**Pacific Northwest Energy Related
Regional Assessment Program**

**ELSA: An Electric Power
Supply Analysis Model for
the Pacific Northwest**

November 1976

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ELSA: AN ELECTRIC POWER SUPPLY ANALYSIS
MODEL FOR THE PACIFIC NORTHWEST

by
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November 1976

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SUMMARY

Battelle, Pacific Northwest Laboratory (PNL) is conducting a Regional Assessment Program for the Energy Research and Development Administration. The purpose is to help assess impacts of energy-related developments through the year 2025 in six northwestern states--Washington, Oregon, Idaho, Montana, Wyoming and Alaska. ELSA (Electric Power Supply Analysis Model), one component of this overall program, is a simulation model of the electric supply system in the Pacific Northwest designed to better define future effects of electrical developments. It was adapted from a series of simulation models constructed by Andrew Ford at Dartmouth College. It permits the analyst to examine the structure of the electric utility industry, to postulate possible scenarios and policy decisions, and to test their effect on the cost and availability of power.

ELSA is divided into three major sectors: production, regulatory, and construction. The production sector uses the installed generating capacity of five types of facilities (hydroelectric, nuclear, coal-fired, oil-fired, and combustion turbines) and the requirements for electricity to compute the electrical reserve capacity and the system load factor. The regulatory sector uses information from the production sector and a number of exogenous variables such as capital costs, fuel costs, and tax rates to determine the price of electricity as well as other financial variables. The construction sector performs three major functions: 1) forecasts the amount of new construction needed, 2) determines the amount of new construction that can be financed, and 3) decides the types of new generating capacity which should be initiated.

Future work with ELSA will extend it to deal with competition among final demand sources of energy. It will also be extended to allocate the various types of generating capacity to supply peaking, intermediate, and base loads. When coupled to the demand component of the energy-economic submodel, ELSA will be sensitive to electricity and substitution prices, as well as regional population and income. When combined with the fossil fuel supply component, prices for primary fuels will be determined not only as functions of time but also as functions of consumption.

PREFACE

Quantification of the long-term evolution of an electric power supply system is difficult. We must make many assumptions and adopt compromises between rigor and detail of analyses and practicality. System planning decision rules applicable in one context may not be applicable in another.

In spite of these difficulties, we have attempted such an analysis with the intent of encouraging comments and suggestions for improvement either in the assumptions and treatment given or in the basic data used. We strongly encourage readers to react--challenge the data and assumptions and point out ways in which the analysis methodology can be improved. We will be most grateful for any comments received.

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INTRODUCTION

Electric power has been an inexpensive source of energy in the Pacific Northwest, with hydroelectric generation supplying almost all of the electric energy requirements. However, forecasted load growth and the limited number of potential new hydroelectric sites will result in a heavier reliance on thermal generation in the future. The gradual transition from a hydroelectric to a thermal baseload power generation system will cause changes in the Northwest which will be reflected in the price of electricity, the environmental consequences of nonhydroelectric generation, and general regional development. The future pathways of electric power supply development will be largely determined by the demand for electric power, basic energy prices, and by public policy. In view of the coming period of change, it is important that the long-term consequences of possible electric energy supply alternatives be understood.

The purpose of this report is to describe the dynamic simulation model ELSA (Electric Power Supply Anal^ysis Model) developed for the Pacific Northwest to forecast the characteristics of the electric supply system over the long term using given estimates of future electrical requirements and certain exogenous policy and energy cost assumptions. ELSA is an adaptation of the ELECTRIC series of national models developed by A. Ford at the Thayer School of Engineering of Dartmouth College⁽¹⁾ and is designed for regional application using the specific characteristics of the Pacific Northwest. Future work will include linking of an electrical power demand model to ELSA so that load growth rates will not have to be exogenously specified. In addition, components will be added for estimating the environmental residuals resulting from power generation.

Currently, the Pacific Northwest has a total of 160 hydroelectric projects that are investor, public, and federally owned. The Federal hydroelectric power development began in the 1930's with the U.S. Army Corps of Engineers' construction of Bonneville Dam near Portland, Oregon. During the same period the Bureau of Reclamation, U.S. Department of the Interior,

undertook construction of Grand Coulee Dam on the Columbia River in north-east Washington. By January 1, 1976, the Federal system had 29 hydroelectric facilities on line with a total installed capacity of 12,500 MW, providing more than half the power generated in the Region.⁽²⁾ Municipal and publicly owned hydroelectric facilities accounted for 7367 MW and privately owned hydroelectric facilities accounted for 2744 MW.⁽³⁾

The Bonneville Power Administration (BPA) was created in the 1930's as the marketing agent for the power produced from federally owned dams in the Pacific Northwest. In addition to this function, BPA also has a role in the development of the regional power transmission network. This transmission system consisting of more than 12,000 circuit miles of lines is designed as a common carrier for all Northwest utilities. As such, the system provides a high degree of reliability for the overall Northwest power system. An operating utility experiencing a failure of one of its facilities can draw on reserves anywhere in the Region to supplement local reserves for such contingencies. In addition, by tying together all Northwest power plants the transmission grid also makes practical the coordinated regulation of hydro facilities to even out the Region's power over all seasons of the year.

In 1964, Congress approved construction funding for the Pacific Northwest--Pacific Southwest Intertie. This intertie provides benefits for both regions, including power exchanges which reduce the need for investment in each region to meet growing loads. In addition, this intertie provides for reciprocal exchanges of energy during shortages or emergencies. For example, from July through November 1973 adverse water conditions occurred in the Northwest and approximately 1 billion kWh of electric power was dispatched to the Northwest by Southwest utilities. Conversely, from December 1973 through August 1974, approximately 10 billion kWh of surplus hydroelectric energy was shipped to the Southwest, decreasing oil consumption by about 16.5 million barrels.⁽⁴⁾

In addition to the interties to the Pacific Southwest, ties also exist between BPA and British Columbia Hydro in Canada. These lines provide the means for sales and exchange of power between the power systems in both countries.

The region dealt with in this report is the West Group Area of the Northwest Power Pool.^(a) This area is shaded in Figure 1.

The first two sections of this report provide a brief historical review of electrical energy supply and demand in the Pacific Northwest. The third section describes the ELSA model and the final section presents the results of a series of simulation runs made with ELSA. Appendixes A through F contain the capital cost, fuel cost, operation and maintenance cost, heat rates, and other exogenous variables used in the model. Appendix G contains a listing of the ELSA model.

FIGURE 1. West Group Area of the Northwest Power Pool

(a) The West Group Area systems include Bonneville Power Administration, Pacific Power and Light Company, Portland General Electric Company, Puget Sound Power and Light Company, Washington Water Power Company, and 115 public agency customers of BPA.⁽²⁴⁾

PACIFIC NORTHWEST ELECTRIC ENERGY DEMAND

Figures 2 and 3 show the growth of electric consumption in the Pacific Northwest. Figure 2 shows the total growth in consumption as well as the growth in the three major end use sectors: Residential, Commercial, and Industrial. The "Other" category includes state and local government use. The annual rate of increase of total consumption is also noted. Figure 3 illustrates the historical change in percent of consumption for each of the four sectors.

From 1960 to 1974 the total residential load in the Pacific Northwest more than doubled, increasing from 15 billion kWh to more than 34 billion kWh. Only about 20% of this growth was attributable to the increase in the number of residential consumers. Almost 80% resulted from the rise in electricity use per consumer. By 1965, the Pacific Northwest was consuming more than twice the electricity per capita than was the rest of the nation.

The availability of low-cost electricity has also caused many energy intensive processing plants to locate in the Pacific Northwest. As of January, 1976, the Pacific Northwest chemical processing industry included: 5 electrochemical plants for production of chlorine and caustic soda, 24 pulp and paper mills, 15 petroleum refineries, a glass-making furnace plant, 10 electric furnace plants for production of calcium carbide, elemental phosphorous and silicon, abrasives, refractory metals and ferroalloys, and 10 large electrolytic reduction plants that together account for 31% of the total U.S. capacity for aluminum metal. (7,p.19)

According to the West Group load forecasts, demand for electricity in the Pacific Northwest will continue to increase through the year 2000. The currently forecasted growth rate is about 4.4% per year.⁽⁵⁾ If continued, this growth rate will almost triple the demand for electricity by the year 2000. Figure 4 shows the historical and projected demand for the base case (4.4% growth rate) from 1950 through 2000.

In addition to the base case demand forecast the effects of other growth rates are also shown in Figure 4. The highest curve corresponds to a 7%

FIGURE 2. Electrical Consumption
Source: Edison Electric Institute (Ref.6)

FIGURE 3. Mix of Electricity Consumption
Source: Edison Electric Institute (Ref. 6)

FIGURE 4. Demand Growth Scenarios

annual load growth from 1975 through 2000. The lowest curve is the result of a 2% annual load growth. Table 1 shows the estimated peak and average electrical loads forecasted by the West Group.

TABLE 1. Load Estimates for West Group Area (a)
Source: Pacific Northwest River Basins
Commission (Ref. 5)

<u>Power Year</u>	<u>January Peak (MW)</u>	<u>Average Energy (MW)</u>
1976-77	23,136	14,953
1977-78	24,626	15,883
1978-79	26,108	16,902
1979-80	27,476	17,722
1980-81	28,916	18,623
1981-82	30,245	19,418
1982-83	31,658	20,265
1983-84	33,081	21,134
1984-85	34,608	22,027
1985-86	36,200	22,959
1986-87	37,896	23,943
1987-88	39,686	24,969
1988-89	41,593	26,055
1989-90	43,590	27,224
1990-91	45,694	28,421
1991-92	47,839	29,687
1992-93	50,202	31,032
1993-94	52,674	32,456
1994-95	55,292	33,958
1995-96	58,033	35,535

(a) Area loads are estimated January peak and critical period average energy firm loads of private utility and public agency systems, Federal agencies, and BPA industrial customers. BPA industrial customers loads include interruptible loads. Loads include area transmission losses.

PACIFIC NORTHWEST ELECTRIC ENERGY SUPPLY

The development of electric power began in the Pacific Northwest prior to the turn of the century. Both public and private utilities contributed to the development of electric generating capacity and transmission and distribution facilities in the Region. Small investor-owned utilities were established to meet the needs of local communities. These utilities eventually developed into the eight large investor-owned utilities which currently operate in the Pacific Northwest.

The first large municipal utility was established in Tacoma at the start of this century. Electric cooperatives were established in the Region in the early part of the century but only began their rapid growth following the creation of the Rural Electrification Administration in 1935. Public Utility Districts were established in the Pacific Northwest following passage of the Bonneville Project Act of 1937.

Throughout the history of electric power development in the Pacific Northwest, hydroelectric generation has contributed the majority of the generating capacity. Before the construction of the large Federal hydro projects, small privately owned hydroelectric facilities accounted for nearly 70% of the installed generating capacity.

To meet the growing needs of the Region, the Hydro-Thermal Power Program was established in the late 1960's. This long-term plan, developed by the Region's utilities and power agencies, was designed to meet the needs of the Pacific Northwest through the 1970's and into the 1980's. The Hydro-Thermal Power Program envisions construction of large thermal plants to meet increasing base load needs; existing hydroelectric facilities will be expanded to provide peaking power. The new thermal facilities are being constructed by the regional utilities while the hydro peaking and high voltage transmission facilities are being developed by the Federal Government. (4,p.15)

Since most of the better hydro sites have already been developed, and those that are undeveloped are subject to increasing social pressure by conservationists, the potential for adding firm energy from hydro is limited.

For the foreseeable future large thermal facilities, either nuclear or coal-fired, will be the most feasible means of generating energy in the Pacific Northwest. These thermal plants are most economically operated at high load factors and thus will normally be operated as base load plants. Table 2 compares loads and resources for meeting base energy demand in the West Group area through 1986-87 based on critical hydro conditions. This table also identifies new base load hydro and thermal generating capacity which is expected during the time period.

To meet peaking requirements generating capacity will have to double over the next 20 yr (see Table 1). However, in contrast to the firm energy situation hydro-generating facilities will play an increasing role in providing peaking power. Planned additions of generating units between 1976-77 and 1986-87 will make it possible for hydro to carry higher loads during the peak hours of the day.

Table 3 compares the peak loads and resources through 1986-87 forecasted by West Group.

