ORBES

CAPITAL REQUIREMENTS AND BUSBAR COSTS

FOR POWER IN THE OHIO RIVER BASIN,

1985 AND 2000

PHASE II

OHIO RIVER BASIN ENERGY STUDY

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CAPITAL REQUIREMENTS AND BUSBAR COSTS FOR POWER IN THE OHIO RIVER BASIN, 1985 AND 2000

by

Richard Newcomb
Bruce Bancroft

West Virginia University
Morgantown, West Virginia 26506

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SECTION 1

INTRODUCTION

This report provides estimates of capital-output ratios and typical operating costs for the comparison of alternative patterns of electric utility expansion in the Ohio River Basin (ORB) over the next twenty-five years. The assumptions of growth in the region of interest are those defined by the Ohio River Basin Energy Study (ORBES). All of Kentucky and portions of Illinois, Indiana, Ohio, Pennsylvania and West Virginia comprise the basin area. The objective of our research is to estimate capital requirements and representative busbar utility prices for power plants described and projected in other ORBES studies for selected counties in each of the states. Industry's estimates of capacity are accepted through 1985 from their plans in progress. Capacities through the year 2000 are conjured by the other ORBES studies. The assumptions concerning the representative sites, types of plant, scale and costs of delivered fuel are given by the ORBES project, along with the demand conditions. Three scenarios are discussed over the future periods ending in 1985 and 2000: (i) "scenario 2," a moderate growth inside ORB assuming no export or nuclear expansion, (ii) "scenario 2n," an expanded export case, the added facilities being fueled by nuclear energy, and (iii) "scenario 7," a high growth coal forecast based on a Nuclear Energy Regulatory Commission (NERC) projection.

SECTION 2

CONCLUSIONS

ORBES assumes ten year construction times for nuclear plants scaled at 1,000 megawatts (MW) scale and five year times for coal plants scaled at 650 MW. Under these assumptions, the incremental power from coal is cheaper by one third than new nuclear power. In 1985 (measured in 1975 constant dollars), capital and fixed costs are 41.5 mills per kwh for coal compared to 65.7 mills per kilowatt hour (kwh) for nuclear. In current 1980 dollars, the busbar price for electricity is 7.5 cents per kwh for coal and 10.2 cents per kwh for nuclear. If coal plants are built to the same scale, the coal price falls further to half that of nuclear. If the longer construction time assumed for nuclear is dropped, the cost of coal and nuclear are approximately equal. It is on this last, ceteris paribus,* basis that the following results of this research are summarized as follows.

(1) The total ORBES capital requirements are large. In 1975 constant dollars the cumulative gross increments to capacity planned in the region through 1985 require a $39 billion investment over five to ten years. This investment total is about 25 percent of current (1975) annual levels of gross product estimated for the region. By the year 2000, the increment required reaches $97 billion in the lowest growth case (scenario No. 2, nuclear foreclosure), $118 billion in the mixed case, (scenario No. 2n, domestic coal and nuclear exports) and $126 billion in the high coal case (scenario, No. 7)).

(2) The capital requirement differences among states by the year 2000 generated for the scenarios are also large for some states. The nuclear export scenario adds $20 billion, most of it in two states, Ohio and Pennsylvania. The high coal case adds $30 billion in coal facilities affecting largely Kentucky, Ohio and West Virginia. The capacities and locations are the same in 1985 for all scenarios.

*Ceteris paribus, or "all things being equal" is a convenient assumption because it implies the closest comparison, but, of course, with two such different technologies, all things never are equal in reality. We describe in detail below how the significant component of cost, capital and fixed charge rates, is affected by ORBES assumptions yielding the ultimate advantages to coal. These advantages would be increased if tax subsidies are calculated following Chapman's ORBES study. Here, costs reflect only the busbar price to the utility user and not the social cost of power.

(3) As one might expect, the component of cost that dominates the price of electricity at the busbar is comprised of capital costs and other special fixed charges. Under public utility accounting conventions, a variety of special charges are added to annual capital costs per kwh. The capital cost is, of course, higher for nuclear plants than for coal. Significant economies of scale are characteristic of both technologies, but nuclear fuel costs are lower. When the advantages of larger scale are combined with lower nuclear fuel costs and the construction times are assumed equal, coal and nuclear costs are close. ORBES assumptions realistically double the time for nuclear plant construction following current experience. When this is assumed, despite higher fuel costs for coal and lower scales, utilities find coal significantly cheaper. If construction times are equalized, nuclear is clearly cheaper nowhere in the region in 1985. However, by the year 2000, nuclear is cheaper by a small fraction in the major coal field states. In contrast, by 2000, coal is cheaper only in Illinois. No cost differences are very large.

(4) Were construction times to be equalized, in a typical case such as at the busbar in Ohio in 1985, coal fixed costs of 35.4 mills per kwh out of a total cost for coal of 50.4 mills would compare closely with nuclear fixed costs of 41.5 mills out of a total 50.3 mills. In current 1980 dollars, total busbar cost approaches 7.0 cents per kwh in 2000. The difference between coal and nuclear costs at the most in 2000 would be less than a cent. These results contrast with other studies, which have generally shown about a 20 percent advantage for nuclear facilities. Major differences are discussed in the text.

(5) Because construction times are unequal, the advantage goes to coal despite the smaller assumed scales. The ORBES acceptance of a longer construction time for nuclear raises its fixed cost 58 percent from 41.5 mills to 65.7 mills per kwh in 1985. The bottom-line busbar cost then becomes 10.2 cents per kwh for the larger scale nuclear plants versus 7.5 cents in current 1980 dollars for the smaller scale coal plants.

Section three gives the framework for this study and section four the computations of capital costs and comparative prices.

SECTION 3

THE FRAMEWORK OF THE STUDY

The comparison of busbar costs for coal-fired or nuclear power facilties variously located in the region defined as the Ohio River Basin (ORB) is accomplished by the analysis of unit costs in process evaluation models simulating (i) power plant construction and (ii) power plant operations. The cost of nuclear fuel or coal supplied to these plants at different sites is added to these capital and operating costs to arrive at estimated prices for electricity at the busbar. Total capital costs are also estimated. Thus, this study forms an important link in the larger ORBES assessment of clean energy alternative supply patterns, benefits and costs for given demands in 1985 and 2000.

The evaluation, while quite detailed for a cost engineering exercise, is relatively simple in terms of accounting and economics. The estimates are developed in six stages, three of them provided by this study and three by correlative studies. First, estimates of conventional mining and preparation costs are taken from the Blome study. Second, estimates of average delivered costs for coal blended to achieve uniform Btu values and sulfur content (1.2% by weight on average) to centroids of each state are accepted from the Page Report (Exhibit 1.5). This forms the basis for average costs for coal in each ORB state for 1985 and 2000. Third, the nuclear fuel cycle is analyzed in this study to arrive at nuclear fuel costs. Fourth, site-specific construction costs are evaluated in the Oak Ridge model CONCEPT V (cf. Appendix). This model distinguishes the differential capital costs of various coal and nuclear power plant constructions, containing dozens of technical or site related parameters and thousands of variable plant costs. The areas for which historical factor prices and other site-related costs are stored in CONCEPT include those typical of the Chicago, Cincinnati and Pittsburgh regions. These are assigned to ORBES counties in Illinois, Indiana-Kentucky, and Ohio-Pennsylvania-West Virginia respectively. Independent runs are made on pressurized water reactors (PWR) and moderate sulfur coal-fired boilers equipped with scrubbers (CS) to generate capital-output ratios. Incremental units sited in the ORB by the Larson and Fowler Studies are then employed to compute current base year (1975), planned (1985) and conjured (2000) capacities and additions net of retirements in the ORB by solid fuel type. These are considered for both greenfield (stand-alone) plants and plants added to existing or planned capacities. We have shown these by state for three scenarios designated by ORBES, coal (2), NERC (7) and Nuclear Export (2n) in Exhibit 1.1. These are reduced in Exhibit 1.2 to estimates of solid fuel electric net capacities by state for each of the

Exhibit 1.1 *CURRENT ('75), PLANNED ('85), AND CONJURED ('00) UTILITY CAPACITY ADDITIONS AND RETIREMENTS IN THE ORBES REGION IN MWe BY SOLID FUEL TYPE,* GREENFIELD (GF) AND ADDED TO EXISTING OR PLANNED (ATE) BY STATE FOR COAL (2), NERC (7), AND NUCLEAR EXPORT (2n) SCENARIOS

			ILLINOIS			INDIANA			KENTUCKY			OHIO			PENNSYLVANIA			WEST VIRGINIA		
Scenario	Fuel	Date	TOTAL	GF	ATE	TOTAL	GF	ATE	TOTAL	GF	ATE	TOTAL	GF	ATE	TOTAL	GF	ATE	TOTAL	GF	ATE
#2	Coal																			
	Conventional																			
	A_{21} • Base Capacity	'75	10,512			10,114			10,948			17,034			9,691			11,966		
	Period[1] Addition		4,399	1,034	3,365	8,951	2,705	6,246	8,880	2,955	5,925	3,927			6,134	1,547	4,587	2,552	1,926	626
	Subtotal		14,911			19,065			19,828			20,961			15,825			14,518		
	Retirements		- 511			- 534			- 837			-1,439			- 336			- 582		
	B_{21} • Net Capacity	'85	14,400			18,531			18,991			19,522			15,489			13,936		
	Period[2] Addition		9,723	8,450	1,273	12,700	11,700	1,000	12,550	10,400	2,150	13,000			9,100	9,100		9,100	9,100	
	Subtotal		24,123			31,237			31,541			32,522			24,589			23,036		
	Retirements		-3,631			-5,272			-4,962			-5,160			-2,552			-3,670		
	C_{21} • Net Capacity	'00	20,492	9,484	4,638	25,959	14,405	7,246	26,579	13,579	8,975	27,362			22,037	10,647	4,587	19,366	11,026	626
#7	NERC Coal																			
	Added Period[2]		3,250	3,250		4,550	4,550		7,800	7,800		7,800			1,300	1,300		7,150	7,150	
	C_{71} • Net Capacity		23,742	12,734	4,638	30,509	18,955	7,246	34,379	21,155	8,975	35,162			23,337	11,947	4,587	26,516	18,176	626
#2	Nuclear																			
	A_{22} • Base Capacity	'75	1,865			-0-			--	--	--	-0-			-0-					
	Period[1] Addition		4,056	2,028	2,028	2,260	1,130	1,130				810	810		1,830	925	925	--	--	--
	Subtotal		5,921			2,260						810			1,830					
	Retirements		--			--						--			--					
	B_{22} • Net Capacity	'85	5,921			2,260						810			1,830			--	--	--
#2n	Period[2] Addition		1,000		1,000	1,000		1,000				10,810		10,810	8,000	8,000				
	Subtotal		6,921			3,260						11,620			9,830					
	Retirements		- 209			--						--			--			--	--	--
	C_{22} • Net Capacity	'00	6,712	2,028	3,028	3,260	1,130	2,130	--	--	--	11,620	810	10,810	9,830	8,925	925	--	--	--
#7	NERC-NUC																			
	Added Period[2]		-1,000		-1,000	-1,000		-1,000	--	--	--	-10,000		-10,000	-8,000	-8,000		--	--	--
	C_{71} • Net Capacity		5,712	2,028	2,028	2,260	1,130	1,130				1,620	810	810	1,830	925	925	--	--	--

Sources: Tables 1 and 3, Electric Generating Unit Inventory, 1976 - 1986, Steven O. Larsen, Energy Resources Center, Univ. of Illinois at Chicago Circle, Nov. 1978, and Supplementary Reports by Gary Fowler, June 20, 1979 (1, 1n) and November 26, 1979 (7).

