	1,388
F1- UREX+3a for Thorium-bearing fuels (Aqueous separations)	$/KgHM	1,245	1,630	1,954	TRI	1,610
F1- COEX for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	1,326	1,718	2,030	TRI	1,691
F1- UREX+1a for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	1,789	2,320	2,776	TRI	2,295
F1- UREX+3a for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	2,000	2,608	3,142	TRI	2,583
ELECTROCHEMICAL REPROCESSING HEAD-END & SEPS						
F2/D2 - Reprocssing - Electrochemical & RH Fuel Recycle (incl. refabrication)	$/KgHM	2,000	2,600	3,200		2,600
WASTE CONDITIONING, STORAGE, & PACKAGING						
G1-1A - Aqueous-derived HLW Conditioning, Storage, Packaging (FP+Ln) in borosilicate glass	$/Kg FP	2,508	5,700	7,524	TRI	5,244
G1-2A - Aqueous-derived Metal Alloy (Tc)	$/Kg Tc	187,500	228,000	263,900	TRI	225,465
G1-2E - Echem-derived HLW co-flows (hulls, etc, other metal [nobles & Ln])	$/kg FP	13,700	17,214	20,660	TRI	17,190
G2 - Spent UOX Conditioning & Packaging prior to longer-term disposition	$/KgHM	67.5	135	175	TRI	126
G3-1 - LLW Conditioning, Storage, Packaging (solids, debris)	$/m3	1,071	1,612	4,500	TRI	2,390
G3-2 – LLW Cond, Storage, Packaging (liquids)	$/m3	4,455	14,850	29,700	TRI	16,335
G3-3 - LLW Conditioning, Storage, Packaging (resins)	$/m3	109,350	121,500	133,650	TRI	121,500
G4-1A - Aqueous-derived LLW-GTCC Offgas absorber (H3, Kr, Xe, Ru)	$/m3gas	10,800	12,770	17,100	TRI	13,560
G4-1E - Echem-derived LLW-GTCC Offgas absorber (H3, Kr, Xe, Ru)	$/m3gas	10,800	12,770	17,100	TRI	13,560
G5 GTCC Contact Handled-TRU Conditioning, Storage, and Packaging	$/m3	21,660	30,780	42,180	TRI	31,540
E-PLANT or R-PLANT RECOVERED URANIUM STORAGE/DISPOSITION						
E-PLANT TAILS						
K1-1 - Depleted Uranium Disposition (E-Plant Tails Deconversion and Packaging)	$/KgDU	4.4	6.5	8.7	TRI	6.5
K1-2 - Depleted Uranium Disposition (De-converted E-plant Tails Geologic Disposal as Stable Oxide form)	$/kgDU	4.4	14.1	45.8	TRI	21.4
AQUEOUS R-PLANT U-PRODUCT						
K2 - Recovered U Disposition (Conv of "new" UNH to storable U3O8)	$/KgU	4.6	13.7	19.4	TRI	12.6
K2 - Recovered U Disp (Conv of "old" UNH to storable U3O8: incl aq polish)	$/KgU	22.8	45.6	57	TRI	41.8
K2 - Recovered U Disp (Conv of "new" UNH to UF6 for re-enrichment)	$/KgU	6.8	16	22.8	TRI	15.2
K2 - Recovered U Disp (Conv of "old" UNH to UF6 for re-enr.: incl aq polish)	$/KgU	33.7	49	65.4	TRI	49

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
K2 - Recovered U Disp (40-yr storage of U3O8)	$/KgU	8	10.3	34.2	TRI	17.5
K2 - Recovered U Disp (Perm Geologic Disposal of U3O8)	$/KgU	21.8	54.5	81.8	TRI	52.7
K2 - Recovered U Disp (Conv of "new" UNH to MOXable UO2 powder)	$/KgU	N/A	65.4	N/A	—	_
K2 - Recovered U Disp (Conv of "old" UNH to MOXable UO2 powder)	$/KgU	N/A	103.6	N/A	—	_
ELECTROCHEMICAL R-PLANT URANIUM PRODUCT						
K3-Recovered U Disp (Perm Geologic Disposal of metal or oxidized form)	$/KgU	81.8	98.1	164	TRI	114.6
K3- Recovered U-metal ingot 300 yr storage	$/KgU	27.3	32.7	109	TRI	56.3
K3-Recovered U-metal conv to UF6 incl fluoride volatility purification	$/KgU	32.7	43.6	65.4	TRI	47.2
K3 - Recovered U-metal to purified UOX conversion for contact-handled MOX usage	$/KgU	32.7	43.6	65.4	TRI	47.2
GEOLOGIC WASTE DISPOSAL						
I - Monitored Retrievable Storage for LWR SNF	$/KgHM	223	501	644	TRI	456
J - Near Surface Disposal	$/m3 of pkg mat	608	1,688	3,375	TRI	1,890
L1 - Geologic Repository (SNF) [mass pricing]	$/KgHM	289	600	873	TRI	587
L1 – Geologic Repository (HLW)	$/kgFP	1,500	6,000	7,500	TRI	5,000
L2 - Geologic Repository of GTCC Waste in enhanced confinement facilities	$/m3	2,300	3,800	5,320	UNIFORM	3,800
L2 – GTCC in Geologic Repository (co-located with HLW)	$/m3	—	5,180	—	—	
TRANSPORTATION including CONTAINERS (per kg material transported)						
O2 – 55 gallon drum for yellow cake	$/kg	2.1	2.7	3.7	TRI	2.84
O2 – Paducah Tiger overpack for UF6 or DUF6 cylinder	$/kg	1.1	1.3	1.4	TRI	1.28
O2 – UX-30 for EUF6	$/kg	15.3	15.8	16.3	TRI	15.82
O2 – CHT-OP-TU for FUO2, UOX or LLW	$/kg	1.7	2.3	3.3	TRI	2.43
O2 – 9975 for TRU or TRUOX	$/kg	201.7	313.8	479.8	TRI	331.8
O2 – CNS10-160B for FP	$/kg	4.5	6.2	8.5	TRI	6.41
O2 – RH-TRU 72B for TRU or FP	$/kg	7.3	10.2	14.2	TRI	10.57
O2 – MCC-4 for PWR assemblies	$/kg	44.5	46.0	48.0	TRI	46.2
O2 – SP-1,2,3 for BWR assemblies	$/kg	66.4	69.7	74.5	TRI	70.19
O1 – From Reactor to Repository	$/kg	23.9	26.7	29.5	TRI	26.7
O1 – From Reactor to Central Storage Facility to Repository	$/kg	103.5	106.3	109.0	TRI	106.3
NUCLEAR REACTORS and OTHER TRANSMUTERS						
R1 - Thermal LWR Reactor (Overnight Capital)	$/Kw(e)	2,500	4,400	6,300	TRI	4,300
R1 - Thermal LWR Reactor (Fixed component of O&M)	$/Kw(e)-yr	60	73	87	TRI	72
R1 - Thermal LWR Reactor (Variable component of O&M)	mills/kwh	0.8	1.8	2.7	TRI	2.0
R2 - Fast Reactors (Overnight Capital)	$/Kw(e)	2,400	4,100	7,600	TRI	4,700
R2 - Fast Reactors (Fixed component of O&M)	$/Kw(e)-yr	65	76	92	TRI	78
R2 - Fast Reactors (Variable component of O&M)	mills/kwh	1.1	2.2	2.9	TRI	2.1
R3- Gas-Cooled reactors (Overnight cost)	$/Kw(e)	2,500	5,000	8,000	TRI	5170
R3- Gas-Cooled reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	N/A	N/A	—	_
R3- Gas-Cooled reactors (Variable component of O&M)	mills/kwh	N/A	N/A	N/A	—	_
R4- Small Modular LWR (Module Deleted)	$/Kw(e)	N/A	N/A	N/A	N/A	N/A
R5- PHWR Reactors (overnight cost)	$/Kw(e)	2,400	4,200	6,100	TRI	4,230

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
R5- PHWR Reactors (Fixed component of O&M)	$/Kw(e)-yr	60	72	87	TRI	73
R5- PHWR Reactors (Variable component of O&M)	mills/kwh	0.8	2.0	2.7	TRI	1.8
R6- Accelerator-driven Systems (ADS) (Accelerator Overnight cost)	$/Kw(e)	1,500	8,200	15,400	TRI	8,370
R6- Accelerator-driven Systems (ADS) (Subcritical Reactor Overnight cost)	$/Kw(e)-yr	3,200	5,000	8,400	TRI	5,530
R6- Accelerator-driven Systems (ADS) (Accelerator Fixed component of O&M)	$/Kw(e)-yr	54	166	278	TRI	166
R6- Accelerator-driven Systems (ADS) (Subcritical Reactor Fixed component of O&M)	$/Kw(e)-yr	65	143	250	TRI	153
R6- Accelerator-driven Systems (ADS) (Variable component of O&M)	Mills/kwh	N/A	N/A	N/A	—	_
R7- Liquid-fueled Salt-Cooled Reactors (Overnight cost)	$/Kw(e)	2,400	6,000	9,800	TRI	6,100
R7- Liquid-fueled Salt-Cooled Reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	NA	N/A	—	_
R7-Liquid-fueled Salt-Cooled Reactors (variable component of O&M)	mills/kwh	N/A	NA	N/A	—	_
R8-Solid-fueled Salt-cooled Reactors (Overnight cost)	$/Kw(e)	2,200	6,000	8,700	TRI	5,600
R8-Solid-fueled Salt-cooled Reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	N/A	N/A	—	_
R8- Solid-fueled Salt-Cooled Reactors (Variable component of O&M)	mills/kwh	N/A	N/A	N/A	—	_
R9-1 – Magnetic Confinement Fission/Fusion Hybrid (Fusion Reactor Component Capital Cost)	$/Kw(e)	6,100	12,000	17,400	TRI	11,800
R9-1 – Magnetic Confinement F/F Hybrid (Fusion Reactor Component:Fixed Conponent O&M)	$Kw(e)-yr	87	131	174	TRI	131
R9-1 – Magnetic confinement F/F Hybrid (Subcritical Fission Reactoar Component:Capital Cost)	$/Kw(e)	2,300	4,800	7,200	TRI	4,800
R9-1 – Magnetic Confinement F/F Hybrid (Subcritical Fission Reactor Component:Fixed Component of O&M Cost)	$/Kw(e)-yr	65	109	250	TRI	141
R9-2 – Inertial Confinement F/F Hybrid (Fusion Reactor Component:Capital Cost)	$/Kw(e)	5,400	8,700	10,900	TRI	8.300
R9-2 – Inertial Confinement F/F Hybrid (Fusion Reactor Component:Fixed O&M Cost)	$/Kw(e)-yr	54	87	109	TRI	83
R9-2 – Inertial Confinement F/F Hybrid (Subcritical Fission Reactor Component:Capital Cost)	$/Kw(3)	2,300	4,800	7,200	TRI	4,800
R9-2 – Inertial Confinement F/F Hybrid (Subcritical Fission Reactor Component:Fixed O&M Cost)	$Kw(e)-yr	65	109	250	TRI	141

ACKNOWLEDGMENTS

The Advanced Fuel Cycle Cost Basis is a living document that has been in existence for 14 years and updated several times. During that time span, the primary authors and contributors have evolved to the point that a full author's list would be too long to include in a reference. Beginning with the 2015 edition, instead of listing authors on the cover of the report, the authors are listed here. We apologize if any authors of earlier editions were inadvertently omitted. Author affiliations are as of the time of contribution.

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CONTENTS

ACRONYMS

ADS	Accelerator-Driven System
AFC	Advanced Fuel Cycle
AFC-CBR	Advanced Fuel Cycle Cost Basis Report (any edition)
AFCI	Advanced Fuel Cycle Initiative
AFS	Assured Fuel Supply
ANL	Argonne National Laboratory
AP	Aqueous Polishing
ATW	Accelerator Transmutation of Waste
AVLIS	Atomic Vapor Laser Isotope Separation
BU	Burned Uranium
BWR	Boiling Water Reactor
CANDU	Canada Deuterium/Uranium Reactor
CBR	Cost Basis Report
CH	Contact-Handled
COA	Code of Accounts
CRBR	Clinch River Breeder Reactor
CY	Calendar Year
D&D	Decontamination and Decommissioning
DDR	Declining Discount Rate
DOE-NE	U.S. Department of Energy-Nuclear Energy
DU	Depleted Uranium
DUF_6	Depleted Uranium Hexafluoride
DUO2	Depleted Uranium Dioxide
EBR-II	Experimental Breeder Reactor II (Idaho)
EIS	Environmental Impact Statement
EMWG	Generation IV Reactors Economic Modeling Working Group
EPA	Environmental Protection Agency
EU	Enriched Uranium
EUF_6	Enriched Uranium Hexafluoride
EUO_2	Enriched Uranium Oxide
FC	Fuel Cycle
FCO	Fuel Cycle Options Campaign (of the NTRD Program)
FCRD	Fuel Cycle Research and Development (Program of DOE-NE)
FEP	Fluorine Extraction Process
FFH	Fission/Fusion Hybrid
FFTF	Fast Flux Test Reactor
FOAK	First-Of-A Kind
FP	Fission Product
FR	Fast Reactor
FV	Future Value
FY	Fiscal Year
G4	Generation IV
GCFR	Gas-cooled Fast Reactor

GDP	Gross Domestic Product
GE	General Electric
GW	Gigawatts = 1000 MW
GNEP	Global Nuclear Energy Partnership
GNP	Gross National Product
GTCC	Greater-than-Class C
HA	Higher Actinides
HEU	Highly-Enriched Uranium (U-235 $\geq$20%)
HLW	High Level Waste
HM	"Heavy metal"—elements with Z$\geq$ 89
HTGR	High-Temperature Gas-Cooled Reactor
HTR	High-Temperature Reactor
HVAC	Heating, Ventilating, and Air Conditioning
IAEA	International Atomic Energy Agency
IC	Inertial Confinement
ICF	Inertial Confinement Fusion
IEER	Institute for Energy and Environmental Research
INL	Idaho National Laboratory
JSFR	Japan Sodium-Cooled Fast Reactor
kW	Kilowatts (usually expressed as kw(e) [electric] or kw(t) [thermal)
kT	Thousands of metric tons (or tonnes)
LANL	Los Alamos National Laboratory
LCAE	Levelized Cost At Equilibrium
LEU	Low Enriched Uranium (typically 1% to 20% U-235)
LLNL	Lawrence Livermore National Laboratory
LLW	Low-Level Waste
LUEC	Levelized Unit of Electricity Cost
LWR	Light Water Reactor
MC	Magnetic confinement
MCFR	Magnetic confinement fusion reactor
MES	Minimum economic scale
MEU	Medium-Enriched Uranium
MFFF	MOX Fuel Fabrication Facility
MIT	Massachusetts Institute of Technolocy
MOX	Mixed Oxide Fuel (usually PuO_2 and UO_2)
MSBR	Molten-Salt Breeder Reactor
MSR	Molten Salt Reactor
MT	Metric Ton or Tonne
MTU	Metric Tons of uranium
MW	Megawatts (1 MW = 1000kW)
MTW	Metropolis Works
N/A	Not Applicable or Not Available
NATU	Natural Uranium
NE	DOE Office of Nuclear Energy
NNSA	National Nuclear Security Administration
NOAK	Nth-Of-A-Kind

NPV	Net Present Value
NRC	Nuclear Regulatory Commission (USA)
NTRD	Nuclear Technology Research and Development (Program of DOE-NE)
NTS	Nevada Test Site (recently renamed Nevada National Security Site
NU	Natural Uranium
NUe	Natural uranium equivalent
O&M	Operations and Maintenance
OECD	Organization for Economic Cooperation and Development
OMB	US Office of Management and Budget
ORNL	Oak Ridge National Laboratory
PHWR	Pressurized Heavy Water Reactor
PNNL	Pacific Northwest National Laboratory
PV	Present Value
R&D	Research and Development
RF	Russian Federation
RH	Remote-Handled
RU	Reprocessed Urainum (also abbreviated REPU)
SEU	Slightly-Enriched Uranium (ca 1% U-235)
SFR	Sodium-Cooled Fast Reactor
SMR	Small Modular Reactor
SNF	Spent Nuclear Fuel (usually denotes UNF that will be disposed)
SRS	Savannah River Site
SWU	Separative Work Units
TRISO	Tristructured Isotopic (form of particle fuel)
TRU	Transuranic (Z>92)
TSLCC	Total System Life-Cycle Costs
UK	United Kingdom
UNF	Used Nuclear Fuel
UNH	Uranyl Nitrate Hexahydrate
UOX	Uranium Oxide (UO_2) fuel
USD	United States Dollars
USEC	United States Enrichment Corporation (now Centrus)
USGS	United States Geological Survey
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure
WIT	What-It-Takes

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 (EMWG 2007) 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 NTRD 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 unless specifically identified otherwise. 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 cost of electricity at equilibrium (LCAE). The levelized unit cost of electricity for a system in equilibrium. In application, fuel cycle is assumed to be complete utilizing NOAK facilities and retiring facilities are replaced with like facilities. In an LCAE analysis, discounting is treated in a relative manner and all learning is assumed to have already occurred.

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 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 or kilowatts electric) 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 includeMy 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.

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.

Unit. See single-unit plant.

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.

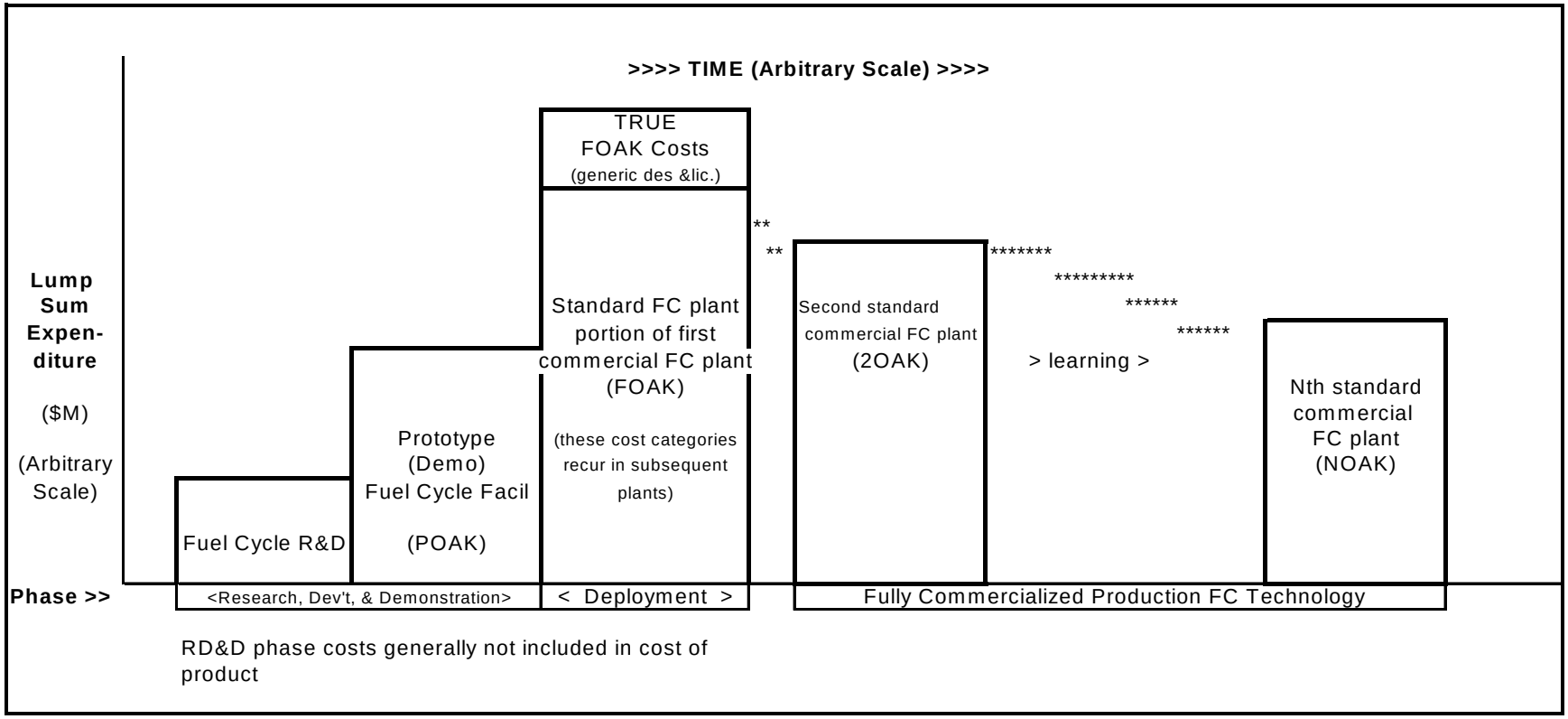


Figure S-4. Temporal relationship of RD&D, deployment, and standard plant costs.

Advanced Fuel Cycle Cost Basis – 2017 Edition

1. INTRODUCTION

This report builds on work performed over the past 14 years by the Fuel Cycle Options (FCO) Campaign of the Nuclear Technology Research and Development (NTRD) Program (formerly the Fuel Cycle Research and Development (FCRD) and Advanced Fuel Cycle Initiative (AFCI) Programs) 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, discussion of a number of cross-cutting cost analysis topics, 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, nor their cost effects or "externalities". 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 internal release of the AFC Cost Basis (AFC-CBR) report is intended to support ongoing FCO fuel cycle cost evaluations.

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 (2017) 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, in the first 7 years of the 21st century, exceeded the reported range due to the enthusiasm of the nuclear renaissance and then later period of post-Fukushima. 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 Brent Dixon at Brent.Dixon@inl.gov or by calling (208) 526-4928.

1.1 Background

The NTRD'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 2007). The NTRD 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 NTRD 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 2007).

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 NTRD 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 NTRD 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. 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 NTRD 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.

The AFC-CBR series has primarily represented costs to a per-unit cost for the fuel cycle function (e.g. cost of dry storage in $/MT UNF). Looking forward, the FCO Campaign expects to perform more transition analyses, and future editions of the AFC-CBR are expected to include more information on facility costs, including capital and both fixed and variable operating costs to improve modeling of facilities in cases of changing utilization factors due to evolving demand.

1.2 Related Program Interfaces and Related Key Evaluations

The NTRD 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 NTRD Economic Analysis activity has received feedback from the EMWG on key NTRD 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 FCO Campaign coordinates with the NTRD Advanced Fuels, Material Recovery and Waste Form Development, and Used Fuel Disposition Campaigns. The FCO 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 NTRD system studies.

1.3 NTRD Cost Basis

As stated previously, the NTRD 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 NTRD Program has been collecting cost references and has expanded the fuel cycle cost data for over 12 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 NTRD Cost Flow Sheet in Figure 1-1.

The flow sheet includes 24 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, K, and L that provide the function of waste disposition. The interfaces between the functional Modules A through L (associated with facilities) are provided by the transportation process, Module O.

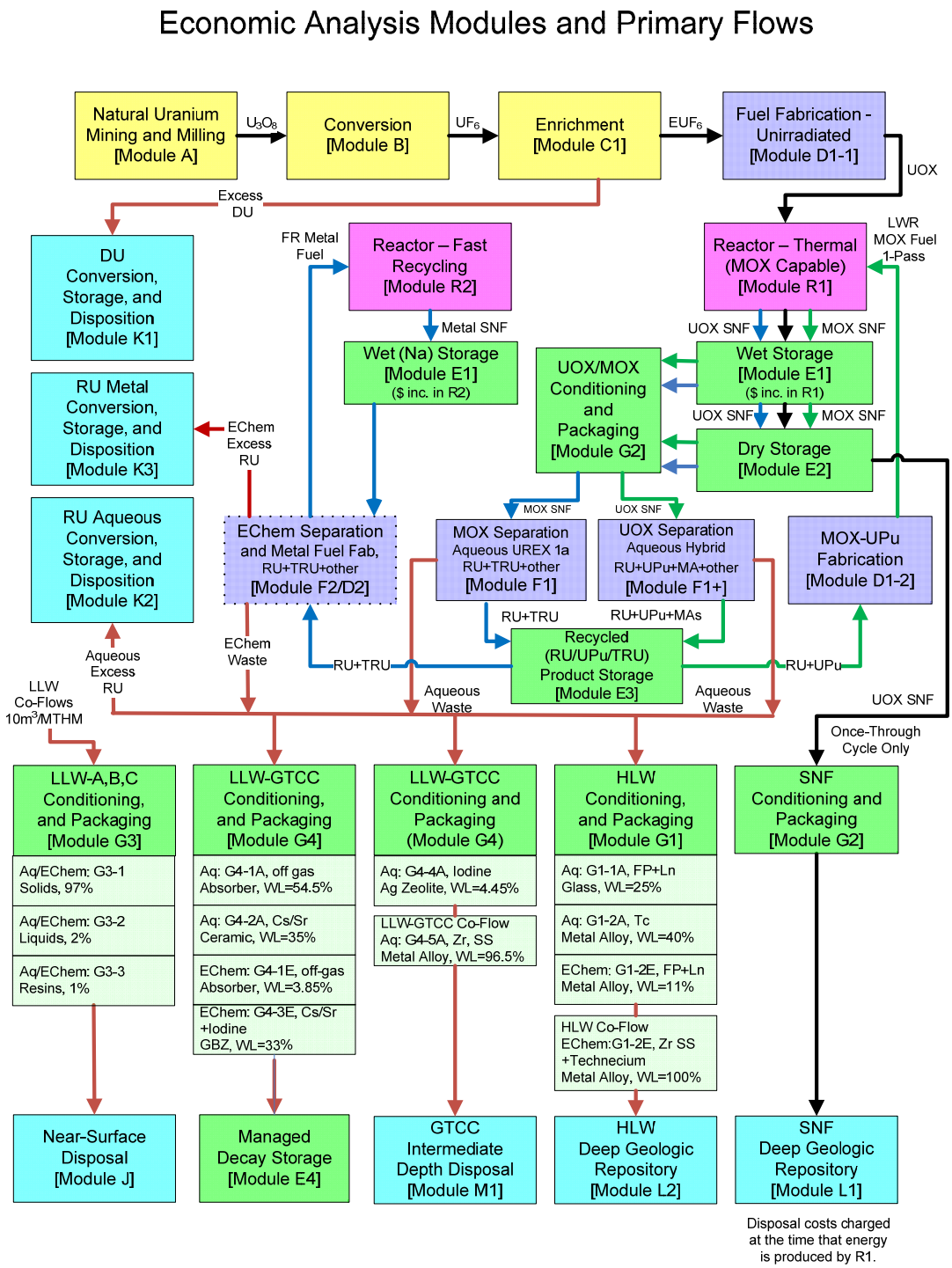


Figure 1-1. NTRD cost flow sheet.

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 (this section) of this report contains the background, program interfaces, description of the annual report cost activities, description of cost modules and diagram of possible 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 (including all code of accounts), verification, data gap analysis, and cost data documentation, and a description of the NTRD cost database. A common cost table that summarizes the module cost data, called the NTRD What-It-Takes (WIT), is described.

Section 3 describes the three basic methods for cost estimating: analogy, parametric, and engineering.

Section 4 describes the organization of the reference cost modules into front-end, back-end, and recycle groups. A general description of the thirty-plus cost modules is provided.

Section 5 provides a procedure for costing fuel cycle options using the unit cost data from the cost modules in this report.

Section 6 includes guidelines for comparing fuel cycle alternatives using qualitative and quantitative techniques.

Section 7 describes the use and integration of the cost data and price data into cost models.

Section 8 provides information on escalation and escalation rates

Section 9 discusses the topic of cost discount rates, including discounting over longer time periods. Recommended discount rates for analyses are included.

Section 10 describes the treatment of uncertainty in the AFC-CBR and discusses current efforts to reduce uncertainty in cost analyses through the development of partial cost correlation co-efficients.

Section 11 provides methodology for evaluation of systems where the use of modular facilities enables phased installation of capacity, including how to treat the phasing of revenue generation and the balance of facility costs.

Section 12 provides a summary of cost analysis tools available to the FCO campaign. These economic models make use of the unit cost data presented in this report.

Section 13 summarizes the conclusions and recommendations resulting from the development of the report.

Section 14 provides general (nonmodule specific) report references, including references for material in the main body of the report.

The 2017AFC-CBR file folder includes multiple separate files for over 2 dozen cost modules. Fuel cycle modules are labelled 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 NTRD WIT table is used to summarize the module fuel cycle cost unit data in a consistent manner.

2. NTRD COST BASIS DEVELOPMENT PROCESS

The goal of the NTRD 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 NTRD 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 application of the AFC-CBR to the Nuclear Fuel Cycle Evaluation and Screening of FY 2012-2014 (FCRD 2014) and current fuel cycle transition studies.

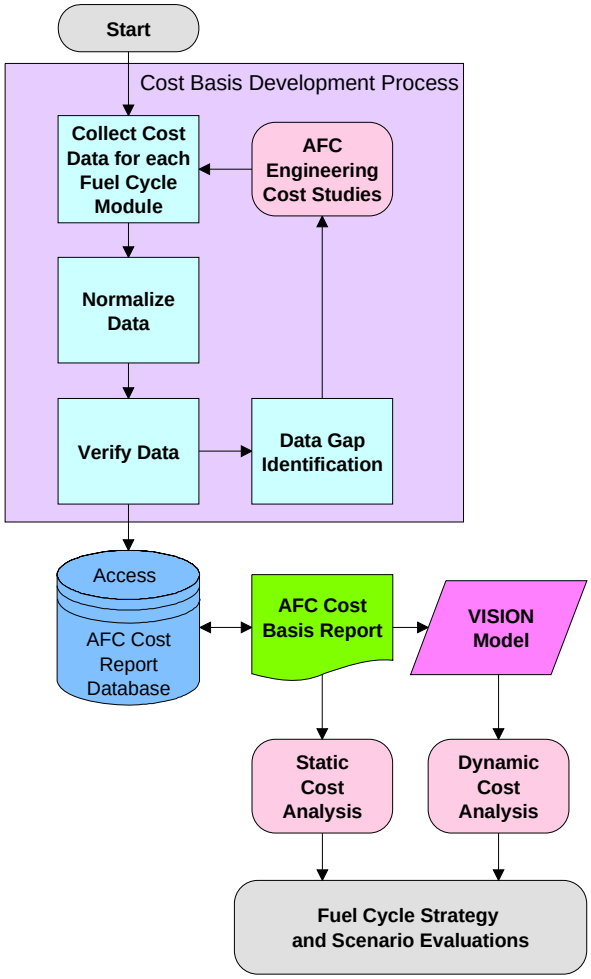


Figure 2-1. NTRD cost basis development process.

2.2 Fuel Cycle Data Collection

Data were collected for a total of 33 fuel cycle modules and submodules and 9 reactor/transmuter modules. The cost data were analyzed and evaluated on a common basis. The complete list of modules is included in Section 4.

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 NTRD program, and those taken from data gathering and modeling efforts of other organizations (e.g., OECD/International Atomic Energy Agency "Red Book" for uranium supply).

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 (WBS) 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 2007). "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 (EMWG 2007) 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.[1]

2.3.5 Common Year (Current Year Basis)

A reference year for constant dollar costing and use of discount/escalation factors was chosen. The NTRD Program has chosen to use 2017 dollars for this latest report. Escalation factors are discussed in Section 8.

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.

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

1. 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. 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 NTRD 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). In FY 2012, several gaps were noted in preparation for the Fuel Cycle Evaluation and Screening (FCRD 2014). New sections were added to the main report addressing the use of price data, discounting, and the treatment of uncertainty and a number of additional reactor cost modules were added.

Ongoing cost analyses and methods development continue to identify data gaps that are addressed as they are identified and data is available. Current areas of development include better treatment of uncertainty, drivers for cost overruns in historic data, treatment of discounting over longer timeframes, and treatment of phased capacity additions based on modular facilities.

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 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 and Diagrams—describes layout of the facility, includes pictures, schematics, etc.

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

1.5 Scaling Considerations—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.

1.7 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.

1.8 Cost Summaries—compiles the cost data that have been placed in the module sections. Data may be presented as graphical cost projections based on parametric scaling analysis of cost vs. capacity or other cost measures. The cost summary information is placed in a WIT table (see example Table 2-1) that shows reference cost bases and 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, the mean for the selected uncertainty distribution, and a most likely value (mode).

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	Low Cost	High Cost	Mean	Mode
$100/MTHM based on capacity of 2,000 ton/yr	+/- 10%	$90/MTHM	$150/MTHM	$120/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)	(Calculated based on the cost distribution)	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.

1.10 References—lists the most relevant references that form the primary basis for the module costs.

1.11 Bibliography—(optional) Additional (more general) data sources applicable to the module.

3. Cost Estimating Methods

Cost estimating is the method used to populate the organizing structure discussed above. Three primary methods are used to estimate costs: analogy, parametric, and engineering. This section summarizes the salient points of each method. The EMWG's Generation IV cost estimating Gen IV Guidelines Document (EMWG 2007) is an excellent guide to estimating costs in nuclear systems. In it, the authors describe top-down and bottom-up estimating. In the language of this section, analogy and parametric methods are consistent with the guideline discussion of top-down estimating. The engineering method is a form of bottom-up estimating. While this section is not a "how-to" manual on cost estimating, it provides sufficient detail to guide the analyst on what must be considered in choosing an estimation method. The first question the analyst must answer in choosing an estimation method is, "What is the present level of development of the project or system under cost analysis?"

Figure 3-1 is from a text describing cost estimating and analysis in defense acquisition programs (Angelis 2015). As opposed to an "x-y" plot, the figure overlays the estimating methods onto phases of a program life-cycle. What would be an x-axis is phases of program development and a y-axis is not represented. It illustrates that where a program (or project, system, etc.) is in its life-cycle influences the estimating method, which then determines the type of cost estimates that will result. Early phases of development, such as concept definition/refinement and technology demonstration, will yield a gross level of cost estimating (where only high levels of projected cost rollup or aggregation available within the cost estimate) whereas analysis during development or production yields much more detailed estimates (many more detailed individual costs available that can be rolled up to higher level cost figures-of-merit). This variation is a function of data availability. At the planning/conceptual phase little data exists from which a cost analysis can be conducted, but when the system is under construction or operational much more cost data are available for the system.

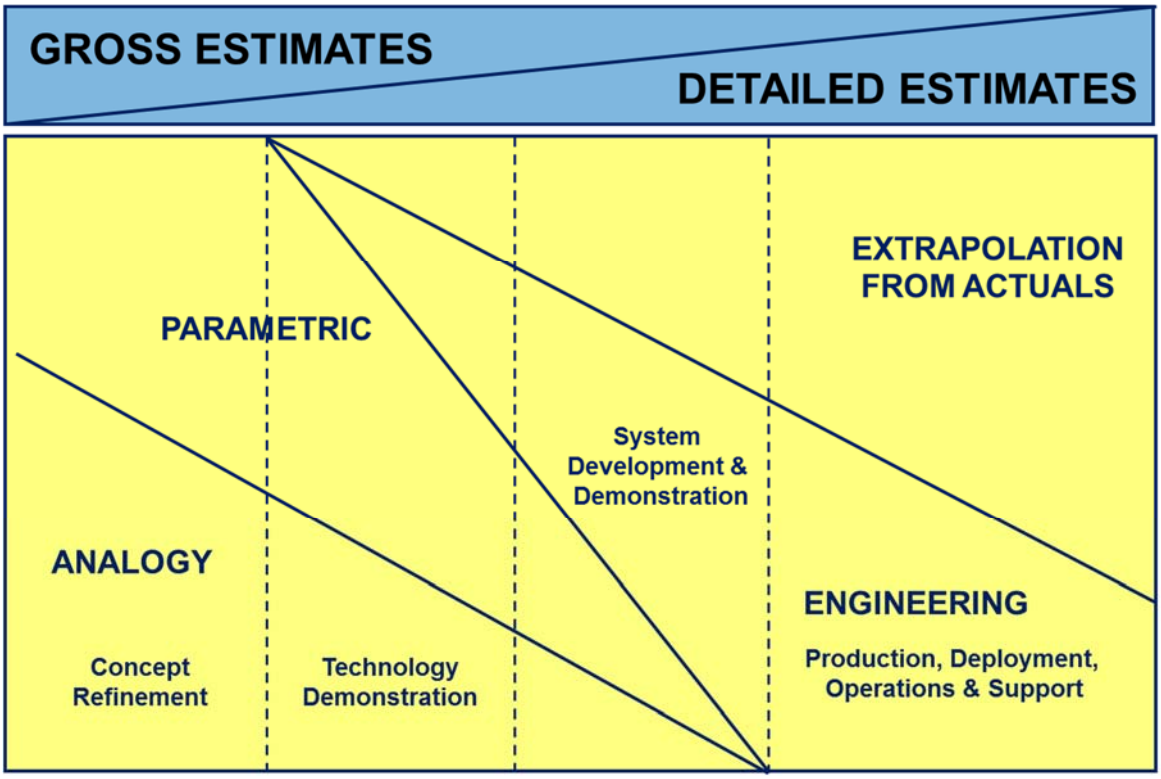


Figure 3-1 Cost Estimating Techniques as a Function of Acquisition Phases (Angelis 2015, p. 118)

Note in the descriptions that follow how projected "should" cost versus actually achieved "did" cost will be reflected. Because analogy and parametric estimating rely on data for similar systems the extrapolated and reference estimates will reflect a "did" cost. Estimates are extrapolated based on these "did" costs for similar systems. On the other hand, the engineering approach – although resource intensive – is a better approximation of "should" costs.

3.1.1 Analogy

"It's like one of these." That is the colloquial expression the International Society of Cost Estimating and Analysis (ISCEAA) uses to refer to the analogy method of cost estimating (Angelis 2015). The analogy method is one of comparison. The analyst chooses a project (or system, object, process, etc.) that is very similar to the "subject" project under evaluation. The analyst then selects the reference project to use as the basis for comparison, using it to compare against the new project. Subjectively, the analyst applies comparative techniques to build a cost estimate for the "subject" project. Data used in the comparison stem from cost and technical data on the reference project that the analyst adjusts for application to the "subject" project under evaluation.

Figure 3-1 shows how the analogy method squares with alternative costing methodologies. Analogy is the appropriate choice for estimating when the project is in a conceptual phase, or when technology is at the point of demonstration. This is the best choice when little is known and data is limited.

The analogy method has strengths and weaknesses. Angelis and Nussbaum (Angelis 2015) point out one of each. Cost estimates using this method are based on actual experience, making them strength of analogy estimates. But a weakness is that the analyst must find a very similar project for the reference comparison. The GAO similarly outlines pros and cons of analogy costing (GAO 2009). GAO lists pros of this approach as the ability to produce an estimate from limited data, and as in Angelis and Nussbaum, analogy is based on actual data. Analogy produces quick estimates of conceptual designs and leaves a good audit trail. As for weakness, the GAO identifies analyst bias as a possibility because adjustments from the reference to the actual are subjectively imposed. Regarding estimation accuracy, it all depends on the similarity of the reference project to the actual one being evaluated. Moreover, when using analogy it is difficult to assess the effects of design change; and the estimates are blind to actual cost drivers.

3.1.2 Parametric

"This pattern holds" is the expression the ISCEAA applies to parametric cost estimating (Angelis 2015). Parametric cost analysis uses cost estimating relationships and mathematical algorithm to establish cost estimates (Angelis 2015). Further summarizing from Angelis & Nussbaum, parametric estimating uses statistical analysis to generalize a relationships between system or project characteristics and cost. Typically using Ordinary Least Squares (OLS) regression analysis, the parametric method generates a mathematical equation where system performance or design characteristics become independent variables on the right hand side of an equation and cost is the depended, left hand side variable. It is a technique to explain the correlation between the independent and dependent variables. This method requires a database of elements from similar projects then OLS is applied to estimate coefficients measuring the relationship between the independent and dependent variables. In addition to coefficients, OLS and other statistical techniques, and information about uncertainty based on estimation error can be useful understanding the system under analysis.

Similar to analogy estimating, the parametric method can be applied at early phases of technology development when concepts and technology are under development. Whereas the analogy method uses a *single* system or project as the reference for comparison, the parametric method uses *multiple* similar projects or systems as references for comparison.

In terms of strengths and weaknesses Angelis & Nussbaum and GAO list each. A key advantage of the parametric approach is that once a cost estimating relationship has been established, applying it is

straightforward, easy to use, and useful in early technology development. The approach is objective and reproducible, moving it away from the subjectivity bias which is a weakness in analogy costing. Because the parametric approach can relate several independent variables to cost figure-of-merit, real world effects and cost drivers can be reflected in the cost estimate. As for weakness, model calibration is important because if data used to calibrate the model are widely dissimilar, e.g. the system under analysis is new to the point of not having close approximations, then the cost estimate can be inaccurate.

The following example illustrates an application of parametric estimating. In 2016 the FCO EWG conducted a type of parametric analysis using the COA. Presented with a reactor design outline in (Devanney 2015), the Group's task was to evaluate how this design compared on a cost basis with other reactor designs. Because little data exists on the proposed concept, the Group applied a parametric comparison based on data in (Devanney 2015).

(Ganda 2015a) summarizes previous economic analyses where a form of the COA structure had been applied. From it, descriptive statistics were computed regarding COA categories in each study. Table 3-1 shows the COA categories under "Aggregated Cost Component" then columns list the studies from which the percentages were computed. Separately the group used the COA structure to organize cost data in (Devanney 2015). The Group could then evaluate a new concept (ThorCon molten salt reactor) with historical LWR experience based on cost.

This type of cost estimating was also used by the European Union representative of the Generation IV Economic Modeling Working Group (EMWG) (Roelofs 2011) (Van Heek 2012) to estimate the specific capital costs of non-LWR Gen IV reactor types based on a 2-digit COA breakdown of reference LWR costs. In this case engineering analysis and scaling were used alter each LWR subsystem to one for a different type of reactor (based on physics and engineering constraints under new operating conditions) and then develop cost-size scaling relationships to determine the new COA 2-digit direct cost for each subsystems.

Parametric analysis has also been used to project life cycle costs for non-reactor fuel cycle steps. In 1984 a parametric cost evaluation methodology involving process science/engineering and coupled cost-scaling relationships was developed to assist DOE-NE in the down-selection of advanced uranium enrichment technologies. Detailed documentation of the methodology appears in (Williams 1984) and a shorter journal article describes it in (Williams 1989). It can be applied to any application where a process-economic model is available, and also has a description of how Monte Carlo uncertainty analysis can be used to calculate probabilities of meeting process performance and unit product cost goals.

Table 3-1 Direct Cost Component as a Percent of Total Direct Cost: Comparing studies summarized in Ganda et al. (2015) to ThorCon as described in Devanney et al (2015).

Aggregated Cost Componenet	NEA (1999)	TVA (2004)	EEDB (1987) Median Experience	EEDB (1987) Best Experience	Average	StDev	ThorCon
Structures and Improvements	29%	21%	25%	22%	24%	3%	18%
Reactor/boiler Equipment	36%	38%	32%	34%	35%	2%	26%
Turbine gen. equipment	18%	25%	23%	25%	23%	3%	27%
Electrical	11%	11%	10%	9%	10%	1%	12%
Cooling and miscellaneous	7%	5%	11%	11%	8%	2%	16%
Total Direct Costs as a % of Total Cost	63%	53%	17%	28%	40%	21%	34%

3.1.3 Engineering

The ISCEA expression for engineering based costing is, "It's made up of these" (Angelis 2015). This is also called bottom-up or industrial-level engineering analysis and is the most detailed of the three estimation techniques. Extra detail further means that it is the most expensive methodology to implement

because it requires that each element of the WBS have a detailed cost estimate associated with it, including granular detail on plans (schedule) and designs. Greater time and resources must be allocated for the engineering approach than the other two methods, and the services of professional cost estimators and cost engineers may be required. Further, the analyst must be well-acquainted with the system under analysis and the system itself must be well-defined. Angelis & Nussbaum note that computing systems can be developed where the purpose is to collect detailed information and facilitate the bottom-up approach, but these systems can be very expensive to develop and operate. Computer software such as "Primavera" management systems are often used to integrate cost and schedule for hundreds of individual WBSs. Such systems require trained experts in their use, but are excellent for managing very large construction projects.

As in the other estimating methods, the engineering approach has strengths and weakness that Angelis & Nussbaum and GAO discuss. A key strength is that of the three methods, this produces more accurate estimates because of the level of detail involved. The level of detail involved lends this method to being most sensitive to economic conditions such as labor rates. It is straightforward to audit the assumptions and analysis used. Because of estimation accuracy, this is a time-honored approach. But the great level of estimation accuracy is expensive. Producing such an estimate is time and labor intensive which makes it the most expensive of the three methods. Another weakness is that detailed information about the systems may not be readily available, especially at early stages of development.

3.2 Cost Indices

Data requirements in cost estimating, particularly methods based on comparisons, necessitate some type of data normalization. Data used in cost estimating models are recorded in ways that may not be consistent with the assumptions underlying the cost model. This is particularly true in cost estimating for nuclear systems where available data may come from an array of countries across many years. Predicting future costs with historical data requires data to be relevant and matches the assumption of the cost model (Angelis 2015). As Angelis & Nussbaum write (p. 133), "Data normalization is the process of making data recorded under different circumstances comparable."

Cost indices provide the analyst a means to normalize data. For example if a cost estimating relationship predicts a certain amount of labor for a nuclear system, based on observed costs for a similar system in Korea, then the analyst must normalize data in two dimensions – labor rates and exchange rates.

The EMWG's Gen IV Guidelines Document (EMWG 2007) has (in Appendix G) an extensive list of indices for cost analysis. Although somewhat dated now, (the document was published in 2007), the appendix records exchange rates for countries that may have cost data on nuclear systems. It outlines labor rates for classes of skill that would be used in nuclear projects. A commodities price list documents what prices should be expected for inputs into nuclear projects. Escalation rates are provided based on COA categories, reflecting the fact that escalation does not necessarily occur at the same rate across all sectors of nuclear projects. Then a detailed record of commodities used in existing nuclear systems is provided. The Gen IV Guidelines appendix is a good representation of the types of indices that should be kept current for use in ongoing cost analysis of nuclear projects.

4. 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 4-1 summarizes information on the 36[2] 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 (A1-2, 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 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 (under arrangements with Russia) was until very recently providing a significant portion of U.S. LWR fuel. UF_6 received from blend-down operations substitutes for fuel cycle operations in Modules A1-2, B, C1, and K1. Module D1, Fuel Fabrication-Unirradiated, is available from a limited number of sources and very little cost data are available at a facility level.
2. Reactor/transmutation baseline cost data are provided in Modules R1 through R9-2 (including numerous types of critical reactors, externally driven systems, and fission-fusion hybrids). The SNF wet and dry storage (Modules E1 and E2) is generally located at reactor sites and have been dropped as separate modules. 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 sometime after reactor construction. Some cost data is available on these storage pads, and may inform the costs of a larger, centralized dry storage facility (Module I).
3. The back-end fuel cycle modules (I and L) are the responsibility of the government as provided by the Nuclear Waste Policy Act. The government funds these functions and the services would be provided by government contractors.[3] 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, G1-5, 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 LLW from reprocessing, or from fuel cycle and reactor facility maintenance and operations. The disposal of U wastes is covered in Modules K1, K2, and K3.
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.

2. Of the 39 modules, some have been combined or deleted netting 36 currently used modules.

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

Table 4-1. 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 nuclear materials (U, Th & Pu chemical forms) and convert them 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 (no longer used)	Wet Storage of SNF	Pool storage (at reactor) of SNF from existing commercial reactor operations. No longer used as costs are included in reactor costs.
E2 (no longer used)	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. No longer used as costs are included in reactor costs.
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 fissile blending needs.
E4	Managed Decay Storage (of certain fission products)	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.
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.

Cost Module	Module Name	General Description
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 or to an off reactor site storage pool.
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 TRU 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 of DUF_6 and disposal of the resulting stable DU form. In some scenarios, this material is later withdrawn to use in breeder fast reactors.
K2	Reprocessed Uranium Disposition-Aqueous	Conversion, storage, and disposal of burned uranium resulting from aqueous reprocessing such as PUREX or UREX (LWR spent fuels)
K3	Reprocessed Uranium Disposition-Electrochemical	Conversion, storage, and disposal and purification of burned uranium resulting from electrochemical reprocessing of LWR spent fuels. Uranium-metal will contain multiple contaminants, including transuranics and some fission products.
L1	Geologic Disposal of SNF and HLW	Cost from inception through closure for geologic repository operations.
L2	Disposal of GTCC LLW	Includes options for GTCC disposal.
M (no longer used)	Alternative Disposal Concepts	Speculative costs for SNF/HLW disposal alternatives to a deep geologic repository, such as deep bore hole, and others. Deep bore hole costs are now included in L1 while other more speculative options such as deep ocean trench have been dropped.
N (no longer used)	Nuclear Fuel Transportation (Contact and remote handled)	[Cost data transferred to Module O1 and O2]

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 (LWRs)	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. (Module dropped since SMRs fit other R categories.)
R5	Pressurized Heavy Water Reactors	Capital, operations and maintenance, and D&D costs for generic heavy water reactors in the U.S.
R6	Accelerator-Driven Systems	Capital, operations and maintenance, and D&D costs for generic accelerator-driven subcritical systems in the U.S.
R7	Liquid-Fueled Salt-Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic liquid-fueled salt-cooled reactors in the U.S.
R8	Solid-Fueled Salt-Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic solid-fueled salt-cooled reactors in the U.S.
R9 (R9-1 and R9-2)	Fission/Fusion Hybrid Systems	Capital, operations and maintenance, and D&D costs for generic fission-fusion hybrids in the U.S. Includes both magnetic confinement and initial confinement designs for the fusion reactor.

Additional cost modules have been defined to distinguish cost differences between modules with different technologies, radioactive environments, and regulatory requirements. Over the past three 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 at reactor storage (Module E1 and Module E2), both of which were subsequently dropped as their costs are typically included in reactors costs, 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.

Cost Module	Module Name	General Description

- 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), SMRs (R4), heavy water reactors (R5), Accelerator-driven systems (R6), liquid-fueled and solid-fueled salt-cooled reactors (R7 and R8) and two types of fission/fusion hybrid systems (R9-1 and R9-2).

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 4-1.

5. STRATEGY COSTING PROCEDURE

The goal of the NTRD strategy costing procedure, shown in Figure 5-1, is to use the data from the NTRD cost database to support NTRD economic analyses of fuel cycle strategies (Shropshire 2009).

5.1 Process Description

The NTRD strategy costing procedure includes defining the scenario and key parameters, selectively linking and scaling the cost modules, and selecting data from the NTRD 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.

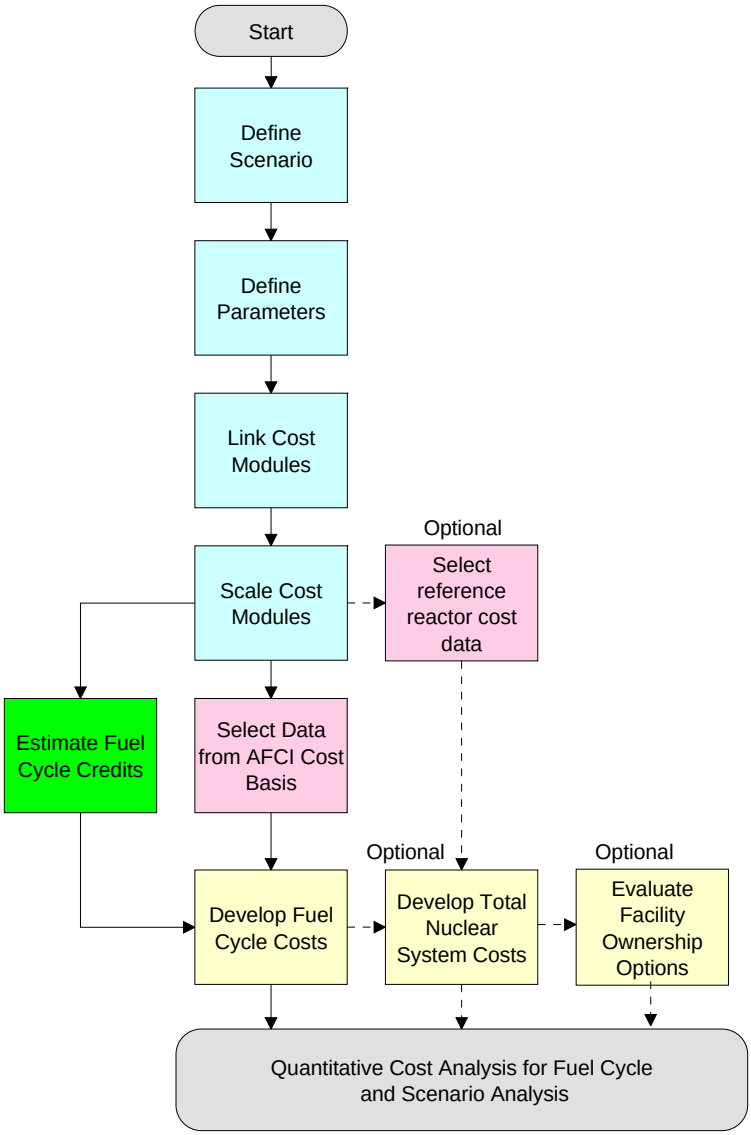


Figure 5-1. NTRD strategy costing procedure.

5.2 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.

5.3 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 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.

5.4 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 5-2 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 calculate and evaluate the dynamic flows between the modules (refer to Section 11).

5.5 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.

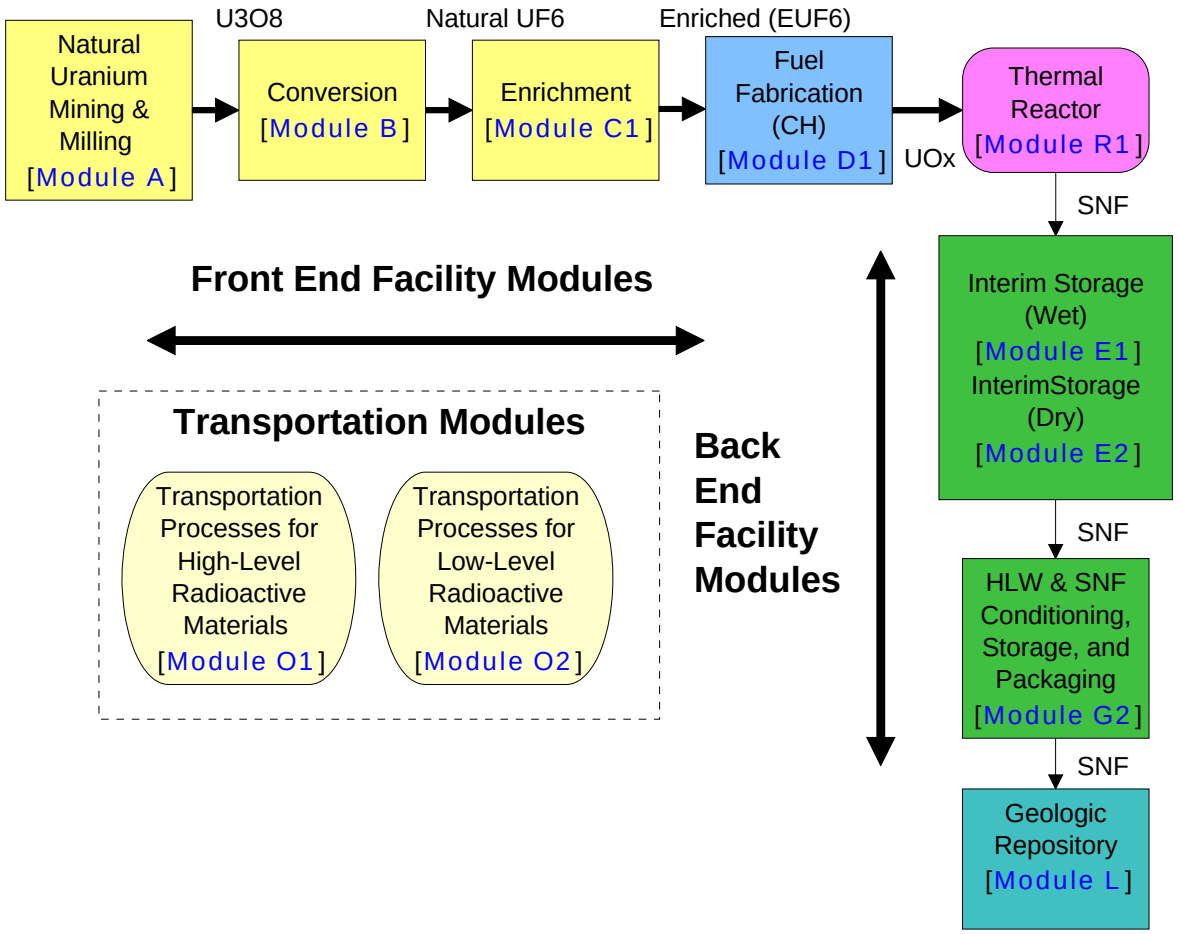


Figure 5-2. Example of linked cost modules.

5.6 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.

5.7 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.

5.8 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.

5.9 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). The topic of risks and associated discount rates for private sector versus government investments is discussed in Section 9. While focused on a different topic, Section 9 provides information that can be used to model differences between vendor costs and utility costs where the utility may be operating in either a regulated or deregulated market.

6. ECONOMIC COMPARSION 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 (US 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 NTRD 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.

7. USE OF PRICE DATA IN NTRD COST-BASIS ESTIMATES

7.1 Introduction and Scope

The AFC-CBR series seeks to provide a comprehensive, consistent, and well-documented set of cost estimates and supporting data to facilitate comparison of economic performance for future nuclear fuel cycles. The estimates for fuel cycle modules are based largely on the technical features of the modules and the interface requirements between them. These estimates result in cost curves that characterize the costs of each technology at the scales at which it would typically be implemented. In general, the effects of the *market setting* in which technologies would be introduced are not explicitly accounted for. This section begins to address one important element of that market setting – the use of price data as an input to or in lieu of engineering cost estimates. Future versions of or addenda to the AFC-CBR will further explore the implications of market setting considerations for specific modules.

7.2 Costs and Prices Defined

Cost and price are two distinct concepts, both central to economic theory and applied economics. A *cost* is a measure of valuation for a good or service, based on the set of resources used (denied to other uses) in the *production* of that good or service. A *price* is a measure of valuation based solely on the property that a transaction or set of transactions was conducted at that price between a willing buyer(s) and seller(s).[4] In general, *producers* incur costs, *buyers* pay prices.

Thus costs are functions of technology (production functions) and input prices, and are reflected in unit cost and supply curves. Prices are function of (individual or average) *supply and demand* and their (often complex) interactions in markets. They tend to be more volatile than costs of production, which display a degree of inertia related to investment in production technology.

A supply curve illustrates one of the important relationships between production costs and market prices. Figure 7-1 (reproduced with permission from (Rothwell 2009) shows a global market supply curve for Separative Work Units (SWU) the production unit for uranium enrichment plants. Each of the horizontal segments of this curve is derived from a cost estimate for a specific productive element (plant or plants) for a specific producer, and represents the long-run marginal cost of production over that quantity interval. The market price resulting from this supply curve will be the production cost for the "marginal supplier" – that supplier required to produce the last unit of production. The resulting market price (of about $160/Kg-SWU) is above most of the producers' average costs, and far above the prospective long-run marginal cost of a new centrifuge plant.

While conceptually distinct, cost and price can be numerically equal under certain conditions[5]. In the long run (and under certain other conditions) prices can exceed costs. Cost of production to a firm cannot indefinitely exceed product price in a free-enterprise context, but certainly can in a mixed government/private context such as nuclear technology development and deployment. From the perspective of nuclear power in a market setting, prospective prices for nuclear electricity generation must exceed costs of generation by a reasonable margin (profit) to attract investment in new plants.[6]

4. Further a market price is one that at which there is some degree of equilibrium in current demand and supply over many buyers and sellers.

5. Among these are market setting of perfect completion and freedom of entry and exit for producers.

6. Put another way, price must be at least as great as a life-cycle cost which includes a reasonable (given risk) return on investment.

In general, the relationship between costs of production and market prices is a complex subject that has occupied a substantial fraction of microeconomic theory for much of its development. Figure 7-2 below provides a simple conceptual schematic for the important domains and relationships.

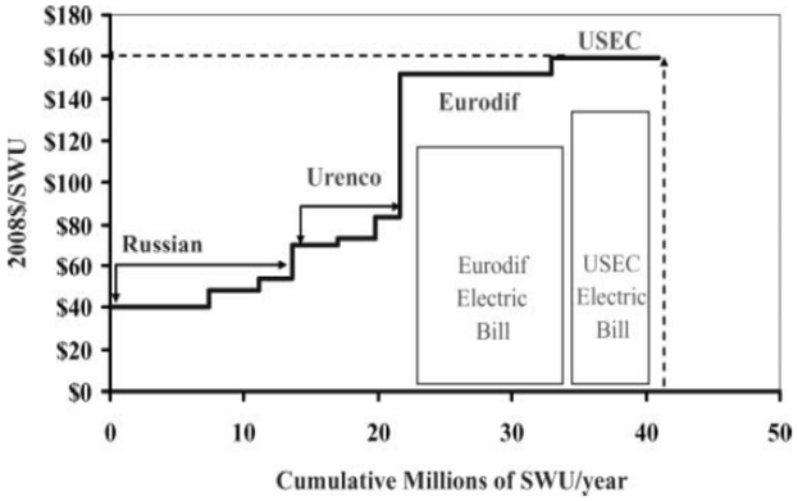


Figure 7-1. SWU market supply curve (Rothwell 2009).

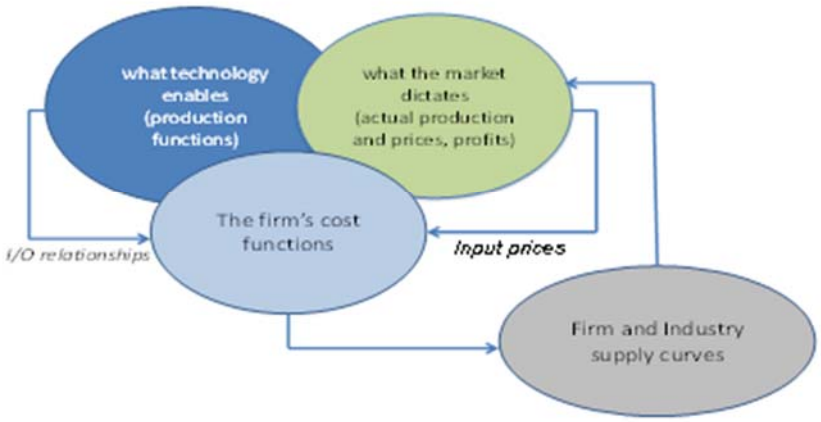


Figure 7-2. Cost and price domains and relations.

7.3 Cost and Prices in the Context of the Cost Basis Report

7.3.1 Objectives for Cost Basis Reports

"The (NTRD's) fundamental objective is to provide technology options that would enable long-term growth of nuclear power while improving sustainability and energy security"[7]

The NTRD Cost-basis series of reports supports this objective by defining a comprehensive and consistent set of cost data for analysis of nuclear technology options, and thus to both identify economic and performance targets for advanced nuclear technology, and identify economically important R&D domains. The focus on identification and evaluation of promising R&D has reinforced a tradition of cost estimates based largely on engineering models.

Within this broad purpose of the cost basis report series, the primary objective for the estimates is;

"…use of the cost data is for the relative economic comparison of [fuel cycle] options rather than for determination of total fuel cycle costs with great accuracy (Summary, 2007 report)."

The fact that the options of greatest interest are emerging or possible future (i.e., advanced) nuclear technologies implies that historical market prices are typically not available as measures of value, and comparison among these options demands estimates of costs "from the bottom up."

Much of the logical content of the estimates derives from *engineering models* of the unit process which can be combined to make complete fuel cycles – that is to say, models that capture the essential features of the physical production functions to which these unit processes contribute, and thus of the cost functions which are their duals.

Prices enter the cost estimation and comparison process in two ways: (1) to calculate probable costs for processes using inputs (materials and services) that are traded, and (2) to acknowledge the broad effects of market setting in implementing the fuel cycle.

The first sense in which prices are relevant is unavoidable. Any cost estimate for a broadly defined nuclear technology domain must, at some level of detail, use price data rather than cost estimates to value inputs to production.[8] In estimating costs for nuclear fuel, we would not typically detail the production technology of fluorspar, used in the production of HF, which is the reducing agent for UF_6 conversion. Instead, an appropriate market price for HF, with appropriate escalation, could be used directly in a fuel cost estimate. All historical data on commodity input costs reflect to some degree market equilibria or transactions (e.g., *prices)*. Seen in this light, it is clear that the real choice is simply the level of input granularity at which price data is introduced into cost-basis calculations.

This section documents current working group practice in using price data, and briefly describes general principles adopted by the working group to insure consistent practice in the future. Such consistency in the use of prices should insure that the comparisons among fuel cycles retain their integrity.

7. Piet, Steven et all 2005, Objectives, Strategies, and Challenges for the Advanced Fuel Cycle Initiative

8. The alternative involves an infinite regress into 2nd, 3rd, and nth order inputs (inputs to inputs to inputs) of production, which in the limit requires specifying the production function for the global economy, and denominating cost in terms of quantities of a "numeraire good."

7.3.2 Short Run, Long Run, and Very Long Run

Cost functions and curves are typically categorized as short, long, or very long run. *Short run* curves assumes that capital (both type and amount) is fixed and that production is varied by changing the quantity and perhaps the character of other inputs. For example, we might estimate the costs of adding fuel production at a fixed set of plants with additional labor, LEU, and hardware inputs. *Long run* curves assume the scale of capital investment can be altered to its optimal level for a given process, thus assuring production at minimum long-run cost. *Very Long Run* cost estimates or curves assume that the *scale and nature* of technology are variable, allowing optimization of the production processes utilized.

When comparing costs of future nuclear technologies, either in the context of system cost minimization, or in understanding which technologies require support with R&D investment, it is the *long run* and *very long run* estimates that seem most relevant[9]. To the extent that innovative or advanced nuclear technologies are of interest, these estimates are the most difficult, since most of the phenomenological content (neutronics, separations chemistry, etc.) must be explicitly modeled or assumed for each module, rather than based on actual experience.

While it is long-run and very-long run *costs* that seem most relevant to these NE missions, the fact is that prices exist in the reality of the short-run, and in the case of options, the long-run contexts. Understanding very-long-run prices requires a general equilibrium model of the economy that spans the technological options, a computational framework which accounts for multiple, correlated sources of uncertainty, and explicit accounting for possible and evolving market settings.

7.3.3 Observed and Predicted Prices

Part of the advantage of using data on market prices is that they are typically published for broadly traded commodities at regular intervals and under a transparent set of accounting rules. Indices for Uranium prices are a good example. Prices of other inputs to production (specialized construction labor, chemicals, steel, etc.) are also typically well documented. The cost basis working group is working to standardize a set of routine sources for the relevant set of inputs and insure that all modules use these standard sources.

Predicting price movements is difficult. In the specific case of nuclear fuel cycle prices, market structure is important and the "imperfections" in market structure are many.[10]

7.3.4 Comparison of Costs with Prices – The Problem of Market Penetration

While costs and prices are conceptually distinct, they are both monetary valuation measures, and thus explicitly comparable. There are many cases where we compare a prospective technology with an existing one which involves this type of comparison. The general context is that of forecasting market penetration for emerging technologies. The best current example may be understanding the market niche for Small and Modular Reactors (SMRs) vis' a vis' more conventionally sized and constructed nuclear plants.

A similar example is estimating the viability of unconventional Uranium extraction methods. Linder and Schneider (2015) has developed cost estimates for U extracted from seawater based on bench scale

9. In a sense, the cost basis report seeks to understand the general shape of the very long-run cost curve for nuclear power – but it approaches this goal using comparative static analysis of long-run cost functions for specified technologies.

10. Among these are barriers to entry for enrichment technology, departures from economic scale for reasons of national control, decreased marginal cost of production associated with defense fuel cycles, and environmental and proliferation externalities.

experimental data for activated polymers. This set of estimates is then compared against observed and extrapolated "market clearing prices" for Uranium from conventional sources such as commodity brokers.

Another case is that of forecasting MOX fuel penetration in a market dominated by UOX fuel (Rothwell and Wood 2011).[11] This requires comparison of a MOX fuel cost estimated from its unit process components with simulated market prices for UO_2 fuel from a stochastic model. In this case, it was useful to characterize the full extent of uranium price volatility as part of the problem, thus establishing a "real options" framework in which to value the future technology.

All of these uses of cost-basis estimates involve comparison of prospective costs with current or forecast prices, and thus require at least implicit assumptions about market settings.

7.4 Price Data Irrelevance

The forgoing cases cited from various cost-basis sections illustrate cases in which use of price data (i.e., assumptions about market settings) have been used in the development of cost estimates. This section presents a few additional examples in which price data have been judged *as inappropriate* for use in cost basis estimation.

7.4.1 Constrained Markets and Price Volatility

Since the front-end of fuel cycle is historically the most fully commercialized, it is rich with cases in which prices from real markets are used at the process level. In some cases, however, the nature of current market influences is explicitly *not* accounted for in setting reference costs. This was the case for both U and SWU prices in 2007:

> *"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."*

Thus transient price fluctuations (volatility) are ignored in practice in setting reference module costs, and that only those price trends (or more broadly those market influences) felt to be reasonably persistent are incorporated in the cost basis estimates. A related example in this vein concerns the appropriate interpretation of current market prices for SWU. Both market data (http://www.uxc.com/review/uxc_PriceChart.aspx?) and analyses of technology-based cost functions (Rothwell, 2009) give high prices for SWU ($140 - $160/kG-SWU). In terms of economic application of available technology, these prices are far above the demonstrated long-run marginal cost of available centrifuge technology, and may be explained (Rothwell 2009) as an artifact of the facts that (1) the marginal supplier now uses a much less efficient technology, (2) there are some restrictions on the entry of new firms in this market. The question posed here is "to what extent should reference fuel cycle costs reflect existing market prices, versus an assumption that efficient technologies will enter the market and set prices?" This question requires making some assumptions on the future market setting for enrichment, and thus the roles of governments and multilateral bodies in setting conditions for its use. The working group continues its consideration of this issue. The situation in 2017 is the opposite of that in 2007. Natural gas and the Fukashima accident put an end to the "Nuclear Renaissance" and the high prices anticipated by it. The market for front end services is now severely depressed.

7.4.2 "Implicit Competition"

Estimating costs for competing reactor concepts assumes that each concept will be developed to and "nth of a kind" level of technological maturity (and corresponding low costs of production). Yet this

11. For example, large-scale MOX fuel for LWRs with UO2 fuel. See Rothwell and Wood 2011.

assumption assumes that a concept survives the development process to achieve this level of development – a process that involves competition for limited R&D and investment resources. In such cases, it is tempting to reason that competitive forces will insure convergence of costs for reactor concepts competing in the same era and markets. Yet the history of the nuclear industry suggests this is an unwarranted assumption, and NTRD estimates do not rely on this type of logic.

7.4.3 Reference Quantities

An issue related to the use of price data concerns another aspect of market outcomes – reference quantities. This question comes in two related forms – (1) with respect to scale of capital plant assumed for estimates and (2) reference capacity utilization within a process or sector of the fuel cycle. The effect of scale in unit costs is very significant in any capital-intensive processes. Enrichment plants are a good example. Figure 7-3 below (reprinted with permission from (Rothwell 2011) shows two unit (average cost curves derived under two different capital; cost assumptions), and the resulting derivation of "minimum economic scale"[12] In typical LWR fuel cycles, enrichment, reactors, and reprocessing, and waste disposal all exhibit large economies of scale. (Forsberg, 2005)

Figure 7-3 makes it clear that defining a reference average production cost for given technology is logically coupled to an assumption about the scale of plants that will be built. This is typically explicit for specific proposed commercial reactor designs, but may not be for advanced reactor concepts or other elements of the fuel cycle.

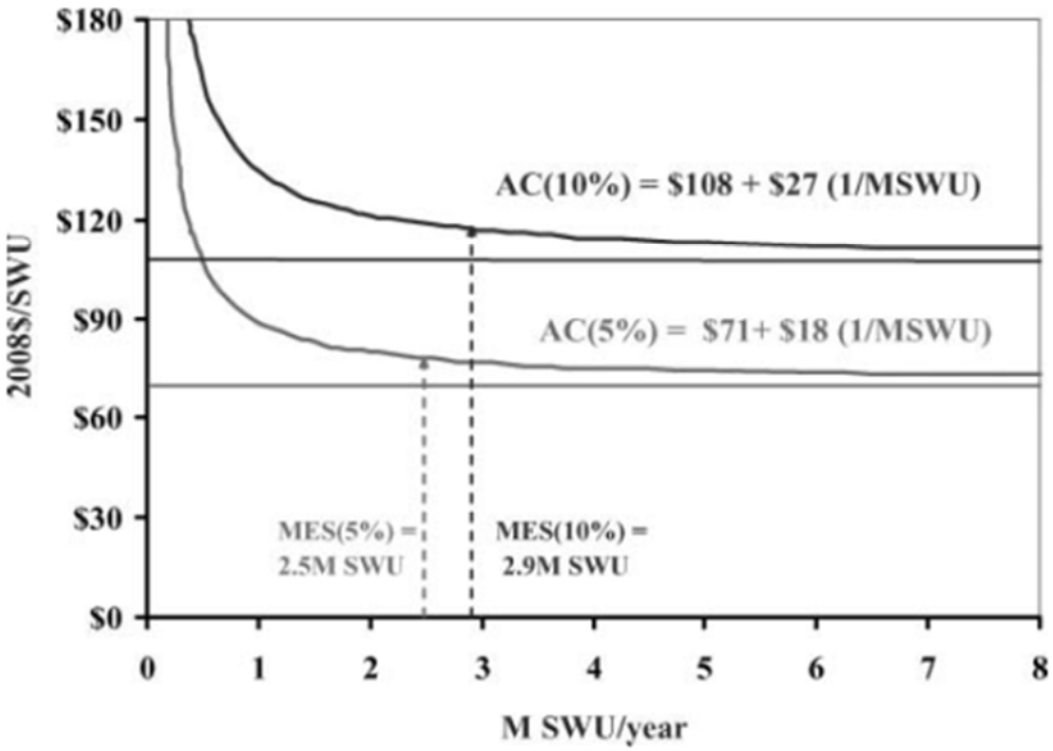


Figure 7-3. Economics of scale in centrifuge enrichment.

12. MES or Minimum economic scale is defined here as the smallest scale of plant (production capacity per year) that achieves a unit cost 10% above the asymptotic limit for a given unit cost curve.

In practice, cost basis results are typically utilized to compare costs of alternative fuel cycles deployed at large scale and often in equilibrium conditions. This context argues that unit costs typical of minimum economic scale for each technology should be used. Unit costs are also sensitive to the capacity factor at which plants are operated, which is to some extent dictated by market setting. Typically, applications of cost basis results include a "mature technology" assumption – a context in which it is reasonable to assume uniformly high capacity factors across plants employing technology from diverse modules.

7.5 Summary of Principles

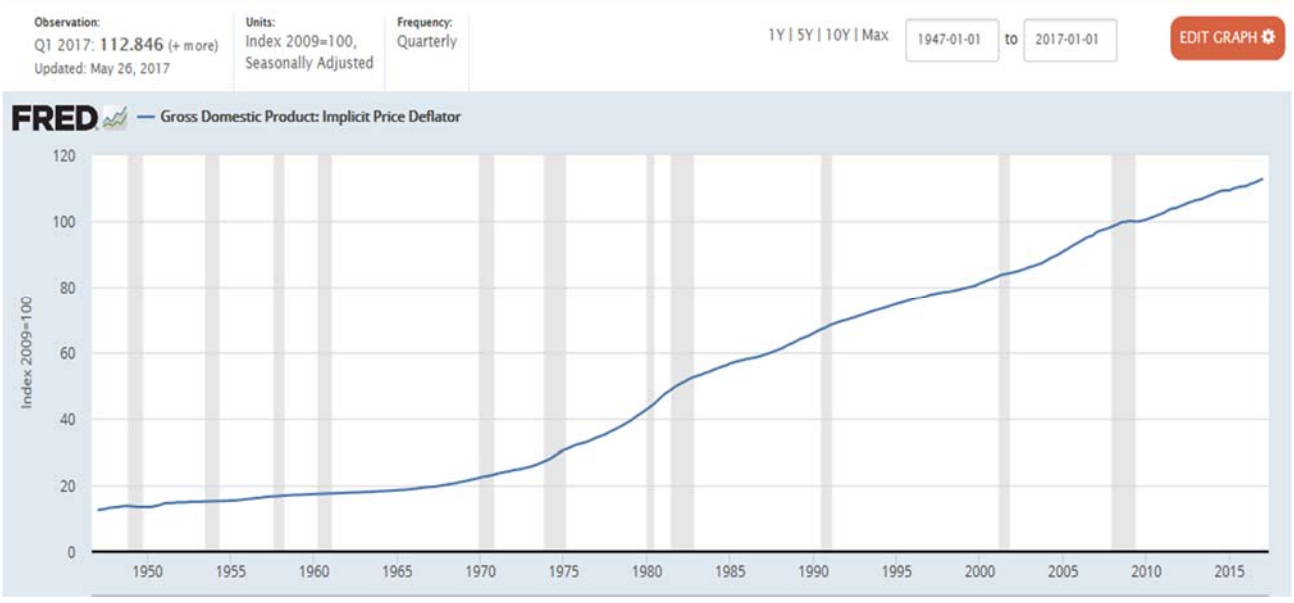
This section summarizes a few principles which we might consider as guidance for use of price data in the cost basis report.

1. Since the objective of the cost basis report and its associated databases is to facilitate comparison among advanced nuclear fuel cycles and their elements, the general model for estimating costs is to rely on a bottoms-up approach in which the production functions characteristic of new or emerging nuclear technologies are modeled as part of the cost estimating process.
2. To the extent that any production function approach specifies inputs to production (which must be valued to estimate costs for the product), some market based (price) data will always be an input to the cost estimation process. Such data should be selected and used in consistent manner from module to module, and should;
    - use broad market averages and indices to the extent possible, and avoid reliance on data from specific transactions or narrow market contexts,
    - reflect long term trends and exclude the transient effects of price volatility in making long term prices assumptions, or
    - be formulated in a stochastic fashion that reflects our degree of uncertainty about future prices.
3. For fuel cycle elements which are already fully commercialized, it may be more efficient to base cost estimates on market data for intermediate products. In cases where this is possible, care should be taken to make explicit the assumptions about continuation or evolution of market structure and efficiency.

8. ESCALATION CONSIDERATIONS

This 2017 AFC-CBD Stand-alone Report has attempted to express as much of the cost data as possible in constant fiscal year (FY) 2017 dollars. Since much of the reference data, and even the 2009 , 2012, 2015, and 2016 AFC-CBD data, are expressed in some other year's constant dollars (even as far back as the 1960's), some manner of escalation must be applied the these values to bring them to 2017$. It should be noted that the term "escalation" is used rather than "inflation". The latter is a term generally applied to a national economy as a whole. In the US general inflation is usually measured by the Implicit Price Deflator calculated by the Bureau of Economic Analysis in the U.S. Department of Commerce. Table 8-1 below shows the Implicit Price Deflator from 1st quarter CY 1947 through 1st quarter 2017 as plotted by the economic research branch of the Federal Reserve Bank of St Louis. The inflation index from a reference year to 2017 is calculated by the ratio of 112.8 (2017 Q1) to the reference years index; which for example year 1965Q1would be 18.6. The ratio is 6.06, which says that in general "things" (the total "market basket" or value of the US Gross Domestic Product [GDP] today is over six times what it was in 1965.) When one starts looking at particular parts of the economy, however, such as nuclear construction, the actual cost ratio actually measured may differ considerable from general inflation. This is due to the fact that the "market basket" for indexing nuclear construction and operations contains items whose prices increased at a rate greater (or in some years less) than inflation. This incremental rate above or below general inflation is called "incremental escalation" and may be positive or negative. Unfortunately for nuclear construction it has been mostly positive and has been affected by commodity price escalation and the labor cost effect of stringent regulation. The net escalation factor in a given year for a given item or industry such as nuclear construction includes both "general inflation" and the "incremental escalation" specific to its "market basket".

Table 8-1. Plot of Implicit Price Deflator from 1947 to 2017

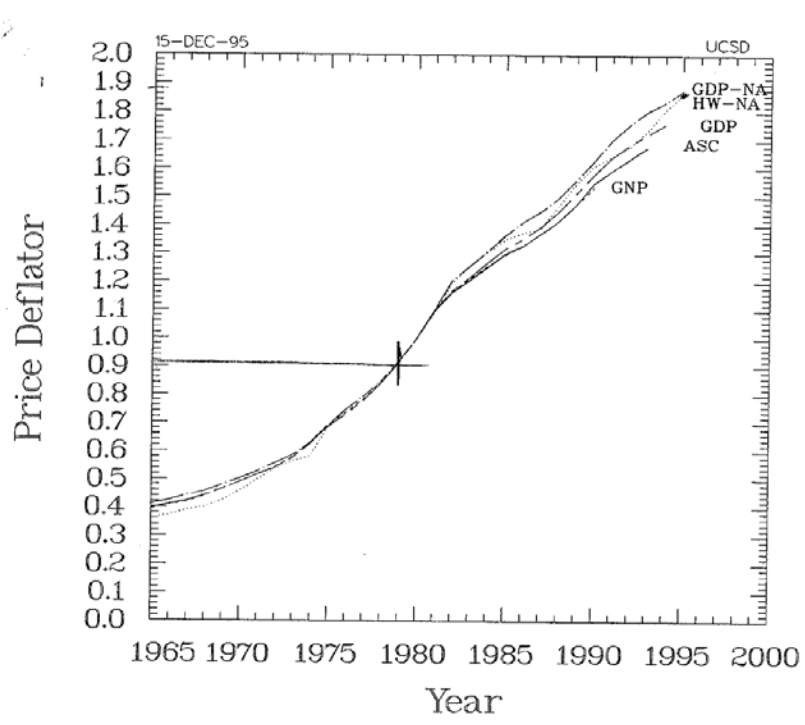


For these AFC-CBR studies the authors attempted to find historical escalation indices which are more specific to the nuclear industry than to the economy as a whole.

Historical escalation indices are published, but generally for very aggregated priced items, such as power plant construction (Handy-Whitman Index), particular labor rates (Department of Labor 2009), or general construction (ENR 2009). It has been difficult to find a publicly available and inexpensive to

purchase (or free) set of escalation indices to use for this purpose. Others have faced the same problem including a University of San Diego author of a nuclear fusion assessment report 1 (Miller 1995). That author, Ronald Miller, compared various indices and found that from the 1960's through 1980 they tracked each other well. (See Figure 8-1 below). From 1980 onward the rate of escalation for construction was higher than for the GNP (Gross National Product) or GDP (Gross Domestic Product as measured by what is now called the Implicit Price Deflator).

For the analyses in this report the Handy Whitman-North America (HW-NA) nuclear power plant construction index (faint dotted line on graph) was used for escalation from years 1965 to 1995.



ASC: Associated Schools of Construction
GDP: Gross US Domestic Product
GNP: Gross US National Product
GDP-NA Gross Domestic Product-North America
HW-NA Handy-Whitman-North America

Figure 8-1. Comparison of various escalation indices (1965-1995).

The Department of Energy occasionally publishes indices for use in budgeting for large construction projects. A November 2009 reference (USDOE 2009) was found with a table that included columns especially for "nuclear" projects. This data is reproduced here:

Table 8-2. DOE Construction Index for Nuclear Projects

Fiscal Year (FY)	Rate (%)	Index 2011 (Base year=1.0)
1990	1.2	0.635
1991	0.9	0.640
1992	0.0	0.640
1993	2.0	0.653
1994	3.0	0.672
1995	2.7	0.691
1996	1.0	0.697
1997	1.9	0.711
1998	0.5	0.714
1999	1.2	0.723
2000	1.0	0.730
2001	0.1	0.731
2002	1.8	0.745
2003	1.0	0.752
2004	12.7	0.848
2005	2.1	0.866
2006	8.1	0.936
2007	3.1	0.965
2008	7.0	1.033
2009	-3.2	1.000
2010	-1.9	0.981
2011	2.0	1.000
2012	1.9	1.019

This DOE Table is used for escalation from 1995 to 2000 since no Handy-Whitman data was available to this project. From 2000 to 2015 the **The IHS North American Power Capital Costs Index (PCCI) was used, since it derived from a larger pool of actual tracked nuclear projects.** The PCCI tracks and forecasts the costs associated with the construction of a portfolio of 30 different power generation plants in North America and tracks the costs of building coal, gas, wind and nuclear power plants, indexed to year 2000. The PCCI is a work product of the IHS North American Power Capital Costs Service, an annual subscription service managed by IHS. Figure 8-2 below shows a plot of the PCCI both with and without nuclear projects included.

Much of the escalation from 2003 to 2008 was due to price increases for steel and concrete, driven heavily by demand in Asia. In 2009 and 2010 there was negative escalation due to the worldwide recession. Only in 2011 did positive escalation resume.

PCCI data for 2015 to 2017 which differentiates nuclear power has not been found, and if they have it this project would have to pay for it. For this reason the GDP Implicit Price Deflator indices were used to derive ratios for 2016 and 2017 escalation.

It can be seen that four methods of escalation indexing have been used in these studies, with each method used for differing times spans:

- Handy Whitman (1965-1995)
- DOE (1995-2000)
- PCCI with nuclear (2000-2015)
- Implicit price Deflator (2015-2017)

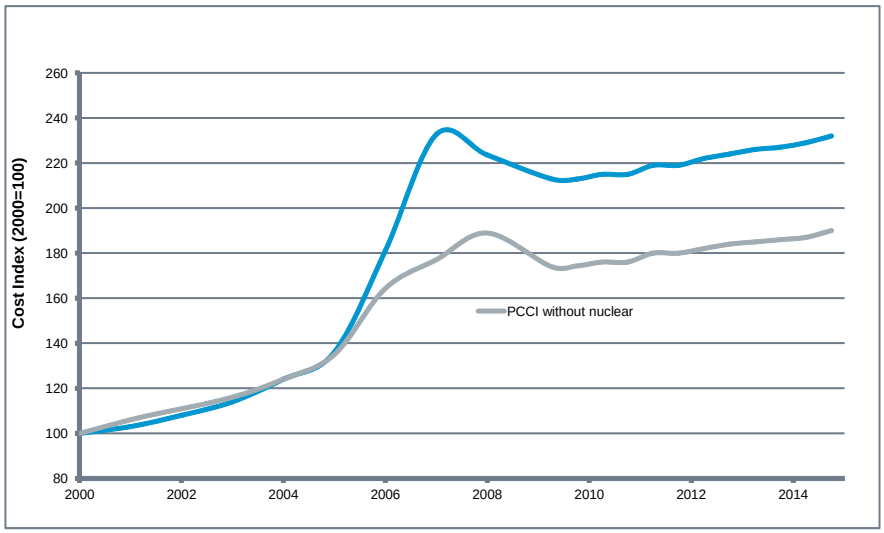


Figure 8-2. Plot of the PCCI Indices (upper curve includes nuclear).

Table 8-3 below shows a composite index derived from all four sources mentioned above which can be used to bring "then year dollars" from any year 1965-2014 to 2017 dollars. This table was prepared by a ratioing method which normalized the three differing indices. The Table 8-3 values will be used to escalate any "then year $" values throughout the cost modules. (For example, if a 1975 cost of $100M was quoted for a fuel fabrication facility, the equivalent today [2017] would be 7.22 from the table below times $100M to obtain $722M). It should be noted that these escalation factors are for the same facility design, and do not include the cost effects of major project scope changes) It should be noted that since 1965 nuclear projects have escalated at a rate about twice that of general inflation as measured by the Gross Price Deflator. General escalation from 1965 to 2017 is over a factor of 6 as opposed to around 13 for nuclear projects.

Table 8-3. Factors for Escalation of "Then Year" Costs to Year 2017 Dollars.

Table 7.3 Composite Historical Cost Index Created from 4 other sets of Indices for which data was available					
1965	13.44	**1982**	4.41	**1999**	2.46
1966	12.74	**1983**	4.06	**2000**	2.44
1967	12.10	**1984**	3.76	**2001**	2.37
1968	11.52	**1985**	3.51	**2002**	2.26
1969	11.00	**1086**	3.40	**2003**	2.14
1970	10.52	**1987**	3.30	**2004**	1.97
1971	9.64	**1988**	3.20	**2005**	1.79
1972	8.90	**1989**	3.11	**2006**	1.35
1973	8.26	**1990**	3.02	**2007**	1.05
1974	7.71	**1991**	2.92	**2008**	1.09
1975	7.22	**1992**	2.83	**2009**	1.14
1976	6.74	**1993**	2.74	**2010**	1.13
1977	6.32	**1994**	2.65	**2011**	1.11
1978	5.95	**1995**	2.57	**2012**	1.06
1979	5.61	**1996**	2.55	**2013**	1.07
1980	5.32	**1997**	2.50	**2014**	1.05
1981	4.82	**1998**	2.49	**2015**	1.03
				2016	1.02
				2017	1.00

Use of this Table: Selection of the "historical" year is important for correct application of escalation to 2017. Within a particular fuel cycle module the "historical" year should be that in which the last "technical" cost basis was changed. For example if a specific ($/kwe) cost in a 2009 AFC-CBD reactor "R" module was based on and escalated from a 1975 detailed cost estimate (latest and best available), the 2017 AFC-CBD should use the above Table 8-3 with the index from 1975 to 2017, i.e. a factor of 7.22.

The following graph shows the differences in escalation indices based on the standard IPD-based "market basket" and the "nuclear market basket" created for use in this report:

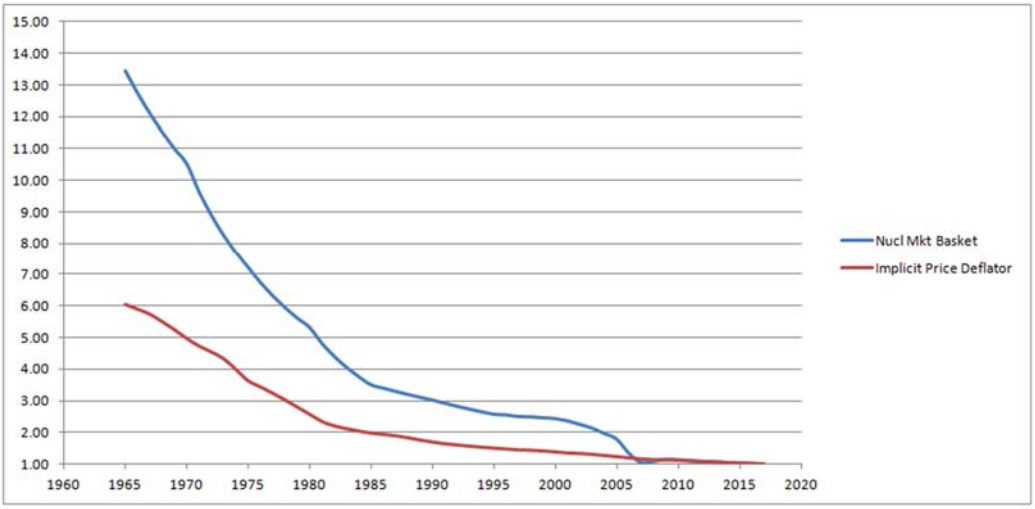


Figure 8-3. Comparison of escalation factors based on IPD and Nuclear "Market Baskets".

9. DISCOUNT RATE FOR NUCLEAR ECONOMIC ANALYSIS

This section presents a topic that was not included in previous AFC-CBR updates, but that is of importance in the economic analysis of nuclear fuel cycles. The conclusions and the suggested values for the practical use of discount rates in the economic analysis of nuclear fuel cycles are based on previous studies on the topic including Chicago (2004), MIT (2003, 2009, 2011), and Arrow (2012), and on the AFC-CBR team's considerations on this topic. It is expected that information on this topic will continue to evolve as new discussions and contributions emerge in the financial and nuclear communities.

9.1 Background Information

The old adage "a bird in the hand is worth two in the bush"[13] illustrates people's preference for the certain over the uncertain because the in-hand, certain bird is twice the value of the uncertain birds in the bush. The past and present are by definition certain so uncertainty is really a characteristic of the future. It follows, then, that since people value certainty over uncertainty, they also value the present over the future (Hansen, 2015). Discounting is the analytical tool whereby the analyst can weight uncertain future cash flows in terms of preferences for the present.

Suppose you have $100 in cash that you can either spend today or deposit in the local bank for 10% annual interest. In making your choice you evaluate what you could do with the $100 now or during the next year versus having $110 at the end of one year. If you left the money in the bank for another year the sum grows to $121 and again you compare the sum to what you could have done with $110 in the intervening year. People who save money recognize this as simply the time value of money where the future value *FV* of the present value sum *PV* grows at a defined rate of interest *r* over the period *t* as in:

$$FV = PV\left(1+r\right)^{t}. \tag{1}$$

The same logic can be used to determine the *PV* of a future sum by simply rearranging the equation as in:

$$PV = FV\left(1+r\right)^{-t}. \tag{2}$$

In discrete terms equation (2) is the mechanism to translate a sum in the future to a value that is meaningful in terms of the present.[14]

Discounting is relatively straightforward; whereas equation (1) identifies the value of money in the future equation (2) reverses the calculation to identify the value of future money today. In the previous example *r* was an interest rate that fit into equation (1) to determine how the $100 deposit grows over time. But in equation (2), as a discount rate, *r* is the rate at which future value is translated into present value. To determine *r* for equation (1) simply call the local bank to find out the rate of interest paid on deposits at that institution. Determining what *r* should be in equation (2) is not such a simple task because it is accounting for opportunity cost and risk. That is the value of the foregone benefits that could have been realized had the sum not been deposited in the bank are what economists call *opportunity cost.* By depositing your $100 in the local bank you risk the chance that you may have been better off using the money in alternative rather than depositing it in the local bank. The trick with discounting is in choosing the rate that best reflects the project's (or investment's) level of "riskiness."

13. Found in John Ray's 1670 Handbook of Proverbs.
14. If the analysis treats time as a continuous variable (as opposed to discrete) then the discounting equation becomes: $PV = FVe^{-rt}$.

A survey of over 2,000 economists verified that wide disagreement exists over what should be the appropriate discount rate (Weitzman, 2001). Although the economists surveyed disagreed about what *r* should be they agreed on what *r* should reflect. Their consensus is founded in the seminal work on the theory of optimal savings (Ramsey, 1928). More recently the U.S. Environmental Protection Agency (EPA) convened a meeting of 12 eminent economists to inform on the state of the art in discounting. The meeting is summarized in Arrow (2012). Similar to the survey of economists, the leading scholars on discounting did not agree on what should be the value of *r*. But like the survey they agreed that *r* should be based on the Ramsey theory of savings.

Ramsey (1928) identified the optimal savings rate so that savings and consumption maximize well-being of all present and future citizens. Based on the theory *r* should reflect two things that economists call the rate of time preference and the weighted marginal utility of future consumption. Time preference can be interpreted two ways (Hansen, 2013). People are generally impatient and prefer not to wait for things, and they are generally averse to deleterious events like death, war, disease or other unwanted events. The component of *r* that belongs to time preference discounts future well-being (Heal, 2007). Marginal utility captures the degree than future generations will be better off than present generations and the weighting on it captures society's risk aversion with respect to consumption (Hansen, 2013). Here risk aversion in consumption means that the utility of money in the hands of a low income person may not be the same as the utility in the hands of a wealthy person. Therefore the second component of *r* discounts future consumption, weighted by how people value consumption (Heal, 2007).

The two components of the discount rate point to perceptions of risk. Ramsey's model is based on conditions of certainty – and even under that assumption risk emerges as a contributing factor to the discount rate. Relax this assumption to conditions of uncertainty to see that discounting is a mechanism to account for risk in uncertain futures. For any investment the risk is that an alternative may have turned out better – that is for any investment there is an opportunity cost. Discounting accounts for the risk that the alternative investment would have performed better. The disparity of viewpoints on the part of the economists in the survey and in the EPA meeting noted earlier stems from how best to account for risk. Unlike an interest rate that is established in highly functioning capital markets, the discount rate is based on project riskiness. Determining a project's level of risk, and the discount rate to match it, is where the straightforward procedure of equation (2) becomes complex. Which rate to choose?

Figure 9-1 shows the implications of various discount rates. For simplicity suppose the cash flow under evaluation is an annual payment of $100 for the next 100 years. The solid blue line at the top of the figure shows the *PV* of the annual payment where the discount rate is 0%, which is to say no discounting is applied. The annual payment of $100 is worth the same in each year as it is in the initial year. By comparison, the dashed purple line shows how the *PV* changes with a discount rate of 10%. In year 10 the *PV* of the sum is essentially half the original value. The line shows that the *PV* of $100 in year 10 is $50. By year 97 the *PV* of the sum is about a penny. The figure illustrates the mechanics of discounting. The higher the discount rate the lower the *PV* of future cash flows.

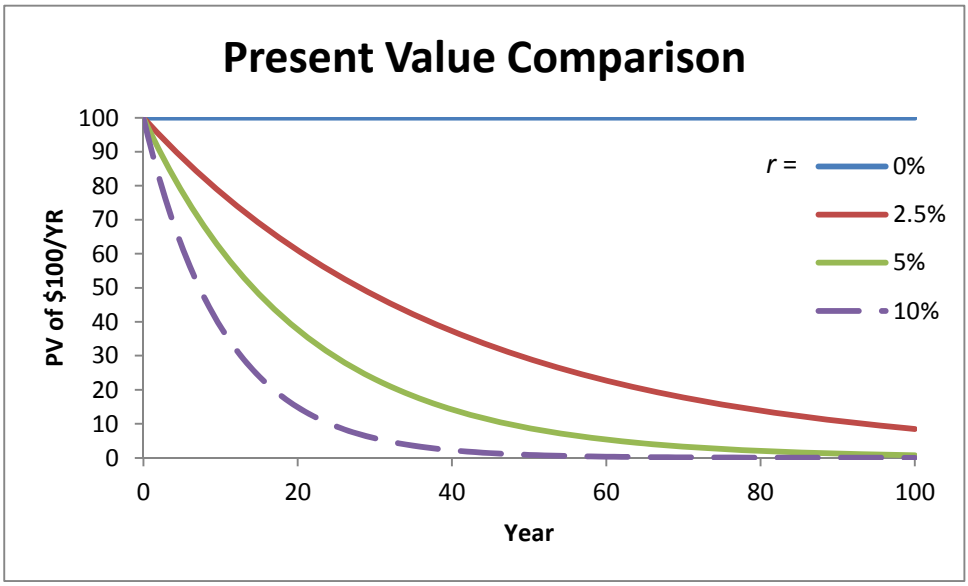
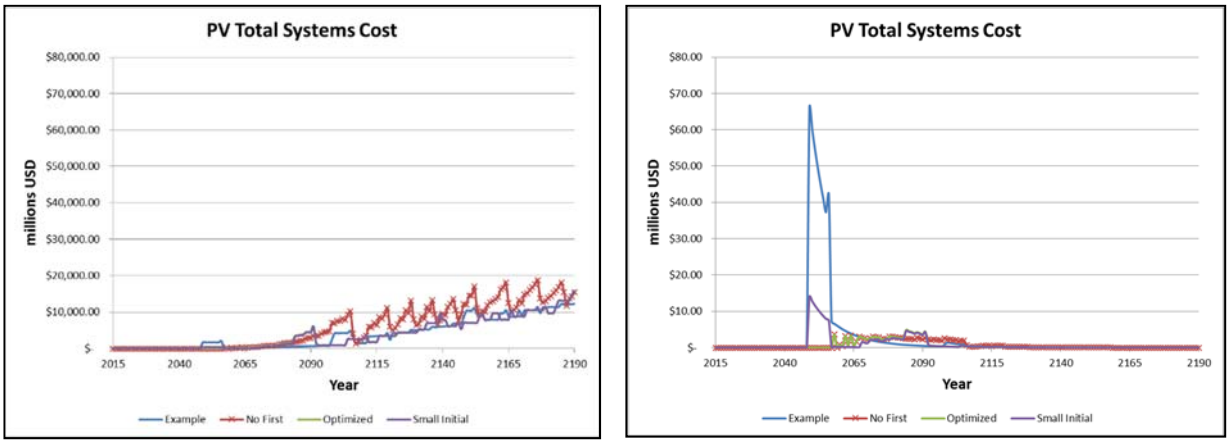


Figure 9-1. PV comparison of an annual payment of $100 over 100 years.

In 2016, EWG researchers conducting analysis on the economics of transition compared four alternative deployment schedules for fuel separations facilities (Dixon 2016). In this analysis the usage cost of LEU fuel (and its accompanying storage) was traded off against the cost of building separations facilities. Because the research question involved cost comparisons over long time horizons (up to 185 years) the analysts applied a 5% discount rate, then conducted sensitivity analysis using a 0% and 10% rate, both consistent with the Cost Basis Update (Dixon 2015). Figure 9-2 is reproduced from that analysis.



(a) r = 0% (b) r = 10%

Figure 9-2 Sensitivity Analysis; testing the sensitivity to the discount rate (Dixon et al., 2016)

The figure illustrates how the discount rate changes the shape of the cost profile over time. In the case of zero discounting, costs escalate with a steady trend, particularly in years beyond 2090 when the number of separations facilities increases with the rate of transition. These are costly facilities and the increasing trend in panel (a) reflects this. (For this discussion on discounting, the specifics on the alternatives are not necessary). Now compare the increasing trend from panel (a) with the decreasing trend from panel (b) where a 10% discount rate is applied. Over the time frame where facility

deployments strongly get underway, the higher discount rate choice essentially "discounts away" the large costs of separations modeled to occur in the next century.

The remainder of this section discusses issues to consider in choosing the discount rate for analysis of investments in nuclear technology made by firms in the private sector and by the government in the public sector. The section addresses issues by sector where investments originate because of how risk is accounted for in each sector.

9.2 Discounting in the Private Sector

In the private sector the expected rate of return on investment *i* (R_i) factors into the choice of discount rate because it represents the firm's opportunity cost from investing in project *i* (Brealey, 2003). Similar to the two components of the discount rate mentioned previously (time preference and utility in consumption), the following equation shows the expected return on investment *i.* It represents how the firm chooses the discount rate.

$$R_i = RF + RP_i \tag{3}$$

In equation (3) RF represents the risk-free component of the discount rate and RP_i represents the risk premium associated with investment *i*. RF can be thought of as reward to investors for postponing consumption and RP_i is the reward for investing in a risky project (Hirschey, 2003). Convention is that RF is typically estimated based on the interest rate paid on short-term US government securities (Hirschey, 2003). Where feasible the Capital Asset Pricing Model (CAPM) is used to estimate RP_i.

The CAPM is used to estimate the expected return on an investment. It is based on the covariance of the investment's risk with market risk. From the CAPM

$$RP_i = \beta_i \left(RM - RF \right), \tag{4}$$

where RM is the market return and β_i is the covariance between investment *i* and the market return. In this model project "betas" are measured econometrically by analyzing the historical relationship between market returns and returns on investments similar to *i*. Projects with $\beta_i < 1$ have less risk than the average risk in the market. Projects with $\beta_i = 1$ have the same risk as average market risk and projects with $\beta_i > 1$ are more risky than market returns.

Applying standard financial theory, based on CAPM, to assess the risk premium for nuclear projects is more challenging than for projects like say a grocery store because of β_i in equation (4). For investments that are widespread in the economy, like grocery stores, ample data exists to econometrically measure the covariance between grocery store success and market success, the β_i. And data is needed to estimate it. Sufficient data is the limiting factor to estimate β_i for a nuclear investment (Chicago, 2004).

Because of the difficulty in measuring project betas for nuclear investments, and therefore the correct risk premium, the weighted average cost of capital (WACC) is a reasonable alternative to choose the discount rate. The WACC can be estimated from data of publicly traded utilities and can therefore proxy for nuclear investments. The standard formula for the WACC is shown in Equation (5),

$$WACC = C_E \frac{E}{E+D} + C_D \frac{D}{E+D}\left(1 - tax_{rate}\right), \tag{5}$$

where C_E and C_D are the costs of equity and debt, E and D are total dollar values of equity and debt of the representative firm, and tax_{rate} is the he tax rate of the representative firms. Equation (5) is based on the fact that, under current U.S. fiscal laws, interest paid on debt is tax-deductible.

The firm's cost of capital, represented in equation (5), is the opportunity cost of capital for the firm's investments. If a firm uses debt financing the expected rate of return on the publicly traded equity is not the same as the return on its assets. The riskiness of the equity is higher because of the financial risk introduced by the use of leverage. In principle, the WACC (including all the existing securities such as common and preferred equity, and debt) should not change if the mix of debt and equity is altered since the riskiness of the underlying assets has not changed (Modigliani 1958). The riskiness of the traded securities may change but the risk in the underlying project has not.

The following sections address considerations and conclusions on the topic of discount rates for nuclear energy projects reported from studies that have presented the topic (Chicago, 2004; MIT 2003, 2009, 2011).

9.2.1 The Chicago Study

A key observation in the Chicago study (Chicago, 2004) is that there is lack of quantitative relationships in the financial literature between risk and risk premiums, as applicable to nuclear projects. This is because a large component of financial risks for nuclear projects is non-systematic rather than systematic. It means that risk in nuclear projects has more to do with project risk than with market risk. This renders the primary tool of modern financial theory of risk, based on correlation of individual securities with market risks (the betas), inapplicable to quantifying financial risks for nuclear projects.

Another important consideration regards the asymmetry of risks for nuclear projects (Chicago 2004). Construction delays and regulatory hurdles, for example, lead to dispersion in possible returns (Chicago, 2004). The effect of different outcomes can be estimated by a weighted average of the returns of each outcome and discounted at the market risk such that a decision tree of possible outcomes results. For projects that entail a non-negligible downside risk (e.g., a nuclear project prevented from operating, and thus prevented from recovering the invested capital, after being constructed), the equivalent discount rate, calculated from such a weighted average, will be higher than the market risk used to discount each branch in the tree.

In this case, it is possible to estimate the higher opportunity cost of capital, r_{Risky}, as shown in Equation (6).

$$r_{Risky} = (1+r) / \left[p_s + (1-p_s)\, f_L \right] \tag{6}$$

Here p_s is the probability of the investment being successful (e.g., a nuclear project finished on time, and starting operations as expected without unexpected cost increases or project delays) and f_L is the fraction of the total investment recovered if the project is not successful (this can also be negative, e.g., if decommissioning costs are incurred if an operational license is not issued).

With regard to the appropriate cost of capital for nuclear projects the following characteristics are listed as advantages and disadvantages based on an investor perspective in Chicago study.

Advantages that reduce investment risk:

- Low and predictable fuel and operation and maintenance (O&M) costs;
- High capacity factor (the current fleet of LWR in the U.S. has been operating at capacity factors above 90% for several years);
- Long Operating Lifetime (currently up to 60 years).

Disadvantages that increase investment risk:

- Large plant sizes (1000-1350 MW_e) and correspondingly large capital outlay (large specific and total unit costs);
- Long construction time (at least twice as long as for combined cycle gas-fired plants). Construction projects for new reactors are assumed in Chicago (2004) at 7 years, in an attempt to cover the entire time range over which construction-related expenditures occur, including the construction start-up phase, the construction and procurement phase and the plant start-up and testing. Expenditures are assumed to occur equally over the construction time.
- Higher specific capital at risk and interest during construction: recent consolidation in nuclear plant ownership should alleviate some of the investment-financing hurdles (based on 2004 data, 13 utilities accounted for 75 of the 103 U.S. reactors), since a larger net worth should make it easier to finance large capital investments.

9.2.2 WACC Numerical Values

The recommended cost of debt and equity from the Chicago study is based on 2004 data from the publicly traded utilities in the US. Financial terms for foreign projects are not necessarily a good guide for the terms that would be appropriate to domestic nuclear projects since at least the following differences exist (Chicago, 2004):

- Differences in business practices and climate;
- Varying degrees of government involvement in nuclear projects and different regulatory regimes.

The costs of debt and equity for US utilities as reported by Bloomberg in 2004 and adjusted from the reported after-tax to the pre-tax rate, is 5.34% for debt and 8.63% for equity. In equation (5) the tax rate is subtracted so the rates in Bloomberg need to be adjusted for the tax effect. However, it is noted that the Bloomberg data are calculated from the spreads over treasury bonds with 10 years maturity, so there is a need to convert those data to a longer maturity to reflect the longer duration of nuclear projects. For this reason, the Chicago (2004) study recommended to add a 0.5% to 1% extra cost of capital to these values of WACC. Additionally, according to Chicago (2004), another 0.5% should be added to the reported rates to account for the abnormally low rates present in 2004, yielding a nominal cost of debt of 6.35 and 6.84% and a nominal cost of equity of between 9.64 to 10.13%. In the Chicago (2004) economic study and calculations, these values have been rounded to 7% and 10%. It is noted that these are nominal rates, (i.e., including the inflation rate). It is also noted that, while these values are justified in the text (see Section 5.4.2.2 in (Chicago 2004)), they appear inconsistent with values given in other parts of the report, such as for example in Table 5-1 in Chicago (2004), and in Section 5.4.3, where values of 15% for equity and 10% for debt are reported.

9.2.3 Debt to Equity Ratios

While there is copious financial literature on the topic of debt/equity ratios, according to the Chicago study proof of a clear target by companies has not been found and/or established. The ratio (in (Chicago 2004)), has been therefore taken to be the average of the utility sector as of 2004, or 50%-50%. Changing the assumption about the ratio will have an impact on the WACC. Here the 50-50 ratio is recognized as a general indication, and is affected by many factors, including the taxation environment of a particular period.

The ratio will vary with the type of financing packages put in place. For example, most nuclear power plants in operation today were built in regulated utility markets where the existing customer base was known providing the utility with an accurate representation of and guaranteed future revenue stream

(IAEA, 2008). This stability reduces the risk premium necessary to attract financing from equity and debt. In today's environment where power plants may be located in de-regulated electricity markets equity investors will likely demand larger risk premiums than was the case for reactors in operation today. Increased risk premiums demanded by equity investors will therefore make debt a more attractive option for capital finance. Greater use of debt over equity will reduce the WACC.

9.2.4 Regulation

Regulation of the electricity markets, including both rate of returns and retail prices, has tended to reduce cost of capital for the regulated utilities, by shielding them from market price risks (Hogan, 2002). In regulated markets where the regulator guarantees the utility a constant rate of return the utility faces less risk. This reduces the cost of capital. However, the risk of having some of the costs disallowed from the rate base is still occasionally present in certain projects for regulated utilities. Regulation that prohibits cost being passed onto rate payers may increase project risk and therefore the return demanded by both debt and equity holders.

9.2.5 The MIT Studies of 2009 and of 2011

Important considerations in these studies regarding the appropriate discount rates are the following:

- "…the aggregate social cost of a nuclear fuel cycle must be evaluated using a cost of capital comparable to what would be employed by any commercial entity".
- "The cost of capital is meant to reflect the full set of risks borne by society associated with the activities of the fuel cycle, and so should not be changed to reflect changes in who bears this risk".

The reasons for this, as reported in MIT (2009), are the following:

- State ownership of nuclear assets does not necessarily imply a lower cost of capital. Arguments for that are often based on considerations such as the following (as examples):
- "Governments do not pay taxes, so they need a lower rate of return to recoup their costs"; However, MIT (2009) argues that the fact that taxes are charged or not to state-owned entities "… have nothing to do with the true social cost of the commercial activity making up the nuclear fuel cycle. It is the true social cost that ought to be guiding public policy".
- "Governments can bear a higher risk than private enterprises, so they need a lower risk premium". However, modern developed capital markets allow investors to diversify risk to a degree that renders this argument invalid.
- Based on similar considerations, it is often argued that utilities operating in a regulated environment face less risk than utilities operating in a deregulated environment. However, from MIT (2009) "… similarly, while certain regulatory structures may lower the amount of risk borne by private investors, thereby reducing the rate of return they need to earn to recoup their investment, this is done by shifting that risk onto ratepayers". "The total cost borne by society is not lower due to the regulatory structure, and this total risk is what should matter for a public policy evaluation of alternatives".

The same numerical values for the discount rates used in MIT (2003) are also used in MIT (2009) and MIT (2011): 10% nominal cost of capital and 3% inflation rate. The 10% nominal cost of capital is obtained from a 8% cost of debt and 15% cost of equity, 50% financing of debt and equity and 38% tax

rate, according to equation (5). The 15% cost of equity is justified based on the higher perceived risk of nuclear projects as compared to the standard riskiness of the generating portfolios of traded utilities. This leads to a nominal discount rate of 7.6% (MIT 2009, 2011).

9.2.6 A Note on Alternative Approaches to the Pricing of Risk for Nuclear Projects

The riskiness of nuclear projects decreases once the construction of the infrastructure is completed, the operational license has been granted and normal operation has begun. It is apparent that, upon successful completion of these steps, the riskiness of the cash flow is substantially lower than before construction, when many uncertainties are present, not least the regulatory and technical ones. It may therefore be justified to use different discount rates for different phases of the projects, to reflect the changing degree of riskiness once a different amount of information is obtained. In this case, the cash flow would have to be weighted for the probabilities of different outcomes, such as the probability of not obtaining an operational license. The discounted cash flow at lower discount rate would then have to be further discounted back at the higher discount rate to the time of the decision making, or beginning of construction, and weighted by the probability that the license for the operation of the facility would be granted after construction is completed (Brealey 2003).

9.2.7 Recommended Discount Rate

The previous sections have discussed a number of considerations on the topic of the appropriate discount rate for nuclear projects, as raised in previous studies. The discount rate values suggested in this section are based on the conclusions of the aforementioned studies and on the AFC-CBR team's considerations on this topic. It is expected that information and recommendations on this topic will continue to evolve as new discussions and contributions emerge in the financial and nuclear communities.

Table 9-1 summarizes the numerical values for the cost of capital suggested in the Chicago and MIT studies. The nominal and real costs of capital are highlighted, ignoring the effect of taxes. While it is recognized that taxation can alter the financial framework for nuclear projects as owned and operated by private players, it is also noted that taxes are country specific, and subject to change with the prevailing fiscal regime and taxation laws. It is the purpose of this document to provide the basis for the long term economic evaluation of nuclear fuel cycles: for this reason, it is recommended to avoid the inclusion of the effect of taxes on the cost of capital when performing the types of analyses for which the values proposed here are intended.

Table 9-1. Summary of numerical values for the cost of capital suggested in Chicago (2004) and in MIT (2003, 2009, 2011).

	Chicago Bloomberg[1]	Chicago Base[1]	MIT (2003, 2009, 2011)
Cost of Equity	10%	15%	15%
Cost of Debt	7%	10%	8%
Debt to Assets Ratios	50%	50%	50%
Nominal cost of capital ignoring taxes	**8.5%**	**12.5%**	**11.5%**
Inflation rate	3%[2]	3%[2]	3%
Real cost of capital ignoring taxes[2]	**5.3%**	**9.2%**	**8.2%**
Tax rate	38%	38%	37%

1. Bloomberg values are justified based on 2004 data provided by Bloomberg in (Chicago 2004), Base values are simply provided in Table 5-1 of (Chicago 2004). See discussion in paragraph "*WACC numerical values*".

2. The inflation rate for the Chicago (2004) values is taken as that suggested in the MIT study.

Based on the previous discussions, it is recommended to use the WACC of publicly traded U.S. utilities as the reference discount rate, or *5.3%* in real terms from Table 9-1, rounded to *5%*: it appears the most justifiable, being based as much as possible on observed data. However, it is noted that no utility is currently a "pure nuclear player", and therefore the cost of capital of utilities is just a proxy for the appropriate risk-adjusted cost of capital of nuclear project, which may as well be as high as the higher values in Table 9-2. For this reason the *Chicago Base* value, being the highest at 9.2%, is recommended as the high value, and rounded to 10%.

In light of the high uncertainties surrounding these values, it is recommended to use a set of values for the opportunity cost of capital, as shown in Table 9-2.

Table 9-2. Suggested real discount rates.

	Upside (Low Cost)	Downsides (High Cost)	Selected Values
Real cost of capital ignoring taxes	3% Risk free rate: investors are compensated for delayed consumption but not for risk associated with the nuclear investment	10% Highest value in real terms between the Chicago (2004) and MIT (2003, 2009, 2011) studies from Table 1, rounded up from 9.2%.	5% WACC of publicly traded U.S. utilities in 2004, as provided by Bloomberg and adapted using realistic long-term financial data in Chicago (2004); rounded from 5.3%.

9.3 Discounting in the Public Sector

Transferring risk from utilities to society (e.g. government loan guarantees) requires a treatment of risk from society's perspective. Whereas the previous section addressed risk premiums and discounting from the firm's perspective this section considers risks that discounting should reflect from society's perspective. For example, government responsibilities such as spent nuclear fuel disposal require discounting based on risk accounting from the public's perspective. Additionally, public funding may be required for nuclear investments where the cash flows are distributed over a very long time. Therefore this subsection discusses a starting point for discounting public investments in nuclear energy then presents the current state of the art with respect to discounting over very long time frames.

9.3.1 Discounting US Federal Projects, OMB Circular A-94 and A-4

The US Office of Management and Budget (OMB) published two circulars that outline how the discount rate should be selected for analysis of federal projects. Circular A-94 outlines policies and protocols for conducing benefit cost analysis and cost effectiveness analysis. Discounting is an integral protocol to these methods of analysis (OMB 1992). Circular A-4 describes how to conduct regulatory impact analysis, of which discounting is also a part (OMB 2003). Taken together A-94 and A-4 describe US policy for selecting a discount rate.

Benefit-cost analysis, as described in A-94, identifies net benefits in monetary units accruing to society for investments undertaken by the federal government. The document indicates that benefits and costs, monetized in dollars, should be discounted at a "real" discount rate of 7%. The terminology of "real" or "nominal" distinguishes discount rates where inflation is removed from the discount rate (the real discount rate) versus the case where inflation is reflected in the rate (the nominal discount rate). The document notes that government investment displaces private investment and consumption and that 7% approximates the marginal pretax rate of return on the average investment had resources remained in the

economy. Then A-94 calls for sensitivity analysis where the outcomes of interest are evaluated under a range of discount rates.

Cost-effectiveness analysis is used to evaluate projects where either monetary benefits are constant or where benefits are measured in units of effectiveness. Suppose several alternatives provide an identical stream of monetary benefits but vary in costs. Then A-94 directs the analyst to use cost-effectiveness analysis. Or suppose the alternatives generate non-monetary benefits, such as lives saved. Then costs of each alternative are compared to the units of effectiveness. In the case of cost-effectiveness analysis A-94 directs the analyst to Appendix C[15] where a list of discount rates is provided consistent with maturities of US treasury notes and bonds: 3 years, 5 years, 7 years, 10 years, 20 years, and 30 years. The analyst chooses a discount rate based on the time horizon of analysis and the maturities listed in Appendix C. In real terms the A-94 recommended real rate for projects with maturity close to 30 years is 1.4%.

At first glance of the recommended discount rates from A-94 there could appear to be a contradiction; a wide disparity exists between 7% (the recommended rate for benefit-cost analysis) and 1.4% (the recommendation for cost-effectiveness analysis). The former discounts alternative flows of monetary benefits and costs over time. The latter discounts alternative flows of costs over time. Keeping in mind the notion of opportunity cost relative to the next best alternative, A-94 recommends discounting benefits at a rate commensurate with benefits that may have been realized if resources would have remained in the private sector. The recommended 7% is based on the average pre-tax rate of return. By contrast in cost-effectiveness analysis benefits are not discounted. So discounting costs is based on the rate the government must pay to borrow money.

OMB Circular A-4 (OMB 2003) outlines considerations for the analyst identifying the impact of regulatory actions. Much of the protocol is similar to A-94 because measuring benefits and costs from regulatory action is analogous to measurement of impacts in federal projects. A-4 makes the same recommendation to use a real discount rate of 7% for the base case then recommends sensitivity analysis at 3%.

Circular A-4 brings up an issue not addressed in A-94 that economists call “intergenerational discounting.” A-4 directs the analyst to consider applying the same discount rate to cash flows impacting future generations but cautions against applying a lower discount rate at points in the far distant future because of the distributional and time inconsistency implications. A-4 is not clear on how to address discounting over long time horizons. The maximum time horizon addressed in A-94 is 30 years. But in reality the government makes investments where flows of benefits and costs are realized over time horizons much larger than 30 year. It is not surprising, then, that EPA convened the meeting of leading economists mentioned earlier to discuss intergenerational discounting.

9.3.2 Intergenerational Discounting

A summary of the meeting EPA convened on discounting can be found in Arrow (2012). The purpose of this meeting was to inform EPA on intergenerational discounting based on the expertise of the group of economists. Those called to the meeting were leading economists who have developed theories and models to better understand discounting.

The experts agreed on key, fundamental points regarding discounting. They agreed with the general premise of discounting grounded in the theory of optimal savings developed in Ramsey (1928), that this framework is the approach to maximize social well-being over time. They agreed that considerable uncertainty exists regarding future, social well-being of the society. One part of *r* discounts future consumption, which is based on economic growth and the well-being of future generations. The

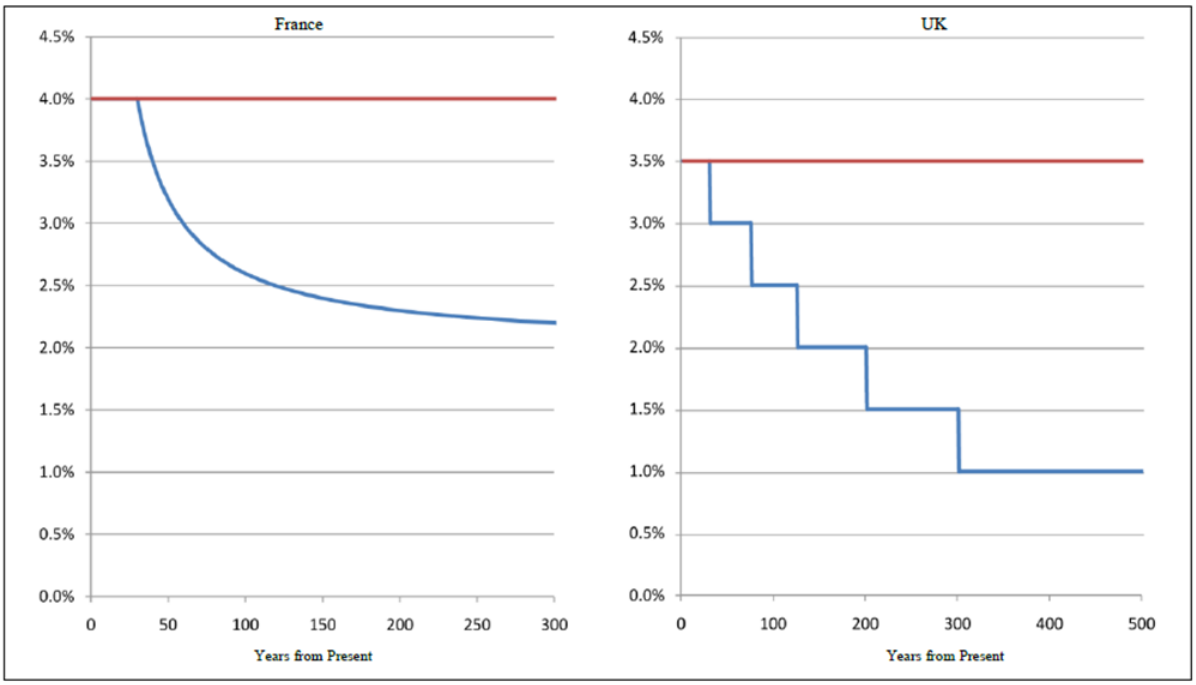
15. Appendix C available at www.whitehouse.gov/omb/circulars_a094/a94_appx-c , last accessed 13 August 2015.

uncertainty revolves around the fact that while societies have been continually better off according to the historic record, continued improvements is not a foregone conclusion. The odds are that future generations will be wealthier and thus better off than the present but the rate at which that growth occurs is uncertain. Uncertainty about that growth induces uncertainty about what is the correct rate to discount benefits and costs that accrue to future generations. Because of this uncertainty the experts agreed that a "precautionary" term should be subtracted from the discount rate. The precautionary term is based on what the economics literature calls "precautionary principle" (Mankiw, 1981). This term accounts for uncertainty, thereby reducing the possibility that the discount rate chosen is too high.

Further, the experts agreed that the precautionary term should not simply be a constant term to subtract from the discount rate. Instead the precautionary term should increase over time so that the discount rate itself declines over time. This leads to what economists refer to as the "declining discount rate" (DDR). So the collective opinion of the experts was that a DDR is appropriate for discounting cash flows in an intergenerational context, but what they did not agree on was how to parameterize the DDR.

The experts noted that two countries have adopted the DDR as the official policy regarding discounting. Figure 9-3, from Arrow (2012) who described it as sourced in Sterner (2012), illustrates the schedule of the DDR in France and the United Kingdom. The French policy regarding the DDR is set forth in Lebegue (2005) and the policy in the United Kingdom is in HM Treasury (2003). At least a couple points stand out as noteworthy. First, the schedules in both countries hold the DDR constant for approximately 50 years. This is consistent with discounting policy in the US (OMB 1992, 2003) discussed previously, and although the DDR begins at a lower rate than the recommended baseline of 7% in A-94 the starting point of the DDR is consistent with the range A-94 directs for sensitivity analysis. A-94 directs that sensitivity analysis be conducted at 3% relative to the baseline 7%. Another noteworthy observation is that the DDR for France and the UK both level off around year 300. In France it levels off slightly higher than in the UK, around 2.25% versus 1%. This is consistent with the interpretation of the summarized response of the survey of economists in Weitzman (2001). Weitzman interpolates from the responses that 300 years is the "distant" future and the discount rate should be 1%. However, in Weitzman (2001) points beyond 300 years are identified as the "far-distant" future and the accompanying discount rate is 0%.

With respect to the DDR, the point where the economists at the EPA meeting disagreed was on how the precautionary term should be parameterized. One group felt that identifying the rate at which the DDR should decrease should follow a prescriptive approach, such that parameterizing *r* should be a matter of policy. Another group felt that parameterizing *r* should follow a descriptive approach and therefore the parameters should be estimated from historical data, including bond rates and market rates of return.



Source: Sterner, Damon, and Mohlin (2012)

Figure 9-3. Declining Discount Rates in France and the United Kingdom (Arrow, 2012).

Arrow (2012) summarizes findings from the literature where the DDR has been estimated for the US. The studies are consistent with the two approaches to parametrizing the DDR, the policy approach and empirical estimation based on data. In review of the studies two insights emerge. Consistent with the policies in France and the UK, in the studies the discount rate is basically constant over the first 50 years of the time horizon. This is consistent with the current US policy on discounting (OMB 1992, 2003). Second, in the studies the DDR levels off around year 300 although this varies a bit based on estimation method. The studies estimate the DDR to begin at 4% certainty-equivalent discount rate[16] then it levels off in a range (0% to 2%) based on policy assumptions and estimation method.

Previously in this chapter the discussion describes the many factors that go into choosing a discount rate, and how the risk perspective influences the choice. The discount rate applied in the discounting formula contributes to a discount factor, which weights future values consistent with the factors that influence discount rate choice (opportunity cost, risk, borrowing cost, etc.). Adjusting the relevant factors of the discount rate leads to, at one end of the spectrum, a 0% discount rate while at the other up to a 10% discount rate. Figure 9-4 shows the effect of the discount rate on the discount factor. The factor illustrates the weight that future values carry in present value terms. Think of the discount factor as the percent of future costs that carry value today.

The figure illustrates how the discount factor, or in other words the weight that future values carry in today's terms, varies with the choice of the discount rate. Looking first at years 0 through 100 shows a fair amount of variation in the discount factor (the lines are spread apart.) This variation is largely what the discount discussion in the economics literature is about; which discount rate choice correctly reflects the underlying assumptions so that the factor accurately reflects the translation of future values to present

16. Certainty-equivalent is a form of adjusting the rate for risk.

terms. But also look at years 100 to 200, where there is scarcely any variation in the discount factors, and the present value collapses to zero. In analysis of nuclear fuel cycle transitions, 100 years-plus is the time frame where much of the cost analysis typically begins! This is the effect the sensitivity analysis shown in Figure **9-2** displays. Any non-zero discount rate weights future cash flows essentially to zero.

One practical impact of discounting in nuclear fuel cycle decisions is that up-front costs of implementing geologic disposal are so much larger than those of dry storage that economic analyses using non-zero discounting will usually favor storage, both for present decisions and future decisions, such as when fuel packaging may begin to degrade and require overpacks.

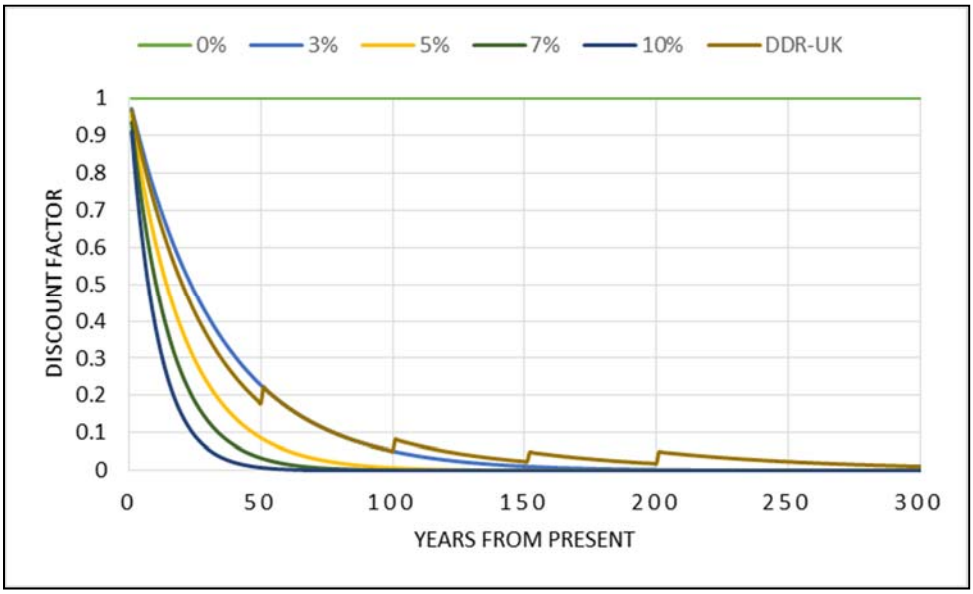


Figure 9-4 Discount Factor by Discount Rate

The Update discussed "Intergenerational Discounting." This is the branch of the literature that seeks to reconcile the need for discounting over time frames into the far distant future. The notion of a declining discount rate (DDR) stems from that literature. Conceptually the DDR decreases the discount rate over time so that the weight of the discount factor does not diminish as quickly with the passage of time. As the Update discusses, national policy in France and the UK prescribe a DDR for analysis of state programs. The discount factor that corresponds to the DDR in the UK is represented in the figure. It tracks similarly to its non-DDR counterparts in the first century of application, and similarly tracks in the second century, approaching zero in the third century.

This example illustrates the importance for the nuclear community to be involved in determining how best to translate cash flows in the far distant future to meaningful present values. Like the arguments regarding climate change mitigation, the benefits of nuclear choices today are long-lived into the future. Without being able to better translate those monetized benefits to meaningful present values, alternative nuclear designs will continue to have difficulty getting past the "kicking the can down the road" type of arguments.

10. TREATMENT OF UNCERTAINTY IN THE COST BASIS REPORT

10.1 Introduction

The objective of the Advanced Fuel Cycle Cost Basis Report is to provide a comprehensive set of cost data supporting an ongoing, credible, technical cost analysis basis for use by the DOE NTRD program. To be credible, this must include acknowledgement and treatment of the significant uncertainties associated with nuclear cost estimates for both existing and advanced systems. These uncertainties arise from multiple sources:

- Large variations in the estimated cost of current nuclear construction projects for similar NRC-certified designs due to differences in financing approaches, regulatory environments (e.g., regulated versus deregulated utilities), differences in grid connection costs, uncertainties of construction schedules, etc.
- Uncertainties for future projects driven by potential changes in designs, interest rates, regulations, construction techniques, fuel costs, competitiveness versus other energy sources, etc., especially when projects may not start construction for decades and the resulting facilities may operate for a half century or more. The future rates of construction and design innovation will also impact learning curves for transition from First-of-a-Kind (FOAK) to Nth-of-a-Kind (NOAK) facilities.
- Significant uncertainties concerning the specific design features and achievable performance of future full-scale facilities using advanced technologies that now have low technical maturities. Most advanced fuel cycles require multiple such technologies.

Due to the above uncertainties, it is unrealistic to expect the AFC-CBR could be used to accurately estimate the cost of an advanced nuclear fuel cycle system. Large uncertainties in the input cost data inevitably lead to large uncertainties in calculated systems costs.

Fortunately, accurate estimates are typically not required to support the NTRD program. Instead, it is usually sufficient to be able to estimate a cost range that includes associated uncertainty and identify the cost drivers. Per Section 1.3, 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.

10.2 Representation of Uncertainty in the AFC-CBR

Each module of the AFC-CBR includes two features that incorporate uncertainty into the recommended unit costs. The first is the "What it Takes" (WIT) table, which summarizes the major drivers for both up-side and down-side costs and provides high and low values along with (usually) a mode and a mean value to use for cost analyses. The intent is for the analyst to use value ranges when assessing system costs, or at least to perform sensitivity studies based on the cost ranges. The WIT is the module author's opinion or best estimate of the cost range indicated by the cost data collected in developing the module.

The second is a suggested cost probability distribution to use when the analysis tools support uncertainty propagation. Two forms of distribution are used in the current AFC-CBR; a uniform distribution using the high and low values from the WIT table and a triangular distribution where the based on the high, low and mode values (see Figures S-2 and S-3). It is incumbent upon the analyst to use these distributions with care, including testing the sensitivity of key data and even the distribution selection as appropriate for the application.

The cost probability distributions are deliberately simple to reflect the limited cost information typically available for each module. The triangular distribution allows for a modal value near the lower end of the uncertainty range when appropriate based on the available data (e.g., yellowcake prices) or

when there is large up-side technical uncertainty. When there are no such drivers, the mode value is near the middle of the range and provides an approximation of a normal distribution. As in the 2009 AFC-CBR, triangular distributions are used for all modules except modules B and C (Uranium Conversion and Enrichment), where market price data suggested the uniform distribution is more accurate.

The AFC-CBR team has noted that many users of the AFC-CBR have been ignoring the cost ranges and using just the mode values, resulting in "point" cost estimates that imply more accuracy than is credible.

10.3 Treatment of Correlated Uncertainties

The AFC-CBR team has noted that the cost uncertainties in the different modules may not always be independent and additive, as indicated in the summary of the 2009 AFC-CBR, but may instead be due to common causes. For example, changes in construction interest rates or concrete prices would impact the costs in most of the modules in a coupled manner - even though the scale of the impacts would vary, the direction would be the same. The impacts of these correlated cost factors are very difficult to assess without much more detailed cost code of accounts breakdowns than are currently available, but are important in that they are not additive when comparing costs across fuel cycles.

The inability to account for correlated costs is likely producing comparative system cost probability distributions that are wider than the actual uncertainties. This is of particular concern when developing relative comparisons of different systems, because it is hard to define and defend any cost advantages of one system over another when the probability distributions significantly overlap (see Figure 10-1 from Shropshire, et. al. 2009).

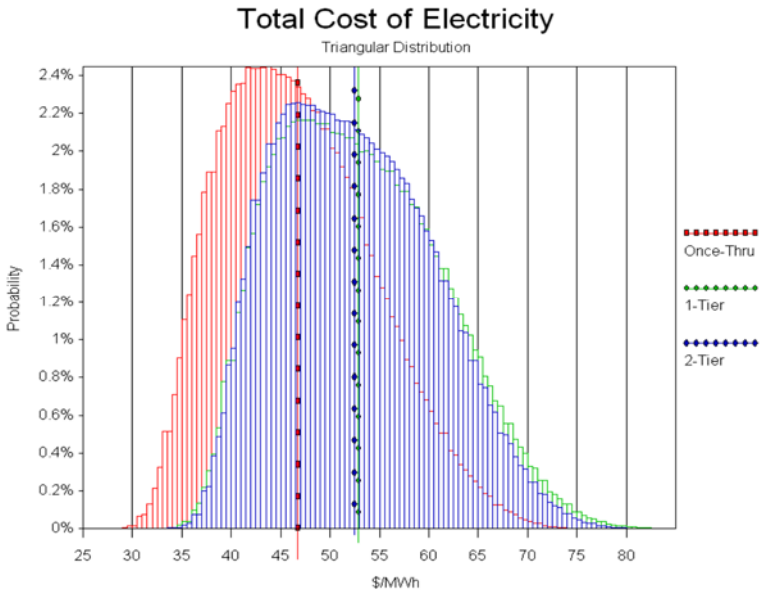


Figure 10-1. Cost comparison of three systems using cost probability distributions[17].

17. From D. E. Shropshire et al., "Advanced Fuel Cycle Economic Analysis of Symbiotic Light-Water Reactor and Fast Burner Reactor Systems", January 2009, INL/EXT-09-15254.
www.inl.gov/technicalpublications/Documents/4235622.pdf

Often with comparing nuclear energy systems, some components may be in common. For example, the three cases in Figure 10-1 all use an LWR in their first stage. When performing comparison analyses using the data from the AFC-CBR, the analyst is cautioned in such cases to treat common components as being correlated when appropriate (e.g., built at the same time, etc.). This will properly reduce some of the comparative uncertainty and narrow the comparative probability distributions.

While the correlations between systems using the same reactor types are obvious, other partial correlations also exist. In two of the cases in Figure 10-1, both LWRs and FRs are used. While the reactor core and coolant systems of these two reactor types are very different, the balance of plant (steam turbines, etc.) of all reactor types is very similar. This results in partially correlated costs between reactor systems. The AFC-CBR team is developing and testing partial correlation factors and associated application methods to enable more accurate comparisons of nuclear energy systems. The limiting factor in development, as in many other areas of nuclear cost analysis, is a lack of data on which to base the partial correlation coefficients. The AFC-CBR team is currently pursuing an expert elicitation approach for establishing these coefficients. Initial findings of this effort are in the material of supporting documents – see AFC-CBR section SD3.

11. MODULARITY ANALYSIS

Modular nuclear reactors have garnered considerable attention of late over the traditional single reactors for the production of electricity. Proponents have cited many potential advantages such as design simplification and standardization leading to reduced probability of cost overruns, shorter construction times, off-site-factory fabrication, foreign fabrication, cost-reduction from repeated fabrication and associated learning and process improvements, and lower and periodic capital requirements. A realistic economic analysis could, however, be useful to determine whether these advantages result in a more competitive nuclear reactor system leading to a lower price of electricity to the consumers while ensuring adequate profit to the reactor operator and reactor manufacturer, particularly in an environment where the price of electricity is controlled by deregulated market forces.

A realistic economic analysis could also account for several factors that influence the cost of construction of the reactor infrastructure and the reactor modules, the cost of nuclear fuel, the operation and maintenance cost, and the cost of borrowing. Modular reactors, because they typically have a smaller generation capacity than a single reactor (for example, the 12-module system of 50 MWe capacity each proposed by NuScale, as opposed to a single traditional unit of 600 MWe capacity), may also be configured differently in time. The example NuScale system could be constructed to start electricity generation either as a single-pack system at one site or as a multi-pack system with different modules coming into generation at different points in time at one site. Configuration flexibility, while offering more choices on how modularity is delivered to the utility and power to the customer, also poses important questions such as the economic feasibility of the different configurations and choice of an optimal system. An economic analysis could also verify the cost reductions, as claimed by the proponents, that may be achieved from learning and improvement following the fabrication of each successive module and the possibility that the balance of the site infrastructure (everything except the reactor) could be built initially and separately from the modules and turbines which would then be simply plugged in ("plug and play" concepts).

A systematic methodology for conducting an economic feasibility analysis for a modular reactor system is presented in the discussion below. The methodology is quite general and scalable in scope. It has been developed to address both the traditional reactor system and multiple configurations of co-located modular reactor systems; but a multi-site configuration is not addressed in the methodology. A number of endpoints could be used to compare a modular reactor system configuration with a single traditional reactor system or with other configurations of the modular reactor system. The levelized unit of electricity cost (LUEC), expressed as $/MWh, and the net present value (NPV) of the venture from a utility's perspective are the two primary endpoints that are used in the methodology.

The annual contribution to the levelized cost, *AC*, for a power plant can be estimated using the following equation:

$$AC = [CF + FUEL(F, p_F) + O\&M(L, p_L)]/E \qquad (7)$$

where *CF* is the annual cost to the utility from construction of balance of infrastructure and fabrication of reactor modules over the operational life of the reactor system ($); *FUEL* is the annual fuel payment ($) and it is a function of amount of fuel (kgU), *F*, and price of fuel ($/kgU), p_F; *O&M* is the annual operations and maintenance expense ($), which is a function of the amount of labor (person-h), *L*, and the price of labor ($/person-h), p_L; and *E* is the total energy output (MWh). LUEC is estimated as the sum of *AC*'s discounted to the start of commercial electricity generation at the discount rate *r* over the operational lifetime of the plant.

The annual profit of a venture, *P*, is estimated on an annual basis using the following equation:

$$P = E \cdot p_E - LC \cdot E \qquad (8)$$

where p_E is the price of electricity. The NPV of the power-plant venture is estimated as the sum of the *P*'s discounted to the start of commercial electricity generation at the discount rate *r* over the operational lifetime of the plant.

This formulation for the estimation of LUEC and NPV is currently in use for the traditional single reactor system (e.g., Rothwell and Ganda, 2014) in which CF is parameterized as the annual overnight cost. When extending the formulation to the modular reactor system, additional considerations need to be addressed. These include, as mentioned earlier, the addition of modules at different points of a system's operational life, the presence of a learning curve that allows the future modules to be manufactured at lower cost or in shorter time, and the specific financing arrangement a utility enters into with lenders. Treatment of these considerations within the framework of Equations (7) and (8) is presented below.

The annual cost to the utility from construction and fabrication consists of two distinct components – the modular reactor fabrication component and the balance of site infrastructure component. The cost for the modular reactor fabrication component is influenced by the specific financial agreement that the utility enters into with the manufacturer of the modules; however, it is estimated on the basis of how the utility finances the payments to the manufacturer. For example, the manufacturer could decide to sell each module at a fixed price regardless of when the modules are delivered and installed at the site. This option allows a manufacturer to take a loss with the initial modules, but as his cost goes down with the learning and standardization after each module, he is able to make profits on later modules. He uses this "loss leader pricing" strategy for market entry as he competes with other technologies in the energy sector. Alternatively, the manufacturer may offer to sell each unit at a price that includes his costs plus a fee provided the utility pays for the fabrication cost as it is incurred, thus reducing the manufacturer's burden of financing the entire fabrication cost up front. The latter transaction is adopted here to explain how *CF* is estimated for a modular reactor system. In both examples, the utility borrows from a lender to pay the manufacturer; again, the methodology presented here is conducted from the economic perspective of the utility.

There are three distinct periods in the lifetime of a module from fabrication to the end of operation. The first period is the pre-fabrication period in which the annual cost to the utility for a module *m* is zero; i.e.,

$$F_m = 0 \; for \; t < t_{SFm} \tag{9}$$

where F_m is the cost of fabrication during the fabrication period for module *m* ($); t is the time (y), $t = 0$ at the start of the construction of infrastructure at the utility's site; and t_{SFm} is the time at the start of fabrication (y).

The second period is the fabrication period; the fabrication occurs at the manufacturer's facility. As discussed earlier, the utility agrees to pay the manufacturer the quoted sales price which includes the fabrication cost plus a fixed fee; all costs up to the power production, including delivery, installation, and commissioning of the module are assumed to be included in the fabrication cost. Since the utility has also agreed to make the payments for the module during the fabrication process as the manufacturer incurs the cost, it borrows the entire amount of the sales price and makes interest-only payments to the lender during the fabrication period and makes fixed payments each year over the expected operational period of the module to pay off the loan. The interest-only part of the repayment during fabrication is similar to the credit card interest-only payment that leaves the principal unaffected. The full payment over the operational period of the module is similar to the home-mortgage amortization scheme in which a fixed payment that includes both principal and interest is made every year towards the loan.

The manufacturer's sale price, in turn, is a function of time and reflects the combined effect of cost reductions through repeated fabrication, installation, and commissioning of the module using a standardized design and associated learning after successful delivery of each module. To address the

overall reduction in cost and the sales price over the years, the manufacturer determines his sale price for module *m* according to the following equation:

$$S_m = S_0 e^{-k_L(t_{Pm} - t_{P0})} \quad (10)$$

where S_m is the sale price of the module ($) at time t_P, S_0 is the sale price of the module at time $t = 0$; k_L is a learning rate constant (1/y); and t_{Pm} is the time (y) at which the module *m* is expected to put electricity on the grid; and t_{P0} is the time when the manufacturer's first unit generated power at the Utility's facility (y). Thus, the manufacturer is able to reduce his sale price as a function of time and the value of k_L controls the speed of learning, higher k_L resulting in faster learning and faster reduction in the sale price.

The Utility's annual cost during the fabrication period for a specific module m is then estimated as

$$F_m = I_F \; for \; t_{SFm} \leq t \leq t_{Pm} \quad (11)$$

where I_F is the total of the monthly interests ($) the utility pays to the lender in a year on the principal S_m during the fabrication period.

The monthly interest rate can be estimated from the discount rate using

$$i = (1 + r)^{(\frac{1}{12})} - 1 \quad (12)$$

where *r* is the annual discount rate (%/y) and *i* is the monthly interest rate (%/m).

In the last period, which represents the expected operational period of the module, the utility repays the loan as a fixed annual payment, amortized over the expected operational period of the module so that

$$F_m = FCR \cdot S \; for \; t_{Pm} \leq t \leq T \quad (13)$$

where *FCR* is the fixed charge rate (%/y) and T is the expected operational life of the module. *FCR* is based on the discount rate and is estimated as

$$FCR = \frac{r \cdot (1+r)^T}{(1+r)^T - 1} \quad (14)$$

In a multi-pack modular reactor system, the values of t_{SFm} and t_{Pm} are module-dependent; i.e., they could be different for each module depending on when its fabrication begins and it starts loading power into the grid. The annual cost *F* depends on contributions from all modules, each module's contribution to the annual cost being evaluated on the basis of the applicable period of the module in the year being evaluated. Thus,

$$F = \sum_{m=1}^{M} F_m \quad (15)$$

where *M* is the total number of modules in the system.

The cost for the balance of infrastructure is also dependent on the specific agreement the utility makes with the lender. Assuming, as before, that the utility makes interest-only payment to the lender until the construction of the infrastructure is complete and pays a fixed annual amount thereafter, the annual balance of infrastructure construction cost can be estimated as

$$C = I_C \; for \; t < t_{P0}, \quad (16)$$

where C is the annual balance of infrastructure construction payment the utility makes to the lender and I_C is the total of the monthly interests ($) the utility pays to the lender in a year on the principal (the total balance of infrastructure cost ($),$C_0$), and the monthly interest rate to estimate I_C is the same as *i*, estimated using Equation (12). The construction loan is then fully paid off during the expected operational period of the facility as a fixed amount *C*, which is estimated as

$$C = C_0 \cdot FCR \; for \; t_{P0} \leq t \leq T. \quad (17)$$

The annual construction cost ($), FC, is then estimated as

$$FC = F + C. \quad (18)$$

Typically, LUEC is estimated in the year the plant starts commercial operation (e.g., Rothwell and Ganda, 2014). For a modular reactor system, it is possible to have different modules starting commercial productions at different points in time. For consistency in assessments and comparisons across different configurations, the LUEC and NPV should be evaluated in the first year that the system starts commercial production.

While Equations (9) through (18) have been developed with specific assumptions regarding financing, they are generalized enough that deviations can be accommodated easily. For example, if the utility does not incur any interest payments prior to the delivery and installation of a module, the annual cost of fabrication for each module will remain zero until the first generation of power from it. As explained earlier, the system of equations is also applicable directly to the case of a traditional single-module reactor; *CF* in Equation (7) can be directly estimated from the overnight cost. For a detailed and comparative analysis of the economic feasibilities of the various modular reactor systems and the traditional reactor system, a sensitivity analysis may be conducted to identify parameters that would most influence the LUEC or NPV. Parameters that may be tested include the learning rate constant, thermal efficiency of the system (which would directly affect the amount of fuel being consumed and, therefore, the fuel cost), time-dependent deployment of the modules (which would reflect differently on the cost profile over the operational period of the system), manufacturer's method of establishing module's sale price (e.g., a fixed sale price to take loss on initial modules and make profit on later ones), discount rate (to accommodate different financing schemes; e.g., different debt to equity ratios), and price of electricity (to account for effects on revenue stream under different configurations of modular system). Alternate estimates of these parameters may be developed to study their impacts on the LUEC and the NPV.

12. ECONOMIC COMPUTER MODELS

12.1 Integration of Cost Modules into Cost Models

The module-by-module unit cost information and general economic parameter 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. (Incorrect material balance.)
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 level and R&D funds needed.
7. Hidden/implicit assumptions
8. Impacts on processing efficiency resulting from future technologies.

12.2 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 NTRD cost data are described in the following sections.

12.2.1 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).

12.2.2 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.

12.2.3 Harvard Spreadsheets

The economic models used in the 2003 Harvard economic study, *The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel* (Bunn 2003), 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).

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

The International Generation IV EMWG has an EXCEL-based model called G4 ECONS (EMWG 2007) 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.

12.2.5 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 Spent Nuclear Fuel and HLW 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).

12.2.6 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 cost module called VISION.ECON was added to the Verifiable Fuel Cycle Simulation (VISION) model (AFCI 2005, Jacobsen 2005) for this purpose. This model was used to perform fuel cycle analysis in support of the AFCI Systems Analysis in

2008 (AFCI 2008). This model used the cost data from this report to analyze various fuel cycle alternatives. Results from the dynamic VISON.ECON were compared to the G4 ECONS model for verification purposes and to help in understand the impacts from modeling under dynamic conditions.

VISION.ECON was created as a submodel of VISION to provide economic analysis of nuclear fuel cycle cases. The submodel produced cost distributions for relative economic comparisons rather than absolute value cost estimates. VISION.ECON extended the modeling capability beyond static equilibrium analysis tools by providing insight to dynamic modeling impacts to cost over time. The tool included the functionality to evaluate cost and system uncertainties. Model output showing the total cost uncertainties of a case were generated within VISION.ECON in a post processing mode using a modified Monte Carlo method. Cost and system uncertainties could be used to identify the variables within the model that have the largest impact on the cost for each case. Updates of VISION.ECON were suspended in VISION version 3 and are not included in the current VISION release, but could be reactivated if need arises.

12.2.7 NE-COST

NE-COST was developed in 2012 to support the nuclear fuel cycle evaluation and screening; specifically for the calculation of the Levelized Cost At Equilibrium (LCAE) metric for complex fuel cycles. One design objective for NE-COST was to allow the calculation of the cost of electricity of arbitrarily complex systems by just changing the input, without the need to alter the code. For this purpose, an “island approach” was adopted where each stage of a fuel cycle can be calculated separately and the results combined. Figure 12-1 shows how the AFC-CBR modules in Figure 1-1 are modeled using the island approach for a three stage fuel cycle that includes a fleet of PWRs fueled with UOX feeding a fleet of PWRs fueled with MOX, which in turn feeds a fleet of burner fast reactors (Ganda 2012). To accommodate the island approach, the general structure of the NE-COST MATLAB code has been developed allowing several alternative front-end and back-end paths, which can be selected by the user by using switches in the input (see Figure 12-2).

NE-COST has been developed with the capability to handle uncertainty as a required functionality, through the capability (1) to estimate the magnitude and the functional form of the uncertainty in the calculated LCAE; and (2) to identify the biggest uncertainty drivers and their individual impact. To this end, the NE-COST structure has been developed specifically to handle distribution information. A Monte-Carlo sampler has been developed, as well as a methodology for the correct propagation of uncertainty between islands, to create a system-wide cost of electricity uncertainty distribution. A suite of tools have also been created to handle the stochastic combination of distributions and the plotting of the results.

NE-COST has been benchmarked against the well-established nuclear economic code G4-ECONS, as well as against previous economic analyses performed under the Global Nuclear Energy Partnership (GNEP) program. In both cases, the NE-COST results are in excellent agreement with the previously-obtained results.

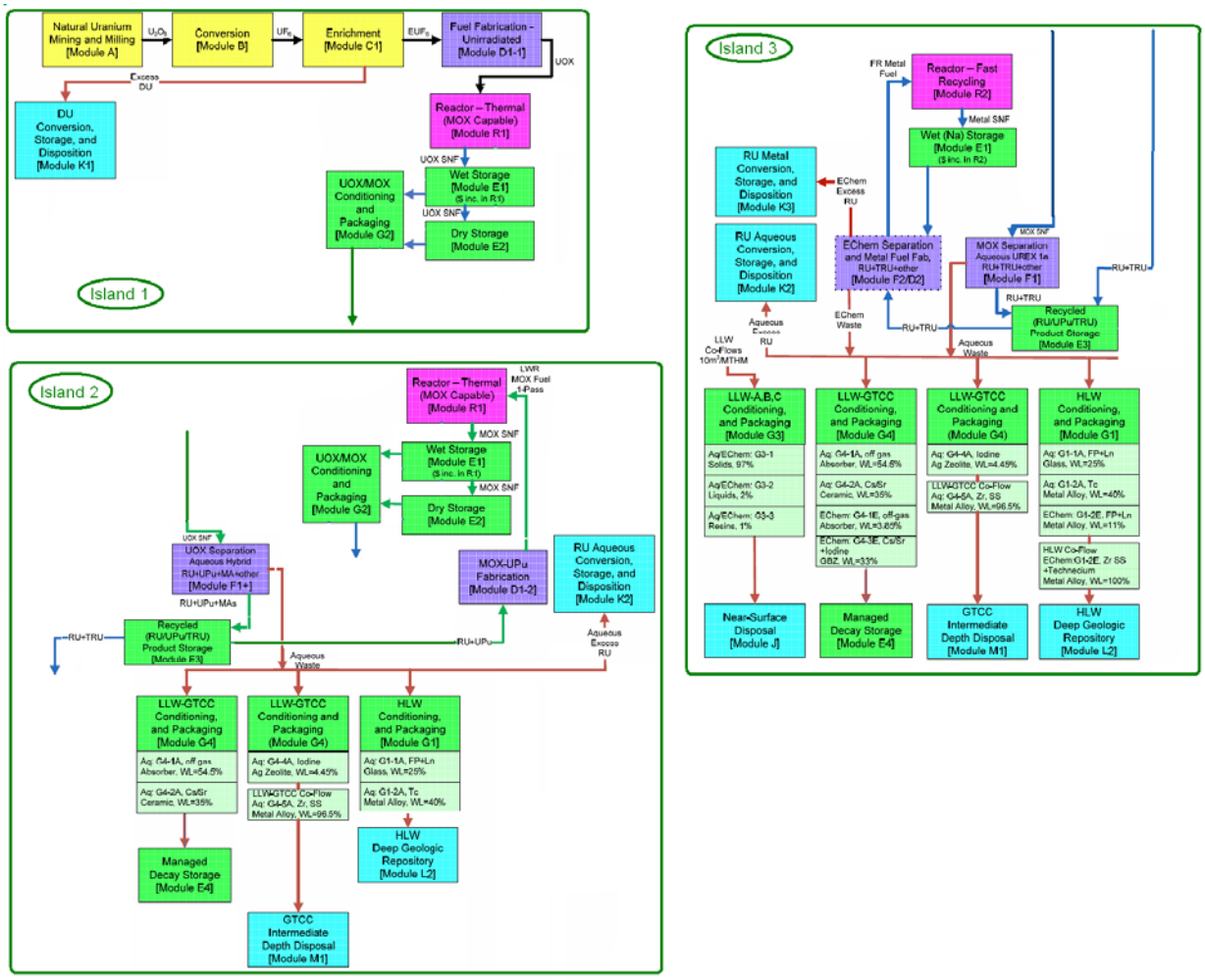


Figure 12-1. Schematic representation of a 3-stage fuel cycle using the island approach.

12.2.8 Additional Tools

Additional cost analysis tools are always under development by NTRD economics personnel to support specific cost evaluations. These typically are simple spreadsheets that are developed, validated, and used for a limited number of analyses. However, some may evolve into more general purpose tools that may be added to this chapter in the future. Several of the tools already in this chapter had similar beginnings.

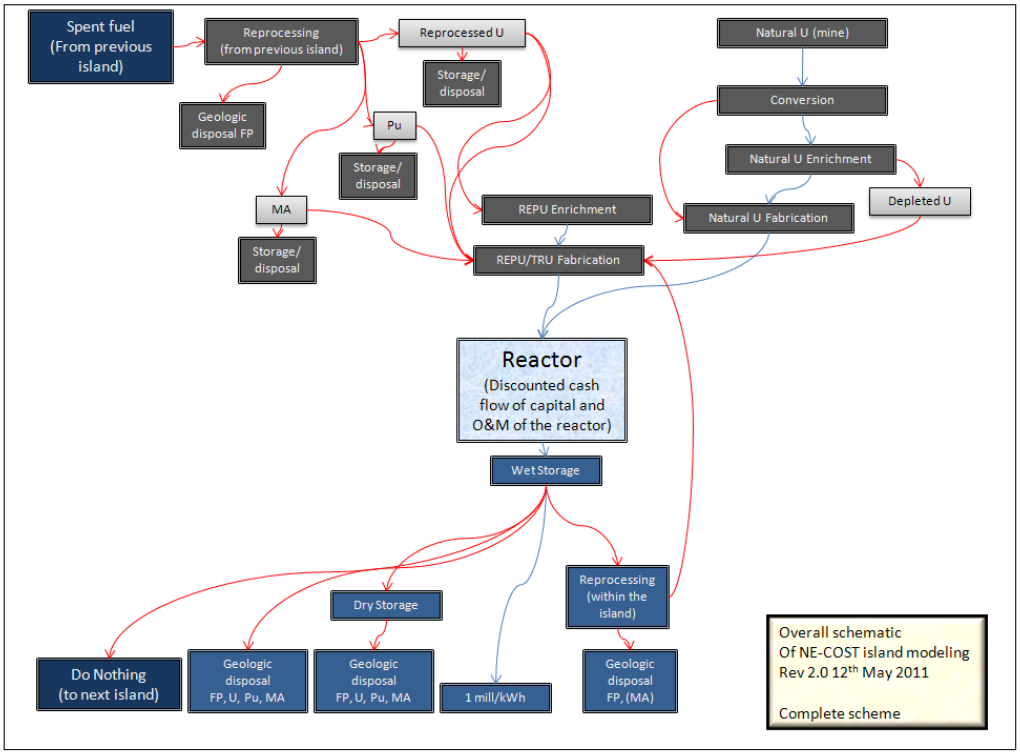


Figure 12-2. Schematic representation of the NE-COST structure.

