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An Economic Analysis of Select Fuel Cycles Using the Steady-State Analysis Model for Advanced Fuel Cycles Schemes (SMAFS)

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Technical Update, December 2007

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REPORT SUMMARY

This report evaluates the relative economics of alternative fuel cycles compared to the current U.S. once-through fuel cycle, including concepts under consideration by the U.S. Department of Energy's (DOE) Global Nuclear Energy Partnership (GNEP). EPRI utilized a model developed by the Nuclear Energy Agency (NEA), *Steady-state analysis Model for Advanced Fuel Cycle Schemes* (SMAFS), to evaluate fuel cycle alternatives. The report also evaluates potential financing options for a fuel recycling facility. Please note that this report contains preliminary results from exercising the SMAFS code.

Background
DOE's GNEP program is currently considering alternatives to the current U.S. once-through fuel cycle. EPRI performed a comparative economic analysis of the alternative fuel cycles, including:

- Fuel Cycle 1: Once-through fuel cycle – the current fuel cycle utilized in the U.S.
- Fuel Cycle 2: Pu recycle with MOX fuel – used in some European and Asian countries.
- Fuel Cycle 3: Advanced fuel cycle – a fully closed fuel cycle that assumes the use of advanced fuel separation technologies and advanced reactors. This is similar to the advanced fuel cycle schemes under consideration as part of DOE's GNEP program.

Objectives
- To examine the relative economics of alternative fuel cycles currently under consideration in the U.S. to determine those components important to fuel cycle and total generation costs.
- To evaluate potential financing strategies for a nuclear fuel recycling facility, including government and private sector financing, in order to gain a better understanding of the cost drivers and financing alternatives.

Approach
The project team used the SMAFS model to perform a comparative economic analysis of alternatives to the current U.S. once-through fuel cycle. The SMAFS model included reference unit costs updated by EPRI for which U.S.-specific data exists or for which the project team could apply more recent cost projections. By performing sensitivity analysis that varied the cost input parameters, EPRI identified those fuel cycle components that drive fuel cycle costs, as well as total generation costs. This may also assist the industry in identifying the best areas for applying research and development (R&D) resources to reduce cost uncertainties or to advance technologies.

EPRI evaluated two financial alternatives for constructing and operating a recycling facility, government and private sector funding. EPRI's base case analysis considered a recycling facility with a capacity of 2,500 metric tons heavy metal (MTHM) per year, with an operating period of 30 years. Sensitivity analyses examined the impact of changes to financial assumptions (interest rates, debt ratio, and rate of return) and operating assumptions (facility capacity, operations and maintenance costs, and operating lifetime) on the unit costs of recycling spent nuclear fuel.

Results

EPRI found that there is no significant difference between total generation and fuel cycle costs for the three equilibrium fuel cycles evaluated, assuming nominal value costs. However, the unit costs associated with Fuel Cycles 1 and 2 are based on current technology, while those for Fuel Cycle 3 are based on technologies, such as FR, that are currently in the R&D stage, resulting in more uncertainty in these cost estimates. EPRI found that the capital and operating costs for nuclear reactors represented between 70% and 90% of total electric generating costs. This was true for all three fuel cycles under all cost sensitivities analyzed. Therefore, the most important nuclear generation cost parameter is the unit cost of the nuclear reactors used in future fuel cycles. There are also potential benefits associated with closing the fuel cycle, including reducing the volume, activity, and decay heat of spent nuclear fuel (SNF) and high level radioactive waste (HLW) requiring disposal.

Under the assumptions for a recycling facility constructed and operated by the government, EPRI calculated a recycling unit cost of $667/kgHM. Assuming private sector funding, the project team calculated the unit cost for recycling as $1,355/kgHM. The higher private sector unit costs are due to higher interest rates for debt financing and the inclusion of a return on investment and taxes not included in a government-financed facility. Based on the sensitivity analyses conducted by EPRI, the largest cost drivers associated with a government funded recycling facility are the overnight capital cost, O&M costs, and facility throughput or capacity. The largest cost drivers associated with a private sector financed recycling facility are the overnight capital cost, rate of return, and facility throughput or capacity.

EPRI Perspective

This report presents a preliminary analysis of the relative economics of three alternative fuel cycles to determine those cost components important to overall fuel cycle costs and total generation costs. It is possible that with focused research and development of advanced reactor systems and recycling technologies, a fully closed fuel cycle could be economically competitive with the current once-through fuel cycle.

Keywords

Spent nuclear fuel
Reprocessing
Once-through fuel cycle
Closed fuel cycle
Fuel cycle economics

ABSTRACT

The U.S. Department of Energy's (DOE) Global Nuclear Energy Partnership (GNEP) is currently considering alternatives to the current U.S. once-through fuel cycle. This report evaluates the relative economics of three alternative fuel cycles to determine those cost components important to overall fuel cycle costs and total generation costs. The analysis determined that the unit cost of nuclear reactors is the most important nuclear generation cost parameter in future fuel cycles. The report also evaluates potential financing options for a nuclear fuel recycling facility in order to gain a better understanding of the cost drivers and alternatives which will allow recycling to become a viable alternative for the U.S. waste management system. The project team determined that with focused research and development of advanced reactor systems and recycling technologies, a fully closed fuel cycle could possibly be economically competitive with the current once-through fuel cycle.

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1 INTRODUCTION

In this study, EPRI evaluated alternative fuel cycles to the current U.S. once-through fuel cycle, including concepts being considered as part of the U.S. Department of Energy's (DOE) Global Nuclear Energy Partnership (GNEP) activities. During 2006, the Nuclear Energy Agency (NEA) of the Organization for Economic Co-operation and Development (OECD) released a study that examined advanced nuclear fuel cycles, entitled, "*Advanced Nuclear Fuel Cycles and Radioactive Waste Management.*" [NEA 2006] As part of that study, NEA developed a computer model to evaluate the economics of the a wide range of advanced fuel cycle options currently under consideration including present fuel cycles such as the once-through fuel cycle used in the United States (U.S.) The NEA model, the *Steady-state analysis Model for Advanced Fuel Cycle Schemes* ("SMAFS"), was used by EPRI to evaluate fuel cycle alternatives that are currently under consideration in the U.S.

EPRI obtained a license to use the SMAFS model to assist it conducting the economic analysis of a range of advanced fuel cycles under consideration in the U.S. The SMAFS model includes all data for the wide range of fuel cycles considered including mass flows, waste generation, cost data, decay heat, etc.

As part of its economic evaluation of alternative fuel cycle schemes, EPRI evaluated three separate fuel cycle schemes that cover the range of options currently in use in the U.S. or Europe or under consideration in the U.S. These fuel cycles include:

- Once-Through Fuel Cycle: This open fuel cycle assumes the use of thermal light water reactors (LWR) and is the current fuel cycle scheme being used in the U.S. The once-through fuel cycle assumes the use of 1450 MWe Pressurized Water Reactors (PWR), conventional uranium oxide (UO2) fuel, and the direct disposal of spent nuclear fuel (SNF) in a geologic repository. This fuel cycle scheme is shown in Figure 1-1. This will be referred to as "Fuel Cycle 1" throughout this report. Since Fuel Cycle 1 describes the current fuel cycle practice in the U.S., it will be used as the reference fuel cycle for comparison with Fuel Cycles 2 and 3.
- Plutonium Recycle with MOX Fuel in PWR (Pu Recycle): This fuel cycle assumes conventional reprocessing of LWR fuel, similar to current fuel cycle schemes being used in some European and Asian counties. This Pu recycle scheme assumes the use of 1450 MWe PWRs using UO2 fuel. The spent UO2 fuel is processed with conventional PUREX reprocessing and the separated plutonium (Pu) is recycled in the form of uranium-Pu mixed-oxide (MOX) fuel in PWRs. This fuel cycle assumes disposal of the resulting high-level radioactive waste (HLW) from the PUREX reprocessing step as well as direct disposal of MOX SNF in a geologic repository. This fuel cycle scheme is shown in Figure 1-2. This will be referred to as "Fuel Cycle 2" throughout this report.

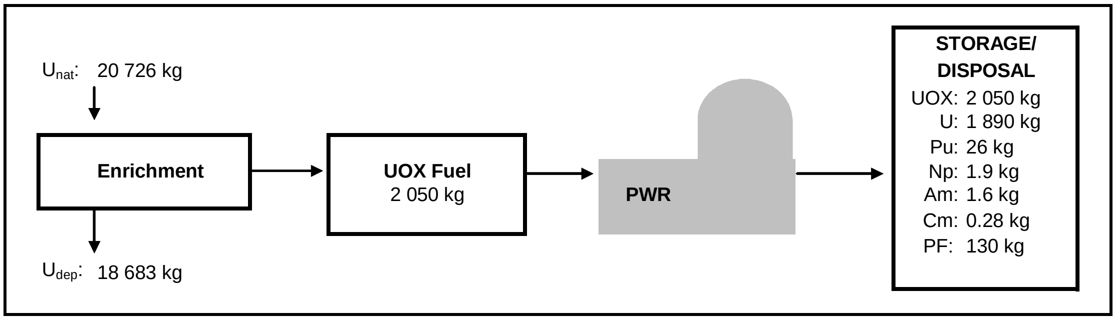

Figure 1-1
Fuel Cycle 1: Once Through Fuel Cycle, Mass Flow Assumptions

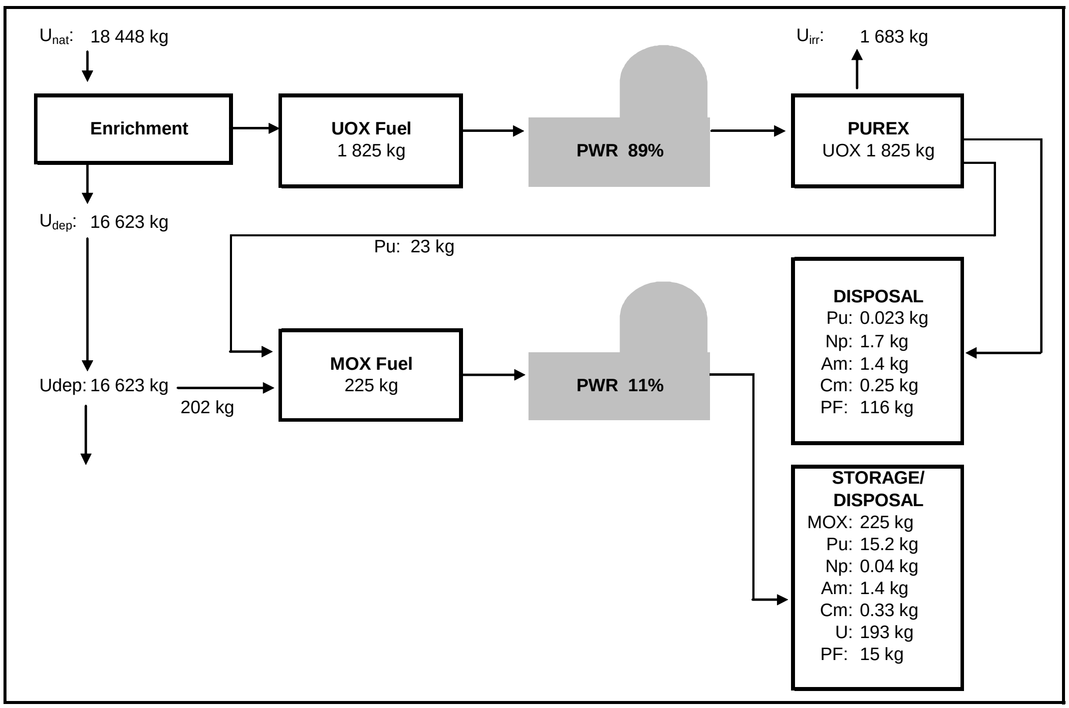

Figure 1-2
Reprocessing Fuel Cycle (PUREX) – One Recycle Using MOX Fuel, Mass Flow Assumptions

- **Advanced Fuel Cycle**: This fuel cycle is a closed fuel cycle and it assumes the use of advanced fuel separation technologies and advanced reactors, and is similar to the advanced fuel cycle schemes under consideration in the U.S. as part of DOE's GNEP program. This was referred to as "Scheme 3a" in the NEA 2006 study. This Advanced Fuel Cycle assumes use of 1450 MWe PWRs using UO_2 fuel. The spent UO_2 fuel is processed utilizing an advanced UREX separation process in which the Pu is not handled separately but is processed with minor actinides. The recovered plutonium and minor actinides are recycled as metal fuel in a fast reactor (FR). DOE's GNEP program considers the use of an Advanced Fuel Cycle Facility (AFCF) that would be designed to separate and fabricate fast reactor transmutation fuel. The Scheme 3a fuel cycle from the NEA study considers pyroprocessing for recycle of FR spent fuel, from which additional FR metal fuel is fabricated . While this last step may be somewhat different from the AFCF facility assumed in DOE's current GNEP planning, NEA 2006's Scheme 3a was the fuel cycle that most closely resembled the current GNEP fuel cycle. This fuel cycle scheme is shown in Figure 1-3. This will be referred to as "Fuel Cycle 3" throughout this report.

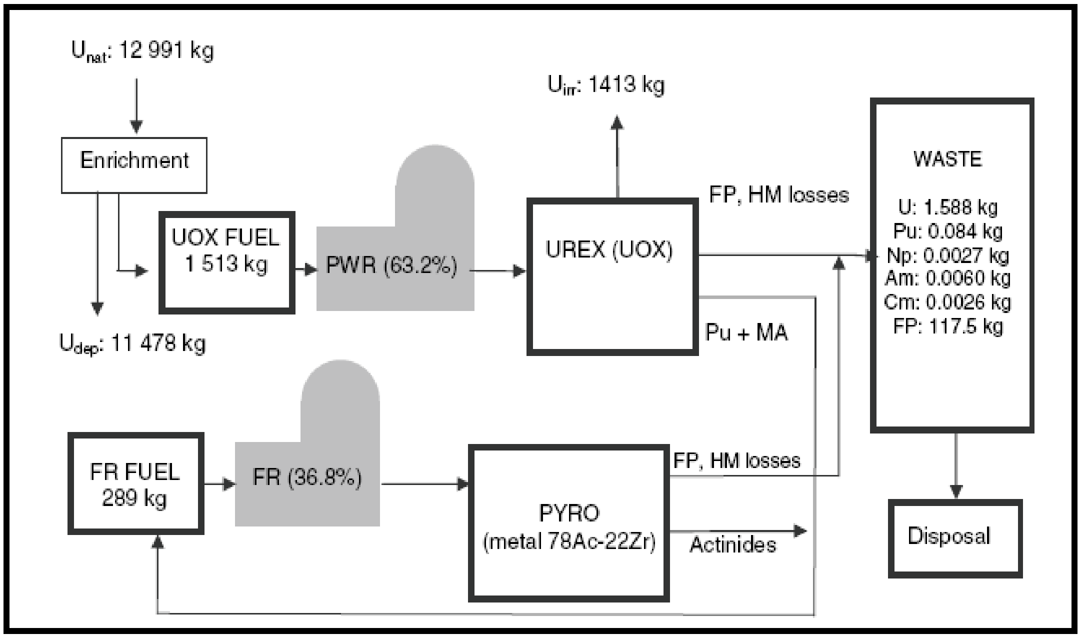

Figure 1-3
Closed Fuel Cycle – Reprocessing (UREX) Using Metal Fuel in Fast Reactors and Pyroprocessing of Fast Reactor Spent Fuel, Mass Flow Assumptions

In utilizing the SMAFS model, EPRI compared the economics of the current U.S. once-through fuel cycle to the MOX fuel cycle used in other countries, and to an advanced fuel cycle that utilizes fast reactors as currently under consideration by DOE's GNEP program. By varying various cost input parameters, EPRI identified those fuel cycle components that drive overall fuel cycle costs as well as total generation costs. This may assist the industry in identifying those areas of advanced fuel cycles where research and development (R&D) resources may best be applied to reduce cost uncertainties or to advance technologies.