Exhibit 1.2 ORBES STATE SOLID FUEL ELECTRIC MWe NET CAPACITIES - CURRENT (1975), PLANNED (1985) AND CONJURED (2000)

Scenario	State	1975 Coal	1975 Nuclear	1975 Other	1975 Total	1985 Coal	1985 Nuclear	1985 Other	1985 Total	2000 Coal	2000 Nuclear	2000 Other	2000 Total
#2	Illinois	(#2) 10,512	1,865	1,582	13,959	(#2) 14,400	5,921	4,640	24,961	(#2) 20,492	5,922	1,600	28,014
	Indiana	10,114	-0-	1,037	11,151	18,531	2,260	1,158	21,949	25,959	2,260	1,000	29,219
	Kentucky	10,948	-0-	1,054	12,002	18,991	-0-	1,186	20,177	26,579	-0-	1,000	27,579
	Ohio	17,034	-0-	2,067	19,101	19,522	810	1,882	22,214	27,362	810	2,000	30,172
	Pennsylvania	9,691	-0-	473	10,164	15,489	1,830	1,260	18,579	22,037	1,830	500	24,367
	West Virginia	11,966	-0-	608	12,574	13,936	-0-	1,098	15,034	19,366	-0-	600	19,966
	Total	70,265	1,865	6,821	78,951	100,869	10,821	11,224	122,914	141,795	10,822	6,700	159,317
#2n	Illinois									(#2n) 20,492	6,712	1,600	28,804
	Indiana									25,959	3,260	1,000	30,219
	Kentucky									26,579	-0-	1,000	27,579
	Ohio									27,362	11,620	2,000	40,982
	Pennsylvania									22,037	9,830	500	32,367
	West Virginia									19,366	-0-	600	19,966
	Total									141,795	31,422	6,700	179,917
#7	Illinois									(#7) 23,742	5,712	1,600	31,054
	Indiana									30,509	2,260	1,000	33,769
	Kentucky									34,379	-0-	1,000	35,379
	Ohio									35,162	1,620	2,000	38,782
	Pennsylvania									23,337	1,830	500	25,667
	West Virginia									26,516	-0-	600	27,116
	Total									173,645	11,422	6,700	191,767

Sources: Exhibit 1

three years for coal, nuclear and other facilities. This permits the calculation of gross additions to capacity from 1975-85 and 1985-00 by state for each scenario (Exhibit 1.3). We have expressed these in terms of "standard plant equivalents" for application to CONCEPT V runs (Exhibit 1.4). The gross additions for coal are 35,100 MW or 54 plants of 650 MW distributed as shown: seven plants to IL, fourteen each to IN and KY, six to OH, nine to PA and four to WV. In addition, nine nuclear power plants of 1,000 MW capacity are distributed to account for the total 44,100 MW obtaining for ORB in all scenarios by 1985. The distributions for the Coal (66,300 MW), NERC (99,150 MW) and Nuclear Export (87,300 NW) scenarios by state for the year 2000 are also shown, again in terms of "standard equivalent plants." Fifth, an evaluation of nonfuel operating and maintenance costs is performed, making use of the model OMCOST (Cf. Appendix). Factor markets for OMCOST variables are assumed to be approximately the same in each of the states. The sixth and last step is left to be performed in the final ORBES report in which the busbar costs generated in this study are input. This will assess the full and more complex social costs and benefits incurred under the various scenarios. A number of considerations are worth noting before proceeding in the next section to the discussion of this study's comparisons of nuclear and coal.

The fuel cost calculations made available by Page in Exhibit 1.5 are from Blome after modifications performed by Teknekron. They are shown in Exhibit 1.5 in constant 1975 dollars of coal as if delivered to a centroid in each state for all utilities. Page calculates these both per ton and per million Btu, i.e., they represent an average blend of coals of various grades with varying Btu content and other characteristics. However, they are estimated to have a constant 1.2 percent sulfur content by weight. Because the coal prices are not reported as a function of quantities delivered by coal type (i.e., as inverse supply functions) there is no way to account for any of the differential rises in real prices of coal over time due to varying quantities drawn from the individual supply regions. However estimated, any real price rise must be a function of depletion net of technological change occurring in the coal fields as mining proceeds over time. In reality the price in any given future year will be a function of cumulative as well as period demands, and the delivered price in each state will be a function of an aggregate quantity supplied from various individual supply districts. To estimate the least cost quantities and determine the market clearing prices in simulation of the spatial supply and demand equilibria which will occur in future years for all coal types would require the solution of a very large transportation program. Ideally the objective function to be maximized should be the net payoff to both the producing and consuming industries represented in a given year by the sum of the producers' and the consumers' surplus. However, the prices of the Blome and Teknekron studies are point estimates assuming determined aggregates and not the result of market cleaning calculations involving supply and demand. While they are useful as an engineering approximation, because they assume that the proportional allocations of coal would be maintained for the periods of Exhibit 1.5 irrespective of changes in demands or the different sitings of nuclear and coal plants,

Exhibit 1.3 GROSS ADDITIONS TO PLANT 1975-85, AND 1985-2000 IN MWe IN THE ORBES REGION BY STATE FOR SCENARIOS 2, 2n AND 7

Scenario	State	1975-1985 Coal	1975-1985 Nuclear	1975-1985 Total	1985-2000 Coal	1985-2000 Nuclear	1985-2000 Total
#2	Illinois	4,399	4,056	8,455	9,723	-0-	9,723
	Indiana	8,951	2,260	11,211	12,700	-0-	12,700
	Kentucky	8,880	-0-	8,880	12,550	-0-	12,550
	Ohio	3,927	810	4,737	13,000	-0-	13,000
	Pennsylvania	6,134	1,830	7,964	9,100	-0-	9,100
	West Virginia	2,552	-0-	2,552	9,100	-0-	9,100
	Total	34,843	8,956	43,799	66,173	-0-	66,173
#2n	Illinois				9,723	1,000	10,723
	Indiana				12,700	1,000	13,700
	Kentucky				12,550	-0-	12,550
	Ohio				13,000	10,810	23,810
	Pennsylvania				9,100	8,000	17,100
	West Virginia				9,100	-0-	9,100
	Total				66,173	20,810	86,983
#7	Illinois				12,973	-0-	12,973
	Indiana				17,250	-0-	17,250
	Kentucky				20,350	-0-	20,350
	Ohio				20,800	810	21,860
	Pennsylvania				10,400	-0-	10,400
	West Virginia				16,250	-0-	16,250
	Total				98,023	810	98,833

Source: Exhibit 1

Exhibit 1.4 STANDARD PLANT EQUIVALENT[1] (SPE) SOLID FUEL GROSS ADDITIONS IN MWe IN THE CONCEPT REGIONS BY STATE FOR SCENARIOS 2, 2n AND 7

Scenario	State (CONCEPT Region)	1975-1985 Coal No. SPE	1975-1985 Coal Mwe	1975-1985 Nuclear No. SPE	1975-1985 Nuclear Mwe	1985-2000 Coal No. SPE	1985-2000 Coal Mwe	1985-2000 Nuclear No. SPE	1985-2000 Nuclear Mwe
#2	Illinois (5)	7	4,550	4	4,000	15	9,750	0	--
	Indiana (6)	14	9,100	2	2,000	20	13,000	0	--
	Kentucky (6)	14	9,100	0	--	19	12,350	0	--
	Ohio (6)	6	3,900	1	1,000	20	13,000	0	--
	Pennsylvania (17)	9	5,850	2	2,000	14	9,100	0	--
	West Virginia (17)	4	2,600	0	--	14	9,100	0	--
	Subtotal	54	35,100	9	9,000	102	66,300	0	--
	TOTAL				44,100				66,300
#2n	Illinois (5)					15	9,750	1	1,000
	Indiana (6)					20	13,000	1	1,000
	Kentucky (6)					19	12,350	0	--
	Ohio (6)					20	13,000	11	11,000
	Pennsylvania (17)					14	9,100	8	8,000
	West Virginia (17)					14	9,100	0	--
	Subtotal					102	66,300	21	21,000
	TOTAL								87,300
#7	Illinois (5)					20	13,000	0	--
	Indiana (6)					27	17,550	0	--
	Kentucky (6)					31	20,150	0	--
	Ohio (6)					32	20,800	1	1,000
	Pennsylvania (17)					16	10,400	0	--
	West Virginia (17)					25	16,250	0	--
	Subtotal					151	98,150	1	1,000
	TOTAL								99,150

1 SPE units of nuclear are 1,000 Mwe. SPE units of coal are 650 Mwe. CONCEPT regions are Chicago (5), Cincinnati (6) and Pittsburgh (17)

Source: Exhibit 3.

Exhibit 1.5

COAL PRICES[a,b,c]
($ per million btu)

State / Year	IL	IN	KY	OH	PA	WV
1976	.782	.652	.665	.918	.907	.911
1985	1.148	1.371	1.168	1.185	1.379	1.196
2000	1.360	1.543	1.944	1.547	1.938	1.99

COAL PRICES[a,b,c]
($ per ton)

State / Year	IL	IN	KY	OH	PA	WV
1976	16.42	14.17	14.59	19.85	21.69	21.45
1985	25.54	32.25	26.80	28.44	33.10	28.70
2000	29.97	34.62	45.79	37.13	46.51	47.76

SOURCE: Walter Page, ORBES Memorandum, December 6, 1979. Table 1, rounded within $\pm$ .05 per MBTU.

a. Coal prices are based on three considerations: (1) coal assignments for Northern Appalachia, Central Appalachia, Southern Appalachia and Eastern Interior provided by D. Blome to Teknekron Research, Inc., for use in connection with Teknekron's USM model; (2) initial estimates of coal prices based on Teknekron's use of ICF coal supply functions in the USM model; and (3) adjustments to Teknekron's preliminary estimates of future supply region prices in light of Page's work on the cost effects of resource depletion. All prices reported are weighted averages (weighted by btu content of supplied coal) as between the four supply regions serving the states as well as the tonnage of cleaned and uncleaned coal. Scenario specifications determined the relative tonnage of cleaned and uncleaned coal used in a specific state.

b. All prices are in terms of real 1975 dollars. In all cases, delivered prices are reported.

c. Cleaned coal is that produced by a level 4 cleaning plant (BOM definition). Essentially this means a dense media separation to 28 mesh particulate size, washed, and thermal dried.

d. Coal characteristics call for blends meeting 1.8% sulphur shipped, by weight.

they ignore and underplay the role of inter-state competition in moderating delivered coal prices. This may help to explain certain anomolies in results.

On the demand side, fuel prices were not considered by ORBES to be the determining factor in their plant choices after 1985 when the ORBES scenarios site nuclear and coal plants independently of competitive market considerations. In defense of this simplified approach, one can say that no better estimates of relative busbar costs would occur if an elaborate optimization program had been attempted or if the potential supply functions of individual regions were adopted from other studies, given the state of the modeling art and information in seam reserves.

On the cost engineering side, the assumptions behind the nuclear fuel cycle cost estimates are also frequently obscure in the literature whether one resorts to government or to industry publications. The assumptions employed here are based on the most current engineering estimates available. The results can be compared with those of the recent authoritative studies (Exhibit 1.6). Estimates of Rossin and Rieck, Wash, Chapman, TRW and Zebroski and Levenson are stated in 1975 dollar equivalents for comparison purposes. The price of yellowcake is taken at $20.00 for 1975. This may be fairly representive of long run average cost. It is closer to existing contract average costs than to marginal cost because the United States Geological Survey potential supply function is accepted and this is relatively elastic. Real prices today are approximately at this level and $20.00 is accepted for 1985. The price is permitted to double in real terms over the subsequent fifteen years. To the extent this estimate is conservative, the results of the study are biased toward nuclear. Section two discusses the nuclear cycle calculations in detail.

