APPENDIX P

FUEL COSTS AND FUEL COST ESCALATION

P-1. General.

a. The assumptions governing the determination of fuel costs are critical in the evaluation of hydropower, because they affect a significant portion of the benefits (see Section 9-5f). Two points are important: (a) the establishment of the fuel cost base that is representative of current market conditions, and (b) recognition of past and future price shifts in order to identify real fuel escalation rates and to develop specific procedures to account for those rates. Section 2.5.8 of the Principles and Guidelines (P&G) provides some guidance in these areas, and the following paragraphs propose procedures for accounting for both aspects within the framework of this guidance.

b. This appendix was drawn essentially intact from Chapter 4 of the Water and Energy Task Force report, Evaluating Hydropower Benefits, dated December 1981 (78). Several wording changes have been made to the original text of the Task Force report in order to reference the 1983 Principles and Guidelines (77) in lieu of the 1979 NED Manual (79), and to make the material conform to current implementation practices. Some editorial changes were also made to make the text conform to the standard Engineering Manual format.

P-2. Base Fuel Costs.

a. Fossil-Fueled Plants.

(1) Sources of Data. The type and cost of fossil fuel used to estimate steam-electric power costs should be determined on the basis of the fuel available and most likely to be used in the particular area under consideration. In most instances, this can be done by examining current fuel purchases. Detailed monthly data describing quantity, price, and thermal content of each utility purchase are maintained by the Department of Energy's Energy Information Administration (EIA). This data is available and can be summarized from computer data files maintained by EIA. This information is supplied for all fossil-fuel steam plants and combustion turbine plants with a combined capacity of 25 MW or greater. The information in DOE data files includes average purchase costs summarized by plant, state, or region. These averages include the effects of purchases made under the terms of both old and new contracts.

(2) Real Fuel Prices. Section 2.5.8(a)(5) of the Principles and Guidelines stipulates that "... fuel costs used in the analysis should reflect economic prices (market clearing) rather than regulated prices." (emphasis added). Care must be exercised, therefore, to insure that costs incurred under old contracts, which may not reflect real economic prices in today's market, are not included. In periods of rising relative fuel prices, the use of upper quartile prices instead of average prices may more accurately reflect economic (market-clearing) prices.

(3) Computation of Fuel Costs. The Federal Energy Regulatory Commission (FERC), through its Regional Offices, can provide the latest available fuel price information based on EIA data. As an example, Tables P-1 and P-2 summarize this data by DOE regions and states for October 1980 fuel costs. In some instances, it may be appropriate to base fuel costs on a larger or smaller geographic area than a DOE region. In general, fuel costs should be representative of the "system" within which the hydropower project is to be operated. Depending on the size of this system, fuel costs typical of a single state or a group of states may be appropriate. FERC can provide cost data for any combination of states and/or DOE regions requested.

(4) Regional vs. National Average Values. Coal prices vary considerably in various parts of the country because of the large differences in mining costs among the different coal-producing areas and the fact that substantial transportation cost components may be reflected in coal prices for nonproducing areas. Accordingly, it is appropriate that specific coal prices be derived for each area or system. However, because the average price of oil for a given powerplant is affected more by world market prices than by variations in source, because oil is readily transportable, and because the cost of transportation is only a small part of the at-site cost of oil, the national average upper quartile price is considered to be a more accurate measure of the "market clearing" price of oil for a given system than the individual regional prices. Table P-1 shows that there is relatively little variation in the upper quartile prices of light oil (or distillate oil). The regional variations in prices of heavy oil (residual oil) are greater, probably because even the fourth quartile prices reflect a fair proportion of long-term contract prices. In time, as the effect of oil price deregulation takes hold, it is expected that the regional variation will be less pronounced.

(5) Fuel Use Limitations. In some cases, certain fuels are strictly limited in availability and should not be considered as real alternatives. The Powerplant and Fuel Use Act of 1978 provides that ". . . natural gas or petroleum shall not be used as a primary energy source in any new electric powerplant . . ." except to the extent that exemptions may be granted. The Act provides for the granting of per-

TABLE P-1.
Regional Electric System Fuel Costs, October 1980 Prices 1/

DOE 2/ Region	Coal Avg.	Coal Upper 1/4	Lignite Avg.	Lignite Upper 1/4	Light Oil Avg.	Light Oil Upper 1/4	Heavy Oil Avg.	Heavy Oil Upper 1/4
1	162.54	164.74	0.0	0.0	625.58	655.52	415.81	461.24
2	161.71	199.08	0.0	0.0	607.18	633.67	448.13	505.40
3	144.10	193.94	0.0	0.0	604.49	631.45	411.78	448.57
4	156.16	198.94	0.0	0.0	599.90	642.67	393.85	431.77
5	145.25	202.07	95.17	103.77	604.76	634.11	595.88	687.70
6	139.24	208.35	58.18	65.00	420.82	596.62	403.34	493.95
7	127.68	179.24	0.0	0.0	596.25	622.53	323.66	330.15
8	77.09	112.31	66.89	86.53	638.03	677.16	0.0	0.0
9	105.73	174.76	0.0	0.0	610.64	640.45	520.19	603.22
10	102.34	112.94	0.0	0.0	622.36	624.95	0.0	0.0
U.S. Average					589.30	642.90 (est.)	535.90	595.30 (est.)