13. CONCLUSIONS AND RECOMMENDATIONS

The NTRD 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.

13.1 Creation of a Credible Reference NTRD 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 NTRD Program. System analysts have used this report to evaluate the impacts and benefits of a wide range of nuclear fuel cycles and deployment scenarios. 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. 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 NTRD cost basis development process, reference information on NTRD 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 36 cost modules and sub modules—26 fuel cycle cost modules and 10 reactor/transmuter 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 NTRD cost developers coordinated closely with the Generation IV EMWG during the initial development of the AFC-CBR and adopted many of the EMWG estimating structures, assumptions, and estimating processes. Additional processed have been developed based on needs of the NTRD Program, including methods for assessing fuel cycles at equilibrium, during transition, and using modular implementation.

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” (WIT) values and a plausible cost distribution for a particular service, operation, or material. In most cases a cost or price 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" cost analysis models such as the Generation IV G4-ECONS reactor economics code. Due to the uncertainty associated with cost data, the use of codes with uncertainty capabilities, such as the NE-COST code are encouraged.

13.2 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 NTRD and interaction with other programs and organizations involved with nuclear cost analysis. Additional cost sensitivity and uncertainty analysis will be performed to expand the knowledge base. Additional studies are underway, including:

- Review of historic cost data to separate added costs of FOAK, regulatory, and special items that added to facility costs and construction times beyond the underlying base costs of those facilities.
- Development of methods for discounting that consider the risks inherent in nuclear facility projects while also incorporating the latest recommendations on discounting over very long time frames such as are expected for fuel cycle transition scenarios.
- Development of more specific imformation on facility capital and fixed and variable operating costs to supplement the current unit-based costing for improved analyses of transitional systems where facility capacity factors are subject to evolving demand.
- Gathering of partial correlation information for improved uncertainty modeling in pair-wise comparisons of fuel cycles and scenarios.
- Identification of factors specific to modular facility deployments that may provide opportunities for cost reduction or value improvement.
- Development of methods and tools for improved modeling of transition-related system costs.

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

NTRD 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 A

Source Materials
(Uranium and Thorium)

Module A1

Uranium Mining and Milling

Module A1

Uranium Mining and Milling

This section provides comprehensive summaries of the long term uranium market in 2009 and 2012 that was reviewed again in 2016 with no changes recommended, and a less-detailed analysis of the near term (spot) market situation in 2009. It updates (2012) the long term cost forecasting methodology used in the 2009 report (2009 CBR) and adds a second, parallel forecasting methodology which basically supports the results of the 2009 analysis. To these forecasting methodologies, this update in 2017 adds a forecast based on time series analysis. It too supports the original forecast done in 2009. Since 2009 the Fukushima accident, the advent of very low natural gas prices, and other socioeconomic factors have greatly decreased the near term demand (next 20 years) for uranium. For this reason a depressed spot market now (2017) exists and will be discussed in new reports referenced below. The authors believe that despite near-term depressed market conditions, there will continue to be a long term (rest of century) demand for uranium supporting a viable long term pricing structure.

A1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation and a new section presenting time series analysis of uranium prices. Section A1-6.2 discusses historic uranium prices and then a price forecast for uranium prices based on historic data.
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was escalated:** Analysis (in 2009) of long term historical trends and their forward projections for uranium and other specialty metal commodities. In 2012 and 2017 additional trend analyses were added, which basically supported the 2009 cost ranges. Escalation of 14% from 2009 to 2017 is utilized to establish the 2017 cost ranges. The escalation factor of 1.14 is calculated from the recently updated Table in the "Escalation Considerations" chapter of this report.

A1-RH. REVISION HISTORY

- **Version of AFC-CBR in which this Module first appeared:** 2004 as Module A (Uranium Mining and Milling). In 2009 AFC-CBR Module A was renamed "Source Materials" and separated into Module A1 for Uranium Mining and Milling and Module A2 (Thorium Mining and Milling).
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 with additional technical analysis in 2012 and 2017 to support 2009 methodology and unit cost values.
- **New technical/cost data which has recently become available and will benefit next revision:** In this revision time series analysis of uranium spot market prices has been added. Although from a different methodological approach, this analysis supports the forecast estimates first documented in 2009.
- **Other cost-related technical areas which may benefit from further literature research**: Improvements to in-situ mining technology due to advancements in hydrocarbon fracking, possible recovery of uranium from used fracking liquids, continued research and improvements in recovery of uranium from seawater.

- **A market analysis in 2016 served as a "spot check" on the situation in the market for uranium**. A summary of that spot check is included in the text below in Section A1-6.6.

A1-1. BASIC INFORMATION

The authors recognize that uranium and enrichment spot prices have recently moved outside the range provided in this cost basis. Prices have declined from peak, "Nuclear Renaissance" values seen in 2007, and are now strongly suppressed. 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 total 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 2006a) 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.

A1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

A1-2.1 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. (1 tonne = 1 metricton = 10^3 kg = 10^6 grams)

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 A1– 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.

A1-2.2 In situ Leaching

With the in situ leaching technology (Figure A1– 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).

A1-2.3 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 A1–3) 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.

A1-3. PICTURES AND DIAGRAMS

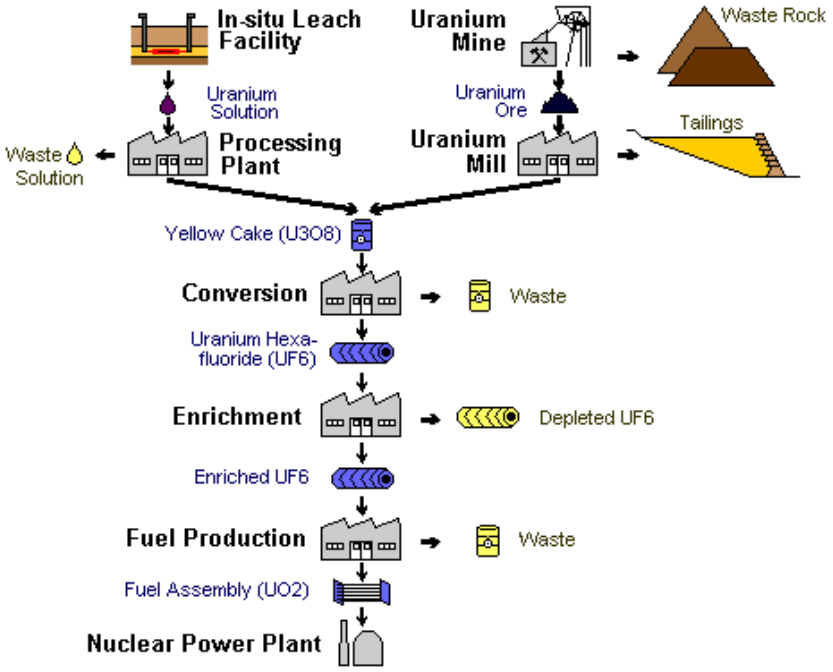


Figure A1– 1 Nuclear fuel production chain for light water reactors (Diehl and Schwedenteich 2005).

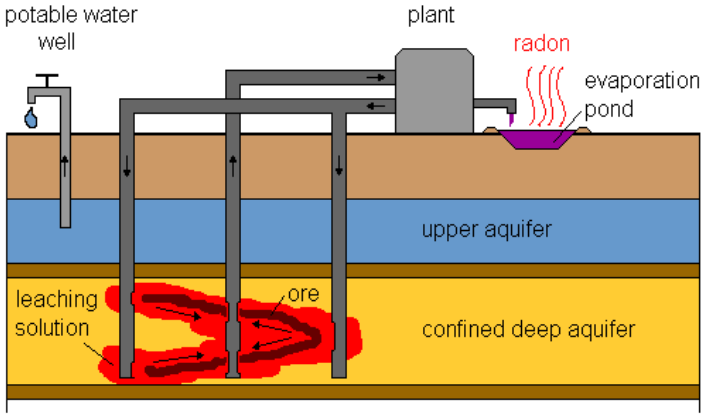


Figure A1– 2 Typical in situ leaching operation (Diehl and Schwedenteich 2005).

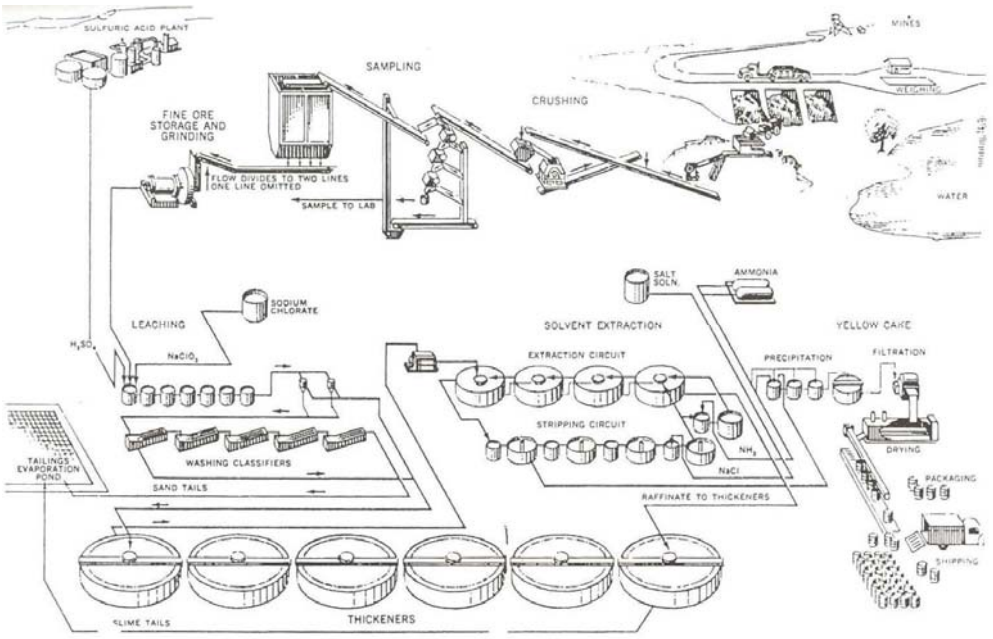


Figure A1– 3 Typical uranium mill (EPA 1995).

A1-4. MODULE INTERFACES

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.

A1-5. SCALING CONSIDERATIONS

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.

A1-6. 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.

The 2009 CBR presented a uranium price forecast that represents expected trends over many decades. The basis for that forecast was USGS historical world production and price data series for 35 mineral commodities (USGS 2005). Data for many of these minerals extends back to 1900, so that more than one hundred years of historical prices and production are given in most of the series. Uranium is unexceptional by several measures used to characterize mineral commodities: its crustal abundance, average grade of ore being recovered and known reserves all fall near the middle of the 35 commodities in the data set.

Therefore, the 2009 CBR postulated that uranium price trends over the coming 100 years are well represented by the range of historical trends for the surrogate commodities. The data used for the 2009 CBR forecast extended to 2004; USGS has subsequently updated the data series through 2010. Most commodities have exhibited a long term trend of gradually declining price overlain by more dramatic increases and decreases associated with the boom-bust cycles typical of mineral prices. Since many commodities experienced price booms during the late 2000s, the extension to 2010 is significant in that it incorporates part of another boom cycle. Please see the 2009 CBR for detailed documentation of the model and justification for using the 35 commodities as surrogates for uranium.

The mineral price history approach will provide one input to the long term price range forecast in this update. A second input, not utilized in the 2009 CBR, will be the uranium price elasticity model developed by MIT for its 2011 study (MIT 2011) on the future of the nuclear fuel cycle. The two sets of results will be averaged to develop the module forecasts, representing equal weighting of the approaches.

Mineral Commodity Index

Table A1– 1 compares the USGS data set for this update to that used in the 2009 CBR. The USGS adjusted the price data in its set to constant year 1998 dollars, so all data and conclusions presented here are based upon inflation-adjusted price trends. During the 2004-2010 period for which new data is available, most prices and annual production rates rose. As discussed in the 2009 CBR, short term price escalation is driven in part by rapidly increasing demand, especially if the increase is larger than anticipated. In the longer term, conflicting forces act to shape production cost and price trends. Depletion of the most economically attractive deposits shifts production to costlier (e.g. lower grade, deeper, more difficult to mill) resources. But the progress of technology leads over time to reduction of recovery costs from known deposits as well as to new methods for prospecting and exploiting previously unknown or unattractive sources.

Table A1– 1 Comparison of 2009 CBR and 2012 CBR mineral commodity data sets.

Mineral commodities in survey	33 (35 in 2009 CBR)
Timespan of data	1900-2010 (1900-2004 in 2009 CBR)
Commodities whose price has increased from 2004 to 2010	24 of 33
Commodities whose annual production rate has increased from 2004 to 2010	26 of 33
Largest relative price increase, 2004-10	Cadmium, $1040 -> $2820/tonne1
Largest relative price drop, 2004-10	Arsenic, $804 -> $325/tonne1
1. Given in 1998 dollars as in the data source.	

The simple model presented in the 2009 CBR and summarized here aims to capture the long term price trend that results from the interplay of these upward and downward acting forces. It fits each price history to a function

$$P = Ce^{Mt} \tag{1}$$

where

P [$/tonne] = commodity price (given in constant year 1998 dollars in [2]),

t [-]= year of data – first year for which data is available,

C [$/tonne] and *M* [-] = regression coefficients.

If the fitting coefficient *M* is positive, the mineral has shown a generally rising price trend over the data period. If *M* is negative, the price has been declining. Table A1– 2 shows the *M*-coefficients for the data sets used in the 2009 and 2012 CBRs.

Table A1– 2 M-coefficients for mineral commodities in the 2009 and 2012 data sets.

	2009 CBR Data Set	2012 CBR Data Set		2009 CBR Data Set	2012 CBR Data Set
Coverage Period	1900-2004	1900-2010	Coverage Period	1900-2004	1900-2010
Aluminum	-2.04E-02	-1.93E-02	Lead	-5.22E-03	-4.04E-03
Antimony	1.36E-03	1.59E-03	Lithium	-2.54E-02	-2.44E-02
Arsenic	-8.70E-03	-1.06E-02	Magnesium	-2.32E-02	-5.01E-03
Bauxite	-7.41E-03	-8.51E-03	Manganese	3.34E-03	4.69E-03
Beryllium	-1.86E-02	-2.09E-02	Mercury	-1.24E-02	-1.16E-02
Bismuth	-2.10E-02	-2.18E-02	Molybdenum	-7.48E-03	-2.49E-03
Boron	-1.53E-03	-1.91E-03	Nickel	-4.35E-03	-2.19E-03
Bromine	-2.83E-02	-2.83E-02	Platinum	-4.63E-03	-3.91E-03
Cadmium	-2.43E-02	-2.45E-02	Pumice	-1.39E-02	5.60E-04
Chromium	7.74E-03	9.13E-03	Rhenium	-4.99E-02	-2.29E-02
Cobalt	-4.87E-03	-4.20E-03	Silver	-1.28E-03	-3.88E-05
Copper	-6.38E-03	-4.49E-03	Tantalum	-5.87E-03	-1.07E-02
Germanium	-2.12E-02	-1.06E-02	Thorium	-4.64E-03	[1]
Gypsum	4.06E-03	-3.27E-02	Tin	1.28E-03	1.48E-04
Indium	-4.07E-02	-6.57E-03	Titanium	-3.95E-02	[1]
Iodine	-1.53E-02	6.45E-03	Tungsten	-1.95E-03	-3.43E-03
Iron Ore	2.88E-03	3.85E-03	Vanadium	-1.21E-02	-1.67E-02
			Zinc	-3.78E-03	-2.91E-03

1. Data for 2005-10 for thorium and titanium were not available, so these commodities were not used in the updated data set. If they were omitted from the set used in the 2009 CBR, the effect would be minimal: the mean would change from -0.0118 to -0.0112 and standard deviation from 0.0136 to 0.0130.

Seven of the 33 *M*-coefficients in the updated data set are positive, against six in the set that did not include the 2005-10 data. The *M*-coefficients are once again close to normally distributed (Figure A1– 4). Fitting them to a normal distribution yields the mean and standard deviation shown in Table A1– 3.

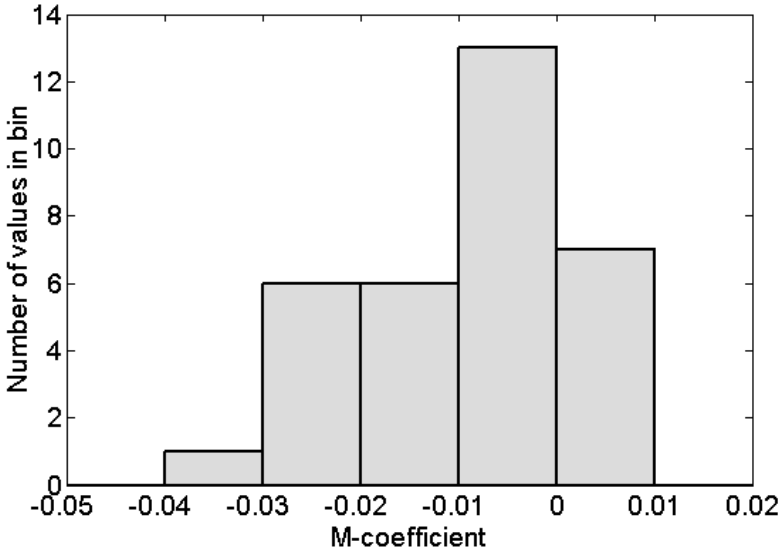


Figure A1– 4 Distribution of M-coefficients.

Table A1– 3 Mean and standard deviation of M-coefficient values for the 2009 and 2012 data sets.

	2009 CBR Data Set	2012 CBR Data Set
Data coverage period	1900-2004	1900-2010
Mean	-1.18E-02	-8.43E-03
Standard Deviation	1.36E-02	1.07E-02
Mean + 2 S.D.	1.53E-02	1.30E-02
Mean - 2 S.D.	-3.90E-02	-2.99E-02

The nominal uranium price forecast is developed by considering the mean value of the M-coefficient. To represent a 95% confidence interval, the high and low forecasts utilize the mean plus and minus two standard deviations, respectively. Forecasts are developed by projecting the uranium price forward in time using Equation (1). To do so, a value for the price at the start of the forecast, C, is needed. C should represent a reasonable estimate of the marginal production cost of the commodity, i.e. the price if the market were in equilibrium. The 2009 CBR took C to be $120/kg U, and indeed uranium prices have remained near this level between 2009 and 2012 (Figure A1– 3). Therefore, C will continue to be chosen as $120/kg U for this update and the reference date against which the time, t, is measured in Equation (1) will remain 2010.

Using Equation (1) with C = $120/kg U and the M-coefficients of Table A1– 3 results in the price trends shown in Figure A1– 5. To develop single-valued estimates for the CBR, numerical averages of each of the curves over the 100 year time period starting in 2010 were taken. The mean forecast is seen to have increased slightly with the 2012 CBR data set, reflecting the effect of including the 2005-10 price boom in the data series from which the *M*-coefficients were derived. On the other hand, the 95% confidence interval has narrowed somewhat[a].

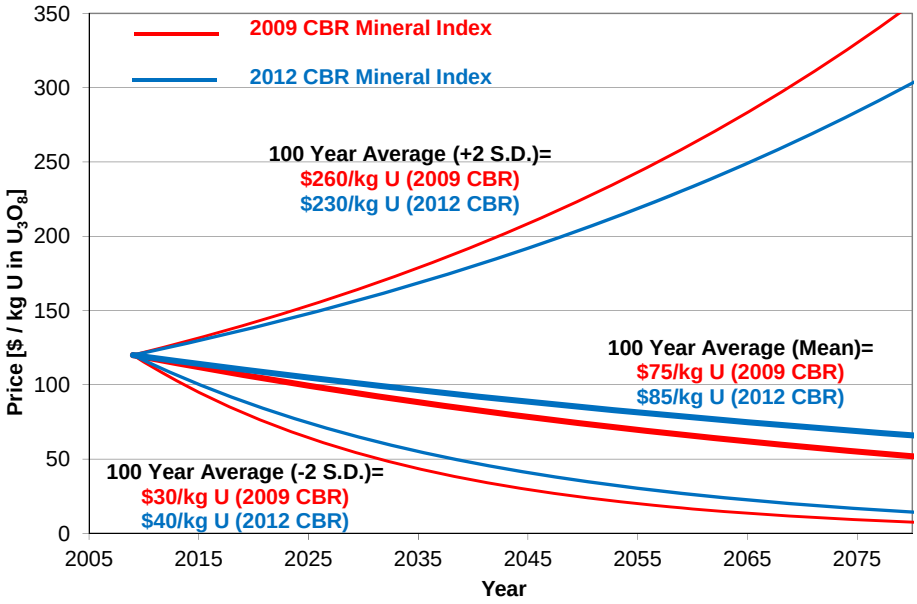


Figure A1– 5 Mean (heavy lines) and +/- 2 standard deviation (thin lines) projections from the 2009 and 2012 CBR Mineral Index models.

[a]. Once the data set was extended through 2010, the M-coefficients were found to have become more tightly grouped. Some commodities with very negative coefficients in the data set to 2005 saw substantial price increases from 2005-10 and their M-coefficients drew closer to the mean (e.g. indium, M=-0.0407 through 2005, M=-0.00657 through 2010).

A1-6.1 MIT Price Elasticity Model

Few quantitative estimates exist for uranium price trends over time frames of half a century or longer. The 2009 CBR reviewed several of these and dismissed them for considering only the resource depletion effects that tend to push prices higher over time while neglecting technological change and other factors that have held commodity prices down over the decades. The 2011 MIT report "The Future of Nuclear Power" (MIT 2011) includes a forecast that aims to account for forces that act to push prices both upward and downward over time.

The form of the MIT forecast is as follows:

$$\left(\frac{P}{P_0}\right)=\left(\frac{U}{U_0}\right)^{\theta} \tag{3}$$

where

U [tonnes U] = cumulative uranium extracted,

U_0 [tonnes U] = cumulative uranium extracted up to an initial reference time,

P [$/kg U] = uranium price when cumulative uranium extracted reaches U,

P_0 [$/kg U] = uranium price at an initial reference time,

θ [-] = exponent that depends on economies of scale, learning rate and resource vs. grade elasticity.

For consistency with the mineral index model, the initial reference time is chosen as 2010 with initial price P0 = $120/kg U and cumulative uranium production up to that date U0 = 2.0x106 tonnes U. This model predicts the price as a function of the total cumulative amount of uranium extracted, U, at some future date. Therefore, it depends on the rate at which uranium is produced into the future. Since the CBR presently does not couple costs or prices to production capacity or cumulative production, an assumption regarding future uranium production, which stood at nearly 55,000 tonnes U/year in 2010 and 2011 [4], is needed. This will be that uranium production increases at 2.6%/year, corresponding to the mid-range nuclear power growth rate estimated by the World Nuclear Association for 2011-30 (WNA 2012).

The θ coefficient is analogous to the M-coefficient in the mineral index model in that it determines whether the price will trend higher or lower. MIT used a range of published estimates of the amount vs. concentration of uranium in the ground, the rate at which technological change acts to reduce production costs in related industries, and the general effects of scale economies to forecast a distribution of values for θ. See Ref. (MIT 2011) for details. Following the approach taken for the mineral index, upper and lower bounding scenarios on θ were chosen to correspond to a 95% confidence interval[b] (Table A1– 4).

Table A1– 4 Mean and bounding theta-coefficients for the MIT price elasticity model.

Mean	1.10E-01
Upper Confidence Interval Bound	4.40E-01
Lower Confidence Interval Bound	-2.50E-01

Figure A1– 6 shows MIT elasticity model projections and compares them to the 2012 CBR mineral index curves previously shown in Figure A1– 5. The projections are largely in agreement, though the MIT model shows the expected price (heavy green line) trending somewhat upward while the mineral index

[b]. Ref. [3] only gave a graphical representation of the □ distribution, so the confidence intervals were estimated from the plot.

model forecasts a decreasing price (heavy blue line). The 95% confidence interval associated with the MIT model is also seen to be narrower than that of the mineral index approach[c].

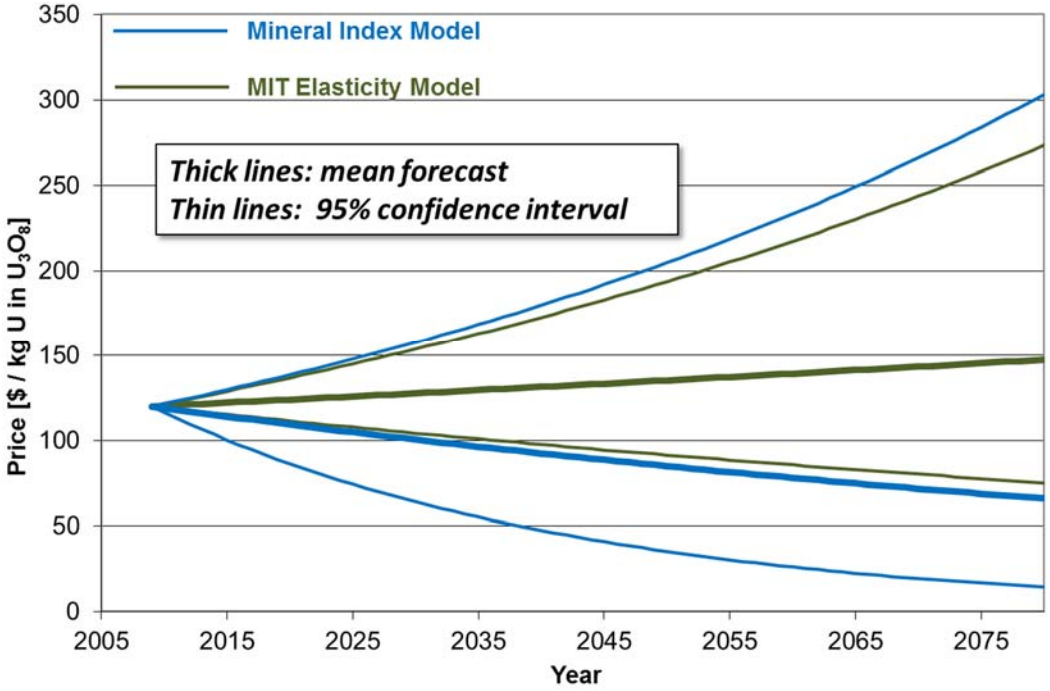


Figure A1– 6 Mean (heavy lines) and 95% confidence interval (thin lines) projections from the MIT Elasticity and Mineral Index models.

A1-6.2 Time Series Analysis of Uranium Spot Market Prices

Analysis of causal relationships is one approach to forecast uranium prices; time series analysis is an alternative. Whereas causal analysis measures the statistical relationship among a set of variables, analysis of time series data measures the statistical relationship of observations on the same variable in the historic record. The historic relationship can then be used to generate forecasts of the variable. This section presents a time series analysis of uranium prices. Coupled with the causal analysis in the previous section, the two methods provide a more robust base of what to expect for uranium prices.

The data for this analysis are from two locations. Roskill (1991) presents uranium price data, (USD/lb) from the US Atomic Energy Commission (USAEC) and from the Nuclear Exchange Corporation (NUEXCO). The International Monetary Fund (IMF) (IMF 2017) publishes commodity prices from NUEXCO, also in USD/lb. Data from USAEC covers the time from 1948 – 1971 and NUEXCO data covers 1972 – 2016. The data, converted to USD/kg, are shown in Figure A1– 7 . Current values are made constant using the escalation method described in Chapter 7 of the Cost Basis Report.

[c]. The confidence interval on the MIT model would be wider if differences in the U demand growth rate were incorporated. A high demand growth rate would lead to more rapidly changing prices. This and other cost feedbacks from plant or industry capacity and throughput may be included in a future update to the Cost Basis Report.

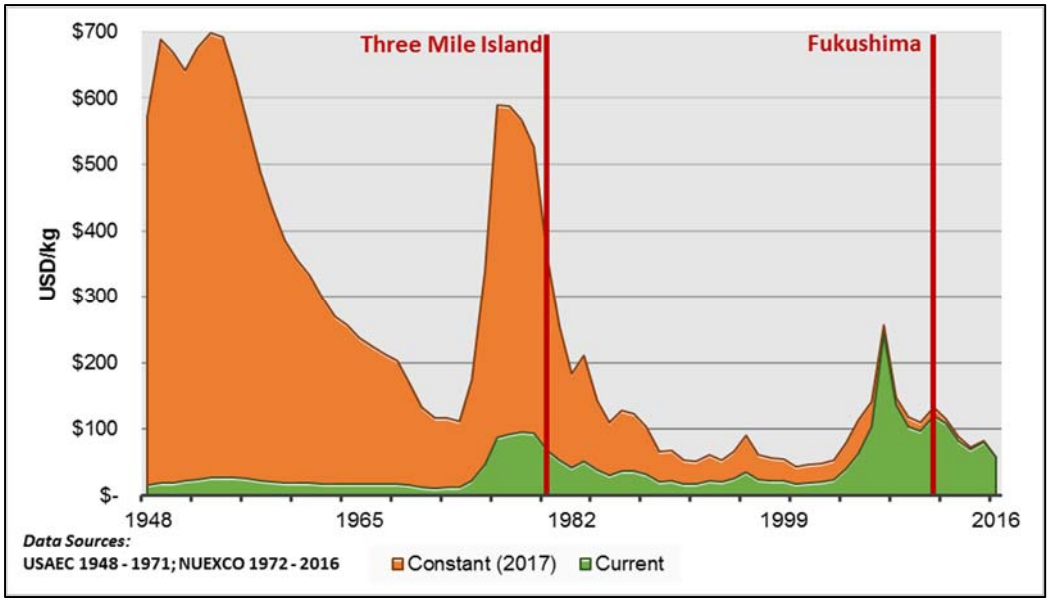


Figure A1– 7 Uranium prices in constant and current dollars annually.

In the analysis that follows, uranium prices in constant 2017 USD (the orange data series in Figure A1– 7) are used as the underlying data source. The timeframe of the data, however, becomes a choice the analyst must make. The analyst could use the entire data series, beginning in 1948, to forecast future uranium prices. Or a subset of the data could be used. The choice depends on at least two important pieces of information: the analyst's expectation of the similarities in the historic record to what one might reasonably expect in the future, and statistical testing to compare prediction error. Visualizing the data from the beginning of the nuclear industry (1948) up to the point of Three Mile Island (TMI) suggests a long period of declining prices with a significant spike just preceding TMI. Following TMI uranium prices entered a long period of declining prices up through the early 2000s, at which point uranium prices, and all energy prices for that matter, spiked. Following the price spike of 2008 uranium prices again entered a period of decline. So which period in the data best represents what one might reasonably expect to approximate market conditions for uranium going forward?

For the uranium price forecast presented here the early days of nuclear, i.e. the period prior to TMI, are not used. The large starting point for price in 1948 is not likely representative of prices one should expect in a well-established market like the uranium market today. One might wonder at the extent that Fukushima had on uranium prices, but interestingly the figure suggests that uranium prices were in a downward trend at the time Fukushima occurred. Based on this intuition, the period of data used in constant 2017 prices, in the forecast analysis below is 1980 – 2016, but coupled with statistical testing. The discussion will return to this decision later.

The central idea in time series analysis is that there is some process that fits a data series, and that process can be used to forecast expectations of what might occur going forward. A simple time trend is a form of this analysis, an algorithm computes the mean values across time and from it generates a trend of possibilities. The simple trend can become more sophisticated with alternative forms such as the moving average (MA) where the average is computed across discrete time periods. For example an MA(2) process is one where the moving average is computed based on the average moving across two periods at a time. Beyond time trend analysis, time series processes can be fit to a stochastic processes. That is the stochastic process measures the randomness observed in the data series then projects a forecast based on the observed randomness in the historic record. Statistical tests are then employed to measure the 'goodness of fit' of each process. Trend-based processes can be compared to stochastic processes based on how well the process or trend fit the data. Examples of stochastic processes include Brownian motion,

autoregressive processes, or generalized autoregressive conditional heteroscedasticity. Once the alternative processes have been fit to the data, the AIC test (Akaike Information Criterion) is used to measure goodness of fit.

Data stationarity is an important statistical property in fitting a stochastic process to time series data. Because the stochastic process fits the randomness of the data, if an underlying trend exists it must first be removed. If not first removed, then the computed mean and variance of the data misrepresent the randomness in the data. The autocorrelation function (ACF) and the partial autocorrelation function (PACF) measure the extent of stationarity in the data. The ACF and PACF are plotted in the correlograms shown in Figure A1– 8 for uranium prices over 1980 – 2016.

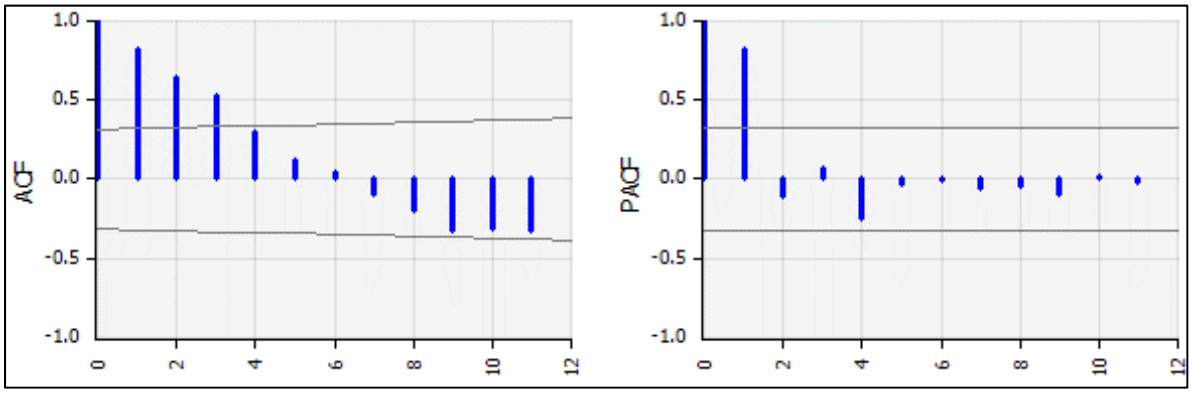


Figure A1– 8 Autocorrelation and partial correlation plots of uranium price data, 1980 – 2016.

The correlogram is a tool to visualize the statistical relationship between a data observation at any point in time and the lagged observation of the same variable. In it the vertical axis measures the correlation, where 0 indicates no correlation and 1 indicates perfect correlation, and the horizontal axis measure the number of lagged periods. The ACF plot illustrates that for a lag period of 1, i.e. 1 year, the data are almost correlated as indicated by a correlation factor of approximately 0.75. That is, the uranium price in year *t* is almost perfectly correlated with the uranium price in period *t* – 1. Further, the ACF indicates that almost 6 lags are required (i.e. 6 years) before the correlation across time periods dissipates. The PACF controls for correlation across lags. Whereas the ACF measures the correlation between periods, it does not control for the fact that correlation has already been measured. In the example given above, the data are correlated for up to 6 periods. That is given a signal impact in year *t* – 6, the ACF does not capture the correlation from the signal across periods up to year *t*. In contrast, the PACF accounts for the correlation across periods so that if the signal occurs in year *t* – 6 the PACF measures the correlation between *t* – 6 and *t* directly and accounts for the correlation in the years between. Looking at the PACF function, uranium prices are strongly correlated for 1 period. Taken together, the ACF informs that uranium prices reflect price signals that happen in a given year for up to 6 years, but he PACF tells us that the largest impact of signal remains for only a single year. One can interpret this as uranium prices are strongly correlated with a one-year lag but noise in the data takes about 6 years to dissipate out. These two correlograms inform that the data series is sufficiently stationary to use in forecasting.

Figure A1– 9 shows the uranium forecast model plotted against the historical data. The historical path indicates the data series from 1980 through 2016. One can think of the figure as representing a forecast in 1980 and asking the question, “How good of job will the forecast model do at predicting uranium prices?” Before discussing the implications of the figure in greater depth, it is first necessary to discuss how it was produced and the data used to generate the forecast.

Noted earlier, Figure A1– 7 shows that in the data series of uranium prices there are at least two distinct time periods and arguably three. First, the time period that could be used for forecasting analysis is from 1948 to 2016. This is analogous to the logic that uranium prices from the beginning of the nuclear

age up through the present ought to be used to generate the forecast of possible uranium prices. A second school of thought is that the nuclear industry was fundamentally different after the event of TMI. This is in part due to the nature of regulation change that followed TMI, but also the fact that many of the early difficulties in getting the nuclear industry underway were resolved by about this time. The third possibility for the seed data for a uranium forecast is TMI up to just prior to Fukushima. This logic suggests that Fukushima is an anomaly and is not representative of what the nuclear industry might look like going forward. So which of these time series of data should be used to forecast uranium prices? Figure A1– 9 is based on uranium prices from 1980 to 2016, and the next paragraph discusses why.

The software used for this is analysis is called @Risk (Palisade 2016). The time series module of @Risk allows the analyst to load seed data and then an algorithm in the software compares the seed data to a number of different stochastic, time series processes. The software presents the analyst with several possible choices and computes the AIC statistics for each model fit. The AIC measures the goodness of fit of the data with the stochastic process, and it is used as a statistic of relative comparison. In the analysis, each possible time frame for data are entered into the software (i.e. 1948 – 2016, 1980 – 2016, and 1980 – 2010). The analyst uses @Risk to fit stochastic processes to each time frame then compares the fitted models for each data series. Using the AIC statistic, a model is selected to represent each of the possible choices for seed data. With the three fitted models arrives the question, "which model best predicts the historic data?"

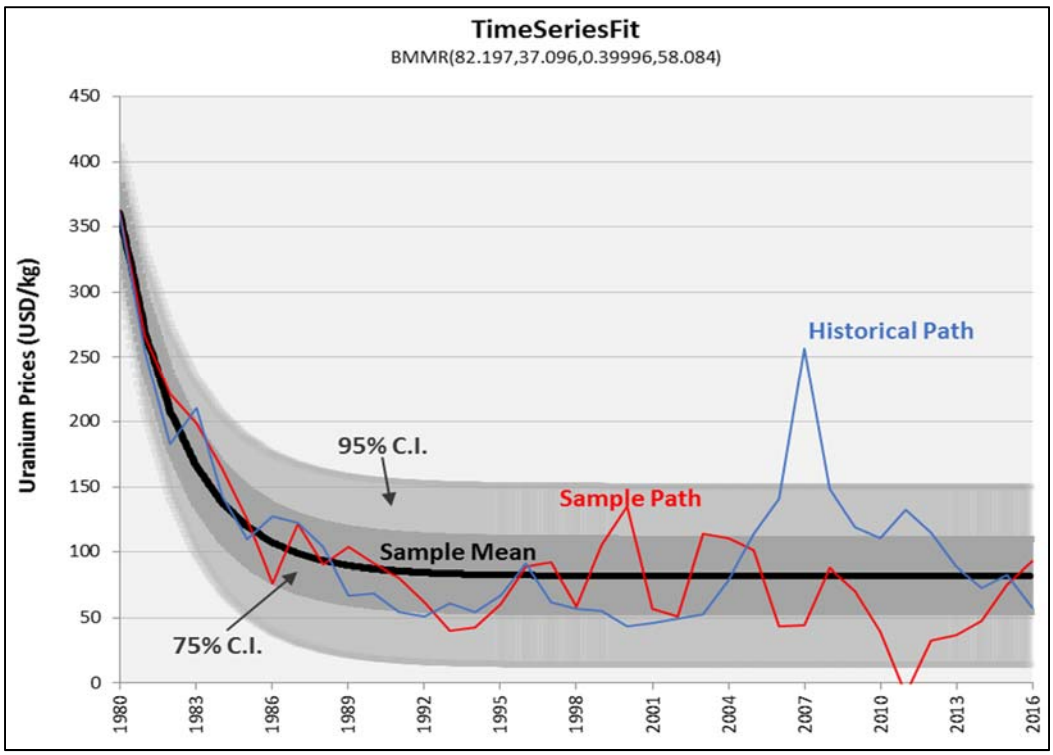


Figure A1– 9 Comparing predictions using time series fitted model with historical data.

To answer this question each model is used to predict observations over the same time frame as the seed data. This allows the analyst to compare how well each model predicts history. The statistic used to compare these predictions is called the Mean Absolute Percentage Error (MAPE). The equation for MAPE is given as where *t* indicates the year of observation:

$$\text{MAPE}_t = \frac{\left|\text{Observation}_t - \text{Prediction}_t\right|}{\text{Observation}_t} * 100$$

For each fitted model the MAPE is computed in each time period. Then, because the MAPE is estimated in absolute terms, it can be averaged over time frames to provide a sense of how well the fitted model predicts the historical values in relation to of choices for the fitted model. MAPE closest to 0 indicates less error in the prediction. The MAPE for the fitted model based on 1948 – 2016 is 1,071. The MAPE for 1980 – 2016 is 32 and for 1980 – 2010 is 38. This finding leads the analyst to conclude that 1980 – 2016 is the best choice for seed data in the uranium price forecast.

The fitted model that best fits seed data from 1980 – 2016 is called Brownian Motion Mean Reversion (BMMR). It is a stochastic process that when given an initial value randomly chooses the value for the next period based on the estimated parameters of the process. Because it is a stochastic process, each time the BMMR is simulated, with the same initial starting value, alternative pathways result because of randomness. Figure A1– 9 shows in red a sample path for the BMMR given the uranium price in 1980. In simulation thousands of sample paths are generated. The light gray area in the figure indicates the 95% confidence interval from the simulated data, and the dark gray area indicates the 75% confidence interval. The figure illustrates that almost all of the historical observations fit within the 95% confidence interval, with the noted exception of the 2008 energy price spike. The sample mean is given as a solid black line. It shows a relatively constant value across time. This is because, in the BMMR process, observations tend towards a central mean. In the figure, the mean of the simulated observations is $82.02.

The BMMR becomes the model used to forecast uranium prices. Figure A1– 10 shows the price forecast through the end of the century. The mean of the observations is represented by the solid blue line in the center of the figure. It increases then levels off because of the mean reversion characteristic of the fitted model. Because the simulation produces a distribution of possibilities in each year, additional statistics about the forecast are provided. The 90% and 10% lines indicate where 80% of the observed values in simulation resulted. The average value for the 10% line is $28.74 and for the 90% line is $134.41. The mean value, the solid blue line, across the simulation is $81.61.

The mode, the red line shown with variation, plots the mode from the distribution in each year. The most frequently occurring value in a distribution, the mode is a useful statistic to answer the question of what is the “most likely” value to expect in a given year. While the mean shows a constant value, the mode illustrates what the volatility in uranium prices might look like through the end of the century.

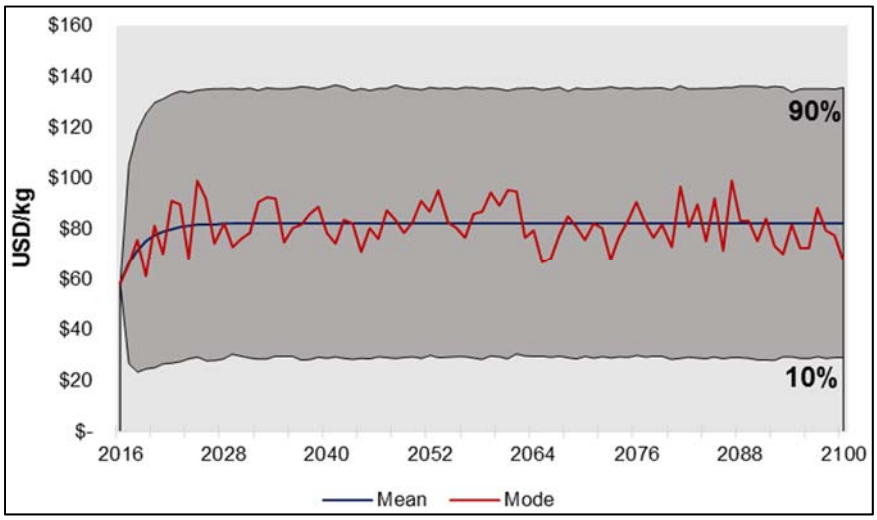


Figure A1– 10 Uranium price forecast using Brownian motion mean reversion time series model based on historical uranium prices from 1980 – 2016 in constant 2016 dollars.

Coupled with Figure A1– 10, Table A1– 5 provides statistics form discrete intervals with in the simulation. Representing possibilities for uranium 10 years out, 25 years out, 50 years out, and through the end of the century, the table provides the statistics that are illustrated in Figure A1– 10. The table

show statistics by year in two formats, “In Year” and “Up to Year.” The In Year statistics come from the distribution of possibilities for the year indicated. The Up To Year statistics represent what one might expect leading up to the year indicated. Notice the tighter confidence intervals and smaller standard deviation in the Up To Year statistics. This results because of the law of central tendency. Because the distributions from each year are averaged to compute the Up to Year statistics, the resulting distribution is more narrow (i.e. has less uncertainty) than the distribution of a single year.

Table A1– 5 Summary statistics of uranium price forecast by year and up to year.

Year(s)	Mean	Mode	Std Dev	10%	90%
In 2027	$81.75	$91.91	$41.55	$27.81	$134.89
Up to 2027	$77.42	$85.04	$24.20	$46.35	$108.47
In 2042	$82.19	$74.26	$41.67	$29.29	$136.58
Up to 2042	$80.24	$74.41	$17.19	$58.33	$102.25
In 2067	$82.20	$67.91	$41.49	$29.19	$135.08
Up to 2067	$81.22	$83.86	$12.70	$64.93	$97.62
In 2100	$82.20	$77.46	$41.40	$29.07	$134.93
Up to 2100	$81.61	$82.38	$10.03	$68.84	$94.44

Figure A1– 11 illustrates how the central tendency across simulation years narrows the distribution over a single year. The blue histogram in the figure results from the distribution in year 2100. The red histogram is the average of the distributions from years 2017 up through 2100. Averaging 83 distributions leads to the more narrow result. Another conclusion that can be taken from this result is that, based on the time series analysis of historic uranium prices, one can expect that over the century uranium prices will tend to oscillate around the $82.

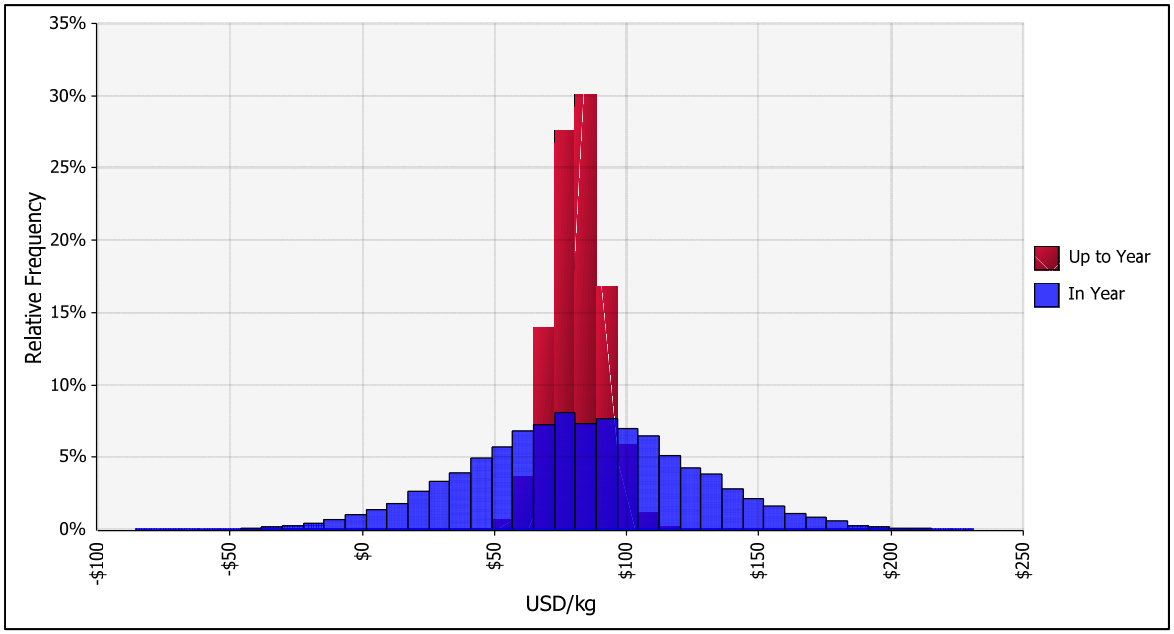


Figure A1– 11 Histogram of uranium prices in year 2100 and up to year 2100.

A1-6.3 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.

A1-6.4 World Reserves of Uranium

The IAEA *Red Book 2007* estimated world reserves are as shown in Table A1– 6. Changes from *Red Book 2005* values are noted in italics (OECD 2006a, OECD 2008). This data is displayed graphically in Figure A1– 12. 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– 6 Red Book 2007 Known World Uranium Resources and changes from Red Book 2006 (italics) (1000 tU).

Resource Category	Cost 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.

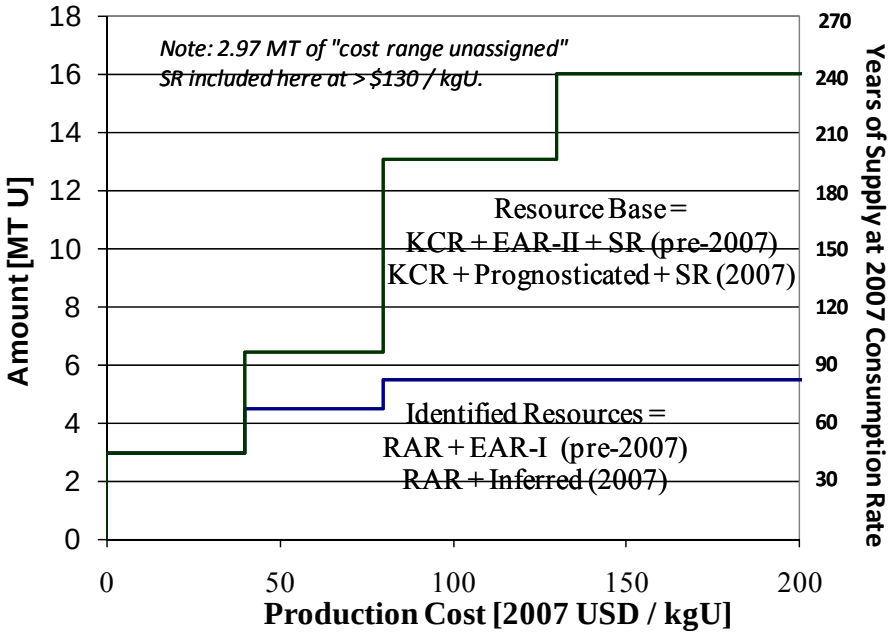


Figure A1– 12 Graphical depiction of Red Book supply estimates.

Table A1– 7 shows that the world reserves of uranium are dominated by foreign supply.

Table A1– 7 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– 13 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.

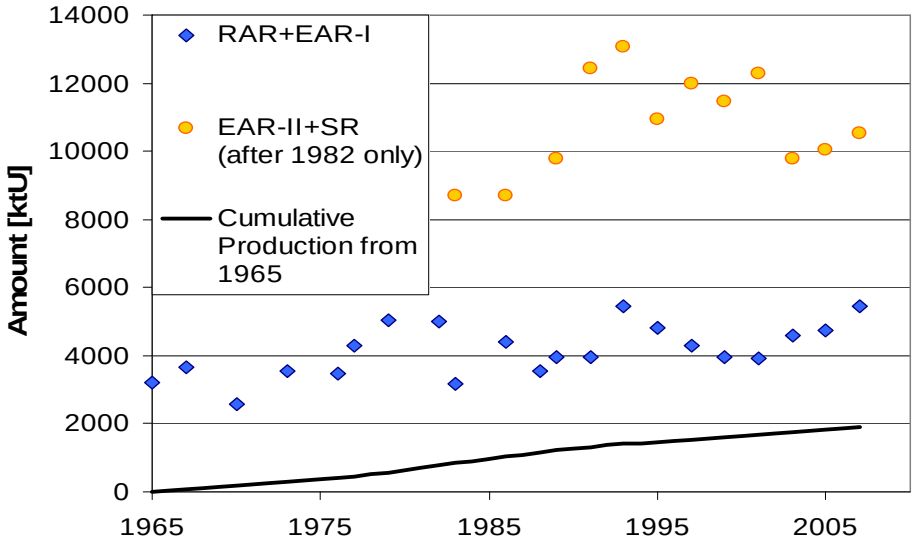


Figure A1– 13 Cumulative uranium production, Red Book Identified (RAR+EAR-I) Resources and Resource Base, 1965-present.

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– 15). 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– 14 [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.

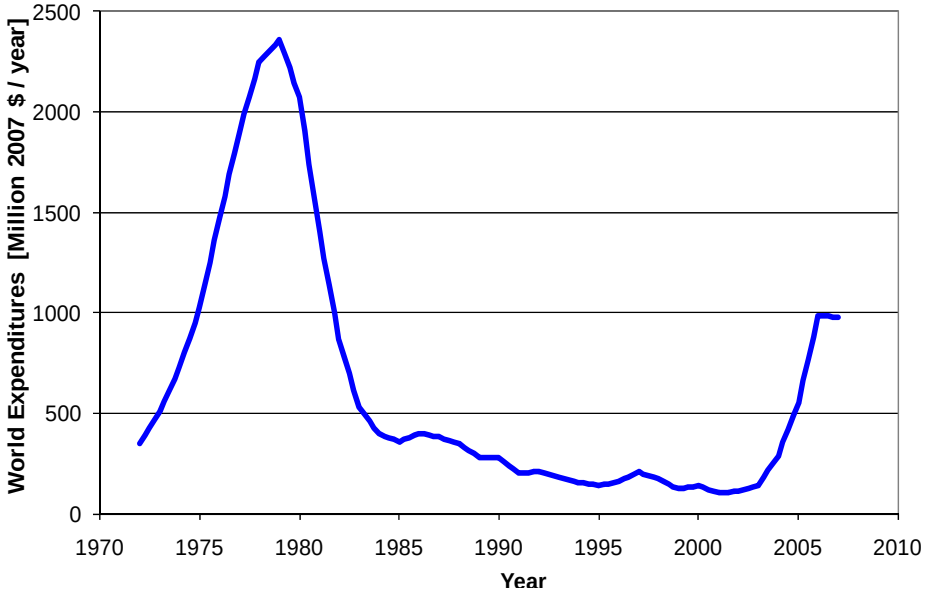


Figure A1– 14 Worldwide annual uranium exploration expenditures, 1972-present.

Figure A1– 15 depicts an evaluation of the abundance of uranium in the earth's crust by K. S. Deffeyes and I. D. MacGregor. The Figure A1-15 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 A1-15 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 A1-15 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– 15 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– 15 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.

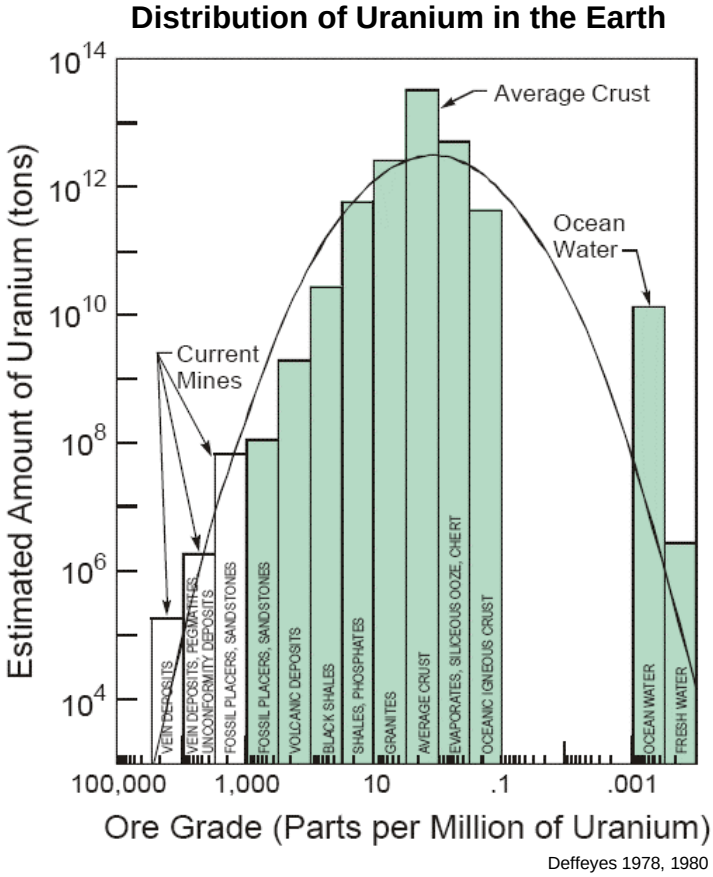


Figure A1– 15 Distribution of uranium in the earth (Deffeyes and MacGregor 1980).

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– 16. Note that in-situ leaching, a new technique that was in its infancy when Chapman wrote, bypasses waste rock haulage.

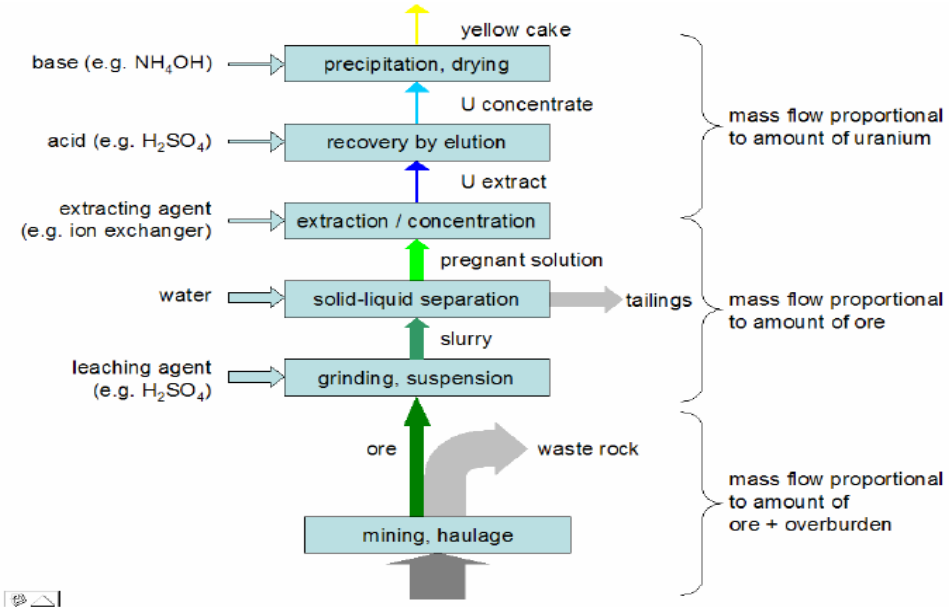


Figure A1– 16 Mass flow through the uranium mining and milling process (from Prasser et al. 2008).

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– 17.

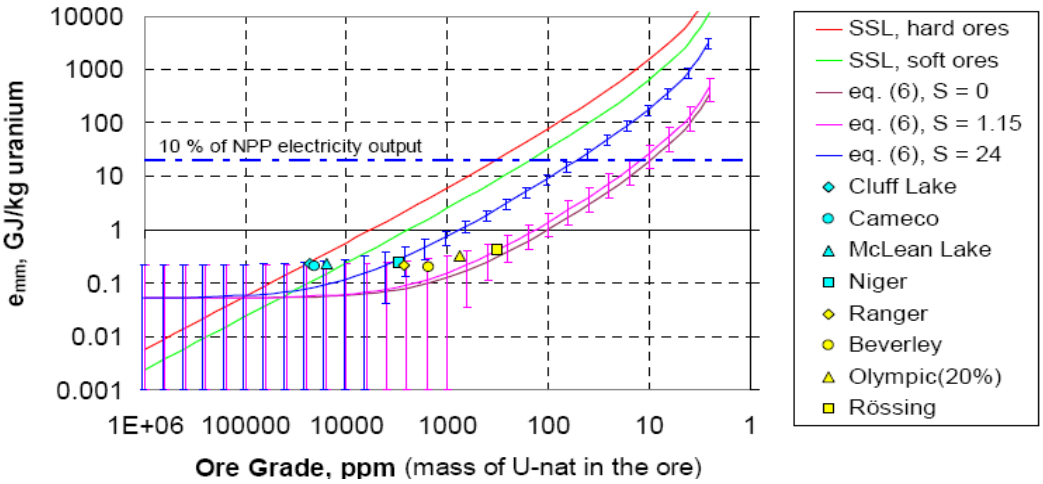


Figure A1– 17 Ore Grade versus mining energy input estimates of Smith and Storm van Leewen (SSL) and Prasser. Figure source: Prasser 2008.

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.

A1-6.5 U.S. Reserves of Uranium

Details on the U.S. uranium reserves by state are provided in Table A1– 8 with geographical locations shown in Figure A1– 18 and Figure A1– 19. The U.S. potential uranium resources by forward-cost category and resource region are included in Table A1– 9. The U.S. uranium mine production and number of mines and sources for the period of 1995–2008 is provided in Table A1– 10.

Table A1– 8 U.S. reserves of forward-cost uranium by state (December 31, 2003)

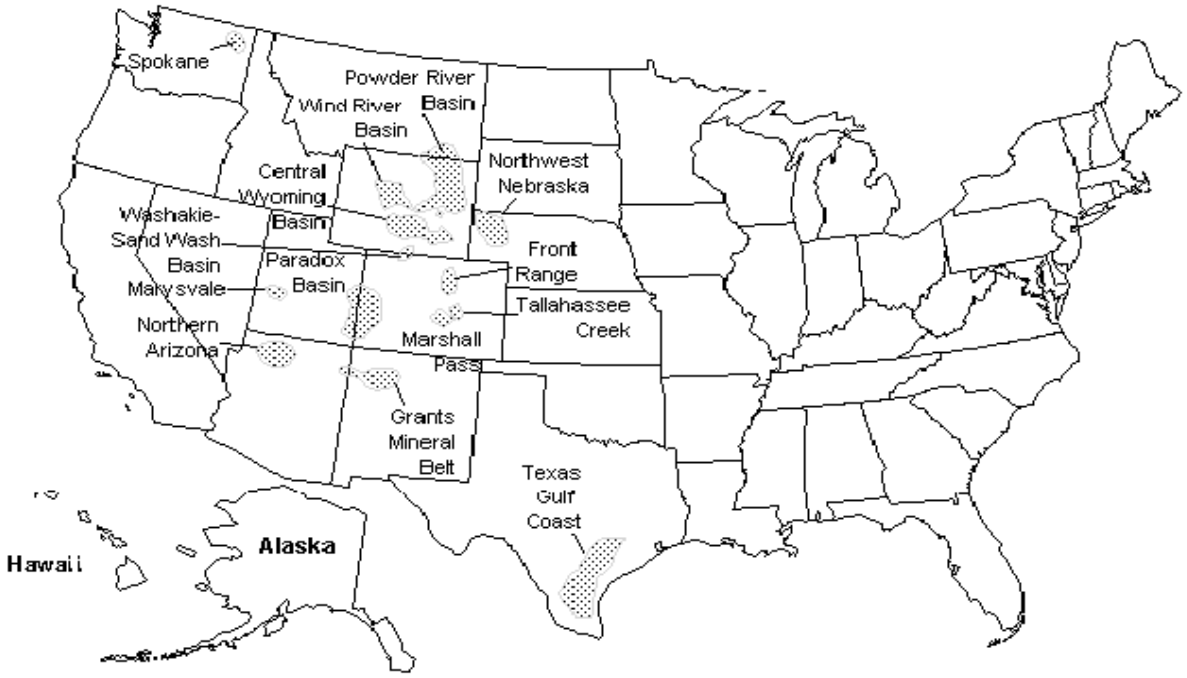
	$30 per pound			$50 per pound		
State(s)	Ore (million tons)	Grade[a] (percent U_3O_8)	U_3O_8 (million pounds)	Ore (million tons)	Grade[a] (percent U_3O_8)	U_3O_8 (million pounds)
Wyoming	41	0.129	106	238	0.076	363
New Mexico	15	0.280	84	102	0.167	341
Arizona, Colorado, Utah	8	0.281	45	45	0.138	123
Texas	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 Resource Evaluation, Interim Report (June 1979) Figure 3.2; and GJPO data files.

Figure A1– 18 Major U.S. uranium reserve areas.

Figure A1– 19 Uranium resource regions of the U.S.

Table A1– 9 U.S. potential uranium resources by forward-cost category and resource region (million pounds U3O8).

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– 10 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).

A1-6.6 Market Price for Uranium

Figure A1– 20 presents uranium supply curves constructed from data in the 2011 OECD Nuclear Energy Agency/International Atomic Energy Agency *Redbook* (OECD 2010, 2011). Total identified and speculative resources have both increased from 2009[d]. The analogous data from the *2009 Redbook*, depicted by the dashed lines in Figure A1– 20, shows that lower-cost resources – at $130/kg U and below – have declined (the solid line is left of the dashed line), but the increase in resources producible at $260/kg U and above has more than compensated. Along with new discoveries, extraction operations at active lower-cost mines as well as reclassification of as yet untapped deposits into higher cost bins have contributed to this shift.

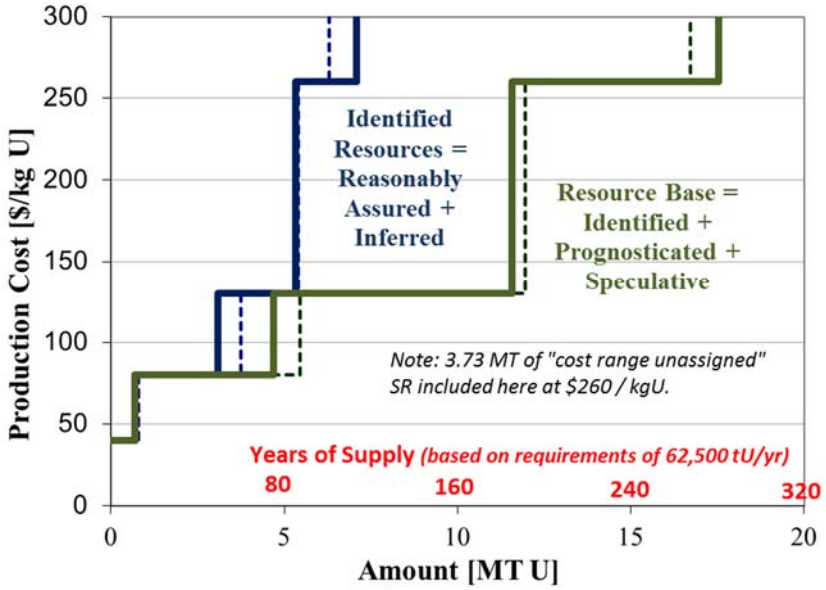


Figure A1– 20 2011 (solid) and 2009 (dashed) Redbook uranium supply curves. [e]

"Identified Resources" stood at 6.31 million tonnes U (MTU) in the 2009 *Redbook* and 7.10 MT in 2011. This increase of 790,000 tonnes U (tU) through 2009 and 2010 represented more than ten years' production at current rates and took place even as 105,000 tU were produced. Ref. [1] cited a boom in exploration induced by higher uranium prices beginning around 2005 as the major driver of this increase.

But the increase is not unprecedented or unusual: since the *Redbook* began publication in 1965, the identified uranium resource pool has risen steadily. Figure A1– 21 shows that identified resources have more than doubled from 3.2 MTU in 1965 to 7.1 MTU in 2011 even though nearly 2.1 MTU of uranium was mined during the same period.

[d]. See the 2009 CBR for definitions of supply categories, discussion of the domestic supply picture, and a review of secondary supply sources.

[e]. In the pre-2007 Redbook classification scheme, RAR = reasonably assured resources, EAR-I and II = estimated additional resources in Categories I and II, with Category II being less certain than Category I, and SR – speculative resources.

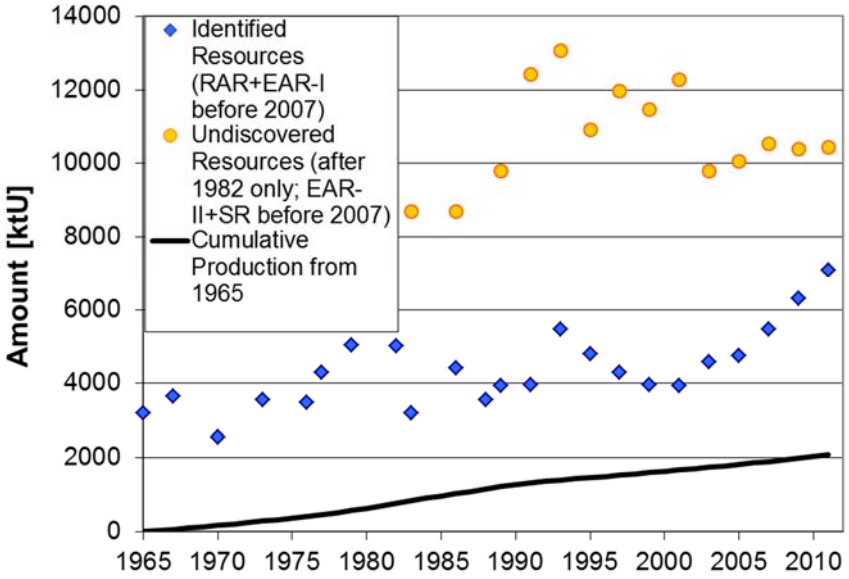


Figure A1– 21 Cumulative production and Redbook resource estimates since 1965.

Following an extended period of depressed prices through the 1990s and early 2000s and a sharp boom from 2005-2008, a measure of stability returned to the uranium market during 2009-12. Figure A1–22 shows that both the spot and long-term delivery prices remained near their mid-2012 levels of \$50/lb U_3O_8 (\$130/kg U) and \$60/lb U_3O_8 (\$156/kg U), respectively, throughout the period. Most uranium transactions are handled through long-term contracts. The long-term price in the figure assumes a delivery time frame of at least 2 years as well as terms often present in contracts such as an allowance for flexibility in the quantity actually purchased. As such, while spot prices are a leading indicator of contract prices, a gap between the two may persist even when the market is near equilibrium conditions.

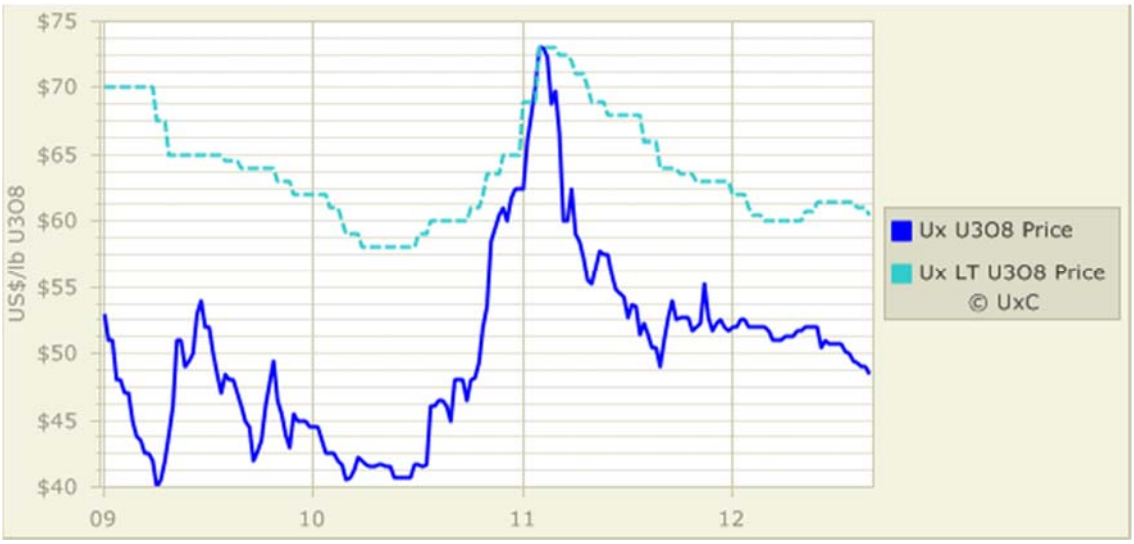


Figure A1– 22 UxC uranium spot (solid) and long-term (dashed) prices, 2009-12. Figure source: the Ux Consulting Company, LLC, http://www.uxc.com.

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– 11 is a summary of the IAEA-NEA projections.

Table A1– 11 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. government does not own any currently producing uranium mines, but DOE does have inventories of secondary supplies as shown in Table A1– 12. 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– 12 Inventories of natural and enriched uranium as of end of year, 1998-2007 (thousand pounds natural U3O8 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	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.

A1-6.6.1 Spot Check on Market for Uranium

Spot prices for uranium ore (yellowcake), conversion and enrichment have all been trending downward since the Fukushima accident in 2011. The accident resulted in the temporary shutdown of all reactors in Japan and the cancellation or delay of other planned reactor construction worldwide, reducing global demand significantly. As of 2016, only 3 of the Japanese reactors have been restarted, though

many others have applied for restart and are in the review process. In addition to Fukushima, other factors have also affected the individual markets. These include short-term effects of the current market supply/demand imbalances as well as some longer-term infrastructure effects. In particular, the magnitude of the price drops have resulted in some suppliers needing to dump additional products into the market to meet cash flow requirements, prolonging and deepening the downward trend in the spot market (a reinforcing loop).

Uranium prices have been descending from a speculative price peak in 2007 during the brief "nuclear renaissance" period. Prices spiked again briefly in 2011 just prior to Fukushima but have been declining since then (See Figure A1– 23).

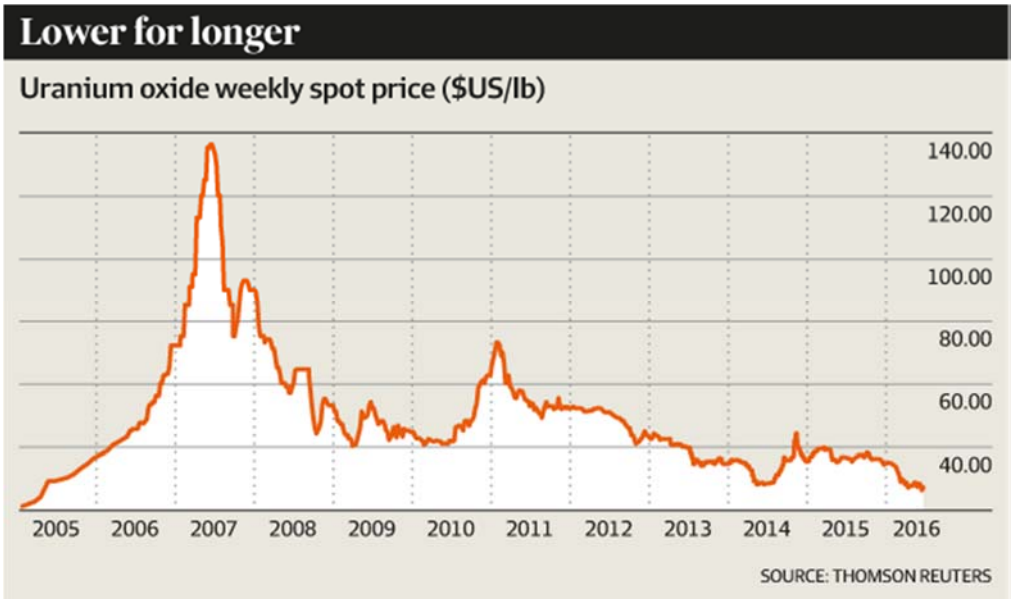


Figure A1– 23 Uranium oxide weekly spot price.

One driver suggested for the low prices [Financial Review 2016] is that producers may have been forced to sell on the spot market to improve cash positions, rather than selling primarily on the long-term market where prices are higher. Several sources have been predicting prices will stabilize because they are currently below the production cost for many producers, or that prices will rebound driven by renewed interest in nuclear energy to combat climate change.

Most uranium is purchased in longer-term contracts, so spot prices are only an indicator of the direction of the market. Price movements in the longer-term contracts tend to be smoother than the spot market and usually lag behind the spot price with respect to prolonged trends. Some longer-term contracts are fixed price while others include periodic market-related price adjustments.

Cameco Corporation provides ~18% of the world's production of uranium. Cameco targets their contract portfolio to achieve a 40:60 ratio of fixed and market-related contracts [Cameco 2016]. (A market-related contract adjusts periodically based on a formula related to current market prices, similar to a variable rate mortgage.) Table A1– 13 indicates how they predict the price they receive for their existing long-term uranium contracts would change going forward based on their portfolio as of June, 2016. Note that they do not include prices significantly lower than the current ~$25 price, implying the market may be near a bottom.

Table A1– 13 Expected realized uranium price sensitivity under various spot price assumptions [Cameco 2016]

Spot prices ($US/lb U_3O_8)	$20	$40	$60	$80	$100	$120	$140
2016	41	43	49	54	60	66	71
2017	38	45	56	68	79	88	96
2018	39	46	58	69	80	89	97
2019	38	47	58	69	79	87	94
2020	42	49	59	70	79	86	92

At the end of August, 2016, the spot price was $25.25 per lb U_3O_8 [UxC 2016]. This converts to $65.64 per kgU, which is within the range from the 2015 update of the CBR (low $32, mode $79, mean $128, high $273/kgU). See Figure A1– 24. Given the short-term uncertainty in the market, the intermediate term historic trend downward, and the projections for prices to stabilized or increase, we see no reason at this time to change the suggested price range for the CBR.

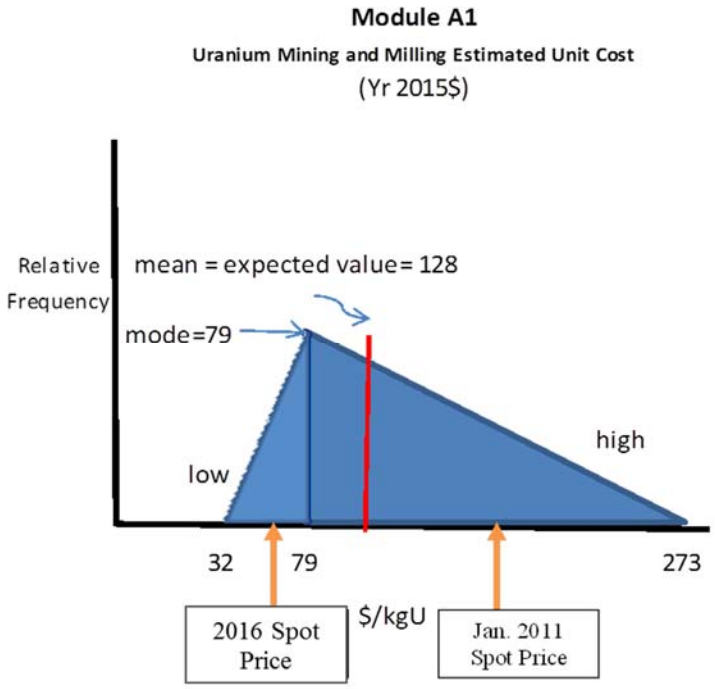


Figure A1– 24 Uranium Cost Range in 2015 CBR showing current and pre-Fukushima spot prices

A1-6.7 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– 14) 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 in 2006 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.[f] 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 K1.

Table A1– 14 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
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

f. Cost estimate based on communication with Uranium Disposition Services, LLC.

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).

A1-6.8 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– 15, 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– 15 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	1,090	1,270	1,560	1,870	2,114	2,822	3,327	3,719	4,346	5,281	7,245
Namibia	2,905	2,780	2,690	2,715	2,239	2,333	2,037	3,039	3,146	3,067	3,800
Niger	3,487	3,714	2,907	2,914	2,919	3,080	3,157	3,245	3,322	3,443	3,633
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	2,580	2,530	2,610	2,760	3,090	2,850	3,073	3,280	3,275	3,190	3,381
South Africa	1,100	965	927	798	878	824	763	747	673	534	750
Spain	255	255	255	255	30	37	0	0	0	0	0
Ukraine	1,000	1,000	1,000	1,005	750	800	800	855	830	808	900
United States	2,170	1,810	1,773	1,522	1,015	902	769	878	1,171	1,805	2,000
Uzbekistan	1,764	1,926	2,159	2,028	1,945	1,859	1,603	2,087	2,300	2,260	2,300
Total	36,724	34,886	32,179	36,011	37,020	36,042	35,492	40,263	41,943	39,603	43,328

NA = not applicable

e = expected

Source: Redbooks, 1997–2007

A1-7. DATA LIMITATIONS

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.

A1-8. COST SUMMARIES

This section presents low, high and nominal uranium price forecasts. Module A1, along with other front-end modules, addresses an industry with a well-developed market. Therefore, although the forecasts presented here are labeled 'costs' for consistency with the format used across this report, they should be interpreted as estimates of the long-term average uranium contract price (see discussion on the use of price data in the main body of this report).

Table A1– 16 summarizes the 100-year constant-dollar averages of the mineral index and MIT elasticity model forecasts from Section A1-2. Both models are ascribed equal credibility, so the module forecasts are generated from the average of the two. The low and high forecasts appearing in the what-it-takes table (Table A1– 17) should thus be interpreted as 95% confidence boundaries on the price forecast.

Table A1– 16 MIT and Mineral Index models: price forecasts [$/kg U] averaged over 100 years.

	Low Price (Bottom of 95% Confidence Interval)	Mean	High Price (Top of 95% Confidence Interval)
MIT Elasticity Model	88	139	227
Mineral Index Model	41	84	231
Average[1]	65	110	230
1. Rounded to the nearest $5/kgU			

Table A1– 17 "What-it-takes" (WIT) Table

Low Cost	High Cost	Nominal Cost
2012 CBR values based on second analytical method (2012$)		
$65/ kg U	**$230/ kg U**	**$110/ kg U**
2009 CBR Values based on first analytical method(2009$):		
$30/kg U	*$260/kg U*	*$75/kg U*
Composite 2012 CBR values essentially incorporating (including within assigned range) new 2012 values from additional methodology 3 rows above (2012$: no escalation assumed from 2009 values.		
$30/kgU	$260/kgU	$75/kgU
2015 CBR values based on escalation of 2012 values (whichare same as 2015 values) by 5% (2015$)		
$32/kgU	$273/kgU	$79/kgU

The approach to long term forecasting taken here explicitly avoids hypotheses over the resource discovery or technology development scenarios that give rise to the low and high outcomes. For instance, unconventional sources such as uranium in seawater, phosphate and shales may become economically attractive in the future as technologies for their recovery evolve. The 2009 CBR module discussed

prospects for these technologies. But the models used in the CBR have been chosen because it is arguably not possible to develop a credible forecast of the cost of these and other commodity-specific extraction and prospecting technologies over a century-long time frame.

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– 25.

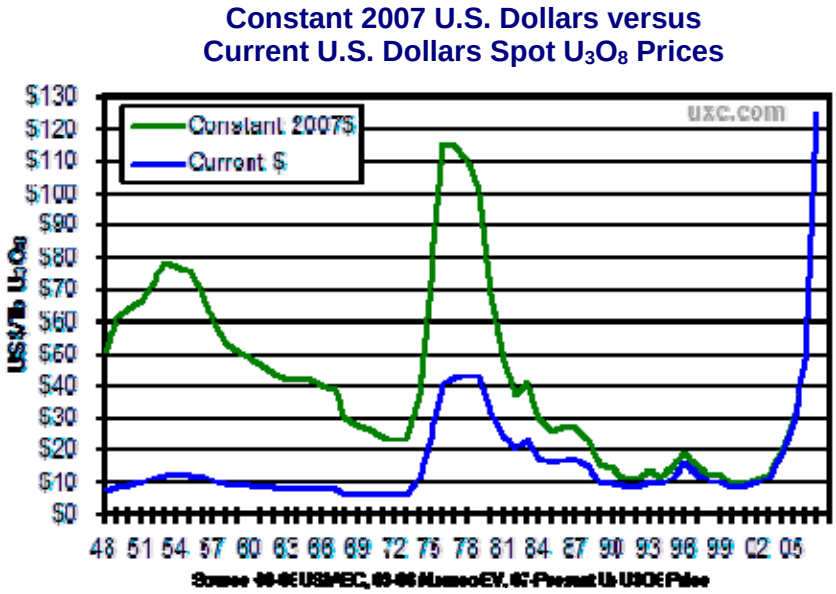


Figure A1– 25 U3O8 spot prices (UXC 2009).

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– 26). 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– 18).

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– 27 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.

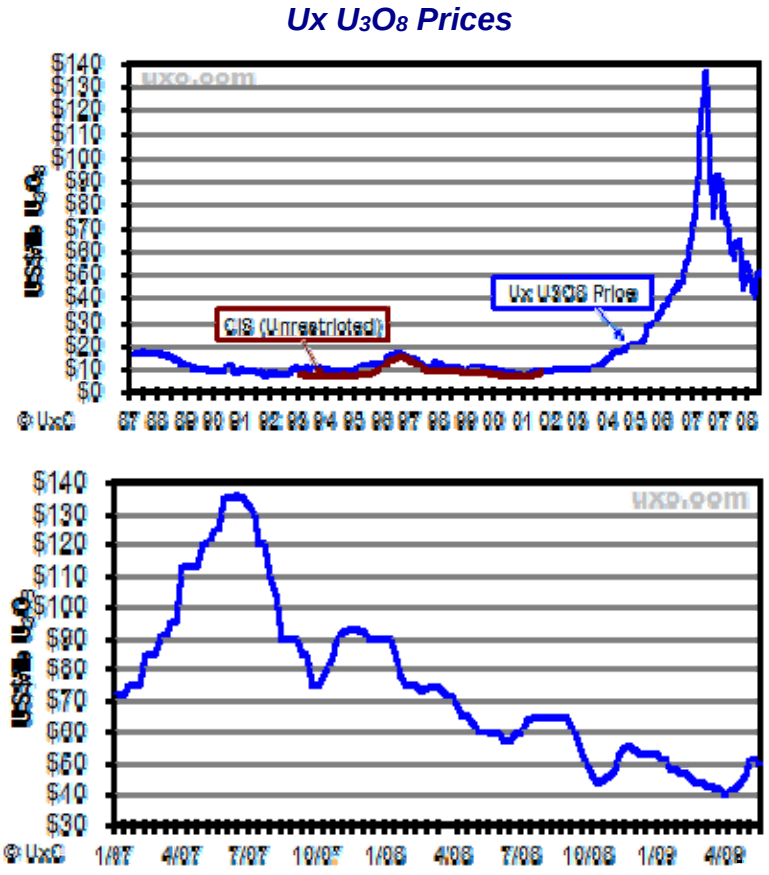


Figure A1– 26 U3O8 spot prices in current dollars, 1987–2009 (top) and January 2007–July 2009 (UXC 2009).

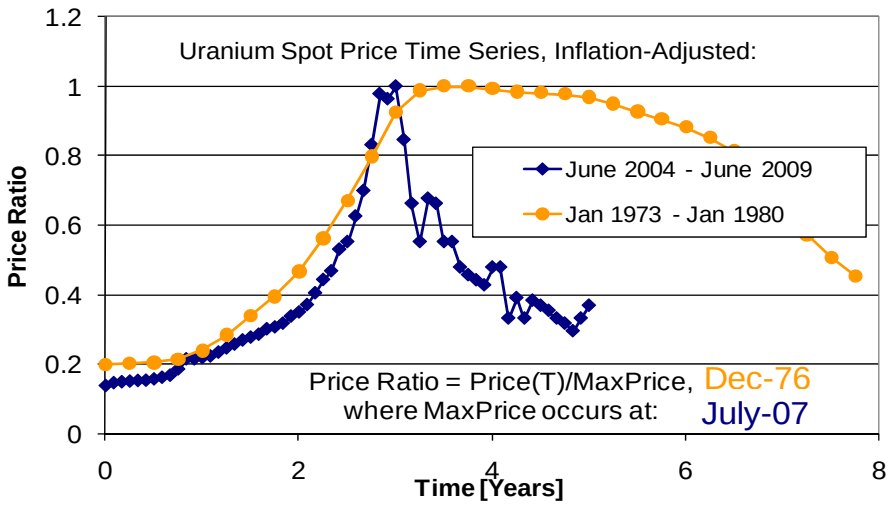


Figure A1– 27 Comparison of price histories during the late-1970s and mid-2000s booms.

Volumes of uranium contracted by utilities continued to be heavy into 2007. Table A1– 18 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– 18 U.S. reactor owner and operator multi-year contract volume (thousand lb U3O8) 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– 19 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[a] 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– 19 shows that utilities have responded to higher prices by moving away from contracts that are tied to spot market prices.

a. http://www.cameco.com/

Table A1– 19 US utility annual spot and contract-specified price (dollars per lb U3O8 unadjusted for inflation) and volume (thousand lb U3O8) 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.

A1-8.1 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 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– 28). Evidently, labor inputs to uranium mining have decreased significantly.

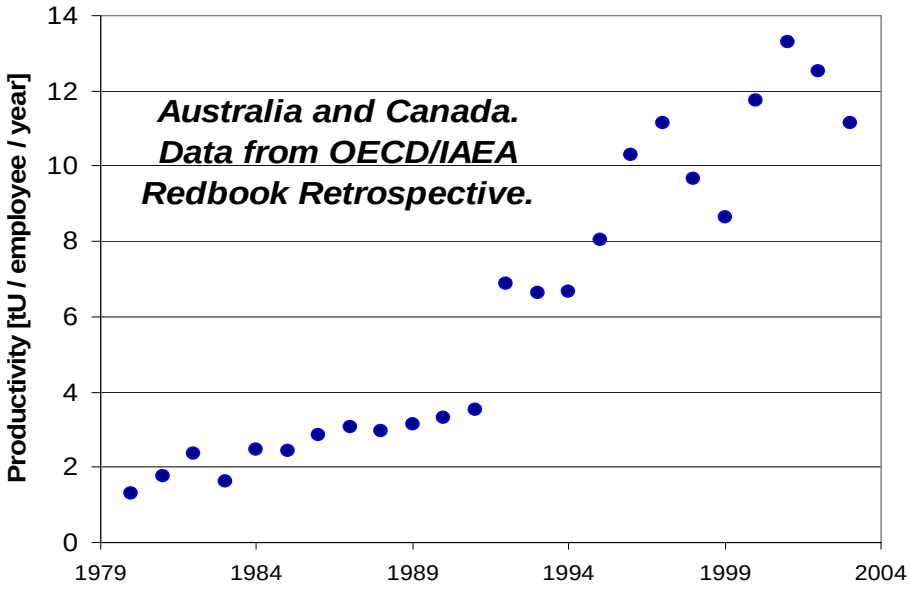


Figure A1– 28 Labor productivity, Australian and Canadian uranium mines.

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 2001). 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– 29. 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– 20gives the *M*-values obtained for all 35 minerals. The *M*-coefficients for six of the minerals were positive, while 29 were negative.

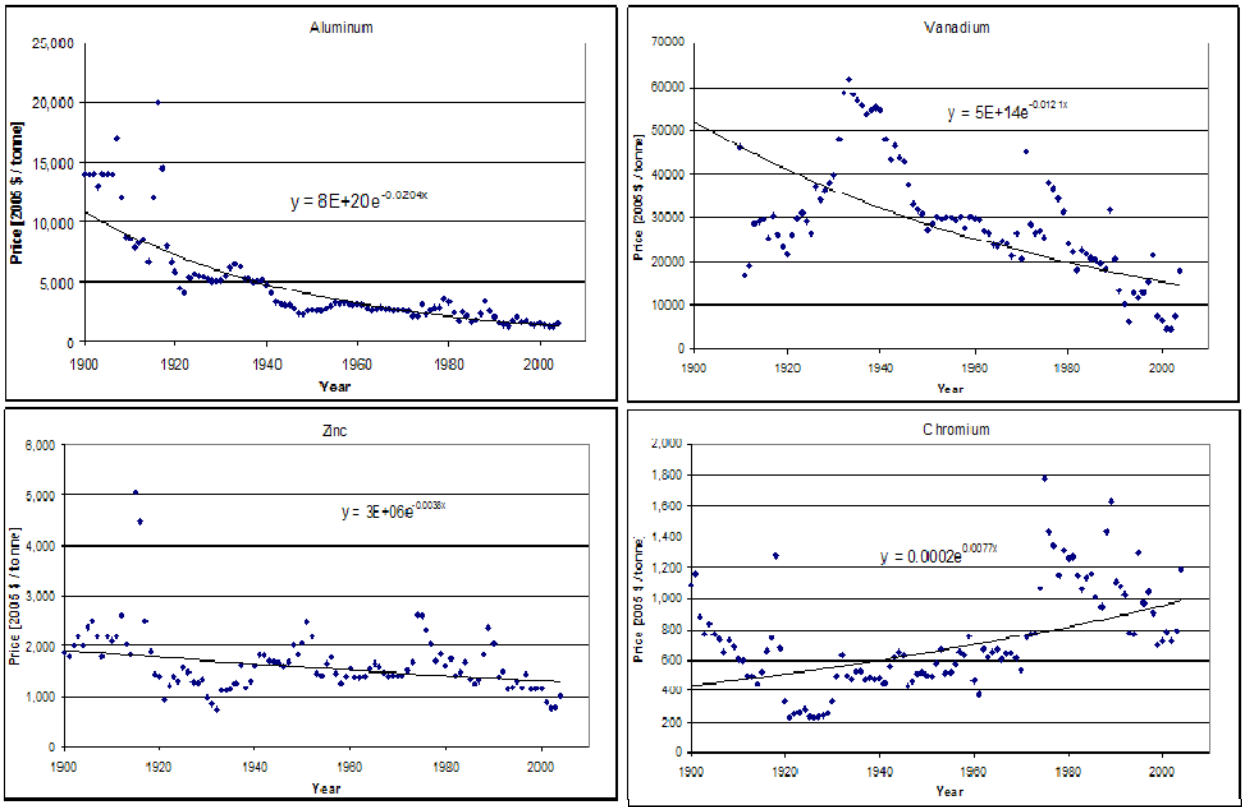


Figure A1– 29 100-year price trends for four minerals.

Table A1– 20 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 A1-20 shows that the mean value was negative: -0.0118. This implies a decrease in average mineral prices with time.[b] 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).

b. 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.

Table A1– 21 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– 26). Although contract prices at the time of delivery have historically averaged somewhat less than $100/kgU, Table A1-20 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)[c] 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– 30.

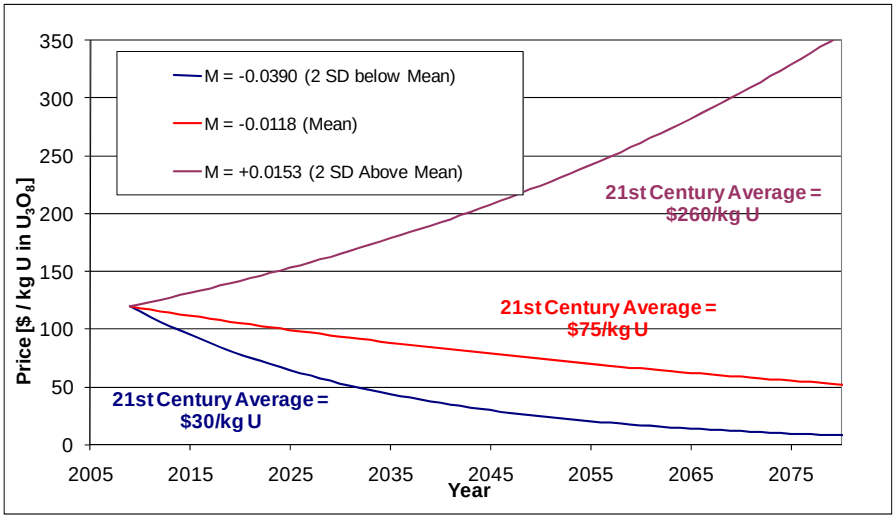


Figure A1– 30 Upper bound, most probable, and lower bound uranium price forecasts obtained from USGS data.

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.d The analysis described above accounted only indirectly for temporal variations in mining

c. 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.

d. 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

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– 22 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 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– 22 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– 22 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– 22 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

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.

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– 23. 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– 23 through Table A1– 27.

Table A1– 23 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– 24 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– 25 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– 26 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– 27 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– 31), 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– 31). 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.

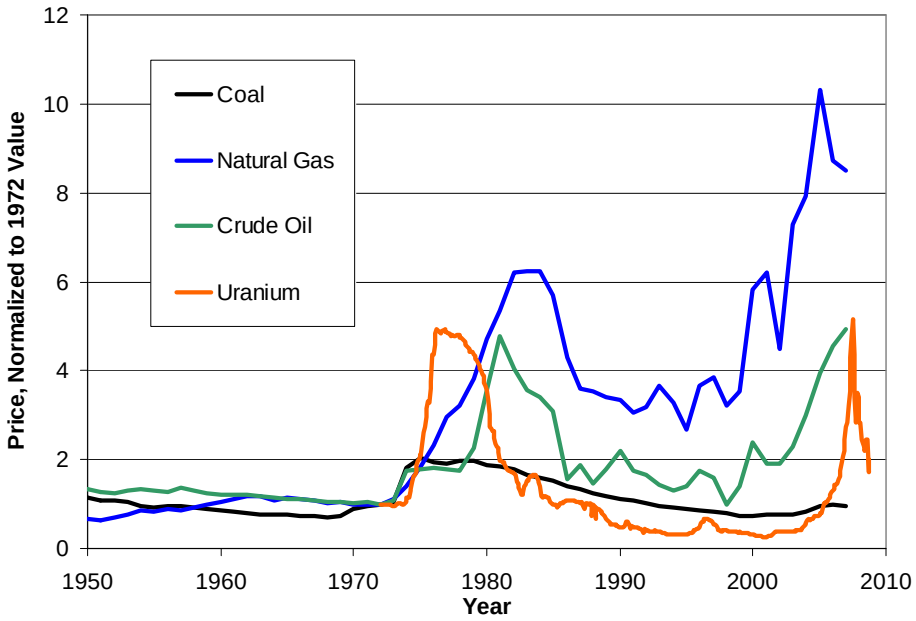


Figure A1– 31 Inflation-adjusted uranium and fossil fuel prices, 1972–2008. 1972 price = 1.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table A1–28. 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– 32. Note that the mean cost associated with this skewed distribution is $122/kgU. See Section A-6.1 for explanation.

Table A1– 28 Cost summary table, 2009$

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

Since the above costs represent long term prices rather than spot market projections, the issue of cost escalation arises. Long term stable prices must have underlying costs, which are subject to long term escalation. For this reason the costs in Table A1– 28 are escalated to 2017$ by 14% in Table A1–29 below. Table A1–30 summarizes all unit costs from four versions of the AFCBD: 2009, 2012, 2015, and 2017.

Table A1–29 Cost summary table escalated to 2017$.

What-It-Takes (WIT) Table					
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Low Cost	Mode Cost	Mean Cost	High Cost
$50–300/kgU	NA	$34/kgU	$86/kgU	$139/kgU	$296/kgU[f]
Reflects near-term (next 10–15 years)					

Table A1–30 Cost summaries by AFC-CBD editions

AFC-CBR Year (also base yr for constant $ costing)	Low	Mode	High	Mean	Change Basis from previous AFC-CBD
2009	30	75	260	122	New analysis by Module A author
2012	65	110	230	135	Supplemental analysis by Module A author essentially supporting original 2009 analysis by being included within 2009 range
2015	32	79	273	128	2009 range selected as basis since it is more inclusive and incorporates 2012 range. Escalation of 2009 values by 5%
2017	34	86	296	139	Escalation of 2009 values by 14%

e. 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.

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.

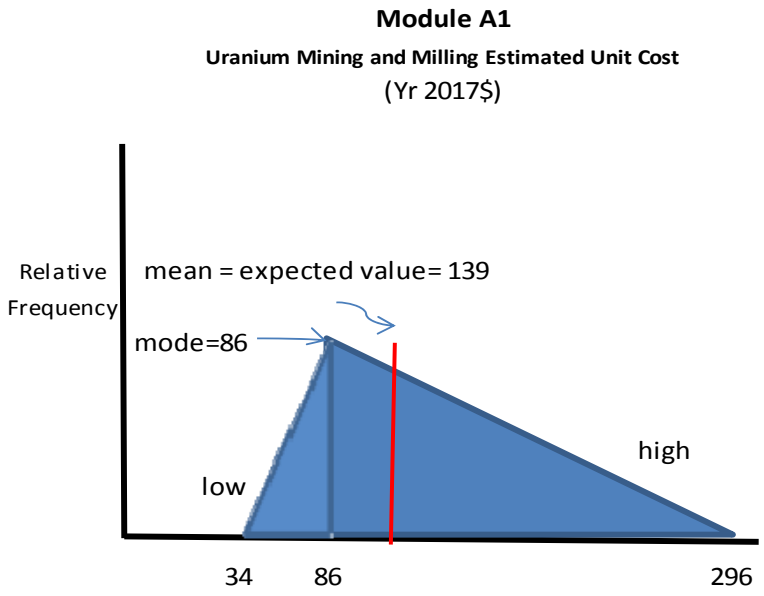


Figure A1– 32 Uranium mining & milling estimated cost frequency distribution.

A1-9. 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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Module A2

Thorium Mining and Milling

Module A2

Thorium Mining and Milling

A2-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from 2009
- **Estimating Methodology for latest technical update (2009) from which this 2017 update was escalated:** The analytical methods for the 2009 Thorium Mining and Milling unit costs/prices are the same as for Module A1 (Uranium Mining and Milling). As with Uranium Mining and Milling (A1) the Thorium costing methodology was augmented in the 2012 version by a different methodology which basicaly supported the results of the 2009 analysis. Cost/Pricing analysis methodology is based on analysis of historical data on other commodity metals which are mined and milled

A2-RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: In 2009 AFC-CBR Module A was separated into Module A1 for Uranium Mining and Milling and Module A2 for Thorium Mining and Milling. Thorium had not been considered in earlier AFC-CBR versions.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012 (This new data supported the 2009 ranges, which were used as the basis to escalate to 2017$)
- **New technical/cost data which has recently become available and will benefit next revision:** No particular new reports were identified. A search of new reports from MSR proponents who have interest in this issue might be warranted. The original author of Module A2 also suggested that costs associated with byproduct recovery of thorium salts from rare-earth mining and milling be eventually considered. This has the potential to reduce costs.

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 the alpha-emitting Th-228 ($T_{1/2}$=1.91 yr) decay product of Th-232, 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:

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

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 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

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).

for its rare earth content. As of 2009, 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 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 "gaslamp 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 AND DIAGRAMS

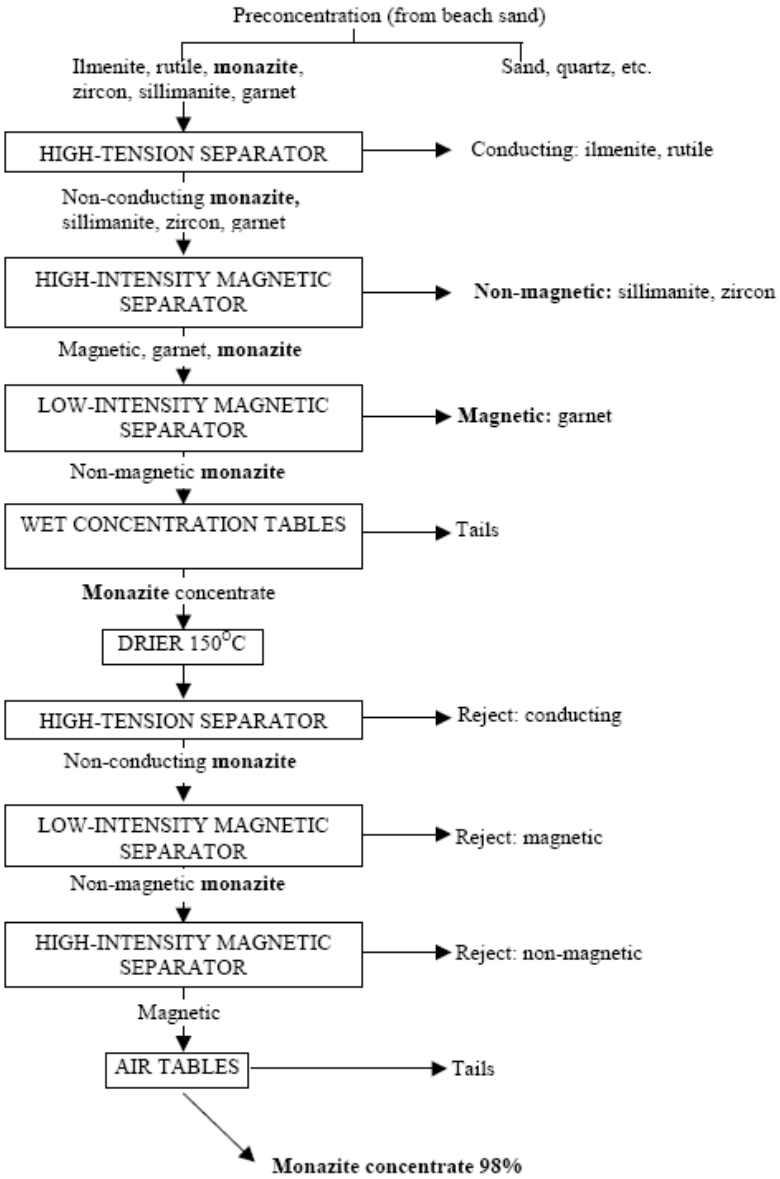

Figure A2-1. Flowsheet for monazite isolation (IAEA 2005).

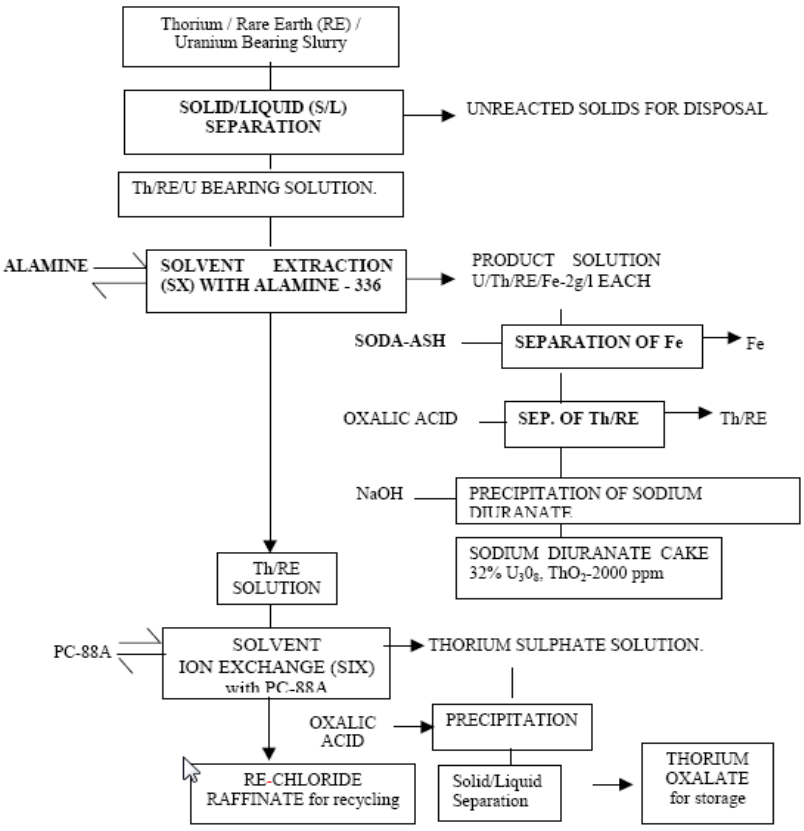

Figure A2-2. Flowsheet for thorium oxalate production from monazite (IAEA 2005).

A2-4 MODULE INTERFACES

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 enriched uranium (EU) is in use as a driver fuel. Therefore, Module A2 interfaces with Modules B and C1 in this context only.

A2-5 SCALING CONSIDERATIONS

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.

A2-6 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.

A2-6.1 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.

A2-6.2 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).

A2-6.3 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

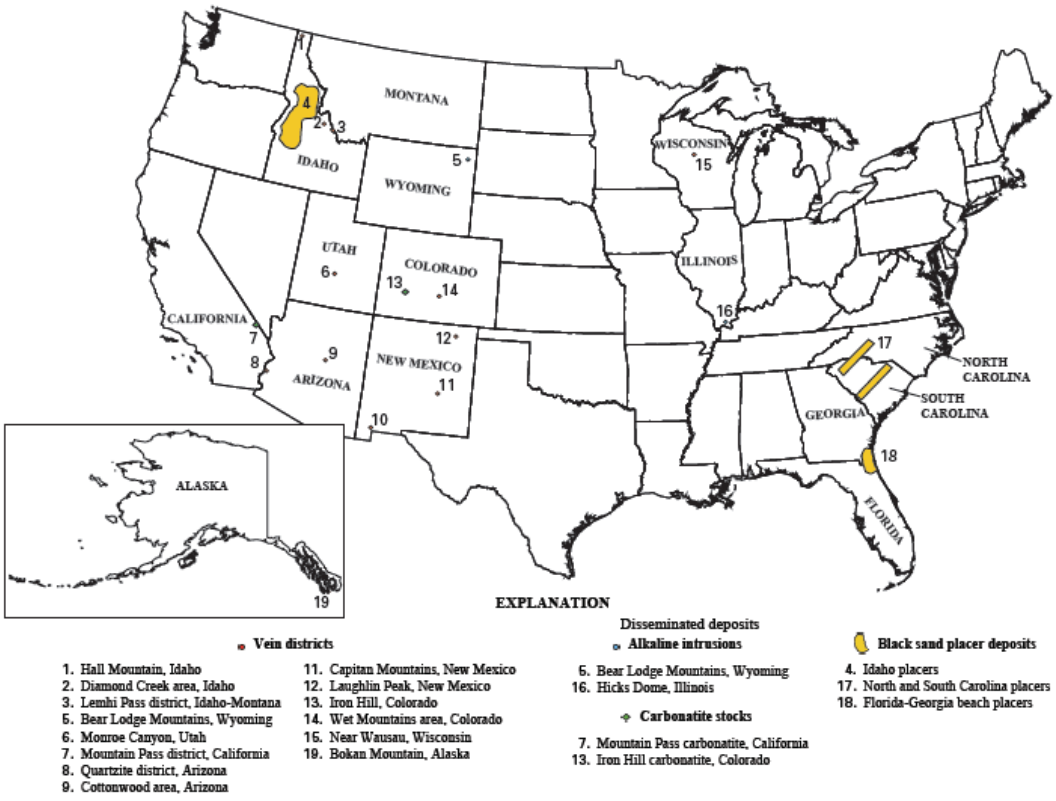

Figure A2-3. Location of prospected thorium deposits in the United States (Van Gosen et al, 2009).

A2-6.4 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.

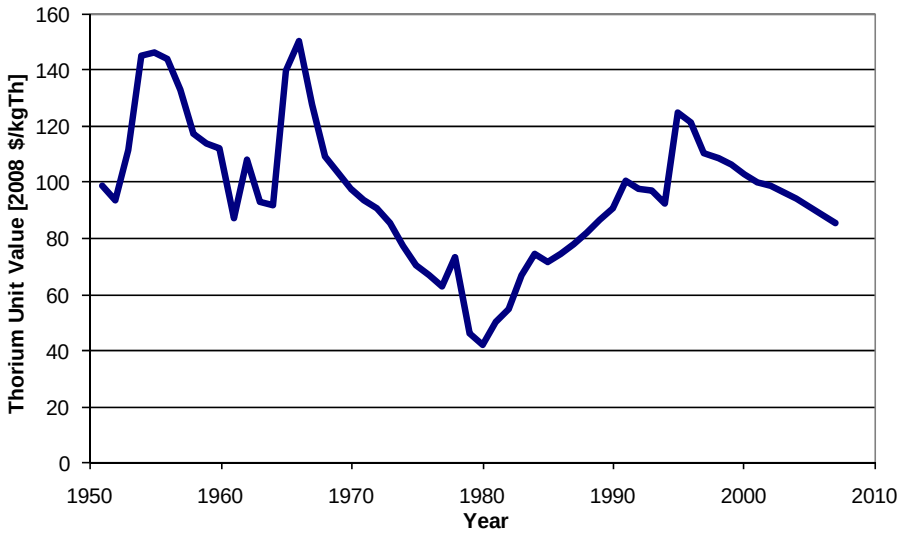

Figure A2-4. Thorium unit value, world mass-weighted average, 1952 to present, data in 1998 U.S. dollars (Hedrick 2009).

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.

A2-6.5 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.

A2-6.6 Consumption and Primary Supplies

Commercial use of thorium for incandescent lighting (ORAU 2009) applications (Welsbach mantles) 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).

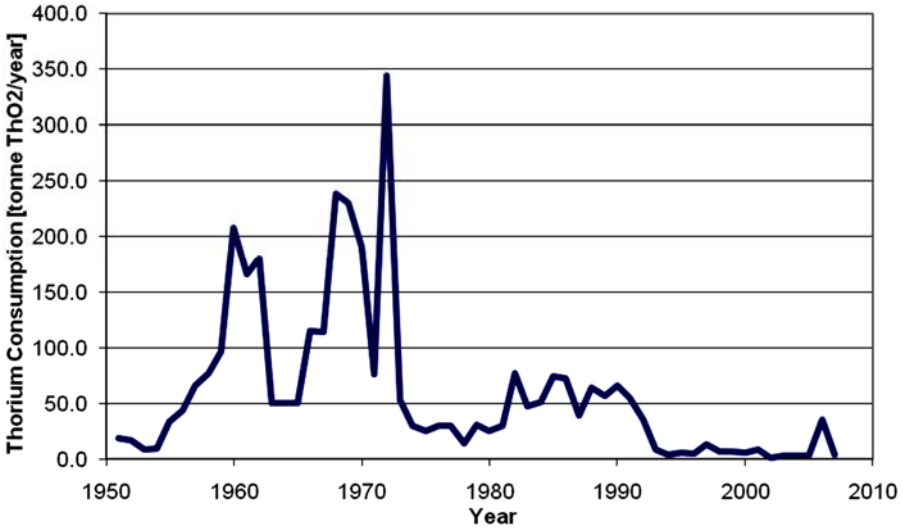

Figure A2-5. World thorium consumption, 1952 to present (Hedrick 2009).

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 2005). 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.

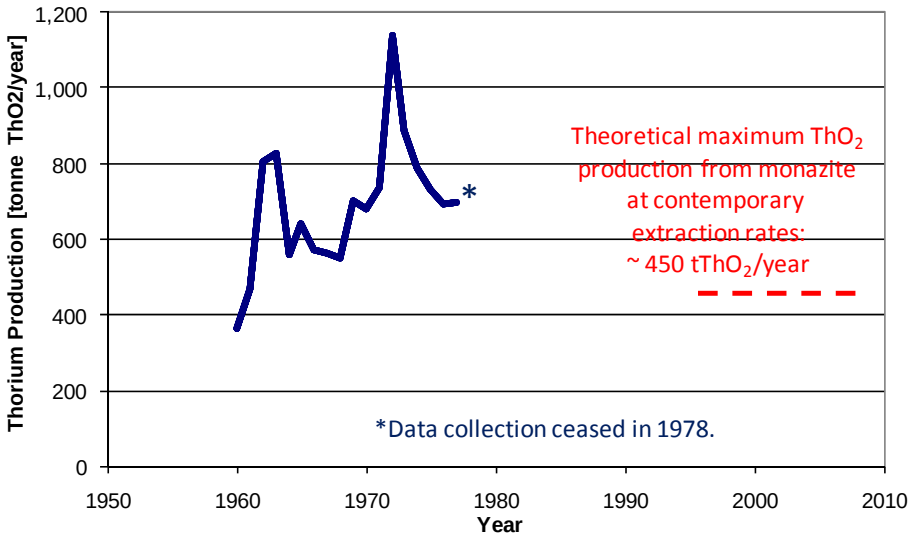

Figure A2-6. World primary thorium production (Hedrick 2000).

A2-7 DATA LIMITATIONS

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.**

A2-8 COST SUMMARIES

The sole update to the thorium mining and milling module is to the what-it-takes table. In the December *2009 Cost Basis Report* (2009 CBR), the relative distribution of low, high and nominal thorium mining and milling prices followed those of uranium, although the values themselves were one-third lower than those for uranium. Please refer to the 2009 CBR for discussion of the basis for this estimate and a review of historical thorium price data and price estimates.

Since the uranium price distribution has changed (see Module A1), the thorium forecast will be adjusted to maintain consistency. Table A2-9 updates the what-it-takes table for thorium mining and milling. All costs are at two-thirds of the corresponding values presented in Module A1, rounded to the nearest $5/kg Th.

Table A2-9. "What-it-takes" (WIT) Table (2012$). [Note: Table A2-12 gives the WIT values for the 2017 update]

Low Cost	High Cost	Nominal Cost
$45/ kg Th	$155/ kg Th	$75/ kg Th
2009 CBR Values:		
$20/kg Th	*$175/kg Th*	*$50/kg Th*

The price given above is for thorium as the oxalate, $Th(C_2O_4)_2 \bullet 2H_2O$. This is the forum of output by the Indian process, and the Indians are the largest producers at present. Thorium has also been shipped in oxide and nitrate forms.

No thorium is currently produced in the United States. Annual domestic consumption is miniscule: in 2011, less than 10 metric tonnes of thorium with a total value of $398,000 were purchased. The unit cost of these transactions averaged $68.6/kg Th [1]. Around the world, thorium is extracted from heavy-mineral sands as a constituent of the rare earth element (REE) bearing mineral monazite. Given low demand, the co-extracted thorium is generally not chemically isolated for marketing as a byproduct of REE operations but instead left in tailings and disposed.

The 2009 CBR estimate of thorium production costs assumes that thorium would be produced at scale as a major or sole product of mining and refining operations, as is the case for uranium. But it may prove that thorium requirements, even at the levels needed to support large-scale use of a thorium fuel cycle, can be satisfied solely through its production as a REE byproduct. Monazite generally contains 6 to 12% thorium oxide. 2011 world production of monazite concentrate was at least 6,410 metric tonnes (China, Indonesia and others may also possess monazite operations but did not report data) [1].

If byproduct production of thorium proves likely to be sufficient, reduction of the low and nominal cost estimates presented here would be justified. The new Th production cost estimates would be tied to the cost of isolating and refining thorium from acid or alkaline solutions during monazite cracking.

Assessments are ongoing of both the feasibility of meeting requirements solely from byproduct operations and the cost of the associated Th refining process. Their results will be addressed in the next update of the CBR.

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 A2-10 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 A2-10. 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.

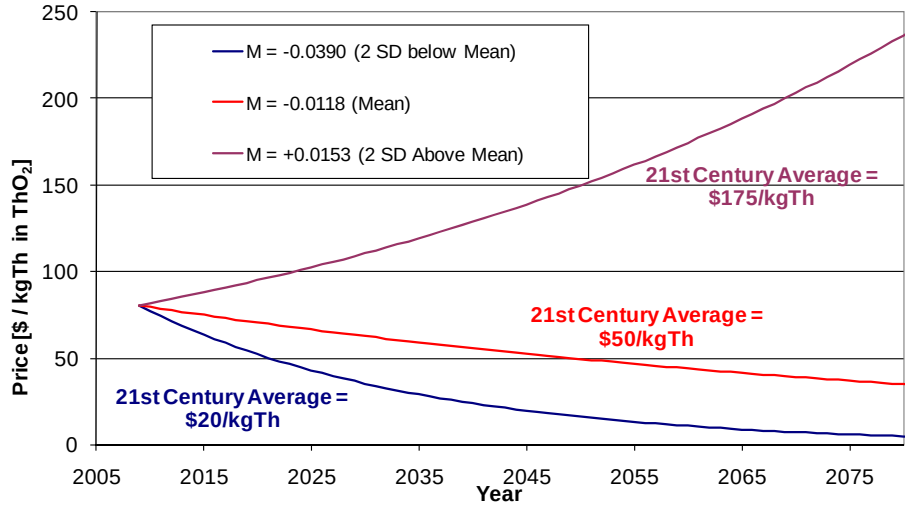

Figure A2-7. Upper bound (purple), most probable (red), and lower bound (blue) uranium price forecasts obtained from USGS mineral price model data.

A2-8.1 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 A2-10. Cost summary table, 2012 $. [Note: these differ from those in Table A2-9 and are based on the same type of analysis as uranium. The range below is inclusive of the values in Table A2-9.]

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

As with uranium mining and milling, throrium mining and milling costs (and ultimately prices) are subject to escalation. Table A2-11 below shows the year 2015 $ costs.

Table A2-11. Cost summary table escalated to 2015 $.

What-It-Takes (WIT) Table					
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Low Cost	Mode Cost	Mean Cost	High Cost
$84/kgTh	NA	$21/kgTh	$53/kgTh	$86/kgTh	$184/kgTh
For Th as ThO_2 (99.9% purity)					

Table A2-12. Cost summary table escalated to 2017 $. [Note: factor of 1.14 esed to escalate from 2009 $.]

What-It-Takes (WIT) Table					
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Low Cost	Mode Cost	Mean Cost	High Cost
$84/kgTh	NA	$23/kgTh	$57/kgTh	$93/kgTh	$200/kgTh
For Th as ThO_2 (99.9% purity)					

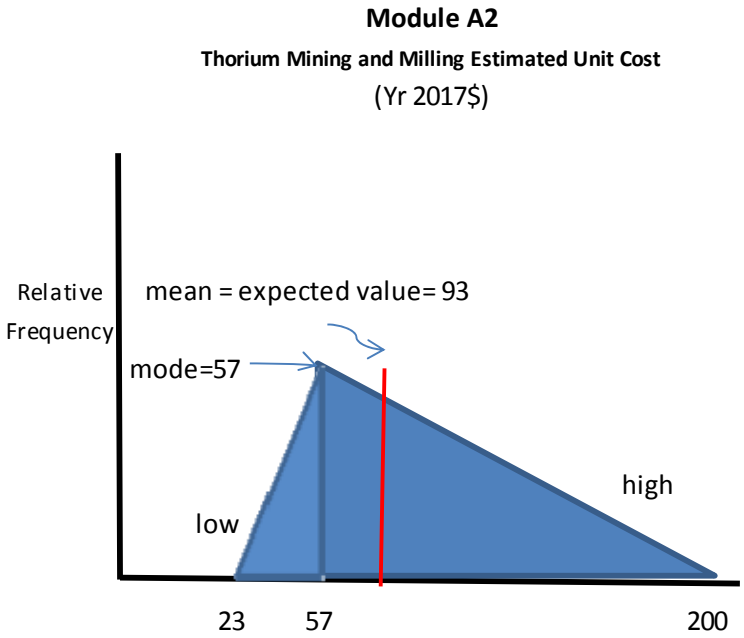

Figure A2-8. Thorium mining and milling estimated cost frequency distribution

A2-9 SENSITIVITY AND UNCERTAINTY ANALYSES

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.

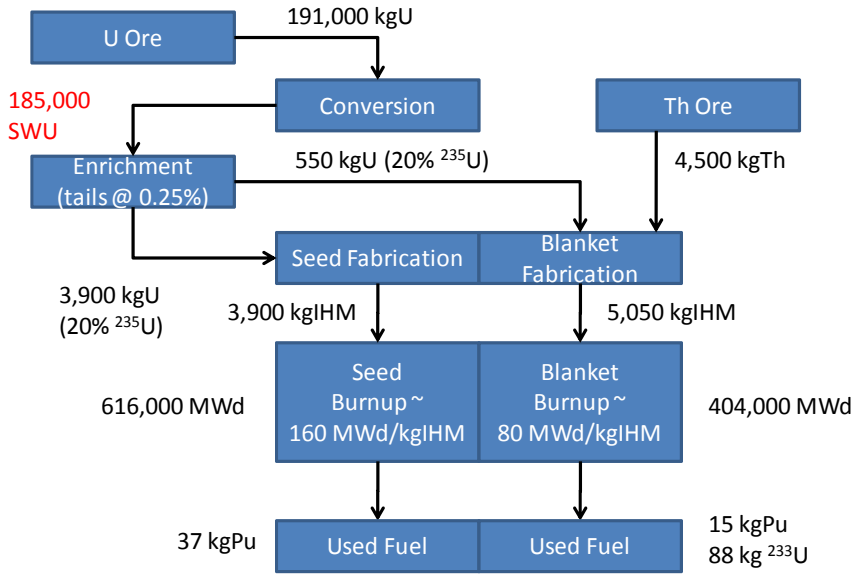

Figure A2-9. Annual mass flow chart for the once-through (Galperin, Radkowsky, Todosow 1999) concept in a 3400 MWt PWR.

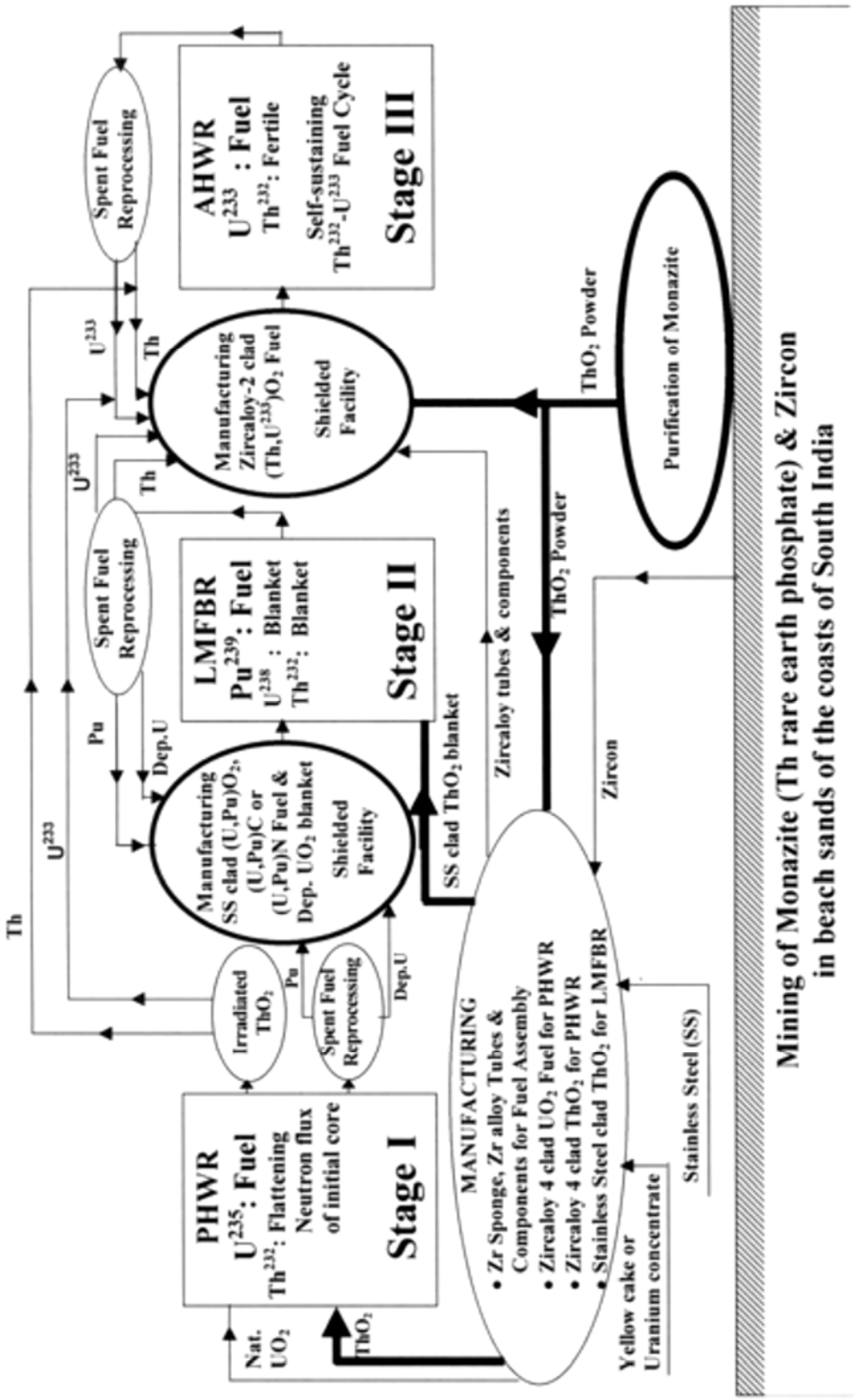

Figure A2-10. India's three-stage path to a closed, breeding thorium cycle (IAEA 2005).

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MODULE B

Conversion

Module B
Conversion

B-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
    - Price and market analysis similar to that use for Uranium Mining & Milling (Module A1)

It should be noted that Module B (Conversion) prices should correlate with mining and milling (ore) unit costs and uranium enrichment costs. This fact should be recognized in any analysis.

B-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module B.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**

  The US conversion plant at Metropolis, Illinois has had to make several NRC-mandated safety upgrades to maintain its license. These may affect the price the owner must charge to cover costs.

  Due to recent poor market conditions (late 2017) the metropolis plant is being placed in standby mode.

  The availability of byproduct HF from depleted UF6 deconversion operations could help reduce feedstock costs to conversion plant owners.
- **A market analysis in 2016 served as a "spot check" on the situation in the market for conversion.** A summary of that spot check is included in section B-6.1.

B-1. BASIC INFORMATION

Module B discusses the step in the nuclear fuel cycle where the mined natural U_3O_8 concentrate is further purified and converted to a natural 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 chemically-purified uranium gaseous form to enrich for fuel fabrication. The U.S. annual demand for conversion (as of 2012) 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. 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, such as for many CANDU-type pressurized-heavy-water reactors (PHWRs), the yellow cake can be processed directly to UO_2 for fuel fabrication. In the more common LWR fuel cycle 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 (F2) 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 B1– 1).

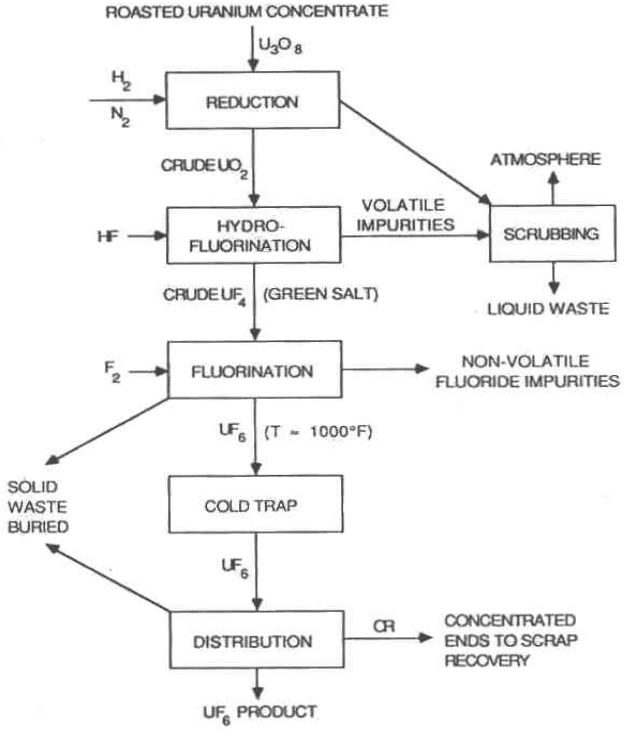

Figure B1– 1 Simplified flow chart of the dry hydrofluorination process to convert U3O8 to UF6.

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 B1– 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%).

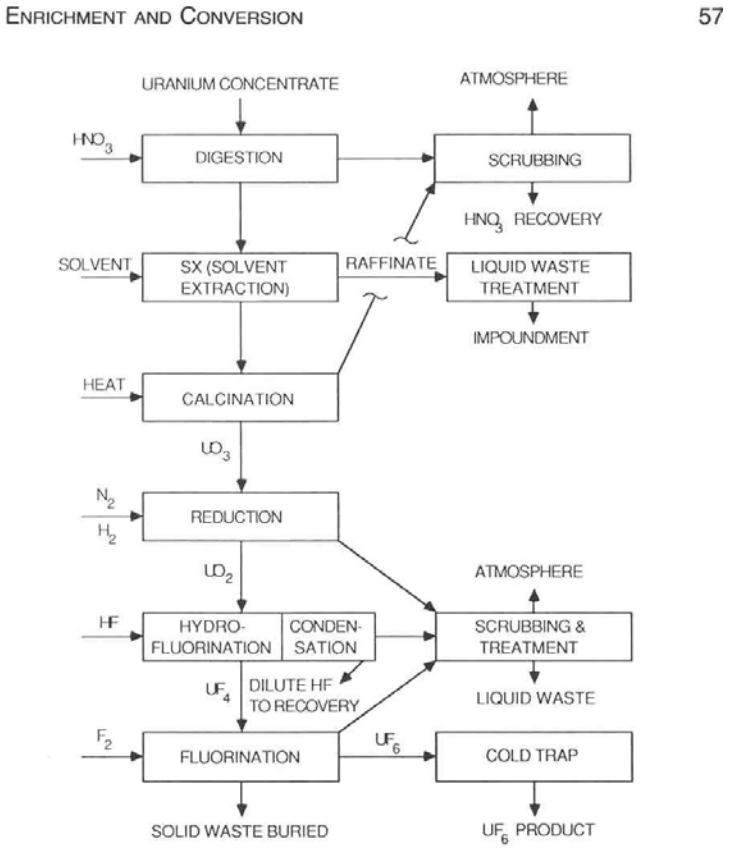

Figure B1– 2 Flow chart of the wet solvent extraction-fluorination process to convert U3O8 to UF6.

B-3. PICTURES AND DIAGRAMS

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 natural UO2 fuel bundles for use in Canada deuterium uranium (CANDU) reactors. Pictures of the conversion facility are shown in Figure B1– 3 and Figure B1– 4. A loaded UF_6 cylinder is shown in Figure B1– 5.

Figure B1– 3 Port Hope Conversion and Fuel Fabrication Plant (Cameco) in Ontario, Canada.

Figure B1– 4 Port Hope conversion facility.

Figure B1– 5 Loaded UF6 cylinder at Port Hope.

B-4. MODULE INTERFACES

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

Mid-2012 world nameplate annual conversion capacity stands at around 75,000 tonnes U in UF_6 (Table B-1). This is considerably in excess of requirements, even if secondary supplies of conversion

services[a] are discounted. Important secondary supplies include the ca. 9,000 tU in UF_6 of conversion requirement avoided by HEU down blend [Schwartz et al 2012a] (see Module C2) and inventories of natural U as UF_6 held by utilities and governments around the world.

In France, AREVA anticipates the COMURHEX II facilities at Malvesi and Pierrelatte to enter production in 2012, reaching a capacity of 15,000 tU in UF_6/year shortly thereafter (WNA 2007a). COMURHEX II involves substantial renovations and construction at Malvesi and an entirely new plant at Pierrelatte. These operations will improve the efficiency of the chemical process equipment and the waste treatment systems. While the project will add only 1,000 tU/year of capacity as compared to the current COMURHEX level, the AREVA website[b] indicates that capacity may rise to 21,000 tU in UF_6/year.

As reported in the *2009 Advanced Fuel Cycle Cost Basis Report*, the industry has been beset with temporary plant closures and production shortfalls, notably at Port Hope, Ontario in Canada. Also, the nominal capacities reported in Table B-1 cannot be achieved at each plant. Port Hope, with a nameplate capacity of 12,500 tU in UF_6/year, has been reported to sustain an annual operating capacity of 8,000 – 10,000 t/year. The Rosatom (Russia) facilities together represent 24,000 tU in UF_6/year of nameplate capacity, but a significant portion of that is not maintained and currently not operational. Operating capacity has been estimated at just 11,000 [Schwartz et al 2012b] to 18,000 [WNA 2012] tU in UF_6/year and actual production during 2008-10 averaged 8,500 tU in UF_6/year [Schwartz et al 2012b].

Part of the Metropolis Works (MTW) in Southern Illinois is offline indefinitely, so that plant has a de facto capacity of 12,000 tU in UF_6/year [Schwartz et al 2012b], 20% below its nameplate level; during 2007-10, production at MTW averaged 9,110 tU in UF_6/year [ENERCON 2012]. In part, this reflects a slowdown associated with a labor disagreement that was resolved in 2010. In July 2012, the US Nuclear Regulatory Commission issued a finding that the UF_6 released from "a credible seismic event could result in a higher risk to the public than currently assumed." As a result, MTW will likely be offline for 12-15 months, through late 2013, while it conducts remedial actions [Steiner-Dicks 2012].

Springfields (United Kingdom) is managed by Westinghouse for the UK Nuclear Decommissioning Authority, but Cameco has contracted for 5,000 tU in UF_6/year conversion services to process UO_3 feed from its Blind River Refinery. Once Cameco's contract expires in 2016 it is likely that Springfields will be decommissioned.

Table B-1. Nominal June 2012 conversion capacities.[1]

Operator / Plant(s)	June 2012 Capacity (tU in UF_6/year)	Technology, Notes
CNNC/Lanzhou, China	3,000	
AREVA-Comurhex/Malvesi and Pierrelatte, France	14,000	Wet process: UF_4 conversion at Malvesi, fluorination to UF_6 at Pierrelatte. Comurhex II coming online 2012.
Cameco/Port Hope, Canada	12,500	Blind River refines yellowcake to high purity UO_3. Port Hope (wet process) converts purified UO_3 to UF_6.
Westinghouse – Cameco / Springfields, UK	6,000	Wet process: Main Line Plant converts to UF_4, Hex Plant to UF_6. May cease operations in 2016.
ConverDyn / Metropolis, IL,USA	15,000	Dry process.
Rosatom / Angarsk, Sverdlovsk-44, Russia	24,000	Wet process: UF_4 conversion at Chepetsk Mechanical Plant, fluorination to UF_6 at Angarsk and Sverdlovsk-44
TOTAL	**74,500**	

1. Only plants having greater than 250 tU/yr capacity reported. Data Source: Ref. B-1. Note that at some facilities operable capacity may be significantly lower than nominal capacity: see text.

[a]. Secondary supplies of conversion represent avoidance of the need to convert natural uranium. This may come about if the uranium was previously converted and is stored as UF_6, or if reactor fuel can be directly produced without the need for conversion and enrichment (e.g. HEU down blend, or conversion to UO3 for PHWR fuel—see footnote 17).

[b]. http://www.areva.com/EN/operations-806/the-comurhex-ii-project-modernization-of-the-industrial-conversion-facility.html

Taken together, the outages, pending retirements and unavailable capacity indicate a considerably tighter supply situation than a comparison of Table B-1 with requirements would indicate. In the near term, the temporary closure of MTW in particular is likely to spur higher prices. On the other hand, much capacity could be brought online relatively quickly by refurbishing unused equipment. Therefore, when looking to medium to long term costs, a future pattern of frequent closures and low facility availability will be considered to inform the high cost estimate. The nominal and low estimates will assume that recent events are not indicative of industry performance in the future.

B-4.2 Demand

Requirements for conversion services closely track uranium requirements, with small differences arising from reactors that use natural uranium as fuel and need no enrichment[c]. The Energy Resources International, Inc., reference forecast predicts that conversion requirements will rise from their 2012 level of 58,000 tU in UF_6/year to 73,000 tU in UF_6/year in 2020 and of 92,200 tU in UF_6/year in 2030 [Schwartz et al 2012b]. The contemporary requirement is somewhat lower than the value in the *December 2009 Advanced Fuel Cycle Cost Basis Report* because elevated uranium prices have pushed utilities to conserve uranium by lowering enrichment tails U-235 assays. The reduction in uranium requirements also lowers the need for conversion services.

Thus, existing capacity, if refurbished, fully utilized and reliably operated, along the mooted AREVA and expansion and secondary conversion supplies would be adequate to meet demand through this decade.

B-5. SCALING CONSIDERATIONS

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

The historical spot market price of conversion services is shown in Figure B1– 6. Most conversion service requirements are met via long term contracts and these have not shown the volatility of the spot prices. They are reported to have remained at around $11-12/kg U as UF6 from 2005-10, closely tracking the spot price. Since that time, though, they have risen steadily, reaching $16.75/ kg U as UF6 as of the end of the first quarter of 2012 [Schwartz et al 2012b]. This reference also notes that the work slowdown at MTW as well as an announcement by ConverDyn regarding future pricing (discussed below) coincided with the increase in long-term contract prices. Contract prices lag spot prices, so the contract price may decline in the near future. Or the low spot price could be a function of lowered expectations for demand post-Fukushima as well as a short-term supply glut. [2017 Note: As of June 26, 2017 the North American and European spot price per UxC stands at $5/kgU as UF6 in an extremely depressed market.]

[c]. These fuels still require conversion services of a sort – from U_3O_8 to UO_3 with an intervening aqueous purification step and subsequently to UO_2. In Canada, the UO_3 operations are carried out at the Blind River refinery, and Port Hope contains facilities for converting the UO_3 to both UO_2 for domestic use and UF_6 for export.

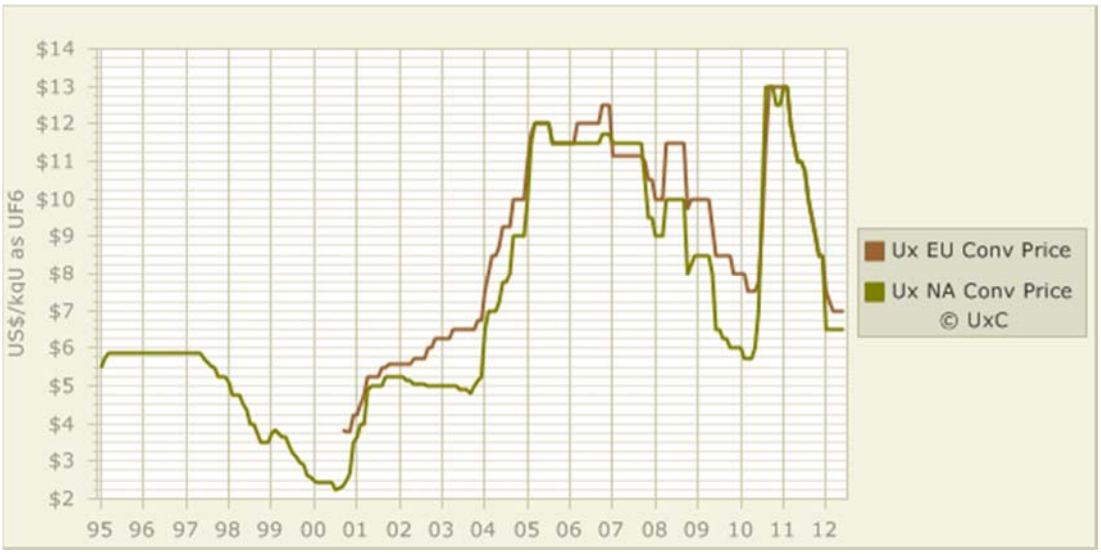

Figure B1– 6 UxC Conversion Spot Prices, 1995-2012, for European (EU) and North American (NA) deliveries. Figure source: The Ux Consulting Company, LLC, http://www.uxc.com/.

An essay at the website of UxC, a brokerage firm whose spot price data is shown in Figure B1– 6, suggests that raw material expenses have played a role in elevating conversion prices [Ux Consulting]. The costliest raw material input to the conversion process is hydrofluoric acid (HF). HF is in turn produced by reacting the mineral fluorspar (CaF_2) with an acid. China, Mexico, South Africa and Canada are major producers of fluorspar, with the United States receiving most (78% in 2011) of its supply from Mexico [USGS 2012]. The spot market price of fluorspar experienced a boom in 2007-08, increasing by 140% from early 2007 to its peak in the fourth quarter of 2008. This boom was in part caused by an increase in an export tax in China, a major producer, as well as sharply increasing demand inside of China and worldwide [Henkel Adhesive Technologes 2009]. Fluorspar prices, which had stood at $290/tonne at the end of 2010, rose again in 2011, reaching $450/tonne[d] by the end of that year, $600/tonne when insurance and freight are included.

Fluorine derivatives are widely used across the industrial sector, for instance in the production of refrigerants. Conversion related consumption of fluorspar represents a tiny fraction of world consumption. For example, US consumption of fluorspar in 2011 was 454,000 tonnes [USGS 2012]. Even if the domestic converter, Metropolis Works, operated at its full capacity of 15,000 tonnes U in UF_6 per year, it would require the equivalent of 14,700 tonnes of fluorspar, just 3.2% of domestic consumption[e]. And even at the end-2011 delivered fluorspar spot price of $600/tonne, purchase of fluorspar would only contribute $0.59/kg U in UF_6 to the cost of UF_6 conversion[f].

The large and diverse demand pool is considered to make it more likely that new fluorspar resources will be prospected and exploited. Additionally, substitutes may be developed within other industries where the commodity is used, restraining prices from increasing dramatically over the long term. While speculative effects and stockpiling arising from a sudden, unexpected increase in the price of fluorspar could affect short-run conversion prices, as arguably occurred in the late 2000s, the contribution of the fluorine input to the cost of UF_6 conversion remained relatively small. While modest further increases in

[d]. Prices are numerical averages of Chinese- and Mexican-delivered free on board (f.o.b.) fluorspar filtercake.

[e]. There are 0.487 kg of fluorine per kg of fluorspar and 0.479 kg of fluorine per kg of U in UF_6. Fluorination of 15,000 tonnes U per year thus requires (15,000)*0.479/0.487 = 14,700 tonnes of fluorspar.

[f]. ($0.60/kg CaF_2)*(2.052 kg CaF_2/kg F)*(0.479 kg kg U in UF_6/kg F in UF_6) =$0.590.

the price of fluorspar are possible, in the long term it is considered unlikely that these will materially affect the cost of conversion.

The cost of energy inputs is more substantial. Metropolis works, which uses a "dry" conversion process, reported average electricity and natural gas consumption over 2007-10 of 6.8 MWh/tonne U as UF_6 and 4.59 thousand cubic meters/tonne U as UF_6, respectively [Enercon 2012]. Other facilities around the world use the wet process, but data furnished by AREVA indicated roughly equivalent final energy consumption on a per unit product basis [Simon et al 2011][g]. Assuming for illustration electricity prices of $100/MWh (10 cents/kWh) and natural gas prices of $111 per thousand cubic meters[h], the direct energy costs for Metropolis would be roughly $1.2/kg U as UF_6.

To this must also be added the energy consumed in creating feed chemicals, particularly hydrofluoric acid. In the 1970s, Rotty estimated the energy embodied in process materials (as cited in [Simon et al 2011]) at 4.25 MWh/tonne U as UF_6 and 3.09 thousand cubic meters of gas/tonne U as UF_6. Using the prices given above, the energy used to create process materials would cost an additional $0.77/kg U as UF_6, bringing the total contribution of operational energy use, both direct and via energy embodied in materials, to roughly $2.0/kg U as UF_6. This constitutes a substantial share of the nominal conversion cost estimate presented in Section B-3 below – one that would increase if natural gas prices rise from their current (2012) depressed levels.

True production costs at the various conversion facilities around the world are proprietary, and market effects are such that prices are not generally tied to production costs at any one facility. But some information can be gleaned. In late 2010, ConverDyn disclosed that its conversion operations were incurring financial losses and as a result it would not offer conversion services at prices lower than $15/kg U as UF_6 [Schwartz et al 2012b]. MTW's production costs can thus be inferred to be at or near this level. It may be the case that MTW is the marginal (i.e. costliest to operate) producer and its move spurred the increase in long term contract prices mentioned earlier. Having been in operation for over 50 years, MTW is the oldest supplier, and as such it is reasonable to assume its operating costs are higher than those of the modern plants.

It should be noted that hydrofluoric acid (HF) is now (2017) being produced as a byproduct of the deconversion of depleted UF6 "tails" from uranium enrichment plants. (See Module K1). Use of this very slightly contaminated HF in another nuclear facility such as a conversion plant is an ideal symbiotic use.

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. 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.

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.

[g]. The Areva figures, from the project Epicure reprocessed uranium conversion facility study, are 28.1 MWh/tonne U as UF_6 and 1.94 thousand cubic meters/tonne U as UF_6. The Areva design evidently favors electricity over natural gas combusted on site, but the total energy use (in GJ/tonne U as UF_6) is very similar to that of MTW. The MTW data is used as it is taken from an operating facility.

[h]. A spot price for July 2012 reported at http://www.indexmundi.com/commodities/?commodity=natural-gas.

B-6.1 2016 Spot Market Check on Market for Conversion

The long-term U3O8 to UF6 conversion price trend has generally followed that of U_3O_8, but within a tighter range and without the speculative spike in 2007. Spot prices have descended from $13/kgU in 2011 to $6/kgU as of the end of August, 2016 [UxC 2016]. Unlike U_3O_8, prices for conversion had a plateau for a year in 2013 around $11/KgU due to the main facility in North America (Honeywell's Metropolis, Illinois facility) being down for seismic retrofits[i]. These retrofits were ordered by the NRC in response to Fukushima.

As of 2016, the conversion spot prices are on the lower end of the range in the 2015 CBR (low $6, mode $13, high $19, mean $13/KgU) and the historic prices have only reached the middle of this range. However, prices for conversion were running between $11-13/kgU between 2011 and 2014, indicating the spot market has been depressed, possibly by DOE inventory sales of UF6 [UxC 2015] – See Figure B1– 7.

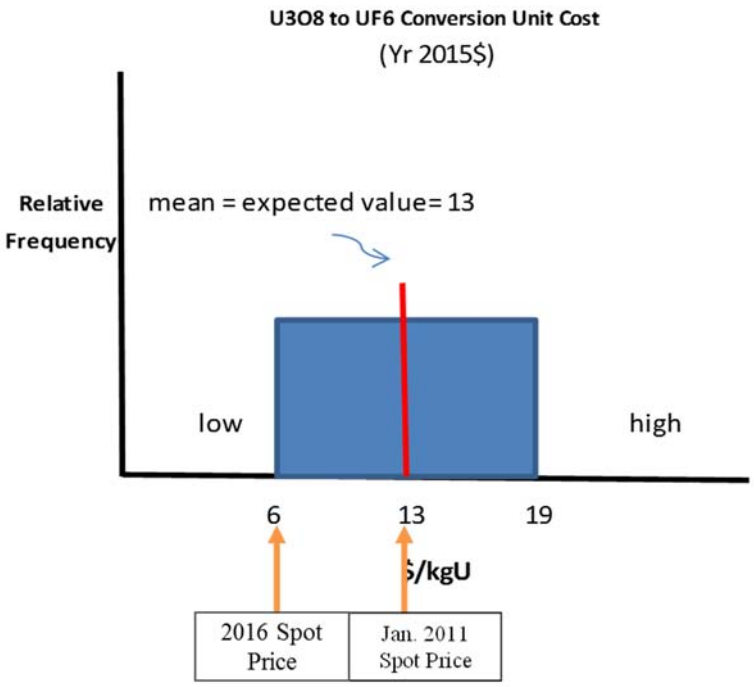

Figure B1– 7 Uranium Conversion Cost Range in 2015 CBR showing 2016 and pre-Fukushima spot prices.

No significant new conversion facilities have been built in 30 years, while demand in Asia had been increasing prior to Fukushima. The current construction in France (Comurhex II) will replace existing capacity. If significant reactor restarts occur in Japan and other construction in Asia and the Middle East continue, or if DOE inventory sales of UF6 cease, then upward pressure on spot prices will occur. For these reasons, we do not recommend any changes in the CBR recommended prices.

B-7. LIMITATIONS OF COST DATA

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

[i] The other facility in North America is Cameco's Port Hope plant in Ontario, Canada.

typically less than 4% of the fuel cost. Short-term fluctuations should have little to no impact on the overall fuel cycle costs.

B-8. COST SUMMARIES

This section presents low, high and nominal conversion **price forecasts**. Module B, along with other front-end modules, addresses an industry with a well-developed market. Therefore, although the forecasts presented here are labeled 'costs' for consistency with the format used across this report, they should be interpreted as estimates of the long-term average SWU contract price. See the earlier section in this addendum on the use of price data for further discussion.

The **nominal** estimate, \$12/kg U in UF_6, splits the difference between the recent spot and contract prices. It assumes that major supply disruptions, a fixture of the industry from the mid-2000s to the present, are a temporary phenomenon. The projection considers a future where first-generation plants are fully retired in favor of facilities utilizing modern equipment and offering favorable operating costs. This transition is being completed in the enrichment industry: see Section C-1 for discussion. On the other hand, the capital costs of many currently-operating plants are fully amortized, so the depressed spot market prices in 2012 may reflect recovery of operating costs alone and underestimate true production costs. Indeed, in April 2012 an Areva executive stated that the Comurhex II "business plan [is] challenged by current spot prices," [Hatron 2012], implying that production costs at Comurhex II will be above \$6/kg U in UF_6. Finally, the nominal projection assumes that the costs of commodity and energy inputs, which are presently mixed compared to their historical levels, will remain near long-term average values.

The **low cost** estimate, \$6/kg U in UF_6, approximates the 2012 spot price. It considers a future where a competitive transition to a new generation of plants does in fact lead to sharply lower production costs. While this will likely be the case for the enrichment industry where the new generation rests upon a substantially superior technology, the conversion process has taken a more evolutionary development path. This estimate allows for a scenario where the effects of technological advancement are substantial. Lower commodity and energy costs would also militate toward the low cost outcome.

The **high cost** estimate, \$18/kg U in UF_6, is close to the early 2012 long term contract price. If the industry continues to suffer from low availability, especially under conditions of strong demand growth and exhaustion of secondary sources of conversion supply, available suppliers will be operating at or near capacity and high prices can be expected to continue. By increasing production costs at all facilities, elevated input commodity and especially energy prices could also push future prices toward the high cost estimate. Per the 2009 CBR, a uniform distribution is recommended for Conversion costs.

Table B-2 summarizes the recommended unit cost range from previous versions of the AFC-CBR.

Table B-2. "What-it-takes" (WIT) Table , 2012\$.

Low Cost	High Cost	Nominal Cost
\$6/ kg U in UF_6	**\$18/ kg U in UF_6**	**\$12/ kg U in UF_6**
2009 CBR Values (in 2009\$):		
\$5/ kg U in UF_6	*\$15/ kg U in UF_6*	*\$10/ kg U in UF_6*

Table B-3 shows the 2012 AFC-CBD values escalated to year 2017 dollars and appropriately rounded. Note that with rounding this range is nearly the same as in the 2015 version, where a factor of 1.05 was used to escalate from 2012\$ to 2015\$. Using the escalation table from the front of this report, a value of 1.088 was used to escalate from 2012\$ to 2017\$. Keep in mind that these are long term price projections based on a price which are assumed to cover production costs. Today's (July 2017) price of \$5/kgU would not be sustainable over the long term of many decades.

Table B-3. “What-it-takes” (WIT) Table escalated to 2017 $.

Low Cost	Mode Cost	Mean Cost	High Cost
$6.5/ kg U in UF_6	**$13/ kg U in UF_6**	**$13/ kg U in UF_6**	**$20/ kg U in UF_6**

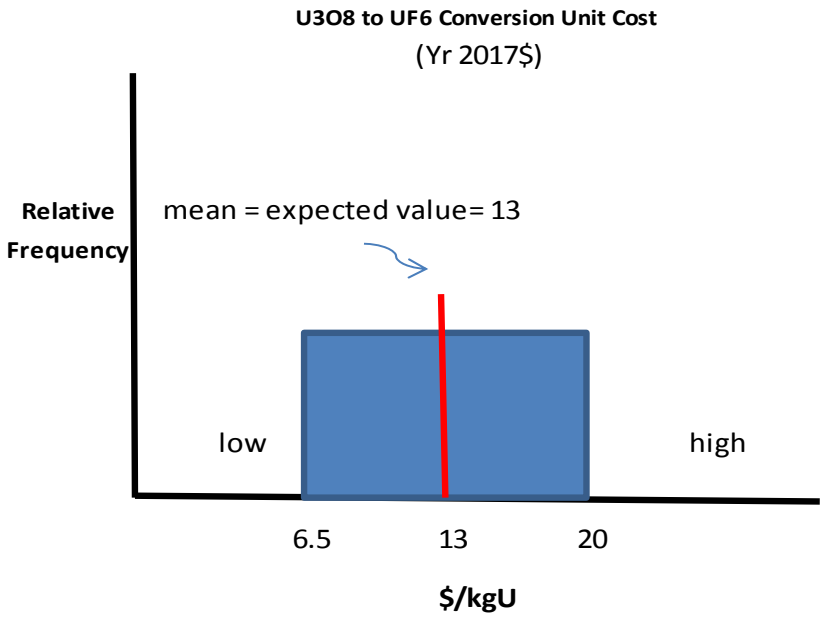

Figure B1– 8 Uniform distribution and parameters for Conversion Cost

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

B-9. 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 B1– 9 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.

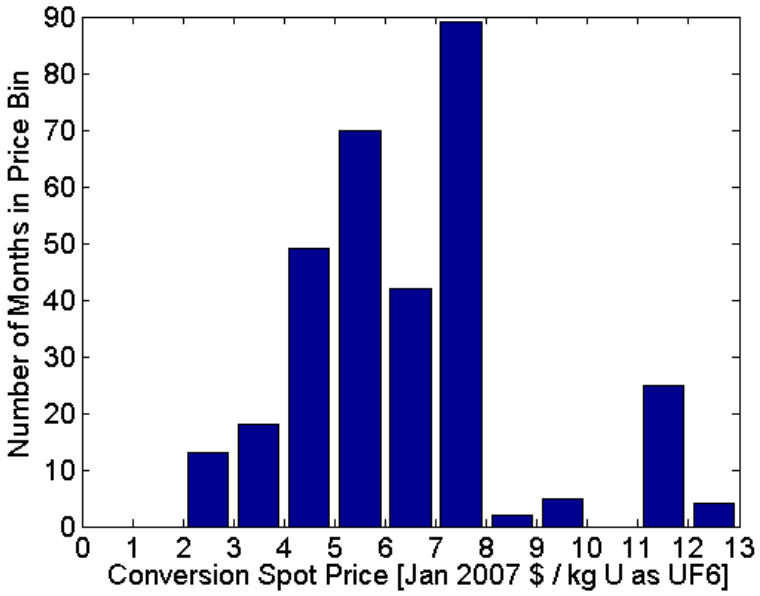

Figure B1– 9 Histogram of monthly conversion spot price.

