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A Survey of Nuclear Fuel Cycle Economics: 1970–1985

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ABSTRACT

This report is intended to provide a coherent view of the diversity of factors which may affect nuclear fuel cycle economics through about 1985. The nuclear fuel cycle was surveyed as to past trends, current problems, and future considerations. Unit costs were projected for each step in the fuel cycle. Nuclear fuel accounting procedures were reviewed; methods of calculating fuel costs were examined; and application was made to Light Water Reactors (LWR) over the next decade. A method conforming to Federal Power Commission accounting procedures and used by utilities to account for backend fuel cycle costs was described which assigns a zero net salvage value to discharged fuel. LWR fuel cycle costs of from 4 to 6 mills/kWhr (1976 dollars) were estimated for 1985. These are expected to reach 6 to 9 mills/kWhr if the effect of inflation is included.

1. INTRODUCTION

The mid-1970s have emerged as an important transitional period in the development of production activities comprising the nuclear fuel industry. From its origins in defense applications, this industry has now passed to a time when major decisions and resource allocations need to be made related to expanding the industrial base toward the level needed for continued support of a viable nuclear power industry. Efforts are being made within both government and private industrial organizations to evolve a workable blend of traditional "marketplace decision" processes and regulatory decision and enforcement procedures needed to maintain an economic and environmentally safe nuclear industry. The outcome of these efforts will determine the precise profile of the power industry of the next two decades. Because it now appears that nuclear fission reactors and coal-fired plants must form the major new sources of electrical energy for at least the next two decades, the importance of timely development of the nuclear fuel supply line appears evident.

The purpose of this report is to briefly appraise recent developments influencing nuclear fuel supply economics and to relate them to near-term expectations of nuclear fuel cycle costs. Here, by the "near-term" qualification, we imply that the report focuses on nuclear fuel cycle cost experience based essentially on commercially-demonstrated technologies. Limiting the forward projections of fuel cycle costs to a period roughly comparable with the current lead time for nuclear plant licensing and installation help insure that typical cost estimates are representative of industry experience and reduces the need for speculation about economics of pre-commercial technology developments.

Elements of uncertainty cannot be completely dispelled even from discussion of near-term fuel cycle economics, however. It is evident that the industry is in a state of flux and will be occupied during the next several years with significant and even crucial demonstrations associated with "closing" the fuel cycle (i.e. reprocessing, recycling uranium and plutonium, and separation and storage of radioactive wastes). The period 1970 to 1985 only loosely circumscribes the development of a commercial fuel supply line for UO_2-fueled Light-Water Reactors (LWR), leading into the above-mentioned demonstrations. Hence, we have attempted to limit the discussion of these leading developments only to details needed to supply perspective about current trends in nuclear fuel costs.

As a rule of thumb, it is useful to view growth of the nuclear fuels supply industry as divided into three phases, the first of which is characterized by significant fission power production prior to "closure" of the fuel cycle, i.e., with pool storage of the spent fuel elements. The second phase, likely to characterize a transitional period in the 1980s, will involve fuel reprocessing and recovery of fissile materials on a commercial scale, demonstration of high level waste isolation, and possibly recycle of plutonium in LWRs, i.e., the set of issues embodied in the GESMO project. The third phase, occurring still later in time, should involve significant production of power from commercial breeder reactors.

The present report deals with the first of the above-mentioned phases. Just as the industry is passing into an expanding and "maturing" phase of development, in writing this report, we have taken for granted a general familiarity with the basic nature and terminology of the nuclear fuel cycle. That is, the attempt is made to avoid redescribing elementary details already available elsewhere. Exceptions are made only where material is judged of sufficient importance to understanding the discussion.

The general organization of the report is as follows: It begins by summarizing current information about the expected growth in nuclear capacity over the time period chosen for study. This is followed by a brief survey of the economic status of the various production stages of the overall fuel cycle. In this time frame, only the light water reactor (PWRs and BWRs) fuel cycle is considered, since commercial application of the High Temperature Gas Cooled Reactor (HTGR) now appears likely to be delayed well beyond original expectations.

The emphasis given in this report to discussing various segments of the nuclear fuel cycle differs, in accord with our judgment about (a) their relative contribution or importance in determining the overall fuel costs paid by the energy consumer over the next several years; (b) the status of the technology for that component and the relative stability of near-term price levels; (c) the amount of quantitative information available to help interpret changes now underway; and (d) uncertainties concerning the resolution of regulatory issues affecting the economics of post-irradiation stages of the fuel cycle. Some components of the cycle are discussed in length, others more briefly. For the developmental phase examined in this report, the key components are the supply of U_3O_8 and separative work; hence, these developments are examined in greatest detail.*

The final section of the report draws on this background to discuss utility nuclear fuel cost allocations, reflecting "typical" utility experience and near-term expectations as of mid-1975. One of the original objectives of this study was to examine the problem of accounting for price escalations within the nuclear fuel cycle over this period. On close examination, this problem is seen to be comprised of many different elements, some of which are better described as "shock escalations,"

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*Most of this study was performed prior to the more comprehensive study on the nuclear fuels supply situation, sponsored by the Edison Electric Institute.[1]

aggravated by the energy crisis or by current uncertainties regarding future regulations on the commercial nuclear power industry.

2. GROWTH OF NUCLEAR-ELECTRIC CAPACITY IN THE NEAR TERM

Although some reduction has occurred in the rate of growth in nuclear generating capacity from forecasts made about two years ago, there is still a good basis for predicting that nuclear plants will comprise about 25% of total installed generating capacity by 1985. This reduction has been associated with factors such as inflation-recession effects in the economy, revisions of forward plans to reflect temporary decreases in the growth rate of electricity consumption, and the special efforts and time being given in the regulatory and licensing process to meeting environmental control criteria. In 1975 nuclear powered generation provided 8.7% of the total electricity generated in the U.S.

A typical forecasted scenario of growth in installed nuclear capacity through 1985, published in February 1974 by the AEC Office of Planning and Analysis, is represented by curve A in Fig. 1.[2] In comparison, curves B in this figure reflect the results of a utility survey taken in mid-1975 of expected nuclear capacity additions over the next decade.[3] As this later survey indicates, the net effect of schedule changes during the 1974—75 period was to delay growth in nuclear-installed capacity by roughly one year, compared to the earlier AEC forecast. The results of a more recent utility survey, taken in March 1976, indicate additional schedule delays were experienced between late 1975 and early 1976, as curve C in Fig. 1 illustrates.[4] Although these recent changes do not appear to significantly alter the forecasts for the immediate future, they do have a pronounced effect on forecasts for the 1980—85 planning period. These readjustments in forecasts must, of course, be made on a continuing basis, as future schedules become firm or new factors enter which influence the overall process of planning, commitment of resources, construction, and installation. However, because the inherent lead time in nuclear plant licensing and installation is now of the order of eight years, curves C of Fig. 1 should provide a fairly firm indication of the capacity requiring nuclear fuel and logistical support over the next decade.

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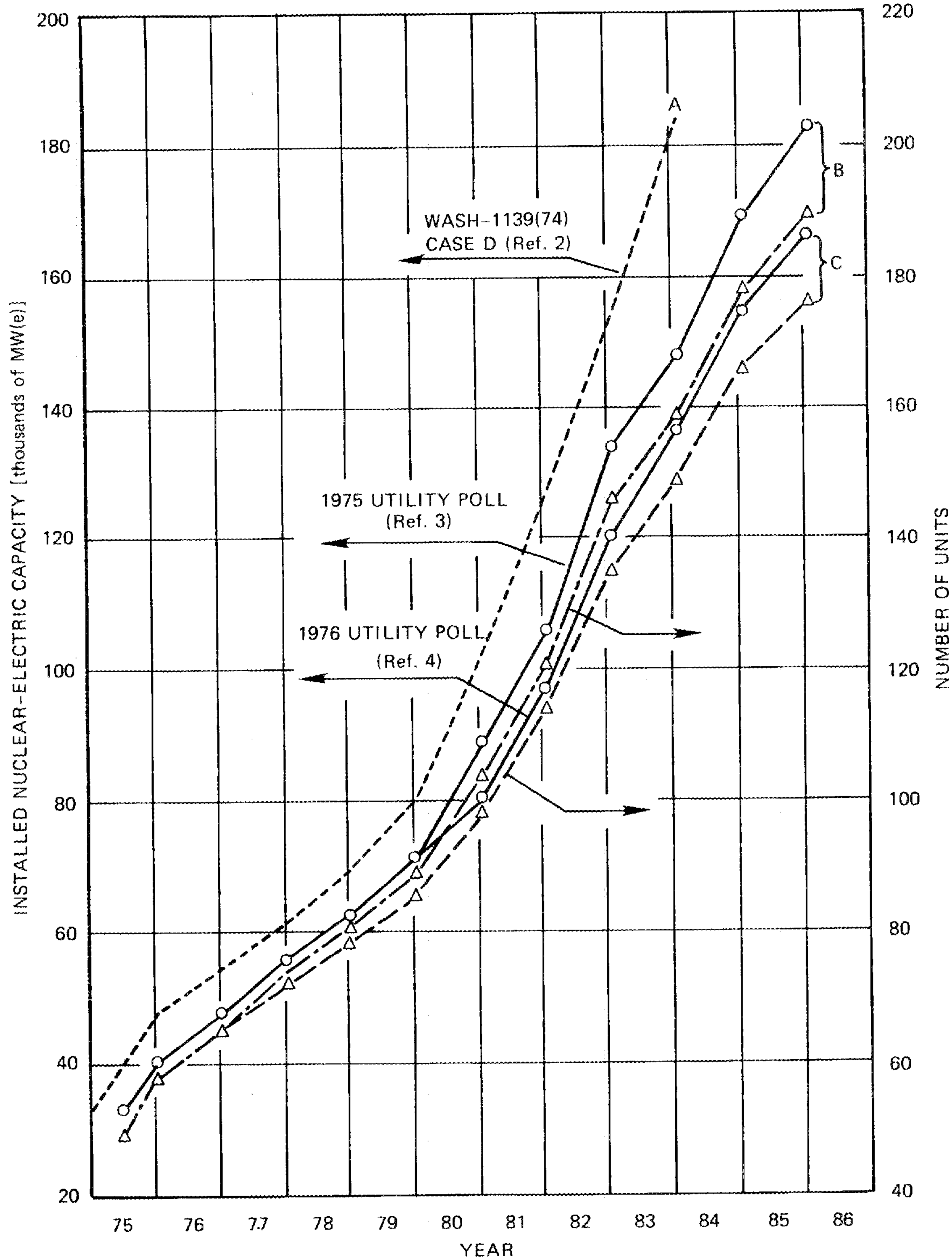

Fig. 1. Projected installed nuclear capacity, 1975–1985.

Although not shown in Fig. 1, essentially all of the nuclear plants currently installed on U.S. utility systems have begun commercial operation during the first half of the 1970s. Along with the net growth in installed nuclear capacity experienced or scheduled between 1970 and 1985, there has been a shift toward larger unit sizes. This is illustrated in Fig. 2. The average capacity of individual nuclear units has approximately doubled in this period, with the largest units slated for commercial operation in the early 1980s tending toward the 1300 MW(e) size category. Multi-unit generating plants, with the units in this general size range, appear likely to be the "standard" for LWR installation during the 1980s.

3. COST-PRICE TRENDS IN COMPONENTS OF THE LWR FUEL CYCLE

3.1 Uranium Ore Supply

The development of the U.S. uranium supply industry has taken an uneven path, starting with the early USAEC procurement phase in the 1950s, extending through a transitional period between governmental and commercial sales into an interval between about 1968 and 1973, when commercial sales agreements were made under depressed market conditions. It has now reemerged as an economically viable industry, and requirements for the industry of the 1980s are being established. The slow-demand years in the early 1970s reflected such factors as an above-average success in uranium exploration during early development of the industry, associated production of stockpiles or "pipeline" inventories, delays in the installation of nuclear capacity, and parallel developments in planning for expansion of the uranium enrichment industry, having consequences in scheduled requirements for uranium feed. The net result was to establish a temporary situation where uranium needed for reactor operations through the 1970s was sold at contract prices less than the cost of replacing or expanding the production base.[5]

Between 1973 and 1975, a fairly abrupt turnaround occurred in the market price quotations for contracts for future delivery of uranium. Within this period, most of the remaining proven reserves minable from existing facilities were placed under contract. The shift in the market price

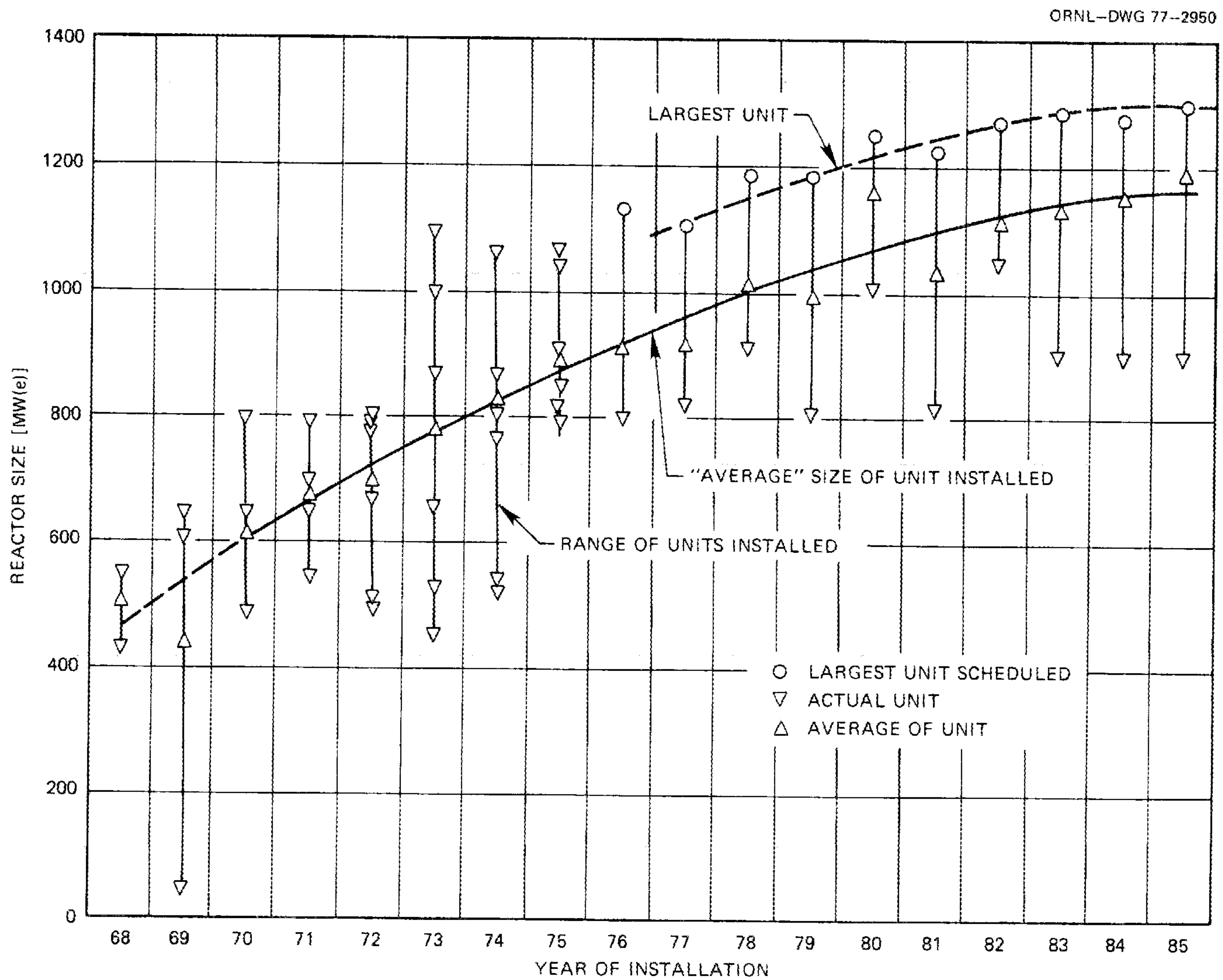

Fig. 2. Size of installed reactor capacity vs year of installation.

situation is illustrated in Fig. 3, taken from a description of conditions prevailing in early 1976.[6] The prices shown in this figure are described as "exchange values, or yardsticks used throughout the industry when parties seek guidance on world market prices." The reported prices that buyers were willing to pay for 1980 delivery increased from about $12/lb U_3O_8 to over $25/lb, between the start and end of 1974. By early November 1975, spot prices for immediate delivery had risen to $26/lb and values for 1980 delivery had reached $39/lb.

In October 1975, in the midst of this period of rapidly increasing market prices, Westinghouse Electric Corporation initiated action to legally extract itself from contract commitments for some 66 million lb of low price uranium (equivalent to $8 to $10/lb U_3O_8) scheduled for delivery over a time period extending to about 1988. This uranium had been committed to utilities during the late 1960s as part of an intensive reactor sales effort. It appears, however, that Westinghouse has on hand or access to only about 15 million lb of U_3O_8, which is sufficient to honor roughly 20% of their original contract commitments. For purposes of perspective, the 66 million lb is equivalent to about 40% of total industry requirements for delivery of feed material to the gaseous diffusion plants between 1974 and 1980.[7] The Westinghouse action and its timing were very significant in that they alone appeared to have stimulated a 10% jump in the U_3O_8 price level during the month of November 1975.[8] By the end of the year, spot prices for 1980 delivery approached $45/lb, as shown in Fig. 3.

These upward readjustments in uranium prices appear to reflect the level of resource commitments required to expand the industry, during a period of high rates of inflation in the economy, the oil embargo experience, and heightened concern over energy supplies. Perspective regarding the resource commitments may be supplied from several observations. First, exploration sufficient to continually maintain a proven reserve base equal or greater than eight years of forward requirements is considered a necessity.[9] At current projected growth in demand, this would equal about 20 times present annual production. In 1974, about 11,500 ton of U_3O_8 in concentrate were produced by 16 uranium mills. About 95% of

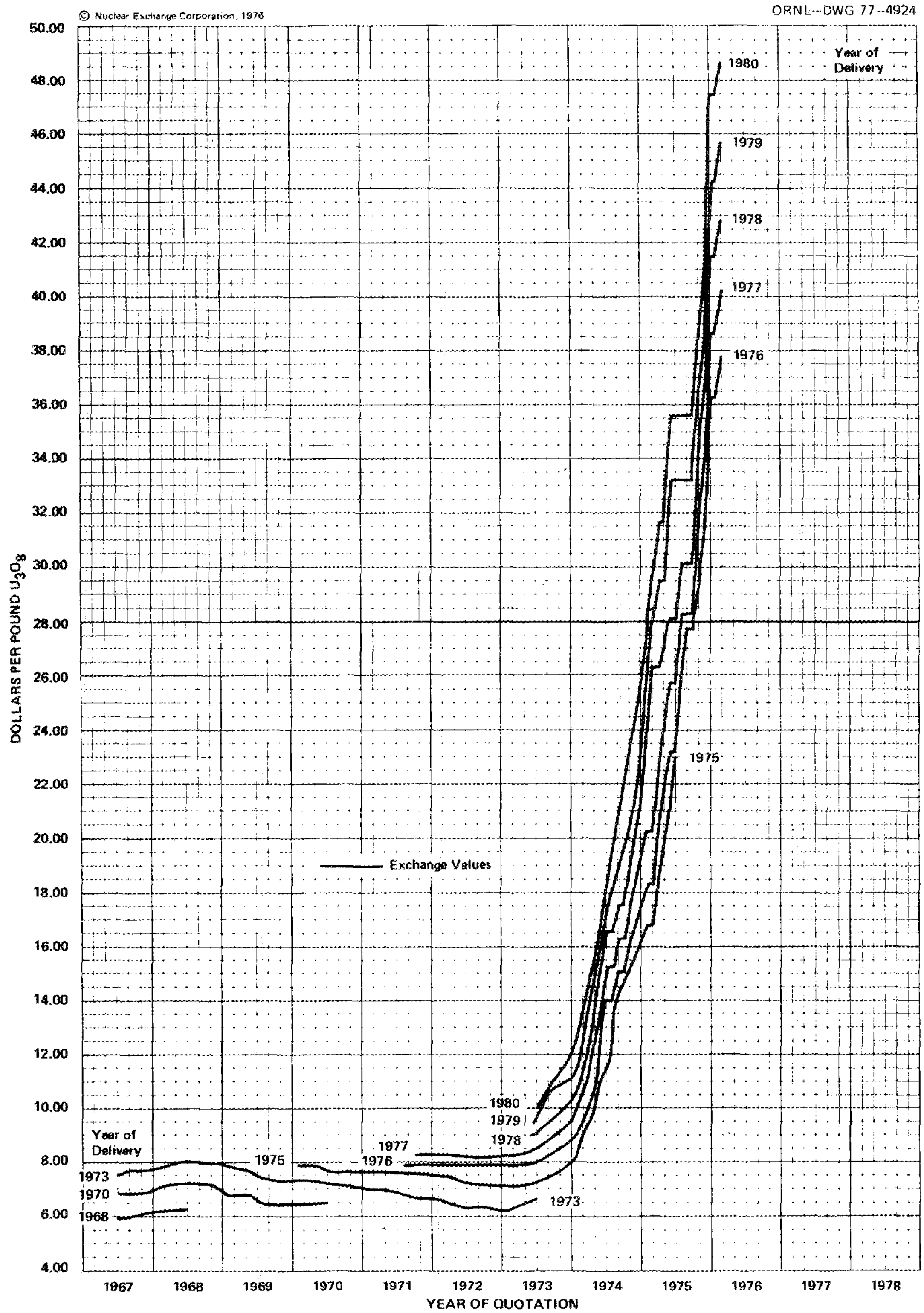

Fig. 3. Historical U_3O_8 exchange values.

this concentrate was produced from ore obtained by 37 of the largest U.S. uranium mining operations.[10]

Expenditures to find and develop the reserves needed to support a new uranium production center (generally consisting of several mines and a mill for U_3O_8 concentrate production) are typically spent between 4 and 9 years prior to start of production.[11] Major construction expenditures for the mines and mill generally are made over a 2- to 3-year period prior to production, and mine development capital expenditures continue during the period of production. Net positive cash flow for a mine-mill venture may not be attained until about the fifth year of operation, or about 13 to 15 years after the time the first expenditures for exploration take place.

The uranium resource grade, or ore assay which must be exploited, will be an increasingly important determinant of economics of production in the 1980s. Here, possible trends may be inferred from past AEC and continuing ERDA evaluations of uranium resource and "cost" categories. Generally, these evaluations use industrial raw data to independently classify proven reserves and potential resources, according to categories of "forward" costs for exploiting the resources. The total forward costs (capital plus operation) are divided according to various cutoff levels. The forward capital costs include those for future mine and mill construction, mine development, and major equipment. Forward operating costs include direct and indirect mining costs, haulage, royalty, and milling costs. The forward costs do <u>not</u> include profit, interest on pre-production investment, income taxes, ore reserve replacement costs, or sunk costs (e.g., past exploration, land acquisition, and developmental drilling). Also, except for periodic reevaluation of cost categories, no account is taken of "built-in" cost escalations. Thus, the ERDA forward cost categories do not imply availability of uranium on the open market at these prices; instead, they are intended mainly to serve as indexes for long-range planning of uranium resource developments.[10]

Average assays of U_3O_8 in ore mined from sandstone-type deposits have been slightly above 0.2% in recent years.[12] As indicated in Fig. 4, these fall within the general ERDA category of reserves minable below a cutoff level of \$8/lb U_3O_8. An analysis reported in 1972 of component

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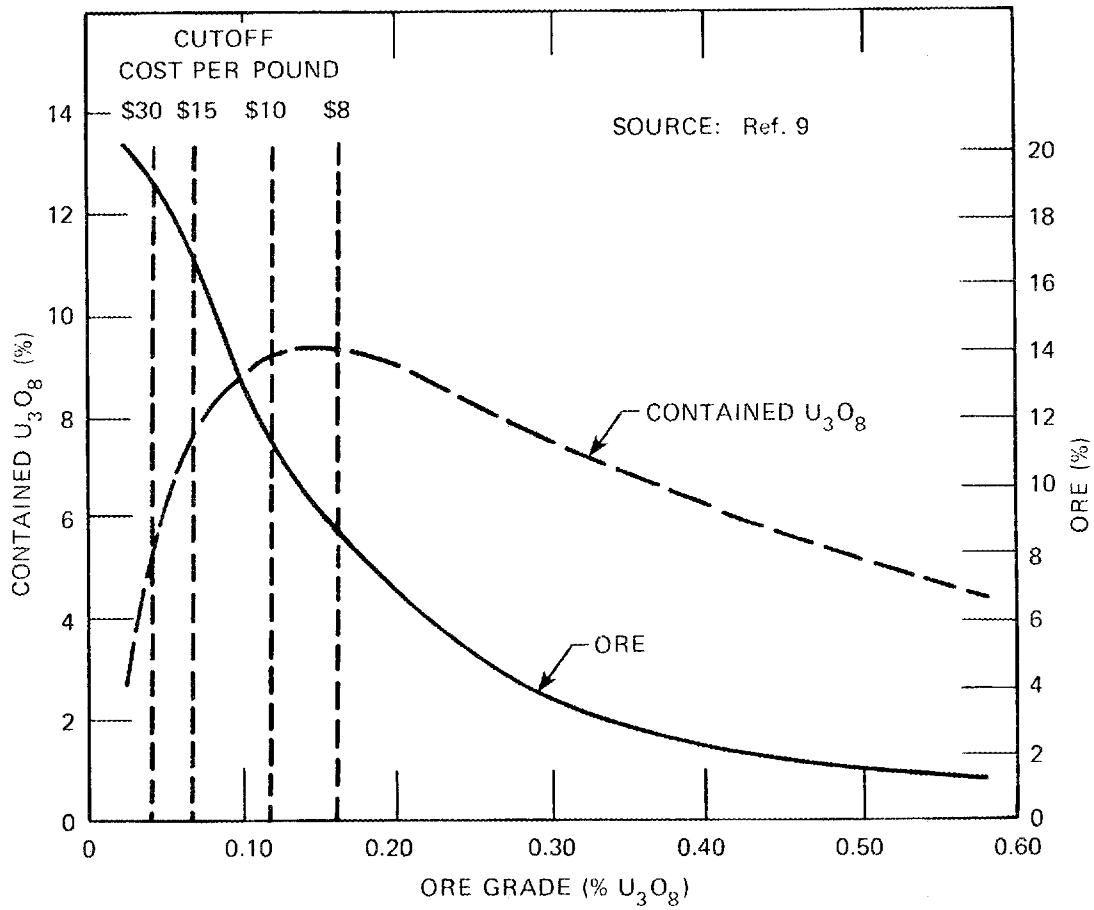

Fig. 4. Incremental distribution of reserves by grade and cutoff cost per pound for a typical sandstone type uranium deposit.

costs for a typical mine-mill venture using these high-grade resources is given in Table 1.[11] These costs are indexed to 1972 dollars, or price levels. As indicated in the table, the $5.94 subtotal encompasses the costs normally included by ERDA in determining reserves or resource categories. This subtotal lies at about the midpoint of the $8/lb cutoff level. Note, however, that the addition of taxes and indirect costs bring the 1972 "viability prices" to a level generally above the market prices prevailing in this period (Fig. 3). This indicates that substantial writeoff of investments in existing production facilities had occurred during earlier years.

Table 1. Cost breakdown for a typical uranium mining-milling venture, exploiting "$8/lb" resources

Costs for mining and milling included in AEC-ERDA reserve calculations	
Capital	\$ 1.68/lb U_3O_8 [a]
Operating, including royalty	4.26
	\$ 5.94
Costs not included	
Exploration	\$ 0.95
Interest on cash invested @ 11% compounded annually	2.67
Income and preference taxes	1.12
	\$ 4.74
Total cost of viability	\$10.68/lb U_3O_8

[a]All costs given in 1972 dollars. Source: Ref. 11.

The expansion of the industry during the next decades will likely require exploitation of proven reserves in the more extensive category of $15/lb forward costs, barring unusual success in finding and developing additional low cost, high-grade reserves. A large portion (∿90%) of the known $15/lb reserves occurs in association with deposits producible at lower costs.[10] However, as indicated in Fig. 4, there is also a tendency for diminishing returns in uranium recovery from sandstone deposits, occurring somewhere in the \$15 to \$30/lb cutoff range.[9] To economically exploit any of these lower grade resources, the average size of mining-milling operations will need to increase.

A breakdown of unit costs applicable to a mining-milling center using lower-grade resources is shown in Table 2, taken from an analysis reported in 1974.[13] All costs shown in this table are indexed to price conditions prevailing as of January 1, 1974. The direct costs for open-pit mining and milling operations of 1000 and 2000 ton/day are listed (production scales selected arbitrarily) followed by the "levelized" prices of U_3O_8 that would be required to generate various aftertax rates-of-return. A 15% discounted cash flow return-rate can be used as a rough measure of the minimum required to attract investment capital in this industry. Hence, from the type of analysis indicated in Table 2, a 2000 ton/day operation using an average ore assay of 0.1% would require a minimum price of about \$12/lb U_3O_8, while the same scale operation using an average assay of 0.05% (breakdown not shown) would require about \$19/lb.[13] These values, along with the cost breakdown shown in Table 2, should be used only as indexes, however, variability of a number of factors (including size, location, and depths of deposits) makes it difficult to specify a truly "typical" mine-mill venture.