In all the cost engineering exercises comparing nuclear and coal fired power plants significantly higher capital investment is shown to be required for nuclear plants than for coal. The associated fixed charges added to this capital burden are also higher than coal. These costs cannot be offset by lower nuclear fuel costs alone for the next twenty-five years under any set of realistic assumptions. If nuclear plants are shown competitive, additional offsets must come, therefore, (i) from assumed site-specific advantages that eliminate transportation and transmission costs for nuclear plants, (ii) by scale advantages, and by greater availability and loading factors, or (iii) by the elimination of certain nuclear use charges to the utility through the conventions of joint costing at various fuel cycle steps, the assumption of tax subsidies, and so on. A very common offset comes from assumed higher nuclear plant scales. Economies of scale are very significant in both coal-fired and nuclear fueled plants. The elasticity of busbar cost with respect to increases in scale assumed in the Oak Ridge models comes out to be about .6 for both types of plant between the scales of 650 and 1,000 MW. In the typical (Pittsburgh) case, CONCEPT V shows the 1975 dollar cost of coal plant per kw falls from $861 to $741 for an increase in scale from 650 to 1,000 MW. The decline is from $1,208 to $963 per **kw** for nuclear plants over the same range. On the other hand, any stretch-out of nuclear plant construction time, rise in the interest rate, fall in rated capacity or availability, decrease in debt ratio, decrease in corporate income tax or increase in _ad valorem_ tax will work

Exhibit 1.6 VARIOUS NUCLEAR FUEL CYCLE STUDY ASSUMPTIONS

(1985 price in 1975 $)

Study (Date)	Time Period of Interest	Yellowcake Price ($/$U_3O_8$)	Conversion Cost S/kg. U	Cost of Separative Work Unit $/kg. SWU	Fabrication Costs $/kg. U	Back-end[1] Costs $/kg. U
Rossin/Rieck (1) (1978)	late 80's	35.90	5.45	67.30	98.70	250
Wash 1174-74 (2) (1974)	1982	14.25	3.60	82.20	76.70	25
Chapman, et. al. (3) (1980)	1980-2017	35.60	3.40	72.60	76.85	265
TRW (4) (1976)	1980-2005	scenario dependent	3.30	100.00	100.00	125
E. Zebroski & (5) M. Levenson (1976)	1984-1985	25.00	4.00	100.00	116.60	150

[1]Assume no reprocessing occurs. Projected costs not adjusted to 1975 $ because of the extreme uncertainty associated with this activity.

against the nuclear plant more heavily than the coal-fired plant. This is due both to the higher scales assumed and to the greater nuclear capital intensity at given scales. In the CONCEPT V cost functions this intensity disadvantage adds 25% to 33% to nuclear costs when construction times are stretched to double coal plant times for equivalent scale. However, the CONCEPT V program neglects many site-specific construction advantages obtaining for typical coal-fired plants, and to this extent the intensity disadvantages are somewhat modified.

The comparisons of Table 2.6 below confirm that differential local construction costs are probably not significant in the ORB. Certainly they are not large relative to the scale and intensity effects discussed above. The cost of construction stretch-out is very high. For nuclear construction, raising this from 5 to 10 years raises the cost of a 1,000 MW nuclear plant from $963 million to $1,560 million! Assuming that 1985 prices are double 1975, the comparison between a coal design completed in six years to a nuclear design taking eleven years would leave the coal plant cheaper by $1,632 per kw, or nearly half the cost of nuclear per unit. These capital aspects of cost comparisons dominate the discussion of technical choices in current utility planning and in the comparisons that follow.

SECTION 4

METHODS USED TO COMPUTE CAPITAL REQUIREMENTS AND BUSBAR COSTS

Capital Requirements

Two sorts of data are needed to compute capital requirements by state for the three scenarios. These are: (1) the projected number of plants by state for each scenario, and (2) the construction cost of plants by state.

The number of plants required is computed from Tables 1 & 3, Electric Generating Unit Inventory, 1976-1986, Steven O. Larsen, Energy Resources Center, University of Illinois at Chicago Circle, No. 1978, and Supplementary Reports by Gary Fowler, June 20, 1969 (2, 2n) and November 26, 1979 (7). For the capital requirements calculations plant sizes are taken at 650 mw_e for coal and 1,000 mw_e for nuclear.

The construction costs of plant by state are arrived at by using CONCEPT-V, a cost model developed by the Oak Ridge National Laboratory. The CONCEPT computer code package has the capability of simulating hypothetical capital cost estimates for various types of nuclear-fueled and fossil-fired power plants as a function of a large number of parameters, including regional and site specific factors.

The parameter values used in this task and associated capital costs are shown in Exhibit 2.1. As shown, the coal plant examined is a "stand alone plant," using a cross-compound turbine and containing a scrubber. The nuclear unit is a PWR stand alone plant.

The capital requirements for the three scenarios are shown in Exhibit 2.2. The CONCEPT program provides capital cost variations due to geographic factors for 22 cities in the U.S. and Canada. In this study three CONCEPT regions are employed representative of the Chicago, Cincinnati, and Pittsburgh areas. Chicago is taken to be representative of Illinois; Cincinnati is assumed to represent Pennsylvania and West Virginia. (Note that the variation among these CONCEPT locations does not exceed 2%.)

All the methods used to compute busbar costs for 1985 and 2000 are straightforward. These costs are divided conventionally into the principal components of busbar costs: capital costs, operations and maintenance costs, fuel costs, and fuel inventory carrying costs. Task results are shown in Exhibit 2.3.

Exhibit 2.1 CAPITAL COSTS FOR COAL AND NUCLEAR PLANTS AS A FUNCTION OF VARIOUS INPUT PARAMETERS

Location (CONCEPT Region)	Plant Size	Type	Steam Supply System Purchase (Yr.)	Construction Permit (Yr.)	Commercial Operation (Yr.)	Total Capital Cost 10^6 1975 $	Capital Cost per kw 1975 $
Pittsburgh (17)	650 mw_e	Coal[1]	1	2	7	561.181	861.8
Cincinnati (6)	650 mw_e	Coal	1	2	7	569.301	875.8
Chicago (5)	650 mw_e	Coal	1	2	7	562.919	866.0
Pittsburgh (17)	1,000 mw_e	Coal	1	2	7	741.244	741.2
Cincinnati (6)	1,000 mw_e	Coal	1	2	7	753.260	753.3
Chicago (5)	1,000 mw_e	Coal	1	2	7	744.634	744.6
Pittsburgh (17)	1,000 mw_e	Coal	1	2	7	1,199.161	1,199.2
Pittsburgh (17)	1,000 mw_e	Nuclear[2]	1	2	7	963.266	963.3
Cincinnati (6)	1,000 mw_e	Nuclear	1	2	7	981.985	982.0
Chicago (5)	1,000 mw_e	Nuclear	1	2	7	963.121	963.1
Pittsburgh (17)	1,000 mw_e	Coal	1	2	7	1,560.182	1,560.2

[1]Coal-fired with SO_2 removal system; using cross-compount turbine; single unit (stand alone plant)

[2]Pressurized-water reactor; single unit (stand-alone plant)

Exhibit 2.2 CAPITAL REQUIREMENTS BY STATE FOR THE TIME PERIODS 1975-1985 AND 1985-2000 FOR SCENARIOS 2, 2n, AND 7
in constant (1975) dollars (000)

		1975-1985				1985-2000			
			COAL		NUCLEAR		COAL		NUCLEAR
Scenario	State (CONCEPT Region)	#SPE	Capital Requirements (10^3 1975 $)	#SPE	Capital Requirements (10^3 1975 $)	#SPE	Capital Requirements (10^3 1975 $)	#SPE	Capital Requirements (10^3 1975 $)
#2	Illinois (5)	7	3,940,433	4	3,852,484	15	8,443,785	0	--
	Indiana (6)	14	7,970,214	2	1,963,970	20	11,386,020	0	--
	Kentucky (6)	14	7,970,214	0	--	19	10,816,719	0	--
	Ohio (6)	6	3,415,806	1	981,985	20	11,386,020	0	--
	Pennsylvania (17)	9	5,041,629	2	1,926,532	14	7,842,534	0	--
	West Virginia (17)	4	2,240,724	0	--	14	7,842,612	0	--
	Subtotal	54	30,579,020	9	8,724,971	102	57,717,612		
	TOTAL			39,303,991				57,717,612	
#2n	Illinois (5)	7	3,940,433	4	3,852,484	15	8,443,785	1	963,121
	Indiana (6)	14	7,970,214	2	1,963,970	20	11,386,020	1	981,985
	Kentucky (6)	14	7,970,214	0	--	19	10,816,719	0	--
	Ohio (6)	6	3,415,806	1	981,985	20	11,386,020	11	10,801,835
	Pennsylvania (17)	9	5,041,629	2	1,926,532	14	7,842,534	8	7,855,880
	West Virginia (17)	4	2,240,724	0	--	14	7,842,534	0	--
	Subtotal	54	30,579,020	9	8,724,971	102	57,717,612	21	20,602,821
	TOTAL			39,303,991				78,320,612	
#7	Illinois (5)	7	3,940,433	4	3,852,484	20	11,258,380	0	--
	Indiana (6)	14	7,970,214	2	1,963,970	27	15,371,127	0	--
	Kentucky (6)	14	7,970,214	0	--	31	17,648,331	0	--
	Ohio (6)	6	3,415,806	1	981,985	32	18,217,632	1	981,985
	Pennsylvania (17)	9	5,041,629	2	1,926,532	16	8,962,896	0	--
	West Virginia (17)	4	2,240,724	0	--	25	14,004,525	0	--
	Subtotal	54	30,579,020	9	8,724,971	151	85,462,891	1	981,985
	TOTAL			39,303,991				86,444,876	

Fuel Inventory Carrying Charges

A specified amount of fuel inventory is treated as a capital cost because the inventory is maintained over the life of the plant and thus actually represents a capital investment. For the coal plant a 90-day inventory is assumed. For the nuclear plant the inventory is the material that the utility owns everywhere in the fuel cycle. This depends on when purchases are made in relation to a specific core refueling. For this study we assume the following lead times:[3]

Fuel Cycle Activity	Lead Time
Uranium Ore	3
Conversion	3
Enrichment	2
Fabrication	1

The busbar cost component of the fuel inventory is arrived at in a similar manner as for the plant. The difference is that the fixed charge rate is non-depreciating and insurance costs are zero. The non-depreciating fixed charge rate employed in this task is shown in section 2.1.

