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GAS REACTOR INTERNATIONAL COOPERATIVE
PROGRAM, INTERIM REPORT

Assessment of Gas-Cooled Reactor Economics

August 1979

Work Performed Under Contract No. EN-77-C-02-4057

General Electric Company
Advanced Reactor Systems Department
Sunnyvale, California

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GAS REACTOR INTERNATIONAL COOPERATIVE PROGRAM INTERIM REPORT

ASSESSMENT OF GAS-COOLED REACTOR ECONOMICS

Volume I

GENERAL ELECTRIC

**ADVANCED REACTOR SYSTEMS DEPARTMENT
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August 1979

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ABSTRACT

This study focuses on the merits of introducing Pebble Bed Gas Reactors (PBRs) into the existing U.S. electric generating sector. The primary objectives were to (1) determine the cost/benefit relationships that exist for PBRs relative to LWRs, (2) determine whether the benefit/cost relationships that exist for PBRs are significantly higher than for the High-Temperature Gas-Cooled Reactor (HTGR), and (3) determine the sensitivity of the benefits and marketability of PBRs and HTGRs to fuel cost, capital cost, and reactor assumptions.

The results show that, if Pebble Bed Reactors (PBRs) or High-Temperature Gas Reactors (HTGRs) can be built and operated at costs equal to or lower than those assumed in this study, then their introduction may offer economic and resource advantages over the continued use of today's LWR if the price of uranium rises in the future as currently projected. This result is dependent on the projection that these reactors can meet fuel and capital cost targets (capital costs 10% higher than an LWR).

By agreement this report has been reviewed by the cognizant Federal Republic of Germany industrial and laboratory operations and the resulting comments incorporated or noted herein.

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ABBREVIATIONS

<u>Abbreviation</u>	<u>Definition</u>
GCR	<u>Gas-Cooled Reactor</u> (Prismatic or spherical fuel)
HTGR	<u>High-Temperature Gas Reactor</u> (Prismatic fuel elements)
HTGR-HC	<u>High-Temperature Gas Reactor</u> with a <u>High Conversion Ratio</u>
HTGR-OC	<u>High-Temperature Gas Reactor</u> on a <u>Once-Through Fuel Cycle</u> (Moderate conversion ratio)
HTGR-RC	<u>High-Temperature Gas Reactor</u> on a <u>Recycle Fuel Cycle</u> (Moderate conversion ratio)
kW _e	<u>Kilowatts electric</u>
LMFBR	<u>Liquid Metal Fast Breeder Reactor</u>
LWR	<u>Light Water Reactor</u>
O & M	<u>Operation and Maintenance</u>
PBR	<u>Pebble Bed Reactor</u> (Spherical fuel elements)
PBR-NB	<u>Pebble Bed Reactor Near Breeder</u>
PBR-PB	<u>Pebble Bed Reactor Pre-Breeder</u>
PBR-RC	<u>Pebble Bed Reactor</u> on a <u>Recycle Fuel Cycle</u>
PBR-4021	<u>Pebble Bed Reactor 4021</u> (Nonrecycle)
PBTBR	<u>Pebble Bed Thermal Breeder Reactor</u>
PBR-RC	<u>Pebble Bed Reactor</u> on a <u>Recycle Fuel Cycle</u>
SWU	<u>Separative Work Unit</u>
Th	<u>Thorium</u>

SECTION I

OBJECTIVES AND SUMMARY

1.1 OBJECTIVES

This paper focuses on the merits of introducing Pebble Bed Gas Reactors (PBRs) into the existing U.S. electric generating sector. The primary objectives of this study were to:

- Determine the cost/benefit relationships that exist for PBRs relative to LWRs
- Determine whether the benefit/cost relationships that exist for PBRs are significantly higher than for the High-Temperature Gas-Cooled Reactor (HTGR)
- Determine the sensitivity of the benefits and marketability of PBRs and HTGRs to fuel cost, capital cost, and reactor assumptions

To realize these objectives, it was necessary to accomplish several secondary tasks because economic and fuel cycle data are not equally available for LWRs, HTGRs, and PBRs. Economic (fuel and capital costs) and fuel cycle data for the LWR are abundant. However, for the PBR and HTGR this information is limited to small plant and test reactor design and operating experience, along with conceptual large plant designs. Additionally, the PBR information is based on overseas cost information and assumptions which posed problems in converting this data base to an equivalent set of costs for products produced and marketed in the U.S. It was thus necessary to:

- Identify and assume characteristics of the fuel cycles for LWRs, HTGRs, and PBRs
- Establish fuel cycle economics (based on U.S. utility accounting practices)
- Assume a probable capital cost for HTGRs and PBRs relative to LWRs
- Identify a power plant introduction scenario for GCRs that could be used to determine their effect on uranium resources and on their cost/benefit relationship

1.2 SUMMARY OF RESULTS

This study has examined the economic benefits of building and operating gas-cooled reactors in the U.S., based on assumed gas reactor capital costs and estimated fuel costs. The cost savings of operating these reactors in place of LWRs has been calculated. The results show that, if Pebble Bed Reactors (PBRs) or High Temperature Gas Reactors (HTGRs) can be built and operated at costs equal to or lower than those assumed in this study, then their introduction may offer economic and resource advantages over the continued use of today's LWR if the price of uranium rises in the future, as currently projected. This result is dependent on the assumption that these reactors can meet fuel and capital cost targets (capital costs 10% higher than a LWR). Plant and fuel cost information is less developed for GCRs today than for LWRs. PBR and HTGR fabrication and reprocessing costs are also uncertain, being based on overseas estimates and experience, which use equipment and services not used in LWR fuels, such as the formation and removal of pyrolytic graphite. It should also be emphasized that this study was a "steady state" analysis without any consideration of how a gas-cooled reactor industry could be developed or at what cost. It is highly likely that the difficulties of the transition to such a scenario and the large financial requirements of such a transition will be as important to the decision of whether to introduce a new reactor system as the long-term projected economic benefits.

The potential benefits of these various reactors arise due to their calculated lower power costs and their reduced uranium requirements. The lower power cost extends the period in which nuclear energy was cost competitive with coal-derived electricity. While the PBR and HTGR have some similarities in fuel and plant design, the benefit of introducing each is different. (See Table 1-1.)

The advantage of the PBR arises principally from a better plant availability assumed in this study. The design of a PBR (spherical fuel elements) promotes the use of on-line refueling, while the HTGR (prismatic fuel elements) requires the reactor to be shut down for refueling. On-line refueling was assumed to offer a 12.5% advantage (from a 70% to 80% capacity factor) in the number of kilowatt-hours of energy that could be produced annually by a Pebble Bed Reactor. Because the capital cost for a PBR and an HTGR were assumed identical (the largest increment of the cost of generating electricity from nuclear

TABLE 1-1

SUMMARY OF GAS REACTOR BENEFITS

	<u>Present Valued Benefit (Billions of \$)</u>	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	46	
benefit of HTGR-OC*	2	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	5	93
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	3	91
benefit of PBR Combination - 4021-PB-PBTER ⁺	35	123
benefit of HTGR-RC ⁺	33	121
benefit of HTGR-HC ⁺	20	108
benefit of PBR-RC ⁺	27	115

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

fuels is the capital cost), an increased number of kilowatt-hours produced in a PBR reduced its unit energy cost over the HTGR. Even though HTGR fuel cycles are more optimized for U.S. economic requirements, the difference in fuel cycle costs between comparative Pebble Bed Reactor and High-Temperature Gas Reactor designs did not override this on-line refueling advantage.

The accumulated energy costs with and without advanced converters (either PBRs or HTGRs) were determined for two nuclear fuel cycle scenarios, one set with recycle and one set without recycle (but with waste management). The nation's decision whether or not to reprocess nuclear fuel influenced both the

desirability of introducing PBRs or HTGRs and also the benefit from these reactors. In all cases the option to reprocess and recycle nuclear fuels should reduce the cost of generating electricity and reduce uranium requirements. Without reprocessing, the advanced converter (PBR and HTGR) options were limited to conversion ratios only slightly better than those obtained with existing LWRs; the benefits of GCRs were correspondingly reduced.

Without the reprocessing option, the introduction of PBR-4021s (no recycle) in the year 1995 produced a benefit to the nation of \$46 billion (Table 1-1) due principally to the assumed better availability of the PBR over the LWR. Without this availability advantage a comparable HTGR-OC produced only small benefits when introduced. Both reactors exhibited lower fuel costs than the existing LWR; however, only the PBR-4021 reactor at initial introduction had a total power cost below that of the LWR, based on assumed 10% higher capital costs (\$/kW_e) than LWRs. The PBR with the reference 80% capacity factor and a 10% larger capital cost had a 2.5% smaller effective annual capital charge than the reference LWR and a lower fuel cycle cost. The HTGR without a capacity factor advantage over the LWR was not as economic as an LWR until later, when uranium prices showed substantial increases.

With nuclear fuel reprocessing and recycle, the reference cost of producing electricity solely from LWRs and coal-fired plants was reduced, setting a new reference cost for plant comparisons. The benefit of reprocessing in LWRs was found to be \$88 billion (Table 1-1) over the case of coal-fired plants and LWRs without reprocessing. This \$88 billion benefit is approximately 45% greater than the \$46 billion benefit from deploying the PBR-4021 with no reprocessing. If LWR reprocessing and recycle are permitted (but not utilized in the once-through PBR-4021 design), the incremental benefit of deploying PBR-4021s over recycle LWRs is only \$5 billion. The cumulative benefit of adding the PBR-4021 benefit to the LWR with reprocessing is \$93 billion greater than the base case LWR without reprocessing. The incremental benefit derived from introducing a similar once-through HTGR design was found to be zero because of its higher total power cost (due to the absence of an availability advantage over LWRs).

The use of reprocessing and fuel recycle in either PBRs or HTGRs will permit the fuel efficiency and high conversion benefits of a U-233--thorium fuel cycle in a thermal spectrum. However, the PBR and HTGR designs available for this study reflected significantly different design philosophies and goals.

These differences significantly affected the relative benefits computed for the two reactor types. The PBR design strategy is to generate U-233 with low-burn-up fuel, which consumes nearly as much U-235 as does an LWR without recycle but maximizes production of U-233. The HTGR approach is more cost-oriented, minimizing generation costs at the expense of fissile fuel production. The HTGR approach maintained a high fuel burnup for a lower fuel cost and reduced U-235 consumption, but also reduced U-233 production.

For the PBR recycle cases studied, a PBR-PB with high initial uranium requirements was used to generate U-233 for the more advanced PBR-NB and PBR-PBTBR reactors. This sequence of sequential designs required considerable time to implement, and the benefit derived from the bred U-233 accrued much later than the cost of purchasing uranium ore. As a result, the benefits for the PBR-NB and the PBR-PBTBR were reduced significantly. The resulting benefit of introducing the PBR-NB was found to be \$2 billion and the PBR-PBTBR to be \$35 billion (Table 1-1). Finally, the PBR-RC had a benefit of \$27 billion.

For the HTGR reprocessing cases, the HTGR-RC (recycle HTGR) with moderate conversion ratio ($CR = 0.68$) was found to have a lower power cost than the current LWR (with the assumed capital cost). If introduced in the year 1995, the benefit for the introduction of the HTGR-RC was found to be \$33 billion. For the higher conversion ratio HTGR ($CR = 0.8$ and thus more uranium-efficient) the cost of operating the plant is higher than the moderate conversion ratio HTGR during the time period of this study. The benefit for introducing a higher conversion ratio HTGR was found to be reduced to \$20 billion (Table 1-1).

1.2.1 CONCLUSIONS

In the absence of reprocessing, the Pebble Bed 4021 Reactor had a lower operating cost, a lower uranium requirement, and a higher benefit (principally due to a higher capacity factor) than a comparable High-Temperature Gas Reactor.

This advantage is shown by the difference in the benefits for cases PBR-4021 and HTGR-OC. With reprocessing this large advantage was not found. The most attractive Pebble Bed Reactor with recycle is the combination which includes the PBTBR while the best HTGR appears to be the RC design. The net benefits of these two reactors were found to be nearly the same, as shown on Table 1-1.

It should be noted, however, that this sequence of PBR designs was developed to maximize production of U-233 fissile fuel rather than to minimize power cost. If a Pebble Bed Reactor design similar to the 4021 is developed to produce separable 233 and have a minimum power cost (similar to the HTGR design philosophy), it is expected that the Pebble Bed Reactor Systems will show an advantage over High-Temperature Gas Reactor Systems because of their higher capacity factor. Since this study was started, data on such PBR cycles was obtained in Germany, and future evaluation should substantiate the advantages of these cycles.

1.3 POWER PLANT DESCRIPTIONS

Four electric power plants were considered in this report: a coal-fired fossil unit, a conventional LWR, a Pebble Bed Reactor (PBR), and a High-Temperature Gas Reactor (HTGR). The reference capacity mix used as a standard for comparing the merits of replacing the LWR industry with a PBR or an HTGR industry was a six-region mix of coal-fired and LWR plants. The comparisons assumed that only one advanced gas reactor would receive sufficient development monies to bring the technology to a point where LWR and advanced gas reactor economics would be comparable in the marketplace. The sensitivity cases thus compared the introduction of either a PBR or an HTGR into the electrical marketplace.

1.3.1 COAL-FIRED POWER PLANTS

The coal-fired power plants used in this report were assumed to meet local and regional environmental standards. Within any single region a distribution of coal and coal-derived fuel costs (Table 2-5) was used to maintain a mix of new nuclear and coal-fueled generating units. The average regional efficiency for new fossil plants was 38%.

1.3.2 LIGHT WATER REACTOR PLANTS

The LWRs in use today are of two varieties: the Boiling Water Reactor (BWR) and the Pressurized Water Reactor (PWR). For this report a single LWR was used to model future sales of BWRs and PWRs. (The Reactor characteristics and costs for the reference LWR are shown in Tables 3-1 through 3-7.)

1.3.3 PEBBLE BED REACTOR PLANTS (See Topical Report 2 for Details)

Five varieties of Pebble Bed Nuclear Reactors (PBRs) were studied in this report: a PBR-4021, a PBR-PB, a PBR-NB, a PBR-PBTBR, and a PBR-RC. Each used helium as its primary heat-transfer medium and carbon spheres (about 3 to

4 inches in diameter) as the moderator. Within these carbon spheres, mixtures of thorium and uranium isotopes were used as fuel. The uranium fuel was either fully enriched uranium (93% U-235) or a mixture of U-235 and near-pure U-233, producing a fissile material concentration of about 93%.

The PBR-4021 reactor was designed for a high fissile material burnup and thus a reduced need for fuel recycle.

The PBR-PB (or prebreeder) was a low-burnup reactor which was designed to maximize U-233 production. It is characterized by three fuel streams. The first fuel stream utilizes fully enriched uranium and thorium, and is burned until the enrichment is reduced to about 70%. These fuel balls are then re-processed and the uranium is used (without re-enrichment) as fuel for stream 2. Thus fuel streams 1 and 2 supply the heat and neutrons to maintain the nuclear reactions. The third fuel stream again utilizes carbon spheres with thorium added but no uranium, and thus generates chemically separable U-233. The three types of fuel balls are separable by their relative masses.

The PBR-NB (or near breeder) is a high conversion ratio gas reactor with two fuel streams. The first stream burns a mixture of uranium isotopes (primarily U-233) with thorium to produce heat and neutrons. The second stream of carbon spheres contains thorium alone and is used to create additional U-233. Because a conversion ratio of 1 (one fissile atom burned for each created) was not attained, this reactor required a small but annual supply of new U-233 from PBR-PBs along with its first core requirements.

The PBR-PBTBR or (Pebble Bed Thermal Breeder Reactor) used in the study was an extension of the PBR-NB design. This design assumed a net breeding ratio of 1.09 and did not require an annual supply of new U-233. First core requirements for U-233 were supplied by PBR-NBs and to a much smaller extent by other PBR-PBTBRs.

The PBR-RC (or recycle) fuel cycle employs three fuel streams. The first stream is a fissile make-up of uranium that is 93% enriched in U-235. The second stream is a recycle one and includes as its input, all the U-233 and U-235 that is discharged from all three streams. The third stream input consists of balls loaded with thorium only to produce U-233 for recycle.

The reactor characteristics for the reference PBRs are shown in Table 3-1.

1.3.4 HIGH TEMPERATURE GAS REACTORS

Three varieties of High-Temperature Gas Reactors (HTGRs) were used in this report: an HTGR-OC, an HTGR-RC, and an HTGR-HC. Each used helium as its primary heat-transfer medium to boil water and prismatic carbon blocks as the moderator. Within these carbon blocks mixtures of thorium and uranium isotopes were used as fuel. The uranium fuel used was either fully enriched uranium (93% U-235) or a mixture of U-235 and U-233, producing a fissile material concentration of about 93%.

The HTGR-OC (or open-cycle HTGR) was designed for a high fissile burnup and no reprocessing. U-233 generated within the carbon blocks was used along with the initial U-235 to produce heat and maintain criticality.

The HTGR-RC (or recycle HTGR) was designed also for a high fissile burn-up but with fuel reprocessing used to reduce its power costs. The conversion ratio attained was 0.68.

The HTGR-HC (or high conversion ratio HTGR) was designed to minimize the need for uranium mining. To attain a high conversion ratio (or high uranium utilization) a low fuel burnup was used to remove fission products from the core and to promote U-233 production.

The reactor characteristics for these HTGRs are shown in Table 3-1.

1.4 REVIEW COMMENTS TO THIS REPORT FROM THE FEDERAL REPUBLIC OF GERMANY

The following comments to this report were provided as a result of a review by Federal Republic of Germany industrial and national laboratory operations. These comments are being evaluated with regard to impact on the results of this economic assessment and will be considered in subsequent analysis effort. The source of the comment, HRB or KFA, is indicated.

Comments by KFA

The essential difference between the PBR and the other systems considered (coal, LWR, HTGR) is its higher load factor of 80% as compared with the 70% of all other systems. These conditions for coal and LWR power plants may apply to USA, but not to German LWR plants, and there is no evidence for the comparison between PBR and block reactor: on the other hand, the assumed conditions greatly control the economic difference of the systems (use of capital improved by 12.5%).

The comparison between PNP and the other reactor systems is insufficient in some aspects because the HTGR cycles are not referred to PNP cycles of corresponding concept.

The study is exclusively based on conditions in USA and is, therefore, not relevant for the European market in many respects.

- Mixed energy scenarios, including coal, have been used.*
- The US territory considered was subdivided into six regions with different cost assumptions related to capital, personnel, and fuel, and with different growth rates. In the Federal Republic of Germany (FRG) the cost level is substantially more homogeneous.*
- The development of uranium prices was considered in an endogenous way, e.g., as a function of the accumulated uranium consumption; and no exogenous assumptions were made, e.g. in the sense of annual price escalation.*

While the costs of fuel element manufacture and recovery are comparable to those in FRG (where manufacture is 5-10% more and recovery 10-17% less expensive), the difference of the storage costs nearly amounts to one order of magnitude (\$ 120/kg SM vs. \$ 1095/kg SM).

Comments by HRB

HRB can agree to the trend that the PBR always offers advantages over LWR and HTGR as long as both are calculated with open fuel cycle.

On the other hand, HRB cannot agree to the opinion that, for closed fuel cycle, the HTGR is superior to LWR and PNP.

The arguments of the study are essentially determined by the constraints of the concepts selected and of the fuel cycles considered.

We cannot agree to the different efficiencies assumed (HTGR 38% as compared with PBR 40%). Such difference, if any, is specific to the

concept (direct-cycle vs. steam cycle projects) and not specific to fuel elements. In our opinion, the same efficiency has to be accorded. Also, we cannot agree to the different load factors (0.8 vs. 0.7 for HTGR) because the 21 days for the change of fuel elements with HTGR does not necessarily result in reduced availability time (taking into account repetition tests, maintenance, servicing, and other operational aspects).

Plant Costs Assumed

Following our own findings we cannot agree to the assumption that the cost for HTR plants is 10% higher than for LWR. We rather expect the first cost of an LWR will be comparable after introduction into the market.

Even the assumption of equal costs for both HTR plants cannot be backed by our opinion. When the actual cost for fuel elements was analyzed, it was found that the first costs of the PBR were higher by 7% than those of the HTGR plant.

Selection of Fuel Costs

In the case of open cycles, HRB generally agrees with the data selected.

In the case of closed cycles, the PB and NB cycles were compared with the selected HTGR fuel cycles. These assumptions are not compatible: the incentive of the HTGR fuel cycles is based on minimizing the use of uranium at present prices, while the PN/NB system is based on minimizing the uranium ore consumption.

Presentation of Utility Values

In this context we miss a comparison with the reference cycle HRM (High Enriched Recycle Mixed Oxide, a conversion rate of 0.74). This cycle is the optimum of fuel cycle costs according to study results in FRG.

SECTION 2

ECONOMIC MODEL

2.1 INTRODUCTION

The ability to forecast the future of nuclear or fossil electrical generation trends and electrical generation costs to the nation hinges upon our ability to model decision processes of the electrical utility industry. The importance of this ability to simulate the decision processes actually used by the electrical utility industry cannot be overstated. Any model intended to forecast electrical generation capacity growth must be intertwined with the evolving character of the utility industry and the utilities' decision process. Models based solely on correlations of historical data or on idealized system optimizations cannot truly forecast future capacity trends and the evolution of electrical energy costs.

Many electric power generation alternatives must be considered in a long-term national forecast. System costs as well as the availability of fuels must be considered. Oil and natural gas additions can essentially be eliminated from further consideration because of clearly limited domestic supplies and the goal of national energy independence. In the foreseeable future, utilities can choose between coal power plants and light water reactors. Eventually, other nuclear systems, such as gas reactors and fast breeders, might penetrate the domestic energy market and supply significant quantities of energy. Finally, long-term sources such as fusion and solar energy may become viable alternatives, but for now their cost and timing is unpredictable.

The electric utility industry is a continually evolving business enterprise influenced by changing social and economic forces generated by the public and the regulatory commissions. Before preparing any economic assessment of long-term trends, one must predict how and on what basis utilities will make

new capacity decisions. Today a variety of scenarios are possible. The impact on load growth of conservation, marginal pricing, Federal and state pollution standards, etc., all complicate long-range forecasts. The model makes use of traditional utility financing and purchasing practices and assumes a business-as-usual environment, with various growth and economic assumptions used to simulate the effect of these and other uncertainties.