1/ Prices in cents per million BTU. A value of 0.0 is indicated when no purchases were reported. Upper quartile prices are based on an average of upper quartile of total BTU's purchased.

2/ States included in Department of Energy regions;

1 - Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island
2 - New York and New Jersey
3 - Pennsylvania, Maryland, Virginia, West Virginia, District of Columbia and Delaware
4 - Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia and Florida
5 - Minnesota, Wisconsin, Michigan, Illinois, Indiana and Ohio
6 - Texas, New Mexico, Oklahoma, Arkansas and Louisiana
7 - Kansas, Missouri, Iowa and Nebraska
8 - Montana, North Dakota, South Dakota, Wyoming, Utah and Colorado
9 - California, Arizona, Nevada and Hawaii 3/
10 - Washington, Oregon, Idaho and Alaska 3/

3/ Data from Alaska and Hawaii not included in average fuel costs.

TABLE P-2. Electric System Fuel

State	Coal 3/ Average	Coal 3/ Upper 1/4 1/	Light oil Average	Light oil Upper 1/4 1/	Heavy oil Average	Heavy oil Upper 1/4 1/
Alabama	164.79	199.21	655.74	773.34	0.0	0.0
Alaska	140.16	173.33	652.17	977.94	471.43	471.43
Arizona	103.20	176.95	636.13	640.10	544.31	654.90
Arkansas	149.33	156.20	487.01	490.93	349.15	352.08
California	0.0	0.0	597.01	630.14	566.10	600.61
Colorado	86.38	114.64	560.00	560.00	0.0	0.0
Connecticut	0.0	0.0	615.32	618.10	459.14	463.82
Delaware	178.41	239.20	591.44	591.60	410.31	415.25
D. C.	0.0	0.0	0.0	0.0	420.30	420.30
Florida	183.66	213.26	592.31	611.44	395.44	432.77
Georgia	152.50	188.71	623.18	632.38	363.50	363.50
Hawaii	0.0	0.0	629.97	632.30	360.38	406.76
Idaho	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	158.00	226.23	612.22	644.00	668.54	687.70
Indiana	127.78	194.68	607.62	621.92	0.0	0.0
Iowa	146.17	194.56	590.03	613.09	0.0	0.0
Kansas	112.46	169.01	503.00	503.00	0.0	0.0
Kentucky	129.85	189.91	648.17	786.97	0.0	0.0
Louisiana	197.70	197.70	575.55	586.22	424.08	440.90
Maine	0.0	0.0	649.10	649.10	388.20	388.20
Maryland	157.43	177.32	601.79	619.34	397.45	420.99
Massachusetts	0.0	0.0	621.01	634.40	398.58	422.34
Michigan	156.33	203.15	631.27	634.77	422.58	470.62
Minnesota	108.45	133.68	600.00	600.00	440.50	442.60
Mississippi	191.54	251.67	592.45	605.10	371.37	371.80
Missouri	124.45	172.32	593.08	600.90	321.50	321.50
Montana	43.07	62.32	537.10	537.10	0.0	0.0
Nebraska	134.72	195.16	648.87	657.53	348.40	348.40

1/ Based on average of upper quartile of total BTU's purchased.
2/ A value of 0.0 indicates no purchases reported.

Costs by State, October 1980

State	Coal Average	Coal Upper 1/4 1/	Light oil Average	Light oil Upper 1/4 1/	Heavy oil Average	Heavy oil Upper 1/4 1/
Nevada	113.53	163.59	0.0	0.0	380.21	438.36
New Hampshire	162.54	164.74	632.87	672.56	401.68	410.50
New Jersey	185.25	216.79	607.07	634.02	456.19	497.54
New Mexico	56.77	99.90	507.75	641.40	423.40	423.90
New York	149.18	174.43	609.40	609.40	447.12	506.37
North Carolina	161.45	192.93	606.38	609.29	0.0	0.0
North Dakota	0.0	0.0	605.43	617.10	0.0	0.0
Ohio	151.20	193.88	591.77	625.83	366.67	505.87
Oklahoma	132.27	149.92	0.0	0.0	0.0	0.0
Oregon	149.00	149.00	621.50	621.50	0.0	0.0
Pennsylvania	135.77	193.51	603.94	636.27	426.93	471.34
Rhode Island	0.0	0.0	0.0	0.0	389.30	389.30
South Carolina	157.73	171.51	611.80	624.56	387.40	388.00
South Dakota	89.70	90.40	651.23	659.24	0.0	0.0
Tennessee	165.31	187.77	597.84	676.48	0.0	0.0
Texas	179.62	217.28	355.96	566.44	462.55	550.70
Utah	108.68	136.07	627.60	652.90	0.0	0.0
Vermont	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	173.32	202.57	599.25	606.84	406.79	431.70
Washington	98.80	98.80	664.10	664.10	0.0	0.0
West Virginia	146.83	189.02	626.13	639.32	0.0	0.0
Wisconsin	143.05	161.51	592.37	598.01	492.70	492.70
Wyoming	62.00	73.63	678.10	733.17	0.0	0.0

3/ Lignite costs reported, by state:

State	Average	Upper 1/4
Minnesota	95.17	103.77
Montana	97.10	97.10
N. Dakota	63.08	83.00
S. Dakota	87.50	87.50
Texas	58.18	65.00

manent exemptions for the use of natural gas or petroleum where it is demonstrated that the plant is to be operated solely as a "peakload powerplant." A peakload powerplant is defined as a plant operating at an average annual plant factor of 17 percent or less. Also, but with somewhat more restrictive conditions, an exemption may be granted for the use of petroleum in an intermediate level powerplant. An intermediate load powerplant is defined as a plant that operates at an average annual plant factor of between 17 and 40 percent per year. Neither oil nor gas should be considered where the alternative would be used as baseload generation.