TABLE 2. West Group Area Loads and Resources Under Critical Hydro Conditions (Average Energy--MW)
Source: Pacific Northwest Rivers Basin Commission (Ref. 5)

	1976-77	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
1. Area Energy Load	14,953	15,883	16,902	17,722	18,623	19,418	20,265	21,134	22,027	22,959	23,943
2. Exports (a)	813	739	658	636	654	474	281	201	228	193	193
3. Total Energy Requirements	15,766	16,622	17,560	18,358	19,277	19,892	20,546	21,335	22,255	23,152	24,136
Resources											
4. Existing (b)	14,124	13,844	13,666	13,652	13,709	13,666	13,623	13,656	13,603	13,589	13,598
5. Imports (a)	582	641	735	739	672	614	575	531	512	511	511
New Hydro (c)											
6. Grand Coulee 3rd P.P.	0	0	0	0	0	0	0	0	0	0	0
7. Lost Creek	15	22	22	22	22	22	22	22	22	22	22
8. Teton (d)	6	9	9	9	9	9	9	9	9	9	9
9. Chief Joseph Additions	-	0	38	64	64	64	64	64	64	64	64
10. Rock Island Additions	-	95	123	123	123	123	123	123	123	123	123
11. Noxon Rapids Addition	-	0	0	0	0	0	0	0	0	0	0
12. Lower Granite Additions	-	0	0	0	0	0	0	0	0	0	0
13. Little Goose Additions	-	-	0	0	0	0	0	0	0	0	0
14. Lower Monumental Additions	-	-	-	0	0	0	0	0	0	0	0
15. Grand Coulee P/G	-	-	-	0	0	0	0	0	0	0	0
16. High Ross	-	-	-	35	35	35	35	35	35	35	35
17. Bonneville 2nd P.P.	-	-	-	-	-	37	37	37	37	37	37
18. Libby Additions	-	-	-	-	-	-	-	0	0	0	0
19. Libby Reregulating	-	-	-	-	-	-	-	22	29	27	27
20. Total New Hydro	21	126	192	253	253	290	290	312	319	317	317
New Thermal (c)											
21. Trojan	529	764	847	847	847	847	847	847	847	847	847
22. Colstrip #2	134	137	140	140	140	140	140	140	140	140	140
23. Jim Bridger #3	140	215	234	250	250	250	250	250	250	250	250
24. WNP #2	-	-	-	550	798	825	825	825	825	825	825
25. Jim Bridger #4	-	-	-	114	229	250	250	250	250	250	250
26. Colstrip #3	-	-	-	-	213	368	368	368	368	368	368
27. Boardman Coal	-	-	-	-	250	362	375	375	375	375	375
28. Colstrip #4	-	-	-	-	-	273	368	368	368	368	368
29. WNP #1	-	-	-	-	-	-	562	891	938	938	938
30. Skagit #1	-	-	-	-	-	-	-	708	950	966	966
31. WNP #3	-	-	-	-	-	-	-	620	899	930	930
32. WNP #4	-	-	-	-	-	-	-	562	891	938	938
33. WNP #5	-	-	-	-	-	-	-	-	248	806	930
34. Pebble Springs #1	-	-	-	-	-	-	-	-	-	756	945
35. Skagit #2	-	-	-	-	-	-	-	-	-	-	708
36. Pebble Springs #2	-	-	-	-	-	-	-	-	-	-	-
37. Total New Thermal	803	1,116	1,221	1,901	2,727	3,315	3,985	6,204	7,349	8,757	9,778
38. Gross Resources (4+5+20+37)	15,530	15,727	15,814	16,545	17,361	17,885	18,473	20,703	21,783	23,174	24,204
39. Reserve Margin	(385)	(396)	(407)	(419)	(437)	(412)	(449)	(457)	(469)	(489)	(515)
40. Net Resources (38-39)	15,145	15,331	15,407	16,126	16,924	17,473	18,024	20,246	21,314	22,685	23,689
41. Surplus or (Deficit) (40-3)	(621)	(1,291)	(2,153)	(2,232)	(2,353)	(2,419)	(2,522)	(1,089)	(941)	(467)	(447)
Surplus or (Deficit) % of Load (41 ÷ 3)	(3.9)	(7.8)	(12.3)	(12.2)	(12.2)	(12.2)	(12.3)	(5.1)	(4.2)	(2.0)	(1.9)

(a) Firm contracts.

(b) Includes existing hydro, existing thermal, and combustion turbines.

(c) The completion dates of the new hydro and thermal generating facilities are subject to constant revision due to labor and financial considerations. However a consistent projection is required for analysis and this schedule is used throughout this report.

(d) No longer exists but included in total.

TABLE 3. West Group Area Loads and Resources Under Critical Hydro Conditions, January Peak (MW)
Source: Pacific Northwest River Basins Commission (Ref. 5)

	1976-77	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
1. Area Peakload	23,136	24,626	26,108	27,476	28,917	30,245	31,658	33,081	34,608	36,200	37,896
2. Exports(a)	2,142	2,234	2,237	2,179	2,196	1,769	1,770	1,613	1,613	1,614	1,614
3. Total Peak Requirements	25,278	26,860	28,345	29,655	31,113	32,014	33,428	34,694	36,221	37,814	39,510
Resources											
4. Existing(b)	26,345	26,461	26,420	26,321	26,360	26,400	26,442	26,337	26,374	26,246	26,380
5. Imports(b)	422	387	616	554	567	407	345	278	251	251	251
New Hydro											
6. Grand Coulee 3rd P.P.	1,380	2,185	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795
7. Lost Creek	18	18	18	18	18	18	18	18	18	18	18
8. Teton(c)	7	7	7	7	7	7	7	7	7	7	7
9. Chief Joseph Additions	-	280	926	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132
10. Rock Island Additions	-	201	388	388	388	388	388	388	388	388	388
11. Noxon Rapids Addition	-	111	111	111	111	111	111	111	111	111	111
12. Lower Granite Additions	-	154	464	464	464	464	464	464	464	464	464
13. Little Goose Additions	-	-	464	464	464	464	464	464	464	464	464
14. Lower Monumental Additions	-	-	-	464	464	464	464	464	464	464	464
15. Grand Coulee P/G	-	-	-	85	128	128	128	128	128	128	128
16. High Ross	-	-	-	246	246	246	246	246	246	246	246
17. Bonneville 2nd P.P.	-	-	-	-	-	389	550	550	550	550	550
18. Libby Additions	-	-	-	-	-	-	-	131	265	265	265
19. Libby Reregulating	-	-	-	-	-	-	-	36	50	50	50
20. Total New Hydro	1,405	2,956	6,173	7,174	7,217	7,606	7,767	7,934	8,182	8,182	8,182
New Thermal											
21. Trojan	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
22. Colstrip #2	165	165	165	165	165	165	165	165	165	165	165
23. Jim Bridger #3	500	500	500	500	500	500	500	500	500	500	500
24. WNP #2	-	-	-	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
25. Jim Bridger #4	-	-	-	333	333	333	333	333	333	333	333
26. Colstrip #3	-	-	-	-	490	490	490	490	490	490	490
27. Boardman Coal	-	-	-	-	500	500	500	500	500	500	500
28. Colstrip #4	-	-	-	-	-	490	490	490	490	490	490
29. WNP #1	-	-	-	-	-	-	1,250	1,250	1,250	1,250	1,250
30. Skagit #1	-	-	-	-	-	-	-	1,288	1,288	1,288	1,288
31. WNP #3	-	-	-	-	-	-	-	1,240	1,240	1,240	1,240
32. WNP #4	-	-	-	-	-	-	-	1,250	1,250	1,250	1,250
33. WNP #5	-	-	-	-	-	-	-	-	-	1,240	1,240
34. Pebble Springs #1	-	-	-	-	-	-	-	-	-	1,260	1,260
35. Skagit #2	-	-	-	-	-	-	-	-	-	-	1,288
36. Pebble Springs #2	-	-	-	-	-	-	-	-	-	-	-
37. Total New Thermal	1,795	1,795	1,795	3,228	4,218	4,708	5,958	9,736	9,736	12,236	13,524
38. Gross Resources (4+5+20+37)	29,967	31,599	35,004	37,297	38,362	39,121	40,512	44,285	44,443	46,815	48,237
39. Reserve Margin	(3,545)	(4,031)	(4,634)	(5,134)	(5,643)	(6,180)	(6,746)	(7,337)	(7,983)	(8,295)	(8,641)
40. Net Resources (38-39)	26,422	27,568	30,370	32,163	32,719	32,941	33,766	36,948	36,460	38,520	39,596
41. Surplus or (Deficit) (40-3)	1,144	708	2,025	2,508	1,606	927	338	2,254	239	706	86
42. Surplus or (Deficit) % of Load (41 ÷ 3)	4.5	2.6	7.1	8.5	5.2	2.9	1.0	6.5	0.7	1.9	0.2

(a) Firm contracts.

(b) Includes existing hydro, existing thermal, and combustion turbines.

(c) No longer exists but included in total.

ELECTRIC POWER SUPPLY ANALYSIS MODEL

To better understand the possible future effects of electric energy development in the Region, a series of models are being developed. The first of these models, the Electric Power Supply Analysis model (ELSA), is now running and is being used for policy analysis. ELSA is an aggregated policy model of the electrical supply system in the Pacific Northwest--specifically the West Group of the Northwest Power Pool. ELSA is being updated as better data become available and as the electric energy supply system becomes more clearly defined.

ELSA is currently being linked to an Electric Power Demand Analysis model (ELDA). These two models running together will give a complete picture of the electric energy system in the Northwest. Since this document is concerned only with the supply side of the system, an exogenous forecasted load growth is used to represent the demand side interactions. This parameter is not "demand" in the economic sense because it is not modified by price.

It is important to keep in mind the reasons for using a computer model in this application. A computer model constructed and used by a policy-making group has these advantages:

1. It requires decision makers to improve and complete fully the rough mental sketch of the causes of the problem under consideration.
2. In the process of formal model building and review, the builders resolve any self-contradictions and ambiguities among their implicit assumptions about the problem.
3. Once an acceptable standard of model validity has been achieved, formal policy experiments reveal quickly the probable outcomes of many policy alternatives. Novel policies can be tested and evaluated.
4. An operating model is always complete, though in a sense never completed. Unlike many planning aids, which tend to be episodic

and terminal (they provide assistance only at the moment the "report" is presented, not before or after), a model is organic and interactive. At any moment the model contains in readily accessed form the present best understanding of the problem.

5. Sensitivity analysis of the model reveals the areas in which genuine debate is needed and guides empirical investigation to important questions. If the true values of many parameters are unknown (which is generally the case in long-term forecasting), the ones that maximally affect the solutions need to be investigated first.
6. An operating model can be used to communicate with people who were not involved in building the model. By experimenting with changes in policy options, by altering model parameters and observing the effects of these changes on behavior, these people can be helped to better understand the dynamic forces at work in the real-world system.⁽⁸⁾

In general, ELSA will allow the analyst to examine the structure of the electric utility industry, to postulate possible scenarios and policy decisions and to test their effect on the cost and availability of power and the market share of various generating sources. Possible specific applications include:

1. Evaluation of the Hydro-Thermal Program

This is the base case for the West Group Region. In this instance, the demand in total kWh is exogenously established as a function of time based on present forecasts. The hydroelectric fraction in the system is specified but the shares of thermal generating capacity (coal, nuclear, and oil) are floating. ELSA can forecast these shares along with the resulting prices.

2. Evaluation of the Effects of Nuclear Safeguards Initiatives

A number of subscenarios might be run including the system behavior with various assumptions about coal price behavior with nuclear competition removed.

3. Implications of Interruptible Load Contract Options

The magnitude of interruptible loads can strongly influence the desired reserve capacity.

4. Implications of Intertie Capacity

Electricity prices and reserve capacity needs can be affected by intertie capacity.

5. Evaluation of the Effects of Changes in Fuel Costs

Changes in fuel prices can affect the advantage of one type of generating capacity over others.

6. Evaluation of the Effects of Changes in Capital Costs

Additional environmental control technology will impact the price of electricity.

7. Evaluation of Technological Changes in Generation

An increase or decrease in heat rates will affect the number of fossil plants required.

8. Effects of Errors in Load Growth Forecasts

Forecasts which are too high could lead to the construction of unneeded facilities and thus to higher cost electric service. Low forecasts could require either extra costs for emergency energy or curtailment of loads and growth.

ELSA will be extended to examine interfuel substitution in the end use of energy. For example, space heating is an end use demand which can use electricity, oil, or natural gas. Once this interfuel competition capability has been added to ELSA, scenarios such as the effects of Canadian natural gas export policies can be examined. The model will also be extended to allocate various types of generating capacity to supply peaking, intermediate, and base loads.

ELSA was adapted from a series of simulation models constructed by Andrew Ford⁽¹⁾ at Dartmouth College. The models developed by Ford were national in scope and dealt with three basic problem areas:

1. The planning and financing of the construction of new generating capacity under changing regulatory conditions.
2. Interfuel substitution between hydro, nuclear, coal, and oil and gas.
3. The problem of SO₂ emissions from power plants. (1,p.11)

In ELSA the major problem areas addressed are the examination of inter-fuel substitution and the planning and financing of new generating capacity. Extensive modifications were required to adapt Ford's models to the unique characteristics of the Pacific Northwest. Many of these characteristics, such as the historical abundance of inexpensive hydro power and the development and influence of the BPA have been previously discussed.