In addition to utilizing the SMAFS code to perform a comparative fuel cycle analysis, EPRI investigators developed a spreadsheet model to evaluate the potential financing strategies for fuel cycle facilities such as a nuclear fuel recycling facility under consideration in the U.S. as part of the GNEP program. EPRI's analysis examined government and private financing of a fuel cycle facility in order to gain a better understanding of the cost drivers and financing alternatives that may result in recycling becoming a viable alternative for consideration as part of the U.S. waste management system.

2 OVERVIEW OF THE SMAFS MODEL

The SMAFS model was developed as a part of the NEA 2006 study, "*Advanced Fuel Cycles and Radioactive Waste Management*," that focused on the impact that advanced fuel cycles might have on waste management policies. The fuel cycles evaluated in NEA 2006 included current fuel cycles utilized in the U.S., Europe and Asia (once-through and Pu recycle), as well as advanced fuel cycles that involve fast reactors and advanced fuel processing facilities. The objective of the NEA 2006 study was to "*analyze a range of possible fuel cycle options from the perspective of their effect on waste management policies using, to the extent possible, indicators or metrics that may drive, or at least influence, waste management policy decision*."[1]

2.1 Key Fuel Cycle and Waste Management Indicators

The SMAFS model was designed to conduct fuel cycle economic analysis and to provide a means of comparing not only costs, but also other key fuel cycle and waste management indicators. The key fuel cycle and waste management indicators utilized in the SMAFS model for comparison of the various fuel cycle schemes evaluated, include the following indicators as described in NEA 2006:[2]

- Fuel cycle cost – this indicator includes front end costs as well as waste management costs.
- Total generation cost – this indicator includes the fuel cycle and waste management costs as well as the capital, investment and operating costs of the nuclear reactors considered .
- Uranium consumption – this is driven, in part, by the number of fast reactors in the fuel cycle scheme considered.
- Reduction of transuranics (TRU) in waste (referred to as TRU Loss) – this indicator is dependent upon the amount of multi-recycling in the fuel cycle scheme.
- Activity of the HLW after 1,000 years – this indicator describes the radioactive source term after the decay of heat generating isotopes in HLW.
- Decay heat of the HLW after 50 years, 200 years – this indicator is important in the handling, conditioning and final disposal of SNF and HLW in underground repositories; and also has consequences for fuel reprocessing and transportation.
- HLW and SNF volume to be disposed – this indicator is of key importance in the capacity needed for HLW and SNF disposal facilities.

[1] NEA 2006, p. 127.
[2] NEA 2006., p. 13.

As noted in the NEA study, the use of the above indicators in carrying out an economic analysis of a range of fuel cycle schemes is meant to illustrate "*through parametric sensitivity cases the impacts of different cost elements, and moreover of the uncertainties on those elements, on the total fuel cycle costs of the various schemes considered*."[3]

2.2 SMAFS Input Parameters

In order to calculate the key fuel cycle and waste management indicators discussed in the previous section, the SMAFS model utilizes the following data input parameters:

- Waste generation parameters associated with:
    - Front-end of the fuel cycle (enrichment and fuel fabrication)
    - Reactor operation (short-lived (SL) and long-lived (LL), low and intermediate level waste [LILW], and SNF) for all reactor types considered.
    - Reprocessing (LILW-SL, LILW-LL, and HLW) for all reprocessing types considered (PUREX, UREX, pyroprocessing, etc.)
- Unit cost parameters associated with:
    - Front-end fuel cycle (natural uranium, conversion, enrichment, fuel fabrication)
        - Reactor investment and operations and maintenance costs for all reactor types considered.
        - SNF transport and storage for all fuel types to be transported and stored.
        - Reprocessing (PUREX, UREX, pyroprocessing, etc.)
        - Dry storage, packaging and long-term storage for all fuel types considered. Long-term storage costs are for materials such as depleted uranium (DU), reprocessed uranium (REPU), and Americium and Curium.
        - Waste disposal, including LILW-SL, LILW-LL, and SNF and HLW.

The SMAFS model includes the waste generation and unit cost parameters that were used in NEA 2006.[4] Unit costs are input as a nominal value (NV), lower bound (LB) and upper bound UB). In addition to the waste generation and cost data, the model also includes mass flows for each fuel cycle considered, and data regarding waste activity, decay heat and neutron sources for SNF and HLW requiring long-term storage and disposal. All of these parameters can be changed by the user. Section 3 of this report will describe the data input parameters used by EPRI in this study for the three fuel cycles modeled by EPRI as well as the rationale for any unit cost or waste generation assumptions made by EPRI that are different from those in NEA 2006 study.

[3] NEA 2006, p. 14.
[4] NEA 2006, Appendix L.

2.3 SMAFS Output

The SMAFS model was designed to calculate equilibrium fuel cycle costs assuming that all reactors in a given fuel cycle scheme operate at constant power and that all mass flows have reached an equilibrium.[5] The model calculates the following:

- A summary of the key indicators discussed in Section 2.1 for purposes of comparing the fuel cycle schemes being considered.
    - For each fuel cycle scheme:
    - SNF and HWL activity in Terra Becquerel (TBq), thermal output in watts (W), and neutron source (neutrons/second/group) at time periods of 5, 50, 200, 1000, and 10000 years. These parameters are normalized to units per TWhe.
    - Fuel cycle and total generation cost, including a detailed breakout of costs for front-end fuel cycle materials; reprocessing, reactor investment, reactor operations and maintenance (O&M), and waste management. Costs are calculated on a mill per KWh (mill/KWh) basis as well as on a comparative basis among the fuel cycles analyzed.
    - Quantities of waste generated requiring decommissioning for each step of the fuel cycle. This includes: LILW-SL (m^3), LILW-LL (m^3), HLW (m^3), SNF (kgHM)

Sensitivity analysis are built into the model to allow cost sensitivity studies to be performed. The sensitivity analyses allow equilibrium fuel cycle costs to be calculated assuming:

- Units costs are varied using the NV, LB and UB values. The model has built in four variations that calculate fuel cycle costs assuming:
    - All unit costs are varied using the LB, NV, or UB.
    - Only Disposal unit costs are varied using the LB, NV, or UB. All other costs use the NV unit costs.
    - Only reactor unit cost are varied using the LB, NV, or UB. All other costs use the NV unit costs.
    - Reactor unit costs use the NV. All other costs are varied using the LB, NV or UB.
- One unit cost parameter is varied within a range of costs set by the user. This allows the sensitivity of the equilibrium costs to be assessed by varying only one unit costs above or below the LB and UB.
- Several unit cost parameters are varied, one at a time. For example, front-end fuel cycle unit costs or reactor investment costs could be varied over a range set by the user. This allows the user to determine the sensitivity of a particular fuel cycle scheme to changes in several important unit cost parameters.

[5] NEA 2006, p. 21.

- Several unit cost parameters are varied together. This allows the user to determine the sensitivity of a particular fuel cycle scheme to changes in several important unit cost parameters.

3
EPRI DATA INPUT ASSUMPTIONS FOR THE SMAFS MODEL

EPRI evaluated three separate fuel cycle schemes that cover the range of options currently in use in the U.S. or Europe or under consideration in the U.S., including:

- Fuel Cycle 1: Once-through fuel cycle – the current fuel cycle scheme utilized in the U.S.
- Fuel Cycle 2: Pu recycle with MOX fuel – the current fuel cycle scheme utilized in some European and Asian countries.
- Fuel Cycle 3: Advanced fuel cycle – a fully closed fuel cycle that assumes the use of advanced fuel separation technologies and advanced reactors. This similar to the advanced fuel cycle schemes under consideration as part of DOE's GNEP program.

The SMAFS model included the reference unit costs that were utilized to calculate fuel cycle costs in the NEA 2006 study. EPRI updated those unit costs for which U.S.-specific data exists or for which more recent cost projections could be applied. For example, U.S.-specific cost projections for new PWR reactor investment costs were utilized rather than the cost assumed in NEA 2006. Unit costs that are utilized in EPRI's analysis of Fuel Cycles 1, 2 and 3 are summarized below. Appendix A also provides a summary of the unit costs utilized in Fuel Cycle 1, 2, and 3 in a tabular format.

3.1 Front-End Unit Costs

The unit costs that comprise the front-end of the nuclear fuel cycle include natural uranium ore concentrates (UOC or U_3O_8); conversion of UOC to natural uranium hexafluoride (UF_6), enrichment of natural UF_6 to enriched UF_6, and fabrication of uranium-oxide (UOX) nuclear fuel assemblies. All three fuel cycles considered by EPRI in this report assume the use of PWRs that utilize UOX fuel as one of the steps in the fuel cycle.

3.1.1 Uranium Ore Concentrates

The spot market price for UOC has risen from approximately $14 per pound U_3O_8 ($36/kgU) in December 2003 to approximately $100/lb U_3O_8 ($260/kgU) in November 2007.[6] The NEA 2006 study assumed a NV of $50/kgU for the NV, a LB of $20/kgU and a UB of $80/kgU for natural uranium unit costs – all well below the November 2007 spot market price of $260/kgU. EPRI assumed that the NV unit cost for natural UOC will be the same as the current long-term market prices, assuming a NV of $100/lb U_3O_8 ($260/kgU); a LB of $60/lb U_3O_8 ($156/kgU),

[6] Platts, NuclearFuel, Volume 28, Number 25, December 8, 2003, p. 2; Platts, Nuclear Fuel , Volume 32, Number 23, November 5, 2007, p. 2.

and a UB of \$140/lb U_3O_8 (\$364/kgU). The LB and UB unit costs are ±\$40/lb U_3O_8 of the NV. As discussed in Section 3.1.5, sensitivity analyses were performed to examine the impact of U_3O_8 unit costs that are double the UB value and that are half of the LB value.

3.1.2 Conversion Services

The NEA 2006 study assumed conversion services unit costs with a NV of \$15/kgU as UF_6, a LB of \$10/kgU as UF_6, and an UB of \$20/kgU as UF_6. EPRI assumed that the long-term prices for conversion services would be \$15/kgU as UF_6, with a LB value of \$10/kgU and an UB of \$20/kgU (±33% of NV). Sensitivity analysis were also performed to examine the impact of conversion services unit costs that are double the UB value and that are half of the LB value.

3.1.3 Enrichment Services

The NEA 2006 study assumed enrichment services unit costs with a NV of \$100 per separative work unit (SWU), a LB of \$80/SWU, and an UB of \$120/SWU. Current market prices for enrichment services are approximately \$140/SWU.[7] EPRI assumed that the long-term prices for enrichment services would be the same as the current market price of approximately \$140/SWU (NV), with a LB value of \$120/SWU and an UB of \$160/SWU(±15% of NV). Sensitivity analysis were also performed to examine the impact of enrichment services unit costs that are double the UB value and that are half of the LB value.

3.1.4 Fuel Fabrication

The NEA 2006 study assumed UOX fuel fabrication unit costs with a NV of \$250 per kilogram heavy metal (kgHM), a LB of \$200/kgHM and an UB of \$300/kgHM. The unit costs from NEA 2006 represent reasonable cost assumptions for UOX fuel fabrication based on current fabrication costs in the U.S. NEA 2006 assumed MOX fuel fabrication cost of \$1,250/kgHM for the NV unit cost, \$1,000/kgHM for the LB, and \$1,500/kgHM for the UB. Since there are no commercial scale MOX fuel fabrication plants in the U.S., the NEA 2006 unit costs were utilized by EPRI. A similar range of costs for MOX fuel fabrication can be found in studies that were conducted by researchers from Harvard University's Project on Managing the Atom [Bunn 2003], Massachusetts Institute of Technology [MIT 2003], and the Boston Consulting Group [BCG 2006]. NEA 2006 assumed that fast reactor (FR) metal fuel fabrication would have a NV of \$2,600/kgHM, \$1,400/kgHM for the LB, and \$5,000/kgHM for the UB. Again, since the FR program is currently in the research and development stages, as is the fuel production for such a reactor, the NEA 2006 unit costs were utilized by EPRI in this report. EPRI conducted sensitivity analyses to examine the impact of fuel fabrication unit costs for UOX, MOX, and FR metal fuel that are double the UB value and that are half of the LB value assumed above.

[7] ; Platts, Nuclear Fuel , Volume 32, Number 23, November 5, 2007, p. 2.

3.1.5 Front-End Unit Cost Sensitivity Analysis

In addition to the NV, LB and UB unit costs identified above, this study will perform sensitivity analysis on front-end nuclear fuel unit costs. The sensitivity analysis will examine the impact on fuel cycle costs and total generation costs associated with:

- Doubling the UB fuel cycle costs for uranium, conversion, enrichment, fuel fabrication and reprocessing. Each parameter will be examined individually and together.
- Halving the LB fuel cycle costs for uranium, conversion, enrichment, fuel fabrication and reprocessing. Each parameter will be examined individually and together.

Reprocessing costs were included in the front-end fuel cycle cost sensitivity analysis since reprocessing may become more economical as the cost of natural uranium and enrichment services rise.

3.2 Reactor Investment Unit Costs

The NEA 2006 study included assumptions for the unit cost of installed power and the load factors for a range of reactor types including the PWR and FR assumed in the three fuel cycle schemes analyzed by EPRI. The NEA 2006 unit costs for a PWR included an assumed NV of $1,600/kWe, a LB of $1,200/kWe, and an UB of $1,900/kWe; and the unit costs for a FR of 1,900/kWe (same as the UB for PWR), a LB of $1,200/kWe (same as the LB for PWR); and an UB of $2,300/kWe. Load factors assumed in NEA 2006 assumed a NV of 90% for a PWR (a LB of 85% and a UB of 95%) and a NV of 85% for a FR (a LB of 80% and a UB of 95%).

For the unit cost of installed power for a PWR, the EPRI study assumed a NV of $2,500/kWe, based on current industry estimates for the overnight cost of installed power for a PWR. EPRI assumed PWR unit costs off $2,000/kWe for the LB, and a UB of 3,000/kWe (± $500/kWe from the NV). For the unit cost of installed power for a FR, the EPRI study assumed a NV of $3,000/kWe (same as EPRI's UB for PWR), a LB of $2,500/kWe (same as NV for PWR), and a UB of $3,600/kWe (20% higher than the FR NV). The EPRI study assumed the same load factors utilized in the NEA study.

EPRI conducted sensitivity analyses to examine the impact of higher investment costs for both the PWR and FR, assuming that the NV is doubled resulting in a PWR unit cost of $5,000/kWe and a FR unit cost of $6,000/kWe.

3.3 Spent Fuel Transport Unit Costs

The NEA 2006 study included assumptions for the costs to transport SNF, assuming different transport costs depending upon the type of SNF being transported (i.e., UOX, MOX, FR). NEA 2006 assumed that the unit cost of UOX SNF transport had a NV of $50/kgHM, a LB of $40/kgHM, and a UB of $60/kgHM. The unit cost of MOX SNF and FR metal SNF transport assumed a LB of $60/kgHM (same as the UB for UOX SNF), a NV of $90/kgHM (50% higher than LB for MOX SNF); and a UB of $240/kgHM (four times the UB for UOX SNF transport).

EPRI assumed a NV for UOX SNF transport of $100/kgHM, a LB value of $75/kgHM, and an UB of $125/kgHM. The NV for UOX SNF transport is based on cost analysis conducted by EPRI to examine preliminary cost estimates for a repository with a capacity in excess of the 70,000 MTU statutory limit. In that analysis, EPRI estimated unit costs for transporting SNF to the Yucca Mountain repository of approximately $100/kgHM.[8] The LB value of $75/kgHM for UOX SNF transport is based on a range of transport costs assumed in a recent economic assessment of SNF management conducted by Boston Consulting Group, as well as cost summary information by collected by Idaho National Laboratory (INL) in a recent study of the cost bases for advanced fuel cycles.[9] [10] The UB value of $125/kgHM is 25% higher than the NV unit costs assumed by EPRI.