(6) Special Cases. Some of the procedures proposed above may not be applicable to isolated regions, such as Alaska, Hawaii, and Puerto Rico. The relatively small loads, the unavailibility of coal, and other factors may dictate the use of oil or gas for baseload as well as for peaking generation. Even where coal is a potential fuel (such as some parts of Alaska), the unavailability of DOE/EIA data makes cost estimating difficult. In these areas, it may be necesaary for FERC and the planning agencies to conduct special studies to identify the most appropriate future fuel sources and fuel costs.

b. Nuclear-Fueled Plants. Nuclear fuel costs, although dependent to a degree on use of a depletable resource, are more related to costs associated with processing, handling, and disposal. As a manufactured fuel with a relatively high ratio of value to transport cost, it has a national rather than a regional value. Periodic estimates of current nuclear fuel costs are available from two principal sources: DOE/EIA and Data Resources, Inc. (DRI). The basic differences between the two information sources are discussed in Section P-3c. It is recommended that DOE/EIA nuclear fuel data be used for developing energy values.

P-3. Real Fuel Cost Escalation.

a. Current Procedures. Current procedures require that NED cost-benefit comparisons are to be expressed in terms of constant dollars. No accounting is made for expectations of future general price inflation since, in the long run, it is not expected to affect the relative values of resources. However, Principles and Guidelines (Section 2.5.8(a)(5)) specifically requires the evaluation of real escalation in fuel prices when the most likely alternative to a hydropower project is a thermal powerplant.

b. Forecast Uncertainty. It must be recognized that fuel price forecasts are not highly reliable. Many variables which are themselves hard to predict impinge on fuel prices. The resultant fuel price forecasts inherently contain a great deal of uncertainty.

Unfortunately, it is not possible to "not forecast" fuel prices, because making the assumption that there is no change in real fuel prices over time is equivalent to using a forecast of zero fuel price escalation. Consequently, the choice which analysts must make is not between forecasting and not forecasting, but instead between one forecast and another.

c. Forecast Sources.

(1) Fuel price forecasts developed by DOE and DRI were studied (67), (4). Fuel price escalation rates based on the 1980 DOE forecast are shown in Table P-3 and those based on the 1980 DRI forecast are shown in Table P-4. Fuel price forecasts are also available from EPRI (Electric Power Research Institute), and the SRI (Stanford Research Institute). However, only the DOE and DRI forecasts are long-term, regionally disaggregated, and periodically updated.

(2) The DOE forecast has been used widely as the source of fuel cost escalation rates in the past. It also has some "official" stature and is available at no cost. Differences between DOE and DRI forecasts are as follows:

- DRI forecasts prices of fuels delivered to electric utilities. DOE also forecasts future utility fuel prices, but at present DOE has no current utility fuel prices which are comparable to the forecast prices. For this reason, 1980-85 price escalation rates cannot be determined from the DOE forecast. To date, DOE forecasts of industrial fuel price escalation rates have been used as a proxy for utility fuel price escalation rates.

- the continued availability of a regionalized DOE forecast is somewhat uncertain.

- region-to-region variation in escalation rates is not as severe in the DRI forecast as in the DOE forecast.

- some aspects of the DOE forecast, including real declines in the prices of fuels in some regions, greater escalation rates for coal prices than for petroleum products over the 1980-85 period, and a substantial real rise in the price of nuclear fuel over the next 5 years, are absent in the DRI forecast.

- an updated DRI forecast is published quarterly. The DOE forecast is updated less frequently and does not become official for several months after the forecast is developed. At the time this study was done, the most recent official

TABLE P-3. Compound Annual Real Energy Price Escalation

Fuel Type	Region 1	2	3	4	5
			1980-1985		
Residual 2/	8.3	7.4	7.4	7.5	7.4
Distillate 2/	3.7	3.1	3.1	3.1	3.1
Coal 2/	10.1	8.7	8.1	13.6	11.0
Nat. gas 2/, 3/	0.1	-0.3	1.0	1.9	1.8
Nuclear 4/	2.9	2.9	2.9	2.9	2.9
			1985-1990		
Residual	2.1	2.0	2.0	2.1	2.2
Distillate	2.1	2.1	2.1	2.1	2.2
Coal	-2.7	2.0	2.5	3.0	2.0
Natural gas	0.1	-0.3	1.0	1.9	1.8
Nuclear	3.4	3.4	3.4	3.4	3.4
			1990-2010		
Residual 5/	3.6	3.5	3.4	3.7	3.4
Distillate	3.8	3.8	3.8	3.8	4.0
Coal	0.3	0.4	0.5	0.0	0.1
Natural gas	2.7	2.7	3.1	4.0	3.1
Nuclear	1.1	1.1	1.1	1.1	1.1

1/ See footnote 2, Table P-4, for a description of DOE regions.