Exhibit 2.3 BUSBAR COSTS IN MILLS/KWH (1975 $) BY STATE FOR 1985 AND 2000[1,2]

						1985						
State	Illinois (5)		Indiana (6)		Kentucky (6)		Ohio (6)		Pennsylvania (17)		West Virginia (17)	
(CONCEPT Region)	Coal[1]	Nuclear[2]	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Busbar Costs												
Capital*	34.4	38.3	34.8	39.0	34.8	39.0	34.8	39.0	34.2	38.3	34.2	38.3
O & M	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5
Fuel	11.3	6.3	13.0	6.3	11.3	6.3	11.3	6.3	13.0	6.3	11.3	6.3
Fuel Inventory carrying chg.	.6	2.5	.7	2.5	.6	2.5	.6	2.5	.7	2.5	.6	2.5
TOTAL	50.0	49.6	52.2	50.3	50.4	50.3	50.4	50.3	51.6	49.6	49.8	49.6

						2000						
State	Illinois (5)		Indiana (6)		Kentucky (6)		Ohio (6)		Pennsylvania (17)		West Virginia (17)	
(CONCEPT Region)	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Busbar Costs												
Capital*	34.4	38.3	34.8	39.0	34.8	39.0	34.8	39.0	34.2	38.3	34.2	38.3
O & M	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5	3.7	2.5
Fuel	13.0	9.2	14.8	9.2	18.6	9.2	14.8	9.2	18.6	9.2	18.6	9.2
Fuel Inventory carrying chg.	.7	4.1	.8	4.1	1.0	4.1	.8	4.1	1.0	4.1	1.0	4.1
TOTAL	51.8	54.1	54.1	54.8	58.1	54.8	54.1	54.8	57.5	54.1	57.5	54.1

[1]Coal Plant Size: 650 mw_e (5 year construction period)

[2]Nuclear Plant Size: 1,000 mw_e (5 year construction period)

Capital Costs

The formula employed for computing the capital cost component of busbar costs is as follows:

$$\frac{(\text{Capital Cost in \$})(1{,}000\text{ mills})(\text{Fixed Charge Rate})}{(\text{Plant Size in kw})(1\$)(8{,}760\text{ hrs.})(\text{Plant Factor})}$$

The capital costs used are those shown in Exhibit 2.1. The task results are given for the 650 mw_e coal unit and the 1,000 mw_e PWR both assumed to have 5-year construction periods. A plant factor of .6 is assumed for both generating units. Calculations for different assumptions as to plant size for coal and construction period for nuclear were also made and will be discussed below.

The fixed charge rate is expressed as a percentage of the original capital investment and when multiplied by that investment gives a yearly levelized revenue requirement which will recoup all the costs associated with the capital investment. This revenue requirement is then allocated to the projected kwh's to be produced from the plant during the year. Following are the fixed charge rates and underlying assumptions employed in this task.

Fixed Charge Rates (%)

	Depreciating	Non-Depreciating (for fuel inventory)
Weighted Average Cost of Capital[1]	14.0	14.0
Sinking Fund Depreciation[2]	.28	
Federal, State & Local Taxes[3]	5.6	7.1
Insurance[4]	1.0	
	20.88	21.1

[1] Debt ratio = .5; debt cost = 13.0; common equity ratio = .5; common equity cost = 15.0.
[2] Economic life of 30 years assumed for both plants.
[3] Federal tax rate = .48; state and local taxes = 1.5. Taxes expressed as a ratio of equivalent annual income taxes to first cost of plant.
[4] Nuclear liability insurance contained in the operatives and maintenance component of busbar costs.

In our capital cost computation we have chosen to ignore tax preferences, i.e., accelerated depreciation for tax purposes and the investment tax credit. In the first place these are often neglected in an analysis of investments to be made very far in the future because of their history of frequent changes. For the ORBES research, as observed by Chapman, they constitute tax subsidies which bias economic studies toward nuclear plants because they are capital intensive. Their impact is measured by Chapman's Report.[3]

All of the components of the fixed charge rate vary spatially and/or temporally. For example, state and local taxes can vary widely from utility to utility. Additionally tax preference allowances, such as accelerated depreciation and the investment tax credit have varied over time. On top of that different accounting methods are used with tax preference allowances depending on the desires of the regulatory body. The cost of debt and equity and a utility's capital structure vary over time.

The "bottom line" result is bothersome because fixed charge rates used in economy studies vary widely depending on the underlying assumptions employed. Unfortunately the busbar cost of electricity is fairly sensitive to such changes in the fixed charge rate. This sensitivity in CONCEPT-V can be seen in Figure 1. For a 1,000 mw_e PWR plant, built in Pittsburgh or Chicago, a change in the fixed charge rate of one percentage point changes the busbar cost component about two mills. This is approximately equal to the total operating and maintenance (O & M) cost. A four percentage point difference in the fixed charge rate produces a change approximately equal to the total of fuel and O & M costs.

Figures 1 and 2 show the capital cost component of busbar costs as a function of the fixed charge rate for all plants listed in Table 2.1. Not all plants are graphically depicted, but multiplicative ratios which can be applied against specified base plants are shown. Also shown along the horizontal axis in Figure 1 is a range which encompasses fixed charge rates used in the studies referenced in the bibliography.

Operations and Maintenance Costs

Nonfuel operations and maintenance costs were obtained using OMCOST, a computer program designed by the Office of Energy Systems Analysis, Division of Reactor Research and Development, U. S. Energy Research and Development Administration. OMCOST was "designed to assist in examining average trends in costs, in determining sensitivity to technical and economic factors, and in providing cost projections."[4]

The program accepts 26 input data variables related to the generating unit itself, characteristics of oil or coal if the plant uses these fuels, and various escalation rates. Plant parameters include plant type (e.g., coal or PWR or BWR etc.), type of heat sink, plant capacity factor, net electrical output, and the number of units per station. Fuel characteristics input to the program include heating value and sulfur content.

The program costs are indexed to 1975, but the program accepts various escalation rates to the year of initial operation. Escalation rates are

FIGURE I – CAPITAL COST COMPONENT OF BUSBAR COSTS

(1000 MW PWR)

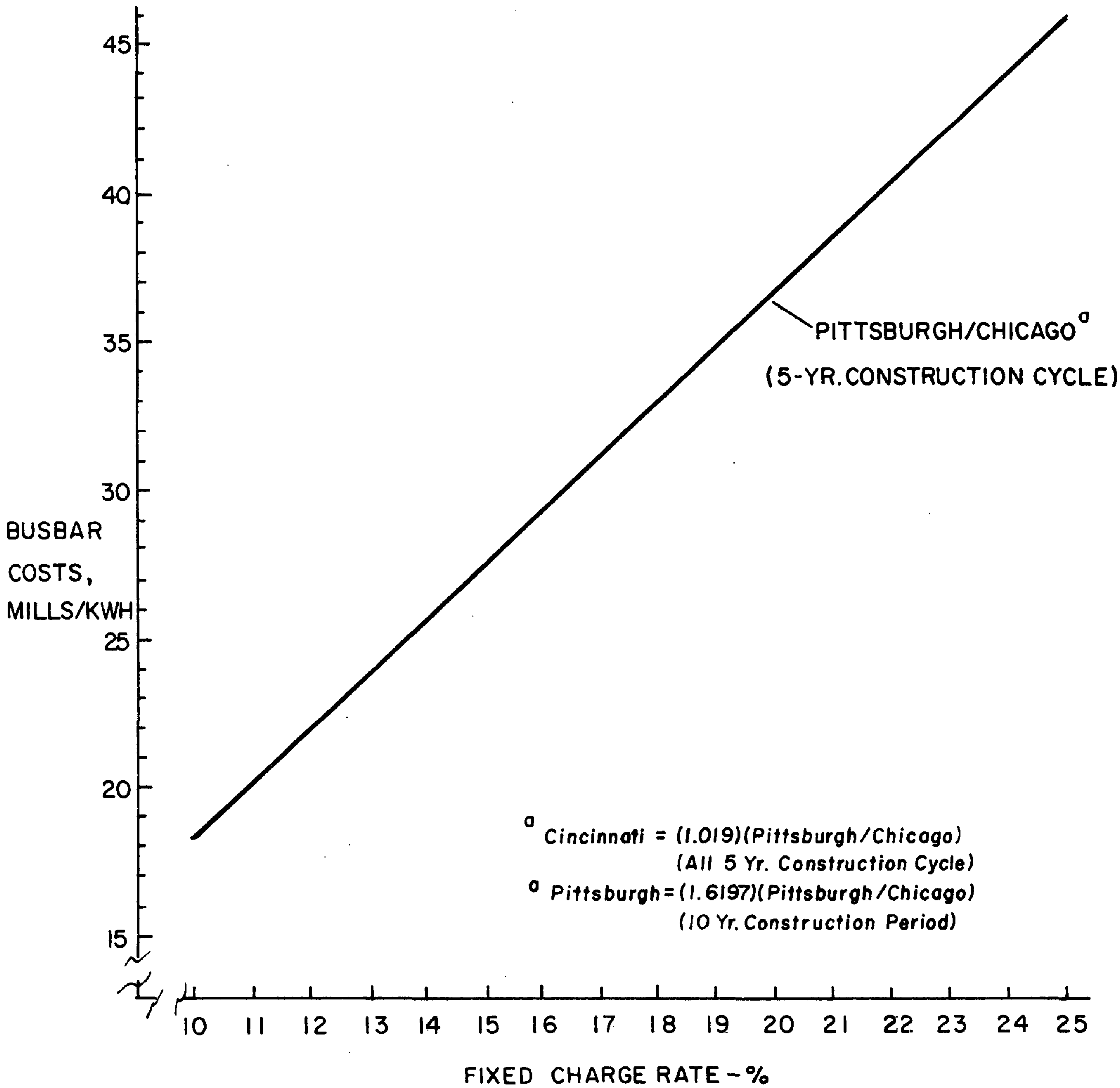
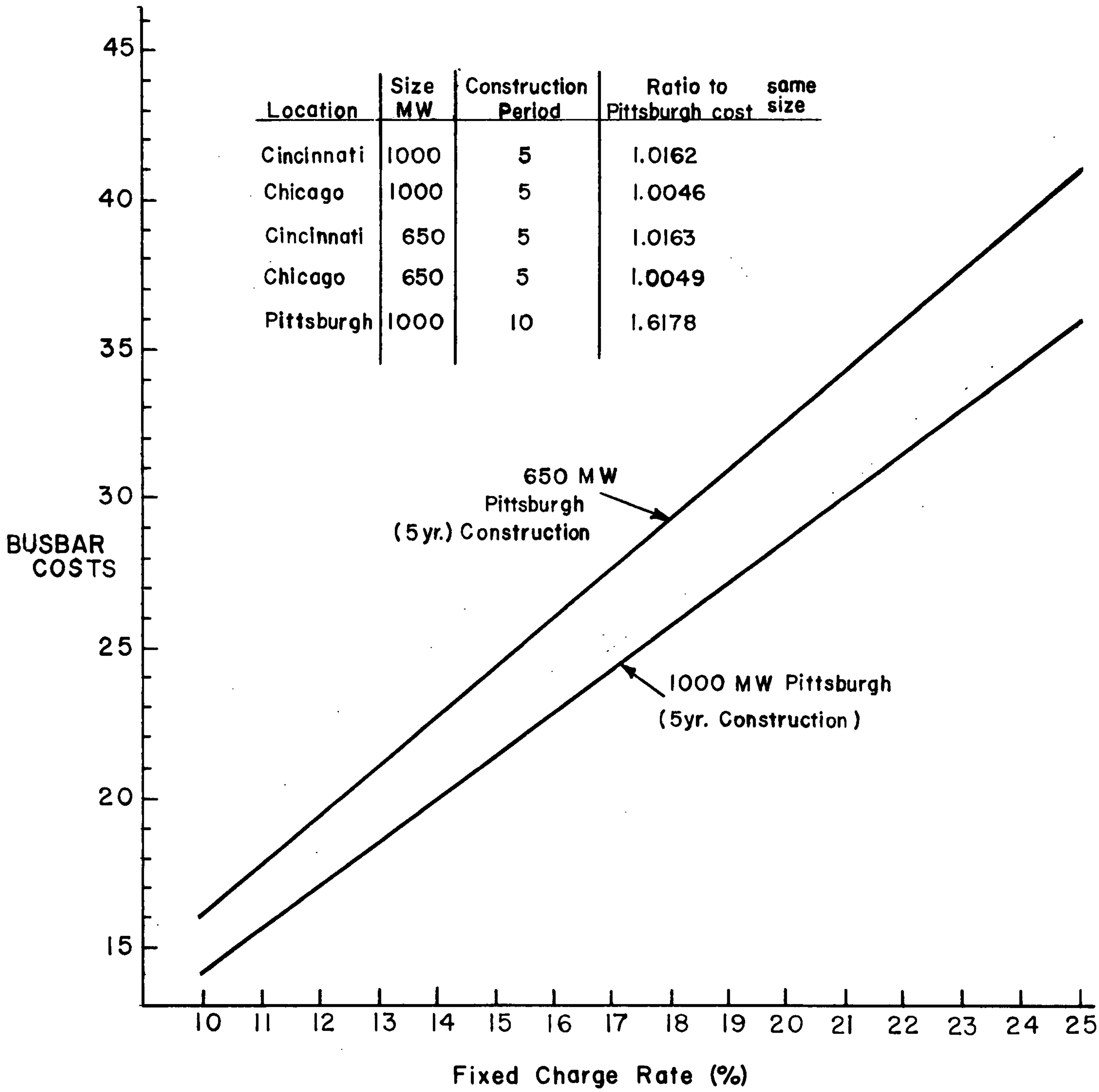