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C MODULES

Uranium Enrichment

Module C1

Uranium Enrichment

Module C1

Uranium Enrichment

C1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only with additional new text explaining current enrichment oversupply situation due to depressed nuclear fuel market. New (2017) analysis to support long term price projections is included in the text below.
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
  - Extensive technical descriptions and market analyses were conducted for both the 2009 and 2012 AFC-CBRs. Escalation here is based on applying a 1.14 factor to the 2009 unit SWU cost ranges.

C1-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module C. In 2005 AFC-CBR Module C was separated into Modules C1 and C2_to differentiate between true "process enrichment" and secondary enrichment achieved by blend-down of HEU to LEU. No true blending costs were available for Module C2, hence, no Unit Cost tables were produced.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 & 2012
- New technical/cost data which has recently become available and will benefit next revision:
  - **The enrichment market in 2017 is severely depressed primarily due to many reactors in Japan still being reviewed for restart post-Fukushima, but also due to lower projections for new nuclear and the premature closing of some US NPPs.**
  - **A market analysis in 2016 served as a "spot check" on the situation in the market for uranium enrichment. A summary of that spot check is included in Section C1-6.2.**

C1-1. BASIC INFORMATION

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 (LWR) nuclear fuel fabrication. It involves receipt of UF_6 feed stock in 12.5-ton cylinders for evaporation, gas-phase enrichment operations, condensation of enriched UF_6 solid and depleted UF6 solid, and shipment of 2.3-ton enriched product cylinders to fuel fabricators. In this module, "SWU" is taken as shorthand for kg-SWU, the formal units for enrichment separative work, assuming that heavy metal mass flows will be gauged in kg.

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 the possible presence of mixed oxide fuel or reprocessed uranium fuel assemblies in the same core . 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 and marine propulsion 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 for several years and is currently stored as UF6 at the enrichment sites for future use (because it does have a significant fissile material loading) or conversion to more chemically stable oxide for long term storage and disposal (Module K1).

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 U.S. annual demand for LEU as of 2012 was 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. Eurodif (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 bundled LEUOX 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. 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 and energy-efficient 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 in special autoclaves, 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 UF6 isotopes through a thin and porous 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 UF6, 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 (called "barrier") 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 Figure C1–1 and Figure C1–2).

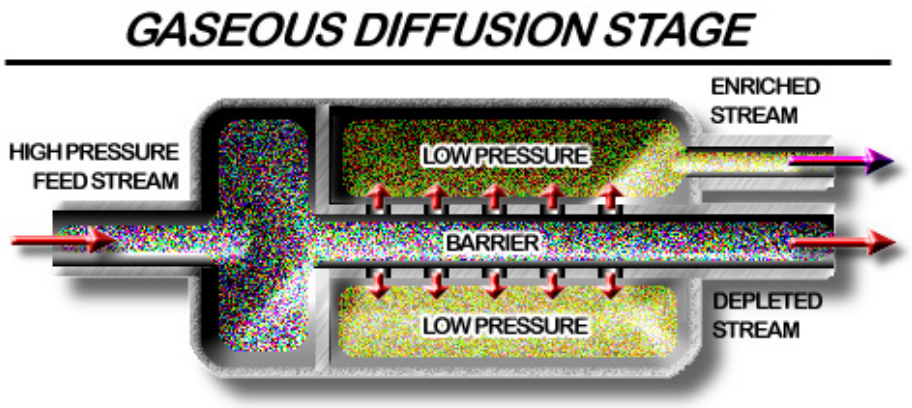

Figure C1–1 Gaseous diffusion stage (Federation of American Scientists 2009).

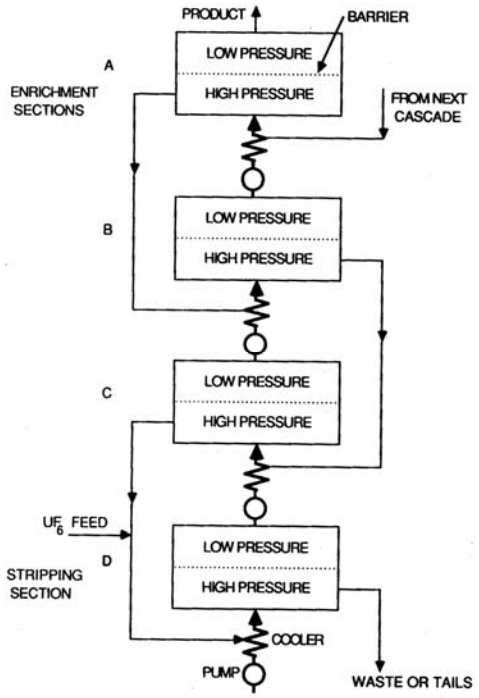

Figure C1–2 Gas must be depressurized, and the heat of compression must be removed.

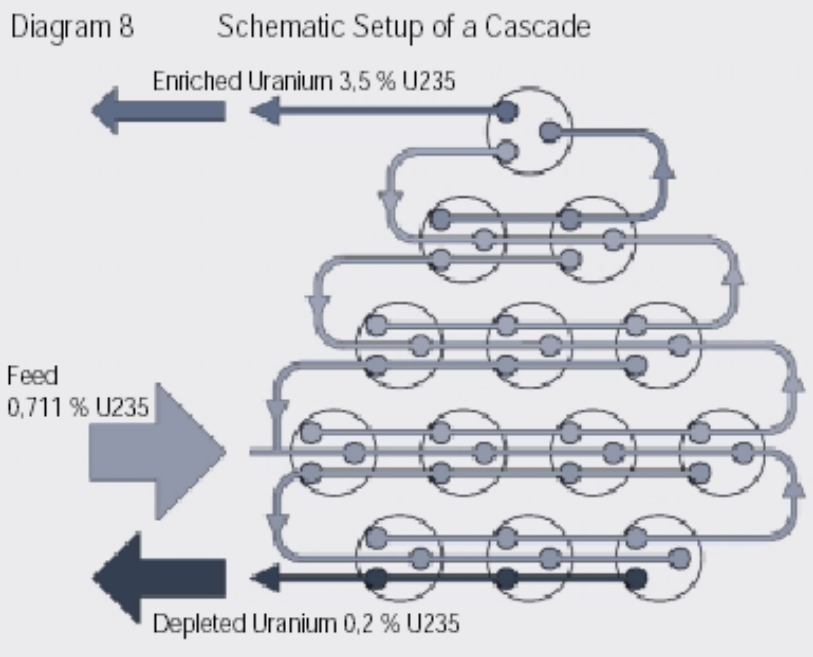

Figure C1–3 Gaseous diffusion cascade for enriching and stripping.

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

Diffusion equipment tends to be large and consumes significant amounts of energy (thousands of kwh per kg-SWU). 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. The depleted “tails” UF6 is also cooled and stored in larger cylinders, generally on site. Concerns about long-range chemical reactivity of DUF6 in corrodible steel cylinders has caused most countries to consider “de-converting” the DUF6 to more stable solid oxide forms such as U3O8. (Module K considers this fuel cycle step in details. In terms of total mass, DUF6 is the largest radioactive waste material in the entire once-through nuclear fuel cycle.

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 considerably 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 total plant 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 further cooled and transported in a solid form to fuel fabrication facilities. Figure C1–4 and Figure C1–5 show schematics of typical gas centrifuges used for U-235 enrichment.

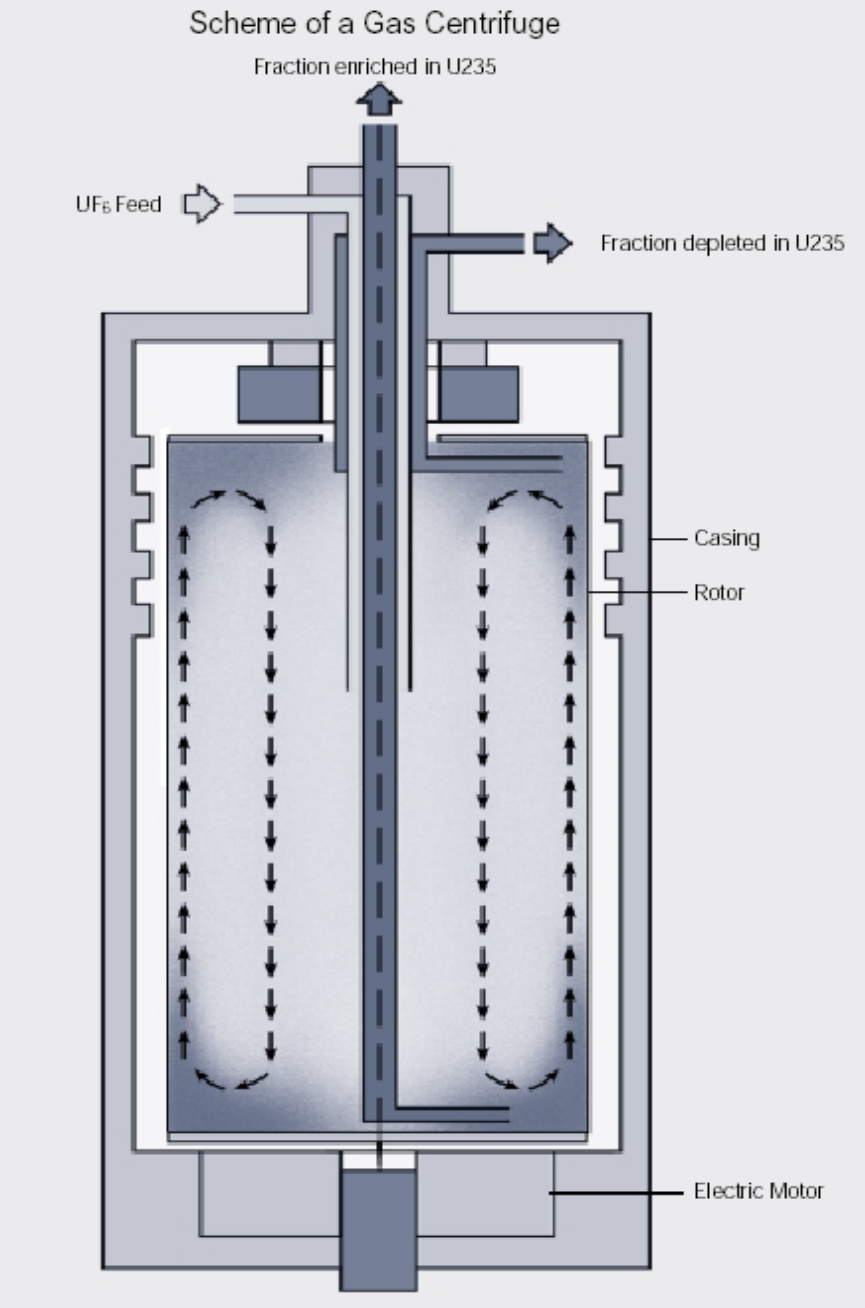

Figure C1–4 Gas centrifuge.

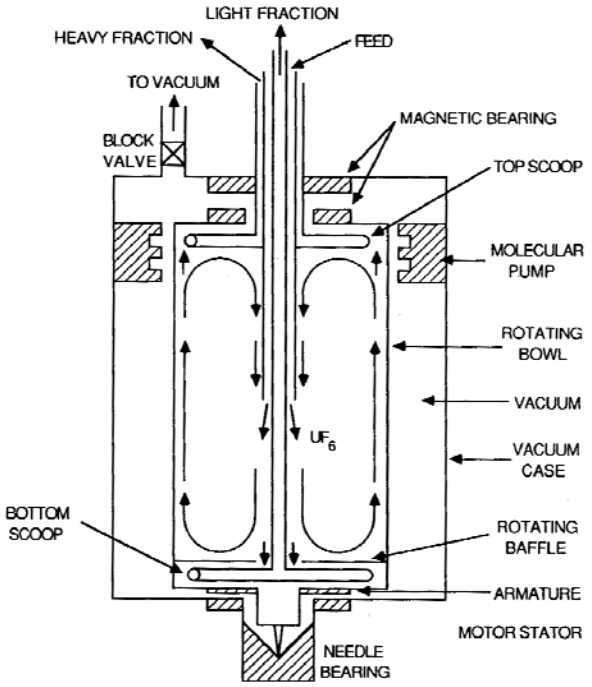

Figure C1–5 A schematic showing the Zippe centrifuge.

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 gaseous 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 withdrawal 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. The product stream, enriched in the excited $^{235}UF_6$, is collected and may be subjected to additional enrichment stages if necessary.

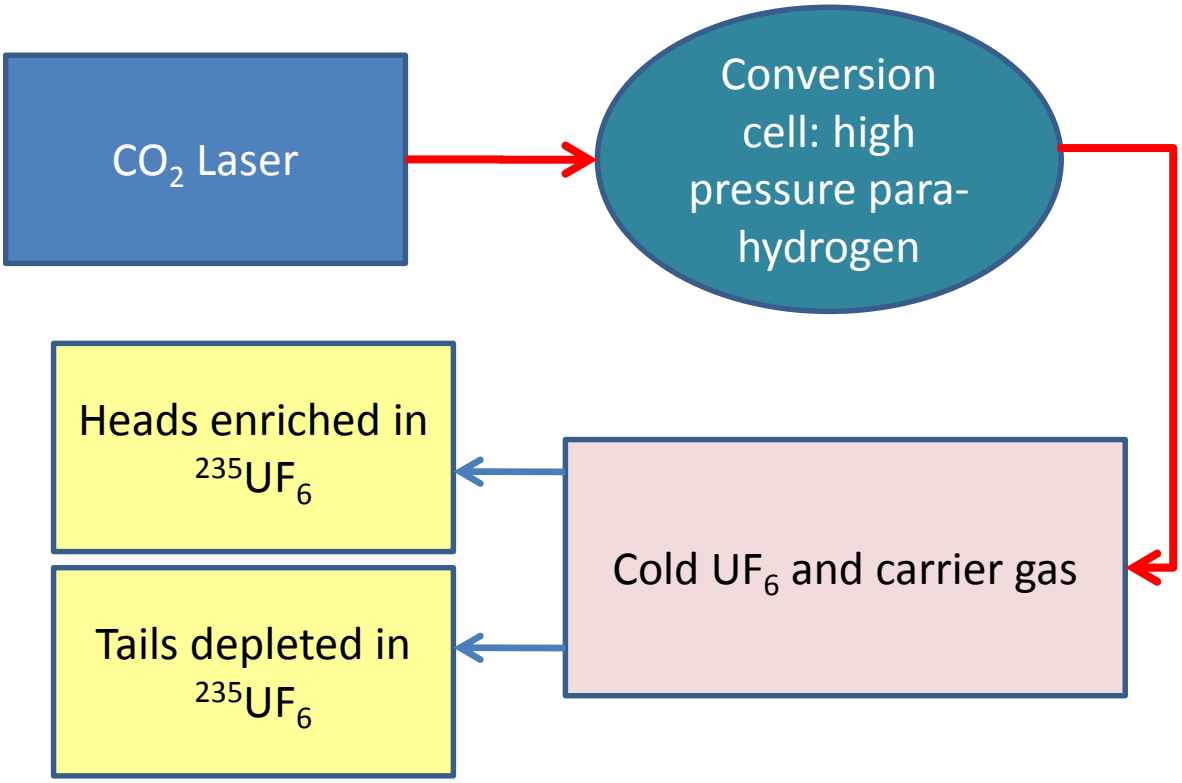

Figure C1–6 Schematic of SILEX process.

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

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).

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 uranium enrichment applications.

C1-3. PICTURES AND DIAGRAMS

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. Figure C1–9, Figure C1–10, and Figure C1–12 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.

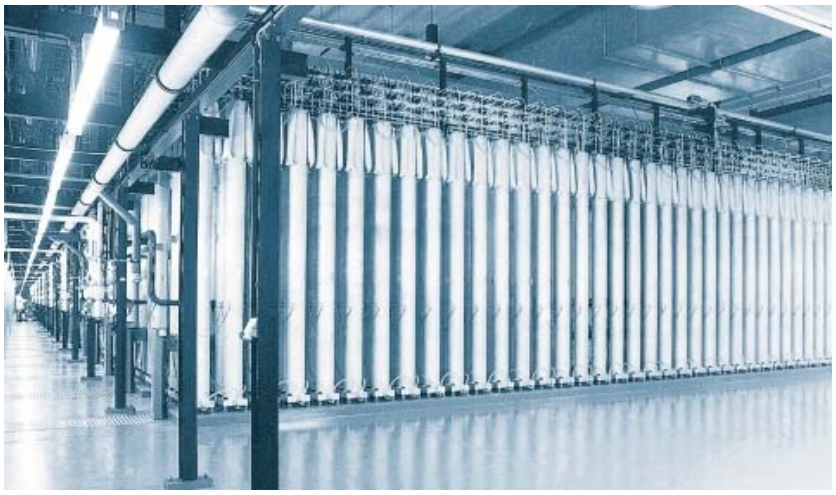

Figure C1–9 Separation Hall with centrifuges at the Gronau Enrichment Plant, Germany.

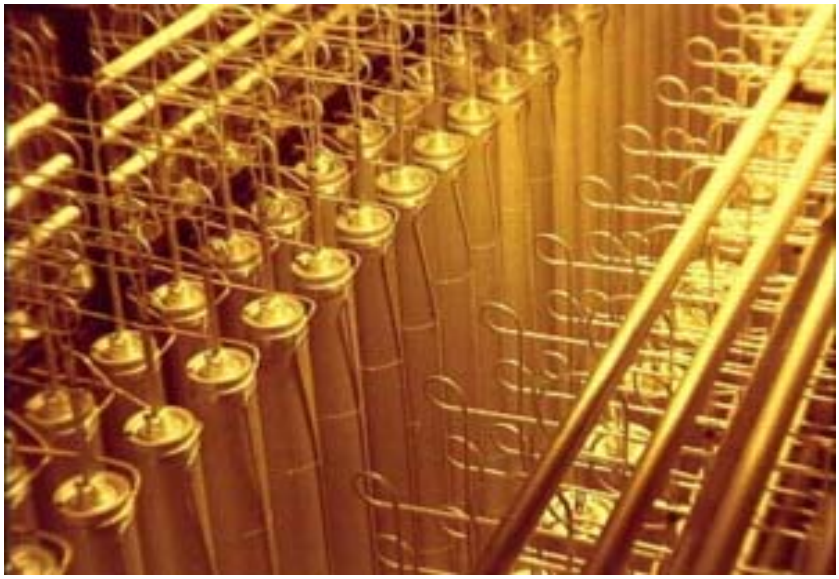

Figure C1–10 Top view of a bank of centrifuges at a URENCO gas centrifuge plant.

Figure C1–11 Enriched UF6 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 possible requirement that enrichment plant "tails" be stored in a less chemically active form than UF6 may impact the operations and economics of uranium enrichment plants. The enrichment price in some cases might include the DUF6 deconversion and subsequent deconverted product disposal costs, since the tails may be viewed as a waste liability. Deconversion and disposal are discussed in Module K1.

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

C1-4.1 Supply

The shift in the supply profile away from the elderly, energy-intensive diffusion process and toward centrifuge technology that began in the 1970s is nearing completion. As of 2009, two large diffusion plants remained in operation, Areva/EURODIF's Georges Besse facility at Tricastin, France and the USEC Paducah Gaseous Diffusion Plant. Areva formally retired Besse from service on June 7, 2012 (AREVA 2012a). The Paducah facility was on the point of shutting its doors in 2012 as well, but in May 2012 an agreement was concluded to re-enrich 9,000 tonnes of DOE-supplied depleted uranium hexafluoride into 480 tonnes of LEU reactor fuel for the Columbia Nuclear Generating Station and TVA-operated reactors (NSNT 2012a). This agreement will allow Paducah to remain in operation into 2013. Its future beyond that date is uncertain, as its current operating license expires on December 31, 2013.

Together these diffusion plants accounted for a name plate annual capacity of over 22,000,000 SWU. Table C1–3 shows that several new centrifuge and laser-based enrichment plants are coming online or planned, and the capacity of a number of existing facilities is being expanded. Together these additions, if completed, will surpass the capacity of the retiring gaseous diffusion plants by more than 20,000,000 SWU.

In the United States, the Urenco / Louisiana Energy Services Urenco USA facility entered production in June 2010. Production at this facility is slated to increase to its design level of 5,700,000 SWU/yr by 2015. Three other facilities are under construction or planned in the US. Areva's schedule for the 3,300 SWU Eagle Rock plant in Idaho Falls, ID has been delayed, but the company has announced plans to

begin construction in 2014, or 2013 if suitable financing can be obtained (AREVA 2012b). As of July 2017 these plans are on hold because of market conditions.

GE-Hitachi will construct the first commercial laser-based enrichment plant in Wilmington, NC. The US NRC has issued an environmental impact statement (EIS) for this facility (NRC 2012) and a combined construction and operating license may be granted as early as the second half of 2012 (World Nuclear News 2012). If that schedule is kept, GE-Hitachi anticipates production to commence in 2014 with full capacity, 3,500,000 SWU/yr, achieved by 2020. As of July 2017 GE-Hitachi has put its plans on hold, most likely due to market conditions.

The fate of the proposed 3,800,000 SWU/yr USEC American Centrifuge Project (ACP) remains uncertain. In early 2012 USEC announced that it would exhaust available funding by May 31 and lobbied DOE to present its case for additional funding to Congress (USEC 2012). Subsequently, the US House and Senate inserted $150M in funding into bills moving through Congress (NSNT 2012b). USEC has argued that maintenance of American-owned and operated enrichment capacity is an issue of national security as well as domestic energy security. But as of mid-2012 USEC has been unsuccessful in its efforts to secure a $2B loan guarantee from the US government. As of July 2017 market conditions are also negatively impacting ACP prospects.

Production began in 2011 at the AREVA Georges Besse II Plant. By 2016, this plant is slated to reach a capacity of 7,500,000 SWU/yr, meeting the French SWU requirement that had been served by the retired Besse gaseous diffusion plant. Besse II will not provide France with substantial capacity for export, although Korean, Japanese and other French corporate partners each own small stakes in Besse's operating company.

Table C1–3 Uranium enrichment capacities.[1]

Operator / Plant(s)	June 2012 Capacity (SWU/year)[1]	Planned 2020 Capacity (SWU/year)[2]	Technology, Notes
CNNC/Lanzhou, Hanzhong, China	1,900,000	6,000,000-8,000,000	Lanzhou: 500,000 SWU/yr centrifuge, 900,000 SWU/yr diffusion. Hanzhong: centrifuge
AREVA/Georges Besse II, France	1,500,000	7,500,000	Centrifuge: began production April 2011
AREVA/Eagle Rock, USA	0	3,300,000	Centrifuge, construction may begin 2013-14
USEC/Paducah GDP & American Centrifuge Project, USA	11,300,000	3,800,000	Paducah: diffusion, likely to be decommissioned between 2013 & 2016. ACP: centrifuge, prospects uncertain
Urenco/Gronau, Germany; Almelo, Netherlands; Capenhurst, UK	14,250,000	12,300,000	Centrifuge
Urenco/Urenco USA	400,000	5,700,000	Centrifuge, began production June 2010
Tenex/Angarsk, Novouralsk, Zelenogorsk, Seversk, Russia	16,600,000	30,000,000-35,000,000	Centrifuge
JNFL/Rokkasho, Japan	1,050,000	1,500,000	Centrifuge
GE-Hitachi, Global Laser Enrichment, USA	0	3,500,000	SILEX, production may begin in 2014
TOTAL	**47,000,000**	**73,600,000 – 80,600,000**	

1. Only plants having greater than 250 tU/yr capacity reported. Data Source: (WISE 2009).
2. Only plants having greater than 250 tU/yr capacity reported. Data Source: (WNA 2012).

A planned expansion of Tenex facilities in Russia, on the other hand, may position Russia with more than 20,000,000 SWU/yr of capacity above domestic needs. The centerpiece of this expansion is the International Uranium Enrichment Center (IUEC) at Angarsk, a joint venture between Tenex and Kazatomprom. Founded in 2007, IUEC is intended to become a model supplier of assured fuel cycle services along the lines of nuclear fuel bank concepts extending back to the 1950s & 1960s era of Atoms for Peace (Loukianova 2008). To this end, the Russian government removed Angarsk from Russia's list of military-supporting facilities and placed it under IAEA safeguards. As discussed in Section C1-2, this expansion will grant Russia considerable leverage over the enrichment market.

The bilateral (U.S.-Russia) "Suspension Agreement" amendment was reached in 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. See Module C2 for further discussion concerning supply from downblend of HEU.

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

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).

C1-4.2 Demand

Table C1–5 breaks down by country and region the forecasted near-term (2015) world SWU requirement of 55,000,000 SWU/yr. Given the total installed capacity in 2012, 47,000,000 SWU/yr, it can be seen that the tightness in the enrichment market may continue, with little or no capacity above requirements until the latter half of the 2010s when large projects in Russia, the USA and France come fully online.

Table C1–5 Forecasted SWU Requirements, 2015 (SWU/yr).[1]

Country	SWU
Mexico	148,000
USA	11,665,000
Belgium	800,000
Czech Republic	465,000
Finland	595,000
France	6,120,000
Germany	1,300,000
Hungary	245,000
Netherlands	55,000
Slovak Republic	362,000
Spain	1,000,000
Sweden	1,040,000
Switzerland	200,000
United Kingdom	810,000
Japan	7,210,000
Korea	4,200,000
TOTAL, OECD	36,215,000
TOTAL, Others	~19,000,000
World Total	**55,215,000**

1. OECD countries forecast from WNA 2012, (others from WNA 2011).

On the other hand, the contemporary shortfall in primary supplies of enrichment services, like that of primary supplies of uranium, is being made up by an important secondary source of supply. This is the down blending of HEU in the United States and Russia. HEU down blend displaces enrichment requirements since the HEU need only be mixed with natural (NU), slightly enriched (SEU: typ ~1% U-235) or depleted uranium (DU) to attain low enriched uranium (LEU) fuel with the proper enrichment for commercial reactors. Figure C1–12 shows that through 2013, when the down blending agreement between the US and Russia expires, approximately 20% of world SWU requirements are being met by this secondary source. The World Nuclear Association (WNA 2012) projects that even after the 2013 expiration of the agreement, HEU down blend will continue to meet ~4,000,000 SWU of requirements. See **Module C2: HEU Blend-Down** for further information.

Ref. C1-16 projects the three SWU demand scenarios shown in Figure C1–12. Although the reference and upper demand scenarios imply requirements exceeding supply after 2020, it is important to note that the supply depiction only includes existing, under construction and announced capacity additions (this is also the case for the data of Table C1–1). As of 2012, no announcements of capacity expansions after 2020 have been made. But if SWU demand followed a trajectory like the reference or upper demand scenarios in Figure C1–12, suppliers would doubtless act to build new capacity. Likewise, if demand does not accelerate, it is probable that some of the expansions and new projects indicated in Table C1–1 will be delayed or abandoned by their owners.

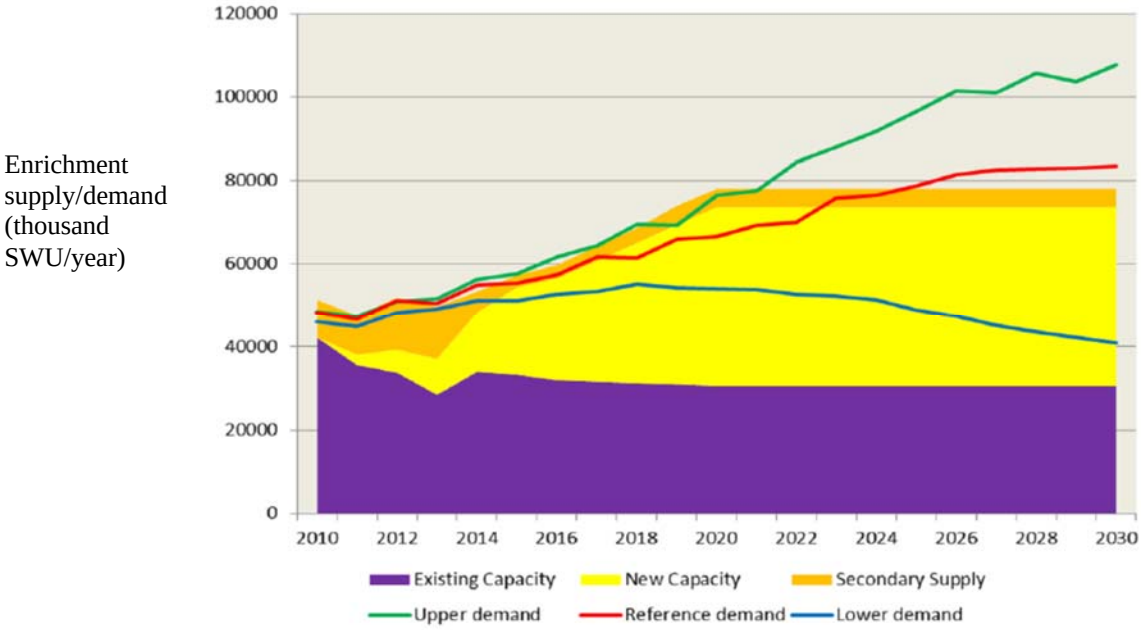

Figure C1–12 World Nuclear Association forecast of enrichment supply and demand (thousand SWU/yr) through 2030. Figure source: (WNA 2011).

C1-4.3 Interaction with Uranium Prices

There is an important interaction between Cost Modules A and C1. Figure C1–13 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.

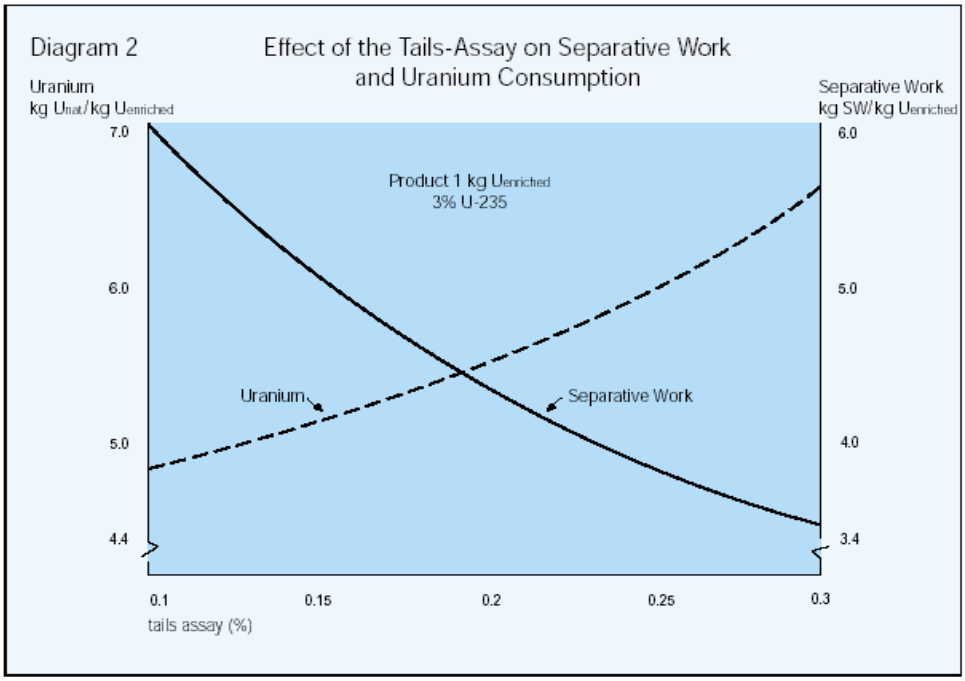

Figure C1–13 Relationship between raw uranium requirements and the enrichment tails assay.

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 C1–14. 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.

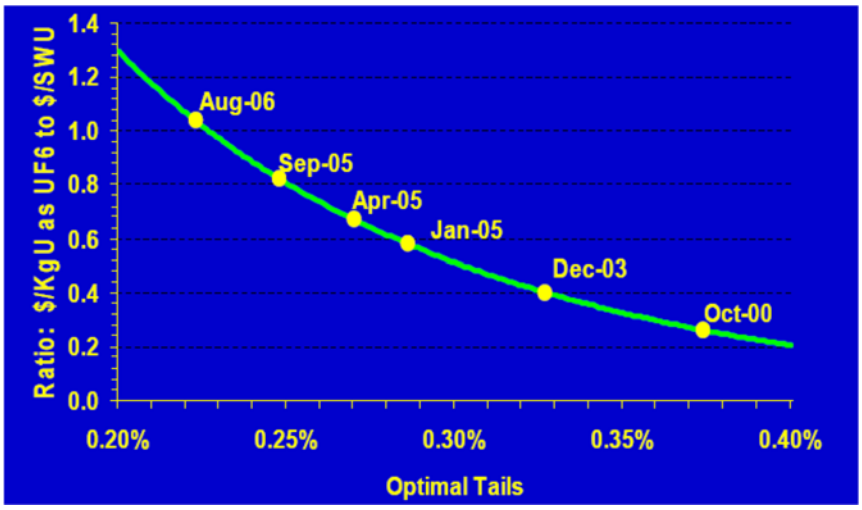

Figure C1–14 Optimal tails as a function of ratio of uranium to SWU price.

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:
- 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. SCALING CONSIDERATIONS

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.

C1-6. COST BASES, ASSUMPTIONS AND DATA SOURCES

The historical spot market price of enrichment services is shown in Figure C1–15. Over 95% of enrichment service transactions between 2009 and 2011 were settled through long-term contracts (Schwartz et al 2012), and **the forecasts made here are intended to reflect contract prices**. But the **spot market price is nonetheless an important indicator of market effects as well as the direction in which future contract prices will move**.

Over the time period covered by Figure C1–14, the U-235 content of depleted uranium tails has varied considerably. Specified by the purchaser of enrichment services and attained by adjustment of the enrichment cascades, it governs the tradeoff between uranium and SWU consumption. A high U-235 content in tails increases NU requirements and decreases SWU requirements, per unit of LEU produced. Since the mid-2000s, elevated uranium prices (see Module A1) have led utilities to request lower tails U-235 content, reducing their NU requirements but increasing SWU consumption. Hence, the tails U-235 content prevailing across the industry has declined from 0.3-0.35% prior to 2003-4 to ca. 0.22% in 2012 (WNA 2011).

The impending (2013) end of the US-Russia HEU agreement, which will reduce a key secondary source of SWU (see Module C2), has exacerbated the upward pressure on prices. Also, as mentioned in Section C1-1.2, requirements and aggregate supply are presently closely matched, leading to a tight market. This situation is transient, arising from the closure of large gaseous diffusion plants in the US and France and gradual replacement of the retired capacity with new centrifuge and laser facilities. In the recent past, then, the spot price increase was likely further spurred by the sensitivity of the energy-intensive gaseous diffusion process to the escalating price of electricity (Schwartz et al 2012). On the other hand SWU spot prices have declined to $130/SWU following a 2009 peak of over $160/SWU and it will be argued that they will likely drop further. Note that the prices in Figure C1–15 are not adjusted for

inflation: in real terms, the 2012 price ($130/SWU) is lower than the CPI-adjusted 1995 price ($90/SWU in 1995 dollars, $135/SWU in 2012 dollars).

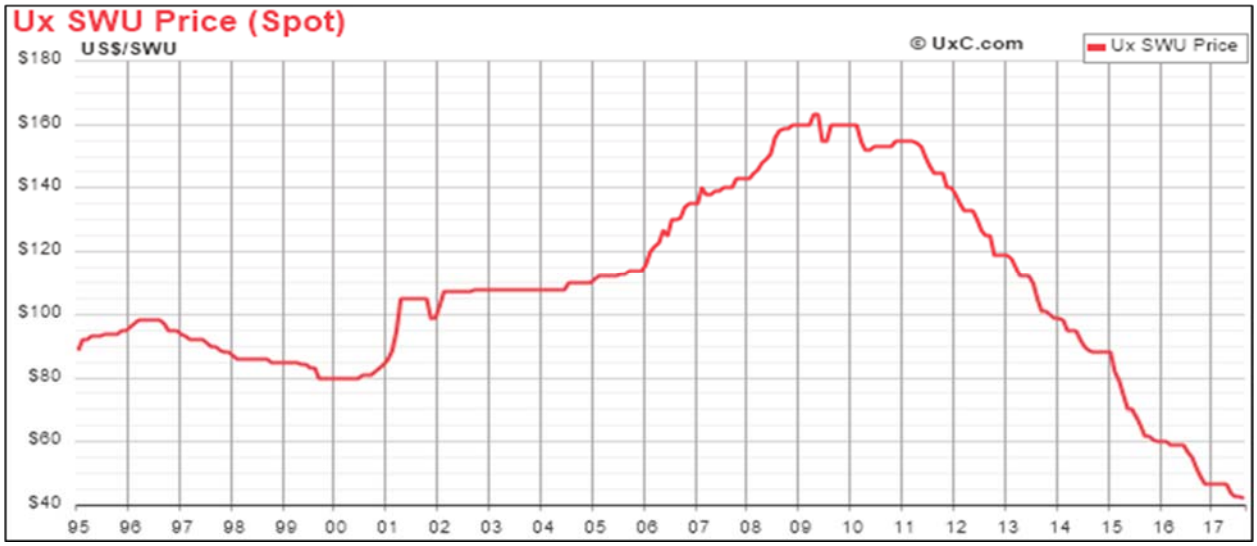

Figure C1–15 UxC SWU Spot Price, 1995-2017. Figure source: The Ux Consulting Company, LLC, http://www.uxc.com/. (Due to depressed market conditions, the June 26, 2017 UxC spot SWU price is $43/SWU)

As discussed in the *2009 Cost Basis Report* and (Schneider et al 2011), the primary impetus for lower long term SWU prices is the completion of the transition to centrifuge technology. Rothwell (Rothwell 2009) obtained construction cost data and estimates for five forthcoming enrichment facilities, three in the USA, one in France, and one in Brazil. Using these data with estimates of labor and other operating costs plus project-specific costs of capital, Rothwell derived a model of the levelized SWU cost, in $/SWU, as a function of these factors as well as plant capacity. Applying the model to existing plants, he obtained analogous replacement costs for the operating facilities.

Thus, SWU supply curves – plots of marginal SWU production cost versus quantity of SWU supplied – can be constructed from the results of (Rothwell 2009) with one plant excepted. Rothwell did not estimate the SWU cost at the forthcoming GE-Hitachi facility. This information continues to be covered by the veil of industrial secrecy. While the EIS for the facility (US NRC 2012) stated that the operator "considers laser-based technology to have lower operating costs and lower capital costs than … gas centrifuge technology," GE declined to publish capital or operating cost forecasts and no credible modern estimates could be found. Therefore, to complete the data set supplied by (Rothwell 2009), a 1982 estimate (Jensen et al 1982) of the SWU cost associated with the AVLIS laser-based enrichment technology will be used. Issues with laser tuning and power led to the cancellation of the US AVLIS program in 1999. The process and its feed form and equipment requirements are distinct from those of Silex. The AVLIS technology and cost estimate should not be viewed as surrogates for Silex. (Jensen et al 1982) projected AVLIS's cost at $30/SWU in 1982 dollars, $72/SWU once adjusted to 2012 dollars via the CPI[a].

a. This cost should be considered as an upper bound for Silex. At the same time, once constructed the GE Silex plant will supply less than 5% of world enrichment capacity. Given the substantial investments being made in centrifuge plants in Europe, Russia and the US, and the probable long (40+ year) lifetime of these facilities, it appears certain that centrifuge technology will dominate the enrichment market for decades to come. Since this addendum forecasts the likely average SWU market

Figure C1–16 displays the 2010 and 2020 supply curves assembled from this data point and the (Rothwell 2009) results adjusted from 2008 to 2012 dollars using the CPI. Superimposing the 2020 WNA SWU demand forecasts[b] on the lower panel of Figure C1–16 permits a simple forecast of the market clearing SWU price. It is important to note that using the levelized SWU production cost of the marginal facility, i.e. the facility that meets the final unit of demand, to project prices is an idealization. It assumes that the market is free, competitive, international in scope, and frictionless (suppliers enter or exit without hindrance or impact on their costs). It further assumes that marketing decisions are made based on the all-in (operating plus amortized capital) cost of SWU, whereas short-term decisions may be driven by variable operating costs. But it retains value for predicting long term contract price trends, subject to considerations that will be discussed below. While the supply curves cannot be plotted past 2020 in view of the absence of company expansion or new build announcements, it is considered that the approach retains its ability to describe the overall structure of the market over the multi-decade lifetime of the upcoming generation of plants, even if they are subsequently expanded.

The lower panel of Figure C1–16 indicates that the 2020 market clearing SWU price might range from ca. $70/SWU (lower demand) to $100/SWU (higher demand). This assumes that all projects depicted in Table C1–1 come to fruition. If they do not, the price from the lower demand case would increase[c]. On the other hand, inflation-adjusted SWU prices have declined over the long term, and the ongoing evolution of the centrifuge technology will likely continue to push production costs downward. In Russian and European plants, a new generation of centrifuges has been developed every 5-10 years; a typical centrifuge remains in operation for 10-15 years before it is replaced. Thus the overall energy intensity (measured in kWh/SWU) of centrifuge plants has improved by a factor of around 6 since large-scale centrifuge enrichment began: from ca. 250 kWh/SWU in the late 1970s to less than 40 kWh/SWU at modern Urenco plants (Schneider et al 2011). Energy intensity is a driver of operating costs, although other centrifuge design and plant-specific factors make it difficult to directly correlate the SWU production cost at a facility to time. From this standpoint, then, the $70-100/SWU projection of the market-clearing price might **over predict** long-term prices.

price over the coming decades, and plants using centrifuge technology will set the price, a precise forecast of Silex costs is not needed.

b. The WNA forecasts include demand for SWU from all sources, primary and secondary. They were each reduced by 4,000 kSWU/year to reflect the WNA projection of secondary (from HEU down blend) SWU supply in 2020.

c. If significant excess capacity does exist, large-scale upgrading (i.e., re-enrichment) of existing stocks of DU tails may resume. Through the 2000s, Tenex re-enriched DU held by Urenco and AREVA to NU levels, delivering approximately 5,000 tonnes of NU to European customers (OECD 2010a and OECD 2010b). As mentioned in Section C1-1, in 2012-13 USEC will re-enrich DOE-owned DU, although this decision was not market-driven. Upgrading of DU is SWU-intensive since the difference in U-235 assay between the feed stock and the so-called secondary tails is small. For instance, if tails assaying 0.35% U-235 are re-enriched with secondary tails at 0.20% (typical values selected from forecasts in [Schneider et al 2011], 12.4 SWU are required to produce 1 kg of LEU at 4.3% U-235 content. Only 7.3 SWU are needed if NU feed is used and tails are still taken to 0.20%. Worldwide, some 250,000 tonnes of DU assays at 0.30% U-235 or higher, and a shift toward upgrading of these stocks would act as a brake on declining SWU prices (see Refs. [Schneider et al 2011] [Schwartz et al 2012] for analysis).

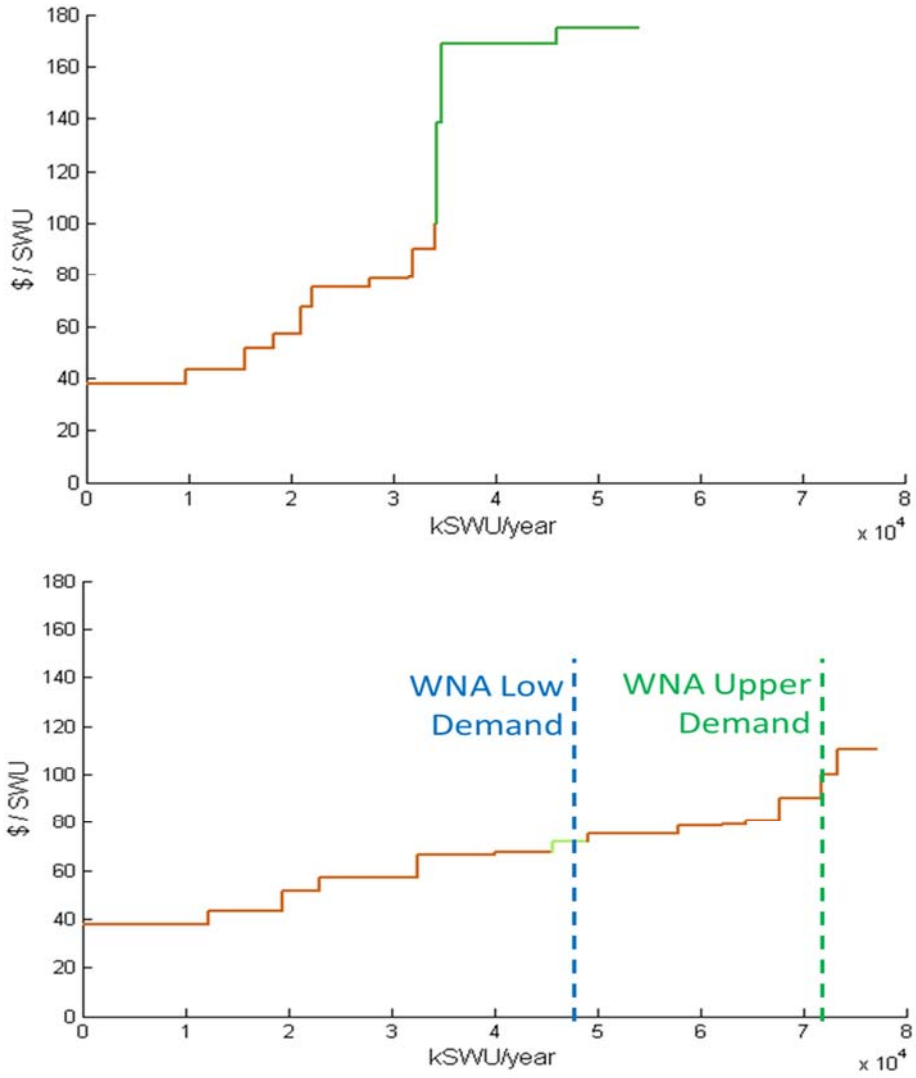

Figure C1–16 SWU supply curves, 2010 (top) and 2020 (bottom). Brown = centrifuge, Dark green = diffusion, light green = laser. Facilities of less than 500,000 SWU excluded.

One of the assumptions behind this simple model of price formation is that the market is competitive and free. Using a standard measure of the degree of concentration in a market, Rothwell showed that the enrichment market is strongly concentrated in the hands of three suppliers: Areva, Tenex and Urenco. Further, Rothwell observed that since Areva and Urenco are co-owners of their centrifuge manufacturer, Enrichment Technology Company Limited, they are incentivized to act in concert within the enrichment market (Rothwell 2009). In this case, the market could take on the characteristics of a duopoly led by Areva/Urenco and Tenex. Duopolists are endowed with market power, the ability to dictate the price of a product above its marginal production cost. By assuming competitiveness, the market-clearing price projection might **under predict** long-term prices.

Russian SWUs have had a significant effect upon European as well as US 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. 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.

C1-6.1 Time Series Analysis of Uranium Enrichment Market

Module A of the CBR contains causal and time series analysis in order to generate forecasts of uranium prices. Both approaches produce forecast estimtates within a similar range. In this moduel, time series analysis is conducted to form a basis of price estimates for SWU. Whereas historic price data on uranium can be accessed for a lenththly time series (see Module A), price data for SWU are more scarce. Because of this, the analyst must rely on what data are available for SWU, and Ux Consulting is a primary source for these data. Figure C1–15 shows the SWU price data used in the analysis below. The schedule of data is not available so instead, the anlayst used the plot in Figure C1–15 to generate a time series. This data sereis is recreated below in Figure C1–17 in green, the current value of the series. The orange plot is of the same series after escalating the data to constant 2017 values using the escalation method outlined in Chapter 7 of the CBR.

Figure C1–17 shows two contrasting trends. For the current values (series in green), an upward trend in prices appears from 1995 through 2010. On the other hand, the constant value (in orange) show essentially a downward trend beginning in 1995. Two observable exceptions are in 2004 and in 2010 when SWU prices spiked for a short time. Otherwise, in real terms, SWU prices have been declining for the past 22 years. Similar to the time series analysis in Module A, SWU prices are forecasted using historical data up through 2016 in constant 2017 dollars. That is, the historical series represented in orange are the seed data used for the time series analysis and forecast of SWU prices.

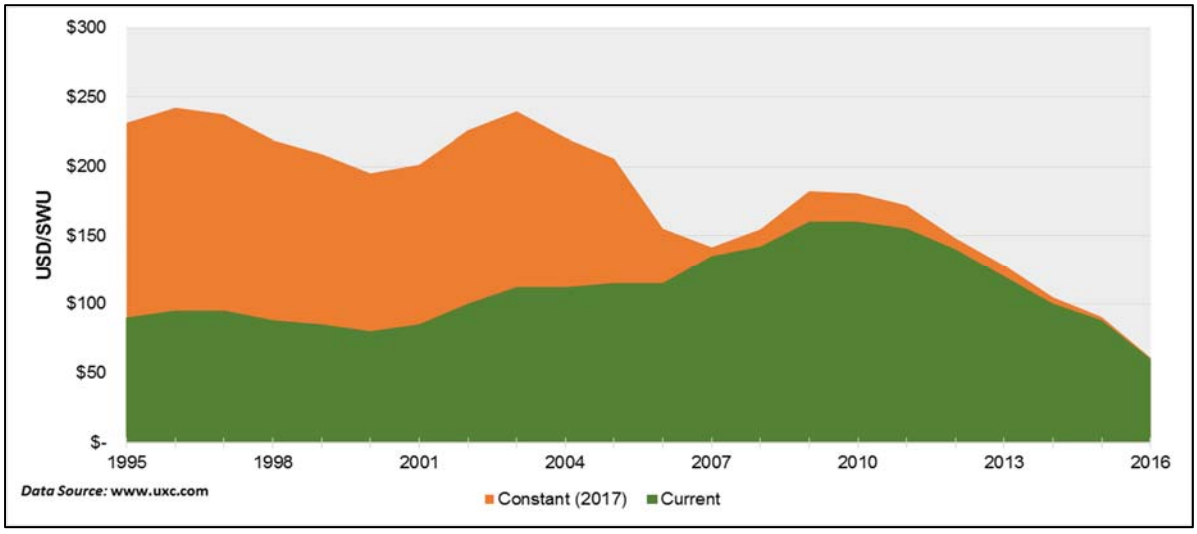

Figure C1–17 SWU Prices in constant and current dollars annually.

In order to use the data series, SWU prices in constant dollars from 1995 to 2016, to forecast SWU prices it must be stationary. Based on the autocorrelation and partial autocorrelation functions, statistical testing indicates that the series is not stationary. Taking first differences and taking the logarithmic values of the data series results in a stationary series. Once stationary, the data can be fitted with a time series process.

Figure C1–18 shows the fitted model, the historical path, and the sample path. The historical path, the blue line in the figure, shows the actual data series from Figure C1–15. These data are best fit using a moving average process over one period. The software @Risk fits the data with many time series and stochastic processes then allows the analyst to compare model fits using the Akaike Information Criterion. Based on fitting the data to a model, the SWU prices data series is best represented with a moving average process, MA(1), where the average is computed over one period. Further the Mean Absolute Percentage Error (see Module A) for the forecast is 20.99, which indicates the forecast does a reasonably good job at reproducing the historical data series.

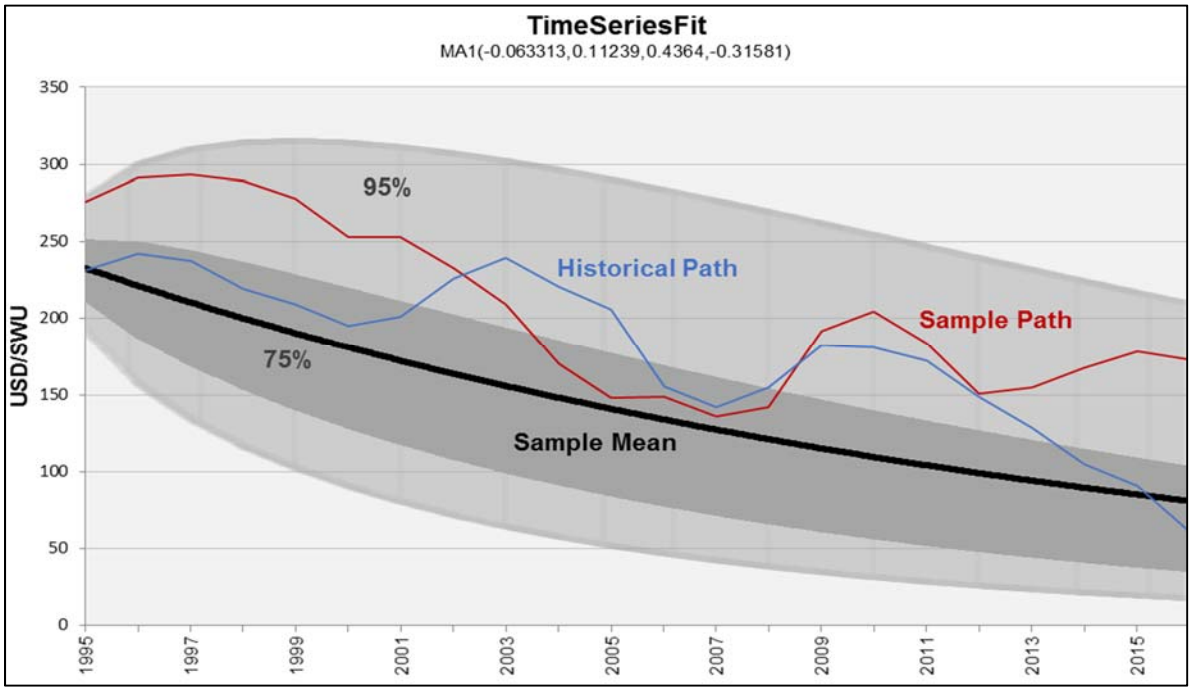

Figure C1–18 Comparing predictions using time series fitted model with historical data.

Using the fitted model and the SWU price of 1995, the MA(1) model produces a sample path indicated in red. Because the MA(1) is a stochastic process, the sample path could take many different routes based on the model random process. The black line indicates the mean of the possibilities and the light gray areas indicate the 95% confidence interval in which simulated observations occurred. The dark gray indicates the 75% confidence interval. The MA(1) becomes the model used to forecast SWU prices out to the end of the century in year 2100.

The MA(1) becomes the model used to forecast SWU prices. Figure C1–19 shows a price forecast through the end of the century. The mean of the observations is represented by the solid blue line in the center of the figure. It steadily decreases through the end of the century because of the downward trend that populates the time series process in the historical data. Because the simulation produces a distribution of possibilities in each year, additional statistics about the forecast are provided. The 90% and 10% lines indicate where 80% of the observed values in simulation resulted. The average value for the 10% line is $5.92 and for the 90% line is $19.84. The mean value, the solid blue line, across the simulation is $12.02.

The mode, the red line shown with variation, plots the mode from the distribution in each year. The most frequently occurring value in a distribution, the mode is a useful statistic to answer the question of what is the "most likely" value to expect in a given year. While the mean shows a decreasing trend, the mode illustrates what the volatility in SWU prices might look like as they decrease through the century.

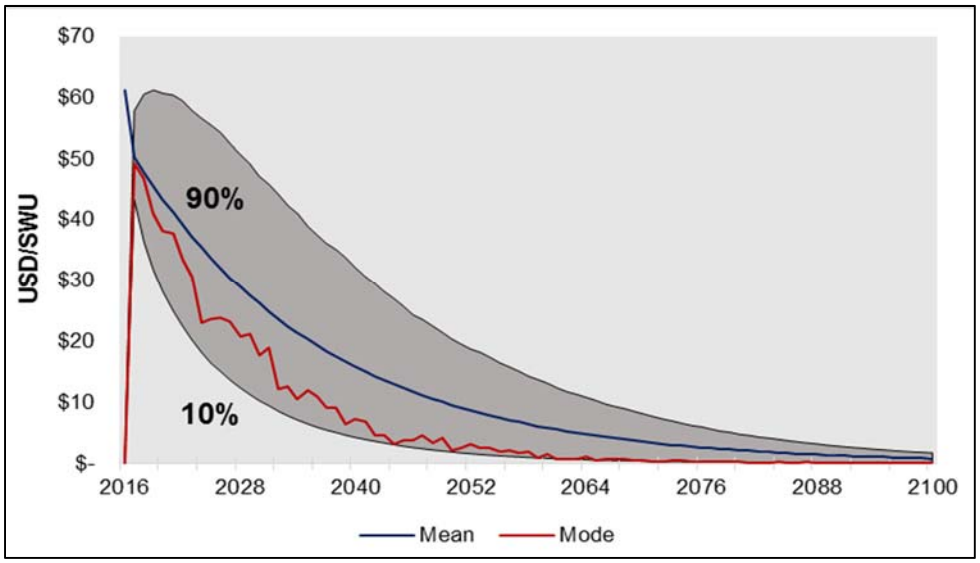

Figure C1–19 SWU price forecast using one-period moving average time series model based on historical SWU prices 1995 – 2016.

Coupled with Figure C1–19, Table C1–6 provides statistics form discrete intervals with in the simulation. Representing possibilities for SWU prices 10 years out, 25 years out, 50 years out, and through the end of the century, the table provides the statistics that are illustrated in Figure C1–19. The table show statistics by year in two formats, "In Year" and "Up to Year." The In Year statistics come from the distribution of possibilities for the year indicated. The Up To Year statistics represent what one might expect leading up to the year indicated. Notice the tighter confidence intervals and smaller standard deviation in the Up To Year statistics. This results because of the law of central tendency. Because the distributions from each year are averaged to compute the Up to Year statistics, the resulting distribution is more narrow (i.e. has less uncertainty) than the distribution of a single year.

Table C1–6 Summary statistics of SWU price forecast by year and up to year.

Year(s)	Mean	Mode	Std Dev	10%	90%
In 2027	$30.42	$20.64	$17.00	$13.56	$51.92
Up to 2027	$39.66	$36.54	$12.19	$26.35	$55.63
In 2042	$14.24	$3.90	$13.45	$3.66	$29.12
Up to 2042	$28.76	$23.49	$12.39	$16.24	$44.26
In 2067	$4.07	$0.54	$6.67	$0.49	$9.02
Up to 2067	$18.56	$12.58	$9.89	$9.48	$30.30
In 2100	$0.77	$0.05	$1.93	$0.04	$1.74
Up to 2100	$12.02	$8.03	$6.95	$5.92	$19.84

The analysis produced using the historical data on SWU prices generates a forecast of prices (Figure C1–19 and Table C1–6) that is significantly different from those recommended in previous versions of the CBR. Previous expectations for SWU prices are shown in Table C1–6. This disparity suggests a need

for in-depth analysis of the market for enrichment. Such analysis has been done previously and supports earlier SWU price recommendations from the CBR. The time series analysis presented here implies that factors in the enrichment market have changed considerably since the time of the last in-depth inquiry.

A possible explanation for this dramatic shift is the recently completed technical revolution. With the technology replacement of the Georges Besse enrichment facility of gaseous diffusion to Georges Besse II with centrifuge. Now that this replacement facility is online and ramped to full capacity as of 2016, it is likely the case that greater capacity at a lower price is contributing to lower SWU prices. Coupled with the reduction in demand from Japan, these could be causes for depressed SWU prices observed in recent history. These market conditions underscore the need for in-depth analysis of the enrichment market. It is very likely the case that enrichment market is in a transition to a new, lower phase of SWU prices. Informed by the time series analysis in this update, a conclusion that one can take is that SWU prices are adjusting down. Greater analysis will inform drivers behind the story the numbers illustrate. For these reasons, the time series presented here is not represented in the recommended prices in the What it Takes Table.

C1-6.2 2016 Spot Check on Market for Uranium Enrichment

Enrichment prices have also been following the same basic pattern as uranium ore discussed above, with lower values of $80-100/SWU prior to 2008 followed by rising prices to $160/SWU in 2009. The prices held in the $150-160/SWU level until Fukushima in 2011, and have declined steadily since then to $55/SWU as of the end of August, 2016. While the pattern is similar, suggesting the same drivers of optimism over the nuclear renaissance followed by post-Fukushima oversupply, there are additional contributing factors.

One factor is the completion of the conversion to centrifuge enrichment with the retirement of the large gaseous diffusion plants in the U.S. and France. Georges Besse (France) ended operations in 2012 while Paducah (U.S.) ended operations in 2013. Both were large capacity facilities with high operating costs, which provided support to the SWU price as essentially dictated by the marginal producers that supply the last segment of demand. With their retirement, prices dropped to reflect the more efficient production costs of the centrifuge facilities (including George Besse II). This impact was predicted in (Rothwell 2009a), with the predicted drop from the $160/SWU level to a new level around $100/SWU (in 2009 dollars). The post-Fukushima oversupply compounded the drop, which may not yet be over.

SWU spot prices as of 2016 at $55 are below the low end of the recommended price range in the 2015 CBR (low $89, mode $116, high $142, mean $116/SWU) – See Figure C1–20. As long as a supply/demand imbalance exists, prices could go lower, especially since the variable cost of production with centrifuges is quite low and centrifuge equipment is designed to run continuously (for decades) rather than be cycled up and down. However, several market adjustments are occurring. On the supply side, new plants in North America have been cancelled (Piketon, OH) or postponed indefinitely (Idaho Falls, ID, Wilmington, NC) but some expansion of plants in China may be occurring. On the demand side there is the continued construction of new reactors in Asia and the Middle East and anticipation for additional reactors to restart in Japan. At this point, no change in pricing is recommended until the near-term impact of reactors in Japan is resolved. The current price mode of $116/SWU reflects the price predicted by Rothwell based on a market using centrifuge production costs, escalated to 2015 dollars.

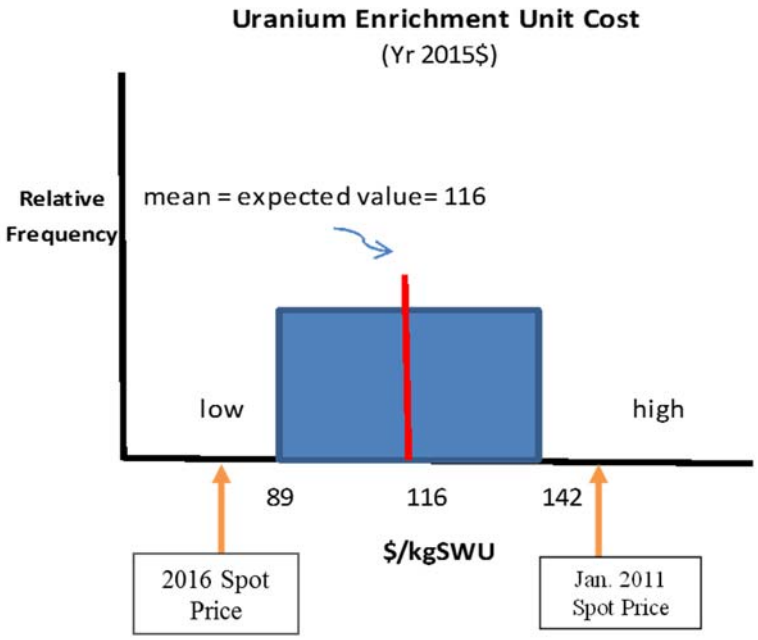

Figure C1–20 Separative Work Unit Cost Range in 2015 CBR showing current and pre-Fukushima spot prices

Using the price ranges for uranium, conversion, and SWUs, an optimal tails assay (% U-235 in the depleted U stream from an enrichment plant) can be determined to minimize the total front end fuel cycle cost for low enriched uranium (LEU). A tool is available on-line (UxC tool) to perform this calculation. Note that secondary considerations such as loss factors, waste disposal costs such as DU disposition, etc., are typically not included in a cost analysis. These secondary considerations are discussed in (WISE 2009a).

Using the UxC calculation, the optimal tails enrichment level is 0.25% U-235 when using the "mode" values for U, conversion and SWU, while it is 0.2% U-235 when using current market prices.

C1-6.3 Enrichment of Reprocessed Uranium

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. (RU reenrichment exposes the cascades to small but significant amounts of U-232 and daughters, some trace transuranics, and some troublesome trace fission products such as technicium-99m.) 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 attributable 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.

C1-7. DATA LIMITATIONS

There are 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.

C1-8. COST SUMMARIES

This section presents low, high and nominal enrichment price forecasts. Module C1, along with other front-end modules, addresses an industry with a well-developed market. Therefore, although the forecasts presented here are labeled ‘costs’ for consistency with the format used across this report, they should be interpreted as estimates of the long-term average SWU contract price. See the price data section in the front of this addendum for further discussion on the use of price data in the Cost Basis forecasts.

The **nominal** estimate, $100/SWU, assumes that capacity remains nearly fully utilized after the transition to centrifuge technology is complete. This is the case for the WNA upper-demand scenario outlined in Section C1-2, and it would likely also be true for the lower-demand scenario as some planned construction is abandoned and other capacity is shifted to DU tails upgrading. The projection is lower than current spot market prices because SWU production costs at all centrifuge facilities are evidently lower than the 2012 price of $130/SWU. SWU production costs will continue to decline in the future thanks to ongoing development of new generations of centrifuge equipment, possibly accelerated by the entrance of Silex. On the other hand, the concentrated nature of the market, dominated by two to three suppliers, will likely prevent prices from falling as far as declining production costs imply they should. Here the balance of these effects is considered to result in prices remaining near the contemporary production cost of the higher-cost players in the market.

The **low cost** estimate, $70/SWU, hypothesizes that significant capacity in excess of demand will be built. Some of this capacity might be engaged, with marginal profitability, in the upgrading of DU tails

stockpiles. Costlier to run facilities might be pushed out of the market entirely over time. Further, the low estimate considers that the market will not exhibit strong duopolistic characteristics, but rather function as a close approximation to a competitive market.

The **high cost** estimate, $120/SWU, assumes that installed capacity is fully utilized, as is the case for the nominal estimate. It may come about if uranium prices trend higher, since elevated uranium prices provide an ongoing incentive for utilities to substitute SWU usage for natural uranium purchase. It may also come about if conditions of effective duopoly prevail and the major suppliers are able to exert a considerable degree of market power. $120/SWU was chosen because it reflects the levelized SWU cost projected by (Rothwell 2009) for the costliest of the proposed centrifuge plants, one that is independent of the duopolists. If the price rises to this level, independent players are thus considered to be in a position to profitably enter the market, effectively capping prices.

The module cost information is summarized in the WIT cost summary in Table C1– 7.

Table C1– 7 “What-it-takes” (WIT) Table (2012$).

Reference Cost(s) Based on Reference Capacity	Low Cost	High Cost	Mean/Expected Cost
2009 CBR Values in 2009$			
$110/SWU	*$85/SWU*	*$135/SWU*	*$110/SWU*
2012 BR Addendum Values			
$100/SWU	$70/SWU	$120/SWU	$97/SWU
2009 CBR Values Escalated by 5% to 2015$			
$116/SWU	*$89/SWU*	*$142/SWU*	*$116/SWU*
2009 CBR Values Escalated by 14% to 2017$ per Escalation Table in Main 2017 CBR			
$125/SWU	$97/SWU	$154/SWU	$125/SWU

A uniform distribution was chosen to reflect SWU prices. See section C1-9 for discussion. The uniform distribution based on the costs in the WIT table is shown in Figure C1–21.

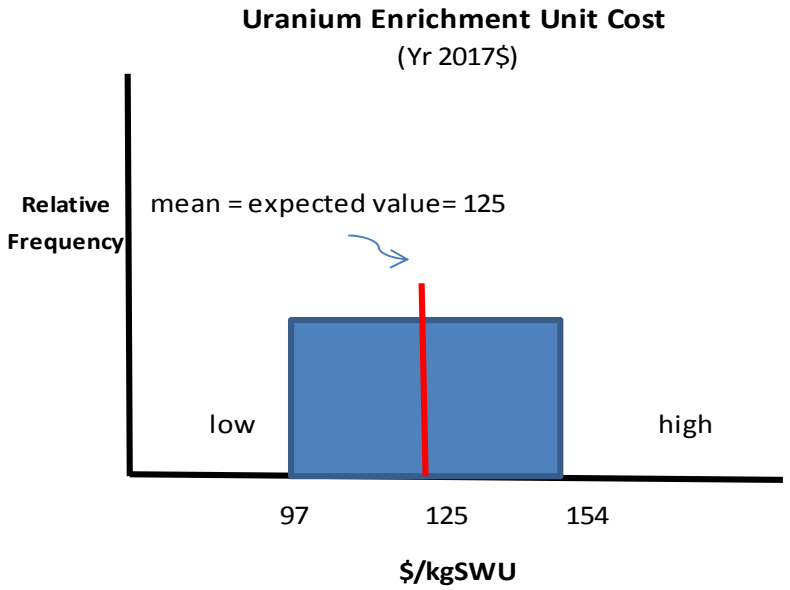

Figure C1–21 Enrichment estimated cost frequency distribution.

C1-9. 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 C1-18 is a histogram of the inflation-adjusted quarterly average SWU price shown in Figure C1-19.

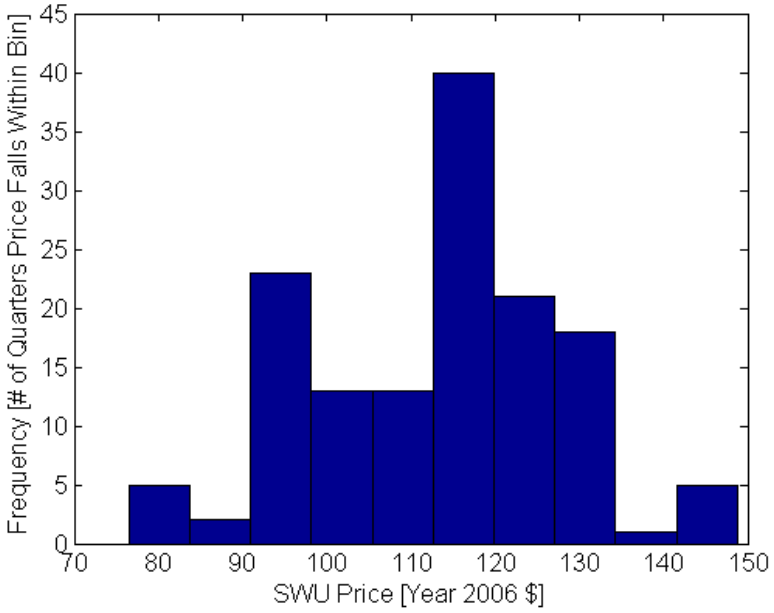

Figure C1–22 Histogram of quarterly SWU prices, 1972–2006.

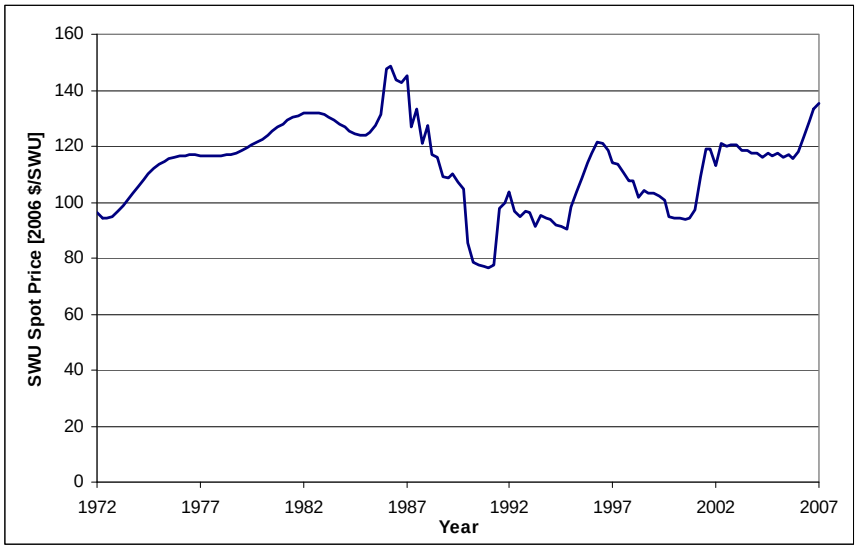

Figure C1–23 Historical SWU price (UxC spot post-1986), adjusted for inflation.

Table C1–8 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 C1–8 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

C1-10. REFERENCES

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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 former 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 (U-metal to UF6) Russian HEU with Russian slightly enriched uranium as UF6. 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.

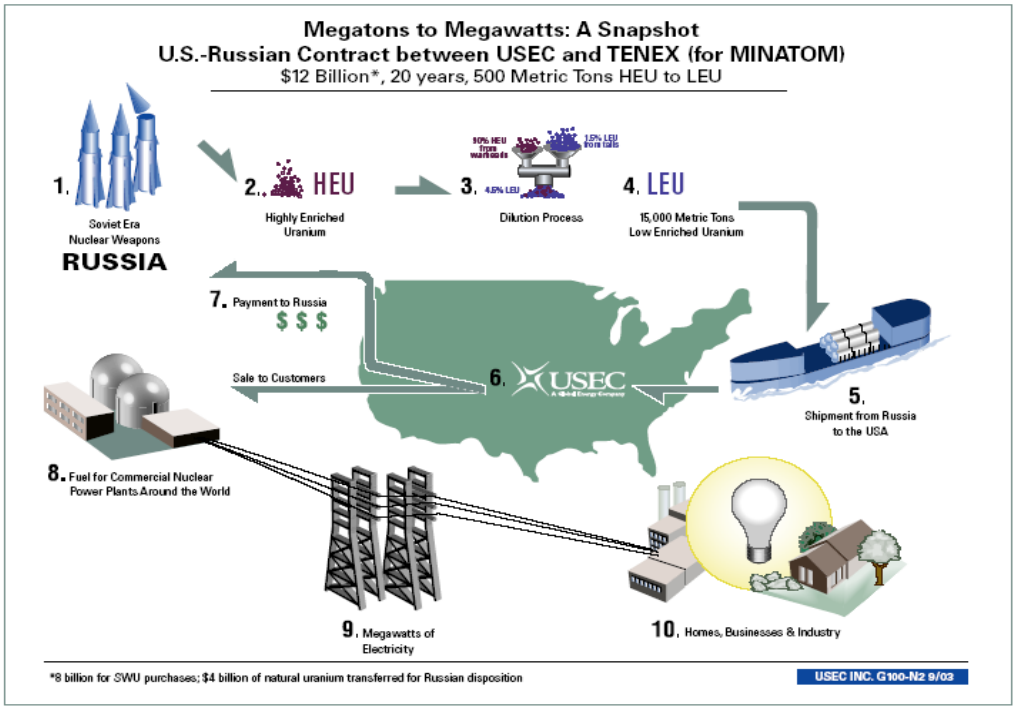

Figure C2-1. Megatons to Megawatts program (USEC 2001).

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 Erwin, 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 2008). 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 or Paducah sites, which are leased by USEC. At theseUS sites, 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.[d]

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.

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(Savannah River Site) 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,

d. USECs 2006 K-10 SEC filing.

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. PICTURES AND DIAGRAMS

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.

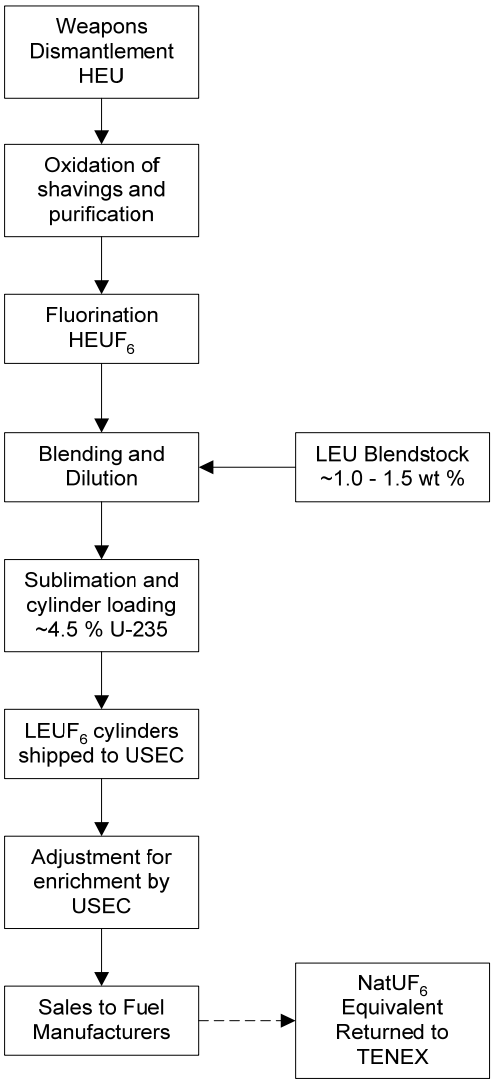

Figure C2-2. Russian HEU to LEU blend process.

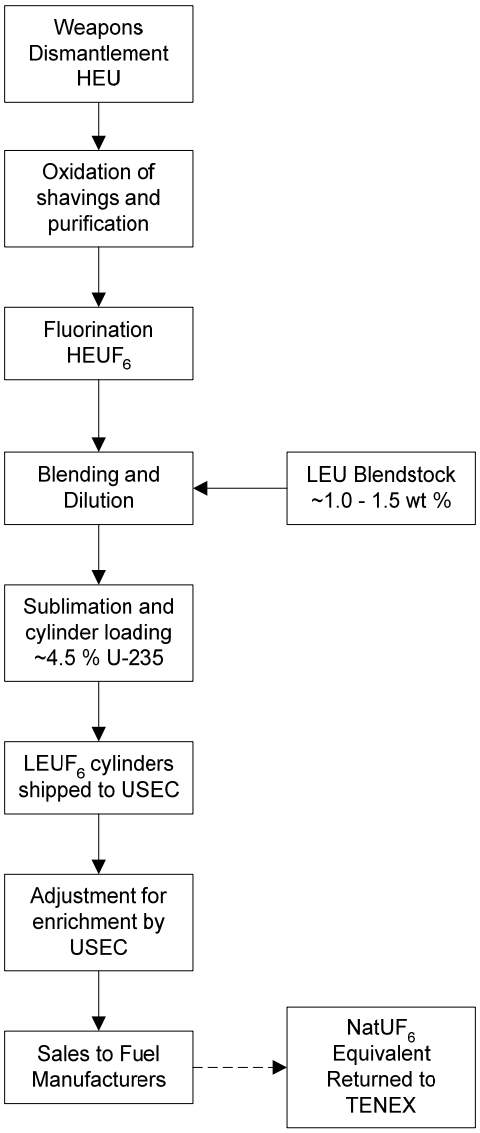

Figure C2-3. Generic U.S. off-specification HEU to LEU blend process. (Selected DOE contractor may modify this generic process.)

C2-4. MODULE INTERFACES

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. SCALING CONSIDERATIONS

Scaling factors do not apply to this model.

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

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 remainder of this section summarizes historical blend-down activities and addresses prospects for this supply source going forward.

C2-6.1 Blend-Down Activities to Date (i.e. thru 2012)

In July 2012, USEC announced that it had received the LEU equivalent of 450 tonnes of HEU from Techsnabexport (Tenex), fulfilling another milestone under the Megatons to Megawatts Program (USEC 2012). Megatons to Megawatts implements the US-Russian HEU Purchase Agreement and is on track to reach its final objective of downblending 500 tonnes of HEU by the end of 2013. The 450 tonnes of HEU received as of July 2012 have been fabricated into LEU with a natural uranium equivalent (NUe) of approximately 88,000 tonnes[e] (Khlopkov 2011). At the same time, the United States has downblended 119 tonnes of HEU that had been declared surplus to the nuclear weapons program, although only 93 tonnes (about 18,000 tonnes NUe) has been committed to the civilian power reactor fleet as of 2012 (US DOE EIA 2012). Together these activities have supplied nearly two years' worth of world uranium requirements at 2012 consumption rates.

C2-6.2 Blend-Down Activities after 2013

HEU downblending is expected to play a diminishing role in meeting uranium demand, if only because the stocks of HEU that could be made available for future use are smaller than those that have already been downblended (see section C2-1.3).

As reported in the 2009 CBR, the Russians in 2006 indicated they would not extend the Agreement past its 2013 expiration date. A 1992 antidumping law banned Russia from selling LEU in the American market outside the Agreement; the 2009 CBR also described an amendment (the 'Suspension Agreement Amendment') to the 1992 law that would allow Russia to market limited amounts of LEU and enrichment services in the US. The quotas specified in the amendment will permit Russia to compete for up to 20 percent of the US market for LEU. In 2010 Tenex opened a US subsidiary, TENAM Corporation, to market Russian uranium and enrichment services; as of mid-2012, TENAM has concluded a number of contracts to supply US power reactors with fuel after 2013 (Khlopkov 2011).

Downblending activities will likely continue in Russia after 2013, though not at the pace of nearly 30 tonnes HEU/year that prevailed during the Purchase Agreement years. A US law passed in 2008 (the 'Domenici Amendment') would raise the US market share for which Tenex could compete from 20% to 25% if Russia continued to downblend HEU at 30 tonnes/year and committed to the disposition of an additional 300 tonnes of HEU (Pomper 2008). But as of 2012 the Russian government has not assented to these conditions.

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[e]. *Natural uranium equivalent (NUe)* is defined as the mass of NU obtained if a resource were enriched or downblended to 0.711% U-235. The NUe is difficult to define for HEU since its enrichment level is generally not known. Throughout this section, it will be assumed that the HEU contains 90% U-235 and is downblended with DU assaying 0.25% U-235. Then a mass balance shows that blending 1 kg of HEU with 194 kg of DU yields 195 kg of uranium with enrichment equal to that of NU. So the NU equivalent of HEU is taken to be 195 kg NUe / kg HEU.

Therefore, the World Nuclear Association forecasts that the rate of Russian HEU downblending will decline to less than 20 tonnes/year after 2013 (WNA 2011). This translates to around 3,000 tonnes NUe/year of lost supply – close to 5% of world annual requirements – that must be made good from other sources. Likewise, the smaller US HEU disposition program is decelerating, with only 56 tonnes remaining of the 175 tonnes NNSA had declared its intent to downblend in the near term (US DOE EIA 2012).

C2-6.3 Remaining HEU Inventories

As of late 2010, the US DOE held 89 tonnes of excess HEU in inventory (US GAO 2011): the 56 tonnes mentioned above plus an additional ca. 34 tonnes subsequently declared surplus by NNSA. Some of this material is allocated: for instance, in 2005 DOE set aside 17.4 tonnes of HEU for the American Assured Fuel Supply (AFS) program. The AFS was inaugurated in 2011 and in 2012 held 230 tonnes LEU equivalent or actually down blended uranium (US DOE NNSA 2008). AFS is meant to serve as a fuel bank to be marketed in the event of a severe supply disruption. Downblending operations in support of the MOX LEU Inventory Backup Project commenced in 2011. This project commits 12.1 tonnes HEU as backup fuel for utilities participating in the DOE weapons Pu disposition program (US DOE EIA 2012). In 2008, when DOE last released its uranium inventory management plan, approximately 67.6 tonnes of HEU remained unallocated[f] to these or other programs (US DOE NE 2008). DOE plans to place LEU downblended from this unallocated inventory on the market, subject to a constraint that the amount sold per year represents not more than 10% of annual domestic demand.

Counting HEU used for the AFS and MOX Backup Project plus unallocated HEU, but discounting uses that would not result in supply to civilian power reactors (e.g. HEU downblend for research reactors or naval propulsion) and excluding downblending activities that have already placed LEU into the civilian fuel cycle, approximately 97 tonnes of US HEU is estimated to be available as a future source of supply.

Much additional HEU remains within the US and Russian weapons programs. Excluding HEU already declared surplus, the International Panel on Fissile Materials (IPFM) estimates that the Russian weapons program retains over 600 tonnes of HEU. The IPFM places the inventory of the US program at ca. 250 tonnes (Pomper 2008).

It is unlikely that all or even most of this material will be released for use in civilian power reactors, and the Russians have not declared a formal post-2013 HEU disposition policy. The Russian government has indicated that up to 300 tonnes of additional HEU may be declared surplus to their weapons program in the future (OECD 2010), but this position cannot be taken as a commitment with a time frame.

HEU inventories in other nuclear weapons states are small and their management policies are not expected to have a substantial effect on the uranium or enrichment markets. Defense-related HEU stocks in China, for instance, have been estimated to lie between 12 and 26 tonnes (Zhang 2011).

In summary, excluding US and Russian HEU already committed to near-term civilian use via the Purchase Agreement and US downblending programs, the following HEU stocks may become available for post-2012 use in civilian power reactors:

- 29.5 tonnes of US HEU via the American AFS and MOX LEU Inventory Backup Projects,
- 67.6 tonnes of unallocated surplus US HEU,

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[f]. The amount of HEU DOE considers committed to certain activities is not precisely fixed, so 67.6 tonnes is an approximate figure. For instance, DOE plans to downblend ‘up to 23 tonnes’ [US DOE EIA 2012] of HEU for use as research reactor fuel.

- up to 300 tonnes of Russian HEU not currently declared surplus.

If all of the above were released for civilian use, they would displace approximately 78,000 tonnes NUe of uranium, slightly more than one year of world annual requirement at 2012 levels.

C2-7. DATA LIMITATIONS

As mentioned, the importance of HEU as a secondary source of uranium supply is expected to decline after 2013. Other secondary supply reservoirs may play a more important role in the future. For example, the 2008 DOE uranium management plan (US DOE NE 2008) reported inventories of over 46,000 tonnes NUe of surplus high-assay depleted, natural and low enriched uranium. This is a considerably larger potential supply than the unallocated US HEU (67.6 tonnes of HEU, ~13,000 tonnes NUe).

Around the world, Ref. (Schneider 2011) estimates civilian NU/LEU stockpiles held by governments and utilities at ca. 150,000 tonnes NUe as of 2011. It places inventories of 'recyclable uranium' – irradiated LEU both still within used fuel and already separated via reprocessing activities – at ca. 270,000 tonnes NUe. Further, (Schneider 2011) estimates that if 2011 depleted uranium (DU) inventories held around the world were re-enriched with secondary tails taken to 0.14% U-235, some 440,000 tonnes NUe would be yielded.

In practice, most recyclable uranium and DU may never be utilized. Outside of limited experiences in France and Russia, recyclable uranium has not been re-enriched and re-fabricated into reactor fuel. Unless uranium prices rise or abundant inexpensive enrichment capacity is available, most DU will simply be stored or disposed. But at some ten years' supply at current annual NU consumption rates, the size of the potential reservoir embodied by DU and recyclable uranium is substantial.

C2-8. COST SUMMARIES

There is no What-it-Takes table for this module. LEU made from downblended HEU is a direct substitute for LEU created from mining, converting and enriching natural uranium and competes in that market. In fact, DOE regularly publishes prices it obtains when it sells uranium from its inventory on the spot market (US DOE 2011, Report to Congress).

Modelers are advised to treat the cost of purchasing HEU-derived LEU as being equal to the cost of purchasing the amount of uranium that would be required if HEU were not available (Module A1), converting it to UF_6 (Module B), and enriching it to LEU levels (Module C1). The quantities of uranium, conversion and enrichment services required are determined from a fuel cycle specific material balance that must be supplied by the modeler.

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.

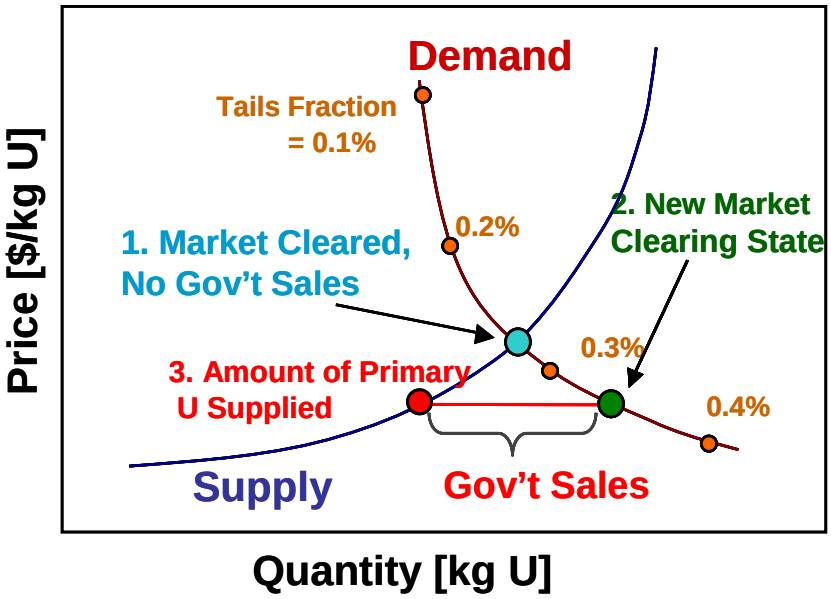

Figure C2-4. Effect of down blended HEU sales on the uranium market.

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. REFERENCES

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D MODULES

Fuel Fabrication

D Modules

Fuel Fabrication

PREFACE TO D MODULES

The introduction to the D-Modules in the 2009 AFC-CBR describes the many in-reactor physical, chemical, and nuclear factors which influence the design and functionality of nuclear fuel. As there are many variations in reactor design; there are even more variations in the design of the fuel which is charged to these reactors. For example, today's commercial LWRs operate on over 20 different "fuel designs", but all contain the same basic ceramic chemical form, either UO_2 (UOX) or mixed UO_2/PuO_2 (MOX) in the fuel "meat." (The colloquial term "fuel meat" is often used to represent part of a fuel rod or assembly containing the main nuclear material constituents whose fissile isotopes undergo fission or undergo other major nuclear transmutation, such as higher isotope production via neutron absorption, inside the reactor). For unirradiated fuel this "fuel meat" is the initial heavy metal (or its chemical compounds) plus any totally blended alloying or matrix constituents. For irradiated fuel the "meat" would include original remaining heavy metal not transmuted plus the mass of any lighter or heavier elements generated by fission or neutron capture transmutation. Because it does not undergo transmutatation as a nuclear material the mass of the cladding and other fuel assembly hardware are generally not included in fuel cycle mass balance and economic calculations. The cost estimating figure-of-merit for back end fuel cycle steps is often expressed in dollars per kilogram of initial heavy metal ($/kgiHM). For a particular fuel type the design variation is mainly in the geometric configuration of the fuel rods and the nature of the zirconium metal or other alloy hardware which support them. For example each of the major LWR fuel vendors, such as GE-Hitachi, AREVA, Westinghouse, TVEL, etc. has their own proprietary fuel designs particular to the class (BWR or PWR) and particular models and vintages of reactors they support.

More advanced reactors may have fuels completely different in form and materials than LWRs. For most of these fuels there are presently no large-scale industries or commercial fabrication vendors for their manufacture. Cost information is based on the extrapolation of small scale or pilot plant building and operations costs. The fuel designs are preliminary in nature and may not have undergone the extensive fuel qualification and in-reactor testing (lead test assemblies) required by many national nuclear regulators (such as U.S.NRC) before large-scale irradiation can commence. It should be noted that for all fuels, the fuel fabrication step is basically a service step, in that the cost incurred is for transformation of a nuclear source material, such as high-quality U, Th, or Pu (or mixes thereof) chemical compounds such as oxides, nitrates, oxalates, or fluorides into a finished, completely inspected fuel assembly ready to be charged to a reactor. The cost of the feed nuclear source material is not included in the fabrication cost; however, there may be an included cost for conversion of the pre-fabrication source material to the fuel grade ceramic compound in the "fuel meat", e.g. low-enriched UF6 from an enricher to fuel grade UO_2 powder (LWRs). For LWR fuel the mining, milling, U3O8 to UF6, and enrichment costs are not part of the fabrication cost, and are covered in Modules A, B, and C. The purchase of non-nuclear fuel assembly components, such as cladding material (e.g., zirconium) or matrix material (such as graphite) and miscellaneous hardware, however, must be included in the fabrication cost. The costs of fuel inspection, certification, and other quality assurance-related activities should also be factored into the cost or price of fuel fabrication. Unit fabrication costs are usually presented in dollars per kilogram of heavy metal ($/kgHM, $/kgU, $/kgTh), even though the actual fuel is in the form of an oxide or other possible chemical compounds. This convention is adopted because of the fact that the nuclear source material (U, Pu, Th, etc.) may change chemical forms several times throughout the overall fuel cycle, and it is simpler to track the elemental heavy metal component material balance over this total fuel cycle.

From the standpoint of cost a major discriminator between fuel types is the nature of the fuel fabrication facility, i.e., whether the in-process fuel can undergo direct or glovebox handling by humans (contact-handling [CH]) or requires non-human or remote handling ([RH] such as by robots) because of the high penetrating radioactivity levels of radionuclides in the fuel meat. The former operations can be handled in a more conventional industrial structure with sufficient security, hardening against natural disasters, and proper ventilation, whereas the latter requires thick, robust radiation shielding of all operations and the use of robots or manipulators for handling in hot cells. The HVAC requirements for the latter are also much more stringent. In this D module contact-handled fuels will be treated in the D1 submodules. (The contact-handling definition will include facilities, such as (Pu, U) O_2 MOX plants, with glovebox operations. In these glovebox-containing facilities the final sealed fuel rod handling and bundling operations allow hands-on direct contact handling). The D2 module will include fuels that are remote-handled in highly-shielded hot cells.

Generally the fuels that can be contact-handled are those directly arising from natural nuclear source materials such as unirradiated uranium or thorium which have never been in a reactor (sometimes called "virgin" materials). Natural and most enriched U fuels are in this category. Fuels containing separated and recovered elements arising from fuel reprocessing can be in this category only if their purity level or radioisotope content excludes or minimizes those isotopes or elements (such as many fission products, higher actinides, or decay daughters) which have associated high penetrating radiation fields. An example would be plutonium and/or reprocessed uranium arising from the aqueous reprocessing of spent LWR fuel. (Aqueous processing allows high decontamination factors for removal of some higher actinides (HAs) such as neptunium, curium, and americium, fission products (FPs), and decay daughters (such as those associated with U-233 production). It should be noted that in many proposed "proliferation-resistant" closed or partially closed fuel cycles complete separation of fission products and higher actinides is neither required nor desired. The intent is to avoid the separation of pure plutonium (or U-233) and make the separated product for fuel refabrication difficult to divert or steal because of its high penetrating radiation fields. These refabricated fuel forms will require remote handling (RH) facilities which will likely have to be immediately adjacent to the reactors or integral to the reprocessing operations. It is important that the reader understand that when products arising from reprocessing of spent fuel are to be fabricated into new fuel, one must know exactly what other radionuclides (FP and HA) will be carried over with the main recovered fuel HM product. As these radionuclides increase the fuel will transition from the CH regime to the RH regime. (This will be true for some of the D1 modules.)

For some reactors we will be dealing with heterogeneous fuel types, where the fissile fuel "driver" may be physically separate in the reactor core from a "blanket" or "target" used for useful nuclear material production (breeding) or waste material destruction (actinide burning). These fuel and target materials are also prepared in facilities with process equipment similar to those for drivers containing the major fissile fuel meat. Fresh blankets containing fertile uranium or fertile thorium for production of plutonium-239 or U-233 are likely to have very low radiation fields and can be contact-handled. Targets containing significant amounts of higher actinides such curium and higher Pu and Np isotopes for "burning/destruction" are likely to require remote handling. This means that for some reactor types using heterogeneous fuel concepts, both remote and contact-handling fabrication facilities will be needed.

As mentioned earlier the cost figure of merit of interest here is the $ per kilogram of heavy metal required for the fuel fabrication service. "Heavy metal" here includes the nuclear materials in the fuel meat, i.e. uranium, thorium, plutonium, higher actinides, and any residual fission products. Nuclear materials fabricated in contact-handling facilities are likely to be used for once-through or single-pass LWR MOX fuel cycles or the production of start-up fissile drivers ($HEUO_2$, high-fissile content MOX, or Pu metal alloy) for a fleet of fast reactors. Remote handling will be required for the spent fuels arising from continuous recycle and re-fabrication of higher-actinide bearing fuel types, especially those involving electrochemical pyrochemical recycle or multiple-pass recycle.

A comparatively high $/kgHM fuel fabrication cost (or price compared to LWR fuel) does not necessarily mean the fuel will be uneconomical in terms of the fuel cycle component of the levelized cost of electricity (LCOE). A higher $/kgHM is usually found for higher enrichment (higher percentage of fissile radioisotopes) fuels for which the security, criticality, and accountability requirements are more stringent. The amount of fuel required per kilowatt-hour, however, is likely to be much lower because of the possibility of higher fuel burnup (MWth-days per KgHM). Thus we have a situation with less fuel required per fuel reload at a higher cost per unit of fuel.

Module Series D1

Fabrication of Contact-handled Fuels

Module Series D1
Fabrication of Contact-handled Fuels

D1. PREFACE AND INTRODUCTION

Nearly all of the world's fuel fabrication facilities operating today are contact-handling (CH) facilities. Contact-handling as here defined can include fuels processed in gloveboxes, but with the final sealed fuel assembly capable of direct human handling if even for a short time. Many of these CH facilities are described in the D1 modules of this 2017 AFC-CBR. Typically a contact-handling facility, including the equipment therein, incurs construction costs in the several hundred to several thousand dollars per square foot of facility including process equipment (Williams 2009). The capacity of the facility depends on the size of the reactor fleet it serves and the expected fabricated fuel usage rate (burnup) during irradiation in these reactors.

The D1 Module for Contact-Handled fuel types is divided into nine sub-modules. The following list indicates the fuel and type of reactor to which it is charged:

D1-1 Pelletized LWR Uranium Oxide (UOX) Fuel – Used in PWRs and LWRs using low-enriched uranium. A mature fuel fabrication technology. As of 2017 considerable development is underway for "accident tolerant" fuels (Nuclear News 2017) with specialized cladding or pellet matrix modifications to reduce the possibility of rapid fuel failure and melting under accident conditions. Fuel designs allowing higher burnup are also under consideration.

D1-2 Pelletized LWR Mixed-oxide (MOX) Fuel – Substituted for some or all low-enriched UOX assemblies in LWRs and PWRs, mostly in Europe and Japan. A mature fuel fabrication technology for separated Pu as oxide arising from aqueous reprocessing.

D1-3 High-temperature reactor particle fuel – Can be used in graphite-moderated, gas-cooled reactors or in molten-salt cooled, graphite moderated reactors. The technology utilizing TRISO (Tristructural-isotropic) particles imbedded in graphite spheres or compacts has been tested at prototype or FOAK (first-of-a-kind) scale in several nations. As of 2017 the fabrication technology is just beginning to reach the maturity required for large-scale, semi-automated plants. This is occurring in China. Most current R&D on TRISO fuels is with uranium; however, the TRISO concept can be utilized for plutonium or thorium.

D1-4 Ceramic Pelletized Fast Reactor Fuel – Similar to D1-1 in concept but requiring pellet-diameters and rod cladding materials compatible with the liquid sodium coolant for fast reactors. Pilot plants have been built in several nations to provide this fuel for prototype fast reactors. Fuel meat can be MOX or Medium-enriched uranium (MEU) as oxide, carbide, or nitride. Maturity is such that the fabrication process could be readily adapted to large scale production.

D1-5 Ceramic vibrocompacted Fast Reactor Fuel – Similar to D1-4 except that oxide powders are not pelletized, but rather poured into tubes (rods) and vibrated to compact the powder. The compacted powder self-sinters during irradiation. This technology has been tested mainly in Russia and as of 2017 is not yet mature enough for large scale production.

D1-6 Metallic or alloyed reactor fuels – Metal fuel has heat transfer advantages in sodium-cooled fast reactors. It has been tested in experimental fast reactors (EBR-II and FFTF) in the U.S. For contact handling the fissile materials therein must be clean and free of fission products or higher actinides capable of producing high radiation fields. The alloying/casting process required has been tested on a pilot scale. This type of fuel is more likely to be used as fast reactor start-up fuel

in conjunction with eventual remote electrochemical fuel recycle as discussed in Module D2. In Russia such U-alloy metal fuel is used for marine reactors. There is some private sector R&D being conducted by the Lightbride Corporation in the U.S. for LWR fuels utilizing metal fuel. This type of fuel would have superior heat transfer characteristics.

D1-7 Pelletized CANDU Reactor fuels – Similar to D1-1 except that natural assay or slightly-enriched UO_2 is used and the fuel assemblies are short and loaded into the CANDU reactors horizontally. A mature fuel fabrication technology employing large-scale facilities exists in Canada.

D1-8 Thorium-based fuels – Thorium oxide has been loaded in pellets and TRISO particles to serve as fertile "blanket" material for the generation of fissile U-233. This concept has been tested in both LWRs and HTRs. Mixed oxide pellets of UO_2 and ThO_2 have also been produced. All thorium-related fuel fabrication has been in pilot scale facilities. Thorium salts can also provide the fertile material for use in Molten Salt Breeder Reactors (see Module R7).

D1-9 Advanced fuels – Much of the recent R&D work on advanced fuels is for the "transmutation fuel" types which would contain higher actinides and even small amount of fission products. These fuels would require remote handling. There is, however, interest in uranium LWR fuels which would be less susceptible to the adverse water-cladding reactions under overheating accident conditions. (These are called "Enhanced Accident Tolerant Fuels.) Such concepts include alternative claddings, such as silicon carbide, and the use of particles imbedded in a clad matrix material. These fuels could likely be handled in "contact" type facilities.

NOTE: *References to all D1-modules are organized by submodules at the end of the entire D1 module chapter*.

For most of the D1 Modules following this Summary Module, 2017 cost updates to the 2009 and 2012 AFC-CBR Modules are now provided along with the original 2009AFC-CBD technology and deployment information. (Future AFC-CBR versions may have more complete technology and deployment status discussions.) Cost summary tables are also provided that update the costs to 2017 dollars using escalation factors.

When considering the nature of Fuel Fabrication facilities and operations, one must remember that 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 fuel cycle category would also apply to blanket or target materials that are irradiated in a reactor along with the driver fuel (i.e. a heterogeneous core reactor system**).**

The nature of these fuel fabrication 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 plant

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.

2. **For once-through fuel cycles the fuel form must also be compatible with the method of temporary storage and ultimate geologic disposal.** The fuel cladding or matrix is essentially the first "line of defense" against eventual contact with the environment. Ideally most of the post-irradiation radionuclides will have decayed to negligible levels before the fuel and cladding begin to seriously degrade.

   Fabricated fuel assemblies take many different physical forms. Every September, Nuclear Engineering International (Nuclear Engineering International 2011) 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)].

3. **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.

4. **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:

1. 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 (D1-x.N) into the same 10 topics (N.1 through N.10; x=1 through 9 depending on fuel type) as if it were a stand-alone module.

2. 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 bundled 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 where major fissile materials are not easily 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 (reprocessing) and D2 (fabrication) modules are combined.

3. 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.

4. For enriched uranium fuels, the feed material to the fabrication plant is assumed to be either virgin (never irradiated) EUF_6 or aqueously reprocessed and converted 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 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.

5. 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, pilot plant development, or low throughput deployment stage of an overall fuel process qualification program.

A cost summary is provided below for each of the nine types of CH 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 over 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 2017 would not cover all the cost-affecting changes in the regulatory, security, and financial environment surrounding new nuclear projects in the U.S.

This table appeared in the 2009 AFC-CBD with all entries in 2008 constant $. The table did not appear in the preface to the 2012 Update AFC-CBD. It is repeated in this new 2017 version with all entries updated with new technology/cost information gleaned from 2009 to 2012 and for escalation only to 2017$.

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).

Table D1-1. 2017 Cost summary table.

What-It-Takes (WIT) Table (updated from 2008 constant $ to 2017 constant $ and for new data where appropriate)				
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Mode Cost)
D1-1 LWR UO_2 Fuel Fab				
NA in 2017	NA	$230/kgU for PWR $285/kgU for BWR	$575 for PWR $575 for BWR	$400/kgU for PWR $400/kgU for BWR, for today's LWR fuel designs
		$250/kgU for PWR REPU $315/kgU for BWR REPU	$635/kgU for PWR REPU $635/kgU for BWR REPU	$435/kgU for PWR REPU, $435/kgU for BWR REPU
D1-2 LWR MOX Fuel Fabrication				
$1000/KgHM based on European Experience	NA	Unit Cost=$800/kgHM	Unit Cost = $1600/kgHM	Unit=$1000/kgHM
D1-3 Gas-Cooled Reactor particle Fuels				
NA in 2017	NA	$3300/kgU	$29,400/kgU	$10,900/kgU
D1-4 Ceramic Pelletized Fast Reactor Fuel				
NA in 2015	NA	Driver MOX: $2700/kgHM Blanket UOX: $270/kgU Driver MEU MOX: $520/kgU	Driver MOX: $7600/kgHM Blanket UOX: $690/kgU Driver MEU MOX: $1290/kgU	Driver MOX fuel: $4900/kgHM Blanket UOX: $500/kgU Driver MEU MOX: $900/kgU
D1-5 Ceramic Vibrocompacted Fast Reactor Fuel (UOX+MOX)				
NA in 2015	NA	$720/kgHM	$1440/kgHM	$900/kgHM if VIPAC assumed 10% cheaper than pellet fast reactor MOX (D1-2)
D1-6 Metallic or Alloyed Fast Reactor Fuel				
Lightbridge Corp investigating U alloy fuel for LWRs. No cost data available	NA	No data	No data	See Module F2/D2 for remote handled FR metal alloy fuel
D1-7 CANDU Fuel				
NA in 2015	NA	Nat U: $125/kgU REPU or SEU: $164/kgU	Nat U: $327/kgU REPU or SEU: $425/kgU	Nat U: $218/kgU REPU or SEU:$284/kgU
D1-8 Thorium-based Fuels				
$(U,Th)O_2$ pellet fuel	NA	$327/kgHM in	$818/kgHM	$573/kgHM
ThO2 blanket fuel	NA	$273/kgTh	$687/kgTh	$490/kgTh
D1-9 "Advanced" Fuels (No cost data available)				

BWR = boiling water reactor	LWR = light-water reactor
EU = enriched uranium	MOX = mixed oxide
HVAC = heating, ventilation, and air conditioning	PWR = pressurized water reactor
LEU = low-enriched uranium	REPU = reprocessed uranium
MEU=medium enriched U (actually lower assay HEU 20 to 30%U-235)	RTPI = Radkowsky Thorium-Plutonium Incinerator

Module D1-1

LWR UO_2 Fuel Fabrication

Module D1-1

LWR UO_2 Pelletized Fuel Fabrication

D1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
  - Literature review of pricing for this commodity service, which is a totally mature technology for zirconium clad LWR fuel. Late 2012 technical assessment noted that unit costs for PWR and BWR fuel are moving closer together, probably a result of commercial fuel fabricators now making both types.

It should be noted that Module D1-1 (LWR UO_2 Fuel Fabrication) has not been updated to reflect new market conditions (2017 depressed oversupply market) and the sale, closure, or opening of existing or new facilities. Proposed fuel pricing data for advanced, accident-tolerant LWR UO_2 fuels with innovative cladding are not yet available.

D1-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module D1-1. In 2008 AFC-CBR the fabrication costs for LWR fuel made from reprocessed uranium were added.
- **Latest version of module in which new technical data or new market assessments were used to establish unit cost ranges:** 2012 for latest market assessment. Most of the text and historical costs in this version are from the 2009 AFC-CBD.
- **New technical/cost data which has recently become available and will benefit next revision:**
  - There has been considerable progress in the area of Enhanced Accident Tolerant LWR Fuels, (EATF) including some types being readied for insertion as lead test assemblies in commercial reactors. It would be useful if any cost projections for these fuel types are available. Most of the technical enhancements are in the fuel cladding; however, some modifications to the structure and chemistry of the "fuel meat" are being considered. One example of an EATF is the "Chromia" fuel being developed and tested by AREVA-NP.
  - Another is Westinghouse "Encore" Fuel (World Nuclear News 2017).
  - Internet research and perhaps a phone call with TVA's nuclear fuels manager would be useful to ascertain the effect of the current depressed market on fuel fabrication prices.

D1-1.1. 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 ($n \times n$) 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.

D1-1.2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Status of the Industry in 2009. 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 1999 and 2002) and general consolidation (Kidd 2005) of the nuclear business, the number of fuel fabrication plants in the U.S. has dropped to four. 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, Rothwell 2007, Rothwell 2010). 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. [(2009 Status) To be updated in future versions].

Plant Owner	Location	Capacity in MTU/yr	Fuel Type
AREVA NP	Lynchburg, VA	600	PWR (fuel assembly only, no pellet production)
AREVA NP (formerly Siemens)	Richland, WA	900	Mainly BWR, some PWR
AREVA NP (ref Energy-Business-review.com 2008)	Erwin, TN	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, NC	1,100	Mainly BWR
Westinghouse Nuclear Fuel	West Columbia, SC	1,150	PWR, some Vod-Vodyanoi Energetichesky Reaktor (VVER)

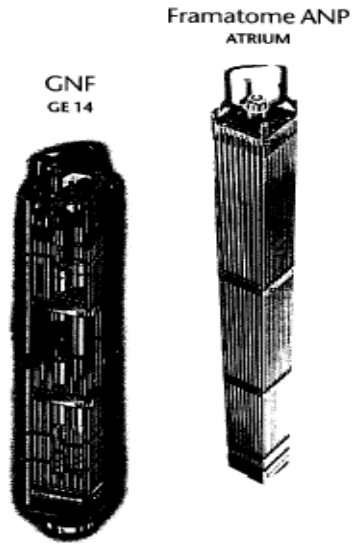


Figure D1-1-1. BWR and PWR fuel assemblies

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.

Status of the Industry in 2012. Little has changed from the *December 2009 Advanced Fuel Cycle Cost Basis Report* in the areas of the basic industrial process, its interfaces to other fuel cycle steps, and the status of LWR fuel fabrication facilities in the U.S.. The following should be noted, however:

- AREVA has closed its commercial reactor fuel fabrication operation at Lynchburg VA and moved its operations to their Richland WA facility (Feb 2011). This facility uses a "dry" process to convert $LEUF_6$ to $LEUO_2$ for pellet production.
- Westinghouse is adding the capability at its West Columbia SC facility to produce a limited amount of BWR fuel. Sinterable $LEUO_2$ powder is produced from $LEUF_6$ via an aqueous ADU process.
- Utilities are trying to diversify their fuel fabrication suppliers as much as possible in the hope that the pricing of this service will be more competitive. Foreign sources will be considered if the fuel and production process meet U.S.NRC licensing regulations and standards.
- No U.S. fuel fabrication facilities are presently using feedstock uranium oxide derived from re-enriched reprocessed uranium derived from commercial spent LWR fuel. Unfavorable economics at today's ore and SWU prices, the lack of a U.S. reprocessing industry, and the need for additional fuel qualification have resulted in minimal interest in this route by U.S. nuclear utilities
- The fuel fabrication industry continues to be dominated by very high quality assurance requirements, especially as utilities move toward the use of "zero-defect" fuel and no fuel failures.
- U.S. fuel fabrication facilities are still limited to the introduction of EUF_6 (enriched UF_6) feed at a U-235 assay of 5.00% or less. (This is not a formal regulation, but rather an industry understanding) For PWRs to exceed fuel discharge burnups of about 55,000MW (th)-days/MTHM or higher, U-235 assays may have to rise above the 5% level [see MIT, Future of Nuclear Power, p.119 (2003)]. Relicensing actions by the NRC will almost certainly be required, which in turn might require significant modifications to facilities for criticality safety and security. This is a contentious issue in the fuel fabrication industry.
- The trend of some utilities and plant operators to "bundle" all front-end fuel cycle materials and services (including fabrication) into a single price for finished and delivered fuel continues.

D1-1.3. PICTURES AND DIAGRAMS

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 deconversion 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).

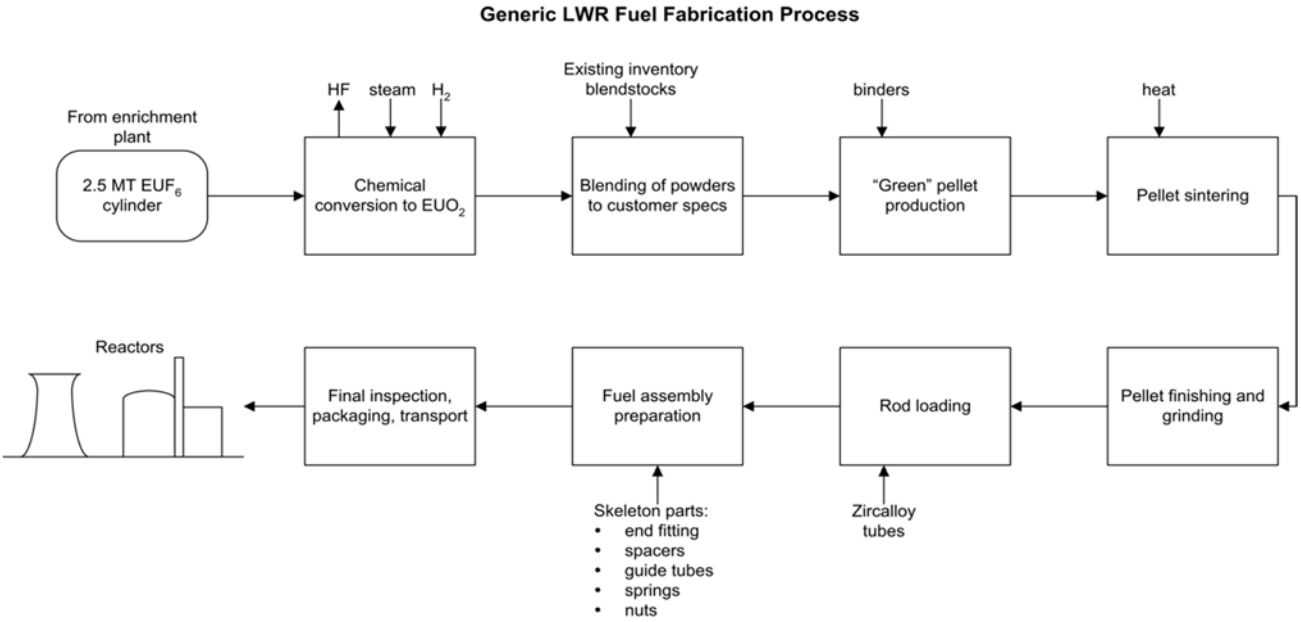


Figure D1-1-2. Generic LWR fuel fabrication process.

D1-1.4. MODULE INTERFACES

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.

D1-1.5. SCALING CONSIDERATIONS

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.

D1-1.6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

2009 AFC-CBR Cost Bases. 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). (Year $ assumed to be same as year of study listed on the left column.)

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 2013; and Tolley and Jones 2004 present similar ranges to above (i.e., $200 to $300/kgU)
c. ERI (Platts 2007a) 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 trace 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 (inflation effect removed) 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 .2009 AFC-CBD Cost summary table for contact-handled fuel fabrication.

2009 AFC-CBD 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

2012 AFC-CBD Update Cost Bases. Several new and recent data sources have been accessed to provide the basis for changing the recommended low, nominal, and high values for the $/kgU (or $/kgHM) price of fuel fabrication. (Note that there are no published data on the actual production cost of the fabrication service.) There is no "spot" market for fabrication services, since the supplied fuel assembly product is generally non-fungible and customized to the particular reactor. (Uranium ore, conversion services, and enrichment are 'fungible" commodities that can be sold back and forth between utilities and brokers.) This means that there is no published price, since most utility/fabricator contracts are proprietary. Specialty nuclear consulting firms, such as UxC, publish proprietary reports on fuel fabrication and other fuel cycle services which are very expensive (thousands of dollars per copy) and for which use is restricted generally to buyers within a particular utility. Even if this program procured such a report, we would not be allowed to make the fuel cycle unit costs or pricing numbers within it publicly available. This reference (NAC Worldwide Consulting 2004) is one such report.

It should be noted that four prices are discussed here, one set for PWRs and one set for BWRs. The other differentiator is the source of the $LEUF_6$ feed to the fabrication plant. Over 95% of the world's fabricated $LEUO_2$ fuel originates as ore and the $LEUF_6$ product fed to the fabrication facility is the result of conventional mining, milling, conversion, and enrichment services. Such material has never been irradiated in a reactor and is often called "virgin" LEU (V-LEU). A much smaller amount of enriched LEUF6 arises from the conversion and re-enrichment of near natural assay or slightly enriched uranium recovered during spent LWR $LEUO_2$ fuel reprocessing outside of the U.S.. This R-LEU is slightly contaminated with very potent U-232 daughter radionuclides which require special ES&H and handling considerations in the fuel fabrication plant. A pricing penalty is added to the V-LEU price to obtain an R-LEU price which includes the additional costs. There is also a penalty for the U-236 which builds in during irradiation. It is a neutron absorber and forces one to up the required U-235 enrichment slightly in R-LWR fuel. The following Table D1-1 shows fabrication price data from various recent sources:

Table D1-1-4. What-it-takes" (WIT) Prices from Various Sources (Constant 2012$).

Study or Ref/Year	Low Value ($/kgU)	Medium or Ref Value ($/kgU)	High Value ($/kgU)
WISE Nuclear Fuel Cost Calculator (Europe) (WISE 2009)			
PWR V-LEU	N/A	460	N/A
DEC 2009 AFC-CBR			
PWR V-LEU	200	250	300
BWR V-LEU	250	300	350
PWR R-LEU	220	300	400
BWR R-LEU	275	350	450
EPRI 1020659 (EPRI 2010)			
PWR V-LEU	150	220	250
PWR R-LEU (10% adder)	165	242	275
MIT Future of Nuclear Fuel Cycle (Massachusetts Institute of Technology 2011)			
PWR V-LEU	N/A	250	N/A
PWR R-LEU (7% adder)	N/A	267	N/A
Nuclear Engineering International (Nuclear Engineering International 2011)			
PWR V-LEU	260 (30% adder)[1]	N/A	420 (40% adder)[1]
BWR V-LEU	N/A	360 (20% adder)[1]	N/A
Private Foreign Source			
PWR V-LEU	400	N/A	500
1. To 2009 AFC-CBD value. (% added is suggested by reference source to be added to prevailing 2009 price)			

The most useful public source of new information was the September 2011 issue of Nuclear Engineering International (NEI 2011) which included a review of the entire front-end fuel cycle. The author's market analysis discussed the significant increase in fabrication prices since the 2008-2009 period. The reasons mentioned were the following:

- Higher costs to cover the higher quality requirements for "zero-defect" fuel
- Large increases in the cost of zirconium due to high demand, especially in Asia. The source material for zirconium cladding and hardware is zirconia (ZrO_2) derived from the mineral zircon. Recent pricing is as follows in $ per metric ton of zircon (imported): [U.S. Geological Survey 2012 and UxC Consulting 2011]
  - 2007 872
  - 2008 773
  - 2009 850
  - 2010 1155
  - 2011 2500
  - 2012 2600
  - 2014 1050 (added July 2017)
- Higher labor costs for qualified professionals
- Recovery of increased capital costs for equipment and facility modifications, including facility expansion

Cost factors related to proposed advanced LWR fuels such as "accident tolerant" silicon carbide-clad UO_2 and particle dispersion fuel will be covered in Module D1-9. These Enhanced Accident Tolerant Fuels would allow higher burnup and longer fuel life in addition to having many safety-violated benefits.

It should also be mentioned that European prices are in general higher than U.S. prices. This is likely due to the fact that European and Asian plants are newer than U.S. plants and may still be including capital recovery for plant construction.

D1-1.7. DATA LIMITATIONS

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 $100 million (2004$) 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 (U.S.EC Inc. 2007) and ceramic-clad fuel (Platts 2007b).

D1-1.8. COST SUMMARIES

The 2009 AFC-CBD module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-1-3 above.

For the 2012 AFC-CBD Update the following set of ranges and distributions (Table D1-1-5) were recommended for use in future fuel studies:

Table D1-1-5. Low, Nominal, and High Suggested Fabrication Price Values in $/kgU (2012 $)

Type of LWR and Type of Feed to Fabrication Plant	Low (2012 $)	Nominal (2012 $)	High (2012 $)
PWR V-LEU	200	350	500
BWR V-LEU	250	350	500
PWR R-LEU(10% adder to above)	220	385	550
BWR R-LEU(10% adder to above)	275	385	550

The 10% adders for the R-LEU cases cover the additional handling costs related to the presence of U-232 daughter radioisotopes.)The following philosophies were used in price range selection for the 2012 update:

- Low ranges are the same as 2009. This would be a slow nuclear growth scenario where there is less pressure on the zirconium market and fewer capital additions which require amortization.
- PWR costs have increased at a rate higher than for BWRs. It is here assumed that the nominal (most likely long-range constant dollar prices will eventually be the same and will be around 20% higher than the 2009 values. Slowly escalating zirconium costs are likely.
- The high values assume that many new fabrication facilities are constructed and the costs recovered in the price. Zirconium is assumed to remain significantly higher than in the 2007-2009 period. The higher price should be used for output of Asian and European facilities. It remains to be seen whether long term zirconium prices will stabilize and/or even come down as is often the case for commodities. A proprietary report (UxC Consulting 2011) examines some of these issues.
- For uncertainty analyses triangular unit cost distributions should be used

No new data for the period 2012 to 2017 has been collected to inform entirely new values to supersede the 2012 values. For this 2017 Report the 2012 values are escalated by ~9%for Year 2017$. Table D1-1-6 summarizes the data.

Table D1-1-6. Low, Mode, Mean, and High Suggested Fabrication Price Values in $/kgU (2017$).

Type of LWR and Type of Feed to Fabrication Plant	Low (2017 $)	Mode (2017 $)	Mean (2017 $)	High (2017 $)
PWR V-LEU	230	400	401	575
BWR V-LEU	285	400	420	575
PWR R-LEU(~10% adder to above)	250	435	435	635
BWR R-LEU(~10% adder to above)	315	435	440	635

The triangular distributions based on the costs in the above WIT Table are shown in Figure D1-1-3.

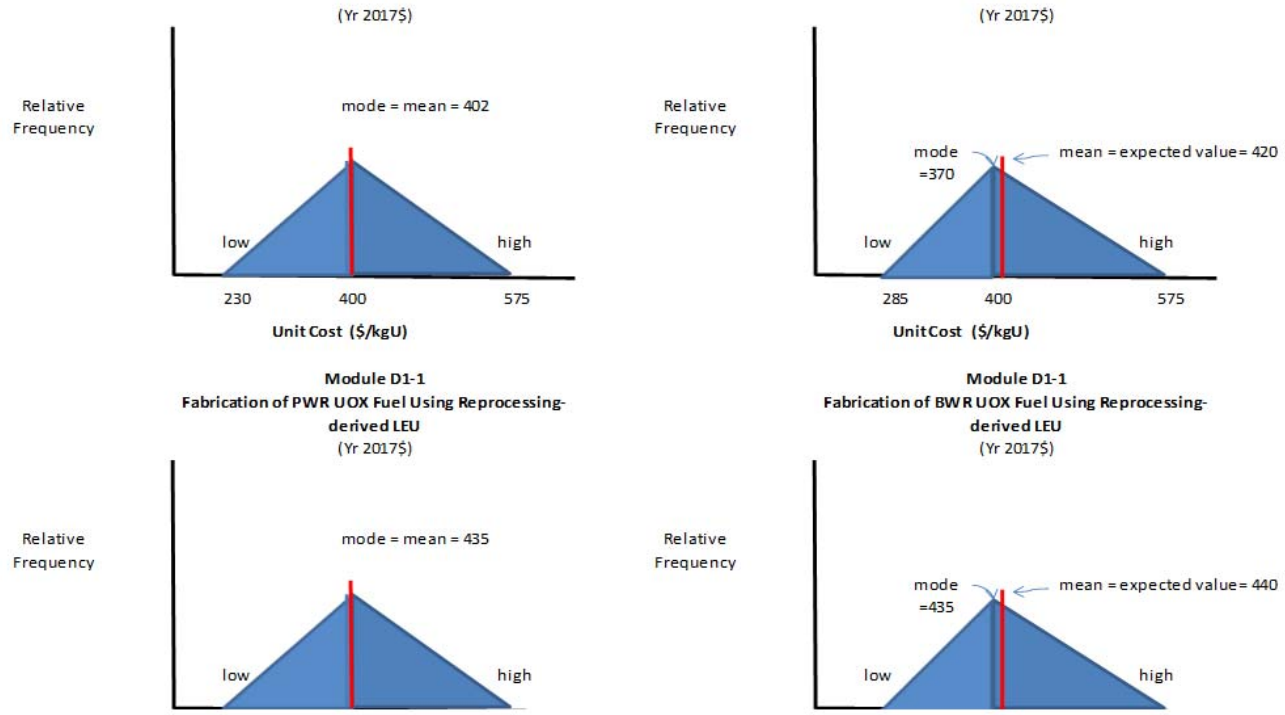


Figure D1-1-3. LWR UO_2 fuel fabrication (PWR & BWR) estimated cost frequency distributions.

D1-1.9. SENSITIVITY ANDUNCERTAINTY 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.

D1-1.10. SPECIAL TOPIC: $LEUO_2$ FABRICATED FROM REPROCESSED URANIUM

(This special section was written for the 2009 AFC-CBD, but is still applicable today). 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 (2009) 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 aqueous solutions from 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 2007).

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_3O_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_3O_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 "lighter" uranium 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 (as of 2008) 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.

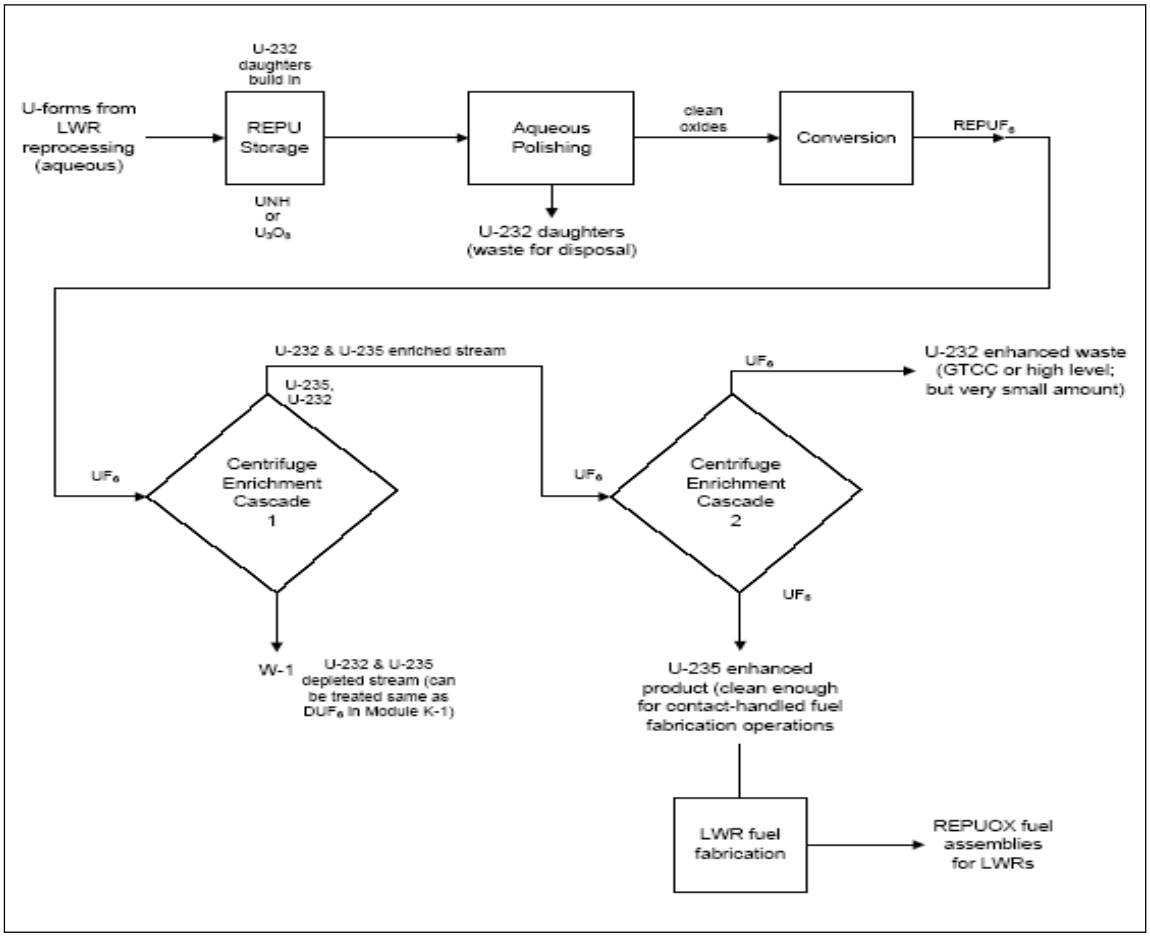


Figure D1-1-5. French-Russian scheme for reprocessed uranium recycle.

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 and Nuclear Street 2009). 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 (Nuclear Fuel Services 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

D1-2.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Revisit of 2015 WIT values and distribution to remove very deleterious (high cost) effects of SRS MFFF (MOX Fuel Fabrication Facility) construction cost and schedule experience.
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was revised:** Literature review on anticipated new MOX facilities including SRS MFFF project to produce MOX from weapons-grade Pu. This 2017 unit cost assessment depends heavily on the more successful European MOX experience with Pu separated from LWR spent fuel via aqueous reprocessing. The SRS experience is being treated as an outlier, since the SRS MFFF is a very small plant and requires extra facilities and operations to accommodate weapons-grade Pu.
- **MOX technology was successfully implemented in France, Germany, and Belgium. The UK had difficulty with their MOX facility at Sellafield. MOX is a mature technology.**

D1-2.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module D1-2
- **Latest version of module from which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Progress in Japan on construction of JMOX plant in Rokkasho-mura.
  - UK reports on possibility of new MOX plant to process their large separated Pu stockpile.

Introduction from 2009 AFC-CBR.

Fuel Form. An LWR MOX fuel assembly with its array of pellet-loaded rods appears 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 90+% 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. 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 formerly THORP in the United Kingdom. The Japanese have begun use of MOX in their reactors as part of their "Pluthermal Fuels" program, and are constructing a MOX facility at Rokkasho-Mura. The UK has

stopped producing MOX, but the SMP (Sellafield MOX Plant) has not yet been decommissioned. (Platts 2007e and World Nuclear News 2011). Up until 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 submitted for licensing for a MOX plant at Anderson, South Carolina, with PuO_2 to come from a nearly completed fuel reprocessing plant at Barnwell, South Carolina. Construction was never started on the Anderson MOX Facility. This empty concrete shell for the Barnwell Reprocessing Plant still sits near the Savannah River Site in SC. 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 (U.S. DOE 1997) 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. These negotiations failed since the SRS-MFFF completion date is too far in the future.) The design of this plant is now complete, NRC construction approval has been received (NTI 2007) and construction is still underway despite NNSA's decision to proceed with another Pu disposition technology [Construction still is underway due to SC Congressional delegation inserting federal funding. DOE-NNSA never plans to use it and pursuing an alternate method (dilute and dispose) for Pu disposition]. The plant will have processed 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 (Platts 2007f) 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 technology transfer, and now political concerns have prevented this LWR-MOX project from proceeding any further. It now appears that the Russian Pu-disposition program will utilize weapons-derived fast reactor MOX in BN-type fast reactors for their Pu-disposition program (Platts 2007f). They are operating a small fast reactor MOX fabrication facility at Zhelesnogorsk Mining and Chemical Combine) Figure D1-2-1 shows a flowsheet for a generic reactor-based plutonium disposition programs. [Editor's note: Russia has now withdrawn from the 2000 Plutonium Management and Disposition Agreement (PMDA; U.S. Dept of State 2000) which it signed with the U.S.]

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 was essentially to have been made available to the utility at a unit cost somewhat below that for $LEUO_2$ fuel assemblies in order to provide an incentive to U.S. electric utility participation.

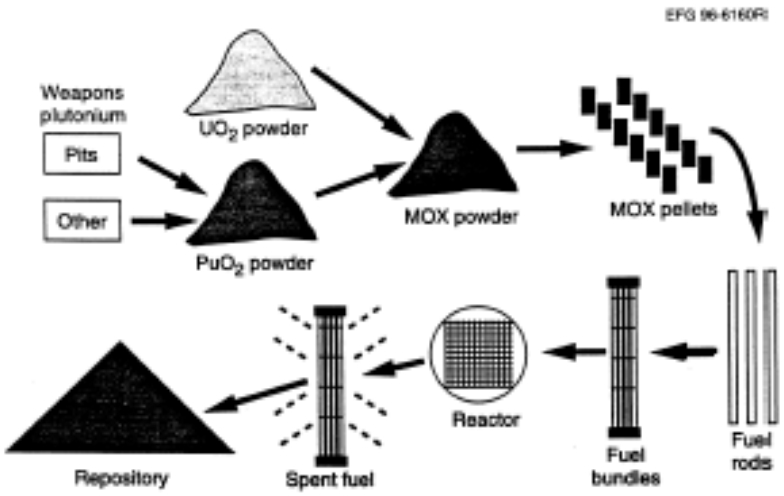


Figure D1-2-1. Generic reactor-based option for weapons plutonium-disposition (ORNL 1999).

Present DOE/National Nuclear Security Administration plans were to have limited the U.S. plant (SRS-MFFF) to weapons plutonium-disposition activities only, even if the plant life was limited to 10 to 12 years of operations. Up until recently (2017), U.S. policy has been to discourage plutonium recycle and the construction of commercial recycling facilities, such as MOX or reprocessing plants. The Trump administration is in the process of reviewing all military and commercial nuclear waste handling policies.

Introduction from 2012 Update to AFC-CBD. Again little has changed from the *December 2009 Advanced Fuel Cycle Cost Basis Report* in the areas of the basic industrial process for MOX fabrication and its interfaces to other fuel cycle steps; there have been, however, a few changes in the status of some of the world's MOX fabrication facilities: The Sellafield (United Kingdom) MOX Plant (SMP) is in the process of shutting down and will be slated for eventual decommissioning. Its major customers were Japanese utilities which are now facing the prospect of shuttered reactors after the March 2011 tsunami-induced Fukushima event. The SMP only realized a fraction of its design production rate of 120 MTHM/yr and only operated for a few years. The UK is still considering the burning of MOX fuel in new Generation III+ LWRs as a method of dispositioning its large stockpile of over 110 MT of separated Pu from its commercial and military reactor programs (Nature News and Comment 2011). A new and larger plant would be required that might also be able to produce MOX fuel for fast reactors. (Module D1-4). The UK is considering the fast reactor as part of its future Pu-disposition strategy and is evaluating the GE-Hitachi PRISM fast reactor design.

- The status of the 130 MTHM/yr J-MOX plant at Rokkasho-Mura is unclear. It began construction in 2010; however, the Fukushima event may spell the end of the Japanese "pluthermal" MOX burning program. At the time of drafting this chapter (August 2017) construction of the J-MOX facility continues but at a slow pace.
- The French MELOX facility continues to operate successfully and has a capacity of 195 MTHM/yr.
- The U.S. MOX Fuel Fabrication Facility (MFFF) is still under construction (over 70% complete) at the USDOE Savannah River, South Carolina, Site. It has been beset with rising projected costs and schedule slippage (Augusta Chronicle 2012). This plant is not designed (from a worker protection and non-proliferation policy standpoint) to take as feed separated commercial reactor Pu, which has higher concentrations of Americium and Pu isotopes other than Pu-239. MFFF's feedstock comes from military programs, thus a special "aqueous polishing" front end is needed to remove weapons-related impurities and prepare a pure PuO_2 powder suitable for MOX fabrication. Another predecessor step is required to render the weapons form or "pit" into feed appropriate for the aqueous polishing from end. This stop will also have to be integrated into the MFFF front end and in other

SRS facilities and with additional cost. A waste packaging facility (Waste Solidification Building) was to also have been constructed at SRS to handle the TRU waste, but has been cancelled. Until 2016 the MFFF was anticipated to make MOX fuel for both PWRs and BWRs. Although limited MFFF construction is ongoing, the NNSA today presumes it will never be completed or operated, and that a "dilute and dispose" process involving geologic disposal at the U.S. WIPP (Waste Isolation Pilot Plant) will be utilized for weapons-grade Pu disposition. The U.S. National Academy of Sciences is in the process of reviewing this option.

- As part of the Year 2000 Joint U.S-Russia Plutonium Management and Disposition Agreement (PMDA) (U.S. Dept of State 2000) both the U.S and Russia had agreed to burn excess weapons Pu in their LWRs. Russia has now decided to burn their Pu in sodium-cooled fast reactors of the BN-800 variety. The type of fuel is likely to be pelletized MOX (Module D1-4) or VIPAC fuel (Module D1-5). The PMDA was modified in 2010 to reflect this new reality. The Russian Federation recently (2016) formally pulled out of the PMDA agreement due to worsening relations with the U.S.; however, they still plan to use WG-Pu in their BN-800 fast reactors. The U.S. has not formally pulled out of the agreement; however, the intent to terminate the MFFF Program essentially negates the PMDA intent to produce (by irradiation in reactors) isotopically altered Pu not suitable for weapons and also self-protecting due to built-in radioisotopes.

Proposed costs for some of these facilities will be discussed below:

D1-2.2 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 much higher 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.

D1-2.3 PICTURES AND DIAGRAMS

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.

D1-2.4 MODULE INTERFACES

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) had been 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. As of 2012 the SRS-MFFF had planned 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 former U.S. gaseous diffusion enrichment plant sites. Shaw-AREVA MOX Services, the DOE/National Nuclear Security Administration plutonium disposition contractor, had been responsible for implementing this conversion step and had 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 had been developing a procurement process to obtain the ~1000 MTU of depleted material needed for MFFF operations. The cost of this uranium conversion step was to be included in the SRS-MFFF operations costs and was likely to have cost in the tens of dollars per kgU, with the actual unit cost depending on the batch sizes and quality and morphology of the UO_2 powder required. Framatome had already prepared cost proposals to Shaw-Areva MOX Services for this operation; however, DOE's ultimate choice of the DUO_2 provider will have depended heavily on economics and the response to the procurement request for proposals (RFP). All of the plans described above are now moot due to NNSA's decision to change WG-Pu disposition options; however, the descriptive material above has been included since the technical and cost issues are germane to any MOX Program.

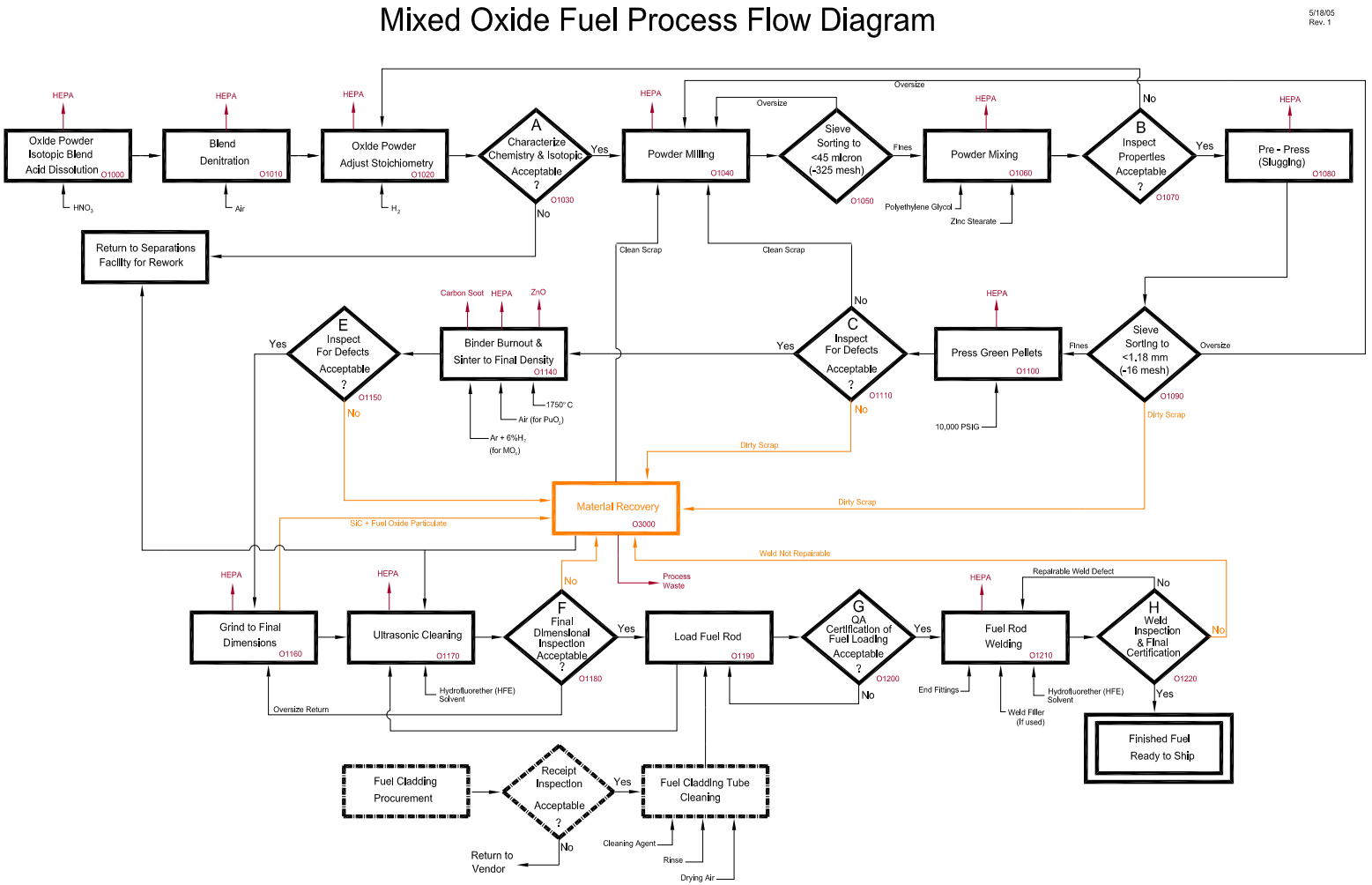


Figure D1-2-2. Generic MOX fuel process flow diagram (DOE-AFCI Fuels Working Group, 2007).

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 was to have been 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, and I discuss some possible waste disposal methods.

D1-2.5 SCALING CONSIDERATIONS

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. In fact, from Table D1-2-1 that shows the known capital costs for existing facilities, it is difficult to notice any capital cost scaling relationship. Because the fixed safety, security, and other infrastructure costs associated with both the capital and operating costs are generally high for MOX fabrication facilities, the unit costs climb rapidly as throughput decreases. In fact, according to Stoll (2002), there is such a relationship for unit costs, which include capital and operating components, as shown in Figure D1-2-3. Therefore, in order for MOX to be more competitive, large throughput plants should be built. Rothwell discusses economy-of-scale issues in (Rothwell and Braun 2007).

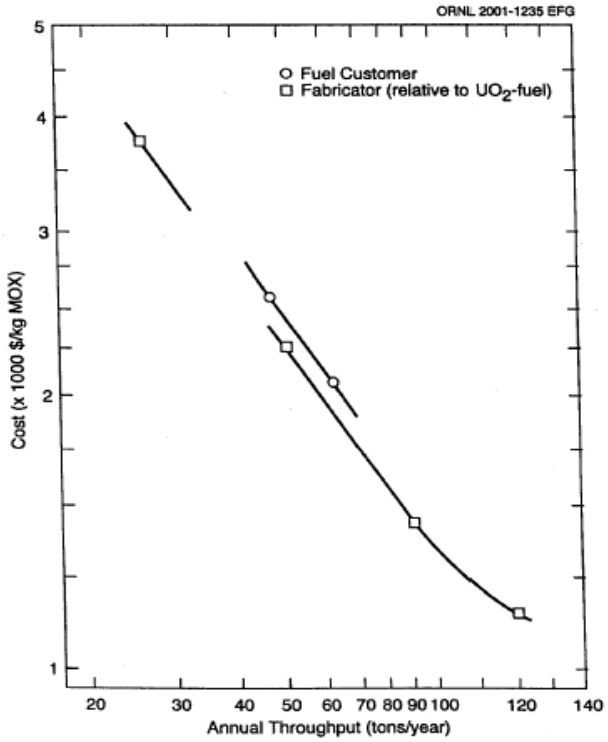


Figure D1-2-3. MOX unit cost as a function of throughput (Stoll 2002).

D1-2.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

Most of the MOX fuel fabrication cost data available are for existing facilities in Europe, although no data were found for the French MELOX or the Belgonuclaire facilities. Bunn, et al. 2003 performed a comprehensive survey of life-cycle cost information. Table D1-2-1 summarizes this information along with the Section D1-2 authors' analysis, described below, of the U.S. SRS-MFFF projected life-cycle costs in 2009, when the analysis was performed. [Note: the expected cost of the still-incomplete SRS MOX plant has since ballooned to several times that amount, according to the most recent press information (sup. Ref: Mufson 2017)]. Each of the studies provides the construction costs, (in the form of overnight cost) and occasionally the operation and maintenance costs. In order to generate a unit cost (in $/kgHM), however, it is necessary to make assumptions on the discount rates and on the facilities' expected lifetimes. A common set of assumptions applied here are described in the bullet list below. (Note: For consistency, the same set of assumptions on discount rates and facility lifetimes are also applied to the analyses performed in module F2/D2).

- **Facility lifetimes of 50 years:** These types of facilities are designed with a high degree of redundancy and reliability, and they could therefore be operated for a long time. However, several MOX facilities in the past were closed after just a few decades of operations, generally for political or commercial reasons, and therefore an expected lifetime based purely on technical factors has not been determined yet. A reasonable analogy could be made with fuel fabrication plants for commercial UOX: For example, the South Columbia Westinghouse fabrication plant was commissioned in 1969, is currently producing without issues and there are no known plans for its shutdown, thus providing a representative example with a proven lifetime of 48 years as of this writing, and probably several more years, if not decades, of expected future operations. Other nuclear facilities, such as reactors, have received U.S. NRC licenses for life extension of up to 60 years, and other types of chemical plants, such as refineries, have been in operations for more than a century. Fifty years was chosen here as representative of a "long lifetime", until more specific data becomes available.
- **Discount rate of 3%**: It was chosen here as representative of a discount rate that would be appropriate for a government project. According to Section 8 of Office of Management and Budget (OMB) Circular A94, which specifies which discount rates should be used for government projects, the treasury borrowing rates (currently about 3%) should be used for discounting if performing "cost-effectiveness analyses". "Cost effectiveness analysis", defined in Section 5, bullet b, of OMB Circular A94, could include various types of reprocessing facilities, under the assumption that the objective is to compare alternative ways to achieve the same benefits to society (such as for example a lower waste heat and volume after reprocessing), and it is impractical to consider the dollar value of those benefits.

In the following, each facility of Table D1-2-1 is analyzed in detail.

The BNFL SMP plant was completed in 1997 but started operations in 2001, and it was later revealed that the planned acquisition of German expertise in MOX fabrication did not materialize as planned, and instead the completion of the plant relied on limited in-house expertise. Eventually it produced only small quantities of usable MOX fuel, about 14 MT in its entire lifetime instead of the planned 120 MT/y (supp. ref: Brady, 2013). The Hanau-2 plant was 95% constructed but never operated (supp. ref: Nuclear Monitor, 1994) so it is difficult to say for sure if the specifications would have been met with the reported costs. However, it is also noted that the Hanau-2 plant was constructed on the same site of a previously operational MOX fabrication facility that operated successfully for several decades, albeit at a much smaller scale. It is conceivable, therefore, that the Hanau-2 facility could build on the experience of Hanau 1, thus reducing the chances of failure. Both Hanau plants have been decommissioned.

Table D1-2-1. 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

The Total Project Costs of the Savannah River MOX Fuel Fabrication Facility (MFFF) was estimated for the 2009 CBR utilizing the expected cost at the time, and adjusting the costs numbers by (1) by removing duplicated scope for administration and other support buildings and by (2) adjusting to the scope of a MOX fuel fabrication facility that uses all of the products produced by an 800MT/yr LWR reprocessing center. Consequently, an un-adjusted and an adjusted unit costs were provided in the 2009 CBR based on the expected cost of the MFFF facility. However, those estimates are now obsolete and new, substantially increased estimates, have been provided. (Supp. ref: The State, 2016) reports a new revised estimate of $17B as of September 2016. The original budget in 1999 was $620 million, with a 2006 starting date: now in 2017 it appears that the project is still about 10 years from the start. (Supp. ref: Mufson 2017)

The total construction cost in 2007 for MFFF was estimated at $4.8B, adjusted for the factors discussed above in the 2009 CBR to a range of $4.0B to $5.1B with levels of contingency ranging from 10% to 40%. O&M costs were calculated in CBR 2009 starting from available staffing levels, and fractions for other O&M costs such as utilities (20%), miscellaneous materials (15%), 3% for insurance and other miscellaneous small projects and $100M for the specialized fuel fabrication hardware costs. This yielded a point estimate of $275M/yr. Without aqueous polishing, the staffing was expected to be reduced to about 700 and the annual operating costs drop to $220/yr. These annual amounts are respectively 6% and 7.5% of the initial capital investment, in line with the range of 4% to 7% reported by (Bunn 2016) for radiochemical facilities.

With an annual capacity of 70 MT/y, a 50 years facility lifetime and 3% discount rates, the adjusted unit cost ranges based on the CBR 2009 estimates are between 2200 $/kgHM and 2800 $/kgHM for capital costs, and between 3100 $/kgHM and 3900 $/kgHM for O&M. Total unit cost for MFFF, based on the CBR 2009 adjusted costs are therefore between 5300 $/kgHM and 6700 $/kgHM. Substantially higher values would be calculated for the 2016-revised capital cost of $17B.

In conclusion, the MFFF project appears to have been a victim of typical "first-of-a-kind" and "altered scope" problems and also mismanaged, with a construction cost (from Table D1-2-1) several times that of other existing and under construction facilities for MOX fabrication. The reasons for the escalating costs are complex, and will not be discussed here. However, the U.S. DOE-NNSA found in a report released in December 2016 that "The contractor lacked the fiduciary will to plan and execute work to fully benefit the project and taxpayer" (supp. ref: Mufson, 2017). Therefore, this facility appears to not be representative of the cost of a well-executed construction project for MOX fabrication. **For these reasons, the cost estimates of the MFFF will not be included in the expected cost of a MOX fabrication facility as assessed in this module.** The summary costs will instead be based on the other 3 facilities for which cost data are at least partially available: the SMP, the Hanau and the Rokkasho MOX facilities.

Regarding O&M costs, the two values of $220-$275 M/y for SRS-MFFF were reported in (the 2009 Cost Basis Repowrt). The operational cost of SMP was reported in (Bunn, 2003), at about $50 M/y, or 7% of the initial investment costs. No information was found on the O&M costs of the Hanau-2 facility, but it is noted that the SMP data, with O&M costs of 7% of overnight construction costs, may be a reasonable assumption to make also for the identically-sized Hanau-2. It is noted that typical ranges for reprocessing facilities were found in (Bunn 2016) to be between 4% & 7%. The 7% cost was then used for Hanau-2, while.

The O&M cost of Rokkasho was not reported in Table D1-2-1 from (CBR 2009). However, subsequent data found in 2010 (Suzuki 2010) increased the total construction cost for the Rokkasho MOX facility from $1B to $2B, and reported a total project cost of $12.5B. With a facility lifetime of 40 years (Suzuki 2010) and no discounting for the expenditures in different years during the operational life of the plant, the annual O&M costs would be $263M, or 13.2% of the initial capital investment. This value is substantially higher than the typical range of 4% to 7% for other radiochemical facilities (Bunn 2016). While an explanation for this value was not found, it could be speculated that it could be due to a higher cost of labor in Japan as compared to U.S. and European countries. Alternatively, it could be a conservative overestimation of the actual O&M costs, since the facility is currently almost completed but has not been operated with actual spent fuel.

The unit costs (in $/kgHM of fabricated fuel) for the fabrication of MOX fuel, based on the costs reported in Table D1-2-1, are shown in Table D1-2-2, for 3 different assumptions about discount rates and facility lifetimes. For the unit costs' "low value" for Rokkasho provided in Table D1-2-2, it was assumed that the O&M cost would be 7% of the construction cost, while for the "high value" the expected 13.2% annual O&M cost from (Suzuki 2010) was utilized. The low, medium and high values for both SMP and Hanau-2 have different assumptions on discount rates and facility lifetimes, from long lifetimes (50 years) with low discount rates for the "low value" to short lifetimes (30 years) and commercial discount rates for the "high value".

Table D1-2-2 Unit cost of MOX fuel fabrication based on the expected cost of various existing (SMP and Hanau-2) and under construction (JNC Rokkasho and SRS MFFF) facilities, for 3 different assumptions about discount rates and facility lifetimes.

Facility	Low cost (3%, 50y) ($/kgHM)	Higher cost (5%, 40y) ($/kgHM)	Highest cost (10%, 30y) ($/kgHM)
SMP (BNFL)	658	778	1074
Hanau-2 Germany (Siemens)	658	778	1074
JNC Rokkasho Mura, Japan [a]	1122	1425	2672

[a] Expected completion in mid-2019 (World Nuclear News 2015)

It is observed from Table D1-2-2 that MOX fabrication unit costs are between 650 $/kgHM and 1000 $/kgHM for both SMP and Hanau, under a range of assumptions on discount rates and facility lifetimes. Rokkasho has higher unit costs, but the facility experienced a substantial amount of cost overruns, due to various factors that will not be discussed here. However, because of this, it is observed that this facility, similarly to the MFFF albeit to a lesser degree, is a poor representation of a well-executed construction project for a MOX fabrication facility. Consequently, the costs derived from this facility are likely to overestimate the unit costs that could be expected from a well-executed construction project.

The average of the costs of the 3 facilities are $813/kgHM, $993/kgHM, and $1606/kgHM, approximated as $800/kgHM, $1000/kgHM, and $1600/kgHM. These unit costs are recommended for the triangular distribution of the expected cost of pelletized MOX glove box fabrication for LWR MOX fuel.

Unit costs from various literature sources

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.

Table D1-2-4. Unit fabrication costs for LWR MOX fuels as proposed by various literature sources.

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 Future of Nuclear Fuel Cycle 2003	(M) 1500
MIT Future of Nuclear Fuel Cycle 2009	(M) 2400
MIT Future of Nuclear Fuel Cycle (MIT 2011)	(M) 2400
Red Impact 2006	(M) 1800
WISE Nuclear Fuel Cost Calculator (WISE 2009)	(M) 1840
DEC 2009 AFC-CBR	(L/M/H) 3,000/3,200/5,000
(EPRI 2009)	(L/M/H) 750/1,250/1,750

D1-2.7 DATA LIMITATIONS

As with LEU fabrication, there is no price list for MOX fabrication. Also, there is no "spot" market for MOX fabrication services, since the product is generally non-fungible and customized to the particular reactor. (Uranium ore, conversion services, and enrichment are 'fungible" commodities that can be sold back and forth between utilities and brokers.) This means that there is no published price, since most utility/fabricator contracts are proprietary.

Most of the data presented in this module is instead based on actual plants constructed in Europe and Japan in the 1990s and never operated or operated from a brief period of time. Cost data on facilities that have a substantial operational experience, such as the MELOX plant in France, could not be found. Consequently, there is an intrinsically high uncertainty in the estimates. The large ranges observed for the costs of MOX fabrication found in the literature, reflect the large uncertainty associated with this cost, and several high estimates may incorporate a large degree of conservativeness, mostly due to the high uncertainty. Since the estimates were calculated in the 1990s, better automation and manufacturing technology may have contributed to reduce the costs of these facilities, while an increase in safeguards, security, life safety, and physical protection requirements may have contributed to an increase in the cost of a well-executed MOX fabrication plant.

Fuels that result from proliferation-resistant reprocessing schemes such as UREX will contain higher actinides in the fuel, i.e., actinides such as neptunium, curium, and americium in addition to the plutonium. 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 requirements, such as a requirement for remote-handling, are discussed in module F2/D2.

A major variable in the calculation of unit cost is the method of financing and ownership of the MOX facility, as well as the facility's expected lifetime. Most of this difference is attributable to the very large carrying charges or interest associated with construction financing and plant amortization.

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 fabrication is significantly more expensive than LEU fabrication.

D1-2.8 COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-2-6. 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 D1-2-6. Cost summary table for commercial LWR MOX fuel.

What-It-Takes (WIT) Table (2017 constant $)			
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
$1,000/kgHM as reference cost for "normal" MOX based on European experience.	Unit=$800/kgHM	Unit=$1,600/kgHM	Unit=$1,000/kgHM
	Mature MOX technology in the U.S. for new facilities. Well executed project. 3% discount rate, 50 years lifetime O&M 7% of initial construction costs.	Project with some cost overruns. 10% discount rate, 30 years lifetime O&M 13% of initial construction costs.	Mature MOX technology in the U.S. for new facilities. Well executed project. 5% discount rate, 40 years lifetime O&M 7% of initial construction costs.

The triangular distribution based on the costs in Table D1-2-8 is shown in Figure D1-2-4.

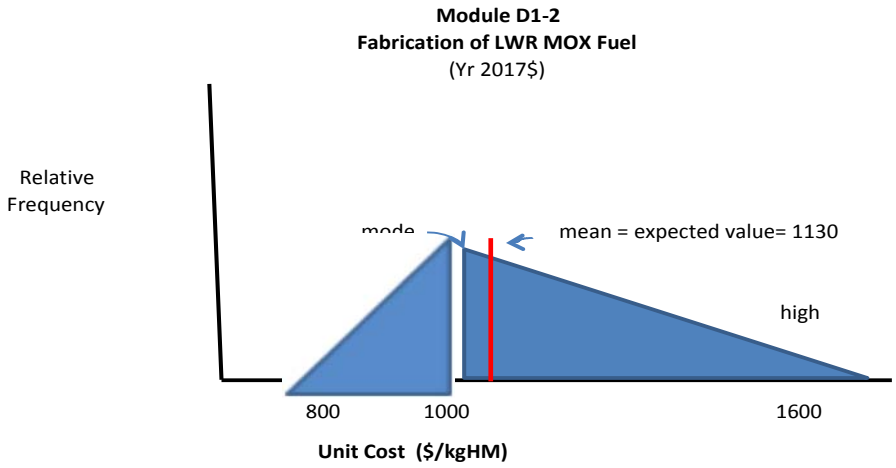


Figure D1-2-4. LWR MOX fuel fabrication estimated cost frequency distribution.