2.2 DESCRIPTION

The electrical generation forecasting code developed in the Fast Breeder Reactor Department of General Electric is designed to predict purchases of large thermal electrical plants based on techniques of economic comparison commonly used by the utility industry.⁽¹⁾ The purpose of the code originally was to better predict the economic outlook of the fast breeder reactor within the nation's nuclear and electrical marketplace. The model's design focused on the nuclear sector, in economic areas which might influence its market share. The code has since been enlarged to include the details of an introduction of gas reactors, such as the Pebble Bed Reactors and the HTGR, into the U.S. electrical generation system. (This entailed primarily an expansion to include uranium-233 material flows within the code.)

The forecasts or results from the model are obtained by constructing future electrical markets from assumptions of electrical growth, plant capital costs, fuel availability, and fuel costs (as a function of time for fossil fuels but as a function of cumulative demand for uranium). The forecasting of nuclear fuel costs and their effect on plant decisions becomes an iterative procedure in which a pattern of nuclear and fossil additions establishes a historical pattern of cost and consumption schedules for natural uranium and bred fuels, such as plutonium and uranium-233. These cost histories are used in turn to generate new forecasts. Until the results and the assumptions agree, the code continues to generate improved forecasts. The plant construction decisions are made annually and on a regional basis throughout the U.S.

2.3 ECONOMIC LOGIC

The model assumes that utilities factor predictable costs and unpredictable risks into decisions of what plants are to be built and that decisions are

made to minimize future capital exposure and revenue requirements. Capital exposure is minimized by limiting investments to projects which show sound advantages over the alternatives in the early years of their life rather than over their total life. Because operating expenses (fuel and maintenance) have tended to increase due to inflation and real price changes, such a strategy has tended to guarantee the lifetime value of any utility investment. Revenue requirements are minimized by choosing projects which have the lowest present-valued customer charges (actual expenses plus interest and tax charges).

Projections of operating and fuel costs from the date of plant startup may be based on the first 10 to 20 years of service, as has been practiced historically, as well as the more ideal full lifetime forecasts of 30 or 40 years, such as are implicitly assumed in energy cost optimization models. Operating costs are calculated assuming the historical costs to the utility are charged to the customer, rather than the replacement or marginal costs. New plant construction decisions are made for base-loaded large thermal plants and are founded on the levelized (discounted) cost of power over the time period used by the utility from the year of plant startup.

Forecasting power costs from the utilities' viewpoint requires an understanding of the utilities' outlook of future costs as well as its internal financial practices. Real expenditures occur at various times throughout the operation of a power plant and must be converted into a predicted uniform series of operating costs. Special care must be exercised to coordinate financial assumptions with predicted costs and more general factors such as inflation.

The approach in this model uses various financial charge rates to determine operating costs to the utility rather than using an actual cash flow analysis. Three charge rates are of primary importance:

- (1) the discount rate for the utility decision-making process
- (2) the level annual revenue requirement excluding depreciation for fuel costs
- (3) the level annual revenue requirement with depreciation, property tax, and insurance for levelizing fixed capital charges.

The discount rate is the weighted average cost of debt and equity monies. The level annual revenue requirement excluding depreciation is the

effective interest rate on nondepreciable assets that the utility must assume so funds will be available to repay the debt holders' investments and provide the prescribed rate of return, after taxes, to the equity holders. This rate is used in determining the interest charges on nuclear fuels. The third charge rate includes tax and depreciation effects and is used in determining the annual charges for capital recovery over the levelization period.⁽²⁾ The development of these charge rates, as used in this report, is shown in Table 2-1. The rates are shown for both zero and six percent inflation; the costs of money for these rates are consistent with historical utility experience.

The approach in determining operating costs is to convert a pattern of irregular expenditures into a uniform series of costs, called one-cycle costs. The one-cycle costs are the present valued costs of one element of the fuel cycle (interest plus depreciation) divided by the present value of the energy (kWh) generated. These costs are assumed to occur annually and to be subject to changes due to inflation and real cost variances. A levelization of the annual charges produces the levelized cost over the period of interest.

For nuclear fuels, determining the fuel cycle cost consists of finding the use and carrying costs and determining when the charges occur. For example: uranium is typically purchased two years before use in the reactor and consumed in the following three or four years. Only in the last three or four years are customers charged for the uranium. These annual charges are found by using standard utility practices⁽³⁾ (see Table 2-2).

2.4 PLANT ADDITION DECISIONS

Plant addition decisions are based on the levelized cost of power from fossil and nuclear power plants. Plant construction decisions are made annually and on a regional basis based on an economic comparison. The resulting pattern of nuclear and fossil additions, in turn, establishes a new pattern of prices for uranium, plutonium, and enrichment. This new set of prices is used to generate new nuclear fuel costs, which in turn initiate a new forecast of plant additions. The process continues until the nuclear fuel assumptions which created the forecast agree with the resulting fuel costs and plant capacities. The development of nuclear fuel cost and capacity forecasts can be seen in Figure 2-1, where the results for a typical study converge after many iterations. In this

TABLE 2-1
COORDINATED FINANCIAL ASSUMPTIONS
FOR INVESTOR-OWNED UTILITIES

	<u>A</u> <u>(%)</u>	<u>B</u> <u>(%)</u>
1. Rate of inflation	0	6
2. Cost of debt money for zero inflation	2.75	2.75
3. Cost of debt money with inflation (1 × 2), e.g., $[(1.06 \times 1.0275) - 1] \times (100) = 8.92\%$	2.75	8.92
4. Cost of equity money for zero inflation	5.5	8.92
5. Cost of equity money with inflation (1 × 4) e.g., $[(1.06 \times 1.055) - 1] \times (100) = 11.83\%$	5.50	11.83
6. Assumed debt/equity ratio for utility industry capitalization	55/45	55/45
7. Assumed Federal plus state tax as: percent of total earnings*	50	50
8. Return on debt (cost for use of debt portion of money), (3 × 6) e.g., $(0.55 \times 8.92) = 4.91\%$	1.52	4.91
9. (a) Return on equity (cost for use of equity portion of money), (5 × 6) e.g., $(0.45 \times 11.83\%) = 5.32\%$, and (b) Federal tax plus state tax (for 50% total tax on earnings)*	2.48	5.32
10. (a) Weighted-average interest rate (net-of-taxes), (8 + 9)	4.00	10.24
(b) Discount rate for utility decision making process (net-of-taxes), (8 + 9)	4.00	10.24
11. Level annual revenue requirement excluding depreciation (Effective interest rate plus taxes), (10a + 9b)	6.48	15.56
12. Level annual revenue requirement with depreciation, 30-year book life and 16-year tax life (determined by calculations using the above assumptions - not shown) [†] - First 16 years	6.44	12.94
13. Charge for property tax plus plant insurance	0.85	1.70
14. Level annual revenue requirements with depreciation, property tax, and insurance (12 + 13) - First 16 years	7.29	14.64
15. Consumer discount rate for zero inflation	6	6
16. Consumer discount rate with inflation (15 × 1) e.g., $[(1.06 \times 1.06) - 1] \times (100) = 12.36$	6	12.36

*At 50%, assumed Federal plus state income tax is equal to return on equity.

[†]This annual charge is derived from the preceding financial assumptions and duly incorporates the effects of the normalization of accelerated tax depreciation, 16-year asset depreciation range (ADR) tax life, and a capital recovery period of 30 years. This represents the capital charge that a tax-paying regulated electrical utility might apply.⁽²⁾

TABLE 2-2
EXAMPLE OF URANIUM FUEL COST CALCULATIONS ⁽³⁾

ASSUMPTIONS

- Minimization of utility revenue requirements
- \$25 per pound U_3O_8
- 40 pounds of U_3O_8 purchased per million kWh_e
- Uranium purchased two years before loading in reactor
- 10.24% discount rate
- 15.56% effective interest rate

FUEL CYCLE COST CALCULATIONS

- Purchase Cost:

$$40 \frac{1b. U_3O_8}{10^6 kWh} \times 25 \frac{\$}{1b. U_3O_8} \times \frac{\text{mills}}{\$} = 1 \text{ mill/kWh}$$

- Value at time of fuel loading:

$$1 \text{ mill/kWh} \times (1.1556)^2 = 1.3 \text{ mills/kWh}$$

- Depreciation and Inventory Costs (mills/kWh):

Year	Book Value At Beginning of Year	Depreciation At End of Year	Interest At End of Year	Total Annual Cost
0	1.3	0.325	0.202	0.527
1	0.975	0.325	0.152	0.477
2	0.65	0.325	0.101	0.426
3	0.325	0.325	0.051	0.376

$$\underbrace{\hspace{10em}}_{1/4 \times \text{Initial Book Value}} \quad \underbrace{\hspace{10em}}_{15.56\% \times \text{Book Value}}$$

- Fuel Cycle Cost (Levelized by the amount of electricity produced)

$$\left[\frac{0.527}{1.1024} + \frac{0.477}{(1.1024)^2} + \frac{0.426}{(1.1024)^3} + \frac{0.376}{(1.1024)^4} \right] \div \left[\frac{0.25}{1.1024} + \frac{0.25}{(1.1024)^2} + \frac{0.25}{(1.1024)^3} + \frac{0.25}{(1.1024)^4} \right] = 1.83 \text{ mills/kWh}$$

Figure 2-1. Results from a Typical Forecast Iteration Sequence

case, low nuclear fuel costs were originally predicted, producing a high nuclear capacity. Each succeeding iteration improved upon the past forecast until after six iterations the marginal improvement was small.

Uranium, the major iteration variable, is a depletable natural resource. The price of it is assumed to increase as the resource is consumed. The rate of change in the price is assumed to be a function of the exploration and mining cost, and the extent of availability versus ore grade. With this relationship the model determines the annual price from the forecasted cumulative uranium consumption.

Plutonium and uranium-233, synthetic fissile elements, are treated in the model as substitute fuels for uranium-235. Their value depends upon the end use and upon the market price of uranium and the cost of nuclear fuel services. The prices are found using a bidding process where plutonium prices are increased until market demand equals market supply. Since uranium-235 prices change with consumption (and thus iteration), plutonium and uranium-233 values are calculated annually for each forecast.

The model assumes that some prices, such as for fossil fuels, operation and maintenance, and nuclear fuel services, may change in real dollar terms with time but not from iteration to iteration. These costs are input to the model. Economies of scale and price and demand elasticity effects are only included through the initial assumptions.

Inflation is added to all costs on an annual basis. Decisions are based on levelizations* of inflated dollar costs for both capital and fuel. Costs are then de-escalated from the year of plant startup to put the levelized plant costs from plants starting up in different years into the perspective of today's dollars.

The model may also be run in a zero inflation, constant dollar mode. Under these conditions, the fuel cycle costs and other costs must be determined with discount and charge rates corrected for the absence of inflation and not with rates which implicitly include inflation as do current utility rates. Neglecting some tax differences, the use of constant dollar assumptions is identical to an analysis with inflation included.

2.5 ELECTRICAL LOAD GROWTH

Load growth is input to the model with price and demand elasticity effects included. New plants are added annually to meet new large thermal base and intermediate load requirements and as replacements for retiring capacity. Retirements are assumed to occur thirty years after plant startup and are based on historical installation patterns.

Two plant load factors are used in the model for each plant: an average capacity factor, modeling that used by utility planners, and an annual capacity factor, modeling the plant's use by a load dispatcher. The first represents the (16-year) levelized capacity factor that utility planners might use in determining which plant to purchase. (A higher than average capacity factor reduces the number of plants purchased.) The second capacity factor is used in determining the fuel requirements for each plant type. For these cases the nuclear plant capacity factors remained constant (see Table 2-3). The fossil units were loaded to meet the remaining electrical load, since their operating costs are even higher than an old nuclear unit.

2.6 REGIONAL CHARACTERISTICS

Regional cost and growth differences are included in the model. The nation is divided into six geographical utility regions that have common capital

*16-year levelizations have been used in this study.

TABLE 2-3
CAPACITY (LOAD) FACTORS

	Capacity Factor Used in Plant Construction Decision	Annual Operating Capacity Factor
COAL	70%	Variable
HTGR	70%	70%
LWR	70%	70%
PBR	80%	80%

and labor costs, capital charge rates, and electrical growth rates. Within each of these regions, there exist four subregions to model the distribution of fossil fuel costs within these six major regions. Because of the availability of data, these regions are divided into groups formed around the electrical coordinating councils, as shown in Table 2-4.

The importance of a regional model can be seen from a tabulation analysis of coal prices across the nation (see Table 2-5). The near order of magnitude variance in prices reflects the cost of transporting coal from mining areas to industrial centers. Similar though less pronounced differences occur for power plant capital costs and electrical demand growth rates.

2.7 TABULATION OF NATIONAL COSTS

Once convergence has been attained and the capacity forecast finalized, an energy cost summary is generated. These accumulated energy costs are a measure of the usage of the basic national resources -- labor and material -- with transfer payments excluded. Transfer payments do not represent real costs, but transfers, and are not relevant to the estimation of real social costs. Transfers include such items as income taxes and financing charges. With transfers excluded, investments such as plant construction costs and nuclear fuel purchases are recorded as they occur.

The time period of this study is from the present until the middle of the next century -- 2050. In any analysis such as this, the termination of

TABLE 2-4
STATES IN REGIONAL MODEL

REGIONS

NORTHEAST (NPCC & MARC*)

1	{	Connecticut, New York
2		Massachusetts, Rhode Island, Vermont, New Jersey, Delaware
Maine, Maryland
3		
4		

SOUTHEAST (SERC)

5	{	Florida, Georgia, Alabama
6		Mississippi, Tennessee
South Carolina, North Carolina, Virginia
7		
8		

EAST NORTH CENTRAL (ECAR)

9	{	Indiana, Kentucky
10		Maryland, Virginia
Michigan, Ohio, West Virginia, Pennsylvania
11		
12		

WEST NORTH CENTRAL (MARCA & MAIN)

13	{	Minnesota, Illinois
14		Montana, North Dakota, South Dakota, Missouri
Nebraska, Iowa, Wisconsin
15		
16		

WEST SOUTH CENTRAL (ERCOT & SPP)

17	{	Kansas, Missouri
18		Louisiana, Oklahoma, Arkansas
Texas
19		
20		

WEST (WSCC)

21	{	Idaho, Wyoming, Colorado
22		Washington, Oregon, California, Nevada, Arizona, Utah, New Mexico
23		
24		

*electric coordinating councils

TABLE 2-5
REGIONAL PRICES FOR NEW COAL*

	<u>Coal Price -- c/MBtu</u>
<u>NORTHEAST (NPCC & MAAC)</u>	
Region 1	111
2	152
3	152
4	191
<u>SOUTHEAST (SERC)</u>	
Region 5	73
6	108
7	108
8	161
<u>EAST NORTH CENTRAL (ECAR)</u>	
Region 9	70
10	124
11	124
12	173
<u>WEST NORTH CENTRAL (MARCA & MAIN)</u>	
Region 13	48
14	77
15	77
16	99
<u>WEST SOUTH CENTRAL (ERCOT & SPP)</u>	
Region 17	24
18	24
19	58
20	100
<u>WEST (WSCC)</u>	
Region 21	40
22	40
23	135
24	135

*The relative regional prices were developed from Federal Power Commission data (4). New coal prices are proportioned from the existing national average.

the calculations at the end of the time period requires particular attention. The approach is to accumulate energy costs through 2050 but to build new plants only until 2020. Through this approach the initial capital costs and the lifetime fuel cycle costs of all plants are reflected fully.

SECTION 3

NUCLEAR FUEL COSTS

3.1 MATERIAL AND FUEL SERVICE REQUIREMENTS

All nuclear reactors, LWRs, HTGRs, Pebble Bed Reactors, LMFBRs, etc., have a reliance on uranium as the initial energy source for their reactions. In the LWR, the HTGR without recycle, and the early Pebble Bed Reactors (4021, PB, and NB), the relatively scarce isotope of uranium, U-235, is directly burned in the core to produce power. In the process these reactors breed new fissionable fuel from the abundant U-238 or thorium isotopes. The HTGR with recycle, the Pebble Bed Reactors NB and PBTBR, and the LMFBR use these bred fissile elements as fuel and thus also rely on the original U-235 resource base.

Because the nation's U-235 resource base may be smaller than desired, it is important to look at the fuel cycle differences between reactor types. The fuel cycle characteristics of the reactors used in this study are shown in Tables 3-1 and 3-2. Table 3-3 gives their uranium and thorium requirements; Table 3-4, their enrichment requirements; Table 3-5, their fabrication requirements; Table 3-6, their reprocessing and/or waste disposal requirements; and Table 3-7, their production rates for bred fissile material. To provide a standard for comparison based on energy production, each reactor is sized at 1000 MW_e and operates at an 80 percent capacity factor.

3.2 MATERIAL AND FUEL SERVICE PRICES

3.2.1 URANIUM RESOURCES AND PRICES

The extension and conservation of the nation's uranium resources is one of the fundamental rationales for developing advanced reactor concepts. The economic argument hinges upon our ability to forecast the availability and price of future uranium supplies. High availability implies a need for advanced reactors when their total energy cost is lower than that of the LWR;

TABLE 3-1

REACTOR CHARACTERISTICS

	LWR (5)	HTGR (6)			PEBBLE BED (7)				
		OC	RC	HC	4021	PB	NB	PBTBR	RC
Burnup (MWd/kg hm*)	27.5	95.0	95.0	61.5	101.5	23.2	24.0	28.8	36.5
Net Cycle Efficiency	0.34	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Specific Power (kW/kg hm)	27	82	76	47	62	51	29	29	56
Power Density (kW/liter)	50	8	8	8	5	5	5	5	5
Conversion Ratio	0.60	0.68	0.68	0.80	0.62	0.74	0.97	1.09	0.80
Fuel Residence Time (years)	3.5	4.0	4.2	4.5	5.6	1.5	2.8	3.4	2.2

*Heavy metal

TABLE 3-2

MASS BALANCES
(kg/gw_e d)

			HTGR ⁽⁶⁾				PEBBLE BED ⁽⁷⁾									
		LWR	OC	RC	HC	4021	PB			NB		PBTBR		RC		
Fuel Stream	LOAD						1	2	3	1	2	1	2	1	2	3
Heavy Metal			26.43	-	-	25.73	1.65	11.40	100.47	75.03	35.86	75.38	35.92	7.89	29.78	34.51
Th-232		0	24.27	24.27	41.04	23.74	0	8.43	100.47	75.03	31.12	75.38	31.26	7.29	26.41	34.51
Uranium		106.95	2.16	-	-	1.99	1.65	2.97	0	0	4.75	0	4.65	0.60	3.37	0
U-233		0	0	0.59	0.93	0	0.13	0	0	0	3.54	0	3.47	0	1.63	0
U-234		0	0	-	-	0	0.02	0	0	0	0.86	0	0.84	0	0.56	0
U-235		2.92	2.01	1.25	0.81	1.85	1.01	2.76	0	0	0.28	0	0.27	0.56	0.36	0
U-236		0	0	-	-	0	0.30	0	0	0	0.06	0	0.06	0	0.59	0
U-238		104.03	0.15	0.09	0.05	0.14	0.19	0.21	0	0	0	0	0	0.04	0.23	0
DISCHARGE																
Heavy Metal		-	-	-	22.92	1.03	9.88	99.81	74.40	33.61	74.89	34.17	7.46	27.50	34.03	
Th-232	0	22.44	22.47	38.97	21.77	0	8.23	98.23	73.03	30.35	73.37	30.49	7.02	25.18	33.29	
Uranium	-	-	-	-	1.14	1.03	1.65	1.60	1.37	3.26	1.53	3.67	0.44	2.32	0.74	
U-233	0	0.57	0.60	0.96	0.50	0.05	0.13	1.44	1.35	2.05	1.51	2.29	0.15	0.85	0.65	
U-234	0	-	-	-	0.15	0.02	0.02	0.15	0.01	0.82	0.01	0.92	0.02	0.51	0.08	
U-235	0.86	0.15	0.15	0.18	0.11	0.40	1.01	0.01	0.01	0.32	0.01	0.38	0.16	0.21	0.01	
U-236	-	-	-	-	0.27	0.38	0.30	0	0	0.07	0	0.08	0.07	0.56	0	
U-238	-	0.14	0.08	0.05	0.10	0.18	0.19	0	0	0	0	0	0.04	0.19	0	
Pu-239	0.61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

TABLE 3-3

URANIUM AND THORIUM REQUIREMENTS - SHORT TONS
(1000 MW_e, 80% Capacity Factor, 0.2% Tails)

	<u>First Core</u>	<u>Annual Reloads*</u>	<u>30-Year Lifetime⁺</u>
LWR (no recycle)			
-U ₃ O ₈	520	200	6320
LWR (full recycle)			
-U ₃ O ₈	520	100	3420
HTGR-OC (no recycle)			
-U ₃ O ₈	362	149	4685
-Thorium	42	9	305
HTGR-RC (with recycle)			
-U ₃ O ₈	362	81	2710
-Thorium	42	9	305
HTGR-HC (with recycle)			
-U ₃ O ₈	555	46	1885
-Thorium	69	15	505
PBR-4021 (no recycle)			
-U ₃ O ₈	337	137	4310
-Thorium	19	7	222
PBR-PB (with recycle)			
-U ₃ O ₈	361	204	6275
-Thorium	60	35	1075
PBR-HB (with recycle)			
-Thorium	49	34	1035
PBR-PBTBR (with recycle)			
-Thorium	49	34	1035
PBR-RC (with recycle)			
-U ₃ O ₈	239	41	1430
-Thorium	33	22	670

*Equilibrium core reloads

+First core plus 29 equilibrium core reloads. The startup fissile transient to obtain the equilibrium core will increase these amounts.

TABLE 3-4

ENRICHMENT REQUIREMENTS - MT SWU
(1000 MW_e, 80% Capacity Factor, 0.2% Tails)

	<u>First Core</u>	<u>Annual Reloads*</u>	<u>30-Year Lifetime⁺</u>
LWR (no recycle)	248	114	3555
LWR (full recycle)	248	72	2336
HTGR-OC (no recycle)	359	149	4680
HTGR-RC (with recycle)	359	81	2710
HTGR-HC (with recycle)	551	46	1885
PBR-4021 (no recycle)	340	138	4340
PBR-PB (with recycle)	363	205	6310
PBR-RC (with recycle)	240	102	3200

*Equilibrium core reloads

+First core plus 29 equilibrium core reloads. The startup fissile transient to obtain the equilibrium core will increase these amounts.