FIGURE 2–CAPITAL COST COMPONENT OF BUSBAR COSTS
(COAL)



Location	Size MW	Construction Period	Ratio to Pittsburgh cost same size
Cincinnati	1000	5	1.0162
Chicago	1000	5	1.0046
Cincinnati	650	5	1.0163
Chicago	650	5	1.0049
Pittsburgh	1000	10	1.6178

specified for eight parameters. These include materials, wages, sludge disposal, limestone, nuclear liability insurance, operating fees, and fuel oil. We assume a 4.0% per year real escalation on all of these factors to 1985, but assume that they then remain constant to the year 2000. O & M costs shown in Exhibit 2.3 are also in 1975 dollars.

Fuel Costs

Coal

Coal prices used in this task are shown below:

Delivered Coal Prices ($ per million btu, 1975 $)

Year	Illinois	Indiana	Kentucky	Ohio	Pennsylvania	West Virginia
1976	.78	.66	.66	.91	.91	.91
1985	1.19	1.37	1.19	1.19	1.37	1.19
2000	1.37	1.55	1.55	1.15	1.95	1.95

The coal cost component of busbar costs is then computed as follows:

$$(\$/\text{MMBTU})\,(1{,}000\ \text{mills}/\$)\,\left(\frac{3413\ \text{BTU}}{\text{kwh}}\right)\left(\frac{1}{y}\right)$$

where, y is the efficiency of the coal plant.
For the 650 mw_e coal unit used in this study $y = .3585$ as specified in the CONCEPT-V program.

To obtain an idea of the sensitivity of the busbar cost to the fuel price, the busbar cost is computed as a function of the delivered fuel price. This computation is graphically depicted in Figure 3. The CONCEPT-V efficiency for the 1,000 mw_e coal plant is also used to compute the busbar cost as a function of price. Also plotted is the case for $y = .33$. This last value is a rough approximation of the average value of all coal plants currently on line.

Nuclear Fuel Cycle

Nuclear fuel cycle cost assumptions for 1985 and 2000 are shown below in Exhibit 2.4.

FIGURE 3 - FUEL COST COMPONENT OF BUSBAR COSTS
(COAL)

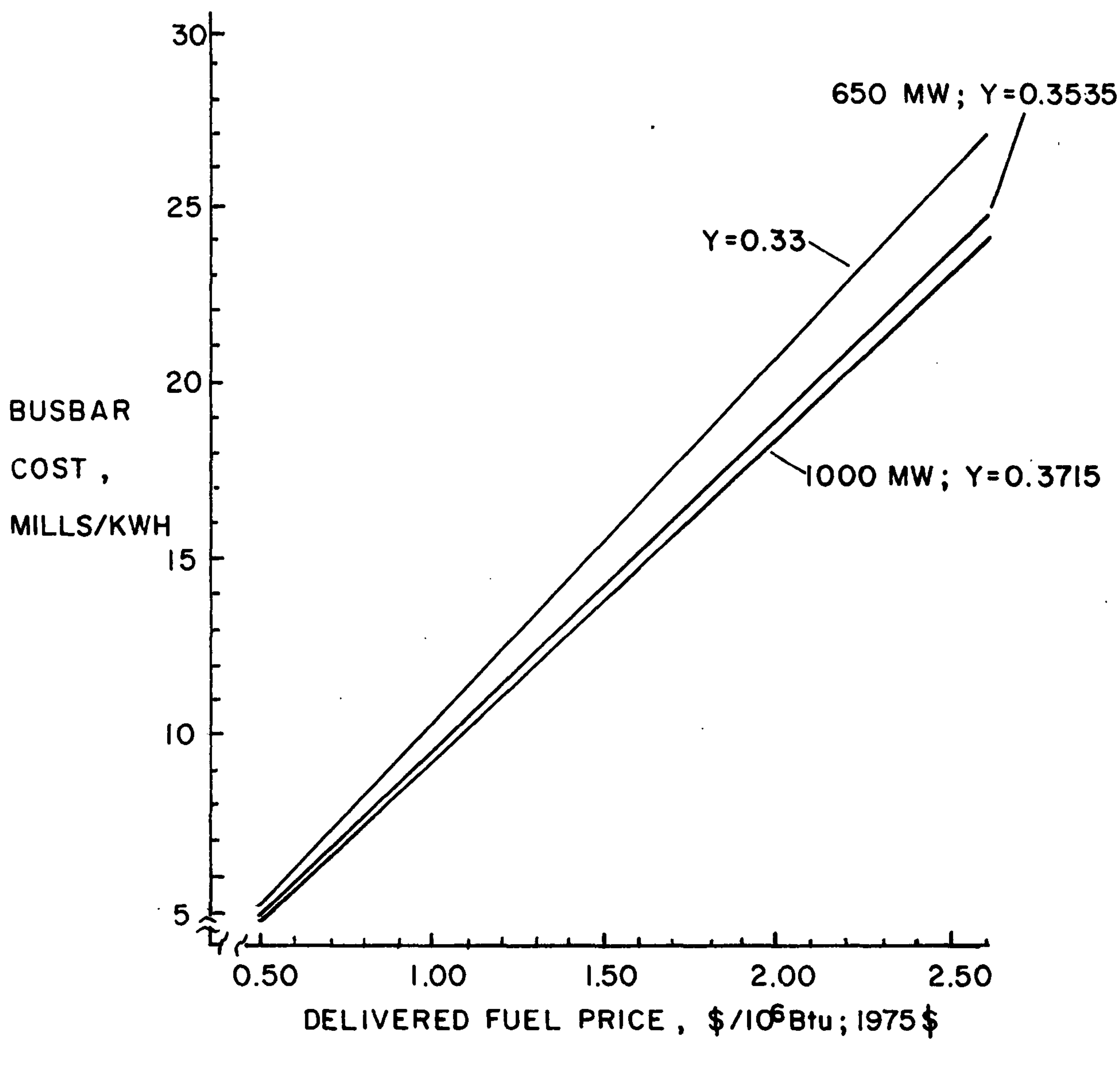


Exhibit 2.4 NUCLEAR FUEL CYCLE COST ASSUMPTIONS (1975 $)

Fuel Cycle Activity	1985	2000
Ore $/lb. U_3O_8	20	40
Conversion $/kg. U	4	4
Enrichment $/kg. SWU	100	150
Fabrication $/kg. U	100	100
Storage and Disposal Fees[5] ($/kg. U)	265	265

To translate these costs into a cost per kwh requires only that the amount consumed per year be known. These quantities are calculated for a plant at equilibrium in order to bypass the variations associated with the first and last cores. The equilibrium annual quantities for three enrichment tails assay's are shown in Exhibit 2.5. Also shown on Exhibit 2.5 are more detailed assumptions about the 1,000 mw_e PWR.

It should be noted that the burn-up figure shown is an average for PWR's. However, it is in fact inconsistent with the assumed plant factor and refueling schedule assumptions. Fuel cycle optimization involves a complex interplay of a number of different factors which produce cost minimizing batch sizes, enrichments, cycle times, in-core loading patterns and fuel designs. Such factors include costs of back up power, unexpected outages, and load changes to name a few. For this task we make an assumption which reflects actual operating experience in the industry, viz., that 1/3 of the core is replaced annually.

In Exhibit 2.5 equilibrium quantities are shown as a function of the enrichment tails assay. The optimum tails assay can be determined by the ratio of feed cost to the cost of separative work.[6] This relationship is shown in Figure 4. Thus for this task equilibrium quantities are used for a 0.30% tails assay in 1985 and for 0.20% in 2000.

As we have done for the other components of busbar cost, we show the busbar cost as a function of the cost of all the nuclear fuel cycle activities. These are shown in Figures 5-9. These graphs are specific to the equilibrium quantities shown in Exhibit 2.5. All costs are in 1975 dollars.

Nuclear fuel cycle cost assumptions also vary widely among study groups. The assumptions associated with some recent studies are shown in Exhibit 1.6. The assumptions were taken to 1985 for reference purposes and are shown in 1975 dollars.

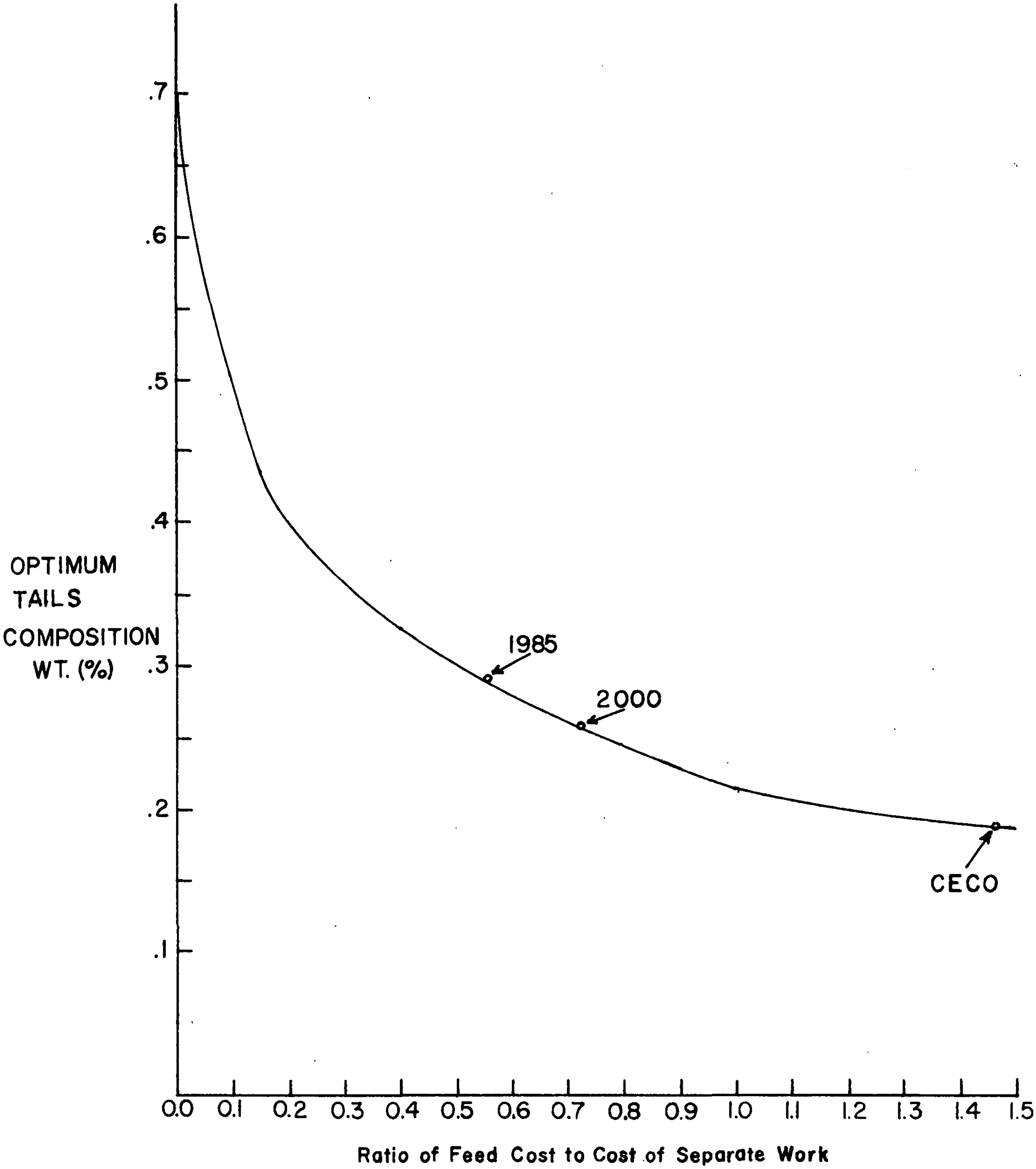
Exhibit 2.5 EQUILIBRIUM ANNUAL QUANTITIES REQUIRED FOR THE NUCLEAR FUEL CYCLE AS A FUNCTION OF ENRICHMENT TAILS ASSAY