Regarding SNF transport unit costs for MOX and FR SNF, EPRI assumed that the LB unit costs are $125/kgHM, the same value as the UB for UOX SNF transport. The NEA study assumed that the LB value for MOX and FR SNF transport equaled the UB unit cost for UOX transport. EPRI assumed that the NV transport costs for MOX and FR SNF are $188/kgHM, 50% higher than the LB value. And the UB value of $500/kgHM is four times the UB value for UOX SNF transport.

Sensitivity analysis were also performed to examine the impact of transport unit costs for UOX, MOX and FR SNF that are double the UB values and that are half of the LB values.

3.4 Interim Spent Fuel Storage Unit Costs

The NEA 2006 study included assumptions for the unit costs for interim storage of UOX, MOX and FR SNF in reactor pools (not dry storage) prior to processing or dry storage. These unit costs included both a fixed unit cost for interim storage as well as an annual cost, both expressed in $/kgHM stored. The study assumed NV interim storage costs for UOX SNF with a fixed NV of $50/kgHM and an annual cost of $5/kgHM per year of interim storage. The LB costs assumed were $40/kgHM with an annual cost of $5/kgHM per year and the UB costs were $60/kgHM with an annual cost of $5/kgHM per year of interim storage. EPRI utilized the NEA 2006 assumptions as these unit costs appeared to be reasonable. EPRI also utilized the NEA 2006 cost assumptions for interim storage of MOX and FR SNF since there is currently no U.S. experience with storage of these materials on a large scale. For interim storage of MOX SNF and FR SNF, the LB unit costs are $60/kgHM with an annual storage cost of $5/kgHM per year (the same as the UB unit costs for UOX SNF); the NV unit costs are $90/kgHM with an annual storage cost of $7.5/kgHM per year of interim storage (50% higher than the LB unit costs for MOX and FR SNF); and the UB unit costs are $240 with an annual storage cost of $20/kgHM per year (four times the UB unit costs for UOX SNF). EPRI conducted sensitivity analyses to examine the

[8] EPRI, *Program on Technology Innovation: Room at the Mountain Analysis of the Maximum Disposal Capacity for Commercial Spent Nuclear Fuel in a Yucca Mountain Repository*, Technical Report 1015046, Technical Report, June 2007, Table 5-10. (EPRI 2007).

[9] Boston Consulting Group, Economic Assessment of Used Nuclear Fuel Management in the United States, prepared for AREVA, July 2006, Figure 6, p. 13. (BCG 2006)

[10] Idaho National Laboratory, Advanced Fuel Cycle Cost Basis, D.E. Shropshire, et.al. prepared for the U.S. Department of Energy, Office of Nuclear Energy, INL/EXT-07-12107, April 2007, Appendix O, p. O-21. (INL 2007a)

impact of interim storage unit costs for UOX, MOX, and FR metal fuel that are double the UB values and that are half of the LB values assumed above.

3.5 Spent Fuel Dry Storage Unit Costs

The NEA 2006 study included assumptions for the unit costs for dry storage of UOX and MOX SNF prior to disposal in Fuel Cycles 1 and 2, as well as dry storage of HLW resulting from recycling of UOX SNF and FR SNF in Fuel Cycles 2 and 3. These unit costs included a fixed unit cost for dry storage, but did not assume an annual cost for dry storage. The study assumed a unit dry storage cost for UOX SNF with a NV of $150/kgHM; a LB unit cost of $100/kgHM, and an UB unit cost of $250/kgHM. Based on EPRI researchers knowledge of the dry storage costs in the U.S., EPRI utilized these same assumptions as these unit costs were reasonable.

EPRI also utilized the NEA cost assumptions for dry storage of MOX SNF and MOX and FR HLW since there is currently no U.S. experience with storage of these materials. For dry storage of MOX SNF, the LB unit costs are $200/kgHM; the NV unit costs are $300/kgHM; and the UB unit costs are $500/kgHM (all are double unit costs for UOX SNF)..For dry storage of MOX and FR HLW, the NEA 2006 study assumed LB unit costs of $80,000/kgHM, NV unit costs of $120,000 per kgHM, and UB unit costs of $200,000/kgHM.

EPRI conducted sensitivity analyses to examine the impact of dry storage unit costs for UOX SNF, MOX SNF, MOX HLW and FR HLW that are double the UB values and that are half of the LB values assumed above.

3.6 Reprocessing Unit Costs

The NEA 2006 study included assumptions for the unit costs for reprocessing and conditioning of SNF. This included estimates for reprocessing UOX SNF using the PUREX process currently used in commercial reprocessing facilities in Europe and Japan, as modeled in Fuel Cycle 2; UOX SNF reprocessing using a UREX process currently under consideration as part of DOE’s GNEP program as modeled in Fuel Cycle 3; and reprocessing of FR metal SNF as modeled in Fuel Cycle 3 as pyroprocessing. Since reprocessing of FR SNF is currently being researched, there is much uncertainty regarding the costs of FR SNF reprocessing as well as the eventual waste stream volumes produced. As noted in the NEA 2006 study, “*the uncertainty is very large on the secondary waste flows of new technologies with exist only at laboratory scale or in conceptual phase.*”[11]

NEA 2006 assumed that the unit cost of reprocessing of UOX SNF using the PUREX process had a LB of $700/kgHM; a NV of $800/kgHM; and a UB of $900/kgHM. The unit cost for reprocessing of UOX SNF using the UREX process had a LB of $600/kgHM; a NV of $800/kgHM, and an UB of $1,200/kgHM. The unit cost for reprocessing FR SNF using pyroprocessing was estimated to have a LB of $1,000/kgHM; a NV of $2,000/kgHM; and an UB of $2,500/kgHM.

[11] NEA 2006, p. 63.

In addition to reviewing the unit costs contained in NEA 2006, EPRI reviewed studies regarding the reprocessing of SNF including the studies, Bunn 2003, MIT 2003, and BCG 2006. EPRI assumed that the unit costs for reprocessing UOX SNF using the PUREX process had a LB of $700/kgHM, the same value assumed in the NEA 2006 study and of a similar magnitude to the unit costs of $630/kgHM assumed in the BCG 2006 report.[12] EPRI's assumption for the NV for UOX SNF reprocessing using PUREX was $1,000/kgHM, the same nominal values assumed in the studies by MIT and Harvard University in 2003.[13] [14] EPRI assumed that the UB unit cost for UOX SNF reprocessing using PUREX was $1,250/kgHM – 25% higher than the NV.

EPRI assumed that the unit costs for reprocessing UOX SNF using the UREX process had a LB of $700/kgHM, the same value as the LB unit costs using the PUREX process. EPRI's assumption for the NV for UOX SNF reprocessing using PUREX was $1,000/kgHM, the same as the NV using the PUREX process. EPRI assumed that the UB unit cost for UOX SNF reprocessing using the UREX process was $1,663/kgHM – 33% higher than the UOX Purex process. This higher UB value for UREX was included to account for uncertainties that may exist due to the fact that the UREX process has only been utilized on a laboratory scale.

EPRI assumed that the unit costs for FR SNF pyroprocessing had a LB of $1,375/kgHM, approximately 10% higher than the UB cost of UOX PUREX reprocessing ($1250/kgHM). This is similar to the relationship between the LB value for FR SNF reprocessing in the NEA 2006 study compared to the UB for UOX PUREX ($1,000/kgHM compared to $900/kgHM). EPRI's assumption for the NV for FR SNF pyroprocessing was $2,750/kgHM, double the LB value; and the UB value was $4,125/kgHM, 50% higher than the NV value.

EPRI conducted sensitivity analyses to examine the impact of changes to the unit costs for UOX PUREX reprocessing, UOX UREX reprocessing, and FR SNF pyroprocessing, assuming costs that are double the UB values and that are half of the LB values assumed above.

3.7 Disposal Packaging Unit Costs

The NEA 2006 study included assumptions for the unit costs for packaging of UOX SNF, MOX SNF, UOX HLW, and HLW for disposal. Based on a comparison of the unit costs in the NEA study to the costs projected by the U.S. DOE for SNF packaging for the Yucca Mountain repository, it appears that the packaging costs in the SMAFS model include the cost of the disposal package as well as the costs associated with loading the waste package (repository surface facilities and loading operations). EPRI concluded that the NV unit costs for UOX SNF disposal packaging, $200/kgHM, were reasonable based on EPRI's estimate of packaging costs assuming the most recent DOE life cycle cost analysis available at the time this study was conducted.[15] EPRI assumed a LB value of $150/kgHM based on its estimate of packaging costs for disposal of SNF at Yucca Mountain. The UB value assumed by EPRI, $350/kgHM, is the same value utilized in the NEA 2006 study. For MOX SNF disposal packaging, EPRI assumed a

[12] BCG 2006, p. 13.
[13] MIT 2003, Appendix 5, Table A-5.D.3, p. 148
[14] Bunn 2003, Table 2.2, p. 20.
[15] U.S. DOE, Analysis of the Total System Life Cycle Cost of the Civilian Radioactive Waste Management Program, DOE/RW-0533, May 2001 (DOE 2001)

LB value of \$300/kgHM; a NV of \$400/kgHM, and a UB of \$700/kgHM. These values are double the values assumed by EPRI for UOX SNF disposal packaging.

EPRI utilized the unit costs for packaging of HLW that were assumed in the NEA 2006. The unit costs for UOX PUREX HLW and FR HLW disposal packaging assumed a LB of \$100,000/m^3 of HLW; a NV of \$200,000/m^3 of HLW; and a UB of \$400,000/m^3 of HLW.

EPRI conducted sensitivity analyses to examine the impact of changes to the unit costs for disposal packaging of UOX SNF, MOX SNF, UOX HLW, and HLW for disposal, assuming costs that are double the UB values and that are half of the LB values assumed above.

3.8 Waste Disposal Unit Costs

The NEA 2006 study includes unit costs for disposal of LILW-SL assuming near-surface disposal, LILW-LL assuming cavern-based geological disposal, and SNF and HLW assuming deep geologic disposal. The SNF and HLW unit costs are captured using two separate parameters – one for the unit cost of deposal galleries in \$/m^3 and a second for the unit volume of disposal galleries that must be excavated for heat generating waste, expressed in m^3/kW.

EPRI utilized the NEA 2006 study unit costs for LILW-SL and LILW-LL wastes. The LILW-SL unit costs assumed a LB of \$1,200/m^3, a NV of \$2,000/m^3, and a UB of \$3,000/m^3. These LILW-SL disposal costs appear to be reasonable estimates that bound the range of disposal costs for near-surface disposal in the U.S.[16] The LILW-LL unit costs for cavern-based disposal assumed a LB of \$4,000/m^3, a NV of \$6,000/m^3, and a UB of 8,000/m^3. Since there are presently no cavern-based geologic disposal facilities for long-lived LLW in the U.S., EPRI utilized the reference costs from the NEA 2006 study.

EPRI estimated the SNF and HLW disposal costs and parameters, based on information for the Yucca Mountain repository. The Yucca Mountain Final Environmental Impact Statement (FEIS) estimated the total excavated repository volume to be 4.4 million m^3.[17] Using subsurface facility costs from DOE 2001, escalated to 2007 dollars (2007\$), EPRI calculated a unit cost for SNF and HLW disposal galleries of \$2,500/m^3 (NV). As the LB value, EPRI utilized the LB of \$600/m^3 from the NEA 2006 study, and EPRI assumed that the UB is \$3,750/m^3 (50% higher than the EPRI NV). Regarding the unit volume of disposal galleries that must be excavated for heat generating waste, EPRI assumed a NV of 41 m^3/kW of SNF or HLW. This value is based on a waste package thermal limit for disposal of 11.8 kW/disposal package, an estimated 11,000 disposal packages and the total excavated repository volume of 4.4 million m^3.[18] Commercial SNF would comprise 60,000 MTHM of the proposed 70,000 MTHM repository capacity, resulting in 3.8 million m^3 of excavated repository volume for commercial SNF. As the LB value, EPRI utilized the NEA 2006 LB value of 10 m^3/kW. EPRI assumed that the UB is 62 m^3/kW (50% higher than the EPRI NV).

[16] U.S. General Accounting Office, Low-Level Radioactive Waste, Disposal Availability Adequate in the Short Term, but Oversight Needed to Identify Any Future Shortfalls, p. 20, GAO-04-604, June 2004. (GAO 2004).
[17] U.S. DOE, Final Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada, DOE/EIS-0250F, February 2002, Table 2-2, p. 2-9. (DOE 2002)
[18] Ibid.

3.8 Other Parameters

In addition to the unit cost parameters described above, the SMAFS model also includes the waste generation parameters described in Section 2. This includes LILW generated during the conversion, enrichment and fuel fabrication processes, during reactor operation, and during reprocessing operations. In addition, the SMAFS includes volumes of SNF and HLW resulting from the fuel cycle schemes considered. EPRI utilized the waste management parameters from NEA 2006.

The SMAFS model includes an estimate of the activity, thermal output and neutron source for SNF and HLW associated with each fuel cycle. EPRI calculated the activity, thermal output and neutron source for PWR SNF with a burnup of 60 GWD/MTU, cooled for 5 years and 50 years using the LWR Characteristics Database (RADDB), which calculates activity, thermal output and neutron source over a range of fuel burnup, enrichment and decay times. EPRI found the values utilized in the SMAFS model to in the same order of magnitude as those calculated by EPRI using RADDB.[19] Therefore, EPRI did not make changes to the values in the SMAFS model for Fuel Cycle 1 and also utilized the SNF and HLW waste management parameters for Fuel Cycles 2 and 3.

The SMAFS model includes values for the amount of time that SNF and HLW remains in interim storage and dry storage. There is no cost parameter associated with the timing of dry storage, therefore changing the SNF and HLW dry storage timing assumptions would not have an impact on the costs of the various fuel cycles. There is an interim storage parameter that is tied to the amount of time SNF and HLW remain in interim storage prior to dry storage or further processing. EPRI will examine the impact of this parameters on the overall cost of electricity of the three fuel cycles evaluated.

[19] Oak Ridge National Laboratory, Characteristics Database System, LWR Radiological Database, DOE/RW-0184-R1, July 1992.

4
BASE CASE FUEL CYCLE ANALYSIS

EPRI evaluated equilibrium costs fuel cycle and total generation costs for the three fuel cycles described previously: Fuel Cycle 1, representative of the once-through fuel cycle currently utilized in the U.S.; Fuel Cycle 2, Pu recycle using MOX fuel; and Fuel Cycle 3, a fully-closed advanced fuel cycle that is similar to the concepts under consideration as part of DOE's GNEP program. Using the unit costs described in Section 3, EPRI calculated a base case comparison of the three fuel cycle schemes that assumed the nominal values for the various cost components. The results of this fuel cycle cost comparison is described below, along with a comparison of the other fuel cycle and waste management indicators that are calculated in the SMAFS model including: uranium consumption; reduction in transuranic waste (TRU Loss); activity of SNF and HLW after 1,000 years; decay heat of SNF and HLW after 50 years and 200 years; and HLW and SNF volume to be disposed.

4.1 Comparison of Costs for Fuel Cycles 1, 2 and 3

As noted earlier, the SMAFS model was designed to calculate equilibrium fuel cycle costs and total generation costs assuming that all reactors in a given fuel cycle scheme operate at constant power and that all mass flows have reached an equilibrium. Assuming the NV unit costs for all input parameters, a comparison of the total generation costs, expressed as the cost of electricity in mills per kilowatt-hour electric (kWhe), is summarized in Table 4-1, including a breakout of the reactor costs, fuel cycle cost, and SNF and HLW disposal costs (which are a subset of the fuel cycle costs).