TABLE 3-5

ANNUAL FABRICATION REQUIREMENTS - kg/YEAR
(1000 MWe, 80% Capacity Factor)

	kg/Year
LWR (no recycle)	31230
LWR (full recycle)	31230
HTGR-OC	8090
HTGR-RC	8090
HTGR-HC	12495
PBR-4021	7570
PBR-PB	33120
PBR-NB	32015
PBR-PBTBR	26685
PBR-RC	22160

TABLE 3-6

ANNUAL REPROCESSING REQUIREMENTS - kg/YEAR
(1000 MWe, 80% Capacity Factor)

	Reprocessing* Package kg/Year	Waste Disposal* kg/Year
LWR (no recycle)	-	31230
LWR (full recycle)	31230	-
HTGR-OC	-	8090
HTGR-RC	8090	-
HTGR-HC	12495	-
PBR-4021	-	7570
PBR-PB	30140	2980
PBR-NB	32015	-
PBR-PBTBR	26685	-
PBR-RC	22160	-

*The quantity of fission products produced is a function of the reactor's thermal power and thus a function of the reactor's thermal efficiency. The quantities shown include the heavy metals which might be recovered and reused and should not be used in determining which reactor produced less radioactive waste.

TABLE 3-7

BRED FISSION QUANTITIES
(1000 MWe, 80% Capacity Factor)

	kg/Year
LWR (no recycle)	0
LWR (full recycle)	178 Pu-239
HTGR-OC	0
HTGR-RC	-4 U-233
HTGR-HC	-6 U-233
PBR-4021	0
PBR-PB	420 U-233
PBR-NB	-40 U-233
PBR-PBTBR	95 U-233
PBR-RC	0

low or moderate availability implies a potential loss of nuclear energy's contribution, should the more uranium-efficient reactors not be developed. The price of uranium influences the demand for nuclear reactors and is also a major factor in the determination of which technology is most competitive.

The evaluation of U.S. resources in the context of a commitment to advanced reactors thus involves two questions:

- 1) How much uranium is available?
- 2) What is the economic cost of discovering and developing that ore?

This analysis considers only domestic resources, and excludes imported uranium, even though more ore exists outside the U.S. than within. Significant price reductions due to uranium imports are assumed to be unlikely. Exporters of uranium, if any, will strive to follow the example of the Organization of Petroleum Exporting Countries (OPEC), and must be expected to formulate and maintain pricing policies which tie the price to that of alternatives. Indeed, the small number of potential sellers of uranium--possibly including Saudi Arabia--coupled with burgeoning global demand, suggests that uranium bargains are most unlikely. Price questions aside, the availability of uranium in significant quantities on the international market may itself be questionable, and it appears that a viable nuclear power industry can be safely based only upon domestic uranium resources.

ERDA and mining industry estimates of domestic uranium resources are based on both known reserves and expected but undiscovered resources in and around existing mining districts. Exploration activities throughout the geologically attractive areas since 1960 have not located any new districts, despite exploration effort exceeding all cumulative exploration up to that time. Current estimates indicate that a total of 4.3 million short tons of U_3O_8 in high-grade ore may be available at costs under \$50/lb U_3O_8 (see Table 3-8). (8)

The ERDA uranium estimate, as shown in Table 3-8, is supported by geological information supplied by Government geologists and the mining companies, and is categorized by the degree of the mineralogical information which is available. The "Reserves" category represents ores which the miners might commit today to future sales. The 840,000 tons of U_3O_8 in this preliminary estimate of total domestic uranium reserves at \$50 per pound is

TABLE 3-8
U.S. URANIUM RESOURCES (8)
(January 1, 1977, Tons U₃O₈)

Cost Category* (\$/lb U ₃ O ₈)	Reserves	Potential Resources†		
		Probable	Possible	Speculative
\$10	250,000	275,000	115,000	100,000
\$10-\$15 Increment	160,000	310,000	375,000	90,000
\$15	410,000	585,000	490,000	190,000
\$15-\$30 Increment	270,000	505,000	630,000	290,000
\$30	680,000	1,090,000	1,120,000	480,000
\$30-\$50 Increment	160,000	280,000	300,000	60,000
\$50	840,000	1,370,000	1,420,000	540,000
By-Product**	140,000			
	TOTAL ESTIMATE	4,300,000		
	PLANNING BASE	2,350,000		

* For the "cost" data reported by the AEC, "forward" costs exclude profits, income taxes, and any sunk costs of capital. If the excluded items are added, based on data from mine simulation studies, one finds that the economic cost is greater than the forward cost by as much as two times the reported forward cost for a given ore class. We refer here to economic costs (roughly equivalent to prices) unless explicitly qualified.

† The reliability of the potential resource estimates decreases from the probable to the speculative class.

**Non-conventional sources through year 2000.

contained in 1.28 billion tons of ore averaging 0.07 percent U₃O₈. The "Potential" resources category represents three ore groups for which progressively less exploratory information is available. The "Probable-Potential" designation is applied to ores for which some drilling information exists; because of the tendency to first explore near known ore deposits, these ores are generally located near existing mines. The "Possible-Potential" group represents ores which should be available once a mining district is fully explored, if one assumes that the unexplored areas of existing mining districts will yield new ore in the same quantity as have the fully explored areas. Similarly, the "Speculative-Potential" group represents ores which should be available from mining districts which are not currently producing and those not yet discovered.

The estimates assigned to the \$30 to \$50 cost increment are more preliminary and less reliable than the estimates of the lower cost resources because --

- Uncertainties and inaccuracies are inherent in interpreting gamma-ray drill hole logs of low-grade material.
- Less information has been generated on the extent, distribution, and continuity of low-grade material (\$30-\$50 increment).
- It is necessary to derive some of the individual deposit estimates by extrapolation of data from distribution curves based on uranium reserves at costs of \$30 per pound and less for those deposits.
- Cost information and mining experience are meager on exploitation of material that would be typical of the low grades included in the \$30-\$50 increment.

Additionally, not all of the estimated resources will actually become available at these costs. Some loss of material in the \$30-\$50 increment takes place as the high-grade ores are mined under currently prevailing market conditions; lower-grade "halo" ores, which are not mined at the same time the higher-grade ores are mined, are available only at much higher cost.

In contrast, many in industry believe the significance of the above ERDA estimate lies in the supporting geological information that has been accumulated. They believe that, because of the importance of being conservative in projecting national energy supplies, probabilities should be placed on actually finding and developing the above ores. When such a procedure is used, U.S. resources have been estimated to be less than half of an estimate using the above ERDA technique.⁽⁹⁾ ERDA has also recognized the uncertainty of any geological estimating procedure and the importance of conservatism. For planning purposes, ERDA considers 2,350,000 tons, consisting of ore "Reserves" plus "Probable-Potential" resources, plus by-product sources, as a prudent planning basis.⁽⁹⁾ Other estimates have been both higher and lower.

In addition to the high-grade conventional sandstone ores, non-conventional sources (of which 140,000 tons were included in the ERDA estimate) may eventually supply 2.7 million short tons of U_3O_8 at a forward cost of up to \$100 per pound U_3O_8 but will be marketed at the price of alternative sources.⁽¹⁰⁾ Non-conventional uranium resources are primarily low-grade concentrations occurring in various rock types which will not be mined solely for

for their uranium content or as products related to other ore processing methods. Most uranium in this category is associated with the copper and phosphate industries. An estimated 160,000 tons of uranium has been estimated to be available at a forward cost of about \$10/lb from processing phosphate solutions. Using ion-exchange or solvent-extraction methods, some copper leach solutions should yield uranium at a cost of \$6 to \$10 per pound U_2O_8 .

The next lower grades of uranium resources in the U.S., ranking well below the conventional sandstone and conglomerate deposits, are the Tennessee shales. The Tennessee (or Chattanooga) shales occupy a large part of eastern Tennessee, bedded in three layers beneath 150 feet of limestone overburden. Only the upper two layers are normally considered recoverable. The top layer is about seven feet thick and contains about 70 ppm U_3O_8 , while the next layer is approximately eight feet thick and contains uranium in concentrations of 25 to 60 ppm. The top layer is estimated to contain nearly 5 million tons of U_3O_8 , while the bottom may contain up to 8 million tons. Past studies indicate that, with stringent environmental standards, the actual price could be as high as \$200 per pound when the two layers are mined together, or \$150 per pound for the top layer alone.⁽¹¹⁾ This figure is significantly higher than the 1960 estimate of \$50. The energy density of these ore deposits is quite low--6,000 to 17,000 Btu per pound of ore, not including the overburden, and before the losses associated with the enrichment process. If the requirement of 50,000 tons of U_3O_8 forecast for the year 2000 were to be met with the higher grade shales, it would require mining nearly 2 million tons of ore per day. That is equivalent to the present rate of 1.9 million tons of coal per day, but concentrated in a single state.

The Conway Granites of New Hampshire contain 20 to 40 ppm of uranium, and are thought to aggregate 25 million tons of U_3O_8 plus by-product thorium, at costs greater than \$200 per pound, and with environmental effects as bad or worse than those involved in mining the Chattanooga shales. Finally, in theory, billions of tons of uranium could be extracted from seawater, but the economics of this process are still remote, even beyond useful speculation.

All that is known with certainty is that adequate quantities of very high-cost uranium have been located and could be developed. The key question for the policy analyst is whether significantly more low-cost ore may be

discovered and, if so, to what extent. This question, although central to any rational decision, is intrinsically unanswerable, because geological forecasting is less accurate even than economic forecasting. Reliable estimates of resources in a geologic province emerge only when the province is near depletion.

Nonetheless, given that resource forecasts are necessary, it is tempting to estimate ultimate resources, such as uranium, by projecting known discoveries by the ratio of unexplored areas or depth horizons to the known areas. This approach, known as the Zapp hypothesis, was used by the U.S. Geological Survey to estimate ultimate reserves of recoverable oil and gas. Recent analyses have revealed the intrinsic upward bias in such extrapolations. Exploration is selective--the promising prospects are investigated first--and the returns of additional exploration effort decrease inexorably with time as the distribution of ore bodies is selectively depleted.

What can be said about the likelihood of substantial new finds of low-cost uranium? Historically, the oil and gas industries found new reserves in the U.S. year after year, so there is precedent for some optimism. On the other hand, we know today that the domestic oil and gas industries can no longer sustain themselves, and declining production is inevitable. Thus any optimism induced by analogy must also be bounded. Some circumstantial evidence suggests measured caution in projecting discoveries of low-cost uranium from its conventional habitats. Uranium mining has grown at a precipitate pace, compared with oil and gas, so that the point of inflection in reserve additions should occur earlier. Diminishing returns are already evident. The average depth of exploration boreholes has trebled since 1964, while the discovery yield, in pounds of U_3O_8 per foot drilled, has declined from 9 to 3, in spite of intensified search after 1966. (12)

The price forecasts used in this analysis are shown in Figure 3-1. The reference ore availability for the low-cost high-grade ores was taken as 2.35 million tons up to a forward cost of \$50 per pound U_3O_8 ; the higher cost ores of the past statistical ERDA estimates were similarly reduced to conform to the ERDA planning base assumptions. The price forecasts assume that the \$10 per pound forward cost ores will sell for 3 times the forward cost, the \$15 per pound ores for 2.5 times, the \$30 per pound ores for 2 times, and the

Figure 3-1. Projection of U₃O₈ Price
vs Cumulative Consumption

\$50 per pound and above forward cost ores for 1.5 times the forward cost.* Additionally, it has been assumed that the lowest forward cost ores will be depleted before the next higher cost ores are mined.

3.2.2 THORIUM RESOURCES AND PRICES

No fissionable material analogous to U-235 exists in thorium ores; all of the natural thorium is fertile Th-232 and does not support nuclear reactions directly. In reactors such as the HTGR and the Pebble Bed Reactor, which breed U-233, the thorium is used as a fertile material instead of U-238. Each year only a few percent of this fertile material in reactors is burned or converted

*Past estimates of price⁽¹³⁾ showed selling prices of 1-1/2 times the forward costs as being reasonable in a stable market. Current prices are above 4 times the forward cost of some ores. Mining representatives explain that higher-cost ores than would normally be mined are now used to meet current demands because of the current mismatch between mining capacity and demand. Future uranium price to forward cost ratios should approach 1.5 in the future.

to fissile elements. The original fissile material, however, is usually depleted at a faster rate, and thus its availability is of principal importance.

Because of its low demand, estimates of thorium resources in the U.S. have not been compiled in as much detail as have uranium resources. Geologists point out that, in the U.S. the earth's crust contains about 3 times as many thorium atoms as uranium atoms and thus some 400 times (3/0.7115%) as many atoms as there are of U-235.⁽¹⁴⁾ Therefore, thorium availability has been considered in this report to be adequate for all nuclear scenarios. Its price was assumed to be \$22/kg heavy metal (1977 \$).

3.2.3 CONVERSION PRICES

The conversion of U_3O_8 to UF_6 was assumed to be constant in price, \$4.5/kg heavy metal (1977 \$).

3.2.4 ENRICHMENT PRICES

LWRs, HTGRs, and Pebble Bed Reactors 4021, PB, and NB require an enriched uranium fuel to generate electricity. The process of enriching the uranium is currently a Government monopoly but may expand in the private sector. It is estimated that one new large enrichment plant will be needed every 3 to 5 years from 1985 through the end of the century.

The cost of separative work is expected to be \$90 (1977 \$) per Separative Work Unit (SWU) based on diffusion plant costs. The cost breakdown for diffusion technology based on Uranium Enrichment Associates'* estimate of the cost of a new private enrichment plant is shown in Figure 3-2.

Centrifuge enrichment may bring down the cost of new separative work, should good centrifuge operating lifetimes be experienced. Centrifuge costs based on today's technology have generally been quoted as slightly less than for enrichment using diffusion technology, but commercial operating experience has not been demonstrated. The advantages of centrifuge technology are the lower power requirements and the smaller investment needed to build a smaller but competitive plant. Disadvantages are the large amount of maintenance required and the risk involved in establishing a new technology.

*Bechtel-Goodyear Tire & Rubber Co.

Figure 3-2. Uranium Enrichment Associates' Preliminary Variable Tariff Schedule (14) (1974 dollars)

Laser enrichment also has reached the point where its feasibility has been demonstrated in the laboratory. However, unlike the gas centrifuge, no experience has been gained to bound enrichment costs using this technology. Laser enrichment is in the early R&D stages of development and is not considered in this report because of its potentially late introduction.

3.2.5 FABRICATION PRICES

Fabrication facilities for HTGR and Pebble Bed Reactor fuels are less well developed than for LWRs. Both HTGR and Pebble Bed Reactor fuels are currently produced in small facilities, and the current fuel types may not be the ones selected for larger power plants. Future fabrication costs for HTGRs and Pebble Bed Reactor fuels are less certain than for LWR fuels, and the subject is treated as a sensitivity study in this report.

Fabrication prices for LWR enriched uranium fuels for this study were set at \$120/kg U (1977 \$) and \$460/kg heavy metal (1977 \$) for LWR mixed oxide (Pu & U) fuels. The reference fabrication prices for HTGR and Pebble Bed fuels (Section 10) are shown in Table 3-9.

TABLE 3-9

NUCLEAR FUEL FABRICATION PRICES

(1977 \$)

	<u>\$/kg Heavy Metal</u>
HTGR (Uranium-235 fuels)	400
HTGR (Uranium-233 fuels)	650
LWR (Uranium fuels)	120
LWR (Mixed uranium-plutonium oxide fuels)	460
PBR-4021	295
PBR-PB	325
PBR-NB	315
PBR-PBTBR	315
PBR-RC	285

3.2.6 RECOVERY AND WASTE DISPOSAL PRICES

The question of whether the nation will reprocess and recycle its spent nuclear fuels or send them directly to waste disposal facilities is one of our most pressing socio political questions. The cost of alternatives is difficult to estimate because of changing views regarding the importance of reprocessing, changing environmental standards, the uncertainty of future nuclear fuel designs, and the reluctance of private companies to invest more monies at this time in reprocessing technologies. A cost estimate is necessary, however, if the question is to be intelligently answered.

The base costs of a recovery package (fuel transportation, reprocessing, and long-term waste disposal) or a waste disposition package are shown in Table 3-10. The development of these costs is shown in Section 10.

3.2.7 BRED FISSILE FUEL CREDITS

Bred fuels, such as plutonium and uranium-233, are valued in the model at the price at which they might be sold if they were to compete with U-235 fuels. The cost per unit of energy, including fissile fuel purchases and sales, fabrication cost, enrichment costs, reprocessing costs, operation and maintenance costs associated with the fuel, and interest costs, for any bundle, sphere, or prismatic fuel element of any one reactor is the same regardless of which fuel, U-235, U-233, or Pu-239, that is used. This classical indifference value approach (Section 6.1) determines the instantaneous exchange values for fissile fuels.

TABLE 3-10
NUCLEAR FUEL REPROCESSING AND WASTE DISPOSAL COSTS
(1977 \$)

	<u>\$/kg Heavy Metal</u>
HTGR-OC*	120
HTGR-RC ⁺	560
HTGR-HC ⁺	560
LWR-OC*	120
LWR-RC ⁺	260
PBR-4021*	120
PBR-PB ⁺	445
PBR-NB ⁺	395
PBR-PBTBR ⁺	395
PBR-RC ⁺	540

*Final fuel disposal cost (No fissile reprocessing)

⁺Reprocessing package (Transportation, reprocessing, waste disposal)

Other approaches, however, give both larger and smaller values for bred fissile elements than the indifference value approach and must be recognized as they impact the choice of plant and fuel cycles. The three most common alternative treatments are the zero-bred fissile approach (ZERO), the reduced speculation approach (RS) and the future value approach (FV).

The ZERO approach assumes that bred fissile fuels are a national resource and not a cost or a credit to any reactor and thus should not enter into the electric cost to the customer. For reactors which breed fissile fuels, such as all reactors which burn U-235, this argument leads to higher operating costs, while, for reactors which burn bred fissile fuels, it leads to lower operating costs and seemingly more economic plants. The approach, however, produced three problems:

- Current electric customers would pay for the production of the bred fuels while future customers benefit from their existence.
- No fissile value exists to determine whether or not it is valuable to deliberately create more or less of the fissile fuel.
- In countries where many utilities exist, no exchange value would be available.

The RS approach is one in which it is recognized that bred fissile fuel values are dependent on the changeable costs of services such as fabrication, enrichment, etc., and that a more conservative reactor choice is one which is made assuming that no fissile sales actually occur. The RS approach uses the classical indifference value approach for determining instantaneous fuel values, but, for plant construction decisions, the sale value of bred fissile fuels is assumed to be less. The use of this approach biases construction decisions away from plants which burn expensive fuels to create new fissile fuel, such as the PBR-PB.

The FV approach projects a value of bred fissile fuel in the future and thus a current value which is often higher than its current exchange value. The higher value occurs whenever there is a projected future difficulty in meeting electrical demand which can be minimized by producing bred fissile today. (Assumptions which include low U-235 or coal availability or high electrical demand can create this situation in computer models.) The approach creates a pyramidal series of bred fissile prices which eventually reach the project future price. With this bred fuel valuing approach, the cost of operating reactors which burn expensive fuels to create new fuels, such as the PBR-PB, are reduced. The approach is unacceptable to utilities, however, because —

- Owning bred fuels becomes more financially risky, since the purchase cost of these fuels becomes larger than their instantaneous exchange value.
- The utilities have no authoritative means of defining a future fuel value other than an exchange value.

3.3 FUEL CYCLE COSTS AND CREDITS

The total fuel cycle costs for the LWR, HTGR, and Pebble Bed Reactors 4021, PB, NB, and PBTBR for \$50 per pound uranium are shown in Table 3-11 (using the assumptions shown in Table 3-12) and for \$100 per pound uranium in Table 3-13 (using the assumptions in Table 3-14.) The uranium price model predicts uranium costs of about \$50 per pound in the year 2000 and \$100 per pound about 10 to 15 years later. For all of the cases studied, the new gas reactor technologies were assumed to be introduced in this period.

TABLE 3-11
ONE-CYCLE FUEL COSTS - \$50/lb U₃O₈
 (Mills/kWh)

	<u>LWR-OC</u>	<u>LWR-RC</u>
Uranium	4.82	4.37
Enrichment	2.28	2.25
Fabrication	0.81	0.81
Recovery (storage)	0.48	1.03
Credits	0.00	-0.59
	<u>8.39</u>	<u>7.87</u>

	<u>HTCR</u>		
	<u>OC</u>	<u>RC</u>	<u>HC</u>
U	3.90	2.29	1.22
E	3.16	1.81	0.91
F	0.72	0.72	1.01
R	0.12	0.56	0.92
C	0.00	1.25	2.00
	<u>7.90</u>	<u>6.63</u>	<u>6.06</u>

Pebble Bed

	<u>4021</u>	<u>PB</u>	<u>NB</u>	<u>PB</u>	<u>PBTBR</u>	<u>PB</u>	<u>RC</u>
U	3.66	4.80	0.16	4.80	0.14	4.80	1.29
E	2.97	3.71	0.00	3.71	0.00	3.71	0.87
F	0.53	1.97	2.02	1.97	1.75	1.97	1.20
R	0.10	1.98	1.65	1.98	1.35	1.98	1.85
C	0.00	-3.66	4.97	-4.17	5.06	-4.88	2.37
	<u>7.26</u>	<u>8.80</u>	<u>8.80</u>	<u>8.29</u>	<u>8.29</u>	<u>7.58</u>	<u>7.58</u>

[] PBR combinations. U-233 is produced by PB reactors for use in the second reactor.