2/ Escalation rates for residual, distillate oil, coal and natural gas were computed using 1980 base prices from October 7, 1980 Federal Register, Table C-1, and forecast prices from November 1980 DOE/EIA Service Report SR/1A 180-16, medium price path, average prices, industrial fuels. Service Report prices converted to 1980 dollars using GNP price deflator. Update factor was 1.094.

3/ Because of uncertainty about schedules and timing of effects of natural gas price deregulation, average escalation rates for natural gas were computed over 1980-1990 period and used for both the 1980-1985 and 1985-1990 periods.

Rates by Region, DOE Forecast (1980-2010) 1/

Region 6	7	8	9	10	Average	Fuel Types
		1980-1985				
7.5	7.5	7.4	7.4	7.4	7.5	Residual
3.1	3.1	3.1	3.1	3.1	3.2	Distillate
14.9	10.2	10.1	10.7	5.7	11.7	Coal
5.0	3.8	4.7	-0.4	2.4	2.9	Nat. gas
2.9	2.9	2.9	2.9	2.9	2.9	Nuclear
		1985-1990				
2.2	2.1	2.1	2.3	2.3	2.1	Residual
2.1	2.2	2.1	2.2	2.2	2.1	Distillate
1.5	2.0	0.0	1.3	10.4	2.5	Coal
5.0	3.8	4.7	-0.4	2.4	2.9	Nat. gas
3.4	3.4	3.4	3.4	3.4	3.4	Nuclear
		1990-2010				
3.6	3.4	3.7	3.6	3.7	3.4	Residual
3.9	4.0	4.0	4.0	4.0	3.9	Distillate
1.4	0.4	0.6	0.3	-0.5	0.7	Coal
3.3	3.3	2.2	0.8	-1.1	3.0	Nat. gas
1.1	1.1	1.1	1.1	1.1	1.1	Nuclear

4/ Nuclear fuel escalation rates were computed from Service Report price projections appearing in utility fuel price tables and 1980 base price supplied by DOE staff.

5/ Service Report indicates decline in real price of residual oil in Regions 5 and 7 after 1980. DOE staff indicated that this is an anomaly created by assumptions about synfuels as a substitute for residual oil, and suggested substituting the average escalation rate for other regions.

TABLE P-4
Compound annual real energy price escalation rates by region (1980-2010), DRI forecast 1/ , 2/

Fuel Type	NENG	MATL	SATL	ENC	WNC	ESC1	ESC2	WSC1	WSC2	MTN1	MTN2	MTN3	PAC	US Avg.
							1980-1985							
Residual 3/	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	2.1
Distillate 3/	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	2.3
Coal 4/	3.5	5.2	6.0	4.3	3.5	5.3	5.9	5.2	5.2	5.1	5.3	5.5	3.8	5.0
Natural gas 5/	7.6	10.2	12.7	10.5	14.3	11.4	11.5	14.8	12.8	12.5	11.1	8.9	9.9	15.5
Nuclear 6/	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
							1985-1990							
Residual	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Distillate	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Coal	3.7	2.3	3.2	1.9	2.7	2.7	2.3	2.2	4.1	4.5	1.8	3.7	3.7	2.1
Natural gas	4.4	5.5	12.4	6.1	7.2	8.7	7.3	9.9	9.7	6.3	8.3	7.0	4.8	8.6
Nuclear	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
							1990-1995							
Residual	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Distillate	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Coal	2.6	2.9	2.4	2.0	1.6	2.3	1.7	2.4	1.8	2.5	0.7	2.2	3.2	2.3
Natural gas	5.3	6.4	7.3	6.5	7.7	7.1	8.0	5.6	5.7	5.8	6.3	8.2	4.9	5.8
Nuclear	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
							1995-2010 7/							
Residual	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Distillate	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Coal	2.1	1.4	1.5	1.4	1.5	1.6	0.9	1.9	0.9	1.7	2.2	2.5	2.3	1.4
Natural gas	1.8	1.9	1.8	2.0	2.0	1.9	2.0	2.5	2.4	2.0	1.9	1.9	2.0	2.7
Nuclear	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

1/ Projected nominal fuel prices were deflated using DRI forecast of GNP deflator (DRI variable PGNP)

2/ Regional definitions used in the DRI energy model:

Region	Abbrev.	States
New England	NENG	Massachusetts, Maine, Vermont, Rhode Island, New Hampshire, and Connecticut
Middle Atlantic	MATL	Pennsylvania, New Jersey, and New York
South Atlantic	SATL	Delaware, Maryland, District of Columbia, Virginia, West Virginia, Georgia, Florida, South and North Carolina
East North Central	ENC	Ohio, Wisconsin, Indiana, Michigan, and Illinois
West North Central	WNC	Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and Missouri
East South Central #1	ESC1	Kentucky and Tennessee
East South Central #2	ESC2	Alabama and Mississippi
West South Central #1	WSC1	Oklahoma
West South Central #2	WSC2	Texas, Arkansas, and Louisiana
Mountain #1	MTN1	New Mexico
Mountain #2	MTN2	Montana, Colorado, Wyoming, Idaho, Utah
Mountain #3	MTN3	Nevada and Arizona
Pacific	PAC	California, Oregon, Washington, Alaska, and Hawaii