Assuming the NV unit costs, Fuel Cycle 1 has equilibrium reactor costs of 43.51 mills/kWhe and fuel cycle costs of 9.82 mills/kWhe for a total cost of electricity of 53.33 mills/kWhe. The reactor cost comprises more than 80% of the cost of electricity. Fuel Cycle 2 has a total cost of electricity of 54.06 mills/kWhe with 43.51 mills/kWhe in reactor costs and 10.55 mills/kWhe in fuel cycle costs. Note that the reactor costs for Fuel Cycle 1 and Fuel Cycle 2 are the same since both scenarios use a reference PWR for electricity production. Fuel cycle costs for Fuel Cycle 2 are higher than Scenario 1 due to the higher costs associated with reprocessing of UOX SNF as well as higher costs associated with MOX fuel fabrication. The increased costs associated with reprocessing and MOX fuel fabrication for Fuel Cycle 2 are offset somewhat by lower costs for uranium, conversion and enrichment and waste management compared to those for Fuel Cycle 1. Using Fuel Cycle 1 as the reference fuel cycle, Equilibrium costs for Fuel Cycle 2 were calculated to be approximately 1% higher than those for Fuel Cycle 1.

Fuel Cycle 3 has an equilibrium cost of electricity of 55.70 mills/kWhe with 46.71 mills/kWhe in reactor costs and 8.99 mills/kWhe in fuel cycle costs. The higher reactor costs are offset somewhat by lower fuel cycle and waste management costs. Equilibrium costs for Fuel Cycle 3 were calculated to be 4% higher than those for Fuel Cycle 1 and 3% higher than those for Fuel Cycle 2.

Table 4-1
Comparison of Equilibrium Total Generation Costs for Alternative Fuel Cycles Assuming Nominal Value Unit Costs (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Reactor Cost	43.51	43.51	46.71
Fuel Cycle Cost	9.82	10.55	8.99
Cost of Electricity	53.33	54.06	55.70
Relative Cost to Fuel Cycle 1	1.00	1.01	1.04
The Cost of Electricity equals the Reactor Cost plus Fuel Cycle Cost.			

The SMAFS model also includes LB and UB values for all unit costs utilized to calculate the equilibrium generation costs for the various fuel cycles. Table 4-2 summarizes the results for Fuel Cycles 1 through 3, assuming that all unit costs are either at the LB or UB values.

Table 4-2
Comparison of Equilibrium Total Generation Costs for Alternative Fuel Cycles Assuming Lower Bound and Upper Bound Value Unit Costs (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Unit Costs: Lower Bound			
Reactor Cost	22.77	22.77	24.86
Fuel Cycle Cost	6.63	7.17	5.85
Cost of Electricity	29.40	29.94	30.72
Relative Cost to Fuel Cycle 1	1.00	1.02	1.04
Unit Costs: Upper Bound			
Reactor Cost	72.41	72.41	77.74
Fuel Cycle Cost	13.39	14.16	13.27
Cost of Electricity	85.80	86.57	91.01
Relative Cost to Fuel Cycle 1	1.00	1.01	1.06
The Cost of Electricity equals the Reactor Cost plus Fuel Cycle Cost.			

Assuming the LB values for all unit costs, Fuel Cycle 1 was evaluated to have a total cost of electricity of 29.40 mills/kWhe – with a reactor cost of 22.77 mills/kWhe and fuel cycle costs of 6.63 mills/kWhe. Fuel Cycle 2 was evaluated to have a total cost of electricity of 29.93 mills/kWhe – with a reactor cost of 22.77 mills/kWhe and fuel cycle costs of 7.17 mills/kWhe. Fuel Cycle 3 was evaluated to have a total cost of electricity of 30.72 mills/kWhe – with reactor costs of 24.86 mills/kWhe and fuel cycle costs of 5.85 mills/kWhe. It should be noted that it is extremely unlikely that all unit costs would trend toward the LB values for all unit cost categories described in Section 3. However, what this analysis shows is that the reactor costs continue to dominate the total cost of electricity, representing 75% or more of the total costs. This indicates that, whether using a once-through fuel cycle or an closed fuel cycle with advanced technologies, the cost for constructing new nuclear power plants will be the most important factor in determining the total cost of electricity.

Assuming the UB values for all unit costs, Fuel Cycle 1 was evaluated to have a total cost of electricity of 85.80 mills/kWhe – with a reactor cost of 72.41 mills/kWhe and fuel cycle costs of 13.39 mills/kWhe. Fuel Cycle 2 was evaluated to have a total cost of electricity of 86.57 mills/kWhe – with a reactor cost of 72.41 mills/kWhe and fuel cycle costs of 14.16 mills/kWhe. Fuel Cycle 3 was evaluated to have a total cost of electricity of 91.01 mills/kWhe – with reactor costs of 77.74 mills/kWhe and fuel cycle costs of 13.27 mills/kWhe. Using the UB values, reactor costs comprise approximately 85% of the total cost of generation. Again, this indicates that the cost for constructing new nuclear power plants will be the most important factor in determining the total cost of electricity under any fuel cycle considered.

4.2 Comparison of Additional Fuel Cycle and Waste Management Indicators

In addition to the cost of generating electricity and fuel cycle cost, it is also important to recognize the differences among three fuel cycles in the other indicators discussed in Section 2.1 that are calculated by the SMAFS model. These indicators include uranium consumption; reduction in transuranic waste (TRU Loss); activity of SNF and HLW after 1,000 years; decay heat of SNF and HLW after 50 years and 200 years; LILW volumes to be disposed, HLW and SNF volume to be disposed and the total volume of disposal galleries to be excavated for disposal of SNF and HLW.

The SMAFS model calculates fuel cycle parameters on a unit per terra-watt hour (TWh) basis. As shown in Table 4-3, implementation of reprocessing and use of MOX fuel, as modeled in Fuel Cycle 2, will result in a reduction in transuranic waste and SNF and HLW volumes compared to Fuel Cycle 1 – reduced from 4.1 m^3 to 0.68 m^3 per TWh . There are also minor reductions in SNF and HLW activity at 1,000 years, SNF and HLW decay heat at 50 and 200 years, and in uranium consumption. However, in order to achieve significant improvements over the activity and thermal output of the SNF and HLW to be disposed, it would be necessary to implement advanced fuel cycles such as that modeled in Fuel Cycle 3. This shows not only a significant reduction in TRU waste and SNF and HLW volumes to be disposed, but also in the activity and thermal output of the waste to be disposed. SNF and HLW volumes are reduced from 4.1 m^3 per TWh to 0.40 m^3 per TWh and activity of waste is reduced from 2110 TBq to 933 TBq per TWh. The LILW-SL volumes for Fuel Cycle 2 increase compared to the volumes for Fuel Cycle 2, from 14.66 m^3 to 16.80 m^3 per TWh. Volumes for Fuel Cycle 3 are 13.74 m^3 per TWh. The LILW-LL volumes for Fuel Cycle 1 are 0.30 m^3 per TWh, compared to 1.90 m^3 per TWh for Fuel Cycle 2 and 2.33 m^3 per TWh for Fuel Cycle 3. The increased LILW volumes for Fuel Cycles 2 and 3 are a result of fuel reprocessing activities. The total volume of the disposal galleries to be excavated for disposal of SNF and HLW for Fuel Cycle 1 is 86.5 m^3 per TWh compared to 83.3 m^3 per TWh for Fuel Cycle 2, and 38.3 m^3 per TWh for Fuel Cycle 3. The disposal gallery volume per TWh for Fuel Cycle 2 is only 4% lower than that for Fuel Cycle 1.

This is due to the fact that the SNF and HLW decay heat at 50 years for the SNF and HLW disposed of Fuel Cycle 2 is only 4% lower than the decay heat of the SNF disposed of in Fuel Cycle 1. It should also be noted that the total volume of waste requiring disposal (SNF, HLW, and LILW) in Fuel Cycle 1, 19.06 m^3 per TWh, is lower than the total volume in Fuel Cycle 2, 19.38 m^3 per TWh. This is due to the increased LILW volumes generated during reprocessing. Moving to advanced fuel cycles, such as that modeled in Fuel Cycle 3, would result in a reduction in total waste volumes requiring disposal, estimated to be 16.47 m^3 per TWh. While the LILW volumes requiring disposal are somewhat higher than those for Fuel Cycle 1, the overall volume of waste requiring disposal decreases due to the significant decrease in HLW and SNF requiring disposal.

Figure 4-1 provides a comparison of a subset of the indicators shown in Table 4-2 (TRU loss, HLW and SNF volume, SNF/HLW activity, SNF/HLW decay heat, and uranium consumption) as well as the fuel cycle and total generation costs for the three scenarios using Fuel cycle 1, the once through fuel cycle, as the “reference” scenario to which Fuel Cycle 2 and 3 indicators are normalized.

Table 4-3
Comparison of Representative Indicators for Fuel Cycles 1, 2 and 3

Fuel Cycle Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
TRU Loss (kg/TWh)	29.78	20.34	0.10
HLW and SNF Volume (m^3/TWh)	4.1	0.6836	0.4019
SNF/HLW Activity (TBq/TWh), 1000 years	201	177	2.43
SNF/HLW Decay Heat (W/TWh), 50 years	2110	2031	933
SNF/HLW Decay Heat (W/TWh), 200 years	591	506	30
Uranium Consumption (kg/TWh)	20,723	18,448	12,991
LILW-SL (m^3/TWh)	14.66	16.80	13.74
LILW-LL (m^3/TWh)	0.30	1.90	2.33
Volume of Disposal Galleries to Be Excavated for Disposal of SNF/HLW (m^3/TWh)	86.5	83.3	38.3
Total Volume Waste (SNF, HLW, LILW) (m^3/TWh)	19.06	19.38	16.47

As shown in Figure 4-1, the majority of the indicators analyzed in the SMAFS model are similar when comparing the results for Fuel Cycle 1 and Fuel Cycle 2. Fuel Cycle 2 has a lower volume of SNF and HLW and TRU waste requiring disposal, but there is not an appreciable difference between the other indicators as noted in the discussion regarding Table 4-3. Total costs, fuel cycle costs, uranium consumption, activity and decay heat are a similar order of magnitude for Fuel Cycle 1 and 2.

However, there is a significant reduction in the amount of TRU waste and SNF and HLW equiring disposal for Fuel Cycle 3 compared to Fuel Cycle 1. There are also significant reductions in the decay heat of SNF and HLW after 200 years and the activity of SNF and HLW requiring disposal. These waste management indicators show the potential benefits that a closed fuel cycle could have in reducing the volume, activity and decay heat of SNF and HLW requiring disposal. While reactor costs drive the total generation costs, in order to achieve these reductions in the waste management indicators, additional R&D will be needed to achieve these potential reductions.

As shown in Table 4-1 and Figure 4-1, there is not a significant difference between the total generation costs and the fuel cycle costs for the three fuel cycles evaluated. However, it should be recognized that the unit costs associated with Fuel Cycle 1 and Fuel Cycle 2 are based on current technology while those for Fuel Cycle 3 are based technologies that are currently in the research and development stage. Therefore, there is a higher risk that cost parameters associated with Fuel Cycle 3 may have higher unit costs than the NV costs shown in Table 4-1 and Figure 4-1. Since the comparison of unit costs in Tables 4-1 and 4-2 indicate that the unit cost for reactors drives total generation cost, this would indicate that the cost of FR technology is the most important parameter for Fuel Cycle 3 costs.

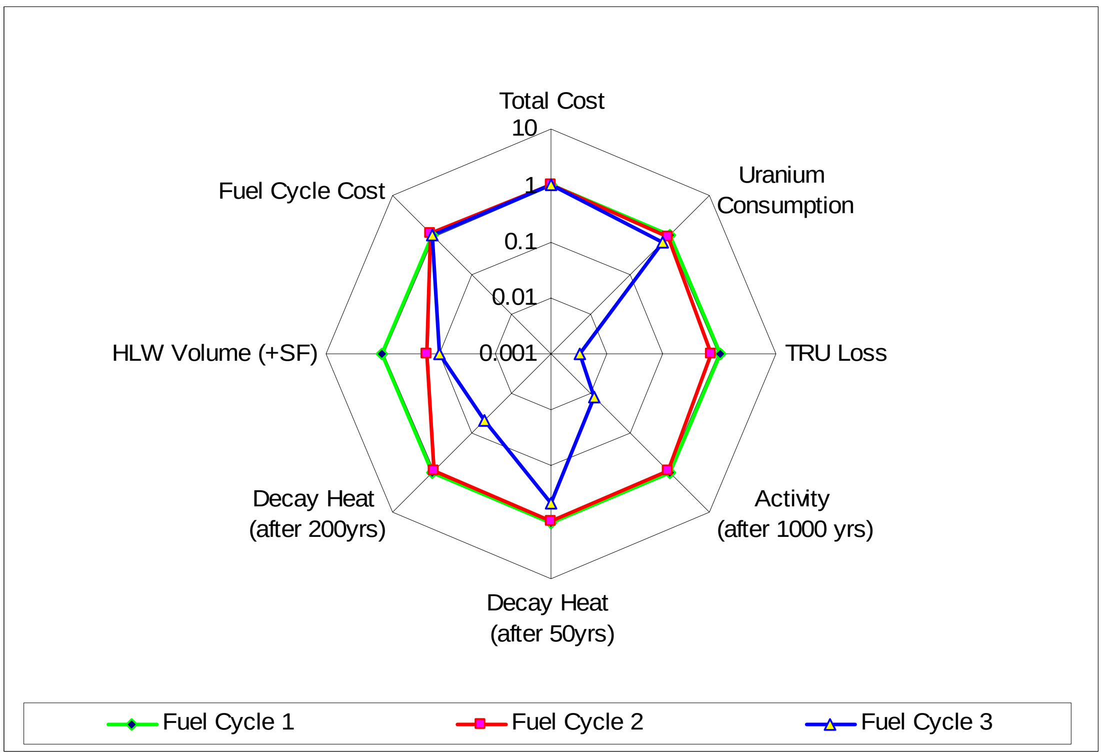

Figure 4-1
Comparison of Representative Indicators For Fuel Cycles 1, 2, and 3, Using Fuel Cycle 1 as the Reference Fuel Cycle and NV Unit Costs

5
SENSITIVITY ANALYSIS

EPRI analyzed the sensitivity of total electricity costs and fuel cycle costs to a changes in the unit cost parameters by varying unit cost parameters together, and one-by-one. This section examines sensitivity analysis associated with using a mix of UB, LB or NV unit costs for various cost parameters to determine if there are any additional cost parameters, other than reactor costs, to which the three fuel cycles are sensitive. In addition, EPRI performed sensitivity analyses that utilize unit costs that are lower than the LB values and higher than the UB values to assist in determining the relative importance of various cost parameters. This can assist the industry in determining areas in which there may be a benefit to directing R&D resources in the future.

5.1 Sensitivity 1: Reactor Related Costs at UB, Remaining Unit Costs at NV

Based on the analyses summarized in Section 4, it is clear that one of the most important unit cost parameters to overall nuclear generation costs is the unit cost of the nuclear reactors that are utilized in future fuel cycles. Section 4 examined total electricity generation costs and fuel cycle costs assuming that all unit cost parameters were at the NV, UB, or LB costs.

Sensitivity 1 assumes a UB values for reactor unit costs including the unit cost of installed power ($3,000/kWe for a PWR and $3,600/kWe for a FR); fixed charge rate for investment of 12%; fixed charge rate for D&D of 8%; an annual reactor operations and maintenance costs that is 5% of the reactor capital cost; and load factors of 95%. All other cost parameters are set to the NV. Table 5-1 presents a comparison of the total generation costs for the three fuel cycles examined in the previous section, including a breakout of the reactor costs, fuel cycle cost, and SNF and HLW disposal costs.