TABLE 3-12
ASSUMPTIONS FOR ONE-CYCLE FUEL COSTS - \$50/lb U₃O₈

	<u>LWR-OC</u>	<u>BWR-RC</u>	
Uranium	50	50	\$/lb
Enrichment	90	90	\$/swu
Fabrication	120	120	\$/kg
Recovery	120	260	\$/kg
Credits	0	25	\$/gm

	<u>HTGR</u>			
	<u>OC</u>	<u>RC</u>	<u>HC</u>	
U	50	50	50	\$/lb
E	90	90	90	\$/swu
F	400	400	400	\$/kg
R	120	560	560	\$/kg
C	0	63	88	\$/gm

Pebble Bed

	<u>4021</u>	<u>PB</u>	<u>NB</u>	<u>PB</u>	<u>PBTBR</u>	<u>PB</u>	<u>RC</u>	
U	50	50	50	50	50	50	50	\$/lb
E	90	90	-	90	-	90	90	\$/swu
F	295	325	315	325	315	325	325	\$/kg
R	120	445	395	445	395	445	440	\$/kg
C	0	65	65	74	74	87	87	\$/gm

[] PBR combinations. U-233 is produced by PB reactors for use in the second reactor.

TABLE 3-13

ONE-CYCLE FUEL COSTS - \$100/lb $U_{3-8}O_8$

(Mills/kWh)

	LWR-OC	LWR-RC
Uranium	9.64	8.74
Enrichment	2.28	2.25
Fabrication	0.81	0.81
Recovery	0.48	1.03
Credits	0.00	-0.66

13.21	12.17
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HTGR

OC	RC	HC
7.80	4.58	2.44
3.16	1.81	0.91
0.72	0.72	1.01
0.12	0.56	0.92
0.00	1.93	3.26

11.80	9.60	8.54
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Pebble Bed

4021	PB	NB	PB	PBTBR	PB	RC
U	7.33	9.61	0.32	9.61	0.27	9.61
E	2.97	3.71	0.00	3.71	0.00	3.71
F	0.53	1.97	2.02	1.97	1.75	1.97
R	0.10	1.98	1.65	1.98	1.35	1.98
C	0.00	-5.63	7.65	-6.27	7.63	-7.33
	10.93	11.64	11.64	11.00	11.00	9.94

☐ PBR combinations. U-233 is produced by PB reactors for use in the second reactor.

TABLE 3-14

ASSUMPTIONS FOR ONE-CYCLE FUEL COSTS -

\$100/lb $U_{3-8}O_8$

	LWR-OC	LWR-RC	
Uranium	100	100	\$/lb
Enrichment	90	90	\$/swu
Fabrication	120	120	\$/kg
Recovery	120	260	\$/kg
Credits	0	50	\$/gm

HTGR

	OC	RC	HC	
U	100	100	100	\$/lb
E	90	90	90	\$/swu
F	400	400	400	\$/kg
R	120	560	560	\$/kg
C	0	97	144	\$/gm

Pebble Bed

	4021	PB	NB	PB	PBTBR	PB	RC	
U	100	100	100	100	100	100	100	\$/lb
E	90	90	-	90	-	90	90	\$/swu
F	300	325	315	325	315	325	295	\$/kg
R	135	445	395	445	395	445	540	\$/kg
C	0	100	100	111	111	130	130	\$/gm

☐ PBR combinations. U-233 is produced by PB reactors for use in the second reactor.

SECTION 4

CAPITAL COST TARGETS

One of the principal advantages of advanced or high converter reactors is their reduced uranium requirements and thus their potential for lower fuel cycle costs than today's LWR. This fuel cycle advantage, however, must be considered in the context of the plant's total operating cost, with capital and O & M costs included.

Unfortunately, capital costs are difficult to estimate, especially for plant designs with no construction experience or experience limited only to small test reactors for evaluating fuel cycle parameters. Because of this limitation, it is important to look at the capital cost premium that could be paid and still allow the plant's total operating cost to remain below that of its competitor (generally the LWR). This premium ($\$/kW_e$), plus the reference cost of the plant's competitor ($\$/kW_e$), is called a capital cost target. This target can be used as a means of determining whether or not a plant is competitive, as well as a cost reference for plant designers.

There are two generally recognized approaches for determining the available capital cost premium. One approach is to use the fuel cycle cost savings and directly convert this savings to a capital cost which has the same annual cost. The second approach is to assume a construction schedule for a number of power plants and then determine the capital cost which would reduce the national benefit to zero.

4.1 CAPITAL COST TARGETS BASED ON FUEL CYCLE SAVINGS

Planners in the electric utility industry weigh the advantages of future fuel savings versus current capital expenditures in their decision as to which plants to construct. The process used is one in which the present value of future revenue requirements (capital recovery plus fuel and O & M costs) is minimized.

This detailed cash flow analysis can be simplified by simulating a cash flow with the use of capital charge, discount, and interest rates. The following alternate process produces levelized total power costs:

$$\begin{aligned} \text{TOTAL POWER COST} &= \left(\begin{array}{c} \text{Capital Cost} \\ (\$/kW_e) \end{array} \right) \times \left(\begin{array}{c} \text{Capital Charge Rate} \\ (\%/Year) \end{array} \right) \times \\ &\quad \left(\frac{\text{Year}}{8760 \text{ hr}} \right) \times \left(\frac{1}{\text{Capacity Factor } (\%)} \right) \times \left(\frac{1000 \text{ mills}}{\$} \right) + \\ &\quad \left(\begin{array}{c} \text{Levelized} \\ \text{Fuel Cycle Cost} \\ (\text{mills/kWh}) \end{array} \right) + \left(\begin{array}{c} \text{O \& M Cost} \\ (\text{mills/kWh}) \end{array} \right) \quad (4-1) \end{aligned}$$

Thus the capital cost premium which might be available is the difference in the power costs between two competing reactors:

$$\begin{aligned} \text{CAPITAL COST} &= \left(\begin{array}{c} \text{Fuel Cycle and} \\ \text{O \& M Cost Savings} \\ (\text{mills/kWh}) \end{array} \right) \times \left(\begin{array}{c} \text{Capacity} \\ \text{Factor*} \end{array} \right) \times \\ \text{PREMIUM DUE} &= \left(\begin{array}{c} \text{Capital} \\ \text{Charge} \\ \text{Rate} \end{array} \right)^{-1} \times (8.76) \quad (4-2) \\ \text{TO FUEL SAVINGS} & \end{aligned}$$

if the capacity factors of the two plants are perceived to be the same.

When the perceived capacity factors for the two plants are different, an additional capital cost premium becomes available for the plant with the higher capacity factor. This occurs due to the larger number of kilowatt-hours of energy sales available to distribute the annual cost of the capital. This additional premium is:

$$\begin{aligned} \text{CAPITAL COST} &= \left(\begin{array}{c} \text{Capital} \\ \text{Cost of} \\ \text{Reference} \\ \text{Plant} \\ (\$/kW_e) \end{array} \right) \times \left(\frac{CF - CF_R}{CF} \right) \quad (4-3) \\ \text{PREMIUM DUE TO} & \\ \text{CAPACITY FACTOR} & \end{aligned}$$

where CF_R is the capacity factor of the reference plant and CF is the capacity factor of the plant to which the premium applies. (For the PBR systems of this

*Capacity factor of the plant in which the premium applies.

report with their on-line refueling and their reference capacity factor of 80%, a 12.5% capital premium is available when compared to an LWR with a 70% capacity factor.)

4.2 CAPITAL COST TARGETS BASED ON COST-BENEFIT STUDIES

Cost-benefit studies (see Section 7) can give the dollar benefit of implementing a new electrical technology. The benefit is in terms of the difference in the present valued costs of generating electricity with and without its implementation. This benefit can be used to justify the cost of the R&D projects, the first-of-a-kind plant capital costs, or the costs not justifiable by the utility industry.

The latter point is important because some benefits are not directly seen by any single utility when deciding which plant to build. This occurs for technologies which affect the cost of future energy supplies. For example, a reduced rate of growth in uranium prices, due to a slower depletion of the nation's uranium resources, would give a net dollar benefit in a cost-benefit analysis but not in a utility analysis. This "externality" increases the capital cost premium above that shown using a fuel cycle cost savings approach.

4.3 REFERENCE CAPITAL COSTS

Capital costs for nuclear plants have traditionally been difficult to reconcile because of scope, accounting, and labor rate differences throughout U.S. utilities. Unanticipated changes in plant costs have occurred due to the ratcheting of environmental standards and due to increased rates of inflation, as shown in Figure 4-1.⁽¹⁶⁾ This tendency to slip schedules and increase the work scope and inflationary costs in nuclear projects has probably not yet come to an end.

Nuclear plants (LWRs) coming on-line in 1976 are showing an average cost of \$494/kW_e, as shown in Table 4-1. This average cost can be expected to vary significantly from utility to utility due to differences in labor productivity, site and local environment conditions, financing costs, and assumed rates of inflation.

Figure 4-1. Historical Nuclear Power Costs⁽¹⁶⁾

Power plants starting up in the 1980's are expected to continue this rising capital cost trend. For this report the following capital costs (1977 \$) were used:

Coal	\$500/kW _e
LWR	\$600/kW _e
PBR	\$660/kW _e
HTGR	\$660/kW _e

4.4 TARGET CAPITAL COSTS

The capital cost targets available for the PBR and HTGR systems are shown in Table 4-2, using the fuel cycle cost savings over the first 16 years* of the plant's life, and in Table 4-3, using a cost-benefit approach. In the fuel cycle cost conversion approach, the capital charge rate used was 14.64%; if a higher charge rate is used by a utility in their decisions as to new capacity, the capital cost

*Current utility conservatism limits plant purchases to projects with clear economic advantages over the early years of the project's life.

TABLE 4-1
NUCLEAR CAPITAL COST TRENDS (16)

Comm'l Date	Plant Vintage		Unit Capacity and Cost			Total for Year	
	No. of Units	Year of Order	Capacity MW _e	Cost Millions	Avg. Cost \$/kW _e	Avg. Size MW _e	Avg. Cost \$/kW _e
1976 (Est)	1	1965	330	\$ 229	\$694		
	2	1966	2174	1175	540		
	5	1967	4538	2078	458		
	1	1968	1130	395	350		
TOTAL	9		7842	\$3877		871 MW _e	\$494
1975	1	1966	1067	\$ 268	\$251		
	6	1967	4962	2217	447		
	3	1968	2177	965	443		
TOTAL	10		8206	\$3450		821 MW _e	\$420
1974	5	1966	4887	\$1597	\$327		
	5	1967	4090	1180	286		
TOTAL	10		8977	\$2777		898 MW _e	\$309
1973	1	1965	873	\$ 212	\$243	1 turnkey	
	3	1966	2116	476	225		
	3	1967	2246	597	266		
TOTAL	7		5235	\$1297		748 MW _e	\$245
1972	2	1965	1336	\$ 349	\$261		
	4	1966	2902	685	236	2 turnkeys	
	2	1967	1287	307	239	1 turnkey	
TOTAL	8		5525	\$1341		691 MW _e	\$243
1971	1	1962	50	\$ 23	\$460		
	1	1965	652	99	151	1 turnkey	
	4	1966	2754	479	174	3 turnkeys	
TOTAL	6		3456	\$ 601		681 MW _e (5 plants)	\$170
1953-70	6	1953-59	870	\$ 411	\$141	1 turnkey	
	8	1960-70	4901	1026		4 turnkeys	
TOTAL	14		5771	\$1437			\$249/kW _e

Note: Nuclear units grouped by the year in which they reached commercial operation. All costs are in the dollars of the year in which the plants were finished.

TABLE 4-2
CAPITAL COST TARGETS FOR PBR AND HTGR SYSTEMS
(Fuel Cycle Approach)

		Ratio: $\frac{\text{Capital Cost Target}}{\text{Reference Cost of LWR}}$			
	<u>Year</u>	<u>1990</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>
<u>PBR</u>					
4021 vs LWR-OC		1.25	1.27	1.37	1.57
4021 vs LWR-RC		1.24	1.24	1.30	1.36
PB vs LWR-RC		-	-	1.02	1.12
NB vs LWR-RC		-	-	1.02	1.12
PBTBR vs LWR-RC		-	-	1.29	1.32
PBR-RC vs LWR-RC		-	1.19	1.23	1.47
<u>HTGR</u>					
OC vs LWR-OC		0.88	0.90	0.92	1.06
RC vs LWR-RC		1.11	1.12	1.21	1.26
HC vs LWR-RC		1.11	1.12	1.23	1.38

TABLE 4-3
CAPITAL COST TARGETS FOR PBR AND HTGR SYSTEMS
(Cost Benefit Approach)

		Ratio: $\frac{\text{Capital Cost Target}}{\text{Reference Cost of LWR}}$
<u>PBR</u>		
4021 vs LWR-OC		1.65
4021 vs LWR-RC		1.16
4021-PB-NB vs LWR-RC		1.13
4021-PB-PBTBR vs LWR-RC		1.70
4021-PB-RC vs LWR-RC		1.42
<u>HTGR</u>		
OC vs LWR-OC		1.13
RC vs LWR-RC		1.46
HC vs LWR-RC		1.32

targets shown in Table 4-2 will be reduced (by 19% for a an 18% capital charge rate). In the cost-benefit approach, PBR or HTGR plants were constructed based on their economics with a capital cost of \$660/kW_e (1977 \$), or 10% larger than that of an LWR. Assuming this construction schedule, the capital cost of the PBRs and HTGRs were increased until the discounted benefit was reduced to zero.

SECTION 5

TIME COMPARISON OF NUCLEAR POWER COSTS

Nuclear power costs are forecast to change as a function of time, principally due to real dollar changes in the cost of uranium; increases in the cost of uranium later in the century will thus increase the fuel cycle costs of the LWRs coming on line today. However, because of present value effects, these increased costs are of smaller concern to today's utility planners than present day uranium costs.

The expected 16-year levelized power costs for the LWR, HTGR, and PBR systems are shown in Table 5-1 as a function of the year the plant goes into commercial operation. The capital and fuel cycle cost assumptions are shown in Tables 5-2 and 5-3, respectively.

TABLE 5-1
16-YEAR LEVELIZED POWER COSTS - LWR, PBR AND HTGR*
(Mills/kWh - deinflated to 1977[†])

<u>Year</u>	<u>1980</u>	<u>1990</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>
<u>LWR</u>					
Open Cycle (OC)	25.9	26.4	27.4	32.1	41.1
Recycle (RC)	25.7	26.2	27.1	31.2	38.5
<u>PBR</u>					
4021	-	24.3	25.1	28.5	35.0
PB	-	-	-	32.0	38.0
NB	-	-	-	32.0	38.0
PBTBR	-	-	-	28.6	35.5
PBR-RC	-	-	25.4	29.6	33.8
<u>HTGR</u>					
Open Cycle (OC)	-	29.6	30.4	34.8	41.8
Recycle (RC)	-	26.1	26.9	29.7	36.3
High Conversion Ratio (HC)	-	26.1	26.9	29.4	34.5
<u>*Uranium prices schedule:</u>					
<u>Year</u>	<u>\$/lb U₃O₈</u>				
1980	30.4				
1990	33.4				
2000	36.5				
2010	53.0				
2020	122.0				

[†]The levelizations are based on actual dollar costs, inflation included.

TABLE 5-2
CAPITAL COST ASSUMPTIONS - LWR, PBR AND HTGR
(\$/kW_e)

	<u>Year of</u> <u>Plant Startup*</u>			
	<u>1977\$</u>	<u>1977</u>	<u>1985</u>	<u>2000</u>
LWR	600	600	960	2290
PBR	660	660	1050	2520
HTGR	660	660	1050	2520

*Inflation (6% per year) included.

TABLE 5-3
16-YEAR LEVELIZED FUEL CYCLE COSTS - LWR, PBR AND HTGR*
(Mills/kWh - deinflated to 1977[†])

<u>Year</u>	<u>1980</u>	<u>1990</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>
<u>LWR</u>					
Open Cycle (OC)	8.6	9.1	10.1	14.8	23.8
Recycle (RC)	8.4	8.9	9.8	13.9	21.2
<u>PBR</u>					
4021	-	7.5	8.3	11.7	18.2
PB	-	-	-	15.2	21.2
NB	-	-	-	15.2	21.2
PBTBR	-	-	-	11.8	18.7
PBR-RC	-	-	8.6	10.8	17.1
<u>HTGR</u>					
Once Through (OC)	-	10.8	11.6	16.0	23.0
Recycle (RC)	-	7.3	8.1	10.9	17.5
High Conversion Ratio (HC)	-	7.3	8.1	10.6	15.7

*Uranium prices schedule:	<u>Year</u>	<u>\$/lb U₃O₈</u>
	1980	30.4
	1990	33.4
	2000	36.5
	2010	53.0
	2020	122.0

*The levelizations are based on actual dollar costs, inflation included.

SECTION 6

INTRODUCTION SCENARIOS

It is important when trying to determine the benefit of a new technology to address two issues. What is the maximum benefit that might be achieved by implementing this technology? What benefits would occur if the most probable development route is actually implemented? The timing (date) and the speed (succession of plants) at which the technology is introduced and brought to full commercial status is as much a part of the design of a reactor program as the design of its fuel cycle.

Three issues are fundamental in addressing these questions:

- The relationships between reactors (which reactors will be developed first)
- The relationships to fuel resource bases (there currently exists only one fissile isotope -- U-235)
- Commercialization (government, industry, and utility commitment)

These issues, as they relate to the LWR, HTGR and PBR, are described below.

6.1 RELATIONSHIPS BETWEEN REACTORS(17)

The economic and fuel relationship between reactors and their competitors is often one of both symbiosis and competition. Two or more reactor types can be interlinked via the value of a common fissile fuel. Such reactor pairs as LWR (uranium cycle)/LWR (plutonium cycle), HTGR (uranium cycle)/HTGR (U-233 cycle), and PB/NB/PBTBR, are of importance in this study. The principal output of each of these reactors is of course electricity, but each pair also produces and uses a common-bred fissile isotope.

The LWR loaded with enriched uranium fuel will create about 165 kilograms of plutonium per year while burning U-235. The same reactor, however,

could be fueled with plutonium and burn a net 370 kilograms of plutonium per year. To the first reactor, the creation of plutonium is a credit to the fuel cycle cost, while for the second reactor, the burned plutonium is a cost because of its need to buy plutonium annually. Two different owners of LWRs could thus see plutonium sales as either a credit or a cost, and each would be relying on the other to either produce or purchase this by-product.

The symbiotic relationship for reactors running on the thorium-based fuel cycles (U-235/Th or U-233/Th) is similar to that of the LWR relationship above. For example, the PB reactor burns enriched uranium (U-235) to produce U-233; another PB, NB, or PBTBR could be the purchaser of this U-233. (The PBTBR requires an initial core of U-233 to become operational. While the PBTBR also produces U-233 for sale, its contribution to reducing the PBTBR's power costs is small in comparison to the inventory costs of the first core. Because no naturally occurring U-233 exists, there will be no U-233-fueled reactors unless there first are U-233-producing reactors.) The cost of operating a PB reactor operating on U-233 or a PBTBR reactor is thus tied in with the cost of generating U-233 from another reactor such as the PB reactor.

Figure 6-1 displays the power cost relationships (fuel cycle plus capital charges) for two reactors, of which one sells a bred fissile element and the other purchases the same fissile element. These reactors might be two PB reactors, such as those of Figure 6-1 which are plotted as a function of the bred fissile material's value.* Note that when a PB reactor is burning U-235, the value of its by-product U-233 is a credit against its fuel cycle cost, and its power cost goes down as the value of U-233 increases. When the NB reactor is burning U-233, its fuel cycle cost goes up sharply as the value of U-233 goes up. On the other hand, the fuel cycle cost (and power cost) of the PBTBR is less sensitive to the value of U-233. This is because the gross production of U-233 helps to defray the cost of the fissile U-233 consumed.

From Figure 6-2 it is possible to surmise how the value of U-233 might behave in a society of mixed reactors such as might occur if two reactor systems were competing for U-233. Let us first consider the competition between

*Pure U-233 or Pu-239 does not generally occur from power reactor fuels. In this report U-233 and Pu refer to the equivalent fissile elements actually discharged.

Figure 6-1. Power Costs for PBR-PB and PBR-NB vs Value of U-233

Figure 6-2. Power Costs for PBR-PB, PBR-NB and PBR-PBTBR vs Value of U-233

PB reactors burning U-235 and NB reactors burning U-233. Theoretically there always will be an "indifference" value of U-233 (U_1) for which both fuels result in the same power cost to the PBR reactors. If U-233 were valued at less than U_1 , PBRs would preferentially burn U-233 (because of the lower costs) until the increased demand would force the value of U-233 up. If the value of U-233 were greater than the indifference value, the lower fuel cycle cost would encourage PBs to burn U-235 rather than U-233, and they would become net producers of U-233 until the increased supply of U-233 would bring the value back down to the indifference value. The intersection of Curves (A) and (B) in Figure 6-2 thus defines an equilibrium value for U-233 in a two-mode system.

When PBs (as burners of uranium and net producers of U-233) and NBs co-exist with another reactor, such as the PBTBR, the indifference value of U-233 (U_2) might be higher than the indifference value when U-233 is used as a fuel for NBs. Consequently, the more successful the PBTBR, the greater is the opportunity cost of U-233; PBTBR fuel cycle costs actually rise (from C_3 to C_2) while PBs benefit from increased by-product credits from sales of U-233, thereby reducing their apparent power costs from C_1 to C_2 . Thus, if the marketplace were ever to reflect this opportunity cost of U-233, some part of the financial benefits due to the PBTBR would be transferred to PBs and would appear as reduced power costs for PBs. U_2 and U_1 , therefore, are the upper and lower bounds for U-233 values, and the actual value would be governed by institutional consideration, market forces, and the extent to which the introduction of breeders is constrained by the total availability of U-233.

The above example of how to calculate a bred fissile element's value is also typical of reactors which produce plutonium as the bred fissile material by-product, such as with LWRs (U-235 cycle), LWRs, (Pu cycle), and LMFBRs (Pu-burning cycle) systems.

6.2 RELATIONSHIPS TO RESOURCE BASES

All reactors have their foundation set in the availability of the only naturally occurring fissile isotope, the uranium isotope U-235. The ability of nuclear power to meet future energy demands is influenced to a large degree by U-235 availability. By the year 2000, should 450 GW_e of LWR capacity be installed in the U.S., the U.S. would need access to 1.8 million tons of uranium to fuel these plants (assuming a lifetime requirement of 4000 tons per GW_e). This amount of uranium would be committed to plants in operation or on order around the year 1990, 13 years from now.