D1-2.9 SENSITIVITY AND UNCERTAINTY ANALYSES

None provided at this time.

D1-2.10 Supplementary References

Added for 2017 revision of module

Brady 2013, "Revealed: £2bn cost of failed Sellafield plant", Brian Brady, The Independent, 8 June 2013.

Nuclear Monitor 1994, Siemens can continue MOX-fuel plant Hanau, Nuclear Monitor Issue: #417, 02/09/1994

Mufson 2017, “Energy Department issues scathing evaluation of nuclear project”, The Washington Post, February 28, 2017

The State 2016, MOX plant at Savannah River Site will cost $12 billion more than initially thought, By Sammy Fretwell, September 08, 2016.

World Nuclear News 2015, “Major work required at Rokkasho for new regulations”, 17 Nov 2015.

Module D1-3

Gas-Cooled Reactor Fuels

Module D1-3

High Temperature Reactor Fuel Fabrication

D1-3.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
  - Literature survey and some unit cost calculations for known MHR or GCR fuel projects.

It should be noted that Module D1-3 is based on a fuels technology that has been demonstrated on a pilot plant scale supporting a single reactor, but has not been automated or scaled up to production levels required for a fleet of reactors

D1-3.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module D1-3.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - China is building an MHR production facility to support a small fleet of gas-cooled reactors. A search of trade press and international nuclear publications might yield some useful cost data.
  - X-Energy in the U.S. is working on MHR development. They may have done some of their own analyses. A U.S. corporation, CENTRUS Corp, is now partnering with X-Energy on TRISO fuel development (CENTRUS 2017).

D1-3.1 BASIC INFORMATION

Basic Information from 2009 AFC-CBD

Fuel Form. The high temperatures envisioned for today's gas-cooled reactor (GCR) designs (IAEA 2001) offer the cost advantages of higher power plant 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 (or a molten salt), 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 and Japan. At one time, South Africa planned to build a demonstration plant called the Pebble Bed Modular Reactor (PBMR). This plant concept was to have been 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.

Basic Information from 2012 AFC-CBD Update.

Again little has changed from the *December 2009 Advanced Fuel Cycle Cost Basis Report* in the areas of the basic industrial process for TRISO-based HTR fabrication and its interfaces to other fuel cycle steps; there have been, however, a few changes in the status of some of the world's planned HTR fabrication facilities. It should be noted that this type of TRISO UO_2 or UCO kernel fuel could also be used with a molten salt coolant, hence the change in the title of this Module from "gas-cooled" to "high temperature". The Gas-cooled reactor itself is still covered in Module R-3 and a new Reactor Module (R-8) has been added for Solid-fueled Molten-Salt Cooled Reactors, aka Fluoride Salt Reactors (FSRs).

- For economic reasons the utility ESKOM and the South African government have abandoned their ambitious Pebble Bed Modular Reactor (PBMR) program. This happened in 2010 prior to construction of a proposed pilot plant for TRISO fuel production. Design for this pilot plant was already well underway.
- The U.S. DOE has slowed down its NGNP (Next Generation Nuclear Plant) RD&D Program, for which the demonstration plant was to be a gas-cooled HTR. The fuel design/development program originally undertaken with AREVA and GA Technologies has also been slowed down. A small particle-fuels program is still underway at some National Laboratories. There is also a small joint effort with Russia on the use of Pu-loaded TRISO fuels for disposition of plutonium from military programs.

Japan continues its HTR program, with a demonstration reactor at O-Orai near Mito City. The plant is supported by a 400 kgU/yr HTR fuel fabrication line at the Nuclear Fuel Industries Tokai Works. As of March 2012 this facility has produced 300 HTR fuel assemblies (Nuclear Fuel Industries, 2012).

- China is now the most active nation pursuing HTR deployment. A two-module HTR with a single 210 MWe generator is under construction at Shidaowan. To support this FOAK plant a 2100 kgU/yr initial fabrication fuel line is being constructed at Baotou in Inner Mongolia. Each sphere in the HTR pebble bed fuel will contain 7 grams of ~9% U-235 as ceramic TRISO fuel particles. 300,000 such TRISO-loaded graphite spheres, each approximately the size of a billiard ball, per year are required. Available cost information on this facility is analyzed below (World Nuclear Organization 2012).
    - Other nations such as the Netherlands, France, and South Korea are pursuing HTR research under the Generation IV VHTR (Very High Temperature Reactor) program. Most of this analytical work deals with the reactors and process heat applications rather than with the fuel manufacturing process.

D1-3.2 UNCTIONAL 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.

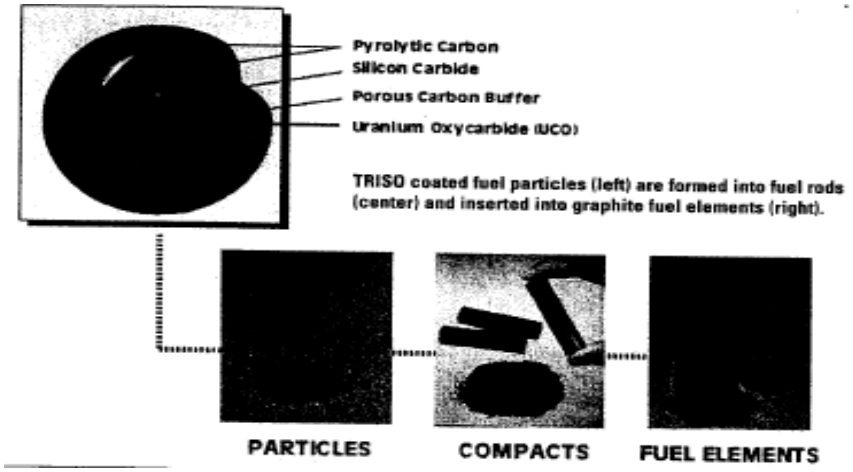


Figure D1-3-1. Prismatic concept utilizing particle fuel (General Atomics concept).

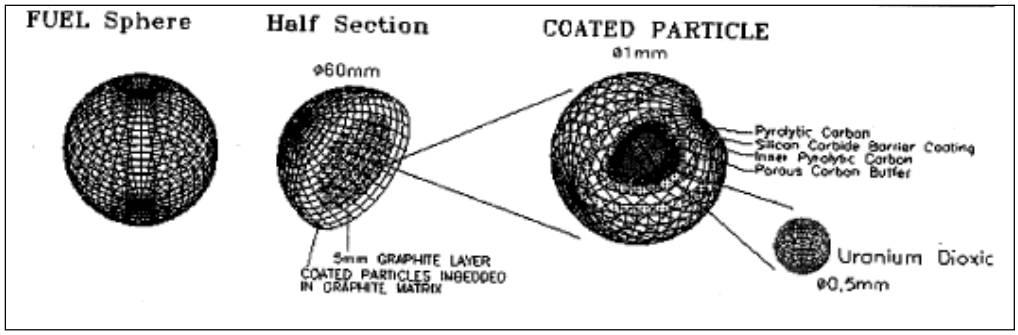


Figure D1-3-2. Pebble concept utilizing particle fuel (UC and OSU 1998).

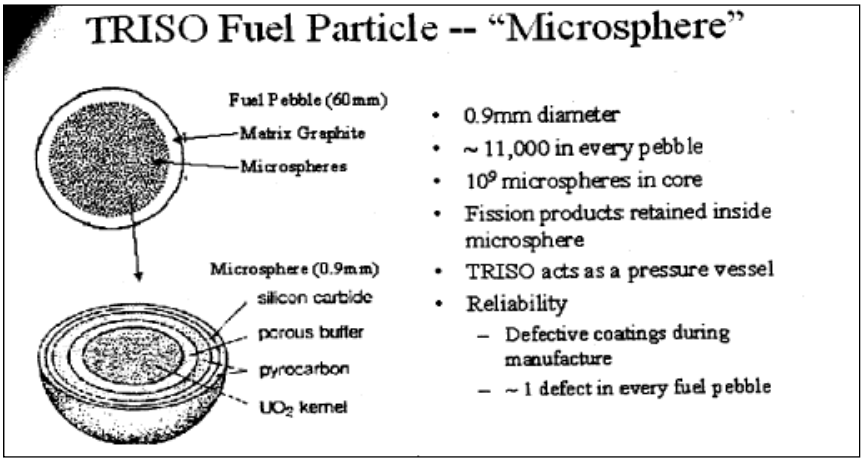


Figure D1-3-3. Illustration of a TRISO fuel particle concept (UC and OSU 1998).

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. X-Energy and CENTRUS are new U.S. cut-outs pursuing this technology.

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 (DOE/NP-24 1991) will be discussed in a section below.

GA (GA Technologies 1994) 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.

b. Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

The South African utility ESKOM had planned a small (maximum 13 MTU/yr) fuel production facility to support their first-of-a-kind demonstration module. This was likely to have been an expansion of the 2.4 MTU/yr pilot plant which was to have been designed and licensed by NECSAs (Nuclear Energy Corporation of South Africa) German contractor Uhde, a division of Thyssen-Krupp. Again, very limited cost information (Platts 2005) 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 (GIF-004-00) reactor concepts involve high temperatures (required for nuclear hydrogen production) and gas-coolants as well as some space reactor concepts. DOE also at one time considered the construction of a NGNP at INL that was to have been 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 PICTURES AND DIAGRAMS

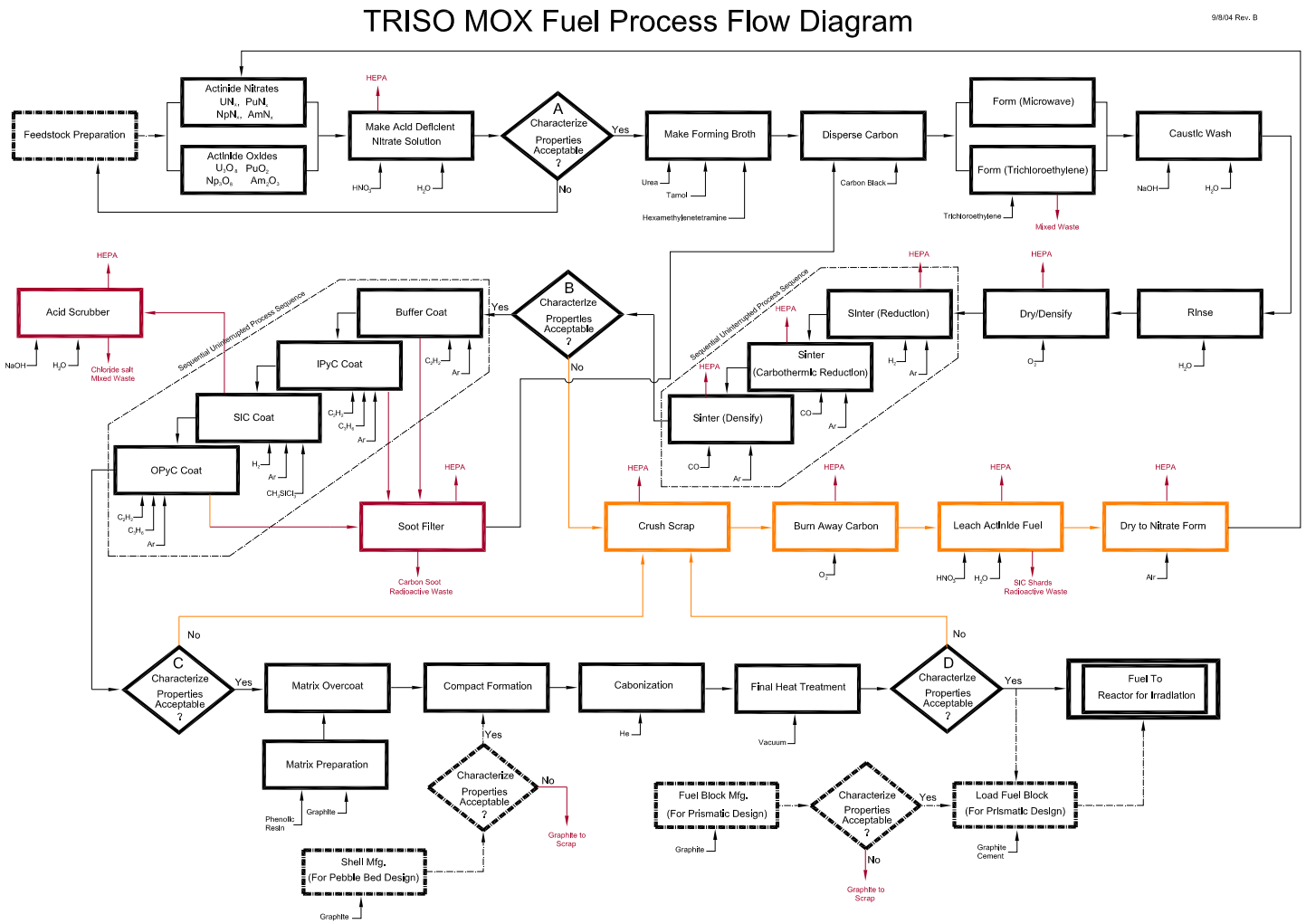


Figure D1-3-4. TRISO MOX fuel process flow diagram (DOE-AFCI Fuels Working Group, 2007).

D1-3.4 MODULE INTERFACES

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 (Fousberg 2006, Fuls 2004, Owen 1999) 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 SCALING CONSIDERATIONS

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

2009 AFC-CBD Cost Data.

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 unpublished 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 (2002$).

Reference: Particle Cost (US 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 (2008) 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; Nuclear 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 US-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 at one time (May 2005) announced (Nuclear Engineering International 2005; Platts 2005) 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.

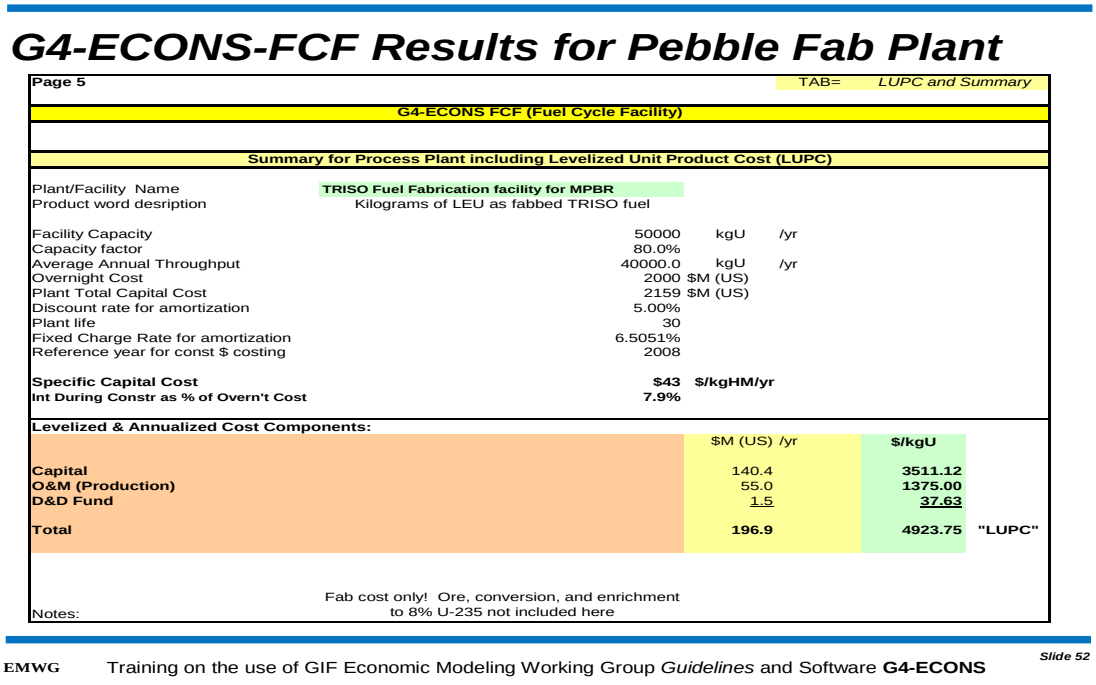
Because of the need for gloveboxes and more nuclear safety controls for plutonium fuels, the costs associated with the use of plutonium TRISO fuels are likely to be an order of magnitude higher than for 19.8% U-235 LEU TRISO on a per kilogram (heavy metal) basis.

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 ($/kgPu/yr)	120229
Estimated capital cost of ESKOM fuel plant based on	23	Operations cost per kgPu processed [$/kgPu]	27099
nth-of-kind cost of $2M/reactor supported ($M)		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		
		Projected Fuel cycle contribution to electricity cost	13
ESKOM Projected Fuel cycle contribution to 16.7 mills/kwh	4.0	(mills/kwh) from nth of a kind Pu-burning plant	
electricity cost (South African conditions; nth of a kind)			
[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 if the SRS-MFFF projected costs are included in the MOX database 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

EMWG Training on the use of GIF Economic Modeling Working Group *Guidelines* and Software **G4-ECONS** *Slide 52*

Figure D1-3-5. Breakdown of unit and capital cost for a TRISO facility.

2012 AFC-CBD Update Cost Data.

A review of the literature since 2009 found very limited or very preliminary recent projected unit cost data for TRISO-type HTR fuels. This means that most values used for this module will in part have to be derived by analogy or constructed from other life cycle cost data. Some recently-found older literature sources; however, may shed light on HTR fuels. In 1979, as part of the U.S. NASAP (Non-proliferation Alternatives Systems Assessment Program), ORNL prepared a cost study (Olsen et al. 1979) on the life cycle costs of manufacturing and reprocessing several types of nuclear fuel. The same group of fuels R&D experts, design engineers, and cost estimators prepared pre-conceptual level estimates for the capital, O&M, and decommissioning costs of large (several hundred MTHM/yr) NOAK (Nth-of-kind) fuel fabrication facilities. A cost levelization technique similar to that used in today's G4-ECONS was used to calculate the unit cost of fabrication for each fuel type. An interest rate typical of privately financed nuclear projects was used in the analysis. Given that the life cycle cost estimates were all prepared with level playing field assumptions by the same individuals, the ratio of the more advanced fuel's unit cost to that of typical PWR UO_2 fuel at that time should give a good indication of the technical complexity of manufacturing these fuels even today. Table D1-3.3 shows the unit cost ratios for selected fuels to that for PWR UO_2 fuel, i.e. what this Module's author calls "complexity ratios". It should be noted that in constant 1979 U.S. dollars PWR fuel fabrication was calculated to cost $110/kgU. Using the Handy-Whitman Power Plant construction index (Miller, n.d.; PJM Inc., n.d.), which is more realistic for nuclear projects than the U.S. Department of Commerce implicit price deflator, the equivalent cost in 2012 constant US$ would be $425/kgU, an escalation factor of 3.5. This unit cost falls in the upper range of the PWR fuel unit price distribution for Module D1-1. Since the upper range would represent new plants with full amortization, the escalated (Olsen et al. 1979). PWR fuel fabrication value seems to be valid. Using a unit cost ratio based on the complexity of the fuels technology a value of $2132/kgU results for fabrication of "HTGR" fuels. Complexity ratios are shown for other fuel types for comparison. For PWR MOX fuel the resulting unit cost is on the low side of the Module D1-2 unit cost distribution.

Because of this observation the author of this module suspects that using “complexity only” ratios for advanced fuels (FR, MOX, and HTR) may be ignoring other cost-affecting factors which have started to more quantitatively dominate fuel fabrication costs for new fuel types since 1979. Most important of these would be regulatory costs such as meeting current nuclear standards, fuel qualification, and very stringent quality assurance requirements for fuel manufacturing. The latter QA factor is especially important to TRISO HTR fuels, since the TRISO coatings are the major “containment” for fission products in the event of a loss of coolant event. This high QA requirement for TRISO particle fuel was mentioned at a recent HTR workshop held at ORNL (Holcomb 2010). The TRISO particle fuel production process together with the “imbedding in graphite” step is very complex when compared to LWR-UOX fuel fabrication. This accounts for much of the high ratio of HTR unit fabrication cost to that of LWR-UOX fuel.

Table D1-3.3. Unit Fuel Fabrication Costs Derived from 1979 ORNL Study (Olsen et al. 1979).

Fuel Type in ORNL/TM-6522	Unit Cost Ratio calculated from Table 18 of ORNL/TM-6522	Module D1-1 "Nominal" Unit Cost for PWR UO2 fuel from 2012 AFC-CBR Update ($/kgHM)	Calculated year 2012 $ unit cost using ratios from ORNL/TM-6522	Remarks on Fuel in Table 18 ORNL/TM-6522
PWR $LEUO_2$	1.00	350	350	High capacity plant (1500 MTU/yr); 1979$ unit cost was 110/kgU or $/kgHM
PWR $(U,Th)O_2$	1.09		382	High capacity plant (1000 kgHM/yr)
PWR MOX (U, Pu)	5.27		1845	MOX plant assumed highly automated with high capacity (1000MTHM/yr); remote ops & maintenance
HWR (nat UO_2)	0.59		207	High capacity plant (1500 MTU/yr)
HWR (slightly enriched $LEUO_2$)	0.60		210	High capacity plant (1500 MTU/yr)
FR MOX (U, Pu)	8.45		2959	High capacity plant (1000 MTHM/yr); remote ops and maintenance
FR metal (U, Pu,Zr)	7.73		2705	High capacity plant (1000 MTHM/yr); remote ops and maintenance
HTGR $LEUO_2$	6.09		2132	High capacity plant (500 MTU/yr)
HTGR $(MEU,Th)O_2$	5.64		1973	High capacity plant (500 MTU/yr)

The only current HTR fuels projects for which projected cost data are available are the Small scale plant under construction in Baotao, China and the USDOE-NE NGNP project. This Chinese 2.1 MTU per year “graphite pebble” plant is projected to cost 230 million yuan or about $36 million U.S. It will fuel the two 100MWe FOAK HTRs under construction at Shidoawan, China. No annual operations cost projections are available for this plant. Table D1-3.2 shows an analysis of the Chinese data from (World Nuclear-Organization 2012) and the module D1-3 author’s own analysis of operations costs which are used to project the unit cost of TRISO-based graphite HTR fuel.

Table D1-3.4. Unit HTR Fuel Fabrication costs derived from Analysis of Chinese data.

DATA		
Plant	Baotou, Inner Mongolia, China	Supports 210 Mwe of HTR
Planned Capacity	300000	TRISO-loaded spheres per year
	2100	kgU/yr
U loading per sphere	7	grams U/sphere
Plant Capital Cost	230	million Yuan
	36.4	million US$
Exchange rate	6.32	Yuan/US$
Assumed real discount rate	3.00%	
Assumed plant life	20	yrs
Calculated fixed charge rate for capital recovery	6.72%	
Assumed annual operations cost		
low	5	$M/yr
nominal	10	$M/yr
high	20	$M/yr
UNIT COST CALCULATION		
Capital recovery component of unit cost	1165	US$/kgU
Operations component of unit cost		
low	2381	US$/kgU
nominal	4762	US$/kgU
high	9524	US$/kgU
Total unit cost		
low ops	3546	US$/kgU
nominal ops	5927	US$/kgU
high ops	10689	US$/kgU

The author of this module assumes a low interest rate typical of Far Eastern projects and a 20-year life for the facility. The resulting fixed charge rate is applied against the $36M capital cost to obtain the capital component of the unit fabrication cost. (This is the method used in G4-ECONS for reactors). Low, nominal, and high annual O&M costs are selected based on the module author's knowledge of small, non-glovebox fuel fabrication facilities. The Table D1-3,4 above shows the calculated O&M components of the unit cost for each. The low, nominal, and high values are derived by adding this O&M value onto the capital component. A range from ~$3,500 to $11,000 per kgU results.

A recent life cycle cost estimate (INL 2012) for HTGRs was prepared by INL and subcontractors for the NGNP program. It includes both a high and low unit fabrication cost which was used in the fuel cycle cost calculations. The assumed fuel was prismatic and assumed to cost from $10,600 to $26,500 per kgU.

The following Table D3-5 summarizes HTR fuel fabrication cost data from the above and other recent sources:

Table D1-3.5. 2012 AFC-CBD Update "What-it-takes" (WIT) HTR fuel fabrication unit costs from Various Sources (Constant 2012 US$.

Study or Ref /Year	Low Value ($/kgU)	Medium or Ref Value $/kgU)	High Value ($/kgU)
DEC 2009 AFC-CBR TRISO HTR incl graphite	5,000	10,000	30,000
ORNL/TM-6522 (Olsen et al.) Handy-Whitman escalation only (LEUO2 kernels from high capacity plant) MHTGR TRISO (D1-17)	N/A	2132	N/A
HTR Pebble Fuel with $LEUO_2$ or UCO Kernels Analysis of Chinese data for low-capacity Shidaowan facility (World Nuclear-Organization 2012)	3,550	5,900	10,600
Recent INL Report on HTGR Life Cycle Costs (INL 2012)	10,600	N/A	26,500
Personal communications from un-named fuels experts (range only)	5,000	N/A	20,000

A few recent un-named data sources, both foreign and domestic, have also been accessed to help provide the basis for changing the recommended low, nominal, and high values for the $/kgU cost of HTR fuel fabrication. (Note that as with UO2 and MOX pelletized fuel there is no published data on the actual unit production cost. These sources have had access to non-public economic feasibility studies for HTR-related projects, and have been willing to verify that the range of the 2009 AFC-CBR (5,000 to 30,000 $/kgU) was reasonable for FOAK fuel fabrication facilities.

D1-3.7 DATA LIMITATIONS

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

2009 AFC-CBD Cost Summary. The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-3-6. 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 D1-3-6. Cost summary table for GCR TRISO fuel (2009 AFC-CBD).

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:

2012 AFC-CBD Update Cost Summary. The following set of "what-it-takes" values and a corresponding probability distribution is recommended for use in future fuel cycle studies. A triangular distribution is suggested.

Table D1-3.7. Low, Nominal, and High Suggested HTR Fuel Fabrication Price Values in $/kgU (2012 $)

Fuel Type	Low (2012 $/KgU)	Nominal (2012 $/KgU)	High (2012 $/KgU)
HTR	3,000	10,000	27,000

The low end of this range has been lowered from $5,000 to $3,000 per kgU. This could reflect a possible future cost from a large capacity, NOAK Far-Eastern facility with low labor costs and high automation. The nominal to high range would be for a Western-style NOAK fabrication facility in a highly regulated environment and in the tens of MTU per year production capacity. Such a facility would also have to be highly automated. The high end cost would likely represent a NOAK facility with less automation and significantly higher personnel costs.

The following Table D1-3.8 merely escalates the 2012 $ amounts above by 9% to 2017$ and rounds to nearest $100/kgHM. No new cost data was gathered in the period 2012 to 2017. The suggested triangular distribution is shown in Figure D1-3-6.

Table D1-3.8. Low, Mode, Mean, and High Suggested HTR Fuel Fabrication Price Values in $/kgU (2017 $)

Fuel Type	Low (2017 $/kgU)	Mode (2017 $/kgU)	Mean (2017 $/kgU)	High (2017 $/kgU)
HTR	3,300	10,900	14500	29400

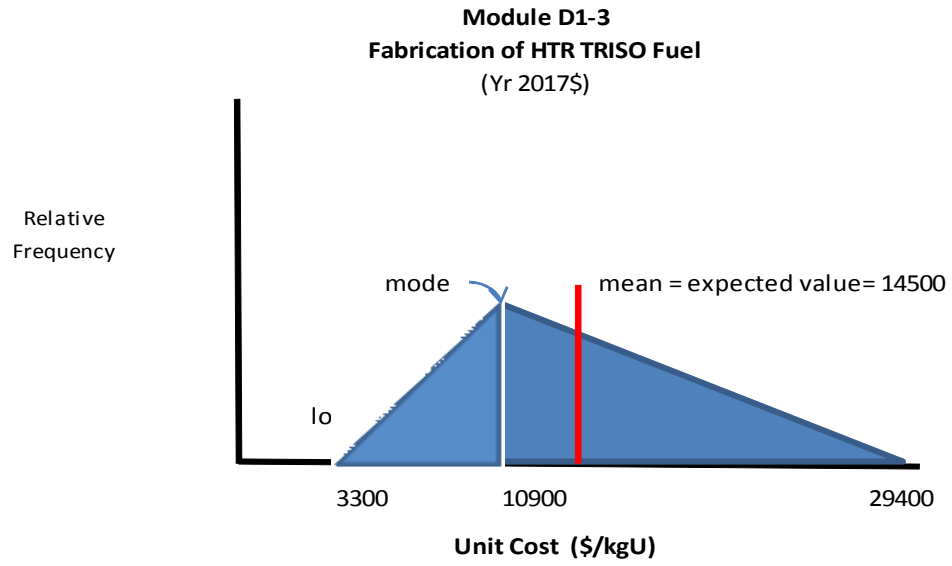


Figure D1-3-6. High-temperature reactor particle fuels estimated cost frequency distribution.

D1-3.9 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.

Module D1-4

Ceramic Pelletized Fast Reactor Fuel

Module D1-4

Ceramic Pelletized Sodium-Cooled Fast Reactor (SFR) Fuel Fabrication

D1-4.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR**)**
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Review of literature followed by unit cost calculations based on G4-ECONS FC methodology. Analogues based on 1979 fuel fabrication comparative studies were also utilized.

D1-4.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module. In the 2012 AFC-CBR costs for the fabrication of higher enrichment UO_2 fast reactor fuels were added to the existing data for MOX-based FR-fuels
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision.**

D1-4.1 BASIC INFORMATION

2009 AFC-CBD Basic Information.

Fuel Form. Ceramic fueled fast reactors can operate on either higher enrichment uranium fuel (such as the BN-600 in Russia) or plutonium-based MOX fuels (such as the French Phenix reactors, the Russian BN 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]

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.

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:

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.

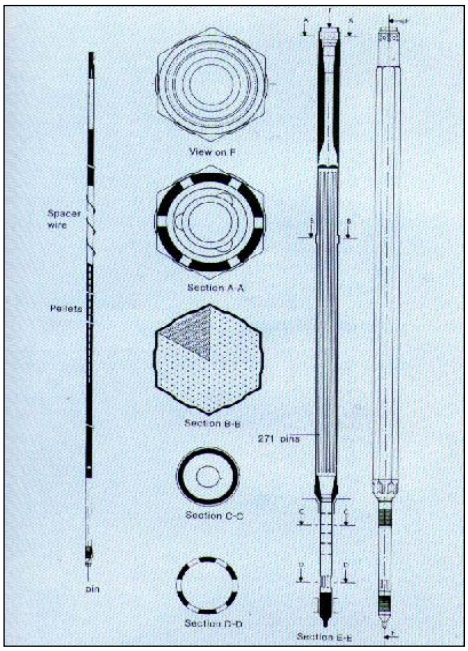


Figure D1-4-1. Superphenix fuel assembly diagram (CEA, 1985).

2012 AFC-CBD Update Basic Information.

Again little has changed from the *December 2009 Advanced Fuel Cycle Cost Basis Report* in the areas of the basic industrial process for FR ceramic pelletized fabrication and its interfaces to other fuel cycle steps. The only fabrication process that has been conducted on a near-industrial scale for FR ceramic fuel is basically the same process that is used to prepare LWR MOX fuel. The main differences are the following, however:

- Fast reactor ceramic fuel must be clad in stainless steel rather than zirconium alloys. This is a result of stainless steel having better compatibility with the hot liquid sodium coolant.
- The enrichment of the fissile material (U-235 or Pu) must be higher than for LWRs because of the nature of the fast reactor neutron spectrum and the nuclear properties of not having a neutron moderator coolant.
- The pin/pellet diameter for fast reactor fuel is generally smaller than for LWR fuel. This is to improve the heat transfer from the higher temperature molten sodium coolant.

It is most important to realize that the fuel we are discussing in this module can be contact handled in gloveboxes as powder/pellets (if it contains plutonium) and outside gloveboxes in sealed pin form (for MOX or enriched UOX). If the fuel is enriched uranium (typically 13 to 25% U-235) in some ceramic form such as UO_2, powder and pellets can be handled outside a glovebox environment. For this reason the fuel must be largely free of fission products, higher Pu or Np-isotopes, or higher actinides such as curium and americium which pose radiation hazards to workers as well as heat-generation problems from the decay of these isotopes. (Such "transmutation" or "actinide burning" fuels or targets are considered in Module D2 which deals with remote-handled fuel. "Proliferation resistant" fast reactor fuels which carry over some FP and HAs would require remote refabrication.) The fuels described here would probably be used as start-up fuels for fast reactor systems or in fast reactor systems for which fuel recycle is not yet established. A good example would be the BN series of fast reactors in Russia. The BN-600 reactor has run mainly on medium-enriched UO_2 ($MEUO_2$) fuel with some (U, Pu) MOX assemblies undergoing lead testing. Russia is now constructing BN-800 sodium-cooled fast reactors which will use MOX fuel with Pu content (in heavy metal with U diluent) in the 15 to 25% range. This fuel will be contact-handled. A small and now shuttered glovebox pilot line "PAKET" at Mayak has been used to fabricate BN-600 test assemblies. The MOX Pu processed and burned in the first BN-800 fast reactors will be weapons-capable material arising from Russian military programs. This material is being fabricated at a small MOX plant inside a mountain at Zheleznogorsk.

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 Update from 2009 AFC-CBD: 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. .

Status Update from 2012 Update AFC-CBD.

It is of interest to explore the status the world's existing or planned fabrication facilities.

- United Kingdom: The UK is still considering the burning of MOX fuel in new Generation III+ LWRs and/or in Sodium-cooled Fast Reactors as a method of dispositioning its large stockpile of over 110 MT of separated Pu from its commercial and military reactor programs (Nature News and Comment 2011). A new MOX plant would be required that might be able to produce MOX fuel for fast reactors in addition to LWRs. The UK is considering the fast reactor as part of its future Pu disposition strategy and is evaluating the GE-Hitachi PRISM fast reactor design, which can be customized for ceramic or metal fast reactor fuels. The hypothetical UK MOX plant is discussed from a cost standpoint in Module D1-2.
- Japan: Japan's Tokai works has the capacity to produce 20 MTHM of fast reactor MOX fuel per year. The capacity is in two 10MT/yr lines, and the facility has made fuel for test reactors. (WNO 2012).
- Russia: As part of the Year 2000 Joint U.S-Russia PMDA (Plutonium Management and Disposition Agreement) both the U.S and Russia had agreed to burn excess weapons Pu in their LWRs. Russia has now decided to burn their Pu in sodium-cooled fast reactors of the BN-800 variety rather than in VVER water reactors. The type of fuel is likely to be pelletized MOX (Module D1-4) or VIPAC fuel (Module D1-5) or both. The PMDA was modified in 2010 to reflect this new reality. At Mayak there is a small, now shut down, FR MOX pilot line called PAKET which has manufactured pellet fuel for lead test assemblies for irradiation in BN-600. The U.S. formerly was to technical and financial assistance to Russia for the eventual construction of a larger FR MOX plant to supply military-derived Pu fuel for the BN-800 reactors. The Pu in the MOX will have the high Pu-239 content typical of weapons Pu. No credible cost estimates are yet available for this proposed facility, which is to be located at Zheleznogorsk.
- U.S.: An industrial scale ceramic fuel fabrication line for Pu-containing FR fuel has never been operated in the U.S., although such a line was constructed at Hanford [the Secure Automated Fabrication (SAF) line] to support the cancelled Clinch River Breeder Reactor Project. The >$100M SAF line was never operated. There is a B&W plant in Lynchburg VA that has the capability to produce enriched U fuels above 5% U-235, and it does this for mainly Government customers (naval fuel, research reactors, etc.) The site security and safety envelope for this site would very likely be adaptable to the production of medium to high-enriched uranium oxide ceramic fuel that might be used for startup of a sodium-cooled fast reactor. A smaller plant operated by Nuclear Fuel Services (NFS) at Erwin, Tennessee can also handle enriched uranium forms greater than 5% U-235.
- China: To support their 1000 MWe China Demonstration Fast Reactor (CDFR), which will start-up in 2017 and will ultimately burn ceramic (U, Pu) MOX fuel, a 40 MTHM/yr FR ceramic MOX plant is planned at Sanming. No cost information is available on this facility.

- India: India's nearly complete 500 MWe Prototype Fast Breeder Reactor (PFBR) will ultimately use (U, Pu) MOX fuel produced in a proposed Fast Reactor Fuel Cycle Facility (FRFCF) located adjacent to the PFBR at Kalpakkam. Fuel rods will be 21 and 28% fissile Pu (SME Times 2010). The FRFCF will also reprocess oxide fuel and handle waste management. Its cost has been estimated at 5000 Crore (U.S.$ 898M).

D1-4.3 PICTURES AND DIAGRAMS

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 INTERFACES

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.

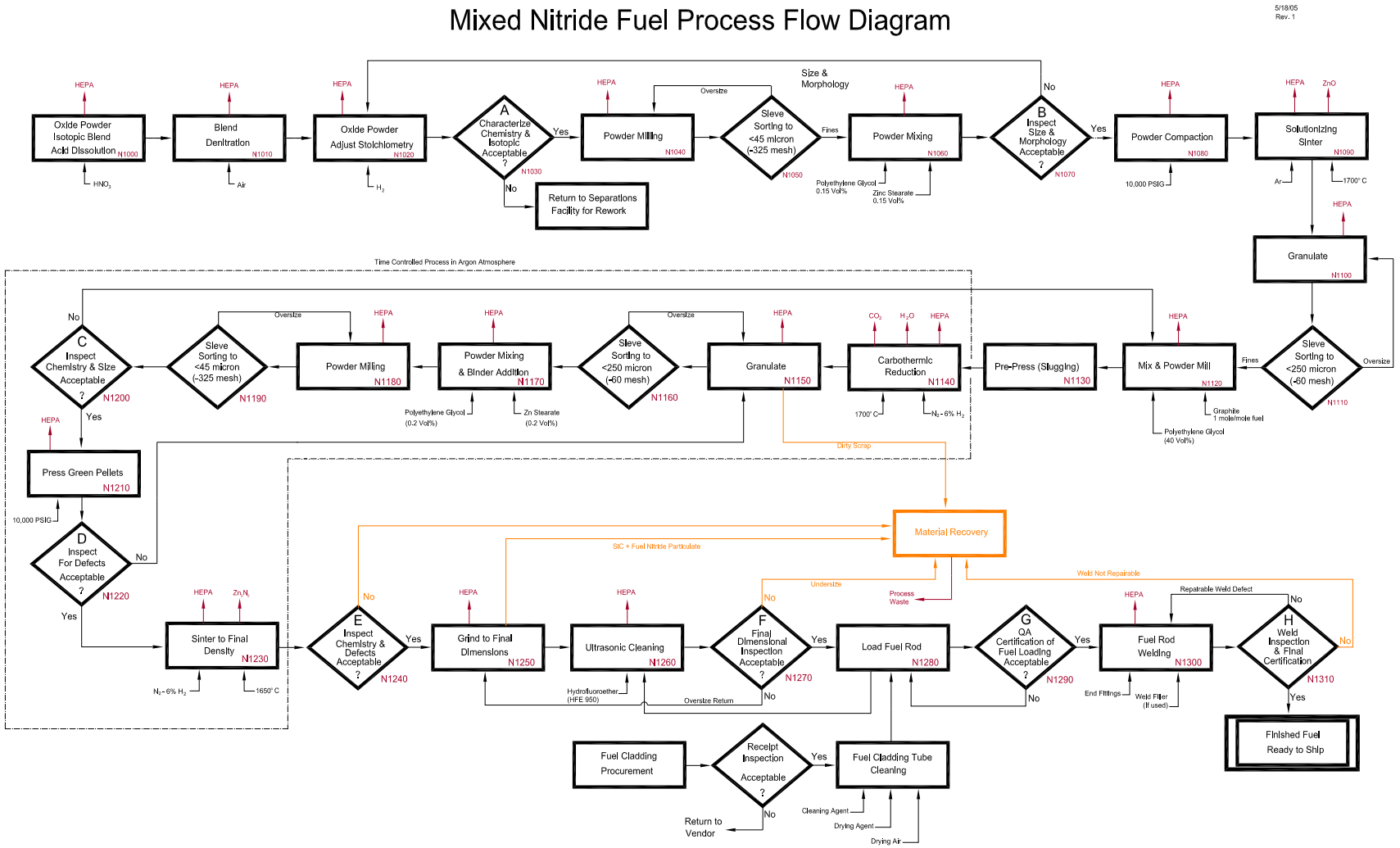


Figure D1-4-2. Fabrication process for mixed nitride fuels (DOE-AFCI Fuels Working Group, 2007)

D1-4.5 SCALING CONSIDERATIONS

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

2009 AFC-CBD 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 (NECDB 1988) 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 (NECDB 1988) 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 1988 study.

Table 5.10. 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 D1-4-2 is calculated based on amortization of this capital cost and the addition of operations and maintenance and decommissioning levelized costs. 2012 AFC-CBD Update Cost Bases.

2012 AFC-CBD Cost Data Sources. A few recent data sources have been accessed to provide the basis for changing the recommended low, nominal, and high values for the $/kgHM cost of ceramic MOX and $MEUO_2/HEUO_2$ fast reactor fuel fabrication. (Note that as with UO_2 pelletized LWR fuel there is no published data on the actual production cost or pricing of material from an operating fabrication facility.) Most fuels of this type are produced (or have been produced) in quantities very small compared to LWR MOX fabrication. The following Table D1-4-4 shows some ceramic pelletized FR fabrication cost data from various sources. Some of the numbers required escalation to bring them to 2012 dollars. Most of the data are for (U, Pu) type MOX fast reactor fuels; however, the cost numbers might be comparable for large scale production of nitride or carbide pelletized FR fuels. Note that enriched U fast reactor fuel has been added since the 2009 AFC-CBR, since this material would likely be used to start-up fast reactors until enough Pu-based fuel became available. The fissile content (Pu or U-235) for all of these fuels would be in the 13% to 25% range. The cost of uranium ore, conversion, and enrichment are not included in the unit fab cost for MEU or HEU FR fuel.

Table D1-4-4. Reactor fuel unit costs from various sources (Constant 2012$ unless otherwise indicated).

Study or Ref/Year	Low Value ($/kgHM)	Medium or Ref Value ($/kgHM)	High Value ($/kgHM)
DRIVER FUEL (U, Pu)			
DEC 2009 AFC-CBR (2009 $) Pelletized (U, Pu) O_2 Ceramic	3200	4000	6000
(EPRI 2010) (2010 $) FR MOX (U, Pu) O_2	750	1500	2100
MIT Economics of Nuclear Fuel Cycle (MIT 2009) (2010 $) FR MOX (U, Pu) O_2	N/A	2400	N/A
Escalated unit cost from ORNL/TM-6522 (Olsen) (U, Pu) MOX FR fuel (Complexity factor=8.45 against $LEUO_2$ fuel)	N/A	2950	N/A
BLANKET FUEL (NATU or Depleted U)			
Escalated from 2003$ (in parentheses) to 2012 $ (Bunn et al. 2003)	175 (150)	300 (250)	425(350)
ORNL 6522 (Olsen) using complexity ratio	N/A	450	N/A
MEU/HEU DRIVER FUEL			
ORNL 6522 (Olsen) using complexity factor	N/A	825	N/A

The most recent reports which include unit costs for the fast reactor fuels category are the EPRI "Multi-recycling" economic study (EPRI 2010) and the MIT "Economics of the Nuclear Fuel Cycle" (MIT 2009) reports. The unit costs are for a hypothetical, mature fuel fabrication industry supporting multiple fast reactors. These values fall in the lower range of the LWR MOX (Module D1-2) range, which leads the author of this module to believe that more credible unit costs will be significantly higher, especially since the higher fissile enrichment fast reactor ceramic fuel will encounter the same manufacturing difficulties, plus some, as LWR MOX fuel. As with HTR fuel in Module D1-3, one can look at old estimates for multiple fuel types prepared by ORNL staff in 1979 (Olsen 1979) to gauge the level of technical complexity of FR ceramic fuel (Driver (U, Pu) MOX in this case) fabrication vis a vis that for LWR UO_2 fuel. If escalation is considered, a unit cost of $2950/kgHM is obtained for a nominal case. The same "complexity factor" approach can also be used to assign a unit cost to the UO_2 "blanket"

fuel required by some fast reactor designs. A nominal value of $450/kgU is obtained for this material, which would be natural or depleted UO_2 that can be contact handled without criticality or security concerns, and with minimal HS&E difficulties. A 2003 cost report on the fuel cycle (Bunn et al. 2003, EPRI 2010) suggested blanket fabrication unit cost values that were the same as for LWR UO_2 fuel. No actual cost data was found on enriched U (15 to 25% U-235 range) ceramic fast reactor driver fuels. The "complexity factor" approach using 1979 ORNL cost studies was again used to obtain a nominal unit fabrication cost of ~ $825/kgU. This fuel would not need glovebox handling; however, criticality and security concerns could be much beyond those for $LEUO_2$ fuel. The higher projected unit cost is therefore appropriate.

D1-4.7 DATA LIMITATIONS

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.

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).

D1-4.8 COST SUMMARIES

2009 AFC-CBD Cost Summary. The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table D1-4-5. 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.

Table D1-4-5. 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

2012 AFC-CBD Update Cost Summary. The following set (Table D1-4-6) of "what-it-takes" year 2012 values and a corresponding probability distribution is recommended for use in future fuel cycle studies:

Table D1-4-6. Low, Nominal, and High Suggested Fabrication Cost (2012 AFC-CBD Update)

Fuel Type	Low (2012 $/kgHM)	Nominal (2012 $/kgHM)	High (2012 $/kgHM)
FR (high-end LEU to low-end MEU U-235 content) Pelletized Ceramic Driver Fuel	475	825	1180
FR Pelletized Ceramic (U, Pu) Driver Fuel such as MOX	2500	4500	7000
FR Pelletized Ceramic NATUO_2 or DUO_2 Blanket Fuel	250	450	630

For uncertainty analyses triangular distributions should be used with each row's the values in the table above. The first row of Table D1-4.6 above provides suggested fabrication costs for the enriched, stainless-steel clad ceramic UO_2 fuel that might be used for the startup of the first fast reactors in a fleet. Enrichment costs, which would be significant for the 15 to 25% U-235 levels required, are not included in this cost. The complexity factor approach based on 1979 ORNL data (Olsen 1979) was also used to assign the low and high values, in addition to the nominal value as was explained above.

Assignment of costs for the (U, Pu) driver fast reactor ceramic fuel required more subjective judgment and comparison to other fuel types, especially LWR MOX fuel because of the fabrication process similarity. The LWR MOX values in Module D1-2 were based on better life cycle cost estimates, and it is assumed by the author of this module that fast reactor MOX fuel will not be any cheaper to manufacture than LWR MOX. The unit costs in the second row reflect this thinking and are also somewhat higher than the 2009 AFC-CBR values dues to inflation in O&M costs and commodities.

Projected costs for ceramic blanket fuel have been added to this 2012 AFC-CBR and are shown in the third row of the table. The "complexity factor" method was again used to assign the low, nominal, and high values.

Table D1.4-7 shows the year 2012 values escalated to 2017$, There is a 9% increase from 2012 to 2017.

Table D1-4-7. Year 2017$: Low, Mode, Mean, and High Suggested Fabrication Cost

Fuel Type	Low (2017 $/kgHM)	Mode (2017 $/kgHMN)	Mean (2017 $/kgHM)	High (2017 $/kgHM)
FR (high-end LEU to low-end MEU U-235 content) Pelletized Ceramic Driver Fuel	520	900	900	1290
FR Pelletized Ceramic (U, Pu) Driver Fuel such as MOX	2700	4900	5060	7600
FR Pelletized Ceramic $NATUO_2$ or DUO_2 Blanket Fuel	270	500	485	690

The triangular distribution based on the costs in Table D1-4-7 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.

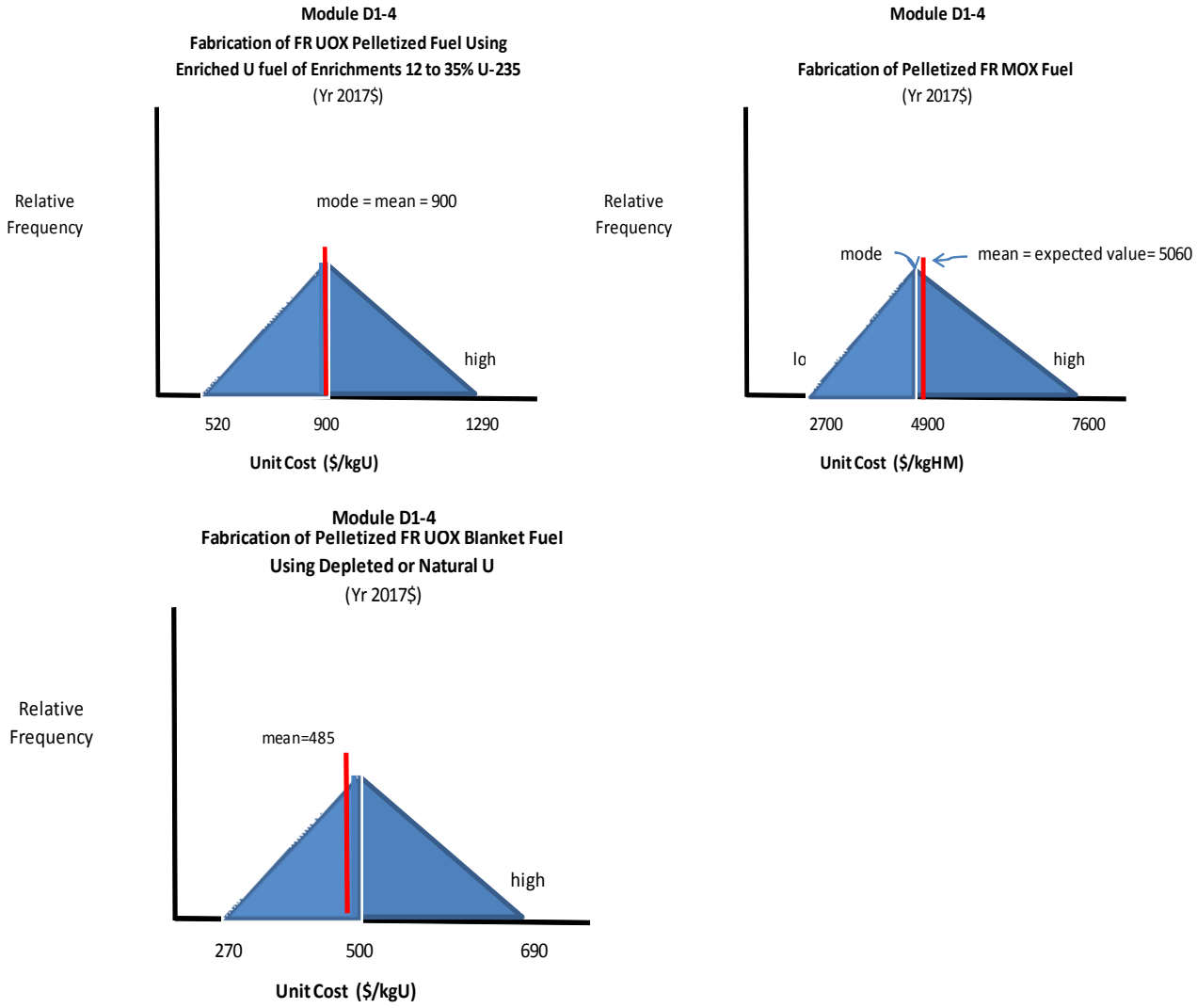


Figure D1-4-3. Ceramic pellet fast reactor fuel estimated cost frequency distributions.

D1-4.9 SENSITIVITYAND 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 Fabrication

D1-5.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Because of simple process VIPAC fuel unit costs assumed to be 10% lower than ceramic fast reactor fuel costs in Module D1-4. VIPAC fuel is at the pilot plant stage of development. Unit costs given are for a hypothetical NOAK VIPAC facility in a structure and under regulatory regime similar to current European pelletized MOX plants.

D1-5.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module D1-4
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Russia continues to develop this technology. A new literature review might yield some cost information.

D1-5.1 BASIC INFORMATION

2009 AFC-CBR 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 (Wade 2005) and would use a U, Pu-nitride fuel.

2012 AFC-CBR Status. In this case nothing has changed from the *December 2009 Advanced Fuel Cycle Cost Basis Report* in the areas of the basic industrial process under development for FR vibrocompacted (VIPAC) fuel fabrication and its interfaces to other fuel cycle steps. The method is still under consideration for the production of (Pu,U) O_2 driver fuel for the BN-800 series of fast reactors being constructed in Russia. As part of a joint U.S./Russia Pu disposition agreement the U.S. was to have made funds (~$400M) available to Russia for this non-proliferation program. Some of these funds were likely to have been used for design and construction of some kind of contact-handling fuel fabrication facility for BN-800 fast reactor mixed oxide fuel. The Russian Federation has not yet decided whether the facility will produce ceramic pellet fuel, VIPAC fuel, or even both types. (Pellet fuel is more likely to be selected due to more experience with this method.)

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 AND DIAGRAMS

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).

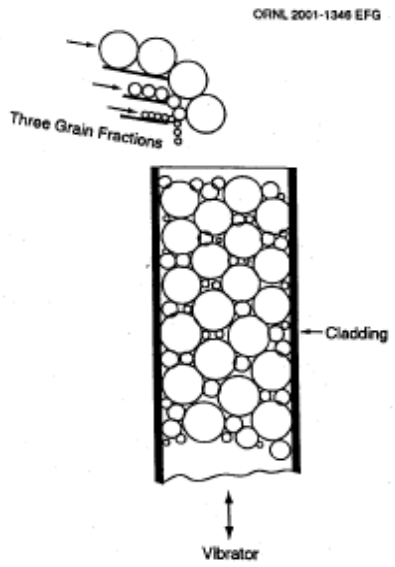


Figure D1-5-2. Conceptualized view of VIPAC as envisioned by ORNL researchers.

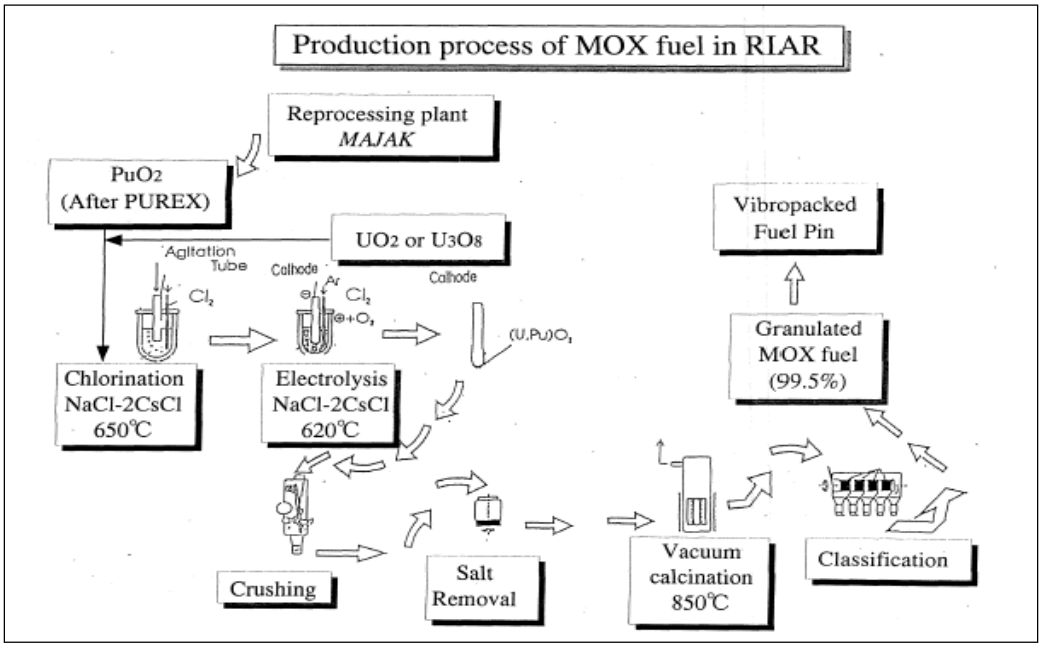


Figure D1-5-3. The VIPAC process and its relation to pyrochemical reprocessing technology as envisioned by the Scientific Research Institute of Atomic Reactors, Dimitrovgrad, Russia (RIAR).

D1-5.4 MODULE INTERFACES

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 SCALING CONSIDERATIONS

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% Pu O_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 2006) 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 DATA LIMITATIONS

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

2009 Cost Summary. Module 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,

e. Gelation rather than electrochemistry produces "rounder" particles which can be vibrationally compacted. Such a process is sometimes called "spherepak."

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 D1-5-1. 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

2012 AFC-CBD Update Cost Summary. The nominal unit fabrication cost of $3600/kgHM in the 2009 AFC-CBR was based on the assertion, largely derived from Russian sources, that the unit fabrication cost would be 10% lower than for pelletized contact-handled ceramic MOX FR fuel. If the same logic is applied the new value for VIPAC FR fuel fabrication will be a reduction of 10% from the new (Module D1-4) nominal ceramic MOX FR value of $4500/kgHM. The resulting Module D1-5 value of $4050/kgHM is rounded to $4000/kgHM to indicate that the value is a rough approximation for a technology still under development. The same ~10% reduction is also applied to the low and high values.

It is important to note that VIPAC fuel fabrication would be more amenable to remote FR fuel production than pelletization because of process simplicity. The Russians have studied this method as a refabrication process in conjunction with electrochemical reprocessing at Dimitrovgrad.

Table D1-5.2. Year 2012$ “What-it-takes” (WIT) Vibrocompacted fast reactor fuel fabrication unit.

Fuel Type	Low Value (2012 $/kgHM)	Medium or Ref Value (2012 $/kgHM)	High Value (2012 $/kgHM)
(U, Pu) O_2 VIPAC Fuel	2300	4000	6300

2017 AFC-CBD Update Cost Summary. Since the VIPAC unit costs are estimated at ~10% lower than pellet MOX (Module D1-2), it was necessary to reset these Module D1-5 costs as a result of the lowering of the Module D1-2 “What-it-takes” costs. This unit cost reduction was the result of removing the deleterious U.S. cost and schedule experience with the SRS-MFFF.

The following Table D1-5.2 updates the Module D1-5 costs in year 2017 dollars to be consistent with the Module D1-2 NOAK, mature European experience unit costs.

Table D1-5-3. Year 2017$ “What-it-takes” (WIT) Vibrocompacted fast reactor fuel fabrication unit.

Fuel Type	Low Value (2017 $/kgHM)	Mode (2017 $/kgHM)	Mean (2017 $/kgHM)	High Value (2017 $/kgHM)
(U, Pu) O_2 VIPAC Fuel	720	900	1020	1440

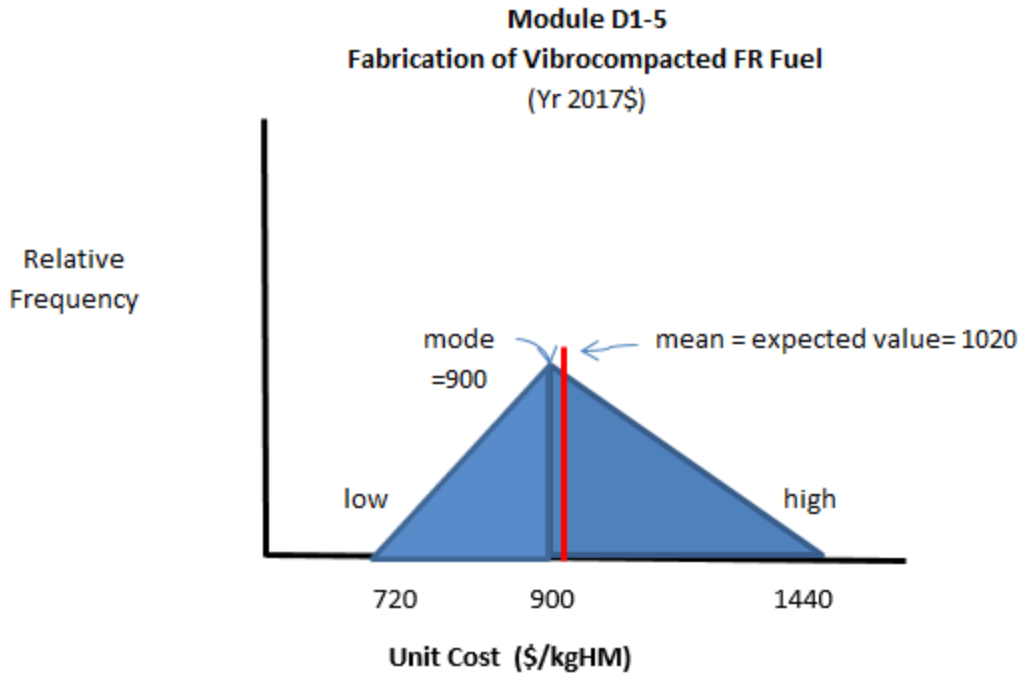


Figure D1-5-4 Probability Distribution for VIPAC MOX Unit Fuel Fabrication Cost

D1-5.9 SENSITIVITY AND UNCERTAINTY ANALYSIS

None provided at this time.

Module D1-6

Metallic or Alloyed Reactor Fuel

Module D1-6

Metallic or Alloyed Reactor Fuel Fabrication

D1-6.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** Not applicable since no cost are presented
- **Nature of this 2017 Module update from previous AFC-CBRs:** Module name change to reflect inclusion of possible LWR metal fuel
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
  - No cost information
  - Mention of possible Pu disposition application
  - Mention of Lightbridge Corporation development activity on metal alloy LWR fuels

D1-6.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module D1-6. In this 2017 update the Module name has been changed from Metallic *or Alloyed Fast Reactor Fuel Fabrication* to just *Metallic or Alloyed Fuel Fabrication*. This reflects the fact that metal fuel is now being considered for LWRs in addition to fast reactors.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** Not applicable since no numerical "what-it-takes" unit cost estimates are currently readily available
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Plutonium disposition reports prepared by DOE-NNSA and its contractors concerning alternatives to the SRS MOX plant and the irradiation of SRS MOX in LWRs
  - Papers and press releases from Lightbridge Corporation on metal alloy LWR fuel

D1-6.1 BASIC INFORMATION

2009 AFC-CBD Status. Metallic reactor fuel, such as is produced by casting operations, is generally part of refabrication schemes associated with on fast reactor-site closed fuel cycles where the reprocessed and refabricated fuel must be handled in hot cells (remote-handling), 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 (all remote-handling); although that does not mean that such contact-handling schemes do not exist. [Some Pu-based metallic fuel for the now-closed Hanford FFTF (Fast Fuel Test Facility) was prepared via contact-handling 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**. It should be noted that metal-fuelled SFRs might have to be initially fueled with Pu arising from aqueous reprocessing of LWR fuel. This lower-activity material could be**

contact-handled. Weapons-grade Pu destined for irradiation in a PRISM-type fast reactor could also be contact-handled.

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.

2012 AFC-CBD Update Status. No new technical or cost information was found on this fuel type. It should be noted that metal fuel has been advanced as the major fast reactor fuel type for integral type FR fuel cycles where the fissile materials recovered from electrochemically reprocessed FR metallic fuel are blended with make-up uranium and recast (refabricated) in the same remote-handling facility as the recycle steps. These remote handling steps are considered in the D2 Modules.

It should be noted that fresh U, Pu, Zr alloy pins have been prepared in contact-handling type facilities for irradiation in prototype fast reactors. Since these fuels did not contain fission products and higher actinides were minimal, they could be prepared in glovebox facilities. For this process one puts the constituents in a coated graphite crucible sets the crucible down in an induction coil, heats it up via AC power, moves coated quartz molds down into the melt, pressurizes the furnace, and produces up to hundreds of 18” metal fuel pins in a single run. All of this takes place in one machine, the casting furnace. After cool-down one removes the fuel pin assembly, breaks off the quartz, and crops the metal slugs to length. The slugs are inserted into cladding tubes pre-loaded with a bit of metallic “bond” sodium. The tubes are capped, sealed, welded, heated, and tapped in a vertical fashion to seat the slug at the bottom of the cladding and have the sodium flow upward around the slug. QA checks are then made. All these steps beyond the casting furnace can be done in a single “pin processor” machine.

Unit costs for large scale deployment of contact-handled FR U, Pu alloy fuel are likely to be lower than for U, Pu MOX due to comparative process simplicity. Unit costs for metal Pu alloy FR fuel are likely to be slightly below MEU pellet FR fuel for NOAK facilities. Since this type of fuel is unlikely to be produced on a large scale, no WIT values are presented.

Higher enrichment metallic uranium alloy FR fuel has also been prepared for experimental use. Such contact-handled fuels (U or (U, Pu) might be used on a larger scale for start-up of fast reactor systems. No cost estimates were found for preparation of these fuel types. Based on technology complexity only, the cost of (U, Pu) alloy fuels prepared under glovebox conditions would probably be less than those for (U, Pu) MOX fast reactor fuels (Module D1-4). The complexity of non-process factors, however, such as safety, security, HVAC, etc., would push the ultimate unit (U, Pu) alloy unit cost closer to that of (U, Pu) MOX.

The MEU/HEU uranium unit fabrication cost for metal alloy fuel would also be on the same order as that for oxide FR uranium “start-up” fuel discussed in Module D1-4. Process complexity would be the major cost driver. It is known that MEU/HEU specialty and research reactor fuels incur fabrication costs in the several thousands of $/kg of heavy metal. It should be noted that Russia has used contact-handled uranium alloy fuel in maritime reactors, and that Lightbridge Corporation in the U.S. is trying to stimulate interest in this U-fuel type in the West for water reactors.

2017 Update Status. Since 2012 NNSA has commissioned some reports (Lightbridge 2009, Lightbridge 2011, Malone, et al. 2012) looking at the costs of irradiating weapons-grade Pu in PRISM-type fast reactors. The Pu metal from weapons would be melted, blended, and cast into metal rods. Projected costs of building and operating such a facility at the Savannah River Site were examined and

could be included in future more-detailed module updates. There is also consideration of the use of metal alloy fuels in LWRs. Lightbridge Corporation (Lightbridge 2016) in the United States is developing this technology and has found a commercial reactor to irradiate some test assemblies. Future versions of this module should include analysis of information from Lightbridge.

D1-6.2 FUNCTIONAL AND OPERATIONAL DESCRIPTION

See Modules D1-9, and F2/D2.

D1-6.3 PICTURES AND DIAGRAM

See Modules D1-9 and F2/D2.

D1-6.4 MODULE INTERFACES

See Modules D1-9 and F2/D2.

D1-6.5 SCALING CONSIDERATIONS

No data available.

D1-6.6 COST BASES, ASSUMPTIONS, AND DATA SOURCES

See Modules D1-9 and F2/D2.

D1-6.7 DATA LIMITATIONS

See Modules D1-9 and F2/D2.

D1-6.8 COST SUMMARIES

See Modules D1-9 and F2/D2.

D1-6.9 SENSITIVITY AND UNCERTAINTY ANALYSES

No data available.

Module D1-7

CANDU Fuel

Module D1-7

CANDU Fuel Fabrication

D1-7.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Reassessment in 2012 of fabrication costs based on increased cost of zirconium. Basically same rationale as for LWR fuels in Module D1-1

D1-7.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module D1-7. In 2005 a special section on the DUPIC concept was added. The DUPIC discussion, based on information from a paper by Choi et al. (Choi 2001), has been moved to Module D2 as a special topic. The DUPIC process requires remote handling, thus, the discussion was moved to D2-2.1. In 2012 AFC-CBR Module unit costs of CANDU fuels fabricated from reprocessed uranium were added
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - CANDU fuels with thorium added to the uranium are being seriously considered.
  - CANDU fuels fabricated from Reprocessed U is being slated for use in Chinese PHWRs
  - Status of Canadian fuel fabrication facilities should be updated

D1-7.1 BASIC INFORMATION

2009 AFC-CBR 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 CANDU $NATUO_2$ 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.

2012 AFC-CBD Status. As for LWR fuel (Module D1-1) a mature industry exists for production of CANDU reactor fuel from virgin natural uranium. The fabrication process, fuel description, and other technical information are described in the 2009 AFC-CBR. GE-Hitachi Canada Ltd continues to produce up to 1800 $MTUO_2$/yr of natural uranium CANDU fuel. Two facilities in Ontario are used: the Toronto facility for UO_2 pellet production and the Peterborough facility for fuel bundle production. The relicensing of these facilities to produce SEU (slightly-enriched 1 to 2.5% U-235) fuel for advanced CANDU reactor designs is under consideration by Canadian nuclear safety authorities.

A recent development regarding CANDU fuel use is that China is considering large scale use of reprocessed uranium from LWR spent fuel reprocessing as a NATU-substitute fuel for their fleet of

CANDU reactors (Ellis 2007, Chen 2011). This reprocessing-derived material has U-235 enrichments in the 0.6 to 1.0% range (typically blended to ~0.9% U-235) suitable for substitution for natural U or SEU. The reprocessed U could come from Russian, European, or Japanese sources of stored reprocessed U. Ultimately China will also have their own LWR spent fuel reprocessing industry which can provide this feed material. If the U.S. were to ultimately reprocess LWR SNF, CANDUs could provide an excellent use for the large amounts of resultant reprocessed uranium.

The use of (U, Th) O_2 pellets is also being considered in CANDU-type fuel. Thorium-based fuels are discussed in Module D1-8.

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 AND DIAGRAMS

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 2005) shows this operation.

Figure D1-7-1. The ACR-700 CANDU fuel assembly (AECL, 2005).

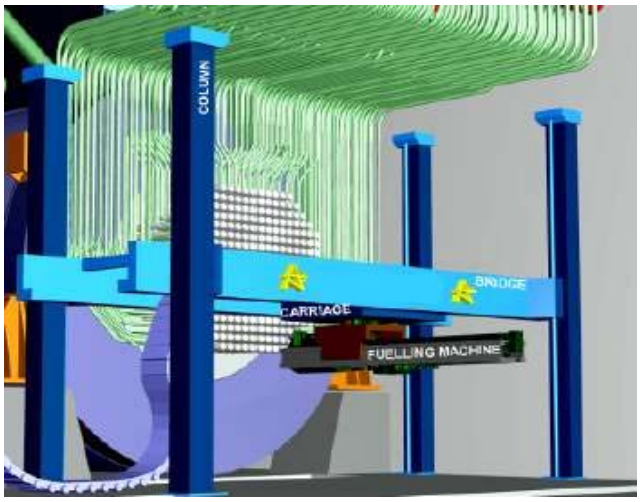


Figure D1-7-2. Horizontal on-line refueling for the ACR-700 CANDU reactor (AECL, 2005).

D1-7.4 MODULE INTERFACES

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. Reprocessing requirements would be similar to those for UO_2 LWR fuels.

D1-7.5 SCALING CONSIDERATIONS

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

2009 AFC-CBD Data. 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 2006) is escalated to 2009 constant dollars, a fabrication cost of $~105/kgU results. To this should be added a conversion cost for slightly enriched EUF6 to ceramic-grade UO2 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.

2012 AFC-CBD Update Data. Like LWR fuel fabricators, the Canadian CANDU fuel fabricator does not publish information regarding costs of fuel production or publish prices received for finished fuel bundles. Because of similarities in production methodology, Canadian vis-à-vis U.S. regulation, quality assurance requirements, and fuel cladding materials (zirconium and zirconium alloys), however, the same factors affecting LWR fuel fabrication from 2009 to 2012 will also affect CANDU fuel. In

Module D1-1 the nominal fuel fabrication unit cost was increased by 40% to account for these factors. If the same 1.4 factor is applied to the 2009 AFC-CBD CANDU fuel unit cost value of 135 $/kgU, a nominal value of 189 $/kgU results.

One can also use the "complexity factor" (subject fuel unit cost divided by PWR fuel unit cost) from (Olsen et al. 1979), a 1979 ORNL report comparing several large-plant fuel fabrication technologies on a "level-playing field" basis. If the factor of 0.59 (for pressurized heavy-water reactor NATU fuel) is applied, a unit cost of $207/kgU results when applied to the $350 $/kgU nominal values from the first line of the D1 option in summary Table S-1, or from Table D1-2 in submodule D1-1.

If reprocessed U (RU) from LWRs is used in CANDUs, the CANDU fuel fabricator will face the same ES&H issues arising from U-232, U-236, and fission product impurities that would affect an LWR fuel fabricator. The additional costs would result in a unit cost "penalty" for RU use. (EPRI 2010) has an analysis which utilizes a 30% increase from the unit cost of fabricating CANDU fuel arising from virgin NATU. Even with this fuel fabrication cost increase, the overall cost of the front end of an open CANDU fuel cycle using LWR-RU is lower than for a cycle using virgin NATU. The savings are due to not having to purchase and process new uranium ore (U3O8).

D1-7.7 DATA LIMITATIONS

The reliability of the cost data is good, since CANDU fuel production is a fully commercialized operation.

D1-7.8 COST SUMMARIES

2009 AFC-CBD 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 $US), 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 (2009 AFC-CBD).

What-It-Takes (WIT) Table (2009$)			
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

2012 AFC-CBD Update Summaries. The following "what-it-takes" values and a corresponding probability distribution shape are recommended for use in future fuel cycle studies:

Table D1-7.2. "What-it-takes" (WIT) CANDU fuel unit fabrication costs (2012 AFC-CBD Update).

Fuel Type	Low Value (2012 $/kgHM)	Nominal Value (2012 $/kgHM)	High Value (2012 $/kgHM)
Pelletized Natural UO_2 Ceramic CANDU fuel	115	200	300
Pelletized UO_2 Ceramic CANDU fuel (RU from LWR spent fuel reprocessing or SEU)'	150	260	390

For uncertainty analyses triangular distributions should be used with the values in the table rows above. The unit fabrication cost values for NATU-derived CANDU fuel in the Table above were calculated by using similar multipliers (2012 AFC-CBR to 2009 AFC-CBR) to those used for LWR "virgin-U" derived fuel. As explained above, this is because of similarities in the LWR and CANDU fuel production, institutional, and regulatory environments. A sustained increase in the price of zirconium is factored into the assumptions. The nominal value of $200/kgU is a rounded average of the $189 and $207 values derived in the section above.

For the new category of RU-derived CANDU fuel a 30% penalty is added to all 3 cases (low, nominal, and high) per the hypothetical case in (Del Cul et al. 2009). The same 30% factor is suggested for CANDU fuel made from slightly-enriched uranium (SEU). This accounts for the more stringent safety and security environment associated with enriched uranium use. Table D1-7.2. "What-it-takes" (WIT) CANDU fuel unit fabrication costs (2102 AFC-CBD Update).

Table D1-7-3 shows the 2012 Update values escalated to Year 2017$ using an escalation factor of 1.09. No new CANDU cost information was gathered in the 2012 to 2017 time frame.

Table D1-7-3 "What-it-takes" (WIT) CANDU fuel unit fabrication costs (escalated to 2017$)

Fuel Type	Low Value (2017 $/kgHM)	Mode Value (2017 $/kgHM)	Mean Value (2017 $/kgHM)	High Value (2017 $/kgHM)
Pelletized Natural UO_2 Ceramic CANDU fuel	125	218	224	327
Pelletized UO_2 Ceramic CANDU fuel (RU from LWR spent fuel reprocessing or SEU)'	164	284	291	425

The triangular distributions based on the costs in the latter WIT Table are shown in Figure D1-7-3. The distributions are not heavily skewed since there is considerable industrial cost experience with CANDU fuel.

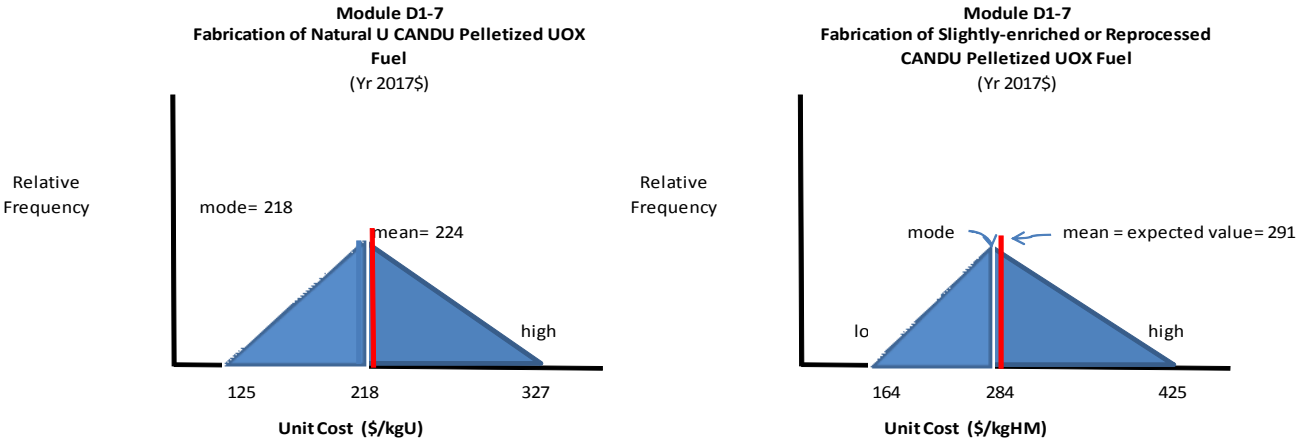


Figure D1-7-3. CANDU fuel estimated cost frequency distributions.

D1-7.9 SENSITIVITY AND UNCERTAINTY ANALYSIS

No data were found or generated.

Module D1-8

Thorium-based Fuels

Module D1-8

Thorium-based Fuel Fabrication

D1-8.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Literature review and analysis of data in 2012 resulted in revised unit costs. Fuels considered were:
  - Enriched U (~19.95% U-235) oxide and fertile Th oxide MOX fuel pelletized fuel burnable in LWRs
  - All ThO_2 blanket pellets
  - All (U, Th)O_2 fertile "blanket" pelletized fuel burnable in LWRs designed on "seed/blanket concept"
  - (Pu, U, Zr) extrudable metal alloy rod usable as a driver along with ThO_2 blankets in seed blanket concept. (Proposed as Pu disposition technique for weapons-grade Pu capable of contact handling before reactor insertion.)
  - Liquid fuels such as those proposed for thorium-based MSR fuel cycles are **not** considered. Costs for these are considered in the Salt-cooled reactor modules

D1-8.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2005 as Module D1-8. In 2012 fertile ThO_2 pellet blanket fuel was added to this module.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Ceramic fertile thorium particles have been used in MHRs. Some cost information might be available.
  - Lightbridge Corporation continues to investigate seed-blanket concepts for LWRs. Some of these involve thorium.

D1-8.1 BASIC INFORMATION

2009 AFC-CBD 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/Lightbridge), 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 (Washington Post 2009). 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)

2012 AFC-CBD Update Status. In the last five years there has been increased interest in the use of thorium fuel cycles, especially by those in academia, non-governmental organizations, and outside the U.S. nuclear industry. The purported Th resource availability, non-proliferation and waste production/management benefits of thorium-based fuel cycles are the subject of dozens of recent reports and papers too numerous to list here. Very little information in the area of economics, for the fuel cycle, the required new reactors, or existing reactor modifications, has been presented.

As a target of past extensive research and development thorium and its fuel cycles are nothing new. Very extensive programs were conducted by USAEC and its contractors in the 1950s through the 1970s. Some early LWRs, such as Shippingport, actually operated with thorium in their cores. ORNL and General Atomics produced many reports on molten salt reactor fuel cycles and HTGR fuel cycles, respectively. Many of these are now available in electronic form. Research and development on thorium-based fuels for several reactor types was well documented, and some "level-playing field" type life cycle cost estimates were prepared for fabrication of several thorium fuel types. The estimates combined the attributes of both "bottom-up" and parametric "top-down" cost estimates for both capital and operations costs. For purposes of comparison, the costs of uranium-only and plutonium-based fuels were included. One such ORNL study from 1978 (Olsen et al. 1979) is cited below.

The 2009 AFC-CBR contained somewhat detailed and much more recent cost information on a Russian "seed-blanket" concept (Radkowsky concept) which could use either enriched uranium or plutonium fuel in a metal alloy driver fuel and (U, Th) O_2 pellets in the surrounding rod/bundle structure typical of PWRs. No new cost information has become available on this "Radkowsky" seed-blanket concept since the 2009 AFC-CBR document.

It was decided that this section could best benefit from a new look at the old (1960-1970s vintage) cost estimates. These are basically for ceramic type fuels which could be either (U, Th) O_2 pellets for LWRs or TRISO type (U, Th) O_2 or (U, Th) CO particles imbedded in graphite for HTRs. These will be the subject of the next section of this module.

The liquid-fueled molten-salt reactor (MSR) concept has also enjoyed considerable recent interest (Pickard 2002). Since it does not require a fuel fabrication facility and the fuel cycle is integral to the reactor, its fuel cycle economics are not covered here, but, rather in the R7-module. In an MSR breeding cycle thorium salts are the main fertile make-up feedstock and are converted to fissile U-233 salts.

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 (or highly-enriched U) 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 Pu alloy driver fuel plant would require 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 DIAGRAMS

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.

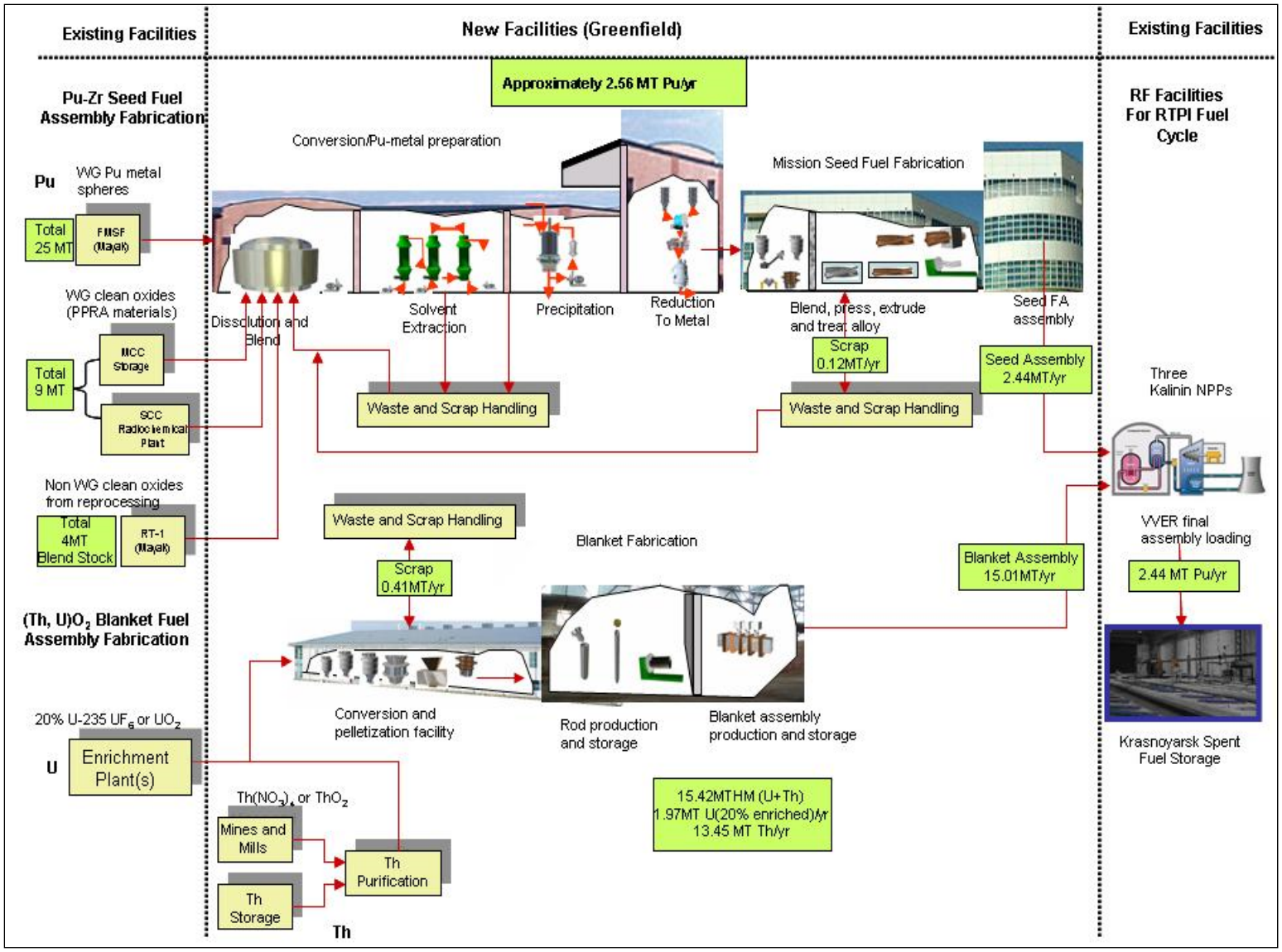


Figure D1-8-1. Fuel fabrication facility process schematics for a thorium concept utilizing both a blanket (U, ThO_2) pelletized fuel and a metallic Pu-Zr driver fuel (RTPI concept proposed for Russian Pu-disposition) (ORNL, 2005).

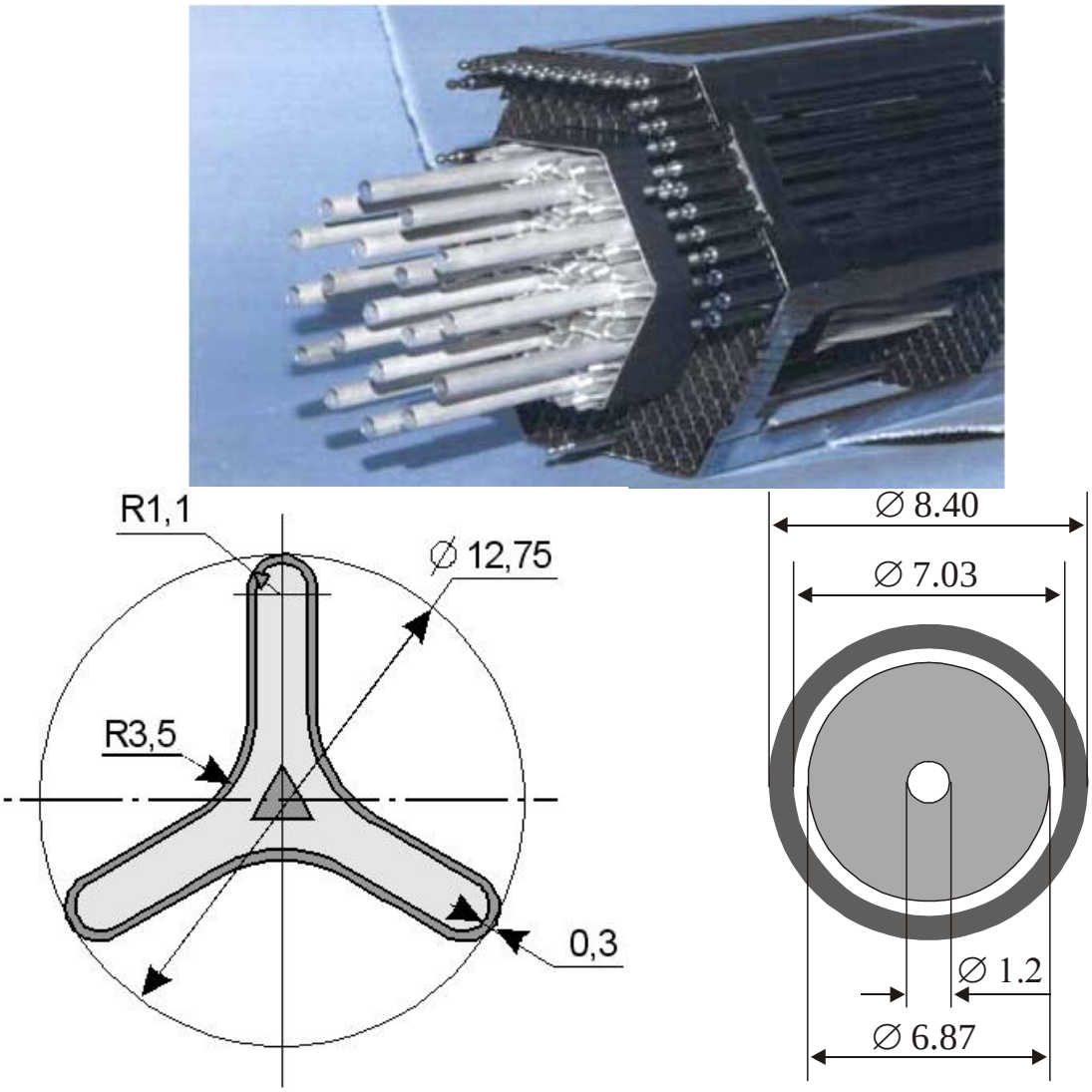


Figure D1-8-2. RTPI blanket/driver fuel envisioned for plutonium-disposition (dimensions are in millimeters) (ORNL, 2005).

D1-8.4 MODULE INTERFACES

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 SCALING CONSIDERATIONS

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. ORNL 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. ORNL 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 (U, PuO_2) MOX or cast (U, Pu,Zr) 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 DATA LIMITATIONS

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

2009 AFC-CBD Cost Summary. 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 $US), 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.

2012 AFC-CBD Update Cost Data. This section presents cost data obtained from 2009 to 2012. Many old ORNL reports were found to have useful data, such as in Table D1-8-2 below.

Table D1-8.2. 1978$ projected costs for various thorium-containing fuels (Olsen et al. 1979).

Table 11. Estimated Fabrication Cost Comparison[a] Summary

Reactor Type	Fuel Material	Relative Cost Factors				Estimated Costs ($/kg)[b]
		Capital	Hardware	Operating	Total	
Part A						
LWR (PWR)	$(^{235}U,U)O_2$	0.33	0.38	0.29	1.00	150[c]
	$(Pu,U)O_2$	1.49	0.38	1.45	3.32	500
	$(^{235}U,Th)O_2$	0.41	0.42	0.44	1.27	190
	$(^{233}U,Th)O_2$	2.18	0.42	1.60	4.19	630
	$(Pu,Th)O_2$	1.49	0.38	1.53	3.40	510
CANDU	Normal UO_2	0.33	0.09	0.11	0.53	80
	$(Pu,U)O_2$	1.49	0.09	0.50	2.08	310
	$(^{233}U,Th)O_2$	1.98	0.12	0.55	2.65	400
	$(Pu,Th)O_2$	1.49	0.09	0.55	2.13	320
LMFBR	$(Pu,U)O_2$	3.19	0.58	2.10	5.87	880
	(Pu,U)C	2.68	0.37	1.66	4.72	710
	$^{233}U,Th$	2.73	0.35	1.61	4.69	700
GFBR	$(Pu,U)O_2$	3.19	0.90	2.29	6.38	960
	$(^{233}U,Th)O_2$	5.01	0.99	2.64	8.64	1300
	$(Pu,Th)O_2$	3.64	0.90	2.40	6.94	1040
Part B						
HTGR	$^{235}UO_2$–ThO_2	0.26	0.42	0.32	1.00	400[d]
	^{233}UCO–ThO_2	1.23	0.42	0.96	2.61	1030
	$^{235}UO_2$–UO_2	0.23	0.35	0.32	0.90	360
	PuO_2–ThO_2	1.23	0.42	0.96	2.61	1030

[a] All cost comparisons are relative to the given base case factors.

[b] 1977 dollars assumed for total kilograms of heavy metal product with a plant output of 2 t/d and operating 260 d/year (520 t/year).

[c] Base case for metal clad fuel rods based on FABCØST 9 estimates [Source: A. L. Lotts, T. N. Washburn, and F. J. Homan, *FABCØST 9, A Computer Code for Estimating Fabrication Costs for Rod-Bundle Fuel Elements*, ORNL-4287 (August 1968).] escalated to 1977 with additions for current scrap and waste treatment requirements.

[d] Base case for all HTGR (Prismatic Fuel Element) cases based on data from personal communication, A. L. Lotts, Oak Ridge National Laboratory, April 11, 1975.

Two old ORNL reports (Olsen et al. 1979) and (Sease 1966) from the “heyday” of the USAEC thorium utilization program provide the best detailed information on the projected costs of adding thorium to more conventional uranium fuels. Table D1-8.1 above from (Olsen et al. 1979).breaks down projected unit costs for several Th-containing fuel types. These comparative estimates and projected unit costs are useful because they were prepared by the same people within a common organization, which provides a level playing field for evaluation. They also can be compared to conventional LWR UOX fuel for which we have real cost/price information. Figure D1-8.1 below reprinted from the earlier (Sease 1966) is also useful since it attempts show how the mode of production (glovebox, full remote, et al.) affects the unit cost. In essence what we have are “complexity factors which might be applied to updated 2012$ unit costs

for conventional fuels. For relatively simple Th-containing fuels, such as (U, Th)O_2 pellets, these "complexity factor" ratios are probably quite useful and applicable.

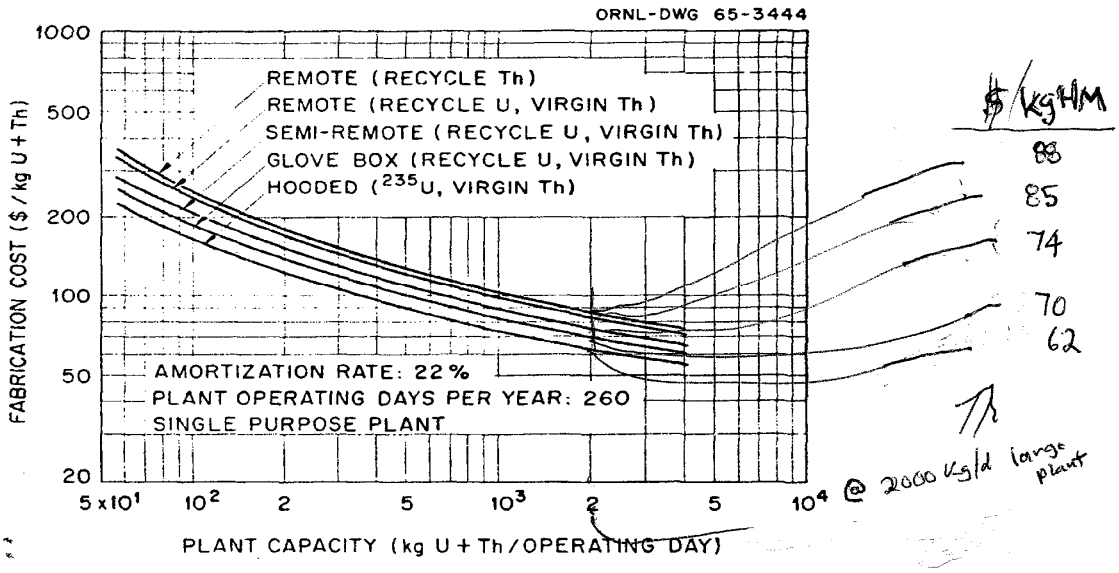


Figure D1-8.2. How mode of fabrication affects projected unit costs of thorium-containing fuels in 1965 dollars (Sease 1966).

For more complex fuels requiring remote handling the author of this section questions the validity of applying simple complexity ratios and the subsequent application of historical escalation. Regulatory, security, Q/A, and institutional factors have greatly increased the cost of both glovebox and remote handling nuclear facilities vis-à-vis contact handling ones. The ratio of the "remote" facility unit costs to the "hooded" (contact handled) unit costs in the above figure are too small (1.5 or less) to be realistic for a high-capacity fabrication plant.

Contact-handled (U,Th)O_2 pelletized fuel using unirradiated U and Th source materials can be used in LWRs, and if the spent fuel is reprocessed, fissile U-233 can be recovered for LWR use, much as Pu is recovered for eventual use in LWR MOX fuel. (It should be noted that thorium-containing fuels are more difficult to reprocess because of the lower solubility of ThO_2 and the higher radiation hazard associated with U-232 daughters which also accompany U-233 production. This is discussed in Module F1. Any U-233 arising from LWR burning and reprocessing of (U,Th)O_2 fuel would have to be refabricated in a remote-handling fabrication facility.) The enrichment of the uranium burned along with the thorium must be considerably higher (> 15% U-235) than the 3 to 5% U-235 for conventional UOX fuel. This is a result of the high neutron absorption by fertile thorium and the need to keep the core critical. The higher (U,Th)O_2 pellet fuel unit fabrication cost is a result of the higher criticality safety and security requirements for handling MEU and the additional HVAC requirements to keep thorium decay daughters (radon and its daughters) at acceptable levels. (Olsen et al. 1979).indicates a "complexity factor" of 1.26 for (U,Th)O_2 fabrication versus UO_2 fabrication.

As noted above, UO_2 fabricated with significant amounts of U-233 present in the fuel would present very high fabrication costs and if data were available would be covered in Module D2 for remotely-fabricated fuels. The U-235 + U-233 content of such fuel would have to be at least 2 to 3% for LWR fuel containing only uranium.

Pellets of ThO_2 only could also be fabricated using contact handling and might be used as blanket or target material for U-233 production in breeding fuel cycle. Because of greater HVAC requirements for Th handling, the unit cost for this operation would be somewhat above that for $NATUO_2$ or DUO_2 LWR

blanket fuel. The following table shows projected unit costs in 2012$ for various Th-related fuels calculated by complexity factors applied to the unit costs for uranium-only fuels.

Table D1-8.2. Thorium-based fuel unit fabrication costs calculated per references (contact-handled fuels only).

Study or Ref/Year	Low Value ($/kgHM)	Reference Value $/kgHM	High Value ($/kgHM)
DEC 2009 AFC-CBR			
$(U,Th)O_2$ pellets for Radkowsky seed/blanket scheme (blanket)	N/A	50% higher than PWR UO_2 per Lahoda ref in 2009 report:1.5 x 250 = 375	N/A
Pu,U,Zr metallic alloy driver fuel for Radkowsky scheme (mostly glovebox-handled Pu (This Pu-related cost is included since the HEU or Pu metal alloy driver is an integral part of the Radkowsy concept for LWRs.)	N/A	27,000 (from study by ORNL for NNSA a part of PU-disposition program)	N/A
Pelletized $(U,Th)O_2$ for LWRs. (U > 15% U-235) [Complexity factor from (Olsen et al. 1979)]	N/A	Complexity Factor of 1.26 applied to 2012 AFC-CBR 350$/kgU unit cost for LWR UO_2 440	N/A
Pelletized pure ThO_2 for LWR blankets [Complexity factor from (Olsen et al. 1979)]	N/A	Complexity Factor of 1.26 applied to U-blanket unit cost (450 $/kgU) in 2012 AFC-CBR Module D1-4 570	N/A
Pelletized (U, Th)O_2 for LWRs [IAEA 2005]	N/A	300	N/A

Some adjustment of the**se** values for the What-it-takes Table D1-8-3 are needed. The more recent report by Ed Lahoda (Lahoda 2004) cited in the 2009 AFC-CBR suggests that fabrication of (U, Th) O_2 fuel will cost 50% more than for UO_2. This 1.5 factor is greater than the 1.26 complexity factor suggested in the 1979 reference and probably better reflects regulatory and ES&H realities. The high, low, and nominal values in the table below use the 1.5 factor applied to the corresponding values in the "WIT" table for LWR UO_2 fuel in Module D1-1.

Table D1-8.3. What-It-Takes (WIT) table for LWR thorium-based fuels (2012$).

Fuel	Low Value ($/kgHM)	Reference Value $/kgHM or $/kgU	High Value ($/kgHM)
DEC 2012 AFC-CBR			
Pu,U,Zr metallic alloy driver fuel for Radkowsky Pu-disposition scheme (mostly glovebox-handled Pu)	N/A	27,000	N/A
Pelletized $(U,Th)O_2$ for LWRs. (U > 15% U-235) (Complexity factor from Lahoda) U-enrichment cost not included!	300	Complexity Factor of 1.5 applied to 2012 AFC-CBR 350$/kgU unit cost for LWR UO_2 525	750
Pelletized pure ThO_2 for LWR blankets (Complexity factor from Olsen 1979)	250	Same as for FR natural or DUO2 blankets 450	630

Table D1-8-4 escalates the Table D1-8-3 data to 2017 dollars using an escalation factor of 1.09. No new thorium fuel cost data was gathered in the 2012 to 2015 periods.

Table D1-8.4. What-It-Takes (WIT) table for LWR thorium-based fuels – escalated to 2017$.

Fuel	Low Value ($/kgHM)	Reference Value ($/kgHM)	Mean Value ($/kgHM)	High Value ($/kgHM)
DEC 2012 AFC-CBR Pu, U, Zr metallic alloy driver fuel for Radkowsky Pu-disposition scheme (mostly glovebox-handled Pu)	N/A	29,400		N/A
Pelletized (U, Th)O_2 for LWRs. (U > 15% U-235) (Complexity factor from Lahoda) U-enrichment cost not included!	327	Complexity Factor of 1.5 applied to 2012 AFC-CBR 350$/kgU unit cost for LWR UO_2 573	573	818
Pelletized pure ThO_2 for LWR blankets	273	Same as for FR natural or DUO_2 blankets 490	483	687

For uncertainty analyses triangular distributions should be used with the second and third entries in this table. Figure D1-8-3 shows the unit cost probability distributions for two thorium fuel types.

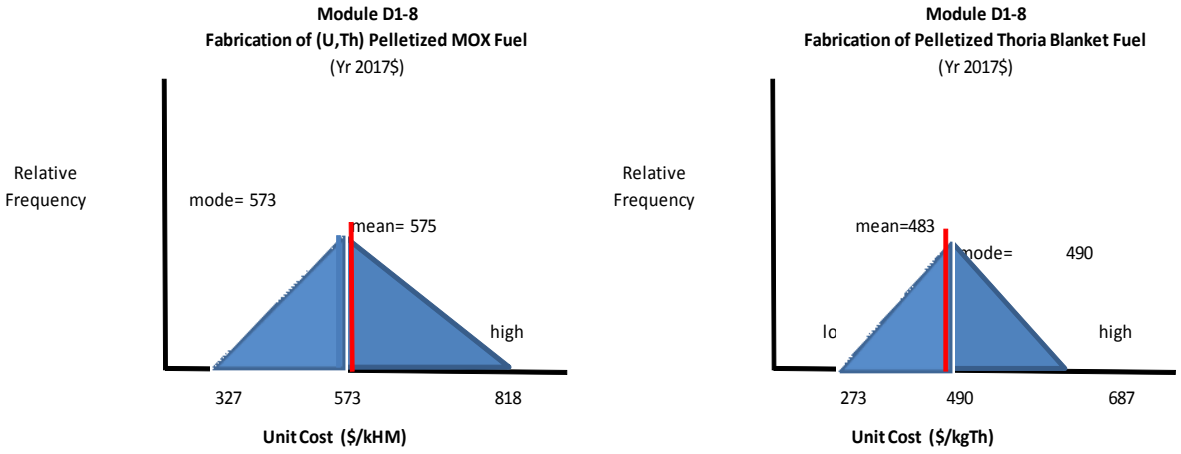


Figure D1-8-3 Uncertainty Distributions for Thoria Fuel Types.

A complexity factor applied to FR blankets (as in Table D1-8.4) probably overstates the cost, since UO_2 FR blankets would already be more expensive on a unit cost basis than LWR UO_2 blankets because of smaller pin size and FR fuel bundle complexity. (Note: Some natural UO_2 pellets are often used at the ends of LWR fuel rods for reactivity control.) The author assumes that pure thorium oxide blanket fuel for LWRs is equivalent in complexity to pure uranium oxide blanket fuel for fast reactors. For this reason the assigned unit costs are the same as for fast reactor UO_2 blankets in Module D1-4.

The same type of comparison logic could be applied to TRISO type HTR fuels containing thorium. This might represent a future modification of Module D1-3.

D1-8.9 SENSITIVITY AND UNCERTAINTY ANALYSES

None provided at this time.

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 the IAEA's 2005 report (IAEA 2005). 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 Fuel/Target Fabrication

Since no unit costs have been presented in this module, there is no Section D1-9.MD or D1-9.RH dealing with Costing Methodology and Cost History

D1-9.1 BASIC INFORMATION

Background and 2009 AFC-CBD 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 (INL 2010).
- 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. An example would be TRISO particles dispersed in zirconium.

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). Some types of research reactor fuel cost over $19,000/kgHM.

2012 AFC-CBD Update Status. Since the 2009 AFC-CBR no new data on the economics of these advanced fuel or target types have been located. (Note that “targets” and “driver fuels” will probably need to be separated from a cost standpoint as well as a physical standpoint for any further economic analyses, since their production requirements are likely to be vastly different depending on fuel/driver isotopics and impurity considerations. This observation is especially true for transmutation systems.)

Calculation of unit costs for some of these fuel types will need to be developed by using parameterization applied to fuel types for which costs are known. Among the "parameters" are radiation environment and building requirements, thermal conditions, number and complexity of manufacturing steps, cost of cladding materials and other non-nuclear materials, quality assurance requirements, and extent to which processes can be automated.

Most of these driver fuel/target types rightly belong in the D2 set of modules, since remote handling is likely to be necessary.

Among the possible future fuels which might be considered here (Section D1 "contact-handled" fuels) are the suggested post-Fukushima accident-resistant LWR fuels (Enhanced Accident Tolerant Fuels) that involve cladding materials other than zirconium or materials with higher melting points (NERAC 2011).The DOE Fuels R&D Program is considering some of these concepts; however, no cost estimates for large scale production of these fuels have been developed.

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 DIAGRAMS

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 INTERFACES

There is not yet enough fuel cycle definition to describe these interfaces.

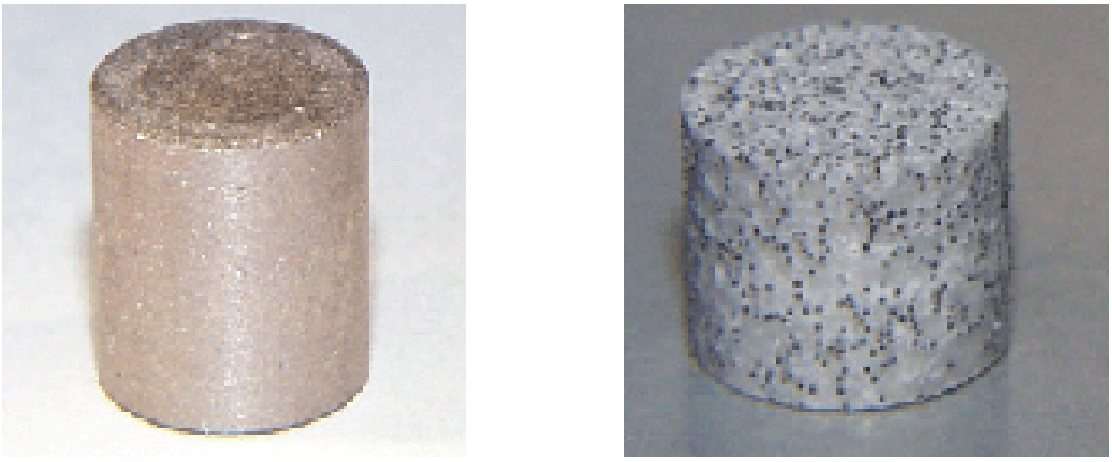


Figure D1-9-1. Solid solution and macro-dispersed inert matrix fuel pellets.

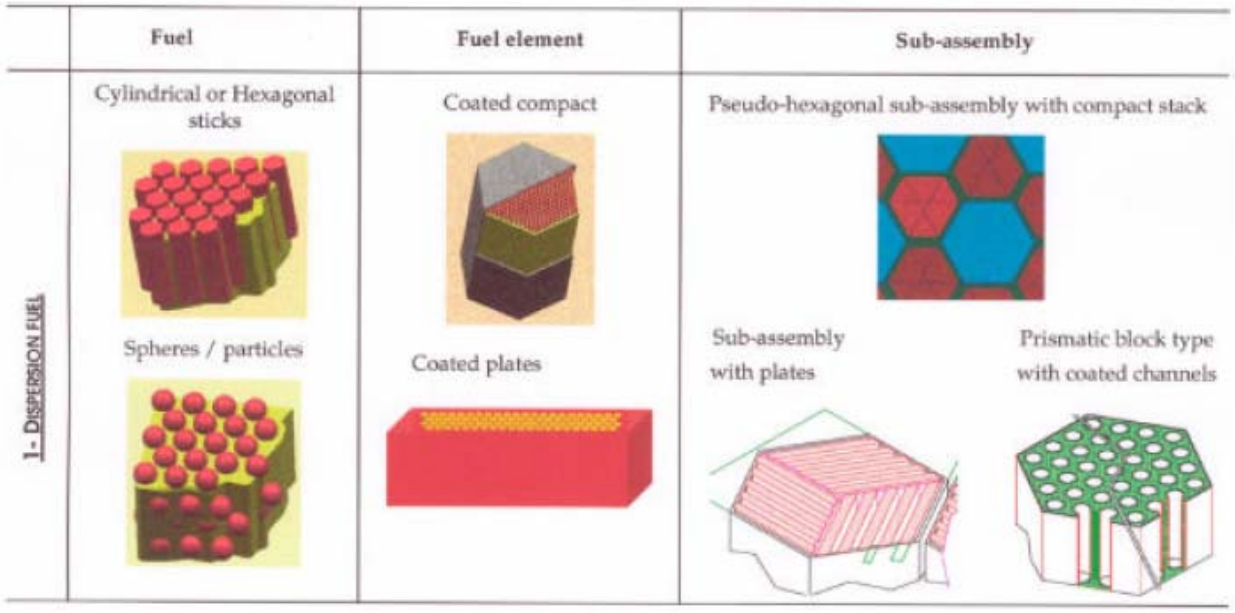


Figure D1-9-2. Dispersion fuel concepts.

D1-9.5 SCALING CONSIDERATIONS

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 DATA LIMITATIONS

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

No data available.

MODULE D1 REFERENCES

References for all of the D1 Modules appear in this section. The sub-headings group them by the modules applicable to each fuel type addressed in 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 Series D2

Fabrication of Remote-handled Fuels

Module Series D2
Fabrication of Remote-handled Fuels

D2. PREFACE AND INTRODUCTION

Remote handled fuel fabrication technologies are generally those in which the new fuel charged to the reactor is composed in part of fissile products arising from the reprocessing of some type of nuclear fuel and containing radionuclides with high radiation fields. The term “re-fabrication” can be applied in many cases. The facilities required for remote handling consist of one or more hot cells which contain manipulators and/or robotics and shield the workers from intense gamma or spontaneous neutron radiation emanating from the fuel heavy metal being processed. The hot cell portion of such facilities generally costs in the range of $10,000 to $30,000 per square foot including process equipment. For the purpose of minimizing criticality, transportation, and security hazards, such operations and their economics can benefit being closely integrated with the reactor and the spent fuel reprocessing facility. The ANL/GE-Hitachi Integral Fast Reactor (PRISM/IFR) is one such concept.

This and other fuel cycle concepts are being considered for destruction of actinides and even long-lived fission products. Some of these concepts involve separate targets that include highly radioactive plutonium, neptunium, and curium radionuclides (or even fission products) that would have to be fabricated in a remote facility. (The driver fuel in this case might not require remote handling and could be fabricated elsewhere.) The following concepts are considered in this module:

D2-1 Metallic Fast reactor refabricated fuel – This U, Pu, Zr alloy fuel is cast from fresh make-up uranium along with the higher actinides (mostly Pu) separated in an electrochemical (pyroprocessing) type integral reprocessing facility. Both reprocessing and refabrication are part of the same process line. This concept is amenable to fast reactor fuel cycles where the fast reactor fuel is continuously recycled and only fission products are separated and packaged for geologic disposal. This refabrication technology can also be used to in conjunction with an electrochemical reprocessing plant that recycles LWR spent fuel. This technology has been demonstrated on a pilot scale at Idaho National Laboratory. **Module D2-1 is combined with Module F2, since electrochemical reprocessing and metal fuel refabrication are part of an integrated recycle process, for which cost information is generally not separated.**

D2-2 Other refabricated fuels –MOX fuels (or targets) and recycled TRISO fuels with higher actinides and/or U-233 would require remote fabrication. It is likely the refabrication process would take place in the same shielded reprocessing facility that handles the spent fuel. Recycle, including refabrication, of LWR MOX, FR MOX, and TRISO type fuels has not been demonstrated on even a pilot scale. No recent cost information is available on any of these processes. At present, module D2-2 contains a discussion of a concept that would utilize spent PWR fuel in CANDU reactors.

Module D2-1

Metallic Fast Reactor Fuel Re-fabrication

(See Module F2)

Module D2-2

Other Re-fabricated Fuels

D2-2.1 SPECIAL TOPIC: DUPIC: THE DIRECT USE OF SPENT PWR FUEL IN CANDU REACTORS

Note: This material was formerly included in the section on fabrication of CANDU Fuel (Module D1-7. Because some fission products would remain in the refabricated DUPIC fuel, remote fabrication processes would be required. Hence, this material was moved to section D2.

No Sections D2-2.1.MD or D2-2.1.RH are included, since no costs are presented.

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 D2-2-1 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 D2-2-2) 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).

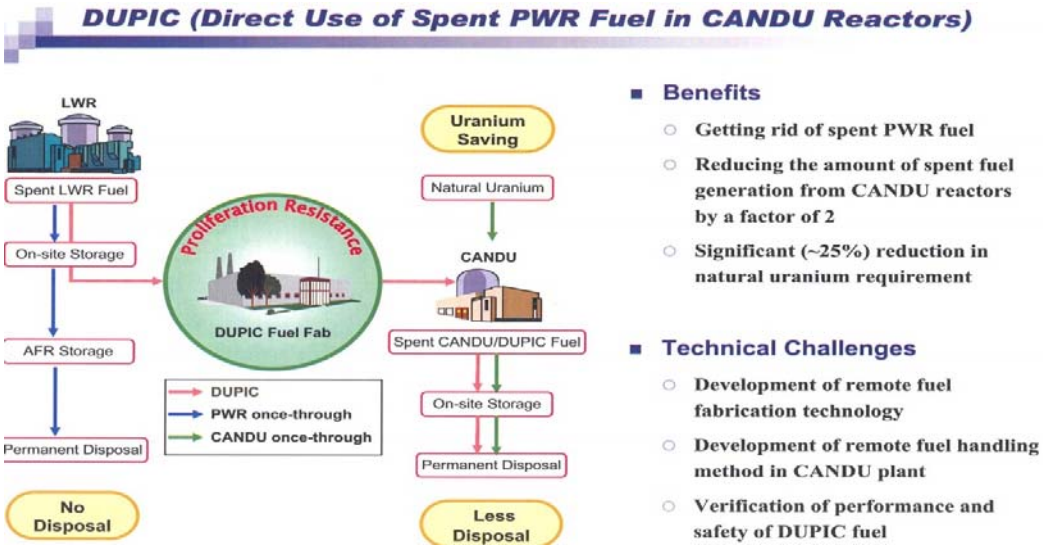

Figure D2-2-1. Benefits and challenges of turning PWR fuel into CANDU fuel (Yang et al., 2006).

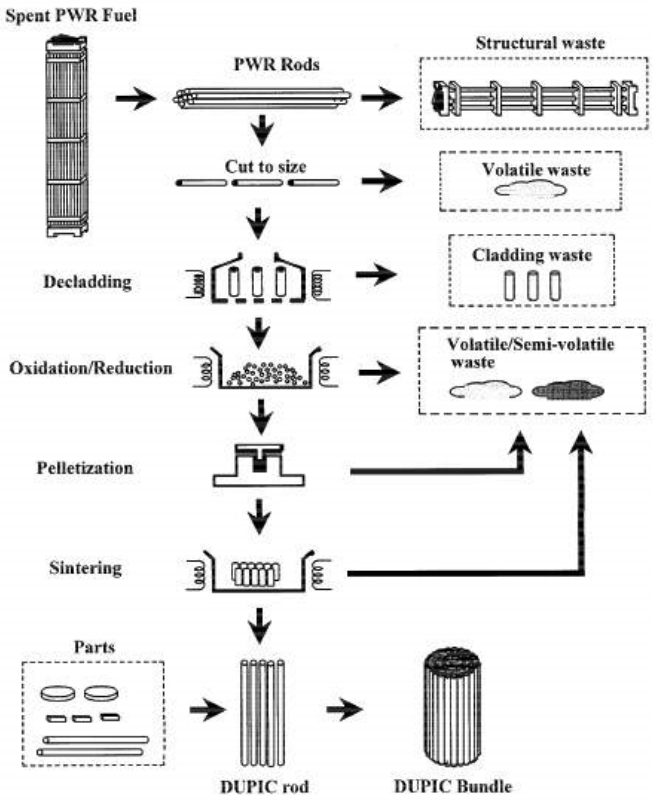

Figure D2-2-2. Process steps for DUPIC CANDU fuel fabrication (Choi, 2001).

MODULE D2 REFERENCES

MODULE SERIES D2-2.1

Choi 2001, op cit in Module D1-7 references.

Del Cul, et al. 2009, op cit in Module D1-7 references.

Yang, M.S., H. Choi, C. J. Jeong, K. C. Song, et al., 2006, "The Status and Prospect of DUPIC Fuel Technology," *Nuclear Engineering and Technology* 38(4).

E MODULES

Storage of Spent Nuclear Fuel and Recycled Products

E1 Modules

Wet Storage of Spent Nuclear Fuel

Module E1

Wet Storage of Spent Nuclear Fuel

E1.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module E1. In 2012 it was decided to discontinue this module since wet (pool) storage of SNF is generally part of reactor Operations and Maintenance costs. Also, no new centralized or on-site SNF storage pools are planned, so no present need for this Module exists.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 (It should be noted that the unit costs in the 2009 version may be indicative of a stand-alone wet storage pool.)
- **New technical/cost data which has recently become available and will benefit next revision:** New cost data on dry interim onsite storage should now be available from the USDOE-NE Used Fuel Disposition Campaign. In future versions of the AFC-CBR this data would appear in Module I (formerly Module E2)

E2 Modules

Dry Storage of Spent Nuclear Fuel

Module E2

Dry Storage of Spent Nuclear Fuel

E2.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module E2. In the 2012 AFC-CBR this Module was renamed Module I (Consolidated Interim Storage). This concept is one of those discussed in the recently-released "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" (U.S. Department of Energy, January 2013). The data in Module I also benefit from the *USDOE-NE Used Fuel disposition Storage, Transportation, and Disposal Interface Cost Study* and the *Used Fuel disposition System Architecture Report*.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:** USDOE-NE Used Fuel Disposition (UFD) studies on the cost and schedules for both on-reactor-site interim spent fuel storage installations (ISFSIs) and consolidated centralized storage should now be available.

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-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest AFC-CBR technical update from which this 2017 update was escalated:**
  - 2009 for stand-alone storage facilities. Most cost bases are pre-conceptual cost estimates for proposed storage facilities. Some data on completed facilities was available.
  - 2015 for storage facilities co-located with reprocessing plants. Bases are pre-conceptual cost estimates for proposed storage facilities.

E3-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module E3.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 for stand-alone storage facilities, 2015 for co-located storage facilities
- **New technical/cost data which has recently become available and will benefit next revision:** None identified.

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).

a. Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

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.

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+ flow-sheets
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. FUNCTIONAL AND OPERATIONAL DESCRIPTION

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 AND DIAGRAMS

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).

b. Beginning February 1, 2005, the name of the Idaho National Engineering and Environmental Laboratory (INEEL) was changed to Idaho National Laboratory (INL).

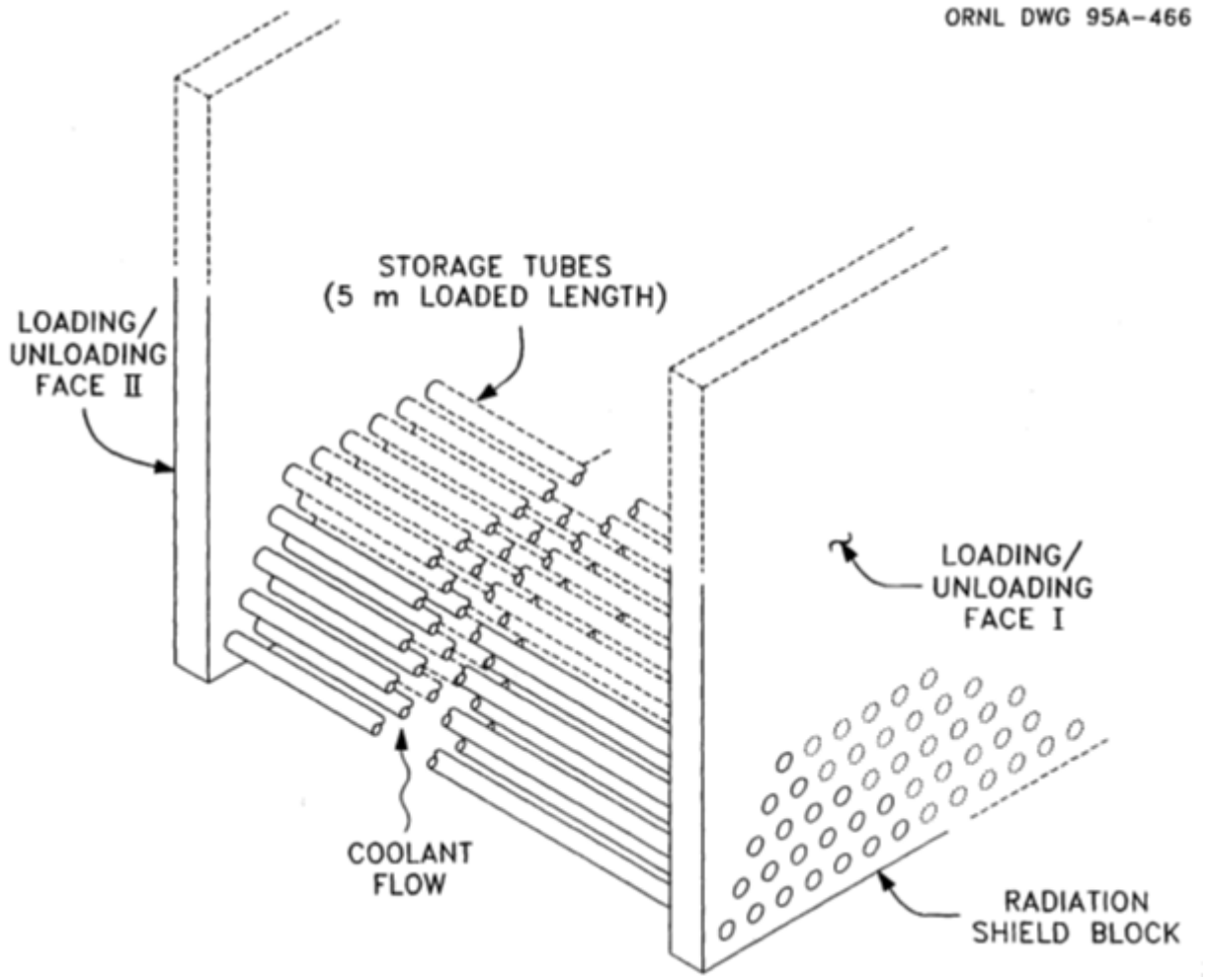

Figure E3-1. Storage module concept using horizontal sleeve geometry within plutonium storage vault.

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.

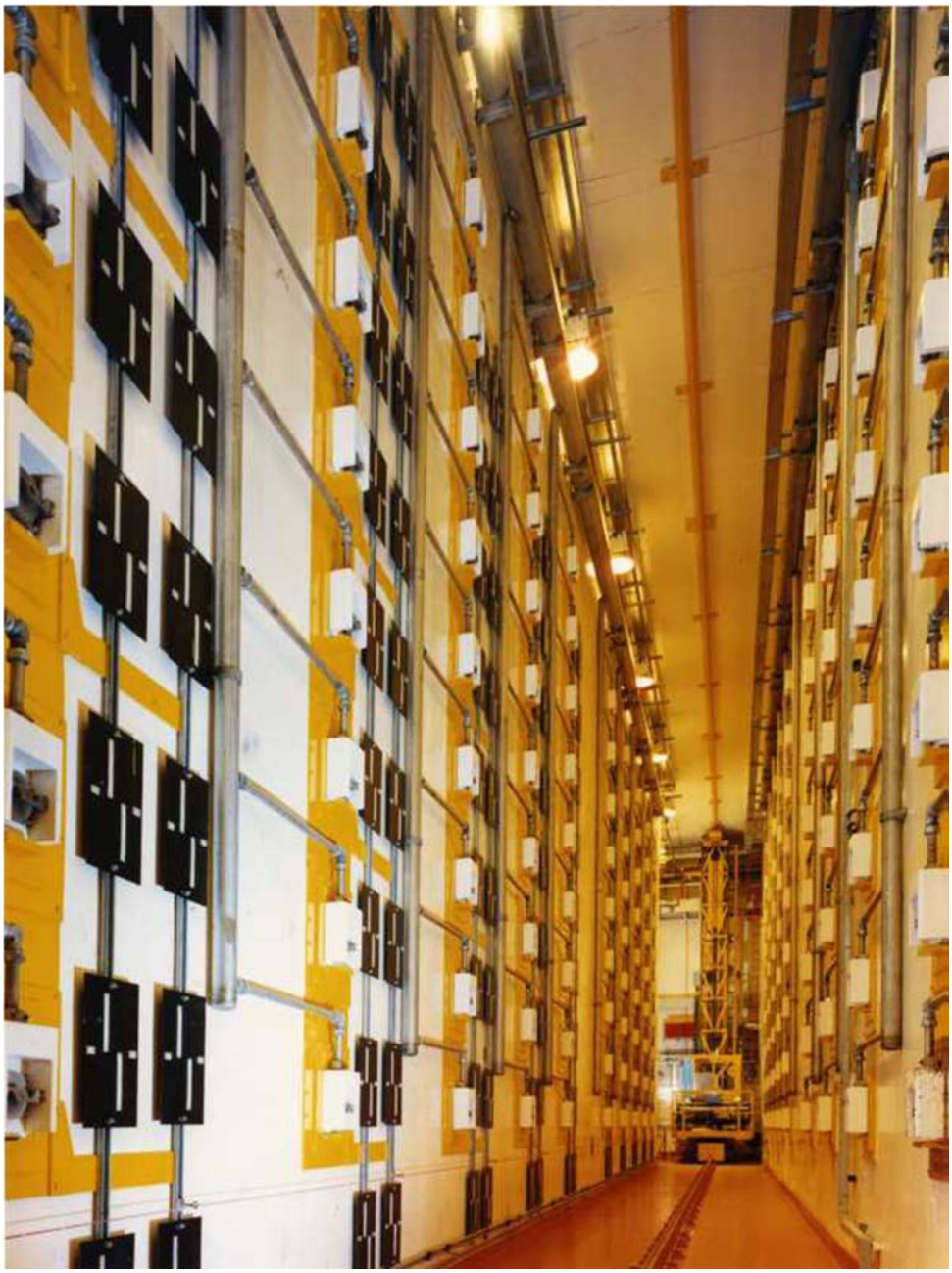

Figure E3-2. Remotely operated store for pure PuO_2 in welded stainless steel canisters in the THORP facility at Sellafield, U.K.

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).

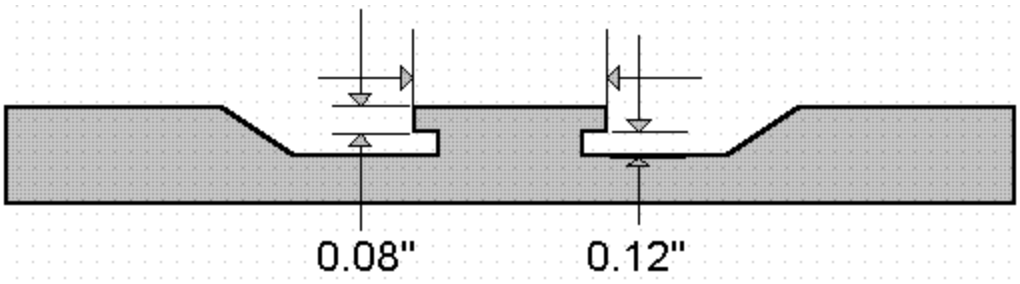

Figure E3-4. Canister top for remote handling of "1330 Canister."

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.

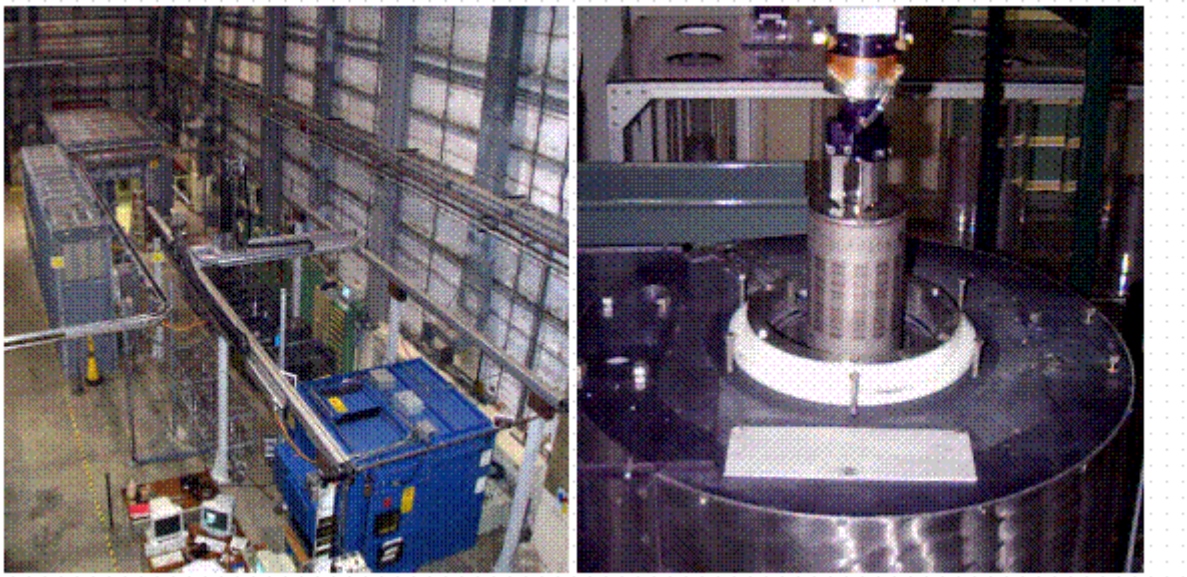

Figure 1. APSF Mockup **Figure 2. Crane Loading ITSC into Neutron Counter**

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 INTERFACES

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. SCALING CONSIDERATIONS

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 (U.S. Army 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] ($9,200/kg)
Store	CFTC EAS UREX+1	CFTC FOEAS UREX+1	CFTC FOEAS U/Pu	CFTC FOEAS UREX+3	
Status	Design Study	Design Study	Design Study	Design Study	
Hardened Area	475,000	28,000	24,000	52,000	
No. of Canisters	114,000	10,000	10,000	20,000	
Storage Capacity	500 MT TRU	44 MT TRU	44 MT Pu	44 MT TRU	
Total of WBS Levels 1–6 in 2007$	$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

E3-6.2 Storage Facility Costs

E3-6.2.1 Mayak Fissile Material Storage Facility

The Mayak fissile material storage 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.

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

E3-6.2.2 Actinide Packaging and Storage Facility (APSF)

The reported capital cost is $330M in 2000 dollars.

E3-6.2.3 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.

E3-6.2.4 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.

E3-6.2.5 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.

E3-6.2.6 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.

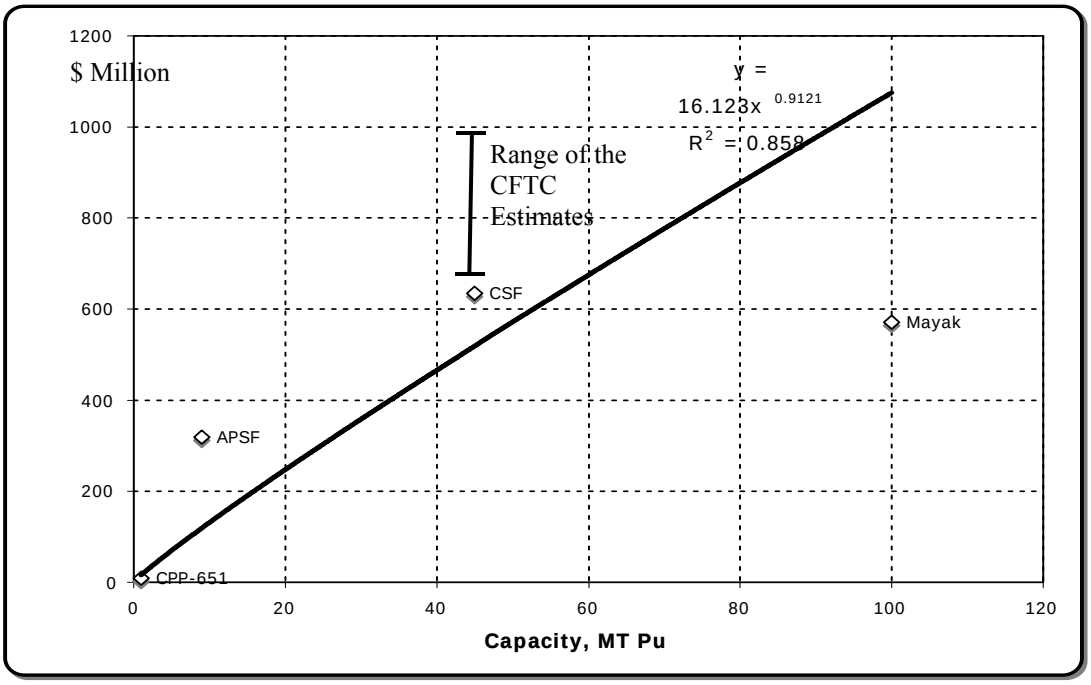

Figure E3-8. Costs of various sizes of plutonium storage facilities.

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. DATA LIMITATIONS

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.

E3-7.1.1 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.

E3-7.1.2 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.

E3-7.1.3 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.

E3-7.1.4 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.

E3-7.1.5 CSF

This "APSF-style" facility was the subject of an unpublished study by SRS in 2001. The estimate was considered rough order of magnitude.

E3-7.1.6 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 What-It-Takes (WIT) table of selected values for storage of mixed recycled plutonium, minor actinides, and uranium (**including escalation to 2017\$). [A factor of 14% was used to escalate from 2009\$ for stand-alone facilities. A factor of 3.2% was used to escalate from 2015\$ for co-located facilities]**

	\$30,000/kg(Pu-MA)[1]				
Reference Unit Capital Cost based on 50 MT(TRU) Capacity	Reference Cost Contingency (+/- %)	Low Cost \$/(kg(Pu-MA)·year)	Mode Cost \$/(kg(Pu-MA)·year	Mean Cost \$/(kg(Pu-MA)·year	High Cost \$/(kg(Pu-MA)·year
From 2009 & 2015 CBAs Stand-Alone Collocated[3].	(± 25%)	\$3,300 \$660	\$4,400 \$880		\$6,000 \$1200
2017 \$ "stand-alone" "co-loc"(2017\$)		\$3762 \$712	\$5016 \$950	\$5206 \$990	\$6840 \$1300
	\$18,000/kg(Pu)[2]				
		Low Cost \$/(kg(Pu)·year)	Mode Cost \$/(kg(Pu)·year)	Mean Cost \$/(kg(Pu-MA)·year	High Cost \$/(kg(Pu)·year)
From 2009 CBA & 2015 CBAs Stand-Alone Collocated[3].		\$2,000 \$400	\$2,600 \$520		\$3,300 \$660
2017 \$ "stand-alone" "co-loc"(2017\$)		\$2280 \$433	\$2964 \$562	\$3000 \$570	\$3762 \$712
		Economy-of-scale for larger capacity facility, increased Pu/MA loading of canisters, or shared safeguards and security functions	For other periods use product of unit storage cost and storage time; minimum period of 1 year.		Increased regulatory/safety requirements, ROM estimate as partial basis

1. 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.
2. 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.
3. Co-located facility costs based on 1/5 of the stand-alone facility costs.

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 distributions.

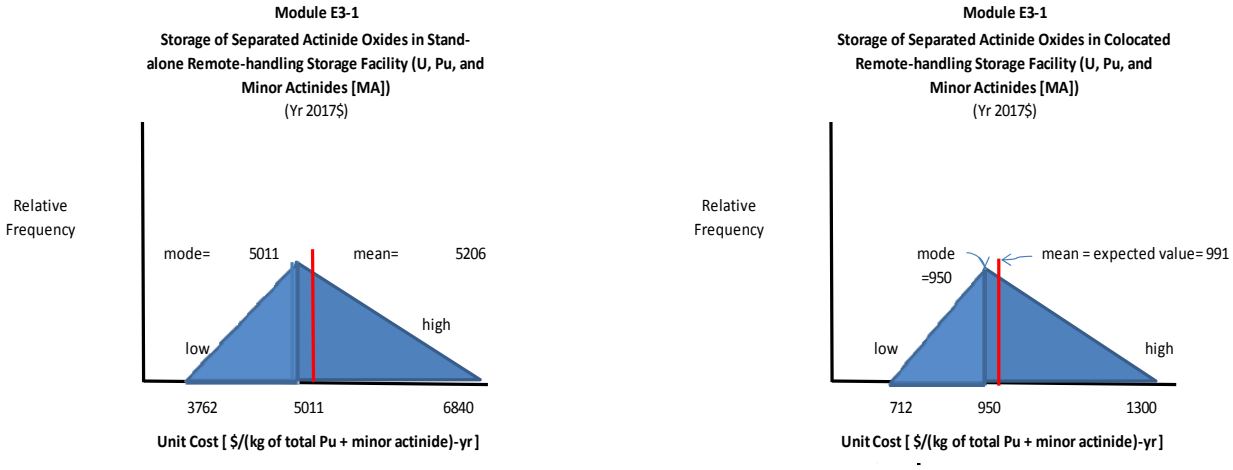

Figure E3-10 gives the estimated cost frequency distribution for the latest generation PUREX product from, for example, reprocessing at Rokkasho, Japan (i.e., mixed plutonium) and uranium oxide material.

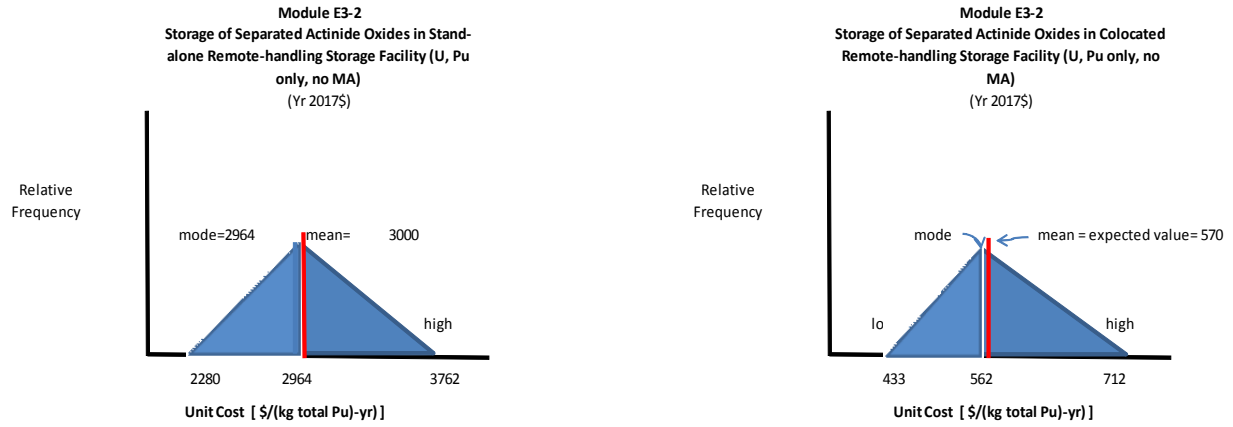

Figure E3-10. Module E3 recycled product storage (Pu-U) estimated cost frequency distributions.

E3-9. SENSITIVITY AND UNCERTAINTY ANALYSIS

None performed to date.

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Module E4

Managed Decay Storage

Module E4

Managed Decay Storage

E4-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2009 AFC-CBR)
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was escalated:** Bottom-up pre-conceptual estimate for large aqueous reprocessing plant based on UREX technology where select fission products are separated and temporarily stored for decay storage. Some data from reprocessing plants which store vitrified waste was also available.

E4-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2009 as Module E-4.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009
- **New technical/cost data which has recently become available and will benefit next revision:** None identified.

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. FUNCTIONAL AND OPERATIONAL DESCRIPTION

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).

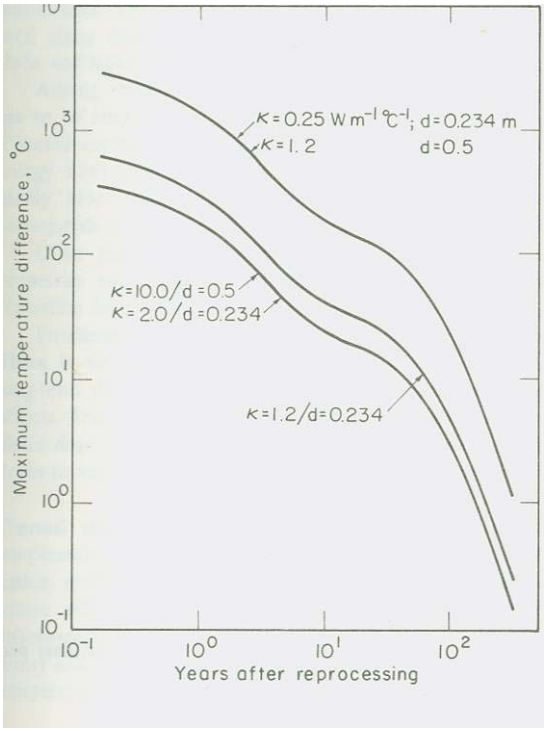

Figure E4-1. Maximum centerline temperature difference of waste form as a function of decay time.

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.

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	$Cs_2TiSi_6O_{15}$ •$3H_2O$ $Cs_3TiSi_3O_{95}$ •$3H_2O$ and Ti analogue of Pollucite $CsTiSi_2O_6$•$3H_2O$	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

Matrix	CsSr Composition	Composition Matrix, (% wt)	Process	Reference
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 2019 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 1991) 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[h]) ≡ 730M (U.S. 2008 dollars[i]). 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 AND DIAGRAMS

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.

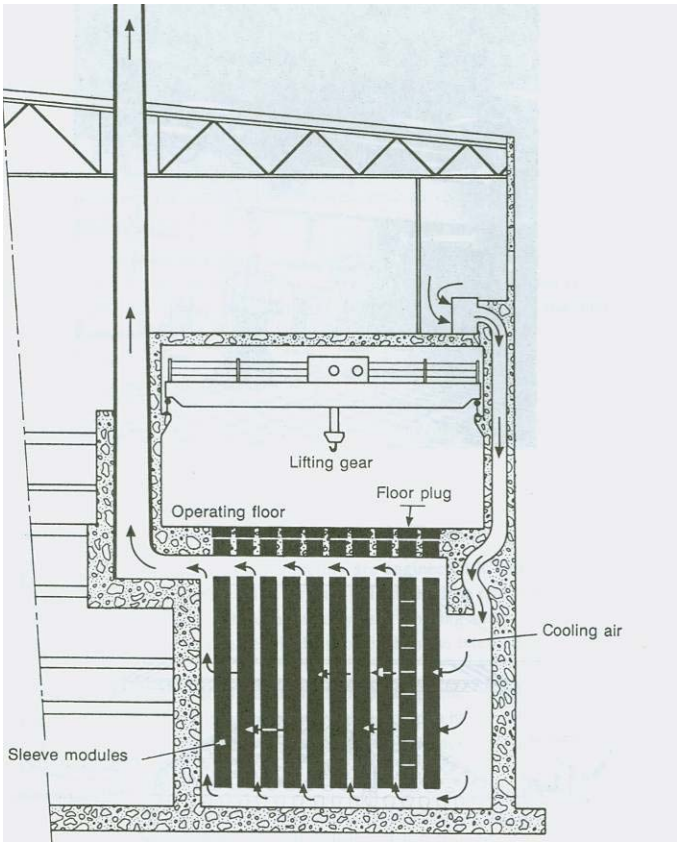

Figure E4-2. WVP VPS natural convection air-cooled storage system.

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.

h Measuring Worth - Exchange Rates Between the United States Dollar and Forty-one Currencies, http://www.measuringworth.com/datasets/exchangeglobal/result.php

i 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.

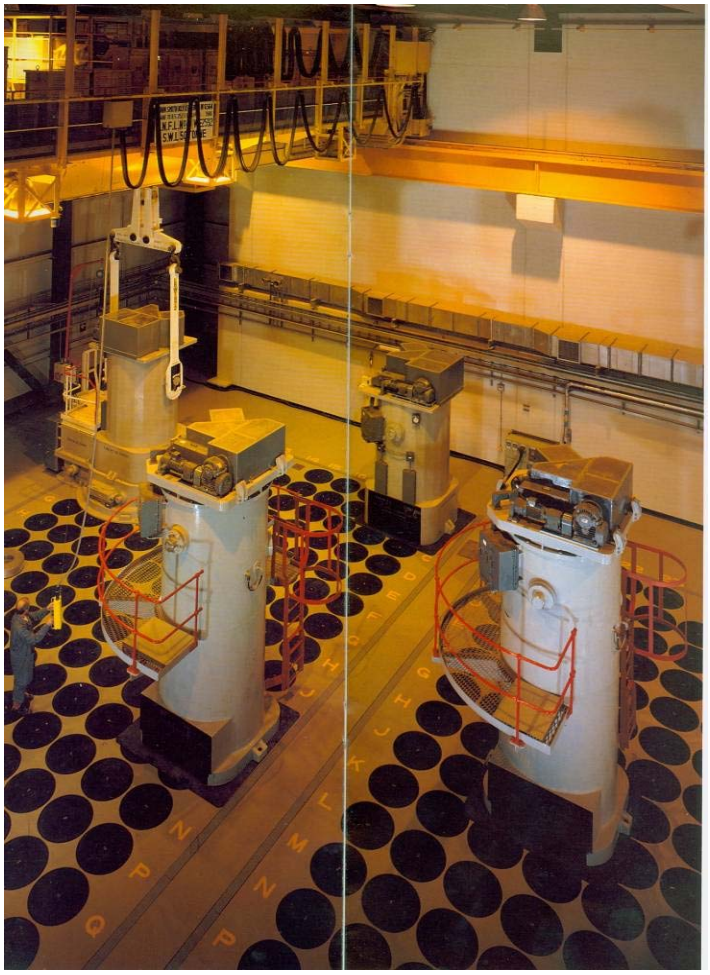

Figure E4-3. WVP VPS charge face showing waste product flasks over storage channels (BNFL 1991).

E4-4. MODULE INTERFACES

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. SCALING CONSIDERATIONS

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 E4-6 summarizes cost data given above.

Table E4-6. 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.

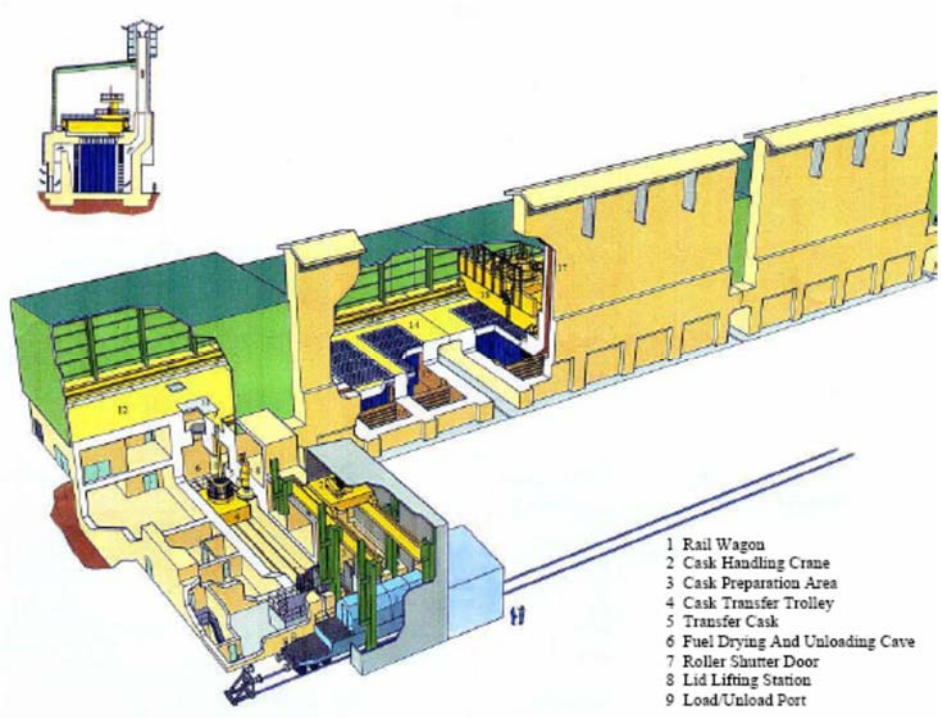

Figure E4-4. Schematic of modular vault dry storage of spent fuel at PAKS, Hungary (Ordogh et al. 2004).

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 E4-7, below:

Table E4-7. 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 E4-8 (Fairlie 2000), that provide discussion of wide differences observed. A reasonable value of $200K/t(iHM) is adopted with 2008 money value.

Table E4-8. 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]

* Reported in Fairlie (2000)

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. DATA LIMITATIONS

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 E4-9:

6. 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.
7. 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).
8. 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.
9. 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.
10. 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 E4-9. Cost summary table of selected values for managed decay storage (storage of Cs/Sr in remote handling facility) including escalation to year 20175$.

What-It-Takes (WIT) Table					
Reference Unit Capital Cost based on xx MT(TRU) Capacity	Reference Cost Contingency (+/- %)	Low Cost $/(kg(Cs/Sr))	Mode Cost $/(kg(Cs/Sr))	Mean Cost $/(kg(Cs/Sr))	High Cost $/(kg(Cs/Sr))
From 2009 CBA $/kg(kg(Cs/Sr)	(± 25%)	$10,000	$22,500		$35,000
Escalated to 2017$ (factor of 14%)		$11,400	$25,650	$25,650	$39,900

The triangular distribution based on the costs in the WIT Table E4-9 is shown in Figure E4-7. 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.

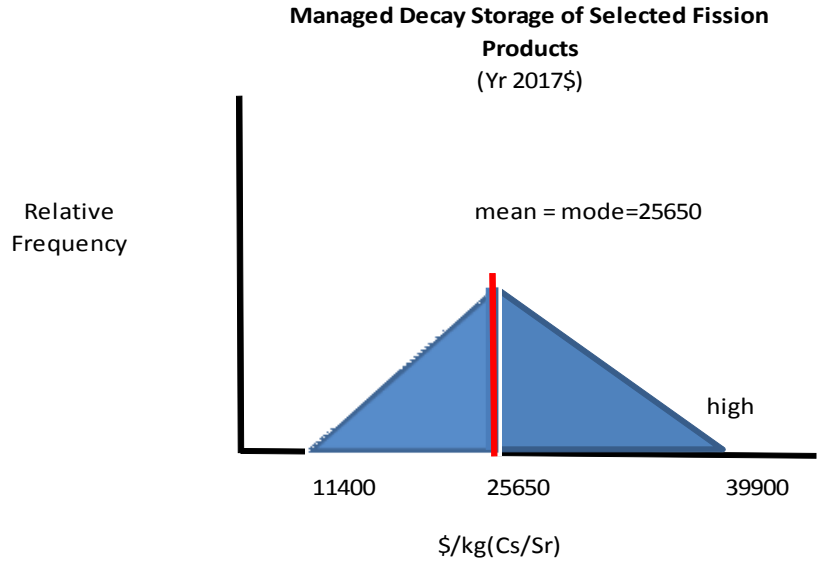

Figure E4- 7 Probability Distribution for Unit Cost of Managed Decay Storage

E4-9. SENSITIVITY AND UNCERTAINTY ANALYSIS

None performed to date.

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F MODULES

SPENT FUEL REPROCESSING

Module F1

Spent Nuclear Fuel Aqueous Reprocessing Facility

Module F1

Spent Nuclear Fuel Aqueous Reprocessing Facility

F1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update**: FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs**: Complete re-visit of detailed estimating bases for 2009, 2012, and 2015 AFC-CBRs. New unit cost ($/MTHM) values were obtained for UREX+1a by analyzing the breakdown of bottom-up Westinghouse Savannah River Company (WSRC) pre-conceptual design estimates for hypothetical aqueous reprocessing plants based on UREX technology. These analyses were discussed in the 2016 AFC-CBR update and further discussed in this 2017 version. By reducing lifecycle costs via better project management and reduction of indirect costs, a 24% reduction in UREX+1a unit cost is possible. Since not all technologies have been analyzed in detail, it was decided to not yet change the WIT values for this 2017 version from the 2009 EAS basis. This WSRC-based EAS data was, however, escalated from 2009 to 2017 $ using the factor presented in the "Escalation considerations" chapter of the mail report. (note: the WSRC documents are part of what were called the Engineering Alternative Studies (EAS) conducted under the GNEP (Global Nuclear Energy Partnership)
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was revised and escalated**: The WSRC studies mentioned above, and first presented in the 2009 AFC-CBR, were detailed bottom-up estimates. There was enough of a breakdown of direct and indirect costs by building and process function that for the 2016 AFB-CBR Update and this 2017 version, adjustments could be made to the estimates for improved project execution and lower indirect costs for UREX+1a. The result is a possible lowering of future "What-it-Takes" unit cost ranges for all reprocessing technology technologies, not just UREX+1a. The adjustments to be made would be analogous to those made in Module R1 of this version for "well-executed" LWR projects.

F1-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module R1. Costs for this version and those up to 2009 were based on a 2003 Washington Group & Bechtel-BWXT (WGI 2004) study for a UREX-1a reprocessing plant called the Spent Fuel Treatment Facility (SFTF). In the 2009 AFC-CBR the WSRC reports (WSRC 2007, 2008a, 2008b) prepared as part of the EAS became the cost bases for this (2009) and the 2012 and 2015 versions. In 2009 unit costs for UREX 3a and COEX reprocessing technology were also added to the "What-it Takes" (WIT) database. Projected unit costs for the reprocessing of thorium-based oxide fuels based on UREX 1a, UREX 3a, and COEX technologies were also added to the F1 module WIT database in 2009. In the 2016 Update a Chapter entitled "Observations on F1 Module from CBR 2015" was added. Its text and estimated unit cost values have been integrated directly into this 2017 F1 Module. In the 2009 version unit costs for "separations only" and "total reprocessing" plant functions were calculated and presented in the WIT table for all three reprocessing technologies.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 (EAS-WSRC data for UREX 1a plant was re-analyzed and adjusted downward for this 2017 version) In the 2016 version this "new adjusted data" for the same facility was first presented. The WIT change for all three aqueous technologies will be reflected in future versions of this document.
- **New technical/cost data which has recently become available and will benefit next revision**:

- No new cost estimates for hypothetical or proposed reprocessing plants have been identified. It is known that India and China are considering the construction of such larger scale facilities
- The EAS data on UREX+3a and COEX needs to be analyzed in more detail to see if reductions unit cost are possible for these technologies.

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. A generic facility typically consists of a spent nuclear fuel receiving area, processing buildings (head-end and chemical separation areas), 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 are the needs for remote handling and 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 (or in Japan by ship). 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 meat 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. The G modules cover many of these steps.

Figure F1-1 shows an example of a proposed 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.

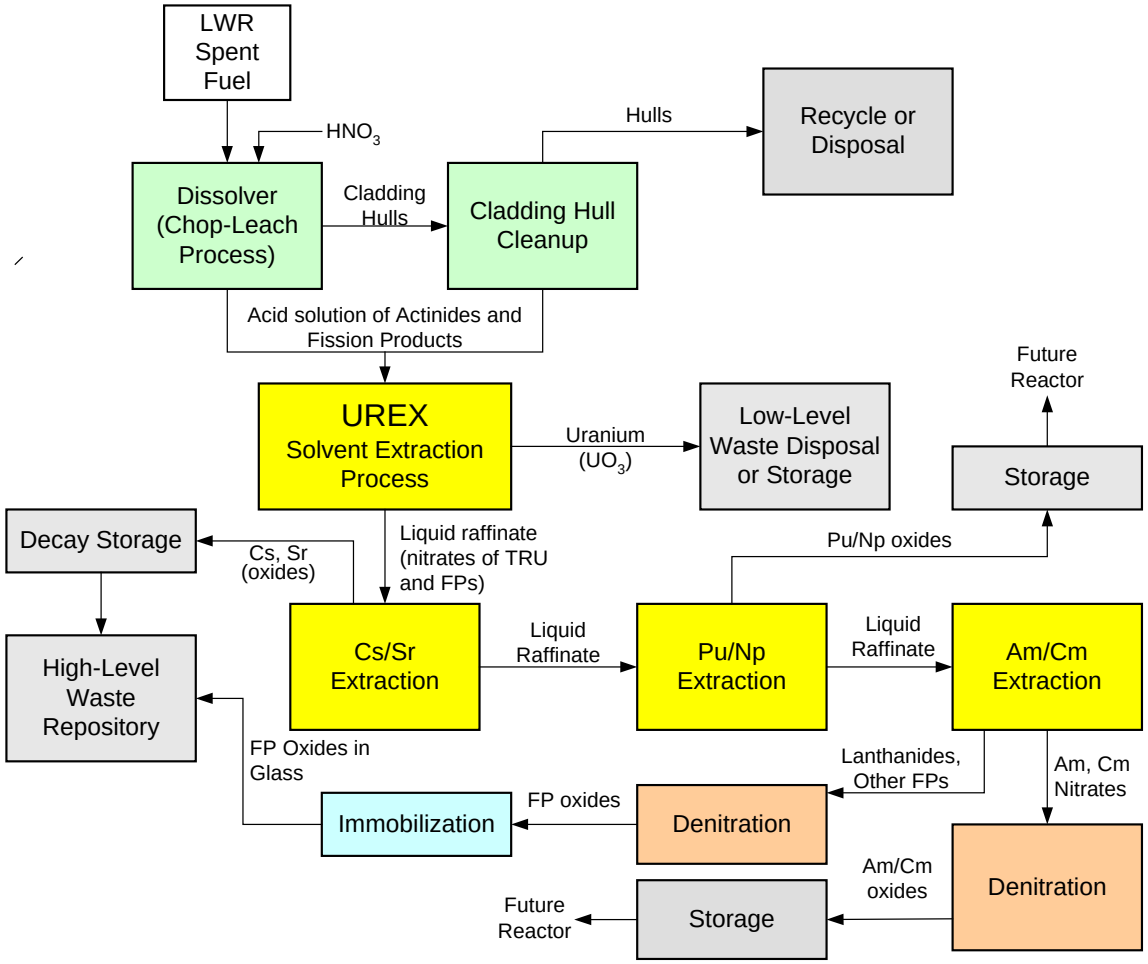

Figure F1-1. Example of UREX+ aqueous reprocessing process flow (Laidler 2003).