Table 5-1
Sensitivy 1: Comparison of Total Generation Costs for Alternative Fuel Cycles Assuming Reactor Costs at Upper Bound Value, Remaining Costs at Nominal Values (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Reactor Cost	72.41	72.41	77.74
Fuel Cycle Cost	9.82	10.55	8.99
Cost of Electricity	82.23	82.96	86.73
Relative Cost to Fuel Cycle 1	1.00	1.01	1.05
The Cost of Electricity equals the Reactor Cost plus Fuel Cycle Cost.			

Fuel Cycle 1 has equilibrium reactor costs of 72.41 mills/kWhe and fuel cycle costs of 9.82 mills/kWhe for a total cost of electricity of 82.23 mills/kWhe. Fuel Cycle 2 has an equilibrium cost of electricity of 82.96 mills/kWhe with 72.41 mills/kWhe in reactor costs and 10.55 mills/kWhe in fuel cycle costs. Fuel Cycle 3 has an equilibrium cost of electricity of 86.73 mills/kWhe with 77.74 mills/kWhe in reactor costs and 8.99 mills/kWhe in fuel cycle costs. Equilibrium costs for Fuel Cycle 2 are 1% higher than those for Fuel Cycle 1. Fuel Cycle 3 total generation costs were calculated to be 5% higher than those for Fuel Cycle 1 and 4% higher than those for Fuel Cycle 2. The relative differences between the three fuel cycles assuming reactor costs at the UB values are not significantly different from those summarized in Table 4-1, assuming all costs were at the NV. Using the UB reactor unit costs results in reactor costs that are 88% of the total generation cost – again indicating that the capital and operating costs of nuclear reactors will be one of the major cost drivers of the cost of electricity.

5.2 Sensitivity 2: Reactor Unit Costs at LB, Remaining Unit Costs at NV

Sensitivity 2 assumes LB values for reactor unit costs including the unit cost of installed power ($2,000/kWe for a PWR and $2,500/kWe for a FR); fixed charge rate for investment of 6%; fixed charge rate for D&D of 8%; an annual reactor operations and maintenance costs that is 3% of the reactor capital cost; and load factors of 85% for PWR and 80% for FR . All other cost parameters are set to the NV. Table 5-2 presents a comparison of the total generation costs, including a breakout of the reactor costs, fuel cycle cost, and SNF and HLW disposal.

Table 5-2
Sensitivy 2: Comparison of Total Generation Costs for Alternative Fuel Cycles Assuming Reactor Costs at Lower Bound Value, Remaining Costs at Nominal Values (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Reactor Cost	22.77	22.77	24.86
Fuel Cycle Cost	9.82	10.55	8.99
Cost of Electricity	32.59	33.32	33.85
Relative Cost to Fuel Cycle 1	1.00	1.02	1.04
The Cost of Electricity equals the Reactor Cost plus Fuel Cycle Cost.			

Fuel Cycle 1 has equilibrium reactor costs of 22.77 mills/kWhe and fuel cycle costs of 9.82 mills/kWhe for a total cost of electricity of 32.59 mills/kWhe. Fuel Cycle 2 has an equilibrium cost of electricity of 33.32 mills/kWhe with 22.77 mills/kWhe in reactor costs and 10.55 mills/kWhe in fuel cycle costs. Fuel Cycle 3 has an equilibrium cost of electricity of 33.85 mills/kWhe with 24.86 mills/kWhe in reactor costs and 8.99 mills/kWhe in fuel cycle costs. Total generation costs for Fuel Cycle 2 are 2% higher than those for Fuel Cycle 1. Fuel Cycle 3 total generation costs are 4% higher than those for Fuel Cycle 1 and 2% higher than those for Fuel Cycle 2. Assuming a LB reactor unit cost and NV for all other cost parameters, the reactor cost comprises approximately 70% of the total generation cost.

5.3 Sensitivity 3: Reactor Unit Costs at NV, Remaining Unit Costs at UB

Sensitivity 3 assumes NV values for reactor unit costs including the unit cost of installed power and that all other cost parameters are set to the UB values. The other cost parameters include front-end fuel cycle, reprocessing and waste management costs. Table 5-3 presents a comparison of the total generation costs, including a breakout of the reactor costs, fuel cycle cost, and SNF and HLW disposal costs.

Table 5-3
Sensitivy 3: Comparison of Total Generation Costs for Alternative Fuel Cycles Assuming Reactor Costs at Nominal Value, Remaining Costs at UB Values (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Reactor Cost	43.51	43.51	46.71
Fuel Cycle Cost	13.39	14.17	13.27
Cost of Electricity	56.90	57.68	59.98
Relative Cost to Fuel Cycle 1	1.00	1.01	1.05
The Cost of Electricity equals the Reactor Cost plus Fuel Cycle Cost.			

Under Sensitivity 3 assuming NV reactor unit costs and UB values for all other cost parameters, the reactor cost comprises approximately more than 75% of the total generation cost. Fuel Cycle 1 has reactor costs of 43.51 mills/kWhe and fuel cycle costs of 13.39 mills/kWhe for a total cost of electricity of 56.90 mills/kWhe. Fuel Cycle 2 has an equilibrium cost of electricity of 57.68 mills/kWhe with 43.51 mills/kWhe in reactor costs and 14.17 mills/kWhe in fuel cycle costs. Fuel Cycle 3 has an equilibrium cost of electricity of 59.98 mills/kWhe with 46.71 mills/kWhe in reactor costs and 13.27 mills/kWhe in fuel cycle costs. Equilibrium costs for Fuel Cycle 2 are 1% higher than those for Fuel Cycle 1. Fuel Cycle 3 total generation costs were calculated to be 5% higher than those for Fuel Cycle 1 and 4% higher than those for Fuel Cycle 2. Thus, even with all other costs at the UB values, the reactor costs continue to drive the total cost of electricity.

5.4 Sensitivity 4: Front-End Fuel Cycle Cost Sensitivity

Based on this above sensitivity analyses, reactor costs will generally comprise 70% or more of the total cost of electricity. In order to determine the impact of changes in front-end fuel cycle costs on overall fuel cycle costs (which include waste management) and on total generation costs, EPRI varied the front-end fuel cycle parameters over a range of costs from costs 50% lower than the LB unit costs to twice the UB unit costs for each front-end parameter. This included costs for uranium, conversion, enrichment, fuel fabrication, and reprocessing, as summarized in Table 5-4.

Table 5-4
Sensitivity 4: Fuel Cycle Parameter Values for Fuel Cycle Cost Sensitivity Analysis

Parameter Name	Low Value (50% of LB)	LB	UB	High Value (2 x UB)
Unit cost of natural uranium ($/kgU)	78	156	364	728
Unit cost of conversion ($/kgU)	5	10	20	40
Unit cost of enrichment ($/SWU)	60	120	160	320
Unit cost of UOX-fuel fabrication ($/kgHM)	100	200	300	600
Unit cost of MOX-fuel fabrication ($/kgHM)	500	1,000	1500	3,000
Unit cost of FR-Metal fuel fabrication ($/kgHM)	700	1,400	5000	10,000
Unit cost of UOX PUREX ($/kgHM)	350	700	1250	2,500
Unit cost of UOX UREX ($/kgHM)	350	700	1375	3,326
Unit cost of FR-Metal fuel PYRO ($/kgHM)	687	1,375	4125	8,250

EPRI varied the individual front-end fuel cycle parameters one-at-a-time over the range of costs presented in Table 5-4. The fuel cycle parameters that impacted the total cost of electricity by 10% or less included uranium, conversion, enrichment, fuel fabrication, UOX PUREX reprocessing, and FR-metal fuel pyroprocessing.

Increasing the unit cost of natural uranium from $78/kgU to $728/kgU, resulted in Fuel Cycle 2's relative cost of electricity varying from +2% to -1% of the cost of electricity for Fuel Cycle 1; and Fuel Cycle 3's relative cost of electricity varying from +8% to -2% relative to Fuel Cycle 1, as shown in Figure 5-1. Fuel Cycle 2's relative fuel cycle costs vary from +20% to -2% relative to Fuel Cycle 1 as uranium prices increase and Fuel Cycle 3's relative fuel cycle costs varying from +10% to -23% relative to Fuel Cycle 1. This indicates that as the price of natural uranium increases, fuel cycles that reduce uranium consumption may become more attractive in terms of both fuel cycle costs and total electricity costs.

The only individual fuel cycle parameter that had more than a ±10% impact on the total cost of electricity for the cost range evaluated was the unit cost for UREX reprocessing. Varying the unit costs associated with UREX reprocessing from $350/kgHM to $3,326/kgHM resulted in Fuel Cycle 3's relative cost of electricity varying from +3% to +11% of the cost of electricity relative to Fuel Cycle 1.

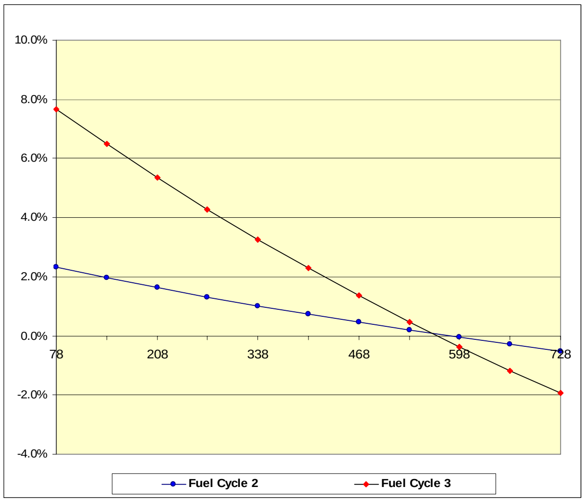

Figure 5-1
Dependence of Relative Cost of Electricity on Uranium Price with Fuel Cycle 1 as Reference

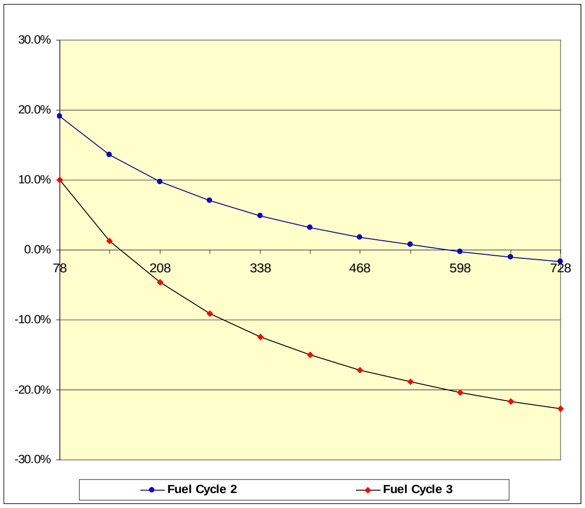

Figure 5-2
Dependence of Relative Fuel Cycle Cost on Uranium Price with Fuel Cycle 1 as Reference

As discussed in Section 3, there has been a ten-fold increase in the price of uranium over the past four years and supply-demand pressures are expected to keep the price of uranium at similar price levels into the future. There has also been an increase in the price of enrichment services due to supply-demand pressures. Increasing front-end fuel cycle costs will result in fuel cycles that include recycling becoming more attractive, assuming all other costs remain at the NV. In order to determine the impact of an increase in front-end fuel cycle costs, EPRI varied the costs for natural uranium, conversion, enrichment, and UOX fuel fabrication within the ranges specified in Table 5-4. All other cost parameters were held at the NV.

As shown in Figure 5-3, varying the unit cost of natural uranium, conversion, enrichment and UOX fuel fabrication within the cost ranges identified in Table 5-4, resulted in Fuel Cycle 2's relative cost of electricity varying from +3% to -1% of the cost of electricity for Fuel Cycle 1; as uranium fuel costs increased. Fuel Cycle 3's relative cost of electricity varies from +9% to -4% of the cost of electricity for Fuel Cycle 1, as uranium fuel costs increase. There is a much larger impact on the relative fuel cycle costs as shown in Figure 5-4. Fuel Cycle 2's relative fuel cycle costs vary from +32% to -3% relative to Fuel Cycle 1 as uranium fuel costs increase. Fuel Cycle 3's relative fuel cycle costs varying from +30% to -25% relative to Fuel Cycle 1. Thus, if there is continued upward pressure on uranium, conversion, enrichment and UOX fuel fabrication costs, both partially closed fuel cycles that includes reprocessing and fully closed fuel cycles implementing fast reactors will become more attractive both in terms of fuel cycle and electricity cost and also due to the reduced uranium consumption.

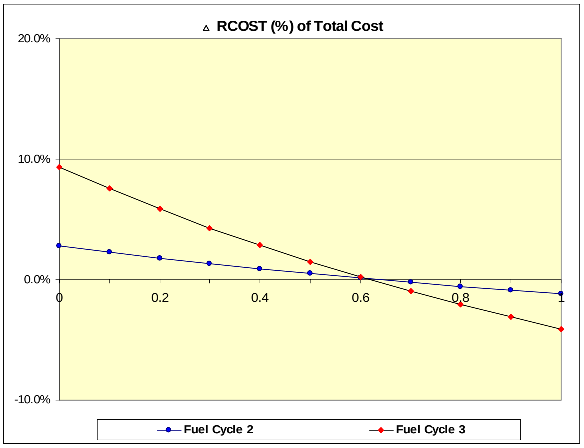

Figure 5-3
Dependence of Relative Cost of Electricity on Cost of Uranium, Conversion, Enrichment and UOX Fabrication Costs, Fuel Cycle 1 as Reference

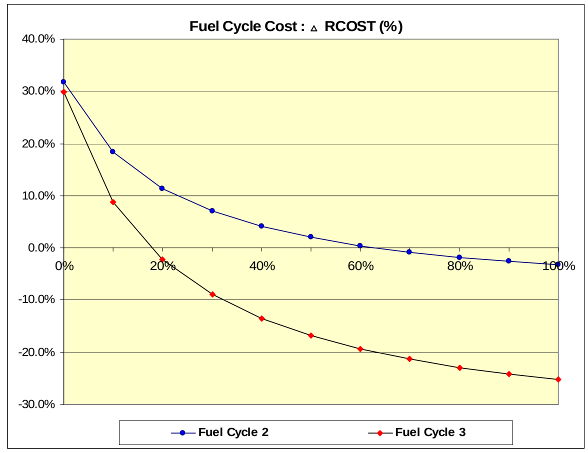

Figure 5-4
Dependence of Relative Fuel Cycle Cost on Cost of Uranium, Conversion, Enrichment and UOX Fabrication Costs, Fuel Cycle 1 as Reference

EPRI also varied the fuel cycle costs that are specific to Fuel Cycle 2 and Fuel Cycle 3 over the range of costs identified in Table 5-4 to determine the impact on the cost of electricity and fuel cycle costs relative to Fuel Cycle 1. EPRI varied the costs associated with Fuel Cycle 2, namely MOX fuel fabrication and UOX PUREX reprocessing; as well as the costs associated with Fuel Cycle 3 including, FR metal fuel fabrication, UOX UREX reprocessing, and FR metal fuel pyroprocessing. All other cost parameters were held at the NV.

As shown in Figure 5-5, varying the unit cost for fuel fabrication and reprocessing associated with Fuel Cycle 2 and Fuel Cycle 3, within the cost ranges identified in Table 5-4, resulted in Fuel Cycle 2 relative costs of electricity varying from -1% to +7% of the cost of electricity for Fuel Cycle 1, as recycling costs increased. Fuel Cycle 3 relative cost of electricity varies from +1% to +18% of the cost of electricity for Fuel Cycle 1, as Fuel Cycle 3 recycling costs increased. There is a much larger impact on the relative fuel cycle costs as shown in Figure 5-6. Fuel Cycle 2's relative fuel cycle costs vary from -6% to +40% relative to Fuel Cycle 1 as Fuel Cycle 2 recycling costs increased. Fuel Cycle 3's relative fuel cycle costs varying from -30% to +70% relative to Fuel Cycle 1. Changes in recycling-related costs for Fuel Cycle 2 and Fuel Cycle 3 that are 50% lower than the LB unit costs and twice the UB values result in greater changes to fuel cycle costs and total electricity costs when compared to the variability in fuel cycle costs and total generation costs associated with changing Fuel Cycle 1 UOX fuel costs as shown in Figures 5-3 and 5-4, above.