ELSA is modeled using the system dynamics methodology developed by Forrester of the Massachusetts Institute of Technology. The basic elements of this approach are described in Industrial Dynamics⁽⁹⁾ and Study Notes in System Dynamics.⁽¹⁰⁾ The original models developed by Ford were programmed in DYNAMO,⁽¹¹⁾ which is a simulation language developed especially for system dynamics. During the regionalization process these models were converted to FORTRAN.

This report is not intended as the final documentation of a completed model. Instead, its purpose is to describe the current status of an evolving model. Many of the additional questions which need to be examined will be identified as well as areas where additional model development is required.

Data for the model, constants, and function tables are preliminary. As new data become available ELSA will be updated and modified.

MODEL DESCRIPTION

This section briefly describes some of the key features of the ELSA model. The major emphasis is on changes which were made to the original ELECTRIC models to more accurately describe the Pacific Northwest. A complete description of the ELECTRIC 1-3 models is presented by Ford.⁽¹⁾

ELSA is divided into three major components:

- Production Sector
- Regulatory Sector
- Construction Sector

Each of these sectors computes some logically distinct variables which are then used in the next sector; the model can be best discussed in terms of these sectors. Figure 5 shows the major variables in each sector and the arrows (representing interactions between sectors) give a general idea of how the sectors are related. Information not indicated in the sector "boxes" must be exogenously specified by the user.

ELSA currently considers the possible construction of five types of generating capacity:

- Hydroelectric
- Nuclear
- Coal-fired
- Oil-fired
- Combustion turbines^(a)

A variety of parameters and function tables are required to describe each of the facilities. Some examples of the parameters are:

- Capital costs for generating capacity
- Unit operating and maintenance costs
- Fuel costs
- Lifetimes of generating capacity
- Construction lead times

(a) Ability to treat pump-storage daily and weekly cycle peaking capacity will be added in the future.

FIGURE 5. Functional Structure of ELSA

The exogenously specified parameters and function tables used in ELSA are listed in Appendices A through F.

Each of these three sectors is discussed in more detail below. Following this discussion, the type of output available from the model is presented. The results of both the base case run (West Group Forecast) and perturbations of this case are then examined.

PRODUCTION SECTOR

The production sector uses the installed generating capacity and the forecasted load growth for electricity to compute the electrical reserve capacity and the system load factor. The installed generating capacity is the sum of contributions from the five types of generating facilities. The base load electricity requirement is exogenously specified to ELSA. The peak demand for power is calculated, using this base load demand. Comparing the installed generating capacity (GC) and the peak demand for power (PDP) the production sector determines the electrical reserve capacity (ERC) as

$$ERC = (GC - PDP) / PDP.$$

The electrical reserve capacity is an indicator of system reliability. To insure system reliability utilities must either maintain excess (reserve) capacity or have arrangements to purchase power during periods of routine plant maintenance and forced outages. Large coal-fired units require from 4 to 6 weeks of routine maintenance per year.⁽¹²⁾ Nuclear plants which are designed to serve as base load capacity are currently operating at 60% of design capacity.^(13,p.39)

For the Pacific Northwest Region a reserve capacity of from 12 to 14% is currently considered to be adequate, whereas nationally, a reserve capacity of about 20% is desired. The reason for this difference is the dominance of highly reliable hydroelectric power in the Region and the extensive intertie system. This implies that as the Region's power production shifts from hydro power to thermal power, the necessary reserve capacity will increase. The equations which describe the desired reserve capacity are discussed in the description of the construction sector.

Once the reserve capacity has been computed it is used to determine the average system load factor (ALF). This variable is defined as the percent of the time that generating capacity must be operated in order to meet electrical demand. Figure 6 shows the functional relationship between the electrical reserve capacity and the average system load factor being used in ELSA. This relationship is obtained by requiring that production equal demand in periods of ample reserve capacity and by setting a maximum on the load factor as the reserve capacity decreases. A relationship which satisfies the first half of the above requirement is presented by Ford^(1,p.69) as follows:

$$EPRO = DE$$

$$ALF * GC * HPY = PDP * ALFBPL * HPY$$

$$ALF = \frac{PDP * ALFBPL}{GC} = \frac{PDP * ALFBPL}{PDP * (1 + ERC)}$$

$$ALF = ALFBPL / (1 + ERC)$$

where

EPRO = electricity production (kWh/yr)

DE = demand for electricity (kWh/yr)

FIGURE 6. System Load Factor as a Function of Reserve Capacity
Source: Ford (Ref.1, p.68)

ALF = average load factor (%)

GC = generating capacity (kW)

HPY = hours per year

ALFBPC = average load factor based on peak load (%)

ERC = electrical reserve capacity (%)

As the reserve capacity decreases, the system load factor must increase to maintain production equal to demand. However, as the reserve capacity decreases below about 10% the system load factor reaches a maximum of 66%. This maximum is set primarily by the required down times for generating facilities.

While the total electrical generating capacity operates with an overall average load factor, individual types of generating capacity may operate at different load factors either higher or lower than the average.

Hydro capacity can operate at relatively high load factors assuming that sufficient water is available. In the case of the generating facilities on the Columbia River system, the total generation over a period of a year is limited by the amount of water flowing. In a critical hydro year the average energy available from West Group hydro facilities is expected to be limited to about 12,000 MW which is equivalent to 106 billion kWh of generation. (5,p.96)
The hydro generation is limited to this value in all the runs simulating critical streamflow presented in this report.

Once the average load factor is computed the generation provided by the combustion turbine capacity is computed. Combustion turbine load factors are typically relatively low, usually about 5 to 30%. In ELSA the combustion turbine load factor is varied between 13 and 30% depending upon the overall electrical reserve capacity.

The remaining generation required is produced by coal and nuclear generating capacity subject to a maximum load factor of 75% for these sources.

The third variable calculated in the production sector is the average economic lifetime of thermal generating capacity, which is also a function of the electrical reserve capacity. Figure 7 shows the functional relationship between the reserve capacity and the average life of thermal generating capacity.

The shape of the curve is determined by financial considerations:

"With a normal reserve capacity ERC of 20%, generating capacity (fossil) is usually retired from the system after 35 years of service. If reserves fall below desired levels, older plants will be maintained for an extra 5 to 10 years before they are too expensive to keep on the system. If a surplus of generating capacity exists, the older, less efficient plants are retired 5 to 10 years earlier than usual."(1,p.A1-6)

FIGURE 7. Average Life of Thermal Generating Capacity as a Function of Reserve Capacity
Source: Ford (Ref.1,p.A1-6)

Hydro generating capacity is assumed to have a constant average lifetime of 50 years and gas turbine capacity a constant average lifetime of 10 years.

REGULATORY SECTOR

The regulatory sector uses information from the production sector and a number of exogenous variables such as capital costs, fuel costs, and tax rates to determine the price of electricity as well as other financial variables. The first calculations made in this sector determine the indicated busbar price of electricity for each type of generating capacity. Each of these indicated prices is determined by dividing the allowed revenues for the particular generating capacity by the amount of electricity which is produced by that type.

After the indicated electricity prices for the five types of generating facilities have been computed they are weighed by the amount of electrical production from each type and combined to yield an indicated average price. This price is combined with the unit cost for transmission and distribution to obtain the indicated price of electricity to the consumer. However, the actual price that electricity is sold for does not equal the indicated price until after a delay caused by the regulatory process.

Each type of generating facility uses a similar set of equations to determine the indicated busbar price of electricity. The sequence of steps necessary to compute this price are:

- Calculate the capital base and, using the capital base, compute the depreciation charges.
- Determine the annual fuel and operating and maintenance costs.
- Using the revenues compute the taxes.
- Calculate the total annual costs as the sum of the depreciation charges, the fuel and operating and maintenance costs, and the taxes.
- Compute the allowed rate of return on capital. The capital base times the allowed rate of return gives the allowed profits.

- Add the total annual costs and the allowed profits to get the allowed revenue.
- Determine the indicated price of electricity for the particular type of generating facility by dividing the allowed revenues by the electrical production.

The method used to determine the capital base for a given type of generating capacity involves averaging the construction costs over an interval of time. The length of this interval depends on the rate at which new plants are added to the system. This averaging delay is thus a function of the system load growth rate. For a given type of generating capacity i , ELSA calculates the capital cost averaging delay as:

$$CCAD(i) = \frac{GC(i)}{CUC(i)} * CCD(i)$$

where

$CCAD(i)$ = Capital cost averaging delay for generating type i ,

$GC(i)$ = Installed generating capacity type i ,

$CUC(i)$ = Capacity under construction type i , and

$CCD(i)$ = Capacity construction delay for type i .

The revenues computed for each type of generating capacity are calculated as the average price of electricity times the electrical production for the given type. Once the revenues are known the taxes are determined as the product of the average revenues and the tax rate. Currently ELSA uses a tax rate of 20% of revenue for all types of generating facilities although we recognize that this can vary among states and also may not truly reflect the mixture of public and investor-owned generating capacity.

The allowed rate of return is set by the state regulatory commissions. In computing it Ford's assumptions are retained:

"The allowed rate of return depends on two factors -- the delayed or imbedded cost of debt and a constant cost of debt markup. If, for example, the imbedded cost of debt were 6% per year, ELECTRIC1 (ELSA) would employ a 50% markup to set the allowed rate of return at 9% per year. The constant markup represents the commission's

calculation of the weighted average cost of capital for the utility. For the constant markup to be appropriate, two conditions must be satisfied. First, the cost of all forms of capital (debt, common stock, and preferred stock) must generally rise and fall together. Secondly, the mix of debt, common stock, and preferred stock in the utility's capital structure must remain approximately constant."(1,p.84)

Using the allowed rate of return and following the steps outlined earlier the indicated busbar prices for electricity from each type of generating facility can be determined.^(a)

The additional costs for transmission and distribution are calculated using a method similar to that used to compute busbar prices. The capital base is calculated and used to determine the depreciation charges and the allowed profits. The indicated price for transmission and distribution is then the sum of the depreciation charges and the allowed profits divided by the total production.

The average indicated price of electricity can now be computed by weighting the busbar prices on the basis of electrical production for each type of generating capacity and adding the unit cost for transmission and distribution. This price is then subject to a delay caused by the regulatory process. Ford indicates the components of this delay including both the time spent in formal hearings as well as the interval required to prepare the cost calculations. Presently, Ford's assumption about the functional form of this delay at the national level is retained. Further work is required to modify this relationship for the Region. Figure 8 shows the "historical pattern" of this delay.

The actual price of electricity times the total electrical production gives the total revenue obtained. The total annual cost is the sum of the annual costs computed for each type of generating capacity and transmission and distribution costs. The profit after taxes can now be determined as the revenues minus the total annual costs. The ratio of the profits to the total capital base is defined to be the rate of return on capital. The rate of return on capital is an important financial variable in determining the

(a) Additional remarks concerning the cost of debt and the cost of debt markup will be made in the construction sector description.

FIGURE 8. Length of Regulatory Lag as a Function of Time
Source: Ford (Ref.1,p.A1-32)

availability of external funds to finance new construction. It will be discussed in more detail in the description of the construction sector.

CONSTRUCTION SECTOR

The construction sector has three major functions. These are:

- forecast the amount of new construction needed to meet future needs,
- determine the amount of this new construction which can actually be financed, and
- decide the types of new generating capacity which should be initiated.

To determine the amount of new capacity construction that will be initiated each year two parameters must be computed. The first involves forecasting the peak demand growth rate (PDGR). This growth rate is then

combined with information concerning the generating capacity both installed (GC) and under construction (CUC), and the average lifetime of generating capacity (ALTGCN) to compute the construction rate required to meet the long-term growth trend (CRLGT). The equation for this calculation is:

$$\text{CRLGT} = (\text{GC} + \text{CUC}) / \text{ALTGCN} + \text{PDGR}(\text{GC} + \text{CUC}).$$

The second parameter required to compute the desired capacity initiation rate is the short-term forecast of the additional construction required to improve the reserve capacity (ACIRC). This parameter is a function of the desired reserve capacity (DRC) and the existing reserve capacity (ERC). For the Pacific Northwest the desired reserve capacity is computed as a function of the fraction of generating capacity which is thermal (FGCT). The functional relationship between FGCT and DRC is shown in Figure 9.