Fuel Cycle Activity	Equilibrium Annual Quantities Enrichment Tails Assay = 0.20%	Equilibrium Annual Quantities Enrichment Tails Assay = 0.25%	Equilibrium Annual Quantitites Enrichment Tails Assay = 0.30%
Yellowcake (U_3O_8)	433,623 lbs.	470,309 lbs.	517,167 lbs.
Conversion	167,136 kg. U	282,384 kh. U	199,344 kg. U
Enrichment	126,096 kg. SWU	111,044 kg. SWU	99,672 kg. SWU
Fabrication	33,447 kg. U	33,447 kg. U	33,447 kg. U
Storage and Disposal	33,447 kg. U	33,447 kg. U	33,447 kg. U

Nuclear Plant Assumptions

- 1,000 mw_e PWR
- P.F. = .6
- 3 region core: refueled annually (1/3 of core)
- core loading: 100,341 kg. U
- fuel enrichment: 2.75%
- burnup: 33,000 megawatt-days per ton

FIGURE 4.- OPTIMUM TAILS COMPOSITION (NUCLEAR)



Source" Nuclear Power Plant Design Analysis, Alexander Sesonske 1973, USAEC, NTIS- TID- 26241

FIGURE 5 - YELLOWCAKE COMPONENT OF BUSBAR COSTS (NUCLEAR)

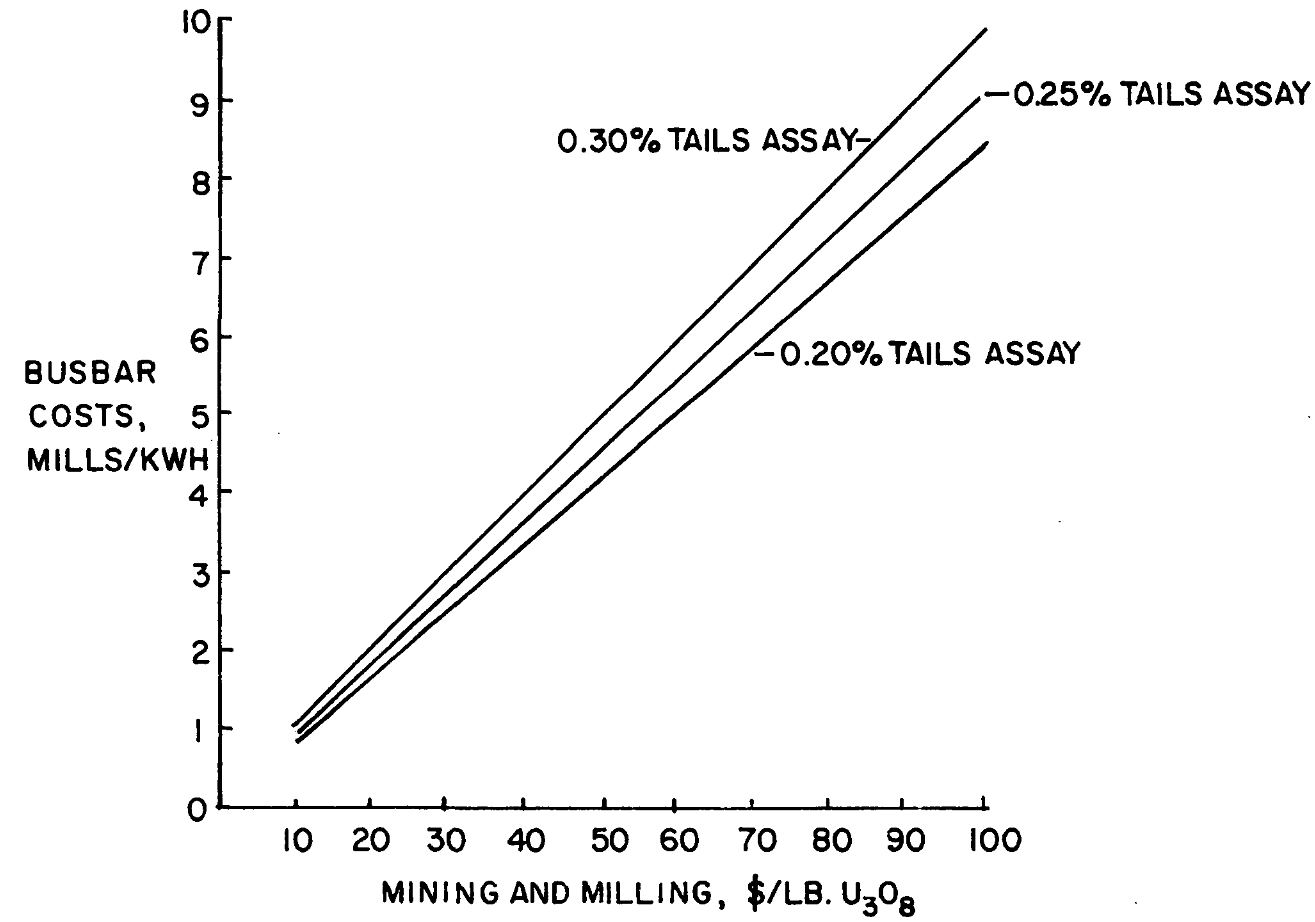


FIGURE 6 - CONVERSION-TO-UF_6 COMPONENT OF BUSBAR COSTS (NUCLEAR)

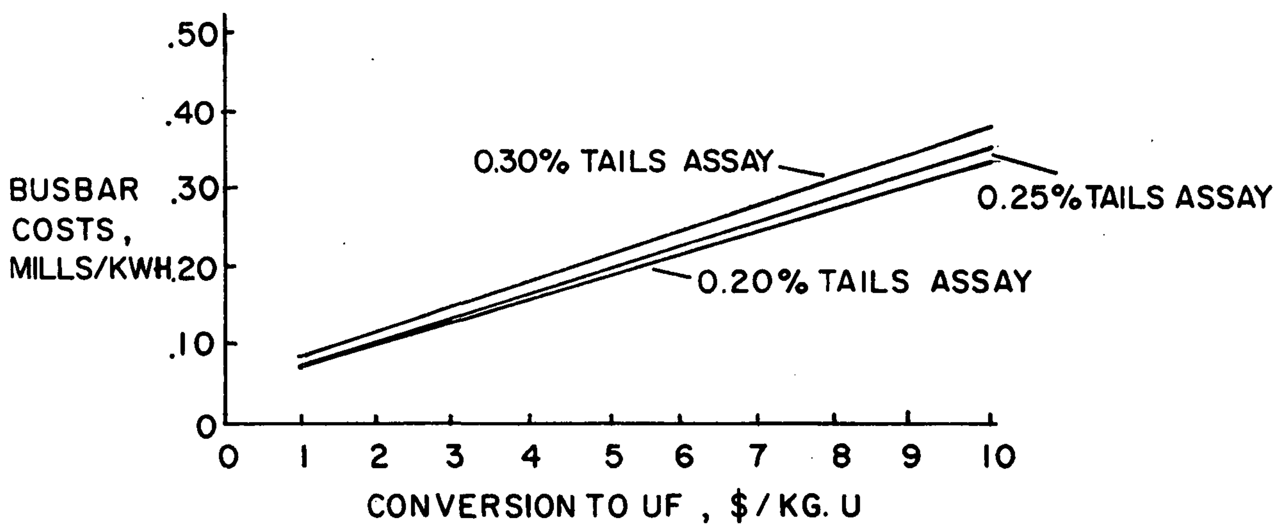
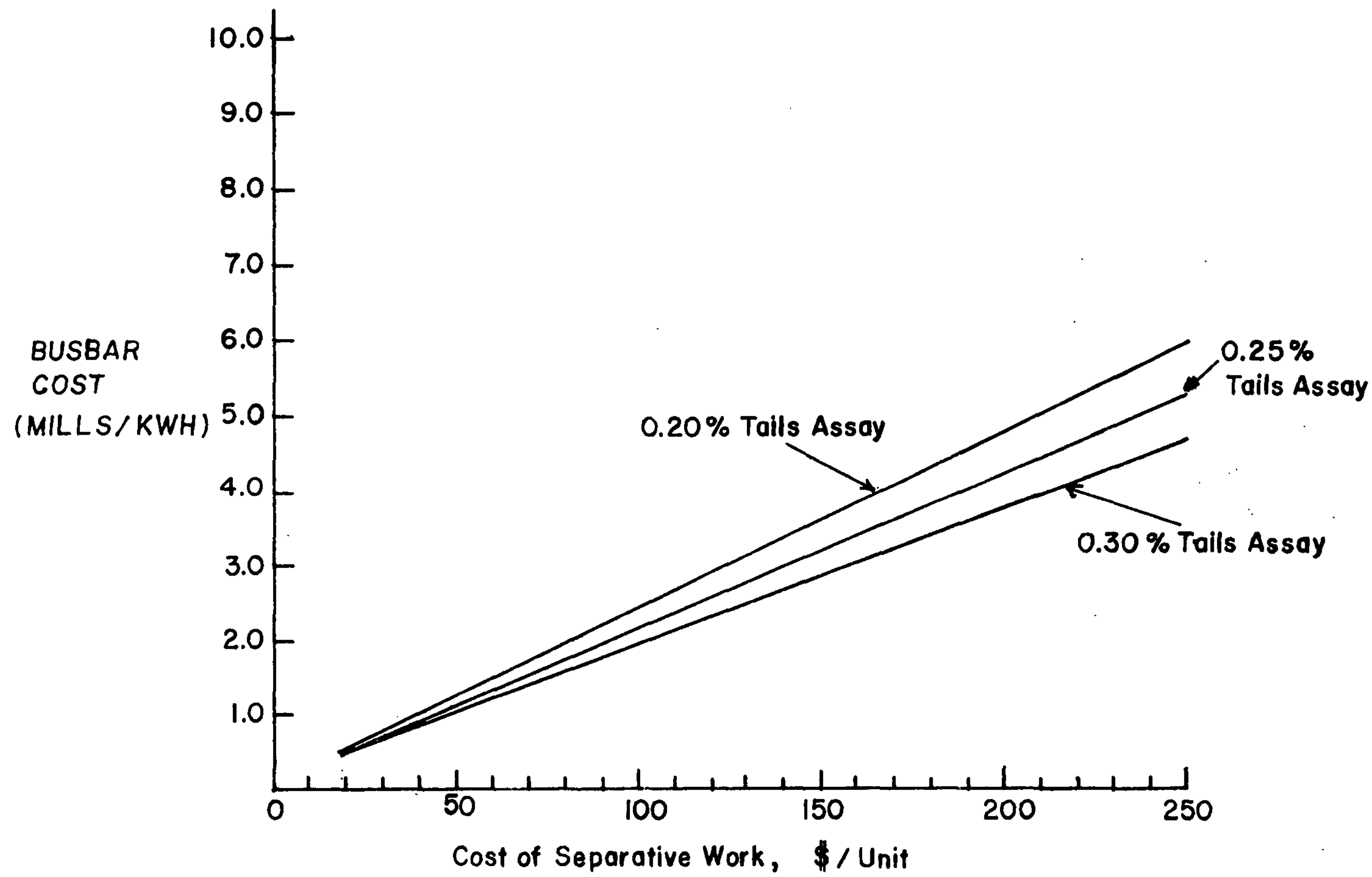