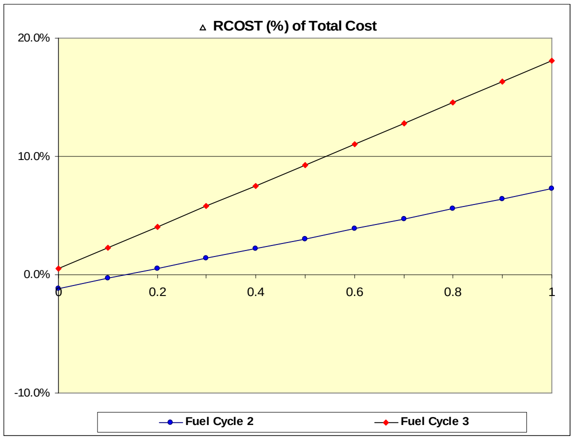

Figure 5-5
Dependence of Relative Cost of Electricity on Fuel Fabrication and Reprocessing for Fuel Cycles 2 and 3, Fuel Cycle 1 as Reference

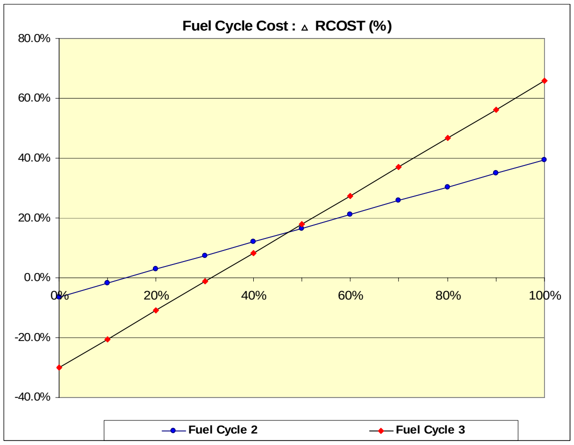

Figure 5-6
Dependence of Relative Fuel Cycle Cost on Fuel Fabrication and Reprocessing for Fuel Cycles 2 and 3, Fuel Cycle 1 as Reference

5.5 Sensitivity 5: Waste Management Cost Sensitivity

In order to determine the impact of changes in waste management costs on overall fuel cycle costs (which include waste management) and on total generation costs, EPRI varied a subset of the waste management parameters over the range of costs identified in Table 5-5. This included costs for UOX SNF interim storage, MOX SNF interim storage, FR SNF interim storage, UOX dry storage, MOX dry storage, UOX PUREX HLW dry storage, UOX UREX HLW dry storage, and FR pyroprocessing HLW dry storage, and transportation costs for UOX SNF, MOX SNF and FR metal SNF, as summarized in Table 5-5.

Unit costs associated with Fuel Cycle 1 waste management parameters were varied over the range of unit costs shown in Table 5-5 including: UOX SNF interim storage, UOX SNF dry storage, and UOX SNF transport. When these waste management parameters were varied one at a time, there was less than a ±2% change in the overall cost of electricity for Fuel Cycle 1. If these waste management parameters are varied together proportionally over the ranges shown in Table 5-4, the resulting waste management costs ranged from 0.94 to 2.58 mills/kWhe, a variation of approximately -30% to +275% of the Fuel Cycle 1 waste management costs for the NV, 1.39 mills/kWhe. However, these combined changes to the Fuel Cycle 1 waste management parameters have an impact of less than ±2% on the overall cost of electricity for Fuel Cycle 1 assuming NV costs.

Similarly, the Fuel Cycle 2 waste management unit cost parameters were varied over the range of unit costs shown in Table 5-5 including: UOX SNF interim storage, MOX SNF interim storage, UOX and MOX SNF transport, MOX SNF dry storage, and UOX Purex HLW dry storage. When these waste management parameters were varied one at a time, there was less than a ±2% change in the overall cost of electricity for Fuel Cycle 2. When these waste management parameters were varied together proportionally over the ranges shown in Table 5-4, the resulting waste management costs ranged from 0.61 to 1.89 mills/kWhe, a variation of -30% to +200% compared to Fuel Cycle 2 waste management costs using the NV unit costs (0.94 mills/kWhe). Despite the large fluctuations in fuel cycle costs, these combined changes to the Fuel Cycle 2 waste management parameters have an impact of less than -1% to +8% on the overall cost of electricity for Fuel Cycle 2 assuming NV costs.

Table 5-5
Sensitivity 5: Fuel Cycle Parameter Values for Waste Management Cost Sensitivity Analysis

Parameter Name	Low Value (50% of LB)	LB	UB	High Value (2 x UB)
UOX SNF interim storage ($/kgHM)	20	40	60	120
UOX SNF interim storage ($/kgHM/year)	2.5	5	5	10
MOX SNF interim storage ($/kgHM)	30	60	240	480
MOX SNF interim storage ($/kgHM/year)	2.5	5	20	10
FR Metal SNF interim storage (fixed)	30	60	240	480
FR Metal SNF interim storage ($/kgHM/year)	2.5	5	20	40
UOX SNF dry storage ($/kgHM)	50	100	250	500
MOX SNF dry storage($/kgHM)	400	200	500	1000
UOX PUREX HLW dry storage ($/kgHM)	40,000	80,000	200,000	400,000
UOX UREX HLW dry storage ($/kgHM)	40,000	80,000	200,000	400,000
FR PYRO HLW Dry Storage ($/kgHM)	40,000	80,000	200,000	400,000
UOX SNF Transport ($/kgHM)	37.5	75	125	250
MOX SNF Transport ($/kgHM)	62.5	125	500	1,000
FR Metal SNF Transport ($/kgHM)	62.5	125	500	1,000

Fuel Cycle 3 waste management unit cost parameters were varied over the range of unit costs shown in Table 5-5 including: UOX SNF interim storage, FR metal SNF interim storage, UOX UREX HLW dry storage, FR metal pyroprocessing HLW dry storage, and UOX SNF transport, and FR metal SNF transport. When these waste management parameters were varied one at a time, there was less than a ±2% change in the overall cost of electricity for Fuel Cycle 3. When these waste management parameters were varied together proportionally over the ranges shown in Table 5-4, the resulting waste management costs ranged from 0.43 to 1.37 mills/kWhe, a variation of approximately -30% to +210% compared to Fuel Cycle 3 waste management costs using the NV unit costs, 0.65 mills/kWhe shown in Table 4-1. However, these combined changes to the Fuel Cycle 1 waste management parameters have an impact of less than ±1% on the overall cost of electricity for Fuel Cycle 2 assuming NV costs.

This sensitivity analysis shows that overall electricity costs are indifferent to changes in the costs associated with interim storage, dry storage, and transport of SNF and HLW over the range of fuel cycles evaluated. This is due to the fact that waste management costs represent approximately 1% to 5% of the cost of electricity, depending upon the fuel cycle being examined. While there may be some technical challenges associated with storage and transport of advanced fuels for fast reactors and the resulting waste products, the costs associated with these activities are generally minor compared to other fuel cycle costs and overall the overall cost of generating electricity.

5.6 Sensitivity 6: Packaging and Disposal Cost Sensitivity

EPRI varied the fuel cycle parameters associated with SNF and HLW packaging and disposal one-at-a-time over the range of costs presented in Table 5-6, including UOX and MOX SNF packaging, UOX PUREX and UOX UREX HLW packaging, FR pyroprocessing HLW packaging, unit costs for disposal galleries for SNF and HLW, and the unit volume of excavated disposal galleries for heat generating SNF and HLW. Individually, these packaging and disposal parameters impact the total cost of electricity by less than 5%.

Table 5-6
Sensitivity 6: Fuel Cycle Parameter Values for Packaging and Disposal Cost Sensitivity Analysis

Parameter Name	Low Value (50% of LB)	LB	UB	High Value (2 x UB)
UOX SNF packaging ($/kgHM)	75	150	350	700
MOX SNF packaging ($/kgHM)	150	300	750	1400
UOX PUREX HLW packaging ($/kgHM)	50,000	100,000	400,000	800,000
UOX UREX HLW packaging ($/kgHM)	50,000	100,000	400,000	800,000
FR Pyroprocessing HLW packaging ($/kgHM)	50,000	100,000	400,000	800,000
Unit cost of disposal galleries for spent fuel ($/m^3)	300	600	3,750	7,500
Unit cost of disposal galleries for HLW ($/m^3)	300	700	3,750	3,750
Unit volume of disposal galleries that have to be excavated for heat generating waste (m^3/kW)	5	10	62	124

As shown in Figure 5-7, varying all of the parameters associated with packaging and disposal of SNF and HLW proportionally within the ranges identified in Table 5-6, resulted in Fuel Cycle 2's relative cost of electricity varying by +2% to +0.1% of the cost of electricity for Fuel Cycle 1; as packaging and disposal costs increased. Fuel Cycle 3 relative costs of electricity vary from +5% to +1% of the cost of electricity for Fuel Cycle 1, as packaging and disposal costs increased. Overall costs of electricity decrease for Fuel Cycle 2 and Fuel Cycle 3 as packaging and disposal costs increase due to the smaller volumes of SNF and HLW requiring disposal compared to Fuel Cycle 1. This was demonstrated in Table 4-3, which presented the total volume of SNF and HLW requiring packaging and disposal decreasing from 4.1 m^3/TWh for Fuel Cycle 1 to 0.40 m^3/TWh for Fuel Cycle 3.

The impact on the relative fuel cycle costs associated with varying the packaging and disposal costs is presented in Figure 5-8. Fuel Cycle 2's relative fuel cycle costs decrease from +10 to +0.2% relative to Fuel Cycle 1 as packaging and disposal costs increase. Fuel Cycle 3's relative fuel cycle costs decrease from -5% to -20% relative to Fuel Cycle 1 fuel cycle costs as packaging and disposal costs increase. Thus, if there continue to be increases in the cost of packaging and disposal of SNF and HLW, the resulting may be that fuel cycles that include reprocessing and advanced reactors will become more economical.

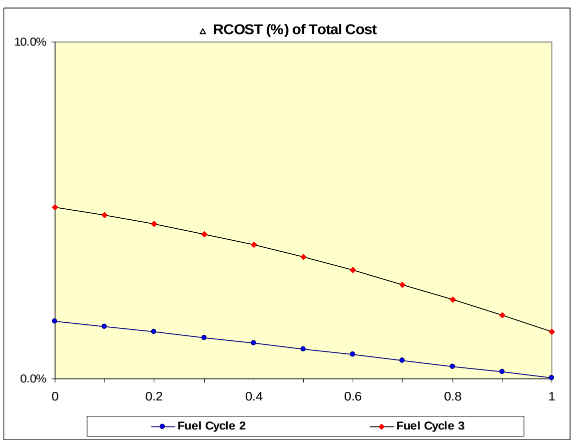

Figure 5-7
Dependence of Relative Cost of Electricity on Packaging and Disposal Costs, Fuel Cycle 1 as Reference

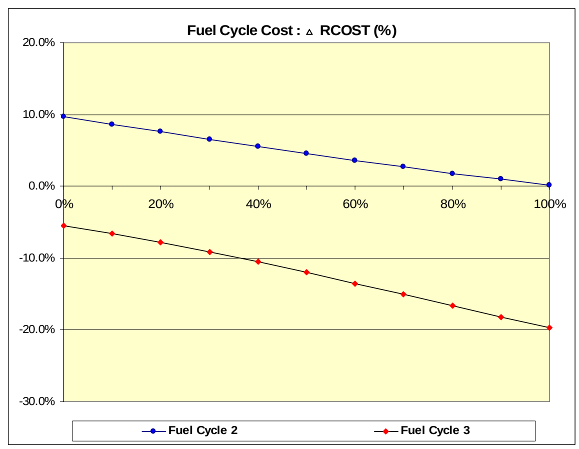

Figure 5-8
Dependence of Relative Fuel Cycle Cost on Packaging and Disposal Costs el Fabrication and Reprocessing, Fuel Cycle 1 as Reference

5.7 Sensitivity 7: Interim Storage Time Sensitivity

The SMAFS model includes values for the amount of time that SNF and HLW remains in interim storage and dry storage. As noted earlier, the parameter for the amount of time assumed for dry storage of SNF and HLW (assumed to be 50 years in Fuel Cycle 1) does not have a cost associated with it. Therefore, changing the time associated with dry storage will not result in any change in the fuel cycle and electricity generation costs. The unit costs for dry storage must therefore capture the long-term operations and maintenance costs as part of the fixed unit cost.

The parameter for the amount of time that SNF and HLW remain in interim storage at reactor sites prior to dry storage or prior to further processing does have a unit cost per year associated with it. The interim storage periods include:

- Fuel Cycle 1:
  - Interim storage of 5 years prior to dry storage.
- Fuel Cycle 2:
  - Interim storage of UOX fuel for 5 years prior to PUREX reprocessing.
  - Interim storage of MOX fuel for 5 years prior to disposal.
- Fuel Cycle 3:
  - Interim storage of UOX fuel for 5 years prior to UREX reprocessing.
  - Interim storage of FR metal fuel for 2 years prior to pyroprocessing.

EPRI evaluated an increase in the interim storage times in the three scenarios to 50 years to determine the impact on fuel cycle costs and total generation costs. Under Fuel Cycle 1, the total fuel cycle costs increased from 9.82 mills/kWhe to 10.28 mills/kWhe, a 5% increase in fuel cycle costs. The overall cost of electricity increased from 53.32 mills/kWhe to 53.78 mills/kWhe, less than a 1% increase in the cost of electricity generation. Under Fuel Cycle 2, fuel cycle costs increased from 10.55 mills/kWhe to 11.04 mills/kWhe, a 5% increase, with less than a 1% increase in the overall cost of electricity. Under Fuel Cycle 3, fuel cycle costs increased from 8.99 mills/kWhe to 9.44 mills/kWhe, a 5% increase, with less than a 1% increase in the overall cost of electricity. Just as overall waste managements costs were shown to have a minor impact on the total cost of electricity generation, the amount of time that SNF remains in interim storage will have a minor impact on fuel cycle costs as well as the cost of electricity.

6 FUEL CYCLE FACILITY FINANCING ALTERNATIVES

In order to close the nuclear fuel cycle in the United States, it will be necessary to construct and operate facilities for recycling of SNF – both recycling of thermal reactor fuel from PWRs and recycling of advanced FR SNF. Development of recycling facilities will require large capital investments by the government, the private sector or some combination of government and the private sector. This section evaluates potential financing alternative for a 2,500 MTHM recycling facility with a range of debt and equity positions, return on investment, debt interest rates, financing periods, and total overnight costs.

6.1 Fuel Cycle Facility Financial Assumptions and Operating Parameters

The financial assumptions and operating parameters utilized in EPRI's analysis of financial alternatives for recycling facilities are summarized in Table 6-1. EPRI considered two financial alternatives for financing and operating a recycling facility: (1) Government funding for construction and operation; and (2) Private sector funding for construction and operation. EPRI's base case analysis considered a recycling facility with a capacity of 2,500 metric tons heavy metal (MTHM) per year with an operating period of 30 years. As shown in Table 6-1, EPRI's base case analysis assumed that a 2,500 MTHM recycling facility's overnight cost would be $12.0 billion and that annual costs for operations and maintenance (O&M) of the facility would be $360/kgHM, estimates used by DOE in 2006 in an evaluation of the economics for GNEP deployment.[20]

For the government funding alternative, EPRI assumed that the 100% of the $12.0 billion overnight cost would be financed as debt, at an interest rate of 4% per year. Since the government funding alternative is financed as 100% debt, there is no equity on which to earn a return on investment. EPRI assumed that there would be no state, local or federal taxes. The financing period and facility operating period are both assumed to be 30 years.