An ERDA analysis reported in early 1975[10] indicated that a uranium production schedule based on exploiting only \$8/lb resources could be attained, which would satisfy currently contracted U.S. requirements through about 1981.* This would require judicious use of inventories as feed material for enrichment plants. The ERDA analysis also indicated that the U.S. uranium industry could meet domestic requirements for all capacity now under contract, plus additional nuclear power growth expected in the mid-1980s, through transition to an industry based on exploiting \$15/lb reserves. A possible production schedule, which assumes transition from an "\$8/lb" industry in 1975 to a "\$15/lb" industry cost index by 1981, is illustrated in Fig. 5 (taken from Ref. 10). A breakdown by types of

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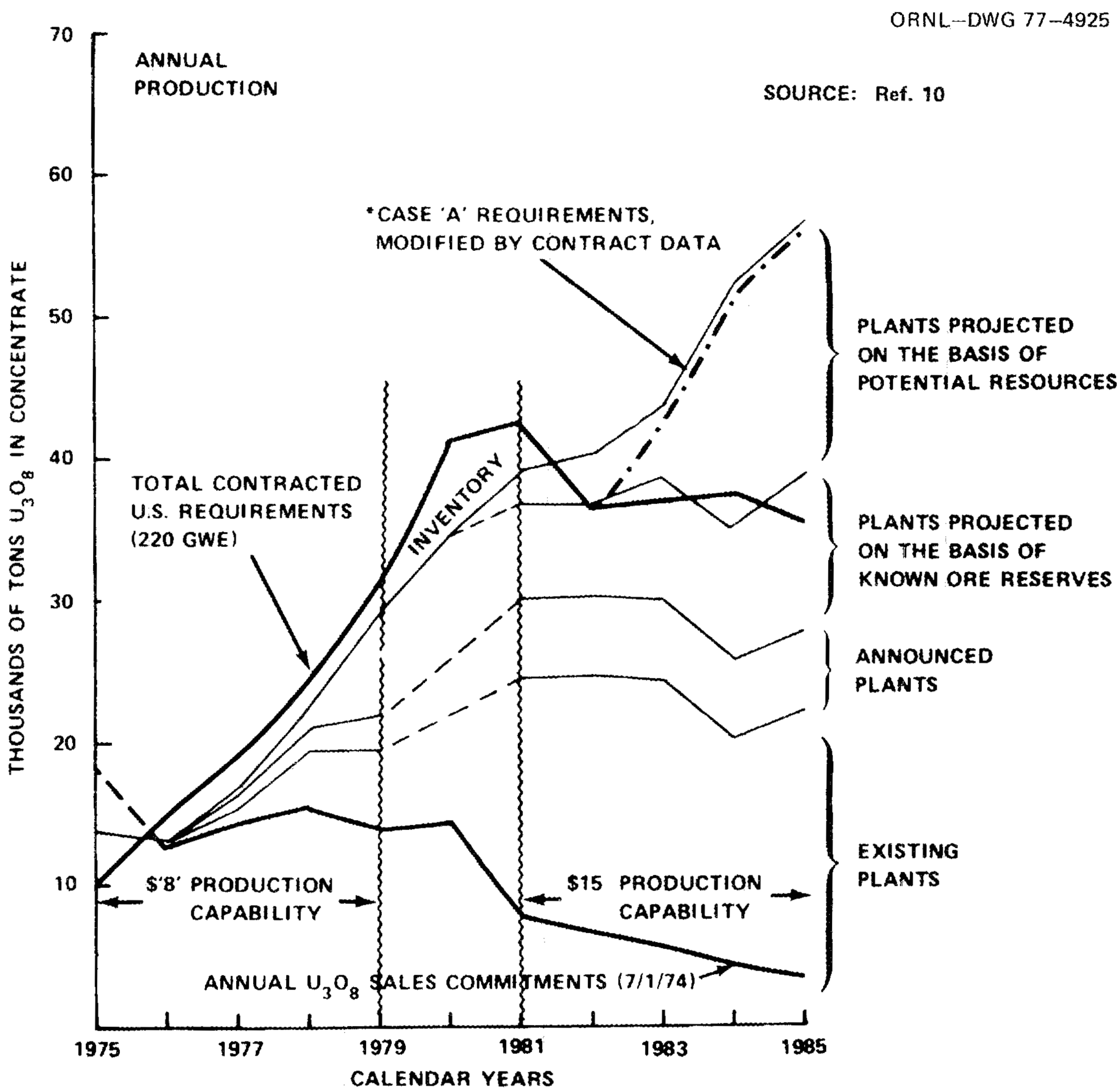
*These total requirements are dependent on the uranium enrichment operating plan, as described in Sect. 3.3.

Table 2. Typical overall economics for a future cycle of uranium concentrate production based on open pit mining operations at 0.1% U_3O_8 in ore[a]

Costs ($/lb U_3O_8)	1000 ton/day operation	2000 ton/day operation
Capital:		
Field expense	0.162	0.162
Property acquisition	0.130	0.130
Exploration drilling	0.216	0.216
Development drilling	0.065	0.065
Mine primary development	3.232	3.049
Mine plant and equipment	0.108	0.103
Mill construction	1.033	0.843
Total capital	4.946	4.568
Operating:		
Mining	0.838	0.757
Hauling	0.405	0.405
Milling	2.854	2.281
Royalty	0.257	0.225
Total operating	4.354	3.668
Total cost	9.300	8.236
Cash flow rate-of-return (%) at price of $10	3.5	8.4
Cash flow rate-of-return (%) at price of $12	10.5	15.1
Cash flow rate-of-return (%) at price of $14	15.8	19.8

[a]Source: Ref. 13.



AVERAGE PRICE PER lb FOR SALES
(CURRENT DOLLARS)

1975	7.85
1976	8.80
1977	9.25
1978	9.60
1979	10.50
1980	11.40

*WASH 1139 (74)

Fig. 5. Transition of $8 to $15 production capability scheduled to meet domestic requirements.

production capacity is also shown in Fig. 5, classified as existing, announced, projected on basis of known reserves, and on potential resources. No assumption is made that the industry will develop in precisely this way; however, the analysis does lend further prespective on the economic forces influencing uranium price levels.

Some additional information about uranium price escalation effects may be gained by examining production cost index variations in the mining industries during the past several years. Although these changes indicate magnitudes of primary cost escalations, time-lag effects are also significant because of the uneven pace of development in the uranium industry and long-term contracting procedures used in recent years. For example, Table 3 lists two overall price indexes calculated for the years between 1967 and 1975, normalized to an index of 100 for the year 1967. The first, labeled "typical U_3O_8 price escalation index,"[12] was developed by combining a 45% labor index component, 35% industrial commodity index component, and 20% fixed price component. According to Ref. 12, this formula is typical of escalation clauses built into U_3O_8 purchase contracts prior to about 1973.* The second index listed is the Marshall and Swift mining and milling index, which is an alternate indicator of cost escalation effects in the industry.[14] Both these overall indexes exhibit the substantial inflationary pressures between 1973 and 1975, but they do not provide a reliable means for extrapolation into the next decade. For this purpose, a judgmental approach is needed, based on all the forementioned elements.

The results of three ERDA surveys of the range of U_3O_8 contract delivery prices, taken in July 1974 and 1975, and in January 1976, are illustrated graphically in Fig. 6.[15] The prices are weighted-average prices for contract purchases by utilities and fuel manufacturers, and are shown by year of uranium delivery. The prices are given in estimated current dollars for that year. These averages are based on contract agreements made between 1967 and 1976 and do not represent prices at

*Values of the index for the years 1967–72 given in Table 3 were taken directly from Ref. 12, while the indexes for 1973–75 were obtained by combining the hourly wage index in the mining industries with the wholesale price index for all industrial commodities.

Table 3. Escalation indexes measuring changes in U_3O_8 primary costs during recent years

Year	Typical U_3O_8 contract price escalation index[a]	Change (%)	Marshall and Swift mining — milling index[b]	Change (%)
1967	100.0	2.8	100.0	3.7
1968	102.8	4.7	103.7	4.1
1969	107.6	3.5	108.0	6.3
1970	111.4	5.1	114.8	6.2
1971	117.1	4.1	121.9	3.3
1972	121.9	5.8	125.9	3.3
1973	130.7	12.6	130.1	15.0
1974	147.2	8.6	149.6	14.2
1975	(159.8)		173.0	15.6
1976			(180.4)	

[a]Source: Ref. 12.

[b]Source: Ref. 14.

which uranium can be purchased now or in the future. The graph depicts the widening range of reported prices, and clearly shows the effects of the large price increases that occurred between late 1974 and mid-1975. The reduction in maximum contract prices for the 1979 to 1982 period is partly attributable to a reevaluation of contract escalation rates.[15] It should be noted that the average contract price is still heavily influenced by older contracts, and this is reflected in the narrower price ranges shown for the 1983 to 1985 delivery period.

Several independent sources of information appraising the U_3O_8 price variations expected over the next several years are combined in Fig. 7. The lowermost two curves in this figure, curves A and B, are the results of the July 1974 and January 1976 ERDA price surveys, respectively. The latest survey (B) shows that the average price per pound of U_3O_8 for delivery in 1975 was $10.50, compared to the $8.45 price that was reported in the July 1975 price survey. As previously discussed, these curves represent weighted-average prices that are heavily influenced by older contracts, and the weighted-average price will tend to be "much closer to the low end of the range of contract prices than it is to the high end."[1]

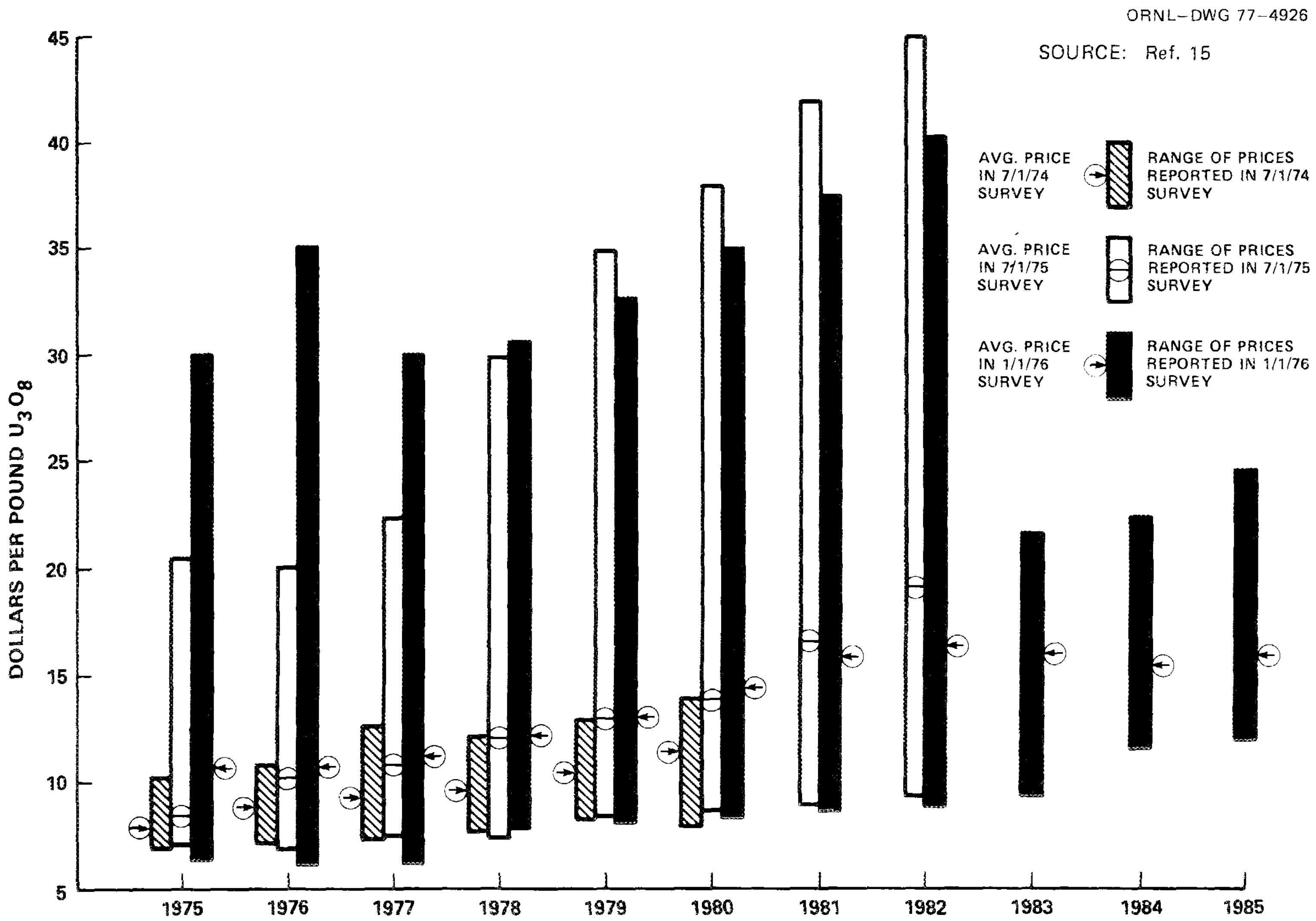


Fig. 6. Range of reported U_3O_8 prices (7/1/74, 7/1/75, and 1/1/76 surveys).

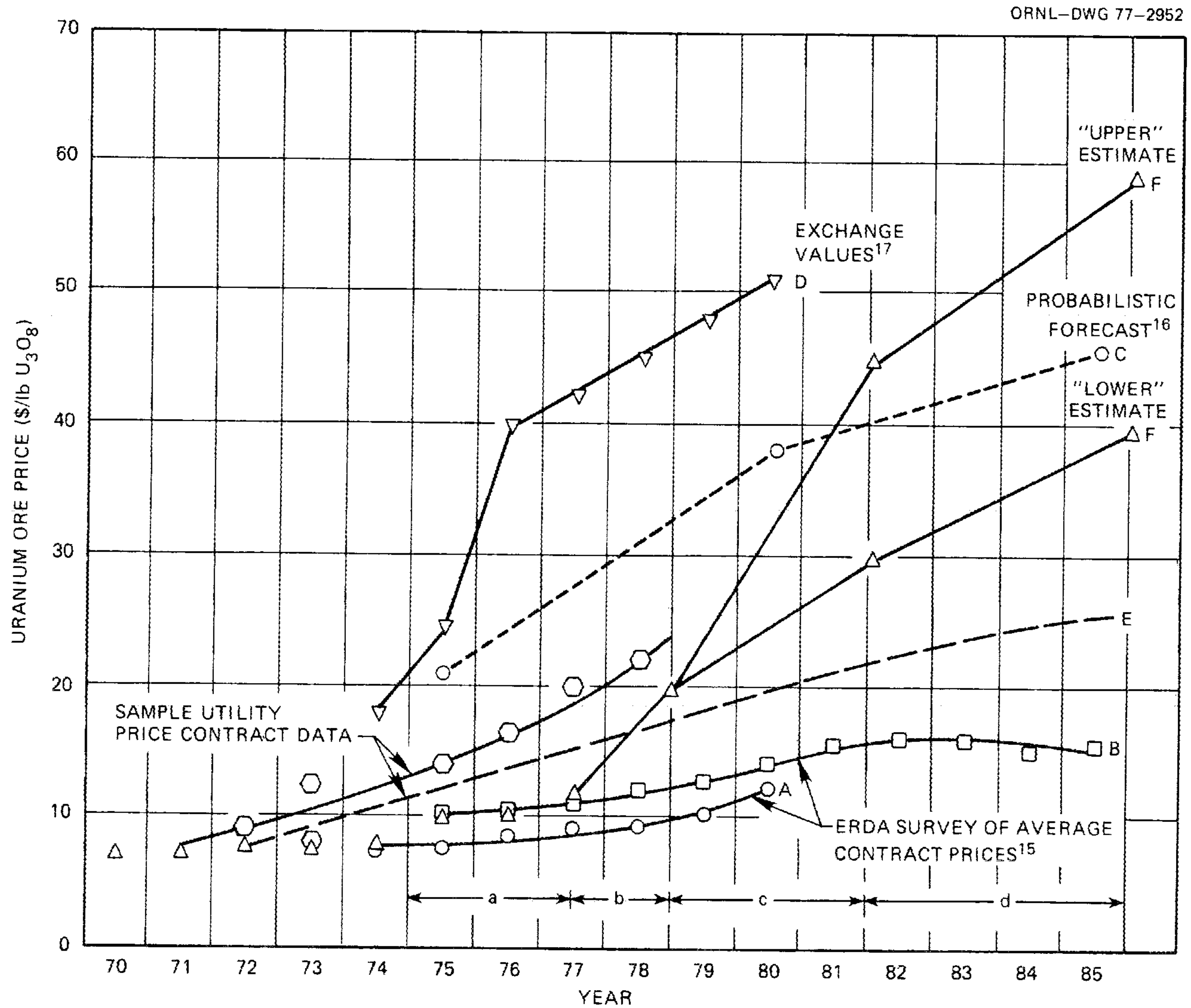


Fig. 7. Uranium ore price projections (current dollars).

Curve (C) in Fig. 7 is the result of a probabilistic forecast of future uranium prices reported in 1975 by the staff of the Nuclear Exchange Corporation.[16] These estimates are described as "future prices for immediate delivery contracts," which attempt to account for various contingencies influencing the uranium supply-demand situation between now and 1985. Subjective probabilities, based on informed judgments, are assigned to contingencies such as the rate of growth in electricity demand, additions to domestic uranium resources, uranium production costs, plutonium recycle, and international trade in uranium. Future prices, weighted according to these probabilities, were estimated in 1975, 1980, and 1985 dollars, and they are connected by straight lines to form curve C, as shown in Fig. 7.

Closely related to these values are recent market price quotations for new contracts for future uranium delivery. Behavior of these prices prior to January 1976, was shown in Fig. 3, and a more recent market price quotation is shown as curve D in Fig. 7, again given in year-of-delivery dollars.[17] This curve lies slightly above the results of the probabilistic forecast, and considerably above the average contracted price levels (curves A and B) reported by ERDA. Both the current market price quotations and probabilistic forecast tend to depict the "leading edge" of the uranium cost-price situation, i.e., they tend to represent levels of economic support required for new mine-mill ventures. In our judgment, they are best viewed as long-run <u>marginal</u> costs of supply, which include capital costs of expanding the industry, and reflect the needs of the marginal, or high-cost, producer.

This interpretation tends to be supported by some additional data obtained in the course of this study. Three independent utilities were contacted, two of which had nuclear plants in operation during the early 1970s. and a third which was committed to bring several nuclear units on-line between 1975 and 1985. The data points represented as "Xs" in Fig. 7 are average prices paid by one utility to fuel three LWRs over the 1972–79 period. (Approximate account has been taken of lead times between U_3O_8 delivery as feed material and actual or planned refueling dates.) For the second utility, the contracted prices followed the general averages represented by curves A and B in Fig. 7. Finally, the third utility had analyzed information available from their vantage point (including consideration of investments in uranium mining lands) to obtain the long-range price trend shown as curve E in Fig. 7 (again given estimated "current" dollars).

What can be concluded about the probable evolution of average uranium prices paid by the utilities, and therefore by the electricity consumer over the next several years? Clearly, price forecasting is an adaptive process which requires continual updating as new information becomes available. The trend is upward, and substantial increases are indicated between the currently-contracted price levels and those applying to delivery in the 1980 to 1985 period. The average prices exhibited as curve B in Fig. 7 are expected to prevail through most of the 1970s, with some additional upward "ratcheting" due to inflationary pressure. Noteworthy, however, is the fact that many current sales agreements for forward delivery were made at fixed prices or with an escalation clause covering only a portion of total costs.

Superimposed onto Fig. 7 is a composite estimate (curves F) of the upward readjustments in average prices of U_3O_8, projected for the 1975 to 1985 period. This judgmental forecast consists of several "sections," including (a) results of the 1976 annual ERDA survey of U_3O_8 contract prices, assumed to apply as given between 1975 and mid-1977; (b) some additional price escalations, assumed to increase the average contract price level to about \$20/lb by the end of 1978; (c) readjustment toward new average contract price levels between \$30 and \$45/lb by the end of 1981, giving the "lower" and "upper" estimates for curve F; and finally (d) average price escalation of 7% per annum from 1981 to 1985, resulting in lower and upper estimates of \$40 and \$59/lb, respectively, by the end of 1985. The approximate nature of this forecast is evident; however, it appears to be a plausible composite representation of all the separate items of price information indicated in Fig. 7. These upper and lower estimates of average uranium ore prices paid by utilities during the next decade have been used for the "representative" time-dependent nuclear fuel cost calculations described in Sect. 5.

3.2 Conversion from U_3O_8 to UF_6

Production of uranium hexafluoride from the U_3O_8 concentrate is perhaps the least complex step in the uranium fuel cycle. According to Ref. 18, two processes can be used for producing UF_6 for enrichment plants. One is a dry hydrofluor process, with continuous successive reduction, hydrofluorination, and fluorination of the ore concentrate, followed by fractional distillation to obtain a pure product. The other uses a wet solvent extraction step at the head end to refine the uranium feed, prior to the reduction, hydrofluorination, and fluorination steps. A typical or "model" conversion plant would process about 5000 tonne of U annually. Approximately two years are required to bring a new production facility on stream.

Because the conversion step utilizes a relatively simple, low-cost technology, the prices associated with this step in the fuel cycle are expected to remain fairly stable during the next few years. As of 1974, a "typical" price level was \$3/kgU, with some price spread depending on the actual contracting arrangements.

Even though no major readjustments in price levels are expected, the effects of general cost escalations still need to be included in price shifts over a 1970 to 1985 time span. One utility consulted in this study recommended converting the 1974 price levels to prices for future delivery by using a composite price index. The latter was derived by applying a 30% weight to the average hourly wage index in the chemical industries, 60% to the wholesale price index for all industrial commodities, and a 10% to the fixed-price component. However, if this formula is applied to the 1974 "typical" price level mentioned above in order to estimate price trends over 1970 to 1980 (Table 4), one encounters the same difficulty as noted previously in discussing price indexes for the uranium mining-milling industry. This is, to what extent is the high inflation rates experienced in 1974 and 1975 representative of trends expected for the remainder of this decade? In Table 4, we have assumed inflation will moderate and have simply applied a nominal, 5% annual escalation rate to determine conversion price levels beyond 1975.

Table 4. Estimated composite price index for U_3O_8 — UF_6 conversion costs

(Based on 1970 index = 100)

Year	Price index[a]	Change (%)
1970	100.0	4.2
1971	104.2	4.0
1972	108.4	6.2
1973	115.1	15.8
1974	133.3	8.3
1975	144.3	5.0
1976	(151.5)	(5.0/year)
1977	(159.1)	↓
1978	(167.0)	
1979	(175.4)	
1980	(184.2)	
1985	((235.0)	

[a]Calculated from Bureau of Labor Statistics for years 1970–75.

3.3 Uranium Enrichment

The uranium enrichment industry is the only segment of the commercial nuclear fuel cycle that remains under government ownership and control. For more than twenty years, ERDA (and the AEC before it) has operated three gaseous diffusion plants and has had exclusive control over uranium enrichment services for all U.S. reactors, plus a number of foreign reactors scattered throughout the world. The ERDA diffusion complex is currently the world's major supplier of separative work, and it is expected to continue in this role. However, even with the massive improvement program now underway, which is designed to increase the production capacity of the three plants by nearly 60%, ERDA's enrichment capacity has been fully committed since mid-1974 under long-term enrichment contracts to domestic and foreign customers. Based on ERDA's forecasts of domestic and foreign nuclear power growth, it is estimated that we will require additional enrichment capacity by the mid 1980's.[19] Since an 8 to 10 year leadtime is required for the design and construction of a new enrichment plant, decisions concerning the expansion of the uranium enrichment industry must be made in the near future.

Many of the problems that face the enrichment industry today revolve around questions concerning government versus private responsibility for construction and operation of new enrichment facilities. Although decisions must be made from technical, engineering, and economic standpoints regarding the choices of appropriate technology for this new enrichment capacity, these decisions should not interfere with the needed expansion of the industry, whether by government or private means. The U.S. has indicated its desire to move toward a commercial enrichment industry, and has announced its intention to raise its separative work prices to competitive levels anticipated for private industry.[20] However, the current uncertainties in the industry coupled with the enormous capital expenditures required for an enrichment venture have lead to uncertainty as to whether or not a private venture would be able to meet the early need for additional enrichment capacity. At the present time, only the gaseous diffusion and centrifuge enrichment processes are in active competition for meeting near term, i.e., 1970 to 1985, expansion needs. Although other separation techniques are being investigated, such as photoexitation with lasers and jet diffusion, the economic competitiveness of these processes cannot be determined with any degree of certainty. For this reason, only the gaseous diffusion and centrifuge enrichment processes will be considered in this analysis.

A thorough examination of the present uranium enrichment industry and its economics requires a knowledge of the current separative work supply-demand picture and a perspective on past as well as present trends in the industry. This is of particular importance in understanding the probable direction of future expansion of U.S. enrichment plant capacity. A brief description of the U.S. uranium enrichment industry follows.

The U.S. has three gaseous diffusion plants which are owned by the government and operated under contract with private industry. The Oak Ridge, Tennessee, and Paducah, Kentucky, enrichment plants are operated by Union Carbide Corporation, Nuclear Division. The third plant, at Portsmouth, Ohio, is operated by the Goodyear Atomic Corporation.

The three plants, built in support of the national defense effort, were constructed over a 12-year period between late 1943 and 1955 at a cost of \$2.1 billion. The plants were operated at high production levels until late 1964 at which time U.S. military requirements for enriched uranium began to drop off. From this peak defense production period, the average annual separative work production rate was reduced sharply until it reached a low in fiscal year 1970. The reduction in defense requirements for enriched uranium resulted in excess plant capability and inventories, not only in the enrichment segment of the nuclear industry, but also in the mining and milling segments as well. The average annual separative work production levels of the three plants since 1944 are shown in Fig. 8.[21]

Each of the plants, although containing essentially the same type of equipment, has certain unique characteristics of its own. For this reason, the three gaseous diffusion plants are operated as a complex, which means their operation is closely integrated to take advantage of the most economic and desirable characteristics of each plant. Figure 9 depicts graphically the integrated relationship of these three facilities.[22] Feed, product, and tails criteria of the plants are carefully coordinated and optimized on a routine basis to maximize the economic return from the facilities.

When fully powered, the three diffusion plants have a combined output capacity of 17.2 million separative work units (SWU) per year, and as noted earlier, the demand for enriched uranium has already exceeded this capacity. For this reason, Cascade Improvement (CIP) and Cascade Uprating (CUP) programs have been planned and are presently in their initial phases of implementation. When completed, the two expansion programs will increase the ERDA production capability by 60%, from 17.2 to 27.7 million SWU/year. The combined CIP/CUP programs, scheduled for completion by 1981, are expected to cost in excess of \$1 billion.

The Cascade Improvement Program is designed to incorporate into the existing gaseous diffusion plants the most recent advances in diffusion technology, thereby increasing the efficiency of the plants. This is being accomplished through equipment modifications such as rebuilding and improving compressors, installing piping and control valves with better

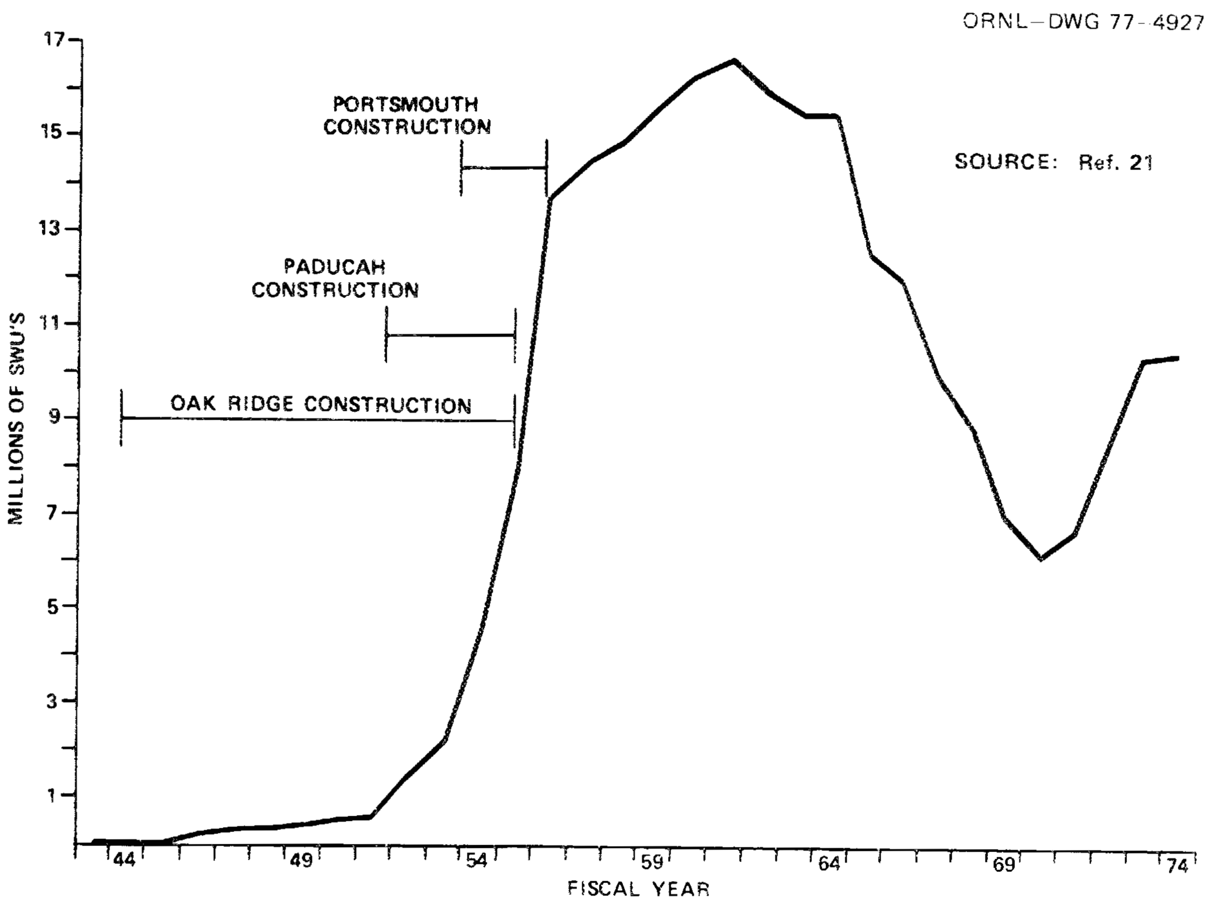


Fig. 8. Historical cascade production.

ORNL-DWG 77-4928

SOURCE: Ref. 22

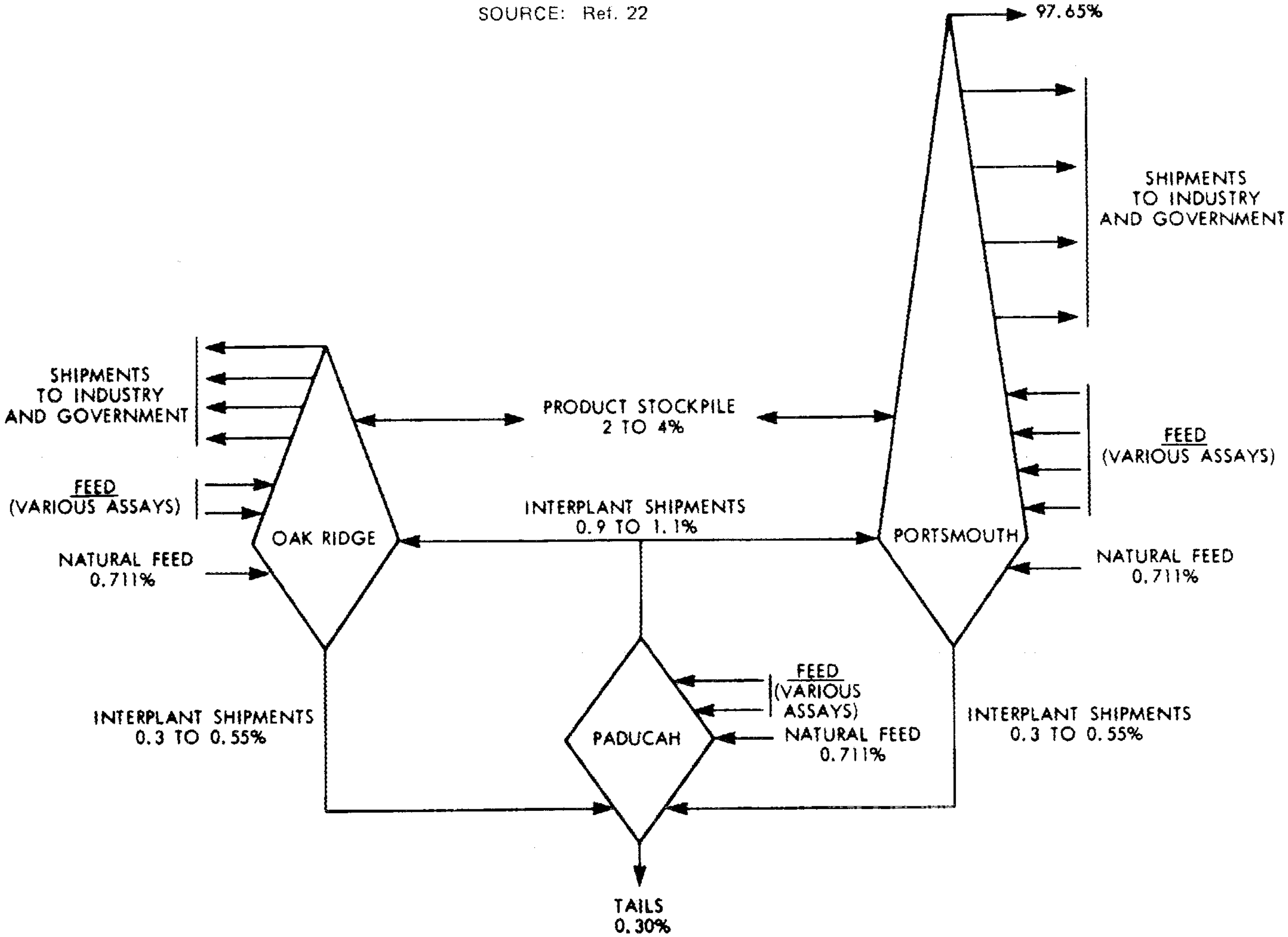


Fig. 9. Mode of operation for gaseous diffusion plants.

aerodynamic characteristics, and installation of improved diffusion barriers. It is principally a capital investment program for which no additional power will be required and will enlarge the capacity of the three facilities without significantly changing their operating costs. The program will result in an increase in separative work capacity of about 5.8 million SWU/year.