As mentioned earlier, the reason for allowing the desired reserve capacity to vary, as a function of the thermal generating capacity, is the large dependence on hydroelectric power in the Pacific Northwest. Because hydro facilities typically have less downtime for plant maintenance etc., a system relying totally on hydro power can operate in relative safety with a reserve capacity of only about 12%. On the other hand a power system relying completely on

FIGURE 9. Desired Reserve Capacity as a Function of Fraction of Generating Capacity Thermal

thermal generating facilities should have a reserve capacity of about 20% for similar safety. However, the Federal Power Commission has estimated that a fully coordinated industry could operate with a reserve capacity of 15% as compared with the currently desired reserve capacity of about 20%. (1,p.A1-8)

Combining both the long-term and short-term growth requirements gives the capacity initiation rate desired (CIRD). Due to the historical growth of hydro capacity in the Region the desired capacity initiation rate is taken to be the maximum of the capacity initiation rate desired and the potential hydro capacity initiation. By using this formulation the model correctly tracks the historical hydro development when actual construction far exceeded demand.

To determine the actual amount of the desired construction which can be initiated ELSA computes the ratio of the total financing obtained (FINO) to the financing required (FINREQ). The financing required to initiate the desired capacity is calculated as the weighted average capital cost of construction times the capacity initiation rate. The weighting coefficients in the capital cost calculations are the fractions of each type of generating facility in the system.

Central to the problem of financing the construction of new generating facilities is the financial health of the utilities. This not only determines how much internal funding will be available to them but will also affect their ability to attract external financing.

A problem arises in defining a suitable metric to describe the financial health of the electric utility industry when a mix of public, private, and Federal capacity exists as it does in the Northwest. The Northwest has a relatively high percentage of publicly owned utilities as well as a large amount of Federal participation in the electric supply system. While private utilities operate as profit making corporations and must show a return on their investment, public utilities do not require a return. In addition, private utilities typically compete for external funds at a higher interest rate than public utilities. Some Federal projects have been justified on different criteria and have been financed at rates less than that for either publicly or privately owned projects.

Because all electric utilities are in some sense regulated, their financial health is determined by their allowed rate of return. At the present time Ford's concept of a single aggregated utility that is representative of the mix in the Region is retained. Because of the high percentage of federally and publicly owned projects in the Region, both the cost of debt and the cost of debt markup should be lower in ELSA than Ford used in his national model. The cost of debt used in the model is a weighted average of the rate paid on corporate Aaa bonds and long-term government securities and is shown in Appendix E, Figure E.1. The cost of debt markup is reduced from Ford's national average of 1.5 to 1.3.^(a)

Financing for new construction is available from both internal and external sources. Ford comments on the assumptions made concerning both of these sources:

"Sources of internal funds are the profits after taxes and the depreciation allowance. A constant fraction of the source of internal funds is assumed to be available for financing new construction ... ELECTRIC1 incorporates a single, simplifying assumption (in computing the amount of external financing obtained). That is, when the rate of return on capital is low compared to the cost of debt, the fraction of external financing obtained will drop below one. This simple assumption reflects investors' desires to earn a higher rate of return during periods of high inflation (periods of high interest rates or high costs of debt)."(1,pp.76-77)

The ratio of the rate of return on capital to the cost of debt is defined to be the financial ratio. This ratio is used to compute the fraction of external funds obtained. Figure 10 shows the functional relationship between the financial ratio and the fraction of external funds obtained. The dashed curve shows the relationship used by Ford. However because of the relatively high percentage of publicly owned utilities in the Northwest with their greater ability to obtain external funds the upper curve shown in Figure 10 is used in ELSA.

(a) We recognize the uncertainty of this value and solicit comments from others regarding its validity.

FIGURE 10. Fraction of External Funds Obtained as a Function of the Financial Ratio
Source: Ford (Ref.1,p.A1-33)

The external funding required (EXTFR) is the difference between the financing required (FINREQ) and the internal financing available (INTFIN). The external funding required (EXTFR) times the fraction of external funds obtained (FEXFO) gives the external funds available (EXTFO). Combining the internal financing and the external financing gives the total financing available (FINO). The fraction of planned construction financed (FPCF) is then defined to be the ratio of the financing available to the financing required.

The actual amount of desired capacity which can be initiated each year (CIR) can now be computed as the capacity initiation rate desired (CIRD) times the fraction of planned construction financed (FPCF). In equation form these relationships can be written as:

$$\begin{aligned}
 \text{EXTFR} &= \max (0, \text{FINREQ} - \text{INTFIN}) \\
 \text{EXTFO} &= \text{EXTFR} * \text{FEXFO} \\
 \text{FINO} &= \text{INTFIN} + \text{EXTFO} \\
 \text{FPCF} &= \text{MIN}(1, \text{FINO} / \text{FINREQ}) \\
 \text{CIR} &= \text{CIRD} * \text{FPCF}.
 \end{aligned}$$

Once the actual capacity initiation rate is determined, decisions concerning what types of new generating facilities to build must be made. The sequence of steps required to make these decisions are referred to as an interfuel competition algorithm. Ford^(1,p.148) has developed a sequence of questions which must be answered to determine the investment in different forms of generating capacity:

1. How much new capacity is required to keep ahead of demand?
2. How much of that can be financed?
3. How much new hydroelectric capacity can be developed? The rest of the new capacity will be thermal capacity.
4. How much of the thermal capacity should be nuclear? (Compare the cost of fossil fuel power.) The rest of the new capacity will be fossil fuel capacity.
5. How much coal capacity should be constructed? (Compare the cost of coal with the cost of oil and gas.)

The first two questions deal with the actual and desired capacity initiation rates and have already been answered. The remaining three specifically deal with interfuel substitution. This set of questions has been expanded in ELSA to include combustion turbines.

As Ford points out, the first of the interfuel competition questions which must be addressed is the availability of hydroelectric sites. This is particularly important for the Pacific Northwest because of the extensive historical hydro development. In ELSA the hydro capacity initiation rate is exogenously specified to match historical behavior and announced future plans (see Tables 2 and 3).

The thermal capacity initiation rate is now determined as the difference between the capacity initiation rate (CIR) and the hydro capacity initiation rate. The fossil fuels compete with nuclear for shares of this new capacity.

The combustion turbine capacity initiation rate (GCIR) is the first of the thermal capacity requirements which is examined. Since combustion turbines have much shorter lead times than the larger base load thermal plants,

a decision rule was implemented in ELSA which favors the construction of combustion turbine capacity when the reserve capacity is low. The shorter construction time (assumed to be 3 years) for combustion turbine capacity as compared to large nuclear and fossil plants (assumed to be 11 and 8 years respectively) enables the model to maintain system reliability during periods of low reserves. The functional relationship used to calculate the combustion turbine capacity initiation rate is shown in Figure 11. The independent variable in this relationship is a function of the electrical reserve capacity given by

$$f(\text{ERC}) = 1 - \frac{\text{ERC}}{\text{DRC}}$$

where

ERC = electric reserve capacity

DRC = desired reserve capacity.

Figure 11 shows that a maximum of 10% of the desired thermal capacity initiation rate (TCIR) will be assigned to combustion turbine capacity if the reserve capacity is less than or equal to zero.

FIGURE 11. Fraction of Capacity Initiated as Combustion Turbines as a Function of Electrical Reserve Capacity

If the reserve capacity is high, a minimum of 5% of the thermal capacity initiation rate is assigned to combustion turbines.

The remaining competition for new generating capacity is between nuclear and conventional oil and coal plants. It is expected, barring major technological breakthroughs, that this competition will continue through the time horizon of ELSA.

To determine nuclear's share of the new thermal generating capacity a comparison is made between the expected cost of electricity production from nuclear generation and that from fossil generation. Figure 12 shows the functional relationship between the independent variable Nuclear's Cost Advantage (NCA) and the dependent variable Nuclear's Share of the New Thermal Base Load Market (NSNTBM). Nuclear's Cost Advantage (NCA) is a function of the expected cost of power from the various generating sources and is computed as:

$$NCA = \frac{ECFFP - ECNP}{ECFFP}$$

$$ECFFP = \text{MIN} (ECPO, ECPC)$$

where:

NCA = Nuclear's Cost Advantage

ECFFP = Expected Cost of Fossil Power

ECNP = Expected Cost of Nuclear Power

ECPC = Expected Cost of Power from Coal

ECPO = Expected Cost of Power from Oil

As Figure 12 shows, if Nuclear's Cost Advantage is zero then the new thermal base load market is divided equally between nuclear capacity and fossil capacity. The slope of the curve shown in Figure 12 is an indication of the elasticity of substitution between the two types of generation. If the expected cost of nuclear power was to decrease by 10% while the expected cost of fossil power remained constant, Nuclear's Share of the New Thermal Base Load Market would increase by 15%.

FIGURE 12. Nuclear's Share of the New Thermal Base Load Market as a Function of Nuclear's Cost Advantage (1,AZ-8)

Thus ELSA uses an elasticity of substitution of 1.5%. This compares with Ford's ELECTRIC2 model which uses an elasticity of substitution between nuclear and fossil power of 1%. (1,p.150)

The Nuclear Capacity Initiation (NCIR) rate can now be determined as

$$NCIR = TBCIR * NSNTBM$$

where

$$\begin{aligned} TBCIR &= \text{Thermal Base Load Capacity Initiation Rate} \\ &= TCIR - GCIR \end{aligned}$$

$$NSNTBM = \text{Nuclear's Share of the New Thermal Base Load Market}$$

The Fossil Fuel Capacity Initiation Rate (FFCIR) can now be determined as the difference between the Thermal Base Load Capacity Initiation Rate (TBCIR) and Nuclear's Capacity Initiation Rate (NCIR).

$$FFCIR = TBCIR - NCIR$$

The Fossil Fuel Capacity Initiation Rate (FFCIR) will be divided between coal and oil fired generating facilities. The variable Coal's Share of the New Fossil Fuel Market (CSNFM) is determined first. This variable is a function of two parameters: Coal's Share of the Existing Fossil Fuel Market (CSEFM) and Coals Gain in Share of the New Fossil Fuel Market (CGSNFM). The first of these two variables (CSEFM) is computed as:

$$CSEFM = COALFC / (COALFC + OILFC)$$

where

COALFC = Coals fired generating capacity (kW).

OILFC = Oil fired generating capacity (kW).

Coal's Gain in Share of the New Fossil Fuel Market (CGSNFM) is a function of Coal's Cost Advantage over oil (CCA) and is shown in Figure E-3 of Appendix E. Coal's Cost Advantage over oil is calculated as the difference between the delivered price of oil and the delivered price of coal. Coal's Share of the New Fossil Fuel Market (CSNFM) is then computed as the sum of CSEFM and CGSNFM. Ford justifies the definitions of CSEFM and CGSNFM in computing CSNFM as follows:

"This assumption is based on the judgment that the changeover costs^(a) are sufficiently large that coal burning utilities will continue to order new coal plants and oil and gas burning utilities will continue to order new oil and gas plants as long as the cost difference between fossil fuels is negligible." (1,p.151)

The coal capacity initiations rate (CCIR) and the oil capacity initiation rate (OCIR) can be determined from coal's share of new fossil market (CSNFM) and the fossil fuel capacity initiation rate (FFCIR). The equations for these two calculations are:

$$CCIR = FFCIR * CSNFM$$

$$OCIR = FFCIR * (1 - CSNFM).$$

(a) Changeover costs do not refer to the costs of converting existing plants from one fossil fuel to another, but rather to the extra costs or inconveniences of developing an operating relationship with a new supplier of fuel for a power plant in the future.

At this point the mix of generating capacities which can be financed has been determined. The last set of calculations which must be performed include this new capacity in the planning and construction queues. The time interval between the decision to build a plant and the time when the plant comes on line is simulated in ELSA with a third order delay.⁽¹¹⁾ The length of the planning and construction delays vary depending on the type of plant to be built. Combustion turbines have a delay time of 3 years while nuclear plants have a delay of 11 years. The output of the delay for a given type of generating capacity minus the capacity retired gives the change in the level of output during the next time period in the simulation.

MODEL BEHAVIOR AND SIMULATION RESULTS

ELSA is currently being used to examine the effects of various scenarios on the future electric supply system in the Pacific Northwest. As mentioned earlier, however, ELSA is being updated as better information becomes available and as the structure and interactions within the electric supply system are more clearly defined. For these reasons the simulation results presented in this section should be viewed as preliminary. It is hoped that they will elicit useful comments from readers which can help guide future modifications. The real significance in the results lies more in the relative difference between scenarios rather than in the absolute magnitudes calculated.

The base case for these simulations is the 4.4% load growth forecast developed by the Pacific Northwest Utilities Conference Committee (PNUCC).⁽⁵⁾ To show the effects of other electricity load growth rates a higher and a lower growth rate are also simulated. Seven percent is used as the upper bound and 2% is used as the lower bound. The upper bound of 7% is a much higher growth rate than is currently forecasted for the Pacific Northwest. It should be noted, however, that over the period 1959-1960 to 1969-1970 the Region's load growth (average energy basis) was typically 7.8%/yr. The 2% growth case could only be brought about by extensive conservation measures and, due to the projected population increase, is unlikely.⁽¹⁴⁾ These two growth rates thus form a reasonable band on probable load growths which could be experienced in the Region.