F1-3. PICTURES AND DIAGRAMS

The following pictures, Figures F1-2–F1-4, show reprocessing sites with currently operating PUREX facilities in France and recently shut-down sites in 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.

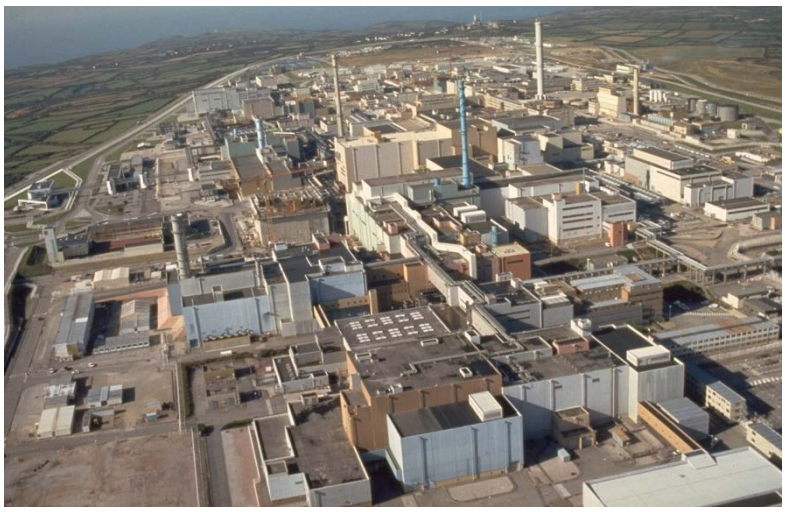

Figure F1-2. La Hague site, France, with reprocessing plants, UP2-800 and UP-3 (AREVA).

Figure F1-3. Sellafield site, U.K., with THORP and B205 reprocessing plants (BNFL, plc).

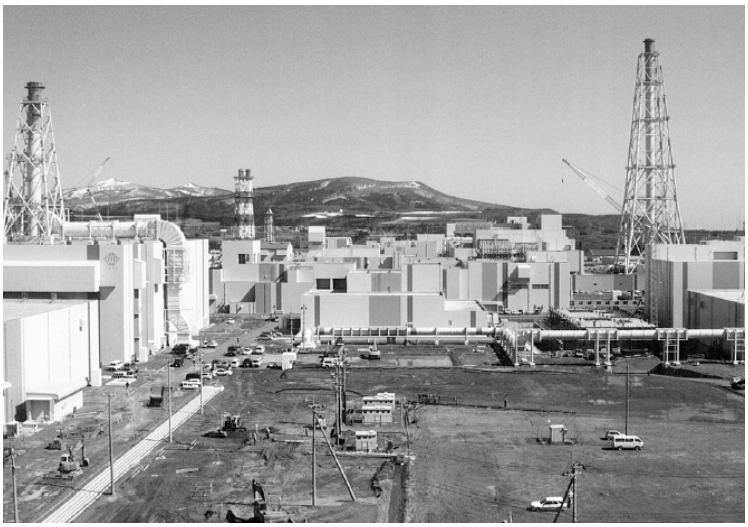

Figure F1-4. Rokkasho-Mura site, Japan, with Rokkasho Reprocessing Plant (JNFL).

F1-4. MODULE INTERFACES

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 colocate 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. SCALING CONSIDERATIONS

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.

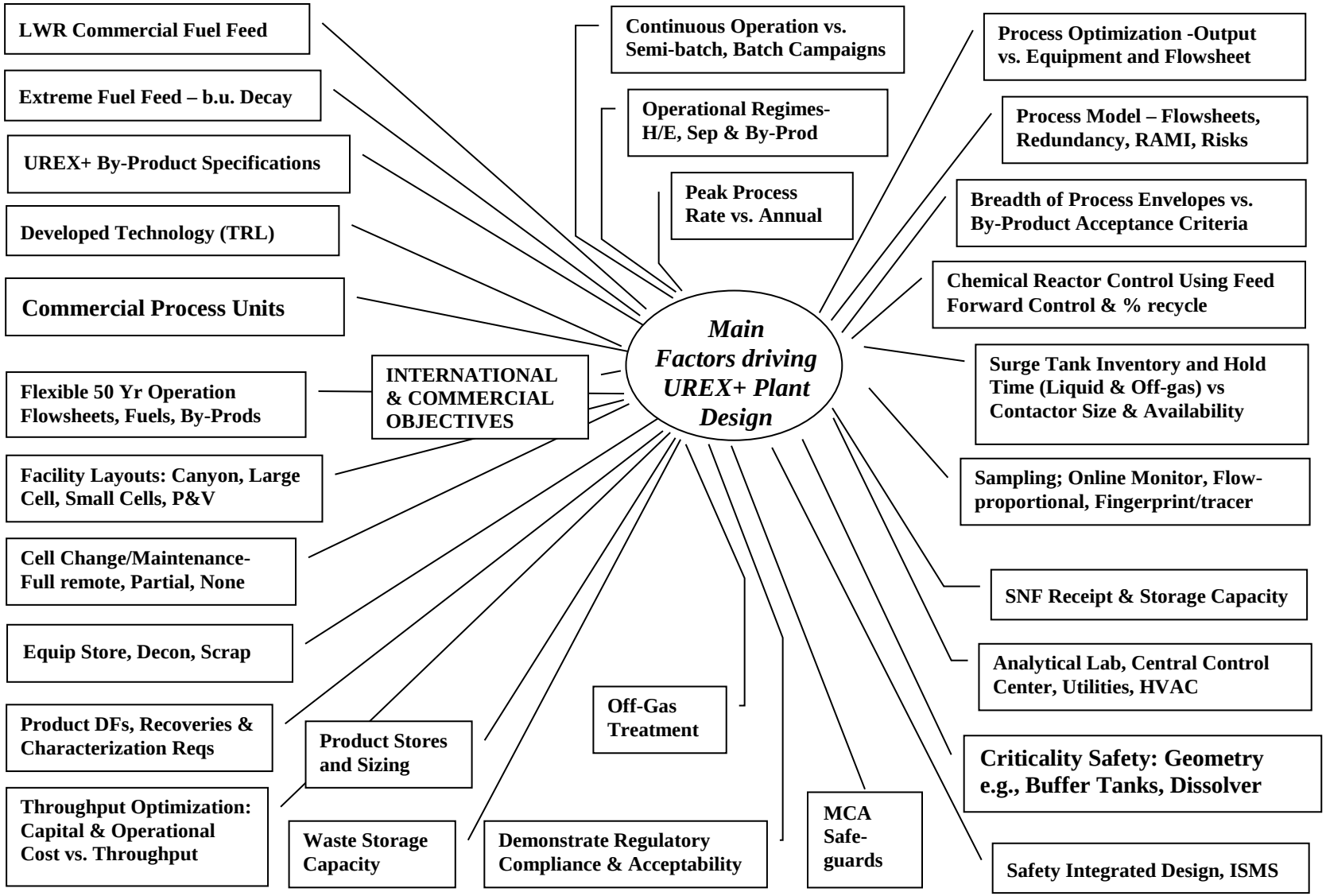

Figure F1-5. Schematic of drivers for UREX+ Plant Concept Design.

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.

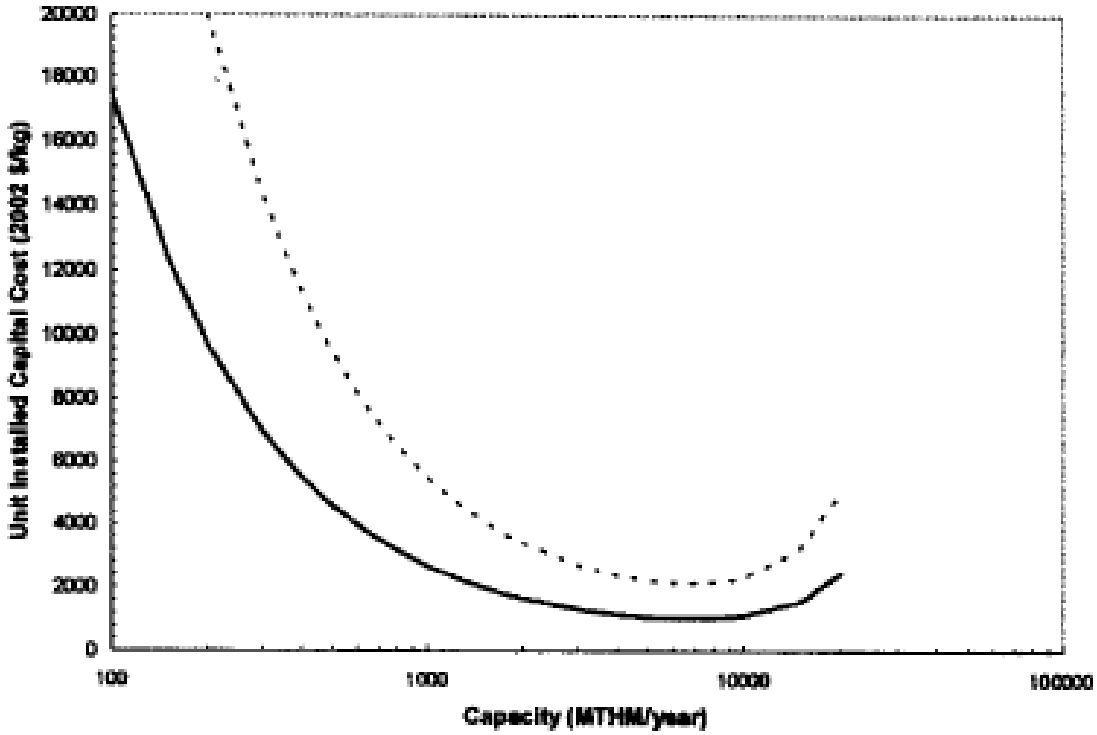

Figure F1-6. Reprocessing unit installed capital cost versus capacity (Haire 2003).

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,n, is typically in the range of about 0.6. However, based on the considerations discussed above, 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).

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 1996). 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 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 1996). 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 from the EAS studies for activities/costs defined in other modules (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.

Table F1-2 provides the LCC estimates for the principle EAS and FOEAS alternatives.

Table F1-1. Capital cost and throughput estimates for various reprocessing plants design studies and actual facilities (prepared in 2005).

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™–AREVA (2006)[22]	8.3 (300)	2,500	COEX™ 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 F1-16.3 for additional notes to this table.								

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

A recent re-examination of the original EAS and FOEAS cost estimates (Washington Savannah River Company 2007, 2008a and 2008b) concluded that there may be scope for a reduction in the originally estimated capital costs, based on a comparison of the non-direct costs with the nuclear industry experience in building LWRs.

A brief summary of those considerations is provided here, after an introduction explaining the main quantitative findings with regards to direct and non-direct costs for PWR.

Direct and non-direct costs from the LWR experience

This section presents a summary of a quantitative analysis of direct and non-direct costs from the LWR historical experience.

Direct construction costs include the cost of bulk commodities, equipment and their installation labor. All other costs are included here in the "*non-direct*" cost category: those include indirect costs (which in

turn typically include the cost of the architect/engineer services, including construction services, engineering, construction management, quality assurance, field supervision, startup, and testing); owner's costs, contingencies and startup costs.

In the actual construction experience, Indirect Costs were found to be the dominant cost component at the two-digit level: 31% of total costs (and approximately 60% of direct costs) in the EEDB Better Experience (EEDB 1988) (i.e. the actual observed construction costs in the 1970s and 1980s of the nuclear plant construction projects that ended without substantial cost overruns) and 42% of total costs (and approximately 120% of direct costs) in the EEDB Median Experience (EEDB 1988) (i.e. the actual observed average construction costs in the 1980s of the nuclear plant construction projects). The indirect costs in the latter case were substantially larger than the entire combined direct costs. This finding is consistent with the framework proposed in (Ganda 2014) to explain the cost overruns observed historically in nuclear construction, based on changes required during the construction phase and associated inefficiencies: the following is a quote from (EEDB 1988)*:"The un-distributable indirect costs account for over half of the total cost change [between 1978 and 1987, in constant dollars] and of this amount about 70 percent is for engineering and field supervision increases. Consequently, the major cost drivers over the first nine EEDB updates appear to be those activities and practices related to meeting accountability type requirements. Accountability encompasses such topics as regulatory reviews, design review, project control, analysis verification, procedure development and implementation, equipment qualification, inspection, testing and similar or related activities."* (EEDB 1988).

Owner's costs were estimated at about 10% of total overnight costs in all the construction estimates analyzed in (Ganda 2014), without significant variations in the percentages. Owner's costs include land, substation, transmission facilities, generator step-up transformer, nuclear insurance, taxes, fees, permits, owner's engineering, supervision and quality assurance, roads, ancillary buildings (e.g. visitor's centers, cafeterias, parking lots etc.), training of operations staff, owner's general and administrative overhead, and licensing with all the local regulatory agencies.

The contingency rate was estimated at ranges of between 8% and 14% in the various construction estimates analyzed in Ganda (2014).

Re-examination of the EAS and FOEAS cost estimates

The 2007 low estimate for the total construction cost of the EAS 3000 MT/y UREX +1 facility was $42 billion in the 2007 EAS. The vast majority of the costs ($35 billion) out of a total of $42 billion for the low estimate (i.e. about 83%) are for the "Process facilities/buildings". Additionally, 90% of the "Process facilities/buildings" costs are from the 7 most expensive process facilities, with the first 3 comprising almost 60% of the total costs. Those are "Fuel", "Extraction" and "U/TRU storage" buildings. The "Fuel" building is the largest and most expensive part of the facility, with an estimated "low" construction cost of approximately $7.8 billion (Washington Savannah River Company 2007). It hosts the following functions:

- Fuel Receipt & Storage, Fuel Shearing;
- Off-gas Removal / Capture;
- Fuel Dissolution;
- Hull Treatment;
- Tc Alloying.

The direct construction cost of the fuel building structures was estimated at approximately $1 billion, while the installed cost (including of installation labor and material) of the building's equipment was estimated at approximately $0.8 billion. Therefore, of the total of between $7.8 and $10.8 billion (the low and high estimates), only about $1.9 billion in both cases are the direct construction costs, while an additional $0.8-0.9 billion are the startup costs (a detailed breakdown of the costs from (Washington Savannah River Company 2007) is provided in Table F1-1).

Moreover, about $1 billion is for design costs that were included in the original $7.8 billion estimate. While it is important to inform on the design costs, a reader would be well served by clearly citing those costs separately from the "construction" costs, if the objective is to inform on the actual cost of constructing a reprocessing facility, as is the purpose of the present module.

The non-direct costs were revised as shown in Table F1-1, as compared to the original estimate derived in the EAS (Washington Savannah River Company 2007) and used in previous versions of the CBR, based on a comparison of the non-direct costs with the nuclear industry experience in building LWR (discussed briefly above).

The "Project Support Services, Project Management and Administrative Costs" are compared to the typical indirect costs for LWR: it was found that the ratio of "indirect/direct" costs is approximately 60% for a well-executed PWR construction project, including a large cost contribution from home-office services, which would not need to be repeated for projects that replicate the design of existing facilities and are well-executed. Excluding this cost, the fraction of indirect/direct costs for LWR would be approximately 40%. However, in the case of the Fuel Building, the fraction of indirect/direct costs is 96% (for the low cost case) to 124% (for the high cost case) in the study by Washington Savannah River Company (2007).

Further, the need for additional "Supplementary Costs" (at $745 million for the "Total Estimated Cost Subfield", i.e. at about 40% of the $1.855 billion of direct construction costs) is not clear. "Supplementary Costs" include "General and Administrative" expenses (about 23% of direct construction costs) and a contractor "fee", of about 17% of the direct construction costs. Administrative expenses were already included in the "Project Support Services, Project Management and Administrative Costs", and that account was found to be larger than typical with LWR: therefore, it is inferred that this cost should not be included. Additionally, the estimates provided here are for a well-executed FOAK project, awarded on a fixed price contract basis, as opposed to the typical cost-plus-fixed fee contract basis that appears to have been assumed in EAS (Washington Savannah River Company 2007). Under fixed price contracting, contractors' fees are not explicitly included in the estimates. In summary, it appears that "Supplementary Costs" should not be included in the total cost estimate.

Also, contingency costs of about 58% of direct construction appear high, when compared to a typical value of about 8-14% of direct construction costs for LWR construction, even when considering that this would be a "first of a kind" plant. Regarding an appropriate contingency rate for the construction of the building, it can be argued that construction of massive concrete buildings has been done multiple times before, and should not present an extraordinary, first-of-a-kind challenge, so perhaps a contingency of 10% on the direct construction costs of the building would be more appropriate. The equipment part would be relatively new, even though complex chemical plants have been constructed before. Therefore, even allowing a 50% contingency on the equipment part of the building, one would reach a total (i.e. building and equipment) contingency cost of approximately 50% of the value utilized in (Washington Savannah River Company 2007) ($100 million for the construction and approximately $400 million for the equipment). This would give a contingency rate of approximately 27% on the total direct costs. It is noted in (Washington Savannah River Company 2007), that contingencies in this estimate are mainly due to uncertainties other than "Process/Equipment Uncertainty".

Regarding startup costs, it was found in a DOE project cost estimating guide (DOE 2016), that "*construction startup costs can range from 0.5 to 10 percent of the installed cost for the conventional construction facility.*" (Chapter 8, DOE 2016). While it can be argued that the Fuel Building is not a "conventional" facility, it can also be argued that the facility is a large chemical plant, and that the "unconventionality" of the facility has already been included in a large allowance for contingency for the equipment installation. For this reason, it appears advisable to follow the guideline on startup costs, perhaps to the upper range, of the "installed" costs including "direct, indirect and contingencies.

In summary, installed costs would be about $3.4 billion, and the startup costs would be $350 million instead of the $815 million estimated in (Washington Savannah River Company 2007). A contingency value for startup costs of 50% would be about $175 million. It is noted that the high percentage value of the contingencies for the startup costs includes conservatism in the estimate.

By applying all of the above considerations, the total construction cost of the Fuel Building for the 3000 MT/y UREX+1A plant would be reduced by about 48% to about $4 billion, of which about half are direct costs (similarly to the historical experience with well executed construction of PWRs), about $1 billion would be for indirect costs, about $500 million would be for construction contingency and about $500 million would be for startup costs and associated contingencies. A design cost of about $1 billion is reported separately and is therefore not included in this construction estimate. It is also noted that the modified estimate of Table F1-1 includes substantial conservatism in the contingencies, to allow for the fact that this unit would be a FOAK. While it would be un-likely that several of these large (i.e. 3000 MT/year) facilities could be constructed in sequence, a NOAK facility should have lower contingency costs, perhaps as much as $400 million less, if the contingency rates that were set at 50% would instead be lowered to 10%. Additionally, a NOAK facility could re-use the design that were developed for the FOAK facility, and thus could avoid design costs. Additionally, a NOAK facility could avoid the home-office engineering services (typically about 25% of indirect costs for a LWR, please see (Ganda 2016)), which would not need to be repeated for projects that replicate the design of existing facilities and are well-executed.

The same logic that was applied to the cost estimate of the fuel building has been applied also to the 2nd most expensive building, the “Extraction Building”, and to the 3rd most expensive building, the “U/TRU Storage Building”. In both cases, the modified estimate is about 55% of the low estimate costs of (Washington Savannah River Company 2007), excluding design costs, which in turn are about 14% of the original Low Estimate, also similar to the values estimated for the Fuel and Extraction buildings.

Since the combined construction costs of the Fuel, Extraction and U/TRU storage buildings comprise almost 60% of the total cost of the project, the analysis performed on these three buildings can be considered representative enough to be extensible to the entire facility using the same fractional costs, using the average cost reduction of three buildings of 52.7%.

Using this fraction, the new updated cost estimate for the “Process facilities/buildings” excluding design costs is $18.4 billion.

Table F1-1 Detailed breakdown by construction cost categories for the "Fuel Building" and modified estimate for the 3000 MTHM/yr fuel building according to the logic described in this Section.

All costs are in (1000s)	Low estimate (Washington Savannah River Company 2007)	Modified estimate
Total Estimated Costs (TEC)		
Engineered Equipment Costs	817,837	817,837
Structures & Improvements Costs	1,037,622	1,037,622
Subtotal Field Directs	**1,855,460**	**1,855,460**
Preliminary & Final Design Costs	1,009,370	0
Preliminary Design Costs	296,874	0
Final Design Costs	712,497	0
Project Support Services, Project Mgmt. & Admn. Costs	1,792,374	1,113,276
Supplementary Costs	745,153	0
Escalation	0	0
General and Administrative	419,148	0
Fee	326,004	0
Contingency Costs	1,080,471	512,681
Subtotal TEC	**6,484,078**	**3,481,417**
Other Project Costs (OPC)		
Start-up Costs	815,011	348,142
Supplementary Costs	260,803	0
Escalation	0	0
General and Administrative	203,753	0
Fee	57,051	0
Contingency Costs	215,163	174,071
Subtotal OPC	**1,291,226**	**522,213**
Subtotal - Fuel Building -Total Project Costs (TPC)	**7,775,304** Design costs of $1bn are included in this number	**4,003,629** Design costs of $1bn are not included in this number

The total cost of design (including both preliminary and final design) was estimated in (Washington Savannah River Company 2007) at 13% of the original Low Cost Estimate of $35 billion, resulting in an additional $4.7 billion in design costs.

No basis was found yet to revise the costs of the Balance of Plant and of the site improvements, at $3.2 b and $4.1 b respectively: therefore, the costs estimated for those parts in (Washington Savannah River Company 2007) remain applicable also in this analysis.

In summary, the updated total project cost is approximately $25.7 billion excluding design, and $30.4 billion including preliminary and final design, instead of a range of $42 billion to $61 billion reported in (Washington Savannah River Company 2007).

Since the estimated construction cost of Table F1-2 is based on the EAS estimate, including the non-direct costs that are being revised here, the same reduction to 52.7% of the construction costs of Table F1-2 is applied here.

For the “low” and “high” costs of $14453 and of $21202 million for the benchmark 800 MT/y UREX +1A facility, the reduction would then lead to $7616 and $11173 million. The “LLC O&M and D&D” costs have not been changed in this CBR revision, and it will be revised in future revision if necessary.

Therefore, the resulting summary cost for a facility lifetime of 40 years and zero discount rate, would be reduced from a range of 903-1339 $/kgHM to 689-1026 $/kgHM.

Additionally, the following is noted:

- The O&M costs of the EAS and FOEAS designs have not been revisited yet, since insufficient information was found in the original sources of the EAS and FOEAS (Washington Savannah River Company 2007, 2008a and 2008b) to re-evaluate this information.
- The direct construction costs have not been revisited yet since the works of Washington Savannah River Company (2007, 2008a and 2008b). It is possible that a cost reduction could be obtained also in this area.

F1-6.3 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 after 2012, when all reactor-lifetime fuel arising has been reprocessed. Decommissioning of this plant is envisioned around 2020. The plant is described in the Nuclear Power Technology article (Marshall 1983).
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. A conceptual design and capital cost estimate (INEEL 1969) for a High-Temperature Gas-Cooled Reactor (HTGR) Reference Fuel Reprocessing Plantwas prepared for Idaho Nuclear Corporation by Bechtel (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. The Midwest Fuel Recovery Plant (MFRP) hybrid aqueous/electrochemical nuclear fuel reprocessing plant was 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. The 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 it has since been decommissioned. A technical description is given in Nuclear Chemical Engineering (Benedict 1981), 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).One of the proposed sites was in Eastern Tennessee south of Oak Ridge.
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 (DuPont 1979). 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 NAS (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” (ENG 2009)] 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 (BCG 2006) 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 Boston Consulting Group [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 and TRU secondary waste treatment costs have been reported in Modules G4 and G-5; LLW treatment and packaging costs have been reported in Module G-3.

F1-7. DATA LIMITATIONS

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 (OECD-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

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.

Based on the agreement of the FOEAS estimates with industry and the most recently deployed commercial reprocessing facilities, the FOEAS is used as the basis for selected values for reprocessing.

Section F1-6.2 include new analyses that suggest that the cost for this module should be lower than what is presented here, (which is based primarily on the un-adjusted EAS cost analysis). However, we feel that additional evaluations of all the available data are needed before implementing those changes in the WIT table and accompanying distributions, which therefore remains un-changed (except for 14% escalation) from the previous version (2009) of the cost basis report where the EAS comprehensive cost estimates were presented..

Table F1-3. Cost summary table. (Note that 2012 WIT values were same as 2009 WIT values)

What-It-Takes (WIT) Table: 2009 AFC-CBD values and escalation to year 2017$				
Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
Co-Ex 800 MT/yr (2009$)	$755/kg HM	$925/kg HM		$1,096/kg HM
Esc to 2017$>>	**$861/kgHM**	**$1055/kgHM**	**$1055/kgHM**	**$1250/kgHM**
UREX+1a 800 MT/yr (2009$)	$903/kg HM	$1,120/kg HM		$1,339/kg HM
Esc to 2017$>>	**$1030/kgHM**	**$1277/kgHM**	**$1277/kgHM**	**$1526/khHM**
UREX +3a 800 MT/yr (2009$)	$1040/kg HM	$1,300/kg HM		$1,558/kg HM
Esc to 2017$>>	**$1156/kgHM**	**$1482/kgHM**	**$1482/kgHM**	**$1776/kgHM**
	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.

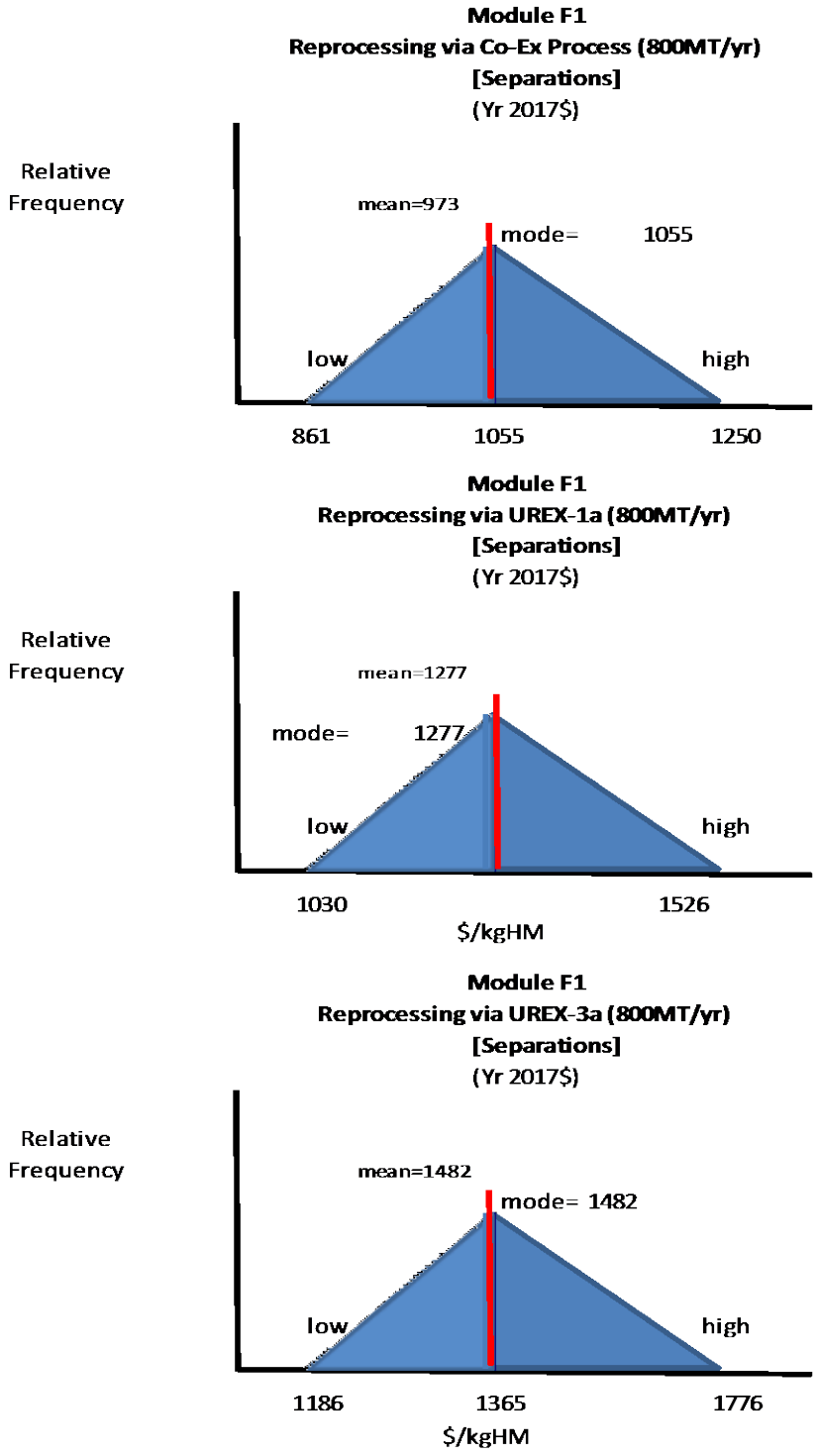

Figure F1-7. Aqueous **separations** estimated cost frequency distributions for three processes.

The extensive analyses, in Appendix J of the 1996 NAS report (NAS 1996), 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 1996 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 (NAS 1996) with more complex processing adding additional cost. Figure F1-8 shows the probability distributions for these total reprocessing costs

Table F1-4. Total reprocessing, waste conditioning, and storage unit costs.

What-It-Takes (WIT) Table: 2009 AFC-CBD values + Escalation to Year 2017$				
Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
Co-Ex 800 MT/yr	$1,108/kg HM	$1,370/kg HM		$1,619/kg HM
Esc to 2017$>>	**$1263/kgHM**	**$1562/kgHM**	**$1557/kgHM**	**$1846/kgHM**
UREX+1a 800 MT/yr	$1,494/kg HM	$1,850/kg HM		$2,214/kg HM
Esc to 2017$>>	**$1703/kgHM1**	**$2109/kgHM**	**$21125/kgHM**	**$2523/kgHM**
UREX +3a 800 MT/yr	$1,670/kg HM	$2,080/kg HM		$2,488/kg HM
Esc to 2017$>>	**$1904/kgHM**	**$2371/kgHM**	**$2371/kgHM**	**$2836/kgHM**

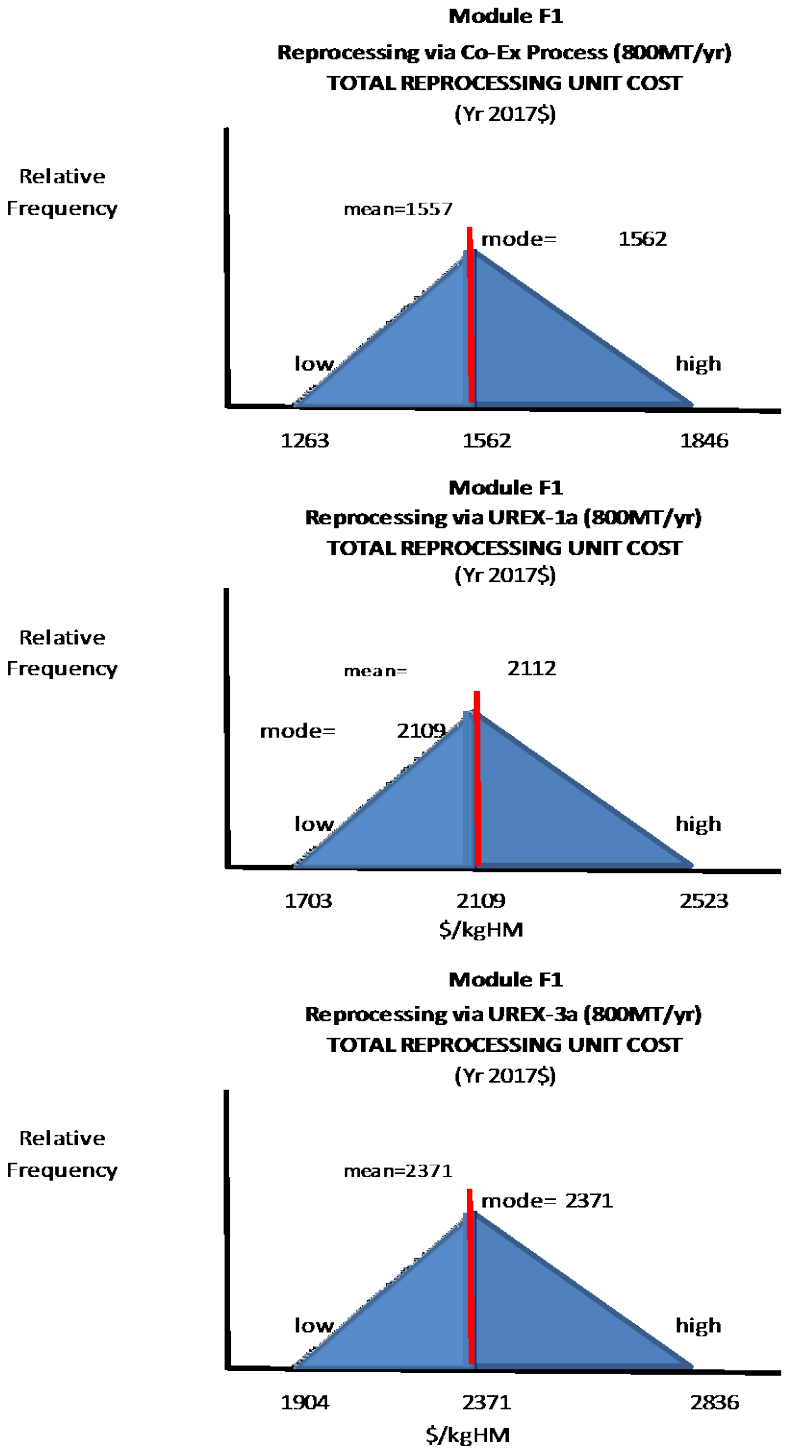

Figure F1-8. **Total reprocessing** estimated cost frequency distributions for three processes.

In May of 2007 Areva and Societa Gestione Impianti Nuclear Spa (Sogin) signed a contract for reprocessing 235MT of used fuel from shutdown Italian nuclear power plants (World Nuclear News, 2007). The contract value was reported as $340million or $1445/kg of heavy metal. The contract includes transportation, reprocessing, and packaging of used nuclear fuel. The vitrified waste will be returned to

Italy. The contract price is within the established range of the Co-Ex reprocessing cost in Table F1-4 and only slightly higher than the nominal cost recommended. This difference is likely the cost of transportation which is not included in the combined cost in Table F1-4. The report confirms Table F1-4 as reasonable estimates for aqueous reprocessing.

F1-8.1 SPECIAL NOTE ON THE REPROCESSING OF THORIUM-CONTAINING FUELS

It was not possible to identify recent documents or references containing cost data for the aqueous reprocessing of thorium-containing fuels, nor detailed cost studies. However, based on discussion with the National Technical Director of the Fuel Cycle Technology's Separation Campaign, it was possible to obtain the following information. As compared to the aqueous reprocessing of uranium-based fuels, thorium-based fuel is harder to dissolve, requiring the use of the hydrofluoric acid, and resulting in larger waste quantities. Both of these would increase the costs. Also, because of the use of the hydrofluoric acid, the dissolver (and possibly other components) would need to be fabricated from more expensive alloys, such as hastelloy. Further increasing the process equipment cost, components would have to be larger for the same heavy metal throughput, because of the slower dissolution rate. It is therefore clear that the cost of reprocessing thorium fuels is expected to be higher than the cost of reprocessing uranium fuel; however, quantifying the incremental cost with any degree of precision is not possible without a detailed study. **The expert opinion is that a cost increment of 5% to 10% would be a reasonable estimate.**

What it takes.

It is therefore suggested the range for the cost of aqueous reprocessing of thorium based fuels, where the low values are increased by 5% as compared to the values of Table F1-3, the high values are increased by 10% and the nominal values are also increased by 10%. The results are shown below in Table F1-5. Figure F1-9 shows the aqueous reprocessing separations cost distributions for the three processes above treating thorium-based fuels.

Table F1-5. Reprocessing (aqueous separations) unit cost for Thorium-containing oxide fuels (2009 AFC-CBD values plus escalation to year 2017$).

Process and Plant Capacity	Low ($/kgHM)	Mode ($/kgHM)	Mean ($/kgHM)	High ($/kgHM)
Co-Ex 800 MT/y	793	1018		1206
Escalated 2017$ >>	**904**	**1161**	**1147**	**1375**
UREX+1a 800 MT/y	948	1232		1473
Escalated 2017$ >>	**1080**	**1405**	**1388**	**1680**
UREX +3a 800 MT/y	1092	1430		1714
Escalated 2017$ >>	**1245**	**1630**	**1610**	**1954**

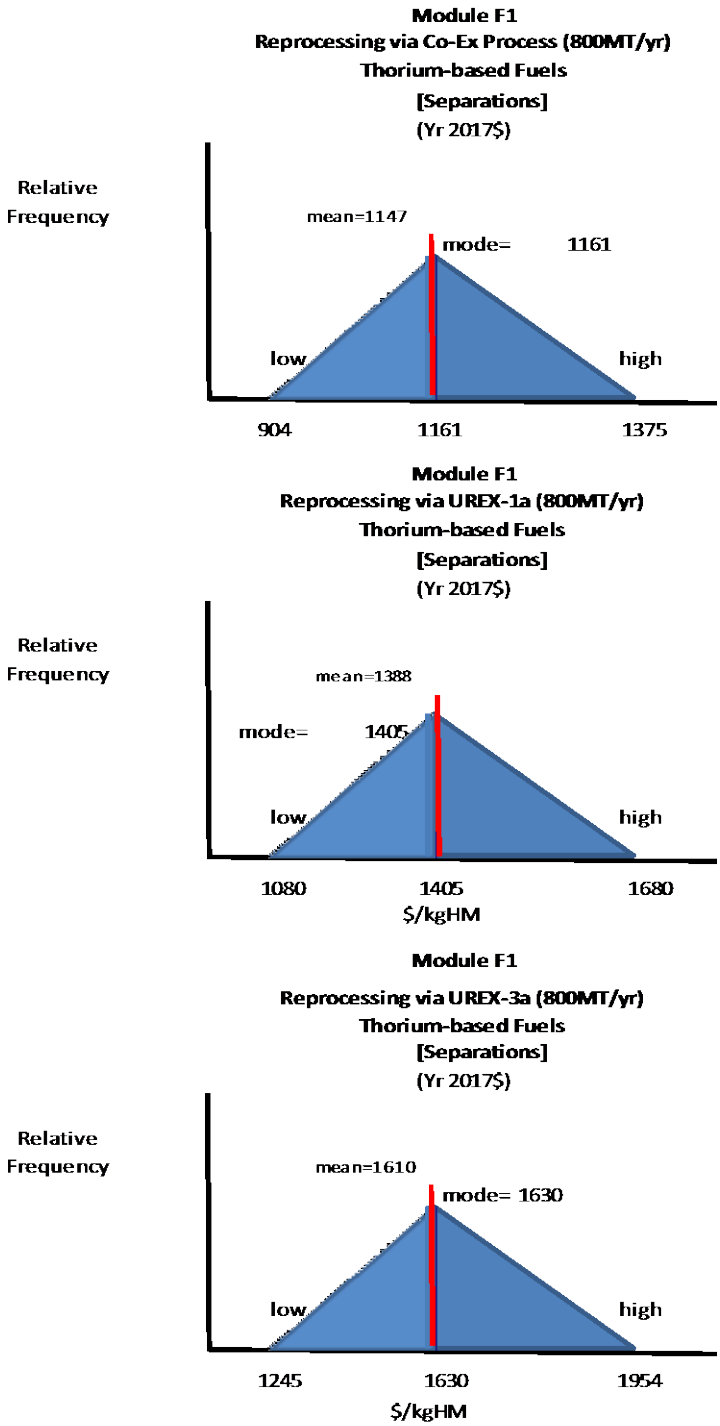

Fig F1-9. Aqueous **separations** estimated cost frequency distributions for three processes.

The costs including all products and waste processing to a final form or buffer storage are shown in Table F1-6, where the costs are also increased by 5% (low value) and 10% (high and nominal values), based on the fact that Th-fuel reprocessing likely will produce a larger amount of wastes.

Table F1-6. Total reprocessing: separations, waste conditioning and storage unit costs of aqueously processed thorium-containing fuels (2012 AFC-CBD values plus escalation from year 2009$ to year 2017$).

	Low ($/kgHM)	Mode ($/kgHM)	Mean ($/kgHM)	High ($/kgHM)
Co-Ex 800 MT/y (2009$)	1163	1507		1781
Escalated 2017$ >>	**1326**	**1718**	**1691**	**2030**
UREX+1a 800 MT/y	1569	2035		2435
Escalated 2017$ >>	**1789**	**2320**	**2295**	**2776**
UREX +3a 800 MT/y	1754	2288		2737
Escalated 2017$ >>	**2000**	**2608**	**2583**	**3142**

Figure F1-10 shows the total reprocessing related cost distributions for the three processes above treating thorium-based fuels, including waste conditioning and storage.

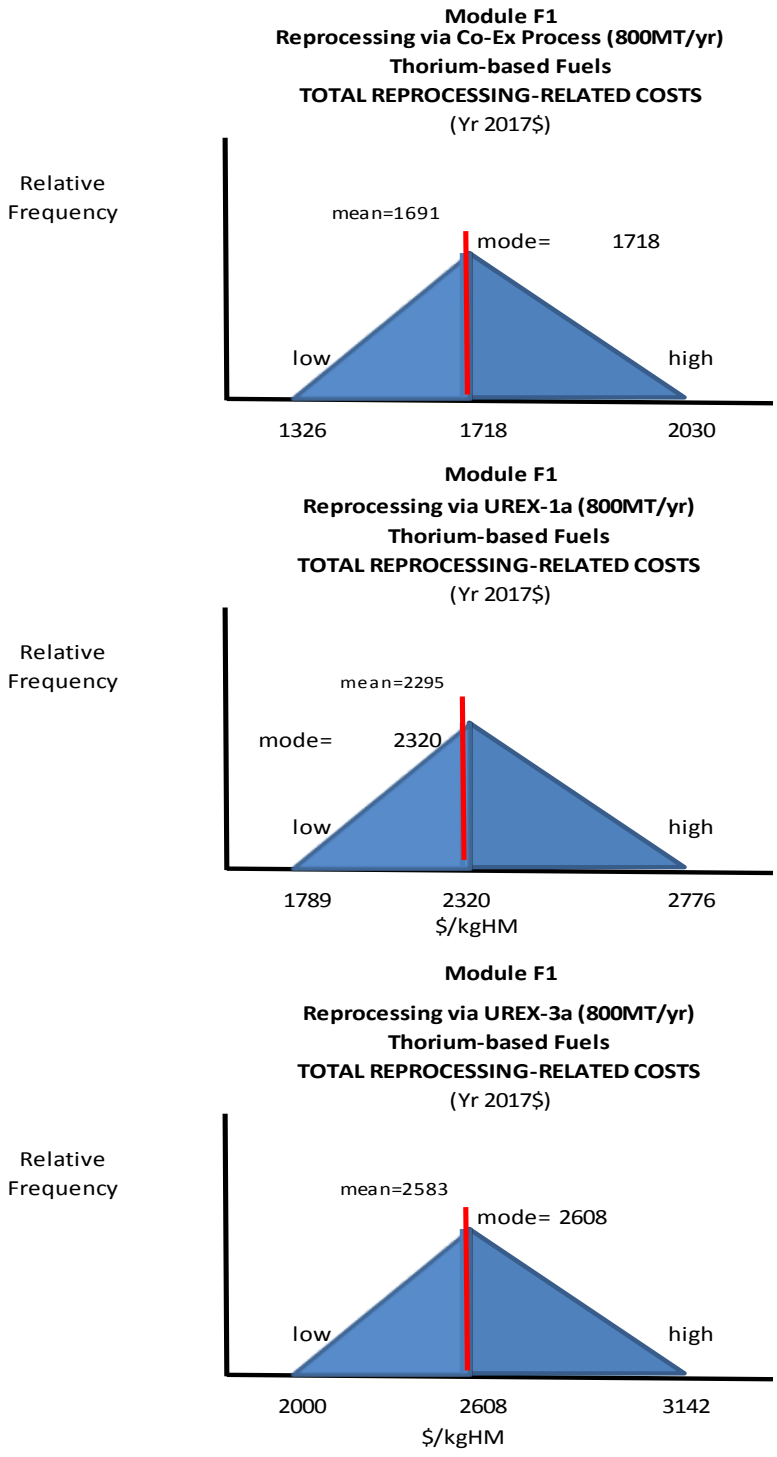

Figure F1-10 Total reprocessing estimated cost frequency distributions for three thorium-related processes.

It should be noted that there are also more difficult environmental, health, and safety considerations for Th-containing fuels than for UOX fuels. The U-232 daughters which build in along with U-233 during irradiation produce very potent gamma radiation. One such daughter is Tl-208 which produces a 2.6 MeV gamma ray upon decay.

It should be noted that on-line reprocessing has been suggested for Th-232/U-233 fuel cycles utilizing liquid-fueled molten salt reactors (MSRs). Such a reprocessing scheme has been discussed in Module R7.

F1-9. 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.

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Combined Module F2/D2-1

Electrochemical Reprocessing and Remote Fuel Fabrication

Module F2/D2-1

Electrochemical Reprocessing and Remote Fuel Fabrication

F2/D2-1-MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update**: FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs**: Significant revisions based on new analysis and new data.
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated**: Preconceptual design report based on bottom-up estimating (Landmark Study 2015).

F2/D2-1-RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module R2. In later AFC-CBRs the Module was renamed D2/R2 to recognize the fact that separated reprocessing (R2) and fuel refabrication (D2) information was not available.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2017.
- **New technical/cost data which has recently become available and will benefit next revision**: Research on pyrochemical/electrochemical methods of fuel reprocessing and refabrication continues in the US, Russia, and South Korea. New reports and technical papers may become available.

F2/D2-1-1. BASIC INFORMATION

This module discusses electrochemical reprocessing of spent nuclear fuel, and remote fuel fabrication with recycled material.

Since remote fuel fabrication is an integral part of the overall recycle system, it is generally envisioned to be housed in the same facility as the reprocessing step. Therefore, the associated remote fuel refabrication step is also included in this module. The technical reasons for such integration are considered in the module. Additionally, while the need for remote fabrication can arise also after aqueous reprocessing, no cost studies were found for remote fabrication only, while few cost studies have been performed on (a) electrochemical reprocessing and (b) on electrochemical reprocessing with integrated remote fabrication. Unfortunately, it was not possible at this point to deduce, by comparison of those costs, the cost of remote fabrication alone, for reasons that will be explained in the module. Therefore, the following approach will be proposed: a best estimate of costs, based on existing studies, will be derived for integral electrochemical reprocessing/remote refabrication (IRRF), and the simple difference between the cost of IRRF and that of UREX+1a, discussed in module F1, will be suggested as the cost of remote fabrication. This approach is obviously imprecise, and likely to understate the cost of remote fabrication only, since synergies between reprocessing and refabrication will be present that lower the cost of the combined step, as compared to each of the two processes alone. The main reason is that in the integrated plants, process operations generally occur in one or two remotely-operated hot cells, making it impossible to delineate processing operations and cost from those of fabrication. These estimates should be updated in the future, if detailed studies on the cost of remote fabrication alone will be produced.

F2/D2-1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

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).[1] 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). Future research and design efforts at the Materials and Fuels Complex (MFC) will eventually result in a pre-conceptual design and preliminary costing for a molten salt electrochemical processing facility to treat current commercial spent nuclear fuel. 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 electro-refining. Metal fuel, such as that which is processed at MFC, is chopped into small segments before immersion in LiCl-KCl salt within an electro-refiner vessel. In order to be compatible with electro-refining, spent oxide fuel would first undergo chemical or direct electrolytic reduction to the metallic form.

Uranium, fission products, transuranics (TRU), 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

1. 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).

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).

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) and to require remote fabrication, due to the high radiotoxicity and radioactivity of the fuel, that prevents glove-box handling rather than from front-end fuel cycle steps such as mining, conversion, and enrichment (Modules A, B, and C).

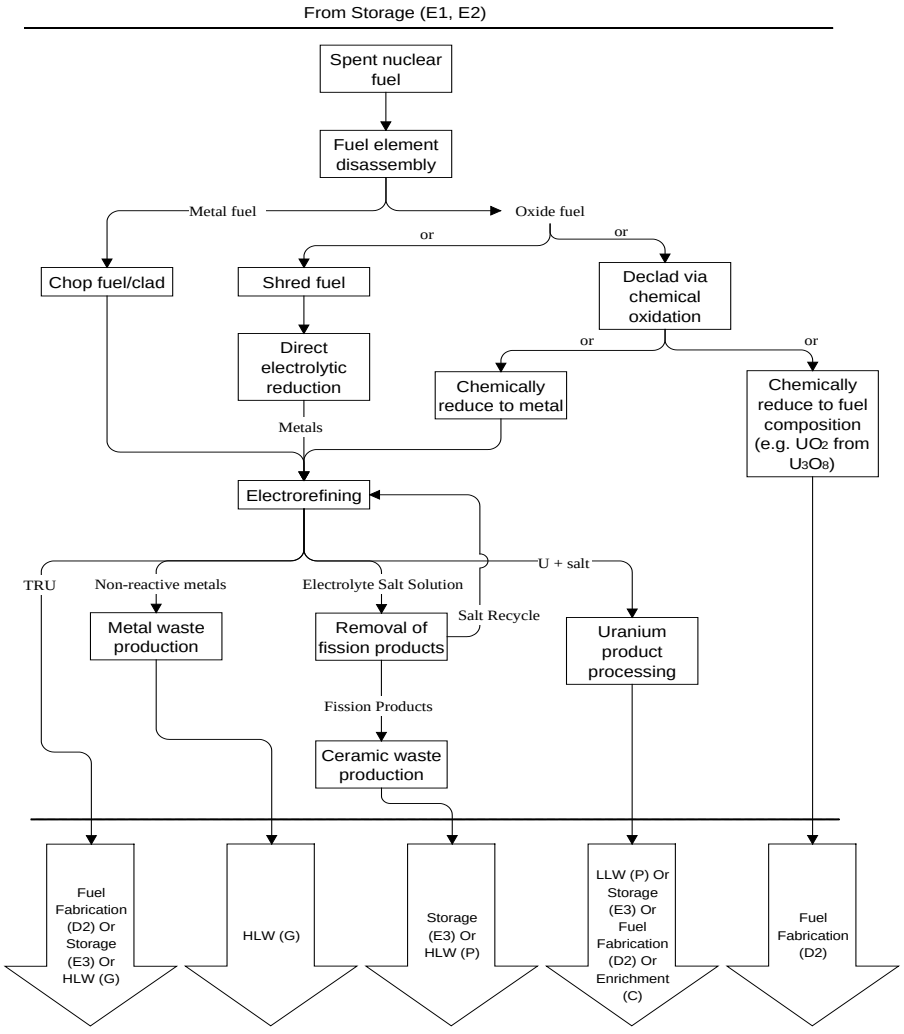

Figure F2/D2-1. Example of electrochemical processing flow sheet for spent nuclear fuel. (Note: HLW metal waste might be diluted with DU to form Class C low-level waste or might be re-refined.)

In general, the fuel refabrication step is generally envisioned as very 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 handled in glove boxes. 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 is generally highly automated while, at the same time, being 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.

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. 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. 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/D2-1-3. PICTURES AND DIAGRAMS

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).

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 pre-conceptual design effort at the INL. Results from this study (Frigo et al. 2003) provide some preliminary cost estimates.

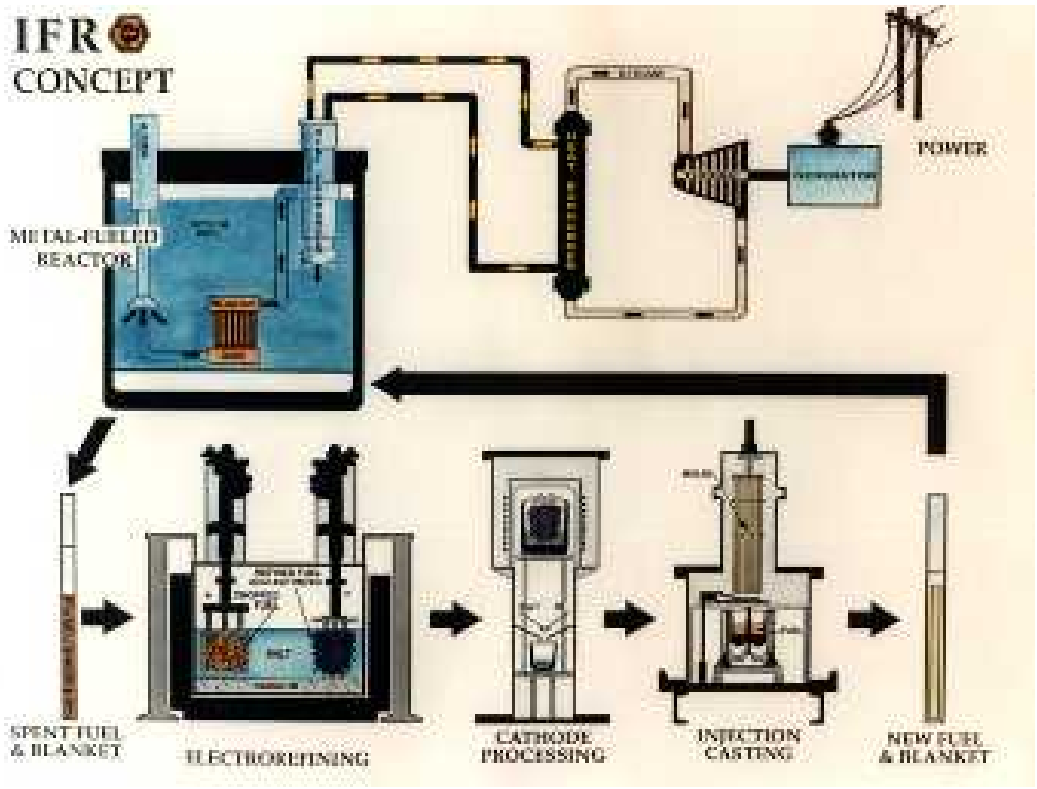

Figure F2/D2-2. ANL Integral Fast Reactor concept showing last three refabrication steps.

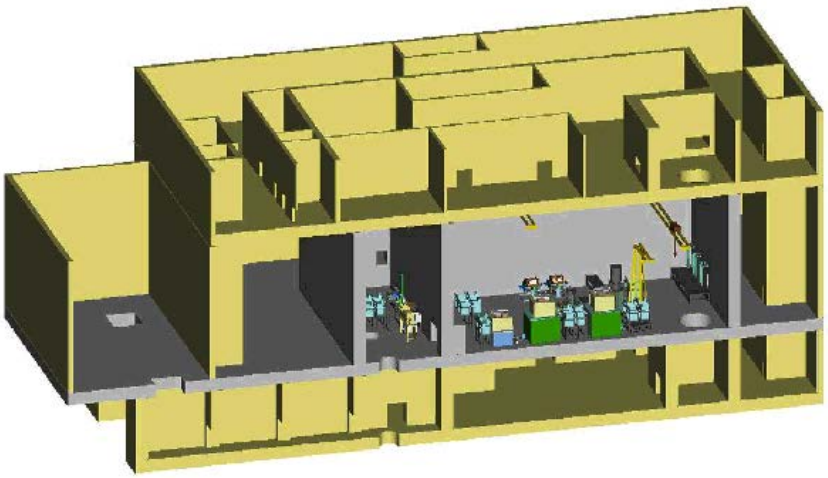

Figure F2/D2-3. Three-dimensional conceptual rendering of the Advanced Pyroprocess Recycle Facility (Frigo et al. 2003).

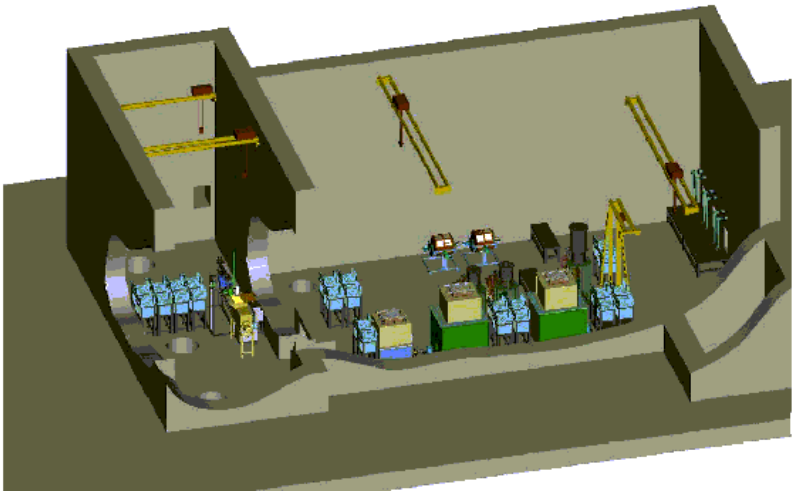

Figure F2/D2-4. Three-dimensional conceptual rendering of the air and process cells (Frigo et al. 2003).

F2/D2-1-4. MODULE INTERFACES

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 small, 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/D2-1-5. 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 from 1985-1993

Additional 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 was assumed, and reactor plant services were 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, a 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).

Table F2/D2-1 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.

A later generation ALMR system, the S-PRISM, incorporated a hybrid recycle scheme with facilities that processed oxide and metal fuel in parallel. 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. These two plants are similar in design and function but significantly differ in heavy metal throughput rates. Cost references for these designs could not be found in the public domain.

Separately, 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. 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). However, such high costs appear to

be driven primarily by the small mass of fuel to be processed, leading to a very small throughput or to a very short facility lifetime; in either cases a sub-optimal utilization of the facility.

Table F2/D2-1. Unit cost data on two ALMR-Integral Fast Reactor recycle plant concepts: central and collocated. The input parameters in blue are [from (Delene et al. 1993; Taylor et al. 1991; ORNL 1992) and from (Jones 1981) or (Lineberry et al. 1985)] while in black are derived value.

Throughput	200	20	MT/y	
Throughput	200000	20000	kg/y	
Overnight capital cost	5.18E+08	1.05E+08	$ of 1991	
Time for construction	3	3	years	
Interest during construction	2.36E+07	4.79E+06	$ of 1991	
Total capital cost	5.42E+08	1.10E+08	$ of 1991	
Facility lifetime	50	50	years	
Discount rate	3.0%	3.0%		
Lev. factor	0.038617	0.038617		
Annual capital charges	2.09E+07	4.24E+06	$ of 1991	
Capital unit cost	**105**	**212**	**$/kgHM**	
Annual O&M cost	1.76E+08	2.78E+07	$ of 1991	
O&M unit cost	**879**	**1390**	**$/kgHM**	
TOT unit cost (in 1991 $)	**984**	**1602**	**$/kgHM**	
Inflation/escalation from 1991 to 2017 (CPI)	1.82	1.82		
TOT unit cost (in 2017 $)	**1790**	**2916**	**$/kgHM**	

Cost studies from other countries

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.

More recent cost studies

Three detailed cost studies, all based on ANL technology, were performed in recent years for pyroprocessing and/or remote fabrication facilities. In chronological order:

1. (WSRC 2008). This study is for a 300 MT/y pyroprocessing facility without refabrication, but including oxide reduction in order to be able to reprocess LWR spent fuel.
2. (Carter 2010). This cost study is for a 21.7 MT/y facility that includes both reprocessing and refabrication.
3. (Landmark 2015). This cost study is for a 100 MT/y pyroprocessing facility with oxide reduction before reprocessing, but no refabrication of the reprocessed fuel.

In the following, each study is analyzed in detail. Each of the study provide the construction costs, (in the form of overnight cost) and occasionally the operation and maintenance costs. In order to generate a unit cost in $/kgHM however, assumptions must be made on the discount rates and on the facilities expected lifetimes. A common set of assumptions applied here are:

- Facility lifetimes of 50 years: These types of facilities are designed with a high degree of redundancy and reliability, and they could therefore be operated for a long time. However, since no commercial pyroprocessing facility has been constructed thus far, it has not been determined yet how long could the expected lifetime be. Other nuclear facilities, such as reactors, have received licenses for life extension of up to 60 years, and other types of chemical plants, such as

refineries, have been in operations for more than a century. Fifty years was chosen here as representative of a "long lifetime", until more accurate data becomes available.

- Discount rate of 3%: It was chosen here as representative of a discount rate that would be appropriate for a government project. According to Section 8 of Office of Management and Budget (OMB) Circular A94, which specifies which discount rates should be used for government projects, the treasury borrowing rates (currently about 3%) should be used for discounting if performing "cost-effectiveness analyses". "Cost effectiveness analysis", defined in Section 5, bullet b, of OMB Circular A94, could include various types of reprocessing facilities, under the assumption that the objective is to compare alternative ways to achieve the same benefits to society (such as for example a lower waste heat and volume after reprocessing), and it is impractical to consider the dollar value of those benefits.

The (WSRC 2008) cost study

This study on pyroprocessing cost was performed as part of a "follow-on" study of a UREX+1a cost study performed the year before (WSRC 2007). The (WSRC 2008) study includes two "benchmark cases", (1) an 800 MT/year plant using the UREX+1b solvent extraction process; and (2) a 300 MT/year plant based on electrochemical separations technology. In addition, a series of deployment alternatives to the benchmarks listed above are studied in (WSRC 2008). Because of the large number of alternative scenarios studied in (WSRC 2008), including the pyroprocessing alternative, few bottom-up cost estimates were performed in that work. Instead, *"the cost estimate details from the original EAS (June 2007) were used as a starting point and adjustment factors were then applied to account for changes in facility footprint sizes and process modifications."* (WSRC 2008). However, the electrochemical process is an exception, for which some bottom-ups estimates were performed, due to the difference in technology and equipment to aqueous separation. In particular, an "engineering analysis" was performed for pyroprocessing to adjust the estimates based only on $/ft^2$, although the details of the engineering analysis are not provided in (WSRC 2008).

In summary, the pyroprocessing costs developed in (WSRC 2008) appear to be largely based on the previous detailed costs estimates developed in 2007 for an aqueous 3000 MT/y UREX+1a facility (WSRC 2007), the cost of which is discussed extensively in Section F1. A recent re-examination of the original EAS and FOEAS cost estimates (WSRC 2007, 2008), also discussed in Section F1, with more details in (Ganda 2016), concluded that there may be scope for a large reduction in the originally estimated capital costs, based on a comparison of the non-direct costs with the nuclear industry experience in building LWRs, to 52.7% of the capital cost estimates in (WSRC 2007). The same fractional cost reduction is consequently applied to the estimates reported here from (WSRC 2008).

The (WSRC 2008) total construction cost for a 300 MT/y pyroprocessing facility without refabrication, of between $11.4B and $16.5B (low and high estimates in 2008-year dollars), was adjusted as discussed above to between $6.0B and $8.7B. For a facility lifetime of 50 years and a 3% discount rate, the unit capital cost would therefore be between 770 $/kgHM and 1120 $/kgHM. O&M was reported in (WSRC 2008) as between $270M and $410M annually, resulting therefore in a unit O&M cost of 900 $/kgHM to 1370 $/kgHM. It is noted that these reported annual O&M costs would be therefore between 4.5% and 6.8% of the adjusted capital costs, but a much lower amount (2.4% to 3.6%) of the un-adjusted capital costs, even of the low estimate for capital costs. The un-adjusted range appears low, as compared to a typical range of 4% to 7% annual O&M costs as a fraction of the original construction cost, as reported in (Bunn 2016), based on historical evidence and a number of specific estimates for aqueous reprocessing facilities. It is noted that the adjusted values, instead, fall within the values reported in (Bunn 2016). This gives additional support to the adjustment performed on the capital costs. While (Bunn 2016) does not provide ranges or O&M cost estimates for pyroprocessing facilities, the range applicable to aqueous facilities is used here as the closest approximation available, considering the similar functionality between the two types of facilities.

The total adjusted pyroprocessing cost of this study are therefore between 1670 $/kgHM (assuming the low of capital and the low of O&M costs) and 2480 $/kgHM (assuming the high capital and the high O&M costs), approximated as 1700-2500 $/kgHM.

The (Carter 2010) cost study

The (Carter 2010) study is for an integrated facility performing both electrochemical separation and remote fabrication of the separated material. As for the (WSRC 2008), the cost estimates for this facility is largely based on the previous detailed costs estimates developed in 2007 for an aqueous 3000 MT/y UREX+1a facility (WSRC 2007), the cost of which is discussed extensively in Section F1. Therefore, the same fractional cost reduction applied to the original EAS and FOEAS cost estimates (WSRC 2007, 2008) (and discussed in the F1 section) and to the (WSRC 2008), in the previous subsection, is applied also to the construction costs estimates reported in (Carter 2010).

The un-adjusted total construction cost was found to be between $2.6B and $3.8B (low and high estimates) for a 21.7 MT/year facility. After the capital cost adjustment discussed above, the expected construction cost was reduced to between $1.4B and $2.0B. Additionally, it was noted in (Carter 2010) that, because of the sub-optimal use of space and equipment, the throughput could be increased to 70 MT/y with little or no additional capital spending *"The capacity can be increased to 70 MT/year within the indicated TPC [Total Project Cost] range."* (Carter 2010, page 18). Therefore, 70 MT/year is used here as the reference throughput.

Consequently, for a facility lifetime of 50 years and a 3% discount rate, the unit capital cost would be between 750 $/kgHM and 1100 $/kgHM. These values are very close to those obtained in (WSRC 2008), at 770 $/kgHM and 1120 $/kgHM, for the larger facility of 300 MT/year, without refabrication but with oxide to metal conversion at the front end of the process. The larger facility without refabrication would instead be expected to have a lower construction unit cost because of (1) larger size, with possible economies of scale; and (2) added remote refabrication step. However, a few considerations are provided here in light of this result.

- While the two estimates have been made by the same research groups, the one in 2010 (Carter 2010) has been performed later than the (WSRC 2008). Additionally, the (Carter 2010) was a dedicated cost study, while the (WSRC 2008) was part of a broader set of sensitivity studies and was characterized as *"an initial effort"* (WSRC 2008) to perform a cost estimate for a pyroprocessing facility. Because of this, more conservatism may have been inserted into the earlier estimate, resulting in an effectively larger unit cost. Based on this logic, more weight should be put on the (Carter 2010) estimate than on the FOEAS estimate (WSRC 2008).
- It is also possible that the remote fabrication part of the process may not add substantially to the capital costs, since it would be largely sharing the same expensive, highly shielded and remotely operated processing space as the separation part. This would justify a similar unit cost of the (Carter 2010) and (WSRC 2008) estimates.
- Conversely, it is also possible that the oxide-to-metal reduction step would add similar capital costs as the refabrication part, again justifying a similar unit cost of the (Carter 2010) and (WSRC 2008) estimates.
- Regarding the expected smaller cost due to the larger size of (FOEAS 2008) facility, it is possible that, as discussed above, no substantial economies of scale exist for pyroprocessing facilities (likely due to the batch nature of pyroprocessing, coupled with criticality safety considerations).

O&M costs were not reported in Carter 2010. However, it is possible to estimate approximate values based on the previously described range of 4% to 7% of initial capital costs, from (Bunn 2016). In that case, the annual O&M expenses would be between about $54M (assuming 4% of the low range of capital cost) and $140M (assuming 7% of the high range of capital cost), resulting in unit O&M costs of between 770 $/kgHM and 2000 $/kgHM.

The total adjusted combined pyroprocessing and refabrication costs of (Carter 2010) can therefore be estimated at between 1525 $/kgHM (with the low range of capital investment and the low fraction of O&M costs of 4%) and 3083 $/kgHM (with the high range of capital investment and the high fraction of O&M costs of 7%), approximated as 1500-3100 $/kgHM. The larger uncertainty range for the (Carter 2010) unit cost reflect the larger uncertainty associated with the fact that O&M costs had not been estimated in the study, and therefore had to be derived from other, only partially related, sources.

The (Landmark 2015) cost study

This is a very recent and detailed bottom-up cost study. Merrick & Company, an architect-engineering firm with experience in heavy industrial construction, was subcontracted to provide construction cost and schedule estimates, based on ANL technology, for the 100 MT/y pyroprocessing facility without refabrication, but with oxide reduction to metal before the processing. The work at both ANL (to provide the facilities design) and at Merrick & Company (to perform the economic evaluation) was sponsored by the Landmark Foundation.

The estimated total construction cost was found to be between $370M and $450M with and without contingencies, respectively. Design costs were excluded from those estimates. However, it was noted in (Landmark 2015) that *indirect costs* (called "general condition and construction management" costs in (Landmark 2015)) were added as 10% of direct costs. This amount appears inconsistent with the experience of the nuclear industry for the construction of large facilities such as commercial reactors: therefore, the authors of this module revised the indirect costs upwards to make them consistent with the "Better Experience" in PWR construction (EEDB 1988), from 10% to 60% of direct costs.

Direct costs, on the other hand, were based on detailed calculations of each building and associated equipment, so the authors of this module had no reason to alter them. Also, owner's costs appear to be excluded from those estimates, so owner's costs were added as 10% of total costs (i.e. both direct and indirect costs) excluding contingencies.

The average contingency is 15% of the combined direct and indirect costs, with different values based on the uncertainty in the estimated cost: 15% for "standard buildings with equivalent industrial examples", 20% for "site security systems" and 25% for "processing facilities", for which there is less construction experience.

After the capital cost adjustment was made, the construction cost including direct costs, indirect costs as 60% of direct costs, owner's costs and contingencies, was calculated at $720M. For a facility lifetime of 50 years and a 3% discount rate, the unit capital cost would therefore be 378 $/kgHM. O&M was reported in (Landmark 2015) as $51M annually, resulting therefore in a unit O&M cost of 510 $/kgHM. It is noted that these reported annual O&M costs would be 7.1% of the adjusted capital costs, but a much larger amount (11.3%) of the un-adjusted capital costs. The un-adjusted range appears high, as compared to the typical historical ranges for O&M costs as reported in (Bunn 2016), as discussed above. Also, it is noted that the adjusted values, instead, fall within the typical values as reported in (Bunn 2016), of 4% to 7%. This gives additional support to the adjustments performed here on the capital costs.

The total adjusted unit pyroprocessing cost are therefore 788 $/kgHM, approximated as 800 $/kgHM, without an uncertainty range available from the (Landmark 2015) report. This value is substantially lower than the unit cost of the functionally-similar but larger facility analyzed in (FOEAS 2008), and of the facility that includes remote fabrication studied in (Carter 2010). The following considerations are proposed here regarding those cost discrepancies:

- The design of the (Landmark 2015) facility has been optimized to reduce costs (e.g. with a square geometry purposely to save on concrete and rebar as opposed to the typical canyon geometry, with cells that allow access to equipment so that it can be repaired remotely rather than having to be over-engineered for no failure, etc…) and the design has advanced enough that the costs estimates in (Landmark 2015) are actually feasible with an effective design.

- The total unit reprocessing cost of (Landmark 2015) is similar to the lower expected cost of UREX+1a, which performs a similar objective, i.e. separating U+TRU. This would indicate that pyroprocessing may have similar costs to aqueous reprocessing.
- If both the (Landmark 2015) and the (Carter 2010) estimates were accurate, the (WSRC 2008) costs would be too high. In that case the difference between (Carter 2010) and (Landmark 2015) would reflect the cost difference between including or not the refabrication stage, and could therefore be used to estimate the cost of remote fabrication, at between 737 $/kgHM and 2295 $/kgHM, approximated as 750 $/kgHM to 2300 $/kgHM. Under these assumptions, the remote fabrication cost derived here would be an underestimation of the refabrication costs, since it would not account for the fact that a combined facility would have lower costs than a stand-alone facility, due to the sharing of certain functions and services.

F2/D2-1-6. SCALING CONSIDERATIONS

No direct scaling relations were found in the literature. Also, because electrochemical processing is a batch process, as opposed to continuous or semi-continuous aqueous processing, traditional chemical plant cost-scaling factors may not apply well. A pyro-batch line would consist of the largest demonstrated equipment run in a serial batch mode: based on current technology, batch size is limited by the efficiency of electro-refining at large volumes and by criticality concerns for the post-refining process steps. The number of parallel lines would produce the desired throughput, and any capacity additions to an existing line would likely be accomplished by adding more parallel process lines.

However, studies have been performed for facilities of different sizes performing the same functional steps, i.e. Integrated Reprocessing and Remote Fabrication (IRRF), based on the same underlying technology. In particular, Table F2/D2-1 shows the unit cost for a 20 MT/y and a 200 MT/y IRRF facilities, both based on technology developed at ANL. The scaling exponent for the capital cost for the two facilities can be calculated at about 0.7, close to the value of 0.6 typical of chemical plants. However, important caveats should be considered before using this scaling exponent. The two cost studies were performed at different times and by different institutions: the 20 MT/y in 1985 was performed by ANL, and the 200 MT/y in the period 1991-1993 was performed by General Electric, although the facility is also based on ANL technology. Additionally, the 20 MT/y facility was supposed to be collocated at a reactor site, and to share some facilities with the reactor, thus likely reducing its costs, while the 200 MT/y was envisioned as a stand-alone facility. Additionally, in the years between the two studies, the precision of cost estimates may have improved, and the technology may have been better developed, with the aim at reducing the costs.

F2/D2-1-7. DATA LIMITATIONS

No commercial-scale pyroprocessing and remote fabrication facility for nuclear fuel has been built so far, and only one engineering-scale facility has operated: the FCF at MFC processed and fabricated metal fuel for the EBR-II and demonstrated electrochemical reprocessing. In practice, virtually all the cost data that were found and collected here are from studies based on the same technology developed originally at ANL.

A detailed discussion of the available data, including a detailed discussion on the similarities and inconsistencies between recent detailed studies, is provided in Section F2/D2-5. One general problem that arises when analyzing costs from different studies is the homogeneity of basic assumptions, including indirect costs (often underestimated), owners' costs, contingencies, inclusion of cost of capital during construction, amount of "nuclear grade" and "non-nuclear grade equipment" etc…

A general problem is that at this point it was not possible to find defensible data on the cost of remote fabrication alone, and instead it had to be deduced, in a very preliminary and approximate level, from the cost of integrated reprocessing and remote fabrication. How this derivation is performed, together with the limitations of the proposed approach, is discussed in Section F2/D2-5.

In the next Section F2/D2-8, unit costs ranges, including probability distributions to quantify the uncertainty ranges associated with the costs, will be provided. One important consideration regarding unit costs is that cost studies for pyroprocessing facilities generally report the total capital cost, in terms of overnight costs, and the annual O&M costs, but not the unit cost in terms of dollars per kg heavy metal ($/kgHM). Therefore, in order to arrive at a unit cost, assumptions on facility lifetimes and discount rates are necessary. A discussion of the assumptions on facilities lifetime and discount rate used to arrive at unit costs in this Section is provided in Section F2/D2-5. Additionally, if the construction time is expected to be significant (i.e. more than 2-3 years), the overnight cost needs to be adjusted to include the cost of capital during construction.

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.

F2/D2-1-8. COST SUMMARIES

The module cost information is summarized in the What-It-Takes (WIT) cost summaries in Tables F2/D2-2 (integrated pyroprocessing separation and remote refabrication) and F2/D2-3 (remote refabrication only). 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.

As discussed in Section F2/D2-2, the unit costs are derived primarily from a recent study of capital cost of an integrated pyroprocessing and remote fabrication facility for fast reactor metallic fuel (Carter 2010). The O&M costs are derived from ranges reported in (Bunn 2016) for aqueous reprocessing facilities, since the (Carter 2010) study only focused on capital costs. Other assumptions, and cross comparison to other cost studies for similar facilities, are discussed extensively in Section F2/D2-5. Other studies that instead included O&M cost estimates are used to confirm the validity of the ranged provided in (Bunn 2016), as explained in Section F2/D2-5.

Since it was not possible to find defensible data on the cost of remote fabrication alone, it was deduced, in a very preliminary and approximate level, as the difference between the cost of integrated reprocessing and remote fabrication from (Carter 2010) and the cost of UREX+1a, as discussed in Section F2/D2-5.

For a full explanation of the derivation of the cost summaries, as well as the limitation and uncertainty of the data, the reader is strongly advised to read the relevant sections of this module.

Figures F2/D2-5 and F2/D2-5 show the probability distributions for summary the unit costs described in Tables F2/D2-2 and F2/D2-3.

Table F2/D2-2. WIT cost summary table for integrated pyroprocessing separation and remote refabrication (2017$).

Reference Cost(s) Based on Reference Capacity	Low	Mode (=Mean)	High
Integrated pyroprocessing separation and remote refabrication	2000 $/kgHM	2600 $/kgHM	3200 $/kgHM
Justification	Approximated from 1968 $/kgHM of (Carter 2010). Reflects the "low" capital cost of the Carter 2010 estimate, and a "low" O&M annual costs of 4% of capital costs (according to Bunn 2016)	Simple average between the two extreme values.	Approximated from 3205 $/kgHM of (Carter 2010). Reflects the "high" capital cost of the Carter 2010 estimate, and the "high" O&M annual costs of 7% of capital costs (according to Bunn 2016)

Table F2/D2-3. WIT cost summary table for remote refabrication only (2017$).

Reference Cost(s) Based on Reference Capacity	Low	Mode (=Mean)	High
Remote refabrication only	1000 $/kgHM	1400 $/kgHM	1800 $/kgHM
Justification	Difference from integrated and UREX+1a	Simple average between the two extreme values.	Difference from integrated and UREX+1a

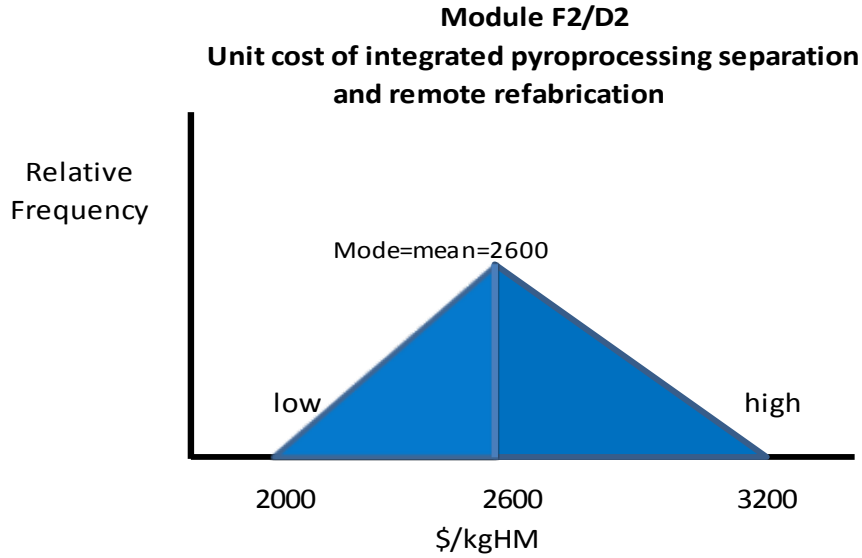

Figure F2/D2-5. Module F2/D2 distribution of combined unit cost for electrochemical reprocessing and remote fabrication of fast reactor metal fuel.

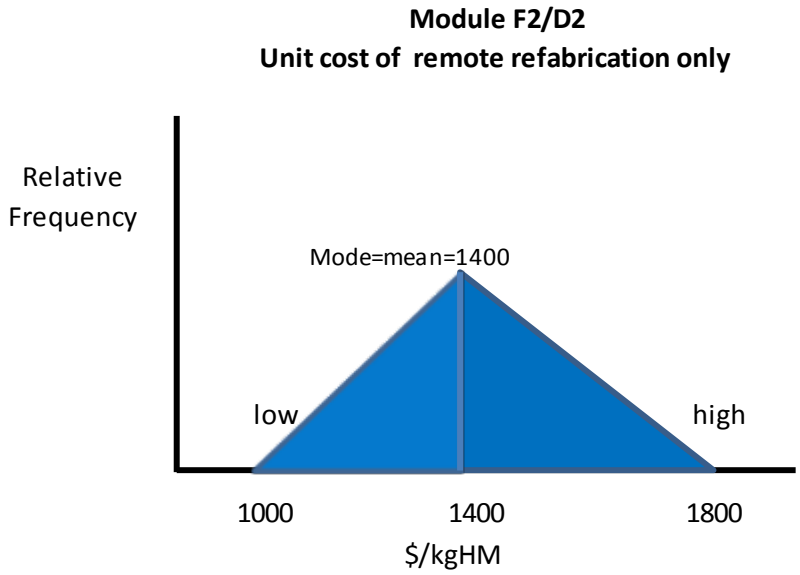

Figure F2/D2-6. Module F2/D2 distribution of unit cost for remote fabrication only.

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G MODULES

Waste Conditioning, Storage, and Packaging

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-2. MODULE SERIES 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.$), the reference basis cost contingency (if known), the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of cost range) based on references and qualitative factors, and selected nominal costs (judgment of the expected costs based on the references, contingency factors, upsides, and downsides). These costs are subject to change and are updated as additional reference information is collected and evaluated, and as a result of sensitivity and uncertainty analysis. The bolded items in the table are expressed in 2017$. (Refer to the "Production-based Costing" supplementary document following the "Modules" section of this report for additional details on the cost estimation approach used to construct the WIT tables.)

Costs for SNF, low-level waste (LLW), GTCC, and TRU handling are for services only and do not include dedicated disposal 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.

[Note: All references for Module G are located in sections G5-10 (References) and G5-11 (Bibliography).]

Table G-1. WIT cost summary table for waste conditioning selected values (2012$ and escalated* to 2017$ and rounded).

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	$5,000/kg FP
Escalated to Yr 2017$	**$2,510/kg FP**	**$7,500/kg FP**	**$5,700/kg FP**
Electrochemical HLW Treatment CFTC EAS	$12,015/kg FP	$18,122/kg FP	$15,100/kg FP
Escalated to Yr 2017$	**$13,700/kg FP**	**$20,700/kg FP**	**$17,200/kg FP**
U/Tc Separation and Solidification CFTC EAS	$161,836 /kg Tc	$231,496 /Kg Tc	$200,000/kg Tc
Escalated to Yr 2017$	**$184,500 /kg Tc**	**$264,000 /Kg Tc**	**$228,000/kg Tc**
Cs/Sr Solidification and Packaging CFTC EAS	$30,700/kg Cs/Sr	$47,600/kg Cs/Sr	$40,000/kg Cs/Sr
Escalated to Yr 2017$	**$35,000/kg Cs/Sr**	**$54,300/kg Cs/Sr**	**$45,600/kg Cs/Sr**
G2—SNF			
$80–100K/MTHM SNF	$50K/MTHM	$130K/MTHM	$100K/MTHM
Escalated to Yr 2017$	**$68/kgHM**	**$175/kgHM**	**$135/kgHM**
G3—LLW			
CFTC EAS (debris)	$1,000/$m^3$ LLW debris	$4,200/$m^3$ LLW debris	$1,500/$m^3$ LLW debris
Escalated to Yr 2017$	**$1,070/$m^3$ LLW debris**	**$4,500/$m^3$ LLW debris**	**$1,600/$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
Escalated to Yr 2017$	**$4,600/$m^3$ LLW liquid**	**$29,700/$m^3$ LLW liquid**	**$14,900/$m^3$ LLW liquid**
$90,000/$m^3$ Resins	$81,000/$m^3$ resins	$99,000/$m^3$ resins	$90,000/$m^3$ resins
Escalated to Yr 2017$	**$109,000/$m^3$ resins**	**$134,000/$m^3$ resins**	**$122,000/$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
Escalated to Yr 2017$	**$10,800/$m^3$ gas**	**$17,100/$m^3$ gas**	**$12,800/$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
Escalated to Yr 2017$	**$10,800/$m^3$ gas**	**$17,100/$m^3$ gas**	**$12,800/$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
Escalated to Yr 2017$	**$21,700/$m^3$ GTCC**	**$42,200/$m^3$ GTCC**	**$30,800/$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

*Escalation to 2017$ is from the year the particular G-module technology and cost basis was originally described and estimated: escalation is 35% from 2006, 14% from 2009, and 2% from 2015. Escalation indices appear in Table 2 in the "Escalation Considerations" section of 2017 AFC-CBR and were revised after 2012.

Module G1

High-Level Waste (HLW) Conditioning, Storage, and Packaging

Module G1

HLW Conditioning, Storage, and Packaging

G1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time (2009) values underwent technical assessment.
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was escalated:** Bottom-up estimates for waste handling facilities and operations for UREX-1a aqueous and Electrochemical reprocessing plants assessed as part of the Engineering Alternative Studies (EAS) during the GNEP. Unit costs were calculated for various types of fission product conditioning, storage, and packaging. (Geologic disposal is not included).

G1-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2009. 2009 data was escalated to 2017$ for this latest revision.
- **New technical/cost data which has recently become available and will benefit next revision:** None identified

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 2005)."

Several examples of existing and planned HLW facilities exist, including two examples in the U.S., 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 2022 for some less complex wastes and 2039 for more difficult wastes. 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 U.S. is defined by DOE in the Waste Acceptance System Requirements Document (DOE 2008) and the DOE-Office of Environmental Management Waste Acceptance Product Specification for Vitrified High Level Waste Forms (DOE 2012) 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 INL 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 (See Module K2). 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 waste form 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 re-enrichment	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%
Zr Cladding Hulls	GTCC	Compacted Metal	100%			
				Re-use in FR metal fuel alloy	No waste	No waste
				HLW	Compacted metal	100%

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
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, typically 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).

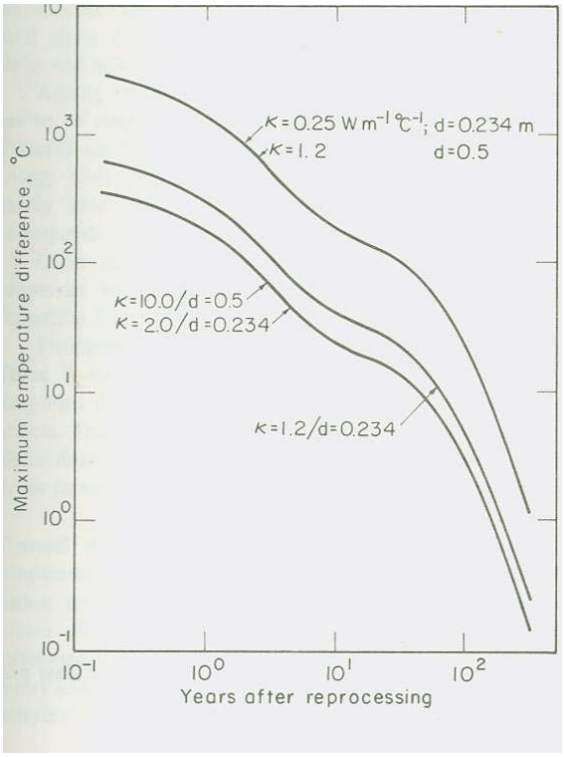

Figure G1-1. Maximum centerline temperature difference of waste form as a function of decay time.

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.

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	Elder et al. 2000 Luca et al. 2006a,b
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. 2006a,b
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	National Research Council, 2003
SrF_2	Sr salt in capsule in pool	CsF_2, 33kCi 260W	IX separation and Evap	National Research Council, 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 √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 (successful continuous operation) and THORP at Sellafield until 2018. (Rokkasho is believed to start full operation in 2018 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, 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 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/Natural	0.59 3.0	670	-	<1,000	<0.25
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 (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.

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.

G1-2.4 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.

G1-3. PICTURES AND DIAGRAMS

Figure G1-1. Defense waste processing plant at the Savannah River Site.

G1-4. MODULE INTERFACES

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 Storage of Recycled Products (Module E4) for advanced reprocessing. 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 $\geq$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. SCALING CONSIDERATIONS

Using data from the CFTC studies (see G1-6) the cost was fitted using the logarithmic relationship:

$$CostofA = CostofB\left(\frac{Capacityof\ A}{Capacityof\ B}\right)^{n}$$

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.

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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.

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.

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) [0% discount rate]	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. Unit costs based on 0% discount rate.								

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. Unit costs based on 0% discount rate.								

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. DATA LIMITATIONS

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.

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 "WhatItTakes" (WIT) table for HLW conditioning selected values.

Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
HLW Borosilicate Glass				
	$2,200/kg FP	$5,000/kg FP		$6,600/kg FP
Escalated Year 2017$	$2,510/kg FP	$5,700/kg FP	$5244/kg FP	$7,500/kg FP
	Unit cost for a 3000MT/yr reprocessing integrated complex with 15% FP loading	Based on an 800 MT/yr reprocessing center with 15% FP loading		Based on the DWPF facility with a 5% FP loading
Electrochemical HLW Treatment CFTC EAS				
	$12,015/kg FP	$15,100/kg FP average of the CFTC high/low values		$18,122/kg FP
Escalated Year 2017$	$13,700/kg FP	$17,200/kgFP	$17,190/kgFP	$20,700/kg FP
U/Tc Separation and Solidification CFTC EAS				
	$161,836 /kg Tc	$200,000/kg Tc average of the CFTC high/low values		$231,496 /kg Tc
Escalated Year 2017$	$184,500/kgTc	$228,000/kgTc	$225,465/kgTc	$264,000/kgTc
Cs/Sr Solidification and Packaging	$52,000/kg Cs/Sr	$45,600/kg Cs/Sr	$44,955/kg Cs/Sr	$54,300/kg Cs/Sr
	Low unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center	High unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center		Average unit cost of a bentonite clay ceramic process integrated into an 800MT/yr reprocessing center

The triangular distributions based on the WIT Table are shown in Figure G1-2. Some distributions are skewed toward the high cost due to the difficulty in achieving fission product loading greater than 10% in the waste form.

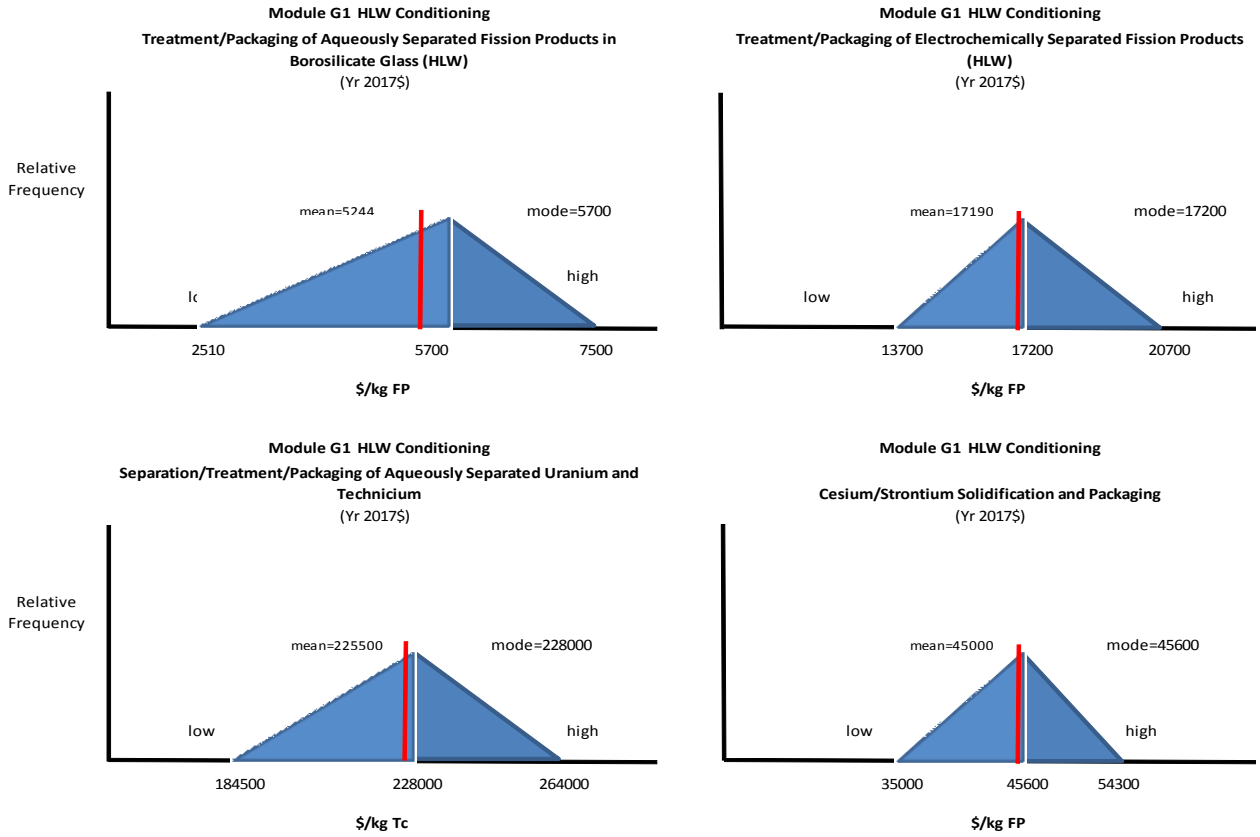

Figure G1-2. HLW conditioning, storage, and packaging estimated cost frequency distributions.

G1-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

G1-10. REFERENCES

See G5-10 and G5-11.

Module G2

SNF Conditioning and Packaging

Module G2

SNF Conditioning and Packaging

G2-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time (2006) values underwent technical assessment:
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was escalated:** 2006 Vendor estimates for conditioning and packaging operations including casks.

G2-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** First became separate submodule in 2006. Cost estimates for pre-reprocessing SNF operations were needed.
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2009. 2006 data was escalated to 2017$ for this latest revision.
- **New technical/cost data which has recently become available and will benefit next revision:**
  - New estimates might be available from vendors and from DOE-NE Used Nuclear Fuel campaign cost and schedule studies.
  - Care should be taken that these conditioning and packaging operations (and casks) are not already in cost data appearing in Modules I (centralized dry storage) or L1 (Geologic Disposal of SNF).

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 (NRC, 1997) 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 DIAGRAMS

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. (BNG Fuels Solutions was formerly BNFL Fuel Solutions)

G2-4. MODULE INTERFACES

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). 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. SCALING CONSIDERATIONS

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. DATA LIMITATIONS

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 the main section of this report for additional discussion of 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 'What-It-Takes' (WIT) table for SNF conditioning selected values.

Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
$80K–100K/MTHM SNF (2006$)	$50K/MTHM	$100K/MTHM		$130K/MTHM
Escalated to Yr 2017$ (35% increase from 2006 per escalation table)	$68/kgHM	$135/kgHM	$126/kgHM	$175/kgHM

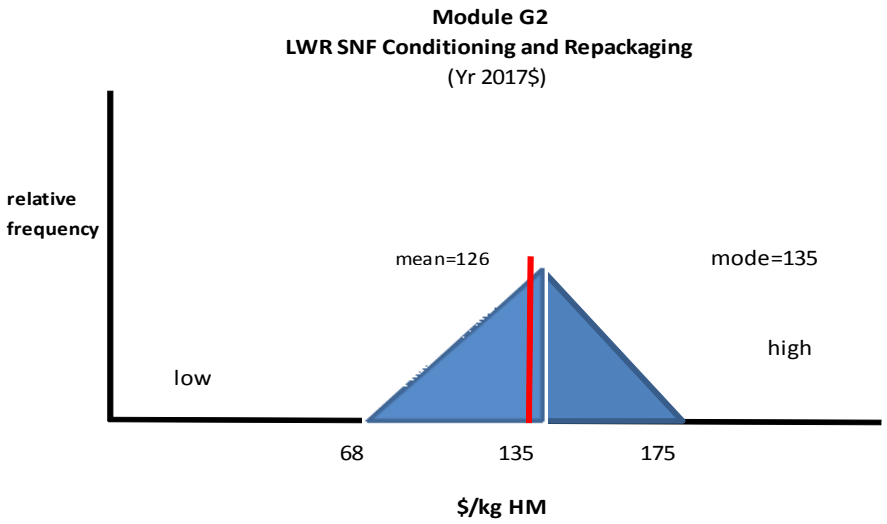

Figure G2-6. SNF conditioning and packaging estimated cost frequency distribution.

G2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

G2-10. REFERENCES

See G5-10 and G5-11.

Module G3

LLW Conditioning, Storage, and Packaging

Module G3

LLW Conditioning, Storage, and Packaging

G3-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs: Escalation only from last time values underwent technical assessment:** 2006 for liquid and resin-derived LLW; 2015 for solid LLW (also for solid DU oxides for Module K1)
- Estimating Methodology for latest technical updates from which this 2017 update was escalated: 2006 DOE estimates for commercial LLW handling for materials generated at Government sites. Also data from bottom-up estimate generated for hypothetical Consolidated Fuel Treatment Center (CFTC), one of the first reprocessing studies performed under GNEP. For standard solids and debris LLW, the processing costs were reassessed (2015) when deconversion and treatment costs for DU oxide were reassessed,

G3-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** First became separate submodule in 2006.
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2006 for all LLW except solids and debris. 2015 data escalated for the latter. 2006 and 2015 data were escalated to 2017$ for this latest revision.
- **New technical/cost data which has recently become available and will benefit next revision:** New estimates might be available in the future from LLW-handling vendors and perhaps from utility users of these services.

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. On a cost per volume basis mixed-waste (toxic and radioactive) 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 in Utah . 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 DIAGRAMS

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 (South Carolina) site (Chem-Nuclear Systems, LLC 1997).

G3-4. MODULE INTERFACES

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 shallow geologic disposal 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. SCALING CONSIDERATIONS

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 (now Nevada National Security 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. DATA LIMITATIONS

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 'What-It-Takes' (WIT)table for LLW conditioning selected values.

Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
	Based on 800MT/yr Aqueous Process	Based on 800MT/yr High Range		Based on 300MT/yr E-chem Process
LLW Debris				
2012 value	\$1,050/m^3	\$1,580/m^3	\$2350/m3	\$4,410/m^3
Escalated to 2015 \$	\$1,070/m^3	\$1,600/m^3	\$2,4000/m^3	\$4,500/m^3
LLW Liquid				
\$11,000/m^3 LLW Liquid (2006\$)	\$3,300/m^3	\$11,000/m^3		\$22,000/m^3
Escalated to 2017\$	\$4600/m^3	\$14,900/m^3	\$16,300/m^3	\$29,700/m^3
Resins				
\$90,000/m^3 Resins (2006\$)	\$81,000/m^3	\$90,000/m^3		\$99,000/m^3
Escalated to 2017\$	\$109,000/m^3	\$122,000/m^3	\$122,000/m^3	\$134,000/m^3

Cost data has been rounded to two or three 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

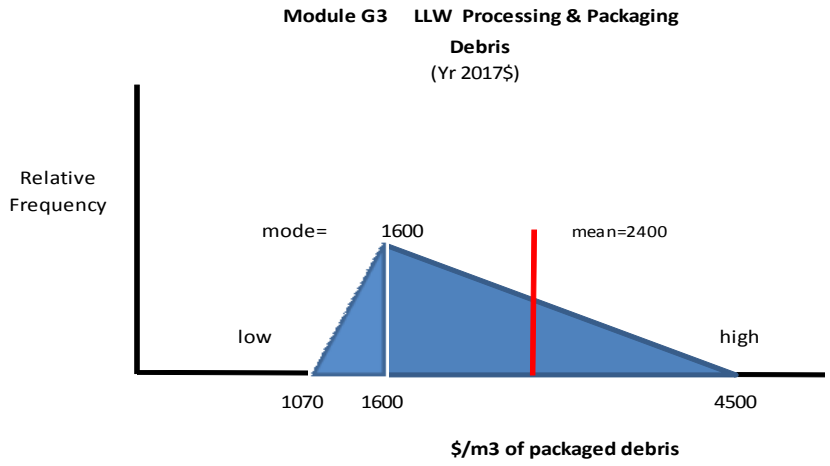

Figure G3-6. Module G3-D LLW conditioning estimated cost frequency distribution.

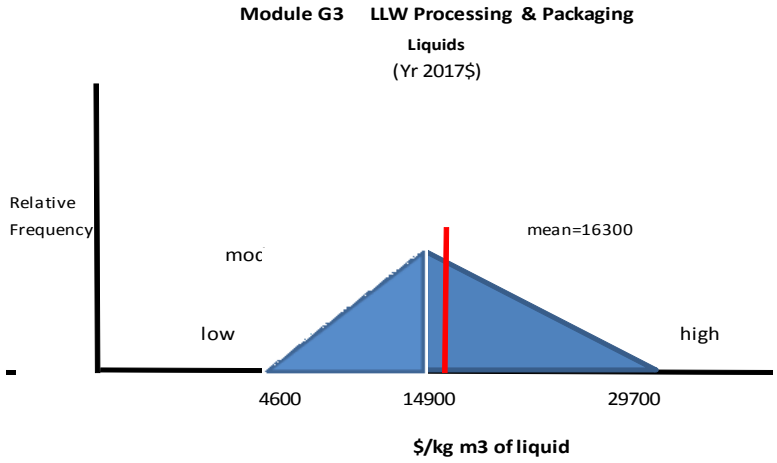

Figure G3-7. Module G3-L LLW conditioning estimated cost frequency distribution.

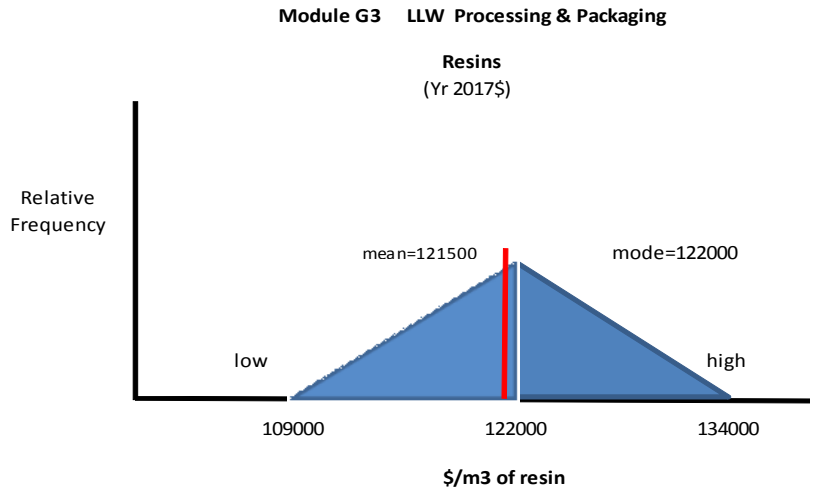

Figure G3-8. Module G3-Resin LLW conditioning estimated cost frequency distribution.

G3-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

G3-10. REFERENCES

See G5-10 and G5-11.

Module G4

GTCC Process Waste Conditioning, Storage, and Packaging

Module G4

GTCC Process Waste Conditioning, Storage, and Packaging

G4-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment: 2009
- **Estimating Methodology for latest technical updates (2009) from which this 2017 update was escalated:** Data from bottom-up estimates generated for hypothetical Consolidated Fuel Treatment Center (CFTC) and subsequent Engineering Alternative Studies for other type reprocessing plant studies performed under GNEP. Many separated fission products would be treated as GTCC.

G4-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** First became separate submodule in 2006.
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2009 for all GTCC fission product classes.
- **New technical/cost data which has recently become available and will benefit next revision:** None identified.

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 DIAGRAMS

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 INTERFACES

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 ≥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. SCALING CONSIDERATIONS

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. DATA LIMITATIONS

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

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.

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).

The cost estimates in Table G4-2 apply to GTCC derived from both aqueous and Echem reprocessing activities.

Table G4-2. Cost summary 'What-It-Takes' (WIT)table for GTCC waste conditioning selected values.

Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
LLW-GTCC Off-gas Absorber (H3, Kr, Xe) [2009$]	$8,000/m^3 gas	$11,200/m^3 gas		$15,000/m^3 gas
Escalated to 2017 $ [14 % increase from 2009]	$10,800/m^3 gas	$12,800/m^3 gas	$13,560/m^3 gas	$17,100/m^3 gas

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 G4-2 (same for both aqueous and E-chem absorber offgases.)

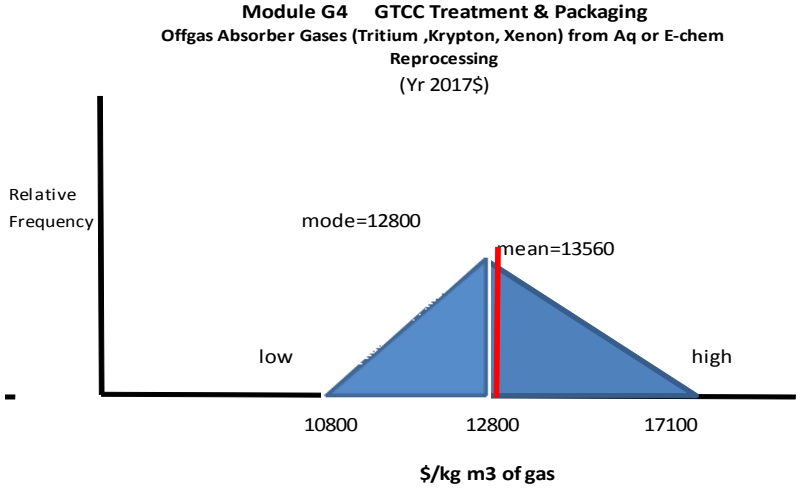

Figure G4-2. Module G4-1Aqueous offgas absorber.

G4-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

G4-10. REFERENCES

See G5-10 and G5-11.

Module G5

GTCC Secondary Waste Conditioning, Storage, and Packaging

Module G5

GTCC Secondary Waste Conditioning, Storage, and Packaging

G5-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- Constant $ base year for 2017 Update: FY 2017
- Nature of this 2017 Module update from previous AFC-CBRs: Escalation only from last time values underwent technical assessment: 2009
- Estimating Methodology for latest technical updates (2009) from which this 2017 update was escalated: Data from bottom-up estimates generated for hypothetical Consolidated Fuel Treatment Center (CFTC) and subsequent Engineering Alternative Studies for other type reprocessing plant studies performed under GNEP. Some data are based on USDOE estimates for preparing wastes for emplacement in WIPP (Waste Isolation Pilot Plant)

G5-RH. REVISION HISTORY

- Version of AFC-CBR in which Module first appeared: First became separate submodule in 2006.
- Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges: 2009
- New technical/cost data which has recently become available and will benefit next revision: New data on waste preparation costs for WIPP might be available. WIPP recently reopened, and DOE sites are shipping permanent packages for geologic emplacement.

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 DIAGRAMS

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.

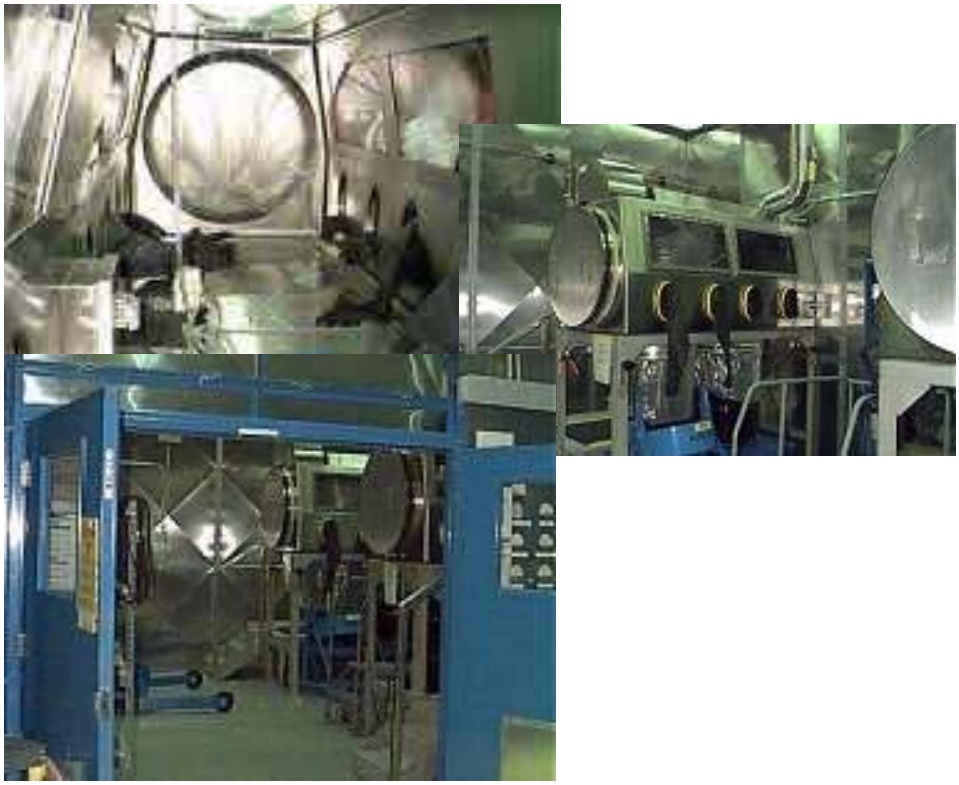

Figure G5-4. Collage of pictures showing a TRU waste sorting system.

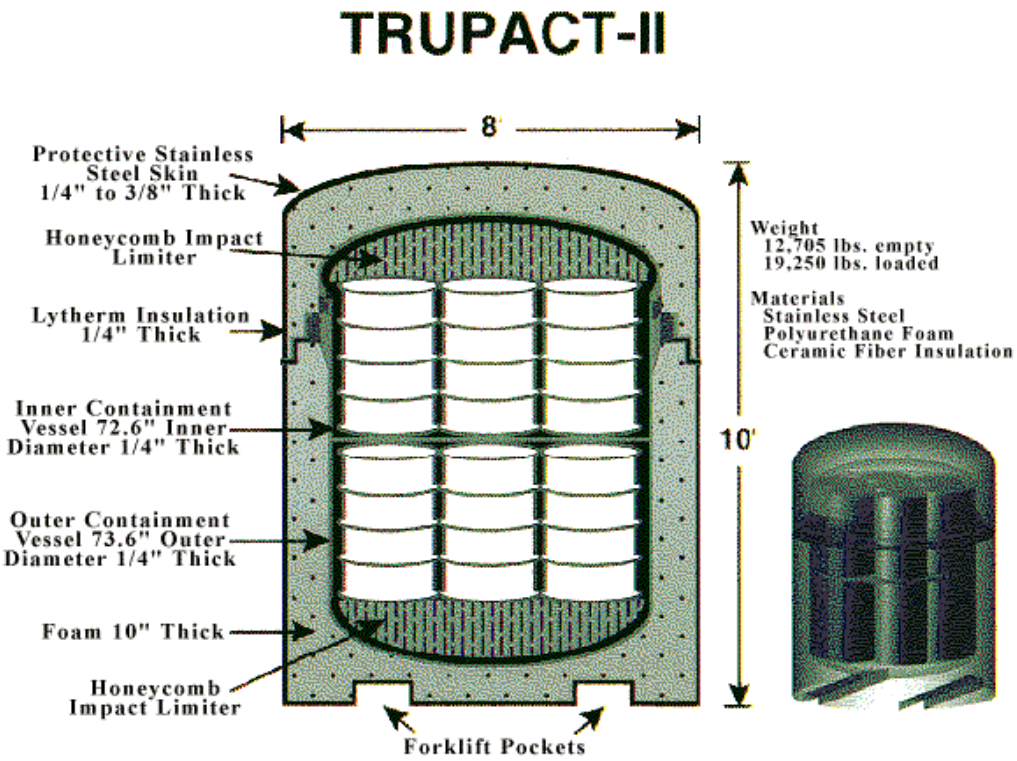

Figure G5-5. Schematic of TRUPACT-II shipping cask for TRU wastes.

Figure G5-6. Truck shipment of three TRUPACT-II casks.

G5-4. MODULE INTERFACES

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, D1-2, D1-4, D1-5 and combined Modules 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. SCALING CONSIDERATIONS

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.

	Average Cost (per drum and m^3)	
Activity	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).

$$\$72{,}937{,}000 \times 0.75 = \$54{,}702{,}750. \quad (1)$$

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).

$$437 \text{ shipments} \times 42 \text{ drums/shipment} \times 0.208 \text{ m}^3\text{/drum} = 3{,}817 \text{ m}^3. \quad (2)$$

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. 0% discount rate				

G5-7. DATA LIMITATIONS

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 'What=It-Takes' table for GTCC secondary waste conditioning.

Reference Cost(s) Based on Reference Capacity	Low Cost	Mode Cost	Mean Cost	High Cost
2009$ >>>	$19,000/m^3 GTCC	$27,000/m^3 GTCC		$37,000/m^3 GTCC
Escalated to 2017 $	$21,600/m^3	$30,780/m3	$31,540/m^3	$42,200/m^3
	Average of Defense TRU waste processing from INL actual costs	Average of the high and low		CFTC EAS high range for 800MT/yr aqueous reprocessing

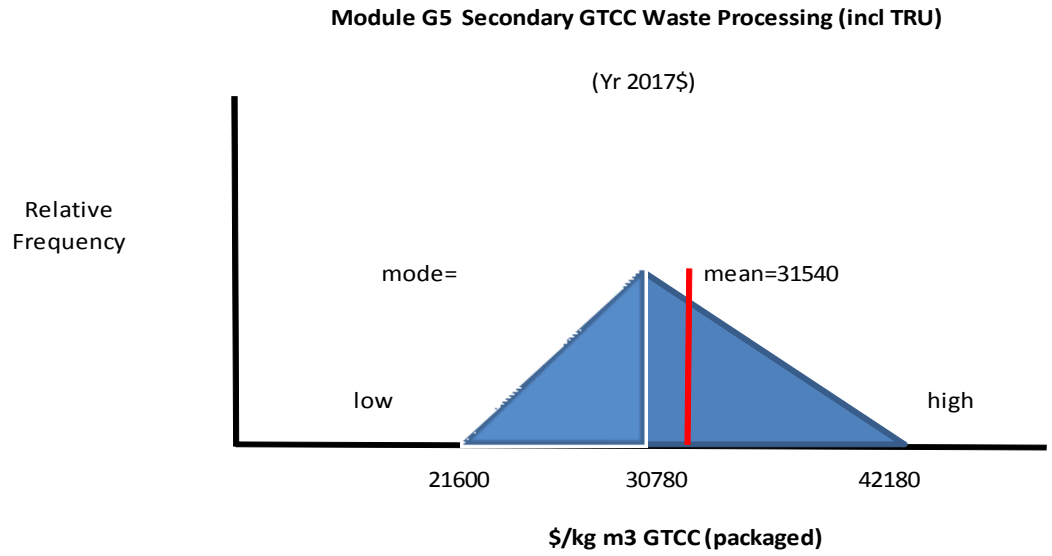

Figure G5-7. Module G5 GTCC secondary waste conditioning estimated cost frequency distribution.

G5-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

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MODULE I

Consolidated Interim Storage
(Formerly Module E2)

Module I

Consolidated Interim Storage

I-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** In addition to earlier cost information on the Private Fuel Storage (PFS) Skull Valley Utah proposal, new FY 2012 information from Systems Architecture Studies conducted by USDOE-NE's UFD Campaign were added.

I-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module E2. In 2012 this module was renamed to Module I. The Module now deals mainly with off-reactor-site, centralized (or "consolidated") interim spent fuel storage.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The USDOE Used Fuel Disposition (UFD) Campaign continues to conduct engineering, cost, and schedule studies. Some of these were conducted in FYs 2015 through 2016. The results of these studies should be included. One such document is a cost sensitivity analysis conducted by Oak Ridge National Laboratory (ORNL 2016).
  - Many utilities are constructing on-reactor-site interim spent fuel storage facilities using US Government funding resulting from lawsuit settlements. Cost information on these "on-site" facilities should be available.

I-1. BASIC INFORMATION

In the 1990s the U.S. Department of Energy (DOE) completed a number of system analyses investigating consolidated interim storage as a part of the waste management solution. These analyses are "dated" and do not reflect the present situation regarding at-reactor used nuclear fuel (UNF) management, alternatives for away from reactor management of used nuclear fuel, and alternatives for the ultimate disposal of UNF. The Blue Ribbon Commission for America's Nuclear Future and the Nuclear Waste Technical Review Board have both pointed out the need for further analysis in light of the current situation, These analyses were re-started in FY2012 by the U.S. DOE-NE Used Fuel Disposition Campaign and are discussed below.

The first consolidated storage concept was conducted when the Skull Valley Band of Goshute Indians 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 an NRC 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 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) semi-gantry 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 (Module L).

I-3. PICTURES AND DIAGRAMS

Figures I-2, I-3, and I-4 describe the Skull Valley site plan and layout.

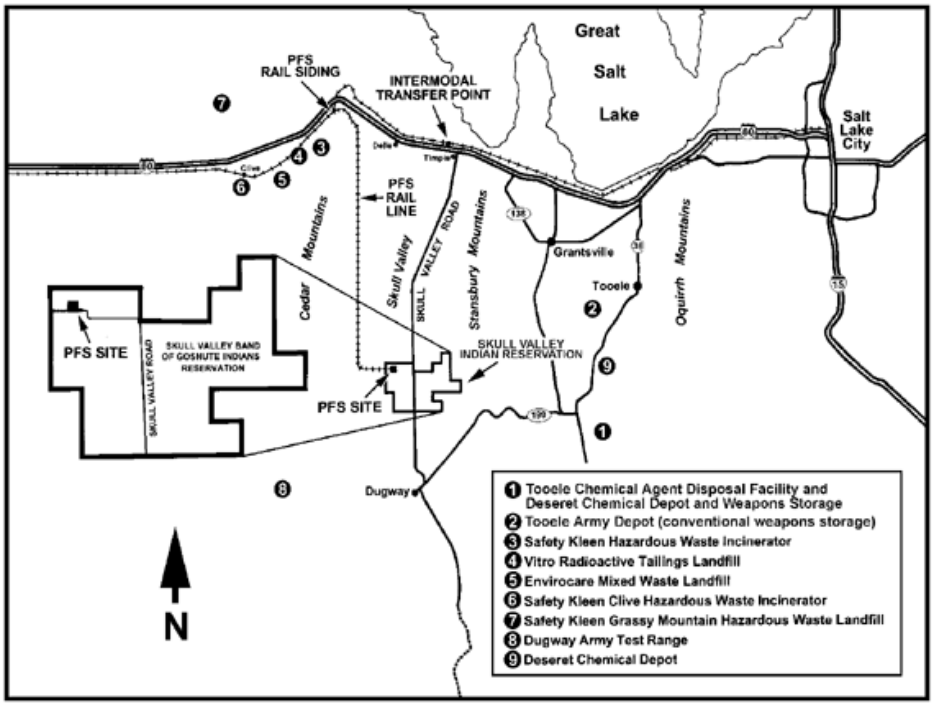
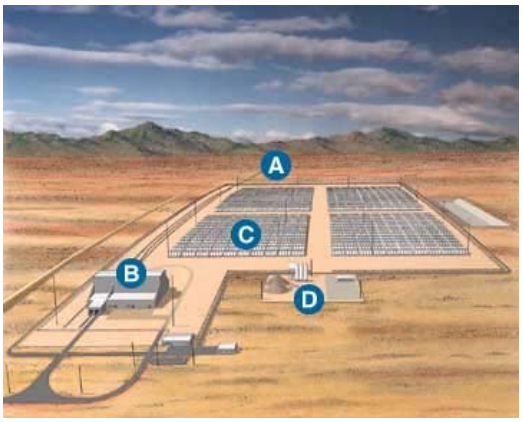


Figure I-2. Basic site plan for the proposed private fuel storage facility.



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-3. Skull Valley facility layout and major components (NRC 2001).

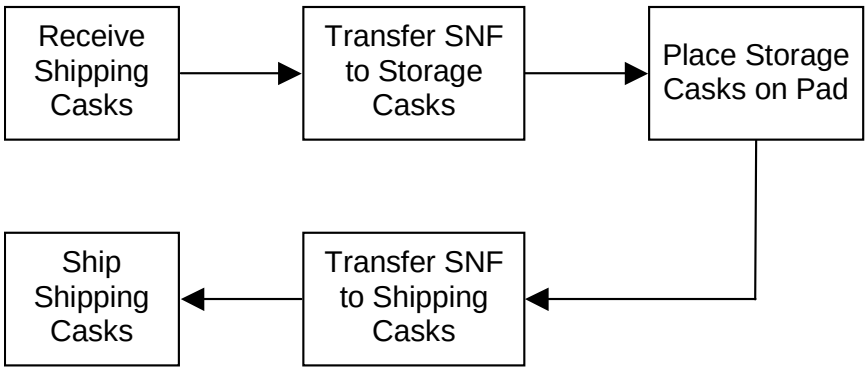


Figure I-4. Facility functional block diagram.

I-4. MODULE INTERFACES

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 various storage cask systems and placed in storage. At unspecified future dates, fuel can be removed for ultimate disposition (Module L) or for reprocessing (Modules F1 or F2/D2). The FY-12 System Architecture Study begins to assess the Life-Cycle Costs (LCC) impact on storage for delays in final disposition.

I-5. SCALING CONSIDERATIONS

Within a site, facilities can be expanded via development of modular concepts. Multiple fuel handling and storage modules are expected to be required, in part due to the increasing number of dry storage systems currently in use at utilities. There are more than 30 dry storage containers in the current inventory and new concepts to continue to be developed as industry continues to develop larger containers.

I-6. COST BASES, ASUMPTIONS, AND DATA SOURCES

I-6.1 PFS COSTS

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. $72/kgHM is approximately 20% of the used fuel disposition cost inherent to the nuclear waste disposal fee of $0.001 per kW(e) collected by the government from the nuclear plant generators.

The Skull Valley annual operating expenses were 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.

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$$	Calculated
Assumed number of years for facility to reach full storage capacity	10	years	ORNL/KA Williams
Facility fill rate	400	casks/year	Calculated
	4,000,000	kgHM/year	Calculated
Operations charge	15,000	$/cask/year	*Nuclear Fuel*, March 27, 2006, Operations: $60 M/y
Operations charge per year per kgHM	1.5	$/kgHM/year	Calculated
Typical storage time	20	years	ORNL/KA Williams
$/kgHM for operations	30	$/kgHM	Calculated
Fixed charge rate	10.00%	%	ORNL/KA Williams
Fixed charge rate to amortize capital over 10 yrs	16.27%	%	Calculated
Annual capital charge for facility	78.12	10^6/year	Calculated
Capital investment per kgHM	19.53	$/kgHM	Calculated
Total levelized storage cost	49.53	$/kgHM	Calculated
Total life-cycle cost for PFS facility (without interest)	2.88	$10^9$$	Calculated
Total life-cycle cost with interest	3.78	$10^9$$	Calculated

I-6.2 SYSTEM ARCHITECTURE STUDY

In Fiscal Year 2012 system-level analyses of the overall interface between at-reactor, consolidated storage, and ultimate disposition along with the development of supporting logistic simulation tools were initiated by the Department of Energy. The objective of the Fiscal Year 2012 effort was two-fold: 1) develop methodologies, approaches, and tools (capability development), and 2) evaluate select UNF disposition scenarios (capability demonstration). The scenarios chosen for evaluation and the assumptions, inputs, and boundary conditions selected allowed for an initial set of analyses to gain insight regarding integrated system dynamics and an understanding of trends. This initial set of analyses also points to where additional system architecture analyses should focus.

An important waste management system interface consideration is the need for ultimate disposal of UNF fuel assemblies contained in waste packages sized to be compatible with the geologic medium of the final repository. Thermal analyses completed by the Used Fuel Disposition Campaign indicate that waste package sizes for the geologic media under consideration by the Used Fuel Disposition Campaign are significantly smaller than the canisters being used for on-site dry storage by the nuclear utilities. Therefore, at some point along the UNF disposition pathway there may be a need to re-package fuel assemblies already loaded into the types of dry storage canisters currently in use unless the feasibility of direct disposal of these large canisters can be demonstrated.

A high-level diagram of the alternative UNF disposition pathways is shown in Figure I-1 and involves UNF storage at a consolidated storage facility (CSF) and UNF packaging/re-packaging prior to ultimate disposal.

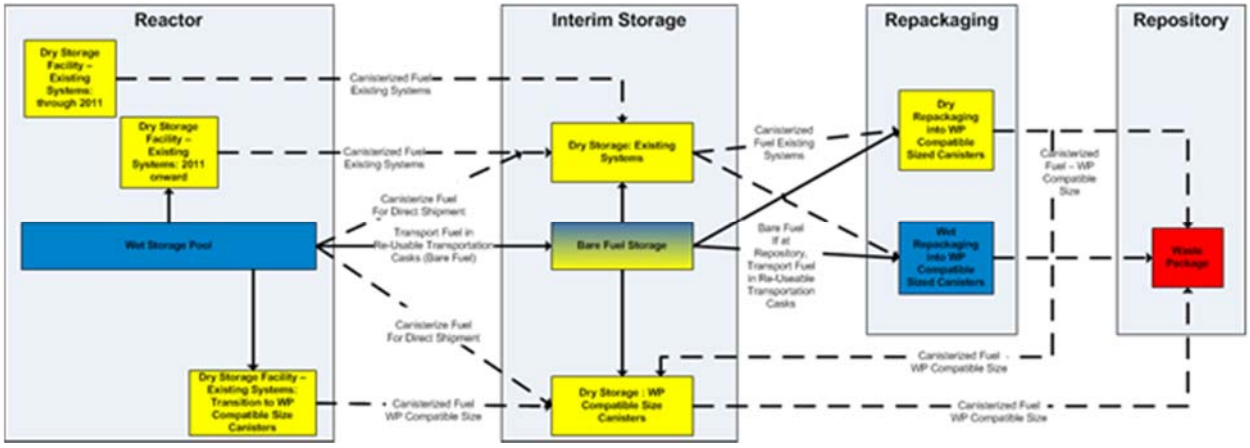


Figure I-5. Alternative Used Nuclear Fuel Disposition Pathways (Nutt, et al. 2012).

While the reactors will continue to transfer UNF to dry storage, there will always be UNF in the used fuel pools, at least until a reactor is shut down and decommissioned. Another important aspect is how the UNF residing in the used fuel pools is managed when acceptance of the fuel from the reactor sites begins. UNF residing in the pools can be transported off-site in re-useable transportation casks, placed in dual-purpose canisters suitable for both storage and transportation, or placed in a standard canister once one is designed and licensed. This choice impacts the design of both a CSF (canistered fuel storage only or canistered and bare fuel storage) and the quantity of UNF that would ultimately have to be re-packaged.

These considerations resulted in the identification of nine potential disposition pathways that consider how UNF would be transported from the reactors, where UNF packaging/re-packaging would be performed (repository or CSF), and when UNF packaging/re-packaging would be performed (at CSF receipt or prior to shipment from the CSF to a repository). These nine disposition pathways were evaluated considering complexity and flexibility, resulting in a down-select of the disposition pathways that would be considered in FY12 to four, representing the possible combinations of two features: what would be accepted from reactors by the waste management system (fuel packaged into existing size canisters only, or bare fuel as well as canisterized fuel), and where/when the canisterized fuel would be packaged/re-packaged for disposal (at a CSF when the fuel is about to be sent to the repository, or at the repository when fuel is received there). The packaging/re-packaging of bare fuel/canisters into disposal size canisters at reactors or into either existing size or disposal size canisters at CSF receipt were not evaluated in this phase of the analysis. The cases considered are summarized in Table I21 (see Section 3.1 for details regarding each case).

Table I-2. TSL Case Matrix.

	Case 1	Case 2	Case 3	Case 4
Transport From Reactors	Existing Size Canisters	Existing Size Canisters / Bare Fuel	Existing Size Canisters	Existing Size Canisters / Bare Fuel
CSF	Existing-Size Canisters	Existing Size Canisters / Bare Fuel	Existing-Size Canisters	Existing Size Canisters / Bare Fuel
Package/ Re-Package at ==>	Repository	Repository	CSF	CSF
Transport from CSF to MGR	Existing-Size Canisters	Existing Size Canisters / Bare Fuel	Waste Package Size Canisters	Waste Package Size Canisters

A range of input parameters was then determined for evaluating each disposition pathway. Parameters selected include start of CSF operations (2020, 2035), start of repository operations (2040, 2055), UNF acceptance rates (1500, 3000, and 6000 MTHM/yr), and waste package size (4/9, 12/24, 21/44 PWR/BWR assemblies). The combination of disposition pathways and input parameters results in 36 individual scenarios that were evaluated.

I-6.3 SYSTEM ARCHITECTURE COST STUDY

Rough order of magnitude life cycle cost (ROM LCC) estimates of the entire nuclear waste management system varied depending on the scenario. Table I-3 provides the LCC summary from this study for the 36 scenarios. Table I-3 includes the ROM LLC for CSF operations, an associated test and validation facility (TVF) as recommended by the BRC and in which extended fuel storage research and development activities will be conducted and the packaging/re-packaging facility (RF) costs. The table is color shaded to group similar processing rates.

Table I-3. Away from Reactor Back End Fuel Cycle Management Life-Cycle Costs.

Scenario	Acceptance Rate	CSF Start	Repository Start	Disposal Canister Size	CSF Total Life Cycle FY 2012 ($B)	TVF Total Life Cycle FY 2012 ($B)	RF Total Life Cycle FY 2012 ($B)	Away From Reactor UNF Management Life Cycle (CSF + TVF + RF) FY 2012 ($B)
Canisters Only - Re-Package at Repository (Case 1)	1,500	2020	2040	4	$7.5	$4.4	$12.0	$23.9
	3,000	2020	2040	4	$11.3	$3.4	$14.4	$29.0
	3,000	2020	2040	12	$11.3	$3.4	$8.4	$23.1
	3,000	2020	2040	21	$11.3	$3.4	$6.6	$21.3
	6,000	2020	2040	4	$17.5	$2.9	$19.6	$40.1
	1,500	2020	2055	4	$11.9	$4.7	$12.0	$28.7
	3,000	2020	2055	4	$20.4	$3.7	$14.4	$38.4
	6,000	2020	2055	4	$25.7	$3.3	$20.3	$49.2
	3,000	2035	2055	4	$12.9	$3.4	$13.6	$29.9
Canisters and Bare Fuel - Re-Package at Repository (Case 2)	1,500	2020	2040	4	$22.5	$4.4	$12.5	$39.4
	3,000	2020	2040	4	$40.2	$3.4	$14.4	$58.0
	3,000	2020	2040	12	$40.2	$3.4	$8.5	$52.1
	3,000	2020	2040	21	$40.2	$3.4	$7.2	$50.7
	6,000	2020	2040	4	$67.2	$2.9	$20.3	$90.4
	1,500	2020	2055	4	$31.8	$4.7	$12.5	$49.0
	3,000	2020	2055	4	$58.4	$3.7	$14.4	$76.5
	6,000	2020	2055	4	$78.7	$3.2	$19.3	$101.3
	3,000	2035	2055	4	$30.5	$3.4	$14.1	$48.0
Canisters Only - Re-Package at CSF (Case 3)	1,500	2020	2040	4	$10.3	$4.4	$13.6	$28.4
	3,000	2020	2040	4	$15.2	$3.4	$15.8	$34.4
	3,000	2020	2040	12	$15.2	$3.4	$8.7	$27.3
	3,000	2020	2040	21	$15.2	$3.4	$6.7	$25.3
	6,000	2020	2040	4	$18.0	$2.9	$24.6	$45.6
	1,500	2020	2055	4	$15.8	$4.7	$13.6	$34.1
	3,000	2020	2055	4	$22.9	$3.7	$15.8	$42.4
	6,000	2020	2055	4	$25.7	$3.3	$24.6	$53.6
	3,000	2035	2055	4	$25.9	$3.4	$15.8	$45.1
Canisters and Bare Fuel - Re-Package at CSF (Case 4)	1,500	2020	2040	4	$28.7	$4.4	$13.0	$46.1
	3,000	2020	2040	4	$50.1	$3.4	$15.8	$69.2
	3,000	2020	2040	12	$50.1	$3.4	$8.7	$62.1
	3,000	2020	2040	21	$50.1	$3.4	$6.7	$60.2
	6,000	2020	2040	4	$67.1	$2.9	$21.2	$91.2
	1,500	2020	2055	4	$40.3	$4.7	$13.0	$57.9
	3,000	2020	2055	4	$64.4	$3.7	$15.8	$83.9
	6,000	2020	2055	4	$78.6	$3.2	$21.2	$103.0
	3,000	2035	2055	4	$37.5	$3.4	$15.6	$56.4
		1500 MTHM/yr			3000 MTHM/yr		6000 MTHM/yr	

I-7. DATA LIMITATIONS

The PFS cost estimate is based on direct conversations with the chairman and chief executive officer, 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 interim 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.

The PFS concept is limited in that it only addressed a single dry storage canister design; it did not recognize the need for an extended storage test and validation facility and did not recognize the need to repackage the fuel to meet disposal constraints for decay heat at the time of waste emplacement. The UFD System Architecture Study explores a number of these limitations with the added program elements increasing cost. The System Architecture Study also indicates higher cost for higher processing rates and continued delays in establishing final disposition. Bare fuel processing and storage, which includes unloading and handling uncontainerized fuel assemblies, also increases cost significantly.

The UFD System Architecture Study is based on a multi-module concept based upon current commercial practices. Cost estimates were developed for individual modules and operating concepts and expanded to cover a broad range of possible fuel cycle back end management scenarios. The individual module concepts are based on pre-conceptual designs and the cost estimates are considered to be rough order-of-magnitude quality. More detailed UFD Campaign studies are currently underway and should reflect a pre-conceptual, bottom-up cost estimating approach.

I-8. COST SUMMARIES

Table I-4 presents the UFD System Architecture Study ROM LCC results as unit costs per kg of initial heavy metal. Due to the inclusion of a broad range of considerations this study, as of 2012, serves as the most comprehensive cost study to date for consolidated storage and related costs.

Table I-4. Away from Reactor Back End Fuel Cycle Management Unit Costs.

Scenario	Acceptance Rate	CSF Start	Repository Start	Disposal Canister Size	CSF Total Life Cycle FY 2012 ($/kg)	TVF Total Life Cycle FY 2012 ($/kg)	RF Total Life Cycle FY 2012 ($/kg)	Away from Reactor UNF Management Life Cycle FY 2012 ($/kg)
Canisters Only - Re-Package at Repository (Case 1)	1,500	2020	2040	4	$53.6	$31.5	$85.6	$170.7
	3,000	2020	2040	4	$80.5	$24.5	$102.5	$207.5
	3,000	2020	2040	12	$80.5	$24.5	$59.8	$164.7
	3,000	2020	2040	21	$80.5	$24.5	$47.0	$151.9
	6,000	2020	2040	4	$125.3	$21.0	$140.2	$286.5
	1,500	2020	2055	4	$85.4	$33.8	$85.6	$204.7
	3,000	2020	2055	4	$145.4	$26.7	$102.5	$274.6
	6,000	2020	2055	4	$183.4	$23.2	$144.9	$351.5
	3,000	2035	2055	4	$92.2	$24.5	$96.9	$213.6
Canisters and Bare Fuel - Re-Package at Repository (Case 2)	1,500	2020	2040	4	$160.7	$31.5	$89.2	$281.4
	3,000	2020	2040	4	$286.9	$24.5	$102.7	$414.0
	3,000	2020	2040	12	$286.9	$24.5	$61.0	$372.3
	3,000	2020	2040	21	$286.9	$24.5	$51.1	$362.4
	6,000	2020	2040	4	$480.3	$21.0	$144.7	$646.0
	1,500	2020	2055	4	$227.2	$33.7	$89.2	$350.0
	3,000	2020	2055	4	$417.3	$26.7	$102.7	$546.7
	6,000	2020	2055	4	$562.5	$23.2	$138.1	$723.8
	3,000	2035	2055	4	$217.9	$24.5	$100.5	$342.8
Canisters Only - Re-Package at CSF (Case 3)	1,500	2020	2040	4	$73.9	$31.6	$97.2	$202.7
	3,000	2020	2040	4	$108.3	$24.5	$112.9	$245.7
	3,000	2020	2040	12	$108.3	$24.5	$62.1	$195.0
	3,000	2020	2040	21	$108.3	$24.5	$48.2	$181.0
	6,000	2020	2040	4	$128.7	$21.0	$175.9	$325.6
	1,500	2020	2055	4	$112.9	$33.8	$97.2	$243.9
	3,000	2020	2055	4	$163.5	$26.8	$112.9	$303.1
	6,000	2020	2055	4	$183.7	$23.3	$175.9	$382.8
	3,000	2035	2055	4	$184.9	$24.5	$112.7	$322.2
Canisters and Bare Fuel - Re-Package at CSF (Case 4)	1,500	2020	2040	4	$205.1	$31.3	$92.8	$329.3
	3,000	2020	2040	4	$357.7	$24.2	$112.6	$494.5
	3,000	2020	2040	12	$357.7	$24.2	$61.8	$443.8
	3,000	2020	2040	21	$357.7	$24.2	$47.9	$429.8
	6,000	2020	2040	4	$479.2	$20.7	$151.3	$651.2
	1,500	2020	2055	4	$287.7	$33.3	$92.9	$413.9
	3,000	2020	2055	4	$460.2	$26.3	$112.6	$599.1
	6,000	2020	2055	4	$561.4	$22.8	$151.3	$735.4
	3,000	2035	2055	4	$267.6	$24.2	$111.3	$403.1
	1500 MTHM/yr				3000 MTHM/yr		6000 MTHM/yr	

The overall range in this table is over a factor of 5 when all program elements are included. Care must be taken when applying these data to follow-on cost studies in selecting the appropriate case therefore aligning the critical values for fuel receipt type, processing rate, start of consolidated storage and final disposition, and the program elements to be included. When the final disposition is a repository then the waste disposal package size is also a key variable. The What-It-Takes Table, I-5 only includes the low, high and nominal cost for Cases 3 and 4. Module L1 on Geological Disposal does not include repackaging at the repository, so Cases 1 and 2 are not included. The nominal values selected where those that define a conservative scenario of costs at the moderate 3,000 MTHM/year throughput.

Table I-5. Cost summary table for Consolidated Interim Storage Total Life Cycle Costs.

What-It-Takes Table (2012 $)				
Scenario	Low Cost	Mode Cost	Mean Cost	High Cost
Case 3 - Canisters only – repackage at CSF	$74 /kgHM	$164/kgHM		$185/kgHM
Case 4 - Canisters and Bare Fuel – repackage at CSF	$205 /kgHM	$460/kgHM		$561/kgHM
Escalated to 2015 $				
Case 4 Escalated to 2015$ >	$215/kgHM	$485/kgHM	$430	$590/kgHM
Escalated to 2017 $				
Case 4 Escalated to 2017$ >	$223/kgHM	$501/kgHM	$456/kgHM	$644/kgHM

Figure I-6 diagrams the interim storage cost ranges defined by Case 4, storage of canisters and bare fuel with repackaging the CSF. While the most conservative from the cost stand-point, it includes management of both containerized and bare fuel bundles and will manage receipt of SNF from either storage pools or dry storage at the reactor sites. The FY 2017 values were obtained by escalating the 2012 values by 9 percent. (Note that 5% escalation was used to calculate the 2015 AFC-CBR values from the 2012 AFC-CBR values.)

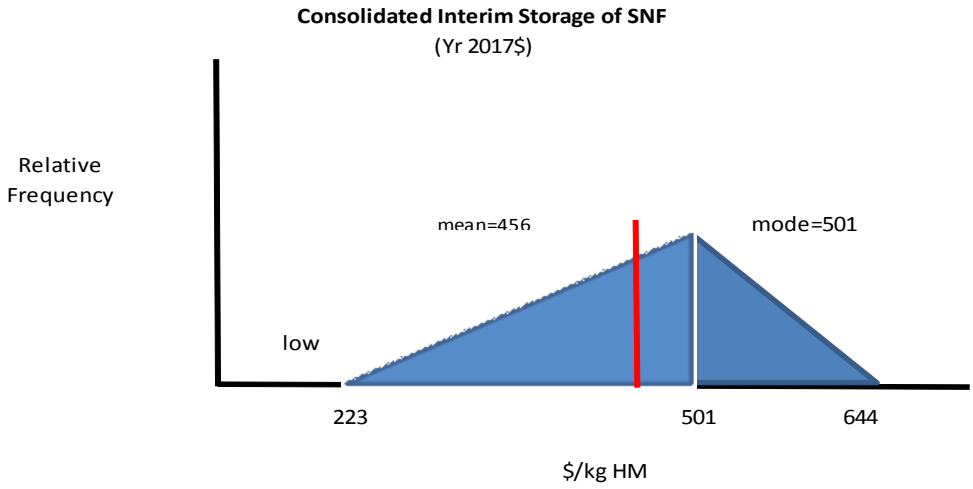


Figure I-6. Consolidated Interim Storage estimated cost frequency distribution.

I-9. SENSITIVITY AND UNCERTAINTY ANALYSES

Table I-3 and I-4 present the average of the high and low range included in the reference document. Inclusion in this additional uncertainty in application of these data in future studies is at the discretion of the cost analyst.

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MODULE J

Near Surface Disposal

Module J

Near Surface Disposal

J-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2006 AFC-CBR)
- **Estimating Methodology for latest (2006 AFC-CBR) technical update from which this 2017 update was escalated:** Bottom-up pre-conceptual design and cost estimate for a commercial Greenfield LLW disposal site. Pricing data from US Private Companies and fees charged by USDOE disposal sites were also used to establish the "What-it-takes" unit cost values for the final geologic disposal of Low Level Waste.

J-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module J. In 2004 and 2005 only rough capital and O&M data were presented. Unit cost ($/m3) data based on an actual design and cost estimate first appeared in the 2006 AFC-CBR.
- **Latest version of module in which new technical data was used to establish unit cost values:** 2006
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The US LLW disposal industry has been undergoing turbulence lately with possible buyouts, lawsuits, and bankruptcies complicating the business outlook. The major players are Energy Solutions (Utah) and Waste Control Services (Texas). It would also be useful to revisit the fees (or calculated unit costs) charged by USDOE sites for the disposal of materials originating at Government sites.

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.

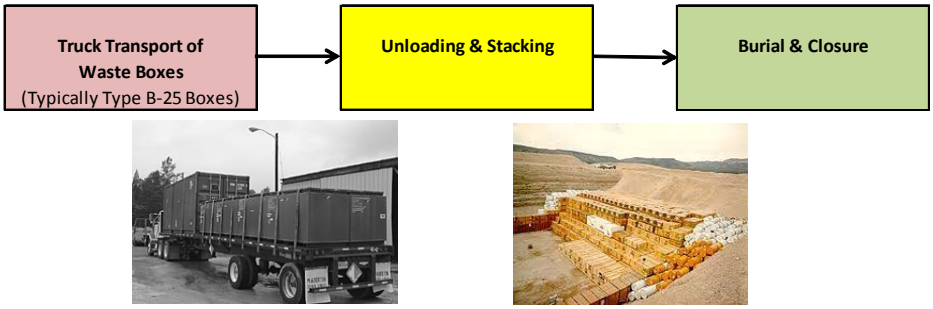

Figure J-1. Functional block diagram for near surface waste disposal.

J-3. PICTURES AND DIAGRAMS

Figure J-2. Low-Level Waste operations at Nevada Test Site (State of Nevada 2009). The NTS has been renamed by the Department of Energy to the Nevada National Security Site

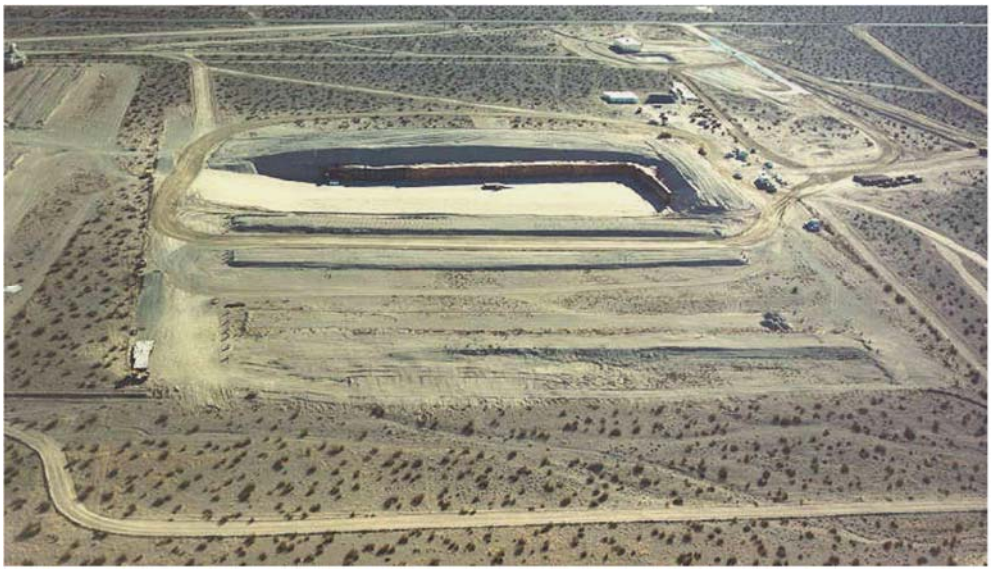

Figure J-3. Nevada Test Site (Nevada National Security Site) low-level waste disposal facility aerial view (State of Nevada 2009).

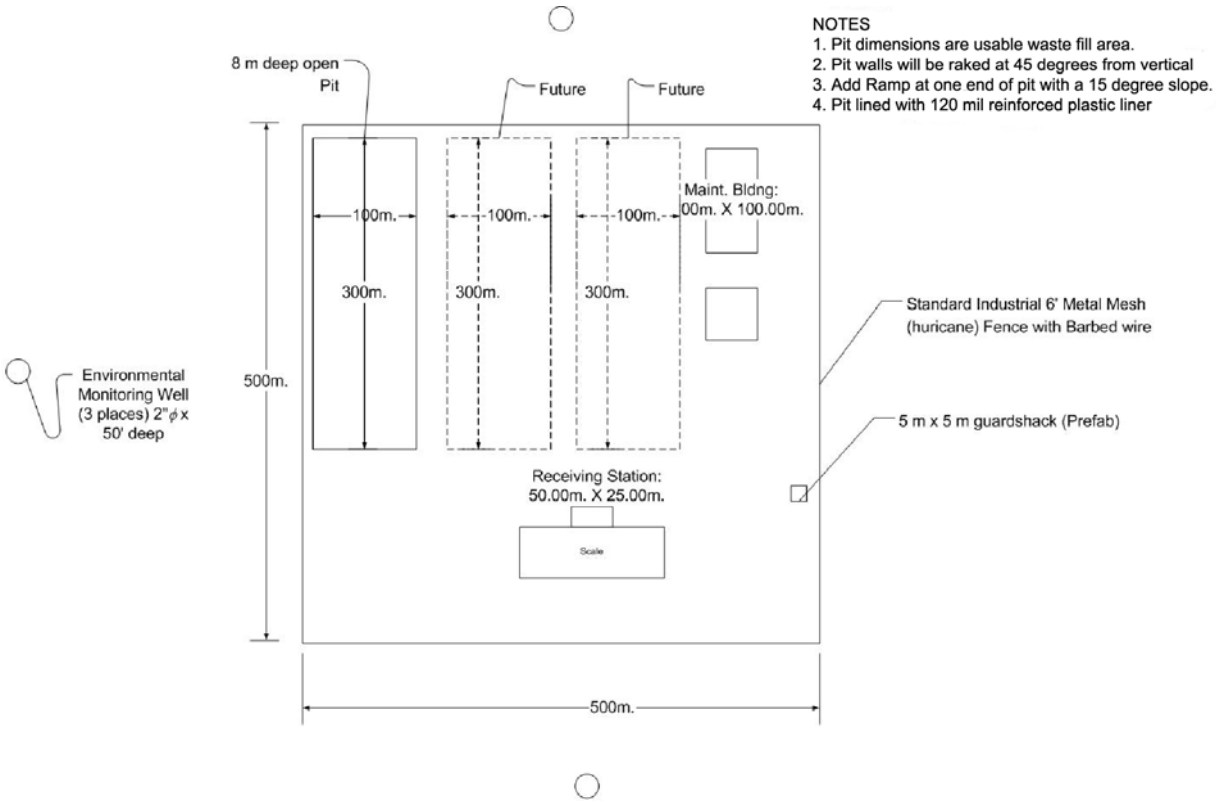

Figure J-4. Typical near surface disposal site dimensions.

J-4. MODULE INTERFACES

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 (Module R).

Module G-3 covers the cost of treating and packaging various types of contaminated materials (bulk solids/debris, liquids, and resins) for disposal as LLW. **So as not to be confused with the G3 Module the J Module covers only the capital and operating expense of the final LLW burial site.** Transportation (Module O2), LLW containers, and ancillary expenditures are excluded. Bulk depleted uranium from enrichment operations and clean REPU from reprocessing operations can also be disposed of as LLW, but the expectation is that it will be dispositioned in special areas of a LLW site due to its higher bulk density and slightly increasing specific activity.. Module K discusses these options in detail. Module J is a terminal module in that nothing leaves once it has been accepted. It should be noted that the majority of disposal containers, sometimes called “B-25 boxes” are relatively inexpensive compared to the disposal operation costs, and they are commercially available from multiple manufacturers.

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 (Now Nevada National Security 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. SCALING CONSIDERATIONS

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 of B-25 Boxes” (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 National Security 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		Quantity	Unit	Matl/Equip Unit Cost	Material/ Equipment	Labor	One Only Mat/Equip	One Only Labor
Code	Description							
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). [2017 note: Some of these facilities are now closed. Prices from the commercial facility are not current, and a new survey would be required to update this Table]

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. DATA LIMITATIONS

- 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 in material from a possible reprocessing facility. 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 contaminated material delivered to the site, which is based roughly on a volume rate similar to the current Nevada Test Site (Nevada National Security 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 What-It-Takes WIT table (2006 $/MTU with escalation to 2017$ using a factor of 1.35).

2006 $					
Reference Cost(s) Based on Reference Capacity	Reference Cost Contingency (+/- %)	Low Cost	Mode Cost	Mean Cost	High Cost
$1,250/m^3	(± 30%) $875–$1,560/m^3	$450/m^3 (Comparable to Envirocare)	$1,250/m^3		$2,500/m^3 (Comparable to US Ecology)
2015 $					
$1625/m^3		$608/m3	$1688/m^3	$1890/m^3	$3375/m3
		Lower capital costs; lower stewardship costs (i.e., Tennessee at $10M)			More stringent requirements for security, environmental protection and long-term stewardship

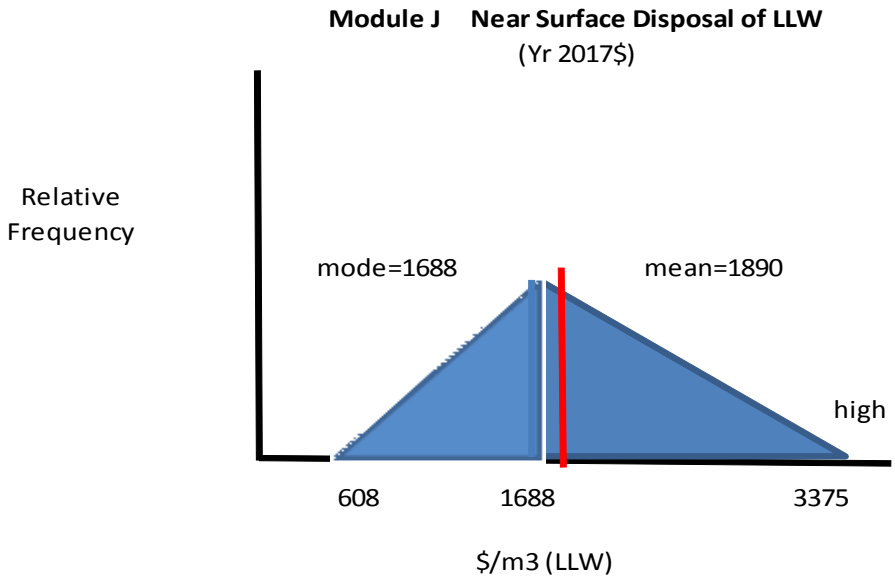

Figure J-5. Module J near surface disposal estimated cost frequency distribution.

J-9. SENSITIVITY AND UNCERTAINTY ANALYSIS

No sensitivity analyses were performed for this module.

J-10. REFERENCES

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J-11. BIBLIOGRAPHY

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K MODULES

Excess Uranium Conversion and Disposal

Module K1-1

Deconversion of Depleted UF6 to Depleted Uranium Oxides

Module K1-1

Deconversion of DUF6 to Uranium Oxides

K1.1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from 2012 values.
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:**
  - For DUF_6 to DUOx deconversion: Actual early operational data for DOE facilities and projected pricing data for private NRC-licensed facility.
  - It should be noted that Module K1-1 does not include geologic disposal of the packaged stable DU oxide. This activity is discussed in Module K1-2.

K1.1-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module K. Enrichment Plant DUF_6 Tails Conversion (Conversion and Disposal were combined). In 2006 AFC-CBR Module K was separated into K1, K2, and K3 to differentiate between deconversion of enrichment plant tails (K1) and deconversion of uranium products (RU) arising from aqueous reprocessing (K2) and pyroprocessing (K3). In 2015 K1 was split into K1-1 (deconversion) and K1-2 (disposal)
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012 for deconversion
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Further analysis by USNRC to establish price for US Government (DOE) deconversion of tails from private US Enrichment plants
  - Published contract information for renewed **deconversion** operations contracts at DOE's Paducah KY and Portsmouth facilities**.** It should be noted that in early CY 2017 these two DOE-EM plants came under a new GOCO contractor: Mid-America Conversion Services. This organization is an LLC composed of US companies Atkins, Westinghouse, and Fluor.

K1-1-1. BASIC INFORMATION

CONTEXT. During the late 1990s and into the 2000s, the US DOE studied disposition options for its 720,000 tonne UF_6 (as of 2007) inventory of depleted uranium (DU). DOE opted to deconvert its UF_6 and dispose of the resulting DU oxide, and plants were constructed at Paducah, KY and Portsmouth, OH to implement this strategy. The *December 2009 Advanced Fuel Cycle Cost Basis Report* (2009 CBR) reviewed the technology and cost analysis literature supporting this project. Having collected data from the DOE project and other domestic and foreign DU deconversion and disposal efforts, the 2009 CBR arrived at a cost estimate for **combined deconversion and disposal operations**.

The subsequent 2012 AFC-CBD update had two parts. First, it reviewed industry events and cost data released subsequent to the 2009 CBR. Second, it reconsidered the data reported in the 2009 CBR in order to break the combined cost estimate into separate estimates for deconversion and disposal. Separating the two processes allowed appropriate low, nominal and high cost estimates to be ascribed to each of the two steps. This is important since the disposal step has much more uncertainty associated with its implementation and cost than the deconversion step. It also permitted modelers to consider post-

deconversion strategies other than near-surface disposal at a LLW facility, the option being pursued by the US and presented in detail as the reference disposal technology in the 2009 and 2012 documents

For this 2015 AFC-CBD document, which is not an update but rather a complete document with all of the background technology and facility information, it was decided to separate Module K-1 into two parts, with Module K-1-1 covering the DUF6 to depleted uranium oxide conversion process and Module K1-2 covering the oxide packaging and oxide geologic disposal. This Module K-1 describes the former and includes some limited new information on deconversion technology and costs obtained in the 2012 to 2015 time frame. Recommended low, mode, high, and mean (expected value) unit deconversion cost projections in year 2015 dollars per kilogram of DU are presented. The reader should note that functional, historical, and operational information from the 2009 and 2012 AFC-CBD documents have been merged. For this reason might be read like a series of newsletters, in which a later paragraph may seem to update or alter time-dependent information in a previous paragraph.

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).

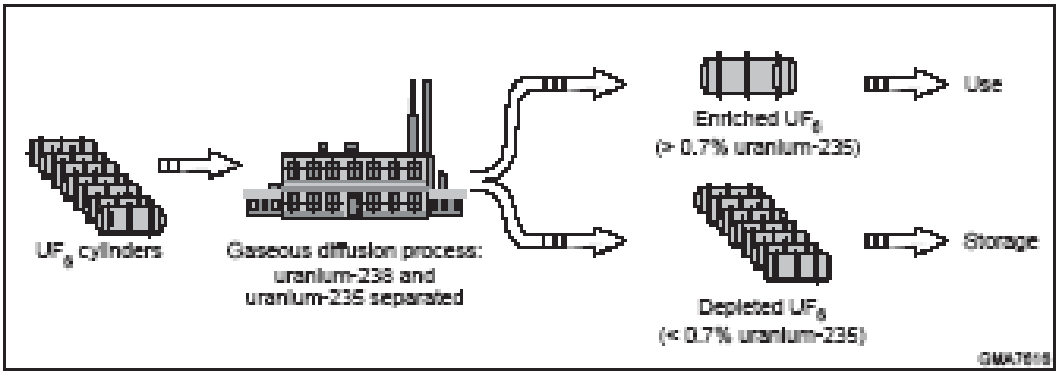

Figure K1-1-1. DUF_6 is the by-product of uranium enrichment (DOE 2001).

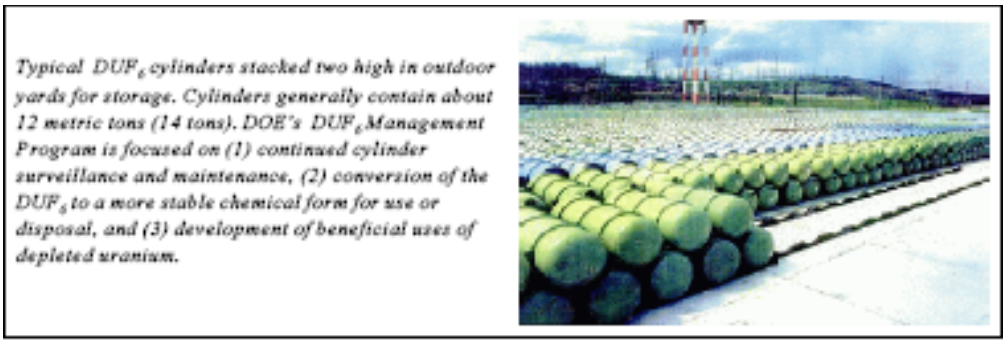

Figure K1-1-2. DUF_6 cylinders stacked for storage at a DOE gaseous diffusion plant site (DOE 2001).