The Cascade Uprating Program involves uprating the CIP-improved diffusion plants to permit operation at a power level of 7400 MW, which will further increase the separative work capacity by 4.7 million SWU/year. This is accomplished by replacing and/or uprating switchyard equipment such as oil circuit breakers and transformers, rewinding electric motors, and making significant changes to the waste heat removal system. Although the CUP program is also a capital improvement program, it will require the purchase of additional electric power to take advantage of the improved facilities. The CIP and CUP programs will be closely coordinated to avoid double handling of equipment and to minimize total stage downtime. Once these two programs are complete, the diffusion plants will be essentially at a practical limit of technology, design, and operating conditions. Figure 10 illustrates the schedule for CIP and CUP completion and the resulting increases in separative work capacity.[22]

During the mid-1960s, in anticipation of a civilian nuclear power economy, the Atomic Energy Commission decided to preproduce enriched uranium to meet its projected large growth in the nuclear industry. Contracts were negotiated with various electric power suppliers and a program of power restoration to the plants was started. Since 1970, the power supplied to the plants has been almost doubled. During this period, the AEC also initiated an operating plan for the plants that used "split tails" transactions for creating a preproduction stockpile of enriched uranium that could be used for covering operating and contingency situations. Three main parameters were weighed in developing this plan;[21] (1) power availability, (2) feed availability, and (3) available plant capacity (this is variable only in that plant capacity is increasing each year until 1981 when the CIP and CUP programs will be completed). These three input variables control both of the major output variables,

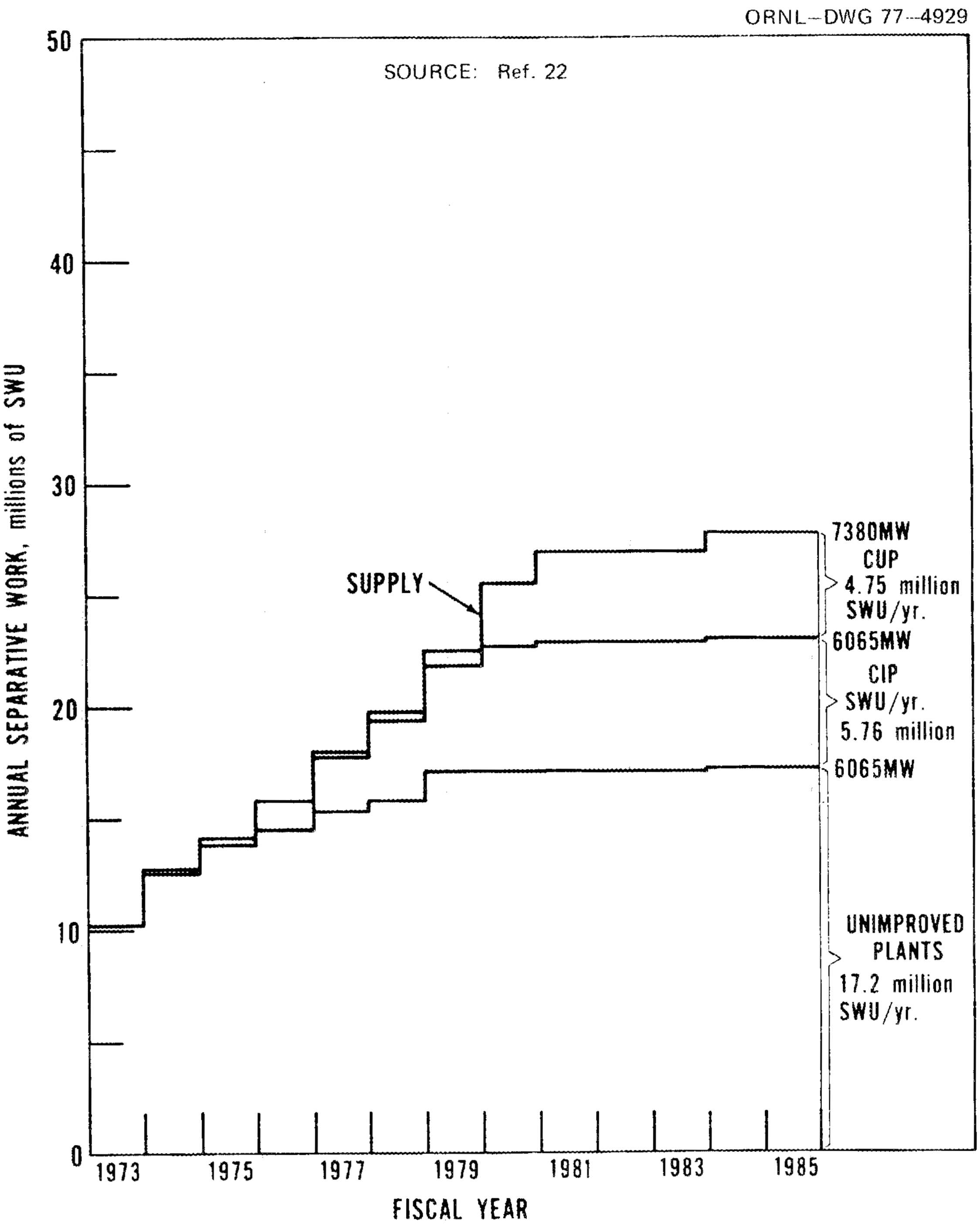


Fig. 10. Projected U.S. sources of separative work.

namely, tails assay and enriched uranium production. Through the years, the AEC continually updated and refined its operating plans, and ERDA is currently in the process of developing a new operating plan for the diffusion plant complex.

Under ERDA's present split tails procedure, enrichment customers supply quantities of uranium feedstock keyed to gaseous diffusion plant operation at a tails assay of 0.20 weight % U^{235} (commonly referred to as "transaction tails"), and pay separative work charges accordingly. The enrichment plants, however, are actually operated at a tails assay of 0.30% U^{235} (known as "operating tails"), which means the customer-supplied uranium feed falls approximately 20% short of actual process requirements. In the past, this deficit, plus the feed used for pre-production, has been supplied by drawing on the government uranium stocks. However, this arrangement of split-tails cannot be sustained because ERDA is now close to exhausting its feed stockpile and excess diffusion plant capability. Since the 0.30% tails assay is essentially fixed by ERDA operating policy, the path taken from 0.20% to 0.30% provides the only real degree of freedom in supplying feed for the plants. As a consequence, ERDA's new operating plan will gradually increase the transaction tails assay from 0.20% to 0.30%. The size of the enriched uranium stockpile will then be determined by the availability of feed material and electric power.

ERDA has two distinct types of enrichment service contracts; fixed-commitment contracts and requirements-type contracts. Under a fixed commitment contract, a customer specifies in advance the amounts of enriching services he requires over a substantial portion of the reactor plant operating life, thus obligating himself to a fixed amount of these services. A requirements-type contract obligates ERDA, within limits, to provide a customer with the amount of enriching services he requires.

ERDA's current operating plan is to maintain the transaction tails assay at 0.20% U^{235} through September 20, 1977, and to increase it in a stepwise fashion over the fiscal year 1978 to 1981 period. The planned increases will be to 0.25 weight % U^{235} at the beginning of FY 1978, to 0.275 at the beginning of FY 1980, and to about 0.30 by October 1, 1981.[23] ERDA supports these changes through claims that the additional feed will allow the building of a larger enriched uranium stockpile, part of which could be used to backup a private enrichment venture. The increased demand for uranium will also encourage further exploration and development of additional uranium resources. Finally, the stepwise adjustment in the transaction tails assay will serve to spread the impact of these necessary increases in feed requirements over several years, reducing the short-term impact on enriching customers.

Shortly after ERDA had committed its entire planned enriching capacity to meet long-term enriching contracts, the U.S. utility industry began announcing delays and/or cancellations of numerous reactor projects that had previously been planned. As a result of these delays and cancellations, a number of utility companies, some of which either no longer needed the enriching services they had under contract, or desired contract adjustments to reflect plant startup delays, began requesting changes in their enrichment contracts. In January of 1975, the AEC, in response to these requests, proposed an option to amend fixed-commitment contracts which would allow customers to delay separative work deliveries.[24]

On June 19, 1975, ERDA expanded this option to allow customers a one-time free termination of long-term fixed-commitment contracts, provided the option was exercised by August 18, 1975. The so-called "Open Season" offer also included options that allowed customers a one-time adjustment of their contract commitments, including adjusting the quantity, schedule, and timing of deliveries. Before the Open Season offer, the AEC had issued enriching service contracts for 364 GW(e), only 329 GW(e) of which remained under contract after the option deadline. Although customers were allowed to defer SWU deliveries under the offer, they are still obligated to deliver a portion of their uranium feed to ERDA in accordance with their original schedule.*

The ERDA pricing level for enrichment service requirements contracts, executed prior to May 9, 1973, is constrained to be not more than a "ceiling charge" computed on the basis of a $30 historical charge escalated by increases in factor prices weighted in a 15:5 (power:labor) ratio

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*Portion of feed associated with original schedules: FY 1976–1977 (100%); FY 1978–1980 (50%); and FY 1981–1983 (25%).

including a \$10 fixed cost component.[25] The \$30 base charge was established at the end of FY 1965. Base rates for power and labor at that time were 3.958 mills/kWhr and \$2.87/hr, respectively. The ceiling charge can therefore be calculated by using the formula:

$$CC = 10 + 15(P/3.958) + 5(L/2.87)$$

where P (in mills/kWhr) is the current average cost of power to the enrichment plants and L is the current value of the wage rate for the chemical and allied products industry. Through 1974, the ceiling charge has escalated at the equivalent of an average annual rate of about 7% while the power component escalation rate has been about 10%.

Figure 11 shows ERDA's actual uranium enrichment pricing, in current dollars, from 1970 through 1976.[26] The most recent price change, announced in the Federal Register on July 30, 1976, increased the fixed-commitment charge from \$59.05 to \$61.30, effective on October 1, 1976. This increase represents an overall price increase of about 66% during the past two years. The present charge of \$66.75 for requirements-type contracts will be increased on January 27, 1977, to \$69.80 or the ceiling charge, whichever is the lesser charge. The ceiling charge is estimated to be \$71.68 on January 1, 1977, so the \$69.80 charge will be the applicable rate for requirements-type contracts. This pricing action is unrelated to proposed legislation to enable ERDA to institute commercial-type pricing for enrichment services. Rather, the increases are the result of increased electric power costs and increasing operating, capital, and process development costs. These new prices will be subject to a 4%/year escalation rate unless they are otherwise modified by ERDA. The lower curve in Fig. 12 shows this 4% escalation rate applied to requirements-type contracts and the resulting projection of separative work costs.

ERDA is presently involved in several ongoing programs to assist industry in entering the field of commercial uranium enrichment. These programs include a technology transfer program for making classified enriching technology available to qualified companies, and a centrifuge qualification program, under which private centrifuge manufacturers may qualify to produce gas centrifuges to ERDA specifications. ERDA also has a program designed to encourage the evolution of a private, competitive centrifuge enriching industry on a timely basis. A pilot gas

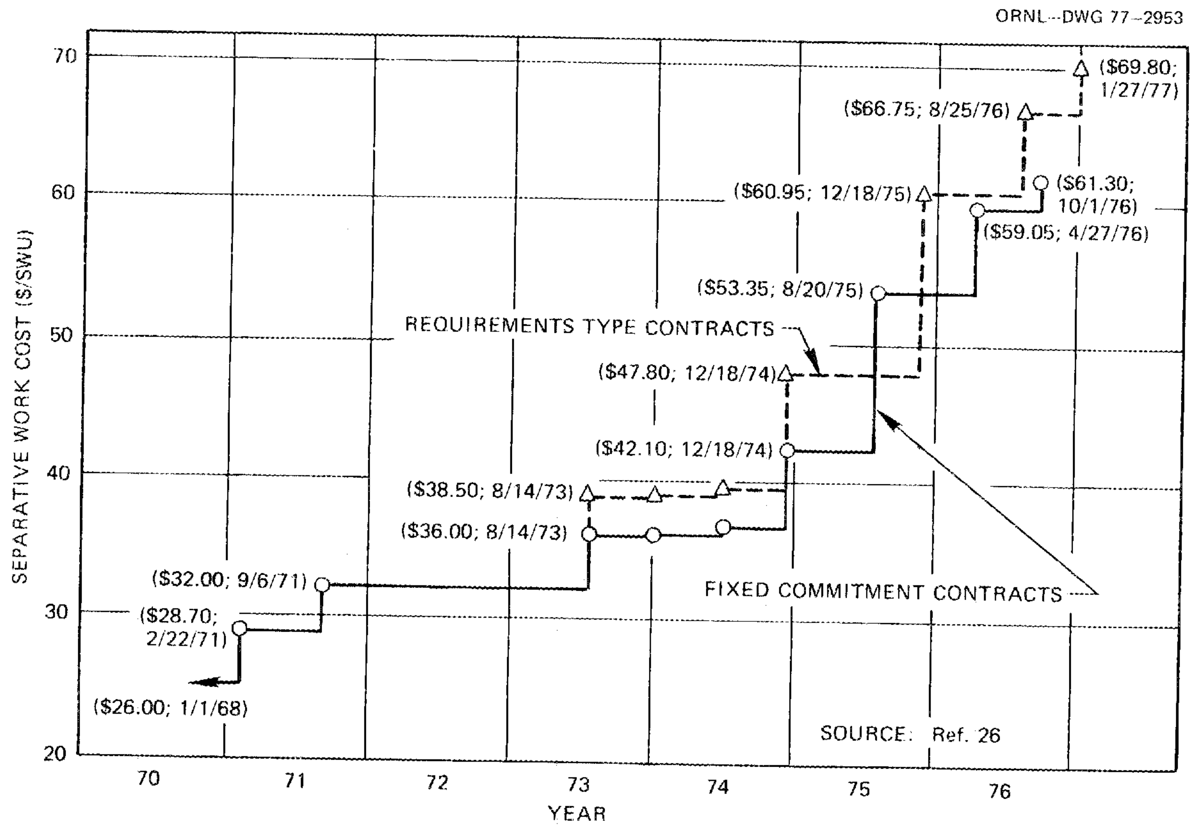

Fig. 11. ERDA separative work costs, 1970 to 1976 (current dollars).

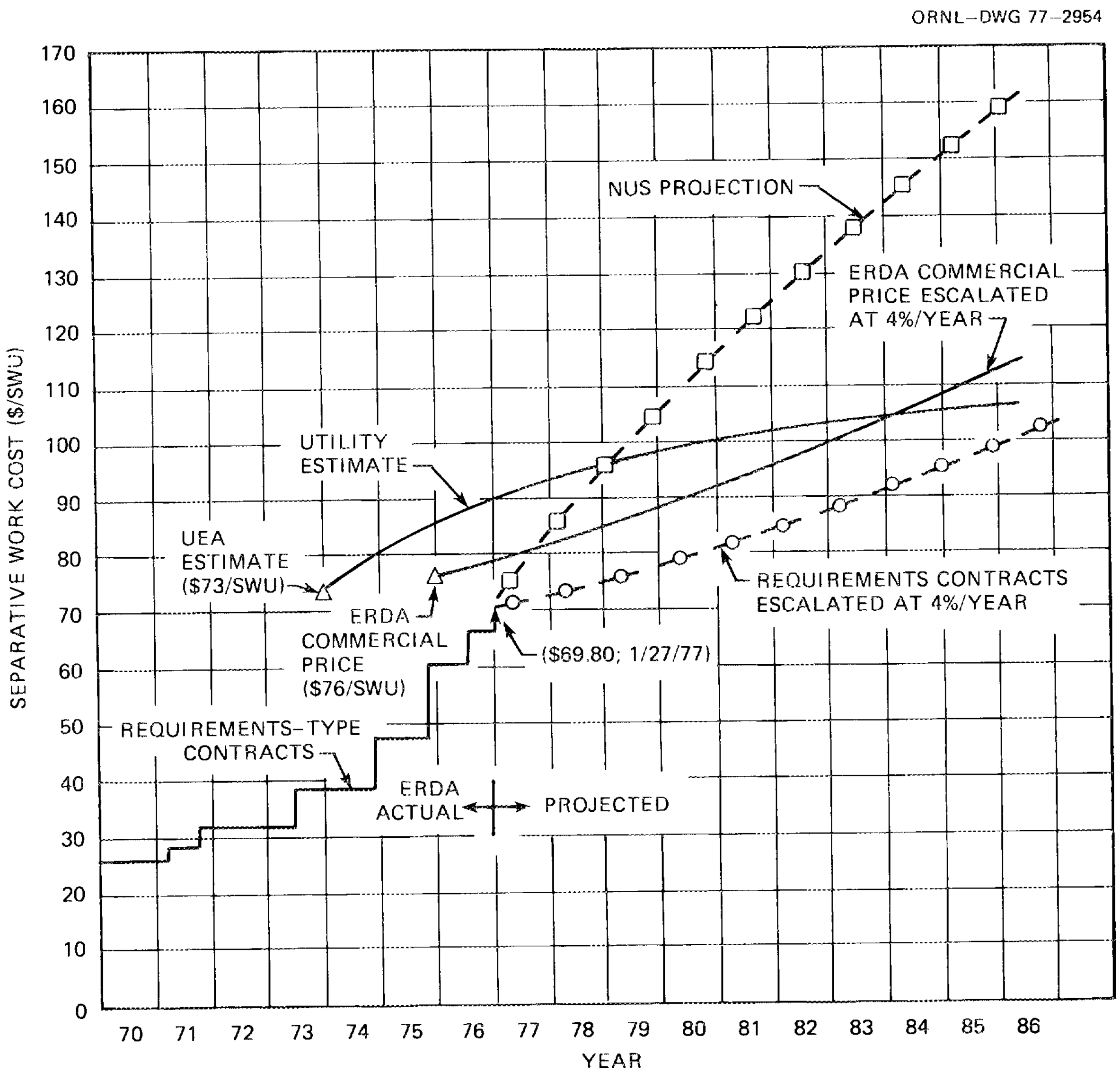

Fig. 12. Uranium enrichment price projections.

centrifuge plant (Component Test Facility), being designed and constructed by ERDA with industrial participation, was expected to be operational in 1976. The pilot plant, currently behind schedule, will proof test the design and operation of the entire production process system. It will also provide plant design, construction, startup, and operating experience to aid in the process and equipment selection for future centrifuge enrichment plants. ERDA also has an Experimental Test Facility, operational since 1971, for reliability testing, and a Component Preparation Laboratory, which was built to evaluate, improve, and demonstrate cost-effective, potentially high-volume production techniques for manufacturing centrifuges.[27]

In July 1974, the United States announced its intention to move toward commercial price levels for uranium enriching services in recognition of the growing maturity of the nuclear power industry, both in this country and abroad. On June 24, 1975, ERDA forwarded to Congress draft legislation which would revise one of the bases for establishing prices for enriching uranium.[28] The proposed legislation would amend the Atomic Energy Act of 1954 as amended to (1) obtain fair value for enriching services sold to domestic and overseas customers, and (2) eliminate or reduce the differential between the governments' charges for enriching services and those of potential enrichment projects. Since ERDA's current SWU costs do not include provisions for taxes, insurance, and risk, their charges are significantly lower than could reasonably be expected from future sources. It is contemplated that should Congress enact the ERDA draft bill, the price under a fixed-commitment contract for a SWU will initially be about $76. Requirements-type contracts would not be affected under the draft legislation.

To lend some perspective to changes in government separative work costs, a series of cash flow breakdowns of costs and revenues associated with ERDA gaseous diffusion complex operation are shown in Tables 5 through 8. These tables provide a basis for comparing the typical ten-year campaign period dollar-flow changes with factors such as increasing cascade power costs, and varying capital and operating costs. Table 5 shows the cost-revenue flows for the operating plan based on sales at $32/SWU, which was effective for a campaign period extending from

Table 5. Cash flow costs and revenues, uranium enrichment operations

Revenues at $32/SWU
(Expressed in millions of fiscal year 1972 dollars)

	Fiscal year									
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Costs:										
Cascade power	89	123	178	207	217	229	241	264	306	335
Other operating	46	51	59	62	63	63	63	60	56	56
Capital	65	78	104	130	130	147	153	179	194	211
Total costs, existing plants:	200	252	341	399	410	439	457	503	556	602
Total revenues, existing plants:	135	179	254	344	420	492	565	611	711	789
Cash flow:										
Annual	−65	−73	−87	−55	10	53	108	108	155	187
Cumulative	−65	−138	−225	−280	−270	−217	−109	−1	154	341

NOTES:
1. Operating tails assay of .20% for FY 1971, .30% for FY 1972–73, .25% for FY 1974–80.
2. Revenues based on $26/SWU through FY 1971, $32/SWU from FY 1972–80.

Source: Ref. 25.

Table 6. Cash flow costs and revenues, uranium enrichment operations revenues at $53.35/SWU under fixed commitment contracts

(Expressed in millions of fiscal year 1976 dollars)

	Fiscal year 1976	Transition budget	Fiscal year													
			1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Costs:																
Cascade power	502.0	134.1	584.4	619.3	636.6	685.9	687.1	672.1	672.1	709.8	755.0	755.0	755.0	755.0	755.0	755.0
Other operating	149.6	39.6	171.9	160.1	183.6	228.1	251.1	251.1	183.5	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Capital	240.9	67.1	296.8	326.1	241.7	141.9	102.1	69.1	60.6	56.9	56.9	56.9	56.9	56.9	56.9	56.9
Total costs, existing plants	892.5	240.8	1,053.1	1,105.5	1,061.9	1,055.9	1,040.3	992.3	916.2	927.7	972.9	972.9	972.9	972.9	972.9	972.9
Revenues:																
Enrichment services, requirements, type	266.3	49.2	299.1	660.3	633.5	613.5	603.7	466.9	507.1	516.8	487.0	488.8	488.2	481.5	473.0	448.7
Fixed-commitments type	187.9	0	275.8	354.2	722.4	781.0	1,116.6	1,150.8	903.2	1,004.1	1,056.3	981.6	951.8	929.9	900.6	852.5
Prepayments	189.1	45.7	−33.2	−15.1	−91.7	−101.5	−145.2	−193.0	−38.0	−6.4						
Total revenues, existing plants	643.3	94.9	541.7	999.4	1,264.2	1,293.0	1,575.1	1,424.7	1,372.3	1,514.5	1,543.3	1,470.4	1,440.0	1,411.4	1,373.6	1,301.2
Cash flow:																
Annual	−249.2	−145.9	−511.4	−106.1	202.3	237.1	534.8	432.4	456.1	586.8	570.4	497.5	467.1	438.5	400.7	328.3
Cumulative	−249.2	−395.1	−906.5	−1,012.6	−810.3	−573.2	−38.4	394.0	850.1	1,436.9	2,007.3	2,504.8	2,971.9	3,410.4	3,811.1	4,139.4

NOTES:
1. Transaction tails assay of 0.20 percent for fiscal years 1976–81 and 0.30 percent for fiscal year 1982 and beyond.
2. Costs are in fiscal year 1976 dollars but include projected fiscal year 1976 cost increases of power from the TVA, OVEC, and EEI. Other operating costs include $25,000,000 per year for advanced isotope separation R. & D. Capital costs include projects for equipment replacement, etc., for assuring operation of the ERDA gaseous diffusion plants through the year 2000 in order that enrichment contracts may be supplied throughout their life.
3. Revenues are based on an April 1975 projection of sales.
4. Requirements-type revenues based on $60.80 per SWU, except for the 1st 6 mo of fiscal year 1976 which was $48.80 per SWU.
5. Fixed-commitment revenues based on $53.35 per SWU, except for the 1st 2 mo of fiscal year 1976 which was $42.95 per SWU.
6. Revenues based on providing enrichment services for 343,000 MW of nuclear power.
7. Advanced payment based on $3,300,000 per 1,000 MW starting 8 yr prior to initial withdrawal spread over a 3-yr period.
8. The $53.35 per SWU charge was calculated for a time period through fiscal year 1980.

Source: Ref. 29.

Table 7. Cash flow costs and revenues, uranium enrichment operations revenues at $76/SWU under fixed commitment contracts

(Expressed in millions of fiscal year 1976 dollars)

	Fiscal year 1976	Transition budget	Fiscal year													
			1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Costs:																
Cascade power	502.0	134.1	584.4	619.3	636.6	685.9	687.1	672.1	672.1	709.8	755.0	755.0	755.0	755.0	755.0	755.0
Other operating	149.6	39.6	171.9	160.1	183.6	228.1	251.1	251.1	183.5	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Capital	240.9	67.1	296.8	326.1	241.7	141.9	102.1	69.1	60.6	56.9	56.9	56.9	56.9	56.9	56.9	56.9
Total costs, existing plants	892.5	240.8	1,053.1	1,105.5	1,061.9	1,055.9	1,040.3	992.3	916.2	927.7	972.9	972.9	972.9	972.9	972.9	972.9
Revenues:																
Enrichment services, requirements, type	266.3	49.2	299.1	660.3	633.5	613.5	603.7	466.9	507.1	516.8	487.0	488.8	488.2	481.5	473.0	448.7
Fixed-commitments type	229.1	0	392.9	503.6	1,029.0	1,112.6	1,590.7	1,639.3	1,286.7	1,430.3	1,504.8	1,398.4	1,355.8	1,324.7	1,282.9	1,214.5
Prepayments	189.1	45.7	−33.2	−14.1	−91.7	−101.5	−145.2	−193.0	−38.0	−6.4						
Total revenues, existing plants	684.5	94.9	658.8	1,149.8	1,570.8	1,624.6	2,049.2	1,913.2	1,755.8	1,940.7	1,991.8	1,887.2	1,844.0	1,806.2	1,755.9	1,663.2
Cash flow:																
Annual	−208.0	−145.9	−394.3	44.3	508.9	568.7	1,008.9	920.9	839.6	1,013.0	1,018.9	914.3	871.1	833.3	783.0	690.3
Cumulative	−208.0	−353.9	−748.2	−703.9	−195.0	373.7	1,382.6	2,303.5	3,143.1	4,156.1	5,175.0	6,089.3	6,960.4	7,793.7	8,576.7	9,267.0

NOTES:
1. Transaction tails assay of 0.20 percent for fiscal years 1976–81 and 0.30 percent for fiscal year 1982 and beyond.
2. Costs are in fiscal year 1976 dollars but include projected fiscal year 1976 cost increases of power from the TVA, OVEC, and EEI. Other operating costs include $25,000,000 per year for advanced isotope separation R. & D. Capital costs include projects for equipment replacement, etc., for assuring operation of the ERDA gaseous diffusion plants through the year 2000 in order that enrichment contracts may be supplied throughout their life.
3. Revenues are based on an April 1975 projection of sales.
4. Requirements-type revenues based on $60.80 per SWU, except for the 1st 6 mo of fiscal year 1976 which was $48.80 per SWU.
5. Fixed-commitment revenues based on $76 per SWU, except for the 1st 2 mo of fiscal year 1976 which was $42.95 per SWU and the following 4 mo of fiscal year 1976 which was $53.35 per SWU.
6. Revenues based on providing enrichment services for 343,000 MW of nuclear power.
7. Advanced payments based on $3,300,000 per 1,000 MW starting 8 yr prior to initial withdrawal spread over a 3-yr period.
8. The $76 per SWU charge was calculated for a time period through fiscal year 1986.

Source: Ref. 29.