Also accepted as a "known" for the base case is the growth of hydroelectric generating capacity. Both the forecasted load growth and the projected hydroelectric generating capacity were given in Tables 2 and 3 for average and peak energy respectively. As shown in Table 2, the average hydroelectric energy available during a period of critical streamflow is about 12,000 MW/yr. In an average year this value would be about 16,000 MW or 33% higher.

The first set of simulation results presented in this section shows the effects of the high, low, and base case load growth assuming average streamflow conditions. The second set of results shows the effects of the same

three load growth rates with the added assumption of critical year streamflow. The third and last set of runs show the behavior of the model assuming no nuclear option is available in the Pacific Northwest. All prices of electricity presented in this section are in constant 1975 dollars.

Figure 13 shows the average delivered prices of electricity for the three load growth rates assuming average streamflow. For the period from 1975 to 1985 the price for the 2% growth scenario is higher than for the other two cases. The reason for this is that the rather sudden lowering of the load growth results in an oversupply of generating capacity which is not required to meet the load but still must be repaid and maintained. Beyond 1985 the price calculated for the 2% growth case is lower than the prices calculated for the two higher load growth cases. The main reason for this is that the system can continue to rely to a much greater extent on lower cost hydroelectric power through the time horizon of the simulation. Similar reasoning explains why the price of electricity for the 7% load growth scenario is higher than that calculated for the base case, i.e., increasing dependence on more expensive thermally generated power.

Figure 14 shows the reserve capacities predicted for each of the three growth scenarios. As was mentioned previously the reserve capacity is calculated as a function of the installed generating capacity and the peak demand for power. For example, the desired reserve capacity of the system in 1985 is about 14% because hydroelectric generating capacity will still account for about 75% of the installed capacity. The abundance of hydroelectric generating capacity to meet peaking demands causes the reserve capacities in the base case and the 2% growth case to be quite adequate in meeting the forecasted load. For the 7% growth scenario the reserve capacity drops close to zero by 1985 and does not recover until about 1990.

The wide fluctuations of reserve capacity shown in the 2% and the 7% growth cases would be unlikely to occur. If reserve capacity began to increase to the extent shown in the 2% growth case, utilities could delay new plant construction schedules. This mechanism is not presently included in the ELSA model. If reserve capacity began to decrease as shown in the 7%

FIGURE 13. Prices of Electricity Assuming Average Streamflow Conditions

FIGURE 14. Electrical Reserve Capacity Assuming Average Streamflow Conditions

growth scenario, utilities could shed interruptible loads. Also, in the present formulation ELSA allows combustion turbine capacity to be used in relatively small amounts corresponding to use for peaking applications only. Future developments will allow ELSA to simulate a policy of installing combustion turbine generating capacity to meet base and intermediate loads. Combustion turbines have a relatively short construction time compared with other types of generating capacity and, as a result, could be built in time to help alleviate the shortage.

Also, no account is taken of the feedback effects of price on utility load growth in the present formulation. An endogenous demand influenced by price would tend to reduce the demand for electricity during periods of low reserve capacity.

Even though the hydroelectric generating capacity allows the system to maintain adequate reserves to meet peaking requirements for the two lower growth cases, the installed generating capacity falls short of the requirements to meet the growth in average energy load. PNUCC notes that through the year 1986-87 resources will not be capable of meeting projected energy loads should critical streamflows occur. In some of these years, energy loads may not even be met with average streamflows. (5,p.97)

The PNUCC analysis is consistent with the results shown in Figure 15 which gives the generation and forecasted electricity loads for the three scenarios as simulated by ELSA. Only in the 2% growth case does generation meet the forecasted load. In both the base case and the 7% growth case there is a discrepancy.

Figure 16 shows the mix of generating capacity through the time horizon of the simulation for the base case. This figure shows that hydroelectric generating capacity dominates the system through most of the simulation. It is not until about 1995 that thermal generation accounts for more than half of the installed generating capacity. As was mentioned previously, this heavy reliance on hydroelectric generation is the main reason for the low cost of electricity in the Region. The thermal capacity is split about evenly between coal and nuclear capacity.

FIGURE 15. Electrical Production versus Forecasted Load Assuming Average Streamflow Conditions

FIGURE 16. Mix of Generating Capacity Assuming Average Streamflow Conditions (Base Case)

Figure 17 gives a comparison of the busbar prices of electricity. Also included in Figure 17 are the transmission and distribution charges. Hydro-electric generation is the least expensive type of electrical generation. Coal-fired generation tends to be more expensive than nuclear throughout the simulation. The sharp rise in the price of electricity generated from coal during the period from 1970 to 1975 reflects the rapid increase in the price of coal during that period. Combustion turbine capacity produces the most expensive electricity. Again, the rapid increase in fossil fuel prices during the early 1970's increases the price of electricity during that period.

FIGURE 17. Busbar Electricity Price and Transmission and Distribution Costs

The second series of runs presented here simulate the behavior of the model assuming critical streamflow conditions. Under this assumption the maximum generation available from hydroelectric facilities is limited to about 12,000 MW. It is important to realize that the probability of critical streamflow conditions is fairly low. However, regional electric power planning is done assuming that an average of approximately 12,000 MW will be available from the Columbia River hydroelectric system.

Figure 18 shows the average delivered prices of electricity for the three growth cases. As before, the price of electricity calculated for the 2% growth case is lower than the prices for the other two cases. However, because there is less electricity generated by hydroelectric facilities, the price of electricity is higher in each case than in the corresponding scenario assuming average streamflow. The prices of electricity for each of these three growth scenarios are about equal through the first 10 years of growth. The reason for this is that a shortage of electrical generating capacity exists during these years in all three scenarios. This means that all the available generating capacity is operating at close to its maximum capacity factor in all three cases. Also, the installed generating capacities for all three scenarios are still about the same through 1985 since the time required for construction of base load facilities is about 10 years.

For the 7% load growth, the price of electricity is higher than that calculated for the base case for about 10 years beginning in 1985. After 1995 the price of electricity in the 7% growth case is actually lower than that computed for the base case. This result is due in part to the method used to calculate the price of electricity.

FIGURE 18. Price of Electricity Assuming Critical Hydro Conditions

Recall that the system load factor is defined as:

$$SLF = \frac{EPRO}{IGC \cdot 8760}$$

where

SLF is the system load factor,

EPRO is the electrical production, and

IGC is the installed generating capacity.

This means that for the base case by the early 1990's sufficient generating capacity exists to meet demand and, with production from the plants decreasing, prices must rise to cover fixed costs.

The reserve capacity maintained under the three load growth scenarios under critical streamflow conditions is shown in Figure 19. As mentioned before, the wide fluctuations in reserve capacity would be highly unlikely in the real system.

The electrical production and load forecasts for the three scenarios assuming critical streamflow conditions are shown in Figure 20. In each case the discrepancy is greater than in the run made assuming average streamflow conditions.

The last scenario examined involves perturbing the base case by eliminating the nuclear option in the Pacific Northwest. The following assumptions are made:

- In January 1976, all initiation of new nuclear capacity is halted. Nuclear plants under construction at this time will be completed.

FIGURE 19. Reserve Capacity Assuming Critical Streamflow Conditions

FIGURE 20. Electrical Production versus Forecasted Load Growth
Assuming Critical Streamflow Conditions

- With no uranium to compete with coal for a share of thermal generation, the delivered price of coal will increase to compete with oil on an effective \$/Btu basis.
- Low sulfur oil suitable for combustion turbine operation will be available at an adjusted price set by the world crude oil price.

For this analysis the PNUCC 4.4% load growth forecast and the average year streamflow will again be designated as the base case. The two bracketing load growth cases of 7% and 2% are also identified for comparison.

Figure 21 shows the effect of this scenario on the prices of electricity calculated for the three growth cases. Compared with Figure 12 for cases with nuclear power available the prices are essentially shifted up a fixed increment in all three cases due to the need to rely on generation fired by the more expensive coal.

FIGURE 21. Price of Electricity Assuming No-Nuclear Option

Figure 22 shows the effects of the no-nuclear option scenario on the electrical reserve capacity. Compare with Figure 14 for cases with nuclear power available. The reserve capacity for the two bounding cases respond similarly. The reserve capacity in the 4.4% base case is actually better in this scenario than in the "Business as Usual" scenario. This is due to the difference in lead times between nuclear plants (11 years) and coal-fired plants (8 years).

Figure 23 shows the mix of installed generating capacity in the no-nuclear option scenario and, as is expected, coal-fired generating facilities take up the majority of the load lost by nuclear.

FIGURE 22. Electrical Reserve Capacity Assuming No-Nuclear Option

FIGURE 23. Mix of Generating Capacity Assuming No-Nuclear Option (Base Case)

It should be mentioned here that two important problems have not been considered by ELSA in running this scenario: the ability of the transportation system to supply the coal required and the implications of increased atmospheric emissions caused by the large number of coal plants.

For the base case in the no-nuclear option scenario, ELSA calculates a need for almost fifty 800 MWe coal-fired power plants by 1995. These coal plants will be required to generate over 200 billion kWh of energy. Assuming that these plants will be built in the West Group Region and burn coal from Montana and Wyoming (about 8780 Btu/lb)⁽¹⁵⁾ and that the plant heat rates are about 9875 Btu/kWh,^(16,pp.6-14) this will mean that approximately 115 million tons of coal per year will be required in the Region. Given unit trains carrying 10,500 tons/trainload,^(16,pp.6-17) almost 11,000 trains/yr will have to enter the Region. Counting arrivals and departures this is equivalent to approximately 60 trains/day. For perspective, the 115 million tons/yr consumption in 1995 can be compared to the 1975 total coal mining activity in Montana and Wyoming of approximately 45.8 million tons.⁽¹⁷⁾

The second factor which was excluded from this analysis is the impact of these coal plants on environmental quality. Table 4 lists some of the major air pollutants from the coal-fired generating plants. This table compares the residuals produced both in the base case "Business as Usual" scenario and the "No-nuclear Option" scenario. Table 4 is based on the assumption that the atmospheric emissions will be at rates comparable to the Federal "New Source Performance Standards." Actually, the emissions may be less depending on the quality of coal burned, future state emissions standards, and the application of control technology. For example the SO₂ emissions from the existing Colstrip 1 plant in Montana are about 40% of the Federal standards.

The supply requirements and pollution impacts are among many major questions which must be addressed when examining the impacts of various policies and scenarios. The ELSA simulation model is an initial building block in a larger model which will be useful in examining and assessing the impacts of various "futures" of the Region.

TABLE 4. Atmospheric Emissions (1995), tons/yr

	<u>Base Case</u>	<u>No-nuclear Option</u>
Particulates	47,000	99,000
NO _x	332,000	692,000
SO ₂	569,000	1,185,000
Basis: EPA New Source Performance Standards		

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APPENDIX A

CAPITAL COSTS

FIGURE A.1. Capital Cost of Hydroelectric Generation Capacity as a Function of Time
Source: BPA, 1975 (Ref.18,p.32)

FIGURE A.2. Capital Cost of Transmission and Distribution as a Function of Time
Source: Ford (Ref.1,p.A1-18)

FIGURE A.3. Capital Cost of Nuclear Generation Capacity as a Function of Time
 Source: 1965-1980: Ford (Ref.1,p.A1-16)
 1980-1990: WPPSS data 8/25/76 (Ref.19)

FIGURE A.4. Capital Cost of Combustion Turbine Generation Capacity as a Function of Time
 Source: (a) Bechtel (Ref.16,pp.6-8)
 (b) Energy 1990 Study (Ref.20,pp.1-50)

FIGURE A.5. Capital Cost of Coal Generation Capacity as a Function of Time
 Source: 1960-1975: Ford (Ref.1,p.A2-34)
 (a) Energy 1990 Study (Ref.20,pp.1-107)

FIGURE A.6. Capital Cost of Oil Generation Capacity as a Function of Time
 Source: 1960-1975: Ford (Ref.1,p.A2-34)

APPENDIX B

FUEL COSTS

FIGURE B.1. Delivered Price of Residual Fuel Oil as a Function of Time
 Source: (a) FPC(Ref.21)
 (b) FEA(Ref.13)

FIGURE B.2. Unit Fuel Costs for Nuclear as a Function of Time
 Source: (a) AEC (Ref.22,p.20)
 (b) Energy 1990 Study(Ref.20,pp.1-149)

FIGURE B.3. Delivered Price of Coal
as a Function of Time
Source: (a) FPC(Ref.21)
(b) FEA(Ref.13)
(c) Energy 1990 Study(Ref.20,pp.1-107)