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 for all owners 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.

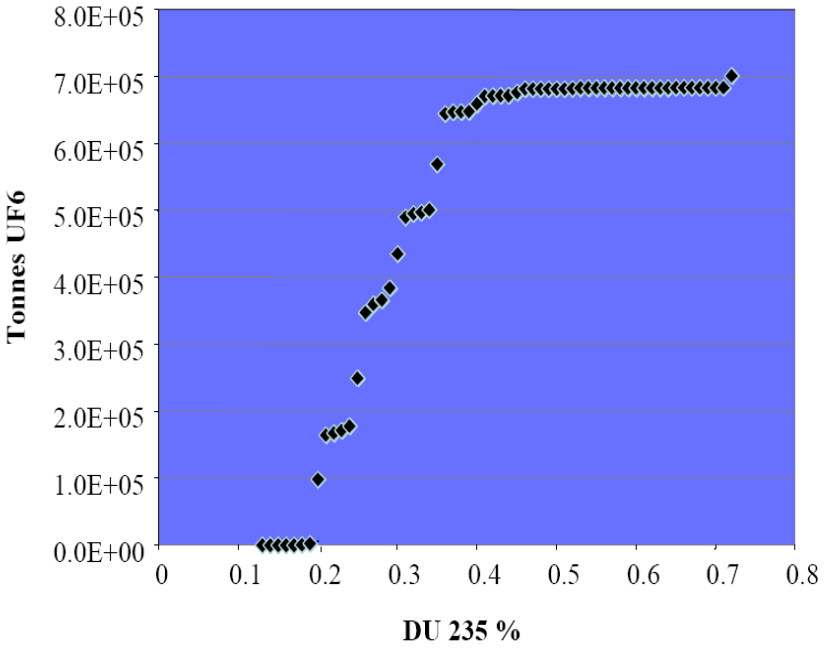

Figure K1-1-3. Cumulative distribution of DUF_6 metric tonnage versus U-235 assay.

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]

[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.

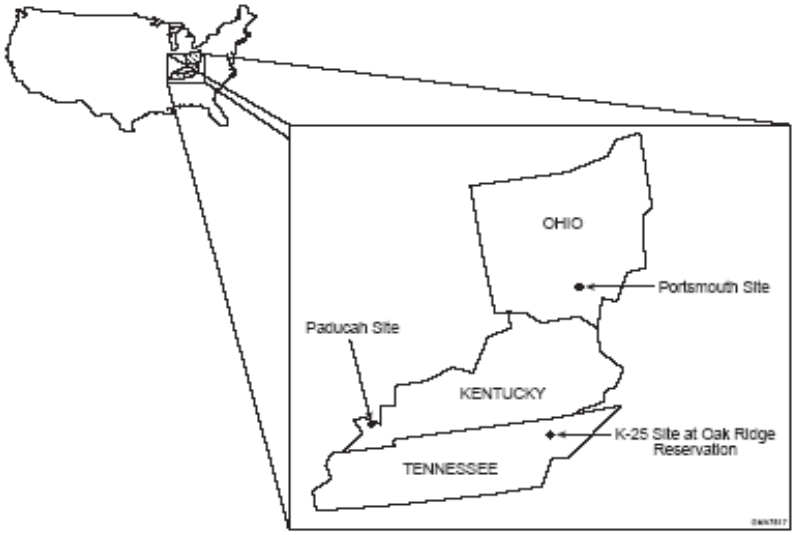

Figure K1-1-4. Source locations of U.S. DUF_6 stockpile (all DUF_6 now at Paducah and Portsmouth) (DOE 2001).

Currently these two deonversion 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 2004a) 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). According to their website this private facility will process ~7,000 MTU/yr and will be an NRC-licensed facility. Its nearness to the LES Enrichment Facility in New Mexico 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 as long as enrichment markets are healthy. 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].)

K1-1-2. 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) → 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).

K1-1-3. PICTURES AND DIAGRAMS

The basic UDS process and material balance, as shown from the Site-Specific Environmental Impact Statement for Paducah (DOE 2004a), is shown on Figure K1-1-5 and described in Table K1-1-1. 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.

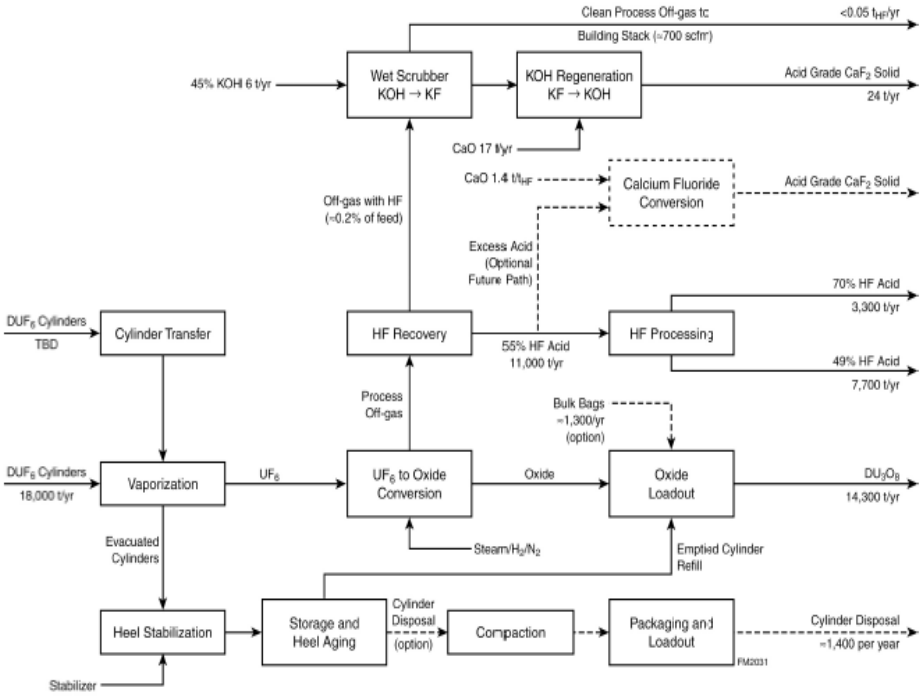

Figure K1-1-5. DUF_6 to DU_3O_8 conversion process (DOE 2007).

Table K1-1-1. 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.

K1-1-4. MODULE INTERFACES

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 compared to processing costs. Module O discusses UF_6 transportation costs.

Back-end interface. (Note: These post-deconversion issues are described in more detail in the K-1-2 DU Oxide Disposal Module.)

K1-1-5. SCALING CONSIDERATIONS

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.

K1-1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The 2012 CBR reported many data points for deconversion, disposal and combined deconversion and disposal costs. These are summarized in Table K1-1-2. Note that Table K-1-2-1 includes cost estimates for deconversion as well as disposal; the full table was carried over from the 2012 CBR because it includes several estimates that combine deconversion and disposal costs. Also included in the table are cost estimates identified by Louisiana Energy Services while it was preparing the license application for its New Mexico enrichment facility [Louisiana Energy Services, 2004]. LES used this data to support of its argument that setting aside $5.5 ($7.04/kg U in 2012) per kg of DU it generated was sufficient to ensure that funds would exist to cover its disposition[d]. The new data presented in Section K1-1-7 concludes the table.

[d]. In the event, LES was required to post a bond of $7.15/kg of DU (2005 dollars).

Table K1-1-2. Summary of deconversion and disposal costs and estimates.

Facility or Author[1]	Scope	Reported Cost [$/kgU]	Basis Year	CPI Factor	**Unit Cost [2012 $/kgU]**	Comments & 2009 CBR Reference
Paducah	Both	3	2004	1.224	**3.67**	DOE 2007; HF credit included
(LLNL Study)	Both	5.38	2004	1.224	**6.59**	Elayat 1997 (Livermore)
(LES Study)	Both	5.5	2002	1.280	**7.04**	NRC 2003
N/A	Both	7.15	2005	1.189	**8.50**	Neary 2005; Bond posted to state of New Mexico to provide surety of disposal funds
(IEER Study)	Both	30	2005	1.189	**35.66**	Makhijani 2005a; IEER position on appropriate value of bond
NTS	Disposal	11.6	2003	1.248	**14.47**	DOE 2005; Thorium disposal. Costs in $/kg Th.
(Diehl Study)	Disposal	110	2007	1.120	**123.21**	Diehl 2007; Discounted as unrealistic
(LLNL Study)	Deconversion	2.64	2002	1.280	**3.38**	HF Sale
(LLNL Study)	Deconversion	3.39	2002	1.280	**4.34**	HF Neutralization
(LLNL Study)	Disposal	1.71	2002	1.280	**2.19**	Trench Disposal
(LLNL Study)	Disposal	2.42	2002	1.280	**3.10**	Vault Disposal
(Claiborne Energy Center Study)	Deconversion	4.93	2002	1.280	**6.31**	Based on quote by Cogema in 1993 for services at Tricastin
(Claiborne Energy Center Study)	Disposal	1.81	2002	1.280	**2.32**	From estimate provided by Urenco in 1993
Data added in 2012 update						
INIS	Deconversion	14.47	2012	1.000	**14.47**	Smaller (Phase 1) plant
INIS	Deconversion	7.35	2012	1.000	**7.35**	Larger (Phase 1&2) Plant
Paducah	Both	5.33	2012	1.000	**5.33**	If a plant identical to Paducah was privately built & operated
INIS	Disposal	1.41	2012	1.000	**1.41**	Low estimate
INIS	Disposal	3.83	2012	1.000	**3.83**	High estimate
1. (Study) = based on a generic plant and process, not tied to a specific facility						

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 K1-1-1 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 $3.34/kg$DUF_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 (including disposal) 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 in the early 2000s 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 C2 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 conversion and geologic 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, now renamed Nevada National Security 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.

K1-1-7. DATA LIMITATIONS

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 product 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.
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 (2007) 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.
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).[e] 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.

Table K1-3. 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

[e]. Personal communication from D. W. Lee, Oak Ridge National Laboratory.

K1-1-8. 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. 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.

2012 Update Table K1-1-4 lists deconversion plants operating and under construction around the world in 2012. Following the commissioning of three plants in 2010, operating deconversion capacity stands at over 41,000 tU in UF_6/year. As of 2007, approximately one-quarter of the ca. 1.5 million tonnes of DU generated around the world have been deconverted (World Nuclear Association, 2012).

Table K1-1-4. Nominal 2012 deconversion capacities, plants operating and under construction.

Operator / Plant	2012 Capacity [tU in UF_6/year]	Notes
AREVA / Tricastin, France	13,500	Opened 1984
Uranium Disposition Services / Portsmouth, OH	9,100	Operations commenced 2010
Uranium Disposition Services / Paducah, KY	12,200	Operations commenced 2010
Rosatom / Zelenogorsk, Russia	6,800	Operations commenced 2010
International Isotopes, Inc./Hobbs, NM	Pending	NRC license decision pending in late 2012; Construction of Phase 1 (2,200 tU/yr) to begin. Planned Phase 2 would bring capacity to 6,600 tU/yr*
TOTAL	41,600 operating; 43,800-48,200 operating & pending	

Data source: WNA 2012

The International Isotopes (INIS) plant is unique in two ways. INIS has acquired assets from the UF_6-to-UF_4 component of the shutdown Sequoyah deconversion plant and is transporting these to its Hobbs, NM site. It also utilizes a different process than the other facilities: INIS' Fluorine Extraction Process (FEP) focuses on recovering high-purity, high value fluorine compounds, in particular SiF_4 (International Isotopes Fluorine Products, 2009).

Construction and operating cost estimates for the facility are available from Ref. (NRC 2011) and decommissioning cost forecasts from (International Isotopes Fluorine Products, 2009). These allow the unit deconversion cost estimates shown in Table K1-2 to be developed. But the acquisition of existing capital stock from Sequoyah may mean that the capital costs are lower than would be the case for an entirely new facility. On the other hand, estimates of proceeds from the sale of fluorine co-products are not available and thus not included in the deconversion unit cost estimate. INIS will likely receive greater

co-product revenues as a result of its FEP process than is the case for other plants that just market a lower-purity HF co-product.

INIS plans to stage the construction of its facility. Construction of Phase 1 is to begin in 2012, with a Phase 2 expansion that would triple capacity to follow several years later. Refs. (International Isotopes Fluorine Products, 2009) and (NRC 2011) provide cost data sets for Phase 1 only as well as Phases 1 and 2 together. Since the data is illustrative of economies of scale benefits that accrue when the capacity is tripled, both sets are shown[f]. Unit deconversion costs, in year 2012 dollars per kg U, are calculated according to the Generation-IV Economic Modeling Working Group (EMWG) methodology referenced and applied in the 2009 CBR.

This facility will be the first privately owned and operated deconversion plant in the world. Hence the real interest rate of capital recommended by the EMWG for private facilities, 10%, was applied. This leads to unit deconversion costs of $7.4/kg U for the large (Phase 1&2) plant and $14.5 for the small (Phase 1 only) alternative, considerably higher than corresponding values for government-owned plants. For example, in the 2009 CBR the EMWG methodology was applied to the Paducah facility but with an interest rate of capital of 3.8%. This analysis led to a deconversion cost of $3.0/kg U in 2004 dollars ($3.7/kg U in 2012 dollars). Therefore, for illustration, the unit deconversion cost for Paducah if it had faced an interest rate of capital of 10% is also shown in Table K1-2. The resulting cost, $5.3/kg U, is close to the $7.4/kg U for the large INIS plant option, but the Paducah estimate includes a credit for the sale of HF. Further economies of scale may also play a role, as the capacity of Paducah is almost 50% greater than that of even the large INIS option.

Table K1-1-5. Unit deconversion costs for INIS and a privately-built plant identical to Portsmouth.

		INIS - Phase 1 Only	INIS - Phase 1&2	Paducah[1]
Overnight Capital	$[2]	1.29E+08	2.07E+08	1.64E+08
Operating	$/yr	1.71E+07	2.43E+07	2.91E+07
Decommissioning	$	1.45E+07	1.72E+07	5.82E+07
Plant Capacity	tonne U/yr	2.23E+03	6.63E+03	9.13E+03
Constr. Time	yr	2.00	2.00	2.00
Operating Lifetime	yr	40.00	40.00	38.00
Interest Rate of Capital	1/yr	0.10	0.10	0.10
Sinking Fund Rate[3]	1/yr	0.10	0.10	0.10
Unit Deconversion Cost	**$/kg U**	**14.47**	**7.35**	**5.33**

1. Private-sector financial assumptions applied to Portsmouth facility capital & operating costs.
2. Year 2012 dollars. Converted from year 2009 dollars for INIS and 2004 dollars for Paducah.
3. Used to amortize decommissioning costs. See 2009 CBR for methodology discussion & reference.

The **mode** estimate, $6/kg U, lies somewhat below the projected cost for the privately operated INIS facility but above the projections for the publicly-owned Paducah plant. As mentioned in the 2009 CBR, the cost estimates for Paducah and Portsmouth appearing in their license applications are known to be optimistic, although realized costs are not yet available. It is likely that the INIS plant would recover significant value, perhaps $1-2/kg U, from sale of fluorine byproducts. This benefit is not reflected in the estimate of Table K1-1-5, and moreover the 10% interest rate of capital may be considered conservative.

[f]. The references give ranges for several of the capital, operating and decommissioning cost components. For this analysis, values at the middle of the range were used. Costs in the references were given in 2009 dollars and were converted to 2012 dollars using the CPI (scaling factor: 1.074). In addition, to simplify the unit deconversion cost calculation for the combined Phase 1 & 2 case, it was assumed that Phase 1 & Phase 2 were constructed simultaneously.

The **low cost** estimate, $4/kg U, is in line with the price quoted by Areva predecessor Cogema for deconversion services in France as well as the most optimistic costs in Table K1-1-5. It is considered to reflect capitalization on economies of scale benefits, ongoing technological advancement, and strong recovery of value from fluorine byproducts.

The **high cost** estimate, $8/kg U, is slightly higher than the estimate for the private INIS facility and close to the value of the bond LES was required to put up to ensure that disposition of its depleted uranium was funded (although that reflects disposal as well). It is more likely to come about if governments phase out their current major role in the industry. It may further reflect a future industry with many small to medium-sized private providers, or a handful of large ones who are able to exert market power. Finally, weak cost recovery from byproduct sale may contribute to this outcome.

Table K1-1-6. "What-it-takes" (WIT) Table (2012$).

	Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Deconversion	$6/ kg U	$4/ kg U	$8/ kg U	$6/ kg U
Disposal	$4/ kg U	$2/ kg U	$22/ kg U	$4/ kg U
Total (2012 values)	$10/kg U	$6/ kgU	$30/ kgU	$10/ kg U
	2009 CBR Values for combined deconversion and disposal:			
Both	$11/kg U	$6/kg U in UF_6	$50/kg U in UF_6	$11/kg U in UF_6

The data in Table K1-1-6 now needs to be updated to year 2017$ for deconversion. It should also be noted that recent data from BWXT Conversion Services[g] (BWXT2014) indicates that their operations costs fall well within the range of Table K1-1-6. This was calculated by dividing their $428M 5-year (2011-2015) contract cost by the approximately 100,000 MTDUF6 they have already processed to date. The excalation factor from 2012$ to 2017$ is only 1.09, so the rounded escalated 2017$ unit costs are just slightly above the 2012 values when rounded to the nearest tenth of adollar. Figure K1-1-6 and Table K1-1-7 show the triangular distribution and defining parameters for the unit deconversion cost and its uncertainty. The mean or "expected value" of the distribution is $6.5/kgU in 2017$. For the 2017 Table and figure below an escalation factor of 1.09 (from 2012$), representing escalation based on the escalation table in the "Escalation Considerations" Section of the Main part of this report, has been assumed.

Table K1-1-7. "What-it-takes" (WIT) Table (2017$).

	Reference Cost(s) Based on Reference Capacity	Low Cost 2017$	Mode Cost 2017$	Mean Cost 2017$	High Cost 2017$
Deconversion only (without oxide geologic disposal)	$6/ kg U in 2012$	$4.4/ kg U	$6.5/ kg U	$6.5/ kg U	$8.7/ kg U

[g] BWXT conversion services was the GOCO (Government-Owned Contractor-Operated) contractor for the Paducah and Portsmouth deconversion facilities prior to selection by DOE of Mid-America conversion services in September 2016.

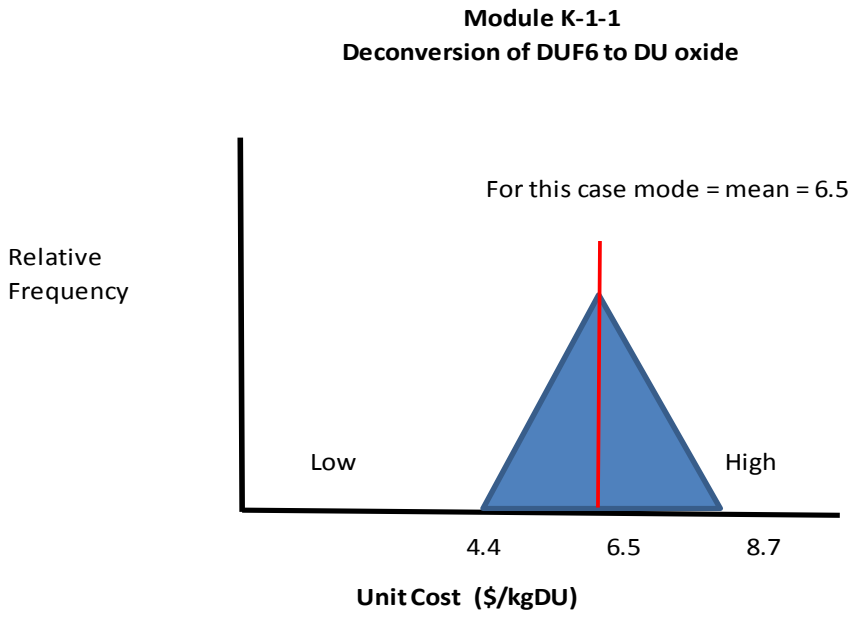

Figure K1-6. Depleted U deconversion estimated unit cost frequency distribution (2017$).

K1-1-9. SENSITIVITY AND UNCERTAINTY ANALYSES

Not presently available.

K1-1-10. REFERENCES

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Module K1-2

Disposition: Geologic Disposal of Depleted Uranium Oxides

Module K1-2

Disposition: Geologic Disposal of Depleted Uranium Oxides

K1.2-MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- Constant $ base year for 2017 Update**: FY 2017**
- Nature of this 2017 Module update from previous AFC-CBRs**: escalation only (from 2012$)**
- Estimating Methodology for latest (201 AFC-CBR) technical update from which this 2017 update was escalated:
  - For disposal of DU oxide converted product: 2015 Parametric analysis of disposal technologies based on projected costs for other nuclear materials [viewgraph report by Schneider and Williams: 2015 supplementary document 2017-CBU-SD] This viewgraph report assumed year 2012$
  - It should be noted that Module K1-2 does not include deconversion of the DUF6 to a stable oxide. This activity is discussed in Module K1-1.

K1.2-RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared**: 2004 as Module K: Enrichment Plant DUF6 Tails Conversion (**Conversion and Disposal were combined**). In 2009 AFC-CBR Module K was separated into K1, K2, and K3 to differentiate between deconversion of enrichment plant tails (K1) and deconversion of uranium products (RU) arising from aqueous reprocessing (K2) and pyroprocessing (K3). In 2015 K1 was split into K1-1 (deconversion) and K1-2 (disposal)
- **Latest version of module in which new technical data was used to establish unit cost ranges**: 2015
- New technical basis: [Schneider, E. and Williams, K.A.; ***DU and RU Disposal Costs***; Powerpoint presentation dated April 2015; 65 pages supplementary document 2017-CBR-SD]. It was used to establish and bound the unit cost ranges. Costs are expressed in 2012 constant dollars.
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The cost will be affected by the final regulations promulgated by the NRC for safe burial of a significant radon-generating uranium material. DOE and its GOCO deconversion contractors are negiating with private waste handlers Energy Solutions (Clive, Utah) and WCS (Andrews County, Texas) for shallow burial of the bulk packaged DU oxide. The trade press may include some cost information as well as any contract announcements by DOE-EM and its winning bidder.

K1.2-1. BASIC INFORMATION

Context. During the late 1990s and into the 2000s, the US DOE studied disposition options for its 720,000 tonne UF_6 (as of 2007) inventory of depleted uranium (DU). DOE opted to deconvert its UF_6 and dispose of the resulting DU oxide, and plants were constructed at Paducah, KY and Portsmouth, OH to implement this strategy. The *December 2009 Advanced Fuel Cycle Cost Basis Report* (2009 CBR) reviewed the cost analysis literature supporting this project. Having collected data from the DOE project and other domestic and foreign DU deconversion and disposal efforts, the 2009 CBR arrived at a cost estimate for **combined deconversion and disposal operations**.

The 2012 AFC-CBR update had two parts. First, it reviewed industry events and cost data released subsequent to the 2009 AFC-CBR. Second, it reconsidered the data reported in the 2009 AFC-CBR in order **to break the combined cost estimate into separate estimates for deconversion and disposal**. Deconversion is an industrially-achieved process with large plants operating in the US and France. It is described in detail in Module K1-1. There is relatively little uncertainty associated with these deconversion costs. On the other hand, considerable disagreement exists between credible estimates of the cost of immobilizing and disposing large amounts of DU. (Much of the disagreement concerns which geologic disposal requirements and methodologies are adequate to protect health and the environment,) Separating the two processes (deconversion and disposal) will allow appropriate low, nominal and high cost estimates to be ascribed to each step. It will also permit modelers to consider post-deconversion strategies other than near-surface disposal at a LLW facility, the option being pursued by the US and presented here.

In this "stand alone" 2015 AFC-CBR the intent is to include all of the relevant information above; however, for purposes of clarity it has been decided to split this K-1 Module into two parts: 1.) Module K1-1 which will consider only the deconversion of depleted UF6 to a stable oxide form, and 2) Module K1-2 which will explore the many possible options for permanent geologic disposal of the packaged depleted oxides. Unit cost probability distributions and a mean (expected value) in $/kgDU are reported in both Modules.

This Module K1-2 deals only with the latter (geologic disposal), and assumes that some stable oxide form exists in packages provided by the UF_6 deconversion contractor. The cost analysis here will include all additional treatment, additional repackaging if required, geologic emplacement, and subsequent monitoring costs required to safely dispose the material in an underground facility. This 2015 Module will also be informed by a recent 30+ page report (Schneider and Williams) taking a detailed look at several packaging and geologic disposal options. Many of these are options not considered in the 2009 AFC-CBR or the 2012 Update AFC-CBR. The chosen projected unit cost values, range, probability distribution, and expected value are all from this recent report.

Basic Information. Early in the DOE DUF6 disposition program it 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 now renamed Nevada National Security Site) near Beatty, Nevada. Construction of the two DOE-owned conversion plants commenced on July 31, 2004 and they were completed in 2010, and are now operating. Early on it was determined that DOE's LLW facility at the Nevada Test Site (now the Nevada National Security Site) was the more economical and environmentally acceptable location for disposal of the DOE-legacy derived U_3O_8 (DOE 2004a and DOE 2004b). Now it appears that two commercial sites in the West are also possible disposal candidates. No material from the DOE Deconversion Plants, now operated by BWXT Conversion Services, has yet been shipped West and buried. The holdup is related to environmental, health, and regulatory issues as will be explained below.

K1.2-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Disposal of the DU_3O_8 powder resulting from conversion has its own regulatory and procurement issues. UDS (now BWXT Conversion Services) or any other conversion plant owner/operator will need to contract with an LLW disposer, such as WCS, 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 combined 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 (NRC 2004). 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 (Fahys, 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 an airborne 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.

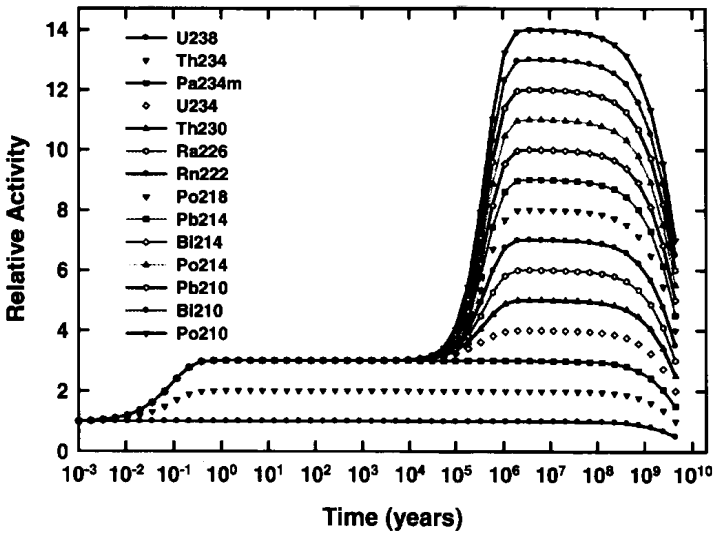


Figure K1-2-1. Buildup of decay products from depleted uranium as a function of time.

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).

K1.2-3. PICTURES AND DIAGRAMS

Figure K1-2-2 shows the generic schematic for the steps involved in the disposal of deconverted DUF_6. Some concepts may involved repackaging or processing the oxides (grouting). Transportation costs are not covered in this Module but are small compared to disposal costs. Because of the low specific activity of depleted uranium oxides, conventional commercial trucks and railcar transport can be used.

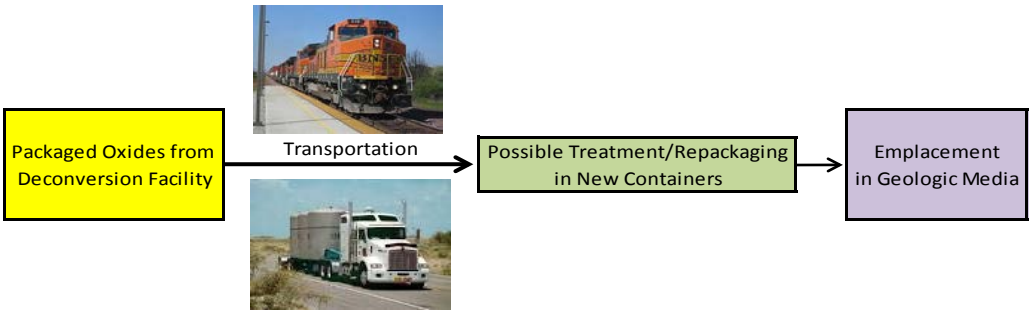


Figure K1-2-2 Generic Disposal Path for Oxides from Deconverted DUF_6.

K1.2-4. MODULE INTERFACES

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. The inherent geology of the disposal medium may be an issue, and performance analyses may be required to certify particular locations and geologies. 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). These issues are discussed in detail in a recent report (Schneider and Williams).

K1.2-5. SCALING CONSIDERATIONS

Since disposal methods require relatively little process chemistry or in-plant processing, process scalability (i.e. plant cost as a function of capacity) is not really an issue. Disposal costs are generally assessed on a cost per volume basis, for this reason powder bulk density, packaging efficiency, and emplacement efficiency will be major cost factors which will drive the cost per unut mass of DU disposed.

K1.2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The 2009 and 2012 CBRs reported many data points for deconversion, disposal and combined deconversion and disposal costs. These are summarized in Table K1-2-1. Note that Table K-1-2-1 includes cost estimates for deconversion as well as disposal; the full table was carried over from the 2012 CBR because it includes several estimates that combine deconversion and disposal costs. Also included in the table are cost estimates identified by Louisiana Energy Services while it was preparing the license application for its New Mexico facility. LES used this data to support of its argument that setting aside $5.5 ($7.04/kg U in 2012) per kg of DU it generated was sufficient to ensure that funds would exist to cover its disposition[h]. The new data presented in Module K-1 of the 2012 AFC-CBR Update concludes the table.

Table K1-2-1. Summary of deconversion and disposal costs and estimates.

Facility or Author[1]	Scope	Reported Cost [$/kgU]	Basis Year	CPI Factor	**Unit Cost [2012 $/kgU]**	Comments & 2009 CBR Reference
Paducah	Both	3	2004	1.224	**3.67**	DOE 2007; HF credit included
(LLNL Study)	Both	5.38	2004	1.224	**6.59**	Elayat 1997 (LLNL Study)
(LES Study)	Both	5.5	2002	1.280	**7.04**	NRC 2003
N/A	Both	7.15	2005	1.189	**8.50**	Neary 2005; Bond posted to state of New Mexico to provide surety of disposal funds
(IEER Study)	Both	30	2005	1.189	**35.66**	Makhijani 2005a; IEER position on appropriate value of bond
NTS	Disposal	11.6	2003	1.248	**14.47**	DOE 2005; Thorium disposal. Costs in $/kg Th.
(Diehl Study)	Disposal	110	2007	1.120	**123.21**	Diehl 2007; Discounted as unrealistic - see 2009 CBR
Data quoted in K1-4 review						
(LLNL Study)	Deconversion	2.64	2002	1.280	**3.38**	HF Sale
(LLNL Study)	Deconversion	3.39	2002	1.280	**4.34**	HF Neutralization
(LLNL Study)	Disposal	1.71	2002	1.280	**2.19**	Trench Disposal
(LLNL Study)	Disposal	2.42	2002	1.280	**3.10**	Vault Disposal
(Claiborne Energy Center Study)	Deconversion	4.93	2002	1.280	**6.31**	Based on quote by Cogema in 1993 for services at Tricastin
(Claiborne Energy Center Study)	Disposal	1.81	2002	1.280	**2.32**	From estimate provided by Urenco in 1993
Data added in this update						
INIS	Deconversion	14.47	2012	1.000	**14.47**	Smaller (Phase 1) plant
INIS	Deconversion	7.35	2012	1.000	**7.35**	Larger (Phase 1&2) Plant
Paducah	Both	5.33	2012	1.000	**5.33**	If a plant identical to Paducah was privately built & operated
INIS	Disposal	1.41	2012	1.000	**1.41**	Low estimate
INIS	Disposal	3.83	2012	1.000	**3.83**	High estimate
1. (Study) = based on a generic plant and process, not tied to a specific facility						

[h]. In the event, LES was required to post a bond of $7.15/kg of DU (2005 dollars).

Antinuclear groups such as Institute for Energy and Environmental Research (Makhijani and Smith 2005a) suggest that even a bond of $8.5 per KgDU 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).

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.

K1.2-7. DATA LIMITATIONS

The following consideration is relevant to depleted-uranium materials in the fuel cycle:

- 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).[i] Even at a government site, such as Nevada Test Site, some radon amelioration measures are likely to be required. As mentioned earlier, NTS or commercial sites such as WCS in Texas and Envirocare (Energy Solutions) in Utah are the preferred disposal options. A new (Aug 2015) report (Schneider and Williams) reviews other options.

In general, the DUF_6 conversion/disposal step of the fuel cycle can be placed in the viable-commercial category of technology readiness.

K1.2-8. COST SUMMARIES

Module K1-1 presented cost data for a private deconversion facility to be built by INIS. There was also some data found which considered disposal costs for their deconverted product. INIS plans to dispose of its DU_3O_8 at a LLW facility. Ref. [International Isotopes Fluorine Products, 2009] identified the Energy Solutions facility in Utah and Waste Control Specialists in Texas as suitable facilities. Low and high range disposal cost estimates are given in [NRC, 2011] in 2009 dollars for the Phase 1&2 option; Table K1-2-2 converts these estimates to 2012 dollars and divides by the Phase 1&2 capacity to arrive at unit disposal costs.

[i]. Personal communication from D. W. Lee, Oak Ridge National Laboratory.

Table K1-2-2. INIS low and high estimates of DU and other waste disposal.[1]

	Low Estimate		High Estimate	
	M$(2012)/yr	$/kg U	M$(2012)/yr	$/kg U
DU3O8	8.59	1.30	24.16	3.65
Other wastes*	0.78	0.12	1.23	0.19
Total Disposal Cost	9.37	**1.41**	25.40	**3.83**
1. Process and miscellaneous LLW, RCRA and sanitary waste associated with DU operations				

Based on the above and other cost studies, the following cost parameters were selected for the 2012 update to the AFC-CBD:

- The **mode** estimate, $4/kg U, is closest to the high-end forecast provided by INIS. It also lies above estimates made by Urenco and LLNL. It assumes that shallow trench burial, or concretization followed by vault burial, will remain feasible even as large amounts of DU reach LLW facilities. But it considers that scale effects may be small or even negative: i.e., disposal of hundreds of thousands of tonnes of DU at a single site may increase unit costs by necessitating deeper burial and/or more extensive and costly vault structures to mitigate radon release or migration into soil. Also, disposal costs have risen over time (see Modules J, K2 and K3) and it is conservative to build in an assumption that they will keep doing so.
- The **low cost** estimate, $2/kg U, compares with the most favorable of the estimates in Table K1-2-3. It assumes that scale effects will be neutral or positive, that shallow trench burial will remain feasible, and that disposal cost escalation will not play a significant role.
- The **high cost** estimate, $22/kg U, is informed by two entries in Table K1-2-3: the $14.5/kg Th cost to DOD of disposing of thorium holdings at the Nevada Test Site and the IEER estimate of $35.7/kg U for deconversion/disposal if deep burial is required. The thorium data point reflects actual, realized costs; while the amount of Th disposed was not large, significant scale benefits may not be present. The IEER figure assumes that the radon source arising from shallow burial DU will be judged unacceptably high so that deep burial will become necessary. $22/kg U is the average of the DOD and IEER figures (having subtracted the nominal deconversion cost from the IEER number), so the high estimate gives equal weight to deep burial and immobilization/disposition in a specialized facility at NTS as cost drivers.

Table K1-2-3. “What-it-takes” (WIT) Table from 2012 AFC-CBR Update (2012$).

	Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Selected Values (Nominal Cost)
Deconversion	$6/ kg U	$4/ kg U	$8/ kg U	$6/ kg U
Disposal	**$4/ kg U**	**$2/ kg U**	**$22/ kg U**	**$4/ kg U**
Total (2012 values)	$10/kg U	$6/ kgU	$30/ kgU	$10/ kg U
	2009 CBR Values for combined deconversion and disposal:			
Both	$11/kg U	$6/kg U in UF_6	$50/kg U in UF_6	$11/kg U in UF_6

We now report the summarized results (in 2012$) of the most recent August 2015 study (See Schneider and Williams presentation in supplementary documents) which addresses disposal only and considers multiple geologic disposal methods.

The **low-cost** case reflects the nominal cost of shallow vault DU disposal reported in Module K1 of the earlier AFC CBRs. This cost estimate was itself a synthesis of several other analyses, and additional calculations for two vault facilities presented in the Schneider-Williams study confirm the value of $4/kg DU. Note that the estimated cost of disposal of DU in shallow boreholes (Case 4a in Schneider and Williams) lies near this value as well. This is unsurprising since the depth and amount of excavation associated with shallow boreholes are similar to those of LLW vaults.

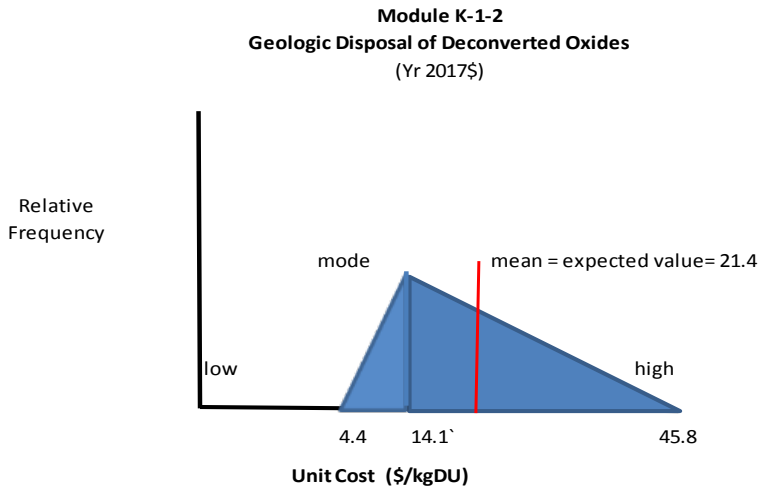
In a substantial change from the 2009 and 2012 AFC CBRs, both the most likely and high cost cases assume that measures beyond shallow vault disposal will ultimately be needed to disposition a growing US DU inventory. While shallow disposal of hundreds of thousands of tonnes of DU may ultimately be realized at WCS, Energy Solutions' Clive facility, NNSS or elsewhere, both co-disposal in a DGR (Case 3a in study) and disposition in intermediate-depth boreholes (Case 4b in study) are considered to be viable with a high degree of confidence even for very large amounts of DU. Hence these are selected to represent the **mode or most likely case**, which is assigned a value of $12/kg DU. Note that DGR case 3a assumes that the excavated footprint of the repository does not need to be expanded in order to co-dispose of DU.

Finally, the **high-cost** case takes the pessimistic view that the DU must be disposed in substantially the same manner as HLW. The two representative cases are now 3b (DGR disposal with additional excavation required to accommodate a larger footprint) and 4c (deep borehole disposal). A cost of $40/kg U is selected, with only one significant figure preserved to reflect the uncertainty associated with this outcome. Table K1-2-4 summarizes the Schneider-Williams results, following the 'what-it-takes' table format of the AFC-CBR**. This new cost analysis was performed in 2012$ to allow consistency with the 2012 CBR, so escalation from 2012 dollars to 2017 dollars was necessary for the table and figure below**. For this 2017 Module K1-2 version, further escalation (a factor of 1.09) from 2012 to 2017 is assumed, and is based on the escalation indices in the "Escalation Considerations" chapter in the main 2017 AFC-CBR.

Table K1-2-4 Unit Disposal Costs for Depleted Uranium Oxides in $/kgDU (2017$)

Low Cost	Mode Cost	Mean Cost	High Cost
$4.4/kg DU	$14.1/kg DU	$21.4/kg DU	$45.8/kg DU
Large quantities of DU can be disposed as LLW in shallow trenches (Case 1) or shallow boreholes (Case 4a)	DU must be disposed in intermediate-depth boreholes (Case 4b) or co-disposed in a DGR (Case 3a)	Calculated	DU must be disposed in deep boreholes (Case 4c) or co-disposed in a DGR with substantial additional excavation required (Case 3b)

Figure K1-2-3 shows the resulting probability distribution and associated calculated mean or "expected value".



K1.2-9. Figure K1-3. Depleted U conversion and disposition estimated unit cost frequency distribution.

K1.2-10.SENSITIVITY AND UNCERTAINTY ANALYSES

Not presently available.

K1.2-11.REFERENCES

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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.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest technical updates from which this 2017 update was escalated:**
  - Conversion and **storage costs** were based on literature survey and some adjustments made in 2009 AFC-CBR. Moxable UO2 preparation costs were revisited in 2012 AFC-CBR.
  - Geologic disposal costs were based on E. Schneider and K. Williams' 2015 analysis cited in the K1 module. **A view graph report of this analysis is a supplementary document to this 2017 AFC-CBR. (2017-CBR-SD-7)**

K2.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2006 as Module K2.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009 and 2012 for most REPU chemical conversion and storage steps, 2015 for oxide geologic disposal step, 2012 for REPU to MOX diluent process.
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Russia occasionally publishes reports on their reprocessed uranium recycling program. New ones might be available.
  - Canada and China are still considering uranium recycling despite the fact that natural U is presently very cheap due to depressed market.

K2-1. BASIC INFORMATION

2009 AFC-CBD 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 or sometimes RU). For LWR operating on enriched UOX, only a small fraction of the total initial uranium radioisotopes is 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 (year 2006) 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 reprocessed 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). Erich 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 uranium 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 (2004), 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

2012 AFC-CBD Basic Information. The 2009 AFC-CBR described in detail the technical and economic considerations associated with the storage, possible recycle, and possible permanent disposition of uranium arising from the aqueous reprocessing of LWR fuels. The choice between the options will be driven mainly by economic considerations, especially the price of natural uranium, for which RU is a substitute. A recent EPRI study [Machiels, 2010] describes these factors and other challenges associated with recycle of uranium and other actinides. The practice of uranium recycle has changed little from 2009. Russia is still the most active player in this area and still takes European RU for conversion, purification, re-enrichment, and refabrication of LWR fuel for use in European LWRs. [Department of Nuclear Power and Nuclear Fuel Cycle, 2010] is a proprietary Russian report (in English) describing the whole operation, its practical, environmental, and economic aspects, and the multiple process steps and facilities needed for its accomplishment. The author of this chapter highly recommends the purchase of this document from IBR to anyone who really wants to understand the details of uranium recycle. No US utilities or enrichers have publicly indicated interest in uranium recycle at this time, since the price of virgin (unirradiated) low-enriched uranium does not justify its consideration.

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 storage boxes that act as shielding against the potent gamma radiation building up from U-232 decay daughters in the inner REPU-containing boxes.
- **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 of enrichment plant derived DU or its compounds as Class A LLW is still an environmental and regulatory issue, as discussed in Module K-1. For current LWR fuel burnups, small amounts of plutonium, neptunium, and technetium, in addition to the usual uranium decay products of radon make this reprocessing-derived material considerably more radioactive than enrichment plant depleted U_3O_8, which should have no or extremely small amounts of fission products or transuranics present. It is likely that low-level waste disposal sites, such as Envirocare and Barnwell, could not

presently accept this type of waste under current regulations.[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 plant tails-derived DU for a future breeder fuel resource, and the former adds about 10% more material to the latter in overall resource sustainability terms. Geologic disposal of REPU was re-examined from a cost standpoint in 2015 (Schneider and Williams 2015)

- **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 cost for this step was reexamined in 2012.

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.

K2-3. PICTURES AND DIAGRAMS

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.

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)

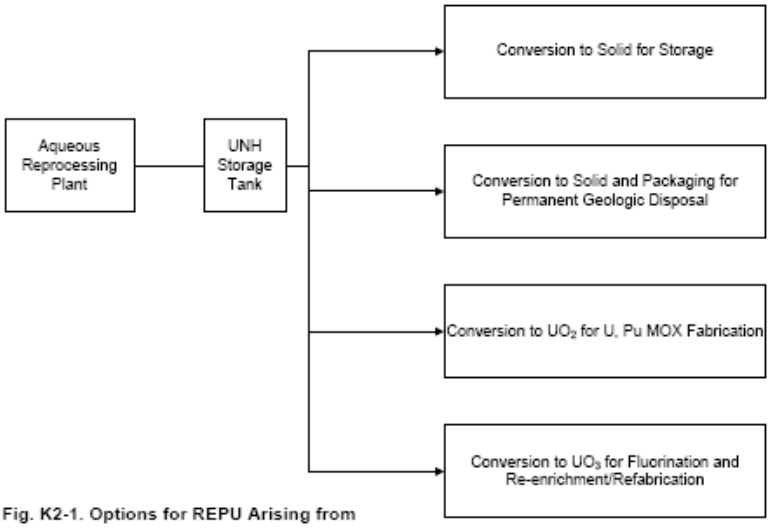


Fig. K2-1. Options for REPU Arising from Aqueous Reprocessing of LWR Fuels

Figure K2-1. Options for reprocessed uranium arising from aqueous reprocessing of light-water reactor fuels.

K2-4. MODULE INTERFACES

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 (see Module O) 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 enrichment plant "virgin" tails derived DU_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 geologic repository without major spacing issues.

An option not yet considered might be to blend enrichment tails-derived 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 or double-counted 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 ($/SWU) and unit fabrication costs ($/kgHM) by up to 20% above that for virgin feed-derived materials.

K2-5. SCALING CONSIDERATIONS

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. 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 1993) 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 (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 enrichment, such as a laser-based process, 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).

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.

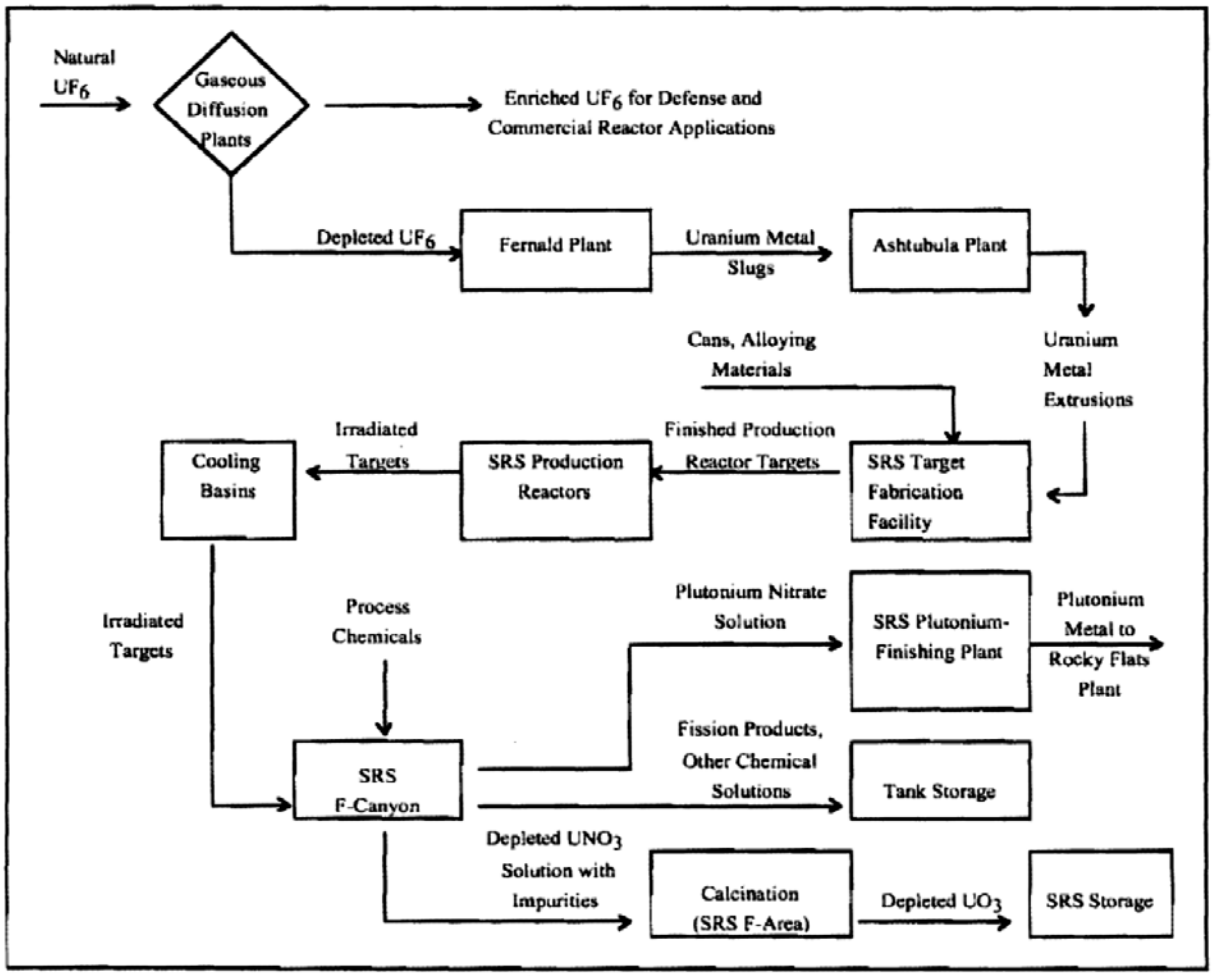


Figure K2-2 Former DU-related steps at Savannah River Site and other Weapons Complex Sites (White 2009).

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 (Fahys; 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 kg U.

K2-7. DATA LIMITATIONS

No information provided.

K2-8. COST SUMMARIES

Some new cost data has been gleaned from various literature sources since 2009. Nearly all of it is associated with the cost of solvent extraction purification (U-232 daughter removal by aqueous polishing) and the conversion of the resultant clean product to UF6 for introduction to an enrichment facility. Unit cost data from WISE (Europe), EPRI (USA), and IBR (Russia) are presented in the Table K2-2. The IBR data had to be adjusted to fit the scope of work described in the left side of the table.

Table K2-2. Aqueously-reprocessed uranium unit handling costs per references (from 2012 AFC-CBD) Update).

Study or Ref /Year	Low Value ($/kgU)	Reference Value $/kgU $/kgU	High Value ($/kgU)
Aqueous polishing and conversion of UNH product from aqueous reprocessing plant to UF6 for re-enrichment (WISE fuel cycle calculator default value)	N/A	39	N/A
Same process as above (EPRI Report 1020659)	15 (would be 5 for NATU w/o aqueous polish)	45	60 (would be 20 for NATU w/o aqueous polish)
Same process as above: (IBR/Moscow Report IBR 2006 & 2008)	38	45	60
Clean UNH to MOX quality UO2 powder (communication from NNSA NA-26 Pu-disposition program)		60	

The last row of the table includes data for converting reprocessed UNH to a UO2 powder form for the production of MOX. This can be accomplished by either a “wet” (aqueous) or “dry” chemical process. The stringent powder morphology and impurity standards for MOX fuel UO2 account for the high unit cost. The $60/kgU value is an approximate figure given to the author by a participant in the NNSA MOX Program for disposition of US weapons plutonium. (The US program uses depleted UO2 as the MOX diluent rather than UO2 from RU; however, the processes and resultant costs would be similar.)

Table K2-3. Cost summary table for reprocessed uranium disposition options (Constant 2008 dollars).

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	$72/kgU if regulatory and siting difficulties arise	$93/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

The What-it-takes Table K2-4 for the 2012 AFC-CBR is changed very little from the corresponding Table in the 2009 AFC-CBR (Table K2-3). Since no new cost data sources were found for RU storage or disposal it was decided to keep the 2009 values. Since escalation from the 2008 to 2012 time frame has been minimal, the 2009 AFC-CBR unit costs are not adjusted. Only three table entries have been changed to reflect new cost information. The $45/kgU "nominal" value for purification and conversion to UF6 is supported by multiple data sources in Table K2-2. The MOX-UO2 related conversion unit costs for RU has been changed as a result of recent data from the NNSA MOX program. Costs have been lowered to reflect K1-2 DU oxide disposal costs plus a premium to handle the higher specific activity of reprocessed material.

Table K2-4. Cost summary 'What-It-Takes' (WIT) table for aq. reprocessed uranium disposition options (Constant 2012 dollars).

U-Handling Step	Upsides (Low Cost)	Selected Value (Nominal Cost)	Downsides (High Cost)
Conversion of UNH to U308 storable form:			
"New" UNH to U308	$4/kgU	$12/kgU	$17/kgU
"Old" UNH to U308 including removal ofU-232 daughters	$20/kgU	$40/kgU	$50/kgU
Reprocessed U_30_8 40-year Storage: Based on $6/kg U for 80,000 MTU/yr Storage Capacity. Annual costs of $1.5M to $5M/yr	$7/kgU if temporary shallow burial allowed	$9/kgU	$30/kgU if facility regulatory and construction difficulties ensue or very long term storage is required
Aqueously-derived reprocessed U308: Permanent Geologic Repository Disposal	$61/kgU if above temporary storage package could be permanently emplaced	$72/kgU including repackaging, transport, emplacement, and perpetual surveillance	$93/kgU if regulatory and siting difficulties arise with "nominal" option
Preparation for RUOX recycle (pre-enrichment):			
"New" product to UF_6 (no aq polish)	$6/kgU	$14/kgU	$20/kgU
"Old" product to UF6 (aq removal ofU-232 daughters)	$30.kgU	$45/kgU (new for 2012)	$60/kgU
Conv to High grade UO2 powder diluent for MOX fuel:			
"New" product for immediate contact-handling to "moxable UO2":	N/A	$60/kgU (new for 2012)	N/A
"Old" product processing requiring removal ofU-232 daughters prior to contact handling	N/A	$95/kgU (new for 2012)	N/A

Table K2-5 shows the above costs escalated to 2017 from 2009$ for most entries using the factor of 1.14 from the "Escalation Considerations" data in the Main Report. The REPU disposal values have been adjusted to take into account the new knowledge gained from the research to prepare Module K1-2 (Depleted Uranium Oxide Geologic Disposal).

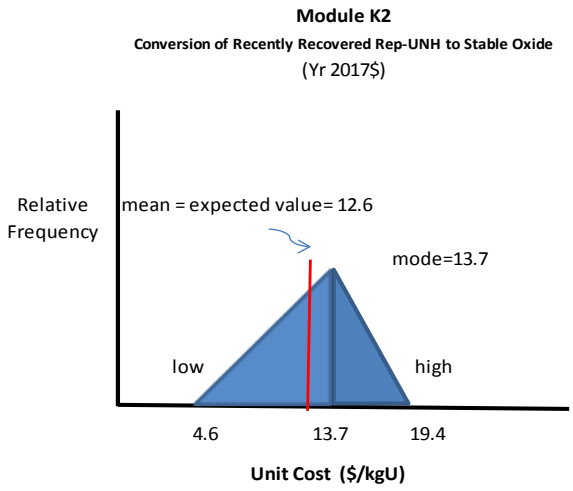
Table K2-5. Cost summary What-It-Takes (WIT) table for aq. reprocessed uranium disposition options (Constant 2017 dollars).

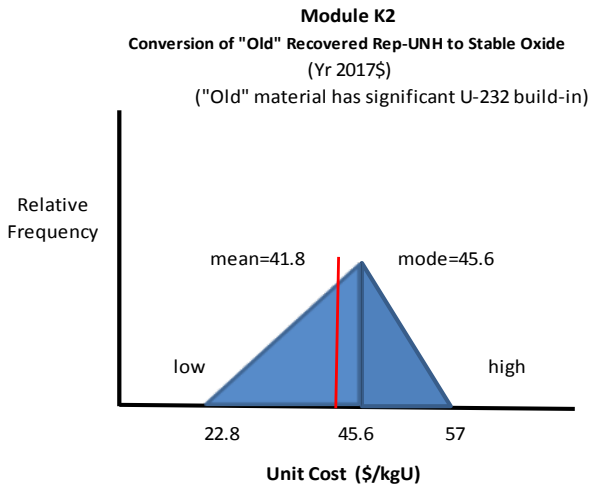
U-Handling Step	Low Cost	Mode Cost	Mean Cost	High Cost
Conversion of UNH to U308 storable form:				
"New" UNH to U308|	$4.6/kgU	$13.7/kgU	$12.6/kgU	$19.4/kgU
"Old" UNH to U308 including removal ofU-232 daughters	$22.8/kgU	$45.6/kgU	$45.6/kgU	$57.0/kgU
Reprocessed $U_3 0_8$ 40-year Storage: Based on $6/kg U for 80,000 MTU/yr Storage Capacity. Annual costs of $1.5M to $5M/yr	$8.0/kgU if temporary shallow burial allowed	$10.3/kgU	$17.5/kgU	$34.2/kgU if facility regulatory and construction difficulties ensue or very long term storage is required
Aqueously-derived reprocessed U308: Permanent Geologic Disposal (Reassessed using new data from 2015) (DUF6 deconversion/disposal study)	$21.8/kgU if above temporary storage package could be permanently emplaced. In shallow trench or borehole	$54.5/kgU including repackaging, transport, emplacement, and perpetual surveillance in mined repository	$52.7/kgU	$81.8/kgU if regulatory and siting difficulties arise with “mode” option
Preparation for RUOX recycle (pre-enrichment):				
"New" product to UF_6 (no aq polish)	$6.8/kgU	$16/kgU	$15.2/kgU	$22.8/kgU
"Old" product to UF6 (aq removal ofU-232 daughters)	$32.7.kgU	$49/kgU (new for 2012)	$49/kgU	$65.4/kgU
Convert to High grade UO2 powder diluent for MOX fuel:				
"New" product for immediate contact-handling to "moxable UO2":	N/A	$65.4/kgU		N/A
"Old" product processing requiring removal ofU-232 daughters prior to contact handling	N/A	$103.6/kgU		N/A

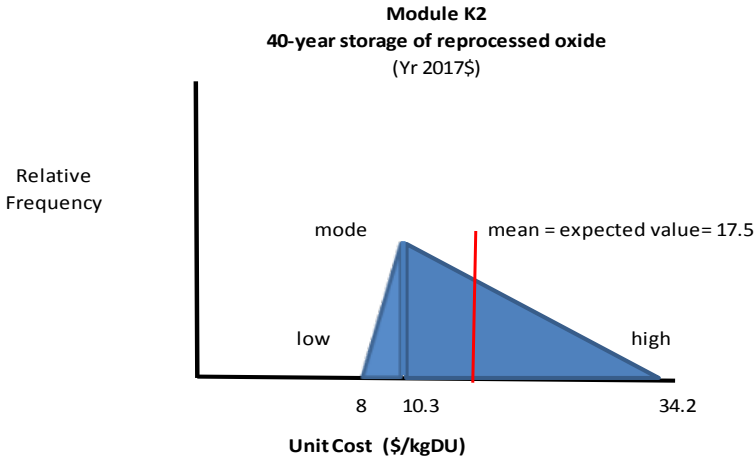
K2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

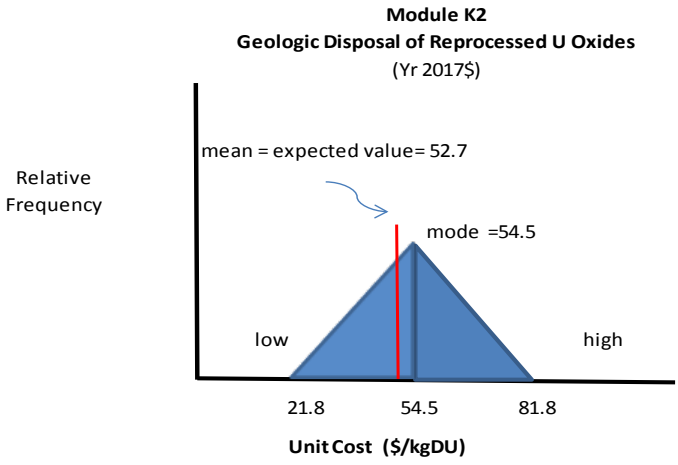
Uncertainty Results from 2009 AFC-CBD: CFTC studies developed a cost estimate range using contingency as the primary difference between the low and high range. Based upon past nuclear project experiences for nth of a kind, low radiation facilities a contingency of 5% for the TPC low range and 30% for the TPC high range was established. An uncertainty range for the LCC estimate components was established as ±20% of the nominal estimate. These are shown in Table K2.3 in year 2008 dollars.

Uncertainty Results from 2012 Update to AFC-CBD: For uncertainty analyses triangular distributions should be used. Escalation from 2008 to 2012 was virtually zero. The triangular distributions in Figure K2-3 have been updated with this 2017 edition.


Module K2
Conversion of Recently Recovered Rep-UNH to Stable Oxide
(Yr 2017$)
Relative Frequency
mean = expected value= 12.6
mode=13.7
low
high
4.6
13.7
19.4
Unit Cost ($/kgU)


Module K2
Conversion of "Old" Recovered Rep-UNH to Stable Oxide
(Yr 2017$)
("Old" material has significant U-232 build-in)
Relative Frequency
mean=41.8
mode=45.6
low
high
22.8
45.6
57
Unit Cost ($/kgU)


Module K2
40-year storage of reprocessed oxide
(Yr 2017$)
Relative Frequency
mode
mean = expected value= 17.5
low
high
8
10.3
34.2
Unit Cost ($/kgDU)


Module K2
Geologic Disposal of Reprocessed U Oxides
(Yr 2017$)
Relative Frequency
mean = expected value= 52.7
mode =54.5
low
high
21.8
54.5
81.8
Unit Cost ($/kgDU)

K2-10. REFERENCES

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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.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only
- **Estimating Methodology for latest (2009 AFC-CBR) technical update from which this 2017 update was escalated:**
    - Conversion and **storage costs** were based on literature survey and some adjustments made in 2009 AFC-CBR. Moxable UO2 preparation costs were revisited in 2012 AFC-CBR.
    - Geologic disposal costs were based on E. Schneider and K. Williams' 2015 analysis cited in the K1 module. **A view graph report of this analysis is a supplementary document to this 2017 AFC-CBR. (2017-CBR-SD-7)**
-

K3.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2006 as Module K3.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2009
- **New technical/cost data which has recently become available and will benefit next revision: at this point no new data.**

K3-1. BASIC INFORMATION

2009 AFC-CBD Introduction. 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 (in 2006) 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 separated 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.

2012 AFC-CBD Update Introduction. Since the 2009 AFC-CBR no new data on the economics of RU disposition from pyroprocessing (electrochemical reprocessing) has been obtained. This is not surprising, since pyroprocessing is envisioned more for fast reactor integral fuel recycling than for LWR fuel recycling. For high fast reactor conversion factors little or no uranium would arise from the internal recycle loop for metal fuel reprocessing/refabrication. For these "burn" or "breed" systems uranium would actually be required as a make-up feed material. If pyroprocessing were to be used for spent LWR fuel reprocessing, large quantities of impure metallic U would be produced. For fast reactors operating in a breeder mode, a portion of the LWR-RU arising from electrochemical LWR fuel reprocessing could be used as blanket material for Pu production (but probably requiring remote refabrication). If the FRs only operate at significantly lower conversion ratios there is little or no need for this electrochemically recovered LWR uranium. As Module K3 in the 2009 AFC-CBR explains, the handling and disposal costs for this actinide and fission product contaminated material (essentially a waste) could be high

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 product fabricated into fast reactor fuel (Module D1-4) for startup of the first fast reactors. This is an especially good option if not enough plutonium is available for the initial fast reactor cores.

K3-3. PICTURES AND DIAGRAMS

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.

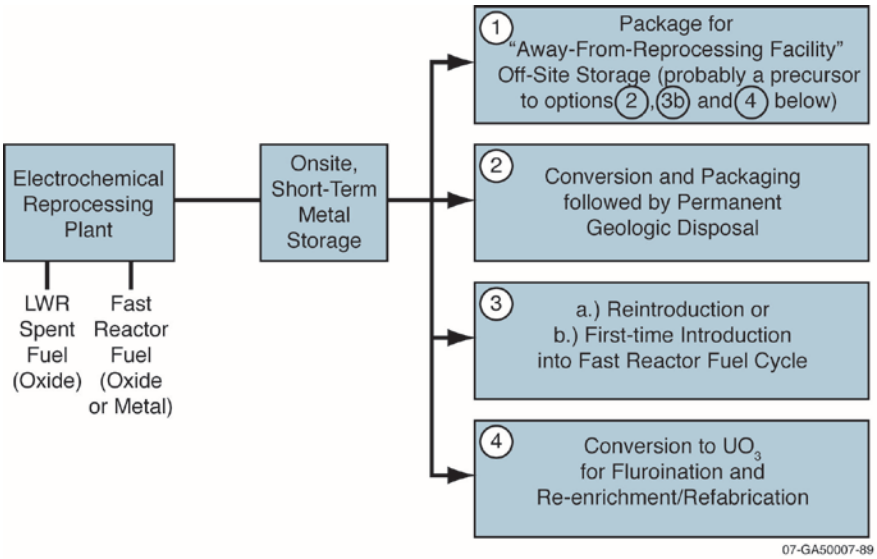

Figure K3-1. Options for reprocessed uranium arising from electrochemical reprocessing of LWR and fast reactor fuels.

K3-4. MODULE INTERFACES

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. SCALING CONSIDERATIONS

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. The 1993 Oak Ridge National Laboratory report (Michaels and Welch 1993) suggests 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.

K3-7. DATA LIMITATIONS

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.

K3-8. COST SUMMARIES

The module cost information in the 2012 AFC-CBD 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 (2012$)				
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

Table K3-2 presents the same data escalated to 2015.

Table K3-2. 2015$ updated "What-It-Takes" Table (2015 $).

REPU Fuel Cycle Step	Low	Mode	Mean	High
REPU Storage	$26 /kgU	$33/kgU	$55/kgU	$105/kgU
Perm Geologic Disposal	$79/kgU	$98/kgU	$112/kgU	$158/kgU
U-metal to UF_6 conv	$32/kgU	$44/kgU	$46/kgU	$63/kgU
Conv to Moxable UO_2	$32/kgU	$44/kgU	$46/kgU	$63/kgU

Table K3-3 presents the same data to year 2017 constant dollars. A factor of 1.14 was used to escalate from 2012 dollars.

Table K3-3. 2017$ updated "What-It-Takes" Table (2017$).

REPU Fuel Cycle Step	Low	Mode	Mean	High
REPU Storage	$28.5/kgU	$35.3/kgU	$62.7/kgU	$114/kgU
Perm Geologic Disposal	$85.5/kgU	$106/kgU	$127.7/kgU	$171/kgU
U-metal to UF_6 conv	$34.2/kgU	$47.9/kgU	$52.4/kgU	$68.4/kgU
Conv to Moxable UO_2	$34.2/kgU	$47.9/kgU	$52.4/kgU	$68.4/kgU

The triangular distributions are based on the costs in the WIT Table is shown in Figure K3-2.

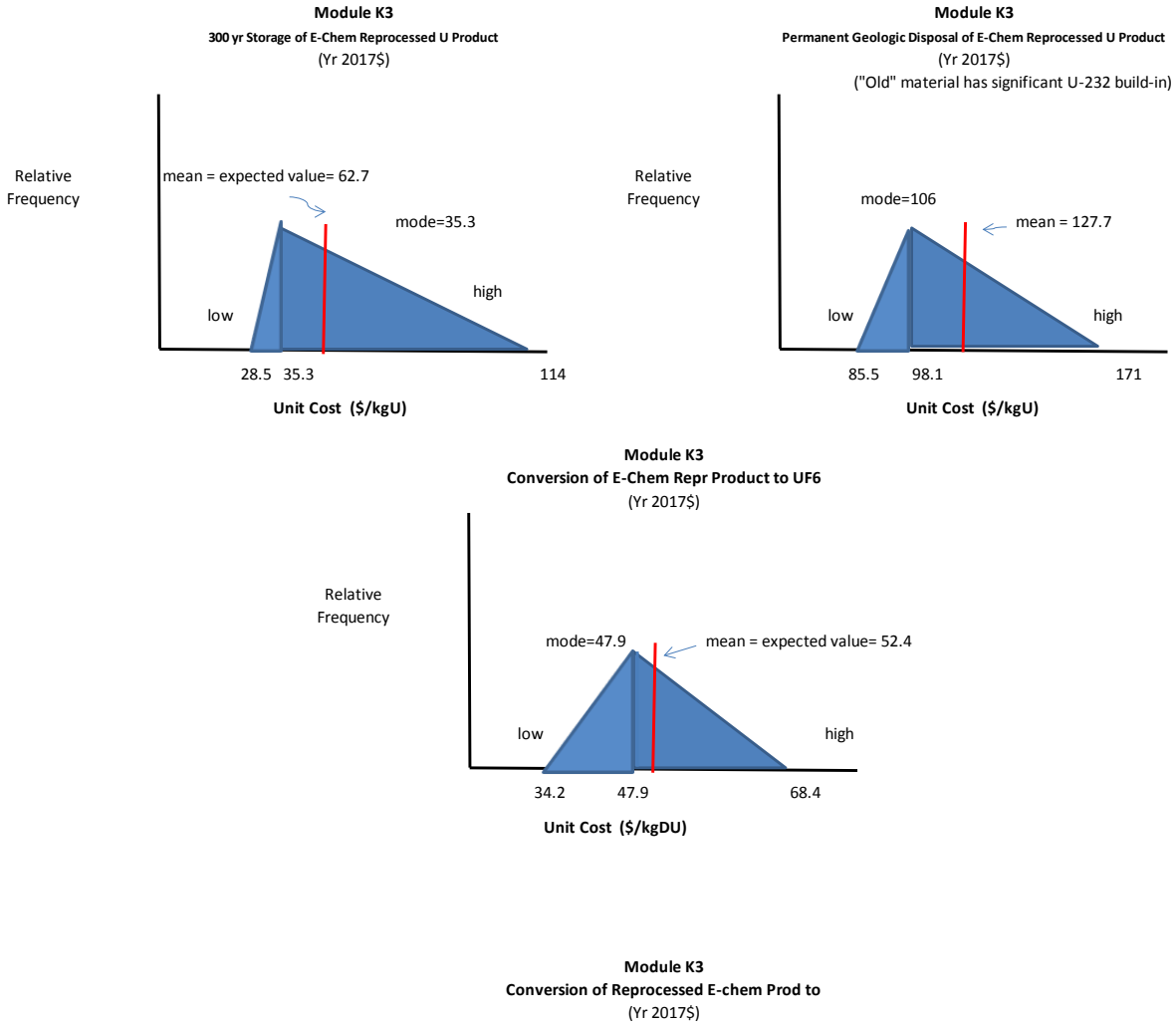

Figure K3-2. Electrochemical reprocessed U disposition estimated cost frequency distributions.

K3-9. RESULTS FROM SENSITIVITY AND UNCERTAINTY ANALYSIS

Due to lack of detailed process/cost data no such calculations were performed.

K3-10. REFERENCES

Michaels, G. and T. Welch, 1993, *Evaluation of Disposition Options for Reprocessed Uranium*, ORNL/TM-12326, Oak Ridge National Laboratory, February 1993.

L MODULES

Geologic Disposal

Module L1

Geologic Disposal of SNF and HLW

Module L1

Geologic Disposal of SNF and HLW

L1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** For SNF and HLW data was developed from Life Cycle Cost Assessments periodically prepared by the Yucca Mountain Project..

L1-RH. Revision History

- **Version of AFC-CBR in which Module first appeared:** 2004. Disposal of GTCC was added in 2012 and the Module was split into L1 (SNF and HLW) and L2 (GTCC including borehole disposition.)
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2012
  - 2012 data was escalated to 2017$ for this latest revision (9% increase in unit cost)
- **New technical/cost data which has recently become available and will benefit next revision:**
  - After issuance of 2012 version of CBR another organization at DOE-NE prepared another Repository Fee Adequacy report which included all anticipated life cycle costs for the Yucca Mountain Project.
  - The successor organization to the Yucca Mountain Project, the DOE-NE Used Fuel Campaign continues to produce reports on the costs and schedules for repository and temporary storage options for SNF (now called Used Nuclear Fuel or UNF). Some of these reports may be publically available. Reference (ORNL 2016) in Module I is one such study.
  - DOE continues to update data on repositories which might be sited in geologies other than Yucca Mountain-type volcanic tuff.
  - DOE has begun a borehole R&D program with possible disposal of some types of defense HLW as a goal. Some cost information is available. A separate repository for the bulk of the defense-related HLW is under consideration.
  - Canada, Sweden, and Finland have made progress on their geologic disposal programs and may have new data.

L1-1. BASIC INFORMATION

This module has been updated to reflect the most recent cost analysis available for seven repository concepts currently seen as viable disposal options[1]. The most recent cost analysis conducted for the Fuel Cycle Research and Development program (FCF&D) is the *Repository Reference Disposal Concepts and Thermal Analysis* (Hardin et al 2012). This is a comprehensive study that performed detailed analyses of

[1] The reader is referred to the 2009 edition of the Advanced Fuel Cycle Cost Basis report for background and cost information for the Yucca Mountain Project.

the first five options below and then incorporated previously developed cost information for Hard Rock Unsaturated (Yucca Mountain Project) and Deep Borehole disposal options. Any costs included from previous studies have been escalated to reflect 2012 values.

1. **Crystalline (enclosed)** - Vertical borehole emplacement is used with a copper waste package (e.g., Swedish KBS-3 concept) with a clay buffer installed at emplacement. Access drifts are backfilled with low-permeability clay-based backfill at closure.
2. **Generic Salt Repository (enclosed)** – A repository in bedded salt in which carbon steel waste packages are placed on the floor in drifts or alcoves, and immediately covered (backfilled) with run-of-mine salt.
3. **Clay/Shale (enclosed)** – SNF or HLW is emplaced in blind, steel-lined horizontal borings constructed from access drifts. SNF is emplaced in carbon steel packages with a clay buffer. HLW glass is emplaced in stainless steel pour canisters, within a steel liner.
4. **Shale Unbackfilled (open)** – A repository in a thick shale formation constructed so that ventilation is maintained for at least 50 to 100 years after waste emplacement. Emplacement drifts are not backfilled at closure but all other openings are backfilled to provide waste isolation.
5. **Sedimentary Backfilled (open)** – Constructed in sedimentary rock so that ventilation is maintained for at least 50 to 100 years after waste emplacement. All waste emplacement and other openings are backfilled with low-permeability clay-based backfill prior to repository closure.
6. **Hard Rock Unsaturated (open)** – Constructed in competent, indurated rock (e.g., igneous or metamorphic) using in-drift emplacement, and forced ventilation for at least 50 to 100 years after waste emplacement. The setting is unsaturated so emplacement drifts need not be backfilled at closure, but other engineered barriers may be installed.
7. **Deep Borehole (enclosed)** – Ongoing studies are assessing the feasibility of drilling large-diameter holes to 5 km in crystalline basement rock (Sandia National Laboratories, 2014). Waste packages would contain single fuel assemblies, and be stacked in the lower 2 km of each hole. The upper section would be sealed.

This update incorporates cost estimates for the Deep Borehole concept previously described in Module M-1. The remaining two disposal options previously discussed in Modules M2 and M3, Seabed Disposal and Extraterrestrial Disposal, have long since been abandoned as viable disposal options for SNF and HLW. Seabed disposal was prohibited under the United Nations Convention on Law of the Sea and the London Convention and Protocol (Rechard et al. 2011) A National Academy of Science (NAS 2001) study summarizes the extraterrestrial disposal option as not currently feasible because of the scientific, technical, and economic challenges. NAS further notes that “Disposal in space is not expected ever to be practicable, safe technology” (NAS 2001, p. 27). Therefore, Modules M2 and M3 have been removed in total from this revision of the cost estimate.

L1-2. 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 L1 is to indicate the costs for geologic disposal of spent nuclear fuel (SNF) and high-level waste (HLW). Module L1 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, if a traditional geologic repository); 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 L1-1 is a simple diagram of the functional flow (Hardin et al. 2012) for Module L1.

The *Repository Reference Disposal Concepts and Thermal Analysis* report (Hardin et al 2012) arrived at similar total time periods, with timelines for the concepts ranging from 130 years up to 181 years. In all cases, the first phase to make the repositories operational spanned 24 years and included site selection, characterization, design and construction. Similarly, the operational phase for all concepts assumed emplacement of 3,000MTHM per year over 47 years to fulfill the design capacity of 140,000MTHM. For the three "enclosed" concepts, the closure phase lasts 10 years followed by 50 years of site monitoring for a total of approximately 130 years. For the two "open" repository concepts, active ventilation and monitoring is estimated at 100 years. Ten years of closure activities then follows, for a total of 181 years.

L1-3. PICTURES AND DIAGRAMS

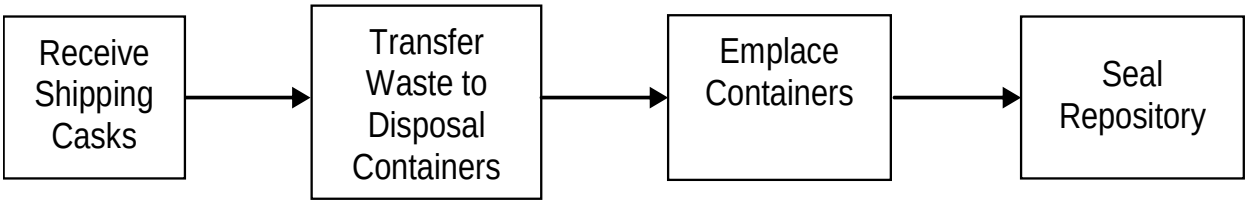

Figure L1-1. Functional block diagram for geologic repository waste disposal.

L1-4. MODULE INTERFACES

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.

L1-5. SCALING CONSIDERATIONS

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 (Bodvarsson and Bandurranga, 1997) 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 that those costs increase significantly as a function of repository capacity.

Total costs increased from $72B (2007 $) for a 70,000 MTHM repository (Case 3, $1029/kgHM) to $150B (2007 $) for a 260,000 MTHM repository (Case 4, $577/kgHM) and up to $338B for 570,000MTHM (Case 5, $593/kgHM). Figure L1-2 provides a comparison of the projected repository costs for three sizes of repositories. The costs rose by approximately 200% for an increase in capacity of almost 400%, or a relationship between costs and capacity size of about 1:2 (200%/400%= 0.5). Assuming a relationship: (Cost/Base Cost) = (Capacity/Base Capacity)^n, the EPRI 70 kT and 260kT data points give a value for the exponent n of 0.56. In the EPRI study, when the 260kT capacity is reached, the fixed costs have been amortized. With estimates of $577/kgHM and $593/kgHM for Cases 4 and 5, respectively, the EPRI report also shows a direct cost to capacity ratio of approximately 1:1 for large repositories. This supports their conclusion that the variable costs, such as mining and waste emplacement, become dominant as repository size continues to increase.

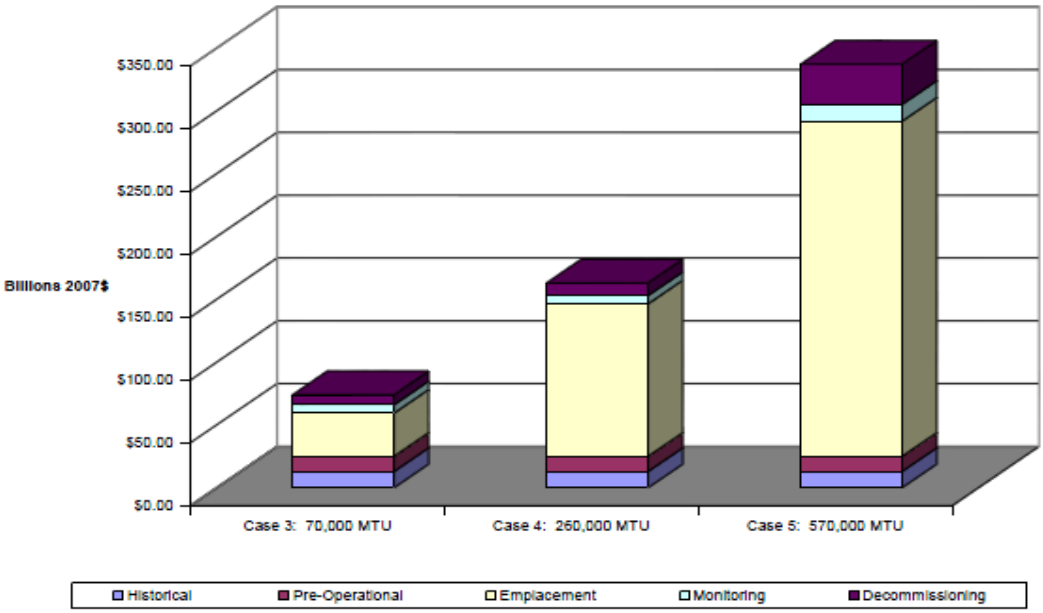

Figure L1-2. Comparison of projected repository costs for 70,000 MTHM, 260,000 MTHM, and 570,000 MTHM repositories (EPRI 2006).

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 as repositories with small or moderate capacities grow in size. The beneficial effects seem to diminish as repository capacity approaches and exceeds 100,000 MTHM.

If a country chose to use multiple, small scale disposal facilities rather than a centralized repository 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 would have already been incurred with only variable costs increasing with the size of the facility.

Based on the experience of the Yucca Mountain Project, it is evident that the fixed costs of site selection, site characterization, facility design and construction of the surface facilities is substantial. For small repositories, the burden is substantial on a per kilogram basis if the fixed costs are amortized over a small volume of waste. From the DOE 2008 and the EPRI 2006 studies discussed above, as the repository size approaches 100,000MTHM or greater, the variable operational costs of mining, packaging, and emplacement become dominant.

Some small economy of scale may still 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, any improvements on a unit cost basis appear to be minimal so a scaling factor of approximately 0.8–1.0 would seem appropriate for large repository concepts.

With current US forecast needs for disposal of a minimum of 140,000 MTHM of SNF from the domestic fleet of reactors, a single repository would seem to be advantageous over building two or more smaller facilities. If the capacity is available for growth, incremental increases in the SNF forecast would best be accommodated in this one repository. If it becomes evident that the power industry will replace, and potentially grow, the existing reactor fleet with new nuclear generating capacity, a second large scale repository of greater than 100,000 MTHM could become viable without negatively impacting the normalized cost of SNF disposal.

L1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The most recent cost estimates for large United States repositories are based on recent analyses in *Repository Reference Disposal Concepts and Thermal Analysis* (Hardin 2012). To be consistent with earlier analyses for based on previous Yucca Mountain Project and Deep Borehole, and more accurately estimate the TSLCC for disposal for all repository concepts, these cost estimates have been adjusted as follows for purposes of this report. Note that any cost estimates that are adjusted to 2012 $'s used the values in the Nuclear Projects column from the table in "Escalation Rate Assumptions for DOE Projects (November 27, 2009)" (http://www.cfo.doe.gov/cf70/escalation.pdf) (DOE 2009).

First the High Range values have been adjusted to include a more conservative use of stainless steel for the waste packages versus the carbon steel evaluated in (Hardin et al 2012 Carter 2012). Since the Crystalline (enclosed) already provided copper disposal overpacks in the original estimate, there is no increase in the High Range. These costs are noted in the "Adjusted Costs for SS Overpack" column in Table L1-1 below. Then to provide a consistent TSLCC bases across all seven domestic repository estimates, $10B for site selection and characterization as estimated for Deep Borehole (Brady 2009) plus $2.8B for "Benefits, Payments Equal to Taxes, Outreach and Institutional (i.e., Set-Asides)" have been

added (DOE 2008) These additional costs add approximately $91/kgHM to the total disposal costs in each of the five 140,000 MTHM repositories. Table L1-1 compares these Total Adjusted Costs.

Table L1-1. Adjustments to Normalized Costs from *Repository Reference Disposal Concepts and Thermal Analysis* (Hardin et al 2012).

Repository Concept	Disposal Capacity (MTHM)	Cost Normalized to Mass ($/kg)	Adjusted Costs for SS Overpack Normalized to Mass ($/kgHM)	Total Adjusted Costs Normalized to Mass ($/kgHM)
Crystalline (enclosed)	140,000	439 to 579	439 to 579	530 to 670
Generic Salt Repository (SNF, enclosed)	140,000	174 to 232	174 to 281	265 to 373
Clay/Shale (enclosed)	140,000	428 to 571	428 to 710	520 to 801
Shale Unbackfilled (open)	140,000	182 to 242	182 to 277	273 to 368
Sedimentary Backfilled (open)	140,000	231 to 309	231 to 344	322 to 435

The latest TSLCC for the Yucca Mountain Project (Hard Rock Unsaturated) was estimated at $97.0B. This accommodated 109,300 MTHM of SNF and 12,800 MTHM of Defense HLW and included $20.3B in transportation costs. Twenty percent of the YMP cost is attributed to Defense Waste disposal (DOE 2008). Subtracting out the transportation costs and 20% of the project costs for Defense Wastes leaves $61.4B for the SNF disposal. This equates to a normalized cost for SNF of $561 per kgHM. Escalated to 2012 $s, the cost actually decreases to $554/kgHM because of a large drop in steel prices from reduced demand and high production rates in 2009 and 2010.

For the Deep Borehole disposal concept Brady et al. (2009) produced a rough estimate of $71B (2007 dollars) for disposal of 109,300 MT of commercial SNF. This estimate included $10B for transportation costs. Module O is defining the transportation costs, therefore this has been backed out of the total. In addition, the cost for drilling a single deep borehole was updated from $20M to $27M by Arnold et al. (2011). With these adjustments and escalating costs to 2012 $'s, the TSLCC value for Deep Borehole disposal remains at $71B and $650/kgHM.

The cost basis for geologic disposal was drawn from domestic studies and Table L1-2 summarizes the latest adjusted cost estimates. The table also includes cost data from international studies for purposes of comparison. The international estimates span the range of low and high estimates presented in this report, but closer comparison is unwarranted because the various estimates likely include different facilities and activities.

Table L1-2 Unit SNF Disposal Cost Comparison (2012 $s).

Estimate	Disposal Capacity (MTHM)	Cost Normalized to Mass ($/kg)	References[1]
United States			
Crystalline (enclosed)	140,000	530 to 670	Hardin 2012
Generic Salt Repository (SNF, enclosed)	140,000	265 to 373	
Clay/Shale (enclosed)	140,000	520 to 801	
Shale Unbackfilled (open)	140,000	273 to 368	
Sedimentary Backfilled (open)	140,000	322 to 435	
Hard Rock Unsaturated (open)	109,300	554	DOE 2008
Deep Borehole	109,300	650	Hardin 2012
NEA	109,300	356 to 710	NEA 2003[2]
Canada	96,000	147	IAEA 2002[2]
Belgium (2000 estimate)	4,900	368	ONDRAF/NIRAS 2000[2]
Czech Republic	3,724	457	IAEA 2002[2]
Finland (2007 estimate)	5,500	714	www.posiva.fi[2]
Hungary	1,320	1036	IAEA 2002[2]
Sweden	12,000	521	SKB 2003[2]

1. Updated international repository values provided by Mark Nutt, ANL in 2012 $s. (Nutt 2009)

2. Basis of estimates may include repository site selection or characterization, at-reactor packaging, centralized storage, re-packaging to meet disposal requirements, and waste transport to the repository, and may therefore be only roughly comparable to values developed in this study.

L1-7. DATA LIMITATIONS

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 ton 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.

L1-8. 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 for SNF disposal (Table L1-3) and HLW disposal of recycled SNF (Table L1-4).

The module cost information is summarized in the Advanced Fuel Cycle (AFC) What-It-Takes (WIT) Tables L1-3 and L1-4. 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 from the WIT Table L1-3 is shown in Figure L1-3. The distribution is skewed toward the high costs due to the current uncertainties in geologic disposal and waste management policies.

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 can be 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.

Table L1-3. Cost summary 'What-It-Takes' (WIT) table for Domestic SNF disposal (Module L1) in a geologic repository.

2012 $				
Reference Cost and Related Capacity	Low Cost $/kgHM (SNF)	Mode Cost $/kgHM (SNF)	Mean Cost $/kgHM (SNF)	High Cost $/kgHM (SNF)
TSLCC $96.18B (122,100 MTHM) (DOE 2008)	$265	$550		$801
2017 $				
	$289	$600	$587	$873
	Use of bedded salt utilizes experience/cost data from WIPP.	Based on average of High Range of most recent US cost estimates for large domestic facilities with good economies of scale.		Most expensive design due to long-term active ventilation and enclosed design.

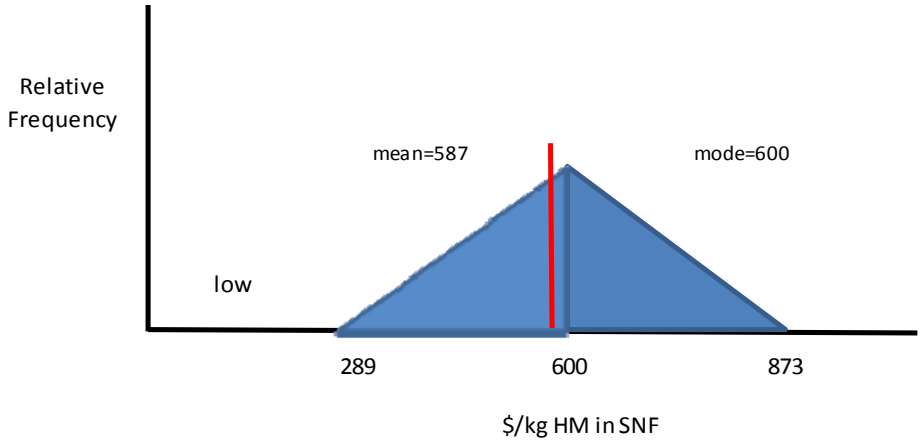

Figure L1-3. Geologic repository for SNF estimated cost frequency distribution.

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 are derived using the nominal cost of SNF disposition at $550/kg HM (or $13,750/kg fission products [FP] based on an average FP composition of 4% of initial heavy metal). The waste loading of the HLW 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 are estimated to range from $1,377/kg FP to $6,880/kg FP, with a nominal cost of $5,500/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.

Table L1-4. Cost summary table for HLW disposal in a geologic repository.

What-It-Takes Table (2012 $)			
Reference Cost and Related Capacity	Upsides (Low Unit Cost)	Downsides (High Unit Cost)	Selected Values (Nominal Cost)
$550/kgHM (SNF) Average High Range TSLCC from Table L1-3.	$1,377/kg FP (HLW) Nominal SNF cost with a FP waste loading of 10x.	$6,880/kg FP (HLW) Nominal SNF cost with a FP waste loading of 2x.	$5,500/kg FP (HLW) Nominal SNF cost with a FP waste loading of 2.5x.
Escalated to 2017$>> 9% from 2012	$1500/kg FP (HLW)	$7500/kg FP (HLW)	$6000/kg FP (HLW)

The triangular distribution for the HLW disposal costs from the WIT Table L1-4 is shown in Figure L1-4. The distribution is skewed toward the high costs due to the greater probability of achieving a waste form loading (glass, ceramic, etc.) in the 2x–4x range.

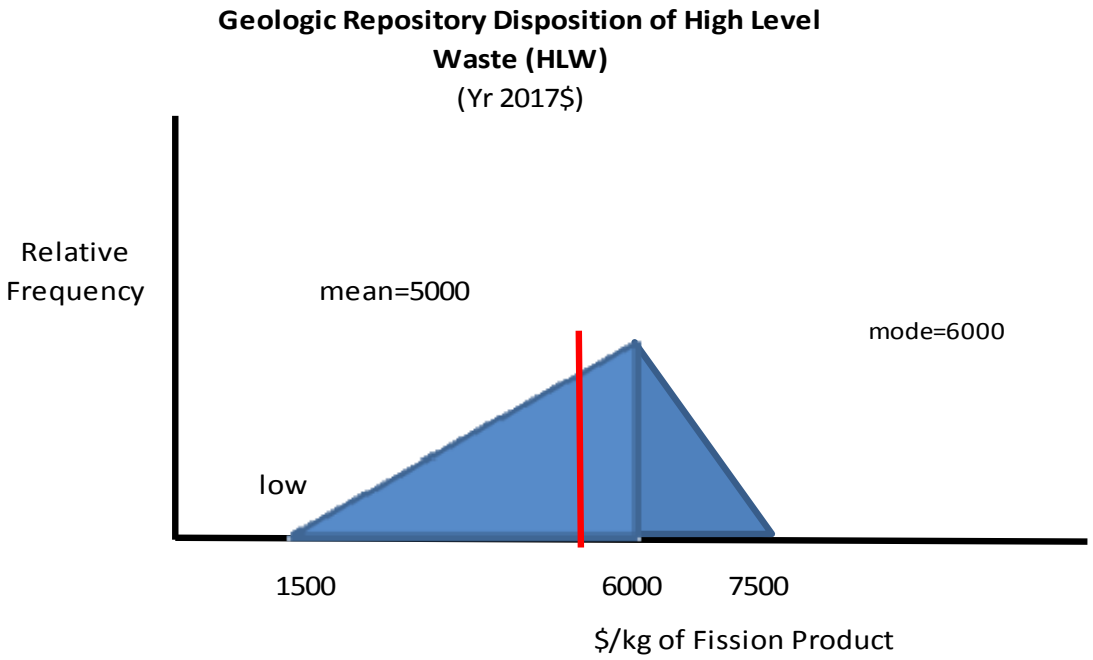

Figure L1-4. Geologic repository for HLW estimated cost frequency distribution.

L1-9. SENSITIVITY AND UNCERTAINTY ANALYSES

No sensitivity analyses were conducted in the preparation of this information. The reader is referred to the references for examples of sensitivity and uncertainty analyses for the SNF/HLW disposal function.

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Module L2

Disposal of GTCC Waste

Module L2

Disposal of GTCC Waste

L2-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2015 AFC-CBR)
- **Estimating Methodology for latest (2015 AFC-CBR) technical update from which this 2017 update was escalated:** Data was developed from estimates prepared by DOE's Office of Environmental Management for waste disposal projects at various Government sites.

L2-RH. Revision History

- **Version of AFC-CBR in which Module first appeared:** 2012. Disposal of GTCC was added in 2012 and the Module was split into L1 (SNF and HLW) and L2 (GTCC including borehole disposition.). No unit cost data appeared in the 2012 version. Unit costs were calculated in 2015 update.
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2015
    - 2015 unit cost data was escalated to 2017$ for this latest revision (3% increase in unit cost)
- **New technical/cost data which has recently become available and will benefit next revision:** DOE may have new information on the costs of borehole disposition. It is being considered for small amounts of some highly radioactive wastes from site D&D projects.

L2-1. BASIC INFORMATION

This Section of Module L discusses Greater Than Class Low-level Radioactive Waste (GTCC LLRW) and GTCC-Like Waste. GTCC LLRW refers to LLRW that has radionuclide concentrations that exceed the limits for Class C LLRW given in 10 CFR 61.55. This waste is generated by activities licensed by the Nuclear Regulatory Commission (NRC) and Agreement State licensees, and it cannot be disposed of in currently licensed commercial LLRW disposal facilities.

GTCC-like waste refers to radioactive waste that is owned and generated by DOE and has characteristics sufficiently similar to GTCC LLRW such that a common disposal approach may be appropriate. GTCC-like waste consists of high activity LLRW and potential non-defense-related TRU waste that has no identified path for disposal. The use of the term "GTCC-like" does not have the effect of creating a new DOE classification of radioactive waste. The DOE is responsible for developing a disposal capability for GTCC LLRW. DOE recently drafted an Environmental Impact Statement (EIS) which describes the planning basis for GTCC waste disposal (DOE 2011).

For the purposes of analysis in the DOE EIS, GTCC LLRW and GTCC-like waste are categorized as being one of three waste types: activated metal, sealed sources, or Other Waste. The waste inventory being addressed in the EIS includes both stored inventory (wastes that were already generated and are in storage) and projected inventory (wastes that are expected to be generated in the future). The stored inventory includes waste in storage at sites licensed by the NRC (GTCC LLRW) or by Agreement States

and at certain DOE sites (GTCC-like waste) and consists of all three waste types (activated metal, sealed sources, and Other Waste).

The three waste types fall into two groups on the basis of uncertainties associated with their generation for analysis in the DOE EIS. Group 1 consists of wastes from current operating facilities that are either already in storage or are expected to be generated from these facilities (such as commercial nuclear power plants). All stored GTCC LLRW and GTCC-like wastes are included in Group 1.

Group 2 consists of projected wastes from proposed actions or planned facilities not yet in operation. These actions include those proposed by DOE and those to be conducted by commercial entities (including electric utilities) for an assumed number of new (i.e., still to be licensed or constructed) nuclear power plants. Some or all of the Group 2 waste may never be generated, depending on the outcome of the proposed actions that are independent of the DOE EIS. No stored GTCC LLRW and GTCC-like wastes are included in Group 2. The inventory considered in the DOE EIS does not include future waste from commercial spent nuclear fuel reprocessing activities; however, the unit cost disposal costs are considered to be valid for this waste source.

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)

L2-2. 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 High Level Waste (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 in the 2009 AFC-CBR (Modules J and B-5) for more detail.

DOE-EM (Environmental Management) developed the four action alternatives after careful consideration of the waste inventory, disposal technologies, and comments received during the public scoping period for the EIS. The WIPP repository is evaluated to determine the feasibility of the disposal of GTCC waste at a geologic repository, which is a disposal method acceptable to the NRC for GTCC LLRW given in 10 CFR Part 61. The proposed land disposal methods (i.e., borehole, trench, and vault) are being evaluated because NRC regulations allow other methods of disposal to be proposed for NRC approval and state that there might be some instances when GTCC LLRW would be acceptable for near-surface disposal with special processing or design. The alternatives are discussed as follows.

- Alternative 1: No Action
- Alternative 2: Disposal at the WIPP geologic repository,
- Alternative 3: Disposal in a new borehole disposal facility,
- Alternative 4: Disposal in a new trench disposal facility, and
- Alternative 5: Disposal in a new vault disposal facility.

Alternative 1: No Action

Under the No Action Alternative, current practices for storing GTCC LLRW and GTCC like waste would continue. The GTCC LLRW generated by the operation of commercial nuclear reactors (mainly activated metal waste) would continue to be stored at the various nuclear reactor sites that generated this waste or at other reactors owned by the same utility. Sealed sources would continue to be stored at interim storage and generator sites. Other Waste would also remain stored and managed at the generator or interim storage sites. In a similar manner, all stored and projected GTCC-like waste would remain at current DOE storage and generator locations. Under this alternative, DOE would take no further action to develop disposal capability for these wastes, and current practices for managing these wastes would continue into the future. National security concerns over the lack of a disposal capability for GTCC sealed sources wound not be addressed.

Alternative 2: Disposal at WIPP

This alternative involves the disposal of GTCC LLRW and GTCC-like waste at WIPP. The current operation at WIPP involves disposal of TRU waste generated by atomic energy defense activities by emplacement in underground disposal rooms that are mined as part of a panel and an access drift. Each mined panel consists of seven rooms. Contact handled (CH) TRU waste containers are emplaced on disposal room floors, and remote handled (RH) TRU waste containers are currently emplaced in horizontal boreholes in disposal room wall spaces. However, DOE has submitted a planned change request to use shielded containers for safe emplacement of selected RH TRU waste streams on the floor of the repository. The use of the shielded containers will enable DOE to significantly increase the efficiency of transportation and disposal operations for RH TRU waste at the WIPP. Consistent with this planned change request, the DOE EIS assumes all activated metal waste and Other Waste-RH would be packaged in shielded containers that would be emplaced on the floor of the mined panel rooms in a manner similar to that used for the emplacement of CH waste.

The analysis discussed in the DOE EIS assumes that current disposal procedures and practices at WIPP would continue, except for the emplacement of activated metal and Other Waste-RH on room floors (not in wall spaces as is the current procedure). It is also assumed that all above ground support facilities would be available for the disposal of GTCC LLRW and GTCC like waste and that construction of additional above ground facilities would not be required.

Alternative 3: Disposal in a New Intermediate-Depth Borehole Disposal Facility

Alternative 3 involves the construction, operations, and post-closure of a new borehole facility for the GTCC LLRW and GTCC-like waste inventory. Reference locations at the following five sites are evaluated for this alternative: the Hanford Site, INL, LANL, NTS, and the WIPP Vicinity. Because of the shallow depth to groundwater at ORR and SRS, this alternative is not evaluated for these two sites. Of the four NRC regions considered for the generic commercial facility, only NRC Region IV (generally, the western U.S. and plains states, excluding ID, MT, WY, and SD) was analyzed in the EIS as the depth to groundwater at the other three regions is considered too shallow for application of this method. A cross section of a conceptual borehole design is shown in Figure L2-1. For purposes of the Draft EIS analysis, a borehole with a depth of 40 m (130 ft) was evaluated.

To dispose of the entire inventory of GTCC LLRW and GTCC-like waste, the conceptual design indicates that about 44 ha (110 ac) of land would be required for the 930 boreholes needed to accommodate the waste packages of GTCC LLRW and GTCC-like waste. This acreage would include land required for supporting infrastructure, such as facilities or buildings for receiving and handling waste packages or containers, and space for a storm water retention pond. Less acreage and fewer boreholes would be required if a decision were made to only dispose of certain GTCC waste types in a borehole facility. The borehole method entails emplacement of waste in boreholes at depths below 30 m (100 ft) but above 300 m (1,000 ft) below ground surface (bgs). Boreholes can vary widely in diameter (from 0.3 to 3.7 m [1 to 12 ft]), and the proximity of one borehole to another can vary depending on the design of

the facility. After placement of the wastes in the borehole, a reinforced concrete barrier would be added above the disposal containers to deter inadvertent drilling into the isolated waste during the post-closure period, and backfill would be added to the surface level.

Alternative 4: Disposal in a New Enhanced Near-Surface Trench Disposal Facility

Alternative 4 involves the construction, operations, and post-closure performance of a new trench disposal facility. This alternative is evaluated for the Hanford Site, INL, LANL, NTS, SRS, and the WIPP Vicinity. The conceptual design of the trench is shown in Figure L2-2. With regard to ORR, Alternative 4, like Alternative 3, is not evaluated because of the shallow depth to groundwater at that site. Alternative 4 is evaluated for the generic commercial location in NRC Regions II and IV in order to allow for a comparison with the federal sites in these two regions. A commercial trench facility could also be considered in Regions I and III.

To dispose of the entire inventory of GTCC LLRW and GTCC-like waste, the conceptual design for the trench method includes 29 trenches occupying a footprint of about 20 ha (50 ac). This acreage includes land required for supporting infrastructure, such as facilities or buildings for receiving and handling waste packages or containers, and space for a storm water retention pond. Each trench would be approximately 3 m (10 ft) wide, 11 m (36 ft) deep, and 100 m (330 ft) long. After wastes were placed in the trench, a concrete layer would be placed on top, and backfill would be added to the surface level. The additional concrete layer would provide additional shielding during the operational period, and at some sites where the material through which drilling would be done is typically soft (e.g., sand or clay), the layer could deter inadvertent drilling into the buried waste during the post-closure period. Measures would be included in the designs of the facilities to reduce the likelihood for future inadvertent human intrusion. In addition to the concrete cover noted above, the conceptual design for the trench is deeper and narrower than conventional near surface LLRW disposal facilities to minimize this potential intrusion during the post-closure period. Additional intruder barriers would also be adopted for those sites in hard rock settings. Protecting against an inadvertent human intruder will be a key feature of the final facility design.

Alternative 5: Disposal in a New Above-Grade Vault Disposal Facility

Alternative 5 involves the construction, operations, and post-closure performance of a new vault disposal facility at the Hanford Site, INL, LANL, NTS, ORR, SRS, and the WIPP Vicinity. The conceptual design of the vault is shown Figure L2-3. Alternative 5 is evaluated for the generic commercial location in all four NRC regions. The conceptual design for the vault disposal employs a reinforced concrete vault constructed near grade level, with the footings and floors of the vault situated in a slight excavation just below grade.

The vault disposal facility to emplace the entire GTCC waste inventory would consist of 12 vaults (each with 11 vault cells) and occupy a footprint of about 24 ha (60 ac). Each vault would be about 11 m (36 ft) wide, 94 m (310 ft) long, and 7.9 m (26 ft) tall, with 12 vaults situated in a linear array. The interior cell would be 8.2 m (27 ft) wide, 7.5 m (25 ft) long, and 5.5 m (18 ft) high, with an internal volume of 340 m3 (12,000 ft3) per cell. Double interior walls with an expansion joint would be included after every second cell. The thick concrete walls and earthen cover would minimize inadvertent intrusion into the vault.

L2-3. PICTURES AND DIAGRAMS

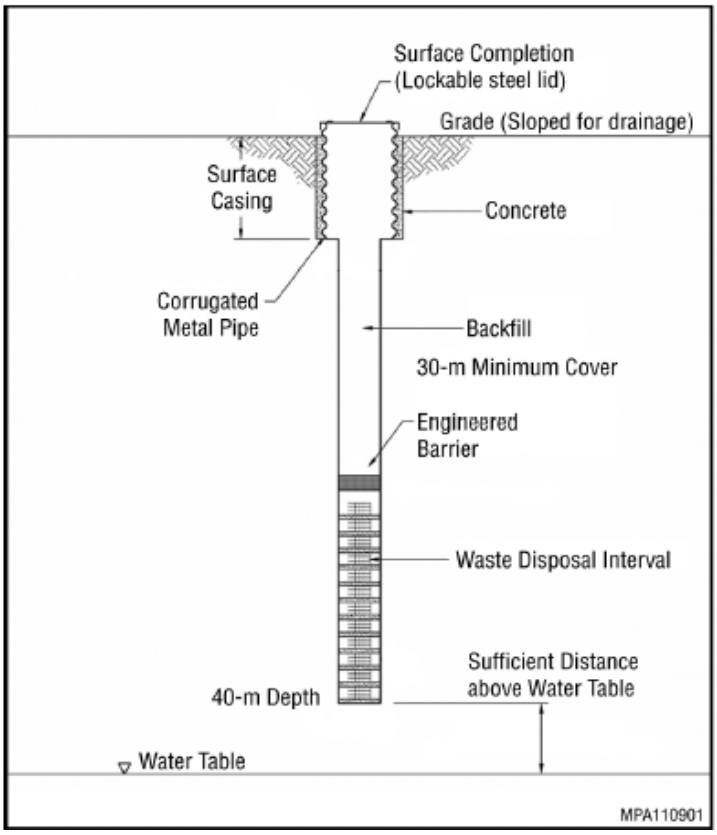

Figure L2-1. Cross Section of the Conceptual Design for an Intermediate-Depth Borehole.

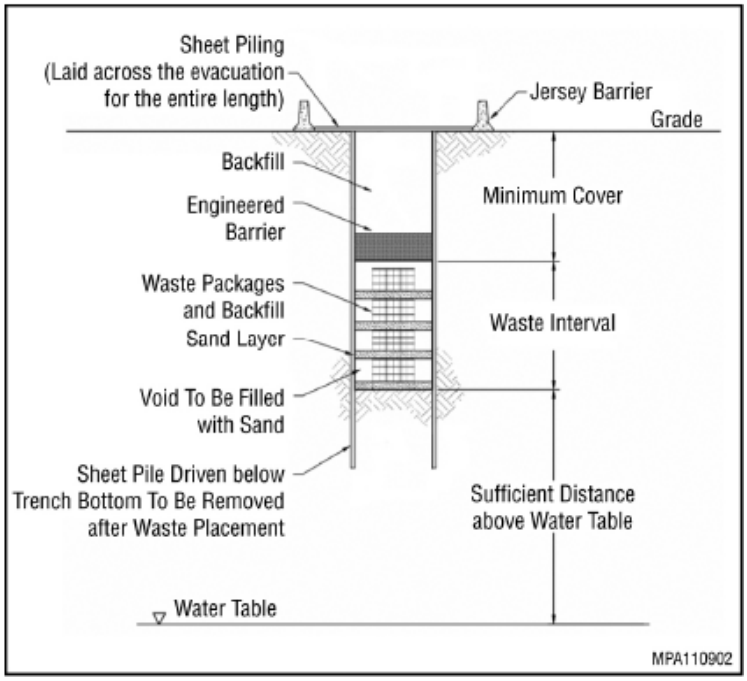

Figure L2-2. Cross Section of the Conceptual Design for a Trench.

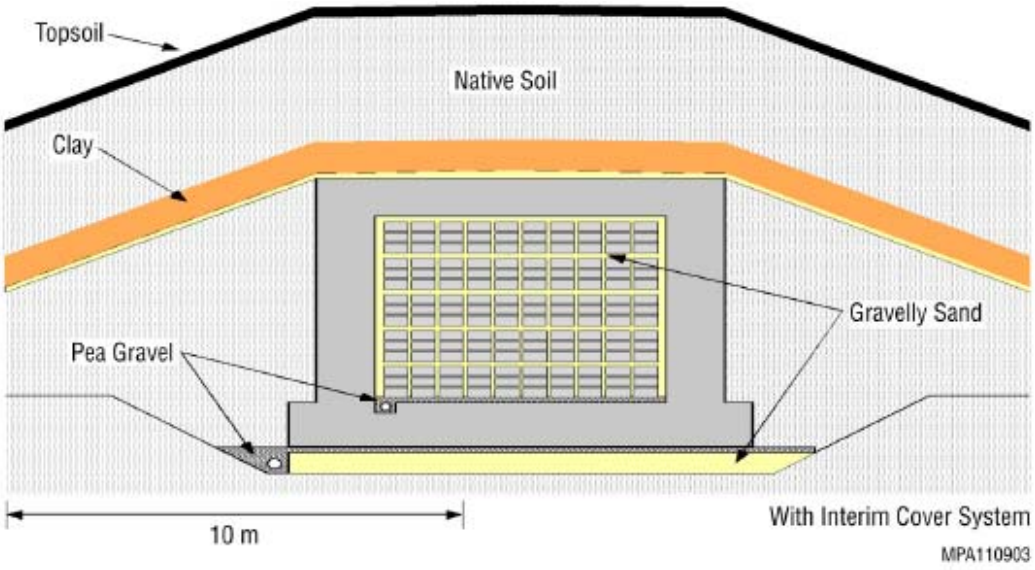

Figure L2-3. Schematic Cross Section of the Conceptual Design for a Vault Cell.

L2-4. MODULE INTERFACES

This module receives GTCC from Module G (Waste Conditioning, Storage, & Packaging) and retains the GTCC in perpetuity.

L2-5. SCALING CONSIDERATIONS

Any non-pilot GTCC disposal facility is assumed to be developed for large-scale operations. The cost estimates in this module are based on this assumption.

L2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The Draft *Greater than Class C Environmental Impact Statement* (DOE 2011) considered the disposal of approximately 120,000 cubic meters of GTCC waste in three different enhanced confinement type near surface concepts (borehole, trench, and vault) and for the deep geologic disposal in the Waste Isolation Pilot Plant (WIPP). The estimated total cost for each disposal concept and the normalized cost (120,000 m3 of GTCC) are shown in Table L2-1 in year 2011$. The costs of disposal in the WIPP reflect mostly O&M costs that would be incurred by placing GTCC into an already-operating deep geologic facility. The unit costs of disposal in the borehole, trench, and vault concepts reflect the construction and operation of new facilities.

Table L2-1. Estimated total cost for each disposal concept and normalized cost.

GTCC Disposal Alternative	Construction Cost ($M)	Operations Cost ($M)	Total Cost ($M)	Normalized Cost (2011 $/m^3)	2017$ Normalized Cost ($/m3)
WIPP	14	560	574	4783	5320
Borehole	210	120	330	2750	3060
Trench	88	160	248	2067	2300
Vault	360	160	520	4333	4820

A uniform distribution Figure L2-4 which spans the above normalized and escalated unit cost is assumed to cover the uncertainty for this waste type.

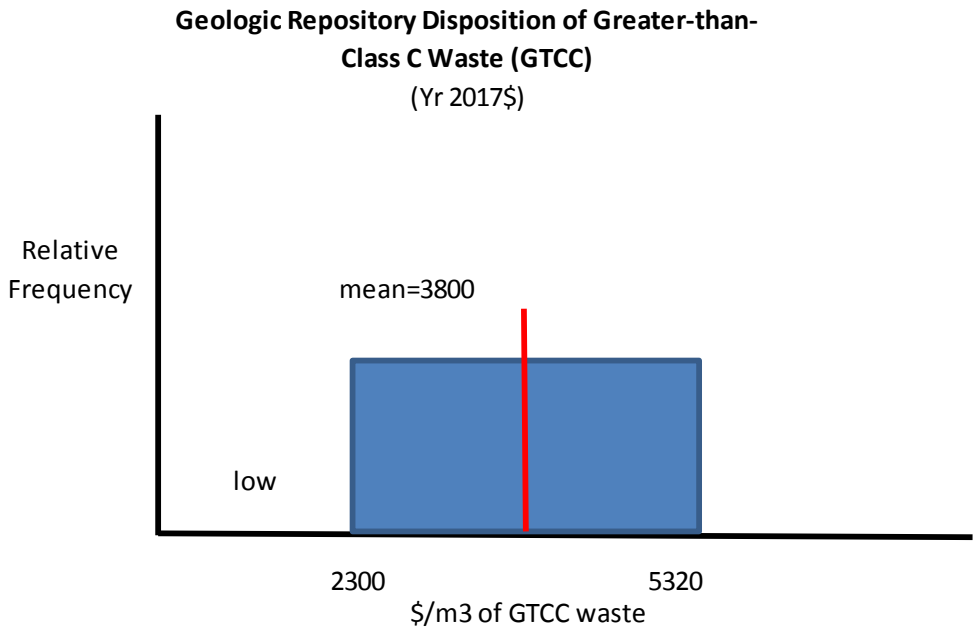

Figure L2-4. Frequency distribution for unit cost of GTCC waste disposal.

L2-7. DATA LIMITATIONS

No GTCC disposal facility has operated in the U.S., so estimated costs are based on designs and not actual experience.

L2-8. COST SUMMARIES

The nominal cost of disposing GTCC in new enhanced confinement facilities will be $3,295/m^3 (average of borehole, trench, and vault cost estimates). If it is preferable to dispose of GTCC in an existing deep geologic repository co-located with SNF or HLW, use the normalized value for WIPP of $5,165/m^3 (DOE 2011).

L2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

No sensitivity analyses were conducted in the development of this information.

L2-10. REFERENCES

U.S. Department of Energy, Draft Environmental Impact Statement, Disposal of Greater-Than-Class C (GTCC) Low-Level Radioactive Waste and GTCC-Like Waste, DOE/EIS-0375D, February 2011.

Rechard, R.P., Goldstein, B., Brush, L.H., Blink, J.A., Sutton, M., Perry, F.V., 2011, Disposal Options for Research and Development for Spent Nuclear Fuel and High-Level Waste, report prepared for Fuel Cycle Research & Development, FCRD-USED-2011-000071, SAND2011-3781P.

O MODULES

Transportation Processes

Module O1

Transportation of Radioactive Materials

Module O1

Transportation of Radioactive Materials

O1-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation (9%) from last time values underwent technical assessment, (2012 Systems Architecture Study reported in 2015 AFC-CBR).
- **Estimating Methodology for latest (2015 AFC-CBR) technical update from which this 2017 update was escalated:** For SNF and HLW transportation cost data is developed from Life Cycle Cost Assessments prepared by DOE-NE's Used Fuel Disposition (UFD) campaign as part of a 2012 Systems Architecture Study. Bottom-up estimates were prepared for shipment to a generic Central Storage Facility and ultimately to a generic Geologic Repository.

O1-RH. Revision History

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module N, which included data on fabricated fuel transportation which was later covered on Module O2. (In 2006 it was decided to include this Module O1 in a two-part Module O. SNF and HLW transportation became Module O1 and other less radioactive material transport as Module O2) Up to 2012 transportation cost estimates were based on shipping SNF and packaged HLW directly to Yucca Mountain. Models developed at Sandia National Laboratory and Oak Ridge National Laboratory were used for cost estimate development (Johnson, et al 2003 and Michelhaugh 2002).
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2015
  - 2012 UFD Campaign transportation cost data (from Systems Architecture Study) was reported for the first time in the 2015 AFC-CBR. It was escalated to 2017$ for this latest revision (9% increase in unit cost from 2012 to 2017).
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Since 2015 the DOE-NE UFD Campaign and its contractors have prepared several reports comparing the costs of Government-financed at-reactor dry cask SNF storage and subsequent geologic repository disposal to the construction and operation of an Interim Storage Facility (ISF) followed by geologic repository disposal. Transportation costs were major parts of these studies.
  - Since 2015 it has been decided that a separate geologic repository is needed for HLW arising from DOE's defense operations. Reposts on the projected costs, including cask transportation for this facility, may be available.

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.
- 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.

- 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.
- 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.

O1-2. 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 O1-2 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

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.

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.

Table O1-1. Cask capacities.

	Pressurized Water Reactor Fuel Assembly Design			Boiling Water Reactor Fuel Assembly		
Cask	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

O1-3. PICTURES AND DIAGRAMS

The block diagram in Figure O1-1 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 O1-1 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.

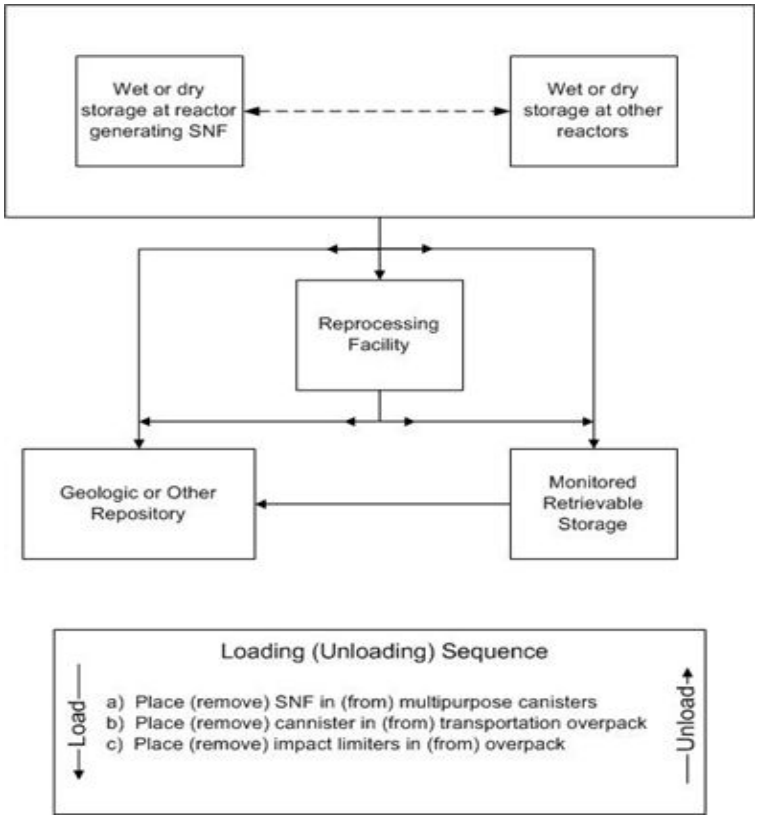

Figure O1-1. Functional block diagram for SNF packaging and transportation.

Figure O1-2 shows the HI-STAR cask canister and transportation overpack and a schematic of one of the two transportation overpack impact limiters.

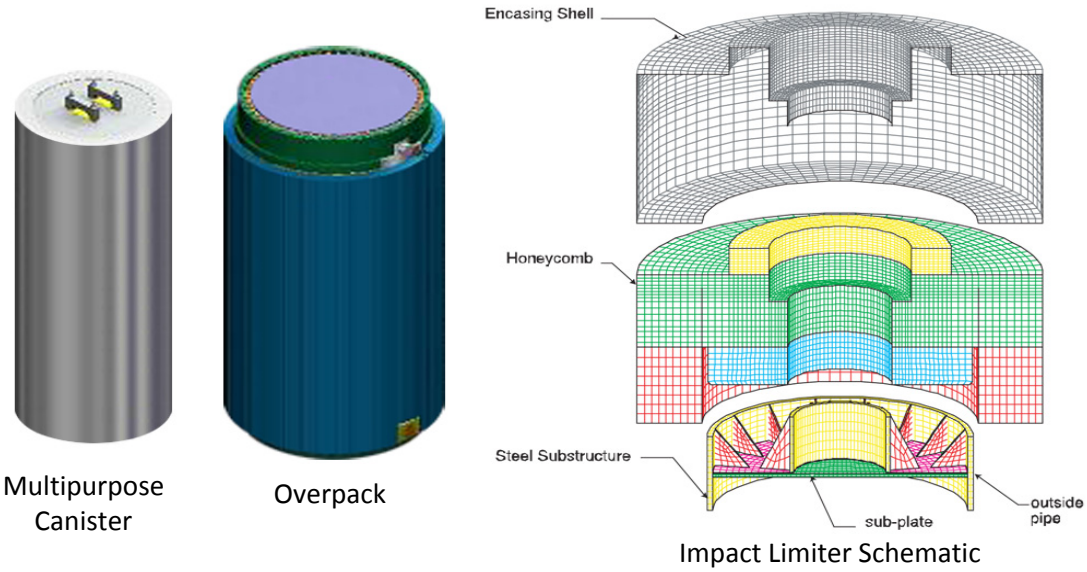

Figure O1-2. HI-STAR cask components.

O1-4. MODULE INTERFACES

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), or to geologic repositories (Module L). 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. SCALING CONSIDERATIONS

The analysis presented below show 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.

O1-6. 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.

O1-6.1 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

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.

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).

Cask System	Direct Cost (Millions of 2007 dollars)				
	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

Table O1-3. HI-STAR cost components.

Component	Cost (Millions of 2007 $)			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 & 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 & become obsolete.

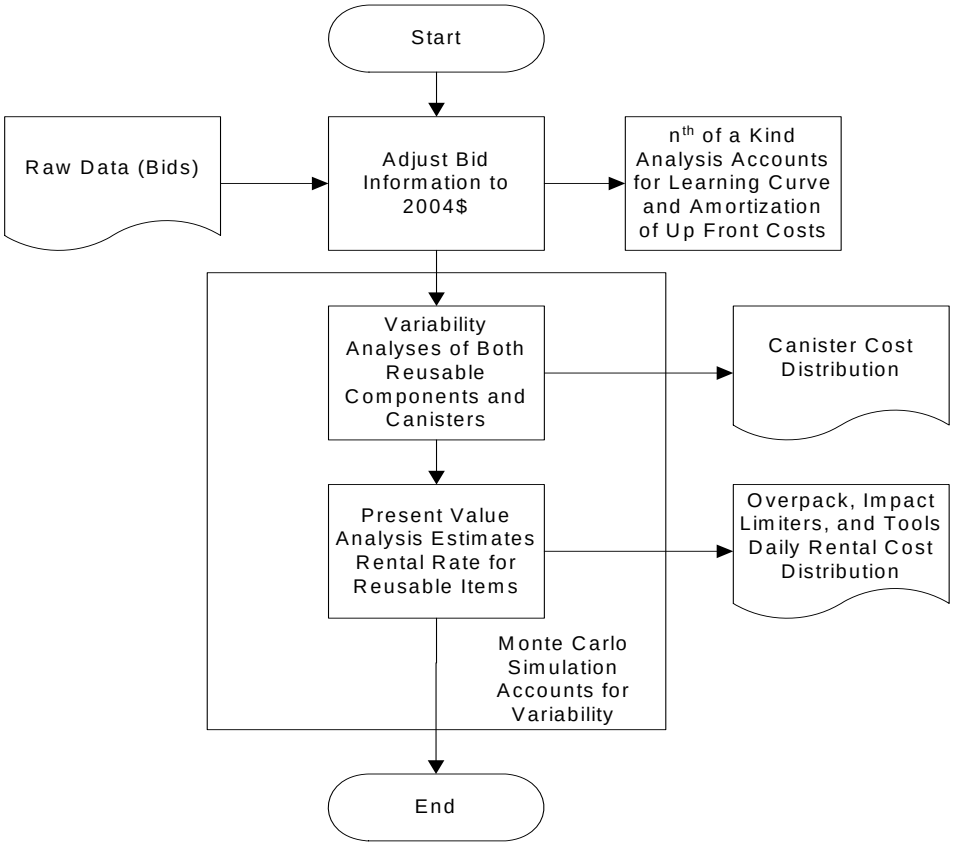

Figure O1-3. Process used to produce consistent cost estimates.

Bids were quoted as n^{th} of a kind (NOAK) 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 G1 and are not costed in this module.

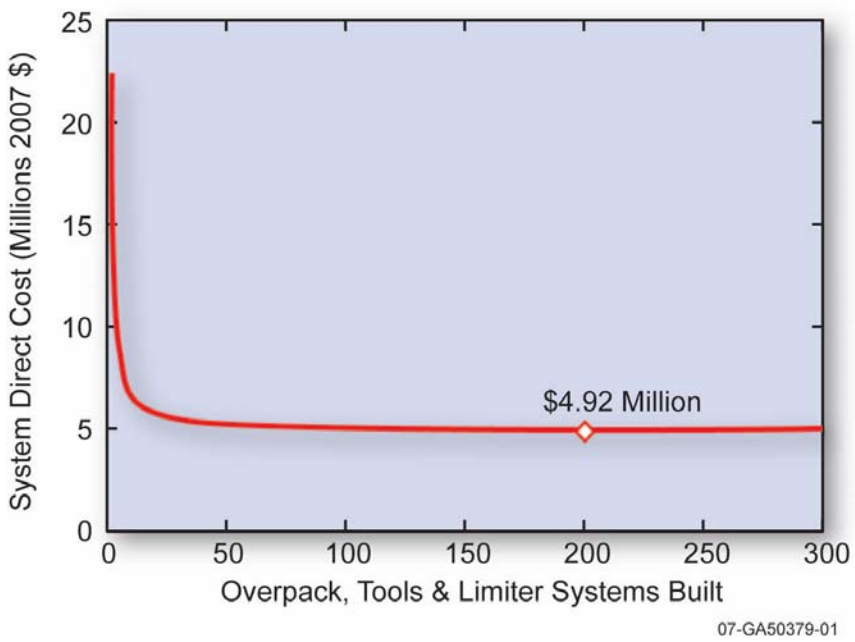

Figure O1-4. N[th] of a kind curve for reusable items based on modal costs.

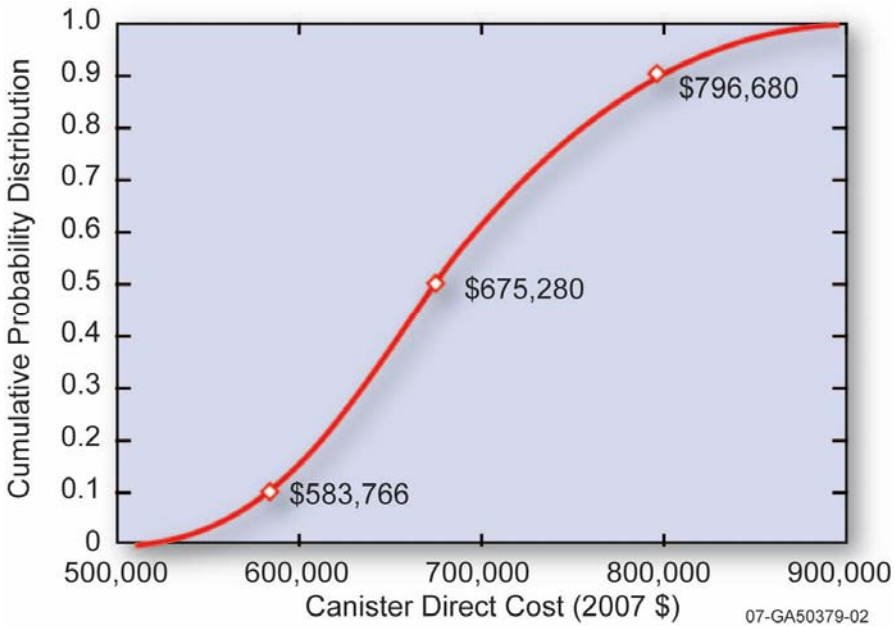

Figure O1-5. Cumulative distribution of multipurpose canister costs resulting from a triangular distribution of canister plus procurement costs.

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 ($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.

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

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.

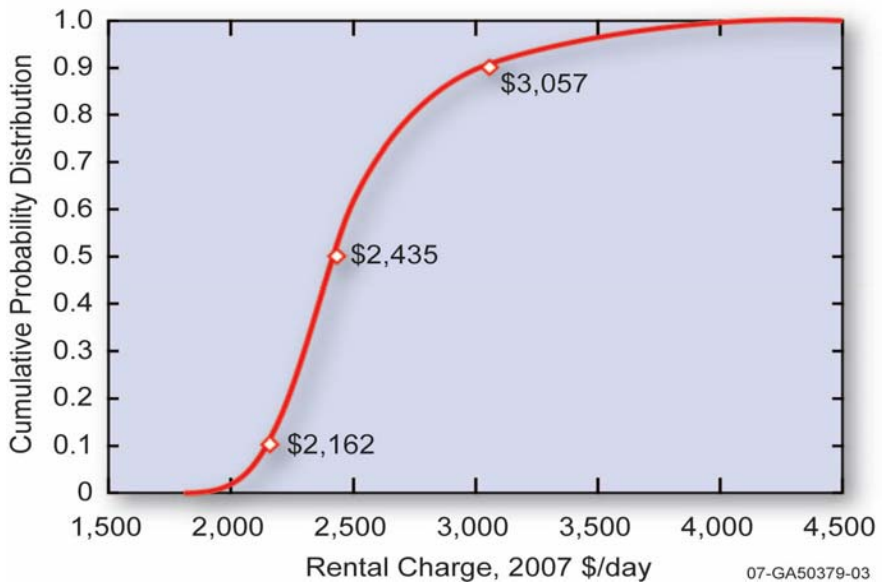

Figure O1-6. Distribution of daily rental cost for reusable cask components. Based on cash flow discounted at 10%.

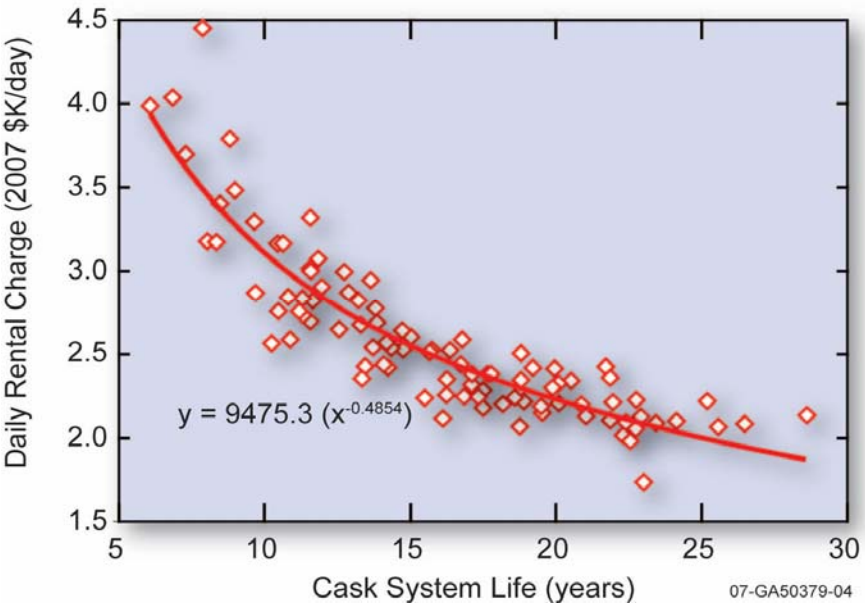

Figure O1-7. Variation of the daily rental rate for cask system reusable components with component useful life.

O1-6.2 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

$$X = \begin{cases} P \le P_{mode} & X = min + \sqrt{P \cdot (max - min) * (mode - min)} \\ P > P_{mode} & X = min + \sqrt{(1 - P) \cdot (max - min) * (max - mode)} \end{cases} \quad (1)$$

where "X" stands for any of the parameters in Table O1-4 or for any other parameter represented by a triangular distribution,

$$P_{mode} = \frac{mode - min}{max - min} \quad (2)$$

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
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

Table O1-5. (continued).

Inputs	Variable Name	Value	Units
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.

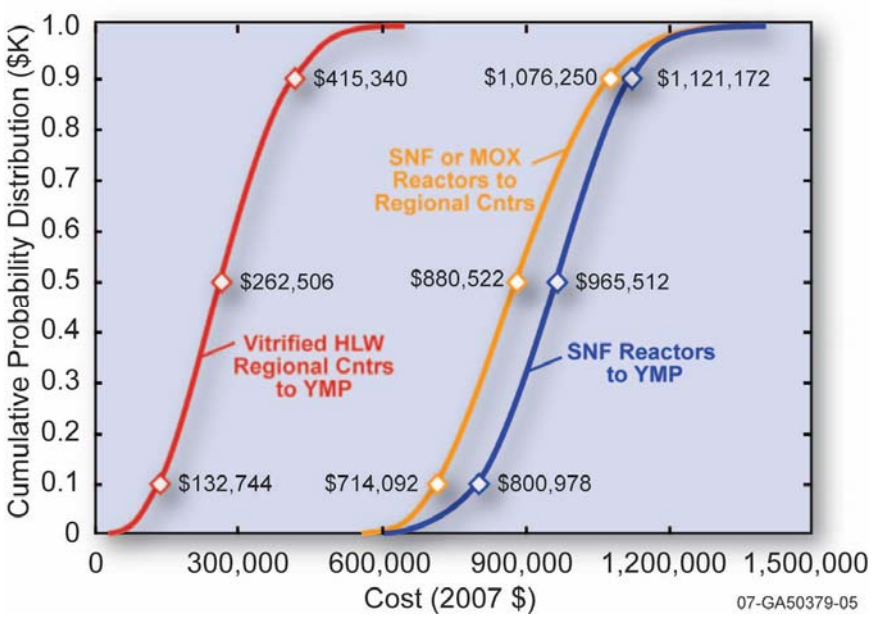

Figure O1-8. Distribution of total shipment costs for shipments of SNF, MOX, and vitrified HLW.

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.

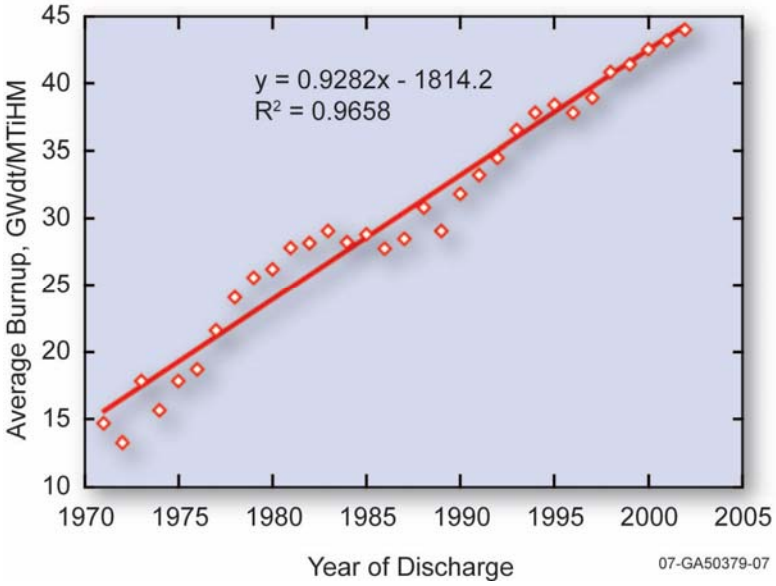

Figure O1-10. Extrapolation of fuel burnup data.

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.

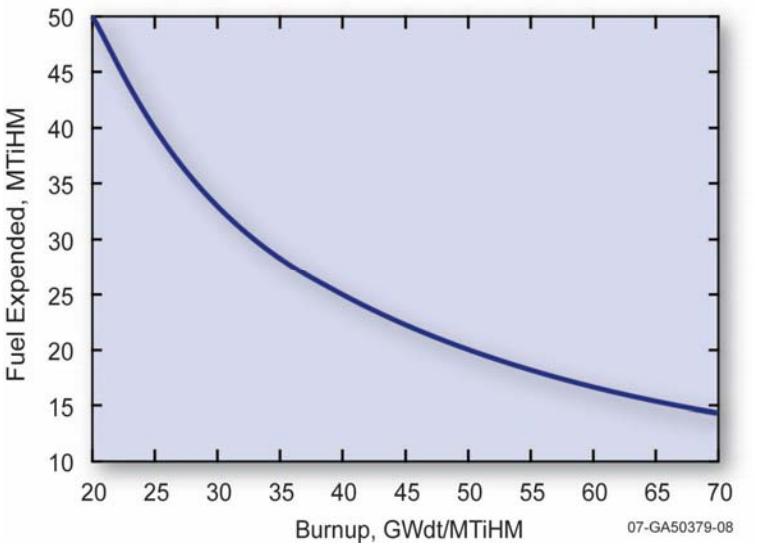

Figure O1-11. Projected SNF production from a typical nuclear power plant.

O1-7. DATA LIMITATIONS

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 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 $) – based on YMP Data.

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 Reprocess Recycle	 1.93 1.95 3.71	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.
9	Annualized financial costs		
	Total Annual Operating Costs Once-Through Reprocess Recycle	 1.93 1.95 3.71	

The What It Takes table above lists costs by several parameters. These costs may be is somewhat obsolete as they were based on Yucca Mountain cost estimates. Similarly, cost per kgiHM per kilometer is a useful metric only when the distance to be shipped is known.

The information above estimates have been revisited and re-evaluated by the DOE's Used Fuel Disposition (UFD) Campaign System Architecture Evaluation (Nutt, 2012). This evaluation is similar to the original methodology in that used nuclear fuel (UNF) is taken from a reactor and sent to a repository, or to a regional storage facility before transportation (potentially years later) to a repository. However, it does not tie directly to Yucca Mountain. Moreover, the original analysis assumed the existence of six regional centers; the current evaluation uses only one.

Additionally, the original methodology assumed 20 MTHM shipped per year; the new methodology assumes between 1500 and 6000 MTHM per year. This is a significant difference that directly impacts the transportation costs by spreading the capital and operations costs over a much greater mass flow. The result is that the new methodology shows a much lower cost of transportation for UNF from the reactor site to the repository. Interestingly, the cost of transportation from the reactor site to the repository via the regional facility does not differ appreciably from the previous revision.

Table O1-9 What-It-Takes (WIT) Cost Summary Table – Based on Systems Architecture Study

Transportation Option	Cost per kilogram of material for transportation			
	Low Cost	Mode Cost	Mean Cost	High Cost
From Reactor to Repository	$21.9/kg	$24.5/kg		$27.1/kg
Escalated to 2017$	**$23.9/kg**	**$26.7/kg**	**26.7/kg**	**$29.5 /kg**
From Reactor to Central Storage Facility to Repository	$95.0/kg	$97.5/kg		$100.0/kg
Escalated to 2017$	**$103.6/kg**	**$106.3 /kg**	**106.3/kg**	**109.0/kg**

For this update, the UFD evaluation high- and low-end reported values corresponding to a 2055 repository start date are used to define the high cost and low cost values. The mean between the high and low is used as the nominal cost.Figure O1-12 shows the probability distributions for the above unit transportation costs.

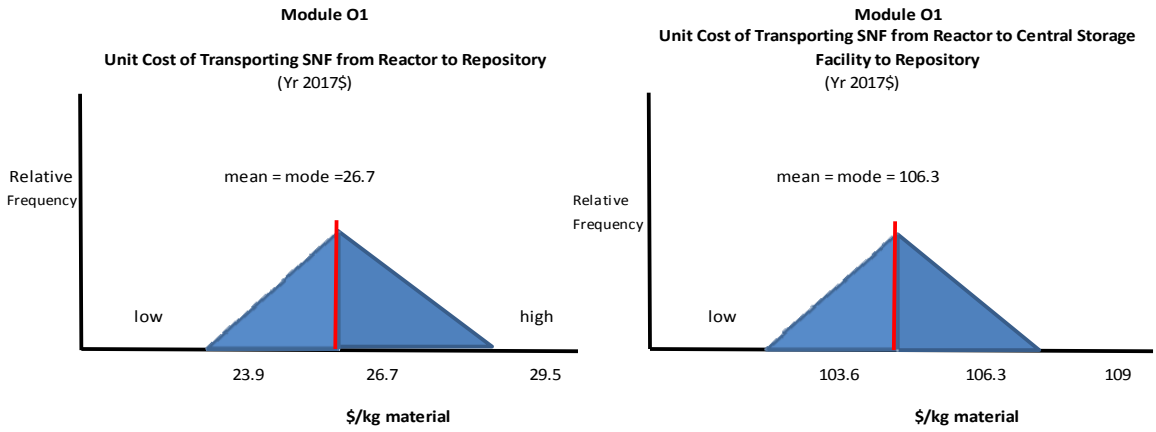

Figure O1-12 Probability Distributions for SNF Unit Transportation Costs

O1-9. SENSITIVITY AND UNCERTAINTY ANALYSES

During the development of shipment cost estimates, 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.

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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

This sub-module, O2, deals with the transport of nuclear fuel and low-level radioactive materials; this is essentially anything not covered by sub-module O1.

O2-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2006 AFC-CBR)
- **Estimating Methodology for latest (2006 AFC-CBR) technical update from which this 2017 update was escalated:** Transportation costs for 9 types of fuels or radioactive substances were developed in a bottom-up estimating manner by Sandia National Laboratory. This data included the costs of the special containers used for waste shipment. In 2009 some cost data, such as that for uranium hexafluoride, was revised to reflect the use of reusable containers.

O2-RH. Revision History

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module N, which also included transportation of SNF and HLW. In the 2006 AFC-CBR it was decided to include this Module in a two-part Module O as Module O2. SNF and HLW Transportation was renamed Module O1 Nuclear Fuel and Low Level Radioactive material transportation became Module O2
- **Version of module in which new technical data was used to establish "what-it-takes" unit cost ranges:** 2006
  - 2006 data was escalated to 2017$ for this latest revision (35% increase in unit cost)
- **New technical/cost data which has recently become available and will benefit next revision:** None.

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.

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.

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.

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.

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.

O2-2. 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.

O2-3. PICTURES AND DIAGRAMS

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.

Figure O2-1. Typical Type-A packagings.

O2-4. MODULE INTERFACES

Columns two and three of Table O2-1 list 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 (R Modules).

O2-5. SCALING CONSIDERATIONS

The analysis show 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.

O2-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

O2-6.1 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.

Material Carried	Name	Certificate	Packages per Truck	Single Value Parameters			Trip Routes	Load/Unload Distribution		
				Cost (2007$)	Loaded Wt. (lb)	Contents (kg HM)		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.

O2-6.2 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.

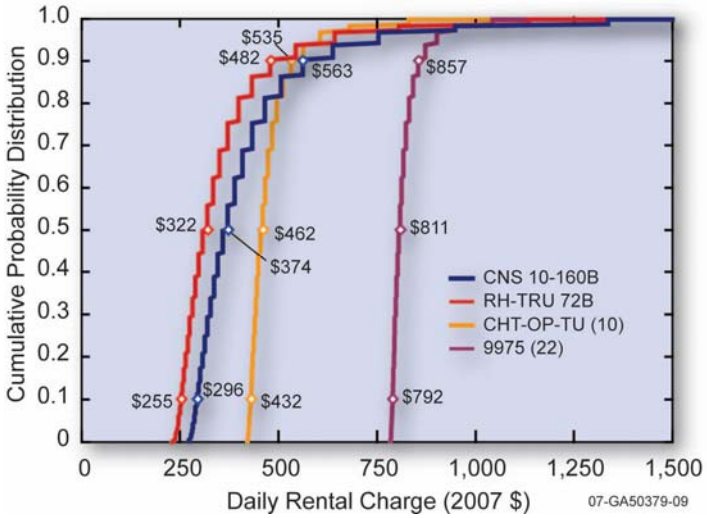

Figure O2-2. Cumulative distribution of daily rental costs for Type B packagings.

O2-6.3 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

$$P \leq Pmode: X = min + \sqrt{P} \bullet (max - min) \bullet (mode - min) \quad (4a)$$

$$P > Pmode: X = max - \sqrt{(1 - P)} \bullet (max - min) \bullet (max - mode) \quad (4b)$$

where "X" stands for any of the parameters in Table O2-4 or for any other parameter represented by a triangular distribution,

$$P_{mode} = (mode - min)/(max - min). \quad (5)$$

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.

O2-6.3.1 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.

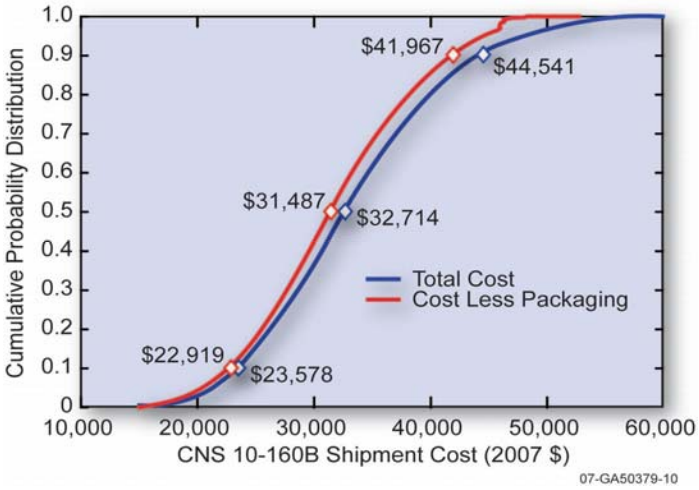

Figure O2-3. Cumulative distribution of shipment costs using a CNS10-160B package.

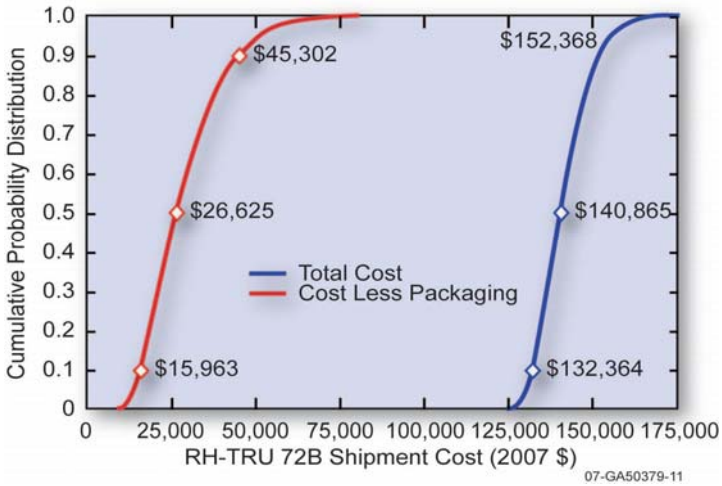

Figure O2-4. Cumulative distribution of shipment costs using a RH-TRU 72B package.

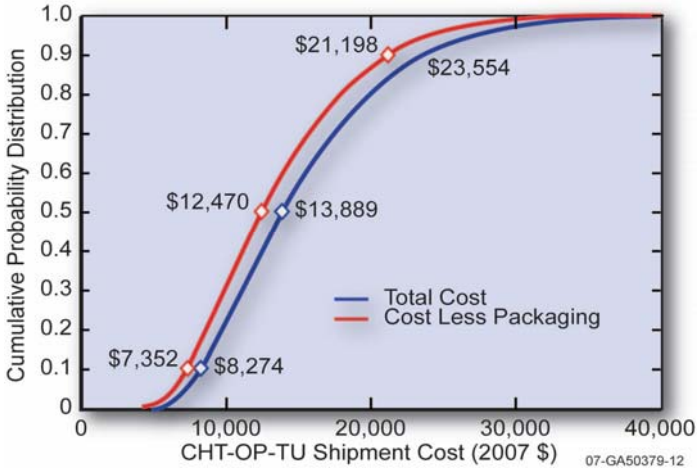

Figure O2-5. Cumulative distribution of shipment costs using a CHT-OP-TU package.

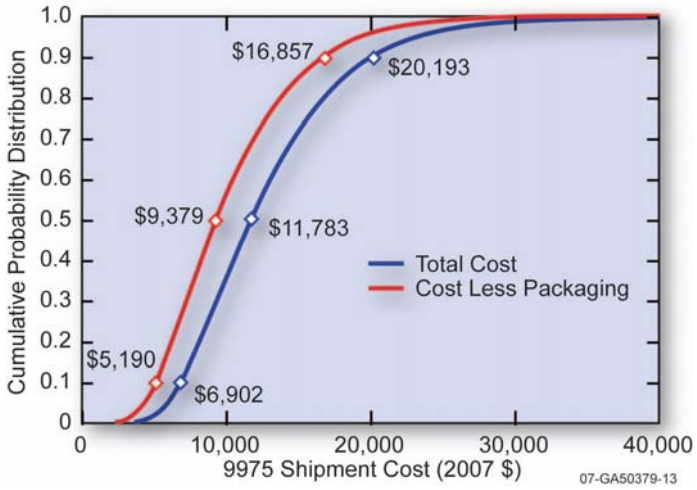

Figure O2-6. Cumulative distribution of shipment costs using a 9975 package.

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.

O2-6.3.2 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.

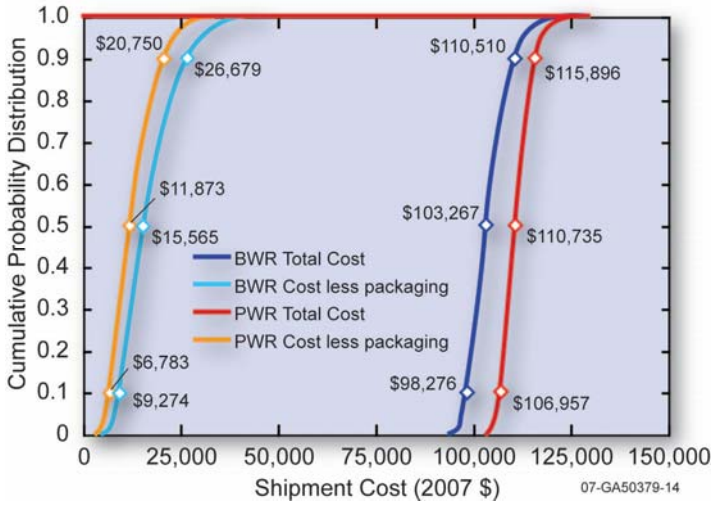

Figure O2-7. Cumulative distribution of shipment costs using an MCC-4 package (PWR fuel) or a SP-1, 2, 3 package (BWR fuel).

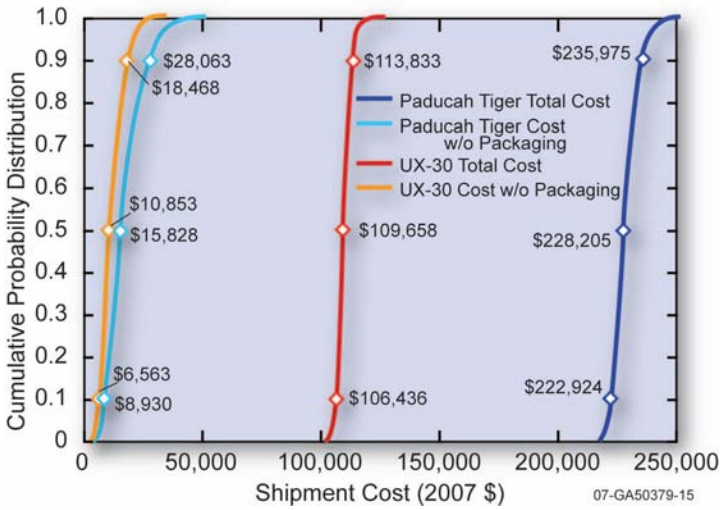

Figure O2-8. Cumulative distribution of shipment costs using a Paducah Tiger or a UX-30 package.

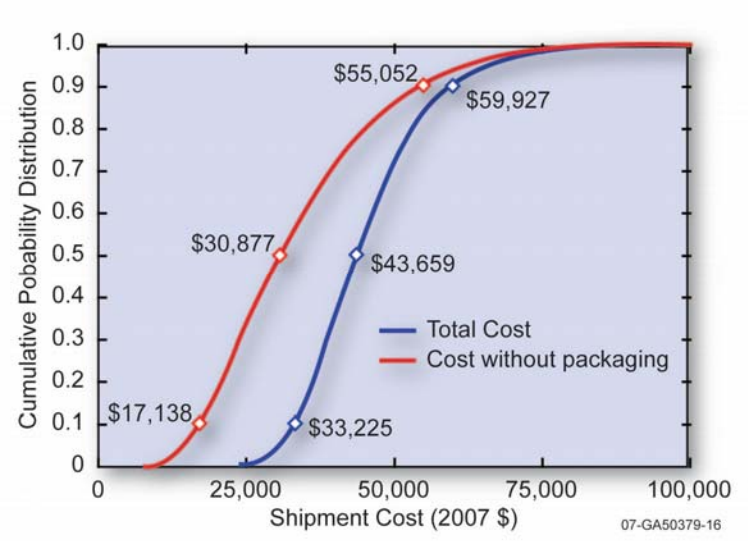

Figure O2-9. Cumulative distribution of shipment costs using a 55-gallon drum.

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	
	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	

Table O2-6. (continued).

	SP-1,2,3 Regional Sites to Reactors		MCC-4 Regional Sites to Reactors	
	Value (2007 $)	Fraction	Value (2007 $)	Fraction
	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			

O2-6.3.3 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. DATA LIMITATIONS

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 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 – Based on Original Data (2006$)

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

The UFD evaluation does not analyze the same material covered in module O2. However, the update to this section is very straightforward. The original evaluation was based on Monte Carlo simulations of transportation of materials between fuel cycle facilities; the same fuel cycle facilities are the bases for the methodology for the update. The only parameters in the evaluation that have changed over time are the costs of the shipping packages. E-mail correspondence with shipping package suppliers were sufficient to determine that these costs have increased between 5% and 10% since the 2009 AFC-CBR; a conservative uniform factor of 10% will cover the spread. Thus, the updated table has values 10% higher than the previous version. This update will also round to the nearest tenth of a dollar ($0.1) for simplification

Table O2-9 What-It-Takes (WIT) Cost Summary Table – Updated for 2012 Shipping Package Costs (and also showing escalation to Year 2017$ (35% escalation from 2006 to 2017 per Escalation Table)

Package and Contents	Cost per kilogram of material for one fully-loaded truck shipment			
	Low Cost	Mode Cost	Mean Cost	High Cost
55-gal drum for yellow cake	$1.7	$2.2		$3.0
Escalated to Yr 2017$	**$2.1**	**$2.7**	**$2.84**	**$3.9**
Paducah Tiger overpack for UF_6 or DUF_6 cylinder	$0.95	$1.05		$1.16
Escalated to Yr 2017$	**$1.1**	**$1.3**	**$1.28**	**$1.4**
UX-30 for EUF_6	$12.5	$12.9		$13.3
Escalated to Yr 2017$	**$15.3**	**$15.8**	**$16.3**	**$15.8**
CHT-OP-TU for DUO_2, UOX, or LLW	$1.4	$1.9		$2.7
Escalated to Yr 2017$	**$1.7**	**$2.3**	**$2.43**	**$3.3**
9975 for TRU or TRUOX	$164.3	$255.7		$391.0
Escalated to Yr 2017$	**$202**	**$314**	**$332**	**$479**
CNS10-160B for FP	$3.7	$5.1		$6.9
Escalated to Yr 2017$	**$4.5**	**$6.2**	**$6.41**	**$8.5**
RH-TRU 72B for TRU or FP	$5.9	$8.3		$11.6
Escalated to Yr 2017$	**$7.3**	**$10.2**	**$10.57**	**$14.2**
MCC-4 for PWR assemblies	$36.2	$37.5		$39.1
Escalated to Yr 2017$	**$44.5**	**$46.0**	**$46.2**	**$48.0**
SP-1,2,3 for BWR assemblies	$54.1	$56.8		$60.7
Escalated to Yr 2017$	**$66.4**	**$69.7**	**$70.2**	**$74.5**

These numbers also agree in most part with those in a 2008 GNEP study references below. Triangular distributions can be used to represent the uncertainty consistent with the above ranges.

O2-9. SENSITIVITY AND UNCERTAINTY ANALYSES

The analysis results presented above 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.

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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,

fTotalCost = fPackCost + fLCost +fShipCost + fUCost. (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,

fPackCost = (cNPack/Ship)[sCanCost + 2(cDays)(sOPCost + sILCost)] (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,

cNPack/Ship = (iNPackVeh)(iNPack/Veh) (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,

cDays = sTrip/sSpeed (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,

fLnCost = (sLHead)(cLDur/Ship)[(sLS)(iNLS) + (sLR)(iNLR) + (sLC)(sNLC)] (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.

fUCost = (sUHead)(sUDur/Ship)[(sUS)(iNUS) + (sUR)(iNUR) + (sUC)(sNUC)] (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,

cLDur/Ship = (cNPack/Ship)(sLDur/Pack) (12)

similarly, for unloading,

cUDur/Ship = (cNPack/Ship)(sUDur/Pack). (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,

fShipCost = 2(cDays)(cNVeh)(sVehCost)+(iNPackVeh)[(cTonnekm)(sTariff)+sDedVeh+(sStates)(sSFee)] (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,

cNVeh = iNPackVeh+iNBufVeh (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

cTonnekm = sTrip(iWtIL + iWtOP + iWtCan + iWtCanCont) (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 sCanCost	Purchase cost single use canister ($)	X	 X				Type A: Table O2-2 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

Table OX-1. (continued).

Parameter	Description	Input			Calc'd		Value	Ref
		S	TD	OD	IC	FR		
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			$0.06/0.075/0.10	S,O
cTonnekm	Tonne-km per shipment				X			
fTotalCost	Total trip cost ($)					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.