Table 8. Cash flow costs and revenues, uranium enrichment operations, including 8.75 million SWU add-on diffusion plant

Revenues at $76/SWU fixed commitment contracts
(Expressed in millions of fiscal year 1976 dollars)

	Fiscal year 1976	Transition budget	Fiscal year 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Costs:																
Existing plants:																
Cascade power	502.0	134.1	584.4	619.3	636.6	685.9	687.1	672.1	672.1	709.8	755.0	755.0	755.0	755.0	755.0	755.0
Other operating	149.6	39.6	171.9	160.1	183.6	228.1	251.1	251.1	183.5	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Capital	240.9	67.1	296.8	326.1	241.7	141.9	102.1	69.1	60.6	56.9	56.9	56.9	56.9	56.9	56.9	56.9
Total costs, existing plants	892.5	240.8	1,053.1	1,105.5	1,061.9	1,055.9	1,040.3	992.3	916.2	927.7	972.9	972.9	972.9	972.9	972.9	972.9
New plant:																
Capital costs	4.0	5.0	75.0	200.0	250.0	300.0	400.0	450.0	475.0	200.0	31.0					
Operating costs	13.0	2.0	10.0	10.0	10.0	40.0	80.0	130.0	220.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Total costs, new plant	17.0	7.0	85.0	210.0	260.0	340.0	480.0	580.0	695.0	500.0	331.0	300.0	300.0	300.0	300.0	300.0
Revenues:																
Existing plants:																
Enrichment services, requirements, type	266.3	49.2	299.1	660.3	633.5	613.5	603.7	466.9	507.1	516.8	487.0	488.8	488.2	481.5	473.0	448.7
Fixed-commitments type	229.1	0	392.9	504.6	1,029.0	1,112.6	1,590.7	1,639.3	1,286.7	1,430.3	1,504.8	1,396.4	1,355.8	1,324.7	1,282.9	1,214.5
Prepayments	189.1	45.7	−33.2	−15.1	−91.7	−101.5	−145.2	−193.0	−38.0	−6.4						
Total revenues, existing plants	684.5	94.9	658.8	1,149.8	1,570.8	1,624.6	2,049.2	1,913.2	1,755.8	1,940.7	1,991.8	1,887.2	1,844.0	1,806.2	1,755.9	1,663.2
New plant:																
Enrichment services											416.5	972.8	629.3	536.6	810.2	674.9
Prepayments			30.1	100.5	139.2	109.1	38.7				−90.3	−211.2	−116.1			
Total revenues, new plant			30.1	100.5	139.2	109.1	38.7				326.2	761.6	513.2	536.6	810.2	674.9
Total revenues	684.5	94.9	688.9	1,250.3	1,710.0	1,733.7	2,087.9	1,913.2	1,755.8	1,940.7	2,318.0	2,648.8	2,357.2	2,342.8	2,566.1	2,338.1
Cash flow:																
Annual	−225.0	−152.9	−449.2	−65.2	388.1	337.8	567.6	340.9	144.6	513.0	1,014.1	1,375.9	1,084.3	1,069.9	1,293.2	1,065.2
Cumulative	−225.0	−377.9	−827.1	−892.3	−504.2	−166.4	401.2	742.1	886.7	1,399.7	2,413.8	3,789.7	4,874.0	5,943.9	7,237.1	8,302.3

NOTES:

1. Transaction tails assay of 0.20 percent for fiscal year 1976–81 and 0.30 percent for fiscal year 1982 and beyond.
2. Existing plant costs are in fiscal year 1976 dollars but include projected fiscal year 1976 cost increases of power from the TVA, OVEC, and EEI. Other operating costs include $25,000,000 per year for advanced isotope separation R. & D. Capital costs include projects for equipment replacement, etc., for assuring operation of the ERDA gaseous diffusion plants through the year 2000 in order that enrichment contracts may be supplied throughout their life.
3. Existing plant revenues are based on an April 1975 projection of sales.
4. Requirements-type revenues based on $60.80 per SWU, except for the 1st 6 mo of fiscal year 1976 which was $48.80 per SWU. Cash flow costs and revenues, uranium enrichment operations, including $8,750,000 SWU add-on diffusion plant (expressed in millions of fiscal year 1976 dollars) revenues at $76 per SWU under fixed commitment contracts.
5. Fixed-commitment revenues based on $76 per SWU, except for the 1st 2 mo of fiscal year 1976 which was $42.95 per SWU and the following 4 mo of fiscal year 1976 which was $53.35 per SWU.
6. Existing plant revenues based on providing enrichment services for 343,000 MW of nuclear power.
7. Advanced payments based on $3,300,000 per 1,000 MW starting 8 yr prior to initial withdrawal spread over a 3-year period.
8. The $76 per SWU charge was calculated for a time period through fiscal year 1986.
9. New plant costs are for an 8,750,000 SWU per year add-on diffusion plant at Portsmouth. Total capital cost is $2,390,000,000 in fiscal year 1976 dollars. Assumes authorization and appropriation in fiscal year 1976 and the transition quarter for title I, II design and advanced procurement only; physical construction to begin in fiscal year 1977.
10. New plant power costs are $280,000,000 per year for 2,400 MW of power at 13.3 mills per kilowatt-hour. Annual other operating costs are $20,000,000.
11. New plant revenues based on supplying enrichment services for 125,000 MW of nuclear power, assuming full plutonium recycle.

Source: Ref. 29.

FY 1972 to 1980.[25] The costs in this table are expressed in fiscal year 1972 dollars. A cash flow breakdown of costs for fixed-commitment contracts, based on the August 1975 to April 1976 charge of $53.35/SWU, is shown in Table 6.[29] The cash flows in this table, as well as in Tables 7 and 8, are expressed in fiscal year 1976 dollars. It should be noted that the $53.35/SWU charge was calculated on the basis of costs, revenues, and other charges for a campaign period extending from FY 1976 to 1986. Table 7 provides a similar cash flow breakdown of costs based on ERDA's proposed $76/SWU charge for fixed-commitment contracts. Finally, Table 8 provides a cash flow breakdown of costs, also based on ERDA's proposed $76/SWU charge, that includes the costs and revenues associated with a proposed 8.75 million SWU/year add-on diffusion plant.

On June 26, 1975, the President sent to Congress a proposed bill, called the Nuclear Fuel Assurance Act of 1975 (NFAA),[30] that would enable ERDA to negotiate and enter into cooperative arrangements with private organizations that wish to build, own, and operate uranium enrichment plants. The proposed legislation is intended to provide needed enrichment capacity and to create a competitive uranium enrichment industry. The NFAA would permit ERDA to enter into cooperative arrangements with as many firms as believed necessary to develop a competitive industry, and would provide various forms of assistance and assurances to these firms. The legislation provides for: (a) furnishing technical assistance, information, inventories and discoveries, enriching services, materials, and equipment on the basis of costs, (b) guaranteeing the quality of government-furnished equipment and materials, (c) assuming that the facility will perform successfully, (d) purchasing SWU from the private enrichment plant, (e) buying the assets or interests of any U.S. citizen or organization in any enrichment plant, and assuming their obligations and liabilities, if private industry cannot finish or bring the plant into commercial operation, and (f) modifying, completing, and operating the plant as a government facility, or disposing of the plant. The proposed legislation also calls for royalties to be paid to the government, imposes an $8 billion limit on the total potential cost to the government in the event all private ventures covered by the cooperative arrangements were to fail, and provides for Congressional review of all arrangements by the Joint Committee on Atomic Energy. NFAA further authorizes ERDA to start construction planning and design activities for expanding one of the government's existing enrichment facilities. This add-on plan is a contingency measure to insure that enrichment capacity would be available if the private ventures fail.

ERDA has received proposals from four corporations or consortia that are interested in financing, building, owning, and operating uranium enrichment plants under cooperative agreements with ERDA as proposed by NFAA. One of these, which was a revision of an earlier proposal, was submitted by Uranium Enrichment Associates (UEA) and calls for the construction of a full-scale gaseous diffusion plant by 1981. The other three proposals, all submitted on October 1, 1975, are aimed towards a full-sized centrifuge enrichment plant to be operational in the 1986 to 1987 time period. ERDA also has its contingency plan that calls for building an add-on diffusion plant at the Portsmouth, Ohio site. This add-on plant would have an initial capacity of 4.4 million SWU and could be expanded to 8.8 million SWU if necessary. The cost of enriched uranium from a new enriching plant may be defined as the sum of three major components; fixed charges, operating electric power charges, and other operating charges. The fixed charges are the sum of the capital charge required to amortize the plant investment and the plant economic life levelized tax rate, where the tax rate is defined as a combination of federal and state tax rates. A new government-owned enriching plant may be exempt from federal taxation although it is anticipated that an equivalent state tax charge would be paid. Table 9 provides a brief summary of the various proposals that are currently under consideration.

The most advanced private enrichment venture to date is Uranium Enrichment Associates, which was formed in September of 1972. It was originally a consorta of three companies, Union Carbide Corporation, Westinghouse Electric Corporation, and Bechtel Corporation, however, two of the companies withdrew in mid-1974 and Bechtel continued the program alone until June 1975, when the Goodyear Tire & Rubber Company became a partner. Later, in October 1975, the Williams Companies also joined the UEA venture. UEA proposes to build a 9 million SWU/year gaseous diffusion plant near Dothan, Alabama. Financial considerations along with

Table 9. Summary of enrichment capacity expansion proposals

Technology	Enterprise	Plant size (million SWU/year)	Proposed schedule
Gaseous diffusion	Uranium Enrichment Associates (Bechtel, Goodyear Tire & Rubber, Williams Company)	9	1981 startup: full-scale operation in 1983 Site: Dothan, Alabama
	U.S. Government	8.75	Add-on to ERDA's Portsmouth Diffusion Plant: early 1983 startup
Centrifuge	Garrett Corporation	3 (Modular construction)	350,000 SWU in 1981, 3 million SWU by 1987
	Centar Associates (Atlantic Richfield Co., Electro-Nucleonics Inc.)	3 (Modular construction)	270,000 SWU in 1981, 3 million SWU by 1986
	Exxon Nuclear Co.	3 (Modular construction)	1 million SWU in 1981, 3 million SWU by 1986

clarification of the type and extent of government assistance to be made available to UEA (as well as other interested firms) have led to major uncertainties in planning. UEA is currently awaiting the outcome of the proposed NFAA legislation. A UEA representative presented plant cost estimates and contract guidelines for their proposed diffusion plant at the 1975 AIF Conference on Nuclear Fuel.[31] The plant scheduled for startup in the 1981 to 1983 time period is estimated to cost $2.75 billion (1974 dollars). ERDA recently indicated the cost would be about 3.5 billion in 1976 dollars. Details of the proposed plant are shown in Table 10. The basic concept of the UEA supply contract is that it would be a cost pass-through agreement, i.e., the customer would pay the actual cost of the operation, whatever that would turn out to be. This cost would be calculated on the basis of all of the expected elements of a unit of separative work, including power and operating costs, debt service, and a guaranteed return on equity throughout the life of the plant. The projected return on equity, not to be less than 15% after taxes, is designed to attract equity money in the current market. The UEA projections indicate that the average price per SWU will be around $73 (1974 dollars). Table 11 provides a detailed breakdown of the components of UEA's anticipated average price for separative work.

Figure 12 shows the $73/SWU (1974 dollars) UEA price projection escalated based on data received from the electric power industry. The fixed charges have been escalated through 1981, when the construction costs were assumed to be capitalized, and power and operating costs were escalated separately. The fixed charge index for price escalation was subject to the following breakdown: 20% construction labor, 15% materials, and 65% equipment. For a 90% capacity factor, the specific investment for the proposed UEA diffusion plant is $339.50/SWU.

In October 1975, Garrett Corporation, Centar Corporation, and Exxon Nuclear Corporation all submitted proposals in response to ERDA's request for centrifuge enrichment plant (CEP) proposals. This request for CEP proposals was intended to encourage the construction and operation of private enrichment plants under the pending NFAA legislation. The three proposals submitted to ERDA are aimed toward a centrifuge plant of the 3 million SWU/year size that would be constructed using a modular approach

Table 10. Uranium Enrichment Associates' gaseous diffusion plant statistics

Capacity	9 million SWU/year
Capital investment	$2.75 billion[a]
Plan and construct period	Years 1975–1983
Start-up period	Years 1981–1983
Operating life	25 years (1984–2008)
Annual operating costs	
Power	Over $200 million[a]
Labor and other	Over $100 million[a]
Annual revenues	Over $700 million[a]
Price per unit	Over $70/SWU[a]

[a]Estimated in 1974 dollars. Source: Ref. 31.

Table 11. Uranium Enrichment Associates' average price/SWU[a]

		Percentage
Power	$24.24	33
Operating, maintenance, general administrative costs, and income taxes	13.44	19
Return to equity participants	7.96	11
Royalties	1.33	2
Debt service	22.11	30
Reserve fund	3.45	5
Total	$72.53	100
Average	$73.00	

[a]1974 dollars.

NOTE: Total unescalated costs over entire operating period divided by total SWU output at 99% of capacity.

Source: Ref. 31.

with the initial module in the 300,000 to 1 million SWU/year range. Assuming initial success, additional modules would be added progressively until a full-sized plant is reached. The modular approach would permit a demonstration period for the first module and reduce the risk of loss of the large investment required for the full-sized plant. This approach will also permit desirable modifications to the full-sized plant design as experimental results are obtained during the demonstration period.

A joint study on the feasibility and economics of centrifuge enrichment plants in the 300,000 to 9 million SWU/year size range was conducted by the Tennessee Valley Authority, Electro-Nucleonics, Inc., and Burns and Roe, Inc. The study, which was initiated in June of 1974, concluded that centrifuge technology can be competitive with gaseous diffusion technology, and may prove to be the superior process in the future. The main advantages of the centrifuge process appears to be in its high degree of modularity and low power requirements. Cost estimates, in 1974 dollars, for a centrifuge enrichment plant ranged from \$56 to about \$95/SWU, depending on plant size and form of ownership.[32] The study also concluded that for centrifuge plants with capacities greater than 3000 tonne SWU/year, the SWU cost tended to flatten out with increasing plant size.

UEA has estimated that plant capital costs for a gas centrifuge enriching plant would be about 9% higher than those projected for a gaseous diffusion plant. However, the attractiveness of the centrifuge process lies in its low power requirements, estimated to be about one-tenth of those required for a diffusion plant. Power costs, which represent about 30% of the total SWU cost in a diffusion plant, would account for only about 4% of the total SWU cost in a centrifuge plant. Although centrifuge plants are estimated to have approximately the same specific investment as diffusion plants, they have a much smaller optimum size (1 to 3 million SWU/year) and are adaptable to modular construction which would permit adding small capacity increments as required to closely follow market needs. The major cost drawback of the gas centrifuge technology appears to result from extremely high operating costs. UEA concludes that the centrifuge SWU costs would be 5% higher than those from a diffusion plant. For purposes of comparison, Table 12 provides a breakdown of costs and statistics for a 9 million SWU/year diffusion plant and a 1.5 million SWU/year centrifuge plant, as estimated by the Nuclear Utility Services (NUS) Corporation.[33]

The uranium enrichment price projections used as reference cases in this study are shown in Fig. 12. As a "lower" limit, we applied a 4%/year escalation rate to ERDA's requirements-type contract price of $69.80, which became effective in January 1977. This yields a 1985 price of $97/SWU. The "upper" limit chosen for the study is the estimate made by the NUS Corporation in 1974. This estimate projects separative work costs ranging from $110/SWU in 1980 to $155/SWU in 1985. As Fig. 12 shows, long range projections tend to fall into the envelope that is formed by these "upper" and "lower" cost projections. Figure 12 also shows the ERDA commercial price estimate of $76/SWU (1976 dollars) escalated at a rate of 4%/year. For purposes of comparison, this yields a 1984 price of about $105/SWU, as does the sample utility price data also plotted in the figure.

3.4 Fuel Fabrication

The growth in requirements for LWR fuel fabrication services, projected over the 1974 to 1990 time period, is shown in Fig. 13.[34] To meet these requirements, as of 1972 there were 10 fabrication plants available, with a plant-average annual capacity of 300–500 tonne of uranium.[34,18] As a consequence of delays in installation of nuclear plants, these facilities should be adequate to meet fabrication demands over most of the 1970s, but by the early 1980s, expansion of plant capacity will be required.

The major present LWR fuel fabrication facilities are owned and operated by the four manufacturers of light water reactors and by the Exxon Nuclear Company, an independent fuel fabricator and affiliate of the Exxon Corporation. In addition to these, Kerr McGee of Cresent,

Table 12. New enrichment plant levelized SWU cost extimates

($/SWU)

	Diffusion		Centrifuge	
	(1974 $)	(1975 $)	(1974 $)	(1975 $)
Fixed charge[a]	41.98	57.09	48.59	65.78
Power cost	24.24	36.36	3.64	3.64
Operating cost	2.24	2.47	25.59	31.10
Other costs[b]	5.99	6.94	6.92	8.24
Total[c]	74.45	102.86[d]	84.74	108.76
Capital cost (10^6 $)	2750	3400[e]	390	480[e]
Amortization period (year)	25	25	10[f]	10[f]
Operational cost (10^6 $/year)	20	20	38	42
Power cost (mill/kWhr)	10	15	15	15
Capital charge rate (%)[a]	13.6	13.6	18.5	18.5
Debt/equity ratio	85/15	85/15	90/10	90/10
Debt/equity rate (%%)	9/15	9/15	9/20	9/20
Nominal capacity (10^6 $ SWU/year)	9	9	1.5	1.5
Capacity factor (%)	99	90	99	90

[a]Includes federal and state tax.

[b]Includes R & D, working capital, product flywheel and 3% royalty.

[c]Noted year dollars.

[d]Total is $90.16/SWU if 10 mill power assumed.

[e]23% cost increase over 1974 estimate assumed.

[f]Based on 5, 10 and 15 years for machines, equipment and process buildings.

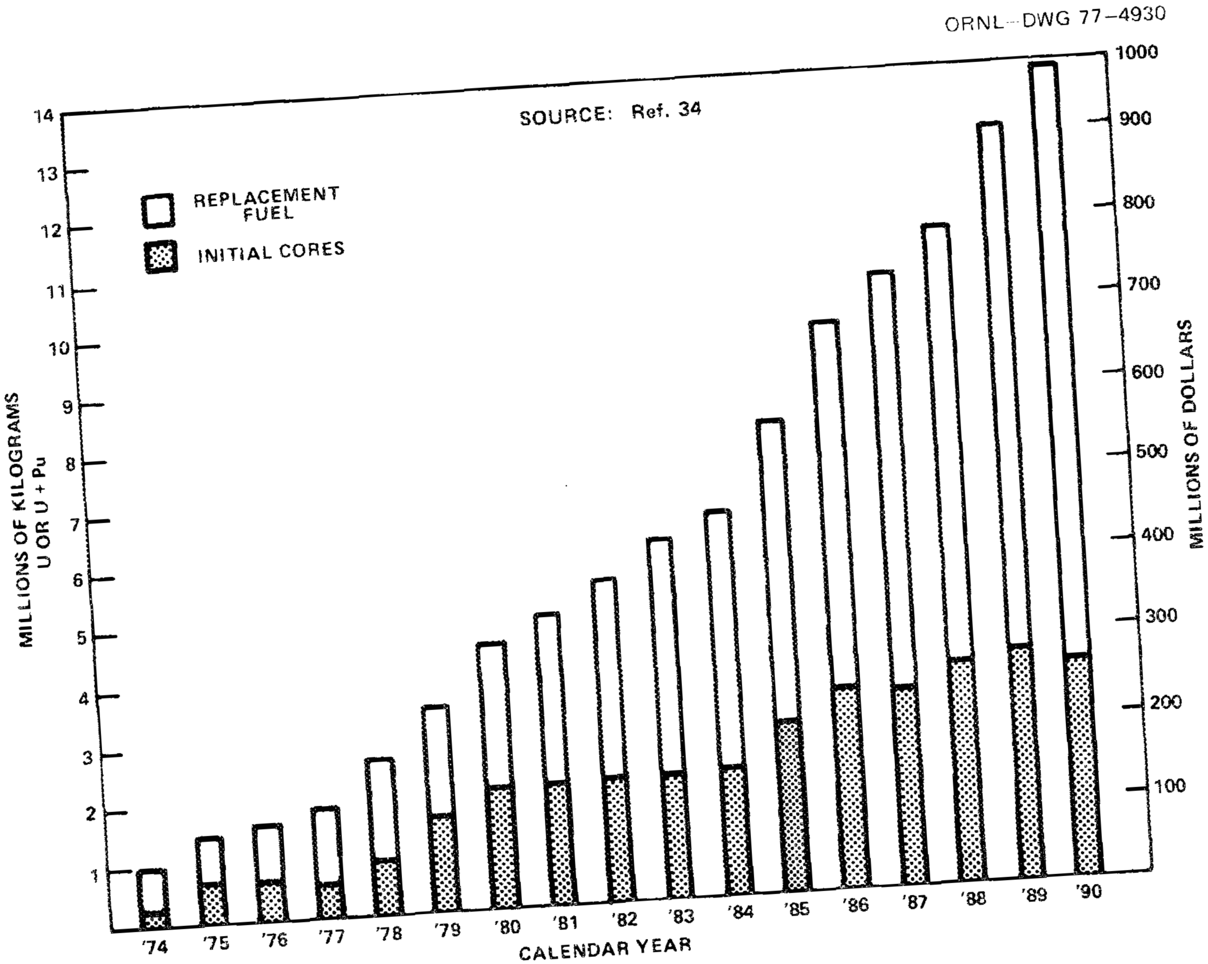

Fig. 13. Light water reactor fuel fabrication annual domestic requirements.

Oklahoma, and Nuclear Fuel Services at Erwin, Tennessee, offer facilities for converting uranium hexafluoride to UO_2 pellets.

The Exxon Nuclear Facility at Richland, Washington, offers the capability for design and fabrication of both UO_2 and mixed-oxide fuels for PWRs and BWRs. Mixed-oxides fabrication capability in the U.S. is presently quite small, about 50 to 75 tonne/year. Westinghouse has submitted application for a license to construct a 350 tonne/year mixed oxide facility at Anderson, South Carolina. Contingent on resolution of criteria for use of plutonium recycle fuels, operation of this facility might, at the earliest, begin in 1979 and reach full capacity by about 1983.[35] It is estimated that 6 to 8 years are currently needed to build and license a similar facility.

Requirements for fabricating slightly-enriched UO_2 fuel elements will clearly dominate the fabrication sector of the nuclear fuel cycle until the early 1980s, or such time as criteria for use of plutonium is specified. Fabrication of UO_2 fuel, which is labor intensive and therefore subject to reductions in production costs associated with learning effects,[36] is considered to be a well developed technology. The industry had been experiencing these reductions between 1968 and 1973, and had been able to accommodate changes in fuel element design associated with emergency core cooling system (ECCS) criteria without significant increases in overall costs. The industry has also accommodated to more stringent manufacturing quality control, aimed at rectifying fuel element failures or problems experienced in early commercial reactor operations, and insuring fuel integrity during the irradiation lifetime. As much as one-third of fuel fabrication costs have been estimated to funnel into quality assurance.[37]

Delays or postponements in plans for installing nuclear units are expected to have negative impact on fuel fabrication economics during the next few years.[36] Since approximately 85% of fabrication costs are associated with labor and materials, slippages in production will generally have deleterious effects on efficient use of trained workers and on manufacturing quality control. As a result, a temporary postponement of additional "learning-effect" cost reductions is expected, extending into the 1980s.

While these factors influence the near-term outlook for cost reductions, general escalation of materials and labor costs have exerted upward pressure on the unit cost of fabrication. Escalation of these input costs obviously tends to counterbalance any effects of learning or economics of scale in a manner illustrated in Table 13. Here estimates of the downward trend in constant dollar fabrication costs, reported in 1973,[37] are listed in column 2, arbitrarily normalized to a price index of 100 in 1970. In column 3, a composite price index recommended by one utility contacted in this study as a suitable measure of fabrication cost escalation is listed. It is also normalized to a value of 100 for 1970. This composite index was calculated by assigning 30% weights each to the hourly wage index in the primary metals industries, the wholesale price index for steel mill products, and the wholesale price index for all industrial commodities, plus a 10% fixed-price component. The product of the indexes in columns 2 and 3, given as column 4 in Table 13, indicates that the high rates of inflation experienced between 1973 and 1975 has outdistanced any cost reductions due to production efficiencies. This product index is intended only to illustrate the general magnitude of the factors underlying the dynamics of the UO_2 fabrication price situation and should not be used as any precise measure of the price vs time trend.

Differences in long-term contract arrangements and warranties used by utilities in recent years also tend to influence fabrication delivery prices. Types of fuel warranties range from those covering only mechanical flaws and integrity of the elements, within specified burnup limits, to fuel cost warranties with special provisions for price escalations beyond control of the fuel manufacturer. In some cases, energy purchase guarantees have also been used. Some agreements may obligate the fuel vendor to provide most performance analysis required in licensing reactor operations. Generally, there will be price variations associated with different degrees-of-responsibility assumed by the vendor.

Utility fuel buying practices have been shifting away from early arrangements covering both purchase of U_3O_8 and fabrication services from the vendor, toward purchase of only the fabrication component with independent arrangements for U_3O_8 supply. As of January 1, 1975, fuel

Table 13. Cost index variations influencing UO_2 fuel fabrication prices between 1969 and 1975

(1970 Index = 100)

Year	Production cost index, excluding escalation effects[a]	Fabrication cost escalation index[b]	Product cost index
	(1)	(2)	(1) × (2) ÷ 100
1969	119	96	114
1970	100	100	100
1971	90	105.5	95
1972	83	112	93.2
1973	79	118	93.5
1974	75	139	105
1975	72	155	112

[a] Source: Ref. 37.

[b] Compiled from Bureau of Labor Statistics; see text description.

fabrication vendors were involved in about 50% of firm arrangements for U_3O_8 supply to reactors scheduled for post-1974 startup.[38] In broad terms, the tendency of nuclear utilities has been to shift away from contracting for a "cradle to grave" treatment in fuel supply toward internal planning and management of the nuclear fuel cycle.

According to utilities contacted in this study, fabrication contracts may be made on a fixed-price basis, or may be referenced to a "base price" at year-of-delivery with provision for cost escalations experienced between the contracting date and time-of-delivery. In the latter case, the fabrication vendor may offer declining base prices to the utility as an incentive for contracting for additional reloads. An example of this,[39] based on a recent opening bid by Westinghouse to Los Angeles Department of Water and Power, is shown in Table 14. When escalation effects are superimposed on these declining base prices, however, the resulting delivery prices appear likely to increase gradually over the next several years under either type of contract arrangement.

Table 14. Unescalated prices (1975 $) for UO_2 fuel fabrication for a pressurized water reactor[a]

		Base price ($/kg)
Initial case		120
Reloads:	1	100
	2	96
	3	93
	4	88
	5	83
	6	80
	7	75
	8	72
	9	69
	10	68
	11	67
	12	67

[a]Source: Ref. 39.

Ref. 36 indicates that $100/kgU is representative of present (1975 $) price levels for UO_2 fabrication. This is supported by findings in the present selective survey of utilities, which indicated that a range of about $80 to $130/kgU was applicable to the mid-1970s. The precise upward movement in price levels during the remainder of the 1970s will depend on the rate of inflation in the economy and other factors specified to the fabrication industry described above. An estimate of the time dependence of prices for delivered assemblies, made by applying a nominal rate-of-escalation (e.g., 5%/year) to 1975 price levels, should be sufficiently reliable for most near-term evaluations of LWR fuel costs.

3.5 In-Core Irradiation

As explained more fully in Sect. 4 and Appendix A of this report, the fuel cost component per unit of energy produced depends strongly on the fuel exposure (MW days per kgU loaded) achieved at discharge. Expenditures which are fixed for any given batch of assemblies (such as fabrication costs) must be recovered from the revenue associated with sale of energy from that batch; thus, the direct cost per unit energy for these components tends to vary inversely with the batch discharge exposure. A similar relationship holds for fuel cost components associated with enriched uranium requirements, once targets for discharge exposure have been set for the batch. In setting these nominal exposure targets, however, the amounts of enriched uranium required to meet reactivity lifetime criteria vary in direct relation to the discharge exposure.

Because of the importance of the discharge exposure and its relationship to the reactor operating history, it is appropriate to briefly examine the data describing commercial experience within the industry. Reactor operating statistics are commonly described by plant availability and capacity factor indices. The plant availability factor is defined as the fraction of time that the plant is either generating electricity at some load level or is available on standby. Since plant availability may be determined by portions of the system not involving the nuclear steam supply system, a reactor availability factor may also be defined, which will generally exceed the plant availability factor. The plant capacity factor is the ratio of the actual energy generated over a given time period to the theoretical maximum energy generated if the reactor operated at rated power (usually gross power rating) for 100% of the same time period.

Figure 14 summarizes the indices for nuclear plant operating experience between 1968 and 1973.[40] More detailed data showing experience of the industry during calendar year 1974 are given in Table 15. As indicated the industry-average plant capacity factors for these years ranged between 55 to 61%.

The plant factor data are presented in a different way in Table 16, which shows the average indices as a function of the number of years since the plants were placed in commercial operation.* These industry averages are also shown graphically in Fig. 15, plotted against a background of data for individual plants. The individual plant information is also listed in Table 17. This data base encompasses only commercial plants brought on line since 1968 and does not include "first generation"

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*Data taken from Ref. 40 and updated.

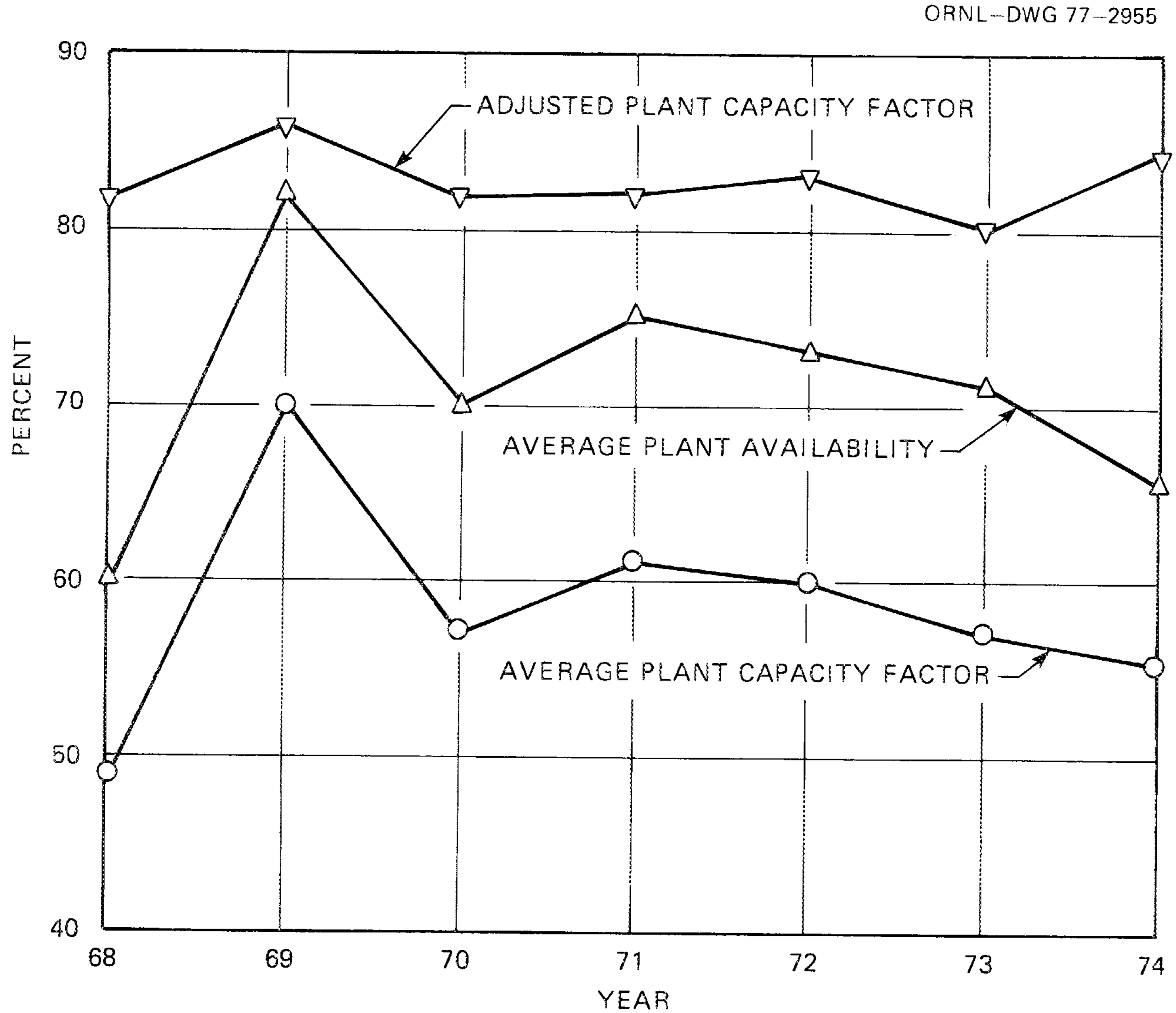

Fig. 14. Nuclear plant operating experience, 1968 to 1973.