APPENDIX C

OPERATION AND MAINTENANCE COSTS

FIGURE C.1. Unit Operation and Maintenance Costs for Nuclear Generation as a Function of Time
Source: (a) Energy 1990 Study(Ref.20,pp.1-149)

FIGURE C.2. Unit Operation and Maintenance Costs for Coal Generation as a Function of Time
Source: (a) Energy 1990 Study(Ref. 20,pp.1-107)

FIGURE C.3. Unit Operation and Maintenance Costs for Oil Generation as a Function of Time

FIGURE C.4. Unit Operation and Maintenance Costs for Combustion Turbines as a Function of Time
Source: (a) Energy 1990 Study(Ref. 20,pp.1-150)

APPENDIX D

HEAT RATES

FIGURE D.1. Heat Rate Coal Plants as a Function of Time
 Source: (a) FPC(Ref.21)
 (b) Energy 1990 Study(Ref.20,pp.1-107)

FIGURE D.2. Heat Rate for Combustion Turbines as a Function of Time

FIGURE D.3. Heat Rate Oil Plants as a Function of Time

APPENDIX E

FINANCIAL AND INTERFUEL COMPETITION VARIABLES

FIGURE E.1. Cost of Debt as a Function of Time
Source: Bureau of the Census(Ref.23,p.457)

FIGURE E.2. Length of Regulatory Lag as a Function of Time
Source: Ford(Ref.1,p.A1-32)

FIGURE E.3. Coal's Gain in Share of the New Fossil Fuel Market
Source: Ford (Ref.1,p.AZ-19)

FIGURE E.4. Fraction of Capacity Initiated as Combustion Turbines as a Function of Electrical Reserve Capacity
(See page 30)

FIGURE E.5. Average Load Factor as a Function of Reserve Capacity
Source: Ford(Ref.1,p.68)

FIGURE E.6. Average Life of Fossil Fuel Capacity as a Function of Reserve Capacity
Source: Ford(Ref.1,p.A1-6)

FIGURE E.7. Nuclear's Share of the New Thermal Base Load Market

FIGURE E.8. Fraction of External Funds Obtained as a Function of the Financial Ratio
Source: Ford(Ref.1,p.A1-33)

FIGURE E.9. Desired Reserve Capacity as a Function of Fraction of Generating Capacity Thermal
Source: For example, see Pacific Northwest River Basins Commission (Ref.5,p.96)

APPENDIX F

CONSTANTS USED IN ELSA

APPENDIX F

CONSTANTS USED IN ELSA

ALFBPL	- Average load factor based on peak load = 61%
GRAI	- Growth rate averaging interval = 5 years
ALTGCN	- Average lifetime of generating capacity normal = 40 years
RCAT	- Reserve capacity adjustment time = 5 years
ALHC	- Average lifetime of hydroelectric generating facilities = 50 years
HCCD	- Hydroelectric capacity construction time = 5 years
NCCD	- Nuclear capacity construction time = 11 years
CCCD	- Coal capacity construction time = 8 years
OCCD	- Oil capacity construction time = 8 years
GCCD	- Combustion turbine capacity construction time = 3 years
TAXR	- Tax rate = 20%
AR	- Annualization rate = 18%

HPY - Hours per year
= 8760

EALFN - Expected average load factor for nuclear
= 75%

EALFC - Expected average load factor for coal
= 75%

EALFO - Expected average load factor for oil
= 75%

CODAD - Cost of debt averaging delay
= 5 years

FIFR - Fraction of internal funds reinvested
= 50%

PYEAR1 - Policy year 1-Reduce regulatory lag to zero

PYEAR2 - Policy year 2-Set nuclear capacity initiation rate to zero

PYEAR3 - Include capacity under construction in rate base calculation

APPENDIX G

FORTRAN LISTING OF ELSA

SUBROUTINE ELSA

ELSA (ELECTRIC POWER SUPPLY ANALYSIS MODEL) IS A SIMULATION TOOL DEVELOPED TO FORECAST THE CHARACTERISTICS OF THE ELECTRICAL SUPPLY SYSTEM IN THE PACIFIC NORTHWEST. ELSA IS AN ADAPTATION OF THE ELECTRIC I-III SERIES OF NATIONAL ELECTRICAL UTILITY MODELS DEVELOPED BY ANDREW FORD AT THE THAYER SCHOOL OF ENGINEERING OF DARTMOUTH COLLEGE. FOR COMPLETE DOCUMENTATION OF THE FORD MODELS SEE "A DYNAMIC MODEL OF THE UNITED STATES ELECTRIC UTILITY INDUSTRY, 1950-2010." DSD-28, JUNE 1, 1975.

TIM HARRINGTON
JAY JACOBSEN

BATTELLE NORTHWEST
P.O. BOX 999
RICHLAND WASH.
99352

IMPLICIT REAL (A-Z)

```
REAL CDDT(11),HRCT(6),HROT(6),HRGT(6),LRLT(7),ALFT(21),
1  ALFECT(5),CCNT(11),CCCT(11),
2  CCHT(8),CCTDT(9),UFCNT(8),DPCT(9),DPOT(11),UOMCNT(6),
3  UOMCCT(6),UOMCOT(6),FEXFOT(7),PHCIRT(11),
4  NSBTAB(15),CGSTAB(11),DET(11),
5  CCOT(11),CCGT(11),DPGT(11),UOMCGT(6),FNTGTT(11)
```

INTEGER NCRDR,NPRNT,NNEOD,JJBEG

* COMMON AREAS *

RUN COMMON

```
COMMON /RUN/ NCRDR ,NPRNT ,NNEOD ,JJBEG ,TTBEG ,TNOW ,
1  TTFIN ,DTACC ,DTSAB ,
2  SS(100),DD(100),SSL(100),DDL(100)
```

INITIAL CONDITIONS

```
COMMON /INITC/ ERCI ,PDPI ,CIRI ,IPEI ,HYDROI,HCIRI ,
1  NUKEI ,NCIRI ,COALFI,CCIRI ,OILFCI,OCIRI ,
2  GASTGI,GCIRI
```

CONSTANTS USED IN ELSA

```
COMMON /ELCON/ ALFBPL,GRAI ,ALTGCN,RCAT ,ALHC ,HCCD ,
1  TAXRH ,ALNC ,NCCD ,TAXRN ,ALCC ,CCCD ,
2  TAXRC ,ALOC ,OCCD ,TAXRU ,ALGC ,GCCD ,
3  TAXRG ,TAI ,AR ,HPY ,EALFN ,EALFC ,
4  EALFO ,CODAD ,FIFR ,PYEAR1,PYEAR2,PYEAR3
```

FUNCTION TABLES-

```

COMMON /ELTABL/ CDDT ,HRCT ,HROT ,HRGT ,LRLT ,ALFT ,
1 ALFECT,CCNT ,CCCT ,CCHT ,CCTDT ,UFCNT ,
2 DPCT ,DPOT ,UOMCNT,UOMCCT,UOMCOT,FEXFOT,PHCIRT,
3 NSBTAB,CGSTAB,DET ,CCOT ,CCGT ,DPGT ,UOMCGT,
4 ENTGTT

```

```

COMMON /PLOT/ PRNT(7),P1(5),P2(4),P3(5),P4(6),P5(6)

```

```

STATE VARIABLES

```

```

EQUIVALENCE      (HYDRO ,SS( 1)),(NUKE ,SS( 2)),(COALFC,SS( 3)),
1 (OILFC ,SS( 4)),(GASTGC,SS( 5)),(INPE ,SS( 6))

```

```

STATE VARIABLES (SLOPES)

```

```

EQUIVALENCE      (HYDROD,DD( 1)),(NUKED ,DD( 2)),(COALFD,DD( 3)),
1 (OILFCD,DD( 4)),(GASTGC,DD( 5)),(INPED ,DD( 6))

```

```

RATES AND DELAYS (FIRST AND THIRD ORDER)

```

```

EQUIVALENCE      (PDPD ,SS( 9)),(COODD ,SS(10)),(ICCH ,SS(11)),
1 (AVREVM,SS(12)),(ICCN ,SS(13)),(AVREVN,SS(14)),
2 (ICCC ,SS(15)),(AVREVC,SS(16)),(ICCO ,SS(17)),
3 (AVREVC,SS(18)),(ICCG ,SS(19)),(AVREVG,SS(20)),
4 (ICCTD ,SS(21)),(PED ,SS(22)),(CIRS ,SS(23)),
5 (HCIRS ,SS(24)),(NCIRS ,SS(25)),(CCIRS ,SS(26)),
6 (OCIRS ,SS(27)),(GCIRS ,SS(28))

```

```

IF(JJBEG) 10,20,10

```

```

*****
*  INITIALIZATION  *
*****

```

```

10 PDP      = PDPI
   CIR      = CIRI
   IPE      = IPEI
   PE       = IPF
   HYDRO    = HYDROI
   HCIR     = HCIRI
   NUKE     = NUKEI
   NCIR     = NCIRI
   COALFC   = COALFI
   CCIR     = CCIRI
   OILFC    = OILFCI
   OCIR     = OCIRI
   GASTGC   = GASTGI
   GCIR     = GCIRI
   CDD      = GTABL(CDDT,TNOW,1950.,2000.,5.)*.01

```

```

GCCD = 2.

```

```

INPE      = 0.
HCIRP     = HCIR
NCIRP     = NCIR
CCIRP     = CCIR
OCIRP     = OCIR
GCIRP     = GCIR

```

```

CCH = GTABL(CCHT,TNOW,1950.,2020.,10.)
CCN = GTABL(CCNT,TNOW,1950.,2000.,5.)
CCC = GTABL(CCCT,TNOW,1950.,2000.,5.)
CCO = GTABL(COOT,TNOW,1950.,2000.,5.)
CCG = GTABL(CCGT,TNOW,1950.,2000.,5.)
CCTO = GTABL(CCTDT,TNOW,1950.,1990.,5.)

C
C *****
C * UPDATE AUXILIARY VARIABLES *
C *****
20 CONTINUE
C DEMAND FOR ELECTRICITY PACIFIC NORTHWEST PROJECTION
DE = GTABL(DET,TNOW,1950.,2000.,5.)

C
C PRODUCTION SECTOR
GC = HYDRO+NUKE+COALFC+OILFC+GASTGC
C CALCULATE EFFECTIVE GENERATING CAPACITY
EHYDRO = AMIN1(HYDRO,23.5)
EGC = EHYDRO+NUKE+COALFC+OILFC+GASTGC
CALL GOLAY(7,9,PDP,GRAI)
PDP = DE/(8.76*ALFBPL)
ERC = (GC - PDP)/PDP
EERC = (EGC-PDP)/PDP
ALF = GTABL(ALFT,ERC,-.2,.8,.05)

C
C MAIN STRUCTURE OF REGULATORY SECTOR
CALL GOLAY(10,10,COD,CODAD)
COD = GTABL(CODT,TNOW,1950.,2000.,5.)*.01
CODD = .CODDD
COMU = 1.3
C REGULATORY LAG
LRL = GTABL(LRLT,TNOW,1950.,1980.,5.)

C
C 1. HYDRO ELECTRIC GENERATING CAPACITY
C
EPROH = AMIN1(106.,ALF*HYDRO*8.76)
ALFH = EPROH/(HYDRO*8.76)
HCUC = SS(29)+SS(30)+SS(31)
CCAD = AMAX1(1.0,(HYDRO/(HCUC+1.E-5))*HCCD)
CALL GOLAY(11,11,CCH,CCAD)
CCHF = ICCH*HYDRO
CCH = GTABL(CCHT,TNOW,1950.,2020.,10.)
CBNH = CCH*HCUC/2.0
C CAPITAL BASE
IF(TNOW.LT.PYEAR3) CBNH = 0.0
CBH = CREH+CBNH
REVH = PE*EPROH
CALL GOLAY(12,12,REVH,TAI)
TAXH = TAXRH*AVREVH*.30
DCH = CBH/ALHC
TACH = TAXH+DCH
APGRH = COMU*CDD
CBH = CBH*.3