3/ Residual and distillate rates from forecasts of national wholesale price indexes for residual and distillate fuels (DRI variables PRF and PDF). Forecasts of price of oil prices to electric utilities by region were also available (DRI variable POILEUB) but were not used because regional price changes reflected changing proportions of distillate and residual fuels as well as changes in the price of each fuel. Also, because there was not a significant difference between escalation rates of oil delivered to utilities and the wholesale price indexes for distillate and residual oil.

4/ Coal rates from forecast of marginal delivered price of coal, including scrubbing costs (DRI variable PDS @), from the DRI coal model.

5/ Natural gas rates from forecast of price of natural gas to utilities, including effective Federal "user" tax on national gas use by utilities (DRI variable PNGEUB @).

6/ Nuclear fuel rates from forecast of acquisition cost of nuclear fuel (DRI variable PNUCACQ).

7/ DRI forecast extends to the year 2000. Rates are held constant to the year 2010. Zero real escalation assumed after 2010.

DOE escalation rates were those that appeared in the October 27, 1980 Federal Register, which were based on a forecast done in the fall of 1979. More recent DOE forecasts were included in the 1980 Annual Report to Congress, but that forecast included no 1980 base year prices from which to compute escalation rates. (Note that DOE has issued updated forecasts periodically since the Water and Energy Task Force report was published, but they continue to be prepared less frequently than the DRI data and they lag the comparable DRI price data by a number of months).

- the DOE forecast is primarily intended to be at the national level. Regionalization of the forecast has secondary priority, and the regional forecasts admittedly are much less reliable than the national forecasts.

- the DRI forecast offers somewhat more regional detail (13 regions vs. 10 regions in the DOE forecast). The DRI forecast extends to the year 2000, while the DOE forecast extends to 1995.

(3) Further in-depth comparison of model structure, input data, and assumptions used in the DOE and DRI models would strengthen the cost escalation analyses and should be performed. Though the DOE forecasts should continue to be used, it is recognized that further in-depth evaluation of the forecasts' changes in energy markets, changes in forecasts, or circumstances surrounding specific project studies may dictate that the DRI forecast or some other forecast be used. Regular semiannual, or at least annual updating, of DOE forecasts is needed for power value work, and these should be made available within 3 months of the base date. More rigorous analysis of regional coal prices in nonproducing coal areas, such as in the states of Oregon, Washington, and California, is also needed. In addition, DOE estimates would be more useful if fuel costs (including nuclear) were separately presented for the electric utility industry.

d. Escalation Rate Applications.

(1) The Principles and Guidelines also requires that future benefits be discounted and presented as an annualized value. To permit easy and quick application of the effects of the real fuel cost growth rates shown in Tables P-3 and P-4, standard discounting procedures have been employed under the following conditions.

(2) The real escalation rate forecast has been limited to a 30-year period from the present. However, a shorter period should be used if the situation warrants. The values shown in Tables P-3 and P-4 are based on escalation over the period 1980-2000. The 30-year

cutoff is based on the expectation that the supply of petroleum products and natural gas will be heavily depleted by the end of that period and that a transition to alternative energy sources and technologies will be well underway. Given the high degree of uncertainty about the nature and costs of replacement energy sources and the diminished (through discounting) impact of further increases in prices, a zero escalation rate beyond 30 years is considered to be the best assumption. A further rationale for the 30-year cutoff is that 30 years is the end of the expected life cycle of the thermal plants being completed today. Sensitivity tests of alternative cutoff dates are encouraged to assess the influence of the 30-year cutoff on hydropower analysis results.

(3) The project economic life is estimated at 100 years, beginning with the POL (power-on-line) date of the project. The common point to which all costs and benefits are brought is the POL date. Real escalation occurring between the present and POL is not discounted while that subsequent to POL is discounted (this is consistent with how costs are treated, for example, where interest during construction is charged on resources committed before the POL date). A graphic depiction of the discounting procedure appears in Figure P-1.

(4) The result of the above procedure is to express in one multiplier the equivalent of 30 years of growth in real escalation, discounted and annualized over the 100-year economic life of the project beginning with the POL date. Tables P-5 and P-6 summarize these multipliers for five fuel types by region and for the United States as a whole, for both the DOE and DRI projections, at a discount rate of 7-3/8 percent.

(5) The fuel cost escalation rates and multipliers are only applicable to the fuel cost component of alternative costs. Thus, adjustments will need to be made in variable energy costs to eliminate O&M costs which may account for approximately 5 to 15 percent of the total.

e. Use of the Multipliers. The multipliers shown in Tables P-5 and P-6 are to be applied under the following conditions:

- when the base current fuel prices approximate 1980 price levels.

- when the project would displace the same type of fuel over its entire life (when the amount or mix of thermal generation displaced by a hydropower project would change over the project's life, the fuel cost escalation adjustment must be computed on a case-by-case basis, using standard discounting techniques).