Table 15. Nuclear performance statistics — 1974[a]

Plant name	MW(e) (gross)	Commercial operation date	Reactor		Plant	
			Hr	%	Available (%)	Capacity (%)
San Onofre	450	1/68	8316	94.93	86.08	84
Connecticut Yankee	600	1/68	6307	72.0	69.6	87
Oyster Creek	670	12/69	6323	72.2	70.4	64.8
Nine Mile Point	650	12/69	6176	72.9	70.5	59.4
R. E. Ginna	490	7/70	5602	63.9	62.4	51.7
Dresden-2	850	8/70	5854	66.8	64.1	48.3
Point Beach-1	524	12/70	7490	85.9	81.5	72.1
Millstone	682	3/71	7087	80.9	79.1	63.1
H. B. Robinson	739	3/71	7551	86.2	83.31	78.2
Monticello	580	6/71	6970	79.6	74.9	60.2
Dresden-3	850	10/71	6004	68.5	65.0	45.6
Palisades	722	12/71	663	7.6	5.5	1.46
Quad Cities-1	832	8/72	5562	64.6	61.9	50.5
Quad Cities-2	832	10/72	7434	84.9	82.6	64.6
Point Beach-2	524	10/72	7245	82.7	81.0	72.9
Vermont Yankee	540	11/72	6729	76.8	74.1	56.2
Maine Yankee	827	12/72	6118	69.8	68.7	52.3
Pilgrim	687	12/72	3550	46.5	39.2	34.0
Surry-1	824	12/72	5185	59.2	54.8	48.5
Turkey Point-3	728	12/72	6424	73.3	69.8	60.7
Surry-2	824	5/73	5491	62.7	44.0	38.5
Turkey Point-4	728	7/73	6916	76.6	77.2	71.9
Oconee-1	911	10/73	5447	62.2	60.1	53.0
Indian Point-2	902	11/73	5487	62.6	39.4	44.6
Browns Ferry-1	1098	12/73	8263	94.3	78.4	55.4
Ft. Calhoun-1	481	12/73	7582	86.5	83.5	60.4
Oconee-2	911	12/73	1946	71.1	68.5	58.2
Peach Bottom-2	1098	12/73	7231	92.7	90.5	81.7
Prairie Island-1	547	12/73	4279	48.9	43.9	31.5

Table 15 (continued)

Plant name	MW(e) (gross)	Commercial operation date	Reactor		Plant	
			Hr	%	Available (%)	Capacity (%)
Zion-1	1085	12/73	5169	59.0	57.2	39.2
Arnold-1	565	1/74	4755	64.0	53.0	35.0
Average					65.7[b]	55.5

[a]Reactor and Plant Availability Data from ERDA-29-74, *Operating History of U.S. Nuclear Power Reactors, 1974*. Plant capacity factors computed with data published in *Nucleonics Week*.

[b]Average reactor availability factor, 70.6%.

Table 16. Average annual plant capacity factors[a]

	Year of operation							
	1	2	3	4	5	6	7	8
PWRs	55 (18)	62 (18)	70 (10)	66 (6)	77 (4)	51 (2)	85 (2)	79 (2)
BWRs	51 (15)	52 (15)	53 (10)	58 (6)	48 (3)	68 (2)		
All	53 (33)	59 (33)	63 (20)	61 (12)	62 (7)	60 (4)	85 (2)	79 (2)

[a]Capacity factors in percent. Numbers in parentheses indicate number of plants upon which average is based.

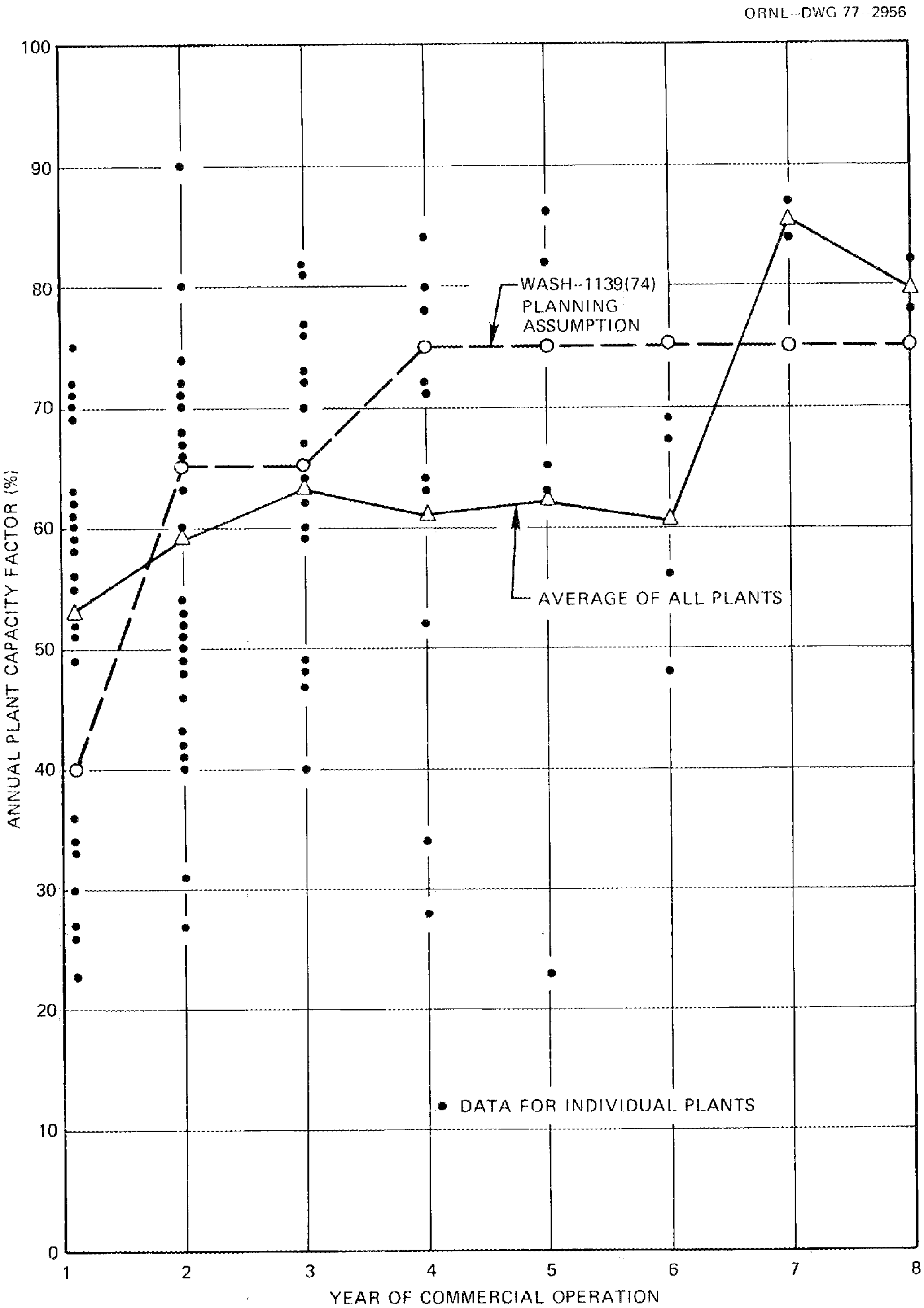

Fig. 15. Achieved plant capacity factors vs year of operation.

Table 17. Operating histories for nuclear plants on-line for more than one year

Plant name	MW(e) (gross)	Commercial operation date	Years in service	Plant capacity factor — by year of operation							
				1	2	3	4	5	6	7	8
San Onofre-1	450	1/68	8	33	72	82	80	82	56	84	82[a]
Connecticut Yankee	600	1/68	8	62	74	72	84	86	48	87	78[a]
Oyster Creek[b]	670	12/69	6	61	68	77	63	65	69[a]		
Nine Mile Point	650	12/69	6	34	53	59	63	63	67[a]		
R. E. Ginna	490	7/70	5	61	68	76	52	65			
Dresden-2	850	8/70	5	30	48	62	64	23[c]			
Point Beach-1	524	12/70	5	75	67	63	71	75[a]			
Millstone-1	682	3/71	4	71	42	48	63[d]				
H. B. Robinson	739	3/71	4	58	66	73	78				
Monticello	580	6/71	4	58	65	72	72				
Dresden-3	850	10/71	4	63	51	49	28[e]				
Palisades	722	12/71	4	30	40	2[f]	34[a]				
Quad Cities-1	832	8/72	3	70	49	67					
Quad Cities-2	832	10/72	3	73	70	40					
Point Beach-2	524	10/72	3	56	90	70					
Vermont Yankee	540	11/72	3	52	59	65[a]					
Pilgrim	687	12/72	3	70	31	47[a]					
Surry-1	824	12/72	3	51	49	64[a]					
Maine Yankee	827	12/72	3	49	52	60[a]					

Table 17 (continued)

Plant name	MW(e) (gross)	Commercial operation date	Years in service	Plant capacity factor — by year of operation							
				1	2	3	4	5	6	7	8
Turkey Point-3	728	12/72	3	55	60	81[a]					
Surry-2	824	5/73	2	69	41						
Turkey Point-4	728	7/73	2	55	63						
Oconee-1	911	10/73	2	69	50						
Indian Point-2	902	11/73	2	36	71[a]						
Browns Ferry-1	1098	12/73	2	26	27[a]						
Ft. Calhoun-1	481	12/73	2	60	46[a]						
Oconee-2	911	12/73	2	23	60[a]						
Peach Bottom-2	1098	12/73	2	63	63[a]						
Prairie Island-1	547	12/73	2	27	80[a]						
Zion-1	1085	12/73	2	33	52[a]						
Arnold-1	565	1/74	2	59	44[a]						
Cooper	800	1/74	2	55	63[a]						
Calvert Cliffs	880	2/74	2		54[a]						

[a]Data for last year estimated based on eight or more months.

[b]In June 1975, Oyster Creek was derated to 530 MW(e) for a 6 to 9 month period.

[c]Dresden-2 was down 26 weeks for refueling and maintenance.

[d]Refueling

[e]Dresden-3 was down 24 weeks for refueling and maintenance.

[f]Down for repairs — "B" steam generator leak.

nuclear units under 400 MW(e). As noted above, system-average capacity factors have ranged around 60% over most of the commercial operation period with some increase indicated beyond the sixth operating year, based upon quite limited statistics. For reference purposes, Fig. 15 also indicated the schedule for capacity factors assumed in some previous forecasting studies by the USAEC.[2] According to these planning schedules, average capacity factors rise from about 40% to about 75% over the first four years of plant operation.

The fuel batch discharge exposure is determined by the product of batch residence time and the average capacity factor achieved during this residence time. Targeted fuel exposures can, in principle, be attained for any specified capacity factor history by stretching the refueling intervals. Stretchout has the effect of increasing net fuel financing charges but does not change the direct cost of energy produced, provided the targeted exposures are achieved. This may be prevented, however, by factors such as fuel element failures. Phenomena such as hydriding, pellet-clad interaction, and densification have caused fuel failures to be experienced in the early years of commercial operation of nuclear plants following 1968. These have been largely eliminated by changes in fuel element design and fabrication procedures. However, assessing the impact of fuel irradiation experience on current fuel costs requires consideration of statistics on these premature discharges. A study made by the Nuclear Assurance Corporation, drawing on industry statistics up to August 1975, noted that the industry-average fuel had attained 75% of its nominally achievable exposure at discharge.[41] This percentage had shown an increasing trend through time, and the fuel discharged during 1974 had attained 91% of its nominally achievable exposure. Moreover, the study noted that 40% of total recoverable fuel materials and 77% of the nonrealized energy due to premature discharges was attributable to three reactors: Dresden-2, Vermont Yankee and Maine Yankee. Thus, the achievement of targeted fuel exposures is a reasonably accurate assumption for currently operating PWRs and BWRs. As of late 1975, the average exposure of all U.S. discharged, zircaloy-clad fuel from LWRs was about 14,000 MW days per tonne U.[42] Maximum discharge exposures were about 25,000 and 32,000 MW days per tonne for BWRs and PWRs, respectively, indicating that most commercial reactors were still on the approach to an "equilibrium" cycle.

3.6 Spent Fuel Reprocessing

If unfissioned uranium left in a fuel element after it is removed from the reactor is to be used, or if the bred plutonium in these elements is to be utilized, then spent fuel must be reprocessed. These fissionable materials remaining in the fuel element have value since they may be reused to fuel reactors, thus reducing the need for mining uranium and to some extent reducing separative work requirements. It is, however, costly to recover this material. Exactly how costly still remains a matter of conjecture.

Perspective about the economic incentives, status, and problem areas involved in "closing" the nuclear fuel cycle was provided in an ERDA task force study released in March, 1975.[19] In addition, an excellent summary of the status of the U.S. reprocessing industry as of mid-1975 is given in Ref. 43. An outline of the status is included here, however, in context with the other fuel cycle segments already discussed.

At present there is no operating plant in the U.S. for the processing of spent commercial reactor fuels. The basic technology for spent fuel processing was developed by the AEC in the 1940s and early 1950s and was used by the AEC at its Hanford and Savannah River plants. The first plant built for the reprocessing of commercial reactor fuels was the Nuclear Fuel Services Plant (NSF) at West Valley, New York. This plant operated between 1966 and 1972, at which time it was shut down in order to expand plant capacity and to increase operating efficiency. At that time it was projected that the plant would return to service in 1975. However, a new construction permit and operating license were required due to the scope of the plant changes and the more stringent regulatory criteria imposed by the Nuclear Regulatory Commission (NRC). In October 1976, NSF announced that they would be unable to meet the seismic design requirements specified by the NRC at an acceptable cost, and as a result, intended to close the facility permanently.

The NRC has stated that it will not issue any permits or licenses related to the use of mixed oxide fuels until the Generic Environmental Impact Statement on the use of Mixed Oxide Fuels (GESMO) is complete and the questions it raises on Pu recycle are resolved. Decision on these matters is not expected before about 1978. In addition to the uncertainties surrounding back-end fuel cycle costs, the net effect has been to delay reprocessing indefinitely as a mode of disposition of spent fuel. This has created a near-term "bottleneck" in the storage of spent-fuel elements.

A second reprocessing plant, built by the General Electric Company (GE) at Morris, Illinois, was originally scheduled to begin operation in 1972. However, due to potential operating problems, GE has concluded that the plant cannot be operated as designed. Presently, the facility will be used for storing spent fuel elements pending completion of further studies pertaining to its disposition.

Allied-General Nuclear Services (AGNS) is building a third reprocessing plant at Barnwell, South Carolina. This is the largest of the current plants having a capacity of about 1500 tonne of uranium/year. Although the plant is nearly complete, it is not yet licensed. If all factors were favorable, AGNS could begin commercial operation in late 1977. However, all factors are not favorable, and the NRC will not grant an operating license for AGNS until GESMO is resolved. AGNS is also having difficulty obtaining a construction permit to build a facility for converting liquid plutonium nitrate solution into a solid form, which the NRC has specified as the form required for shipping recovered plutonium.

Regulatory issues and GESMO-related decisions will have the effect of delaying reprocessing facilities for several years. If all questions are resolved favorably, AGNS could begin operation in the 1979—80 period with a second facility following around 1986.[44] However, decision delays and court battles could delay these starting dates even further. An unfavorable decision could do away with spent fuel reprocessing altogether, eliminating plutonium recycle LWRs or breeders. However, it is expected that plutonium recycle will be allowed but under as yet undefined stringent and costly safeguard ground rules.

Historically, the cost of reprocessing had been about \$30/kg. The current range of estimates are that reprocessing costs, including waste disposal and shipping costs from the new and modified plants, will be from \$100 to \$300/kg.[19,45,46] Since the Barnwell facility will not be operational for several years, and since new regulations will probably be imposed by the NRC, perhaps leading to increased prices, fuel reprocessing costs could easily approach \$300/kg.

If reprocessing costs rise to this level, it may be more economic to use a throwaway cycle and to bypass spent fuel reprocessing altogether. Here, the costs for long-term storage of these elements will have to be paid and the delayed effect on uranium prices considered. The throwaway cycle is a nonsolution, however, and should be considered only under circumstances such as if the nuclear option is phased out with no breeder and no plutonium recycle. It represents the loss of a potentially large source of energy to an economy which is already short of energy.

It is reasoned that the law of supply and demand will eventually make reprocessing an economic choice. If the breeder is to be commercialized, large quantities of plutonium will be needed. This Pu is made available only through reprocessing. The price of plutonium will rise to the point where its value is at least equal to its cost of recovery (reprocessing cost). If recycle uranium and plutonium are not used in light water reactors, the greater demand on newly mined uranium will cause its price to increase. The higher uranium prices will in turn increase the economic incentive for reprocessing.

ERDA estimates of the breakeven reprocessing costs for various combinations of uranium and separative work prices are shown below.[19]

U_3O_8 (\$/lb)	Enrichment (\$/SWU)	Reprocessing(\$/kg)
15	45	125
30	70	240
50	100	400

(20% mixed oxide fuel in LWR, \$80 mixed oxide fabrication penalty)

A uranium price of over \$30/lb U_3O_8 and an enrichment price of at least \$70/kg will be needed to meet the projected reprocessing costs.

In view of the uncertainty that surrounds the reprocessing industry, it is helpful to examine the problem from a utility viewpoint. Reprocessing contracts were written before the rapid escalation of reprocessing costs became evident, and the typical unfilled contract is for about \$40/kg. The companies which wrote these contracts are attempting to renegotiate them since projected reprocessing costs are substantially higher than contract price. It is unlikely that these old contracts will be honored and the typical utility is not using these numbers to estimate future reprocessing costs.

In the system of accounts used by utilities (Sect. 4), the discharged fuel from the reactor is considered to have a net salvage value. This is the value of the material left in the fuel less the cost of extraction (i.e., reprocessing cost). While the value of the recovered uranium is directly obtainable, the reprocessing cost and plutonium worth are speculative. Although some utilities may be using their old reprocessing contract prices in their net salvage value calculations, most realize that these are not realistic. There is great uncertainty both in and out of the utility industry as to what the final cost of reprocessing will be, or even if discharged fuel will be allowed to be reprocessed.

An approach which bypasses the need for placing a dollar figure on reprocessing cost or plutonium value was being used by one utility contacted during the course of this study. In this approach a zero salvage value is assigned to the fuel leaving the reactor. Implicit in this method is the assumption that the fuel cycle back-end costs on a present value basis will be just equal to the worth of fissionable materials extracted. When the fuel is ultimately reprocessed or disposed of, the plan is to take a one time financial gain (or possibly loss) for the fuel.

The value of the plutonium extracted in the reprocessing step will not be determined by the cost of reprocessing, but by its value as a substitute fuel for enriched uranium. In LWRs the value of plutonium will depend on the value of U^{235} enriched fuel it can replace and the differential costs for fabrication, reprocessing, etc., of the two fuels. However, if this indifference value for plutonium is not large enough to pay for its recovery from spent fuel, there will be no commercial plutonium recycle in LWRs. The costs of disposal of spent fuel elements as opposed to the management of reprocessed high-level wastes must also be factored into the economic trade-off analysis.

Until more definitive information becomes available as to what actual reprocessing costs will be, this "zero net salvage value" method may be used as a "benchmark" procedure in analyzing near-term nuclear fuel cycle costs. Another benchmark procedure would make use of a negative salvage value, corresponding to cost penalties for long-term storage of spent fuel elements. Both these methods of cost normalization are considered in the calculations described in Sect. 5.

3.7 Spent Fuel Storage

As a consequence of the delays experienced over the past several years in bringing nuclear fuel reprocessing facilities into operation, serious problems have developed with regard to the adequacy of spent fuel storage capacity for discharged reactor fuel elements. During the late 1960s and early 1970s, utilities entered into reprocessing contracts fully expecting reprocessing capacity to be available by the mid-1970s. Principally for this reason, nuclear plants were designed with the capability of storing only a limited number of spent fuel elements in their on-site storage basins. Typically, it was expected that discharged reactor fuel would be placed in the storage basin for a six to nine month cooling period, and afterwards be transported to a fuel reprocessing plant for recovery of residual uranium and fissile plutonium for recycling. Due to the lack of operational reprocessing facilities, and the present uncertainty that surrounds the reprocessing industry, utilities must now store discharged fuel elements for extended periods of time. Recent surveys indicate that spent fuel storage may be required through the mid-1980s, or perhaps even longer, depending on the status and development of the reprocessing industry.

There are a number of options available for alleviating the problem of interim storage of reactor spent fuel elements, including; (a) expansion of existing on-site reactor pool capacity, (b) shuffling spent fuel between various reactor sites, (c) utilizing and/or expanding existing storage basins at the GE, NSF, and AGNS fuel reprocessing plants, (d) constructing new on- or off-site storage basins, and (e) storing the spent fuel at a government-owned facility.[1] In addition, future shortages could be eased by designing new reactor plants with larger capacity storage basins and/or with more compact storage racks, and by anticipating longer delays between fuel discharge and transport to a reprocessing facility. Several recent studies on spent fuel storage alternatives indicate that the expansion of existing on-site facilities has a clear cost advantage over the other options presently available.[44] Typically, increasing the capacity of existing storage racks involves compaction of the discharged fuel assemblies, which can be accomplished by using special neutron poison structures, such as boral plates, boron stainless steel plates, or boron carbide pins and plates. Redesigned storage racks can increase original plant storage capabilities in PWRs by as much as 150 to 250%, and by 100 to 150% in BWRs.

Expansion of existing spent fuel storage facilities, as well as the construction of new storage basins, requires the review and approval of the Nuclear Regulatory Commission. Between October 1975, and May 1976, the NRC approved seven applications for expansion of on-site fuel storage capacity. This action has significantly alleviated the spent fuel storage problem and has delayed the pinch* date of the affected reactors to 1979 or beyond. As of early July 1976, the NRC had under consideration requests for increasing the fuel storage capacity of 14 additional reactors. There are four main criteria the NRC considers in granting approval of requests for expanded fuel storage facilities, namely; (a) the effect of increased storage on criticality, (b) pool heat loads, (c) seismic design criteria, and (d) cask drop accidents.[47] Table 18 provides a summary of the status of spent fuel storage expansion plans, including both those approved and those that are currently under consideration by the NRC.

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*The pinch date is defined as the date at which fuel would have to be shipped off-site to permit reactor refueling.

Table 18. Summary of proposed on-site spent fuel storage expansion plans[a]

Reactor	Type	Power [MW(e)]	Request date	Approval date	Elements in core	Basin capacity (elements)		% increase	Estimated pinch date
						Old	New		
Indian Point 2	PWR	873	3/4/75	12/16/75	193	264	482	82	1983
Maine Yankee	PWR	827	3/27/75	10/31/75	217	318	953	119	1986
Oconee 3	PWR	839	9/12/75	12/22/75	177	216	474	119	1979
Oyster Creek	BWR	650	9/19/75	5/24/76	560	840	1540	83	1983
Pilgrim 1	BWR	655	12/17/75	5/24/76	580	900	2500	177	1991
Point Beach 1 & 2	PWR	497 each	3/28/75	10/20/75	121/unit	208	351	68	1979
Robinson	PWR	663	9/5/75	2/9/76	157	240	276	15	1977[b]
Nine Mile Point 1	BWR	500	8/8/75		532	800	1140	42	1980
Arkansas 2	PWR	990	5/23/75		177	247	486	96	1986
Connecticut Yankee	PWR	575	12/19/75		157	252	1172	365	1994
Dresden 2	BWR	715	12/8/75		724	1160	1440	24	1980
Dresden 3	BWR	715	12/8/75		724	1160	1440	24	1980
Fort Calhoun 1	PWR	481	7/29/75		133	178	400	124	1985
La Crosse	BWR	50	3/31/75		72	84	134	59	1979
Millstone Point 1	BWR	650	10/31/75		580	880	1800	104	1985
Quad Cities 1	BWR	809			724	1158			1980 + addition
Quad Cities 2	BWR	809			724	1158			1980 + addition
Rancho Seco	PWR	850			177	258			1979 + addition
Turkey Point 3	PWR	760	1/2/76		157	217			1978 + addition
Yankee Rowe	PWR	155			76	110			(Shipping to NFS)
Zion 1 & 2	PWR	1080 each	10/24/75		193/unit	340	868	155	1983

[a]Source: Ref. 47.

[b]Additional action is expected.

In March 1975, ERDA published a report which contained a compilation of data depicting the National LWR spent fuel disposition situation through 1985.[48] This survey contained five scenarios that were based on utility and reprocessor forecasts and plans as of January 1, 1975. The base case in this study, which assumes only currently available storage facilities, estimated that as many as 18 reactors might be forced to shut down by 1978 if no solutions to fuel storage problems were found. As a result of the NRC's action in 1975–76, however, ERDA has revised these earlier estimates and the base case now indicates that only five reactors may be forced to shut down by 1978 due to a shortage of spent fuel storage capacity.[49] A comparison between the five cases reported in the two ERDA surveys, and a description of the assumptions used for each of the cases, are shown in Table 19.

A recent NRC study indicates that on the average, the reactor basin storage capacity of an existing 1000 MW(e) nuclear plant could be expanded to hold an additional five discharges [$\sim$150 tonne heavy metal (HM)] at a cost of approximately \$2 million.[50] Considering that this added capacity may have a relatively short useful lifetime, i.e. useful until reprocessing capacity becomes available, and a low utilization factor ($\sim$50%), the cost associated with this type of storage is estimated to be in the range of \$5 to \$8/kg HM/year. However, the same type of storage in a new reactor could yield storage costs as low as \$2 to \$3/kg HM/year. Cost estimates for a new central storage facility with a 1000 tonne capacity storage basin were estimated to be \$20 million in August 1974, while 1976 estimates for the same plant typically are in the \$50 million range.[51,47] These recent estimates of costs for a central storage basin operating with long-term utility contracts yield a unit cost in the range of \$7 to \$10/kg HM/year.[43] Table 20 shows a breakdown of estimated unit storage costs for several spent fuel storage options. The costs calculated for the case of high density storage racks in a reactor basin were based on a 7% effective cost of capital, while the costs for the central storage basin were based on an 11.5% effective cost of money. In our analysis, we used an upper estimate of \$10/kg HM as the annual cost for long-term storage of spent fuel elements.

Table 19. LWR spent fuel disposition capabilities: number of reactors requiring additional spent fuel storage capacity to permit scheduled discharges[a,b]

Case	Survey[c]	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
1	A	0	4	6	18	27	37	56	65	69	82	
	B	0	0	1	5	8	10	16	25	35	40	55
2	A	0	3	6	17	25	35	54	63	68	80	
	B	0	0	1	4	7	9	16	25	35	40	55
3	A	0	0	6	14	23	33	51	60	65	78	
	B	0	0	1	4	7	9	16	24	35	40	55
4	A	0	0	0	0	0	0	0	0	0	0	
	B	0	0	1	2	2	0	0	0	0	0	0
5	A	0	0	0	0	0	0	0	0	0	0	
	B	0	0	1	2	2	0	0	0	0	0	0

[a]Source: Ref. 49.

[b]Assumptions: Case 1 — Currently available facilities (GE storage basin at 700 tonne U and NFS storage basin at 250 tonne U).

Case 2 — Case 1 plus increase in NFS storage capacity at 45 tonne U in 1976.

Case 3 — Case 2 plus availability of AGNS storage basin with 360 tonne U capacity in 1977.

Case 4 — Case 3 plus projected AGNS reprocessing capability beginning in 1978 and reaching full capacity of 1500 tonne U/year in 1980.

Case 5 — Case 4 plus projected resumption of NSF reprocessing in 1983 and reaching full capacity of 750 tonne U/year in 1984.

[c]"A" results of 1975 survey; "B" results of 1976 survey.

Table 20. Estimated unit storage cost for several spent fuel storage options ($/kg HM/year)[a]

	Capacity utilization	
	50%	80%
High density racks in reactor basins:		
5-year amortization	8.00	5.00
10-year amortization	5.20	3.30
30-year amortization	3.75	2.30
Central storage basin with 15-year amortization:		
1000 tonne capacity	8.80	5.50
4000 tonne capacity	7.70	4.80

[a]Source: Ref. 50.

3.8 Financing Cost Trends

The indirect fuel cycle costs are financial costs. They are essentially the charges on the capital necessary to finance, or carry, the unamortized fuel costs and pay any taxes incurred. This money comes from the general capital base of the utility company.

Generally, a utility's capital structure may be divided into three categories: (a) debt, mostly long-term bonded debt; (b) preferred stock; and (c) common capital stock equity. This latter category includes the book value of the common stock and any capital surplus and retained earnings. The cost of the capital is in the form of interest on the debt, dividends on the preferred stock, and return on the common equity. The debt interest differs from the return on preferred and common stock in that it is deductible for income tax purposes.

In recent years the returns on new bonded debt and on new preferred stock have been rising. A summary of these average yields for recent years is given in Table 21.[52]

Table 21. Yields on new utility bonds and preferred stock

Year	Bond[a] yield %	Preferred[b] yield %
1966	5.53	5.37
1967	6.07	6.03
1968	6.80	6.44
1969	7.98	7.75
1970	8.76	9.01
1971	7.71	7.74
1972	7.50	7.53
1973	7.91	7.50
1974	9.65	9.95

[a]Electric and gas utilities.

[b]All utilities.

The steep rise in 1974 was brought about by tight money, double-digit inflation, and by questions of solvency in the utility industry. The severe fuel price increases of that year caused cash flow problems for a number of utilities. For example, New York's Consolidated Edison Company stopped dividend payments on its common stock, causing repercussions throughout the utility industry. In 1975 and 1976, interest rates retreated somewhat from their peaks although they still remained high by historic standards.

The interest or dividend rates on new debt or preferred stock do not represent in themselves the working capital cost of debt or preferred stock, since there are other debt and preferred stock in the utility capital structure sold in prior years at different rates. They represent the marginal cost of capital and indicate in what direction the utility's indirect costs are heading. The average return on a utility's debt and preferred stock, based on book value, will change more gradually than the new issue prices but will follow these prices. The past history of these average returns are given in Table 22[52] for investor-owned electric utilities.

Table 22. Average rates of return,%[a]

Year	Debt cost[b]	Preferred cost	Return on common equity[c]
1967	4.05	4.64	12.73
1968	4.29	4.86	12.29
1969	4.58	4.98	12.16
1970	5.07	5.22	11.77
1971	5.48	5.93	11.64
1972	5.75	6.20	11.74
1973	6.01	6.33	11.46
1974	6.50	6.89	10.65

[a]Based on linearly averaged capitalization for year.

[b]Interest on long-term debt

[c]Income available to common as a percent of average common capital stock equity.

While the average return on debt and preferred stock has been rising, there has been a gradual decrease in the real return on common equity in the last few years.

Table 23[52] shows the recent trends in the fraction of capital contributed from debt, preferred stock, and from common capital stock equity. Table 23 indicates that the capital structure of the average utility has not changed appreciably in the last decade. Debt has remained even, while a gradual rise in the preferred stock fraction has been offset by a gradual drop in the common equity fraction.

The utility capitalization fractions and capital return rates which should be used for analyses dealing with the next decade are important if accurate predictions of the true nuclear fuel cycle cost are to be made. Such analyses have their bases in scenarios for the future. In making our analysis, we assume that interest rates on new utility bonds and preferred stock remain high (8 to 10%) over the next five years. In the early 1980s they will drop some (7 to 9%) as the stature of utility credit improves and inflation abates. The average cost of all outstanding

Table 23. Utility capitalization fraction

Year	Bond	Preferred	Common equity
1966	.525	.095	.380
1967	.533	.097	.370
1968	.541	.096	.363
1969	.550	.095	.355
1970	.553	.098	.349
1971	.547	.107	.346
1972	.537	.117	.346
1973	.529	.120	.351
1974	.533	.123	.344

bonds and preferred stock to the utility will rise until it reaches the new issue average price of about 8%. The utilities, in order to improve their financial standing, will attempt to raise the common equity fraction as well as its yield with only moderate success. Federal and state income tax rates will remain at about present levels. The economic parameters used in our fuel cycle evaluations are given in Table 24.