```

```

APROH = ARORH*CBH
AREVH = IACH+APROH
IPEH = 0.0
IF(EPROH .LE. 0.) GO TO 25
IPEH = AREVH/EPROH

C
C      2.      GAS TURBINE GENERATING CAPACITY
C
25      ALFG = .3-1.0*AMAX1(0.,AMIN1(ERC,.17))
      EPROG = ALFG*GASTGC*8.76
      GCUC = SS(41)+SS(42)+SS(43)
      CCAD = AMAX1(1.0,(GASTGC/(GCUC+1.E-5))*GCCD)
      CALL GDLAY(19,19,CCG,CCAD)
      CBEG = ICCG*GASTGC
      CCG = GTABL(CCGT,TNOW,1950.,2000.,5.0)
      DPG = GTABL(DPGT,TNOW,1950.,2000.,5.0)
      UOMCG = GTABL(UOMCGT,TNOW,1950.,2000.,10.)
      CBNG = CCG*GCUC/2.0
C      CAPITAL BASE
      IF(TNOW .LT. PYEAR3) CBNG = 0.0
      CRG = CBEG+CBNG
      REVG = PE*EPROG
      CALL GDLAY(20,20,REVG,TAI)
      TAXG = TAXRG*AVREVG
      HRG = GTABL(HRGT,TNOW,1950.,2000.,10.)
      UFOMG = UOMCG+(DPG*HRG/100000.)
      AFOMG = EPROG*UFOMG
      DCG = CBG/ALGC
      TACG = TAXG+DCG+AFOMG
      ARORG = CDMU*CODD
      APROG = ARORG*CBG
      AREVG = TACG+APROG
      IPEG = 0.
      IF(EPROG .LE. 0.) GO TO 30
      IPEG = AREVG/EPROG

C
C      CALCULATE LOAD FACTOR FOR BASE-LOAD THERMAL
      ALFBT = AMIN1(.75,(DE-(HYDRG*ALFH+GASTGC*ALFG)*8.76)/
1      ((NUKE+COALFC+OILFC)*8.760))

C
C      3.      NUCLEAR GENERATING CAPACITY
C
30      ALFN = ALFBT
      EPRON = ALFN*NUKE*8.76
      NCUC = SS(32)+SS(33)+SS(34)
      CCAD = AMAX1(1.0,(NUKE/(NCUC+1.E-5))*NCCD)
      CALL GDLAY(13,13,CCN,CCAD)
      CBEN = ICCN*NUKE
      CCN = GTABL(CCNT,TNOW,1950.,2000.,5.0)
      UFCN = GTABL(UFCNT,TNOW,1950.,2020.,10.0)
      UOMCN = GTABL(UOMCNT,TNOW,1950.,2000.,10.)
      CBNN = CCN*NCUC/2.0
C      CAPITAL BASE

```

```
IF(TNOW .LT. PYEAR3) CBNV = 0.0
```

```
CBN = CBNV+CBNV
```

```
REVN = PE*EPRN
```

```
CALL GDLAY(14,14,REVN,TAI)
```

```
TAXN = TAXRN*AVREVN
```

```
UFOMN = UOMCN+UFON
```

```
AFOMN = EPRN*UFOMN
```

```
DCN = CBN/ALNC
```

```
TACN = TAXN+DCN+AFOMN
```

```
ARORN = CDMU*CODD
```

```
APRON = ARORN+CBN
```

```
AREVN = TACN+APRON
```

```
IPEN = 0.0
```

```
IF(EPRN .LE. 0.) GO TO 35
```

```
IPEN = AREVN/EPRN
```

```
C
```

```
C
```

```
C
```

```
35
```

4. COAL FIRED GENERATING CAPACITY

```
ALFC = ALFBT
```

```
EPROC = ALFC*COALFC*8.76
```

```
CCUC = SS(35)+SS(36)+SS(37)
```

```
CCAD = AMAX1(1.0,(COALFC/(CCUC+1.E-5))*CCUC)
```

```
CALL GDLAY(15,15,CCUC,CCAD)
```

```
CREC = ICC*COALFC
```

```
CCC = GTABL(CCCT,TNOW,1950.,2000.,5.0)
```

```
DPC = GTABL(DPCT,TNOW,1950.,1990.,5.0)
```

```
UOMCC = GTABL(UOMCCT,TNOW,1950.,2000.,10.)
```

```
CBNC = CCC*CCUC/2.0
```

```
C
```

CAPITAL BASE

```
IF(TNOW .LT. PYEAR3) CBNC = 0.0
```

```
CBC = CREC+CBNC
```

```
REVC = PE*EPROC
```

```
CALL GDLAY(16,16,REVC,TAI)
```

```
TAXC = TAXRC*AVREVC
```

```
HRC = GTABL(HRCT,TNOW,1950.,2000.,10.)
```

```
UFOMC = UOMCC+(DPC*HRC/100000.)
```

```
AFOMC = EPROC*UFOMC
```

```
DCC = CBC/ALCC
```

```
TACC = TAXC+DCC+AFOMC
```

```
ARORC = COMU*CODD
```

```
APROC = ARORC+CBC
```

```
AREVC = TACC+APROC
```

```
IPEC = 0.
```

```
IF(EPROC .LE. 0.) GO TO 40
```

```
IPEC = AREVC/EPROC
```

```
C
```

```
C
```

```
C
```

```
40
```

5. OIL FIRED GENERATING CAPACITY

```
ALFO = ALFBT
```

```
EPROC = ALFO*OILFC*8.76
```

```
CCUC = SS(38)+SS(39)+SS(40)
```

```
CCAD = AMAX1(1.0,(OILFC/(CCUC+1.E-5))*CCUC)
```

```
CALL GDLAY(17,17,CCUC,CCAD)
```



```

      CBEO = ICCO*GILFC
      CCO = GTABL(CCOT,TNOW,1950.,2000.,5.0)
      DPO = GTABL(DPOT,TNOW,1950.,2000.,5.0)
      UOMCO = GTABL(UOMCOT,TNOW,1950.,2000.,10.)
      CBNO = CCO*OCUC/2.0
C     CAPITAL BASE
      IF(TNOW .LT. PYEAR3) CSNO = 0.0
      CBO = CBEO+CBNO
      REVO = PE*EPROO
      CALL GDLAY(18,18,REVO,TAI)
      TAXO = TAXRG*AVREVO
      HRO = GTABL(HROT,TNOW,1950.,2000.,10.)
      UFOMO = UOMCO+(DPO*HRO/100000.)
      AFOMO = EPROO*UFOMO
      DCO = CBO/ALOC
      TACO = TAXO+DCO+AFOMO
      APORO = CDMU*CODD
      APRRO = APORO*CBO
      AREVO = TACO+APROO
      IPEO = 0.
      IF(EPROO .LE. 0.) GO TO 45
      IPEO = AREVO/EPROO
C
C     ELECTRIC POWER INDUSTRY PRICING SECTOR
C
45    CONTINUE
C
C     COMPUTE TOTAL ELECTRICAL PRODUCTION
      EPRO = EPROH+EPRON+EPROC+EPROO+EPROG
C
C     COMPUTE PRICE CONTRIBUTION FOR TRANSMISSION DISTRIBUTION
C     SIMULATE S.P.A.
      CCAO = 7.
      CALL GDLAY(21,21,CCTD,CCAO)
      CCTD = GTABL(CCTDT,TNOW,1950.,1990.,5.)
      CRTD = ICCTD*GC
      DCTD = CRTD/30.
      TACTD = DCTD
      APRDRTD = CDMU*CODD
      CBTD = CRTD*.5
      APRDRTD = APRDRTD*CBTD
      IPETD = (TACTD+APRDRTD)/EPRO
C
C     SET PRICE OF ELECTRICITY
      CALL GDLAY(22,22,IPE,LRL)
      IPE = (IPEH*EPROH+IPEH*EPRON+IPEC*EPROC+IPEC*EPROO+
1      IPEG*EPROG+IPETD*EPRO)/EPRO
      PE = IPE
      IF(TNOW .LT. PYEAR1) PE=PED
C
C     DETERMINE REVENUE
      REV = PE*EPRO
      TAC = TACH+TACN+TACC+TACD+TACG+TACTD

```

```

PROAT  = REV-TAC
CP      = CRH+CBN+CHC+CHO+CPG+CBD
DC      = DCH+DCN+DCC+DCO+DCG+DCTD
RORC    = PROAT/CP

```

C

C

```

PLANNING OF NEW CONSTRUCTION
PDGR    = (PDP-PDPD)/(GRAI*(PDP+PDPD)/2.)
PDGR    = PDGR
CUC      = NCUC+HCUC+CCUC+OCUC+GCUC
CRLGT    = (GC + CUC)/ALTGCN + PDGR*(GC+CUC)
ALFFC    = GTABL(ALFFCT,ERC,0.0,.4,.1)
FGCT     = (NUKE+COALFC+OILFC+GASTGC)/GC
DRC      = .08*FGCT+.12
EXGC     = (EERC-DRC)*GC
ACIRC    = -EXGC/RCAT
CIRD     = AMAX1(1.E-5,CRLGT+ACIRC)

```

C

C

```

FINANCING OF NEW CONSTRUCTION
FR       = RORC/COD
FEXFO    = GTABL(FEXFOT,FR,.7,1.3,.1)
CALL GDLAY(23,23,CIR,2.0)
CALL GDLAY(24,24,HCIR,2.0)
CALL GDLAY(25,25,NCIR,2.0)
CALL GDLAY(26,26,CCIR,2.0)
CALL GDLAY(27,27,OCIR,2.0)
CALL GDLAY(28,28,GCIR,2.0)
WHYDRO   = HCIRS/CIRS
WNUKE    = NCIRS/CIRS
WCOAL    = CCIRS/CIRS
WOIL     = OCIRS/CIRS
WGAST    = GCIRS/CIRS
WCHK     = WHYDRO+WNUKE+WCOAL+WOIL+WGAST
WEIGHTED CAPITAL COSTS
WCC      = CCTD+CCH*WHYDRO+CCN*WNUKE+CCC*WCOAL+CCO*WOIL+CCG*WGAST
FINREQ   = CIRD*WCC
SINF     = PROAT+DC
INTFIN   = FIFR*SINF
EXTFR    = AMAX1(0.0001,FINREQ-INTFIN)
EXTFO    = FEXFO*EXTFR
FINO     = INTFIN+EXTFO
FPCF     = AMIN1(1.0,FINO/FINREQ)
FMIXR    = INTFIN/FINO
PHCIR    = GTABL(PHCIR,TNOW,1950.,2000.,5.)
CIP      = AMAX1(PHCIR,CIRD*FPCF)

```

C

C

```

EXPECTED COST OF POWER -- NUCLEAR, COAL, OIL AND GAS
EUCCN    = (CCN*AR*1000.)/(EALFN*HPY)
ECCN     = EUCCN+UOMCN+UECN
EUCCC    = (CCC*AR*1000.)/(EALFC*HPY)
EUFCO    = DPC*HRC/100000.
EOPC     = EUCCC+UOMCC+EUFCO
EUCCO    = (CCO*AR*1000.)/(EALFO*HPY)
EUFON    = DPO*HRO/100000.

```

```

      ECPO      = EUCCO+UOMCO+EHFCO
      ECFFP     = AMIN1(ECPC,ECPO)

C
C  CHOICE OF FUELS SECTOR
C  HYDRO GENERATING CAPACITY
      HCIR      = AMIN1(PHCIR,CIR)

C
C  GAS TURBINES ...
C  FRACTION OF NEW THERMAL CONSTRUCTION IN GAS TURBINES
      FNTGT = GTABL(FNTGIT,(DRC-ERC)/DRC,0.,1.,.1)
      GCIR = FNTGT*(CIR-HCIR)

C
C  NUCLEAR POWER
      TCIR     = CIR-HCIR-GCIR
      NSNTBM   = GTABL(NSBTAB,(ECFFP-ECNP)/ECFFP,-.7,.7,.1)
      NCIR     = TCIR*NSNTBM
      IF(TNOW .GE. PYEAR2) NCIR = 0.0
      IF(TNOW .GE. 1993.) CCCC = 12.0
      ALTNC    = ALFFC

C
C  COMPETITION BETWEEN COAL AND OIL-GAS
      FFCIR    = TCIR-NCIR
      CSEFM    = COALFC/(COALFC+OILFC)
      CCA      = DPO-DPC
      CGSNFM   = GTABL(CGSTAB,CCA,-50.,50.,10.)
      CSNFM    = AMAX1(0.0,AMIN1(1.0,CSEFM+CGSNFM))
      CCIR     = FFCIR*CSNFM
      OCIR     = FFCIR*(1.-CSNFM)

C
C  *****
C  * CALCULATE RATES *
C  *****

C  HCOLR --- HYDRO CAPACITY ON LINE RATE (MILLION KW/YR)
50 HCOLR = DELAY(29,31,HCIRR,HCCD)
C  HCIRR --- HYDRO CAPACITY INITIATION RATE (MILLION KW/YR)
      HCIRP   = HCIR
C  HCDR  --- HYDRO CAPACITY DEPRECIATION RATE (MILLION KW/YR)
      HCDR    = HYDRO/ALHC
C  NCDR  --- NUCLEAR CAPACITY DEPRECIATION RATE (MILLION KW/YR)
      NCDR    = NUKE/ALTNC
C  NCOLR --- NUCLEAR CAPACITY ONE LINE RATE (MILLION KW/YR)
      NCOLR   = DELAY(32,34,NCIRR,NCCD)
C  NCIRP --- NUCLEAR CAPACITY INITIATION RATE (MILLION KW/YR)
      NCIRP   = NCIR
C  CCOLR --- COAL CAPACITY ON LINE RATE (MILLION KW/YR)
      CCOLR   = DELAY(35,37,CCIRR,CCCD)
C  CCDR  --- COAL CAPACITY DEPRECIATION RATE (MILLION KW/YR)
      CCDR    = COALFC/ALFFC
C  CCIRP --- COAL CAPACITY INITIATION RATE
      CCIRP   = CCIR
C  OCOLR --- OIL CAPACITY ON LINE RATE (MILLION KW/YR)
      OCOLR   = DELAY(38,40,OCIRP,OCDD)
C  OCDR  --- OIL CAPACITY DEPRECIATION RATE (MILLION KW/YR)
      OCDR    = OILFC/ALFFC