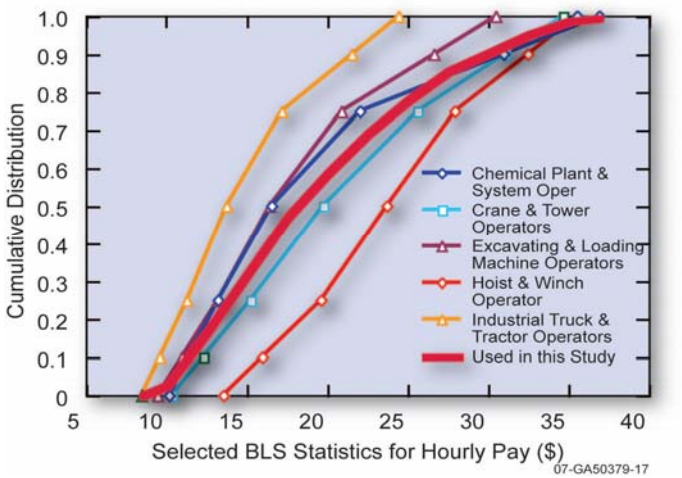


Figure OX-1. Hourly labor wage (Bureau of Labor Statistics 2006).

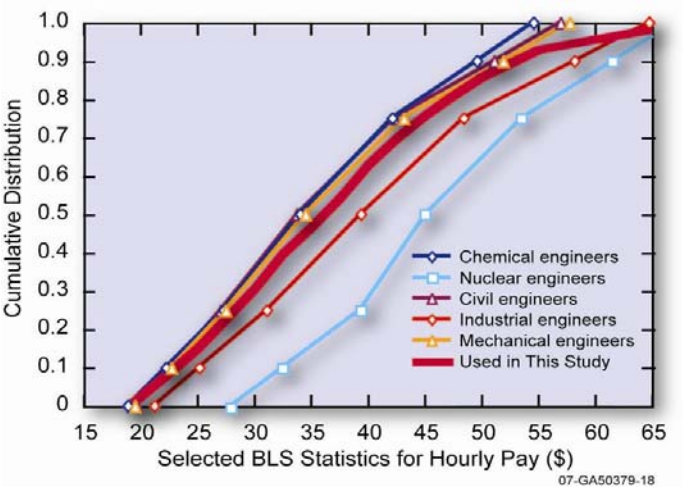


Figure OX-2. Hourly oversight wage (Bureau of Labor Statistics 2006).

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.

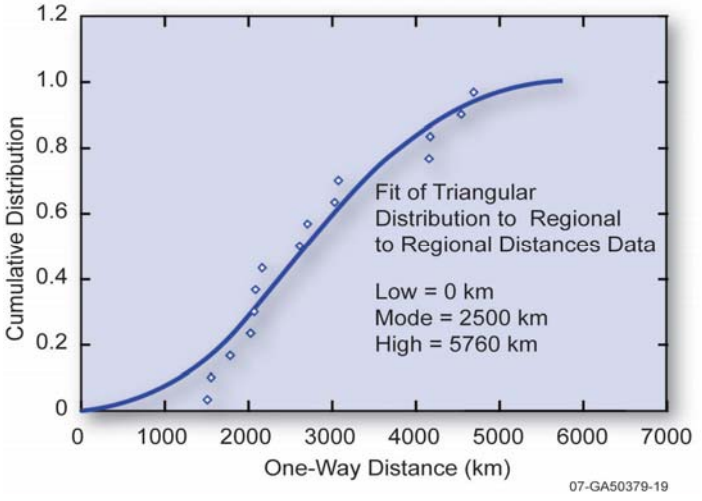
Region	Location
North Western	Hanford, WA
North Central	Prairie Island Indian Reservation, MN
North Eastern	West Valley, NY
South Western	Yucca Mountain, NV
South Central	Kay County, OK
South Eastern	Savannah River, SC

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.

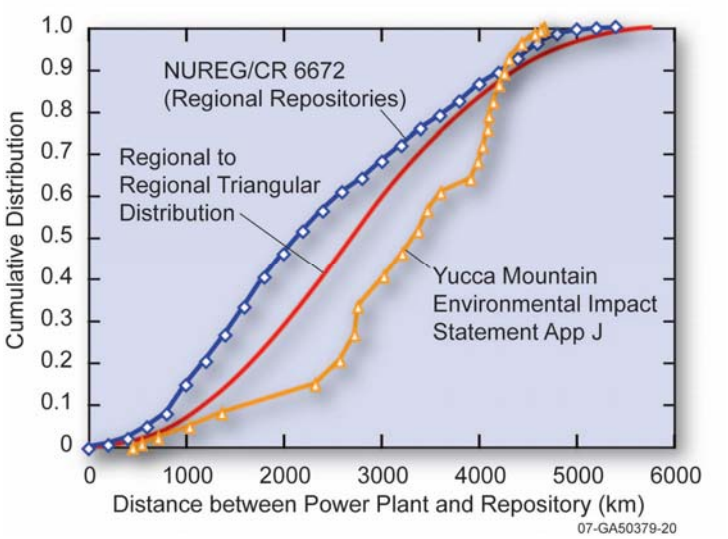


Figure OX-5. Distribution of trip distances (sTrip) for rail shipments from reactors to Yucca Mountain and for shipments to regional storage facilities.

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.

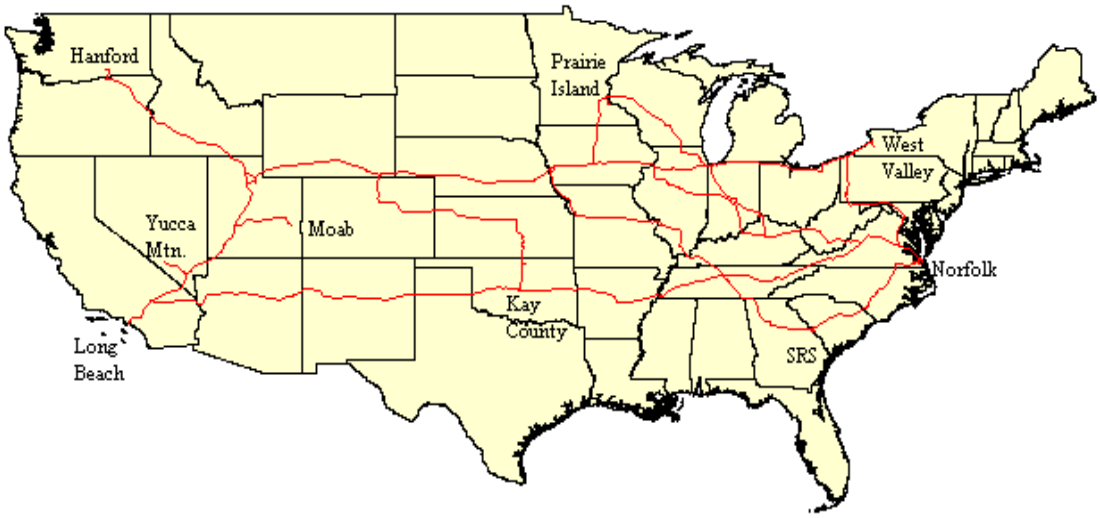


Figure OX-6. Truck routes calculated using TRAGIS that connect the yellow cake shipment sites to the six hypothetical locations for regional facilities.

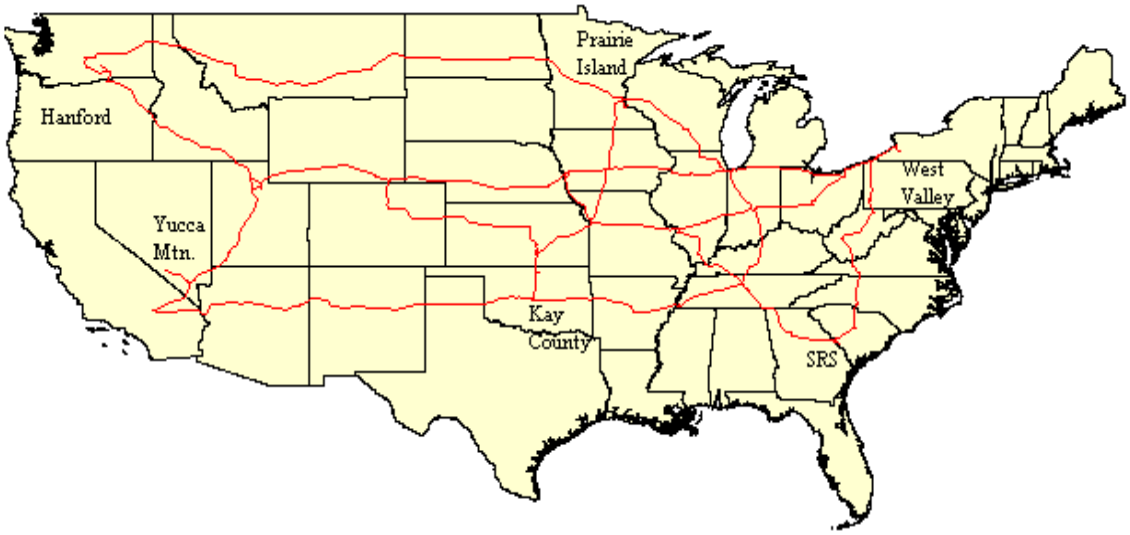


Figure OX-7. Truck routes calculated using TRAGIS that connect the six hypothetical locations for regional facilities.

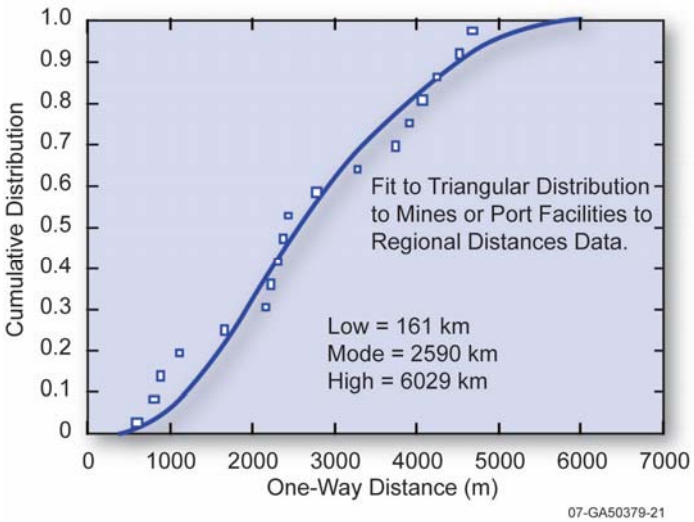


Figure OX-8. Cumulative distribution fit to the 18 route lengths that connect uranium mines in Moab, Utah, or the Long Beach, California, and Norfolk, Virginia, ports of entry to the six hypothetical regional facility sites.

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.

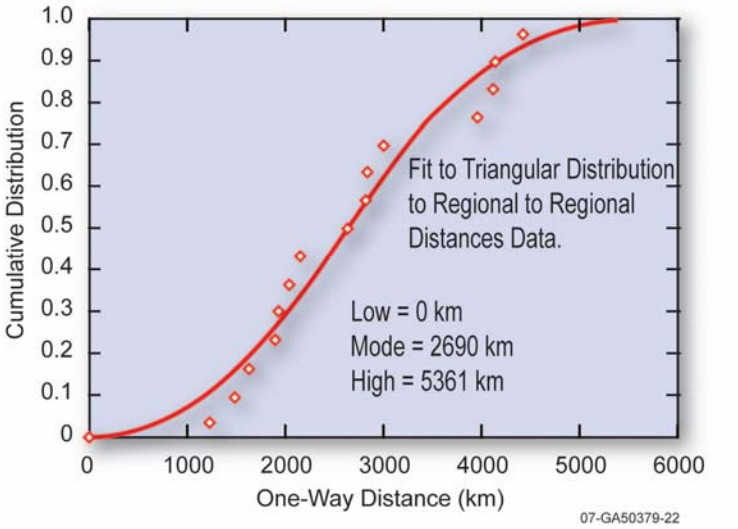


Figure OX-9. Fit of region to region truck distance data to triangular distribution.

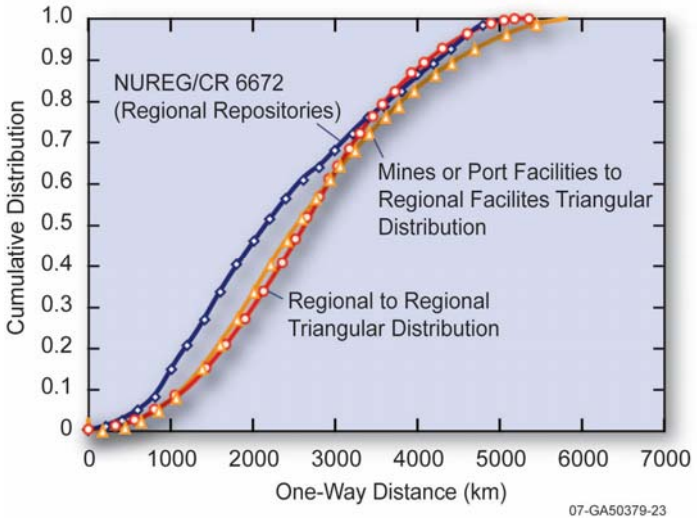


Figure OX-10. Cumulative distribution of trip distances (sTrip) for shipments from regional facilities.

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.

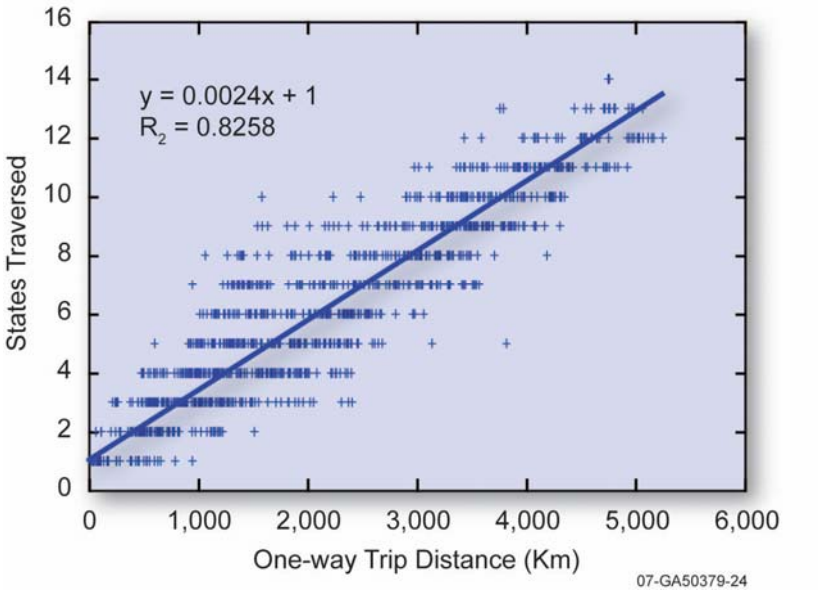


Figure OX-11. States traversed vs. trip distance.

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 $R^2 = 0.8258$.

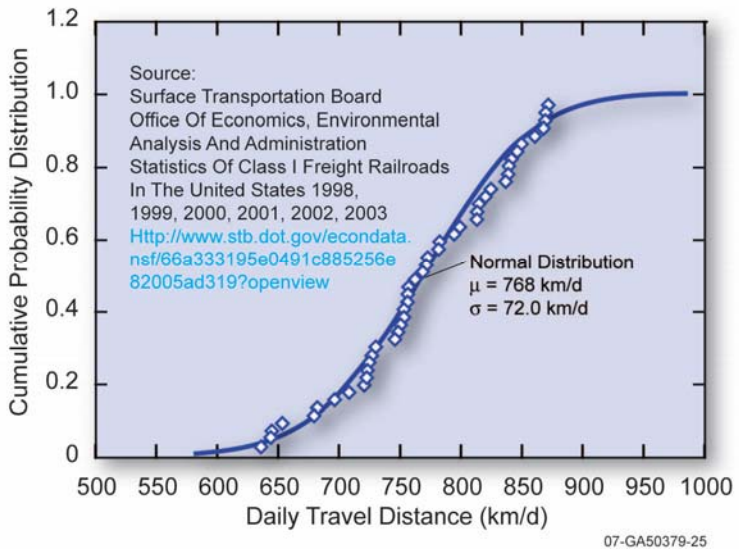
For the Monte Carlo calculation of trip costs, the estimate of sStates was taken as the random variate of a normal distribution using the linear relation for $sStates_{av}$ as a function of distance as the mean value of this distribution and the value of SE_y as its standard deviation. Thus,

$$sStates = (N|\ sState_{av}, SE_y). \quad (18)$$

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.

$$sSpeed = (N|x_{av} = 768, s = 216) \quad (19)$$

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.

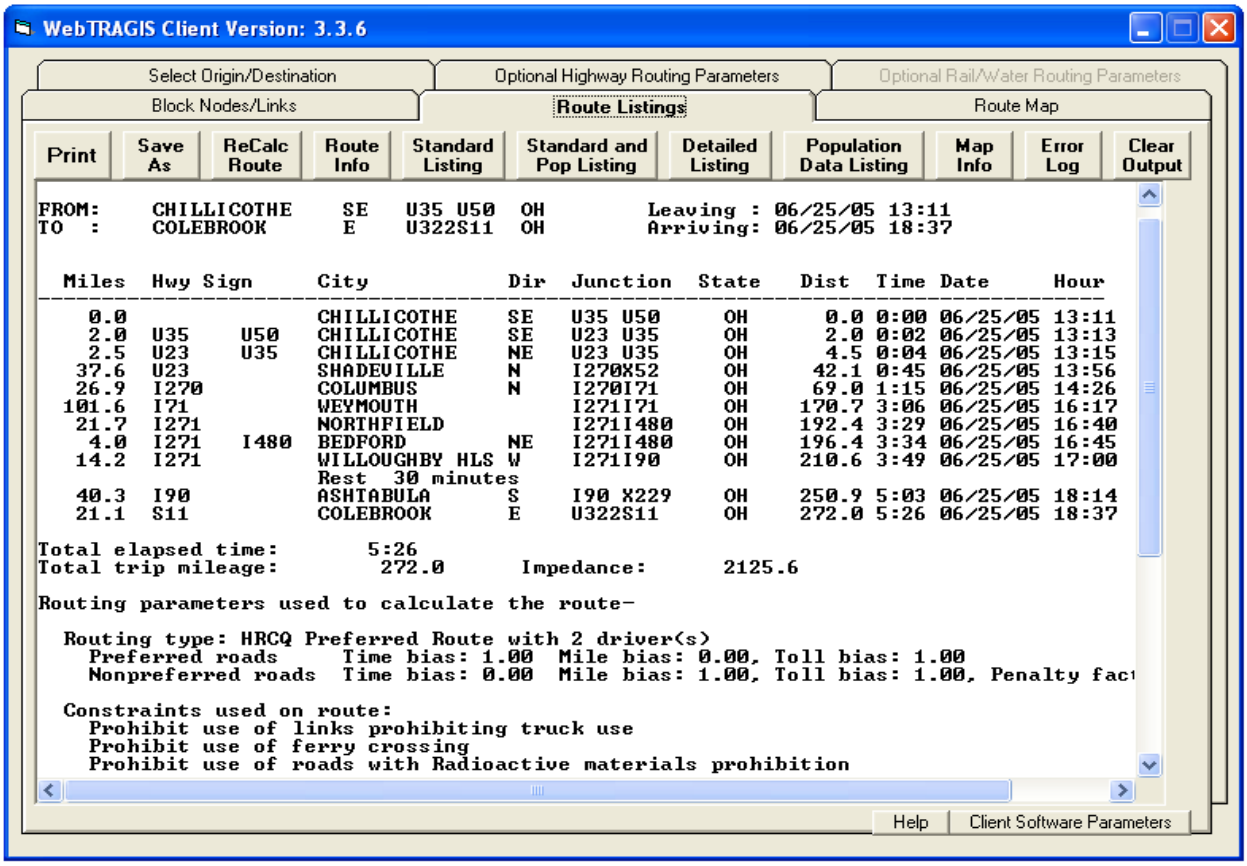


Figure OX-13. TRAGIS standard listing output.

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.

$$sTariff_{av} = 3.27\ sTrip^{-0.4221}. \quad (20)$$

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

$$sTariff = (N|sTariff_{av},.304) \quad (21)$$

which is the equation that was used to calculate sSpeed during the Monte Carlo calculation of Trip Costs.

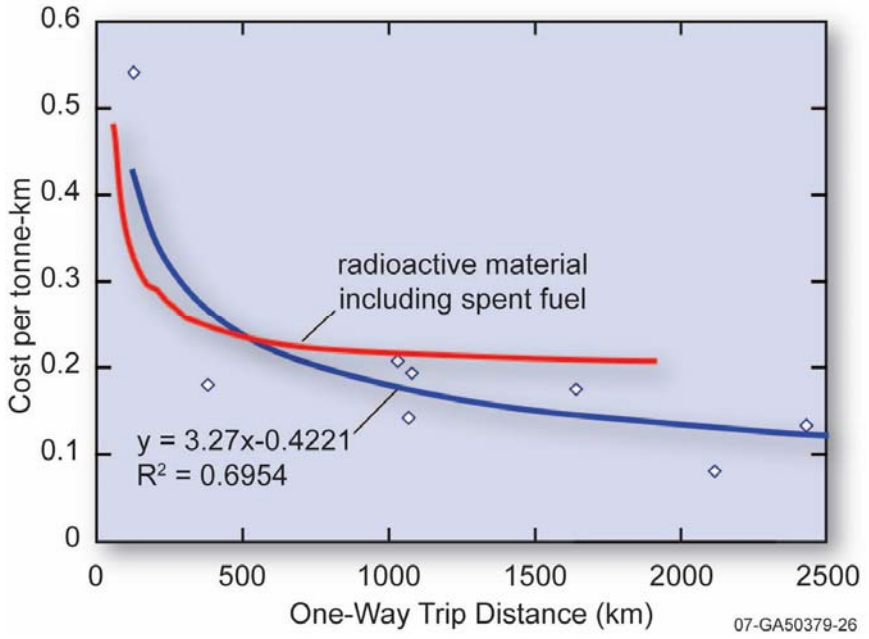


Figure OX-14. Railway tariff as a function of trip distance.

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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R MODULES
Reactors and Transmuters

Preface for R Modules

The R modules are incrementally being updated to reflect the estimation methodologies discussed in the Cost Estimating Methods chapter of the main report. In this edition, the R1 module has been updated using a detailed combination of Engineering and Extrapolation from Actuals method. The R2 module has been updated using a Parametric estimation method documented in the supporting document 2017 SD6 (Parametric Approach for R Modules). With the exception of the pressurized Heavy Water Reactor (PWHR or "CANDU" Reactor: Module R5), most of the other reactor types are less mature, and the planned approach is to update them in subsequent editions using either this same parametric approach or an Analogy approach using partial correlation coefficients that is under development as discussed in the supporting document 2017 SD3 (Cost Correlations).

Module R1

Light Water Reactors

Module R1

Light Water Reactors (LWRs)

R1.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Complete technical revision of overnight capital cost. O&M escalated from AFC-CBR 2015.
- **Estimating Methodology for latest (2017 AFC-CBR) technical update from which this 2017 update escalated:** Past construction experience, along with on-going construction experience, was evaluated to look for the best experience attributes. This was done in order to assess the overnight cost **without** the significant cost overruns due to the many factors that are **not** part of the cost of well-built reactor, which is the result of a well-executed construction project.

R1.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module R1.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2017
- **New technical/cost data which has recently become available and will benefit next revision:**
  - A recent report from the Breakthrough Institute (Lovering 2016) includes some data on Far Eastern NPP costs.

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 the light water moderated class of "thermal" reactors; i.e. 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. In thermal reactors, the moderators most commonly used are light water (this Module R1), heavy water (Module R5), or graphite (carbon) (Module R3). 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 deployment 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: Module R5), and gas-cooled reactor s (Module R3) such as those used predominantly in the UK, which use a graphite moderator.

LWRs come in two basic types, the Pressurized Water Reactor (PWR) and the Boiling Water Reactor (BWR). Figure R1-1 below shows the PWR concept, which has two light water flow loops. The primary water coolant is at high pressure and remains a liquid at temperatures around 315 C. Heat is transferred to a secondary loop where steam produced at around 290 C drives the turbine generator

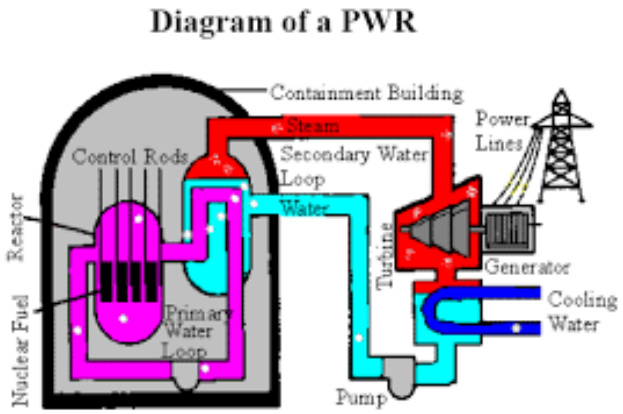

Figure R1-1. Pressurized Water Reactor Concept.

In the BWR concepts shown in Figure R1-2 below, the water in the core exists in both the liquid and vapor phase. Steam from the top of reactor vessel drives the turbine-generator in a single coolant loop.

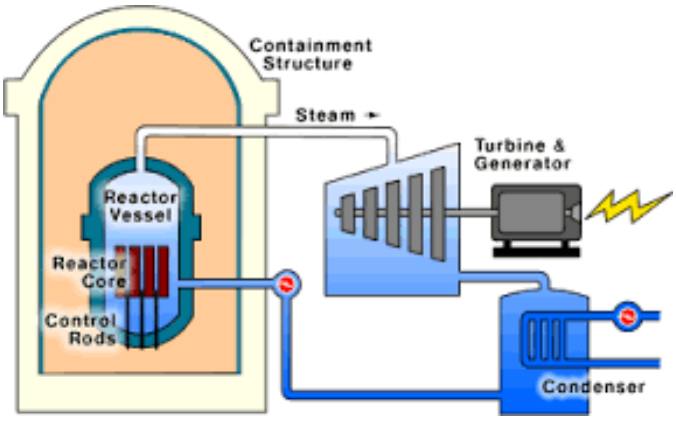

Figure R1-2. Boiling Water Reactor Concept.

Most LWRs in the world are the PWR type; however, both types have enjoyed excellent performance and reliability worldwide.

The predominant product from LWRs 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 1,600 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=1/1,00 0^{th} 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 (2009-2017) 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, but stringent regulation also contributes to higher costs. Massive amounts of steel and concrete with the associated installation labor and quality assurance 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.

In the paragraphs above from the 2009 AFC-CBR the generic technical and economic considerations associated with LWR were described in detail. In the 2012 AFC-CBR the scope of Module R1 was changed somewhat. This type of reactor is still the predominant type of reactor in the US and in the world; however, the 2012 AFC-CBD Module deals with the "large" or "gigawatt class" version of this reactor type. (Module R4's 2012 update dealt mainly with the small modular LWR.) It should be kept in mind that even newer large LWRs are somewhat modular in nature, since many reactor subsystems can be assembled in factories and shipped to the reactor site. This is indeed the case for the Vogtle and Summer AP-1000 PWRs, either recently or now under construction in Georgia and South Carolina respectively, where many modules are built in Lake Charles, Louisiana.

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. Figures R1-1 and R1-2 show this schematically. 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 degradation of 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 2020 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 was discussed in detail in Module R4 of the 2009 & 2012 updates AFC-CBRs but is not included in the 2017 version.. Since "modularity" is an issue generic to all types of reactors its discussion has been covered in a chapter of the Main Report for this 2017 AFC CBR.

The following describes the commonly used code of accounts that is used in the breakdown of the cost of reactors. This breakdown is from EEDB 1988 (ORNL 1988b):

- **Structures and Improvements (Account 21):** This account includes the on-site surface buildings, structures, related subsurface foundations, tunnels that house and support all equipment, components, piping, ducting, and wiring, except for the foundations for individual plant machinery or the buildings and foundations heat rejection systems. Included are site improvements, such as excavation, grading, roadways and railroads, substructure and superstructure details and architectural features. Also included are equipment and piping for the heating, ventilating and air conditioning systems, piping for the roof, floor and sanitary drains, and equipment for the lighting and service power systems.
- **Reactor or Boiler Plant Equipment (Account 22):** This equipment includes the reactor, reactor safety systems, fuel storage systems, and radioactive waste handling systems. Also included are the interconnecting piping systems, structural supports for equipment, and necessary instrumentation and control systems.
- **Turbine Plant Equipment (Account 23):** This account includes the power conversion system equipment including the turbine-generator unit, condenser, systems to purify and return the condensate to the reactor or boiler plant (condensate and feedwater systems), elevated turbine-generator pedestal, main vapor piping system, auxiliary support systems, interconnecting piping systems, structural supports for equipment, and necessary instrumentation and control systems.
- **Electric Plant Equipment (Account 24):** This account includes the systems and equipment required to deliver the generated electric power to the off-site transmission system, provide auxiliary electric power for all power plant equipment and auxiliaries, and provide standby power for safety systems for nuclear power plants or emergency backup power for selected systems for fossil power plants. Included are the cable and raceways for all power, control and instrumentation systems, structural supports for equipment, generator control system equipment and plant grounding, lightning protection, freeze protection and cathodic protection equipment. Although building lighting and service power equipment are included in Account 21, the equipment for the distribution of power to these systems is included in this account.

- **Miscellaneous Plant Equipment (Account 25):** This account includes the auxiliary mechanical and electric equipment required for normal power plant start-up, operation and maintenance including the transportation and lift equipment (cranes), equipment in the air, water and steam service system, auxiliary boiler, fire detection and protection systems, communication system, non-radioactive waste water treatment system, various plant monitoring systems, miscellaneous furnishings and fixtures, and necessary interconnecting piping systems and structural supports for this equipment.
- **Main Condenser Heat Rejection System (Account 26):** This account includes the equipment and associated structures and piping that dispose of the heat rejected by the power plant and provide make-up water to the power plant including the cooling towers and the structures, equipment and interconnecting piping systems for obtaining and pretreating the plant make-up water.
- **Construction Services (Account 91):** This account includes the temporary structures and facilities, janitorial services, maintenance of temporary facilities, guards and security, roads, parking lots, laydown areas, temporary electrical, heat, air, steam and water systems, general cleanup, and related items and activities; The rental and/or purchase of construction equipment, small tools and consumables (fuel, lubricants, etc.), as well as maintenance of construction equipment. Insurance and taxes related to craft labor, such as Social Security taxes and state unemployment taxes, workmen's compensation insurance, and public liability and property damage insurance; Permits, Insurance and Local Taxes and Builders all-risk insurance.
- **Engineering and Home Office Services (Account 92):** This account includes the Home Office Services: the salaries of personnel, direct payroll-related costs (DPC), overhead loading, expenses and related fees associated with the engineering and design (both home office and field), procurement and expediting activities, estimating and cost control, engineering planning and scheduling, and reproduction services, plus expenses associated with performance of the above functions (i.e., telephone, postage, computer use, travel, etc.); Home Office Quality Assurance (Nuclear Power Plants): the salaries, DPC, overhead loading and expenses (e.g., travel) associated with the services of home office quality assurance engineers and staff personnel including reviews, audits, vendor surveillance, and other activities as required for design and construction of the nuclear safety-related portion of the facility. Home Office Construction Management: the salaries, DPC, overhead loading and expenses associated with the services of the construction manager and his assistants including construction planning and scheduling, construction methods, labor relations, and utilization of safety and security personnel.
- **Field Supervision and Field Office Services (Account 93):** This account includes the Field Office Expenses: the costs associated with purchase and/or rental of furniture and equipment (including reproduction), communication, postage, stationery, other office supplies, first aid and medical expenses. Field Job Supervision: the salaries, DPC, overhead loading, relocation costs and fees associated with the resident construction superintendent and his assistants, craft labor supervisors, field accounting, payroll and administrative personnel, field construction schedulers, field purchasing personnel, warehouse personnel, survey parties and clerical personnel; Field Quality Assurance/Quality Control: the salaries, DPC, and overhead loading associated with personnel located at the job site engaged in equipment inspection, required documentation of safety-related equipment (nuclear power plants only), inspection of construction activities and construction training meetings; Plant Startup and Test: the salaries, DPC, overhead loading, and miscellaneous related expenses associated with preparation of start-up and plant operation manuals and test procedures, direction and supervision of testing of equipment and systems as the plant nears completion and direction of start-up of the facility. (Costs of craft labor required for start-up and testing activities are included in the appropriate Direct Cost line items.)

R1-3. PICTURES, DIAGRAMS, AND DEPLOYMENT STATUS

The "Generations" concept as applied to reactors is explained in Figure R1-3.

To further the advancement of Generation III and III+ reactors in the U.S., the U.S. Department of Energy (DOE) instituted the NP-2010 program. The NP-2010 program focused 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).

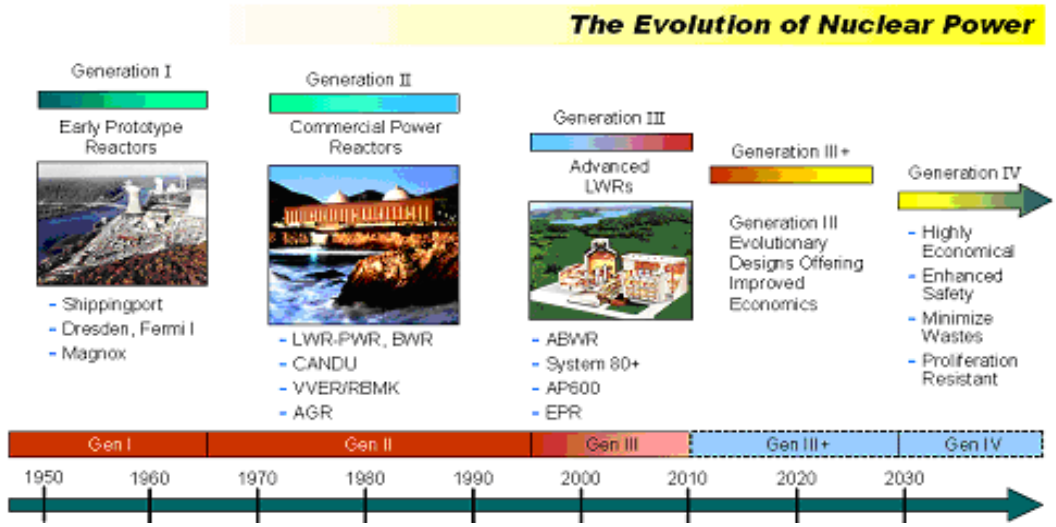

Figure R1-3. Nuclear power evolution by "generations" (DOE 2001).

The technology focus of the Nuclear Power 2010 program was 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 also included investment stimuli for new nuclear power plants (NPPs). These included:

- 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 was to make investors (Wall Street) more likely to finance the high up-front costs required for a reactor project in the middle of the first decade of the 21st century. Utility interest in these incentives was intense as was evidenced by the number of projects that announced to the NRC their intent to pursue a COL. Table R1-2 lists the projects announced as of Summer 2009. Since 2009 most of these projects have been cancelled or deferred for economic reasons. Only Vogtle is still under construction, and for economic and market reason its completion is uncertain as of the end of 2017.

Table R1-2. New plant table as compiled by the nuclear regulatory commission in 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. MODULE INTERFACES

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 Module I). Direct transfer to an aqueous reprocessing facility is also possible (see Module F1). Module G2 considers the costs of conditioning and repackaging spent fuel if required before transport.

R1-5. SCALING CONSIDERATIONS

It is not clear if economies of scale can be proven to exist for LWRs, or if they even become dis-economies of scale after a certain size, based on the historical US construction experience. It is generally possible to obtain scaling factors for individual components, but in general it is not recommended to

simply scale costs for a certain power reactor to a different power level using a power exponent, until more definite proof of economies of scale can be demonstrated.

R1-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

After a description of historical construction costs in the U.S. and France, and the introduction of a framework to interpret the construction cost escalation and cost overruns, a summary is provided with recommended expected values and probability density functions for the "engineering" and "non-engineering" construction costs.

R1-6.1. The Historical U.S. Reactor Construction Cost

A brief history and cost data of the U.S. LWR reactor construction experience is provided in this section. Historical information for other countries can be also provided in this Section, as the information is collected and considered reliable/defensible enough, in successive CBR updates.

The Atomic Energy Commission's (AEC) Power Reactor Demonstration Program, which existed between 1955 and 1963, subsidized the construction of the first demonstration power reactors in the U.S.: a dozen 10-75 MW reactors that started service in the 1950s and three 200 MW-class reactors that started service in the early 1960s. The beginning of commercial nuclear energy in the U.S. was 1968, with the commercial operation of the first 500 MW class reactors (Haddam Neck (CT) and San Onofre (CA)).

Afterwards, a dozen "turn-key" plants started operations: these plants were sold at a fixed price by Westinghouse LLC and by General Electric Co. in order to demonstrate the commercial viability of nuclear energy. The first of these was the 650 MW Oyster Creek (ordered in 1963), while the almost identical Nine Mile Point 1 was ordered months later on a commercial (i.e. non turn-key) basis. The cost data for the first turn-key units are either unavailable, and/or unreliable, and therefore they are not included in the cost-database presented here. The following 15, mostly turn-key U.S. reactors built before 1971 are therefore excluded from the database:

- Connecticut Yankee (also known as Haddam Neck);
- San Onofre 1;
- Oyster Creek;
- Nine Mile Point 1;
- Ginna,
- Dresden 2 and 3,
- Point Beach 1 and 2,
- Millstone 1,
- Robinson,
- Monticello,
- Quad Cities 1 and 2,
- Indian Point 2.

The cost database shown in Table R1-3 is based on the data in (Koomey and Hultman, 2007) for 99 U.S. reactors, containing, among other things: reactor name, overnight cost, total capital investment in today's dollars and construction duration. In turn, (Koomey and Hultman, 2007) relied mostly on data from (Komanoff, 1981) and later updated, with the exception of the cost for Comanche Peak 1 and 2 (which were built by Texas Utilities), Seabrook (which was completed by a consortium of utilities in the NorthEast), and Watts Bar 1 (which built by Tennessee Valley Authority (TVA)).

For each of these, the complete time series of the construction expenditures was obtained by the authors of (Koomey and Hultman, 2007), and converted to constant-1987-dollars using the Handy-

Whitman escalation index, and then to 2004 using the general GDP index. Additionally, (Koomey and Hultman, 2007) obtained:

1. Construction duration data from an NRC database,
2. Electrical power level and capacity factors from an IAEA database; and
3. Electrical efficiency from the Global Energy Decision Database through the NEI.

The cost data were originally collected by the Federal Power Commission and later by the DOE's Energy Information Administration, and published through several years in the *Steam-Electric Plant Construction Costs and Annual Production Expenses* (DOE/EIA-0033 series). The methodology to convert "as expended" dollars to "constant dollars" of a given year, is detailed in *An Analysis of Nuclear Power Plant Construction Costs* (DOE/EIA-0485) (DOE, 1986). Additionally, the cost data for the following plants were originally obtained by Komanoff through direct communication with the utilities: Browns Ferry 3, Crystal River 3, Indian Point 3, Fitzpatrick, Davis Besse 1.

Figure R1-4 shows the specific overnight capital cost (in 2004 $/kWe) for the U.S. nuclear power plants as a function of construction start-year and end-year. The cost data can be updated to 2014 using the Handy-Whitman escalation index for nuclear power plants, or the general inflation rate: for example, the CPI can be found online at the U.S. Bureau of Labor Statistics web site (BLS, 2014). The cumulative change in CPI between 2004 and 2014 is 1.26.

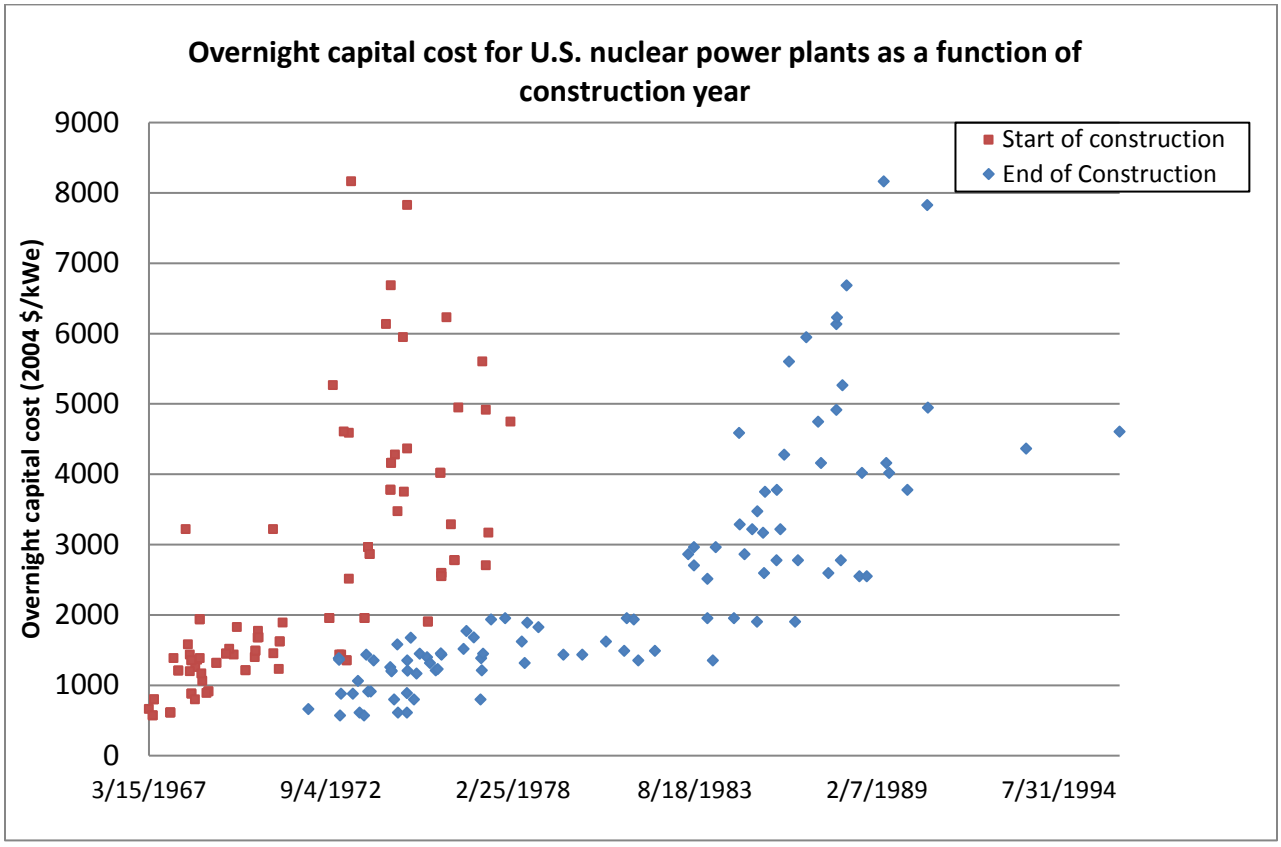

Figure R1-4. Overnight capital cost (in 2004 $/kWe) as a function of construction start year and end-year, from the U.S. reactor cost database of Appendix A. The distance between the red dots and the blue dots of the same vertical level is the construction duration.

The average U.S overnight construction cost was 2450 $\$_{2004}$/kWe (3086 $\$_{2014}$/kWe); the median construction cost was 1825 $\$_{2004}$/kWe (2300 $\$_{2014}$/kWe); Turkey Point 3 and 4 had the lowest overnight

cost at 571 $\$_{2004}$/kWe each (719 $\$_{2014}$/kWe); and Shoreham featured the highest overnight cost at 8165 $\$_{2004}$/kWe (10,288 $\$_{2014}$/kWe).

It can be observed from Figure R1-4 that a few of the earliest plants had an overnight capital cost lower than 1000 $\$_{2004}$/kWe, and were completed relatively quickly (often 4-5 years). Additionally, all the plants completed before 1983, did so for an overnight cost lower than 2000 $\$_{2004}$/kWe. Also, while cost escalation and lengthening construction times were already observable in the mid to late 1970s, after the TMI accident of March 1979 no new construction has been started, and costs escalated dramatically for the plants that reached completion. The framework proposed in Section R1-6.3 has been developed to explain these observed trends.

Table R1-3. U.S. Nuclear Plants Cost Table from (Ganda 2014)

Name of Reactor	MW		State	Start of construction	End of construction	Shutdown	Years for construction	Lifetime	Thermal Efficiency	Overnight capital cost (2004 $)	Total capital cost (2004 $)
Palisades	697	PWR	MI	3/15/1967	12/31/1971	12/31/2011	4.8	40	32.90%	664	745
Vermont Yankee	507	BWR	VT	12/12/1967	11/30/1972	11/30/2012	5	40	33.70%	1386	1561
Maine Yankee	879	PWR	ME	10/22/1968	6/29/1973	12/6/1996	4.7	23.4	32.50%	1064	1188
Pilgrim	672	BWR	MA	8/27/1968	12/2/1972	12/2/2012	4.3	40	33.50%	1361	1501
Surry 1	790	PWR	VA	6/26/1968	12/22/1972	12/22/2012	4.5	40	33.90%	881	978
Turkey Point 3	672	PWR	FL	4/28/1967	12/14/1972	12/14/2012	5.6	40	31.00%	571	656
Surry 2	793	PWR	VA	6/26/1968	5/1/1973	5/1/2013	4.8	40	33.90%	881	989
Oconee 1	851	PWR	SC	11/7/1967	7/15/1973	7/15/2013	5.7	40	32.80%	611	704
Turkey Point 4	673	PWR	FL	4/28/1967	9/2/1973	9/2/2013	6.4	40	31.00%	571	671
Prairie Island 1	511	PWR	MN	6/26/1968	12/16/1973	12/16/2013	5.5	40	31.80%	1352	1546
Zion 1	1069	PWR	IL	12/27/1968	10/19/1973	2/21/1997	4.8	23.3	32.50%	912	1023
Fort Calhoun	478	PWR	NE	6/8/1968	9/26/1973	9/26/2013	5.3	40	32.10%	1435	1632
Kewaunee	521	PWR	WI	8/7/1968	6/16/1974	6/16/2014	5.9	40	31.00%	1259	1457
Cooper	764	BWR	NE	6/6/1968	7/2/1974	7/2/2014	6.1	40	31.80%	1199	1397
Peach Bottom 2	1078	BWR	PA	2/1/1968	7/2/1974	7/2/2014	6.4	40	32.40%	1208	1422
Browns Ferry 1	1026	BWR	AL	5/11/1967	7/31/1974	12/31/1985	7.2	11.4	32.70%	800	966
Oconee 2	851	PWR	SC	11/7/1967	9/9/1974	9/9/2014	6.8	40	33.10%	611	729
Three Mile Island 1	790	PWR	PA	5/19/1968	9/2/1974	9/2/2014	6.3	40	30.60%	1579	1852
Zion 2	1001	PWR	IL	12/27/1968	11/14/1973	9/19/1996	4.9	22.8	32.50%	912	1025
Arkansas 1	836	PWR	AR	12/7/1968	12/19/1974	12/19/2014	6	40	30.80%	890	1036
Oconee 3	851	PWR	SC	11/7/1967	12/16/1974	12/16/2014	7.1	40	33.00%	611	735
Peach Bottom 3	1068	BWR	PA	2/1/1968	12/23/1974	12/23/2014	6.9	40	32.40%	1208	1443
Prairie Island 2	510	PWR	MN	6/26/1968	12/21/1974	12/21/2014	6.5	40	31.70%	1352	1596
Duane Arnold	535	BWR	IA	6/23/1970	1/30/1975	1/30/2015	4.6	40	31.30%	1677	1868
Browns Ferry 2	1087	BWR	AL	5/11/1967	3/4/1975	3/4/2015	7.8	40	32.70%	800	984

Name of Reactor	MW		State	Start of construction	End of construction	Shutdown	Years for construction	Lifetime	Thermal Efficiency	Overnight capital cost (2004 $)	Total capital cost (2004 $)
Rancho Seco	862	PWR	CA	10/12/1968	4/2/1975	6/7/1989	6.5	14.2	32.50%	1167	1377
Calvert Cliffs 1	834	PWR	MD	7/8/1969	5/8/1975	5/8/2015	5.8	40	31.40%	1450	1677
James A. Fitzpatrick	801	BWR	NY	5/21/1970	7/28/1975	7/28/2015	5.2	40	34.20%	1398	1585
Donald C. Cook 1	1013	PWR	MI	3/26/1969	8/28/1975	8/28/2015	6.4	40	31.80%	1318	1552
Brunswick 2	820	BWR	NC	2/8/1970	10/30/1975	10/30/2015	5.7	40	32.60%	1211	1396
Edwin I. Hatch 1	801	BWR	GA	10/1/1969	12/31/1975	12/31/2015	6.2	40	31.30%	1437	1684
Millstone 2	864	PWR	CT	12/12/1970	12/26/1975	12/26/2015	5	40	33.60%	1453	1640
Trojan	1085	PWR	OR	2/9/1971	11/21/1975	11/9/1992	4.8	17	32.50%	1233	1381
Indian Point 3	967	PWR	NY	8/14/1969	8/30/1976	8/30/2016	7	40	33.00%	1517	1822
Beaver Valley 1	814	PWR	PA	6/27/1970	10/1/1976	10/1/2016	6.3	40	31.40%	1774	2079
St Lucie 1	829	PWR	FL	7/2/1970	12/21/1976	12/21/2016	6.5	40	31.20%	1681	1983
Browns Ferry 3	1091	BWR	AL	8/1/1968	3/4/1977	3/4/2017	8.6	40	32.70%	800	1009
Brunswick 1	821	BWR	NC	2/8/1970	3/18/1977	3/18/2017	7.1	40	34.10%	1211	1457
Crystal River	823	PWR	FL	9/26/1968	3/13/1977	3/13/2017	8.5	40	32.00%	1384	1737
Calvert Cliffs 2	836	PWR	MD	7/8/1969	4/2/1977	4/2/2017	7.7	40	31.40%	1450	1780
Salem Creek 1	1106	PWR	NJ	9/25/1968	6/30/1977	6/30/2017	8.8	40	31.60%	1938	2456
Davis-Besse 1	877	PWR	OH	3/25/1971	7/31/1978	7/31/2018	7.4	40	33.60%	1890	2291
Joseph M. Farley 1	826	PWR	AL	8/17/1972	12/2/1977	12/2/2017	5.3	40	31.00%	1955	2224
North Anna 1	905	PWR	VA	2/20/1971	6/3/1978	6/3/2018	7.3	40	34.00%	1620	1960
Donald C. Cook 2	1063	PWR	MI	3/26/1969	7/2/1978	7/2/2018	9.3	40	31.90%	1318	1697
Three Mile Island 2	906	PWR	PA	11/5/1969	12/2/1978	3/28/1979	9.1	40	30.60%	1825	2336
Edwin I. Hatch 2	829	BWR	GA	12/28/1972	9/2/1979	9/2/2019	6.7	40	31.10%	1437	1706
Arkansas 2	858	PWR	AR	12/7/1972	3/26/1980	3/26/2020	7.3	40	29.80%	1437	1740
North Anna 2	908	PWR	VA	2/20/1971	12/14/1980	12/14/2020	9.8	40	34.00%	1620	2123
Joseph M. Farley 2	834	PWR	AL	8/17/1972	7/30/1981	7/30/2021	9	40	31.00%	1955	2492
Sequoyah 1	1137	PWR	TN	5/28/1970	7/2/1981	7/2/2021	11.1	40	33.50%	1488	2031
Salem Creek 2	1109	PWR	NJ	9/25/1968	10/13/1981	10/13/2021	13	40	31.90%	1938	2820

Name of Reactor	MW		State	Start of construction	End of construction	Shutdown	Years for construction	Lifetime	Thermal Efficiency	Overnight capital cost (2004 $)	Total capital cost (2004 $)
McGuire 1	1119	PWR	NC	2/23/1973	12/2/1981	12/2/2021	8.8	40	32.60%	1355	1718
Sequoyah 2	1126	PWR	TN	5/28/1970	6/3/1982	6/3/2022	12	40	33.50%	1488	2093
Susquehanna 1	1089	BWR	PA	11/4/1973	6/3/1983	6/3/2023	9.6	40	32.50%	2862	3722
San Onofre 2	1070	PWR	CA	10/19/1973	8/8/1983	8/8/2023	9.8	40	34.50%	2966	3885
St Lucie 2	836	PWR	FL	5/3/1977	8/8/1983	8/8/2023	6.3	40	30.70%	2704	3169
Lasalle 1	1079	BWR	IL	9/11/1973	1/1/1984	1/1/2024	10.3	40	32.20%	1954	2600
V C Summer	936	PWR	SC	3/22/1973	1/1/1984	1/1/2024	10.8	40	32.80%	2514	3398
McGuire 2	1114	PWR	NC	2/23/1973	3/2/1984	3/2/2024	11	40	33.30%	1355	1845
San Onofre 3	1080	PWR	CA	10/19/1973	4/2/1984	4/2/2024	10.5	40	34.50%	2966	3966
Lasalle 2	1080	BWR	IL	9/11/1973	10/20/1984	10/20/2024	11.1	40	31.80%	1954	2668
Columbia Generating St.	1103	BWR	WA	3/20/1973	12/14/1984	12/14/2024	11.7	40	33.90%	4589	6397
Callaway	1124	PWR	MO	4/17/1976	12/20/1984	12/20/2024	8.7	40	32.60%	3287	4154
Susquehanna 2	1105	BWR	PA	11/4/1973	2/13/1985	2/13/2025	11.3	40	32.60%	2862	3931
Diablo Canyon 1	1081	PWR	CA	4/24/1968	5/7/1985	5/7/2025	17	40	32.60%	3221	5351
Catawba 1	1130	PWR	SC	8/8/1975	6/29/1985	6/29/2025	9.9	40	33.80%	1906	2503
Grand Gulf	1186	BWR	MS	9/5/1974	7/1/1985	7/1/2025	10.8	40	30.60%	3473	4700
Wolf Creek	1158	BWR	KS	5/31/1977	9/3/1985	9/3/2025	8.3	40	35.00%	3168	3951
Byron 1	1137	PWR	IL	1/1/1976	9/16/1985	9/16/2025	9.7	40	32.80%	2595	3388
Waterford 3	1076	PWR	LA	11/15/1974	9/24/1985	9/24/2025	10.9	40	32.40%	3751	5082
Limerick 1	1110	BWR	PA	6/20/1974	2/2/1986	2/2/2026	11.6	40	32.10%	3778	5247
Palo Verde 1	1238	PWR	AZ	5/26/1976	1/28/1986	1/28/2026	9.7	40	32.10%	2777	3623
Diablo Canyon 2	1087	PWR	CA	12/10/1970	3/14/1986	3/14/2026	15.3	40	32.50%	3221	5041
Millstone 3	1138	PWR	CT	8/10/1974	4/24/1986	4/24/2026	11.7	40	34.20%	4279	5959
River Bend	953	BWR	LA	3/26/1977	6/17/1986	6/17/2026	9.2	40	29.90%	5602	7204
Catawba 2	1130	PWR	SC	8/8/1975	8/20/1986	8/20/2026	11	40	33.60%	1906	2596
Palo Verde 2	1281	PWR	AZ	5/26/1976	9/23/1986	9/23/2026	10.3	40	32.50%	2777	3700

Name of Reactor	MW		State	Start of construction	End of construction	Shutdown	Years for construction	Lifetime	Thermal Efficiency	Overnight capital cost (2004 $)	Total capital cost (2004 $)
Hope Creek	1044	BWR	NJ	11/5/1974	12/21/1986	12/21/2026	12.1	40	31.50%	5950	8400
Shearon Harris	886	PWR	NC	1/28/1978	5/3/1987	5/3/2027	9.3	40	33.70%	4747	6111
Vogtle 1	1145	PWR	GA	6/29/1974	6/2/1987	6/2/2027	12.9	40	31.40%	4162	6030
Byron 2	1120	PWR	IL	1/1/1976	8/22/1987	8/22/2027	11.6	40	33.50%	2595	3605
Beaver Valley 2	828	PWR	PA	5/4/1974	11/18/1987	11/18/2027	13.5	40	32.30%	6134	9069
Perry	1212	BWR	OH	5/4/1977	11/19/1987	11/19/2027	10.5	40	33.20%	4917	6595
Clinton	987	BWR	IL	2/25/1976	11/25/1987	11/25/2027	11.7	40	34.00%	6229	8686
Palo Verde 3	1241	PWR	AZ	5/26/1976	1/8/1988	1/8/2028	11.6	40	32.70%	2777	3857
Fermi	1077	BWR	MI	9/27/1972	1/23/1988	1/23/2028	15.3	40	33.80%	5265	8259
Nine Mile Point 2	1106	BWR	NY	6/25/1974	3/11/1988	3/11/2028	13.7	40	32.50%	6687	9942
Shoreham	820	BWR	NY	4/16/1973	4/21/1989	6/28/1989	16	40	32.50%	8165	13108
Braidwood 1	1144	PWR	IL	1/1/1976	7/29/1988	7/29/2028	12.6	40	33.10%	2549	3651
South Texas 1	1250	PWR	TX	12/23/1975	8/25/1988	8/25/2028	12.7	40	32.50%	4020	5777
Braidwood 2	1127	PWR	IL	1/1/1976	10/17/1988	10/17/2028	12.8	40	33.10%	2549	3678
Vogtle 2	1146	PWR	GA	6/29/1974	5/20/1989	5/20/2029	14.9	40	31.40%	4162	6435
South Texas 2	1250	PWR	TX	12/23/1975	6/19/1989	6/19/2029	13.5	40	33.60%	4020	5934
Limerick 2	1123	BWR	PA	6/20/1974	1/8/1990	1/8/2030	15.6	40	32.50%	3778	5972
Comanche Peak 1	1150	PWR	TX	12/20/1974	8/13/1990	8/13/2030	15.6	40	32.30%	7827	12412
Seabrook 1	1155	PWR	NH	7/7/1976	8/19/1990	8/19/2030	14.1	40	33.60%	4949	7457
Comanche Peak 2	1150	PWR	TX	12/20/1974	8/3/1993	8/3/2033	18.6	40	32.10%	4364	7653
Watts Bar 1	1121	PWR	TN	1/24/1973	5/27/1996	5/27/2036	23.3	40	32.50%	4604	9521

R1-6.2. The French Nuclear Construction Cost

References were collected on historical reactor costs in France for all the 58 French reactors, including overnight capital costs as made publicly available in early 2012 by the "Cour de Comptes", the French equivalent to the U.S. Government Accountability Office (GAO) (Rangel, 2012). The single, most complete previous estimate was made by Arnulf Grubler and was obtained indirectly by examining EDF financial data (Grubler, 2010).

Table R1-4 and Figure R1-5 show the construction cost of all 58 French power reactors currently in operations. They are divided in 3 "*palier*" or size categories: 900 MW_e (34 reactors), 1300 MW_e (20 reactors) and 1450 MW_e (4 reactors). In turn, the 900 MW_e *palier* is comprised of the CP0, CP1 and CP2 types; the 1300 MW_e *palier* is comprised of the P4 and P'4 type and the 1450 MW_e is of the N4 type. Types CP0, CP1, CP2 and P4 are Westinghouse-licensed designs (in blue in the figure), while the P4 and N4 types have been constructed allowing less standardization during construction (Rangel 2012), which may have led to a higher ultimate construction cost (in red in Figure R1-5). It is noted that the cost data in Table R1-4 had to be converted from the original un-escalated French Francs to Euros (which was done by the Cour de Comptes), and then to U.S. dollars (which was done using an exchange rate of 1.3, prevalent in 2013/2014). This sequence of conversions, by itself, is a source of uncertainty: therefore the cost numbers of Table R1-4 and Figure R1-5 should be considered only approximations.

Table R1-4. French nuclear plants' construction costs. Data source: Cour des Comptes, 2012 (Rangel, 2012).

Palier	Plant	MW	Criticality	Type	Cost (E2010/kW)	Cost ($/kW)
900 MW	Fessenheim1.2	1780	1978	CP0	836	1087
900 MW	Bugey2.3	1840	1979	CP0	886	1152
900 MW	Bugey4.5	1800	1979	CP0	899	1169
900 MW	Damprierre1.2	1800	1980	CP1	1,217	1582
900 MW	Gravelines1.2	1840	1980	CP1	822	1069
900 MW	Tricastin1.2	1840	1980	CP1	1,188	1544
900 MW	Blayais1.2	1830	1982	CP1	1,110	1443
900 MW	Dampierre3.4	1800	1981	CP1	1,172	1524
900 MW	Gravelines3.4	1840	1981	CP1	856	1113
900 MW	Tricastin3.4	1840	1981	CP1	1,247	1621
900 MW	Blayais3.4	1820	1983	CP1	890	1157
900 MW	Gravelines5.6	1820	1985	CP1	1,093	1421
900 MW	Saint Laurent 1,2	1760	1983	CP2	1,120	1456
900 MW	Chinon 1,2	1740	1984	CP2	1,148	1492
900 MW	Cruas1.2	1760	1984	CP2	1,119	1455
900 MW	Cruas3.4	1760	1984	CP2	1,253	1629
900 MW	Chinon3.4	1760	1987	CP2	978	1271
1300 MW	Paluel1.2	2580	1985	P4	1,531	1990
1300 MW	Paluel3.4	2580	1986	P4	1,157	1504
1300 MW	St Alban1.2	2600	1986	P4	1,129	1468
1300 MW	Flamanville1.2	2580	1987	P4	1,287	1673
1300 MW	Cattenom1.2	2565	1987	P'4	1,358	1765
1300 MW	Belleville1.2	2620	1988	P'4	1,083	1408
1300 MW	Cattenom3.4	2600	1991	P'4	1,149	1494
1300 MW	Nogent1.2	2620	1988	P'4	1,194	1552
1300 MW	Glofech1.2	2620	1992	P'4	1,305	1697
1300 MW	Penly1.2	2660	1991	P'4	1,227	1595
1450 MW	Chooz1.2	2910	2000	N4	1,635	2126
1450 MW	Civaux1.2	2945	2002	N4	1,251	1626

Figure R1-6 shows the construction times of the French nuclear plants (from Grubler 2010). While few of the plants had longer construction times (especially the later P'4 and the N4 types), the average construction time of 76 months is very short in comparison to the average US case of 108 months (Table R1-3). About half of the plants had construction times of less than 72 months (6 years).

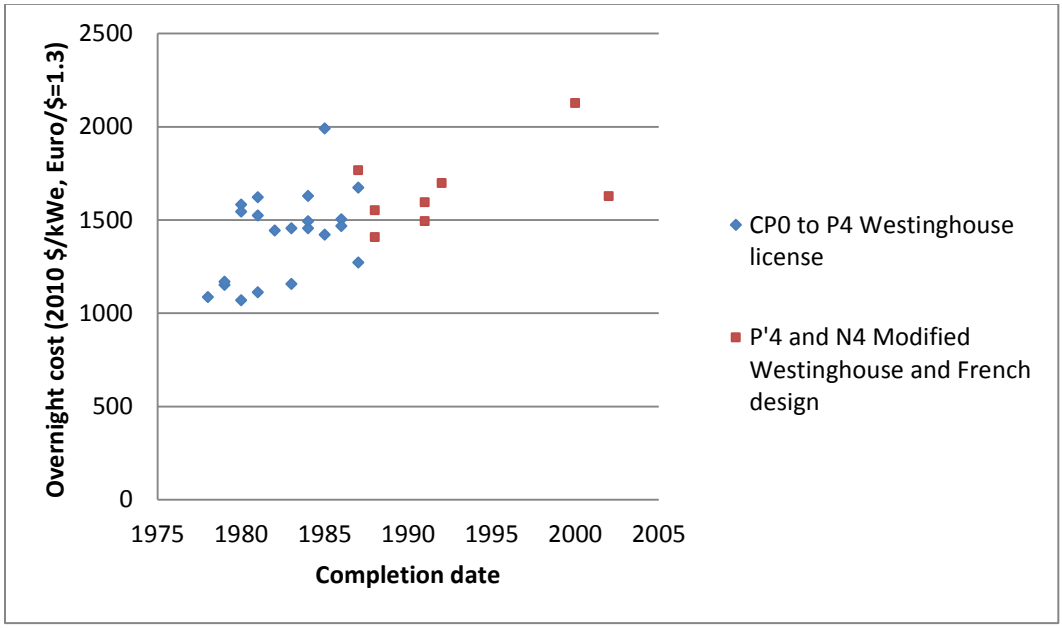

Figure R1-5. Construction cost for all 58 French reactors.

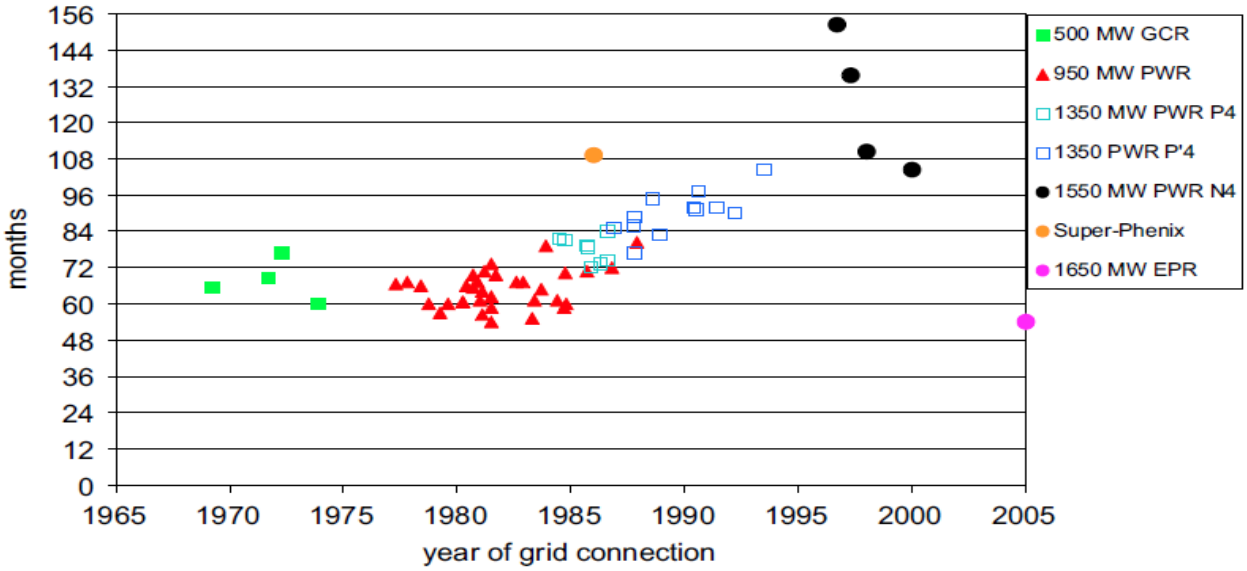

Figure R1-6. Construction times of the French plants (Flamanville unit 3, labelled "1650 MW EPR", is currently under construction).

It is of interest to understand the variation in costs associated with the French construction program, since it may lead to useful insight to quantify an appropriate uncertainty distribution for the "engineering" construction costs. A useful metric for that purpose is the ratio of the "standard deviation" to the average cost. Table R1-5 shows that for the entire construction program, the ratio of "standard deviation/average" was 17%. However, within the construction period, there was a clear increase in cost, as the construction

program evolved (Figure R1-5): the standard deviation of the entire series would also "capture" the up-trend in cost, which is not relevant to intrinsic uncertainty of the "engineering" or un-avoidable costs. For this reason, the "de-trended" data is also presented in the last column of Table R1-5.

First the trend-line has been calculated, leading to the following Equation:

$$Cost = 26.042 \cdot Year - 50216$$

Afterwards, the trend values have been subtracted from the actual construction cost to obtain the "de-trended" data.

As expected, the average of the "de-trended" line is now close to zero, and MAX and MIN represented then maximum and minimum deviation from the trend line. The standard deviation has also been reduced from 251 $/kW$_e$ to 201 $/kW$_e$, thus reducing the ratio of "standard deviation/average" from 17% to 13%. Further subdivisions can be made by power level (i.e. the "*palier"* type) and by the level of design standardization: "*Palier* 1300" had the lowest standard deviation/average construction cost ratio, at 11%, while the highest was for "*Palier* 1450", at 19%; however the "*Palier* 1450" values are based on only two data points. The two large groups "largely Westinghouse-based" (i.e. the CP0 to P4) and the "largely French design" P'4 and N4 had ratio of "standard deviation/average" construction cost of, respectively, 17% and 13%.

Table R1-5. Min, max, average and standard deviation of reactors constructed in France 1978-2002 (all in $/kW$_e$ with a €/$ exchange rate of 1.3).

	All reactors	Palier 900	Palier 1300	Palier 1450	CP0 to P4	P'4 and N4	All reactors (de-trended)
MAX	2125.5	1628.9	1990.3	2125.5	1990.3	2125.5	512.9
MIN	1068.6	1068.6	1407.9	1626.3	1068.6	1407.9	-293.8
AVERAGE	1485.6	1363.8	1614.6	1875.9	1420.0	1657.8	0.1
stdev	251.0	201.0	173.0	353.0	234.4	219.5	201.2
stdev/average	*17%*	*15%*	*11%*	*19%*	*17%*	*13%*	*13%*

R1-6.3 Best Experience in Reactor Construction (i.e. "Engineering Construction Cost")

The objective of this section is to draw a conceptual distinction between (1) construction cases in which cost overruns were minimized, i.e. the "best experiences" in reactor constructions and (2) cases that experienced substantial cost overruns; thus establishing a framework for understanding the reasons for the observed reactor capital costs, including the fundamental drivers of costs and the main reasons for the biggest cost overruns observed historically.

Most of the literature that dwells on reactor construction's historical costs attempts, through econometric techniques, to interpolate and extrapolate from historical data, often coming to the conclusions that future reactor costs can have very large and very uncertain costs. (See for example, (Koomey and Hultman 2007, Komanoff 1981, Rangel and Leveque 2012).

What is done here is, instead, different. The main focus will be on those constructions in which the process went reasonably well from a cost perspective, thus establishing a basis for costs in the "*best experience*" cases. The numerous cases in which costs escalated, sometimes dramatically, offer the opportunity to understand what underlying issues are most often responsible for the cost escalation.

A key driver of cost overruns during construction was found to be *the degree of changes requested during the construction phase* of a new reactor. These changes are, in turn, typically driven by (1) incomplete engineering at the start of construction (i.e. *engineering instability*); and (2) requests for alteration induced by regulatory changes after the construction has started (i.e. *regulatory turbulence*).

If the design is fully completed before the construction starts and no changes are required during the construction phase, complex construction projects can be kept reasonably within budget by the standard use of "*fixed price"* contracts, negotiated with competitive bidding: the efficiencies built into this process minimize the construction costs. However, if design changes significantly during the construction phase, the original "*fixed price*" contracts become un-tenable, since re-bidding is usually impractical. Therefore, in these cases it becomes necessary to switch the "*fixed-price"* contracts to "*cost-plus"* contracts, and efficiencies are lost, generating potentially substantial cost overruns, while the utility and architect-engineer lose control over the contractors' expenditures. On the other hand, fixed price contract arrangements *"create incentives to work efficiently and expeditiously to maximize the contractor's profit"*; while *"the objective under cost-plus contracts is to maximize total revenues, which shifts the prevailing orientation towards longer schedules and greater expenditures."* (Komanoff 1981).

The following are among the main causes of cost-increases due to design alterations during the construction phase:

- Completed work need to be removed and/or altered, with the obvious cost of removal (which can be substantial, such as for example for reinforced concrete that has already cured) and reconstruction. An important cost effect of reconstructions is that it often affects nearby systems as well (an effect known as "systemic effect", typical of nuclear power plants), which otherwise would not have been directly affected by the changes, either (1) because of logistical constraints (e.g. having to remove and later reinstall piping already installed in order to insert a new piece of equipment that was not in the original design), or (2) because of errors (e.g. inadvertently damaging equipment already in place when adding a new piece of equipment), or (3) because contractors previously released from the site had to be re-called and retrained. For example, the following is a quote from a testimony from PG&E before the California Public Utilities Commission: *"There are significant inefficiencies in trying to design to fit existing buildings and installed components. […] Work has to be done out of sequence in a restricted access and work area."* (Brand 1979).
- Construction sequences have to be altered, and equipment delivery schedules have to be altered, potentially idling groups of workers while waiting for the new equipment or for the re-design to be completed. This can dramatically reduce the labor productivity and increase the labor costs.
- Increased construction duration can produce a self-reinforcing feedback loop, more important during periods of high regulatory turbulence, by exposing the project to the risk of additional regulatory changes. Additionally, longer construction duration increases directly the "Interest during construction" costs and can further disrupt the construction logistics.

Stricter regulatory oversight, which generally increased with increasing regulatory turbulence throughout the 1970s and 1980s, also increased the costs overruns (1) by increasing the direct labor costs through the extra requirements for supervision and compliance; and (2) by largely impeding the "dynamic" engineering adaptation and "on-the-spot" problem solving that may have otherwise easily corrected minor challenges that arose during the construction phase. The procedures required, instead, to re-submit the modified design for a new regulatory approval, which cost delays that resulted in idled skilled crews and un-expected capital charges. (Kessides 2012).

Additionally, there is a self-reinforcing feedback loop between scope changes and regulatory oversight. In an environment of frequent changes to the on-going work that require re-construction, it is not un-common for staff to start developing negative expectations on the outcome of work, which can, by itself, reduce productivity. Additionally, when workers start anticipating that a job will be redone several times, because of changes to regulations and/or design alterations, they may be less careful during the installation, which can lead to high rejection rate by the regulators, completing the feedback loop between scope changes and regulatory oversight (Komanoff 1981).

It was also found that the capital cost escalation of nuclear power plants – already observable for plants completed in the pre-TMI period (i.e. pre-1979) – has been primarily driven by increasing

regulatory stringency, which in turn has been quantitatively associated with the overall expansion of the nuclear power sector. The increased regulatory stringency manifested itself in: (1) the application of more stringent and explicit safety standards, which caused a direct increase in the amount of labor, material and equipment required to build nuclear plants; and (2) the expansion of the regulatory effort, requiring greater documentation and standardization of regulatory requirements: this mostly caused a substantial increase in labor costs. Both effects caused a fundamental increase in the cost of nuclear plants. None of the several studies attempted in the past, however, could establish a quantitative relational link between increased requirements for commodities and labor driven by specific regulatory changes, and the ultimate cost of new construction. This is because nuclear power plants feature substantial "systemic effects", for which the cost of altering/adding equipment propagates beyond the system being altered, and is in contrast to the case of coal, for example, for which most cost increases in the 1970s could be quantitatively traced to the addition of individual components mandated for pollution control, the effects of which on the plant construction cost could be isolated.

R1-6.5. Reconciliation to the Late 1980s Cost Observations with the Currently Observed Construction Costs

The base construction costs of the EEDB "Better Experience" PWR was observed to be 1272 $/kW$_e$ in 1987 dollars (ORNL 1988b), which would be 2658 $/kW$_e$ in 2014 dollars using the Consumer Price Index (CPI) general inflation index between 1987 and 2014. This amount does not include owner's costs and contingencies, which typically add about 10% each to the base construction cost, to arrive at the overnight cost. After adding owner's costs and contingencies, the resulting observed overnight cost would be about 3200 $/kW$_e$.

However, it was also calculated in (ORNL 1988b) that between 1978 and 1987, the total construction costs for the "Better Experience" PWR increased by 3% points annually *in real terms* (i.e. above the rate of general inflation), while the construction costs for the "Median Experience" PWR increased by 10% annually above the rate of the general inflation.

Since the EEDB report series had no further updates after 1988, but construction continued in the United States until 1996 (when the first criticality of Watts Bar 1 was reached), it is of interest to calculate the expected current Best and Median Estimates construction costs if: those cost increases had continued at the same rates while construction was on-going in the U.S., and then just increased with the general rate of inflation after the construction program stopped. The logic for this is that construction cost increases above the rate of inflation were found to be mostly driven by increased regulatory stringency (Ganda 2014), which in turn was found to be strongly correlated with the overall expansion of the nuclear sector (Komanoff 1981). Based on these considerations, it can be argued that no real cost increase is to be expected during periods of non-expansion in the overall nuclear sector, such as the period between 1996 and 2014 for the U.S. Using this approach, the overnight construction cost of (EEDB 1988) for the best experience cases would have been escalated to 4181 $_{2014}$/kW$_e$, which is similar with the pre-construction estimates of Vogtle and VC Summer (Ganda 2014). Additionally, this cost is roughly consistent with the 4 identical reactors being built in the UAE, United Arab Emirates, by South Korea, having a construction cost of about $3650/kW. These plants are replicas of two reactors currently being built in South Korea. If a project is an exact replica of a previous identical construction, it is conceivable that *the home office engineering services* cost (of about 505 $/kWe) could be mostly avoided: these costs are primarily associated with the engineering and design, project planning and associated overhead. However, if a project is a replica of a previously well-executed project, this cost should be minimal, since little new engineering should be necessary, and any work by the home office service should be just incidental. Eliminating the 505 $/kWe cost of the *home office engineering services* cost from an expected cost of 4100 $/kWe leads to a cost very similar to the outcome of the UAE project, of about $3650/kWe.

R1-6.6. The Probability Density Function That Best Approximates the U.S. Historical Data Distribution (i.e. the Non-Engineering Costs)

Historical U.S. construction cost data can be used to gain a quantitative understanding of the "non-engineering" construction cost, since they include a wide range of actual outcome, several of which included substantial cost overruns. The key assumption when using this data would be that, in the future, many of the mistakes done in the past could be repeated, leading to similar quantitative outcomes.

In general, the use of raw historical construction cost data is *not* recommended for fuel cycle equilibrium economic analyses, such as those performed for the Fuel Cycle Evaluation and Screening in 2013 (Ganda et al. 2013**),** for which an "engineering cost" probability density function is instead discussed in Section R1-6. The assumption is that, having reached a status of equilibrium, the construction capabilities, including the regulatory infrastructure, are sufficiently mature as to avoid the typical causes of cost overruns observed in the past. However, it still can be useful to have the capability to use "non-engineering" probability density functions for other types of economic evaluations based on historical data. It is also useful to test the validity of functional forms for uncertainty distributions of nuclear plant costs that should be grounded in historical data.

For the purpose of performing Monte Carlo calculations of the LCOE using historical construction data, it is of interest to identify the probability density function that approximates best a bar plot of such data.

It was found that a good approximation could be obtained by a log-normal probability density function, which appears better fitting than other functional forms of the distributions: Figure R1-8 shows a bar plot of the historical overnight costs of U.S. reactors (in 2004 $/kWe), and a log-normal probability density function that approximate the historical curve. The parameters of the curve, together with the equation used to generate them based on the historical data, are listed below:

- Probability density function (pdf): $p(x) = \frac{1}{x\sqrt{2\pi\sigma}} e^{-\frac{(\ln x-\mu)^2}{2\sigma^2}}$.
- Median of the distribution: 1825 $\$_{2004}/kW_e = e^{\mu}$, therefore μ=7.5.
- Mean of the distribution: 2450 $\$_{2004}/kW_e = e^{\mu+\frac{\sigma^2}{2}}$, therefore σ=0.767.
- Standard Deviation of the distribution: $std = \sqrt{\left(e^{\sigma^2}-1\right)e^{2\mu+\sigma^2}}$=2171 $\$_{2004}/kW_e$.
- Standard Deviation/Mean=2171/2450=88.6%.

Additionally, the log-normal probability distributions should be truncated to best represent the historical U.S. construction data. The truncation can be implemented, for example, through the method of "rejection sampling" if a Monte Carlo approach is used for the simulation, as is currently implemented in the NE-COST code. A resulting sampled probability density function is shown in Figure R1-9.

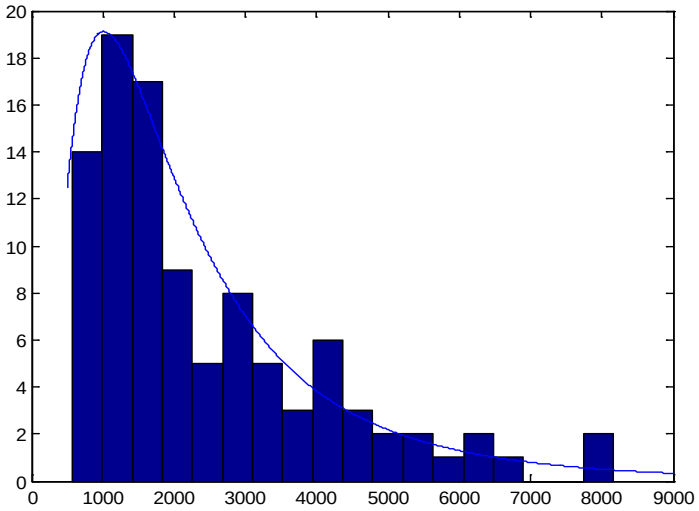

Figure R1-8. Historical overnight costs of U.S. reactors (in 2004 $/kWe) and fitting log-normal pdf.

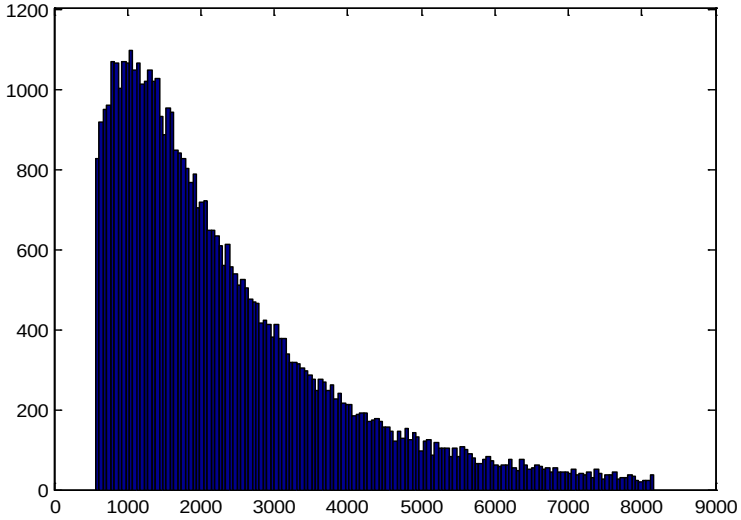

Figure R1-9. Truncated Log-normal probability density function of the historical US reactor costs (in 2004$) as sampled by a Monte Carlo sampler using the previous equations.

R1-6. Summaries of Engineering and Non-Engineering Costs, and Suggested Uncertainty Distributions

Engineering costs: expected values and uncertainties distributions.

It was found that the current expected value of the "engineering" construction cost of LWRs in the U.S. is $4100/kWe, in 2015 dollars, based on the pre-construction estimates of the current construction projects, as well as on the observations made in the late 1980s and reconciled to today's dollars using the methodology described in section R1-6.5. This value is also consistent with the outcome of the well-executed UAE construction project, as explained in Section R1-6.5

It was also found that the historical standard deviation for the "engineering" construction cost of U.S. LWR is about 30% of the expected "engineering cost", when using the pre-construction estimates as approximations for "engineering", or avoidable costs. It was also found that the reactors constructed in France had substantially lower cost standard deviations (as a ratio of expected values) than the U.S. pre-construction estimates (of between 11% and 19%, depending on the observation subset), even though the French data are based on the actual construction outcomes, and the U.S. data are based on the budget, or

pre-construction estimates. The reasons for this difference could be attributable to a higher construction standardization in France, and to the high rates of cost overruns in the U.S., which may have led the estimators to insert a higher (and varying from project to project) contingency allowance in the preconstruction estimates. However, further investigation should be performed in this area to better understand the reasons for the observed differences.

Adopting as reference the de-trended data, it is recommended to use a ratio of standard deviation to mean value of 13%, or 15% for a greater level of conservativeness, for the "engineering" construction cost uncertainties. Additionally, it is recommended to use a lognormal distribution to describe quantitatively the uncertainty associated with the contingency.

Therefore, the following are the parameters of the log-normal LWR overnight cost, plotted in Figure R1-10:

E= 4100 $\$_{2014}$/kW$_e$ and STD=600 $\$_{2014}$/kW$_e$, (i.e. 15% of E), then $\mu=8.2829$ and $\sigma=0.14917$.

Non-Engineering costs: expected values and uncertainties distributions.

Regarding the "non-engineering" expected costs and uncertainties, i.e. for the cost that could include overruns, construction delays etc…, it is recommended to use the historical U.S. data (in Section R1-6.6.) as a guide. This data can be used when the assumption is made that future mistakes may lead to a similar range of outcomes as those of the past. However, the historical data do also include early constructions, for which the cost was substantially lower than what could be observed currently in the U.S. (the lower cost can be mostly attributed to substantially less stringent regulatory requirements: please see (Ganda 2014)). Those early lower construction cost lowers the mean of the historical data to a value that is substantially lower than what appears achievable today, even under the best circumstances. For this reason, it may be advisable for the reader to use the historical construction cost data information (1) to obtain the functional for of the historical uncertainties, which is well represented by a log-normal pdf; and (2) to obtain information on the standard deviation of the historical construction costs *as a fraction of the historical mean*, which was about 90% of the expected value, in order to calculate the standard deviation of the currently expected construction cost.

With this approach, the user could chose a lognormal probability density function with an expected value of 4100 $/kWe and a standard deviation of 3700 $/kWe to model the "non-engineering" costs. Since it cannot be ascertained with full confidence that this distribution should be truncated at a particular value (as was instead the case for the actual cost data), it can be sampled as un-truncated, at the discretion of the user.

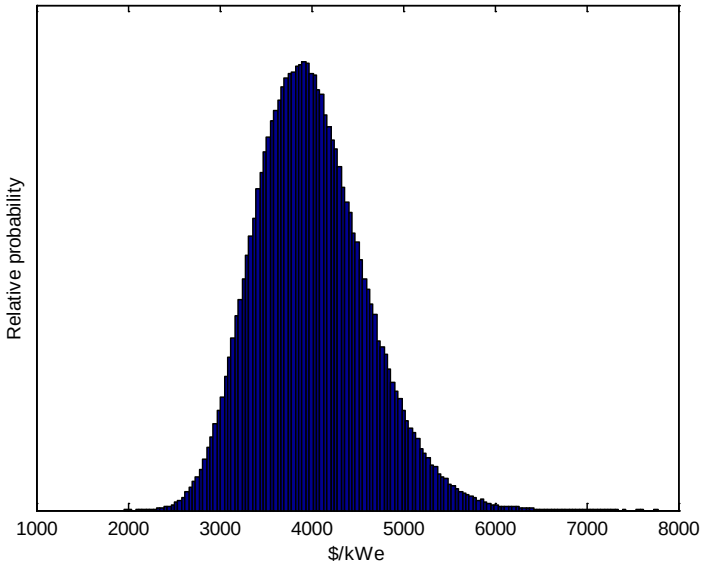

Figure R1-10. PDF of the LWR overnight cost with an expected value of 4100 $/kW$_e$, a standard deviation of 15% of the expected value and a log-normal functional form.

R1-6. Capital and O&M Cost Distributions

If the log-normal cost distribution is not desirable and a more simplified triangle distribution is preferred as is common throughout the AFC CBR, the suggested distribution based on the analysis and distribution discussed prior for overnight capital cost is provided. The fixed and variable operation and maintenance were escalated from the AFC CBR 2015 with an escalation factor of 1.032 and rounded. Figure R1-11 shows the triangular distributions for overnight specific cost and the two components of the O&M cost for LWRs. The means (expected values) for each distribution are also shown on the graphs. These mean values should be used when discussing "single point" estimates without reference to uncertainty. All values are in year 2017 dollars.

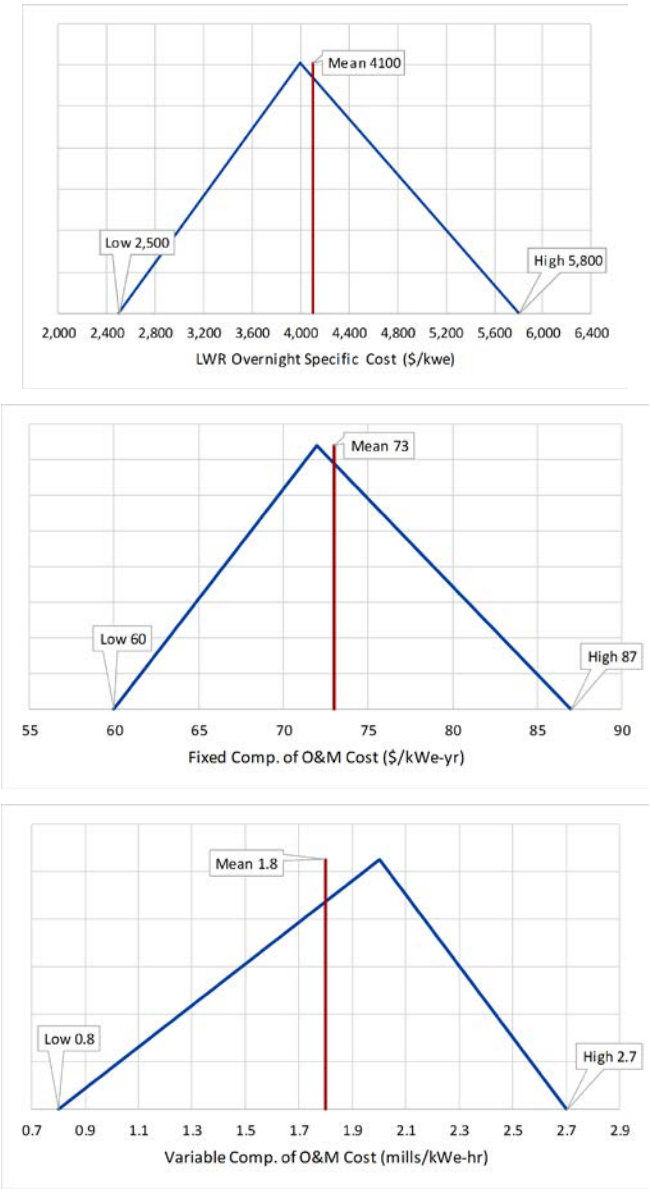

Figure R1-11. Probability Distributions and Means for LWR Cost Parameters.

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Module R2

Fast Reactors

Module R2

Fast Reactors

R2.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** The methodology described in Section RP2 of the earlier AFC-CBRs (now a supplementary document in the 2017 version entitled: *A Proposed Methodology for Transformation of Reactor Cost Data to the "What It-Takes" Table*, See CBR SD6) was applied to the available cost and design information for the with sodium fast reactors(SFRs) to extrapolate this available information to estimate the implied cost for an Nth-of-a-kind, well-built, well-designed, and well-executed fast reactor project at optimum commercial scale. The historical and very high $/kWe values resulting for many very small FR demonstration reactors when projected to large commercial scale FR projects often suggest costs ranges that are very high. When the above methodology is applied to real LWR and SFR design data these SFR projected costs turn out to be more comparable to LWRs and not to the sky high SFR costs often quoted as a result of mere extrapolation. The projected range of historical costs for the different projects; however, was considered and was then combined with engineering judgment to give the range and distribution for the 2012 AFC-CBR.

R2.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2004 as Module R1.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - New methodology being considered for estimating costs of new advanced reactor concepts that looks at scaling based on different features (e.g., whether it scales based on thermal or electric power). Also there is significant interest in lead-cooled fast reactors and molten-salt fueled fast reactors and all current data is for sodium-cooled fast reactors which my require addition of new Modules or sub-modules for different fast reactor types.

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 never got much beyond the design stage, and was terminated in 1983. 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), and France (Superphenix). 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 better (lower) parasitic absorption to fission ratios resulting in more efficiently burning of the fissile isotopes 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 reactors (e.g. LWRs) require 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 reactor performance 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 and Th-232 to fissile U-233, 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, which will then serve (at minimum) as the startup fuel for the fast reactors.
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 compared to chemical fuel sources such as fossil fuels. The high capital cost of nuclear power is in part because of the need to include safety features (e.g. containment building) to confine radioactive materials originating in the reactor core during 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 or

when contacted by water. 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 overnight construction 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 have a higher minimum fissile content to achieve criticality than thermal reactors which with low absorbing moderators like deuterium and carbon can operate with natural uranium, while fast reactors require fissile contents over and possibly well over 10% depending on the design and fuel composition. 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, typically 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, DIAGRAMS, AND DEPLOYMENT STATUS

Figure R2-1 shows the flow concepts within a pool-type fast reactor using a liquid sodium coolant. The other common configuration is a loop-type which is very similar in configuration to a PWR except that pumps and heat exchangers are located outside the primary reactor vessel (in the pool configuration, all primary system components are inside one [larger] reactor vessel). In either case there is a secondary sodium loop or loops that contain non-radioactive sodium. These "IHXs" isolate the steam system from radioactive sodium in the primary vessel.

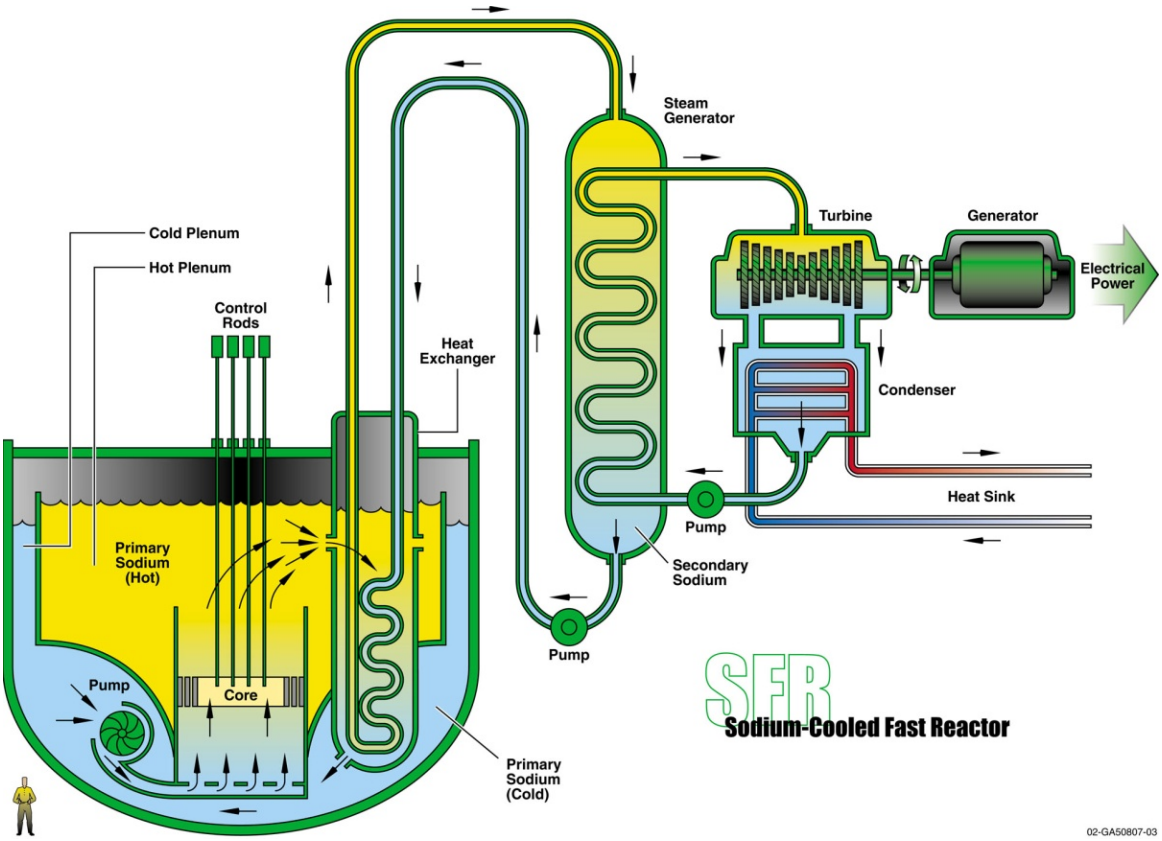

Figure R2-1. Major elements of a liquid-metal cooled fast reactor.

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.

R2-4. MODULE INTERFACES

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 to medium 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 typically placed in in-vessel storage for one cycle prior to transfer, and then 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 sufficiently to be cooled passively by air, the fuel assemblies might be moved to storage casks for onsite or offsite storage to await processing. 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 which significantly reduces the external cycle time. For high growth scenarios, doubling time (the time to double the fissile inventory necessary to operate the fast reactors) is limiting and is a strong function of the external cycle time since the inventory required to operate a fast reactor includes all the

fissile material in the reactor plus all fissile material in storage, transport, process, and fabrication destined to be return to the fast reactor to complete the cycle. If the fuel residence time is 5 years, and the total external cycle time is 10 years (not unreasonable for off-site), the total fissile requirement is 3 times the reactor inventory. For on-site, the external cycle time of 2.5 years, would reduce the total required fissile inventory by half which would reduce the doubling time by a factor of 2 for identical reactors. Besides doubling time there may be other potentially desirable benefits such as proliferation benefits of lower out of core inventories and elimination of transport of the intact fast reactor fuel with its very high radiation levels, high fissile content, etc.

R2-5. SCALING CONSIDERATIONS

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. In earlier AFC-CBRs, Section R4 (Modular Reactors) addressed some of the issues of small and medium-sized reactors. 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; Platts 2006) that will precede them. However, as discussed above, it should be noted that fast reactors are viewed by many as 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. Tables R2-2 and R2-3 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).

This data was used (see Preface to Reactor Modules) with a proposed methodology to incorporate the large variations in the designs and their state of development towards a final NOAK power plant that is optimized for commercial operations. This resulted in a small, but arguably more defensible basis for the values included in the What-It-Takes table for overnight capital cost.

Table R2-1. Historical capital costs for completed fast reactor systems and projected costs for recently announced or currently under construction systems.[1]

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

1. 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 350	MWth Mwe	late 1980s (term in 1983)	3600	US$	1	1984	3600	1.75	6300	18000	6300
BN-800	Beloyarsk, Russia	2300 800	MWth Mwe	2010	2000	US$	1	2006	2000	1	2000	2500	870
Prototype Fast Breeder Reactor (PFBR)	Kalpakkam, India	1400 500	MWth Mwe	2010	3492	crores	0.205	2003	717	1.07	767	1534	548
Japanese Sodium-cooled Fast Reactor (JSFR)	Japan (Conceptual Plant)	3530 1500	MWth MWe	2050	224700	Yen	0.009346	2006	2100	1	2100	1400	595
General Electric S-Prism (modular:2 power blocks/4 Rx modules) Nth of a kind	USA (Conceptual Plant)	4360 1651	MWth MWe	2020	2200	US$	1	1996	2200	1.22	2684	1626	616
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. DATA LIMITATIONS

All fast reactors constructed to date have been "first-of-a-kind" (FOAK) facilities and typically a size substantially less than full scale commercial power plant 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 or the benefits of economy of scale. As a result, 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. All this makes projection to the cost of a full scale NOAK commercial power plant quite uncertain. The upper bound of what-it-takes based on past experience is very high and the lower bound of what-it-takes suggest a potential for a significant cost savings over LWRs assuming the design improvements from the lessons learned and design optimization can be achieved as have been suggested (e.g., Boardman 1999).

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 were 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 R1 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. 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 the LWR nor the 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 and eliminating the need for enrichment.

The module cost information is summarized in the What-It-Takes (WIT) cost summary in Table R2-3. These values are 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. The primary driver is the view that the lowest cost estimates of concepts are probably too optimistic and the extrapolation of smaller scale demonstration projects is too pessimistic, so the range of cost estimates is reduced. As is to be expected, with greater uncertainty a broader range compared to the LWR is appropriate which is represented by a slightly lower upside and a somewhat higher downside. Future versions of this report are anticipated to provide greater detail and better basis and justification for the cost values per the methodology described in Module RP2. 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. 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 additional report for additional details on the cost estimation approach used to construct the WIT table (Table R2-3).

Table R2-3. What-It-Takes cost summary table from 2012 AFC-CBD Update.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Expected (Mean Cost)	Selected Values (Nominal Cost)
Overnight Cost for NOAK FR in U.S.	$2200/kWe	$7000/kWe	$4600/kWe	$4600/kWe
O&M Fixed Component including D&D fund contribution (no ref. available)	$60/kWe-yr	$85/kWe-yr	$70/kWe-yr	$65/kWe-yr
O&M Variable component including Capital Replacement Component (no ref. available)	1.0 mills/kWh	2.7 mills/kWh	1.9 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. In the table above the fixed component of the O&M cost has been increased somewhat from the 2008 values to reflect O&M cost escalation. The following Table R2-4 updates all costs to Year 2015$.

Table R2-4 What-It-Takes cost summary table updated to 2017$.

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Expected (Mean Cost)	Selected Values (Mode Cost)
Overnight Cost for NOAK FR in U.S.	$2400/kWe	$7600/kWe	$4700/kWe	$4100/kWe
O&M Fixed Component including D&D fund contribution (no ref. available)	$65/kWe-yr	$92/kWe-yr	$78/kWe-yr	$76/kWe-yr
O&M Variable component including Capital Replacement Component (no ref. available)	1.1 mills/kWh	2.9 mills/kWh	2.1 mills/kWh	2.2 mills/kWh

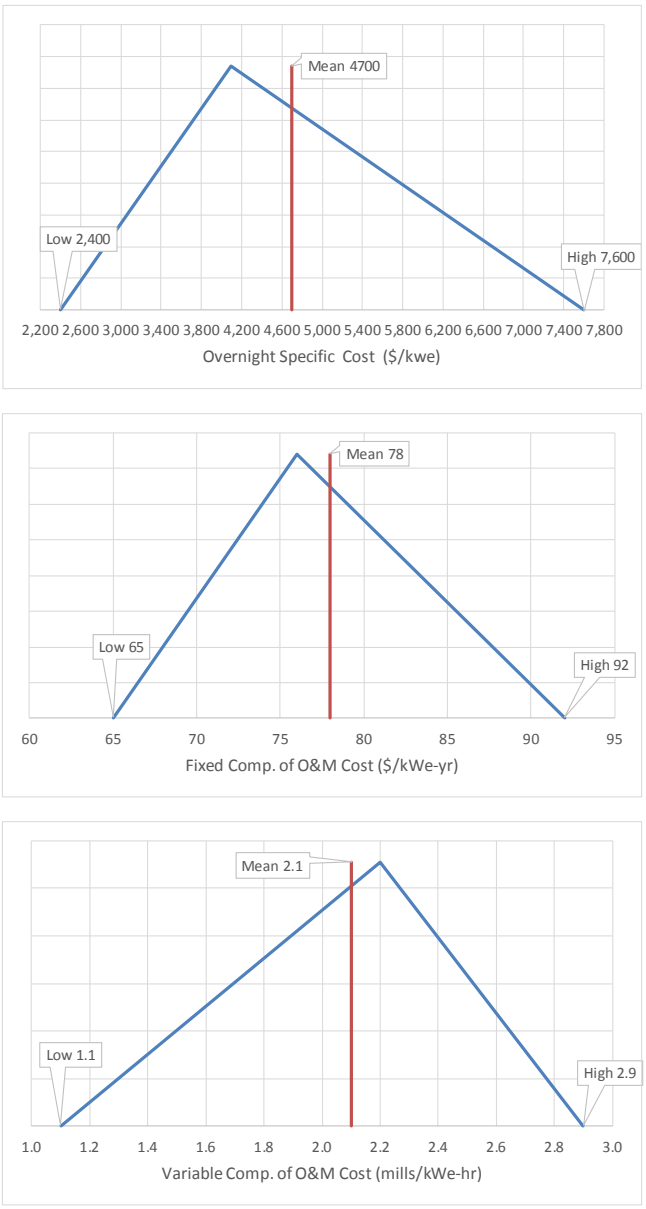

Figure R2-2 Probability Distributions for SFR Cost Parameters.

R2-9. SENSITIVITY AND UNCERTAINTY 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.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** There are a number of design/cost studies and limited operational experience that were accessed to try to project the overnight capital cost of gas cooled reactors.

R3.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2009 as Module R3.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - A new methodology being considered for estimating costs of new advanced reactor concepts considers cost scaling based on different design features (e.g., whether the technology scales based on thermal or electric power). The method in 2015 RP-2 and now a Support Document for the 2017 Version (*A Proposed Methodology for Transformation of Reactor Cost Data to the "What-It-Takes" Table*, See SD6) can be applied to the data available for small-scale single unit demonstration projects.
  - Need to incorporate historical and projected information on O&M costs to complete section.
  - Consider renaming this Module to Gas-Cooled Thermal Reactors.

R3-1. BASIC INFORMATION

2009 AFC-CBR Introduction. This module was 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 is discussed under "Modularity" in the Main Report; 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. In the early 2000's, the U.S. was 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.

2012 Update AFC-CBR Introduction. Module R3 of the 2009 AFC-CBR described in detail the technical and economic considerations associated with Gas-cooled Reactors. (The name of this Module has was changed to High Temperature Gas-cooled reactors to reflect the importance of the high temperature for industrial applications and the implied use of high-temperature TRISO-type fuel. (Note that solid-fueled salt-cooled reactors can also achieve high temperatures. These will be discussed in Module R8). The HTGR has garnered considerable renewed industry and government attention over the last twelve years because of its potential to produce process heat for a multitude of industrial uses, including hydrogen production. More recently HTGR-generated heat has been proposed for use in the petrochemical industry; however, the recent low prices for wholesale natural gas are making nuclear heat appear less attractive. Electricity generation (or co-generation of heat and electricity), however, is still an important mission. The Department of Energy and the Nuclear Industry at one time were spending millions of dollars per year toward HTGR development, mainly in the planning for a demonstration reactor, the Next Generation Nuclear Project (NGNP). Pre-conceptual designs for both pebble-bed fueled and prismatic fueled reactors have been prepared by nuclear industry vendors with DOE support. Current thinking was that the NGNP demo would be in the 350 to 600MW (thermal) range, and that process heat would be the main product. This demonstration plant would need to be located near an industry that could purchase the energy and help offset the life cycle costs. (Discussion of the technology and economics of TRISO-type particle fuel appears in the update for Module D1-3. There is also a discussion therein of the status of national HTGR and TRISO fuel programs outside the US.) Presently Japan and China are the only countries with operating demonstration projects. China's HTR Program plans for the ultimate deployment of 18 modular pebble-bed HTGRs of 110MWe each. It should be noted that a U.S. company, X-Energy, is pursuing R&D on this option.

This 2015 AFC-CBR does not contain any new background information; however, new selected values for low, mode, high, and mean (along with probability distributions) are presented. These values are presented in year 2015 dollars calculated by application of the appropriate escalation factor.

Economic Terminology. 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 and are now in the low end of this range.) 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* (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 (EMWG 2007), 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 AND 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.

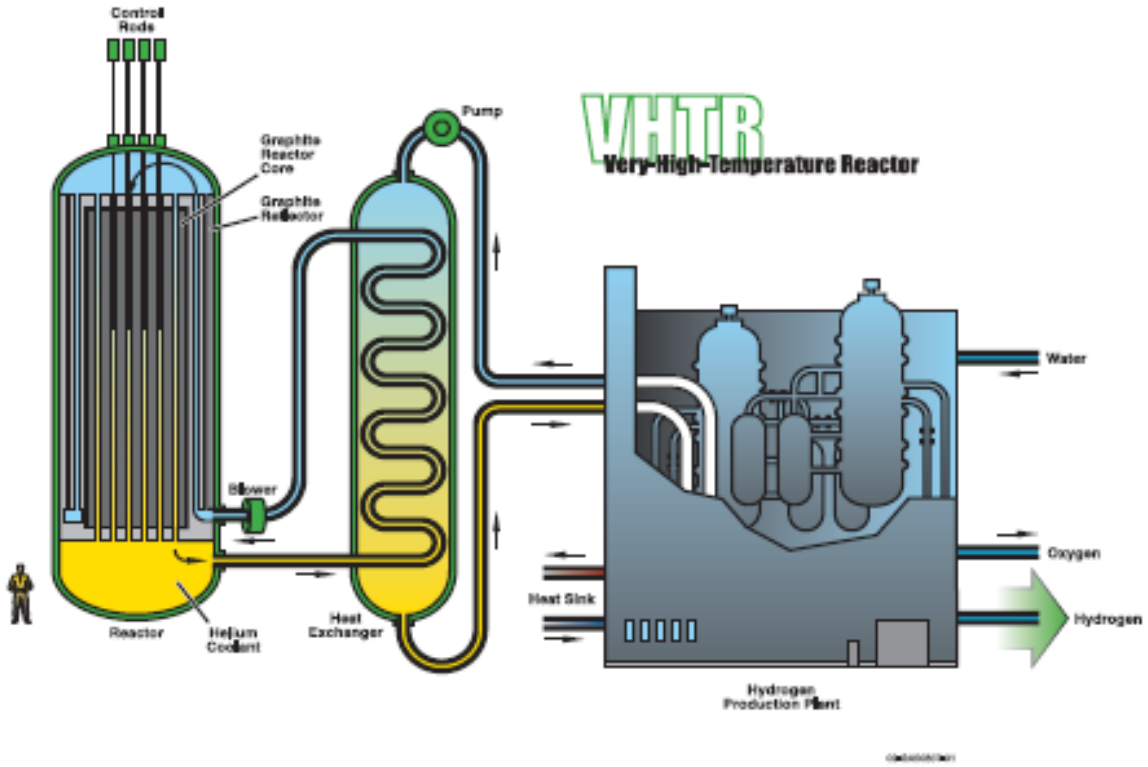

Figure R3-1. VHTR/HTR schematic.

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. In the early 2000's, GA was still pursuing the HTGR design; however, the product was to be more modular in nature, called the Modular Helium Reactor (MHR). A direct cycle design was 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 was 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. MODULE INTERFACES

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. SCALING CONSIDERATIONS

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.

R3-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

2009 AFC-CBR Discussion. 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 that have been 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 (2009 AFC-CBD).

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 Research Center (test reactor: no electricity production) (IAEA 2007) (FOAK) (U.S. Handy-Whitman Index used for escalation)	$700M (1992$) $1260M (2008$)	$23,000/kWt (1992$) $41,000/kWt (2008$)
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) (World Nuclear Association)	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)
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

2012 Update Discussion. As with LWRs and SFRs the most commonly found traditional cost figure of merit is the specific capital cost in dollars per kilowatt of electrical power capacity. Since most proposed applications of the MHTGR now are for process heat, however, the overnight cost figure of merit has now become the specific cost of thermal capacity in $/kW(th). Again one must be careful to understand whether the specific "overnight" cost or the specific "all-in" cost is being discussed. Since these modules are for comparing technology-related costs as opposed to financing-related costs, the "overnight" figure-of-merit is the applicable one discussed and presented here. If only the $/kW(th) figure-of-merit is given, one can approximate the $/kWe cost for an HTGR system by dividing the former thermal figure-of-merit by an assumed thermodynamic efficiency. The cost of a turbine/generator (T/G) must be added to the thermal only system prior to this adjustment (which would probably add less than 15% to the heat-only capital cost. Many HTGR designs will include the T/G so that they can be co-producers, therefore T/G costs are included.

The values shown in the following tables are mostly for Nth-of-a-kind (NOAK) projects unless otherwise noted and include the effects of assumed construction learning from the lead or "first-of-a-kind" (FOAK) or "lead" plants. Table R3-2 below presents HTGR specific overnight cost data gleaned from various literature sources since 2009. The table includes overnight capital cost data from two surveys (WNA, n.d.; Yankov, 2012) of country-by-country reactor specific costs and the results of two cost/design studies (INL 2011; INL 2012) supported by Idaho National Laboratory and DOE-NE. These latter studies are based on design work performed by nuclear industry subcontractors for the NGNP Program. Operations and maintenance costs for HTGR systems will be added to future AFC-CBR updates.

Table R3-2. Specific Overnight Costs for HTGRs from Literature Sources in the 2012 AFC-CBD Update.

Study or Ref /Year	Low Value $/KWe or $/KW(th)	Reference Value $/KWe or $/KW(th)	High Value $/KWe or $/KW(th)
AFC-CBR 2009 (NOAK - WIT)	3000	4500	7500
World Nuclear Association website on China (WNA, n.d.) 2 module HTR-PM at Shidaowan, China (Each module is 110 kwe; electricity prod.)	N/A	$3710 /KWe FOAK $1300/KWe target NOAK	N/A
Bulatom Presentation on SMRs: Chinese 2-module HTR-PM (Yankov 2012)	N/A	$3900/KWe (FOAK)	N/A
INL Technical Evaluation Study (INL 2011) (2010$) Lead & NOAKs NGNP 600 MW(th) NGNP 350MW(th) NOAK 4-pack [4 X600MW(th)] NOAK 4-pack [4 X 350MW(th)] (*43% thermodynamic eff., 850C reactor outlet temp)	 $4510/kW(th) $6550/kW(th) $1453/kW(th) ($3380/kWe*) $3113/kW(th) ($7240/kWe*)	 N/A N/A N/A N/A	 $9664/kW(th) $14036/kW(th) $1785/kW(th) ($4151/kWe*) $3824/kW(th) ($8890/kWe*)
INL Industrial Applications Study (INL 2011) 1-2 600MW(th) modules 3 or more 600MW(th) modules NOAK (*40% thermodynamic eff., 700-825C reactor outlet temp.)	 N/A N/A	 $2000/kW(th) ($5000/kWe**) $1400/kW(th) ($3500/kWe**)	 N/A N/A

The INL Technical Evaluation Study was the most recent, most valuable, and most detailed study accessed. The estimate was largely "bottom-up" in its preparation, and a contingency range of -30% to +50% was suggested to be used with the baseline estimates. This study presented only the $/kW(th) figure-of-merit. The author of this module assumed a thermodynamic efficiency appropriate for the reactor coolant outlet temperature of 850C in order to convert them to $/KWe.

R3-7. DATA LIMITATIONS

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.

R3-8. COST SUMMARIES

2009 AFC-CBD Summary. 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).

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.

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 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 R3-3 lists these costs in this range.

Table R3-3. 2009 AFC-CBD 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.

Update AFC-CBD Summary. The unit cost values for the What-it-takes Table for the 2012 AFC-CBR have changed somewhat from those in the 2009 AFC-CBR. The values selected are based partly on Table R3-2 above with conversion of the specific cost figure-of-merit from thermal energy to electrical energy. The upside (low) value assumes that Far Eastern factories and workers might be able to produce and install HTGR-SMRs at a target NOAK cost of $2500/kWe which is above the stated Chinese target value of $1300/kwe, which was felt to be overly optimistic and probably reflected very early estimates and low labor and commodity costs. The high value was chosen to approximate the higher values derived from the INL Technical Evaluation Study (INL 2012). The nominal value is near the middle of the "high/low" range Note that this "What-it-Takes" overnight specific cost range is higher than for LWRs and SFRs. The realized higher projected cost for HTGR electrical generation systems is tending to push the HTGR mission toward thermal energy production only rather than electricity production. The high reactor coolant outlet temperature uniquely available from high-temperature reactors allows process heat applications that could not be undertaken by LWRs and SFRs with their lower reactor coolant outlet temperatures. If the price of conventional fossil process heat fuels such as natural gas rises again or "carbon-costing" is mandated, nuclear heat may become competitive in terms of the levelized unit cost of thermal energy ($/kw(th)-h or $/million BTUs).

Table R3-4. 2012 AFC-CBD Update: What-It-Takes Capital and Recurring Costs for NOAK HTGRs (2012$).[1]

	Upsides (Low Cost)	Selected Value (Nominal Cost)	Downsides (High Cost)
NOAK Overnight Cost ($/KWe)	2500	5000	8000
1. For uncertainty analyses a triangular distribution should be used with the values in this table.			

b. Based on personal communications with the NGNP Project.

For this 2017 edition of the cost basis report, the most recent specific cost data from 2012 has been escalated to 2017$ using a factor of 1.088 and some rounding, as shown below in Table R3-5. A triangular relative probability distribution with low, mode, and calculated mean value are displayed in Figure R3.2

Table R3-5. Year 2017$ What-It-Takes Capital and Recurring Costs for NOAK HTGRs (2017$).[1]

	Upsides (Low Cost)	Downsides (High Cost)	Excepted (Mean Cost)	Selected Value (Mode Cost)
NOAK Overnight Cost ($/KWe)	2700	8700	5600	5400
1. For uncertainty analyses a triangular distribution should be used with the values in this table.				

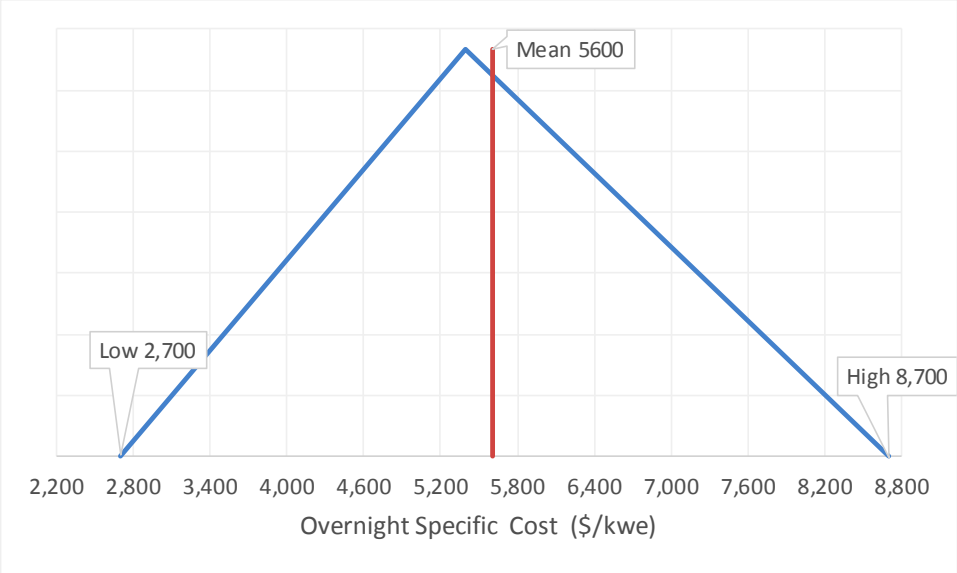

Figure R3.2 Probability Distribution for Specific Overnight Cost of HTR

R3-9. SENSITIVITY AND UNCERTAINTY 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 (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.

c. Note that this price includes no carbon tax on emissions from combustion of natural gas.

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Module R4

This module has been deleted and is no longer in use.

Module R5

Pressurized Heavy Water Reactors

Module R5

Pressurized Heavy Water Reactors

R5.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** There is a large amount of cost data for PHWRs built outside the U.S. that was compiled to estimate the overnight capital costs. The O&M costs were assumed to be the same as LWRs.

R5.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R5.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - There should be sufficient O&M data available to improve the basis for those parameters. However, given the lack of interest of this type of reactor in the U.S., it doesn't seem warranted for the next revision.

R5-1. BASIC INFORMATION

This module describes the pressurized heavy water reactor (PHWR). These are thermal spectrum reactors that use "heavy" water—water enriched in deuterium—instead of "light" water as the moderator and primary coolant. All operating commercial reactors in the United States are light water reactors, but worldwide PHWRs currently provide approximately 25.6 GWe, with another 5.1 GWe under construction. PHWRs are in commercial use in Argentina, Canada, China, India, Pakistan, Romania, and South Korea. The existing reactors range in size from the 90 MWe Rajasthan Unit 1 in India to the 878 MWe Darlington units in Canada, while the units under construction range from the 620 MWe Cernavoda units in Romania to the 692 Atucha Unit 2 in Argentina (Nuclear News 2012).

The most common PHWR in commercial use is the CANDU, short for CANada Deuterium Uranium reactor (and a registered trade name owned by Atomic Energy of Canada, Limited). Nearly all PHWRs are CANDU-based reactors, so PHWR and CANDU are generally interchangeable terms when discussing PHWRs.

R5-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Pressurized heavy water reactors share many characteristics with pressurized (light) water reactors. However, there are a few important differences. While these differences do not necessarily affect the cost of construction, they do affect the cost of operations.

The first difference is the makeup of the primary system. In PHWRs, the primary system (and thus the moderator and primary coolant) is heavy water; this is water enriched in the deuterium isotope of hydrogen. By enriching the water in deuterium, this slightly changes some thermal hydraulic properties; for example, the density increases from 1 g/cc to 1.11 g/cc (and is thus "heavier"). However, the main

effect is in its properties as a neutron moderator: heavy water has a smaller absorption cross section than light water, and thus removes fewer neutrons from the core. This leads to the second difference.

Since the moderator absorbs fewer neutrons, the PHWR can use lower-enriched uranium than the LWR. In fact, the PHWR can use natural uranium as its fuel, but the low fissile content (0.7%) of natural uranium leads to low fuel burnup before discharge—the typical PHWR burnup is 7 GWtd/MTU. The PHWR can be fueled using slightly (approximately 1%) enriched uranium to increase the discharge burnup to over 20 GWtd/MTU (Hindu 2012), but this is still less than the nearly 50 GWtd/MTU for PWRs. This low burnup leads to low resource utilization, which then causes high fuel throughput and spent fuel storage requirements. Another difference is a consequence of this requirement.

Since the reactor requires high fuel throughput, PHWRs are designed to accommodate on-line refueling instead of batch refueling. This allows the reactor to operate at full power while fresh fuel is inserted and used fuel is removed. LWRs generally have a pressure vessel, but the PHWR has pressure tubes within the core (called a calandria). The fresh fuel is inserted into the front of the pressure tube, pushing the used fuel out the back of the pressure tube. The PHWR can consistently achieve capacity factors around 90% (CNS 2012).

A PHWR typically uses unenriched (i.e., natural) uranium oxide pellets as its fuel. However, a PHWR can use other heavy metals as fuel. This allows the PHWR to be a part of any type of fuel cycle, ranging from single-use fuel through full recycle of actinides from used nuclear fuel and including uranium-233 breeding in a thorium cycle. The PHWR can also use the slightly-enriched recovered uranium (SEU) from the LWR fuel cycle.

While the PHWR fuel is similar to LWR fuel in chemical composition, it does not resemble the LWR fuel in form. The PHWR fuel is manufactured in short bundles instead of long assemblies, and these bundles are used in the online refueling process.

R5-3. PICTURES, DIAGRAMS, AND DEPLOYMENT STATUS

Diagrams of a typical PHWR, its fuel configuration, the associated fuel cycle, and fuel bundles are shown below in Figures R5-1 through R5-4.

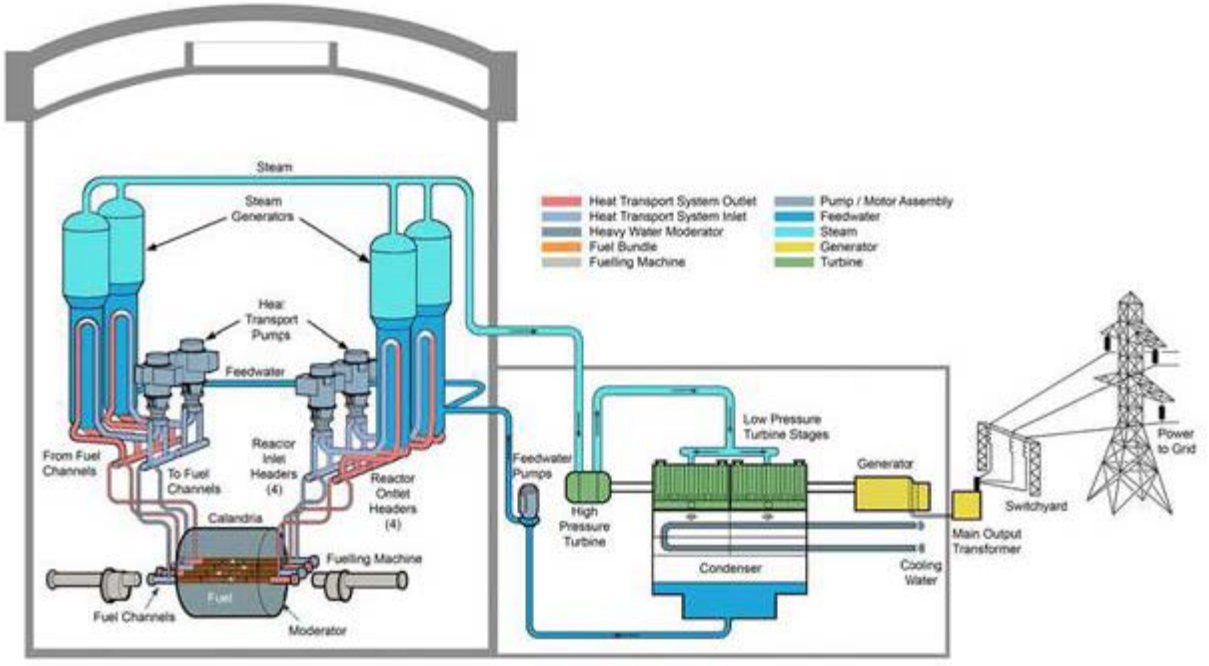

Figure R5-1. PHWR Schematic (IAEA a).

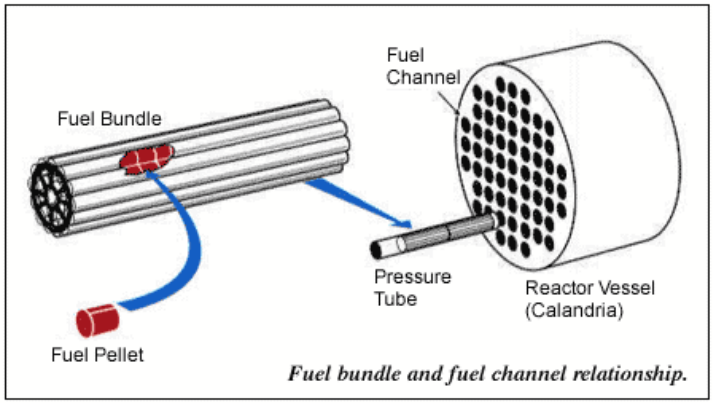

Figure R5-2. PHWR Fuel Pellets, Bundles, and Channels (Nuclear Tourist 2012).

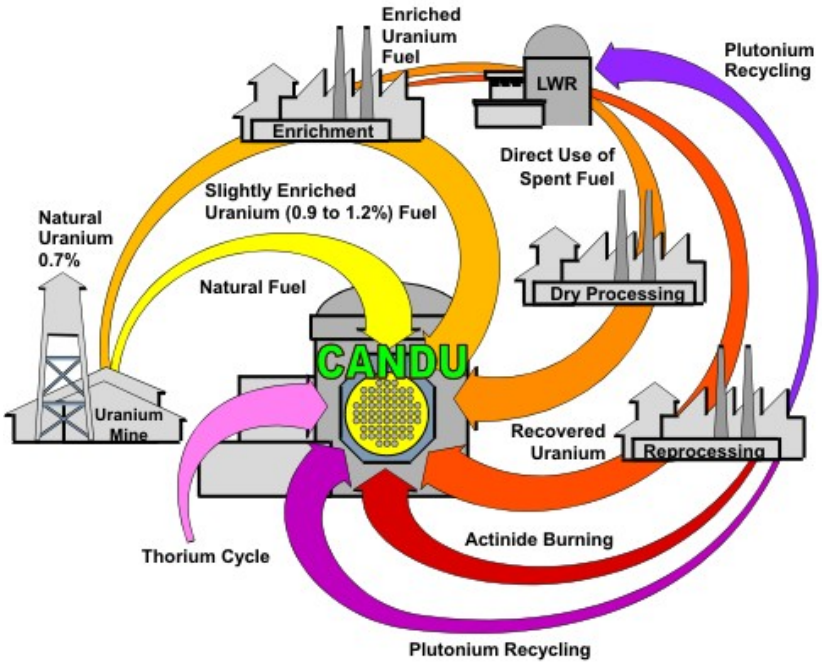

Figure R5-3. PHWR Fuel Cycles (Wikipedia 2012).

Figure R5-4. PHWR Fuel Bundles (WNA a).

The PHWR is deployed in seven countries, with the oldest operating units coming online in 1971 at Canada's Pickering plant. There are eight units currently under construction. Table R5-1 lists the currently operating and planned PHWRs. "UC" denotes "Under Construction".

Table R5-1. Currently Operating and Planned PHWRs (Nuclear News 2012).

Plant	Unit	MWe	Country	Date
Atucha	1	335	Argentina	1974
Atucha	2	692	Argentina	UC
Embalse	1	600	Argentina	1984
Bruce	1	769	Canada	1977
Bruce	2	769	Canada	1977
Bruce	3	730	Canada	1978
Bruce	4	730	Canada	1979
Bruce	5	817	Canada	1985
Bruce	6	817	Canada	1984
Bruce	7	817	Canada	1986
Bruce	8	782	Canada	1987
Darlington	1	878	Canada	1992
Darlington	2	878	Canada	1990
Darlington	3	878	Canada	1993
Darlington	4	878	Canada	1993
Gentilly	2	635	Canada	1983
Pickering	1	515	Canada	1971
Pickering	2	515	Canada	1971
Pickering	3	515	Canada	1972
Pickering	4	515	Canada	1973
Pickering	5	516	Canada	1983
Pickering	6	516	Canada	1984
Pickering	7	516	Canada	1985
Pickering	8	516	Canada	1986
Point Lepreau	1	635	Canada	1983
Qinshan	III-1	650	China	2002
Qinshan	III-2	650	China	2003
Kaiga	1	202	India	2000
Kaiga	2	202	India	2000
Kaiga	3	202	India	2007
Kaiga	4	202	India	2011
Kakrapar	1	202	India	1993
Kakrapar	2	202	India	1995
Kakrapar	3	640	India	UC
Kakrapar	4	640	India	UC
Kalpakkam	1	205	India	1984
Kalpakkam	2	205	India	1986
Narora	1	202	India	1991
Narora	2	202	India	1992
Rajasthan	1	90	India	1973
Rajasthan	2	187	India	1981
Rajasthan	3	202	India	2000
Rajasthan	4	202	India	2000
Rajasthan	5	202	India	2010
Rajasthan	6	202	India	2010
Rajasthan	7	640	India	UC
Rajasthan	8	640	India	UC
Tarapur	3	490	India	2006
Tarapur	4	490	India	2005
Kanupp	1	125	Pakistan	1972
Cernavoda	1	650	Romania	1996
Cernavoda	2	650	Romania	2007
Cernavoda	3	620	Romania	UC
Cernavoda	4	620	Romania	UC
Cernavoda	5	620	Romania	UC
Wolsong	1	597	South Korea	1982
Wolsong	2	710	South Korea	1997
Wolsong	3	707	South Korea	1998
Wolsong	4	708	South Korea	1999

R5-4. MODULE INTERFACES

This module interfaces with Module D1-7 (CANDU Fuel) for the incoming unirradiated fuel material. It would then interface with the same modules as the LWR module for the storage, reprocessing, or disposition of its used fuel.

R5-5. SCALING FACTOR CONSIDERATIONS

The PHWR is similar to the LWR with respect to the costs associated with reactor size. The two reactor types share the same basic characteristics with respect to lower specific cost ($/kWe) for larger reactors and lower total capital at risk for smaller reactors.

Figure R5-5 shows the rated power for each reactor by its date brought online. The cluster at 2020 is the group of reactors currently under construction.

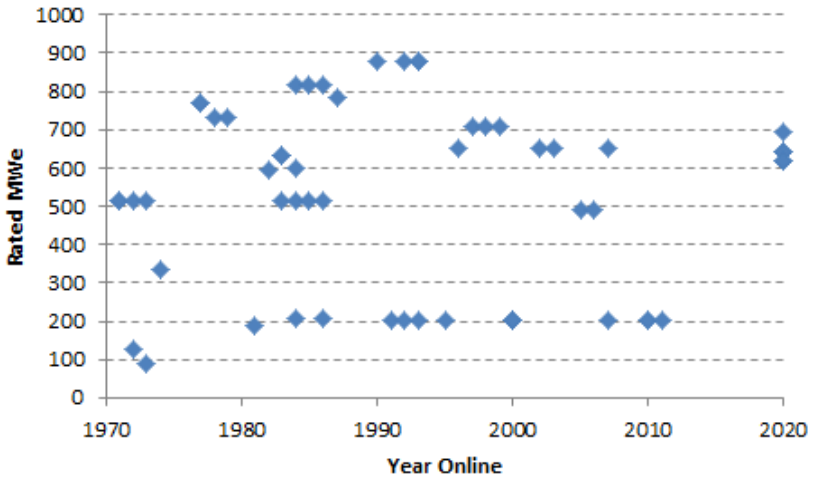

Figure R5-5. PHWR Rated Power versus Date Online.

The power range of currently-operating PHWRs is 90 to 878 MWe, a range spanning nearly 10x. However, the range for reactors coming online since 2000 is only 202 to 707 MWe (a range of 3.5x), and since 2010 only the 202 MWe reactors in India have come online. Conversely, all plants currently under construction (in Argentina, India, and Romania) are between 620 and 692 MWe.

R5-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The most recent capital costs for PHWRs come from India, China, and Romania. The capital costs for those reactors are shown in Table R5-2.

Table R5-2. Recent Capital Costs for PHWRs.

Plant	Year	MWe	Indigenous Cost	Million USD	$/kWe	$/kWe (2011$)	Reference
Kaiga 1 and 2	2000	404	2896 (Crore)	630	1559	3414	Ramana a 2005
Rajasthan 3 and 4	2000	404	2511 (Crore)	546	1352	2961	Ramana a 2005
Qinshan III-1 and 2	2003	1300	--	2880	2215	4255	CNNC 2012
Tarapur 3 and 4	2006	980	6420 (Crore)	1396	1424	1723	Himal 2012
Cernavoda 2	2007	650	--	700	1077	1012	Chicago 2004
Rajasthan 5 and 6	2010	404	3072 (Crore)	668	1654	1685	Nucleargreen 2012
Kaiga 3 and 4	2011	404	3282 (Crore)	713	1765	1765	Nucleargreen 2012

The USD-Rupee conversion rate for 2000 through 2011 was approximately 1 USD/46 Rupee (OANDA 2012). The USD is brought to 2011$ using the IHS CERA PCCI (IHS 2012).

The table shows a recent capital cost range of $1000 to $4300 per kWe. The lowest specific cost belongs to Cernavoda Unit 2; however, this unit had begun construction in the 1980s, so its specific cost does not necessarily reflect the costs incurred by greenfield construction. Removing it from consideration, the range for capital costs is then $1700 to $4300 per kWe.

The cost estimates for units under construction range from $1700 per kWe for the Kakrapar and Rajasthan plants (WNA b 2012) to $3468 per kWe for the Atucha plant (Power Technology 2012); this is consistent with the recent costs above.

R5-7. DATA LIMITATIONS

The cost data here reflect construction primarily in non-Western countries, although most of the construction is performed by AECL, a Canadian company.

The cost data here also do not reflect the capital cost of a heavy water enrichment plant. One of India's heavy water plants, Manuguru, had a capital cost of 983 crore in 1992. Based on a USD-Rupee exchange rate of 1 USD/31 Rupee (OANDA 2012), this is 317 million USD in 1992$. This plant has an annual capacity of 185 MT of heavy water. (Ramana b 2007)

The above costs also do not reflect non-fuel operations costs. Since the PHWR is similar to the LWR in many respects, it can be assumed that its non-fuel operational costs are also similar to the LWR costs.

R5-8. COST SUMMARIES

The reference capital cost range for a generic PHWR is assumed to be $1700 to $4300 per kWe in year 2011dollars. This is consistent with the recent historic costs, as well as with the current estimates for plants under construction. However, noting that most of the construction has taken place in non-Western countries, a "Westernization" premium should be applied to account for differences in the regulatory, safety, and industrial practices. Using a 2011 international construction cost survey (Gardiner 2011) as the basis, industrial construction in India ranges from $36 to $63 per square foot, and in China ranges from $50 to $88 per square foot. Comparable construction in metropolitan areas in the United States is greater than $88 per square foot. Assuming US construction would not be in a metropolitan area such as Boston or Los Angeles, that $88 can be used as a proxy value for US construction. The arithmetic mean of the Chinese construction values is $69; the $88 for US construction then represents a 28% premium over the average Chinese. For simplicity, and to reflect great uncertainties in all quantities, this cost estimation will use a 30% premium. Applying a 30% premium changes the estimates to $2200 to $5600 per kWe. These high and low values are shown in the "What-It-Takes" Table R5-3. Previous studies have shown that the PHWR cost per kWe is approximately equal to the LWR cost per kWe (IAEA b); these correspond well to the costs in Module R-1.

Table R5-3. 2012 AFC-CBR Update: Selected "What-It-Takes" Specific Overnight Cost Range (2012 $) for PHWRs.[1]

"What-it-Takes" Specific Cost Range ($/kWe) in year 2011 $	Low	Nominal	High
PHWR	2200	3900	5600
1. For uncertainty analyses a triangular distribution should be used with the values in this table.			

For the 2017 AFC-CBD the 2012$ values for the overnight capital cost are escalated to 2015$ using a factor of 1.088 per the escalation factor table at the beginning of this report .They are then rounded to carry a reasonable number of significant digits. Table R5-4 shows the new values, and Figure R5-6 shows the probability distribution and associated parameters. The O&M cost parameters are the same as for the LWR due to many inherent similarities.

Table R5-4. 2017 AFC-CBR Update: Selected "What-It-Takes" Specific Overnight Cost Range (2017 $) for PHWRs.[1]

What-It-Takes (WIT) Table				
Reference Cost(s) Based on Reference Capacity	Upsides (Low Cost)	Downsides (High Cost)	Expected (Mean Cost)	Selected Values (Mode Cost)
Overnight Cost for NOAK FR in U.S.	$2400/kWe	$6100/kWe	$4200/kWe	$4200/kWe
O&M Fixed Component including D&D fund contribution (no ref. available)	$60/kWe-yr	$87/kWe-yr	$73/kWe-yr	$72/kWe-yr
O&M Variable component including Capital Replacement Component (no ref. available)	0.8 mills/kWh	2.7 mills/kWh	1.8 mills/kWh	2.0 mills/kWh
1. For uncertainty analyses a triangular distribution should be used with the values in this table.				

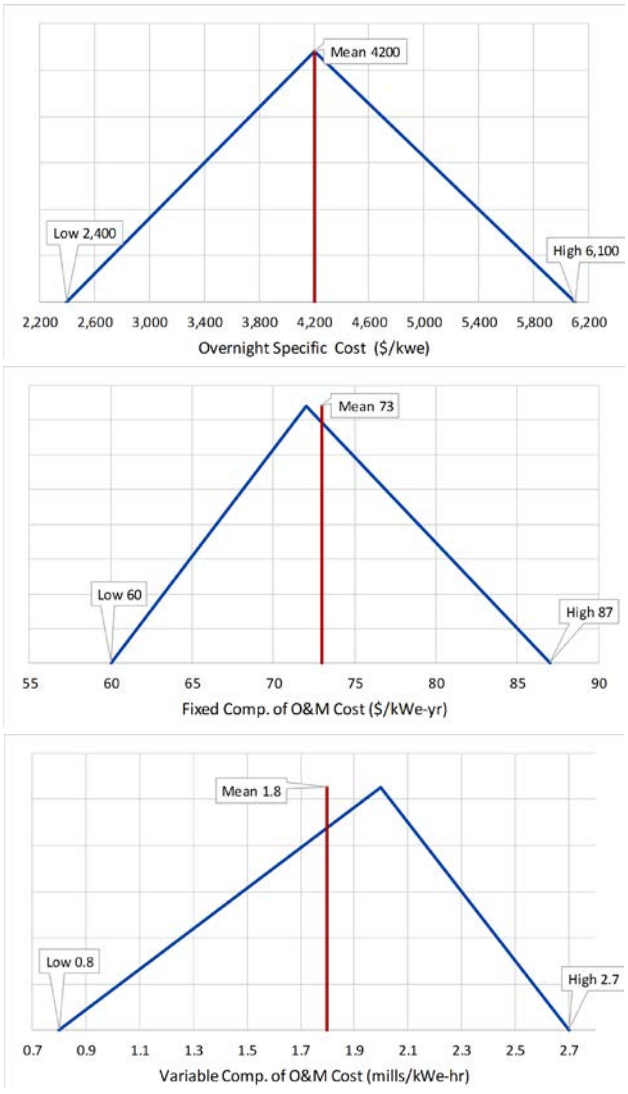

Figure R5-6. Distributions for PHWR Cost Parameters.

R5-9. SENSITIVITY AND UNCERTAINTY ANALYSES

The LUEC for PHWRs would have the same sensitivities to interest rates and construction times as LWRs.

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Module R6

Accelerator-Driven Systems

Module R6

Accelerator-Driven Systems

R6.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Estimate from a few pre-conceptual studies on the concept. No bottom-up estimate was available for a complete accelerator-driven system.

R6.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R6.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The use of this AFC-CBR information and its format for the Evaluation and Screening Report (INL 2014) did not work mesh well the range of ADS concepts considered during screening. The cost of the accelerator needs to calculated in terms of the size of the accelerator required, which in turn is a function of the degree of sub-criticality and thermal power of the sub-critical reactor. In addition, the electricity requirements (usage) should be included asa lifecycle cost component like O&M. Essentially, instead of rolling all the technology/cost assumptions into a final single $/kWe, the ADS systems analyst should provide them separately so the cost estimator can better account for the specific ADS that they are evaluating.

R6-1. BASIC INFORMATION

This module has been newly drafted for the FY2012 Cost Basis Report update. It is concerned with the capital and operational cost of Accelerator Driven Systems (ADS), defined in this module as industrial scale machines. It is highlighted that no such machine has been constructed nor operated as of yet, therefore all the costs presented here are derived from paper studies. In particular, most of the cost data are derived from the in-depth cost analysis ATW (Accelerator Transmutation of Waste) project (DOE 1999, PNNL 1999) of the late ‘90s. The European MYRRHA (Multi-Purpose Hybrid Research Reactor for High-tech Applications) project is advancing towards demonstration of the technology, with construction scheduled to start in 2015 (INL 2014), but very limited cost data are available as of this writing. While the ATW system was envisioned with the purpose of transmuting transuranics while generating electricity for sale, the MYRRHA machine’s main purpose will be to generate isotopes for research, with a substantially lower power level.

R6-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

ADS are composed of two coupled main parts: (1) a sub-critical reactor in which the power is maintained at the desired level through the use of an external neutron source and (2) a proton accelerator that, through the use of spallation reactions, generates the source neutrons.

It is assumed that, by dropping the constraint of maintaining the nuclear core critical, additional flexibility can be gained by ADS as opposed to critical transmuters[1]. This flexibility in turn can be used for certain types of reactor applications, such as the transmutation of large quantities of heavier MA. In fact, there are not substantial technological differences between fast reactors and the subcritical parts of the ADS (more on this in the rest of this section), to the extent that the cost of FR is assumed as the basis for the cost of the subcritical part of the ADS. Both FR and ADS can achieve similar reduction in the overall TRU/MA inventory and radiotoxicity (OECD/NEA 1993), but the safety characteristics of the two systems are different. Of particular interest are such parameters such as β_{eff} (or the fraction of delayed neutrons emitted in fission), the Doppler coefficient of reactivity and the void effect. β_{eff} in particular is of primary importance to quantify the degree of super-criticality that can be allowed during power excursion: for an ADS loaded with MA only, β_{eff} is about half that of a TRU/Pu burner FR [and this value is in turn about half that of LWR fueled with enriched uranium, from reference (OECD/NEA 1993), page 75]. By being able to operate the ADS in a sub-critical mode, there is a larger margin of safety to the inadvertent/accidental insertion of positive reactivity. The Doppler Effect, another important safety mechanism, is ~1 order of magnitude smaller for MA ADS than for TRU/Pu fast reactors. The values of those important parameters discourage the use of MA-only fast reactors. The subcritical system's degree of subcriticality and the accelerator power level are coupled through the following Equation (7):

$$i_p[\mathrm{A}] = \frac{\nu\left(\frac{1}{\mathrm{keff}}-1\right)}{\varphi^* Z \epsilon_f[\mathrm{MeV}]}\mathrm{P}$$

where

P (in MW) = in a subcritical core of eigenvalue k_{eff},

A = proton current i_p (in A),

ν = the average number of neutrons per fission,

k_{eff} = the standard neutron multiplication number of the subcritical system,

φ^* = the ratio of source neutrons to the average importance of fission neutrons,

ε_f = the energy per fission (in MeV), and

Z = the number of spallation neutrons per incident proton (OECD/NEA 1993).

It is observed that, as k_{eff} becomes smaller, the necessary current becomes larger, increasing the capital and operational cost of the accelerator. Figure R6-1 shows the necessary accelerator power for different sub-criticality levels as a function of the energy of the incident protons (Shropshire et al. 2009). It is observed that no substantial reduction in the accelerator power is obtained for energy higher than 1 GeV, for k_{eff} of 0.95 and 0.98. It is also noted that as reactivity is lost during irradiation, the required beam current (or accelerator power) increases. In turn, reactivity loss is larger for deeper transmutation and longer cycle lengths.

[1]. Fast Reactors are also capable of transmuting large quantities of MA per pass, particularly if designed with a conversion ratio smaller than 1.

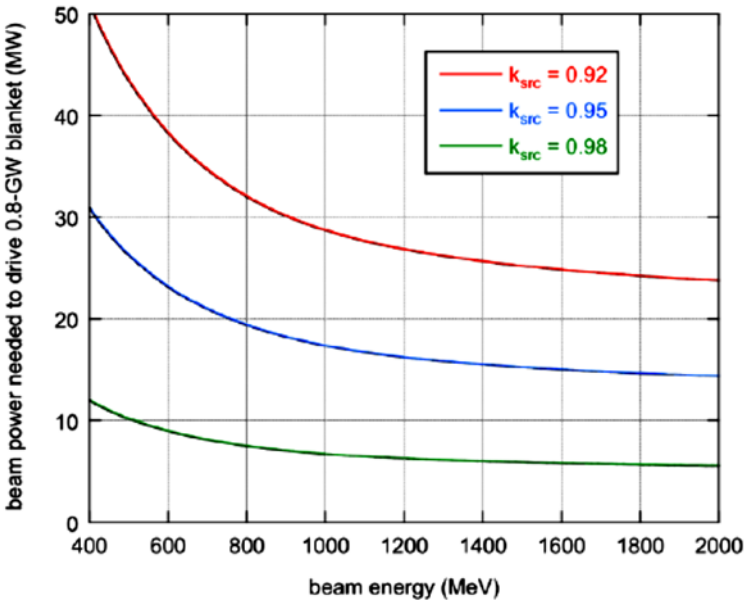

Figure R6-1. Beam power for different accelerator energy, from (Shropshire et al. 2009).

The preferred accelerator of choice for most of the ADS design studies is of the linear type (LINAC): linear accelerators are believed to be capable of generating up to 100 mA of proton accelerated to ~1 GeV (OECD/NEA 1993), so they can potentially be used to generate a continuous beam of up to 100 MW. Cyclotrons are limited to a few MW (probably not more than 10 MW: at present the most powerful is the 590 MeV, 1.8 mA cyclotron at the PSI, Switzerland (De Bruyn et al. 2011), resulting in a power level of ~1 MW), since they are limited by the strength of the magnetic field necessary to keep the ions on a curved path (DOE 1999). LINACS also are capable of nearly continuous particle output: while reactors have a history of reliable/continuous operations, accelerators have a more mixed reliability record (DOE 1999) (i.e. the beam interruption frequency would need to be reduced by 3 orders of magnitude as compared to most operating accelerators (DOE 1999). Even relatively short accelerator shutdown periods can reduce the system availability and degrade the ADS system performance. Additionally, beam interruptions in ADS would be damaging to the subcritical systems due to thermal cycling, shock waves, and loss of power to the grid even if time-integrated availability were to be high. The ATW, and later the AAA (Advanced Accelerator Applications) programs assumed that the causes of failure could be identified and addressed (mostly by improvements and redundancies). The European MYRRHA project (De Bruyn, D. et al. 2011), for a core power of 57 MW_{th}, relies on more proven 1.3 MW LINAC (600 MeV, 2.2 mA) accelerator.

Recommended Procedures for the practical calculations of the capital and O&M cost of an ADS system:

Most types of spallation targets identified in various studies are either (1) the same liquid lead-bismuth (LBE) coolant for LBE-cooled systems (2) tungsten cooled by liquid sodium, for system where sodium is the thermal vector (see Figure R5-4). Some protons are lost at the window between the accelerator and the target, degrading the system performance: to minimize losses, the windows should be thin; however, thick barriers are normally preferred in nuclear system for safety reasons. Some of the European R&D has been devoted towards windowless systems in the past, but the recent effort for the MYRRHA project focused on systems with a window between the beam and the target. Procedures for the practical calculations of the capital cost of an ADS system Procedures for the practical calculations of the capital cost of an ADS system are illustrated below.

The capital cost for ADS system is strongly dependent on the accelerator power: the beam power, P_B, required to generate the neutron source rate necessary to support the subcritical blanket is:

$$P_B[W] = \frac{ns[neutron/s] \times 1.6 \times 10^{-13}[J/MeV] \times E_p[MeV/proton]}{N[neutron/proton]} \quad (5)$$

where E_p is the energy of a proton in the beam, and N is the number of source neutrons generated per proton in the target.

The required accelerator power, P_A, to sustain the required neutron source rate, ns, is easily obtained using the accelerator efficiency, η_A:

$$P_A[W] = \frac{P_B}{\eta_A} = \frac{P_{th} \times E_p \times \nu \times (1 - k_{eff})}{\eta_A \times N \times E_f \times k_{eff}} \quad (6)$$

Equation (6) can be rewritten:

$$P_A[W] = P_{th} \times A \times \left(\frac{1}{k_{eff}} - 1 \right) \quad (6)$$

with $A = \frac{E_p \times \nu}{\eta_A \times N \times E_f}$.

Accelerator efficiencies can be assumed to be of the order of 50%.

Using equation 6, it is possible to calculate the maximum power level of the accelerator, based on the minimum keff during the fuel cycle, i.e. the capital cost should be based on the *maximum* (not *average*) beam power required during the equilibrium cycle. This is the value used to estimate the capital investment needed for this system.

The specific cost of accelerators, normalized per MW of beam power, have a distribution of 35.63 $/W, 180.17 $/W and 360.34 $/W. These costs generally need to be normalized to the power delivered by the system (accelerator plus sub-critical blanket) to the grid, to obtain the overnight cost distributions in ($/kWe). Regarding the subcritical part of the ADS, it is noted that the capital cost in this document are given as normalized per kWe specifically for the ATW system, for which the net electrical efficiency is assumed to be 36.7%. However, for the calculation for the cases with lower electrical efficiency, it is noted that the actual capital investment is more closely related to the amount of thermal power (and thus the dimension) that the system has to be sized for. To obtain a more accurate representation of the likely cost of the system, the specific capital costs from this section should be re-normalized by the ratios of the thermal efficiencies. The specific capital costs are then the sum of that of the sub-critical part of the plant and of the accelerator. For the statistical analysis they must be treated as independent variables and sampled separately, since they have different uncertainty distributions.

R6-3. PICTURES AND DIAGRAMS

Figure R6-2 shows the conceptual scheme of the ATW system. Figure R6-3 shows a Reference ATW target/blanket configuration (Hill et al. 1999). Figure R6-4 shows the main options for spallation targets for the ADS modules as conceived in the ATW project (Hill et al. 1999) and Figure R6-5 from (Hill et al. 1999).

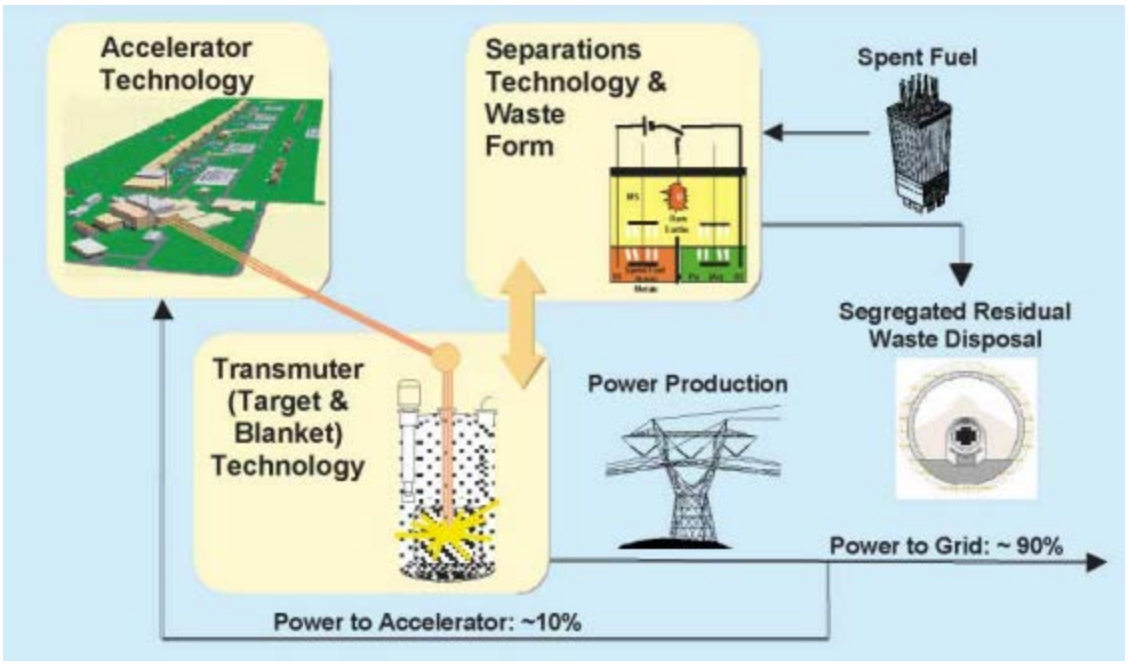

Figure R6-2. Conceptual Scheme for the ATW System (DOE 1999).

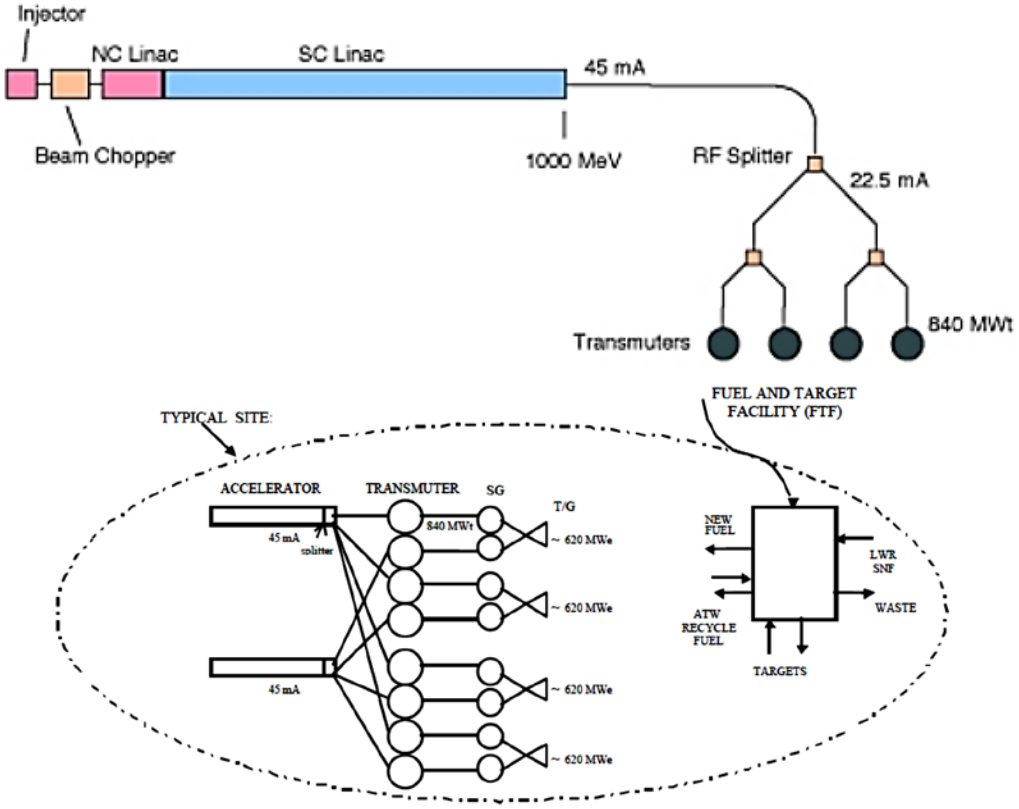

Figure R6-3. Schematic representations of each of the eight envisioned stations of ATW (DOE 1999).

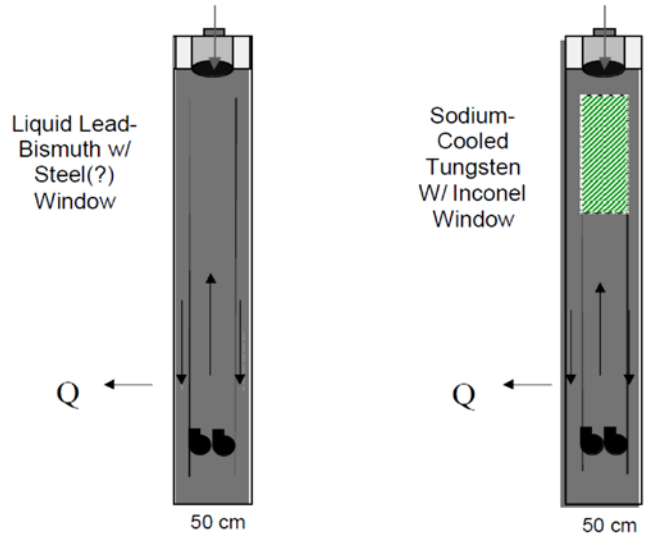

Figure R6-4. Options for spallation target for ADS modules (Hill et al. 1999).

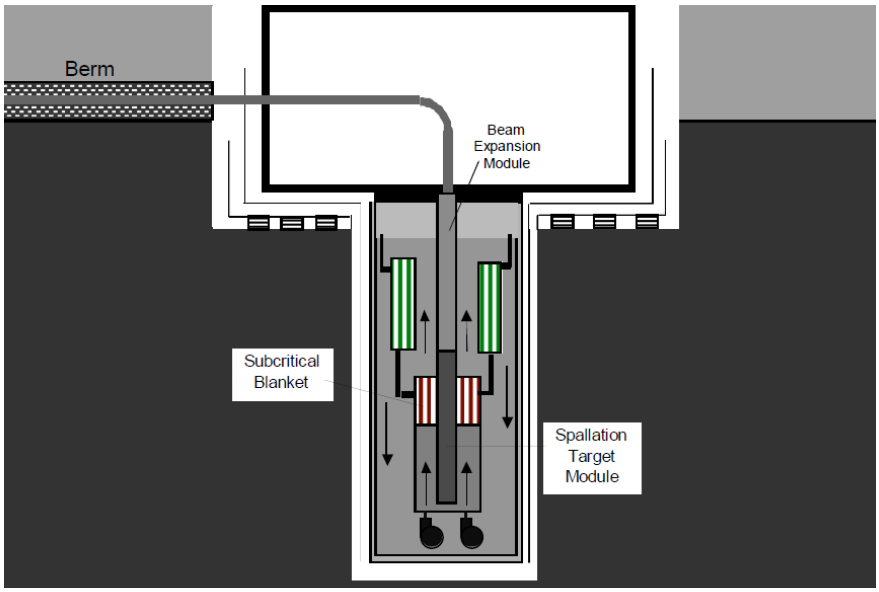

Figure R6-5. Reference ATW target/blanket configuration (Hill et al. 1999).