Table 24. Economic parameters

	Return %	Fraction
Capitalization		
Debt	8.0	.53
Preferred stock	8.0	.12
Common equity	12.0	.35
Taxes		
Federal income, %		48
State income, %		2.5

4. NUCLEAR FUEL COST ACCOUNTING

From the viewpoint of electric utilities, the major differences between fuel cost accounting for nuclear and fossil-fired generating plants stem from the much longer time intervals comprising stages in the "life-cycle" of nuclear fuel. To illustrate this point, Table 25 lists the characteristic intervals used by ERDA in certain long-range planning activities, particularly those of projecting requirements for separative work. In comparison to the 3 to 4 year period in which a typical batch of fuel assemblies produces energy in the reactor core, the residence time of fossil fuels in the combustion chamber of a boiler is essentially instantaneous; moreover, the period between mining and combustion is much shorter than the pre-irradiation stages in the nuclear fuel cycle, listed in Table 25.

Table 25. Nominal time intervals in LWR fuel cycle[a]

Fuel cycle "stage"	Nominal time-span (Quarter years)
U_3O_8 procurement to enriched uranium withdrawal	2
Enrichment	1
Enriched uranium withdrawal to reactor charging	
First cores	5
Reloads	2
Fabrication	
First cores	2
Reloads	1
In-core irradiation	2–4 years
Discharge to reprocessing	2
Discharge to return of spent fuel as enriched fuel to fabrication	4
Discharge to return of plutonium	3

[a]Source: Ref. 2.

Generally, there will be a range of variation about the "nominal" pre- and post-irradiation intervals listed in Table 25. These variations will be associated with factors such as differences in production lot sizes (reactor size classes), inventory backlogs, or any special conditions affecting the process times and delivery logistics for that particular service. The front-end processing and delivery of intermediate product or finished assemblies will stretch through overlapping subintervals of the pre-irradiation portion of the fuel cycle. Correspondingly, the cumulative investment by the utility in the unirradiated fuel will increase as the front-end service is "delivered."

An illustration of the kind of variations which have been experienced in production of first cores is shown in Fig. 16.[53] Here, the accumulation of front-end investments over a 10-month period, beginning between the first withdrawal of slightly-enriched UF_6 from the gaseous diffusion plant and ending with delivery of the last finished assembly to the reactor site, is shown for two reactor cores, for a 600 MW(e) and 800 MW(e) size class (cores A and B), respectively. In one case, (A), delivery of UF_6 to the fabricator takes place over a 6-month interval, followed by a 1-month period with no withdrawals or shipment, then by a 3-month period of deliveries of finished assemblies to the reactor site. In Case B, a shorter, 4-month period of UF_6 withdrawals is followed by a 2-month "plateau," before shipment of finished assemblies begins. In this latter case, there will be a longer average period in which carrying charges must be applied before the final product is received at the reactor.

Although the time-schedules for monetary payments for front-end services will generally tend to follow the schedules for delivery, there may not be a precise matching in all cases due to special contract arrangements for advance payments for the service. The cumulative investment curves in Fig. 16 are included here only to supply some perspective about the variations from "nominal" production schedules, implied by the lead times listed in Table 25. The latter are quite useful for comparative cost evaluations and some planning purposes; however, if a high degree of accuracy is required in accounting for pre-irradiation carrying charges, the component payment schedules must be examined on a case-by-case basis.

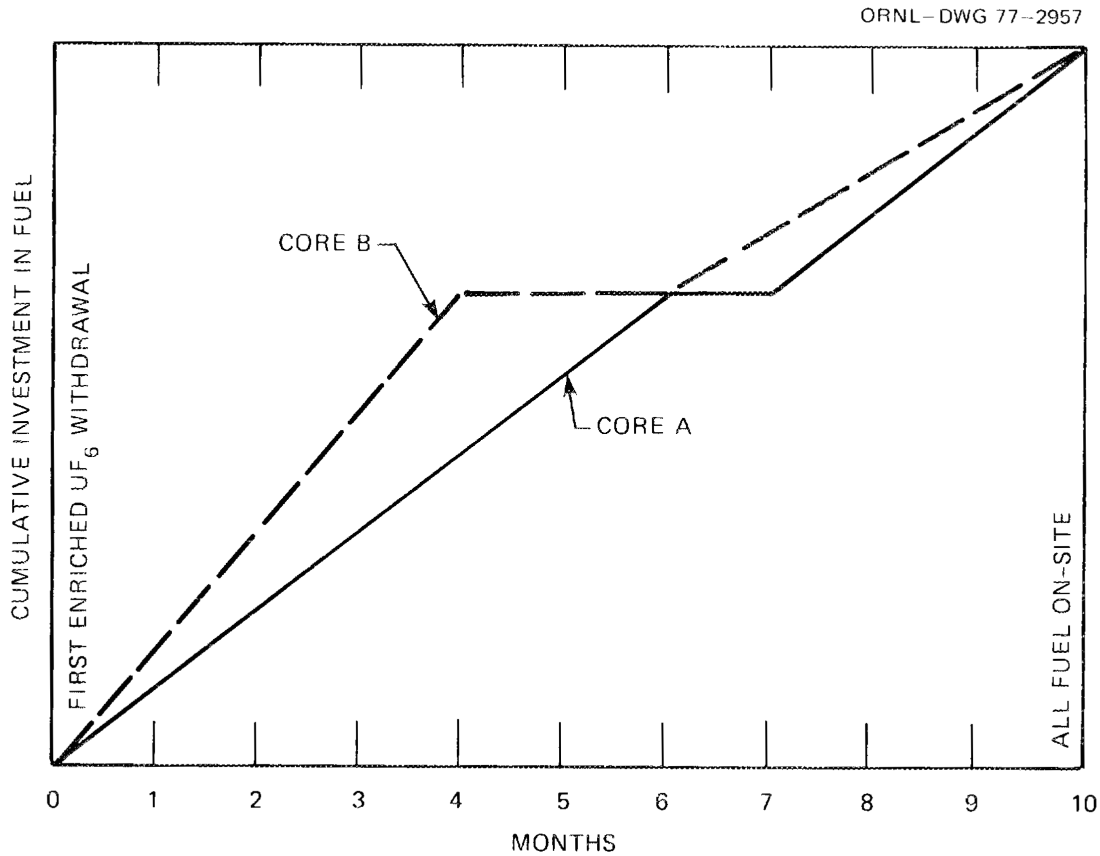

Fig. 16. Variations in cumulative investment of unirradiated fuel.

Because the intervals when cash payments are made for all component services in the nuclear fuel cycle are separated in time from the periods when energy is released in the core, the procedure for fuel cost accounting must treat the payments as capital expenditures, which are amortized (recovered) as the energy is delivered. Inventory carrying charges must be applied at all times to the net unamortized investment. Although the methodology for cost accounting makes use of basic concepts in investment analysis, there are some differences which occur in the way certain financial details may be treated. These differences are reflected in a number of computer programs developed at various installations within the industry for performing nuclear fuel cost analysis.[54-58] (See also Appendix B.)

As indicated in Table 25, over most of the operating life of a light water reactor plant, each separate reload batch of fuel elements will deliver energy in-core for an average 3- or 4-year period before removal. At each refueling, tandem replacement of a fraction of the core (about one-third to one-fourth) takes place, usually on an annual cycle. Each batch of elements included in a reload is therefore coupled neutronically, throughout its nth-cycle residence time, to fuel at all stages of irradiation between zero and (n-1) cycles. After an initial transition period, roughly corresponding to the time in which replacement of the initial core takes place, an "equilibrium" or "cyclic" refueling pattern will tend to develop. For some purposes, comparative fuel cost evaluations may be based on this equilibrium cycle concept, using its mass-flow characteristics together with "levelized" prices assumed applicable to each component (ore, fabrication, etc.) of the fuel cycle. In this case, nuclear fuel cost analysis is also readily amenable to hand calculation methods.[59]

Even if all component prices in the fuel cycle were stationary in time and equal to these levelized values, the operational neutronic coupling mentioned above will influence the initial transition to equilibrium and can produce variations about the equilibrium cycle as operations continue. This can give rise to time variations in the fuel logistical requirements and energy costs associated with the fuel.

As implied by the discussion in Sect. 3, price escalations must also be superimposed on these varying mass-flow requirements. The cost accounting procedure used must be capable of translating the actual cash payments made during reactor operations into a time-dependent energy cost associated with these payments. Thus, any attempt to track the evolution of nuclear fuel cycle costs over time cannot rely solely on analysis based on the equilibrium cycle. The necessary time-dependent analysis can be handled most efficiently by the computer-based techniques referred to above. Many of these are based on the methodology of discounted cash-flow (D.C.F.) analysis.

A detailed exposition of the D.C.F. method has been given elsewhere, in context with the development of computer programs for power and fuel cost analysis.[60] However, the interpretation of nuclear fuel cost information given in the following section will be aided by describing the essential features of this method and showing how it relates to the fuel cost accounting procedures used by utilities. To make the report self-contained, this qualitative description is supported by a brief mathematical derivation given in Appendix A. Basically, D.C.F. analysis established an energy "cost" associated with fuel by (1) identifying the set of fuel investments (payments or credits) associated with production of a specific quantity of energy over a given time span; (2) requiring that the revenue stream from sale of this energy be equal to that needed to pay interest and return on bond and equity components of the capital investments, pay federal and state taxes and insurance, and continuously retire the level of outstanding investments to zero by the end of economic "life" of that set of fuel investments. The D.C.F. levelized cost is defined as the price which must be charged for each kWhr(e) to establish the equivalence in (2). This composite price thus includes both "direct" costs (amortization of investment) and "indirect" charges (financing, taxes, and insurance).

The particular computer program which was used for the fuel cost calculations summarized in the next section is the REFCO program, developed at ORNL.[56] In this program, the D.C.F. procedure is applied on a "batchwise" basis, i.e., a levelized fuel cycle cost is calculated for each discreet batch of fuel elements loaded into the reactor. (Here, a batch is defined as a set of elements with specific charge and discharge times and with the same fuel composition at the time of charge.) The REFCO program then accounts for all front-end and back-end (pre- and post-irradiation) payments as investments associated with each batch. The batch levelized fuel cycle cost is the cost of energy required such that the sales revenue from the energy produced by the batch during its in-core residence recovers all investments in the batch and pays all carrying charges.

As mentioned above, because a fractional core-reloading procedure is used in LWRs, several batches at different stages of irradiation and cumulative energy release will generally be present in the time period or "cycle" between two refuelings. In principle, these batches could be producing energy at different levelized batch costs, particularly if the component investment prices for each batch are changing in time. However, the energy produced from all batches during a given cycle is, of course, a homogeneous product. Hence, the fuel cost accounting program must include a logical procedure for prorating the batch energy costs to obtain a "cycle-levelized" cost of energy. In REFCO, this prorating is done on the basis of the energy produced by the batch during that cycle, i.e., the cycle-levelized cost is the weighted sum of batch-levelized costs, with the weight factors equal to the fraction of the total cycle energy produced by each batch. This comprises the essential elements of the REFCO program logic.

While the D.C.F. analysis procedure is widely used for comparative economics evaluations of both fixed-plant and fuel investments in nuclear units, the accounting methods used by utilities in calculating year-by-year expenses for nuclear fuel differ slightly from the D.C.F. procedure described above. The Federal Power Commission's Uniform System of Accounts, prescribed for public utilities and licenses, illustrates certain of these differences.[61] Accounts systems used by state public service commissions for investor-owned utilities are basically similar to the FPC system.

The balance-sheet subaccounts pertaining to nuclear fuel cycle costs under the FPC Uniform System are listed in Table 26. Account 120.1 in this table includes "the original cost to the utility of nuclear fuel

Table 26. FPC uniform system of accounts pertaining to nuclear fuel. (Balance sheet accounts giving assets and other debits)

Account number	Title
120.1	Nuclear fuel in process of refinement, conversion, enrichment, and fabrication
120.2	Nuclear fuel materials and assemblies — stock account
120.3	Nuclear fuel assemblies in reactor
120.4	Spent nuclear fuel
120.5	Accumulated provision for amortization of nuclear fuel assemblies
157	Nuclear materials held for sale

materials while in the process of refinement, conversion, enrichment, and fabrication into fuel assemblies and components including processing, fabrication, and necessary shipping costs." It also includes the salvage value of nuclear materials which are being reprocessed for use, transferred from Account 120.5.

Upon delivery of completed fuel assemblies for use in refueling or as spares, Account 120.1 is credited and 120.2 debited for the cost of these assemblies. (For this initial reactor core, the transfer is made directly to Account 120.3.) It also includes the original cost of partially irradiated assemblies held in stock for reinsertion in a reactor, which had been transferred from Account 120.3. Finally, it includes the cost of nuclear and by-product materials being held for future use but not actually in process in Account 120.1.

Account 120.3 includes the cost of nuclear fuel assemblies when inserted into a reactor for electricity production. The amounts included are transferred by debiting this account and crediting Account 120.2. (For the initial reactor core, the transfer is made directly from Account 120.1.)

Upon removal of assemblies from the reactor, the original cost of removed assemblies is transferred by crediting 120.3 and debiting Account 120.4 (or 120.2 if reinsertion is planned). Account 120.4 thus includes the original cost of spent fuel assemblies in the process of cooling, pending reprocessing or long-term storage. After the cooling period is over, 120.4 is credited and Account 120.5 is debited and the cost recorded in the former account.

Account 120.5, accumulated provision for amortization of fuel assemblies, is credited and a current expense account — No. 518, Nuclear fuel expense — is debited at the end of each period for the amortization of the net cost of nuclear fuel assemblies used in producing energy:

> "The net cost subject to amortization shall be the original cost of assemblies, plus or less the expected net salvage value of uranium, plutonium, or other by-products."

Note that this salvage value will subtract from original cost in determining the cost subject to amortization, if the value of recovered materials exceeds the costs of reprocessing and waste disposal; coversely, it will add to it if there are net penalties for long-term storage of the end products.

Account 120.5 is credited with the net salvage value of recovered materials when such materials are sold, transferred, or otherwise disposed of. Correspondingly, Account 120.1 will be debited with the net salvage value of nuclear materials to be reprocessed; Account 120.2 will be debited with the net salvage value of materials held for future use and not actually in process in Account 120.1; and Account 157 will be debited for the net salvage value of nuclear materials to be held by the company for sale or other disposal, but not to be reprocessed or reused by the company in its electric utility operations. (Note: Any difference between the amount recorded in this account and the actual amount realized from the sale of materials shall be credited or debited, as appropriate, to "current" Account 518, at the time of sale.)

Account 518, Nuclear fuel expense, is debited and Account 120.5 credited for amortization of net cost of fuel assemblies used in producing energy, where the net cost is as defined above. The utility accounting procedure should assure that charges to this account are distributed according to the thermal energy produced in the period. This account also includes any costs involved when the fuel is leased and costs of other fuels required for any ancillary facilities. The account is debited or credited as appropriate for any significant changes in the amounts estimated as net salvage value of nuclear materials contained in Account 157 and the amounts realized on final disposition of these materials. "Significant declines in estimated realizable value of the items carried in Account 157 may be recognized at the time of market decline by charging Account 518 and crediting Account 157. If the decline occurs while the fuel is recorded in Account 120.3, the effect shall be amortized over the remaining life of the fuel."

In summary, the FPC Uniform System of Accounts establishes the value of all fuel in any particular stage of the fuel cycle as balance sheet assets in an account for that stage. These balance sheet subaccounts may be viewed as a "snapshot" of the net inventory values or investment levels for that stage at any particular time. By making the appropriate crediting or debiting and following the balance sheet "history" of any particular fuel batch from acquisition to disposition, one can calculate the total costs incurred in any accounting period. The direct (amortization) costs will be those included in Account 518. Once appropriate rates for debt, equity, taxes, and insurance are assigned, a net carrying-charge rate can be determined, and the inventory values recorded in the balance sheet may then be used to calculate indirect costs incurred in any period; however, in general these will not appear as an explicit item in the accounts, but instead will be included in aggregate categories such as interest on debt, return to stockholders (including any earned surplus) and taxes incurred in overall utility operations.

This cost-accounting procedure is similar in concept to the "investment-time diagram" approach to calculating nuclear fuel costs.[62] Here, the direct charges in any time period are determined from the reduction (amortization) of net investment level as thermal energy is produced by that fuel batch. This is equivalent to determination of the fuel amortization expenses in Account 518, described above. The indirect charges are then determined by applying the carrying charge rate to the time-varying investment level.

The basic difference between the D.C.F. analysis procedure and the FPC (or investment-time diagram) accounting procedure is that the D.C.F. method levelizes all costs for any fuel batch, direct plus indirect, over the portion of energy produced by that batch. In principle, this procedure requires knowledge of all pre- and post-irradiation charges associated with that fuel batch. The FPC system, however, is equivalent to levelizing only the direct cost components (amortizing them in proportion to energy produced) and allowing the indirect costs to vary over time in accord with the current levels of investment. Thus, indirect or fixed charges could be incurred in an accounting period lagging those when the batch energy was produced; moreover, the procedure described above allows crediting or debiting of Account 518 for changes realized in the salvage values of nuclear materials, if future "back-end" cycle costs change. These one-time expense adjustments can be allocated to current accounting periods even though the energy was produced from that batch during earlier accounting periods. In either accounting procedure both direct and indirect costs are accounted for. However, the precise cost allocations according to energy and time may differ slightly. During real utility operations, several fuel batches will simultaneously be in overlapping stages of the fuel cycle in any one accounting period. The net costs calculated by either procedure will therefore tend to average out over time to match one another.

5. UTILITY NUCLEAR FUEL COSTS

5.1 Criteria for Cost Calculations

The preceding Sects. (3 and 4) provide a background of data and methodology for analyzing current utility nuclear fuel cycle cost experience and estimating the magnitude of changes expected over the short-range future (∿10 years). It has been shown that the primary "driving forces" controlling these changes are expected to be the costs for U_3O_8 and separative work, and that present uncertainties about future regulations and technological developments involved in closing the fuel cycle place the costs associated with back-end fuel disposition still in a pre-commercial or "contingency" status.

With regard to present utility procedures for accounting for these uncertain back-end costs, the problem may be viewed as one of establishing a reasonable basis for a "net salvage value" of spent fuel elements. Here, the practical consequence is that for the next several years utilities will need to use an estimated salvage value of spent fuel to determine the net fuel investment subject to amortization. Cost accounting procedures such as the FPC Uniform System of Accounts then allow adjustments to current expenses for nuclear fuel as changes from the previously estimated expenditures are actually realized.

Even though component costs for back-end processes are currently uncertain, it should be noted that certain accounting rules would apply to the value of recovered fissile material, if commercial reprocessing is ultimately allowed. Generally, the historic, or "book-value" of equivalent natural uranium and separative work should be applied to the recovered uranium on a batch-by-batch basis, even during a time when substantial upward readjustments are taking place in the marketplace (replacement) values. With respect to plutonium, the precise manner in which an accounting value of plutonium may evolve has not yet been established. It is recognized, however, that one can determine a theoretical "indifference value" for plutonium, assuming that plutonium is recycled as mixed oxides (Pu/U) in the same reactor, and that its value is based on the equivalence of the displaced requirements for slightly enriched uranium, minus the penalty for mixed-oxides fabrication. The costs for interim storage of plutonium oxides after reprocessing are also likely to influence the intrinsic plutonium value for recycle. In general, the criteria for establishing a plutonium value are contingent on the outcome of the GESMO resolution; hence, wherever appropriate only "nominal" values of fissile plutonium were used for calculations in this study.*

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*Some preliminary work toward establishing a logical basis for calculating a time-dependent parity value for plutonium, using the REFCO program, is summarized in Appendix C.

Prior to development of commercial fuel reprocessing, additional plant-site storage of spent fuel elements is being provided through installation of special poisoned storage racks (Sect. 3.7). In this case, these costs would likely appear indirectly within the overall utility accounting system, as plant-related, fixed investment costs rather than directly in nuclear fuel cost accounts. However, if charges for long-term, off-site storage of spent fuel are incurred, they should be treated analogously to reprocessing charges and reflected (in a negative sense) in the net salvage value of spent fuel elements.

In lieu of complete knowledge of back-end cycle costs, two simple approximations toward bracketing a current salvage value can be used. These consist of (a) assigning a zero value to all spent fuel removed after a normal burnup interval and (b) assigning a negative value which corresponds to an estimated long-term storage charge. The first approximation implies that reprocessing will not be undertaken unless the economic value of recovered materials achieves a minimum "break-even" point with the costs for recovery and waste handling, transport, and storage. Since all costs are escalating in time, this implies that the values of recovered materials will also escalate to achieve the breakeven point. The second case corresponds to the extreme viewpoint that no reprocessing and recycle of uranium or plutonium will be permitted, at least until fast breeder technology is more fully developed (probably well toward the end of this century). In numerical calculations for alternative (b), we used an upper estimate of \$10/kgU as the annual charge for long term storage of spent fuel elements, as discussed in Sect. 3.6.[63] When present worthed at an average discount factor of 8%, this corresponds to an equivalent one-time charge of about \$125/kgU. Although obtained in a slightly different manner, this value is in reasonable conformance with an estimated median cost of \$150/kgU and a possible range of \$50 to \$300/kgU for the throwaway cycle, given in Ref. 4.

5.2 Historic Fuel Cycle Costs

The average nuclear fuel costs for the past decade for privately-owned electric utilities (FPC class A and B) are shown in Table 27.

Table 27. Historic fuel cycle cost[a]

Year	Direct fuel cost mills/kWhr(e)
1965	3.80
1966	3.02
1967	3.11
1968	2.71
1969	2.42
1970	2.17
1971	2.04
1972	1.85
1973	2.16
1974[b]	2.44

[a]From power generation and fuel expense data in "Statistics of Privately Owned Utilities in the United States 1973," Federal Power Commission.

[b]Preliminary, based on information in various issues of FPC News.

These costs were derived from FPC information by dividing the reported nuclear fuel expense by the nuclear power produced during a given year.[52] The reported nuclear fuel expense in the FPC system of accounts contains the actual value of fuel depleted during the year. Any one-time writeoff or gain from nuclear fuel will also be included in the fuel expense category. Such an instance may occur when discharged fuel is reprocessed. The fuel cycle costs listed in Table 27 represent only the direct costs, and do not contain any financial charges or taxes. Indirect charges may add an additional 30 to 40% to the direct fuel cycle costs.

As shown in Table 27, nuclear fuel costs tended to decrease during the late 1960s and early 1970s reaching a low in 1972. Since that time, however, the trend has been upward with increasing unit fuel cycle costs. The relatively high fuel costs experienced during the mid 1960s were principally the result of early reactors that were small, partly experimental units with inefficient fuel cycles. In addition, the fuel cost was kept at a higher level due to the initial startup fuel costs of reactors coming on-line. As the units reached a standard or equilibrium operating cycle, the fuel costs tended to drop.

In the early 1970s unit cost increases began to effect the fuel cycle costs. Enrichment and fabrication costs started rising. The utilities began to recognize that early reprocessing cost estimates were much too low, and upward revisions of these estimates decreased the apparent worth of discharged fuel. The recent surge in uranium ore price, however, will not show up in increased costs until later in the decade. This is because of existing contracts at low prices in the near term and because of the long lead time between uranium purchase and its depletion in the fuel cycle.

5.3 Changes in Nuclear Fuel Cycle Costs, 1970–1985

The net effects that developments now taking place in the nuclear fuels supply industries might be expected to have on utility fuel cycle costs in the 1970 to 1985 time frame are illustrated in Fig. 17. This is a composite plot of (1) historic FPC data for industry-averaged, annual direct fuel amortization costs, adjusted upward by 30% to account approximately for indirect charges; (2) fuel cycle costs for a PWR and BWR typical of the commercial reactors operating in the mid-1970's, calculated using the REFCO fuel cycle program and the component price data base described in the preceding sections; (3) forecasted fuel cycle costs for a large-scale PWR [1300 MW(e)], representative of the reactors to be placed in operation in the early 1980s; and (4) forecasted fuel cycle costs for a 1300 MW(e) PWR which are expressed in 1976 dollars by factoring out an overall 6% inflation rate. These latter forecasts were also calculated with the REFCO program, using "upper" and "lower" variants for unit price data expected to apply during that period. Table 28 summarizes the unit price data used in making these high and low variant forecasts. In the calculations for (2), the reactor refueling mass-balance information (charge and discharge quantities, composition, and schedules) was obtained through direct contact with the utilities

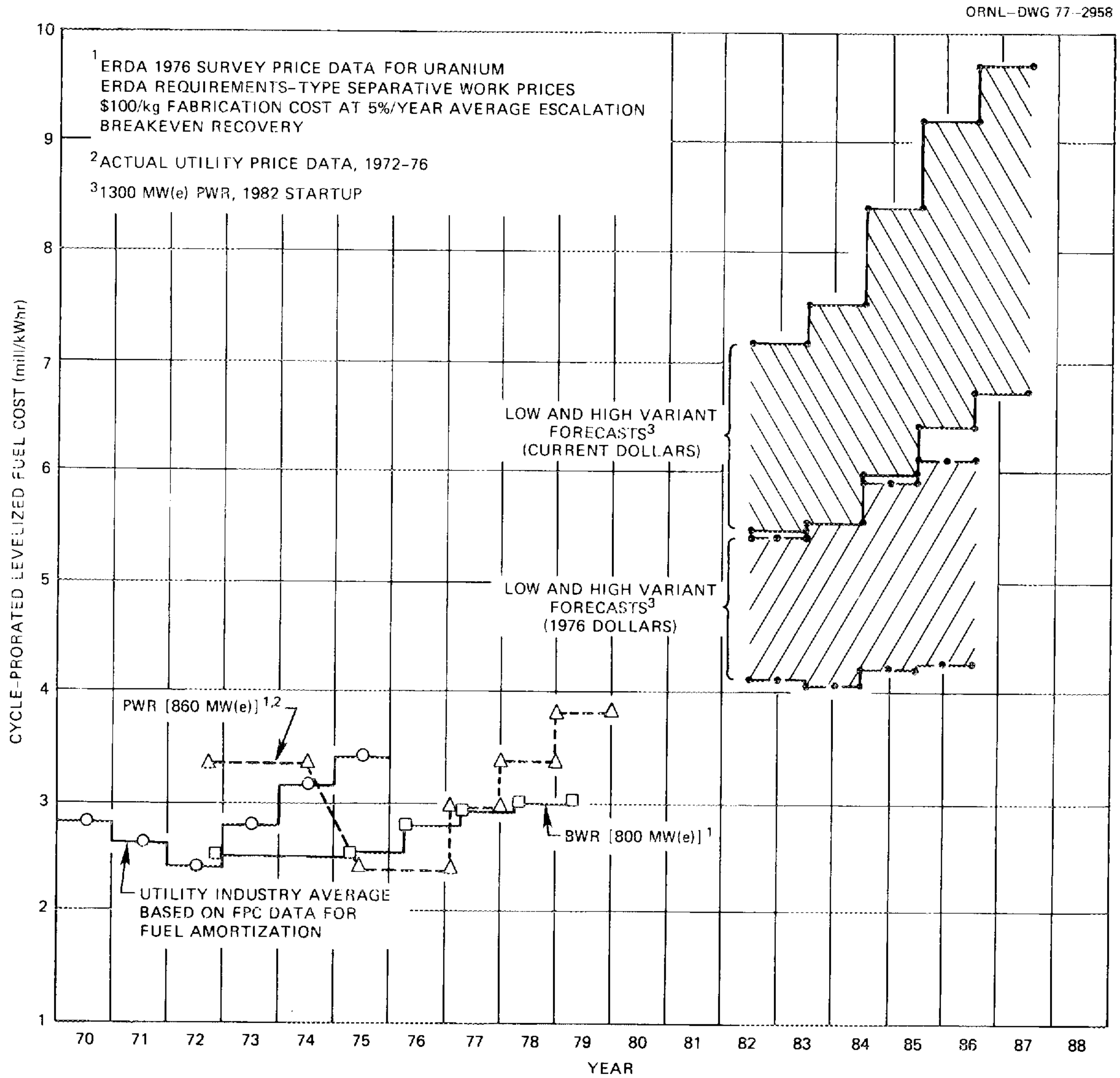

Fig. 17. Cycle-prorated levelized fuel cycle costs.

Table 28. Summary of component price data used in fuel cycle cost calculations[a]

Year	U_3O_8 price, \$/lb U_3O_8		Conversion \$/kgU	Separative work, \$/SWU		Fabrication \$/kgU
	Low	High		Low	High	
1970	7.00	7.00	2.56	26.00	26.00	78.30
1971	7.00	7.00	2.61	28.70	28.70	82.20
1972	7.50	7.50	2.70	32.00	32.00	86.30
1973	8.00	8.00	2.96	38.50	38.50	90.70
1974	8.00	8.00	3.39	47.80	47.80	95.20
1975	10.50	10.50	3.60	48.75	48.75	100.00
1976	10.70	10.70	3.74	63.00	63.00	105.00
1977	12.00	12.00	3.85	71.00	77.00	110.20
1978	17.50	17.50	3.94	74.00	90.00	115.70
1979	21.75	25.00	4.21	76.00	100.00	121.50
1980	25.50	33.00	4.27	79.00	110.00	127.60
1981	28.00	41.50	4.35	83.00	120.00	134.00
1982	31.50	47.00	4.40	86.00	130.00	140.70
1983	33.75	50.00	4.46	89.00	138.00	147.70
1984	36.50	54.00	4.51	93.00	146.00	155.10
1985	38.50	57.50	4.55	97.00	155.00	162.90

[a]Current dollars.

operating the reactors. The mass balance information for (3) and (4) was derived from data provided by one of the PWR manufacturers.

The ordinate in Fig. 17 is the cycle-prorated, levelized fuel cost,* calculated by REFCO from batch-levelized costs* using the analysis procedure outlined in Appendix A. For the two "staircase" curves located in the middle of Fig. 17 [800 MW(e) BWR and 860 MW(e) PWR], industry-average price data for U_3O_8, taken from the 1976 ERDA survey of year-by-year delivery contract prices (see Sect. 3.1), was used in combination with the utility refueling information. Appropriate corrections were

*See page 79 for definitions.

made for average lead times between ore purchase and the beginning of the reload cycle. For separative work, the ERDA year-by-year price schedule for requirements type contracts was used. No net charges were applied to back-end fuel disposition, i.e., the breakeven situation described in Sect. 5.1 between reprocessing costs and credits for recovered materials was assumed.

The particular PWR chosen for this example had experienced a premature discharge of the initial core due to fuel clad failures, and this is registered in the calculated fuel cycle economics by a typically high cost for the initial cycle. For subsequent cycles, the PWR and BWR cost differences are rather insignificant.