TABLE P-5. Summary of Equivalent Annual Fuel Cost Multipliers 1/, by

Fuel Type	Region 2/ 1	2	3	4
		1980 POL Date		
Residual (heavy)	1.94	1.85	1.84	1.89
Distillate (light)	1.62	1.58	1.58	1.58
Coal	1.42	1.58	1.58	1.95
Natural Gas	1.19	1.15	1.31	1.51
Nuclear	1.35	1.35	1.35	1.35
		1985 POL Date		
Residual (heavy)	2.24	2.12	2.10	2.18
Distillate (light)	1.84	1.78	1.78	1.78
Coal	1.46	1.71	1.71	2.15
Natural Gas	1.27	1.22	1.43	1.70
Nuclear	1.46	1.46	1.46	1.46
		1990 POL Date		
Residual (heavy)	2.52	2.37	2.34	2.46
Distillate (light)	2.08	2.02	2.02	2.02
Coal	1.44	1.75	1.77	2.19
Natural Gas	1.38	1.32	1.58	1.93
Nuclear	1.54	1.54	1.54	1.54

1/ Factors which express in one number the 100-year average annual equivalent of real growth (escalation) in fuel prices through the year 2010. Future values have been discounted at 7-3/8 percent interest to the POL dates specified. To use, multiply the factor by the fuel component of unadjusted 1980 energy value.

Fuel Type, Region, and POL Date - DOE Forecast, 1980 Price Level

Region 2/						
5	6	7	8	9	10	U. S. Average
			1980 POL Date			
1.85	1.89	1.85	1.89	1.89	1.90	1.85
1.61	1.59	1.61	1.60	1.61	1.61	1.60
1.71	2.13	1.68	1.59	1.67	1.73	1.85
1.40	1.83	1.66	1.64	1.01	1.13	1.51
1.35	1.35	1.35	1.35	1.35	1.35	1.35
			1985 POL Date			
1.11	2.17	2.11	2.17	2.16	2.19	2.11
1.83	1.80	1.83	1.82	1.83	1.83	1.81
1.85	2.40	1.83	1.70	1.80	1.96	2.05
1.54	2.12	1.89	1.86	1.03	1.15	1.69
1.46	1.46	1.46	1.46	1.46	1.46	1.46
			1990 POL Date			
2.37	2.44	2.37	2.44	2.44	2.47	2.37
2.08	2.04	2.08	2.07	2.08	2.08	2.05
1.88	2.53	1.88	1.73	1.83	2.05	2.13
1.71	2.39	2.13	2.04	1.05	1.13	1.88
1.54	1.54	1.54	1.54	1.54	1.54	1.54

2/ See footnotes to Table P-3 for definition of regions.

TABLE P-6. Summary of Equivalent Annual Fuel Cost Multipliers, 1/

Fuel Type	NENG	MATL	SATL	ENC	WNC	ESC1
			Region 2/			
			1980 POL Date			
Residual	1.78	1.78	1.78	1.78	1.78	1.78
Distillate	1.77	1.77	1.77	1.77	1.77	1.77
Coal	1.52	1.52	1.61	1.41	1.39	1.54
Natural gas	1.97	2.37	3.45	2.47	3.12	2.86
Nuclear	1.45	1.45	1.45	1.45	1.45	1.45
			1985 POL Date			
Residual	2.03	2.03	2.03	2.03	2.03	2.03
Distillate	2.02	2.02	2.02	2.02	2.02	2.02
Coal	1.69	1.68	1.79	1.53	1.52	1.70
Natural gas	2.28	2.81	4.32	2.95	3.82	3.49
Nuclear	1.64	1.64	1.64	1.64	1.64	1.64
			1990 POL Date			
Residual	2.26	2.26	2.26	2.26	2.26	2.26
Distillate	2.26	2.26	2.26	2.26	2.26	2.26
Coal	1.85	1.81	1.93	1.63	1.62	1.83
Natural gas	2.55	3.20	5.07	3.38	4.43	4.04
Nuclear	1.90	1.90	1.90	1.90	1.90	1.90

1/ Factors which express in one number the 100-year annual equivalent of real growth (escalation) in fuel prices through the year 2010. Future prices have been discounted 7-3/8 percent interest to the POL dates specific. To use, multiply the factor by the fuel component of unadjusted 1980 energy value.

by Fuel Type, Region, and POL Date - DRI Forecast, 1980 Price Level

Region 2/

ESC1	ESC2	WSC1	WSC2	MTN1	MTN2	MTN3	PAC	Avg.
				1980 POL Date				
1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77
1.54	1.49	1.53	1.54	1.62	1.47	1.67	1.57	1.48
2.86	2.81	3.40	3.09	2.65	2.71	2.49	2.20	3.39
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
				1985 POL Date				
2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03
2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
1.70	1.62	1.69	1.71	1.84	1.60	1.89	1.77	1.61
3.49	3.42	4.20	3.81	3.18	3.29	3.01	2.57	4.18
1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64
				1990 POL Date				
2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
1.83	1.71	1.82	1.81	2.01	1.70	2.06	1.96	1.73
4.04	3.98	4.87	4.41	3.62	3.79	3.49	2.89	4.85
1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90

2/ See footnote 2, Table P-4 for definitions of regions.