The advanced reactor concepts, such as the PBRs, require U-235 to start up the industry and create the new resource base U-233. Because net breeding for the U-233-Th cycles* is less than 1% fissile gain per year (best PBTBR), growth cannot in general be accomplished from industry-generated fissile material. New net capacity additions will require some new commitment of uranium

*LMFBR U-238/Pu-239 fuel cycles require the burning of U-235 in LWRs to produce plutonium. The LMFBR U-238/Pu-239 fuel cycles produce new fissile material at about 4-5% per year. Any growth within an LMFBR industry above this rate also cannot be attained with industry-generated fissile material.

(U-235) resources in order for the U-233 resource base to be expanded. Once this U-233 resource base is created, however, it can be maintained if a net breeder is available (such as the PBTBR) or depleted at a slow rate if a high converter is used.

To make the maximum impact on the nation's uranium consumption or to maximize the number of advanced converters, these plants must therefore be installed early in the lifecycle of the uranium resource base because advanced reactors essentially replace LWRs. If they are to make a large reduction in the nation's uranium consumption, then large numbers of advanced reactors must be installed in comparison to the number of LWRs actually committed. This can best be accomplished if advanced reactors are committed and installed when the number of LWRs is still small.

6.3 COMMERCIALIZATION

New reactor designs and concept estimates are constructed in the electric utility industry based on both the cost of the project and the financial risk. To the manufacturing and utility industries, risk is most easily associated with the operating experience associated with the concept or a similar concept. Both the utility industry and manufacturing industry consciously limit their commitments to new technologies until their attributes have been demonstrated.

Both the PBR and the HTGR have only some plant operating experience with small reactors. This study assumes that experience is satisfactory to commit new PBR or HTGR plants in 1985 for a 1995 introduction. Plants would be added at the following levels starting in the year 1995: 1 GW_e, 2 GW_e, 4 GW_e, 6 GW_e, 9 GW_e, 12 GW_e, 14 GW_e, 16 GW_e, 18 GW_e, 20 GW_e, and limited by economics thereafter. Sensitivity to these assumptions was addressed in this study by looking at two additional introduction dates, 1990 and 2000.

SECTION 7

DOMESTIC ECONOMIC INCENTIVES

This section focuses on the economic merits of adding either PBRs or HTGRs in place of LWRs in the U.S. utility generation system. Additionally, this section focuses on whether the benefits from the PBR are sufficiently greater than the benefits of deploying the HTGR. To realize these objectives, it was necessary to accomplish several secondary tasks such as information collection and the setting of assumptions.

7.1 ASSUMPTIONS

The approach taken to define the economic merit of the PBR and HTGR systems was to look at the present valued cost to the nation of generating electricity for two scenarios, one with a new reactor system (either the PBR or HTGR) and one with only coal-fired and LWR generating plants. The difference in the costs of these two scenarios was taken to be the benefit for introducing the GCR technology.

The accumulated energy costs were measured in terms of the basic national resources -- labor and materials -- with transfer payments excluded. Transfer payments do not represent real costs, but transfers, and are not relevant to the estimation of real social costs. Transfers include such items as income taxes and financing charges. With transfers excluded, investments such as plant construction costs and nuclear fuel purchases are recorded as they occur.

The time period in which costs were recorded was from the present to the middle of the next century -- 2050. In any analysis such as this, the termination of the calculations at the end of the time period requires particular attention. The approach was to accumulate energy costs through 2050 but to build new plants only until 2020. Through this approach the initial capital costs and the lifetime fuel cycle costs of all plants are reflected fully.

Construction decisions were performed using standard utility accounting and financing practices. New plant construction decisions were based on the present valued cost of operating each plant over the first sixteen years of its plant life, the lowest-cost plant then being constructed. This forecasting approach is intended to predict what the future market might be.

The gas reactor scenarios investigated in this study assumed that only one technology would be introduced in the U.S. Each gas reactor technology was allowed to compete against LWR and fossil technologies but not against another gas reactor technology. Six basic gas reactor cases, three PBR and three HTGR cases, were investigated.

The first PBR assumed to become available in the U.S. is the 4021 reactor. In all three PBR cases, the 4021 was assumed to be introduced in the year 1995. The first PBR case assumed that no future design changes would occur for PBR's. The second PBR case assumed that the 4021 reactor would be succeeded by a future PBR combination, the PB and NB in year 2016. The third PBR case assumed that the new PBR offerings were introduced in year 2010 and, again, no 4021 reactors would be sold after their introduction. This reactor combination was the PB and the PBTBR. The introduction dates for the advanced PBR technologies were chosen to coincide with their probable economic need.

Each of the three HTGR cases investigated assumed that a single HTGR technology was introduced in year 1995. These HTGR technologies were the once-through cycle, an advanced recycle fuel cycle, and a high-conversion cycle. This introduction basis was chosen to illustrate the potential of each design in competing with the LWR.

Both the PBR and the HTGR have only some plant operating experience with small reactors. This study assumes that experience is satisfactory to commit new PBR or HTGR plants in 1985 for a 1995 introduction. Plants would be added at the following levels starting in the year 1995: 1 GWe, 2 GWe, 4 GWe, 6 GWe, 9 GWe, 12 GWe, 14 GWe, 16 GWe, 20 GWe, and limited by economics thereafter. Sensitivity to these assumptions was addressed in this study by looking at two additional introduction dates, 1990 and 2000.

Electrical load growth in the base and intermediate large thermal market was taken as 5% per year through the year 2000, and 3% from the year 2001 to the year 2020. The effect of price elasticity was not taken into account. Should PBRs or HTGRs reduce electricity prices, the actual benefits could be larger than is indicated.

Nuclear capacity was constrained in the model through the year 2000 to conform with current projections. In the year 2000, 450 GW_e of nuclear capacity were assumed to be on line. For those cases where a higher capacity factor plant (PBR) was assumed to be added (before year 2000), the total number of kilowatt-hours generated was held constant and the number of LWRs was reduced.

A summary of the assumptions used in this report is shown in Table 7-1.

7.2 COST-BENEFIT ANALYSIS

To investigate the importance of the reference set of assumptions, eight sensitivity cases were investigated with the computer model:

- Basic data set
- High uranium availability
- 50% higher GCR fabrication costs
- 50% higher GCR reprocessing costs
- Year 1990 GCR introduction scenario
- Year 2000 GCR introduction scenario
- Results of utilities' base construction decisions for PBRs on a 75% capacity factor
- Capital cost of GCRs 1.2 times that of LWRs

Within each data set, ten reactor and reprocessing combinations were investigated to determine the benefit for introducing PBRs or HTGRs. The combinations investigated were:

TABLE 7-1
REFERENCE CASE ASSUMPTIONS

Electrical Growth Rate	
years 1977-2000	5%
years 2001-2020	3%
Nuclear Capacity in Year 2000	450 GW _e
Inflation Rate	6%
Discount Rate for Benefits	
without inflation	6%
with inflation	12.36%
Uranium Price	Figure 3-1
Enrichment Price	\$85/SWU (1977 \$)
Nuclear Characteristics	Tables 3-1 to 3-7
Nuclear Fuel Service Costs	Tables 3-8 & 3-9
Coal Price for New Fossil Capacity	
year 1977	\$1/MBtu (1977 \$)
year 2020	\$1.6/MBtu (1977 \$)
Regional Coal Price Distribution	Table 2-5
Capital Costs	
coal-fired plants	\$500/kW _e (1977 \$)
LWR	\$600/kW _e (1977 \$)
PBR	\$660/kW _e (1977 \$)
HTGR	\$660/kW _e (1977 \$)
Capacity Factors	
coal-fired plants	variable
LWR	70%
PBR	80%
HTGR	70%
Introduction Date for PBRs and HTGRs	1995
Construction Sequence for New PBRs and HTGRs	1, 2, 4, 6, 9, 12, 14 16, 18, 20 GW _e /year

- No reprocessing and the LWR as the only nuclear option
- With reprocessing and the LWR as the only nuclear option
- No reprocessing and the LWR & PBR-4021 as the only nuclear options
- With reprocessing and the LWR & PBR-4021 as the only nuclear options
- With reprocessing and the LWR, PBR-4021, PBR-PB, and PBR-NB
- With reprocessing and the LWR, PBR-4021, PBR-PB, and PBR-PBTBR
- With reprocessing and the LWR and PBR-RC
- No reprocessing and the LWR & HTGR-OC as the only nuclear options

- No reprocessing and the LWR & HTGR-RC as the only nuclear options
- No reprocessing and the LWR & HTGR-HC as the only nuclear options

The computer model output is shown in Appendix A.

7.2.1 SUMMARY OF BASE CASE RESULTS

This study has examined the economic benefits of building and operating gas-cooled reactors in the U.S., based on assumed gas reactor capital costs and estimated fuel costs. The cost savings of operating these reactors in place of LWRs has been calculated. The results show that, if Pebble Bed Reactors (PBRs) or High-Temperature Gas Reactors (HTGRs) can be built and operated at costs equal to or lower than those assumed in this study, then their introduction may offer moderate economic and resource advantages over the continued use of today's LWR if the price of uranium rises in the future as currently projected. This result is dependent on the assumption that these reactors can meet fuel and capital cost targets (capital costs 10% higher than a LWR). Plant and fuel cost information is less developed for GCRs today than for LWRs. PBR and HTGR fabrication and reprocessing costs are also uncertain, being based on overseas estimates and experience, which use equipment and services not used in LWR fuels, such as the formation and removal of pyrolytic graphite. It should also be emphasized that this study was a "steady state" analysis without any consideration of how a gas-cooled reactor industry could be developed or at what cost. It is highly likely that the difficulties of the transition to such a scenario and the large financial requirements of such a transition will be as important to the decision of whether to introduce a new reactor system as the long-term projected economic benefits.

The potential benefit of these advanced converters arises as a result of their calculated lower power costs and their reduced uranium requirements. The lower power cost extends the period in which nuclear energy was cost-competitive with coal-derived electricity. While the PBR and HTGR have some similarities in fuel and plant design, the benefit of introducing each is different (see Table 7-2).

The advantage of the PBR arises principally from a better plant availability assumed in this study. The design of a PBR (spherical fuel elements) promotes the use of on-line refueling, while the HTGR (prismatic fuel elements) requires the reactor to be shut down for refueling. On-line refueling was

TABLE 7-2
BASE CASE RESULTS

	Present Valued Benefit (Billions of \$)	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	46	
benefit of HTGR-OC*	2	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	5	93
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	3	91
benefit of PBR Combination - 4021-PB-PBTBR ⁺	35	123
benefit of HTGR-RC ⁺	33	121
benefit of HTGR-HC ⁺	20	108
benefit of PBR-RC ⁺	27	115

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

assumed to offer a 12.5% advantage (from 70% to 80% capacity factor) in the number of kilowatt-hours of energy that could be produced annually by a Pebble Bed Reactor. Because the capital costs for a PBR and an HTGR were assumed identical (the largest increment of the cost of generating electricity from nuclear fuels is the capital cost), an increased number of kilowatt-hours produced in a PBR reduced its unit energy cost over the HTGR. Even though the HTGR fuel cycles are more tailored for U.S. economic requirements, the difference in fuel cycle costs between comparative Pebble Bed Reactor and High-Temperature Gas Reactor designs did not override this on-line refueling advantage.

The accumulated energy costs with and without advanced converters (either PBRs or HTGRs) were determined for two nuclear fuel cycle scenarios, one set with recycle and one set without recycle (but with waste management). The nation's decision whether or not to reprocess nuclear fuel influenced both the desirability of introducing PBRs or HTGRs and also the benefit from these reactors. In all cases the option to reprocess and recycle nuclear fuels

should reduce the cost of generating electricity, and reduce uranium requirements. Without reprocessing, the advanced converter (PBR and HTGR) options were limited to conversion ratios only slightly better than those obtained with existing LWRs, and the benefits of GCRs were correspondingly reduced.

Without the reprocessing option, the introduction of PBR-4021s (no recycle) in the year 1995 produced a benefit to the nation of \$46 billion (Table 1-1) due principally to the assumed better availability of the PBR over the LWR. Without this availability advantage a comparable HTGR-OC produced only small benefits when introduced. Both reactors exhibited lower fuel costs than the existing LWR; however, only the PBR-4021 reactor at initial introduction had a total power cost below that of the LWR, based on assumed 10% higher capital costs (\$kW_e) than LWRs. The PBR with the reference 80% capacity factor and a 10% larger capital cost had a 2.5% smaller effective annual capital charge than the reference LWR and a lower fuel cycle cost. The HTGR without a capacity factor advantage over the LWR was not as economic as an LWR until later when uranium prices showed substantial increases.

With nuclear fuel reprocessing and recycle, the reference cost of producing electricity solely from LWRs and coal-fired plants was reduced, setting a new reference cost for plant comparisons. The benefit of reprocessing in LWRs was found to be \$88 billion (Table 1-1) over the case of coal-fired plants and LWRs without reprocessing. This \$88 billion benefit is approximately 45% greater than the \$46 billion benefit from deploying the PBR-4021 with no reprocessing. If LWR reprocessing and recycle are permitted (but not utilized in the once-through PBR-4021 design), the incremental benefit of deploying PBR-4021s over recycle LWRs is only \$5 billion. The cumulative benefit of adding the PBR-4021 benefit to the LWR with reprocessing is \$93 billion greater than the base case LWR without reprocessing. The incremental benefit derived from introducing a similar once-through HTGR design was found to be zero because of its higher total power cost (due to the absence of an availability advantage over LWRs).

The use of reprocessing and fuel recycle in either PBRs or HTGRs will permit the fuel efficiency and high conversion benefits of a U-233/thorium fuel cycle in a thermal spectrum. However, the PBR and HTGR designs available for this study reflected significantly different design philosophies and goals. These differences significantly affected the relative benefits computed for the two reactor types. The PBR design strategy is to generate

U-233 with low burnup fuel, which consumes nearly as much U-235 as does an LWR without recycle but maximizes production of U-233. The HTGR approach is more cost-oriented, minimizing generation costs at the expense of fissile fuel production. The HTGR approach maintained a high fuel burnup for a lower fuel cost and reduced uranium-235 consumption, but also reduced U-233 production.

For the PBR recycle cases studied, a PBR-PB with high initial uranium requirements was used to generate U-233 for the more advanced PBR-NB and PBR-PBTBR reactors. This sequence of sequential designs required considerable time to implement, and the benefit derived from the bred U-233 accrued much later than the cost of purchasing uranium ore. As a result, the benefits for the PBR-NB and the PBR-PBTBR were reduced significantly. The resulting benefit of introducing the PBR-NB was found to be \$3 billion and the PBR-PBTBR to be \$35 billion dollars (Table 7-2).

For the HTGR reprocessing cases, the HTGR-RC (recycle HTGR) with moderate conversion ratio ($CR = 0.68$) was found to have a lower power cost than the current LWR (with the assumed capital cost). If introduced in the year 1995, the benefit for the introduction of the HTGR-RC was found to be \$33 billion. For the higher conversion ratio HTGR ($CR = 0.8$ and thus more uranium-efficient), the cost of operating the plant is higher than the moderate conversion ratio HTGR during the time period of this study. The benefit for introducing a higher conversion ratio HTGR was found to be reduced to \$20 billion (Table 7-2).

7.2.1.1 Conclusions

In the absence of reprocessing, the Pebble Bed 4021 Reactor had a lower operating cost, a lower uranium requirement, and a higher benefit (principally due to a higher capacity factor) than a comparable High-Temperature Gas Reactor.

This advantage is shown by the difference in the benefits for cases PBR-4021 and HTGR-OC. With reprocessing this large advantage was not found. The most attractive Pebble Bed Reactor with recycle is the combination which includes the PBTBR while the best HTGR appears to be the RC design. The net benefits of these two reactors were found to be nearly the same, as shown in Table 7-2.

It should be noted, however, that this sequence of PBR designs was developed to maximize production of U-233 fissile fuel rather than minimize power cost. If a Pebble Bed Reactor design similar to the 4021 is developed to have a minimum power cost (similar to the HTGR design philosophy), it is expected that the Pebble Bed Reactor Systems will show an advantage over High-Temperature Gas Reactor Systems because of their higher capacity factor.

7.2.2 HIGHER URANIUM AVAILABILITY RESULTS

In all of the cases studied, uranium availability itself was not a constraint to nuclear fuel utilization; rather, the price of uranium influenced the number of plants built. Uranium was assumed to be available at increasingly higher prices as the cumulative quantity of uranium mined increased. The reference uranium price schedule (solid line, Figure 7-1) assumed that 2.35 million tons of U_3O_8 would be available from high-grade U.S. ores and be available at a forward cost of less than \$50 per pound or at less than a market price of \$75 per pound. If 80% more high-grade uranium (bringing the total to 4.3 million tons) is available, the price of uranium may not rise as fast as was assumed in the base cases. The price curve for uranium might then follow the dashed line in Figure 7-1, and uranium prices in general would be lower.

Figure 7-1. Projection of U_3O_8 Price Vs Cumulative Consumption

With a higher uranium availability and lower uranium prices, the advantages of the more uranium-efficient PBR combinations (PB-NB and PB-PBTBR) and HTGR systems (HTGR-RC and HTGR-HC) are reduced (see Table 7-3).

The benefit of introducing the PBR-4021, however, was found to increase slightly with lower uranium prices (Table 7-3). This occurred principally because the PBR-4021 became more competitive with coal-fired fossil plants with lower uranium prices, and its other competitor, the LWR, remained a higher-cost

TABLE 7-3
HIGHER URANIUM AVAILABILITY RESULTS

	<u>Present Valued Benefit (Billions of \$)</u>	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	49	
benefit of HTGR-OC*	0	
Benefit of Reprocessing to LWR Industry		
LWR Only	70	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	9	79
benefit of HTGR-OC*	0	70
benefit of PBR Combination - 4021-PB-NB ⁺	6	76
benefit of PBR Combination - 4021-PB-PBTBR ⁺	15	85
benefit of HTGR-RC ⁺	21	91
benefit of HTGR-HC ⁺	10	80
benefit of PBR-RC ⁺	18	88

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

option. This did not occur for the other reactor types. With lower uranium prices, the other reactor types lost some competitiveness with LWRs and thus some of their benefit.

7.2.3 RESULTS USING 50% HIGHER GCR FABRICATION COSTS

With 50% higher fabrication costs for PBR and HTGR systems, the benefits of introducing these reactors are reduced, as shown in Table 7-4. Since higher uranium conservation in PBRs and HTGRs is accomplished primarily by reducing fuel lifetimes (burnup) and thus increasing fuel processing volumes, the PBR combinations (PB-NB and PB-PBTBR) and HTGR systems using recycle lost more of their benefit with higher fabrication costs than did the once-through reactors such as the PBR-4021.

7.2.4 RESULTS USING 50% HIGHER REPROCESSING COSTS

With 50% higher reprocessing and waste disposal costs for PBRs and HTGRs, the benefits of introducing these reactors are reduced, as shown in Table 7-5. Since higher uranium conservation in PBRs and HTGRs is accomplished primarily

TABLE 7-4
RESULTS USING 50% HIGHER GCR FABRICATION COSTS

	Present Valued Benefit (Billions of \$)	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	43	
benefit of HTGR-OC*	0	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	2	90
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	0	88
benefit of PBR Combination - 4021-PB-PBTBR ⁺	14	102
benefit of HTGR-RC ⁺	19	107
benefit of HTGR-HC ⁺	8	96
benefit of PBR-RC ⁺	18	106

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

by reducing fuel lifetimes (burnup) and thus increasing fuel flow rates, the PBR combinations (PB-NB and PB-PBTBR) and the HTGR systems using recycle lost more of their benefit with higher reprocessing costs than did the once-through reactors, such as the PBR-4021.

7.2.5 RESULTS FROM INTRODUCING GCRs IN YEAR 1990

Savings in energy costs which occur early in time are more heavily weighted in a cost-benefit analysis than savings which occur later. With the introduction of PBRs and HTGRs five years earlier (in year 1990), the benefits from these reactors will increase by 34% ($1.06^5 - 1$) as shown in Table 7-6. If the HTGR can be introduced into the U.S. earlier than a PBR system, the benefit of the HTGR can be larger for a later PBR with a lower power cost.

7.2.6 RESULTS FROM INTRODUCING GCRs IN YEAR 2000

Similar to the cases where PBRs and HTGRs are introduced five years earlier than in the reference cases, a five-year delay changes their benefit

TABLE 7-5
RESULTS USING 50% HIGHER GCR REPROCESSING COSTS

	Present Valued Benefit (Billions of \$)	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	45	
benefit of HTGR-OC*	1	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	4	92
benefit of HTGR-OC*	1	89
benefit of PBR Combination - 4021-PB-NB ⁺	2	90
benefit of PBR Combination - 4021-PB-PBTBR ⁺	15	103
benefit of HTGR-RC ⁺	23	111
benefit of HTGR-HC ⁺	11	99
benefit of PBR-RC ⁺	17	105

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

by the discount rate raised to the fifth power, a loss of about 25%. Along with this loss, an additional loss in benefits occurs because fewer PBRs and HTGRs are constructed.

The benefits of introducing GCRs and replacing new LWRs starting in year 2000 with PBR and HTGR systems is shown in Table 7-7.

7.2.7 RESULTS IF UTILITIES BASE CONSTRUCTION DECISIONS FOR PBRs ON A 75% CAPACITY FACTOR

If utilities base their construction decisions for PBRs on a 75% capacity factor rather than the reference 80% capacity factor, the capital cost premium which utilities might be willing to pay for a PBR over an LWR (seen in Section 4.1), based solely on a capacity factor advantage, will decrease from 12.5% to 6.7%. Since the PBR (and the HTGR) is expected to cost 10% more than an LWR, the annual capital charges for a PBR with a 75% capacity factor would be 3% larger than for an LWR, making the PBR an economic choice only when its fuel savings were larger than this capital cost penalty.

TABLE 7-6
YEAR 1990 GCR INTRODUCTION RESULTS

	<u>Present Valued Benefit (Billions of \$)</u>	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	86	
benefit of HTGR-OC*	1	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	25	113
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	23	111
benefit of PBR Combination - 4021-PB-PBTBR ⁺	52	140
benefit of HTGR-RC ⁺	42	130
benefit of HTGR-HC ⁺	26	114
benefit of PBR-RC ⁺	56	144

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

For the cases studied, PBR fuel cycle costs were smaller than LWR fuel cycle costs, making PBR power costs smaller than the power cost of the LWR. With this lower total power cost, the model continued to construct PBRs in approximately the same numbers as in the reference cases. With the further assumption that PBRs would ultimately obtain an 80% capacity factor, the benefit of introducing PBRs was found not to change (Table 7-8) when utilities based their construction decisions on a 75% capacity factor rather than an 80% capacity factor for PBRs.