R6-4. MODULE INTERFACES

The ADS system receives fuel assemblies from the fuel fabrication plant, which can be central or co-located with the ADS facility. After irradiation, the discharged fuel would be kept in wet-storage on site until ready for on-site storage or off-site storage or disposal, or reprocessing. Although both aqueous and electrochemical reprocessing is possible, electro-refining is often envisioned as the fuel reprocessing method for the discharged ADS fuel (DOE 1999, PNNL 1999, OECD/NEA 1993), which would be normally co-located with the ADS. Co-location would save the off-site transportation costs.

R6-5. SCALING CONSIDERATIONS

While the subcritical system will feature a reduction in specific costs as the system power increases, the same cannot be said for the large accelerators required for ADS systems, due to the complexity and uniqueness of large accelerators with low beam trip required for these kinds of applications.

R6-6. COST BASES, ASSUMPTION AND DATA SOURCES

The ATW cost basis is used as a reference cost assessment, mostly because of the detailed economic study performed for the ATW roadmap. The following ATW systems was envisioned (DOE 1999, PNNL 1999, Hill et al. 1999) to operate for a period of 117 years: 8 stations: each station has 2 accelerators feeding 4 power blocks, in turn containing 2 sub-critical reactors and 1 turbine, for a total of 64 sub-critical reactors, generating 2480 net MW_e per station (see Figure R5-3). The cost summary is divided in two parts: (1) the accelerator (capital and O&M) and (2) the subcritical reactor and the power conversion equipment (capital and O&M). In this section, the fuel processing/fabrication facilities are excluded, since they are treated in detail in Section D2/F2.

Capital and O&M Cost of the Subcritical Reactor

The basic assumption in the ATW cost study is that the capital cost of the sub-critical part of the system will be similar – in fact, slightly higher – to that of a critical fast reactor similar in size/power level to the sub-critical unit. The specific cost (i.e. $\$/kW_e$) of the reactor/power conversion is going to be higher than that of a similar critical fast reactor because (PNNL 1999):

1. The extra size of the plant necessary to generate the electricity needed to run the accelerator: this is electricity that is not available for sale. The extra electricity needed is about 8% of the total in the case of ATW: each subcritical unit has an electric output of 310 MW_e, and needs an accelerator with a power level of 11.25 MW. Considering that the typical accelerator efficiency is 45%, the electric consumption of the accelerator is about 25 MW, or about 8% of the total.
2. In addition to the standard FR components, there will be extra complications such as target and accelerator/target connections.
3. Some components will be absent or reduced, such as control rods, but the cost benefit of this is likely to be over-compensated by the extra cost of components needed in ADS and not in FR (PNNL 1999).

The Advanced Liquid Metal Reactor (ALMR) has been used as a reasonable cost basis for ATW in (PNNL 1999), because of the large amount of work done on the cost of the ALMR (funded by DOE from 1989 to 1995 (DOE 1999)). Table R6-1 gives the capital cost for the ATW subcritical reactor and for the steam generator and turbine, from (PNNL 1999) data converted from 1999 $ to 2009 $ using a CPI deflator of 1.29 (Williamson 2010), both for the First of a Kind (FOAK) and for the N^{th} of a kind (NOAK). Because of the additional complexity outlined above, the capital cost of the subcritical unit and of the site support are increased from the ALMR values by about 10% (or ~70m$ per unit) according to judgments made by the experts of the ATW group (PNNL 1999). The turbine/generator section of the plant is left un-affected, since it is reasonable to assume that it will be the same (thus having the same costs) for critical and sub-critical units. The specific cost in $\$/W_e$ are to be normalized by the net electricity available for sale, equal to the total electricity produced by the subcritical unit minus the electricity consumed to run the accelerator.

Table R6-1. ATW capital cost (from (DOE 1999), converted from 1999 % to 2009 % using the CPI deflator of 1.29).

Subcritical Part of ATW	310 MW_e Reactor Capital Cost (m$)	Reactor Specific Cost ($/$W_e$)	620 MW_e Turbine Cost (m$)	Turbine Specific Cost ($/$W_e$)	Site Support Cost (m$)	Power (MW_e) Supported by Site Support	Site Support Specific Cost ($/$W_e$)	Total Specific Cost ($/$W_e$ to the grid)
FOAK	954.21	3.35	505	0.89	225	620.00	0.40	4.63
NOAK	627.84	2.20	389	0.68	210	2480.00	0.09	2.98

The O&M costs for the sub-critical part and for the power conversion of the power station of the ATW system are shown in Table R6-2 in 2009 $, converted using the CPI deflator (Williamson 2010). The values are based on the FOAK values reported in (PNNL 1999), for the ATW studies adapted from

the ALMR data. The NOAK data were derived by the authors by assuming that the O&M cost (in million$/y) will remain the same from the 1st to the Nth unit, with the difference that the power level will increase. For this reason, the overall specific O&M yearly cost will decrease from 229 to 131 $/(kW$_e$y)[2].

Table R6-2. ATW O&M cost (from (PNNL 1999), converted in 2009 $).

Subcriztical Part of ATW	310 MW$_e$ Reactor O&M Cost (m$/y)	Reactor Specific Cost ($/W$_e$ y)	620 MW$_e$ Turbine O&M Cost (m$/y)	Turbine Specific O&M Cost ($/W$_e$ y)	Site Support O&M Cost (m$/y)	Power (MW$_e$) Supported by Site Support	Site Support Specific O&M Cost ($/W$_e$ y)	Total O&M Cost Specific to the Net Electrical Output ($/kW$_e$ y)
FOAK	21.54	0.08	13.16	0.02	74.30	620.00	0.13	229.03
NOAK	21.54	0.08	13.16	0.02	74.30	2480.00	0.03	131.26

Capital and O&M Cost of the Accelerator Part

The accelerator cost data are available from the APT project (Accelerator Production of Tritium) (PNNL 1999), where the estimates have been derived within 10 years of collaborative work between two industrial partners, General Atomics and Burns & Roe Enterprises. The reference accelerator for the APT project is a LINAC with a 1 GeV, 100 mA proton beam, for an accelerator power of 100 MW. The accelerator costs from the APT program – adapted by the expert group for the ATW project – are summarized in Table R6-3, where the values for FOAK and NOAK are both reported, in 2009 $ adjusted using the CPI deflator, for the reference linear 1 GeV accelerator. The FOAK accelerator has 12 MW of output, and will feature a substantially higher design and construction costs than the NOAK, resulting in a specific capital cost of 180 $/W. The NOAK is expected to feature a substantially lower capital cost for design and construction, resulting in a specific capital cost of 35.6 $/W. When these costs values are normalized to the electric output available for sale (i.e. output of the turbine/generator of the subcritical multiplier minus the electricity consumed by the accelerator itself, considering the fact that the typical accelerator efficiency is 45%), the specific capital costs in 2009 $ for the FOAK and NOAK accelerator are 7110 $/kW$_e$ and 1410 $/kW$_e$ respectively.

Table R6-3. Accelerator total and normalized power costs (from (DOE 1999), converted in 2009 $ using the CPI deflator).

Linear Accelerator	Design Cost (m$)	Construction Cost (m$)	Current (mA)	Total Capital Cost (m$)	Capital Cost Specific to the Accelerator Power ($/W)	Accelerator Power (MW)[1]	Cost of Accelerator/ Subcritical Unit (m$)	Specific Accelerator Capital Cost ($/W$_e$ to the grid)
FOAK	548.25	1613.79	12	2162.04	180.17	11.25	2026.91	7.11
NOAK	211.56	1391.91	45	1603.47	35.63	11.25	400.87	1.41
1. This is the power necessary to drive each 310 MW$_e$ subcritical unit								

The O&M of the accelerator part of the ATW are shown in Table R6-4, in 2009 $, in absolute value (i.e. million$/y) and in normalized value ($/kW$_e$ y).

Table R6-4. Accelerator O&M cost (from (PNNL 1999), converted in 2009 $ using the CPI deflator).

Accelerator	Current (mA)	O&M Cost (m$/y)	Specific O&M Cost ($/W y)	MW/Each 310 MW Subcritical Unit	O&M Cost of Accel/Unit (m$/y)	Accelerator O&M Cost $/kW$_e$ y
FOAK	12	78.69	6.56	11.25	73.77	258.85
NOAK	45	56.76	1.26	11.25	14.19	49.79

[2]. This value is to be used to easily obtain the annual O&M cost by multiplying the net electrical output of the system by the value in the table: for example, for a 10^6 kW$_e$ system, the annual O&M cost of the NOAK subcritical unit would be 131.26 million $.

R6-7. DATA LIMITATIONS

No ADS has been constructed and operated to date, therefore the cost assumptions presented here are largely estimates of costs based on paper studies. In fact, most of the data in this revision rely on a single cost study (the ATW effort of the late '90s) that contain the most detailed and complete effort to estimate not only the R&D costs, but also the cost of a NOAK system.

While few critical fast reactors have been constructed around the world – therefore providing both a demonstration of the technical feasibility and some base for FOAK cost estimates – no accelerator has been built of the power level required to drive an industrial-scale ADS. An increase in the power level by 1-3 orders of magnitude as compared to the currently most powerful machines, appears to require a technological leap. Additionally, a reduction in the beam interruption frequency by 3 orders of magnitude as compared to the present accelerator's performance, seems to also require a technological leap. As an example of the excessive optimism that may be contained in the ATW cost data, it is noted that, by private conversation of the authors with the designers of the European MYRRHA facility, it was possible to obtain a specific cost of that machine in the order of 200-300 $/W, higher than the FOAK specific cost proposed for the ATW project of 180 $/W, while the accelerator for the MYRRHA project features a power level within the limits of available technology. The spallation target technology also appears not fully demonstrated, as well the connection/interface between the accelerator and the subcritical reactor. The combined effect may affect the technological feasibility of such a system, and will have an impact on cost which is difficult to predict at this early stages of technological maturity, not to mention the extrapolation to the cost of an NOAK facility.

R6-8. COST SUMMARIES

The specific costs of the ATW system, as representative of an ADS system (in 2009 $), are summarized in Table R6-5. It is observed that there is a large variation in specific cost between the FOAK and the NOAK construction costs, mostly attributable to the large cost variation of the accelerator. To justify this large reduction in accelerator costs, the learning curve for the accelerators was set at 85%, while that of the nuclear systems was assumed at 95%. The capital costs reported here do not include decommissioning and decontamination costs, which are assumed as 10% of fabrication cost for activated parts (Murphy 1984), and at 5% for non-contaminated parts such as some of the accelerator's components. Decommissioning costs can be assumed to follow the same 95% learning curve as the nuclear system.

Table R6-5. Summary of the specific capital cost of the ATW system, in 2009 % as representative of an ADS system.

	Subcritical Reactor + Power Conversion Cost ($/kW$_e$)	Accelerator Cost ($/kW$_e$)	Total Specific Cost ($/kW$_e$)	Accelerator Cost as a % of Total Cost
FOAK	4630	7110	11740	60.6%
NOAK	2980	1410	4390	32.1%

The total normalized O&M of the whole ATW system in 2009 $ is shown in Table R6-6.

Table R6-6. Summary of the specific O&M of the ATW system, in 2009 $, as representative of an ADS system.

	Subcritical Reactor + Power Conversion O&M Cost ($/kWey)	Accelerator O&M Cost ($/kWey)	Total Specific O&M Cost ($/kWey)	Accelerator Cost as a % of Total Cost
FOAK	229.03	258.85	487.88	53.1%
NOAK	131.26	49.79	181.05	27.5%

The operation and capital costs of ADS are higher than those of critical reactors, mostly because of the added costs of the accelerators. However, even if the accelerator capital cost were 0 and the subcritical reactor would cost the same to build and operate as a critical reactor, ADS would still be more expensive than FR because of the relatively large fraction of the electricity produced that is needed to run the accelerator (about 8% in the ATW study) and consequently would not be available to generate revenue.

No reliable uncertainty ranges could be obtained to-date on the O&M and capital costs of ADS. However, the higher specific costs of the MYRRHA accelerator, for example, would suggest that a cost of the FOAK facility could be twice as high as the specific value suggested in the ATW work, or as much as 300 $/W. It is further noticed that the degree of learning implied in the accelerator cost reduction from FOAK to NOAK may never materialize. It therefore appears prudent to the authors, considering the degree of technical immaturity of this technology, to assign the NOAK ATW specific cost as the lowest, most optimistic scenario, the FOAK ATW as nominal value and twice that value consistent with the MYRRHA accelerator suggested specific cost – as a high (or most pessimistic) value. Table R6-7 summarizes the "what-it-takes" values for the specific overnight capital and O&M costs for both the accelerator and the sub-critical parts.

For the NOAK case, the sub-critical reactor part of the capital cost has been estimated at 2980 $/kW$_e$, by scaling up this value from the ALMR cost of 2350 $/kW$_e$. If these costs were higher, as for example suggested in [Shropshire et al. 2009] (i.e. 4200 $/kW$_e$), the specific cost of the subcritical part would be correspondingly higher. The ATW estimated NOAK cost has been therefore adopted as lower boundary (or most optimistic scenario), and the values of [Shropshire et al. 2009], scaled up by 10%, as selected and upside values.

Table R6-7. What-It-Takes Cost Summary Table.(2012$)

	Upside (Low Cost)	Selected Value (Mode Cost)	Downside (High Cost)
Capital Cost of the Subcritical Reactor	2980 ($/kW$_e$)	4620 ($/KW$_e$)	7700 ($/kW$_e$)
Capital Cost of the Accelerator	1400 ($/kW$_e$)	7100 ($/KW$_e$)	14200 ($/kW$_e$)
O&M Cost of the Subcritical Reactor	60 ($/kW$_e$y)	131 ($/KW$_e$)	230 ($/kW$_e$y)
O&M Cost of the Accelerator	50 ($/kW$_e$y)	153 ($/KW$_e$)	256 ($/kW$_e$y)

Table R6-8. Shows the same Table with all cost numbers escalated to Year 2017 dollars:

Table R6-8. What-It-Takes Cost Summary Table (2017$)

	Low Cost	High Cost	Mean Cost	Mode Cost
Capital Cost of the Subcritical Reactor	3200 ($/kW$_e$)	8400 ($/kW$_e$)	5500 ($/KW$_e$)	5000 ($/KW$_e$)
Capital Cost of the Accelerator	1500 ($/kW$_e$)	15400 ($/kW$_e$)	8200 ($/KW$_e$)	7700 ($/KW$_e$)
O&M Cost of the Subcritical Reactor	65 ($/kW$_e$y)	250 ($/kW$_e$y)	153 ($/KW$_e$)	143 ($/KW$_e$)
O&M Cost of the Accelerator	54 ($/kW$_e$y)	278 ($/kW$_e$y)	166 ($/KW$_e$)	166 ($/KW$_e$)

Regarding the O&M costs, it is noted that the FOAK and NOAK values suggested for the ATW appear to have substantially higher values and span a substantially larger range than the values suggested in [Shropshire et al. 2009] for the fast reactors. Therefore it is retained prudent to adopt the low fast reactor value of reference [Shropshire et al. 2009] as Upside (Low Cost), the NOAK FOAK ATW O&M costs as selected and downside values, respectively. For the accelerator, the NOAK and FOAK O&M costs have been adopted as Low and High estimates, respectively. Figure R6-7 shows the probability distributions for the specific capital cost and specific O&M cost for the two parts of an ADS system.

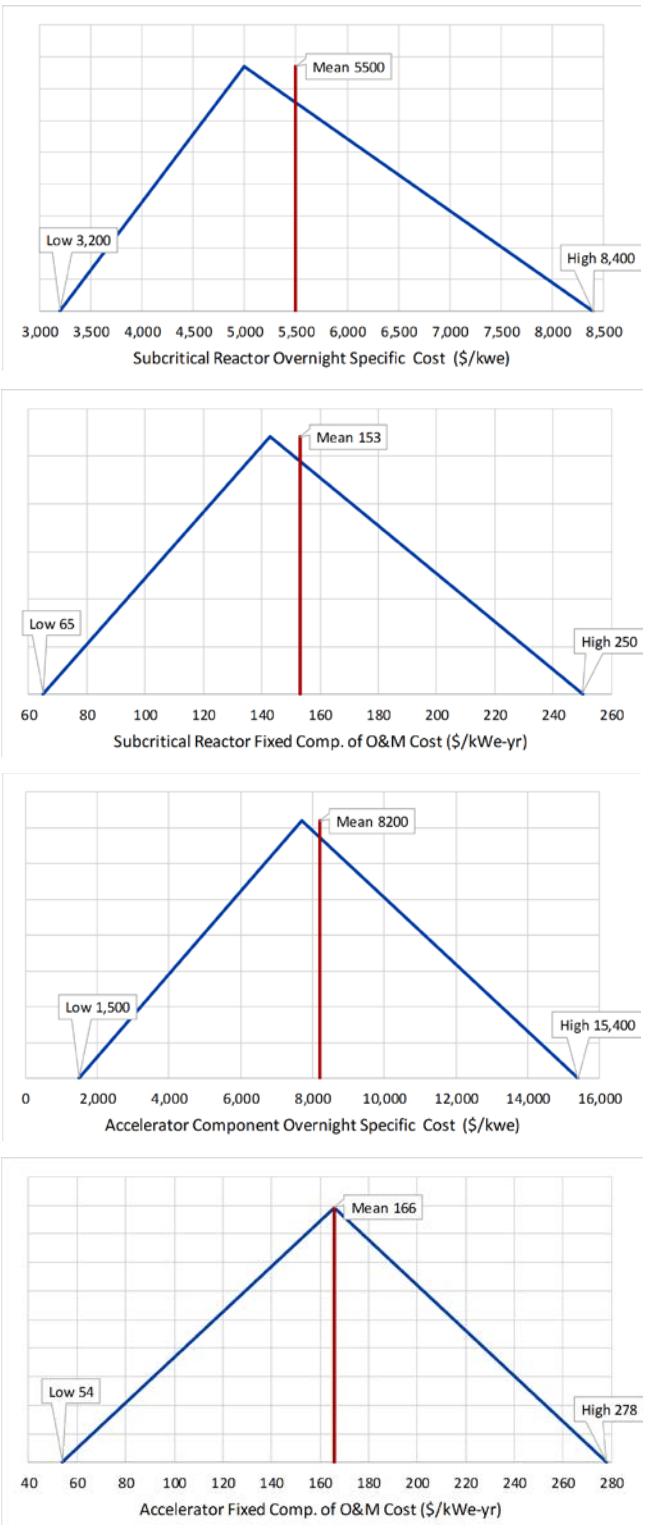

Figure R6-7. Frequency distributions and parameters for the cost elements of a generic ADS system.

R6-9. SENSITIVITY AND UNCERTAINTY ANALYSES

None available.

R6-10. REFERENCES

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Module R7

Liquid-Fueled Salt-Cooled Reactors

Module R7

Liquid-Fueled Salt-Cooled Reactors

R7-MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Some bottom-up MSR design and cost estimates from ORNL work in the 1970s were utilized to develop updated cost estimates combined with engineering judgment of the MSR's differences from LWRs.

R7-RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R7.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - A large interest in this type of reactor has evolved recently. This recent attention to MSR concepts is mostly by private companies, which are likely to keep their cost estimates proprietary. There is likely to be some new MSR economics information available, but the authors are unaware of any specific well-documented information. A recent report (EIRP 2017) on advanced reactor economics used some of this private industry post projection data ($/kWe for various NOAK designs) to examine overall economic feasibility of advanced reactors (of all types) as a class vis-à-vis conventional reactors.

R7-1. BASIC INFORMATION

(Module R7 was a new addition to the 2012 AFC-CBD Update report). Liquid-fueled Salt-cooled reactors, more **commonly referred to in the literature as just Molten Salt Reactors (MSRs)** represent a class of reactors that involve the use of dissolved fuel in fluoride or chloride salts that also serve as the coolant material. (It should be noted that a solid-fueled, high temperature reactor can have a molten-salt coolant. This type of Advanced High-temperature Reactor (AHTR) is the subject of Module R8.) The fuel-containing salt can additionally be processed, either online or in a batch mode, to allow the removal of fission products and the introduction of fissile fuel and fertile materials during the operation of the reactor. MSRs concepts have been developed with both thermal and fast neutron spectrums and with uranium, thorium, and plutonium fuels. The MSR is most commonly associated with the U-233/Thorium fuel cycle as the nuclear properties of U-233 combined with the online removal of parasitic absorbers results in the ability to design a thermal-spectrum breeder reactor.

An extensive program supporting research and development of a thermal-spectrum Molten Salt Breeder Reactor (MSBR) at ORNL in the 1950s – 1970s resulted in reactor designs and a significant amount of technology development in materials, salt technology, and reactor components. This research program included the operation of the Molten Salt Reactor Experiment (MSRE) in the late 1960s. As a result of rising proliferation concerns an alternative design was developed in the 1970s, the Denatured Molten Salt Reactor (DMSR) concept was developed in which there is minimal fuel salt processing and

uranium is added to ensure that there is sufficient U-238 present to “denature” the U-233 and U-235 (a non-proliferation objective). The molten salt reactor has been selected as one of the six Generator IV system concepts. China is now pursuing this option in earnest with a $350M R&D program. This is in part driven by the fact that China has considerable thorium reserves. Alternative concepts have been proposed with a fast neutron spectrum [Renault2009] and to support actinide-burning applications [Ignatiev2005]. In addition, molten salts have also been proposed in the use of Accelerator Driven Systems (ADS) [Bowman 1998] and Fission-Fusion Hybrids (FFH) [Lee 1981]. This is the first time the MSR has been considered in the AFC-CBR, hence more technical descriptions of the reactor and fuel handling system are present in this module.

The MSBR provides an example of a full recycle system in which the nuclear fuel is fully recycled with only fission products and other processing wastes being disposed. The DMSR could be considered in the once-through or modified open cycles based on the level of fuel processing that is performed. At the time of development, ORNL considered the system a once-through system but with definition given above, the DMSR is an example of a modified open system that involves minimal processing of the fuel, improved source material (U or Th) resource utilization (in comparison to LWRs) and with disposal of fuel as well as fission products. These systems were selected as illustrative examples for this study primarily because of the availability of a significant amount of historical design information and the relatively complete concept design documents that are available. Alternative concepts, as discussed above, can be included in future assessments based on the available and development of technical information.

Since considerable economic analysis data were available from early and recent (Spring 2010) ORNL documents, it has been decided to include the details of the latter unpublished life cycle cost estimate for the thermal MSR, which was prepared by the author of this Module R7 section shortly before he retired from ORNL, as part of this document. This economic assessment was undertaken as part of series of MSR assessments undertaken by ORNL staff as part of the early Fuel Cycle Options Assessment Program funded by NE-FCRD. Some technical details prepared by other ORNL staff are included and form the design basis for the cost estimate.

R7-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Basic Reactor Features. The unique characteristic of Molten Salt Reactors is the use of liquid rather than solid fuel. The use of a liquid fuel allows many reactor design features that are not possible with solid fuel. These include circulation of the fuel-containing liquid to act as a coolant and heat transfer mechanism, performing on-line chemical processing to remove parasitic absorbers and optimize breeding and burning of materials, and a different means of passive safety, such as draining the fuel from the core. The MSR designs of the 1960s and 1970s were focused on optimizing the thorium cycle to achieve a high level of breeding performance by on-line chemical processing. At the time, it was envisioned that there would be a very quick growth in nuclear energy with fissile material availability representing a limit to growth. The fuel for MSRs consists of fissile and fertile actinides dissolved in a liquid carrier salt. The most common salt that is used is a LiF-BeF2 salt with lithium being enriched in its Li-7 content to minimize neutron absorption and tritium production. Many other salts have been considered based on sodium, zirconium, rubidium and other materials. In addition for fast-spectrum systems, chloride-based salts have been considered, however, the majority of all research and development up to 2012 has been with fluoride salts, which will be the primary focus in this module.

The on-line chemical processing system is fundamentally based on fluoride chemistry to allow effective removal of the uranium from the salt, followed by vacuum distillation for the removal of fission products (with the gaseous fission products being easily removed by helium sparging). The removal of the highly-absorbing fission products as well as allowing the U-233 precursor, Pa-233, to decay outside of the core, results in an optimal breeding system for a thorium reactor (breeding ratio ~1.07). Combined with the low fissile loading, the thermal spectrum MSR can achieve doubling times that are similar to fast

spectrum systems with a much higher breeding ratio. The core region of the reactor consists of a matrix of graphite blocks that provide moderation to create a critical system with interspersed fuel and fertile blanket regions for a two-fluid reactor.

The reactor operates at a high temperature, with the fuel salt core exit temperature of 700 °C and was originally a design based on a steam power conversion system with a 44% power conversion efficiency. Current concepts would likely utilize a Brayton cycle, which is a better match with the high temperatures of the reactor. The safety of the reactor was ensured by its negative reactivity coefficients and the use of freeze plugs with a drain tank system with passive decay heat removal. Should the fuel salt temperature increase, the freeze plugs will melt and the fuel will drain into tanks that are in a subcritical configuration and have sufficient decay heat removal. Given that the fuel salt will distribute radioactive materials throughout the primary fuel circuit, the system was designed for remote maintenance, which was demonstrated in the operation of the MSRE.

Fuel Cycle Application of MSRs. In the traditional thorium-based breeder application, the MSBR provides a long-term option for nuclear energy based on the large quantity of available thorium. Additionally, the waste stream is comprised primarily of fission products as the higher actinide production is relatively low in the thorium-uranium cycle and the actinides are circulated in the fuel salt until fissioned. While first conceived of as a breeder reactor, the MSR concept was further extended at ORNL to a Molten Salt Converter Reactor (MSCR) when it became apparent that fuel resource availability (U and Th) would not be a concern for a considerable time. The MSCR differed from the MSBR in that it had a simpler chemical processing system since it did not have to achieve a conversion ratio greater than unity. Additionally, as concerns with proliferation of reprocessing technology (DOE 1980) increased in the late 1970s, a Denatured Molten Salt Reactor (DMSR) was developed without on-line processing and with the addition of low-enriched uranium to ensure that the fissile uranium content was in the LEU range. Of course, the addition of low-enriched uranium will increase the higher actinide production over that of the pure U-233/thorium system.

In the past decade, interests in MSRs for the mission of actinide management have become more prominent in France, Czech Republic, and Russia. Several concepts have been developed to use minor actinides and transuranics as fuels with the waste products being predominately fission products. The Czech Republic concept is known as SPHINX and consists of a fast-spectrum MSR with fuel based on plutonium and minor actinides from used LWR fuel. [Hron 2009] The French have studied a thermal-spectrum burner (AMSTER) that uses spent LWR tranuranics as fuel with thorium support. [Vergnes 2001] In Russia a fast-spectrum molten salt reactor transmuter concept has been developed (MOSART). [Ignatiev 2005] More recently, a molten salt fast reactor (MSFR) has been developed in France [Delpech 2009]. China now has a $350M RD&D program to develop this technology and India is still pursuing it; however, not necessarily for actinide management. A number of new concepts are now (2017) under development by companies such as Terrestrial Energy (Canada), Moltex Energy (UK), ThorCon Power (USA), Flibe Energy (USA), Transatomic Power (USA), and TerraPower (USA). At the time of writing this Module R-7, no data was available to evaluate any of these concepts.

R7-3. PICTURES, DIAGRAMS, AND DEPLOYMENT STATUS

A large number of systems configurations based on MSR are possible and many have been considered to a varying degree of detail. Based on the availability of information two concepts have been chosen that provide representative systems for both full recycle and modified open fuel cycle options. These concepts include:

- Molten Salt Breeder Reactor – full recycle system concept based on U-233/Thorium fuel cycle
- Denatured Molten Salt Reactor – modified open fuel cycle system based on thorium/LEU fuel cycle with limited processing.

In addition to these concepts, an additional system based on an actinide burning system (light water reactor used fuel into a molten salt reactor) could additionally be considered as an additional modified open fuel cycle system. This Module considers only the MSBR.

Molten Salt Breeder Reactor (MSBR) Description/Schematic. The MSBR concept selected for this work is that of the final ORNL design, which was based on a single fluid system [Robertson 1971 and Bettis 1970]. A conceptual layout of the reactor is shown in R7.1. The design is a single-fluid concept that contains ~ 43 m^3 of fuel salt (71 mole% ^7LiF, 16 mole% BeF_2, 12 mole% ThF_4, and ~0.3 mole% $^{233}UF_4$) as per Figure R7-2. The plant is a four-loop design with an average core power density of approximately 22 kW/liter. A total of 295,000 kg of graphite was used in the design and the approximately 205,000 kg of that was to be replaced approximately every 4 years A summary of the MSBR key design and operating parameters is presented in Table R7-1.

Table R7-1. MSBR key design and operating parameters.

Parameter	Value
Reactor Thermal Power (MW)	2250
Reactor Electrical Power (MWe)	1000
Fissile fuel inventory (kg)	1501
Thorium inventory (kg)	68,100
Thorium feed rate (kg/yr)	~6000
Inventory U/Np/Pu/Am/Cm (kg)	1988/15.3/13.4/2.3/6.2
Waste Th/Np/Pu/Am/Cm (kg/GWe-yr)	5400/0.72/0.63/0.11/0.29
Waste Total TRU (kg/GWe-yr)	1.74
Breeding ratio	1.06
Doubling time (years)	22
Fuel salt components	^7LiF-BeF_2-ThF_4-UF_4
Fuel salt composition (mol %)	71.7-16-12-0.3
Core inlet/outlet temperature (°C)	566/704 °C

In terms of core design parameters the MSBR core, shown in Figure R7-1, has a peak power density of 70.4 kW/liter and an average power density of 22.2 kW/l. Graphite in the reflector region was expected to last the 30-year life of the reactor. The maximum flow velocity in the core was estimated to be 2.6 m/s.

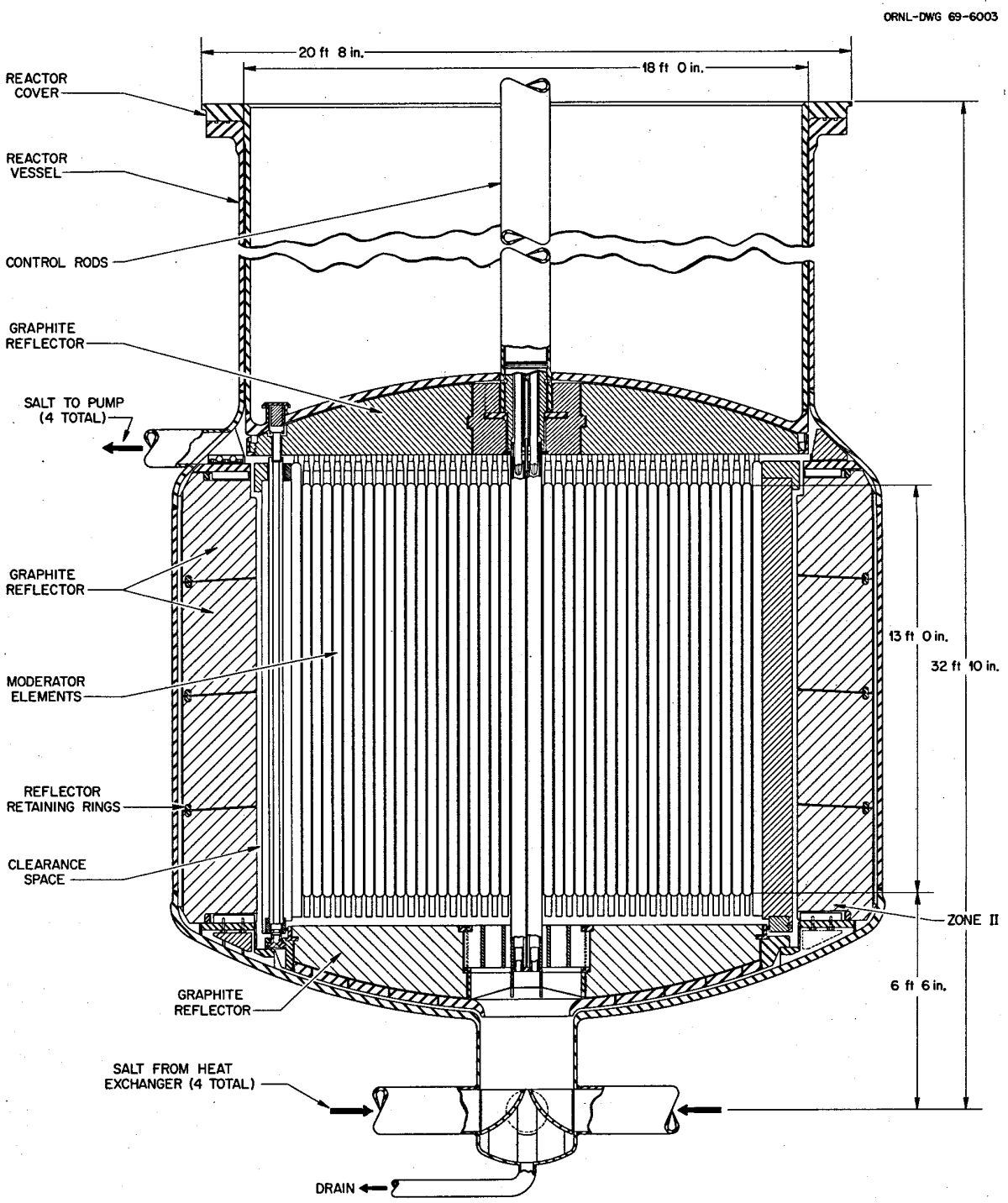

Figure R7-1. Single fluid MSBR core diagram [Robertson 1971].

The total volume of the fuel salt was estimated to be 48.7 m^3 with approximately 30.4 m^3 of fuel salt in the core. The continuous salt-processing system, a schematic of which is shown in Figure R7-2 consists of two steps: (1) the removal of uranium and protactinium from salt leaving the reactor along with reintroduction of uranium and (2) removal of rare-earth fission products. The flow rate of the processing stream is approximately 3.3 liters/min. In the first process a fluorinator removes approximately 95% of

the uranium as gaseous UF_6. The salt then flows to a reductive extraction column where protactinium and the remaining uranium are chemically reduced and extracted into liquid bismuth in a counterflow arrangement. The bismuth contains lithium and thorium as reducing agents that are added at the top of the extraction column. It is not clear whether the latter extraction process was demonstrated on anything other than a small scale, but the initial fluorination process and uranium reintroduction was demonstrated during MSRE operation.

The TRU inventory is very low in this system, with the Pu inventory being ~15 kg and the total TRU inventory being ~37 kg. This will result in a very low discharge fuel TRU content of actinide wastes.

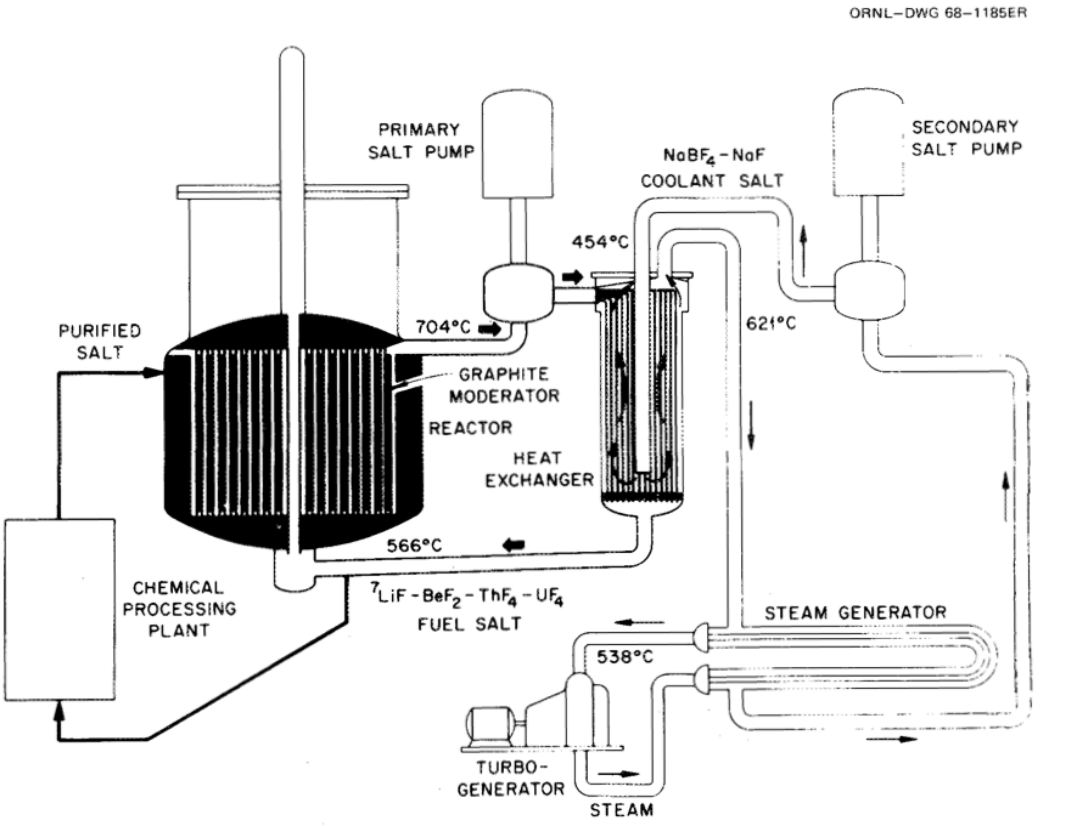

Figure R7-2. Single fluid MSBR key system diagram [Engel 1980].

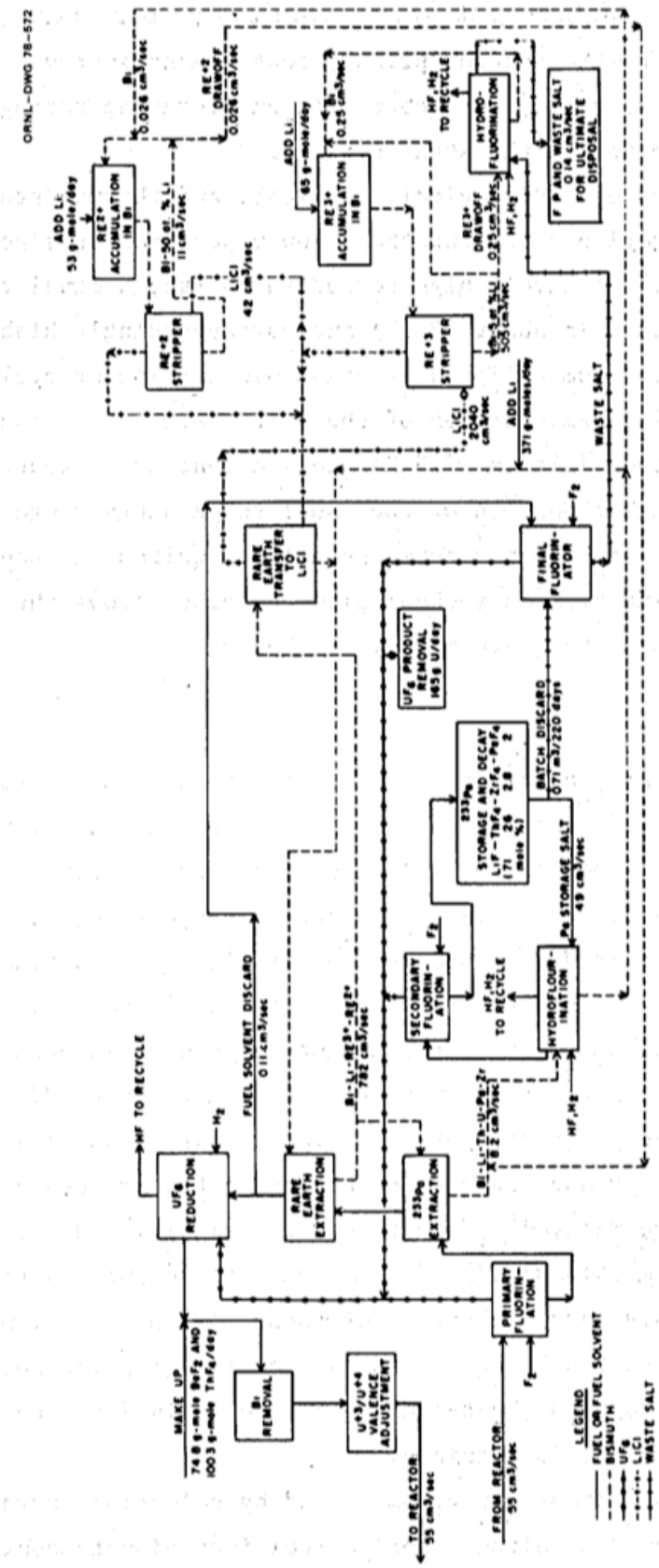

Figure R7.3. Schematic of a single-fluid reactor concept salt processing flow [Engel 1978].

R7-4. MODULES INTERFACES

This reactor concept is unique by the fact that the fuel is part of the coolant. The fabrication of solid fuel forms required by most reactor types is not required. It is likely that the heavy-metal containing chemical compounds would be added as powders for dissolution in the salt. Uranium enrichment requirements would depend on the type of MSR deployed and whether enriched uranium is required as a startup material. Some conversion steps for both uranium and thorium would be required to prepare the correct chemical compound (salt) for use as part of the coolant.

The fuel cycle back-end will need to process the waste materials withdrawn continuously from the molten salt coolant. Little detail is available on the treatment and packaging processes required. These processes are likely to be variants of those described in the "G"-modules.

R7-5. SCALING CONSIDERATIONS

Since this reactor concept is in large part a chemical plant, scaling rules for chemical plants are likely to apply.

R7-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The basic objective for a reactor concept is to "maintain an economical nuclear fuel cycle." The corresponding parameters for fuel cycle economic evaluation are as follows:

- Overnight cost for the reactor (including the $/kWe "specific" cost)
- Recurring operations and maintenance (O&M) costs
- Fuel cycle costs, normalized per unit of energy produced
- Levelized unit cost of energy.

In the development of the MSBR cost estimates were determined along with the cost estimate for a corresponding PWR (in 1971). The cost estimate for the MSBR was re-evaluated as part of recent (FY-2010) fuel cycle options studies at ORNL and the life cycle costs escalated to a recent date (2010) with the details provided in the paragraphs below. This economics analysis has been performed to provide a levelized cost of electricity unit cost (LCOE) based on scaling of detailed cost estimates developed as part of the MSBR program and life cycle cost levelization methodology based on the G4-ECONS model.

The only other cost study found of recent vintage was a levelized electricity cost study by Ralph Moir of Livermore National Laboratory and published in *Nuclear Technology* (Moir 2002). Both studies are summarized in the Table R7-2 below

Table R7-2. Reference costs from two recent MSR Life Cycle Cost Analyses (2012 const $ assumed ~ 2010 const $).

	Low	Reference NOAK	High
(Moir 2002) 1000MWe MSR [Const yr 2000$]	N/A	Overnight capital; $1548/KWe LCOE: $38.4/MWh	N/A
(ORNL 2010 unpublished) 1000MWe {2010$]	N/A	Overnight: $4000/KWe LCOE: $63.5/MWh	N/A

Historical Estimates. Cost estimation of the MSR has the benefit of a reasonably comprehensive conceptual design and cost study done for a full-sized (1000 MWe) plant prepared shortly after the MSRE at Oak Ridge was shut down. This 180 page report, *Conceptual Design Study of a Single-Fluid Molten-Salt Breeder Reactor* was issued in June 1971 as ORNL-4541 [Robertson 1971]. This report contains process layouts, chemical flowsheets, energy and material balances, commodity lists, equipment descriptions, and life cycle costs for a complete fuel cycle system including both the reactor plant and a

self-contained chemical processing plant for treatment of the salt bearing the dissolved fission products and other fuel components. Availability of this ORNL report made it possible to prepare an updated parametric life cycle cost estimate based on the following economic and institutional changes from 1970 (when the estimate was prepared) to the present day (2010):

1. General escalation/inflation
2. A much more stringent regulatory environment
3. Greater quality assurance and inspection requirements
4. Permitting costs reflecting more stringent environmental regulations
5. Increased recognition of non-proliferation requirements.

Fortunately, at the time the MSR estimate was prepared, there was also available detailed capital cost information on the 1970 vintage PWR prepared by the same estimating team. A side-by-side, account-by-account comparison is printed in ORNL-4541[Robertson 1971] as Table 15.1. Since we know how to what extent the life cycle costs for today's new PWRs have increased since 1970, we can examine the factors behind the increase (beyond general inflation) which might also be applicable to a MSR today.

Table R7-3 shows the rolled up comparative costs prior to preparation of this 2010 MSR estimate. All of the costs, including the levelized "mills/kW-h" busbar electricity generation costs, in the "1970 MSR" column come directly from the ORNL-4541 report and are reported in 1970 constant dollars. The "1970 PWR" column includes PWR capital costs from the ORNL MSR report. The other PWR figures of merit given (capacity, factor, levelized electricity costs, etc.) are based on actual cost experience in the early 1970's for this vintage 1000-MWe PWR and are also in constant 1970 dollars. The third column, 2010 PWR cost, is based on projections for today's Generation III+ PWR of comparable size, such as the Westinghouse AP-1000. The values are in today's (2010) constant dollars. The levelization technique used to obtain unit electricity costs for the 2nd and 3rd columns is described in the *Global Nuclear Energy Partnership Economic Tools, Algorithms, and Methodologies Report* [Shropshire 2009a]. Economic parameters for the 2010 PWR, including its "once-through" fuel cycle, are presented in the 2009 *Advanced Fuel Cycle Cost Basis* report [Shropshire 2009b]. Along with the costs of labor and costs of equipment, commodity (concrete, steel, etc.) quantities became the basis of a "bottom-up" estimate for the reactor "overnight" cost, which included direct, indirect, owner's costs and contingency costs. The "all-in" cost includes the cost of financing (interest during construction) for the reactor project, and sums up all the costs incurred prior to commercial operation. Such "bottom-up" estimates were prepared for both the MSR and PWR in 1970.

The 2010 PWR costs are based on adjustments to financial data submitted by utilities to economic regulators. ([Shropshire 2009a] and Module R1 of this update reference the sources of much of this data). No detailed "bottom-up" estimates are publicly available for these plants because of the proprietary nature of such data. It should be noted that the costs in Table R7-10 are for "Nth-of-a-kind" or NOAK reactors for which the benefits of licensing, construction, and operational learning relative to the "first-of-a-kind" or FOAK units have been realized. Many of the LWR reactor projects now being licensed are essentially FOAK projects and all-in capital costs in the range of $3500 to $8000/kWe are predicted.

Table R7-3. Summary Nth-of-a-Kind (NOAK) Cost Data Available Prior to Preparation of 2010 Parametric Estimate.

Attribute	1970 MSR	1970 PWR	2010 PWR
Reactor net electric power capacity (Mwe)	**1000**	**1000**	1000
Capacity factor	**80%**	60%	90%
A II-in Capital Cost ($/kWe) (Const yr-of-est $)	**202.6**	**200.7**	4000
Plant economic life (for capital recovery)	**20**	20	60
Plant Regulatory life	**40**	40	60
Levelized costs			
Capital Recovery	**4.0**	3.7	38.6
O&M incl capital upgrades & replaceables	**0.5**	0.9	10.2
Fuel Cycle (MSR includes proc. eqt cap recovery)	**08.**	.9	5.9
D&D of reactor	**0.0**	0.1	1.0
Total	**5.3**	7.6	55.7
Carbon steel required[1] (MT) for construction	**2333.8**	40000	42000
Concrete required (cubic meters)	**79696**	75026	
Hastelloy-N required (lb) for construction	**638000**	0	0
Graphite required (lb) for construction	**730000**	0	0
1. MSR# does not include containment or structural steel (bolded values are from ORNL-4541)			

It should also be noted that the costs considered in the 1970 ORNL study and this study do not include the costs to develop and demonstrate MSR technology, nor the costs of prototype or first-of-a-kind (FOAK) plants.

Approach to Preparation of 2010 MSR Estimate. The cost estimate in ORNL-4541 was examined in four different areas: capital cost, non-fuel operations and maintenance (O&M) costs, fuel cycle costs, and decommissioning costs. Each of these is addressed below. It is first necessary, however, to identify and list some base assumptions regarding the hypothetical MSR which have effects throughout the estimate. These include the following:

1. Thermal Power: 2250 MWth; Net Electrical capacity: 1000 MWe;
2. Thermodynamic efficiency: 44%
3. Electricity production 7 billion kilowatt-hours per year
4. Capacity factor: 80%
5. Fuel cycle: Closed thorium/U-233 cycle with both fertile and fissile materials incorporated in a single fluid molten salt mixture
6. Breeding ratio : 1.06; Fissile yield: 3.3%; Doubling time 22 yrs
7. Steam Rankine Cycle with single turbine/generator
8. Salt composition: 71.7 mole% LiF (Li-7 enriched); 16.0 mole % BeF2;
9. 12.0 mole % ThF4; 0.3 mole % UF4 (mostly U-235)
10. Material balance basis: equilibrium cycle established, only fertile ThF4 feed
11. Moderator: Graphite; core components replaced every 4 years
12. Reactor cell diameter and height: 72 ft dia; 42 ft high

13. Average overall core power density: 22.2 kW/liter
14. Salt temperature: ~700C
15. Startup fissile material assumed in ORNL-4541 report: U-233 from a stockpile
16. Startup fissile material assumed for this report: 19.95% U-235 LEU (alternate assumption made for non-proliferation considerations)
17. Chemical processing cell located in same building as reactor; costs of chemical processing equipment, but not hot cell structure, included in fuel cycle cost.
18. Percent of salt replaced annually: 6.67% of initial inventory incl ~8000 kg ThF_4
19. Ownership and plant financial environment: Regulated private utility
20. Cost basis: Nth-of-a-kind plant
21. MSR fleet size assumed for sizing of support facilities such as lithium-7 enrichment and salt purify
22. Containment dome: Yes: 134 ft diameter, 189 ft height.

Plant Capital Cost. Since the authors of ORNL-4541 found that the capital cost per kilowatt for the MSR was nearly identical to that of the PWR, it is useful to see if that finding would still hold today. The first step taken in this analysis was to escalate the PWR cost of ~200$/kWe in ORNL-4541 to today's dollars. Using the Handy-Whitman [Whitman 2008] nuclear construction cost index from 1970 to 2009 a factor of 6.7 results, giving a value of $1350/kWe for today's PWR. This value is known to be low by a factor of ~3 for the projected NOAK 1000-MWe class PWR's being considered for deployment today. (This 2012 update to the *Advanced Fuel Cycle Cost Basis* report suggests a range of $2300/kWe to $5800/kWe for the NOAK overnight cost of a generic LWR. This implies that non-direct construction factors other than inflation have driven up capital costs since 1970. Among these factors would be regulatory, financial, schedule, start-up, quality assurance, ES&H, and security related requirements and factors which have changed from 1970 or did not even exist in 1970. For the following reason it is assumed that these factors would affect the MSR the same way the PWR was affected. The following arguments are presented in this regard:

- Despite the low pressure of the MSR system, the containment must be designed to withstand external threats such as an airplane crash. This is a requirement which has changed since 1970.
- In addition to being a nuclear plant, the MSR is also a small radiochemical plant operating in a hot cell. In addition to nuclear-related hazards such as criticality and radiotoxicity, there are also concerns associated with high-temperature operations, such as fire safety, equipment reliability, and treatment, packaging, and disposition of high level waste in halide or halide-derived chemical forms.
- The construction of the MSR requires the use of additional materials for which the unit costs (cost per unit mass) are likely to be higher than for the typical materials used in LWRs and their cores, such as carbon steel, stainless steel, and zircalloy. Among the structural materials are high purity, high temperature graphites and Hastelloy-N. (The special salts will be discussed under fuel cycle costs.) Initial analysis indicates that the unit costs for these materials, especially the graphite, have risen considerably from the values used in the 1970 ORNL study. Table R7-4 shows the unit costs and material requirements for the MSR and PWR.
- The 1970 estimate had MSR indirect costs as only 35% of direct costs. For most of today's nuclear projects, these "people-related" indirect costs are now a much higher fraction of or are equal to the direct construction costs. This is a result of today's regulator-mandated requirements for quality control, design certification, inspections, etc.

Table R7-4. Construction commodities and unit costs.[1]

Material	Quantity for 1000 Mwe MSR Construction and Initial Inventory	Mass Units	1970 Unit Cost	2010 Unit Cost
Li-7 Enriched Lithium Fluoride Salt	60816	kg LiF	33.1	473.0
Beryllium difluoride salt	24430	kg BeF2	16.5	135.7
Thorium as Thorium Tetrafluoride	90540	kg Th	8.6	65.0
Hastelloy-N	638000	lb	18.2	20.0
Graphite	730000	lb	10.7	80.0
Carbon Steel (non-strucutral, non-containmnet)	2334	MT	1323	500.0
Concrete	49696	cubic meters	134.7	98.0
1. Bolded values are from ORNL-4541.				

There are also factors which can have a beneficial effect on capital costs vis-a-vis the LWR:

- Because of the high (~700C) coolant temperature, the MSR could be adapted to a more efficient Brayton cycle utilizing a gaseous working fluid. The higher thermodynamic efficiency would lower the capital component of the overall electricity cost by allowing more electricity production from the same 2250 MWth thermal power capacity.
- Lower plant operating pressure results in equipment metal fabrication thicknesses and weights that are lower than those for PWR components. This would allow more fabrication to be done domestically and in regional foundries. Transportation cost to the plant site would also be greatly reduced.
- The MSR concept is readily adaptable to the "small reactor" more flexible siting requirements now envisioned for LWRs such as the NuScale© and mPower© concepts.

It is arguable that are no reasons or "show-stoppers" that would cause the overall specific capital cost ($/kWe) of an NOAK MSR to significantly exceed that for the PWR. The ranges for the NOAK LWR suggested in the 2009 and 2012 updated Advanced Fuel Cycle Cost Basis report should be applicable to the NOAK MSR. These are:

	2009	2012
Low	2300 $/kWe	2300
Nominal (most likely)	3500 $/kWe	N/A
High	5000 $/kWe	5800
Suggested MSR value	4000 $/kWe	N/A

This means that the recommended "all-in" cost for a 1000-MWe NOAK MSR would be around $4 billion. It should be noted that for the current analysis the $/KWe cost for all of the "raw" or "base" construction commodities, not including the salts, would be less than $100/KWe. This is also true of PWRs, for which an analysis by Per Peterson of UC-Berkeley [Peterson 2009] shows are on the order of $35/kWe. This means that most of overall direct material costs for construction of any kind of reactor are "value-added" costs in going from raw materials to specifically fabricated parts or equipment, or materials requiring special installation requirements such as "nuclear-grade" concrete. These "people-related" or costs with high labor content will be present regardless of the selected reactor technology.

MSR NON-FUEL O&M COSTS. ORNL 4541 presents a list of calculated annual O&M costs and a list of major MSR materials requiring periodic replacement. The ORNL-4541 Tables are reproduced below as Table R7-5 below.

Table R7-5. Annual costs from Cost estimate in ORNL 4541 (Robertson 1971).

Table D.15. Cost of replacing reactor core assemblies in the MSBR

In thousands of dollars

Cost of assembly	
Hastelloy N – see Table D.4	1,092
Graphite – see Table D.5	3,753
	4,845
Chargeable power revenue loss during core assembly replacement[a]	
Special labor cost per replacement[b]	500
Total cost per replacement	5,345
Effect on power production cost, mills/kWhr[c]	0.17

[a]It is assumed that the MSBR core assembly can be replaced during the plant downtimes for inspection and repair of other equipment, such as the turbine-generator, which are accommodated by the 80% plant factor, and no additional plant outage is chargeable against core replacement.

[b]The labor force for making core replacements is assumed to be in addition to the normal plant operating and maintenance crew.

[c]While various methods could be used to estimate the cost of future core replacements, a sufficiently representative and straightforward method is to assume an extra amount charged per kilowatt-hour, which is set aside, at 8% interest compounded annually, so that at the end of four years the total cost of a replacement will have been accumulated.

Table D.16. Estimated annual costs for plant operation and maintenance[a]

Staff payroll[b]	$ 800,000
Fringe benefits[b]	80,000
Subtotal – plant staffing	880,000
Consumable supplies and equipment	400,000
Outside support services	140,000
Miscellaneous	80,000
Subtotal	1,500,000
General and administrative	225,000
Coolant-salt makeup[c]	9,000
Nuclear liability insurance	
Commercial coverage (net)	240,000
Federal Government coverage	67,500
Total direct annual cost	2,061,500
Fixed charges on operation and maintenance working capital	38,800
Total annual cost	$2,080,300
Contribution to power cost[d]	0.30 mill/kWhr

[a]Based on cost breakdown and computation prescribed in NUS-531 (ref. 119). The values agree reasonably well with those reported by Susskind and Raseman (ref. 121). Costs do not include chemical processing, which is included in the fuel-cycle cost, nor special costs associated with periodic replacement of the core graphite.

[b]Based on NUS-531 (ref. 119) recommended values for July 1968 escalated 8%.

[c]Makeup cost assumed to be 2% of inventory

It can be seen that the total O&M contribution to the busbar cost totals 0.47 mills/kW-h in 1970 constant dollars. The comparable number for today's PWR would be over 20 times higher at ~10 mills/kW-h. There are several factors which have caused this to increase at a rate greater than general inflation. For example the 1970 estimate above has $888K/year for staffing costs (not including the chemical plant). This average loaded salary of $11,000/per person per yr (1970) represents a staff of 80. ES&H, security, regulatory, and training-related requirements have driven the number of people required to operate a 1000-MWe nuclear plant of any type to a few hundred permanent staff and more could reasonably be expected because fuel processing plant staff is required. For the 2010 MSR estimate a staff of 250 is assumed at an average loaded salary of $110,000/ per person per year. Table R7-6 shows the other adjusted O&M costs. These are taken from an estimate [Gen IV 2007] for today's PWR in the 1000-MWe size class.

Table R7-6. Annual O&M and Non-Salt Material Replacement Costs (Const 2010 dollars).

O&M Categories					**Annual $M**	**mills/kwh**
Staff Payroll incl fringes (250 people @ 110K @ ave)					27.500	
Consumables					21.500	
Subcontracts & miscellaneous					5.000	
G&A incl regulation					11.000	
Salt make-up (2% of inventory)					0.642	
Insurance (private and federal) + taxes					6.000	
Charges on working capital					0.000	
Subtotal					**71.642**	**10.22**
Major core structures replaced every 4 years						
Labor cost			5.00	div by 4	1.25	0.18
Graphite core structures	351382 lb	80 $/lb	28.11	div by 4	7.03	1.00
Hastelloy-N structures	134830 lb	20 $/lb	2.70	div by 4	0.67	0.10
					8.95	**1.28**
TOTAL ANNUAL O&M incl REPLACEABLES						**10.31**

The costs for replaceables utilize the unit commodity costs assumed in Table R 7.4 for Hastelloy-N and graphite. A major uncertainty in the annual costs is the handling of waste and the staffing involved. Waste management was not substantially addressed in ORNL-4541.

MSR Fuel Cycle Costs. The major claimed cost advantage for the MSR over other reactor types is in fuel cycle costs. In the 1970 estimate, the advantage from the fuel cycle component of the busbar electricity cost was over 4 to 1 (0.8 mills/kW-h for the MSR and 2.9 mills/kW-h for the PWR [the latter number based on actual PWR experience]). From the 2010 analysis there still appears to be an advantage on the order of 30% in terms of busbar cost for the MSR against the PWR operating on a UOX once-through cycle. The escalation above inflation observed for O&M and capital costs is assumed to not exist for the fuel cycle steps. The cost advantage exists for the following reasons:

- Since the MSR is assumed to be an "equilibrium" breeder, only relatively inexpensive ($65/kgTh) fertile material is required. PWRs are operated on low-enriched UOX costing at least $1600/kgU for fresh reload UOX fuel assemblies. The source material utilization for PWRs is less than 1%, i.e. over 99% of the initial mined U ends up either in the spent fuel or in enrichment plant tails. The source material utilization for mined thorium is essentially 100% or higher in the breeder mode.
- The only fissile required is the 19.95% U-235 material required for reactor startup. The cost of this material (over $13,000/kgU) is amortized over many years of operation.
- The molten salt reactor concepts eliminates the need for separate fuel fabrication and reprocessing services, and transportation to and from the reactor for fresh and spent fuel assemblies. It incorporates a totally "integral" fuel cycle.
- The fissile inventory of the overall systems, and the annual fertile makeup requirement, is very low. Just over 8000 kg of ThF4 per year are needed to sustain the reactor.

The fuel cycle assumptions and cost implications used in this analysis are as follows:

1. The material balances for both the initial inventory and salt replacement are complex and the extensive material balance tables and flowsheets from ORNL-4541 are not repeated here.
2. The LiF salt must be over 99.9% enriched in the isotope lithium-7. No large scale facility exists for this purpose, nor is a design and cost estimate for such a facility available as of 2010. The "natural" lithium product should be readily available at $4000 to $6000 per ton of lithium carbonate (Li_2CO_3). Discussions with isotope experts at ORNL indicate that the 99.99% Li-7 material could cost as much as $6 per gram Li, but this would be for kilogram type quantities. If a large plant (700 MT Li/yr of feed and 190 Kg of enriched Li product) capable of producing this material for the initial inventories and makeup salt for 32 GWe of MSR capacity could be constructed, the unit cost ($/g of enriched Li) should scale downward.
3. A beryllium salt, BeF2, is also required. Its unit cost has increased significantly from the 1970 estimate. This is probably due to its use as a strategic defense material and the significant ES&H issues associated with its handling.
4. The overall "flibe" salt must be very pure. A purification step is required, but no costs for this were presented in the 1970 estimate. An arbitrary cost of $100/kg of salt is assumed for a large facility servicing multiple MSRs.
5. The long term forward average price for thorium of $65/kgTh is from the 2009 *Advanced Fuel Cycle Cost Basis* report [Shropshire 2009a]. (See Module A2 for updated values and ranges.)
6. The 1970 report did not include waste management costs such as conditioning, packaging, and disposal costs for GTCC and high level fission product wastes. For this 2010 analysis unit waste handling costs from the 2009 Advanced Fuel Cycle Cost Basis report were applied to particular classes of fission products, such as volatiles, alkali metals, etc.

Table R7-7 itemizes the unit material costs used in both the 1970 and 2010 studies. Costs are normalized to $/kg where possible.

Table R7-7. Unit Cost Values for 1970 and 2010 MSR Cost Studies.

Item	1970$ Cost Value	Measurement Units	1970 Cost in $/kg	2010$ Cost Value	Measurement Units	2010 Cost in $/kg
Enriched LiF salt	15	$/lb LiF	33.1	473	$/kgLi	
Beryllium salt	7.5	$/lb BeF2	16.5	136	$/kgBeF2	
Thorium salt	6.5	$/lb ThF4	14.3	65.0	$/kgTh	
U-233	13	$/gram U as UF4	13000	n/a		
Pa-233	13	$/gram Pa as PaF4	13000	n/a		
93.5% U-235	11.2	$/gram U as UF4	11200	n/a		
19.95% U-235				13781	$/kgU	
Graphite	11	$/lb	24.255	80	$/lb	176.40
Hastelloy-N	8 to 38	$/lb (14 used)	18 to 80	20	$/lb	44.10
Pu-239	9.3	$/g Pu	9300	n/a		
Salt purification			-	100	$/kg salt	
Carbon steel	0.6	$/lb	1.32	500	$/MT	0.50
Concrete	103	$ per yd3 (installed)		98	$/m3	n/a
Stainless steel	1.2	$/lb	2.65	3000	$/ton	3.31

Annual recurring costs for the fuel cycle materials are calculated by multiplying the unit cost ($/kg) times the annual “make-up” requirement (kg/yr) from the material balance. The costs for initial inventories are annualized and recovered using a fixed charge rate of 13.7%. The $13.5M 1970 cost for chemical process equipment has been escalated to $135M in 2010 dollars and is distributed over all of the operating years by use of a 13.7% fixed charge rate. Table R7.8 shows a summary of the fuel cycle costs in both millions of dollars per year and as a component of the overall busbar cost of electricity in mills/kW-h. The 2010 calculated value of 4.2 mills/kW-h is lower than the unit cost projected for PWRs operating on either a once through or partial recycle mode.

Table R7-8. Summary of Fuel Cycle Costs for 1970 and 2010 Estimates.

RE-CREATION of 1970 ESTIMATE								
Capital Recovery of Initial Inventories (A+B from Table D.2 of ORNL 4541)		Amount	Unit cost	Cost Units	Total cost ($M)	CRF	Annual cost ($M/yr)	**Unit cost (mills/kwh)**
Enriched Li salt (99.99% Li-7) as LiF		16373 kg Li	123	$/kg Li	2.01	0.1320	0.27	0.04
Beryllium salt as BeF2		24430 kg BeF2	16.54	$/kgBeF2	0.40	0.1320	0.05	0.01
Salt purification		85246 kg (LiF+BeF2)	0.00	$/kg salt	0.00	0.1320	0.00	0.00
Initial Thorium load (as ThF4)		90540 kg Th	19.03	$/kg Th	1.72	0.1320	0.23	0.03
Initial Uranium-233 (as UF4)		1286 kg U-233	13000	$/kgU	16.72	0.1320	2.21	0.31
Initial Protactinium-233 (as PaF4)		110 kg Pa	13000	$/kg Pa	1.43	0.1320	0.19	0.03
Initial Uranium-235 (as VHEUF4)		112 Kg U-235	11200	$/kgU	1.25	0.1320	0.17	0.02
Subtotal					23.54		3.11	**0.44**
Capital Recovery of Chem proc Eqt incl indirects (Item D from Table D.2)			13.5	$M		0.137	1.85	**0.26**
Annual Fuel Cycle Material & Service Usage (Item C from Table D2)								
Enriched Li salt (99.99% Li-7) as LiF		1092 kg Li/y	123	$/kgLI	0.134	---	0.13	0.02
Beryllium salt as BeF2		1629 kg Be/y	16.54	$/kgBeF2	0.027	---	0.03	0.00
Salt purification		5683 kg salt	0.00	$/kg salt	0.000	---	0.00	0.00
Thorium load (as ThF4)		8005 kg ThF4/y	14.33	$/kgThF4	0.115	---	0.11	0.02
Subtotal							0.28	**0.04**
O&M Costs for Chemical processing System (Item E from Table D2)					0.70	---	0.70	**0.10**
Production Credit								**-0.09**
TOTAL FUEL CYCLE COST					---			**0.76**

RE-Estimate with 2010 Unit Costs and no HEU								
FUEL CYCLE: Capital Recovery of Initial Inventories		Amount	Unit cost	Cost Units	Total cost ($M)	CRF	Annual cost ($M/yr)	Unit cost (mills/kwh)
Enriched Li salt (99.99% Li-7) as LiF		16373 kg Li	1757	$/kg Li	28.77	0.0847	2.44	0.35
Beryllium salt as BeF2		24430 kg BeF2	136	$/kgBeF2	3.32	0.0847	0.28	0.04
Salt purification		85246 kg (LiF+BeF2)	100	$/kg salt	8.52	0.0847	0.72	0.10
Initial Thorium load (as ThF4)		90540 kg Th	65	$/kg Th	5.89	0.0847	0.50	0.07
Initial Enriched Uranium (as UF4)		7522 kg U	13781	$/kgU	103.67	0.0847	8.78	1.25
(assume 19.95% U-235); req'd fissile (235) for Start Up is:	1500.72							
Subtotal							**12.71**	**1.81**
Capital Recovery of Chem proc Eqt (unrec cost 10x 1970 #) (no production credit)			135	$M		0.0847	**11.43**	**1.63**
Annual Fuel Cycle Material & ServiceUsage								
% of loaded salt inventory replaced per year =	6.67%							
Enriched Li salt (99.99% Li-7) as LiF		1092 kg Li/y	1757	$/kgLI	1.92	---	1.92	0.27
Beryllium salt as BeF2		1629 kg BeF2/y	136	$/kgBeF2	0.22	---	0.22	0.03
Salt purification		5683 kg salt	100	$/kg salt	0.57	---	0.57	0.08
Thorium load (as ThF4)		6030 kg Th/y	65.00	$/kgTh	0.39	---	0.39	0.06
Subtotal							**3.10**	**0.44**
Waste management incl geologic disposition (what is not incl in O&M)								
Volatile FPs		54 kg FP/yr	22500	$/kg FP			1.22	0.17
Alkali-metal FPs		51 kg FP/yr	6500	$/kgFP			0.33	0.05
Noble & Lanthanide FPs		120 kg FP/yr	6500	$/kgFP			0.78	0.11
							2.33	**0.33**
TOTAL FUEL CYCLE COST								**4.22**

Decontamination and Decommissioning Costs (D&D). End of life reactor D&D costs are usually calculated as a fraction of the direct costs if no detailed D&D estimate is available. The 1970 estimate did not include any D&D costs. D&D for this study is assumed to cost 25% of the assumed "all-in" capital cost or $1 billion in constant 2010 dollars. An escrow or sinking fund is collected annually during operations such that this amount is available at end of life to cover these costs. If a 7.5% discount rate is assumed, a little over $4M per year is required. The busbar cost component for this category is 0.6 mills/kW-h.

Total Life Cycle Busbar Cost or Levelized Cost of Electricity (LCOE). Table R7-9 Summarizes the "Mills/KW-h" or "$/MW-h" unit electricity generation cost results from the 1970 estimate and this study. The same figures of merit for today's new 1000-Mwe class PWR are also shown for comparison. The PWR is assumed to have a 60 year life and amortization period. The MSR is assumed to have a 40 year life and amortization period (although future MSRs would certainly be designed for 60 year lifetimes, the original MSRs designs considered a shorter lifetime). This account for the lower capital component for the PWR; however both are assessed at $4000/kWe.

Given the many uncertainties in the estimates, the 2010 MSR estimate falls well within the range projected for new PWRs. At this time no economic "show-stoppers" have been identified that would make this concept non-competitive. This study did not incorporate a complete uncertainty analysis, thus "deterministic" or single point values were used. In reality uncertainty ranges exist for all parameters and additional effort in the area of uncertainty analysis is recommended.

Table R7-9. Comparison of Busbar Generation Costs.

	1970 MSR	2010 MSR	2010 PWR
Capital	4.0	48.3	38.5
O&M	0.5	10.3	10.2
Fuel Cycle	0.8	4.2	5.9
D&D	0.0	0.6	2.0
Total (mills/kW-h)	5.3	63.5	56.6

R7-7. DATA LIMITATIONS

Molten salt reactors were considered to be attractive power producers because of favorable economic, fuel utilization, and safety characteristics. Rosenthal et al. were optimistic in their 1970 assessment [Rosenthal 1970]:

"The avoidance of fuel fabrication, the ease of processing, and the low fissile inventory should result in low fuel cycle costs."

It was thought that the cost of handling radioactive fluids in conjunction with reactor operation would be offset by other compelling features, including, higher temperature leading to increased thermal efficiency, low pressure operation, significant safety margin related to boiling margin. However, limited economic analyses of the MSR concepts have been performed.

The following issues represent significant cost uncertainties for extrapolating MSRE experience to a power reactor:

1. The cost of handling radioactive fluids at the reactor site. Many institutional issues also exist,
2. The flexibility to startup with ^{233}U, ^{235}U or Pu allows the core to be started with the most economic (or prudent) of the available options.
3. The availability of high temperature power conversion systems to utilize the available temperature of salt fueled reactors.
4. Length of time graphite can be used in the vessel (neutron damage) or in contact with the fuel salt (contamination) before requiring replacement.
5. Cost of salts and the ability process them for continuous use compared to the need to replace them periodically.
6. Capital costs, including the reactor and salt processing equipment.

7. Material costs, particularly the increased costs of nickel-based alloys compared to that of stainless steel.
8. Radiation induced embrittlement of Hastelloy-N was a concern for extrapolating that material from use on the MSRE to the MSBR and a modified version of the alloy using titanium or hafnium as a stabilizer was thought to overcome this issue.
9. Graphite dimensional changes with flux and temperature were a significant concern for a power reactor application requiring periodic replacement of the graphite moderator

R7-8. COST SUMMARIES

A summary of the cost parameters developed from the recent ORNL study are provided in Table R7-10. These results indicate that the MSBR has a lower fuel cycle cost and a larger levelized electricity cost (~10%). The primary driver for the larger levelized electricity costs is the assumption that the PWR lifetime is 60 years (as is the current experience), while the MSBR is assumed to be 40 years. With the same reactor lifetime the overall levelized electricity cost is essentially the same for the MSBR and PWR. No cost estimates were prepared for the DMSR, although it would be expected to have a lower capital cost than the MSBR because of the lack of a need for the fuel salt processing system. The DMSR would be expected to have a larger fuel cycle cost because of the need for enriched uranium.

Table R7-10. Comparison of Fuel Cycle Component and Total LCOE of MSR and PWR systems.

	MSR (1970)	MSR (2010)	PWR (2010)
Fuel Cycle Costs (mills/kWe-hr)	0.8	4.2	5.9
Levelized Electricity Cost (mills/kWe-h)	5.3	63.5	56.6

- An update of economics evaluation performed for the MSBR indicates a levelized electricity cost that is approximately 10% higher than the LWR reference. With a comparable reactor lifetime, the MSBR would have a levelized electricity cost that is comparable to the LWR reference. The DMSR.
- The MSR has safety advantages and disadvantages in comparison with the LWR reference. The advantages include low excess reactivity, lower radionuclide inventory, low pressure system, passive decay heat removal, fuel is already molten – fuel meltdown accident is not possible. Disadvantages include contamination of primary system, the enhanced production of tritium, high temperature operation, and chemical hazards associated with fuel processing system.
- While two molten salt reactors have been built and operated, the average technology readiness level can be characterized as “proof of principle” (TRL 5-6) and considerable research and development as well as significant amount of technology development will be required to bring the system to the level of commercial operation.

For comparison to other reactors in the “R” Modules a “What-it-Takes” overnight cost range is required. The values selected in Table R7-11 are based partly on the recent ORNL estimate above.

Table R7-11. “What-It-Takes” Specific Overnight Cost for Liquid-Fueled Molten-Salt Reactor.

What-It-Takes Overnight Cost:	Low (2012$)	Nominal (2012$)	High (2012$)
Thermal MSR System	2200	5500	9000

Assigning a range to this value is difficult because no uncertainty analysis was performed as part of the recent ORNL study. The low value selected here was based on taking the Moir study (Moir 2002) specific overnight cost of $1584/kwe and escalating it to 2012$ using the escalation Table at the beginning of the 2012 Update report. A value of $2200/kWe results. (Moir’s study seems to be based on optimistic parameters, such as a capacity factor of 90%.). Since this reactor concept is so different from solid-fueled concepts, and has such a large-component of its cost dedicated to chemical systems, the

capital cost risk is very high. This is especially true given the recent cost experience with nuclear chemical facilities such as reprocessing plants. For this reason a high overnight cost value greater than the other R-Module reactor types was assigned. The nominal value is assumed to lie approximately in the middle of this range.

For 2015, the values in Table R7-11 were escalated from 2012$ to 2017$ using an escalation factor of 1.088 from the table at the beginning of this report followed by appropriate rounding. The following" What it Takes" Table R7-12 results:

Table R7-12. "What-It-Takes" Specific Overnight Cost for Liquid-Fueled Molten-Salt Reactor.

What-It-Takes Overnight Cost:	Low (2015$)	High (2015$)	Mean (2015$)	Mode (2015$)
Thermal MSR System	2400	9800	6100	6000

Figure R7-4 below shows the uncertainty distribution and parameter for the thermal MSR evaluated in this module:

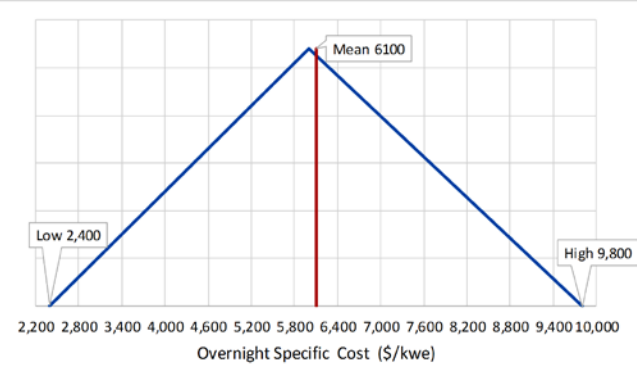

Figure R7-4. Distribution and parameters for MSR specific overnight cost

The work performed here represents a very preliminary review and assessment of MSR technology. Proposed future work include:

- Assessment of a minor actinide burning MSR, such has been proposed elsewhere, as an additional modified open cycle concept. With these systems, the reactor is fueled with used LWR fuel with the fuel circulated to achieve a high burnup of actinides. Both thermal spectrum and fast spectrum systems should be considered along with the used LWR fuel processing based on fluoride volatility.

A report on the design aspects of the Fast Spectrum MSR options was recently prepared at ORNL (Holcomb 2011). No cost estimate was prepared as part of this study; however, some quantitative economic conclusions might be drawn by comparing recent reports.

R7-9. SENSITIVITY AND UNCERTAINTY ANALYSES

No sensitivity studies have been recently undertaken for MSR systems. This will likely become an objective for further MSR System Assessment tasks.

R7-10. REFERENCES

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Module R8

Solid-Fueled Salt-Cooled Reactors

Module R8

Solid-Fueled Salt-Cooled Reactors

R8.MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Examples salt-cooled HTR estimates from ORNL were utilized to develop cost estimates combined with engineering judgment of the differences with LWRs. Some bottom-up estimating data was available.

R8.RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R8.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - Not aware of any new cost information (Holcomb, et al. 2011).

R8-1. BASIC INFORMATION

Liquid-fueled Salt-cooled reactors, more **commonly referred to in the recent literature as Advanced High Temperature Reactors** (AHTRs) represent a class of reactors that involve the use of fluoride salts which serve as the reactor coolant material and can accommodate reactor coolant outlet temperatures of up to 750C. (It should be noted that a liquid-fueled, high temperature reactor has a molten-salt coolant that also contains the fuel. This reactor is discussed in Module R7 and is usually what is meant when the term "MSR" is used. The term AHTR might also be applied to advanced high-temperature gas-cooled reactors, which are discussed in Module R3. **For these reasons a better acronym for the subject of this module would be FHR (Fluoride-salt High-temperature Reactor).**

This reactor type borrows design characteristics from several reactor types:

- Coolant: Molten salt nearly identical to that for MSRs
- Fuel: High-temperature tolerant TRISO particle fuel used for HTGRs
- Moderator: Graphite moderator and fuel support structures (like prismatic HTGR)
- Reactor Vessel: Pool configuration similar to SFR
- Power cycle: Rankine (Brayton cycle is possible)

The reactor can produce both process heat (hot salt pumped to process) and electricity (using a high-efficiency Rankine steam cycle in the near term). Only one detailed cost estimate has been prepared for this reactor (Holcomb, Peretz, and Qualls 2011) and forms the basis for most of the information (reference case) in this module. Work on the FHR concept is ongoing at ORNL, the University of California at Berkeley, and other universities. The reference cost-estimate was developed using EEDB (Energy Economic Data Base) and G4-ECONS (Gen IV Excel Computation of Nuclear Systems) tools

developed at ORNL. Use of these tools and scaling relationships allows one to build up an estimate for an advanced reactor using detailed historical LWR cost information.

R8-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Basic Reactor Features. The reference reactor operates at a high temperature, with the fuel salt core exit temperature in the range of 700 to 750 °C and includes a Rankine steam power conversion system with a 45% power conversion efficiency. The assumed thermal power capacity is ~3400 MW(th) and the electrical capacity ~1530 MWe. The system is passively safe and utilizes heat rejection via a Direct Reactor Auxiliary Cooling System (DRACS). The capacity factor is assumed to be similar to that of LWRs, i.e. ~90%. The fuel consists of enriched uranium (ceramic U compounds such as UOC or UO2) TRISO particles imbedded in graphite fuel plates. Until a more technically mature and economic method for reprocessing particle fuel emerges, this reactor would likely operate on a once-through fuel cycle.

R8-3. PICTURES, DIAGRAMS, AND DEPLOYMENT STATUS

Figure R8-1 below (from a University of California website) shows the basic reactor concept and how it can be utilized for electricity and/or process heat applications. Note that one application that garnered considerable interest was the use of process heat for hydrogen production. The reactor in the figure below is a pebble-bed example. Like the HTGR both pebble-bed and prismatic fuel configurations are possible. ORNL has concentrated on the prismatic option and UC Berkeley on the pebble-bed option. Figure R8-2 shows the prismatic plate fuel concept used for the reference reactor in the ORNL study. The fuel configuration is shown in Figures R8-3 and R8-4 below.

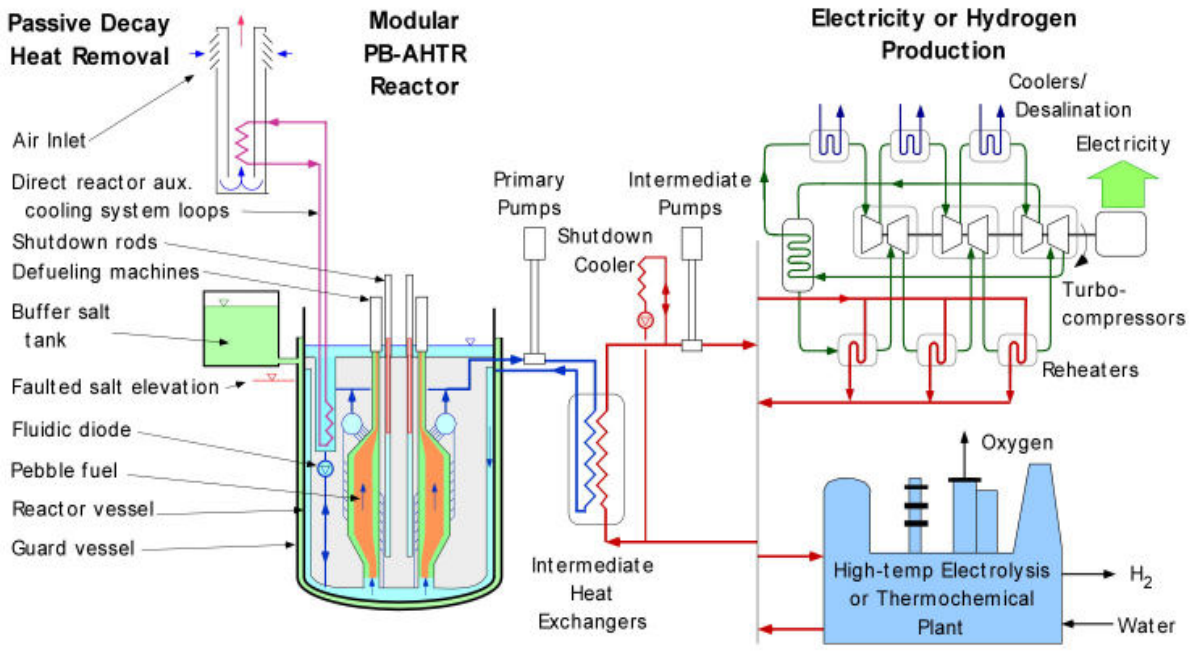

Figure R8-1. Basic ATHR-FHR Concept and its Applications (Pebble-bed example).

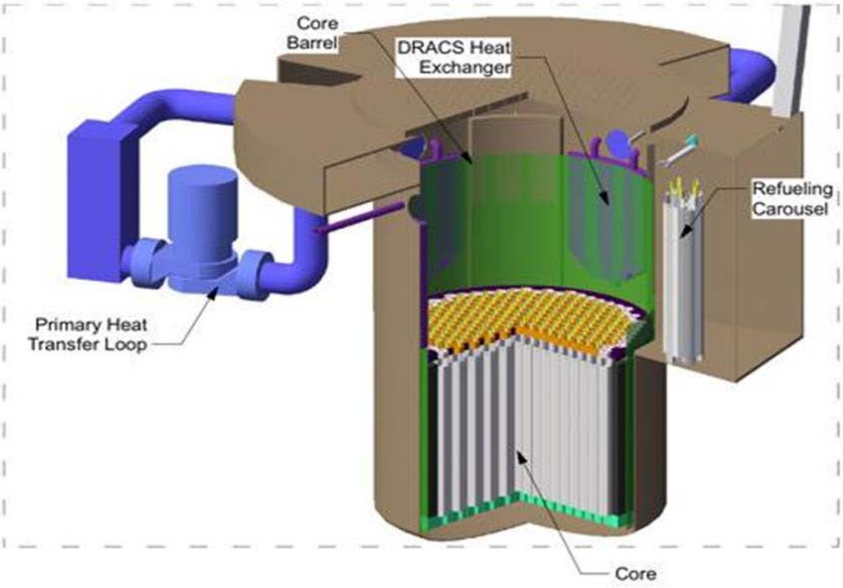

Figure R8-2. Prismatic-fueled reference AHTR-FHR concept.

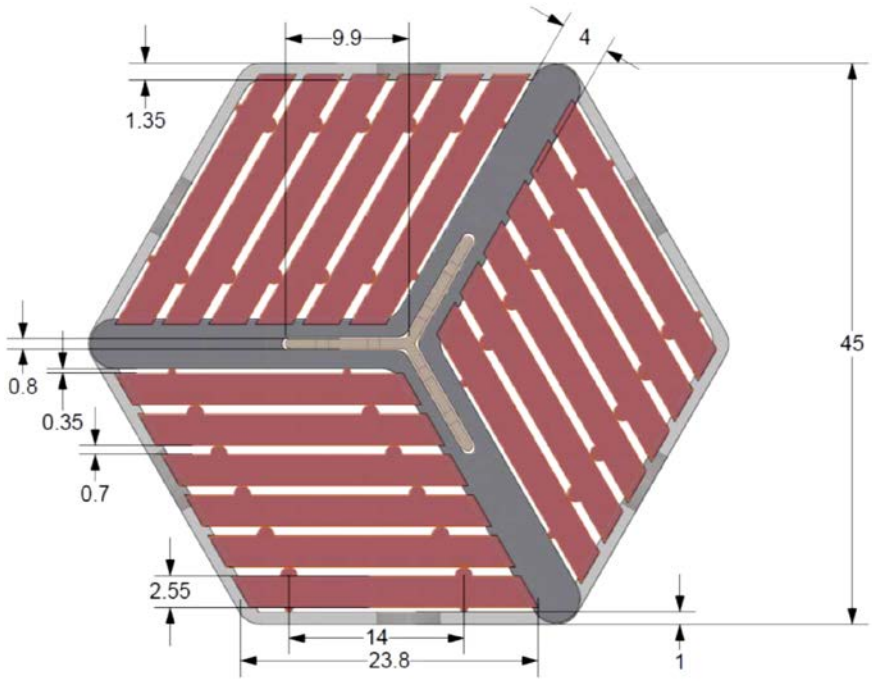

Figure R8-3. Top-down View of the reference AHTR fuel assembly showing beveled rectangular prism graphite fuel plates.

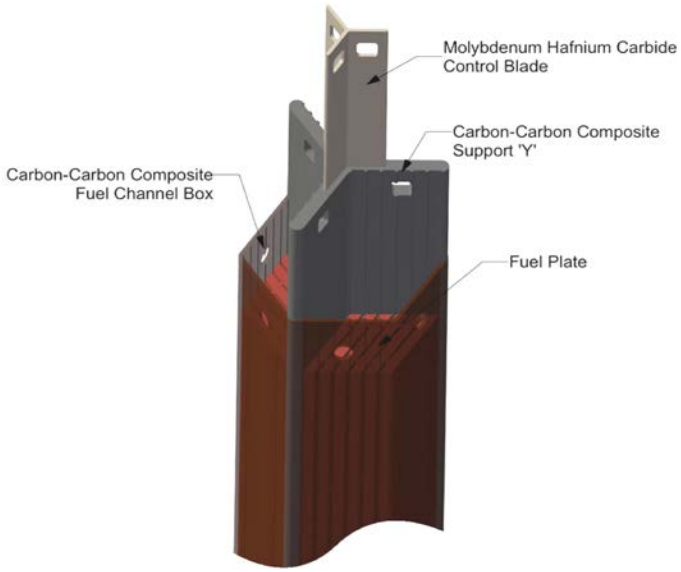

Figure R8-4. 3-dimensional side view of reference AHTR fuel assembly.

A major economics-influencing design factor for this reactor is the fact that a liquid-coolant allows much more heat to be removed from the TRISO fuel than if the coolant were a gas such as helium or carbon dioxide. A higher power density for the AHTR as compared to the HTGR is the result.

R8-4. MODULE INTERFACES

The interfaces would be much the same as for HTGRs and TRISO fuel (Modules R3 and D1-3). Treatment, packaging, and disposal of salt waste would require development and could benefit from work on Electrochemical Reprocessing (Module D2/F2).

R8-5. SCALING CONSIDERATIONS

Detailed information on scaling is described in the ORNL reference (Holcomb, Peretz, & Qualls 2011).

R8-6. COST BASES, ASSUMPTIONS, AND DATA SOURCES

The only data source to date on this reactor concept is the recent ORNL Technical Memorandum 2011/364 (Holcomb, Peretz, & Qualls 2011; http://info.ornl.gov/sites/publications/files/Pub32466.pdf). The following data in Table R8-1 are extracted from that report. Note that the authors started with a reference PWR to develop the estimate as was the case with the MSR in Module R7. G4-ECONS was used to calculate the LCOE, and the assumptions and details are in the reference report. Note that the specific cost is lower than for the reference LWR. The major contribution to this decrease is the higher thermodynamic efficiency of the FHR system (43%) as compared to the LWR (33%). This means that a reactor of similar size in terms of concrete and steel can produce significantly more electricity. Note that the specific costs shown in Table R8-1 below are based on the overnight cost. The ones presented in the ORNL report (Holcomb, et al.) are based on the "all-in" cost, which includes interest during construction.

Table R8-1. Comparison of Overnight and Total LCOE of FHR and PWR systems.

	FHR with 19.75% U-235 fuel (2010$)	FHR with 9.0% U-235 fuel (2010$)	System 80+ PWR (2001$)	1134 MWe PWR (2010$)
Overnight Cost incl initial fuel load ($/kWe)	2900	2700	<2000	3532
Levelized Electricity Cost (mills/kWe-h)	51.6	43.1	30.6	48.2

R8-7. LIMITATIONS OF COST DATA

There are many technical issues related to the salt and high-temperature materials which are still outstanding. These and other technical issues which influence cost are discussed in the MSR Module R7. The cost of the isotopically-enhanced lithium fluoride salt could be a major issue.

R8-8. COST SUMMARIES

Low, nominal, and high values are reported for the specific overnight cost, which suggests the use of a triangular distribution for uncertainty analysis. Table R8-2 shows a range for NOAK reactors which should be consistent with the other Reactor "R" Modules.

Assigning a range to this value is difficult because only a limited uncertainty analysis (single-variable sensitivities) was performed as part of the recent ORNL study. The low value selected here was based on taking the MSR low value (2200 $/kwe) downward to account for the more conventional reactor core and solid-fuel handling systems. The high value for the MSR ($9000/kwe) was also lowered to $8000/kwe, which is the high value for the HTGR (Module R3) for the same reason. The nominal value was chosen as the midpoint of this range.

Table R8-2. "What-It-Takes" Specific Overnight Cost for Solid-Fueled Molten-Salt Reactor.

What-It-Takes NOAK Overnight Cost:	Low (2012$)	Nominal (2012$)	High (2012$)
Molten Salt AHTR System	2000	5000	8000

For this 2017 AFC-CBD the year 2012$ amounts above were escalated to 2017$ using an escalation factor of 1.088. The resulting values were then rounded to maintain a proper number of significant digits. Table R8-3 results:

Table R8-2. "What-It-Takes" Specific Overnight Cost for Solid-Fueled Molten-Salt Reactor.

What-It-Takes NOAK Overnight Cost:	Low (2015$)	High (2015$)	Mean (2015$)	Mode (2015$)
Molten Salt AHTR System	2200	8700	5600	6000

Figure R8-5 below shows the probability distributions and parameters for this reactor type.

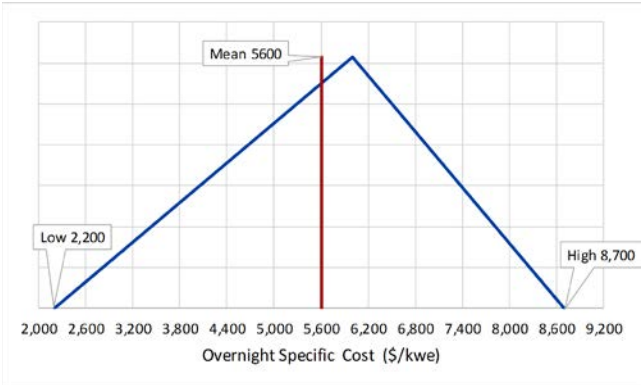

Figure R8-5. Distributions and parameters for Specific Capital Cost of Solid Fueled AHTR.

R8-9. SENSITIVITY AND UNCERTAINTY ANALYSES

A few sensitivity studies are described in the ORNL reference (Holcomb, Peretz, & Qualls 2011).

R8-10. REFERENCES

D.E.Holcomb, F.J.Peretz, A.L.Qualls, *Advanced High Temperature Reactor Systems and Economic Analysis*: September 2011 Status, Rev 0, ORNL/TM-2011/364, Sept 30, 2011 (http://info.ornl.gov/sites/publications/files/Pub32466.pdf)

R8-11. BIBLIOGRAPHY

Other Technical Report Describing AHTR-FHR systems and components:

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R9 Modules

Fission/Fusion Hybrid Systems

Module RP9

Preface to
Fission/Fusion Hybrid Systems

Module RP9

Preface to Fission/Fusion Hybrid Systems

RP9-1. BACKGROUND

Note: This module was added in 2012 as part of the AFC-CBD update. No new data has been added in the 2013-2015 time frame. Unit costs have, however, been escalated to year 2017 dollars.

In this concept, the transmuter/energy generation device contains features both of a nuclear fission system (which via nuclear reaction burns fissile and fertile very heavy elements with atomic number > 90) and a nuclear fusion system (which via nuclear reaction burns the very lightest elements with atomic number of 3 or less). Basically the FF (fission/fusion) reactor would consist of a fusion reactor surrounded by blankets consisting a heat removal medium, such as Li-6 enriched lithium metal or a Li-containing molten salt, and fertile fission reactor fuel such as solid or liquid heavy metal forms containing thorium-232 and/or uranium-238 in subcritical configuration.

The concepts studied to date are those based on the deuterium-tritium (D-T) fusion reaction:

$_1H^2 + {}_1H^3 \rightarrow {}_2He^4$ (3.52 MeV) + $_0n^1$ (14.06 MeV)

The energetic 14MeV "fast" neutrons produced are capable of fissioning U-238, which in a thermal neutron system like an LWR, will not fission. Additional "fast" neutrons are also formed by this U-238 fission. Some of the fast neutrons from both fusion and fission can also convert thorium-232 to uranium-233, a fissile uranium isotope that can be burned in thermal reactors, thus establishing an overall nuclear power enterprise symbiosis with thermal fission systems such as LWRs. Useable heat for electricity generation is produced by both the fusion and fission reactors and is removed via the circulating lithium-based coolant. Tritium can be removed from the lithium coolant where it is produced by the (Li-6, n) and (Li-7, n) reactions as follows:

$_3Li^6 + {}_0n^1 \rightarrow {}_1H^3 + {}_2He^4$

$_3Li^7 + {}_0n^1 \rightarrow {}_1H^3 + {}_2He^4 + {}_0n^1$

This "bred" tritium is then recycled to the fusion reactor. Figure RP9-1 shows a diagram of the basic fission/fusion hybrid concept. The following list contains the advantages of this concept per its proponents:

- It makes efficient use of the fertile materials U-238 and Th-232
- The fuel cycle does not require uranium enrichment, a non-proliferation advantage
- The fuel cycle can be operated as an electricity generator, a nuclear waste "incinerator", or a breeder for Pu-239 and/or U-233. Combinations of these functions are possible
- One FF reactor system of a given thermal output can produce fuel for several LWRs of the same thermal output
- The "Q" (ratio of "energy out" to "energy in" for the fusion part of the FF system) can be much lower than for a pure fusion electrical generation reactor
- The nuclear reactor part of the FF system can be subcritical, which may be a safety and operational advantage. This is also true for the Accelerator Driven System, ADS, discussed in Module R6
- The 14 MeV fast neutrons from fusion allow the fission part to act as an "energy amplifier" by the generation of additional fissions and neutrons

- Deuterium is a natural component of the earth's waters, thus the supply is nearly unlimited. Tritium is regenerated from the (Li6,n) reaction, and lithium is also very abundant in the earth's crust.

References RP9-1, RP9-2, and RP9-3 treat Fission/Fusion Hybrids in general and should provide useful background information to the user.

Presently there are two fusion reactor concepts being developed in the US that could potentially serve as the "fusion" part of a hypothetical FF system. Both concepts heat D-T to temperatures of about 10 keV (100,000,000 K), required for a significant fusion cross section and reaction. To fuse a significant fraction of the DT, the product of plasma density and confinement time is the key parameter. Higher density results in more frequent collisions and hence more D-T collisions for a given confinement time, and higher confinement time results in more D-T collisions for a given plasma density.

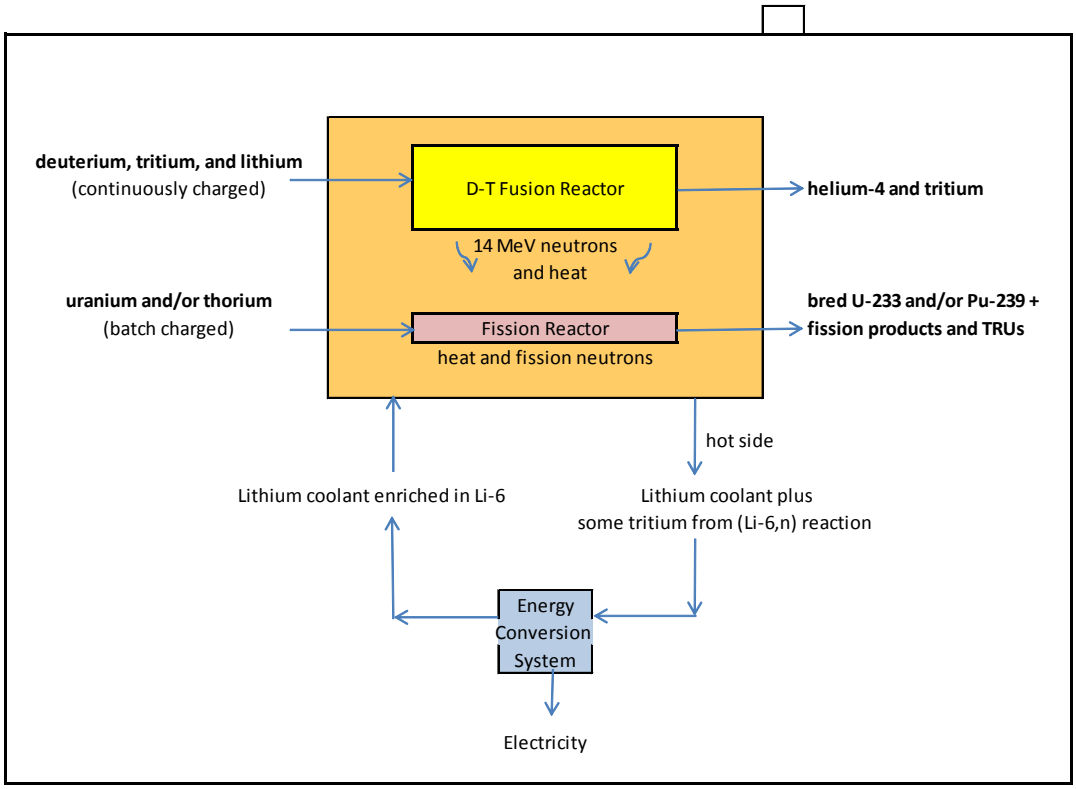

Figure RP9-1. The Generic Fission/Fusion System Concept. (The fission reactor in the figure is a subcritical fission blanket cooled by lithium. Outside fission reactors fueled by the bred U-233 or Pu-239 are not shown).

The magnetic confinement (MC) method uses a very high magnetic field and a high-energy plasma injection scheme to contain a D-T mixture such that a fusion reaction can be sustained for a significant confinement time. The plasma density is limited by the stress limits of the magnets and container (plasma pressure is high because of the high temperature). A lithium blanket would provide heat removal and regeneration of tritium fuel. The international ITER Project, in which the US participates, is constructing a 500 MWth demonstration MC reactor in France that uses the doughnut-shaped "tokamak" configuration for plasma confinement. Other plasma/magnet configurations such as "magnetic mirrors" or "stellarators" are possible for MC fusion.

The inertial confinement method uses a "driver", which directly or indirectly (via x-rays) ablates and implodes a millimeter-scale sphere containing the D-T mixture. Various drivers have been considered including lasers, heavy ion beams and pulsed power (Z-pinch). The confinement time is set by the time it

takes a sound wave to traverse the compressed sphere, and the required density is thus about 100 times that of solid lead. At the time of implosion stagnation, the kinetic energy of implosion is converted to heat, producing the required plasma temperature at the central hot spot of the plasma. In the compressed plasma, the density is high enough to capture the fusion alpha particles in the layer surrounding the central hot spot, heating it to the required temperature. This thermonuclear wave persists for the short time it takes the compressed sphere to disassemble. The overall efficiency of this process can be very high – with fuel burn-up of roughly 30% per shot. After the fusion chamber clears, another sphere is injected and the process repeats; a repetition rate between 5-20 Hz can produce a significant amount of power. Inertial confinement fusion using a laser driver and indirect-drive target is the most advanced. This approach is being pursued in the US by a team led by Lawrence Livermore National Laboratory (LLNL). The National Ignition Facility (NIF) demonstration facility (Ref. RP9-4) is now operating at LLNL for development of this concept. The major purpose of this DOE Defense Programs project is to simulate thermonuclear weapons effects and support the NNSA Stockpile Stewardship program. Pulsed power driven ICF is being led by Sandia National Laboratories, and heavy ion fusion related basic science R&D is led by Lawrence Berkeley National Laboratory.

LLNL is also pursuing a pure fusion power plant design, called Laser Inertial Fusion Energy (LIFE). The LIFE design is derived from the anticipated potential of the NIF to provide full-scale performance demonstration data for a 1000 MWe plant. Figure RP9-2 shows a conceptual LIFE Engine (called so by the LIFE team due to its repetitive mode of operation, distinct from a reactor). LIFE (References RP9-5 and RP9-6) is a pure fusion system with the blanket breeding tritium (for its own use and for use in other systems) and capturing the heat. The fusion reaction is in the small pea-size capsule irradiated by the laser on the fly at the center of the chamber. The chamber shape itself is a transition from a sphere (which is natural given the point source) and a cylinder (which is well suited to a blanket arrangement conducive to use of replaceable modules). Figure RP9-3 from Ref. RP9-5 shows a view of the LIFE system that includes the lasers and the maintenance area for the replacement chambers. The lasers (where the red beams start; the red beams change to blue after frequency conversion) are much smaller than the NIF laser modules, and there is a conceptual design to operate the lasers at the required repetition rate. Figure RP9-4 from Ref. RP9-5 shows a view of the LIFE systems that includes the entire plant footprint.

FFH concepts were studied earlier by LLNL, but are not currently being pursued. See Module R9-2 for more discussion.

Because the fusion concepts are markedly different in configuration and proposed operation, any FF concepts utilizing either MC or IC will be markedly different from the other, Also, different organizations are involved in the research and development and scoping work. The inertial confinement pure fusion configuration is being investigated at LLNL in a small adjunct effort to the NIF work. The magnetic confinement FF concept is mainly a university research project, with most work being conducted at the University of Texas, Austin; Georgia Tech; and the University of California at San Diego. LLNL has also conducted some paper studies on the MC method using magnetic mirrors (References RP9-7, RP9-8, and R9-P.9). For this reason, the authors have split this R9 Module into two parts: Module R9-1 deals with the magnetic confinement FF method, and Module R9-2 with the inertial confinement FF concept.

Figure RP9-2. Conceptual Scheme for the LIFE IC System Pure Fusion Chamber.

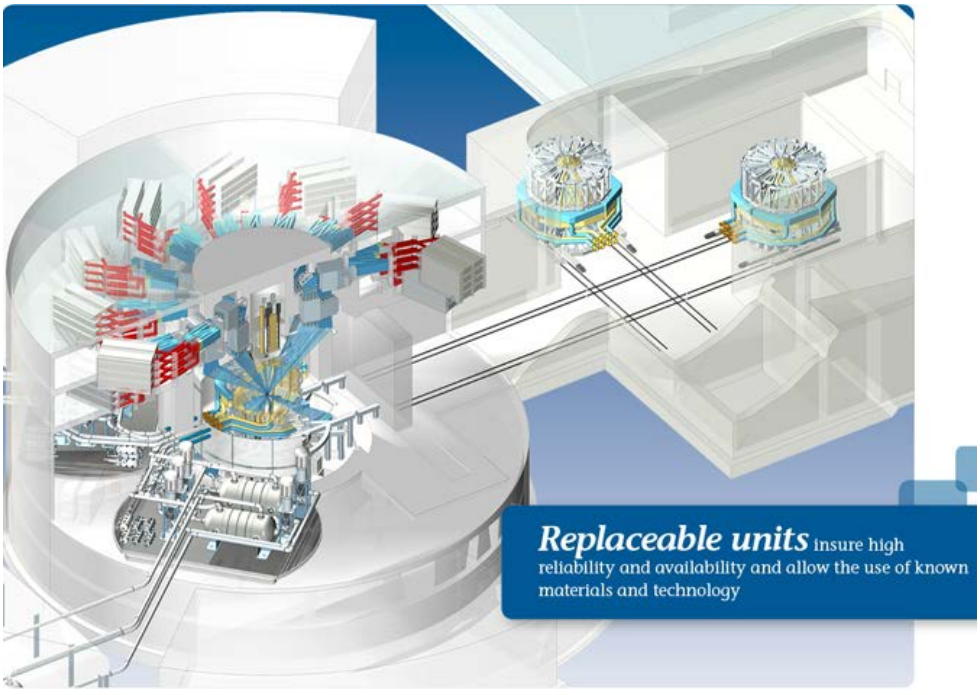

Figure RP9-3. The LIFE IC System Lasers and Maintenance Area for a pure fusion system.

Figure RP9-4. The LIFE IC System Overall Plant Configuration for a pure fusion system.

Figure RP9-5. Cutaway View of ITER pure fusion reactor.

Figure RP9-5 above shows a cutaway schematic of the ITER pure fusion magnetic confinement reactor under construction in France. This can be compared to the IC pure fusion schematics preceding it.

RP9-2. REFERENCES/BIBLIOGRAPHY

RP9-1 Bethe, Hans; *The Fusion Hybrid*; **Physics Today**; May 1979, pp 44-51

RP9-2 Lidsky, L.M.; *Fission-Fusion Hybrid Systems: Hybrid, Symbiotic, and Augean*; Nuclear Fusion (IAEA); Vol 15, No 1, Feb 1975

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RP9-5 LIFE website; https://**life.llnl**.gov/

RP9-6 Dunne, M., et al.; *Timely Delivery of Laser Inertial Fusion Energy (LIFE)*; **Fusion Science and Technology**; Vol 60, July 2011, pp 19-27

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RP9-8 Moir, R.W.; *The Fission-Fission Fuel Factory*; Vol 1, in **Fusion**, by Edward Teller; Academic Press, New York; 1981, pp 411-451

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Module R9-1

Fission/Fusion Hybrid Systems: Magnetic Confinement D-T Fusion

Module R9-1

Fission/Fusion Hybrid Systems: Magnetic Confinement D-T Fusion

R9-1.MD. SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
- **Nature of this 2017 Module update from previous AFC-CBRs:** Escalation only from last time values underwent technical assessment (2012 AFC-CBR)
- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** System descriptions from fusion research laboratories and universities were utilized, along with some scaling calculations, to develop rough cost estimates. These were combined with engineering judgment of the overall system differences from LWRs.

R9-1.RH. REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R9-1.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The use of this unit cost information (and its format) in the Evaluation and Screening Report [Reference R9-1.9] did not mesh well with the range of FFH concepts considered in the screening exercise. The cost of the MC fusion reactor needs to be cast in terms of the size of the fusion device required, which is in turn a function of the degree of sub-criticality and thermal power of the reactor. In addition, the electricity requirements or net production should be included as an annual cost (or revenue) like O&M. Essentially, instead of rolling all the system (fusion reactor +subcritical reactor) cost assumptions into a final $/kWe, they should be provided separately so the cost estimators can more accurately assess life cycle costs for the specific FFH system that they are evaluating.

R9-1-1. BASIC INFORMATION

This module has been newly drafted for the FY2012 Cost Basis Report update. It is concerned with the capital cost of Magnetic Confinement (MC) Hybrid Fission/Fusion Systems (FF), defined in this module as industrial scale Nth-of-a-kind (NOAK) electricity production machines. As with ADS (Module R6), it is highlighted that no such machine has been constructed nor operated as of yet; therefore, all the costs presented here are derived from paper studies based on hypothetical systems. The capital cost is best subdivided between the fusion and fission parts of the overall structure. This is similar to how the system cost for ADS was partitioned between the accelerator and subcritical reactor portions. In particular, most of the cost data on the MC fusion part of the FF system are derived from studies related to ARIES, ITER, and other pre-conceptual design magnetic confinement fusion reactor (MCFR) studies. The International ITER (Latin for "the way" *to future energy*) fusion reactor project is advancing towards demonstration of the MCF technology, with early construction and equipment procurement underway.

The capital costs for the fission reactor portion of an FFH system are based on those for relevant reactor systems covered in earlier R-modules, particularly the subcritical fission system for ADS (Module

R6) and the critical fast reactor (Module R2). Most of this section deals with costs for the MC fusion reactor. The MCFR for the FFH system is likely to be a Tokamak-based system, such as ITER and the one proposed by the University of Texas, Austin (Ref. R9-1.1), or a magnetic mirror concept (Ref. R9-1.2).

R9-1-2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Magnetic Confinement Hybrid Systems (FFHSs) are composed of two coupled main parts: (1) a sub-critical fission blanket (reactor) in which the power is maintained at the desired level through the use of an external neutron source and (2) a magnetic confinement fusion reactor (MCFR) that, through the use of the D-T fusion reaction, generates the fast 14 MeV source neutrons capable of fissioning U-238, sustaining fission, and/or breeding Pu-239 from U-238 or U-233 from Th-232.

It is assumed that, by dropping the constraint of maintaining the nuclear core criticality, additional flexibility can be gained by MC-FFHs as opposed to critical fission transmuters. This flexibility in turn can be used for certain types of reactor applications, such as actinide burning (transmutation of large quantities of heavier minor actinides – MAs) or breeding of Pu-239 or U-233 for use in fission-only reactors (sustainable nuclear power via symbiosis). In fact, there are not substantial technological differences between fast reactors and the subcritical parts of the FFH system; therefore, the cost of a fast reactor (FR, Module R2) is assumed as one of the bases for the cost of the subcritical part of the FFHS (and ADS).

R9-1-3. PICTURES AND DIAGRAMS

Figure R9-1.1 shows a conceptual scheme for an MC-FFH system. This example, from the University of Texas Program (Ref. R9-1.1) is a waste burner. The “Fission Waste” section shown in the diagram could be fission heat source for power generation and/or a breeder of fissile materials from fertile U-238 or Th-232. The fusion reactor is of the familiar donut-shaped tokamak design.

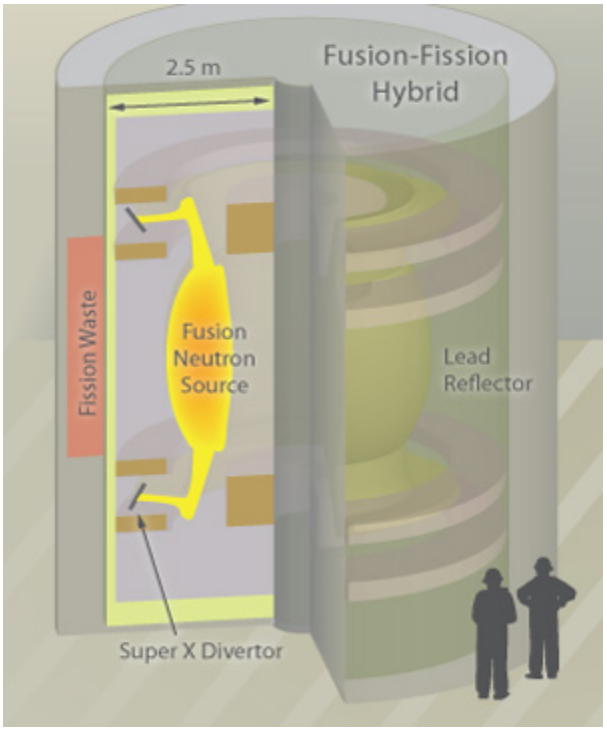

Figure R9-1.1. Conceptual Scheme for the MC-FFH System.

R9-1-4. MODULE INTERFACES

The subcritical fission portion of the MC-FFH system receives solid fertile fuel assemblies from the fuel fabrication plant, which can be central or co-located with the MC-FFH facility. The liquid coolant, most likely lithium metal or a molten salt lithium compound, removes useable heat from both the fusion and fission portions of the blanket surrounding the fusion source and transports it to the power conversion system for electricity generation. After irradiation, the discharged highly radioactive fission fuel would be kept in wet-storage on site until ready for on-site storage or off-site storage or disposal (for the actinide burner application), or reprocessing and recovery of useful fissile materials (for the sustainable nuclear power by symbiosis application). Although both aqueous and electrochemical reprocessing are possible, electro-refining is often envisioned as the fuel reprocessing method for the discharged MC-FFH metal fuel. These integral fuel recycle facilities would be normally co-located with the reactor systems. Co-location would save the off-site transportation costs and enhance security. It should be noted that there is also a FFH concept that marries the features of the liquid-fueled molten salt reactor (Module R7) and fusion reactors.

R9-1-5. SCALING CONSIDERATIONS

Both the subcritical fission system and the MCFR system should feature a reduction in specific overnight costs ($/kW) with increasing system power for each.

R9-1-6. COST BASES, ASSUMPTION AND DATA SOURCES

The cost summary is divided in two parts: (1) the MC fusion reactor (capital and O&M) and (2) the subcritical blanket and the power conversion equipment (capital and O&M). In this section, any fuel processing/fabrication facilities are excluded, since they are treated in detail in the D and F modules. In order to cost out the whole FFH transmutation system, total neutron and power balances are required. For the neutron balance, one begins with the neutrons required to breed tritium. Most of the tritium to be bred is to replace tritium consumed in fusion reactions, but a small additional amount is needed to make up for losses in the fusion chamber exhaust and tritium processing systems. The remaining neutrons are available for use in the subcritical fission blanket surrounding the fusion chamber. Those neutrons can be absorbed to breed U-233 or Pu-239, fast fission U-238, or can be absorbed by other materials or leak through the neutron reflector. The amount of fast fissions per fusion reaction (and also the consideration of energy released or consumed by non-fission nuclear reactions in the blanket) determines the balance of power between the fusion and fission portions of the FFH system. To roughly calculate the overall system specific overnight capital cost one can use the following relationship:

$/kW for total FFH machine =

(% of net power from fusion reactor portion) x ($/kW for MCFR) +
(% of net power from fission reactor portion) x ($/kW for fission reactor)

A key parameter for the fusion system is the “Q” (ratio of fusion power out to the “power in” required to drive the magnets and injectors which sustain the fusion reaction) of the MCFR. For a FFH system, one has additional cost for the fission blanket, but also has additional energy from the fission reactions. This means that a lower “Q” is required for the fusion reactor in order to provide a given amount of overall FFH system power. Bethe, in Reference RP9-1, showed example energy balances.

The nature of the fission reactor fuel influences both the neutron and the power balances. For a uranium system, U-238 fissions are more likely than neutron absorption and transmutation for a flux of 14 MeV neutrons, and the fission component of the FFH can produce a higher percentage of the heat eventually converted to electricity. In contrast, for a thorium system, a higher percentage of the 14 MeV neutrons from fusion would be used to convert thorium to U-233 by absorption (without the energy

release from fission in the FFH system). A higher percentage of the useable heat for electricity production by the FFH system would come from the fusion portion of the FFY.

For rough life cycle estimating, the system O&M costs, expressed in $/kWe-y, could be calculated in the same manner using power partitioning.

Capital and O&M Cost of the Subcritical Blanket (Reactor). The basic assumption in the ADS (Module R6) and FFH cost studies is that the capital cost of the sub-critical part of the system will be similar – but slightly higher – to that of a critical fast reactor similar in size/power level to the sub-critical unit. As with the ADS, the specific cost (i.e. $/kWe) of the reactor/power conversion portion of the facility will be higher than that of a similar critical fast reactor because:

- The extra size of the plant necessary to generate part of the electricity needed to run its own pumps and part of the fusion reactor input power system (magnets, tritium recovery, injectors, etc.); this is electricity that is not available for sale. The extra electricity needed is about 8% of the total in the case of ATW; a similar or higher number is assumed for the FFH system depending on the "Q" of the MCFR (10% higher is assumed for this case). In addition to the standard FR components, there will be extra complications such as coolant/blanket connections for both nuclear fuel rods and tritium removal subsystems.
- Some components will be absent or reduced, such as reactor control rods, but the cost benefit of this is likely to be over-compensated by the extra cost of components needed in FFH systems and not in a FR.
- The subcritical blanket geometry will be subject to the constraints due to the toroidal plasma vessel and the surrounding magnets.

The Advanced Liquid Metal Reactor (ALMR) has been used as a reasonable cost basis for ATW because of the large amount of work done on the cost of the ALMR (funded by DOE from 1989 to 1995) as documented in Module R2. Table R9-1.1 gives the specific capital cost for the critical fast reactor (Module R2) and the subcritical portion of the FFH system including its share of the overall steam generator and turbine costs. This range is close to but slightly above that used for the sodium-cooled fast critical reactor in Module R2 and encompasses the range of subcritical reactor costs discussed in Module R6 (ADS) as well as the overnight cost of $4,000/kWe in the 2009 update to the MIT Future of Nuclear Power study. Note that for the ATW system discussed in Module R6, there was a more-detailed pre-conceptual design and cost estimate available from the ATW Program that could be analyzed.

The range for the fixed component of O&M cost was obtained in a similar fashion. The low end of the range was taken from Module R2, for a critical FR. The high end of the range was taken from Module R6, for an Accelerator Driven System.

Table R9-1.1 What-it-Takes Cost Range for Critical Fast Reactors and the Subcritical Portion of a FFH System (2012 $).

Item	Low Cost	High Cost
Subcritical Reactor Portion of the FFH system (Specific Overnight Cost)	$2,100/kWe NOAK (10% above critical FR due to complexity)	$6,600/kWe NOAK (10% above critical FR due to complexity)
Subcritical Reactor Portion of the FFH system (Fixed Component of O&M costs)	$60/kWe-y (same as critical FR)	$230/kWe-y (same as ADS Module R6)
Critical Fast Reactor (Specific Overnight Cost) Module R2	$1,900/kWe NOAK (from Module R2)	$6,000/kWe NOAK (from Module R2)
Critical Fast Reactor (Fixed Component of O&M costs)	$60/kWe-y (from Module R2)	$85/kWe-y (from Module R2)

Capital and O&M Costs of the MC Fusion Reactor. Over the 60+ years that fusion energy has been pursued, there have been numerous cost estimates and cost models developed for MCFR concepts. None are very recent (last 5 years) and do a credible NOAK-to-NOAK comparison against a LWR reactor. Descriptions of models such as SYMECON (Ref. R9-1.5) were found, but the model itself was not available. There is a cost estimate for the ITER design, but ITER is a developmental project not wholly representative of a commercial MCFR design. Table R9-1.2 below shows a compilation of cost information gleaned from the literature and internet sources. Most values given were for the MCFR only, but a few cost estimates for complete FFH systems were also found and are presented. Most values have been converted to specific overnight cost ($/kWe) and to 2012 constant dollars. In some cases, O&M costs were available, but only for the fixed ($/kWe-y) component. This is still useful, since for most reactor systems, the fixed component is considerably larger than the variable component (which varies with power production).

It is not known what contingency values were added to the base construction cost in the numbers given above. At this point in MCFR development, anything lower than 50% is probably not realistic. (This would be the cost contingency only. The possibility that the fusion system will not achieve its stated design performance in terms of net power output and capacity factor is not considered here, as successful development of the concept must be assumed to provide the basis for NOAK costs. However, successful development is a valid concern given the low technology readiness level of the concept and the significant technical issues remaining.

Table R9-1.2 Cost data on Magnetic Confinement Fusion Reactors from Literature Sources.

Reference Item	Cost Data
Bethe (Ref. RP9-1) [1979]	For a fusion reactor with "Q" of 10, specific MCFR capital cost is 3 times that of LWR (multiplying Module R1 range by 3 gives $6,900/kWe to $17,400/kWe). Whole FFH system specific capital cost is 1.26 to 1.46 times that of a LWR (depends on MCFR "Q" and fuels used in fission reactor, the range would be $2,100/kWe to $8,500/kWe). R&D would cost $10B in 1979$ ($35B in 2012$).
Beyond ITER (Ref. R9-1.4) [2008]	1.5 GWe FOAK MCFR = $8,000/kWe (2012$) 1.5 GWe NOAK MCFR = $4,000/kWe (2012$) Article uses $3,000/kWe for NOAK LWR fission.
2011 Update of Technology Map (Ref. R9-1.3)	Large DEMO follow on to ITER will cost $10,000/kWe (1995$); $14,500/kWe in 2012$
Moir (Ref. 9-1.2) [2012]	1.38 GWe FFH System would cost $4.87B in 1982$. Would be ~15B in 2012$
UCSD (Ref. 9-1.5) [2008]	States consensus view that $/kWe for MCFR will be greater than for LWRs
ORNL (Ref. R9-1.8) [2000]	Overnight NOAK range is $4,000 to $5,700/kWe in 1999$. ($5,600/kWe to $8,000/kWe in 2012$). Report assumed ARIES type tokamak MCFR was used as base case. Fixed O&M cost of $60/kWe-y assumed ($84/kWe-y in 2012$).

R9-1-7. DATA LIMITATIONS

No FFH system or continuously-operating MCFR has been constructed and operated to date; therefore, the cost assumptions presented here are largely estimates of costs based on paper studies for hypothetical systems. In fact, most of the MCFR data in this section rely on cost projections made for MCFRs that would follow the 500 MWe ITER MCFR being constructed in France. These studies (Refs. 9-1.3 and 9.1-4) have tried to project NOAK MCFR costs based on ITER and follow-on demonstration costs. (ITER's project cost estimate started around $5B, but is now estimated to be closer to $15B.) The cost uncertainties for MCFRs are much higher than for fission reactors of any type. This is a result of the

much lower technical maturity of controlled fusion vis-à-vis controlled fission. (Fusion reactors have not yet reached the goal of sustained energy "breakeven" output that the first fission reactors reached during the early Manhattan project [1942]). Ref. R9-1.5 discusses the very considerable R&D needs for commercial fusion. Ref. R9-1.6 discusses the R&D needs for FFH systems. Ref. R9-1.7 presents the views of skeptics of FFH technology.

R9-1-8. COST SUMMARIES

The specific costs of the two major components of a MC FFH system are summarized in the "What-it-Takes" Table R9-1.3. In order to calculate the specific costs for a complete FFH system, the user (fuel cycle analyst in this case) must define the mission, material balance, and energy balance for the whole system. (The formula for apportioning cost by power output is discussed in Section R9-1-6.)

The operation and capital costs of both the subcritical blanket (reactor) and MCFR portions of the FFH are higher than those of most critical reactors, mostly because of the added costs of the fusion reactor system and its integration with the fission portion, and also because of the higher complexity and integration requirements of the subcritical system. The technical maturity of this system compared to the ADS is smaller, because accelerators have been built on a fairly large scale and are successfully operating (e.g. the Spallation Neutron Source in Oak Ridge).

For the NOAK case, the subcritical reactor part of the capital cost range has been estimated at 2100 $/kWe, to $6600/kWe by adding 10% to both the ALMR (Module R2) low and high "What-it-Takes" specific costs. The low end of the MCFR range has been derived by escalating the low-end specific overnight cost value from the 1999 Oak Ridge (Delene, et al.) cost study (Ref. R9-1.8). The high-end value is triple the low-end value. A factor of three was used to account for the very low technical maturity, high design uncertainties (including the present non-availability of very radiation and heat resistant materials), and tripled estimated cost of the ITER Project. Nominal values were selected near the midpoints of these ranges.

The "What-it-Takes" fixed component of the O&M cost was derived in a similar manner, with the ORNL report (Ref R9-1.8) providing a low value (after escalation) and a doubling of this value for the high O&M cost.

Table R9-1.3. What-It-Takes Cost Summary Table for a MC FFH System (from 2012 AFC-CBD Update; Year 2012$.

	Upside (Low Cost)	Nominal (most likely cost)	Downside (High Cost)
Capital Cost of the Subcritical Reactor	2,100 ($/kWe)	4,400 ($/kWe)	6,600 ($/kWe)
Capital Cost of the MC Fusion Reactor	5,600 ($/kWe)	11,000 ($/kWe)	16,000 ($/kWe)
O&M Cost of the Subcritical Reactor	60 ($/kWe-y)	100 ($/kWe-y)	230 ($/kWe.y)
O&M Cost of the MC Fusion Reactor	80 ($/kWe-y)	120 ($/kWe-y)	160 ($/kWe.y)

The following Table R9-1.4 provides the same data escalated to Year 2017$ (1.088 escalation factor followed by rounding).

Table R9-1.4. What-It-Takes Cost Summary Table for a MC FFH System in Year 2017$.

	Low Cost	High Cost	Mean Cost	Mode Cost
Capital Cost of the Subcritical Reactor	2,300 ($/kWe)	7,200 ($/kWe)	4,800 ($/kWe)	4,800 ($/kWe)
Capital Cost of the MC Fusion Reactor	6,100 ($/kWe)	17,400 ($/kWe)	11,800 ($/kWe)	12,000 ($/kWe)
O&M Cost of the Subcritical Reactor	65 ($/kWe-y)	250 ($/kWe.y)	141 ($/kWe-y)	109 ($/kWe-y)
O&M Cost of the MC Fusion Reactor	87 ($/kWe-y)	174 ($/kWe.y)	131 ($/kWe-y)	131 ($/kWe-y)

Figure F9-1.2 shows the cost-related probability distributions for the Magnetic Confinement variant of the Fission/Fusion hybrid Option.

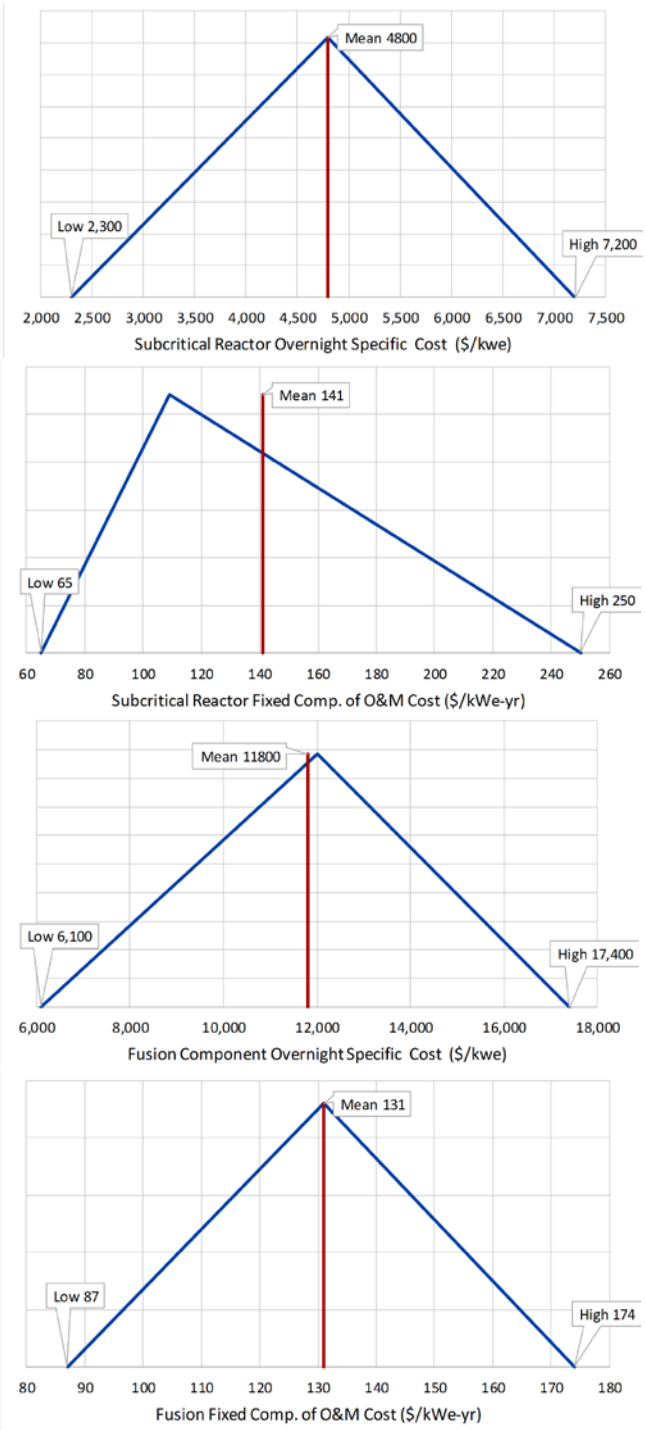

Figure R9-1.2. Probability Distributions for Hybrid Fission/Fusion System: Magnetic Confinement Fusion.

R9-1-9. SENSITIVITY ANALYSES

None available.

R9-1-10. REFERENCES

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R9-1.2 Moir, R.W., et al.; Axisymmetric Magnetic Mirror Fusion-Fission Hybrid; Transactions of Fusion Science and Technology; Vol 61; Jan 2012

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Module R9-2

Fission/Fusion Hybrid Systems: Inertial Confinement D-T Fusion

Module R9-2

Fission/Fusion Hybrid Systems: Inertial Confinement D-T Fusion

R9-2.MD SHORT DESCRIPTION OF METHODOLOGY USED FOR ESTABLISHMENT OF MOST RECENT COST BASIS AND UNDERLYING RATIONALE

- **Constant $ base year for 2017 Update:** FY 2017
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- **Estimating Methodology for latest (2012 AFC-CBR) technical update from which this 2017 update was escalated:** Technology descriptions from LLNL along with scaling relationships were utilized to develop a rough lifecycle cost estimate for a Fission-Fusion Hybrid system. The analysts also took into account engineering judgment of the differences of this FFH system from LWRs.

R9-2.RH REVISION HISTORY

- **Version of AFC-CBR in which Module first appeared:** 2012 as Module R7.
- **Latest version of module in which new technical data was used to establish unit cost ranges:** 2012
- **New technical/cost data which has recently become available and will benefit next revision:**
  - The use of this unit cost formatted AFC-CBR information in the Evaluation and Screening Report [Reference R9-2.14] did not mesh well with the range of FFH concepts considered in the screening exercise. The cost of the fusion reactor needs to be cast in terms of the size of the fusion device required, which is in turn a function of the degree of sub-criticality and thermal power of the fission reactor. In addition, the electricity requirements or net production should be included as a cost (or revenue) like O&M. Essentially, instead of rolling all the cost-related assumptions into a final $/kWe, they should be provided separately so the cost estimator can estimate more accurately the specific FFH system life cycle costs they are evaluating.

R9-2.1. BASIC INFORMATION

This module has been newly drafted for the FY2012 Cost Basis Report update. It is concerned with the capital cost of Inertial Confinement (IC) Hybrid Fission/Fusion Systems (FF), defined in this module as industrial scale Nth-of-a-kind (NOAK) electricity production machines. As with ADS (Module R6), it is highlighted that no such machine has been constructed nor operated as of yet; therefore, all the costs presented here are derived from paper studies based on hypothetical systems. Furthermore, the most credible cost estimate for a pure fusion IC system should be used with caution when applying it to a FF system, because the FF system will likely be subject to NQA-1 quality assurance and Nuclear Regulatory Commission licensing processes, whereas a pure fusion system may be regulated under a system that can be exercised with less cost and lead time. The pure fusion cost estimates in this section assume the simpler regulatory system.

The capital cost is most easily subdivided between the fusion and fission parts of the overall structure, although of course this does not provide a rigorous cost basis for an integrated plant. This is similar to how the system cost for ADS was partitioned between the accelerator and subcritical reactor portions. In

particular, most of the cost data on the IC fusion part of the FF system are derived from pure fusion inertial confinement fusion studies, which rely on data from the National Ignition Facility (NIF) and industrial consultations drawn from the LIFE project. The NIF project is advancing towards demonstration of the Inertial Confinement Fusion (ICF) technology, with construction complete, the initial National Ignition Campaign complete, and with ongoing calculations and experiments working toward demonstration of ignition (net energy gain).

The capital costs for the fission reactor portion of an FFH system are based on those for relevant reactor systems covered in earlier R-modules, particularly the subcritical fission system for ADS (Module R6) and the critical fast reactor (Module R2). Most of this section deals with costs for the IC fusion plant. The pure fusion system is likely to be a solid-state laser-based system, using technology developed for various industrial applications (such as semiconductor laser diodes), coupled to information arising from the NIF project. Ongoing research at LLNL is addressing reduction in physical size of the laser driver, removal of laser heat to accommodate a 5-20 Hz repetition rate, and mass production of the fusion fuel (References R9-2.1, R9-2.2 and R9-2.3). It is assumed that the pure fusion design can be the starting point for a FF hybrid system design, if that concept is pursued in the future, with the substantial caveat that the licensing regime and overall system design may be quite different for the FF system.

R9-2.2. FUNCTIONAL AND OPERATIONAL DESCRIPTION

Inertial Confinement Hybrid Systems (FFHSs) are composed of two coupled main parts: (1) a sub-critical fission blanket (reactor) in which the power is maintained at the desired level through the use of an external neutron source and (2) an inertial confinement fusion system that, through the use of the D-T fusion reaction, generates the fast 14 MeV source neutrons capable of fissioning U-238, sustaining fission, and/or breeding Pu-239 from U-238 or U-233 from Th-232.

It is assumed that, by dropping the constraint of maintaining the nuclear core criticality, additional flexibility can be gained by IC-FFHs as opposed to critical fission transmuters. This flexibility in turn can be used for certain types of reactor applications, such as actinide burning (transmutation of large quantities of heavier minor actinides – MA) or breeding of Pu-239 or U-233 for use in fission-only reactors (sustainable nuclear power via symbiosis). In fact, at a conceptual level there are not substantial technological differences between fast reactors and the subcritical parts of the FFH system; therefore, the cost of a fast reactor (FR, Module R2) is assumed as one of the bases for the cost of the subcritical part of the FFHS (and ADS). Only detailed design activity will determine whether these assumptions are valid or not.

R9-2.3. PICTURES AND DIAGRAMS

The major differences between a FF hybrid and a pure fusion system are a completely different blanket design that can include the fertile materials; the need for a fission fuel processing area; the likely need for substantially more safety structures, systems and components; a different approach to maintenance and replacement of the blanket; and the need for fuel preparation and disposal infrastructure.. The licensing regime for a FF hybrid will be much more stringent than for a pure fusion system, with criticality control and decay heat playing a key role in the design; hence cost estimates for the pure fusion system should be used with caution. References R9-2.4, R9-2.5, and R9-2.6 discuss prior FF hybrid designs developed at LLNL in more detail; current LLNL studies are focusing on the pure fusion option.

Figure R9-2.1 from Reference R9-2.4 shows the fusion chamber and subcritical blanket for a system producing 375-500 MW of fusion power and a total of 2000-5000 of total thermal power.

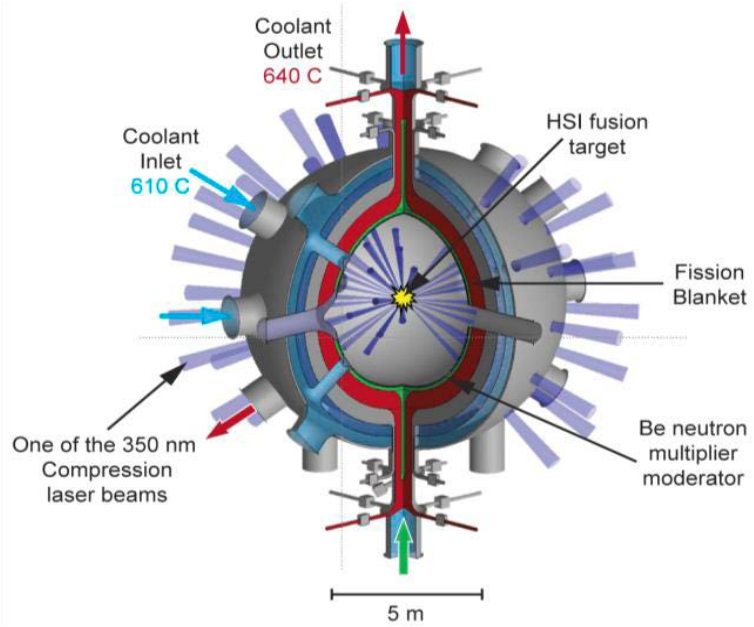

Figure R9-2.1. Conceptual Scheme for an IC-FFH System.

Figure R9-2.2 from Reference R9-2.7 shows the same system, with more information on the flow of coolant and fuel pebbles.

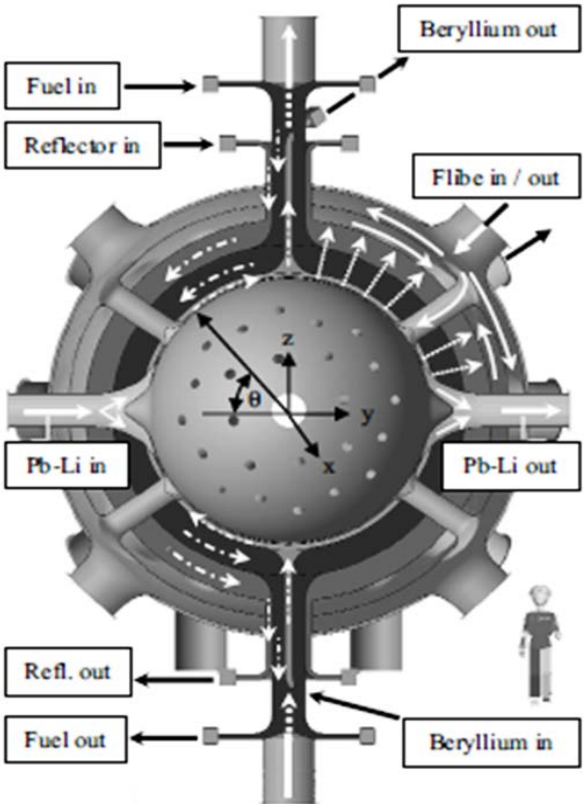

Figure R9-2.2. The internal structures, pebble movements, and coolant flows of an IC FF Hybrid.
Solid arrows: Coolant flow (Pb-Li or Flibe)
Dotted arrows: Coolant flow through pebbles
Dot-Dash arrows: Creeping pebble movement (Be, fuel, reflector)

R9-2-4. MODULE INTERFACES

The subcritical fission portion of the IC-FFH system receives solid fertile fuel assemblies from the fuel fabrication plant, which can be central or co-located with the IC-FFH facility. The liquid coolant removes useable heat from both the fusion and fission portions of the blanket surrounding the fusion source and transports it to the power conversion system for electricity generation. Some significant fraction of this coolant will need to contain lithium, to provide adequate tritium breeding capability. After irradiation, the discharged highly radioactive fission fuel would be kept in wet-storage on site until ready for on-site storage or off-site storage or disposal (for the actinide burner application), or reprocessing and recovery of useful fissile materials (for the sustainable nuclear power by symbiosis application). Although both aqueous and electrochemical reprocessing are possible, electro-refining is often envisioned as the fuel reprocessing method for the discharged IC-FFH metal fuel. These integral fuel recycle facilities would be normally co-located with the reactor systems. Co-location would save the off-site transportation costs and enhance security. It should be noted that there is also a FFH concept that marries the features of the molten salt reactor (Module R7) and fusion reactors.

R9-2-5. SCALING CONSIDERATIONS

Both the subcritical fission system and the ICFR system should feature a reduction in specific overnight costs ($/kW) with increasing system power for each.

R9-2-6. COST BASES, ASSUMPTION AND DATA SOURCES

The cost summary is divided in two parts: (1) the IC fusion plant (capital and O&M) and (2) the subcritical blanket and the power conversion equipment (capital and O&M). In this section, any fuel processing/fabrication facilities are excluded, since they are treated in detail in the D and F modules. In order to cost out the whole FFH transmutation system, total neutron and power balances are required. For the neutron balance, one begins with the neutrons required to breed tritium. Most of the tritium to be bred is to replace tritium consumed in fusion reactions, but a small additional amount is needed to make up for losses in the fusion chamber exhaust and tritium processing systems. The remaining neutrons are available for use in the subcritical fission blanket surrounding the fusion chamber. Those neutrons can be absorbed to breed U-233 or Pu-239, fast fission U-238, or can be absorbed by other materials or leak through the neutron reflector. The amount of fast fissions per fusion reaction (and also the consideration of energy released or consumed by non-fission nuclear reactions in the blanket) determines the balance of power between the fusion and fission portions of the FFH system. To roughly calculate the overall-system specific overnight capital cost one can use the following relationship:

$/kW for total FFH machine =

(% of net power from fusion reactor portion) x ($/kW for fusion plant) +
(% of net power from fission reactor portion) x ($/kW for fission reactor)

A key parameter for the fusion system is the “gain” (ratio of fusion power out to the “power in” required to drive the lasers which sustain the fusion reaction) of the fusion plant. For a FFH system, one has additional cost for the fission blanket, but also has additional energy from the fission reactions. This means that a lower “gain” is required for the fusion plant in order to provide a given amount of overall FFH system power. Bethe, in Reference RP9-1, showed example energy balances.

The nature of the fission reactor fuel influences both the neutron and the power balances. For a uranium system, U-238 fissions are more likely than neutron absorption and transmutation for a flux of 14 MeV neutrons, and the fission component of the FFH can produce a higher percentage of the heat eventually converted to electricity. In contrast, for a thorium system, a higher percentage of the 14 MeV neutrons from fusion would be used to convert thorium to U-233 by absorption (without the energy release from fission in the FFH system). A higher percentage of the useable heat for electricity production by the FFH system would come from the fusion portion of the FFY.

For rough life cycle estimating, the system O&M costs, expressed in $/kWe-y, could be calculated in the same manner using power partitioning.

Capital and O&M Cost of the Subcritical Blanket (Reactor). The basic assumption in the ADS (Module R6) and FFH cost studies is that the capital cost of the sub-critical part of the system will be similar – but slightly higher – to that of a critical fast reactor similar in size/power level to the sub-critical unit. As with the ADS, the specific cost (i.e. $/kWe) of the reactor/power conversion portion of the facility will be higher than that of a similar critical fast reactor because:

1. The extra size of the plant necessary to generate part of the electricity needed to run its own pumps and part of the fusion plant input power system (lasers, tritium recovery, etc.); this is electricity that is not available for sale. The extra electricity needed is about 8% of the total in the case of ATW; a similar or higher number is assumed for the FFH system depending on the "gain" of the fusion plant. In addition to the standard FR components, there will be extra complications such as coolant/blanket connections for both nuclear fuel rods and tritium removal subsystems.
2. Some components will be absent or reduced, such as reactor control rods, but the cost benefit of this is likely to be over-compensated by the extra cost of components needed in FFH systems and not in a FR.
3. The subcritical blanket geometry will be subject to the constraints due to the fusion chamber and laser entrance ports. These constraints are expected to be less significant than the analogous constraints for a MCFR.

The Advanced Liquid Metal Reactor (ALMR) has been used as the cost basis for ATW because of the large amount of work done on the cost of the ALMR (funded by DOE from 1989 to 1995) as documented in Module R2. Table R9-2.1 gives the specific capital cost for the critical fast reactor (Module R2) and the subcritical portion of the FFH system including its share of the overall steam generator and turbine costs. This range is close to but slightly above that used for the sodium-cooled fast critical reactor in Module R2 and encompasses the range of subcritical reactor costs discussed in Module R6 (ADS) as well as the overnight cost of $4000/kWe in the 2009 update to the MIT Future of Nuclear Power study (Ref. R9-2.8). Note that for the ATW system discussed in Module R6, there was a more-detailed pre-conceptual design and cost estimate available from the ATW Program that could be analyzed.

The range for the fixed component of O&M cost was obtained in a similar fashion. The low end of the range was taken from Module R2, for a critical FR. The high end of the range was taken from Module R6 (an ADS).

Table R9-2.1 What-it-Takes Cost Range for Critical Fast Reactors and the Subcritical Portion of a FFH System (2012$).

Item	Low Cost	High Cost
Subcritical Reactor Portion of the FFH system (Specific Overnight Cost)	$2,100/kWe NOAK (10% above critical FR due to complexity)	$6,600/kWe NOAK (10% above critical FR due to complexity)
Subcritical Reactor Portion of the FFH system (Fixed Component of O&M costs)	$60/kWe-y (same as critical FR)	$230/kWe-y (same as ADS)
Critical Fast Reactor (Specific Overnight Cost) Module R2	$1,900/kWe NOAK (from Module R2)	$6,000/kWe NOAK (from Module R2)
Critical Fast Reactor (Fixed Component of O&M costs)	$60/kWe-y (from Module R2)	$85/kWe-y (from Module R2)

Capital and O&M Costs of the IC Fusion Plant. Over the 40+ years that inertial fusion energy has been pursued, there have been numerous cost estimates and cost models developed for fusion power plant concepts. The cost estimates for a pure fusion plant are the most mature, but it must be remembered that

they are based on an assumed regulatory structure that is not as costly and time-consuming as the regulatory system likely for fission power plants (or for FF hybrids). The LLNL costing tool is proprietary. It incorporates costs for the plant (structures and conventional power plant equipment) by an Architect & Engineering firm in 2012, laser costs based on NIF construction experience and vendor bids (e.g., laser diodes), and costs based on engineering estimates for other fusion-specific components.

LLNL's model includes algorithms for moving from direct capital cost to overnight capital cost, annual maintenance and staffing costs, depreciation, expenditures of capital funds over time, etc.

For the fusion system, the following are the top level cost areas:

1. Owners cost (project management and licensing)
2. Fusion Operations Building (includes the mechanical and electrical plant)
3. Plant Support Operations, Facilities, and Improvements (includes site works, electrical substations, administrative building, plant support building and process gas plant, and laser beam prep building)
4. Supervisory Control System
5. Fusion Engine (includes fusion chamber, vacuum chamber, chamber gas and fusion debris recovery system, primary coolant loop, secondary cooling loop, inert gas system, engine maintenance building, and remote maintenance equipment)
6. Fuel Injection, Tracking and Engagement System
7. Laser System (includes special equipment, beam path infrastructure, fusion operation building beam path infrastructure, and laser cooling system)
8. Procured Fuel Components
9. Fusion Fuel Operations (includes 50% of tritium plant and fuel handling building, spent hohlraum recycle and disposal, and on-site target manufacturing system)
10. Tritium Plant Equipment (includes 50% of tritium plant and fuel handling building, and tritium plant equipment)
11. Power Conversion Island including Structures (includes turbine generator equipment)

Costs are estimated one or two levels (code-of-accounts) below this top level, accumulated to this level, and then processed through a time of expenditure algorithm to obtain the capital costs. Operation and maintenance costs are built at a similar level of detail. References R9-2.9 and R9-2.10 describe the LLNL cost model and the influence of design parameters on its results.

The previously mentioned papers on ICF hybrids do not include capital or operating cost estimates. However, Anklam (Ref R9-2.9) provides some cost information for a pure fusion IC plant. Three plants are discussed with fusion powers of 400, 2200 and 2660 MW. The thermal power of these pure fusion plants would be about 20% higher. The 2200 MW fusion plant corresponds to 1 GWe of net power. The cost of these plants ranges from $4-6B. Assuming the middle of the cost estimate range ($5B) corresponds to the 1 GWe plant gives $5000/kWe. Operating costs are not shown, but assuming a fixed O&M cost of ~1% of the capital cost results in $50/kWe-y. This is slightly lower than the $60/kWe-yr used for the subcritical systems. These are the values used for the "Low Cost" entries in Table R9-2.2.

Similar to the assumption for a MCFR, the authors of this module assign a "High Cost" of twice the pure fusion model reference cost to reflect design uncertainty, cost uncertainty, and the economy of scale penalty of a (likely) smaller fusion engine appropriate for the FF hybrid application.

Table R9-2.2 What-it-Takes Cost Range for the IC Portion of a FF Hybrid System (2012$).

Item	Low Cost	High Cost
Inertial Fusion Portion of the FFH system (Specific Overnight Cost including contingency)	$5,000/kWe NOAK	$10,000/kWe NOAK
Inertial Fusion Portion of the FFH system (Fixed Component of O&M costs)	$50/kWe-y	$100/kWe-y

The possibility that the fusion system will not achieve its stated design performance in terms of net power output and capacity factor is not considered here, as successful development of the concept must be assumed to provide the basis for NOAK costs. However, successful development is a valid concern given the low technology readiness level of the concept and the significant technical issues remaining.

R9-2-7. DATA LIMITATIONS

No FFH system or continuously-operating fusion power plant has been constructed and operated to date; therefore, the cost assumptions presented here are largely estimates of costs based on paper studies for hypothetical systems. Further, the rigorous licensing regime for fission system, necessitated by the stored thermal energy in the fission products and the need to limit criticality excursions, will apply to FF hybrid systems, but will not apply to pure IC fusion systems. It is again noted that the costs for a dedicated FF hybrid design may be considerably different than those generated by costing the two sides of the plant separately.

The cost uncertainties for ICFRs are much higher than for fission reactors of any type. This is a result of the much lower technical maturity of controlled fusion vis-à-vis controlled fission. (Inertial fusion facilities have not yet reached the goal of plasma ignition that is a rough analogy to achieving criticality in the first fission reactors during the early Manhattan project of the early 1940s). Ref. R9-2.11 discusses the very considerable R&D needs for commercial fusion; this is one of a series of reports by that group, which usually focused on MC, but did consider IC to a lesser extent. Ref. R9-2.3, from the LLNL pure IC fusion project, discusses IC R&D needs. Ref. R9-2.12 discusses the R&D needs for FFH systems. Ref. R9-2.13 presents the views of skeptics of FFH technology.

R9-2-8. COST SUMMARIES

The specific costs of the two major components of an IC FFH system are summarized in the “What-it-Takes” Table R9-2.3. In order to calculate the specific costs for a complete FFH system, the user (fuel cycle analyst in this case) must define the mission, material balance, and energy balance for the whole system. (The formula for apportioning cost by power output is discussed in Section R9-2-6.)

The operation and capital costs of both the subcritical blanket (reactor) and pure fusion portions of the FFH are higher than those of most critical reactors, mostly because of the added costs of the fusion system and its integration with the fission portion, and also because of the higher complexity and integration requirements of the subcritical system. .

For the NOAK case, the subcritical reactor part of the capital cost range has been estimated at 2100 $/kWe, to $6600/kWe by adding 10% to both the ALMR (Module R2) low and high “What-it-Takes” specific costs. The low end of the ICFR range is the reference cost reported for a recent pure fusion design, using the LLNL proprietary cost model. The high-end value is twice the low-end value. The factor of two is meant to account for design uncertainty, cost estimate uncertainty, and economy of scale penalties associated with a smaller fusion engine in the case of a FF hybrid.

The “What-it-Takes” fixed component of the O&M costs was derived in a similar manner, with the ALMR (Module R2) providing the low end of the range, and with the ADS (Module R6) providing the high end of the range, for the subcritical reactor. For the inertial fusion portion of the hybrid, reference

R9-2.9, based on information for a recent pure fusion design, provides the low end of the range, with doubling for the high end of the range. Mode values were selected near the midpoints of these ranges.

Table R9-2.3. What-It-Takes Cost Summary Table for an IC FFH System (2012 AFC-CBD Update).

	Upside (Low Cost) 2012$	Nominal (Most Likely) 2012$	Downside (High Cost) 2012$
Capital Cost of the Subcritical Reactor	2,100 ($/kWe)	4,400 ($/kWe)	6,600 ($/kWe)
Capital Cost of the IC Fusion plant	5,000 ($/kWe)	8,000 ($/kWe)	10,000 ($/kWe)
O&M Cost of the Subcritical Reactor	60 ($/kWe-y)	100 ($/kWe-y)	230 ($/kWe-y)
O&M Cost of the IC Fusion plant	50 ($/kWe-y)	80 ($/kWe-y)	100 ($/kWe-y)

Table R9-2.4 shows the escalated values used for this 2017 AFC-CBD (1.088 escalation factor followed by rounding).

Table R9-2.4. What-It-Takes Cost Summary Table for an IC FFH System (2017$).

	Low Cost 2017$	High Cost 2017$	Mean 2017$	Mode 2017$
Capital Cost of the Subcritical Reactor	2,300 ($/kWe)	7,200 ($/kWe)	4,800 ($/kWe)	4,800 ($/kWe)
Capital Cost of the IC Fusion plant	5,400 ($/kWe)	10,900 ($/kWe)	8,300 ($/kWe)	8,700 ($/kWe)
O&M Cost of the Subcritical Reactor	65 ($/kWe-y)	250 ($/kWe-y)	141 ($/kWe-y)	109 ($/kWe-y)
O&M Cost of the IC Fusion plant	54 ($/kWe-y)	109 ($/kWe-y)	83 ($/kWe-y)	87 ($/kWe-y)

Figure R9-2.3 shows the resulting probability distributions and parameters for the costs in the Table above. The mean or “expected value” is also calculated.

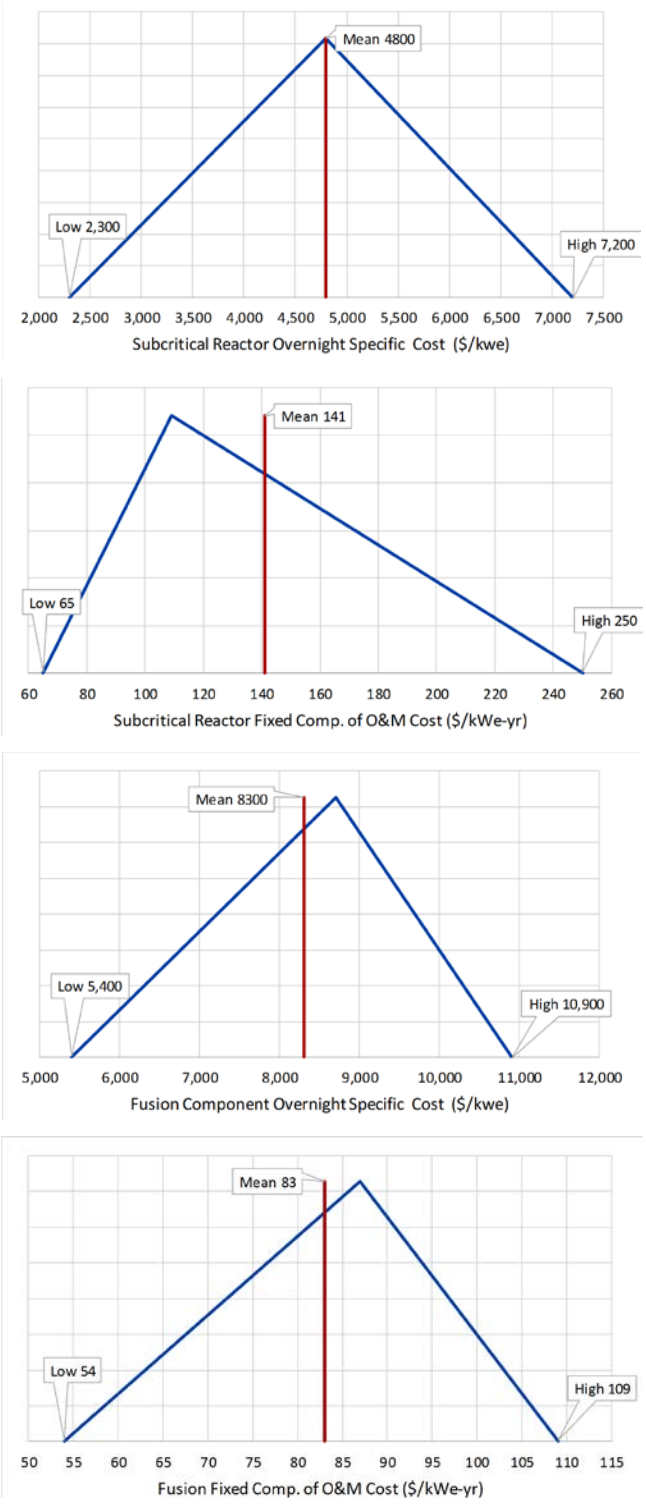

Figure R9-2.3. Probability Distributions for Hybrid Fission/Fusion System: Inertial Confinement Fusion

R9-2-9. SENSITIVITY ANALYSES

None available.

R9-2-10. REFERENCES

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R9-2.2 LIFE website; https://**life.llnl**.gov/

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R9-2.12 USDOE; Research *Needs for Fusion-Fission Hybrid Systems; Report of the Research Needs Workshop (ReNeW)*; USDOE Workshop: Sept 30-Oct 2, 2009; Gaithersburg, MD

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