- when the project life is 100 years and the discount rate is 7-3/8 percent.

Multipliers can be computed for current price levels, discount rates, and other criteria using the technique described in the preceding section. North Pacific Division's Economics Branch has developed a computer program for doing this automatically for any POL dates.

f. Actual and Forecast Price Differences.

(1) One common problem in application of fuel price escalation rates is that the fuel prices used in project analyses are often not the same as the base year fuel prices which appear in the price forecast. This gap between actual fuel prices and those which appear in the forecast can occur for several reasons. In most cases, it is appropriate to use the actual current fuel price and apply the forecast escalation rates to it. This will be incorrect only when the gap

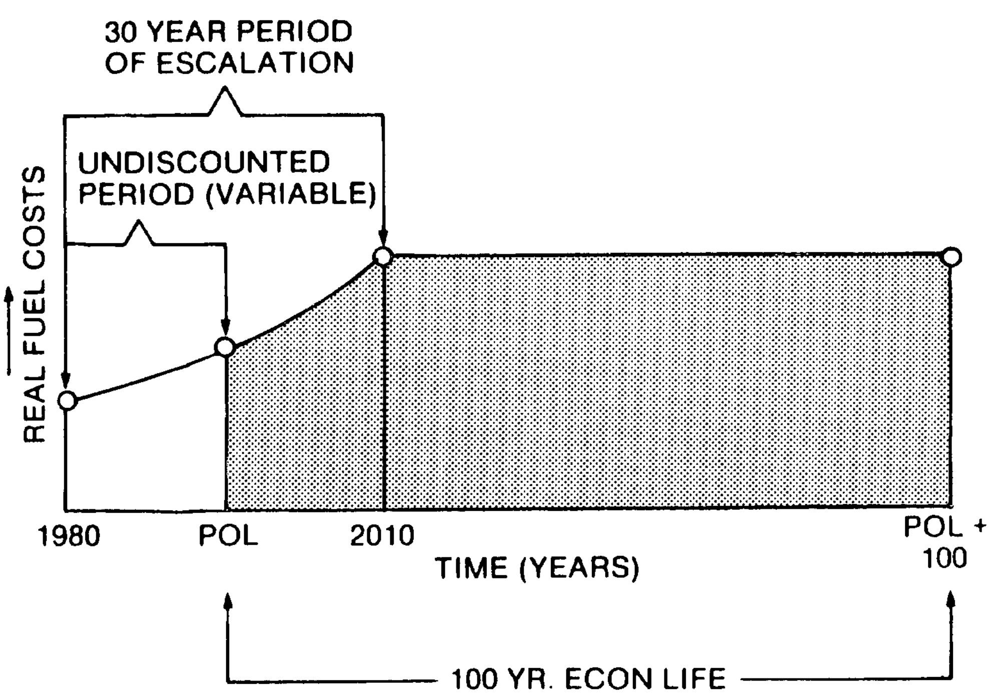

Figure P-1. Discounting methodology for real fuel escalation (shaded area represents accumulated present worth to project on-line (POL) date plus 100 years) between the actual price and the price from the forecast results from a transitory disturbance in the fuel market, such as a temporary glut or shortage. If a significant price gap is known to result from such a temporary market disturbance, then the escalation rate should be revised. Otherwise, the escalation rates should not need modification. Figure P-2 illustrates this problem. In this situation, the analyst has three options:

- Option 1: disregard the actual price and use the current price from the price forecast instead. This is not an acceptable option in most instances, since actual energy prices are subject to rapid change, and the hydropower analysis should reflect the most current information. The forecast also represents regional averages, which may not be applicable to a specific locality.

- Option 2: use the actual current price and recompute the real price escalation rate so that future prices converge with the forecast. This option requires the assumption that the actual price is simply a temporary deviation from the price forecast. This approach is depicted as Price Path 1 on Figure P-2.

- Option 3: use the actual current price and the price escalation rates from the original or some new escalation rates (Price Path 2). As Figure P-2 shows, this results in a forecast of future real prices which may be higher (or lower) than the original forecast.

(2) The choice between the second and third options is more difficult. Actual current fuel prices can deviate from the price forecast for a number of reasons, including the following:

- some basic long-term change in energy market relationships may have occurred. Examples are: a technological breakthrough which reduces energy production costs, a large new energy resource discovery, or a drastic change in OPEC pricing policy. Such changes in basic energy market relationships can be expected to change the future path of energy prices, as illustrated by Price Path 2 in Figure P-2.

- a transitory change in market relationships may have occurred. Examples are a price increase caused by temporary shortage due to a transport system breakdown, or a price reduction caused by a temporary oversupply due to suppliers' miscalculation. Such temporary changes do not invalidate the original price forecast. Price Path 1 represents the most reasonable assumption in such cases.