For the private sector funding alternative, EPRI assumed that 40% of the overnight costs would be financed as debt at an interest rate of 10%. The 60% equity would earn a 16% return on investment. Similar debt and equity ratios were made in the DOE's 2006 GNEP analysis. (Crozat 2006) Federal taxes of 33% per year were assumed. State and local taxes of 5% per year were assumed. Similar tax rates were assumed in a December 2005 analysis of nuclear fuel

[20] Crozat, Matthew, Analyst, U.S. DOE, Office of Nuclear Energy, *Evaluating the Economics for GNEP Deployment*, First Annual Nuclear Fuel Cycle Monitor Global Nuclear Renaissance Summit, Washington, DC. December 6, 2006 (Crozat 2006).

financing strategies performed by Idaho National Laboratory staff.[21] The financing period and facility operating period are both assumed to be 30 years.

Table 6-1
Fuel Cycle Facility Analysis Financial Assumptions

	Government Funding	Private Sector Funding
Plant Capacity	2,500 MTHM/year	2,500 MTHM/year
Operating Period	30 years	30 years
Overnight Cost	$12.0 Billion	$12.0 Billion
Operating and Maintenance Cost	$360/kgHM	$360/kgHM
Debt Ratio	100%	40%
Debt Interest Rate	4%	10%
Equity Ratio	0%	60%
Return on Investment	not applicable	16%
Federal Taxes	not applicable	33%
State and Local Taxes	not applicable	5%
Financing Period	30 years	30 years

In addition to calculating unit costs for a fuel cycle facility using the above base case assumptions with either government or private-sector funding, EPRI also performed sensitivity analyses to determine the impact of changes to the financial and operating assumptions. As summarized in Table 6-2, EPRI utilized values that are ±25% of the financial assumption values contained in Table 6-1. Plant capacity was analyzed at a lower bound of 1,900 MTHM per year and an upper bound of 3,000 MTU per year. The overnight costs were evaluated at $9.0 billion and $15.0 billion. It should be noted that the BCG 2006 economic assessment of used fuel management estimated the overnight capital costs for a recycling facility with a capacity of 2,500 MTHM per year to be $16 billion.[22] O&M costs of $270/kgHM and $450/kgHM were assessed. Regarding the specific financial assumptions associated with government financing, the 100% government debt financing was not changed; however, the rate of interest of debt was evaluated at 3% and 5% per year. Regarding private sector financing assumptions, EPRI evaluated debt ratios of 50% and 30%, debt interest rates of 7.5% and 12.5%, and a rate of return on investment of 12% and 20%. In addition, EPRI analyzed the impact of extending the operating period to 40 years, while keeping the financing period at 30 years for both the government and private sector financing alternatives.

[21] Shropshire, David, S. Chandler, *Financing Strategies for a Nuclear Fuel Cycle Facility*, Idaho National Laboratory, INL/EXT-05-01021, December 2005 (INL 2005)
[22] BCG 2006, p. 10.

Table 6-2
Sensitivity Analysis Parameters for Financial and Operating Assumptions

	Government Funding		Private Sector Funding	
	Lower Bound	Upper Bound	Lower Bound	Upper Bound
Plant Capacity (MTHM/year)	1,900	3,000	1,900	3,000
Overnight Cost	$9.0 Billion	$15 Billion	$9.0 Billion	$15 Billion
Operating and Maintenance Cost	$270/kgHM	$450/kgHM	$270/kgHM	$450/kgHM
Debt Ratio	100%	100%	50%	30%
Debt Interest Rate	3%	5%	7.5%	12.5%
Equity Ratio	0%	0%	50%	70%
Return on Investment	not applicable	not applicable	12%	20%
Federal Taxes	not applicable	not applicable	24.75%	
State and Local Taxes	not applicable	not applicable	3.75%	

6.2 Results and Sensitivity Analyses

6.2.1 Base Case Results

EPRI developed an MSExcel spreadsheet to calculate the unit costs for a 2,500 MTHM/year recycling facility with a $12.0 billion overnight capital cost, operating for a period of 30 years. Separate analyses were performed using the government and private sector financial assumptions summarized in Table 6-1. EPRI's analysis assumed that construction occurred over a three-year period prior to the start of operations and that the facility reached the full 2,500 MTHM/year capacity by the fifth year of operation.

In calculating the unit costs, EPRI calculated the costs associated with operations, debt financing, taxes, profit, and depreciation on a year-by-year basis over the life of the facility. As presented in Table 6-3, assuming government funding a recycling unit cost of $667/kgHM was calculated given the assumptions presented in Table 6-1. Assuming private sector funding, the unit cost for recycling was calculated to be $1,355/kgHM. The higher private sector unit costs are due to the fact that private sector financing must account for higher interest rates for debt financing and the inclusion of a return on investment and taxes that are not included in a government financed facility. In a 2006 evaluation of the economics for GNEP deployment, DOE calculated a unit cost for private sector financing of $1,411/kgHM.[23] This is of the similar order of magnitude as the $1,355/kgHM calculated by EPRI, which would be expected since EPRI utilized similar base case assumption to those used in the DOE analysis.

[23] Crozat 2006.

Table 6-3
Base Case Units Costs

	Government Funding	Private Sector Funding
Plant Capacity (MTHM/Year)	2,500 MTHM/year	
Operating Period (Years)	30 years	
Overnight Cost (Billions of 2007$)	$12.0 Billion	
Unit Costs ($/kgHM)	$667	$1,355

6.2.1 Sensitivity Analysis of Government Financed Facility

In performing the sensitivity analysis associated with a recycling facility that is financed, constructed and operated by the government, EPRI varied the financial and operating parameters, described in Table 6-2, one-by-one to determine the impact of each parameter on the unit cost. The impact on the unit cost of recycling was analyzed for the financial and operating assumptions, shown in Figure 6-1 and compared to the unit cost of $668/kgHM calculated for the government funding base case.

The financial parameters were varied by ±25% of the base case values:

- The base case overnight capital cost of $12 billion was varied from $9 billion to $15 billion, resulting in unit costs of $592 to $743 per kgHM, respectively.
- Debt interest rate was varied from 3% to 5%, resulting in unit costs of $625 to $713 per kgHM.
- Annual O&M costs were varied from $270/kgHM to $450/kgHM, resulting in unit costs of $576 to $759 per kgHM, respectively.

The facility throughput or capacity was varied from 1,900 MTHM/year to 3,000 MTHM/year, resulting in a unit cost of $762 to $617 per kgHM, respectively.

A 40-year operating period, assuming the base case 30-year financing period, was also analyzed, resulting in a unit cost of $593/kgHM compared to the base case of $668/kgHM.

Based on the results presented in Figure 6-1, the largest cost drivers associated with a government funded recycling facility are the overnight capital cost, O&M costs, and facility throughput or capacity. A 25% reduction in the overnight capital costs results in reducing the unit costs by approximately 12%. A 25% reduction in O&M costs results in reducing the unit costs to $576/kgHM, approximately 86% of the base case value. A 20% increase in facility throughput from 2,500 MTHM per year to 3,000 MTHM per year results in unit costs of $617/kgHM, 92% of the base case value of $668/kgHM.

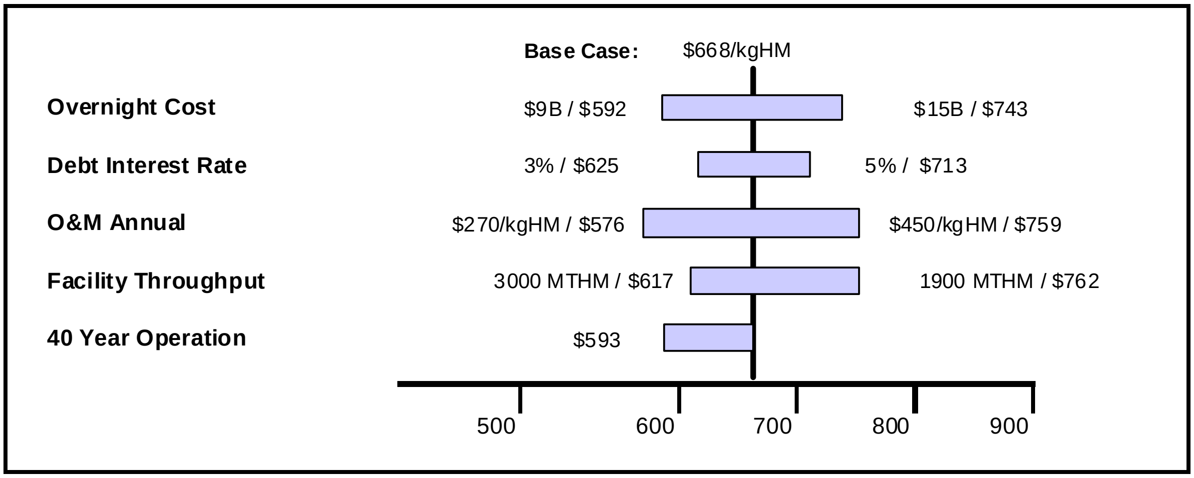

Figure 6-1
Sensitivity Analysis: Comparison of Estimated Unit Costs For Recycling Assuming Government Funding Over a Range of Financial and Operating Assumptions

6.2.2 Sensitivity Analysis of Private Sector Financed Facility

In performing the sensitivity analysis associated with a recycling facility that is financed, constructed and operated by the private sector, EPRI varied the financial and operating parameters described in Table 6-2, one-by-one to determine the impact of each parameter on the unit cost. The impacts on the unit cost of recycling were analyzed for the financial and operating assumptions, shown in Figure 6-2, and were compared to the unit cost of $1,355/kgHM calculated for the private sector funding base case.

The financial parameters were varied by ±25% of the base case values:

- The base case overnight capital cost of $12 billion was varied from $9 billion to $15 billion, resulting in unit costs of $1,107 to $1,593 per kgHM, respectively.
- Debt ratio was varied from 30% to 50%, resulting in unit costs of $1,413 to $1,289 per kgHM, respectively. The debt rate was varied separately from 7.5% to 12.5%, resulting in unit costs of $1296 to $1424 per kgHM, respectively.
- The rate of return was varied from 12% to 20%, resulting in unit costs of $1,137 to $1,577 per kgHM.
- Annual O&M costs were varied from $270/kgHM to $450/kgHM, resulting in unit costs of $1,251 to $1,444 per kgHM, respectively.
- Taxes were lowered by 25%, to 24.75% for Federal taxes, and 3.75% for local taxes, resulting in unit costs of $1,274/kgHM.

The facility throughput or capacity was varied from 1,900 MTHM/year (-24%) to 3,000 MTHM/year, (+20%) resulting in a unit cost of $1,195 to $1,663 per kgHM, respectively.

The impact of a 40-year operating period was also assessed and compared to the base case operating period of 30 years. A 40-year operating period, assuming the base case 30-year financing period, results in a unit cost of $1,330/kgHM compared to the base case of $1355/kgHM. The relatively small impact is largely due to the effect of discounting at 16% per year for years 31-40, too far out in time to have a significant impact on the unit cost.

Based on the results presented in Figure 6-2, the largest cost drivers associated with a private sector financed recycling facility are the overnight capital cost, rate of return, and facility throughput or capacity. A 25% reduction in the overnight capital costs results in reducing the unit costs to $1,107/kgHM, 82% of the base case unit cost. A 25% reduction in the rate of return results in reducing the unit costs to $1,137/kgHM, 84% of the base case unit cost. A 20% increase in facility throughput from 2,500 MTHM per year to 3,000 MTHM per year results in unit costs of $1,195/kgHM, 88% of the base case value of $1355/kgHM.

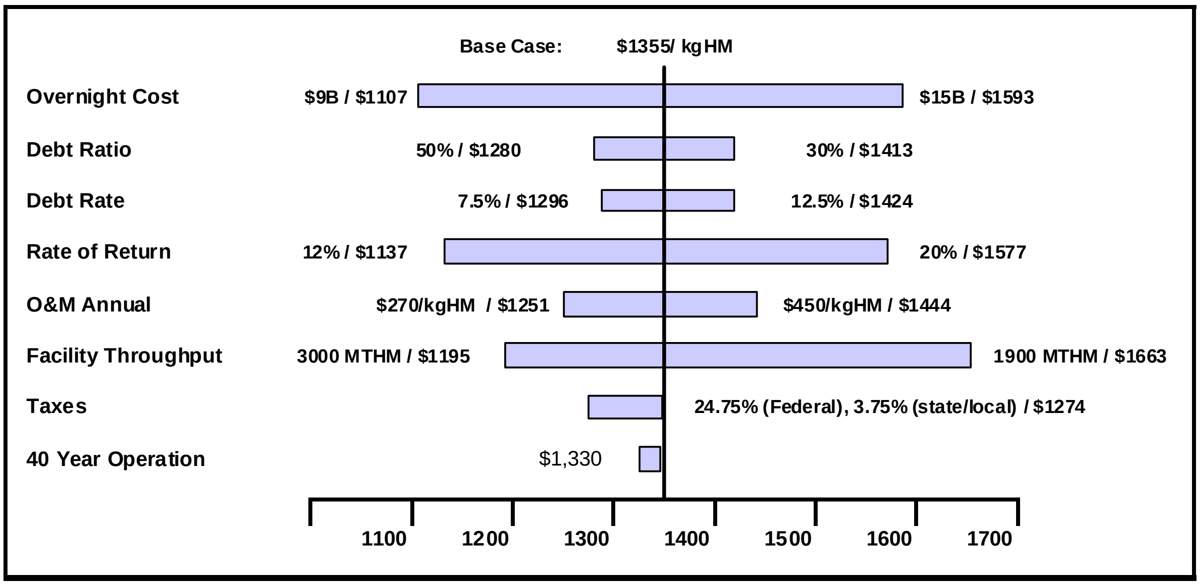

Figure 6-2
Sensitivity Analysis: Comparison of Estimated Unit Costs For Recycling Assuming Private Sector Funding Over a Range of Financial and Operating Assumptions

6.3 Summary

In order to close the nuclear fuel cycle, it will be necessary for the U.S. to construct and operate facilities for recycling of SNF, which will require large capital investments by the government, industry or a government/industry partnership. While EPRI's analysis indicates that facilities that are constructed and operated by the government would result in lower unit costs for recycling than private sector financed and operated faculties, it must be recognized that there are large uncertainties associated with government projects including the appropriation of adequate funding on a timely bases, and government management and operation of large capital projects.

Thus, there may be benefits to a government-private partnership that takes advantage of the governments lower cost of debt and the private sectors' potential to operate and maintain a facility more cost effectively than the government. The cost drivers that pose the greatest risk to the economic construction and operation of a recycling facility, whether government or private-sector funded, are those associated with the facility capital costs, throughput rate, and operations and maintenance costs. Government incentives that could minimize the risk of private sector funding of fuel cycle facilities, such as incentives that would lowering the investor rate of return or debt interest rates, could assist in lowering the costs of recycling for a private sector facility.

7 CONCLUSIONS

Using the SMAFS model, EPRI performed a comparative economic analysis of alternative fuel cycles to the current U.S. once-through fuel cycle, including concepts being considered as part of the DOE's GNEP activities. The fuel cycles evaluated include:

- **Fuel Cycle 1**: Once-through fuel cycle – the current fuel cycle scheme utilized in the U.S.
- **Fuel Cycle 2**: Pu recycle with MOX fuel – the current fuel cycle scheme utilized in some European and Asian countries.
- **Fuel Cycle 3:** Advanced fuel cycle – a fully closed fuel cycle that assumes the use of advanced fuel separation technologies and advanced reactors. This similar to the advanced fuel cycle schemes under consideration as part of DOE's GNEP program.