7.2.8 RESULTS WHEN CAPITAL COST OF THE GCR IS 1.2 TIMES THAT OF THE LWR

The capital cost estimates for PBRs and HTGRs are less certain today than for LWRs. If the capital cost of a PBR or HTGR turns out to be 20% greater than that of an LWR, then the benefit of introducing these reactors is reduced (see Table 7-9).

For the PBR with its higher capacity factor, a 20% capital cost premium results in total power costs for the PBR-4021 which were below those of the LWR (without recycle) and for the PBR-4021, PBR-PB, PBR-NB, and PBR-PBTBR,

TABLE 7-7
YEAR 2000 GCR INTRODUCTION RESULTS

	Present Valued Benefit (Billions of \$)	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	22	
benefit of HTGR-OC*	0	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	1	89
benefit of HTGR-OC*	2	90
benefit of PBR Combination - 4021-PB-NB ⁺	0	88
benefit of PBR Combination - 4021-PB-PBTBR ⁺	30	118
benefit of HTGR-RC ⁺	22	110
benefit of HTGR-HC ⁺	13	101
benefit of PBR-RC ⁺	16	104

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

TABLE 7-8
RESULTS USING A 75% PBR CAPACITY FACTOR
FOR UTILITY CONSTRUCTION DECISIONS

	Present Valued Benefit (Billions of \$)	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	46	
benefit of HTGR-OC*	2	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	6	94
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	4	92
benefit of PBR Combination - 4021-PB-PBTBR ⁺	23	111
benefit of HTGR-RC ⁺	33	121
benefit of HTGR-HC ⁺	20	108
benefit of PBR-RC ⁺	26	114

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

TABLE 7-9

RESULTS WHEN CAPITAL COST OF GCR ARE 1.2 TIMES THAT OF AN LWR

	<u>Present Valued Benefit (Billions of \$)</u>	
No Reprocessing		
LWR Only	0	
benefit of PBR-4021*	39	
benefit of HTGR-OC*	0	
Benefit of Reprocessing to LWR Industry		
LWR Only	88	
With Reprocessing (incremental and cumulative benefits over LWR reprocessing)	<u>Incremental</u>	<u>Cumulative</u>
benefit of PBR-4021*	0	88
benefit of HTGR-OC*	0	88
benefit of PBR Combination - 4021-PB-NB ⁺	0	88
benefit of PBR Combination - 4021-PB-PBTBR ⁺	13	101
benefit of HTGR-RC ⁺	7	95
benefit of HTGR-HC ⁺	3	91
benefit of PBR-RC ⁺	17	105

*No reprocessing in these advanced converters.

⁺Reprocessing required for these reactor combinations.

which are near those of the LWR. For the HTGR fuel designs investigated, a 20% capital cost premium resulted in total power costs which were above those of the LWR until about the year 2010. After the year 2010, HTGR power costs were smaller but similar to LWR power costs.

SECTION 8

SELECTING A DISCOUNT RATE FOR NATIONAL ENERGY SUPPLY STUDIES*

8.1 INTRODUCTION

Comparing costs of alternative means to meet a need is an everyday necessity. When the need is complex and extends over a period of time, the nature of the costs for the alternatives will usually be dissimilar. More important, the pattern and timing of the costs are often different; the bulk of costs for one alternative may occur many decades ahead or behind that of a competing alternative. An example of such a difference might be the choice faced by a utility between (1) a nuclear power plant with its relatively high "front-end" outlay, followed by 3 decades of low fuel-cycle costs, and (2) an oil-fired power plant, where the initial outlay is modest but there will be 3 decades of high oil costs.

When such alternatives must be compared, it is necessary to select a reference time at which the comparison will be made and then convert the actual costs of the alternatives to equivalents that can be compared at that time. The reference time that is most often selected is the present, the time of analysis, decision, or implementation. This is called present-valuing a cost.

The factor for converting the actual costs in each future year to the present-valued costs must allow for the benefits which might be realized if the same funds were used elsewhere during the period (from the present to the time of the actual costs), or when the actual cost is incurred before the present, the loss of benefits (cost) that will occur because of the need to divert and use funds from elsewhere for the period. For example, assume a certain corporation can earn 10% interest on its money. A cost of \$100 in 1977 can be met by a \$100 payment in 1977, or by investing \$90.91 in 1976 and using it, plus the interest earned, to meet the \$100 payment in 1977. Here, \$90.91 is the present

*Extracted from a paper by H.L. Wyckoff, Commonwealth Edison Co., 1976

0 value of the \$100 expense in 1977. Similarly \$100 in savings or benefits in the year 2000 would be worth \$11.17 in investments in 1977. In this example, the interest rate alone is the basis for present-valuing. In an actual case, usually a choice can be made from among a number of interest rates. The actual interest rate used is called the discount rate. The "discount rate" concept provides a common denominator for measuring costs and benefits, even though their time patterns may differ.

8.2 WHAT SHOULD THE DISCOUNT RATE BE?

The previous section has suggested that a discount rate must be used in economic analyses of any project longer than one year. But what should the discount rate be? The choice of discount rate depends upon the answers to three questions:

1. Who makes the decision?
 - If minimum cost is to be the selection criteria -- minimum cost to whom?
 - If the criteria is to be maximum income -- maximum income to whom?
 - If the option is to be selected on the basis of maximum "xyz" benefits -- maximum benefits to whom?
2. What is the target or objective? What is being present-valued as a criterion for decision making?
 - Cost -- wish to minimize it?
 - Income -- maximize for a particular company or maximize for a particular industry?
 - Tax -- wish to minimize tax liability?
 - Benefits -- wish to maximize "xyz" benefits?
 - Gross national product -- wish to maximize?
 - Private consumption -- wish to maximize?
 - Federal tax revenues -- wish to maximize?
3. What is the value of money to the beneficiary of the project, in the context of the target or objective?
 - Value to a particular corporation?
 - Value to a particular industry?
 - Value to all of industry?
 - Value to the Government from a fiscal standpoint?

- Value to consumers (consumption preference rate)?
- Value to the Government as agent for implementing national economic or social objectives?

It is this value of money that will be the appropriate discount rate to use in the analysis. (In any particular analysis, several discount rates are simultaneously employed because reinvested funds may appropriately be discounted at a rate different from that of funds used for consumption. The relative contribution of the several discount rates will depend on the overall objectives of the undertaking (Question 2).

The determination of the appropriate discount rate can be illustrated with three examples (the last is germane to analyses that examine the benefits to the nation of a new energy technology):

Example 1: A utility wishes to determine the lowest cost of several options.

An electric utility must select a discount rate to use in determining the lowest cost (to the utility) of several options.

Here:

1. Q. Who is the decision-making body?
A. A specific utility company
2. Q. What is the objective?
A. Lowest cost to utility company
3. Q. What is the value of money to the utility company and hence the appropriate discount rate?
A. Effective interest rate (composite cost of debt + equity, with income taxes excluded)*

Example 2: The Federal Government seeks to make a cost-benefit study of a certain project it is considering undertaking.

1. Q. Who is the decision-making body?
A. Federal Government
- Q. What is the objective?
A. Lowest cost of project to government including effects of lost

*That Federal taxes must be paid on the earnings portion of the utility's cost of money does not enter into the discount rate in this instance because these taxes are not seen by the utility company. The Federal taxes ultimately are transfers from the customer to the Federal Government (flow through).

taxes, and reflecting the alternative productivity of capital that can be realized if funds are employed in private sector.

3. Q. What is value of money for conditions of (2)?
 - A. Opportunity cost of capital in private industrial sector plus allowance for taxes that are lost because tax-producing capital has been diverted from private sector (pretax opportunity cost of capital in private sector).

Example 3: A study is undertaken to determine the national incentive for developing a new energy technology to meet the nation's future energy needs. It is assumed the facilities which use the new technology will be constructed and operated by the utility industry.

1. Q. Who is the decision-making body?
 - A. The nation -- Government's decision to develop, utilities decision to implement.

Decision is keyed on incentive to the nation of having a new energy technology available. This can be quantified by looking at the incentive to the nation's consumers (of electricity and the goods and services that electricity plays a part in providing -- effectively all consumers).
2. Q. What is the objective?
 - A. Minimizing the cost of the national product (long-term) that is available for consumption -- reduced electricity costs flow through to consumer (directly relates to enhancing the nation's standard of living).
3. Q. What is value of money to consumers?
 - A. Consumers borrowing-lending rate (consumption preference rate).

Hence the consumption preference rate is the appropriate principal discount rate for this type of analysis because the quantity that is being present-valued, and upon which basis a decision is being rendered, is the cost of electricity to consumers. Analyses that examine the benefits to the nation's standard of living of competing energy technologies, all of which are presumed to generate the same future supply of electricity, differ fundamentally from the usual cost-benefit calculation (Examples 1 & 2).

- It is the benefits to the nation's consumers (the nation's standard of living) that is serving as a basis for judging the alternatives; these benefits of reduced costs for making electricity flow through to final consumers.
- Only a modest fraction of the cost savings to consumers is reinvested, in marked contrast to the cost of corporate investment in projects, where 60-80% of cash flow is reinvested.

- The "benefits" - i.e., electricity -- are the same for all alternatives; it is the costs which differ.

Hence, the discount rate must relate to the financial effect on consumers, when they incur some energy cost later or earlier than the present-value reference time. And this effect depends, of course, on the rates at which consumers can borrow or lend money (the consumption preference rate). In short, it is the costs to consumers that are being present-valued and accumulated. Hence, the interest rate that consumers see must be used for present-valuing. This interest rate might fall in the range of 3-6% when corrected to zero inflation.

SECTION 9

NUCLEAR FUEL CYCLE COST CALCULATION CODE -- RAMMER

9.1 INTRODUCTION

The RAMMER code will calculate the fuel cycle costs for a Pebble Bed Reactor, an HTGR, or an LWR. It will not calculate costs for an LMFBR that has several zones and multiple fuel residence times. In addition to calculating fuel cycle costs, the code also calculates the values required for input to the more sophisticated code, PROPHET, which performs cost-benefit and market analyses.

The RAMMER code was written in the FORTRAN language and is meant for use on a timeshare system. The method of data input is simple. The code asks a series of questions which are answered by the data operator sitting at the timeshare printer. After sufficient data have been input, the calculation is done and the results are printed out.

To facilitate understanding of what the code will calculate, a sample RAMMER code run is included, Table 9-1. The case shown is for the Pebble Bed Reactor known as the prebreeder. This reactor is characterized by three streams of fuel. One stream is all uranium, one is a mixture of uranium and thorium, and one is all thorium. RAMMER handles each of these streams as shown in the sample run. Two sets of uranium loads and discharges are specified and two sets of thorium are loaded. The thorium discharges are set equal to zero because thorium is not recovered for resale.

TABLE 9-1

SAMPLE NUCLEAR FUEL COST CALCULATIONS
(Typical Pebble Bed Pre-Breeder Reactor)

INPUTS COMMON TO ALL CALCULATIONS

ready

*RUN

ENTER AVERAGE BURNUP (MWD/MTHM)
=23200

ENTER NET CYCLE EFFICIENCY (%)
=40

ENTER DISCOUNT RATE (%/YR)
=10.24

ENTER CARRYING CHARGE RATE (%/YR)
=15.56

ENTER INFLATION RATE (%/YR)
=6

ENTER FUEL RESIDENCE TIME IN CALENDAR YEARS
=1.54

FABRICATION COSTS

WHICH VARIABLE ? (FABRICATION = 1, RECOVERY = 2, URANIUM = 3,
ENRICHMENT = 4, CREDITS = 5, STOP = 6)
=1

ENTER UNIT COST OF FABRICATION (\$/KG)
=325

ENTER TIME BETWEEN PAYMENT AND STARTUP (MONTHS)
=12

ENTER TIME BETWEEN SHUTDOWN AND CREDIT (MONTHS)
=12

FABRICATION = 1.87441 MILLS/KW HR

TABLE 9-1 (Cont'd)

URANIUM COSTS

WHICH VARIABLE ? (FABRICATION = 1, RECOVERY = 2, URANIUM = 3,
ENRICHMENT = 4, CREDITS = 5, STOP = 6)
=3

THE FOLLOWING INFORMATION IS USED TO DETERMINE ENRICHMENTS. NOTE THAT
THE BURNUP IS BASIC TO THE CALCULATED ANSWER.

ENTER URANIUM MASSES LOADED (2 SETS)-CONSISTENT UNITS
=1.56,2.82

ENTER U235 MASSES LOADED (2 SETS)-CONSISTENT UNITS
=.96,2.62

ENTER THORIUM MASSES LOADED (2 SETS)-CONSISTENT UNITS
=8.01,95.45

ENTER URANIUM MASSES DISCHARGED (2 SETS)-CONSISTENT UNITS
=0.0,1.58

ENTER U235 MASSES DISCHARGED (2 SETS)-CONSISTENT UNITS
=0,.97

ENTER THORIUM MASSES DISCHARGED AND AVAILABLE FOR SALE. (2 SETS)
-CONSISTENT UNITS
=0,0

ENTER TAILS ASSAY (%)
=.3

ENTER THE PENALTY FOR U236 BUILDUP IN THE DISCHARGE STREAM (%).
0 = NO PENALTY
=0

ENTER PROCESSING LOSSES. FABRICATION THEN RECOVERY (%)
=1,1

ENTER COST OF U308 (\$/LB)
=50

ENTER COST OF CONVERSION (\$/KG)
=3.5

ENTER COST OF THORIUM (\$/KG)
=22

ENTER TIME BETWEEN PAYMENT AND STARTUP (MONTHS)
=24

ENTER TIME BETWEEN SHUTDOWN AND CREDIT (MONTHS)
=12

URANIUM DEPLETION = $0.05890 \text{ (MILLS/KW HR)} / (\$/\text{LB U308})$

URANIUM INVENTORY = $0.05382 \text{ (MILLS/KW HR)} / (\$/\text{LB U308})$

TOTAL URANIUM COST = $5.63620 \text{ (MILLS/KW HR)}$

TABLE 9-1 (Cont'd)

ENRICHMENT COSTS

DO YOU WISH TO RUN ENRICHMENT WITH THE SAME INPUT? (0 = NO, 1 = YES)
=1

ENTER ENRICHMENT COST (\$/SWU)
=90

ENTER TIME BETWEEN PAYMENT AND STARTUP (MONTHS)
=12

ENTER TIME BETWEEN SHUTDOWN AND CREDIT (MONTHS)
=12

ENRICHMENT DEPLETION = 0.02078 (MILLS/KW HR)/(\$/SWU)

ENRICHMENT INVENTORY = 0.01254 (MILLS/KW HR)/(\$/SWU)

TOTAL ENRICHMENT COST = 2.99877 (MILLS/KW HR)

RECOVERY PACKAGE OR WASTE DISPOSITION COSTS

WHICH VARIABLE ? (FABRICATION = 1, RECOVERY = 2, URANIUM = 3,
ENRICHMENT = 4, CREDITS = 5, STOP = 6)
=2

ENTER UNIT COST OF RECOVERY (\$/KG)
=465

ENTER TIME BETWEEN SHUTDOWN AND REPROCESSING PAYMENT (MONTHS)
=12

RECOVERY = 1.96315 MILLS/KW HR

TABLE 9-1 (Cont'd)

U-233 (or Plutonium) CREDITS

WHICH VARIABLE ? (FABRICATION = 1, RECOVERY = 2, URANIUM = 3,
ENRICHMENT = 4, CREDITS = 5, STOP = 6)
=5

ENTER TOTAL U-233 (OR PU) MASS LOADED-CONSISTENT UNITS
=0

ENTER TOTAL HEAVY METAL MASS LOADED-CONSISTENT UNITS
=107.84

ENTER TOTAL U233 (OR PU) MASS DISCHARGED-CONSISTENT UNITS
=1.37

ENTER PROCESSING LOSSES. FABRICATION THEN RECOVERY (%)
=1.1

ENTER U233 (OR PU) FISSILE PRICE (\$/GM)
=10

DO YOU WISH TO EMPLOY OPTION TO REDUCE SPECULATION ON FISSILE CREDITS
BY ASSUMING A DECLINING SALE PRICE? (0 = NO, 1 = YES)
=0

ENTER A 1 IF YOU WANT TO INCLUDE INFLATION IN THE RATE BASE, OR
ENTER A ZERO IF YOU WANT INFLATION AS A CAPITAL GAIN.
=0

ENTER INFLATION RATE FOR PRICE OF FISSILE MATERIALS (%/YEAR)
=0

ENTER TIME BETWEEN PAYMENT AND STARTUP (MONTHS)
=12

ENTER TIME BETWEEN SHUTDOWN AND CREDIT (MONTHS)
=12

U233 CREDIT = 0.04579 (MILLS/KW HR)/(\$/GM)
= 0.45793 (MILLS/KW HR) AT 10.0 \$/GM FISSILE

9.2 INPUT

For any given reactor fuel cycle, there are six inputs that are common to all of the calculations, as shown in Table 9-1. Following these universal inputs, a particular cost category is selected; then additional data for each cost category are entered. The five cost categories, which may be run in any order desired, are as follows: fabrication, recovery (or storage), uranium (U-235), enrichment, and credits (Pu-239 or U-233).

Most of the required input is self-explanatory; however, one set of data needs to be discussed. The units of the masses loaded and discharged are not specified. These isotopic inputs may be entered in any single consistent set of units desired (e.g., kg/GW day, or kg/year, etc.). Since these data are used to obtain enrichment values, the units of mass cancel when the enrichments are calculated.

9.3 OUTPUT

The output for each cost category follows immediately after the input questions for a given category. In three of the cost categories there are two different sets of data. The first output in these cases contains the input required for PROPHET (e.g., (mills/kWh)/\$1/lb) and the second output is used for a total fuel cycle cost calculation (mills/kWh). In the remaining two cost categories only the total costs (mills/kWh) are calculated.

9.4 CREDITS

Most of the inputs and outputs illustrated in the sample run are self-explanatory. However, there are three options in the credits category that are not obvious. The first option is in regard to the price at which the fissile plutonium or uranium is sold. A utility may want to assume in selecting a power plant that the sale of fissile materials (Pu-239 or U-233) will be made at an ever-increasing price. In fact, a case can be made that the price of bred fissile materials will actually decrease in the future. Thus the question asked by the code is: do you want to reduce speculation of fissile credits? An input of zero will not reduce the sale price. If a one is input, the code will ask for the number of years for the price to reach zero and over how many years the price is to be levelized. Choosing the latter option causes a significant reduction in the credits calculated.

The second option does not have as large an effect. This option relates to how the inflation on the fissile material prices is handled. If a zero is entered, the inflation is treated as a capital gain. Conversely, a one entered here causes the inflation to be treated as an instantaneous credit, and thus it is included in the rate base.

Finally, there is an option in which the inflation rate on sales of fissile materials may be different from the inflation rate used elsewhere in the code. If a zero inflation rate is entered, the previous option on inflation will not have any effect.

The method used in calculating fuel costs is that developed and used in "Breeder Reactor Economics" by Harvey Wyckoff, et al. The comment cards provided in the code listing, Table 9-2, may also help in understanding this methodology.

TABLE 9-2
RAMMER CODE LISTING

```

100***RAMMER***THIS PROGRAM WILL CALCULATE THE ONE CYCLE FUEL CYCLE COST FOR
200 A REACTOR WITH UP TO TWO FUEL STREAMS.IT A MODIFICATION OF THE METHODS
300 DESCRIBED IN "BREEDER REACTOR ECONOMICS" BY H. WYCKOFF...WHILE INTENDED
400 PRIMARILY FOR THE PEBBLE BED REACTOR. IT CAN ALSO BE USED FOR A BWR,
500 PWR, OR HTGR...IT IS NOT INTENDED FOR MULTI-ZONE, MULTIPLE FUEL
600 RESIDENCE TIME REACTORS, SUCH AS AN LMFBR. *** TCO 2 WAS AUG 1977 ***
700
800 INTERNAL FUNCTION FOR ENRICHMENT FEED TO PRODUCT RATIO
900 FEED NEEDED (KG/KG) = (DESIRED ENRICH. - OPERATING TAILS ENRICH.)
1000 / (ENRICH. OF NATURAL U - OPERATING TAILS ENRICH.)
110 FRATIO (A,B) = (A-B)/(0.007115-B)
1200 INTERNAL FUNCTION FOR ENRICHMENT,S SEPARATIVE WORK FUNCTION
130 SFUNC (A) = (2.*A-1.)*ALOG(A/(1.-A))
1400 INTERNAL FUNCTION FOR THE SEP. WORK UNIT RELATIONSHIP
150 SEPWK(A,B)=(SFUNC(A)-SFUNC(B))-FRATIO(A,B)*(SFUNC(0.007115)-SFUNC(B))
1600
1700 THE FOLLOWING INPUTS ARE COMMON TO ALL SUBSEQUENT CALCULATIONS
1800
1900 CORE AVERAGE BURNUP IS INPUT HERE...HM REFERS TO HEAVY METAL,
2000 IE: THORIUM SHOULD BE INCLUDED.
210 WRITE(06,801)
220 801 FORMAT(1H0,"ENTER AVERAGE BURNUP (MWD/MTHM)")
230 READ, BURN
240 WRITE(06,802)
250 802 FORMAT(1H0,"ENTER NET CYCLE EFFICIENCY ( % )")
260 READ, EFFY
270 EFFY = EFFY/100.
280 WRITE(06,803)
290 803 FORMAT(1H0,"ENTER DISCOUNT RATE ( %/YR )")
300 READ, D
310 D = D/100.
320 WRITE(06,804)
330 804 FORMAT(1H0,"ENTER CARRYING CHARGE RATE ( %/YR )")
340 READ, R
350 R = R/100.
360 WRITE(06,805)
370 805 FORMAT(1H0,"ENTER INFLATION RATE ( %/YR )")
380 READ, SI
390 SI = 1.+SI/100.
4000 NOTE WHEN FUEL RESIDENCE TIME & BURNUP ARE SPECIFIED, THE CAPACITY
4100 FACTOR IS DETERMINED FOR ANY REACTOR WITH A CONSTANT SPECIFIC POWER.
420 WRITE(06,806)
430 806 FORMAT(1H0,"ENTER FUEL RESIDENCE TIME IN CALENDAR YEARS")
440 READ, T
4500
4600 DETERMINE WHICH FUEL CYCLE VARIABLE TO CALCULATE.
470 1 WRITE(06,807)
480 807 FORMAT(1H0,"WHICH VARIABLE ? (FABRICATION = 1,RECOVERY = 2,
490 & URANIUM = 3,.,,ENRICHMENT = 4,CREDITS = 5,STOP = 6)")
500 READ, I
510 IF (I.LT.1) GO TO 1
520 IF (I.GT.6) GO TO 1
530 GO TO (10,20,30,40,50,999) , I
5400
5500 FABRICATION SECTION. READS THE UNIT COST FOR FABRICATION ($/KG).
5600 CALLS FOR THE APPROPRIATE SUBROUTINE, AND THEN CONVERTS THE SUM OF
5700 DEPLETION AND INVENTORY COSTS TO MILLS/KW HR...NOTE THAT THE
5800 SALVAGE VALUE OF FABRICATION IS EQUAL TO ZERO:
5900 THE PRICE INPUT IS THE SELLING PRICE AT THE TIME FUEL IS LOADED.