FIGURE 7. SWU COST COMPONENT OF BUSBAR COSTS (NUCLEAR)



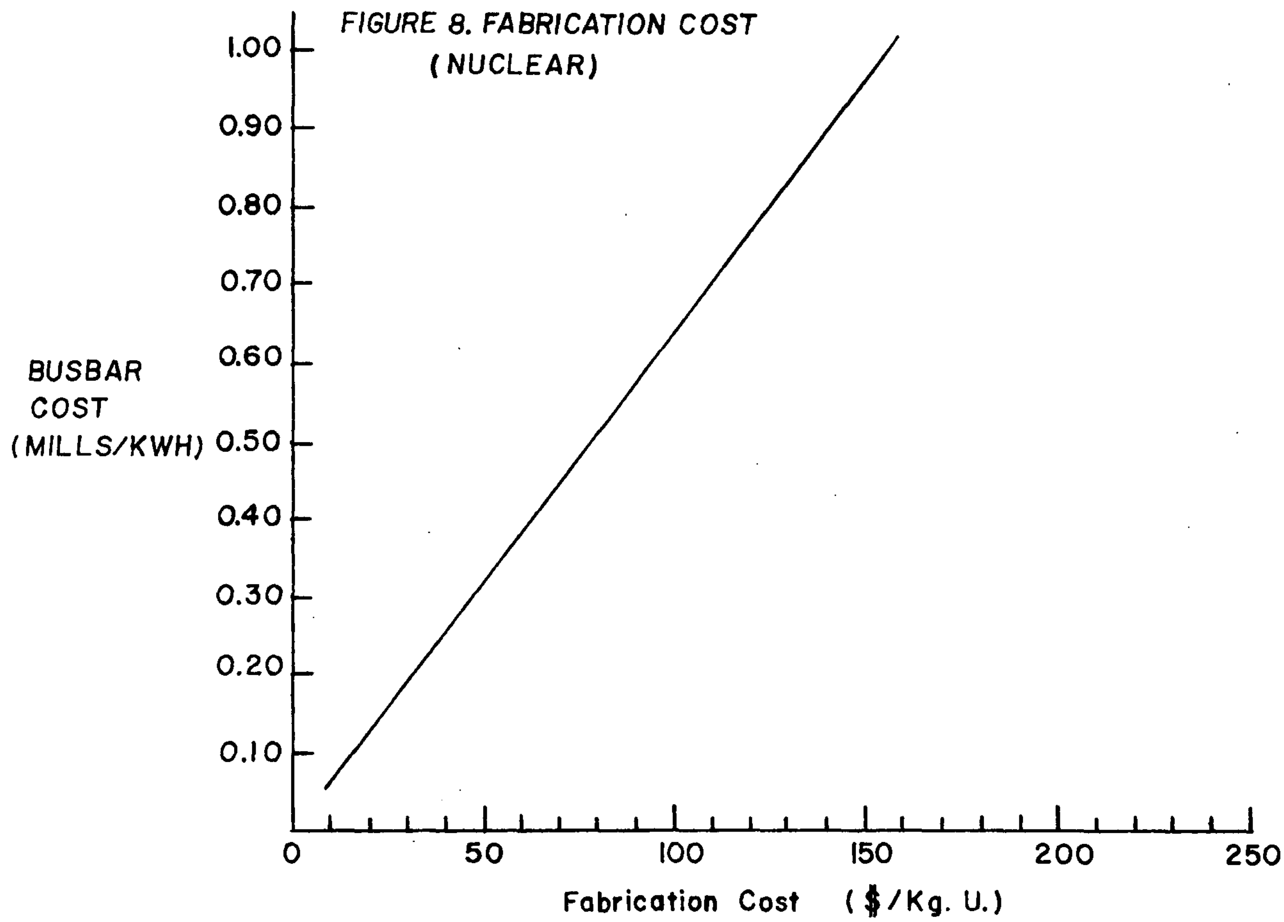
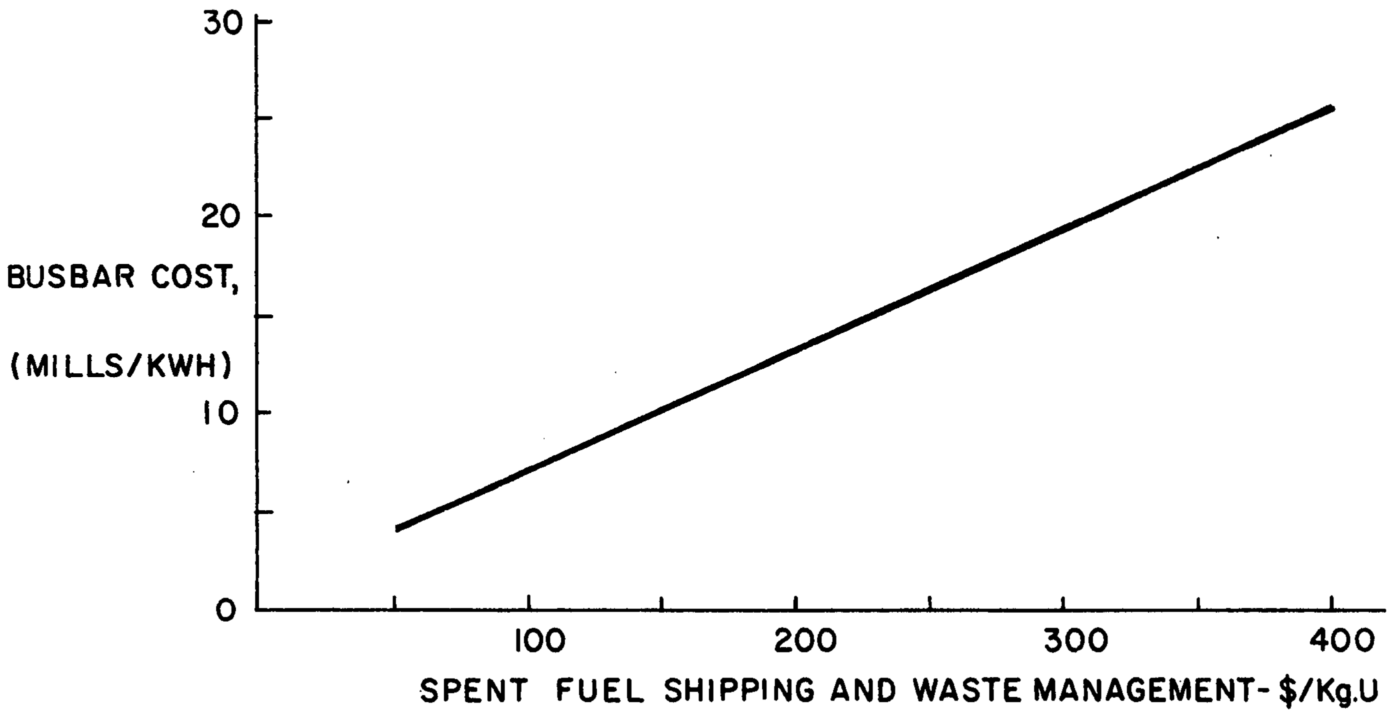


FIGURE 8. FABRICATION COST (NUCLEAR)

FIGURE 9 - SPENT FUEL SHIPPING AND WASTE MANAGEMENT COMPONENT OF BUSBAR COSTS (NUCLEAR)



APPENDIX

This report presents two formulations of cash flow models for the assessment of capital and operating costs of individual utilities supplying energy to the ORB region under alternative assumptions. The models provide the computational means of analyzing the impacts on costs of varying parameters specific to sites, the scales of activity, the movement of subordinate cash flows (wages, taxes), and so on. The work draws heavily on past and on-going studies at West Virginia University (WVU) in the College of Mineral and Energy Resources (COMER) and Engineering (COE) on the siting of such facilities.

The cash-flow models represent facilities for low and high sulfur coal-based conventional steam generated electric power, with and without stack gas desulfurization equipment (scrubbers), for light-water nuclear reactors and heavy-water nuclear reactors.

The basic model is CONCEPT-V which compares nuclear with conventional power generation using coal directly made available by Argonne National Laboratories. The schema for CONCEPT-V is shown in Exhibit A1. Lists of major variables are given in Exhibits A2 to A4.

Plant costs are separated into individual components, appropriate cost indexes applied and the adjusted components summed. Three sets of cost indexes as functions of time and location are used to adjust the costs of equipment, labor, and materials respectively. The equipment cost indexes are calculated from basic parameters. These include wage rates for the various crafts, labor productivity, and overtime considerations. The materials cost indexes are calculated from unit costs for site-related materials. These include structural steel, reinforcing steel, concrete and lumber. A very detailed breakdown is made of the labor and materials categories.

Historical cost data for craft labor and site-related materials are stored for 22 areas in the LAMA data file by a CONLAM auxiliary program. These data consist of construction labor rates and materials costs that are reported monthly in Engineering News-Record. It is possible to enter cost data for other locations if data are available.

The labor cost data consist of hourly rates (including union-negotiated fringe benefits, but not including employers' contributions for social security and workmen's compensation insurance) for 16 classifications of craft labor. The materials cost data consist of market quotations for seven classifications of materials. The present data set includes 15 years of historical cost data taken from Engineering News-

Record, beginning with 1961 and ending with 1975. The file has space allocated for 30 time entries and several hundred locations.

The model for assessing non-fuel operating costs is OMCOST, and can be used independently or in combination with CONCEPT-V. A list of major OMCOST variables is given in Exhibit A5.