A detailed breakdown of the component results of fuel cost calculations for the 800 MW(e) BWR is shown in Table 29. The year-by-year component price schedules assumed typical during this time period are listed in Table 28 under the headings labeled "Low" U_3O_8 and "Low" separative work price. The only exceptions to this are the uranium ore prices for 1977 and 1978, which were estimated in the 1976 ERDA price survey to be \$10.10/lb and \$12.20/lb U_3O_8, respectively. Table 29 summarizes the cycle-prorated levelized energy costs for the various fuel cycle components. When an average spent fuel element storage charge of \$125/kgU is assumed to be required for back-end disposition of fuel from the reactor, the cycle-prorated levelized costs would be modified as indicated under the headings labeled "storage" in Table 29. The additional storage charge will have the effect of altering the cycle carrying charges as well as the total cycle levelized costs.

A similar tabular breakdown of the cycle levelized costs for the 860 MW(e) PWR is shown in Table 30. These costs were based upon the component price schedules described above with the exception that the cost information for the first three cycles was supplied by the utility operating the reactor and represents the "actual cost" for those cycles. The table also shows the effects on the cycle prorated levelized costs due to a spent fuel storage charge of \$125/kgU.

Detailed tabular breakdowns of the cycle-prorated levelized cost information for the projected "high" and "low" variant cases for a 1300 MW(e) PWR (1982 startup) are shown in Tables 31 and 32. Table 31

Table 29. Summary of cycle-prorated levelized fuel cycle component costs: 800 MW(e) BWR (1972–1983 startup)

[mills/kWhr(e)]

Operating cycle		U_3O_8	Conversion	Separative duty	Fabrication	Storage[a]	Carrying charges		Total	
Start	End						Base	Storage[a]	Base	Storage[a]
1972.83	1974.97	.502	.072	.361	.525	.733	1.04	.718	2.51	2.91
1975.33	1976.33	.470	.073	.401	.500	.678	1.07	.759	2.56	2.93
1976.33	1977.33	.515	.074	.438	.463	.616	1.18	.874	2.70	3.01
1977.33	1978.33	.513	.078	.522	.469	.585	1.31	.998	2.93	3.21

[a] Base case with an equivalent one-time spent fuel storage charge of $125/kgU.

Table 30. Summary of cycle-prorated levelized fuel cycle component costs: 860 MW(e) PWR (1972–1976 startup)[a]

[mills/kWhr(e)]

Operating cycle		U_3O_8	Conversion	Separative duty	Fabrication	Storage[b]	Carrying charges		Total	
Start	End						Base	Storage[b]	Base	Storage[b]
1972.76	1974.50[c]	.727	.122	.811	.750		.981		3.39	
1974.80	1975.32[c]									
1975.45	1977.04	.416	.065	.786	.473		.657		2.40	
1977.16	1977.90	.556	.083	.945	.478	.561	.898	.751	2.97	3.38
1978.00	1978.90	.631	.087	1.13	.478	.534	1.05	.906	3.39	3.78

[a]Costs for the first three cycles calculated using utility supplied price information.

[b]Base case with an equivalent one-time spent fuel storage charge of $125/kgU.

[c]Typically high costs due to premature fuel discharge.

Table 31. Summary of cycle-prorated levelized fuel cycle component costs: low and high-variant forecasts (1982–1985) (current dollar component costs)

[mills/kWhr(e)]

Year	U_3O_8		Conversion	Separative duty		Fabrication	Carrying charges		Total	
	Low	High		Low	High		Low	High	Low	High
1982	1.98	2.77	.123	1.01	1.46	.877	1.49	1.99	5.50	7.22
1983	1.94	2.76	.117	1.12	1.65	.613	1.74	2.42	5.55	7.56
1984	2.12	3.10	.119	1.23	1.86	.567	1.97	2.78	6.02	8.43
1985	2.34	3.48	.121	1.31	2.03	.583	2.09	2.99	6.45	9.21

Table 32. Summary of cycle-prorated levelized fuel cycle component costs: low and high-variant forecasts (1982–1985)
[constant dollar (1976) component costs][a]

[mills/kWhr(e)]

Year	U_3O_8		Conversion	Separative duty		Fabrication	Carrying charges		Total	
	Low	High		Low	High		Low	High	Low	High
1982	1.52	2.12	.093	.758	1.09	.647	1.13	1.50	4.16	5.46
1983	1.46	2.06	.086	.818	1.20	.443	1.29	1.77	4.10	5.58
1984	1.52	2.22	.084	.861	1.30	.389	1.39	1.96	4.26	5.96
1985	1.58	2.35	.081	.862	1.33	.378	1.38	1.98	4.29	6.14

[a]An overall inflation rate of 6% was assumed in the calculations.

shows the results of the "low" and "high" variant cost calculations, in current dollars, from reactor startup through 1985. The impact of ore and separative work prices on the overall levelized fuel costs for these years is evident. The two cases show levelized fuel cycle costs rising to span the 6 to 9 mills/kWhr range in 1985. In comparison, Table 32 shows the results of both the "low" and "high" variant cases in terms of constant 1976 collars. An overall inflation rate of 6% was assumed in the calculations.

The overall cost trend depicted in Fig. 17 shows levelized fuel cycle costs rising from the 2 1/2 to 3 mills/kWhr level, characteristic of reactors operating in the 1974 to 1976 period, upward to the 6 to 9 mills/kWhr bracket by 1985 (current dollar estimates). The constant dollar ($1976) estimates generally show levelized costs in the 4 to 6 mills/kWhr range by 1985. Once again, it should be pointed out that the cycle-prorated levelized fuel costs were calculated using the "breakeven" backend assumption, and that the costs include both direct and indirect charges. When an annual spent fuel storage charge of $10/kgU is applied, corresponding to a one-time storage cost of $125/kgU, the resultant cycle-prorated levelized costs generally range from 10 to 15% higher than in the breakeven cases, as indicated in Tables 29 and 30.

6. DISCUSSION AND CONCLUSIONS

In this report each step of the nuclear fuel cycle was surveyed and unit costs projected. The FPC accounting procedures used for the fuel cycle were discussed, and methods of calculating nuclear fuel costs were examined. A procedure used by utilities to account for backend fuel cycle costs which assigns a zero net salvage value to discharged fuel and which conforms to FPC accounting procedures was described. The result of the analytical portions of this report is a projection of nuclear fuel costs through 1985. This projection gives a fuel cost (1976 dollars) of from 4 to 6 mills/kWhr.

The intention of this report was to provide a coherent view of the diverse changes now affecting nuclear fuel cycle economics, using the theme of "typical" utility fuel cost experience over the 1970 to 1985 time frame. In contrast to an approach strictly oriented toward constructing a normative model of fuel cycle economics, a mixed descriptive and analytical approach was used here to survey and project costs for each step in the nuclear fuel cycle. This approach should provide some measure of the diversity of factors impacting on fuel cycle costs and therefore give a perspective for evaluating fuel cycle decisions. It should also give enough information to provide a basis for revising nuclear fuel cost projections as new information or data becomes available.

There are at present many uncertainties concerning the future of nuclear power and the fuel cycle cost. Some of these uncertainties have been discussed herein and include uranium ore availability and price; separative work technology and whether expansion will occur in the private or public sector; and whether reprocessing and plutonium recycle will be allowed or if so, if it is economically justifiable. Some of these uncertainties may be resolved in the near future. The economic justification for reprocessing will depend upon the cost of providing an equivalent quantity of U^{235} enriched fuel without reprocessing. Considerable attention has been devoted in this study to a survey of current and projected U_3O_8 prices and separative work costs, the principal charges determining the cost of U^{235} enriched fuel.

Models of nuclear fuel cycle economics pertaining to a longer range time frame must, of necessity, be of a more normative character, i.e., they must assume certain "standard" elements or relationships apply in comparisons, and they must be contingent on no major unaccounted-for developments or hidden parameters influencing their validity. The material described here is rooted in positive commercial experiences within the nuclear industry and should provide useful background in normalizing such cost models and projections.

Appendix A

ANALYTICAL BASIS FOR TIME-DEPENDENT NUCLEAR FUEL COST EVALUATIONS

1. Discounted Cash Flow Analysis for a Fuel Batch

To properly assess the impact of nuclear fuel price escalations on utility fuel cost experience over the next several years, it is necessary to understand the quantitative analytical basis for time-dependent cost allocations. The purpose of this Appendix is to provide a capsule description of this basis. This is done by applying a general theoretical model for time-dependent financial transactions within the utility, viewed as a regulated business enterprise.* The general model is used to develop the discounted cash flow formulas for nuclear fuel cycle costs. The D.C.F. method is widely used for purposes of nuclear fuel bid evaluations and is closely related to the actual utility cost accounting procedures involved in preparing income and balance sheet statements, although it differs in certain respects from these latter procedures. The basic difference, as indicated in Sect. 4 of this report, is that the D.C.F. method enters cash receipts and expenditures according to the actual time they are incurred, whereas cost accounting practices generally disperse investment costs through time according to certain schedules for depreciation or amortization. The method of derivation used here helps exhibit the interrelation between the cost accounting procedures. While the discounted cash flow formulation may at first appear more complex, the method provides a precisely defined reference for relating other procedures applicable to fuel cost calculations, including approximate methods.

In the model considered, there is a flow of "capital" and "current" monetary resources into and out of the enterprise, precisely as the term "cash flow" implies. Thus, referring to the graphical representation in Fig. A.1, these two "parallel" flows of money are linked together in terms

*The derivation in this Appendix follows the theoretical development and notation used in Ref. 64.

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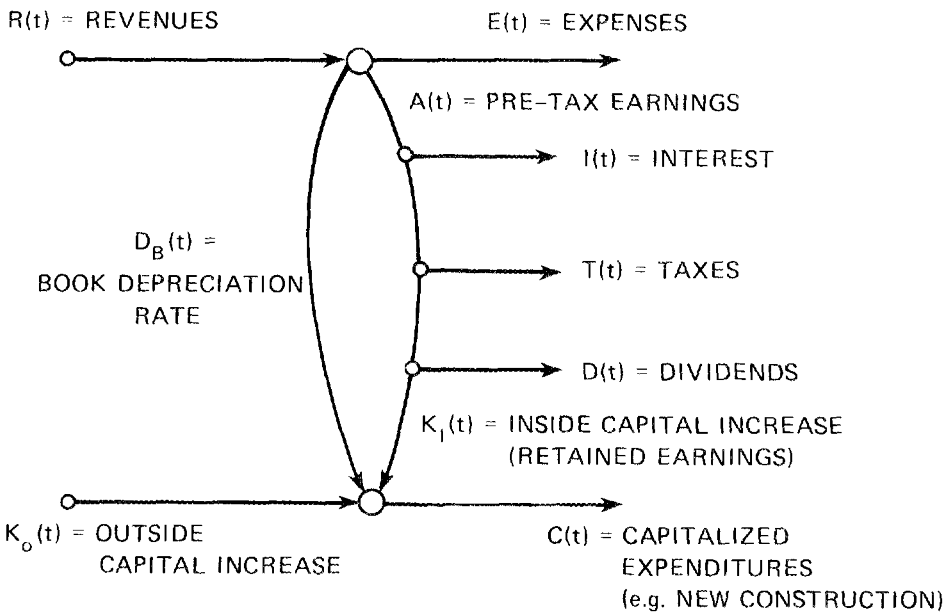

Fig. A.1. Model of utility cash flows.

of the rate of book depreciation or amortization of the capital asset (in this case, nuclear fuel investments). In the first part of this description, we will consider the fuel batch* as the basic "unit" for allocating fuel costs and show later how cycle or annual costs relate to these batch costs.

The production of energy and receipt of revenue from any given fuel batch will generally occur over a time interval spanning several accounting periods. Therefore, the accounting process must properly allocate this revenue to write down all capital investments in the fuel batch, pay all current expenses (i.e., expenses in any period considered to be recovered by revenue received during the same accounting period),† and pay interest on debt, return on equity (dividends plus retained earnings) and taxes.

Two categories of capital input to the utility are distinguished in the model indicated in Fig. A.1. The first, designated by $K_O(t)$, is the net capital accumulated from outside sources through sale of stocks and bonds. (The capital flow, K_O, in Fig. A.1 is the time derivative of this quantity.) The second, designated by K_I, represents net capital acquired from "inside" sources, i.e., through retained earnings. The total capital account level at time, t, is $K(t) = K_O(t) + K_I(t)$.

In Fig. A.1, the monetary flows are defined to be positive in the sense of the arrows. Within a real utility accounting situation, a number of fuel batch investments would be managed simultaneously, and the depreciation component of the revenue stream would generally be applied toward capital expenditures for replacement fuel batches. Thus, the net investment level, K(t), would remain roughly constant, i.e., the corresponding balance sheet account levels would generally fluctuate about some average level (which will gradually increase over time if there are fuel price escalations). It is appropriate to refer to these components as

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*A fuel batch is defined here as a set of fuel elements with a specified initial composition, which are inserted into the reactor on a given date and removed as a group on a later date. The term "region" and "segment" have also been applied in this context.

†The current expense term can be equated to zero in applying this cash flow model to nuclear fuel cycle cost analysis. However, it is retained in the present derivation.

"working capital." However, when following the revenue and cost allocations for energy generated from a specific fuel batch, it is conceptually useful to view the capital flow from outside sources, $\dot{K}_O$, as algebraically negative during energy production, i.e., to allocate D_B to a fictitious "retirement" of stock and bond indebtedness over the economic life of that fuel batch.

In order not to obscure the purposes intended by this discussion, we will include only federal income taxes in the cash flow formulas, noting at the outset that inclusion of state and local taxes requires relatively minor modifications of these formulas. Also, because federal income tax rules allow use of depreciation schedules which differ from the "book" depreciation rate, the depreciation schedule for tax purposes will be denoted by $D_T(t)$.

With these preliminaries, we can sum the cash flows around each node in Fig. A.1 to obtain the following relations:

$$R = E + A + D_B \tag{1}$$

$$C = D_B + \dot{K}_O + \dot{K}_I \tag{2}$$

$$T = \tau(R - E - I - D_T) \tag{3}$$

$$\dot{K}_I + D = A - I - T \tag{4}$$

In these equations, τ is the federal income tax rate, and all other quantities are defined in Fig. A.1. The revenue, R, must be sufficient to cover all costs including current expenses, taxes, interest, and return on equity. In the particular financial model used here, it is assumed that a specified fraction, b, of the total capital obligation at time, t, is in the form of bond indebtedness, calculated at a continuous interest rate, i. The remaining fraction, $(1 - b)$, is assumed to represent a mix of common and preferred stock equity, which has an average rate-of-return, r. This rate may be defined by setting the after-tax earnings, given by Eq. (4), equal to $r(1 - b)K(t)$, while the interest term, I, is set equal to ibK. Thus, Eqs. (1), (3), and (4) may be combined as follows:

$$R = E + D_B + (A - I - T) + I + T \;, \qquad (5)$$
$$= E + D_B + ibK + \tau(R - E - D_T - ibK) + r(1 - b)K \;.$$

Solving for R gives the revenue stream required to recover all direct costs, financing charges, and taxes,

$$R = \frac{E + D_B + \hat{i}K - \tau(E + D_T)}{1 - \tau} \;, \qquad (6)$$

where,

$$\hat{i} \equiv b(1 - \tau)i + (1 - b)r \;. \qquad (7)$$

The revenue, R(t), which by definition is the product of the unit energy cost and the generation rate, Q(t), therefore depends implicitly on the time variation of the capital account level, K(t). This implicit dependence can be eliminated by combining Eq. (6) with the integrated form of the capital flow equation (2). In particular, we wish to determine the explicit form of K(t) which will "levelize" the price of energy over all expenditures required for any given batch (or combination of batches).

Before completing this derivation, one caveat needs to be considered, relating to the fact that utility practice in nuclear fuel cost accounting allows financing charges in payments made prior to irradiation to be treated as "interest during construction." Within the framework of the present model, this procedure may be rationalized by noting from Eqs. (1) through (4) that, prior to generation of energy and receipt of revenue from fuel uses, there are no net pre-tax earnings, the book depreciation rate, D_B, is zero, and no tax dispersements occur. Then, if all financing charges are in the form of interest payments on debt calculated at the rate, i^* (which may differ from i), then the applicable form of Eq. (2) is,†

†Note that $\dot{K}_I$ must be set equal to zero in applying the cash flow model to this situation in order to prevent outside sources of capital from being "disinvested" into current interest payments.

$$\dot{K} = \dot{K}_o = I + C , \qquad (8)$$
$$= i^*K + C .$$

If t_o is defined to be the time of insertion of the fuel batch into the reactor and t_L is the lead interval during which pre-irradiation payments are made, then the integrated form of Eq. (8) is,

$$K(t_o) = \int_{t_o - t_L}^{t_o} e^{i^*(t_o - t)} C(t)dt , \qquad (9)$$

where C(t) is the actual schedule of pre-irradiation expenditures for the fuel batch in question. The interest payments are thus capitalized to obtain the total investment level at start-of-irradiation.

For the in-core and post-irradiation stages of the fuel cycle, Eq. (2) may be applied directly. Multiplying the equation by $e^{-\hat{i}t}$ and integrating from t_o to a variable time point, t_1, gives;

$$\int_{t_o}^{t_1} e^{-\hat{i}t}\dot{K}dt = K(t_1)e^{-\hat{i}t_1} - K(t_o)e^{-\hat{i}t_o} + \int_{t_o}^{t_1} e^{-\hat{i}t}\hat{i}K(t)dt ,$$
$$= \int_{t_o}^{t_1} e^{-\hat{i}t}D_B(t)dt + \int_{t_o}^{t_1} e^{-\hat{i}t}C(t)dt , \qquad (10)$$

where the first step follows from integration by parts. Solving Eq. (6) for $\hat{i}K$ and substituting the result in Eq. (10) gives,

$$K(t_o)e^{-\hat{i}t_o} - K(t_1)e^{-\hat{i}t_1} + \int_{t_o}^{t_1} e^{-\hat{i}t}C(t)dt$$

$$= \int_{t_o}^{t_1} e^{-\hat{i}t} \left\{D_B + [R - E - D_B - \tau(R - E - D_T)]\right\}dt \ . \tag{11}$$

Equation (11) is a formulation of the discounted cash flow condition relating the time schedule of capital expenditures to the revenue required to recover these costs. The factor, $e^{-\hat{i}t}$, is the present worth factor for the continuous discounting model. Note that this formulation follows the definition generally found in engineering economics textbooks, wherein cash flow is defined as the sum of book depreciation, D_B, and the quantity $R - E - D_B - \tau(R - E - D_T)$, the after-tax return on total investment (including bond indenture). Also, note that D_B formally cancels from this expression, so that there is no need to explicitly calculate depreciation or amortization, except for tax purposes.

Upon substituting $R = \overline{P}_b Q(t)$ into Eq. (11), where $\overline{P}_b$ is defined as the levelized unit cost for the fuel batch, we can solve for $\overline{P}_b$;

$$\overline{P}_b = \frac{K(t_o)e^{-\hat{i}t_o} - K(t_1)e^{-\hat{i}t_1} + \int_{t_o}^{t_1} e^{-\hat{i}t}C(t)dt + \int_{t_o}^{t_1} e^{-\hat{i}t}[E - \tau(E + D_T)]dt \ .}{(1 - \tau)\int_{t_o}^{t_1} e^{-\hat{i}t}Q(t)dt} \tag{12}$$

This expression relates the levelized unit cost to the schedule of expenditures, tax credits, and the remaining investment, $K(t_1)$. The particular levelized cost of interest is that which reduces $K(t_1)$ to zero at the end of the economic lifetime of the fuel batch. In view of the significance of post-irradiation expenditures for any batch, it is necessary to make this "economic lifetime" concept more precise.

As written, Eq. (12) is a general expression which applies to any schedule of payments or credits, whether made prior to irradiation, in-core, or in the post-irradiation period. The levelized fuel costs may thus be determined on a component by component basis (e.g., U_3O_8 procurement, enrichment, . . ., reprocessing, etc.). In the case of front-end (pre-irradiation) components, the magnitude of the costs are governed by the capitalized account levels at start-of-irradiation, $K(t_o)$. To interpret the levelized cost components associated with back-end (post-irradiation) payments, it is instructive to break the calculation into two stages, showing the relationship between the accumulation of revenue, changes in capital account levels, and expenditures.

Assume that post-irradiation payments are made over a time interval, t_ℓ, following removal of the batch from the reactor. Let t_b be the time that the fuel batch resides in-core. Since the post-irradiation payments must be covered by revenue received from prior sale of the batch energy, the capital account level for these components builds up in a negative manner, starting at $K(t_o) = 0$. That is, within the logic of this cash flow model, this is equivalent to cash on hand which could temporarily displace capital from outside sources needed to cover expenditures for other fuel batches. In this model, we assume that the effective rate-of-return on this displaced investment is also $\hat{i}$. This return is therefore also equivalent to a displacement of financing charges, relative to the overall fuel investment. Equation (11) may then be applied to calculate the capital account level during the batch irradiation period, $t_o \leq t_1 \leq t_o + t_b$;

$$K(t_1)e^{-\hat{i}t_1} = -(1 - \tau)\int_{t_o}^{t_1} e^{-\hat{i}t}R\,dt + \int_{t_o}^{t_1} e^{-\hat{i}t}\,[E - \tau(E + D_T)]\,dt\ , \quad (13)$$

since the payment schedule, $C(t)$, is assumed to be zero in this interval. For the post-irradiation interval $(t_o + t_b \leq t_1 \leq t_o + t_b + t_\ell)$, R is zero since no additional revenue is received from energy produced by this fuel batch. At the end of the payment period, the expenditures, $C(t)$, must reduce the capital account level to zero. A similar application of Eq. (11) to this interval then gives,

$$K(t_o + t_b)e^{-\hat{i}(t_o + t_b)} = -\int_{t_o + t_b}^{t_o + t_b + t_\ell} e^{-\hat{i}t} C(t)dt - \int_{t_o + t_b}^{t_o + t_b + t_\ell} e^{-\hat{i}t}[E - \tau(E + D_T)]dt \ , \tag{14}$$

where we have set $K(t_o + t_b + t_\ell) = 0$.
On setting $t_1 = t_o + t_b$ in Eq. (13) and eliminating $K(t_o + t_b)$ between the (13) and (14), we obtain for all post-irradiation payments;

$$(1 - \tau)\int_{t_o}^{t_o + t_b} e^{-\hat{i}t} R(t)dt = \int_{t_o + t_b}^{t_o + t_b + t_\ell} e^{-\hat{i}t} C(t)dt + \int_{t_o}^{t_o + t_b + t_\ell} e^{-\hat{i}t}[E - \tau(E + D_T)]dt \ ,$$

or,

$$\bar{P}_b = \frac{\displaystyle\int_{t_o + t_b}^{t_o + t_b + t_\ell} e^{-\hat{i}t} C(t)dt + \int_{t_o}^{t_o + t_b + t_\ell} e^{-\hat{i}t} [E - \tau(E + D_T)]dt}{\displaystyle(1 - \tau)\int_{t_o}^{t_o + t_b} e^{-\hat{i}t} Q(t)dt} \qquad (15)$$

Note that this result is the same as that of applying Eq. (11) directly to the entire interval, including the post-irradiation payment period. This demonstrates rigorously that post-irradiation payments can be discounted back to the time of batch removal from the reactor, and this discounted value then used to calculate the levelized fuel cost.

For the special case of a uniform rate of expenditure during the pre- and post-irradiation periods, a schematic representation of the buildup and write-down of the appropriate capital account levels is shown in Fig. A.2. If credits are received for materials recovered in reprocessing, these credits also need to be allocated to the revenue producing period. Equations (13) to (15) can be applied by interpreting credits as negative expenditures. In this case, the credit component is equivalent to a displacement of revenue requirements, and the corresponding theoretical capital account buildup would be positive at the intermediate time, t_1.

Except for the fact that a continuous discounting model was used, the formulas derived above are equivalent to the levelized cost equations developed and applied in a number of computer programs for fuel cost analysis. (The REFCO program applied in this study uses continuous discounting.) In the discreet model, the receipt of revenue is usually allocated to the end of each accounting interval, cash payments are assumed to occur at the start of an interval, and discreet interest compounding is used, equivalent to expressing the capital flow Eq. (2) as a finite difference equation. The derivation in Ref. 64 also takes account of state and local taxes and insurance; however, no basic concepts are required other than those discussed above.

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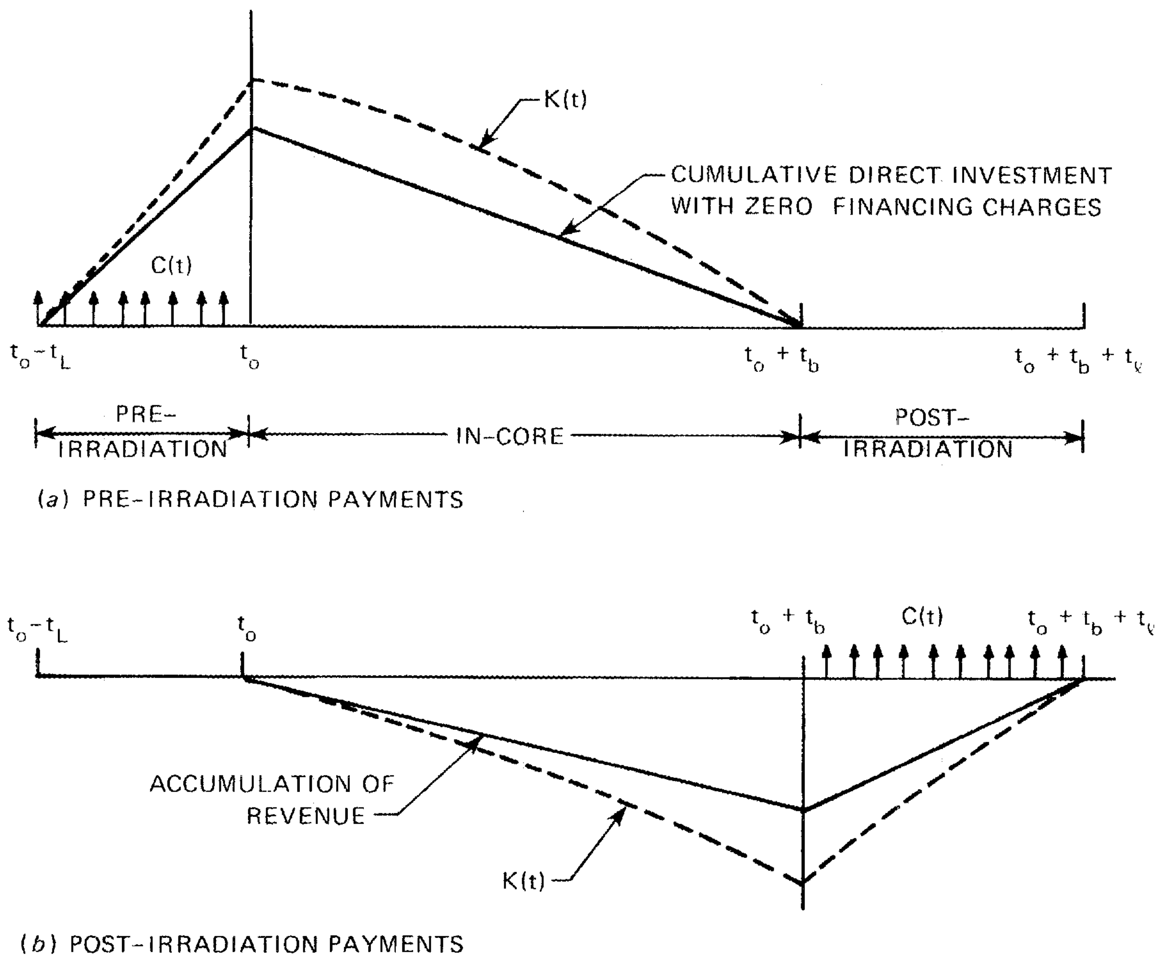

Fig. A.2. Schematic representation of account level changes in discounted cash flow analysis.

2. Relation Between Batch and Cycle-Levelized Costs

The discounted cash flow formulas given in the preceding section may be applied to a single fuel batch or to a specific sequence of fuel batches. In the latter case, the result is a cumulative levelized cost applying to the total energy produced from the sequence. The main requirement in applying the previous formulas is to utilize discount factors appropriate to a single time scale; that is, for all batches beyond the first of the sequence, discount factors for all payments, credits, energy production, and revenue receipt must be expressed relative to a single origin of time. It is then quite easy to demonstrate that Eq. (12) can be applied recursively, i.e., the cumulative levelized cost for a sequence of n + 1 batches can be calculated from the cumulative levelized cost for the n-batch sequence and the levelized cost for batch n + 1. This procedure is incorporated into the REFCO program, applied for this study.

Equations (11) and (12) can also be used to calculate a cycle-levelized cost, by properly attending to the time sequences of loadings and discharges for each batch present during that cycle. To illustrate, assume that all batches are loaded in tandem and remain in the reactor for n reload cycles. Suppose, furthermore, that the refueling cycles are of uniform length, t_c ($t_b = nt_c$). By definition, to calculate a levelized cost, $\overline{P}_{cj}$, for the j(th) reload cycle, we must sum the discounted revenue streams obtained for each batch irradiated in the cycle and divide by the sum of the discounted batch energies produced in that cycle,

$$\overline{P}_{cj} = \frac{\displaystyle\sum_{k\varepsilon j} \int_{t_j}^{t_j + t_c} e^{-\hat{i}t}\overline{P}_{bk} Q_{bk}(t)dt}{\displaystyle\sum_{k\varepsilon j} \int_{t_j}^{t_j + t_c} e^{-\hat{i}t} Q_{bk}(t)dt} , \qquad (16)$$

where $\overline{P}_{bk}$ is the batch-levelized cost for the batch inserted at $t = t_k$, $Q_{bk}(t)$ is the energy generation rate from that batch, and $k \epsilon j$ indicates that the sum is taken over all batches k present during cycle j. (Note that, if energy generation rates for all batches remain constant during the cycle, the discount factor may be omitted from this calculation.)

For the batch inserted at $t = t_k$, the batch-levelized cost is determined by Eq. (12);

$$\overline{P}_{bk} = \frac{K_k e^{-\hat{i}t_k} + \int_{t_k}^{t_k + nt_c + t_\ell} e^{-\hat{i}t}[C_k + E_k - \tau(E_k + D_{Tk})]dt}{(1 - \tau)\int_{t_k}^{t_k + ntc} e^{-\hat{i}t} Q_{bk}(t)dt} , \qquad (17)$$

where, e.g., K_k is the capitalized investment for that batch at the start of irradiation and other quantities are defined accordingly. In Eq. (16) the sum over $k \epsilon j$ will be taken over batches for which $t_k = t_j$, $t_j - t_c$, $t_j - 2t_c$, . . ., $tj - (n - 1)tc$, or in general $t_k = t_j - mt_c$, where $m = o$, 1, 2, . . ., $n - 1$.

In addition to a levelized cost for each reload cycle, the above analysis may also be extended to calculate a cumulative levelized cost for any sequence of reload cycles. Similar to batch sequences, this can also be performed in a recursive manner. Although explicit derivation will be omitted here, this calculation has also been incorporated into the REFCO program.