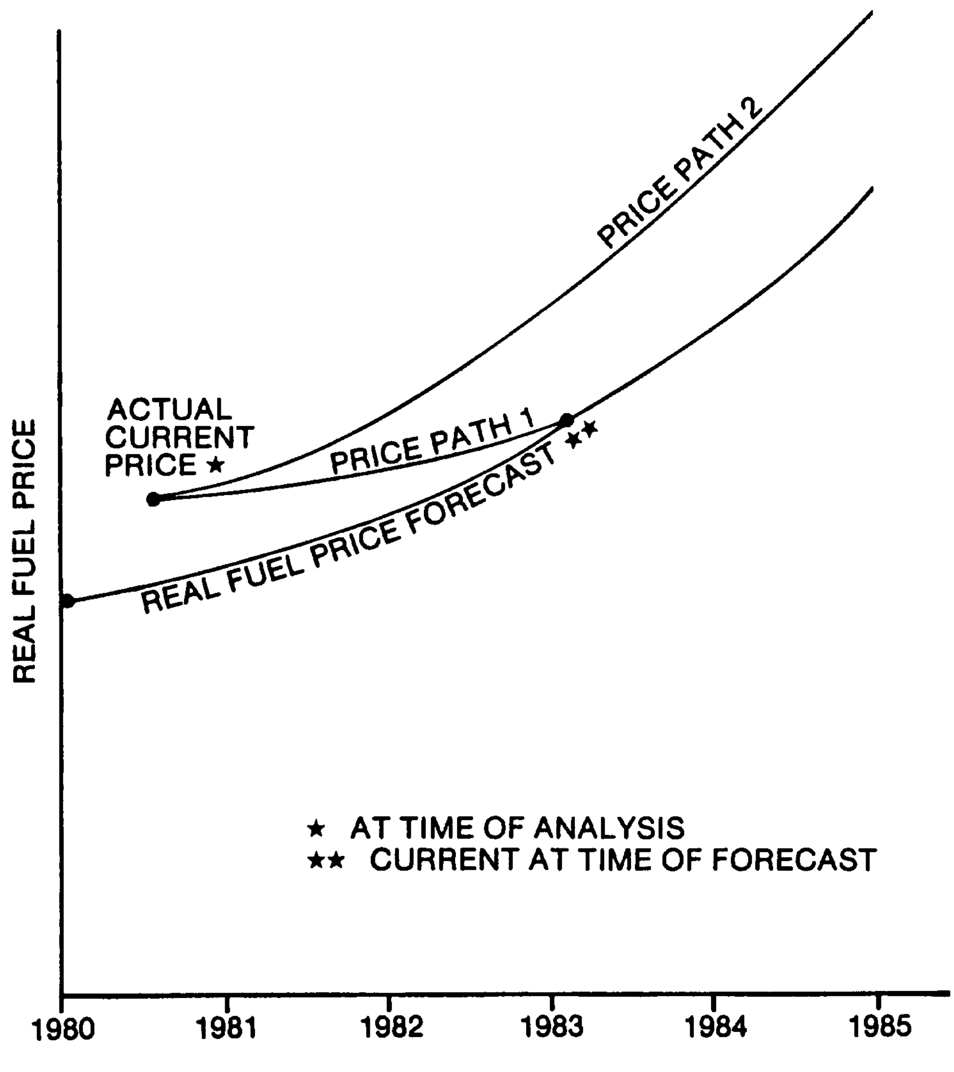

Figure P-2. Price paths reflecting different base prices

- the fuel prices shown in the forecast are averaged over large regions. Prices in any local area may be different from the regional average due to transportation cost differentials, requirements for specific grades of fuel, and other reasons. In such cases, the actual price for the local area should be used, and regional price escalation rates probably remain appropriate. Price Path 2 is again the correct choice in most cases, but changes in regional mix of fuel sources may require modification of escalation rates.

- actual prices may differ from those used in the forecast because a different source was employed, using different price-reporting conventions than was used by the forecasting agency. In such cases, it is generally reasonable to assume that the forecast escalation rates are applicable to the actual price. Again, Price Path 2 is indicated.

- finally, actual prices may differ simply because the wrong price has been chosen as the source of "actual" prices. Use of a current average price for petroleum products rather than a price based on the world oil price is an example of this problem. The solution is to find the correct actual price.

(3) As this discussion indicates, there is no single "correct" procedure to be followed when there are significant differences between actual current fuel prices and those shown in the price forecast. Fortunately, the severity of the problem is reduced if regularly updated forecasts are used. This should tend to keep prices shown in the forecast reasonably consistent with actual current prices.

(4) This discussion also strongly suggests that any particular gap between actual and forecasted fuel prices is less likely to be the result of transitory energy market disturbances than of one of the other reasons cited. This conclusion indicates that Price Path 2 will be the best assumption in most cases. As drawn in Figure P-2, Price Path 2 would yield higher alternative thermal plant costs.

(5) Given the complexity of energy markets and the difficulty of obtaining energy price data, it is not possible to identify the real reason for the fuel price gap in many cases, if not in most cases. Where the reason for the price gap cannot be identified, the best choice is to apply the forecast price escalation rates to the actual current fuel price. This will result in a continuing gap between the original price forecast and the future prices used in the project analysis. This approach is the most realistic solution when the

reason for the price gap is not known because, as discussed above, fuel price gaps are less often due to transitory energy market disturbances than to other factors.

(6) Considering the great number of variables and assumptions that enter into the calculation of the multipliers, only significant price gap differences would justify reconstructing the multipliers.