```


TABLE 9-2 (Cont'd)

```

600C THE CODE WILL REMOVE ANY INFLATION BETWEEN THE ACTUAL PURCHASE DATE
610C AND THE DAY OF FUEL LOADING.
620 10 WRITE(06,808)
630 808 FORMAT(1H0,"ENTER UNIT COST OF FABRICATION ($/KG)")
640 READ, FAB
650C FABRICATION HAS A ZERO SALVAGE VALUE
660 F = 0.0
670 CALL RAM(D,R,SI,T,FAB,F,CADL,CAIL)
680 FARS = CADL + CAIL
690C CONVERT LEVELIZED $/KG TO MILLS/KW HR
700 BWRFAB = (1000.*FARS)/(BURN*EFFY*24.)
710 WRITE(06,809) BWRFAB
720 809 FORMAT(1H0,"FABRICATION =",F10.5," MILLS/KW HR")
730 GO TO 1
740C
750C RECOVERY SECTION. READS THE UNIT COST FOR RECOVERY(SHIPPING PLUS
760C REPROCESSING PLUS WASTE DISPOSAL) AND CONVERTS THE SUM OF THE ACTUAL
770C PLUS INVENTORY COSTS TO MILLS/KW HR. NOTE THAT THE INITIAL VALUE
780C IS EQUAL TO ZERO...IF A THROWAWAY CYCLE IS DESIRED, THE PRESENT
790C WORTHED COST (PRESENT VALUED TO FIRST PAYMENT) FOR SPENT
800C FUEL STORAGE SHOULD BE INPUT FOR REC.
810C ALL PRICES ARE AT DAY OF FUEL LOADING.
820 20 WRITE(06,810)
830 810 FORMAT(1H0,"ENTER UNIT COST OF RECOVERY ($/KG)")
840 READ, REC
850C THE RECOVERY FUND IS ZERO AT THE DAY OF FUEL LOADING
860 A = 0.0
870 CALL ROD(D,R,SI,T,A,REC,CADL,CAIL)
880 RECS = CADL + CAIL
890C CONVERT LEVELIZED $/KG TO MILL/KW HR
900 BWRREC = (1000.*RECS)/(BURN*EFFY*24.)
910 WRITE(06,811) BWRREC
920 811 FORMAT(1H0,"RECOVERY =",F10.5," MILLS/KW HR")
930 GO TO 1
940C
950C URANIUM-235 SECTION. READS THE INPUTS FOR ISOTOPIC MASS FLOWS
960C AND CALCULATES THE U235 DEPLETION AND INVENTORY CHARGES...IF A
970C THROWAWAY CYCLE IS DESIRED THE DISCHARGE MASSES SHOULD BE
980C SET EQUAL TO ZERO.
990 30 WRITE(06,832)
1000 832 FORMAT(1H0,"THE FOLLOWING INFORMATION IS USED TO DETERMINE ENRICH
1010 &MENTS. NOTE THAT "/,"THE BURNUP IS BASIC TO THE CALCULATED ANSWER.")
1020 WRITE(06,812)
1030 812 FORMAT(1H0,"ENTER URANIUM MASSES LOADED (2 SETS)-CONSISTENT UNITS")
1040C THE OF ISOTOPIC MASSES LOADED AND DISCHARGED
1050C MAY BE INPUT IN ANY SET OF UNITS.
1060 READ, UI1, UI2
1070 WRITE(06,813)
1080 813 FORMAT(1H0,"ENTER U235 MASSES LOADED (2 SETS)-CONSISTENT UNITS")
1090 READ, UI51, UI52
1100 WRITE(06,814)
1110 814 FORMAT(1H0,"ENTER THORIUM MASSES LOADED (2 SETS)-CONSISTENT UNITS")
1120 READ, TH11, TH12
1130C SKIP THORIUM QUESTIONS IF NO THORIUM WAS LOADED
1140 ITHOR = 0
1150 IF(TH11.GT.0.0001.OR.TH12.GT.0.0001) GO TO 310
1160 ITHOR = 1
1170 310 WRITE(06,815)
1180 815 FORMAT(1H0,"ENTER URANIUM MASSES DISCHARGED(2 SETS)-CONSISTENT UNITS")

```

TABLE 9-2 (Cont'd)

```

1190 READ, UF1, UF2
1200 UF51 = 0.0
1210 UF52 = 0.0
1220 IF(UF1.LT.0.0001.AND.UF2.LT.0.0001) GO TO 315
1230 WRITE(06,816)
1240 816 FORMAT(1H0,"ENTER U235 MASSES DISCHARGED (2 SETS)-CONSISTENT UNITS")
1250 READ, UF51, UF52
1260 315 THF1 = 0.0
1270 THF2 = 0.0
1280 IF (ITHOR.EQ.1) GO TO 320
1290 WRITE(06,817)
1300 817 FORMAT(1H0,"ENTER THORIUM MASSES DISCHARGED AND AVAILABLE FOR SALE.
1310 &(2 SETS)",/,,"-CONSISTENT UNITS")
1320 READ, THF1, THF2
1330 320 WRITE(06,818)
1340 818 FORMAT(1H0,"ENTER TAILS ASSAY ( % )")
1350 READ, EW
1360 EW = EW/100.
1370 IF(EW.GE.0.007115) GO TO 320
1380 325 WRITE(06,845)
1390 845 FORMAT(1H0,"ENTER THE PENALTY FOR U236 BUILDUP IN
1400 & THE DISCHARGE STREAM ( % ).",/,," 0 = NO PENALTY")
1410 READ, U236P
1420 IF(U236P.GT.100.0) GO TO 325
1430 U236P = (100.-U236P)/100.
1440 326 WRITE (06,840)
1450 840 FORMAT(1H0,"ENTER PROCESSING LOSSES. FABRICATION THEN RECOVERY (%)")
1460 READ ,FLOSS,RLOSS
1470 IF (FLOSS.GE.100.0.OR.RLOSS.GT.100.0) GO TO 326
1480 FLOSS = 1.-FLOSS/100.
1490 RLOSS = 1.-RLOSS/100.
1500 330 WRITE(06,819)
1510 819 FORMAT(1H0,"ENTER COST OF U308 ($/LB)")
1520C ALL PRICES ARE AT THE TIME OF FUEL LOADING. THE CODE WILL
1530C HANDLE INFLATION BETWEEN TIME OF PURCHASE AND FUEL LOADING.
1540 READ, COY
1550 WRITE(06,820)
1560 820 FORMAT(1H0,"ENTER COST OF CONVERSION ($/KG)")
1570 READ, CUC
1580 COT = 0.0
1590 IF (ITHOR.EQ.1) GO TO 340
1600 WRITE(06,821)
1610 821 FORMAT(1H0,"ENTER COST OF THORIUM ($/KG)")
1620 READ, COT
1630C CALCULATE THE INITIAL U-235 ENRICHMENTS FOR THE 2 FUEL STREAMS.
1640C EI1 AND EI2 ARE THE INITIAL ENRICHMENTS OF U235.
1650C FPI1 AND FPI2 IS THE INITIAL FEED TO PRODUCT RATIOS.
1660 340 FPI1 = 0.0
1670 IF(UI1.LT.0.0001) GO TO 345
1680 EI1 = UI51/UI1
1690 IF(EI1.LE.0.007115) GO TO 345
1700 FPI1 = FRATIO (EI1,EW)
1710 345 FPI2 = 0.0
1720 IF(UI2.LT.0.0001) GO TO 350
1730 EI2 = UI52/UI2
1740 IF(EI2.LE.0.007115) GO TO 350
1750 FPI2 = FRATIO (EI2,EW)
1760C THE COST OF URANIUM FEED ($/KG U METAL)
1770 350 COF = 2.5998*COY + CUC

```

TABLE 9-2 (Cont'd)

1780C THE COST OF ENRICHED PRODUCT (\$/KG U METAL PRODUCT)
1790 VIU1 = COF*FPI1
1800 VIU2 = COF*FPI2
1810C TMF IS THE TOTAL MASS LOADED INTO ALL FUEL STREAMS.
1820 TMF = UI1 + UI2 + TH11 + TH12
1830C VIHM IS THE INITIAL VALUE OF ALL FUEL STREAMS
1840C LOADED IN TERMS OF DOLLARS PER KILOGRAM OF HEAVY METAL.
1850 VIHM = (VIU1*UI1+VIU2*UI2+COT*(TH11+TH12))/(TMF*FLOSS)
1860C CALCULATE THE U-235 ENRICHMENTS AND FEED TO PRODUCT RATIOS OF
1870C THE DISCHARGED FUEL STREAMS, ASSUMING NO BLENDING OF FUEL
1880C STREAMS DURING REPROCESSING.
1890C FPF AND EF ARE THE FEED TO PRODUCT RATIOS AND
1900C U235 ENRICHMENTS OF DISCHARGED FUEL.
1910 FPF1 = J.O
1920 IF(UF1.LT.0.0001) GO TO 360
1930 EF1 = UF51/UF1
1940 IF(EF1.LE.0.007115) GO TO 360
1950 FPF1 = FRATIO (EF1,E1)
1960 360 FPF2 = 0.0
1970 IF(UF2.LT.0.0001) GO TO 370
1980 EF2 = UF52/UF2
1990 IF(EF2.LE.0.007115) GO TO 370
2000 FPF2 = FRATIO (EF2,E2)
2010C THE VALUE OF THE TWO FUEL STREAMS (\$/KG U METAL)
2020 370 VFU1 = COF*U236P*FPF1
2030 VFU2 = COF*U236P*FPF2
2040C VFHM IS THE FINAL VALUE OF THE STREAMS IN \$/KG HM.
2050 VFHM = (VFU1*UF1+VFU2*UF2+COT*(THF1+THF2))/(TMF*RLOSS
2060 CALL RAM(D,R,S1,T,VIHM,VFHM,CADL,CAIL)
2070C BWRDUC AND BWRIUC ARE THE VARIABLES LWRDUC AND LWRIUC
2080C TO BE INPUT TO PROPHET.
2090 BWRDUC = (1000.*CADL)/(BURN*EFFY*24.*COY)
2100C CONVERT LEVELIZED \$/KG TO MILLS/KW HR.
2110C NOTE THE UNITS (¢/KWH)/(\$/LB) ASSUME CONVERSION AND THORIUM
2120C PRICES CHANGE AS U308 PRICES CHANGE.
2130 BWRIUC = (1000.*CAIL)/(BURN*EFFY*24.*COY)
2140 WRITE(06,822) BWRDUC
2150 822 FORMAT(1H0,"URANIUM DEPLETION =",F10.5," (MILLS/KW HR)/(\$/LB U308)")
2160 WRITE(06,823) BWRIUC
2170 823 FORMAT(1H0,"URANIUM INVENTORY =",F10.5," (MILLS/KW HR)/(\$/LB U308)")
2180 BwRTOT = (BWRIUC+BWRDUC)*COY
2190 WRITE (06,838) BwRTOT
2200 838 FORMAT(1H0,"TOTAL URANIUM COST = ",F10.5," (MILLS/KW HR)")
2210C THIS OPTION SAVES THE ENRICHMENT INFORMATION.
2220C ALLOWING IT TO BE USED AGAIN IN THE ENRICHMENT CALCULATION
2230 380 WRITE(06,824)
2240 824 FORMAT(1H0,"DO YOU WISH TO RUN ENRICHMENT WITH THE SAME
2250 & INPUT? (0 = NO, 1 = YES)")
2260 READ, J
2270 IF(J.LT.0) GO TO 380
2280 IF(J.EQ.0) GO TO 1
2290 IF(J.NE.1) GO TO 380
2300 GO TO 430
2310C
2320C U-235 ENRICHMENT SECTION. WILL HANDLE TWO U-235 ENRICHMENT STREAMS
2330C FOR THE SAME FUEL LOADING.
2340C THE FOLLOWING INFORMATION IS USED TO DETERMINE ENRICHMENTS. NOTE THE
2350C BURNUP IS BASIC TO THE CALCULATED ANSWER.
2360 40 WRITE (06,832)

TABLE 9-2 (Cont'd)

2370C ENTER URANIUM MASSES LOADED
2380 WRITE(06,812)
2390 READ, UI1, UI2
2400C ENTER U-235 MASSES LOADED
2410 WRITE(06,813)
2420 READ, UI51, UI52
2430C ENTER THORIUM MASSES LOADED
2440 WRITE(06,814)
2450 READ, TH11, TH12
2460C SKIP THORIUM QUESTIONS IF NO THORIUM WAS LOADED
2470 ITHOR = 0
2480 IF(TH11.GT.0.0001.OR.TH12.GT.0.0001) GO TO 410
2490 ITHOR = 1
2500C ENTER URANIUM MASSES DISCHARGED
2510 410 WRITE(06,815)
2520 READ, UF1, UF2
2530C ENTER U-235 MASSES DISCHARGED
2540 UF51 = 0.0
2550 UF52 = 0.0
2560 IF(UF1.LT.0.0001.AND.UF2.LT.0.0001) GO TO 415
2570 WRITE(06,816)
2580 READ, UF51, UF52
2590 415 THF1 = 0.0
2600 THF2 = 0.0
2610C SKIP THE QUESTIONS IF NO THORIUM WAS LOADED.
2620 IF (ITHOR.EQ.1) GO TO 420
2630C ENTER THORIUM MASSES DISCHARGED
2640 WRITE(06,817)
2650 READ, THF1, THF2
2660C ENTER TAILS ASSAY (%)
2670 420 WRITE(06,818)
2680 READ, E1
2690 EW = E1/100.
2700 IF(EW.GE.0.007115) GO TO 420
2710 425 WRITE(06,845)
2720C ENTER THE PENALTY ON DISCHARGED FUEL FOR U236 BUILDUP (%).
2730 READ, U236P
2740 IF(U236P.GT.100.0) GO TO 425
2750 U236P=1.-U236P/100.
2760 426 WRITE (06,840)
2770C ENTER PROCESSING LOSSES. FABRICATION THEN RECOVERY (%)
2780 READ ,FLOSS,RLOSS
2790 IF (FLOSS.GE.100.0.OR.RLOSS.GT.100.0) GO TO 426
2800 FLOSS = 1.-FLOSS/100.
2810 RLOSS = 1.-RLOSS/100.
2820 430 WRITE (06,841)
2830 841 FORMAT(1H0,"ENTER ENRICHMENT COST (\$/SWU)")
2840 READ ,CSW
2850C CALCULATE NUMBER OF SEPARATIVE WORK UNITS PER UNIT OF PRODUCT
2860C THAT ARE REQUIRED FOR STREAM 1 ASSUMING NATURAL URANIUM FEED
2870 DELI1 = 0.0
2880 IF (UI1.LT.0.0001.OR.UI51.LT.0.0001) GO TO 440
2890 E11 = UI51/UI1
2900 IF(E11.LE.0.007115) GO TO 440
2910 DELI1 = SEPNK (E11,EW)
2920C CSW IS IN UNITS OF \$/SWU AND DELI IS IN UNITS OF
2930C SWU/KG ...THUS VIS IS IN \$/KG OF PRODUCT.
2940 440 VIS1 = CSW*DELI1
2950C CALCULATE THE NUMBER OF SEPARATIVE WORK UNITS PER UNIT OF PRODUCT

TABLE 9-2 (Cont'd)

```

2960C   THAT ARE REQUIRED FOR STREAM 2 ASSUMING NATURAL URANIUM FEED
2970 DELI2 = 0.0
2980 IF(UI2.LT.0.0001.OR.UI52.LT.0.0001) GO TO 450
2990 EI2 = UI52/UI2
3000 IF(EI2.LE.0.007115) GO TO 450
3010 DELI2 = SEPMK (EI2,EW)
3020 450 VIS2 = CSW*DELI2
3030 TMF = UI1+UI2+THI1+THI2
3040C   ENRICHMENT VALUE OF NEW FUEL ($/KG)
3050 VSW = (VIS1*UI1+VIS2*UI2)/(TMF*FLOSS)
3060C   CALCULATE ENRICHMENT CREDIT FOR STREAM NUMBER 1
3070 DELF1 = 0.0
3080 IF(UF1.LT.0.0001.OR.UF51.LT.0.0001) GO TO 460
3090 EF1 = UF51/UF1
3100 IF(EF1.LE.0.007115) GO TO 460
3110 DELF1 = SEPMK (EF1,EW)
3120 460 VFS1 = CSW*U236P*DELF1
3130C   CALCULATE THE ENRICHMENT CREDIT FOR STREAM NUMBER 2
3140 DELF2 = 0.0
3150 IF(UF2.LT.0.0001.OR.UF52.LT.0.0001) GO TO 470
3160 EF2 = UF52/UF2
3170 IF(EF2.LE.0.007115) GO TO 470
3180 DELF2 = SEPMK (EF2,EW)
3190 470 VFS2 = CSW*U236P*DELF2
3200C   FINAL ENRICHMENT VALUE OF SPENT FUEL
3210 VFSW = (VFS1*UF1+VFS2*UF2)/TMF*RLOSS
3220 CALL RAN(D,R,SI,T,VISW,VFSW,CADL,CAIL)
3230C   BWRDEC AND BWRIEC ARE THE VARIABLES LWRDEC AND LWRIEC TO
3240C   BE INPUT TO PROPHET.
3250 BWRDEC = (1000.*CADL)/(BURN*EFFY*24.*CSW)
3260 BWRIEC = (1000.*CAIL)/(BURN*EFFY*24.*CSW)
3270 WRITE(06,825) BWRDEC
3280 825 FORMAT(1H0,"ENRICHMENT DEPLETION = ".F10.5," (MILLS/KW HR)/(S/SWU)")
3290 WRITE(06,826) BWRIEC
3300 826 FORMAT(1H0,"ENRICHMENT INVENTORY = ".F10.5," (MILLS/KW HR)/(S/SWU)")
3310 BWRTOT = (BWRIEC+BWRDEC)*CSW
3320 WRITE(06,839) BWRTOT
3330 839 FORMAT(1H0,"TOTAL ENRICHMENT COST = ".F10.5," (MILLS/KW HR)")
3340C   TRANSFER BACK TO URANIUM SECTION WITH SAME ASSUMPTIONS
3350 480 WRITE(06,827)
3360 827 FORMAT(1H0,"DO YOU WISH TO RUN URANIUM WITH THE SAME
3370 & INPUTS? (0 = NO, 1 = YES)")
3380 READ ,J
3390 IF(J.LT.0) GO TO 480
3400 IF(J.EQ.0) GO TO 1
3410 IF(J.NE.1) GO TO 480
3420 GO TO 320
3430C
3440C   BRED FISSILE CREDITS. THIS SECTION CALCULATES U233 (OR PU239) CREDITS.
3450C   NOTE: THIS SECTION ASSUMES A CHEMICALLY SEPARABLE PRODUCT OR ONE
3460C   THAT DOES NOT NEED ENRICHMENT SERVICES.
3470 50 WRITE(06,828)
3480 828 FORMAT(1H0,"ENTER TOTAL U-233 (OR PU) MASS LOADED-CONSISTENT UNITS")
3490 READ ,UI33
3500C   THE TOTAL HEAVY METAL MASS IS USED IN CONJUNCTION WITH THE BURNUP
3510C   TO CALCULATE THE NUMBER OF KWHRS GENERATED.
3520 501 WRITE(06,829)
3530 829 FORMAT(1H0,"ENTER TOTAL HEAVY METAL MASS LOADED-CONSISTENT UNITS")
3540C   NOTE THAT TMF MAY BE EQUAL TO WHAT WAS CALCULATED ABOVE.