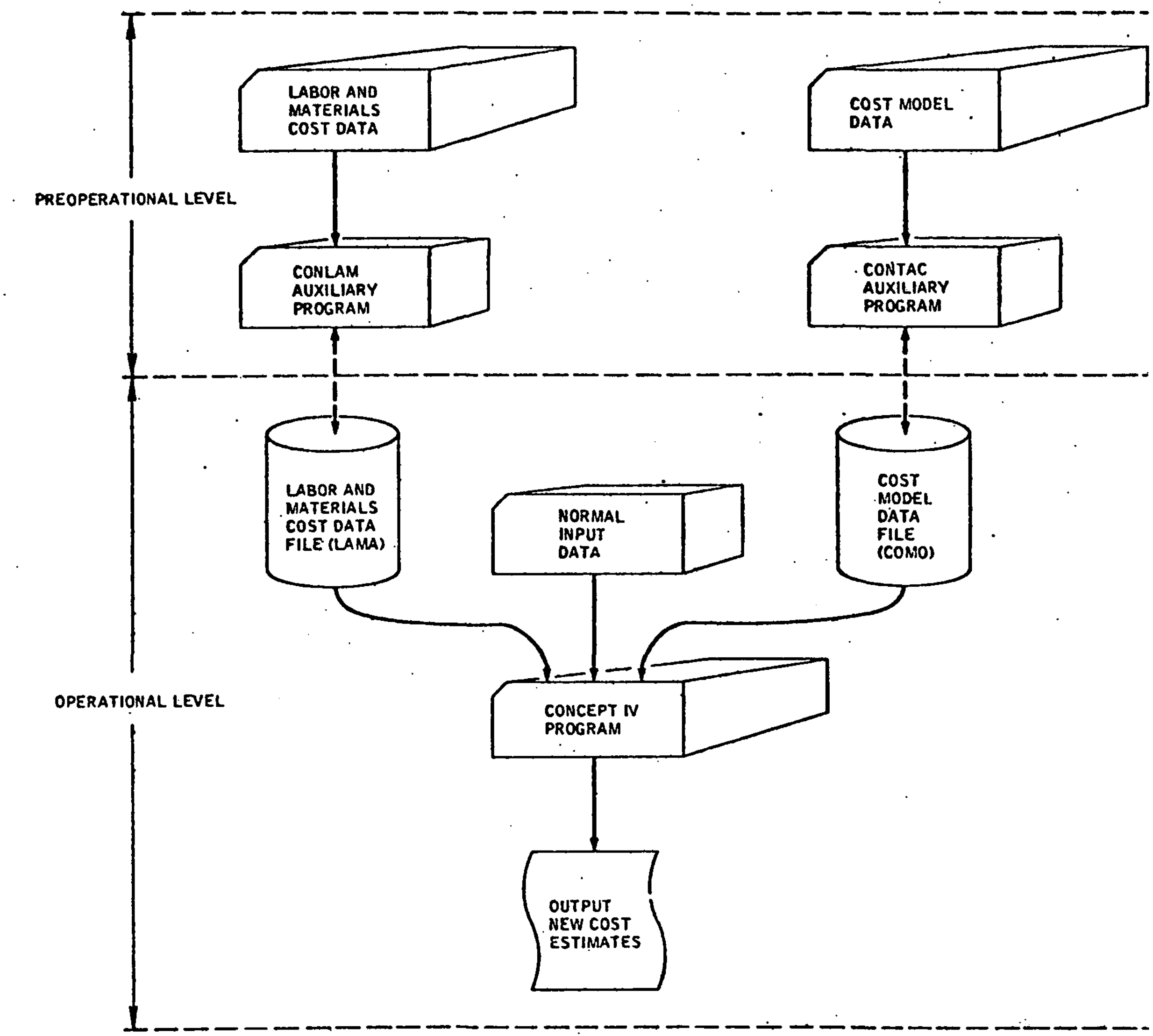


Exhibit A1. The CONCEPT Package

Exhibit A2

CONCEPT Variable List

MWE	The net capacity of the desired unit in MWe.
TYPE	Type of power plant.
LOC	The city where the plant is to be located.
YRSSS	Date steam supply system is purchased.
YRPER	Date construction permit is issued.
YRCOP	Date of initial commercial operation.
RIB	Average annual interest rate for interest during construction, %. (If not input, 7%/yr. will be used).
AA(I,J)	Scaling coefficients for adjusting the direct and indirect costs as a function of size according to the relation $\alpha_1 + \alpha_2 (MW_1/MW_0)^{\alpha_3}$ for each two-digit account. (I = 1,3 determines the α. & J = 1,11 defines the account)
APC(I), BPC(I)	Productivity indices for each two-digit direct and indirect cost account. (I = 1,11).
COB(I), COS(I)	Contractor's overhead burden factor for each two-digit direct and indirect cost account in the base model (COB) and the specific case (COS). (I = 1,11).
CONTL(I), CONTM(I), CONTE(I)	Contigency percentage for labor, material, and factor equipment, respectively, for each two-digit direct and indirect cost account. (I = 1,11).
DEOT(I), OTP(I), OVERS(I)	Labor efficiency coefficient, overtime payment premium, and labor efficiency factor, respectively, for each two-digit direct and indirect cost account. (I = 1,11).
FACS1(I,J), FACS2(I,J), FACS3(I,J)	Weighting factors for labor, material, and equipment, respectively, for each two-digit direct and indirect account (J = 1,11). The first dimension, I, correlates a weighting factor to a specific labor, material, or equipment index in the CONLAM file.
FILS(J), ISITE(J)	Weighting factor and site location number for up to twenty locations to be combined in a composite site. (J = 1,20).
RINT(J)	Interest rate expressed as a decimal number for each of the fifty time periods between the steam supply date and commercial operation date. (J = 1,50).

(continued)

Exhibit A2 (continued)

YFIRST YLAST	The first and last dates to be considered in performing a linear regression on the historical equipment, labor, and material file.
HWI(J) HW	The number of hours worked per week for each two-digit direct and indirect cost account (J = 1,11), or, alternately, the number of hours worked per week in all the accounts.
FACE(I,J)	An escalation factor for equipment, labor, and material (I = 1,3) in each of the two-digit direct and indirect cost account. (J = 1,11).
AMAN	The direct labor man-hours per kilowatt for the specific case being run.
CFCA(I,J)	Cash flow date for each two-digit direct and indirect cost account (I = 2,12) in each of the fifty time periods between the steam supply date and commercial operation date. (J = 1,50).
D(I,J)	Lowest-digit account direct and indirect costs divided into equipment, labor, and material (I = 1,3) for a given account. (J = 1,350).

Exhibit A3

CONLAM Variable List

NOPER	Number of actual data points stored on file, less than or equal to MAXREC.
MAXREC	Maximum number of time periods on file for each location, not to exceed 30.
NCITY	Number of locations on file, presently 24.
E(1)	Hourly rate for building labor.
E(2)	Hourly rate for heavy construction.
E(3)	Hourly rate for bricklayers.
E(4)	Hourly rate for carpenters.
E(5)	Hourly rate for structural ironworkers.
E(6)	Hourly rate for plasters.
E(7)	Hourly rate for electrical workers.
E(8)	Hourly rate for steamfitters.
E(9)	Hourly rate for operating engineers.
E(10)	Hourly rate for small tractor operators.
E(11)	Hourly rate for scrapper operators.
E(12)	Hourly rate for crane operators.
E(13)	Hourly rate for air compressor operators.
E(14)	Hourly rate for truck drivers. (<4 yd^3).
E(15)	Hourly rate for boilermakers.
E(16)	Hourly rate for all other crafts.
F(1)	Material costs for channels. $/100 lb.
F(2)	Material costs for I-beams. $/100 lb.
F(3)	Material costs for W-flanges. $/100 lb.
F(4)	Material costs for re-bars. $/100 lb.
F(5)	Material costs for 3000-psi Redimix concrete. \$/yd^3.
F(6)	Material costs for 3/4-in. B-B plyform. \$/1000 ft^2.
F(7)	Material costs for 2 x 4 fir or pine lumber. $/1000 bd. ft.
F(8)	Cost for land, $.

Exhibit A4

CONTAC Variable List

TYPE	Plant type.
BWE	Plant capacity, MWe.
YBC	Year of reference case costs.
PO	Fraction of time expended up to date of construction permit.
MHT	Total craft labor in thousands of man-hours for direct cost accounts for reference plant.
MHP(1)	Craft labor in thousands of man-hours for each direct cost account. (I = 1,7).
AEB(1)	Coefficient used for factory equipment rate. (I = 1,7).
AMB(1)	Coefficient used for site-related materials rate. (I = 1,7).
ALB(1)	Coefficient used for craft wage rate. (I = 1,7)
AI(J)	Constants for equation describing indirect cost curves.
AA(J)	Constants for equation describing direct costs, minus contigency and spare parts, for two-digit accounts.
D(J,I)	Array containing direct costs at lowest-level accounts (J = 1,3).
CFCA(J,I)	Array containing cash flow curves for each direct cost account. (J = 1,8 & I = 1,50).
FACS1(J,I)	Weighting factors for site labor. (J = 1,7 & I = 1,16).
FACLAB(J,I)	Labor categories. (J = 1,2 & I = 1,16).
FACS2(J,I)	Weighting factors for site material. (J = 1,7 & I = 1,16).
FACMAT(J,I)	Material categories (J = 1,2 & I = 1,16).

Exhibit A5

Major OMCOST Variables

Variable	Definition	Default
YEAR	Yr. of operation	1975
TYPE	Plant type PWR = pressurized water reactor BWR = boiling water reactor HTGR = high-temperature gas-cooled reactor LMFBR = liquid metal-cooled fast breeder reactor (PWR, BWR, HTGR, LMFBR: nuclear) COAL OIL GAS	PWR
SINK	Type of heat sink NET = natural-draft evaporative cooling tower MET = mechanical=draft evaporative cooling tower RUN = once-through or run-of-river cooling	NET
PLTFAC	Plant capacity factor $= \frac{\text{Kwh generated/yr.}}{\text{rated capacity in Kw x 8760 hr/yr.}}$ Base load = 0.7, midrange = 0.4, peaking = 0.15	0.80
MWT	Thermal <u>input</u> to plant (single unit), MW can be calculated by = 100 x MWN/ηnet. ηnet stored in the program is shown in Table 5.1, p. 35	3092
MWN	Net plant electrical <u>output</u> (single unit), MW present industrial ave = ~600, by 1980-85: ~1000	1000
ISOX	= 1, SO_2 removal specified = 0, SO_2 removal not specified	0
UNITS	No. of units per station, (can be 1, 2, 3, 4)	1
WAGERT	Wage rate before adders (base yr [1975]), \$/hr (\$4.50 ~ \$7.50?)	5.75
FRINGE	Operator fringe benefits as % of wage rate (30 ~ 35%?)	5.75

(continued)

Exhibit A5 (continued)

Variable	Definition	Default
SUPER	Plant supervision as % of wages + fringe benefits (10 - 15%?)	30
BTUCOL	Heating value of coal, Btu/lb.	11,000
BTUBBL	Heating value of oil, million Btu/barrel	6.2
XLIMS	Tons of limestone per ton of sulfur	4
PCTS	Sulfur in oil, %	2.5
PCTSUL	Sulfur in coal, %	3.5
SLURRY	Cost of sludge disposal (base yr), $/ton	5.
COSLM	Cost of limestone (base yr), $/ton	5
ESWAGE	Escalation rate on wages, %/yr.	7
ESOIL	Escalation rate on cost of fuel oil, %/yr.	10
ESSLUR	Escalation rate on cost of sludge disposal, %/yr.	6
ESLIME	Escalation rate on cost of limestone, %/yr.	6
ESCINS	Escalation rate on cost of commerical liability insurance	5
ESGINS	Escalation rate on cost of government liability insurance	5
ESFEES	Escalation rate on cost of operating fees	3
ESMATL	Escalation rate on cost of materials and supplies (expenses)	6

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