Appendix B

SURVEY OF NUCLEAR FUEL CYCLE COST CODES

During the course of our study, we investigated the principal features of several nuclear fuel cycle cost analysis codes that were developed and are being used by various installations within the nuclear industry. To provide some perspective for evaluating the REFCO program, brief descriptions of the fundamental logic and calculational methods used in three of these codes, CINCAS, FUELCOST-IV, and PACTOLUS, are presented in this Appendix.[55,54,57] Although numerous other fuel cost analysis programs are available, these three codes, along with the description of the REFCO program (outlined in Sect. 4 and described in greater detail in Appendix A), provide a good overall survey of fuel cost programs currently being used within the nuclear industry.

1. CINCAS

CINCAS is a nuclear fuel cycle cost code which may be used for either engineering economy predictions of fuel cycle costs or for accounting-forecasting of such costs. The code was developed through cooperation of representatives of the Commonwealth Edison Company, Iowa-Illinois Gas and Electric Company, Northern States Power Company, Consumers Power Company, Arthur Anderson and Company, and Sargent and Lundy, Engineers. CINCAS may be used to calculate: (1) dollar costs and mass inventory on a batch and case basis, (2) variable monthly batch heat production rates and plant efficiencies, (3) present-worthed or straight cash flows over a specified time interval, (4) types and amounts of uranium progress payments, (5) fuel material cost allocation either on an actual value or straight line unit of production basis, and (6) escalation of fabrication progress payments due to labor and material price increases, and a number of other user specified calculations.

CINCAS calculates fuel costs for each month of a period, specified by the user, which usually begins with the arrival of a fuel batch at the reactor site and ends with the withdrawal of the batch from the reactor. Pre-irradiation costs incurred as uranium and fabrication progress payments for the batch are treated as interest during construction and are assigned to beginning inventory values, while post-irradiation expense is allocated to the irradiation period in accordance with the burnup experienced during each month of the irradiation period. All costs incurred by the batch are assigned to one or more cost categories or accounts. CINCAS has six direct or expense cost categories, namely, uranium, plutonium credit, fabrication, shipping, reprocessing, and reconversion, and four inventory cost categories, uranium, plutonium, fabrication, and post-irradiation. The direct costs are allocated to each month in proportion to the fission heat produced during the month. The inventory costs are obtained by applying an appropriate interest rate to the average monthly inventory value.

The direct and inventory costs associated with the enriched uranium and plutonium in the fuel are calculated using one of two methods: (1) the actual value method, or (2) the straight line unit of production method. In the first case, the actual value method, the value of the uranium is taken as the value of the actual amount of uranium existing in the batch, as determined by the market price of virgin (nonrecycled) uranium of the same enrichment. The value of plutonium in the batch is taken as the value of the actual amount of plutonium at the selling price expected when the plutonium is finally recovered. For the straight line method, the total change in value of the uranium and of the plutonium is taken to be the difference between the values at startup and discharge. A fraction of this change is allocated to each month of in-core time in proportion to the fraction of total burnup experienced during that month. In both methods, adjustments are made to allow for salvage losses and for the capitalized interest charges on the uranium progress payments. Inventory charges are based on the midmonth value of the fuel with allowances made for salvage costs.

2. FUELCOST-IV

FUELCOST-IV is a computer program developed to compute nuclear fuel costs for light water reactors, high-temperature gas-cooled reactors, and fast breeder reactors. The code is a generalized extension of several earlier and more specialized versions of FUELCOST that were developed wholly or in part by NUS Corporation. the FUELCOST-IV program may be used for: (1) comparative economic evaluations of different types of LWR, LMFBR, or HTGR reactors, (2) bid evaluations between these reactor types, (3) evaluations of fuel offers, including plutonium recycle in LWRs, (4) computations of economic consequences of various core management schemes, (5) computation of effect on fuel cost of various operating decisions, such as changes in capacity factor, (6) sensitivity studies for changes in various materials and process costs (such as the price of U_3O_8), and (7) determination of nuclear fuel costs in fossil versus nuclear studies.

The code computes fuel costs by batch for each of five basic cost components, namely, uranium, plutonium, fabrication, shipping, and reprocessing. These batch costs are combined by component into fuel costs and working capital requirements for each reactor cycle, and are summarized for any specified accounting interval by type of fuel assembly as well as by total reactor, which includes all types of fuel assemblies present. The code accepts any desired time sequence of plant capacity factors, heat rates, basic fuel material and process costs by assembly type, fuel cycle lead and lag time, and any sequence of batch refueling, including holdout and reinsertion. FUELCOST-IV treats each batch as an independent entity and calculates all cost quantities from the input parameters, and these costs are then combined into cycle and accounting interval values. The program user also has the option of specifying pre-reactor, in-core, and post-reactor interest rates for each cost component of each batch.

FUELCOST-IV, which uses a revenue requirements method of computing nuclear fuel costs, determines the unit charges, on a per unit of fuel mass or per unit of energy production basis, which must be recovered during the production of energy in order to exactly meet all fuel expenditures. These expenditures can be either the direct expenditures for fuel materials processes, and services, or the direct plus indirect expenditures covering interest charges on working capital invested in the fuel. When only the direct expenditures are considered, FUELCOST-IV uses a procedure called the Utility Accounting Method for determining revenue requirements, and uses a second procedure called the Accrual/Discount Method when both direct plus indirect expenditures are considered. Basically, the Utility Accounting Method for determining fuel costs is the same as the Accrual/Discount Method, except that all interest rates are set equal to zero. There are no accrued or discounted values as in the Accrual/Discount Method, so the working capital balances at the beginning of energy production represent the exact amounts paid for initial uranium, plutonium, and fabrication. Likewise, the working capital balances at the end of energy production represent the exact amounts to be received from final uranium and plutonium credits, and the amounts needed for spent-fuel shipping and reprocessing. On the other hand, in the Accrual/Discount Method, as payments are made for various nuclear materials and processes in the fuel cycle prior to the production of energy (U_3O_8 purchase, conversion, enrichment, and fabrication), an accumulation of investments occurs. The post-reactor costs and credits are assumed to be paid in lump-sums without progress payments at specified times after batch removal. The pre-reactor costs are accrued with an interest rate until the date the batch is inserted in the reactor and starts producing energy, while the post-reactor costs and credits are discounted with an interest rate from the time at which they actually occur to the end of energy production.

3. PACTOLUS

PACTOLUS is a computer code developed by Battelle-Northwest Laboratories for computing nuclear power costs. The program calculates the cash flows for the entire life of a nuclear project, and determines the revenues and the unit cost of power required to earn a specified return on investment. Although developed primarily for computing the costs and material flows associated with nuclear power plants, PACTOLUS can be used to calculate the power costs of fossil-fueled plants. Employing a discounted cash flow procedure, the program (1) transforms reactor investment, operating data, and fuel cycle cost and time information into material and cash flow schedules, (2) calculates taxes, and (3) transmits this information for use in a computer model of the U.S. electrical power economy.

PACTOLUS is built upon the following logic: (1) capital investments, including interim capital replacements, are simply entered as cash outlays at the time incurred, (2) salvage values and recoverable investments are credited at the time and value received, and (3) nondepreciable investments are treated as cash outlays at the beginning of the project, or cash receipts at the end. The user has the option of using either a straight-line or sum-of-the-years digits method for calculating depreciation, and has several options regarding the type of bond repayment, including uniform principal reduction, uniform annual payment, delayed uniform principal reduction, and/or simple proportional repayment. The code will accept a variable load factor scheme and will calculate an optimum tails concentration for gaseous diffusion plant operation.

Appendix C

MODIFICATIONS AND ADDITIONS TO REFCO

To make the REFCO fuel cycle cost program more flexible and comprehensive, several modifications and additions were made to the original version of the code, as documented in ORNL-TM-3709.[56] These modifications included some minor changes in input and output variables as well as the addition of several options that required changes in the program logic. A basic description of the major changes made to the code follows along with a user's manual that describes the procedures required and options available for using the current version of the program.

1. General Modifications

Several minor revisions to the code were made to include the following features:

1. Separate treatment of U_3O_8 and conversion to UF_6; this includes separate lead times, unit prices, and escalation rates.
2. Provision for variable tails assay; the tails assay is now a function of batch number as well as fuel type.
3. Additional breakdown of escalation rates; separate escalation rates may be applied to each component cost of the fuel cycle.

2. Calculation of Cycle Lengths from Input Capacity Factors

This option may be used to calculate absolute cycle lengths based on input of average capacity factors and plant capacity ratings. It may also be used for calculations involving system-aggregated reactor data. The program combines the input data on capacity factors and maximum generating capacity, which is entered on a cycle-by-cycle basis, with fuel burnup data in the following manner to calculate cycle lengths:

$$CL(NP) = \frac{\sum_{\substack{\text{all NB} \\ \text{in NP}}} MWD\ (NB) * F\ (NB,NP)}{365.* MWTH\ (NP) * CF\ (NP)}$$

where CL(NP) = length of cycle NP.

MWD(NB) = burnup of batch NB.

F(NB,NP) = fraction of thermal energy from batch NB produced in cycle NP.

MWTH(NP) = plant thermal capacity.

CF(NP) = capacity factor corresponding to cycle NP.

Once the actual cycle lengths have been calculated, the program logic simplifies the results by modifying these lengths to the nearest multiple of tenth years, and finally recalculates a slightly altered set of capacity factors using the "rounded" cycle lengths.

3. Calculation of a Breakeven Value for Reprocessing

This option may be used for calculating a breakeven composite charge for transportation, reprocessing, and waste disposal, based upon the interpolated market value of uranium and plutonium recoverable from each batch. If a unit reprocessing charge is set equal to zero, the program calculates a charge that will just equal the direct sales credits for plutonium sale, uranium ore credit, and separative work credits recovered from each batch. This is expressed by the following relation:

$$\begin{aligned} EXPDIR\ (NB,6) = {} & EXPDIR\ (NB,7) + EXPDIR\ (NB,8) \\ & + EXPDIR\ (NB,9) \end{aligned}$$

where EXPDIR (NB,K) is the direct expense for batch NB and process K, and where the K = 7, 8, 9 indices correspond to plutonium sale, uranium ore credit, and uranium separative work credit, respectively.

4. Calculation of a Time-Dependent Plutonium Parity Value

This addition to the REFCO program provides the user with the option of calculating a plutonium "sale value" which is just sufficient to offset any cost penalties associated with UO_2 fueling plus plutonium stockpiling, compared with U/Pu recycle. This modification follows the logic described in Ref. 65. The procedure involves the following basic steps.

1. For a slightly-enriched UO_2 fueling mode, calculate the time-dependent cycle and cumulative levelized costs (levelized between reactor startup and the end of successive load cycles), following the normal logic of the REFCO program. Here, recovered uranium is credited in accord with the equivalent amounts of feed and separative duty and their prices forecasted for that time period; however, no sales value or credit is assigned to the recovered plutonium.

2. Calculate the modified time-dependent cycle and cumulative levelized costs for a self-generated Pu-recycle mode. Here, it is assumed that all plutonium recovered from successive batches is refabricated and returned to the reactor core. The modified cumulative cost schedule or "target cost" [TGTCUM(NP)] will be lower by the effect of any net difference between the value of displaced UO_2 and the penalty for fabricating mixed-oxides elements. Again, no internal (inventory) value is assigned to plutonium for this analysis.

3. Under the UO_2 fueling mode used in step (1), recovered plutonium batches are now assumed to be stockpiled until the end of any designated cycle, at which time the cumulative amount is sold and credit allocated to the cumulative energy produced, using appropriate present-worth formulas. A new subroutine (PLUVAL) then calculates a unit sales value or "price" necessary to equate the cumulative fuel cost schedule under UO_2 fueling with the target cost schedule derived for U/Pu recycle.

To use the plutonium parity value option, the program user must input the target cumulative fuel costs, TGTCUM(NP), for each period NP, along with the plutonium storage costs, RSTG(K), in units of $/kg-Pu/year. There are basically three sets of parameters that must then be calculated before subroutine PLUVAL can be called. The first two are: (1) the individual amounts of plutonium recovered from each batch of fuel, and

(2) the times, relative to reactor startup, that the recovered plutonium becomes potentially available for sale. Finally, the interval, from the time the plutonium is made available to the time it is actually sold, must be calculated. As noted earlier, the plutonium recovered from each batch is assumed to be stored for a period of time, and eventually sold "in a lump." Subroutine PLUVAL then uses this information to calculate a time-dependent plutonium parity value. A brief outline of the basic logic used in developing PLUVAL and a FORTRAN listing of the routine follows.

The target cumulative costs, which are input to REFCO, are equated to the cycle cumulative costs that are corrected to account for two additional terms: (1) plutonium sales credits and (2) plutonium storage costs. Each of these two corrections terms can be further broken down into (a) cash expenditure, and (b) tax credit components. This can be written in the following form,

$$\text{TGTCUM (NP)} = \frac{\text{CYTOP2}'}{\text{CYBOT2}}$$

where CYTOP2′ is the modified cumulative prorated present-worthed expense and CYBOT2 is the present-worthed energy generation. Then, CYTOP2′ may be written as,

$$\text{CYTOP2}' = \text{CYTOP2} + C_1 + C_2$$

where CYTOP2 is the cumulative prorated present-worthed expense, and where C_1 represents the correction term for plutonium sales and C_2 represents the storage costs correction term. After some manipulation, these two terms may be defined as follows:

$$C_1 = -\frac{1}{1-T}\begin{bmatrix}\text{Total Present-Worthed}\\ \text{Sales Credit}\end{bmatrix} + \frac{T}{1-T}\begin{bmatrix}\text{Total Present-Worthed}\\ \text{Tax-Deductible}\\ \text{Sales Credit}\end{bmatrix}$$

C_2 = cumulative present worthed storage cost at period NP.

where T is the federal income tax rate.

After applying appropriate uniform present-worth factors, these terms can be combined and finally the unit value of plutonium, VALPU(NP), for cycle NP, can be calculated:

$$\mathrm{VALPU(NP)} = \frac{\mathrm{TGTCUM(NP)} * \mathrm{CYBOT2} - \mathrm{CYTOP2} - \mathrm{STGCST(NP)}}{-\frac{1}{1-T}\left[\mathrm{SALPU(NP)} * \mathrm{EXP(-GTB)}\right] + \frac{T}{1-T}\left[\frac{\mathrm{SALPU(NP)} * \mathrm{CYBOT2}}{\mathrm{CUMKWH}}\right]}$$

where STGCST(NP) = cumulative present-worthed storage cost at period NP.

SALPU(NP) = total amount of plutonium available for sale at NP.

CUMKWH = total kWhr produced in all periods up to NP.

EXP(—GTB) = present worth factor for a discrete expenditure (or credit) at time of plutonium sale.

FORTRAN Listing of Subroutine PLUVAL

```
      COMMON LCA,XT(120)
      COMMON LL(14),DES(13),D(35),TLEAD(70,10),PRICE(120,10)
      COMMON G,XF,PWEXPS,TXRE,TXPM,PWEXPA,CORE,RRA,PPV
      COMMON    NBMAX,NTMAX,NPMAX,NYMAX,NPRICE,NYCOST,YRSTRT
      COMMON PFW(500),CURA(500),CFAB(500),CREP(500),CPLU(500),KMAX
      COMMON CHPU(120),CHFPU(120),NTYPE(120),BLVCST(120),
     1 BLV2(120),EXPDIR(120,9),NTA(120),NTB(120),CHU(120),CH235(120),
     2 DSU(120),DS235(120),DSPU(120),DSFPU(120),TIME(120),PWF(120),
     3 NPA(120),NPB(120),DEDUC(120),TOTKWH(120),BCOST(120),NAA(120),
     4NBB(120),BKWH(120,40),BTOKWH(120),BBUY(120),PWBEXP(120),BDUC(120)
      COMMON/PCALC/PTOP(40),PBOT(40),TGTCUM(120),RSTG(120),TPU(120),AVPL
     1U(120)
      DIMENSION VTOP(40),VBOT1(40),VBOT2(40),VBOT3(40)
      DIMENSION STGCST(40),STGPWF(120),SALPU(40),VALPU(40)
      DIMENSION NTMA(40),NTMB(40)
      DIMENSION PWDTC(40),PWSC(40)
C
C-----SUBROUTINE PLUVAL CALCULATES A PLUTONIUM "SALES VALUE" USING
C-----A CUMULATIVE LEVELIZED COST METHOD.  ALL PU AVAILABLE AT THE
C-----END OF PERIOD NP IS SOLD IN A LUMP, WITH A UNIFORM RATE OF
C-----STORAGE PAID ON THE PU FROM TIME OF AVAILABILITY TO TIME OF SALE.
C
C-----PWFCN IS THE UNIFORM PRESENT WORTH FACTOR
      PWFCN(GTA,GTB)=(EXP(-GTA)-EXP(-GTB))/(GTB-GTA)
      DO 100 NP=1,NPMAX
      VALPU(NP)=0.0
      PWDTC(NP)=0.0
      PWSC(NP)=0.0
      STGCST(NP)=0.0
      SALPU(NP)=0.0
      TGTCUM(NP)=TGTCUM(NP)/1000.0
      PTOP(NP)=PTOP(NP)*1.0E+06
      TOTKWH(NP)=TOTKWH(NP)*1.0E+09
      PBOT(NP)=PBOT(NP)*1.0E+09
      NTMA(NP)=2*NP-1
  100 NTMB(NP)=NTMA(NP)+1
      DO 150 K=1,120
  150 RSTG(K)=PRICE(K,10)
      X1=D(7)
      X2=1.0-D(7)
      X3=X1/X2
C-----ROUTINE FOR CALCULATING STGCST(NP) AND SALPU(NP);
C-----STGCST(NP)= THE CUMULATIVE PRESENT-WORTHED STORAGE COST AT NP.
C-----SALPU(NP)= THE TOTAL KG'S OF PU AVAILABLE FOR SALE AT PERIOD NP.
      DO 275 NP=1,NPMAX
      TP=TIME(NTMB(NP))
      DO 275 NB=1,NBMAX
      TB=TPU(NB)
      IF(TB.LE.TP) GO TO 250
      GO TO 275
  250 GTA=G*TB
      GTB=G*TP
      STGPWF(NB)=PWFCN(GTA,GTB)
      NYZ=1+TIME(NTB(NB))
      TNY=YRSTRT-NYCOST+TB+1.0
      IF(TNY.LT.1.0) TNY=1.0
```

```
      NY=TNY
      ZPRICE=RSTG(NY)+(TNY-NY)*(RSTG(NY+1)-RSTG(NY))
      STGCST(NP)=STGCST(NP)+AVPLU(NB)*STGPWF(NB)*ZPRICE*(TIME(NTMB(NP))-
     1TPU(NB))
      SALPU(NP)=SALPU(NP)+AVPLU(NB)
  275 CONTINUE
C-----ROUTINE FOR CALCULATING VALPU(NP), PWDTC(NP), AND PWSC(NP);
C-----VALPU(NP)= THE UNIT VALUE ($/KG) OF PU SOLD AT PERIOD NP.
C-----PWDTC(NP)= TOTAL PRESENT-WORTH DEDUCTIBLE TAX CREDITS.
C-----PWSC(NP)= TOTAL PRESENT-WORTH SALES CREDITS.
      CUMKWH=0.0
      DO 300 NP=1,NPMAX
      GTB=G*TIME(NTMB(NP))
      CUMKWH=CUMKWH+TOTKWH(NP)
      VTOP(NP)=TGTCUM(NP)*PBOT(NP)-PTOP(NP)-STGCST(NP)
      VBOT1(NP)=SALPU(NP)*EXP(-GTB)
      VBOT2(NP)=SALPU(NP)*PBOT(NP)/CUMKWH
      VBOT3(NP)=(-VBOT1(NP)/X2)+X3*VBOT2(NP)
      IF(VBOT3(NP).EQ.0.0) GO TO 300
      VALPU(NP)=VTOP(NP)/VBOT3(NP)
      PWDTC(NP)=VALPU(NP)*SALPU(NP)*PBOT(NP)/CUMKWH
      PWSC(NP)=VALPU(NP)*SALPU(NP)*EXP(-GTB)
  300 CONTINUE
      WRITE(6,500)
      WRITE(6,502)
      WRITE(6,504)
      DO 325 NP=1,NPMAX
      TP=TIME(NTMB(NP))+YRSTRT
      WRITE(6,506)NP,TP,SALPU(NP),TGTCUM(NP),PWDTC(NP),PWSC(NP),STGCST(N
     1P),VALPU(NP),NP
  325 CONTINUE
  500 FORMAT(1H1,35X,'RESULTS OF PLUTONIUM PARITY-VALUE CALCULATIONS',//
     1/)
  502 FORMAT(26X,'KG-S PU',5X,'TARGET',8X,'PW DED',7X,'PW SALES',5X,'PW
     1STORAGE',5X,'PU VALUE')
  504 FORMAT(5X,'PERIOD',6X,'YEAR',6X,'SOLD',6X,'FUEL COST',4X,'TAX CRED
     1IT',6X,'CREDIT',9X,'COST',9X,'($/KG)',6X,'PERIOD',/)
  506 FORMAT(7X,I2,6X,F7.2,4X,F7.2,4X,1PE9.2,4X,1PE9.2,5X,1PE9.2,5X,1PE9
     1.2,5X,1PE9.2,7X,I2)
      STOP
      END
```

5. Input Instructions for the REFCO Fuel Cycle Code

This section contains a card by card description and explanation of the input data required for the REFCO code.

The order of the input data cards is as follows:

Card 1. — This card contains the control signals LL(1) through LL(14), and the problem title DES(I), I = 1,13. Format is 14I2, 13A4. The control signals LL(K) are defined as follows:

If LL(1) = 0, prices are supplied as a function of the year of procurement with linear interpolation for fractions of a year. If LL(1) = 1, it is the same as 0 with no linear interpolation. If LL(1) = 2, prices are supplied as a function of batch.

If LL(2) = 0, deductible expense is collected by batches and prorated to each operating period on the basis of the energy produced by a given batch in that period. If LL(2) = 1, deductible expense is collected over the entire reactor history and prorated to each period on the basis of the energy produced in that period.

If LL(3) = 0, costs are calculated in mills/kWhr. LL(3) = 1, costs are calculated in ¢/M Btu.

If LL(4) = 0, a full set of input cards, 1 through 9, is provided. If LL(4) = 1, only the first card, card 1, is provided. If LL(4) = 2, cards 1 and 2 only, are provided. If LL(4) = 3, cards 1, 2, 3, 4, and 5 only, are provided. If LL(4) = 4, cards 1 and 4 only, are provided. If LL(4) = 5, cards 1 and 5 only, are provided. NOTE: when options 1 through 5 are used, the remaining data is the same as that used in the preceeding problem.

If LL(5) = 1, the program uses the capacity factor — Cycle Length option. The program reads Cards 10, which contain capacity factors and MW plant ratings. If LL(5) = 0, the capacity factor routine is omitted. Note, if LL(5) = 1, LL(10) must equal 0.

If LL(6) = 0, subroutine OUT2 is called. This prints both batchwise and cumulative batchwise cost breakdowns. If LL(6) = 5, program prints batchwise component cost breakdowns. If LL(6) = 6, subroutine OUT2 is called and batchwise component cost breakdowns are printed.

If LL(7) = 0, no price escalation is used. If LL(4) = 1, then this may be used to control escalation for another data set. If LL(7) = 1, escalation factors, provided on cards 2 are used.

If LL(8) = 0, cards 9, the energy distribution for each batch by cycles, are read. If LL(8) = 1, cards 9 are omitted, and the energy delivered by each batch is divided equally among the cycles during which the batch is in the reactor.

If LL(9) = 0, the first entry on each card 7 is in kilograms of total uranium charged. If LL(9) = 1, the entries signify kilograms of total uranium.

If LL(10) = 0, energies are input in terms of BBURN(NB) and BHVMET(NB), the burnup per batch (MWd/tonne), and tonne of heavy metal per batch. If LL(10) = 1, omit BBURN(NB) and BHUMET(NB) and input directly the energy per batch, in 10^9 kWhr. If LL(10) = 2, same as 1 except input energy as 10^{14} Btu.

If LL(11) = 0, credit is given for uranium feed and separative work. If LL(11) = 1, no uranium credit is given.

If LL(12) = 1, the program uses a breakeven procedure for calculating reprocessing costs. If LL(12) = 0, no breakeven procedure is used.

If LL(13) = 1, the program calls subroutine PLUVAL, and calculates a plutonium parity value. If LL(13) = 0, subroutine PLUVAL is not called.

If LL(14) — not presently used.

DES(I), I = 1, 13. Problem Title.

Cards 2. — These five cards contain the constants D(N), N = 1,35. Format is 7E10.0. The constants are defined as follows:

Card 1 D(1) through D(3), not used
D(4) = fraction of capital in bonds (debt fraction) (Eq. 6)
D(5) = annual interest rate on debt (Eq. 075)
D(6) = annual after-tax earning rate on equity (Eq. 14)
D(7) = federal income tax rate (Eq. 50)

Card 2 D(8) = design capacity of reactor, MW(e)
D(9) = escalation factor for U_3O_8
D(10) = escalation factor for conversion
D(11) = escalation factor for separative work costs
D(12) = escalation factor for fuel fabrication, type 1
D(13) = escalation factor for fuel reprocessing, type 1
D(14) = escalation factor for plutonium credit

Card 3 D(15) = state income tax rate (Eq. 04)
D(16) = state gross revenues tax rate (Eq. 0.0)
D(17) = property tax rate (Eq. 03)
D(18) = reactor lifetime, years
D(19) = property insurance rate (Eq. 0025)
D(20) = escalation factor for cost of depleted UF_6 tails
D(21) = escalation factor for fuel fabrication, type 2

Card 4 D(22) = fraction of core value for tax assessment (Eq. 65)
D(23) = escalation factor for fuel reprocessing, type 2
D(24) = U^{235} assay of natural uranium (.00711)
D(25) through D(28), not used

Card 5 D(29) = not used
D(30) = thermal efficiency of reactor (Eq. 0.31)
D(31) = fissile plutonium loss (percent) ($\sim$1%)
D(32) = U_3O_8 — UF_6 conversion loss (percent) ($\sim$1%)
D(33) = fabrication less (percent) ($\sim$1%)
D(34) = plutonium reprocessing loss (percent) ($\sim$1%)
D(35) = U^{235} reprocessing loss (percent) ($\sim$1.3%)

Card 3. — Card 3 contains six variables. Format is 615, F15.0. Definitions of these variables are as follows:

NBMAX = total number of batches

NTMAX = twice the number of cycles

NPMAX = total number of operating periods (cycles)

NYMAX = number of years for which lead and lag times are specified (cards 4)

NPRICE = number of price cards to be read (cards 5)

NYCOST = year in which lead and lag times and price data start (Eq., 1980).

YRSTRT = year in which reactor starts up (Eq. 1980.25)

Cards 4. — Cards 4 contain the lead and lag times which are entered as a function of time, one card for each year. These are NYMAX of these cards, and all times are given in years. The quantities are read TLEAD(NY,M), M = 1, 9, NY = 1, NYMAX. Format is 9E8.0. The initial year for these data is NYCOST, the same as for the price data. If fewer than 70 cards are read, the data for the remaining years are made the same as for the last year read. Lead times are entered as positive quantities referred to the start of irradiation; lag times are entered as negative quantities and are referenced to the time of discharge of fuel from the reactor. The order in which the lead and lag times are specified are:

1. Lead, U_3O_8 purchase
2. Lead, conversion to UF_6
3. Lead, enrichment
4. Lead, fabrication
5. Lag, reprocessing
6. Lag, sale of Pu
7. Lag, U^{235} credit
8. Lead, purchase of tails
9. Lead, purchase of plutonium

Cards 5. — Cards 5 contain the unit prices of fuel cycle services. The number of cards read is NPRICE. The quantities are read PRICE(NY,M), M = 1,10, NY may equal either year or batch. If fewer than 120 cards are read, the prices for the remaining years or batches are the same as last card read. Format is 10E8.0.

1. U_3O_8 cost, \$/lb U_3O_8
2. Conversion cost, \$/kgU
3. Separative duty, \$/kg SWU
4. Fabrication cost, type 1, \$/kg HM
5. Reprocessing cost, type 1, \$/kg HM
6. Plutonium credit, \$/kg fissile Pu
7. Cost of depleted UF_6 tails, \$/kg U
8. Fabrication cost, type 2, \$/kg HM
9. Reprocessing cost, type 2, \$/kg HM
10. Plutonium storage cost, \$/kgPu

Cards 6. — Cards 6 contain the time points, in years, at the start and end of each cycle. The first time point, representing the initial reactor startup, is always 0.0. The quantities read are (TIME(NT), NT = 1, NTMAX). These are eight points per card. Format is 8E10.0.

Cards 7. — Cards 7 contain the mass charge and discharge data. The cards must be arranged in the order in which the batches are numbered. Quantities are in kilograms. Format is 8E10.0. The items are entered:

CHU(NB) = total uranium charged
CH235(NB) = U^{235} charged
CHPU(NB) = total Pu charged
CHFPU(NB) = fissile Pu charged
DSU(NB) = total uranium discharged
DS235(NB) = U^{235} discharged
DSPU(NB) = total Pu discharged
DSFPU(NB) = fissile Pu discharge

Note: There are NBMAX of these cards, one for each batch.

Cards 8. — Cards 8 give the batch number and fuel type, the cycles during which this batch delivers energy, and the amount of energy delivered. There are NBMAX of these cards. Format is 4I4, 5E10.0.

NB = batch number
NTYPE(NB) = fuel type (1 or 2). This determines which set of fabrication and reprocessing prices is used
NPA(NB) = number of cycles at the start of which this batch enters the reactor

NPTOT(NB) = total number of cycles during which this batch remains in reactor.

XT(NB) = U^{235} tails assay for batch NB

The next items depend on LL(10):

If LL(10) = 0, enter BBURN(NB) = total burnup for this batch, MWd(thermal), per tonne of heavy metal, and BHVMET(NB) = total tonne of heavy metal charged in this batch. If LL(10) = 1, enter BTOKWH(NB) = energy delivered by this batch, 10^9kWhr. If LL(10) = 2, enter BTOKWH(NB) = energy delivered by this batch, 10^{14} Btu.

Cards 9. — These cards give the energy distribution for each batch, by cycles, for the cycles during which it is in the reactor (or is being held out). Format is 8E10.0. There is one card for each batch. The numbers entered represent the quantities of energy produced by the batch during each cycle for the cycles starting with NPA(NB) and ending with NPA(NB) + NPTOT(NB) — 1. Any set of energy units may be used since the code normalizes these quantities to fractions by dividing each entry by the sum of the entries for a given batch. If the batch is held out, the entry for that cycle is 0. If these cards are omitted [LL(8) = 1], the energy for each batch is divided equally among its cycles; this option cannot be used when there are holdout cycles.

Cards 10. These cards give the plant capacity factors and thermal MW ratings, cycle by cycle. The program uses this information to calculate new cycle lengths (to the nearest 1/10 of a year), and modified capacity factors for each cycle. If LL(5) = 1, enter CAPFI(NP) and THMW(NP), where NP refers to the cycle number. Format is 2E10.0. These cards must be omitted if LL(5) = 0.

Cards 11. These cards contain the target cumulative fuel costs corresponding to a plutonium recycle case. This information is used in subroutine PLUVAL for calculating a "sales value" of Pu. For LL(13) = 1, enter TGTCUM(NP), where NP refers to the cycle number. Format is 8E10.0. If LL(13) = 0, cards 11 are not read, and must be omitted.

This completes the input data.

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