```

```

C      OCIRR  --- OIL CAPACITY INITIATION RATE
C      OCIRR  = OCIR
C      GCOLR  --- GAS TURBINE CAPACITY ON LINE RATE (MILLION KW/YR)
C      GCOLR  = DELAY(41,43,GCIRR,GCCD)
C      GCDR   --- GAS TURBINE CAPACITY DEPRECIATION RATE (MILLION KW/YR)
C      GCDR   = GASTGC/ALGC
C      GCIRR  --- GAS TURBINE CAPACITY INITIATION RATE
C      GCIRR  = GCIR

C
C      *****
C      * UPDATE STATE VARIABLES *
C      *****
C      HYDRO  --- HYDRO GENERATING CAPACITY (MILLION KW)
C**     HYDRO  = HYDRO+DTNOW*(HCOLR-HCDR)
C      HYDROD = HCOLR-HCDR
C      NUKE   --- NUCLEAR GENERATING CAPACITY (MILLION KW)
C**     NUKE   = NUKE+DTNOW*(NCOLR-NCDR)
C      NUKED  = NCOLR-NCDR
C      COALFC --- COAL GENERATING CAPACITY (MILLION KW)
C**     COALFC = COALFC+DTNOW*(CCOLR-CCDR)
C      COALFD = CCOLR-CCDR
C      OILFC  --- OIL GENERATING CAPACITY (MILLION KW)
C**     OILFC  = OILFC+DTNOW*(OCOLR-OCDR)
C      OILFCD = OCOLR-OCDR
C      GASTGC --- GAS TURBINE GENERATING CAPACITY (MILLION KW)
C      GASTGC = GASTGC+DTNOW*(GCOLR-GCDR)
C      GASTGD = GCOLR-GCDR
C**     INTEGRATE COST
C      IMPE   = IMPE + DTNOW*(PE*EPRO)
C      INPED  = PE*EPRO

C
C      SET SOME PLOT VARIABLES
C      PRNT(1) = IMPE
C      PRNT(2) = CIR
C      PRNT(3) = CB
C      PRNT(4) = REV
C      PRNT(5) = TAC
C      PRNT(6) = EPRO-DE

C
C      P1(1)  = ERC
C      P1(2)  = PE
C      P1(3)  = IPE
C      P1(4)  = ROFC
C      P1(5)  = FPCF

C
C      P2(1)  = DE
C      P2(2)  = GC
C      P2(3)  = PDP
C      P2(4)  = EPRO

C
C      P3(1)  = ALFH*HYDRO
C      P3(2)  = ALFET*NUKE
C      P3(3)  = ALFET*COALFC
C      P3(4)  = ALFG*GASTGC

```

```
      P4(5) = P3(1)+P3(2)+P3(3)+P3(4)
      PENT(7) = P3(5)-POP*ALFRPL
C
      P4(1) = GC
      P4(2) = HYDRO
      P4(3) = NUKE
      P4(4) = COALFC
      P4(5) = OILFC
      P4(6) = GASTGC
C
      P5(1) = IPEH
      P5(2) = IPEN
      P5(3) = IPFC
      P5(4) = IPEO
      P5(5) = IPEG
      P5(6) = IPETD
C
      RETURN
      END
```

BLOCK DATA

THIS BLOCK DATA SETS UP THE FUNCTION TABLES FOR ELSA

.....NOTE:

ALL COSTS IN THIS DATA SET ARE IN 1975 DOLLARS
TIM HARRINGTON JAY JACOBSEN

IMPLICIT REAL (A-Z)

```

REAL CCOT(11),HRCT(6),HROT(6),HRGT(6),LRLT(7),ALFT(21),
1  ALFECT(5),CCNT(11),CCCT(11),
2  CCHT(8),CCTDT(9),UFCNT(8),DPCT(9),DPOT(11),UOMCNT(6),
3  UOMCCT(6),UOMCOT(6),FEXFOT(7),PHCIPT(11),
4  NSBTAB(15),CGSTAB(11),DET(11),
5  CCOT(11),CCGT(11),DPGT(11),UOMCGT(6),FMTGTT(11)

```

FUNCTION TABLES

```

COMMON /ELTAB/ CCOT ,HRCT ,HROT ,HRGT ,LRLT ,ALFT ,
1  ALFECT,CCNT ,CCCT ,CCHT ,CCTDT ,UFCNT ,
2  DPCT ,DPOT ,UOMCNT,UOMCCT,UOMCOT,FEXFOT,PHCIPT,
3  NSBTAB,CGSTAB,DET ,CCOT ,CCGT ,DPGT ,UOMCGT,
4  FMTGTT

```

* FUNCTION TABLES *

```

DET      - DEMAND FOR ELECTRICITY (BILLION KWH/YR)
DATA DET /25.,35.,50.,70.,97.6,126.,169.,202.8,250.6,312.9,370./
CCOT     - COST OF UTILITY DEBT (%/YEAR)
DATA CCOT /2.0,2.8,4.2,4.4,7.7,7.8,7.8,7.8,7.8,7.8,7.8/
HRCT     - HEAT RATE FOR COAL PLANTS (BTU/KWH)
DATA HRCT /14000.,10500.,10000.,9700.,9500.,9500./
HROT     - HEAT RATE FOR OIL PLANTS (BTU/KWH)
DATA HROT /14000.,10500.,10000.,9700.,9500.,9500./
HRGT     - HEAT RATE FOR COMBUSTION TURBINES (BTU/KWH)
DATA HRGT /15000.,13300.,12000.,11600.,11400.,11300./
LRLT     - LENGTH OF REGULATORY LAG (YEARS)
DATA LRLT /12.,12.,10.,6.,1.5,1.0,1.0/
ALFT     - AVERAGE LOAD FACTOR (%) /100.
DATA ALFT /.66,.655,.65,.63,.62,.6,.58,.565,.54,.52,.5,.48,
1 .464,.448,.433,.419,.406,.393,.382,.371,.36/
ALFECT   - AVERAGE LIFE OF FOSSIL FUEL CAPACITY (YEARS)
DATA ALFECT /40.,35.,30.,25.,20./
CCNT     - CAPITAL COST OF NUCLEAR GENERATION ($/KW) AUG. 1976
DATA CCNT /1000.,1900.,500.,410.,410.,500.,630.,640.,640.,
1 640.,640./
CCCT     - CAPITAL COST OF COAL-FIRED CAPACITY ($/KW) AUG 1976
DATA CCCT /510.,380.,310.,250.,315.,380.,440.,460.,460.,
1 460.,460./
CCOT     - CAPITAL COST OF OIL-FIRED CAPACITY ($/KW) AUG 1976
DATA CCOT /459.,342.,279.,225.,243.,342.,396.,414.,414.,
1 414.,414./
CCGT     - CAPITAL COST OF COMBUSTION TURBINES ($/KW)

```

```

DATA CCGT /300.,270.,245.,230.,185.,135.,165.,165.,165.,
1 165.,165./
C CCHT - CAPITAL COST OF HYDRO GEN CAP. ($/KW) AUG 1976
DATA CCHT /400.,420.,500.,540.,540.,540.,540.,540./
C CCTDT - CAPITAL COST FOR TRANSMISSION AND DISTRIBUTION
C ($/KW) AUG 1976
DATA CCTDT /550.,435.,335.,300.,335.,365.,375.,375.,375./
C UFCNT - UNIT FUEL COSTS FOR NUCLEAR (MILLS/KWH) AUG 1976
DATA UFCNT /10.0,5.8,3.7,3.6,5.2,5.2,5.2,5.2/
C DPCT - DELIVERED PRICE OF COAL (CENTS/MBTU)
DATA DPCT /25.,25.,25.,25.,30.,114.,114.,114.,114./
C DPOT - DELIVERED PRICE OF OIL (CENTS/MBTU)
DATA DPOT /50.,52.,55.,60.,65.,200.,250.,250.,250.,250./
C DPGT - DELIVERED PRICE 2 FUEL OIL FOR GAS TURBINES
C (CENTS/MBTU)
DATA DPGT /50.,52.,55.,60.,65.,200.,250.,250.,250.,250./
C UOMCNT - UNIT O-M COST FOR NUCLEAR (MILLS/KWH) AUG 1976
DATA UOMCNT /10.,2.1,1.25,1.5,1.5,1.5/
C UOMCCT - UNIT O-M COSTS FOR COAL-FIRED CAPACITY (MILLS/KWH)
C AUG 1976
DATA UOMCCT /1.25,1.15,1.15,1.2,1.2,1.2/
C UOMCOT - UNIT O-M COSTS FOR OIL FIRED CAPACITY (MILLS/KWH)
C AUG 1976
DATA UOMCOT /1.15,1.05,1.05,1.1,1.1,1.1/
C UOMCGT - UNIT O-M COSTS FOR GAS TURBINES (MILLS/KWH)
DATA UOMCGT /1.5,1.5,1.5,1.5,1.5,1.5/
C FEXFOT - FRACTION OF EXTERNAL FUNDS OBTAINED
DATA FEXFOT /.25,.5,.75,1.0,1.0,1.0,1.0/
C PHCIRT - POTENTIAL HYDRO CAP. INITIATION RATE (MILLION KW/YR)
DATA PHCIRT /.2,1.05,0.0,2.8,0.0,3.0,0.0,.68,.68,.68,.68/
DATA FNTGTT /.05,.05,.05,.05,.05,.05,.06,.07,.08,.09,.1/
C NSBTAB - NUCLEAR S SHARE OF THE NEW THERMAL, BASE LOAD MARKET
DATA NSBTAB /0.,0.,0.,.02,.05,.2,.35,.5,.65,.8,.95,
1 .98,1.0,1.0,1.0/
C CGSTAB - COAL'S GAIN IN SHARE OF THE NEW FOSSIL FUEL MARKET
DATA CGSTAB /-1.2,-.8,-.45,-.2,-.1,0.,.1,.2,.45,.8,1.2/
END

```

SUBROUTINE TITLE
 IMPLICIT REAL (A-Z)

 * COMMON AREAS *

INITIAL CONDITIONS

COMMON /INITC/ ERCI ,POPI ,CIRI ,IPFI ,HYDROI,HCIRI ,
 1 NUKEI ,NCIRI ,COALFI,CCIRI ,OILFCI,OCIRI ,
 2 GASIGI,GCIRI

CONSTANTS USED IN ELSA

COMMON /ELCON/ ALFBPL,GRAI ,ALTGCN,RCAT ,ALPC ,HCCD ,
 1 TAXRH ,ALNC ,HCCD ,TAXRN ,ALCC ,CCCD ,
 2 TAXRC ,ALDC ,HCCD ,TAXRO ,ALGO ,GCCD ,
 3 TAXRG ,TAI ,AR ,HPY ,EALFN ,EALFC ,
 4 EALFO ,CODAO ,FIER ,PYEAR1,PYEAR2,PYEAR3

ERCI = .2
 POPI = 1.59
 CIRI = 1.56
 IPFI = 15.00
 HYDROI = 5.0
 HCIRI = 1.5
 NUKEI = 0.
 NCIRI = 0.
 COALFI = .2
 CCIRI = .03
 OILFCI = 0.0
 OCIRI = .0
 GASIGI = 0.07
 GCIRI = 0.03
 ALFBPL = .05
 GRAI = 5.0
 ALTGCN = 40.0
 RCAT = 5.0
 HCCD = 5.0
 ALPC = 50.0
 HCCD = 11.0
 AR = .13
 HPY = 8750.
 EALFN = .75
 EALFC = .75
 EALFO = .75
 CCCD = 8.0
 HCCD = 8.0
 HCCD = 2.0
 TAXRH = .2
 TAXRN = .2
 TAXRC = .2
 TAXRO = .2
 TAXRG = .2
 ALCC = 50.0
 ALDC = 50.0

ALGO = 50.0
TAX = 2.0
COSTAD = 7.0
FTR = .5
PYEAR1 = 3000.
PYEAR2 = 3000.
PYEAR3 = 3000.

C

RETURN
END

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