In addition to the comparative economic analysis performed using the SMAFS model, EPRI also examined potential financing strategies for fuel cycle facilities such as a nuclear fuel recycling facility as envisioned by GNEP. EPRI's analysis examined government and private financing of a fuel cycle facility in order to gain a better understanding of the cost drivers and alternatives that may assist in allowing recycling to become a viable alternative for consideration as part of the U.S. waste management system.

7.1 Conclusions Regarding Base Case Equilibrium Fuel Cycle Analysis

In its Base Case fuel cycle analysis summarized in Section 4, EPRI analyzed the three fuel cycles using NV, LB and UB unit costs described in Section 3 and Appendix A of this report. As summarized in Table 7-1, Fuel Cycle 1, the current once-through fuel cycle, was evaluated to have equilibrium costs for total electricity generation that are 1% to 2% lower than the equilibrium costs for Fuel Cycle 2, which uses MOX recycle. Fuel Cycle 1 was also evaluated to have equilibrium costs for total electricity generation that are 4% to 6% lower than Fuel Cycle 3, the closed fuel cycle that utilizes advanced reactors and advanced recycling.

As shown in Table 7-1, there is not a significant difference between the total generation costs and the fuel cycle costs for the three fuel cycles evaluated that assume NV unit costs. However, it should be recognized that the unit costs associated with Fuel Cycle 1 and Fuel Cycle 2 are based on current technology while those for Fuel Cycle 3 are based technologies, such as FR technology, that are currently in the research and development stage. Based on the analyses summarized in Table 7-1, it is clear that one of the most important unit cost parameters to overall electricity generation costs is the unit capital cost of the nuclear reactors that are utilized in future fuel cycles.

While Fuel Cycle 1 was evaluated to have somewhat lower equilibrium costs than Fuel Cycles 2 or 3, EPRI would note that there are potential benefits associated with moving to a closed fuel cycle. As presented in Figure 4-1, there is a significant reduction in the amount of TRU waste and SNF and HLW requiring disposal for Fuel Cycle 3 compared to Fuel Cycle 1. There are also significant reductions in the decay heat of SNF and HLW after 200 years and the activity of SNF and HLW requiring disposal. These waste management indicators show the potential benefits that a closed fuel cycle could have in reducing the volume, activity and decay heat of SNF and HLW requiring disposal. While reactor costs drive the total generation costs, in order to achieve these reductions in the waste management indicators, additional research and development regarding advanced reactors and advanced separation technologies will be needed to achieve these potential reductions in waste disposal volumes and activity.

Table 7-1
Comparison of Equilibrium Total Generation Costs for Alternative Fuel Cycles Assuming NV, LB, UB Unit Costs (Mills/kWhe)

Cost Indicators	Fuel Cycle 1	Fuel Cycle 2	Fuel Cycle 3
Unit Costs: Nominal Value			
Reactor Cost	43.51	43.51	46.71
Fuel Cycle Cost	9.82	10.55	8.99
Cost of Electricity	53.33	54.06	55.70
Relative Cost to Fuel Cycle 1	1.00	1.01	1.04
Unit Costs: Lower Bound			
Reactor Cost	22.77	22.77	24.86
Fuel Cycle Cost	6.63	7.17	5.85
Cost of Electricity	29.40	29.93	30.72
Relative Cost to Fuel Cycle 1	1.00	1.02	1.04
Unit Costs: Upper Bound			
Reactor Cost	72.41	72.41	77.74
Fuel Cycle Cost	13.39	14.16	13.27
Cost of Electricity	85.80	86.57	91.01
Relative Cost to Fuel Cycle 1	1.00	1.01	1.06

7.2 Conclusions Regarding Fuel Cycle Sensitivity Analysis

Section 5 summarized the sensitivity analysis associated with using a mix of UB, LB or NV unit costs for various cost parameters to determine if there are any additional cost parameters, other than reactor costs, to which the three fuel cycles are especially sensitive. In addition, sensitivity analyses were performed that utilize unit costs that were 50% lower than the LB values and twice the UB values to assist in determining the relative importance of various cost parameters.

Under the scenarios that examined a mix of UB, LB and NV unit costs, the capital and operating costs of nuclear reactors represented between 70% and 90% of total electric generating costs. This was true for all three fuel cycles, under the UB, LB and NV unit costs. Therefore, the most important unit cost parameters to overall nuclear generation costs is the unit cost of the nuclear reactors that are utilized in future fuel cycles. However, this does not imply that changes to fuel cycle cost assumptions are not important.

In order to determine the impact of changes in front-end fuel cycle costs on overall fuel cycle costs and on total generation costs, EPRI varied the front-end fuel cycle parameters over a range from 50% lower than the LB unit costs to twice the UB unit costs for each front-end parameter. EPRI found that individual front-end fuel cycle parameters generally had an impact of less than ±10% on the total cost of electricity. For example, as natural uranium prices increase over the price range evaluated, EPRI found that Fuel Cycle 2's relative fuel cycle costs vary from +20% to -2% relative to Fuel Cycle 1 and Fuel Cycle 3's relative fuel cycle costs varying from +10% to -23% relative to Fuel Cycle 1. However, the impact of increasing the cost of natural uranium did not have as dramatic an impact on the overall cost of generating electricity. Varying the unit cost of natural uranium from $78/kgU to $728/kgU resulted in Fuel Cycle 2's relative cost of electricity varying by only +2% to -1% of the cost of electricity for Fuel Cycle 1; and Fuel Cycle 3's relative cost of electricity varying by only +8% to -2% relative to Fuel Cycle 1. The relatively lower cost of electricity (-1% and -2%) indicates that as the price of natural uranium increases, fuel cycles that reduce uranium consumption may become more attractive in terms of both fuel cycle costs and total electricity costs.

The only individual fuel cycle parameter that had more than a ±10% impact on the total cost of electricity for the cost range evaluated was the unit cost for UREX reprocessing. Varying the unit costs associated with UREX reprocessing from $350/kgHM to $3,326/kgHM resulted in Fuel Cycle 3's relative cost of electricity varying from +3% to +11% of the cost of electricity relative to Fuel Cycle 1. Even at the lowest cost range for UREX reprocessing, Fuel Cycle 3 had higher costs of electricity generation than Fuel Cycle 1. This indicates the importance of research and development activities associated with advanced reprocessing technologies that are being studies as part of the GNEP program.

EPRI also examined the impact of an increase in all front-end fuel cycle costs, not just those for natural uranium. When EPRI varied the costs for natural uranium, conversion, enrichment, and UOX fuel fabrication proportionally within a range of costs specified, Fuel Cycle 2's relative cost of electricity varied from +3% to -1% of the cost of electricity for Fuel Cycle 1; as uranium fuel costs increased. Fuel Cycle 3's relative cost of electricity varies from +9% to -4% of the cost of electricity for Fuel Cycle 1, as uranium fuel costs increase. In addition, Fuel Cycle 2's relative fuel cycle costs vary from +32% to -3% relative to Fuel Cycle 1 as uranium fuel costs increase. Fuel Cycle 3's relative fuel cycle costs varying from +30% to -25% relative to Fuel Cycle 1. Thus, if there is continued upward pressure on uranium, conversion, enrichment and UOX fuel fabrication costs, both partially closed fuel cycles that include reprocessing and fully closed fuel cycles implementing fast reactors will become more attractive both in terms of fuel cycle and electricity cost and also due to the reduced uranium consumption.

EPRI conducted a sensitivity analysis that examined changes to the fuel cycle costs associated with MOX fuel fabrication, UOX PUREX reprocessing; FR metal fuel fabrication, UOX UREX reprocessing, and FR metal fuel pyroprocessing. EPRI concluded that even assuming very low unit costs for fuel fabrication and reprocessing under Fuel Cycle 2 and Fuel Cycle 3, the total cost of electricity generation may only be marginally lower than the costs for Fuel Cycle 1 (using NV costs). However, if the unit costs for advanced fuel cycle fuel fabrication and reprocessing are at the high end of the cost range evaluated, the overall cost of electricity increases significantly compared to that for Fuel Cycle 1, Fuel Cycle 2's relative cost of electricity would be 7% higher than the NV cost of electricity for Fuel Cycle 1; and Fuel Cycle 3's relative cost of electricity would be 18% higher than the NV cost of electricity for Fuel Cycle 1.

As a result of the sensitivity analysis conducted regarding waste management parameters (interim storage, dry storage and transportation), EPRI concluded that the overall electricity costs are indifferent to changes in the costs associated with interim storage, dry storage, and transport of SNF and HLW over the range of fuel cycles evaluated. Changes to these parameters over the range of costs evaluated result in less than a ±2% change in the overall cost of electricity . This is due to the fact that waste management costs represent approximately 1% to 5% of the cost of electricity, depending upon the fuel cycle being examined. While there may be some technical challenges associated with storage and transport of advanced fuels for fast reactors and the resulting waste products, the costs associated with these activities are generally minor compared to other fuel cycle costs and overall the overall cost of generating electricity.

EPRI also concluded that when varying the parameters associated with packaging and disposal of SNF and HLW, the overall costs of electricity decrease for Fuel Cycle 2 and Fuel Cycle 3 as packaging and disposal costs increase. This is a result of there being less volume of SNF and HLW requiring disposal compared to Fuel Cycle 1. Fuel Cycle 2's relative cost of electricity varying by +2% to +0.1% of the cost of electricity for Fuel Cycle 1; as packaging and disposal costs increased. Fuel Cycle 3's relative cost of electricity varies from +5% to +1% of the cost of electricity for Fuel Cycle 1, as packaging and disposal costs increased. Thus, if there continues to be increases in the costs associated with disposal of SNF and HLW, fuel cycles that include reprocessing and advanced reactors will become more economical.

7.3 Conclusions Regarding Fuel Cycle Facility Financing

EPRI evaluated two financial alternatives for financing and operating a recycling facility: (1) Government funding for construction and operation; and (2) Private sector funding for construction and operation. EPRI's base case analysis considered a recycling facility with a capacity of 2,500 MTHM per year with an operating period of 30 years and overnight capital costs of $12.0 billion.

The unit costs for recycling were based on a year-by-year calculation of costs associated with facility operations, debt financing, taxes, profit, and depreciation over the life of the facility. Under the assumptions for a recycling facility constructed and operated by the government, EPRI calculated a recycling unit cost of $667/kgHM. Assuming private sector funding, the unit cost for recycling was calculated to be $1,355/kgHM. The higher private sector unit costs are due to the fact that private sector financing must account for higher interest rates for debt financing and the inclusion of a return on investment and taxes that are not included in a government financed facility.

Based on the sensitivity analyses conducted by EPRI, the largest cost drivers associated with a government funded recycling facility are the overnight capital cost, O&M costs, and facility throughput or capacity. The largest cost drivers associated with a private sector financed recycling facility are the overnight capital cost, rate of return, and facility throughput or capacity.

While EPRI's analysis indicates that facilities that are constructed and operated by the government would result in lower unit costs for recycling than private sector financed and operated facilities, there are large uncertainties associated with government projects including the appropriation of adequate funding on a timely bases, and government management and operation of large capital projects. Thus, there may be benefits to a government-private partnership that takes advantage of the governments lower cost of debt and the private sectors' potential to operate and maintain a facility more cost effectively than the government. There may also be benefits associated with government incentives that could minimize the risk of private sector funding of fuel cycle facilities, such as incentives that would lower the investor rate of return or debt interest rates, could assist in lowering the costs of recycling for a private sector facility.

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A
FUEL CYCLE COST PARAMETERS

Table A-8-1
General Fuel Cycle, Reactor, Fuel Fabrication, and Reprocessing Unit Costs

Parameter Description	Lower Bound (1)	Nominal Value (2)	Upper Bound (3)	Unit
General				
Unit cost of natural uranium	156	260	364	$/kgU
Unit cost of depleted uranium	156	260	364	$/kgU
Unit cost of conversion	10	15	20	$/kgU
Unit cost of enrichment	120	140	160	$/SWU
Unit cost of storing depleted uranium	2.6	3.6	4.6	$/kgU
Unit cost of storing reprocessed uranium	2.6	3.6	40.0	$/kgU
Fixed charge rate for investment	6%	9%	12%	%/year
Fixed charge rate for D&D	8%	8%	8%	%/year
Annual Rx O&M costs (as fraction of capital cost)	3%	4%	5%	%/year
Reactors				
Unit cost of installed power PWR	2,000	2,500	3,000	$/kWe
Unit cost of installed power FR	2,500	3,000	3,600	$/kWe
Load Factor for PWR	85%	90%	95%	%
Load Factor for CANDU	85%	92%	95%	%
Load Factor for FR	80%	85%	95%	%
Fuel Fabrication				
Unit cost of UOX-fuel fabrication	200	250	300	$/kgHM
Unit cost of MOX-fuel fabrication	1,000	1,250	1,500	$/kgHM
Unit cost of FR-Metal fuel fabrication	1,400	2,600	5,000	$/kgHM
Reprocessing				
Unit cost of UOX PUREX	700	1,000	1,250	$/kgHM
Unit cost of UOX UREX	700	1,000	1,663	$/kgHM
Unit cost of FR-Metal fuel PYRO	1,375	2,750	4,125	$/kgHM

Table A-8-2
SNF and HLW Transportation, Interim Storage and Dry Storage Unit Costs

SNF And HLW Transportation				
Unit cost of UOX SNF Transportation	75	100	125	$/kgHM
Unit cost of MOX SNF Transportation	125	188	500	$/kgHM
Unit cost of FR_Metal SNF Transportation	125	188	500	$/kgHM
Interim SNF Storage				
Unit cost of UOX SNF interim storage (fixed)	40	50	60	$/kgHM
Unit cost of UOX SNF interim storage (var. with time)	5	5	5	$/kgHM
Unit cost of UOX SNF interim storage (fixed)	60	90	240	$/kgHM
Unit cost of UOX SNF interim storage (var. with time)	5	7.5	20	$/kgHM
Unit cost of FR-Metal SNF interim storage (fixed)	60	90	240	$/kgHM
Unit cost of FR-Metal SNF interim storage (var. with time)	5	7.5	20	$/kgHM
Dry Storage				
Unit cost of UOX SNF dry storage	100	150	250	$/kgHM
Unit cost of MOX SNF dry storage	200	300	500	$/kgHM
Unit cost of UOX PUREX HLW Dry Storage	80,000	120,000	200,000	$/m^3
Unit cost of UOX UREX HLW Dry Storage	80,000	120,000	200,000	$/m^3
Unit cost of FR PYRO HLW Dry Storage	80,000	120,000	200,000	$/m^3

Table A-8-3
SNF and HLW Packaging and Disposal Unit Costs

Packaging				
Unit cost of UOX SNF Packaging	150	200	350	$/kgHM
Unit cost of MOX SNF Packaging	300	400	700	$/kgHM
Unit cost of UOX PUREX HLW Packaging	100,000	200,000	400,000	$/m^3
Unit cost of UOX UREX HLW Packaging	100,000	200,000	400,000	$/m^3
Unit cost of FR PYRO HLW Packaging	100,000	200,000	400,000	$/m^3
Disposal				
Unit cost of LILW (short lived) near-surface disposal	1,200	2,000	3,000	$/m^3
Unit cost of LILW (long lived) cavern-based and geological disposal	4,000	6,000	8,000	$/m^3
Unit cost of disposal galleries for spent fuel (underground cost)	600	2,500	3,750	$/m^3
Unit cost of disposal galleries for HLW (underground cost)	600	2,500	3,750	$/m^3
Unit volume of disposal galleries that have to be excavated for heat generating waste	10	41	52	m^3/kW

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