```

TABLE 9-2 (Cont'd)

```

3550 READ, IMF
3560 IF (IMF.LT.0.0001) GO TO 50
3570 IF (IMF.LT.0.0001) GO TO 501
3580 503 WRITE(06,830)
3590 830 FORMAT(1H0,"ENTER TOTAL U233 (OR PU) MASS DISCHARGED-CONSISTENT UNITS")
3600 READ, UF33
3610 504 WRITE (06,840)
3620C ENTER PROCESSING LOSSES. FABRICATION THEN RECOVERY (%)
3630 READ ,FLOSS,RLOSS
3640 IF (FLOSS.GE.100.0.OR.RLOSS.GT.100.0) GO TO 504
3650 FLOSS = 1.-FLOSS/100.
3660 RLOSS = 1.-RLOSS/100.
3670 505 WRITE(06,846)
3680 846 FORMAT(1H0,"ENTER U233 (OR PU) FISSILE PRICE ( $/GM )")
3690 READ ,PRICE
3700 IF (PRICE.LT.0.001) GO TO 505
3710 506 WRITE (06,833)
3720 833 FORMAT(1H0,"DO YOU WISH TO EMPLOY OPTION TO REDUCE SPECULATION ON
3730 &FISSILE CREDITS",/,"BY ASSUMING A DECLINING SALE PRICE? (0 = NO, 1 = YES)"
3740 READ, IOPT
3750 FACTR = 1.0
3760 IF (IOPT.EQ.0) GO TO 507
3770 IF (IOPT.NE.1) GO TO 506
3780C REDUCE SPECULATION ON FISSILE MATERIAL BY ASSUMING THAT THE FISSILE
3790C SALE PRICE WILL DECREASE IN TIME. IE. THAT A UTILITY WOULD ONLY BUY
3800C A REACTOR ONLY IF IT IS A GOOD DEAL WITHOUT THE FISSILE SALES.
3810 WRITE(06,835)
3820 835 FORMAT(1H0,"ENTER THE NUMBER OF YEARS FOR THE SALE PRICE
3830 & TO REACH ZERO")
3840 READ, Y2
3850 WRITE(06,837)
3860 837 FORMAT(1H0,"ENTER THE NUMBER OF YEARS IN THE FUEL COST LEVELIZATION.")
3870 READ, Y1
3880C LEVELIZE A LINEARLY DECLING SALE PRICE.
3890 QS = 0.0
3900 DIS = 0.0
3910 N = IFIX(Y1)
3920 DO 540 I = 1,N
3930 TOP = Y2 - I
3940 IF (TOP.GT.0.0) GO TO 530
3950 TOP = 0.0
3960 530 DEN = Y2*(1.+D)**I
3970 Q = TOP/DEN
3980 QS = QS + Q
3990 DI = 1./(1. + D)**I
4000 540 DIS = DIS + DI
4010 FACTR = QS/DIS
4020 507 WRITE(06,842)
4030 842 FORMAT(1H0,"ENTER A 1 IF YOU WANT TO INCLUDE INFLATION IN THE
4040 & RATE BASE,OR",/," ENTER A ZERO IF YOU WANT INFLATION AS A
4050 & CAPITAL GAIN.")
4060 READ, ICHOIC
4070 IF (ICHOIC.LT.0.0.OR.ICHOIC.GT.1) GO TO 507
4080 WRITE(06,843)
4090 843 FORMAT(1H0,"ENTER INFLATION RATE FOR PRICE OF FISSILE
4100 & MATERIALS (%/YEAR)")
4110 READ, S2
4120 S2 = 1. + S2/100.
4130 IF (ICHOIC.EQ.1) GO TO 510

```

TABLE 9-2 (Cont'd)

```

4140C  CALCULATE THE CREDIT ASSUMING INFLATION IS INCLUDED ONLY AS A
4150C  CAPITAL GAIN. THUS THE UTILITY DOES NOT GIVE THE CUSTOMER A CREDIT
4160C  UNTIL THE FISSILE HAS BEEN SOLD.
4170  VI33 = 1000.*UI33/(TMF*FLOSS)
4180  VF33 = 1000.*UF33/TMF*RLOSS
4190  CALL RAM(D,R,S2,T,VI33,VF33,CADL,CAIL)
4200  GO TO 520
4210C  CALCULATE THE CREDIT ASSUMING THE INFLATED SALE PRICE IS INCLUDED
4220C  IN THE RATE BASE AND REDUCES CUSTOMER CHARGES BUT INCREASES UTILITY
4230C  REVENUE REQUIREMENTS.
4240  510 VF33 = -1000.*UF33/TMF*RLOSS
4250  VI33 = -1000.*UI33/(TMF*FLOSS)
4260  CALL ROP(D,R,S2,T,VI33,VF33,CADL,CAIL)
4270  520 CADL = (-1.0)*CADL
4280  CAIL = (-1.0)*CAIL
4290C  CALCULATE THE TOTAL ONE CYCLE CREDIT
4300  V33S = CADL + CAIL
4310  BWRSEI = (1000.*V33S)/(BURN*EFFY*24.)
4320C  PRINT FINAL RESULTS
4330  550 BWRSEI = FACTR*BWRSEI
4340  WRITE(06,831) BWRSEI
4350  831 FORMAT(1H0,"U233 CREDIT =",F10.5," (MILLS/KW HR)/(S/GM)")
4360  BWRSEI = BWRSEI*PRICE
4370  WRITE(06,844) BWRSEI,PRICE
4380  844 FORMAT(1H0,"          =",F10.5," (MILLS/KW HR) AT ",F5.1,
4390  & " S/GM FISSILE")
4400  GO TO 1
4410  999 STOP
4420  END
4430C
4440C  SUBROUTINE "RAM" IS THE CALCULATION AS PER BREEDER
4450C  REACTOR ECONOMICS WHERE AN INITIAL VALUE "A" IS DEPRECIATED
4460C  TO A FINAL VALUE "F". WHICH MAY BE EQUAL TO ZERO. THE FINAL
4470C  VALUE MAY HAVE INFLATION INCLUDED; IF INCLUDED, IT IS NOT INCLUDED
4480C  IN THE RATE BASE UNTIL THE REVALUATION HAS OCCURRED.
4490  SUBROUTINE RAM(D,R,S1,T,A,F,CADL,CAIL)
4500C  D = UTILITY,S DISCOUNT RATE (FRACTION)
4510C  R = UTILITY,S INTEREST RATE (FRACTION)
4520C  S1 = INFLATION RATE (ONE PLUS A FRACTION)
4530C  T = FUEL RESIDENCE TIME (YEARS)
4540C  A = VALUE OF FUEL IF PURCHASED AT START OF FUEL LOADING
4550C  F = CALCULATED VALUE OF FUEL AFTER BURNUP IF THERE IS NO INFLATION.
4560C  CADL = LEVELIZATION OF THE DEPRECIATION CHARGES
4570C  CAIL = LEVELIZATION OF THE INTEREST CHARGES
4580  WRITE(06,1)
4590  1 FORMAT(1H0,"ENTER TIME BETWEEN PAYMENT AND STARTUP (MONTHS)")
4600  READ, T1
4610  T1 = T1/12.
4620  WRITE(06,2)
4630  2 FORMAT(1H0,"ENTER TIME BETWEEN SHUTDOWN AND CREDIT (MONTHS)")
4640  READ, T2
4650  T2 = T2/12.
4660  J = IFIX(T)
4670  J1 = IFIX(T1)
4680  J2 = IFIX(T2)
4690C  DETERMINE THE ACTUAL COST OF FUEL DUE TO IT BEING PURCHASED T1 YEARS
4700C  EARLY, WITH T1 YEARS OF INFLATION NOT OCCUPRING.
4710  A = A*(1./S1)**T1
4720  CAI = 0.0

```

TABLE 9-2 (Cont'd)

```

4730 CAD = 0.0
4740C  PRESENT VALUE OF THE FIRST INTEREST CHARGE.
4750 AI = A*R*(T1-FLOAT(J1))*(1.+D)**J1
4760 CAI = CAI + AI
4770 IF(J1.LT.1) GO TO 20
4780C  PRESENT VALUE OF THE INTERST CHARGES ON THE FUEL INVESTMENT
4790C  NOT YET LOADED INTO THE CORE.
4800 DO 10 I = 1,J1
4810 II = I - J1
4820 AI = A*R*(1./(1.+D))**II
4830 10 CAI = CAI+AI
4840C  B IS THE UNDEPRECIATED INVESTMENT
4850 20 B = A
4860C  PRESENT VALUE OF THE INTEREST AND DEPRECIATION CHARGES ON FUEL
4870C  WHILE IT IS IN THE CORE.
4880 DO 30 I = 1,J
4890 AI = B*R
4900 AD = (A-F)/T
4910 B = B-AD
4920 AI = AI*(1./(1.+D))**I
4930 AD = AD*(1./(1.+D))**I
4940 CAI = CAI+AI
4950 30 CAD = CAD+AD
4960 AD = (B-F)*(1./(1.+D))**T
4970 AI = (B)*R*(T- FLOAT(J))*(1./(1.+D))**T
4980 CAD = CAD+AD
4990 CAI = CAI+AI
5000C  REEVALUATE FUEL DUE TO INFLATION AT TIME OF SALE.
5010 AD = F*S1**(T+T2) - F
5020 AD = AD*(1./(1.+D))**(T+T2)
5030 CAD = CAD-AD
5040C  PRESENT VALUE OF THE INTEREST CHARGES FROM THE TIME OF DISCHARGE
5050C  TO THE TIME OF SALE.
5060 IF(J2.LT.1) GO TO 50
5070 DO 40 I = 1,J2
5080 TI = FLOAT(I)
5090 AI = F*R*(1./(1.+D))**(T+TI)
5100 40 CAI = CAI+AI
5110 50 AI = F*R*(T2-FLOAT(J2))*(1./(1.+D))**(T+T2)
5120 CAI = CAI+AI
5130C  CALCULATE AN ANNUITY FACTOR BASED ON THE AMOUNT OF ELECTRICITY
5140C  GENERATED.
5150 SUM = 0.0
5160 DO 60 I = 1,J
5170 S = 1./(1.+D)**I
5180 60 SUM = SUM+S
5190 S = (T-FLOAT(J))/(1.+D)**T
5200 SUM = SUM + S
5210 SUM = SUM/T
5220C  CONVERT PRESENT VALUES TO ONE CYCLE LEVELIZED COSTS.
5230 CADL = CAD/SUM
5240 CAIL = CAI/SUM
5250 RETURN
5260 END
5270C
5280C  SUBROUTINE "ROD" HANDLES THE CALCULATION OF A QUANTITY
5290C  WITH AN INITIAL VALUE WHICH APPRECIATES TO A
5300C  FINAL VALUE "F". THE FINAL VALUE F MAY INCLUDE INFLATION.
5310C  IF INCLUDED, IT IS INCLUDED IN THE RATE BASE AS THE ELECTRICITY
5320C  IS GENERATED.

```


TABLE 9-2 (Cont'd)

```

5330 SUBROUTINE ROO(D,R,SI,T,A,F,CADL,CAIL)
5340C D = UTILITY,S DISCOUNT RATE (FRACTION)
5350C R = UTILITY,S INTEREST RATE (FRACTION)
5360C SI = INFLATION RATE (ONE PLUS A FRACTION)
5370C T = FUEL RESIDENCE TIME (YEARS)
5380C A = VALUE OF FUEL IF PURCHASED AT START OF FUEL LOADING
5390C F = CALCULATED VALUE OF FUEL AFTER BURNUP IF THERE IS NO INFLATION.
5400C CADL = LEVELIZATION OF THE DEPRECIATION CHARGES
5410C CAIL = LEVELIZATION OF THE INTEREST CHARGES
5420 CAI = 0.0
5430 CAD = 0.0
5440 IF(ABS(A).LT.0.0001) GO TO 5
5450 WRITE (06,801)
5460 801 FORMAT(140,"ENTER TIME BETWEEN PAYMENT FOR FISSILE AND STARTUP (MONTHS)"
5470 READ ,T1
5480 T1=T1/12.
5490 J1=IFIX(T1)
5500 A=A/SI**T1
5510C PRESENT VALUE OF FIRST INTEREST CHARGE
5520 AI=A*R*(T1-FLOAT(J1))*(1.+D)**J1
5530 CAI = CAI+AI
5540 IF (J1.LT.1) GO TO 5
5550C PRESENT VALUE OF PREBURNUP INTEREST CHARGES
5560 DO 4 I=1,J1
5570 I1=I-J1
5580 AI=A*R*(1./(1.+D))**I1
5590 4 CAI = CAI+AI
5600 5 WRITE(06,802)
5610 802 FORMAT(140,"ENTER TIME BETWEEN SHUTDOWN AND REPROCESSING
5620 & PAYMENT (MONTHS)")
5630 READ, T2
5640 T2 = T2/12.
5650 J = IFIX(T)
5660 J2 = IFIX(T2)
5670C DETERMINE ESTIMATED FINAL FUEL VALUE WITH INFLATION INCLUDED.
5680 F = F*(SI)**(T+T2)
5690 B = A
5700C CALCULATE DEPRECIATION AND INTEREST CHARGES WHILE FUEL IS IN THE CORE.
5710 DO 10 I = 1,J
5720 AI = R*R
5730 AD = (F-A)/T
5740 B = B+AD
5750 AI = -AI*(1./(1.+D))**I
5760 AD = AD*(1./(1.+D))**I
5770 CAI = CAI+AI
5780 10 CAD = CAD+AD
5790 AD = (F-B)*(1./(1.+D))**T
5800 AI = -(B)*R*(T-FLOAT(J))*(1./(1.+D))**T
5810 CAD = CAD+AD
5820 CAI = CAI+AI

```

TABLE 9-2 (Cont'd)

5830C CALCULATE INTEREST CREDITS DUE TO HAVING COLLECTED PAYMENT EARLY.
5840 IF(J2.LI.1) GO TO 30
5850 DO 20 I = 1,J2
5860 TI = FLOAT(I)
5870 AI = -F*R*(1./(1.+D))**(T+TI)
5880 20 CAI = CAI+AI
5890 30 AI = -F*R*(T2-FLOAT(J2))*(1./(1.+D))**(T+T2)
5900 CAI = CAI+AI
5910C DETERMINE ANNUITY FACTOR BASED ON THE AMOUNT OF ELECTRICITY
5920C GENERATED.
5930 SUM = 0.0
5940 DO 40 I = 1,J
5950 S = 1./(1.+D)**I
5960 40 SUM = SUM+S
5970 S = (T-FLOAT(J))/(1.+D)**T
5980 SUM = SUM+S
5990 SUM = SUM/T
6000C CONVERT PRESENT VALUES TO ONE CYCLE LEVELIZED COSTS.
6010 CADL = CAD/SUM
6020 CAIL = CAI/SUM
6030 RETURN
6040 END

SECTION 10

PBR AND HTGR FABRICATION AND REPROCESSING COSTS

10.1 INTRODUCTION

This section provides the basis for the estimates of fabrication and reprocessing costs used in the RAMMER fuel cycle cost code.

Three basic references were used:

- The Washington ANS paper of Dr. E. Teuchert of (18)
- An ORNL TM (19)
- A GHT report for EPRI (20)

It should be noted that independent calculations were not made by General Electric. At the present time uncertainty exists as to the requirements, both political and technical, for reprocessing. Thus, any estimate carries a high level of uncertainty.

Data for fabrication from two different countries, both of whom manufacture fuel in moderate quantities, is not always comparable, especially with respect to capital charge rates for both commercial and Government facilities.

Thus, the possibility of error exists in these values, and care should be used in drawing conclusions based on fuel cycle costs which are strongly dependent on fabrication and reprocessing costs.

10.2 COST CONSIDERATION

Table 10-1 shows the cost data abstracted from Reference 18. Figures 10-1 and 10-2 show this data graphically. This data, originally from Hobeg, correlates quite well using a cost/ball plus an adder for the fuel in \$/kg HM. This is true for almost all cases except those with TRISO fuel. Since the TRISO particles do require extra steps in both fabrica-

TABLE 10-1

DATA ON FABRICATION/REPROCESSING
COSTS FOR PBR REACTORS
 (from reference 18)

COLD BALLS (U-235 and/or Th)

Type Cycle	Particle Diameter (μm)	Fuel Type	Loading (gm/ball)	<u>Fabrication</u>		<u>Reprocessing</u>	
				\$/kg HM	\$/Ball	\$/kg HM	\$/Ball
UOT-1	800	BISO U	10.2	366	3.73	616	6.28
TOT-1	400	BISO Th/U	11.2	347	3.89	586	6.56
MOR-1	400	BISO Th/U	11.2	347	3.89	586	6.56
RSE-1	400	BISO Th/U	15.0	295	4.42	511	7.66
SFB-2	200	TRISO U	2.0	2520	5.04	6060	12.12
SFB-3	400	BISO Th	20.1	207	4.16	451	9.06
PB-2	400	BISO Th/U	5.0	600	3.00	957	4.78
PB-3	400	BISO Th	32.4	164	5.31	390	12.64
NB-1	400	BISO Th	32.4	164	5.31	390	12.64

REMOTE BALLS (U-233 and/or Th)

MOR-2	400	BISO Th/U	11.2	1041	11.66	599	6.71
RSE-2	200	TRISO U	1.7	8174	13.90	4240	7.21
SFB-1	400	BISO U	8.9	1202	10.70	749	6.67
SFB-4	400	BISO Th/U	20.1	766	15.40	463	9.31
PB-1	200	TRISO U	1.8	8035	14.46	2897	5.21
NB-2	400	BISO Th/U	32.4	635	20.57	395	12.80

Figure 10-1. Fabrication Costs (KFA Data)

Figure 10-2. Reprocessing Costs (KFA Data)

tion and reprocessing, this is not surprising. A simple \$/kg HM fuel cost is not very useful for PBRs. Table 10-2 shows the least squares fit to this data.

Table 10-3 shows the cost information from Reference 19.

This Oak Ridge Data is on a \$/kg HM basis. When compared to the KFA data, the fabrication data range matches in the area which represents current ball loadings, 10-15 gm HM/ball. The reprocessing data matches in this range only if the ORNL data is modified by reducing the fixed-change rate for capital from 30% to 18%.

This latter change is appropriate if Government financing or Government guarantees are involved.

Table 10-4 shows the fuel cycle cost data from Reference 20 (GHT).

The GHT data is actually a year older than the rest, going back to a mid-1975 meeting. Again, \$/kg HM is used. Fabrication costs are higher than the ORNL or KFA data, but reprocessing costs are much lower than either.

Some data from the LWBR program show a very low value for fabrication and reprocessing, about one-half that reported by GHT on a \$/kg basis.

Listed below are the ratios of remote fabrication cost of U-233 containing fuels to cold fabrication cost for each reference.

GHT (20)	3.5
KFA (Teuchert 18)	3.0
ORNL (19)	2.6
LWBR	2.5

Note that the KFA data is right in the middle.

In summary, the data used by KFA appears to be as good as any reviewed. In addition, it does show the proper effect of fuel element loading, so that trends between different cycles are probably correct.

TABLE 10-2
LEAST SQUARES FIT TO KFA DATA
(No TRISO Cases)

A - FABRICATION COSTS

- 1) BISO, Remote, U/Th or U
Cost = \$6.96/ball + \$420/kg HM
- 2) BISO, Cold, U/Th or U
Cost = \$2.29/ball + \$142/kg HM
- 3) BISO, Cold, Thorium only
Cost = \$2.28/ball + \$94/kg HM

Therefore adder for remote is:
\$4.67/ball + \$278/kg HM

B - REPROCESSING COSTS

All BISO Cases
Cost = \$3.55/ball + \$282/kg HM

TABLE 10-3
COST DATA FROM REFERENCE 19

A - FABRICATION AND REFABRICATION COSTS

<u>Fuel Form</u>	<u>Plant Size</u>	
	<u>< 5 Mg HM/da</u>	<u>≥ 5 Mg HM/da</u>
$U^{235}O_2 - ThO_2$	400 \$/kg HM	316 \$/kg HM
$U^{233}C_2 - ThO_2$	1030 \$/kg HM	814 \$/kg HM

Note that KFA data matches quite closely in the area of 8-18 gm HM/ball.

B - REPROCESSING COSTS

- 1) 5 Mg HM/day throughput
- 2) HTGR Fuel ($^{233}UC_2$ (TRISO)/ ThO_2 (BISO))

Cost Breakdown (\$/kg HM)

Shipping	30		
Reprocessing	622	Capital @ 30%	449
Waste Disposal	85	Operating	173
Total	737		

Note that the 30% capital charge rate is representative of an industrial firm, not a utility or a government operation. If the 30% FCR is reduced to 18%, the total now becomes \$558/kg HM, which is about the same as KFA in the 10-16 gm/ball range.

TABLE 10-4
FUEL CYCLE COST DATA
(FROM SECTION 6, REFERENCE 20)

Item	Units	Reactor Type		
		LeU HTR	HTGR	LWR (PWR)
Conversion Ratio		0.55	0.70	0.45
Burnup	MWD/kg HM	66	66	33.5
Efficiency/Load Factor	%	40/80	40/80	33.5/80
Fabrication Cost	\$/kg HM	470	470	160
Shipping Cost	\$/kg HM	52	28	18
Reprocessing Cost	\$/kg HM	200	260	104
Refabrication Cost Adder	\$/kg HM	-	1175.2	-
Total Refabrication Cost	\$/kg HM	-	1645	-
Fuel Cycle Costs	mills/kWh			
Fuel Costs				
Ore @ \$20/lb U ₃ O ₈		1.08	0.44	1.28
SWU's @ \$60.95		1.24	0.64	1.16
Cost of U233 & Th		-	0.02	-
Credit for U		-0.20	-0.06	-0.20
Credit for Pu		-0.16	-	-0.24
Total Fuel Cost		1.96	1.04	2.00
Total Fab. & Refab.		0.80	1.48	0.60
Reprocessing & Shipping		0.36	0.40	0.40
Total Fuel Cycle Cost		3.12	2.92	3.00

NOTE: "The fuel cycle cost considerations are based on data presented at the Twentieth Dragon Countries Physics Meeting, mid-1975. Recently performed calculations, using actual input data with modifications concerning reactor layout, tails assay and costs of natural uranium, separative work and fuel service, resulted in significant increases of costs for all mentioned fuel cycles. These increases, however, are larger for the uranium cycle in the HTR as well as in the LWR than for the thorium cycle HTR, thus increasing the difference in favour of the thorium cycle in the HTR."

The only charge not included so far is the cost of transporting and storing fuel from once-through cycles (store-away). Data from GE sources was used to estimate a cost of \$120 to 135 per kilogram heavy metal.

10.3 SPECIFIC VALUES FOR THE COST BENEFIT STUDY

Table 10-5 shows the recommended values for this study. Note that the HTGR costs are slightly higher because of the use of TRISO particles for the fissile fuel. This requires extra processing steps in both the fabrication and reprocessing plants.

TABLE 10-5
SPECIFIC COSTS FOR COST - BENEFIT FUEL CYCLES

Cycle Description	Fuel Description	Costs (\$/kg HM)	
		Fabrication	Reprocessing
<u>4021</u> Once-Through Thorium-Uranium Cycle	15 g/ball HM BISO Particles.	295	120-135**
<u>PB</u> Pre-Breeder	3 Fuel Streams.	325 (avg)	445* (avg)
<u>NB and PBTR</u> Near Breeder and Net Breeder	2 Fuel Streams.	315 (avg)	395 (avg)
<u>HTBR</u> Block Fuel Open Cycle	Fuel Pins. TRISO Uranium Particles. BISO Thorium Particles.	400	120-135**
<u>HTGR</u> Block Fuel Recycle and High Conversion Cycles	Same basic fuel as Open Cycle HTGR	400	560

*Assumes that one of the streams is a store-away.

**Long-term storage charges

SECTION 11

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